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VIA ELECTRONIC FILING

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

Attention: Filing Center

RE: UM 2005 – PacifiCorp Response to Oregon Public Utility Commission Staff's Utility Survey (Section A through C) and Stakeholder Survey (Section D)

Attached for filing is PacifiCorp's d/b/a Pacific Power Response to Staff's Utility Survey and Stakeholder Survey in the above-referenced docket.

If you have questions about this filing, please contact Cathie Allen, Regulatory Affairs Manager, at (503) 813-5934.

Sincerely,

Etta Lockey
Vice President, Regulation

Enclosures

Section A

In Section A of your response, please provide the following information about the current distribution plans, reports, and other relevant components of distribution system planning:

Question A.1

1) Strategy: Please include an overview of the utility's approach to distribution system planning, including:

a. What are the utility's planning goals? What are the major planning objectives?

Response: PacifiCorp's distribution system planning goals, like other planning goals, align with state commission policy of encouraging safe, reliable, affordable electric service to all customers in a least-cost, least-risk manner.

There are two types of formal planning for transmission and distribution (T&D) systems—scheduled and ad-hoc—and their objectives are similar. Scheduled planning is cyclical in nature, and generally covers a large geographic area. For example, if load growth activity is high in a given planning area, that whole area might be studied every two years, while less active areas might be studied every five years.

Ad-hoc planning is typically driven by a load, generation interconnection service, or transmission service request. This type of study is generally focused on a limited area, and the immediate effects of the request on reliability and load service.

b. Which objectives are primary vs secondary?

Response: In each case, the primary objective of the planning process is simply to determine the condition of the system at a future state, and to address any shortcomings associated with that future condition. Where issues are found to exist in the future system model, solutions are developed, compared and proposed in the completed study. All solution alternatives are developed in order to maintain safe, reliable delivery of energy under normal operating conditions. Each proposed solution is accompanied by its purpose and necessity (P&N). For an ad-hoc study, the P&N becomes part of the discussion with the customer making the request. For a scheduled study, the P&N is used in the budgeting process to prioritize the proposed work. Development of solutions also entails determining cost causation—system-driven costs or costs driven by individual customers or specific state or local policies.

Several secondary objectives are also associated with the planning process. A current study aids in system awareness for the creator of the study and for management. This awareness plays a part in the support of operational activities, as well as any efforts to adjust the timing or scope of proposed construction.

c. **Provide a general description of how the utility plans for:**

i. **Load growth**

Response: Feeder and substation bus loads are determined on a one-in-five peak (20 percent exceedance). Generally, this means the highest peak in the last five years is used as baseline. From there, a trend line is developed using recent load trends, local knowledge, and economic conditions. For distribution system purposes, block loads are considered when a Master Electric Service Agreement has been signed and the project has a high probability of moving forward.

ii. **Aging infrastructure (replacement)**

Response: Most equipment is maintained to extend its useful life as long as possible. When equipment is slated for replacement, other similar or related equipment nearby or in the same station may also be changed out (i.e. an old oil breaker fails; the adjacent breaker may be replaced at the same time).

iii. **Increased penetration of the various types of DERs—What does the utility do to accommodate DER penetration in its distribution system?**

Response: Net metering projects and small generator interconnection projects requesting connection at the distribution level are approved or denied based on the requirements for the Generation Interconnection Process established by the state and/or the Federal Energy Regulatory Commission (FERC).

iv. **Climate change impacts on the system**

Response: Load forecasts are performed once a year and are intended to identify trends that may affect the company's provision of electric service. Historically, however, load forecasts have not attempted to isolate and identify the specific trends caused by climate change within the five-year planning horizon used to design/operate the system. While forecasting continues to evolve, the impacts of climate change have historically been difficult to isolate and quantify; similarly, it has been difficult to accurately determine causation.

v. **Advances in equipment (e.g. controls, communications, awareness)**

Response: Employees maintain awareness of advances in equipment in several ways. Examples include industry seminars and conferences, discussions with sister utilities, vendor visits, tours of vendor and utility facilities, membership/engagement in industry associations/consortiums, and industry periodicals/articles.

When new options are available that appear to provide a solution to an issue, research and technical vendor meetings are generally the next step. A pilot project scoped to test a new device may be funded as a result.

vi. Reliability

Response: The company uses a broad set of tools to inform its reliability planning efforts. It uses these tools in structured processes, applying industry best practices to deliver improvements at the best possible cost.

Outage Data Collection for Reliability Analysis

The beginning point for reliability analysis is underlying data sets, which identify historic performance within particular portions of the electrical network. Customer trouble calls and supervisory control & data acquisition (SCADA) events are interfaced with the company's real-time network connectivity model, Computer Aided Distribution Operations System. By overlaying these events onto the network model, the program infers outages at the appropriate devices (such as a transformer, fuse, or other interrupting device) for all customers down line of the interrupting device. The outage is then routed to appropriate field operations staff for restoration and the outage event is recorded in the company's Prosper/US outage repository. This outage data is collected as inherent processes through the completion of outage reporting, work organizing, and trouble response.

In addition to this real-time model of the system's electrical flow, the company relies heavily upon the SCADA system it has in place and is integrating its just-implemented Advanced Metering Infrastructure (AMI) system, as well as data captured in Dispatch Log System (an SQL database application) which serves to collect all events on SCADA-operable circuits. The company is reliant upon data assembled through its automated outage management system; a diagram of the data flow process is provided as **Attachment A – Data Flow Process**.

Data Collected: Conventions, Indices and Certain Definitions

System Average Interruption Duration Index (SAIDI), System Average Interruption Frequency Index (SAIFI), Customer Average Interruption Duration Index (CAIDI) and Momentary Average Interruption Frequency Index (MAIFI) are the most common indicators or indices used by utilities across the nation for measuring and reporting reliability. Along with other indices, they were first rigorously documented in Institute of Electrical and Electronics Engineers (IEEE) Standard 1366-1998, and since modified in IEEE 1366-2003/2012, IEEE Guide for Electric Power Distribution Reliability Indices.

For performance reporting PacifiCorp uses the current standard indices, applied at the state level as well as to each of the districts in which it provides service; these serve as "local areas" as defined within reporting requirements. Major event days are calculated at the state level and then applied at each of these districts consistent with the requirements of OAR Chapter 860, Division 023. PacifiCorp then aggregates districts to establish reliability reporting regions, for which it verifies that it conforms to appropriate statistical tests to ensure proper application of IEEE 1366. PacifiCorp collects outage data on all outages on the source side of the electric meter. When it is required to interrupt power in order to perform work on the system, it records these outages with a separate designation to identify whether they were taken without notice, or whether the outages were pre-arranged or planned. For the purposes of the data provided in this report, Planned Outages are those in which either the customer or the company made arrangements for the power interruption to occur. In certain situations the notice may be very short, but generally two days' notice is the goal. Certain other outages may be performed intentionally by employees without notice (such as when a car strikes a utility pole and the crew replacing the damaged pole takes an operational outage), but since they happen precipitously, they are not classified as Planned Outages. The company also collects information about outages that happen on equipment at voltages higher than distribution level, specifically the transmission or generation system; transmission voltages within PacifiCorp are those in excess of 34.5 kilovolt (kV). If an interruption occurs to distribution customers as a result of events at those facilities, PacifiCorp designates these outages as Loss of Supply outages.

Reliability Tools & Data Analysis

The company continues to grow its ability to use reliability data strategically with the development and implementation of reliability-centered tools. It uses a web-based notification tool that alerts when interrupting devices (such as substation breakers, line reclosers, or fuses) have exceeded specific performance thresholds. It then promptly investigates these situations, many of which result in localized improvements, such as can occur when a cable section is replaced or when a slack span is re-sagged. It has also overhauled its geospatial reliability analysis tool, augmenting its functionality to better distinguish circuit details in light of reliability events, particularly in the area of underground cable fault and replacement history. The use of these tools results in maximum improvement for the efforts expended, improving reliability to customers at the best possible costs.

Cost Effective Improvements

PacifiCorp uses its reliability data in a variety of ways that are designed to improve reliability to its customers. It has devised methods that are contained in the industry guide for electric reliability, IEEE 1782-2014. Some of these analytical methods render the outage data in a tabular, graphical, or geospatial manner. All of them serve as inputs to identify and develop projects that improve reliability using the company's fuse coordination program (Fuse It or Lose It: FIOLI), its circuit-hardening program (Saving SAIDI), and its capital construction program (Network Initiatives). It evaluates the history of outages within a circuit and at specific devices (fuses, reclosers, circuit breakers) across the entire service area and determines the probability of avoiding outages of specific cause categories. The programs (FIOLI, Saving SAIDI and Network Initiatives) are evaluated for their forecast improvements to network reliability, as measured by the avoidance of customer interruptions, customer minutes interrupted, and momentary customer interruptions. Each project has a value calculated for the cost of the project divided by the avoided interruptions. PacifiCorp uses this cost per avoided customer interruption and customer minute interrupted to identify cost-effective reliability improvement projects. It assembles each of these candidate projects and their cost-to-benefit value into a project priority listing, which rank-orders the projects and, based upon the best-cost projects, prepares a suite of projects that align with metric improvement and budget targets. As projects are completed, the list is re-evaluated to determine whether reliability performance or funding levels have changed and warrant modifications to the plan.

Improvement History

The company focuses on improved system hardening and enhanced system protection. Through targeted reliability projects, protective coordination has been improved by replacing hydraulic reclosers, installing new line reclosers, enhancing the existence of fuses that are able to reduce the amount of customers exposed to those fault events, and replacing substation relays. This new equipment has allowed for smaller and more coordinated protective operations to clear fault events. Additionally, the company has continued reliability-centered hardening activities on circuits whose equipment may be performing in a way indicating a lack of resilience to fault events. Using the company's proprietary analytical tools, portions of circuits are identified that warrant additional hardening activity, often comprised of crossarm or cut-out replacement. Along with circuit hardening and protection efforts, the company reviews outage history and circuit topology to obtain better segmentation of circuits, as well as increasing feeder ties and replacing damaged cable. The company continues to pilot installation of new technologies which augment its reliability-centered toolset.

Improvement Effectiveness

The company further evaluates the effectiveness of the actions it has taken. It compares "benchmark" or pre-construction reliability performance against after-improvement performance and uses this track record to establish future expectations, identify deficiencies or over-achievement compared to targets, and recognize areas in which additional work may need to take place.

c. How does the utility define "distribution system"?

Response: For purposes of distribution planning and consistent with PacifiCorp's FERC-approved open access transmission tariff (OATT), PacifiCorp defines distribution systems as those systems delivering power and energy to the company's electric customers at voltages between 1.385 kV and 34.5 kV. It exists between the transmission and generation systems upstream, and the secondary system downstream. The low side winding of a substation transformer (≤34.5 kV) is typically included as the "beginning" of the distribution system. The secondary system (<1.385 kV) may at times be included in distribution system discussion and analysis, but its performance is more difficult to predict due to customer usage patterns, and for this reason it is frequently generalized when treated on a large scale.

d. **In its whitepaper launching the DSP investigation, Staff cited the U.S. Department of Energy's definition of distributed energy resources (DER):**

> **Distributed generation resources, distributed energy storage, demand response, energy efficiency, and electric vehicles that are connected to the electric distribution power grid**

Staff is also considering adopting the National Association of Regulatory Utility Commissioner (NARUC's) definition of a DER for this investigation:

> **A DER is a resource sited close to customers that can provide all or some of their immediate electric and power needs and can also be used by the system to either reduce demand (such as energy efficiency) or provide supply to satisfy the energy, capacity, or ancillary service needs of the distribution grid. The resources, if providing electricity or thermal energy, are small in scale, connected to the distribution system, and close to load. Examples of different types of DER include solar photovoltaic (PV), wind, combined heat and power (CHP), energy storage, demand response (DR), electric vehicles (EVs), microgrids, and energy efficiency (EE).[1,2]**

Does either definition align with the utility's definition of DERs or are there modifications that the utility would suggest?

Response: The U.S. Department of Energy (DOE) definition aligns better with the company's definition, although PacifiCorp notes that the reference to specific technologies contained in that definition may not ultimately be flexible enough to accommodate all future DER mechanisms. DER may be far from customers and sited for the utility efficiency (e.g. battery storage located to alleviate system congestion). The NARUC definition includes the potential for inconsistencies by trying to address a variety of situations. For example, while DER can be used to reduce hourly-demand, it frequently does not reduce peak demand (e.g. solar panels reduce energy delivered, but often fail to reduce evening peak demand). Further, without contractual agreements in place (e.g. guaranteed output), DER often does not contribute to the ancillary service requirements of the distribution grid. DER comes in many sizes and can affect both the distribution and transmission systems.[3] Given the complexity, the NARUC definition creates confusion by including purported benefits that some DERs will not deliver or, more importantly, would create additional system issues requiring longer-term efforts to implement appropriate cost-benefit analyses, price signals, and regulatory support. The DOE definition allows for a

[1] National Association of Regulatory Utility Commissioners, Manual on Distributed Energy Resources Rate Design and Compensation, p. 45. https://pubs.naruc.org/pub/19FDF48B-AA57-5160-DBA1-BE2E9C2F7EA0#page=46
[2] NARUC's definition includes a caveat that diesel-fired backup generators may also fit in this definition and the individual jurisdiction should determine whether to include in its definition of DER.
[3] In addition, the transmission planning provisions in PacifiCorp's FERC-approved OATT state that alternatives to (or deferrals of) transmission line costs, such as the installation of distributed resources (including distributed generation, load management and energy efficiency) are a type of long-term transmission plan costs. These provisions note, however, that this type of cost does not include demand resources projects that do not have the effect of deferring or displacing other transmission line costs.

discussion on the specific attributes of each DER resource, without implying a range of benefits that may, or may not, be delivered. PacifiCorp, however, looks forward to continued discussion on this topic.

<u>Question A.2</u>

2) Resources: Please describe the general distribution planning tools and other resources utilized, including:

a. Types of planning and modeling software used and for what specific purpose. For example, does the utility make use of GIS technology in distribution system planning?

Response: Both distribution and transmission planning utilize PI Historian data for equipment load information. The model for distribution system planning is maintained in CYME CYMDIST, which receives circuit connectivity data from Schneider ArcFM and customer load data from the company's Customer Service System (CSS). The model for transmission system planning is maintained in Siemens PSS®E and models the transmission system down to the distribution substation bus.

PSS®E and CYMDIST both provide power flow and short circuit analyses, together with other related features. ASPEN OneLiner also contains an important subset of transmission and generation system information, and it informs other systems pertaining to distribution system planning.

The company also uses the internally developed Geographic Reliability Enhancement and Analysis Tool Entirely Revised (GREATER) tool which overlays customer data, outage histories, and reliability information in a geographic information system (GIS) mapping environment.

b. What advanced tools and other planning resources is the utility investing in?

Response: The company uses several advanced tools to inform the planning process. For example, GREATER is an internal application created to overlay outage and reliability information in a map environment. This tool continues to grow to meet needs and has been the focus of much industry attention.

The CYME module for Python programming (CymPy) is an advanced tool the company has used to automate some modelling, analysis and reporting activities within the CYMDIST application.

Another advanced in-house application is Asset Management Planning System (AMPS), which is a desktop and web application used to enter issues and solutions into planning studies.

The AMI infrastructure in Oregon is populating a data lake with customer usage information much richer than the historical monthly usage values available to planning engineers. The company is still in the early stages of leveraging the value of that new data set, and it is not yet part of the formal study process.

Lastly, the company is investing in Communicating Fault Circuit Indicators (cFCIs) and Fusesavers on a limited basis. When implemented, they can in some instances provide useful planning data such as phase loading and reliability information.

c. Applicable engineering standards

Response: Company guidelines and design policies are developed based on industry engineering standards and best practices. Examples include IEEE 1547 covering DER interconnections, IEEE C57.91 covering transformer loading, ANSI C84.1 covering nominal operating voltages, National Fire Protection Association 70 (National Electrical Code), and the IEEE National Electrical Safety Code.

d. Personnel commitment: What personnel resources are involved in distribution system planning? Please include utility personnel as well as contracted services.

i. Please provide the number of personnel involved in distribution system planning per year, for the period of 2014 – 2018, identify whether in-house or contract staff.

Response: For distribution systems in the company's Oregon service territory, approximately 15 full time employees were involved in the authorship of cyclical planning studies. In any given year, up to six part-time student engineers may contribute to planning studies. While contractors have been utilized to help maintain study currency, this did not occur in the period specified.

ii. Please provide an overview of roles and responsibilities.

Response: The employees performing distribution system planning studies are almost exclusively in the role of "Field Engineer." The primary responsibilities of a Field Engineer include the following, listed roughly in order of total time commitment:

a) Technical support for a given geographic area (customer power quality investigations, construction support (both design and build), customer arc flash studies, material change and material failure support, planned and emergency system reconfiguration support, outage response support, post-construction audits, etc.);
b) Maintaining all distribution overcurrent protection devices (new device sizing, creation of all device settings for sectionalizers, reclosers, feeder breakers, and new intelligent electrical devices (e.g. Fusesavers, TripSavers, and cFCIs), troubleshooting device behavior (blown fuse analysis, outage and reliability-related post-mortem investigations, e.g. investigation of device control logs such as recloser sequence of events records, waveform/oscillography, etc.));
c) Completion of assigned distribution planning studies;
d) Performing scheduled overcurrent device coordination studies, typically on circuits

where reliability metrics exceed a threshold (full review of existing devices, their protective reach and device-to-device coordination, proposals for new devices, etc.);

e) Specification feedback to engineering standards based on real world application;
f) Completion of ad-hoc system impact studies (new large load proposals);
g) Completion of customer generation interconnection studies;
h) Review of key account power quality and reliability levels;
i) Providing mentorship and training of new hires, and training of Operations personnel with regard to new devices on the system; and
j) Maintain currency of mandated training (driver safety, CPR, monthly meetings, etc.), and attend technical/industry training as appropriate.

The employees performing transmission system planning studies are in the role of "Area Planner." Area Planners are primarily involved in the operation and planning processes for the local transmission systems, which inform the Distribution System Plan being proposed by the Public Utility Commission of Oregon (OPUC). The Area Planner will inform the Field Engineer regarding substation transformer load levels and necessary upgrades required to serve new loads and/or meet load growth needs, and in turn the Field Engineers inform the Area Planners to correlate load levels and coordinate projects on the distribution system. The primary responsibilities of an Area Planner are much the same as the Field Engineers, with the primary difference being a focus on the local transmission systems sourcing the distribution systems.

<u>Question A.3</u>

3) Planning description: Please provide an overview of the distribution planning schedules and process, including:

a. A description of the various distribution system planning processes, reports and other components utilized.

Response: Most distribution planning studies include a basic set of common elements. Engineers add to the common elements as needed based on their knowledge of the system, recent events, new concerns highlighted by the study process, etc.

i. Planning elements or considerations included (or not included) in regular updates and revisions and a description of each. For example: circuit or substation data, power flow analysis, power quality analysis, fault analysis, load and demand forecasts, external policy and regulations, etc.

Response: The basic elements included in the planning study process are:

- Review previous planning study. Were proposed projects completed? Did forecast growth materialize? Did other study assumptions hold?
- Research area activity (e.g. new industries or large accounts, known operational issues, history of problematic outage restorations, weather patterns, etc.)
- Complete any necessary model corrections. For example, a device may have an unknown rating in the GIS, and the study engineer will determine the rating and input

that correction in the model. Typically normal open points are confirmed, and large load data is verified.

- Taking into account weather conditions, historical switching events, distributed generation contributions, etc.,
  - Determine starting load conditions for each circuit.
  - Determine the growth rates to use for each circuit and for each season.
- Input demand and growth rates to the model.
- Determine any large load additions, known circuit topography changes, etc., and their expected timing and input to the model.
- Perform power flow analysis on the model in the base year (i.e. starting summer and winter load conditions).
- For each future year in the planning horizon:
  - Evaluate the system for overloaded equipment
  - Evaluate the system for unacceptable voltage
  - Consider the effects of generation existing on the system.
- Based on the results of the future conditions, determine reasonable solutions to any issues. Work with Area Planner for solutions that may involve substation modifications.
- For each possible solution, model the scenario. Using engineering judgment and accounting for construction costs and timeline, determine the preferred alternative.
- Determine the necessary timing for any solution project, and for any necessary field reads. For example, if the summer peak condition simulation shows problematic high reactive power flow, the engineer may arrange for Volt-ampere Reactive (VAR) recorders to be placed on the span in question during hot weather in the coming summer.
- Compete the documentation for each project, including its purpose and necessity, and the shortcomings of solution alternatives not selected.
- Compile report components in AMPS and route it for approval.

In addition to those basic elements, each study engineer may expand a given study based on his or her judgment. For example, if outage or loading information suggest a fuse size needs to be changed, this may prompt a miniature overcurrent coordination study that ordinarily would not be considered a required part of the planning study. If distributed generation is a significant contributor to the state of a circuit, the engineer may run several load vs. generation scenarios to test whether the system will behave properly under all conditions. Ultimately, when the study is complete, the engineer should have confidence that any reasonably likely risks have been addressed.

b. Frequency with which the utility conducts the distribution system planning processes.

Response: Distribution system planning occurs year round. Typically half of the studies assigned in a given year are due in June, and the other half are due in December. Field engineers balance their own workload to meet these and other goals.

c. **Frequency of planning updates or revisions: Are updates dependent on a set timing frequency (i.e. every 1, 2, 5, or 10 years) or are there events that may trigger a more frequent planning cycle or revision? If so, please explain.**

Response: Distribution system planning studies are each assigned a frequency class from one to five. Class one studies are scheduled to be updated each year. Class five studies are scheduled to be updated every five years. Study schedules are evaluated each year and studies may be shifted to occur sooner or later depending on a number of factors. For example, if assumptions used for the previous edition are deemed questionable due to large previously unforeseen load additions (one or more System Impact Studies or Electric Service Study Agreements, etc.) the study may be moved up. Also, studies may be moved to maintain study currency and balance workload. Study class and the circuits included in a study are reviewed and adjusted as needed. Currently, for the Oregon service area, approximately 45 percent of studies are Class five, 47 percent are Class four and 8 percent are Class three.

d. **Iterative updates and/or new plans: Are planning processes based on continuations of past plans, new planning cycles, or some combination? How long is each planning cycle's time horizon?**

Response: The process for scheduled distribution planning begins with a detailed look at the existing system, as detailed in 3.a.i. Past studies are reviewed for the reasons mentioned there. The geographic scope of a given study may change over time, as two small studies get combined into a single study, or a large study area gets broken into two or more manageable studies, for example. But the comprehensive process of evaluating the condition of the system with growth, and securing field reads to corroborate the simulation results, does not materially change year to year. Distribution studies begin with the base year (more recent summer, most recent winter) and look forward five years from there.

e. **Integration of existing planning processes: How do the distribution plans inform the Integrated Resource Plans (IRPs), competitive procurement of generating resources (resource RFPs), Smart Grid Reports, transmission planning, and interconnection studies?**

Response: On an annual basis, potential projects identified in distribution planning studies as having a traditional solution with an estimated capital cost equal to or greater than $1 million are evaluated using the Alternative Evaluation Tool to compare the cost of a traditional solution such as a transformer, circuit breaker, recloser, or distribution line capacity increase against alternative solutions including energy efficiency, demand side management, DER, and storage technologies. These alternative solutions are included in the Smart Grid Report. Additionally, the identified distribution capital investments, along with transmission capital investments are used to calculate the T&D investment deferral benefits used as an input to the IRP.

Distribution feeder load projections are coordinated with substation bus level load projections to inform transmission system planning efforts. Transmission planning studies also use as an input identified deficiencies and planned projects resulting from distribution planning studies.

The power flow models developed through the distribution planning process are actively used to evaluate interconnection requests and produce interconnection studies, often in combination with transmission planning models and evaluations.

f. How do IRPs, resource RFPs, Smart Grid Reports, transmission planning, and interconnection studies inform distribution system planning?

Response: Energy efficiency and demand side management resources identified in the IRP are considered as alternatives to traditional capital solutions for projects identified in the distribution planning studies. This evaluation is performed on an annual basis using the Alternative Evaluation Tool described in the Smart Grid Report. Scenarios performed in the Smart Grid Report, including evaluation of potential system impacts of residential EV adoption, inform future distribution planning efforts.

Distribution feeder load projections are coordinated with substation bus level load projections to inform distribution planning efforts. Distribution planning studies also use as an input identified deficiencies and planned projects resulting from distribution planning studies. Distribution plans are not based on potential interconnection projects that are still in the study phase. However, the power flow models developed through the distribution planning process are actively used to evaluate interconnection requests and produce interconnection studies.

g. What is the outcome of your distribution planning process? A plan/report? Budget by field area/region?

Response: Each study process concludes with a report. The common elements required for a completed distribution study are:

- Planning study summary. This reports the substation included, the author, and completion date. It lists the proposed projects over the duration of the planning horizon. It also acts as the signature page for approval from requisite parties.
- Study area description. This is an executive summary of the area studied. It typically describes what makes the area unique, the dominant customer types and causes for growth, etc.
- Study area summary. This is a brief account of what will be required to ensure the system meets requirements in the future. It may explicitly call out assumptions used, the need for follow-up, and any dependencies that may exist (e.g. other planning study results, changes to the area's economy or neighboring T&D systems, etc.).
- Study area map.
- Load forecasts, typically for both summer and winter. This tabular section of the study lists each substation transformer and circuit, their load capacity, growth rate, and planned additions to load and reactive power compensation, along with their expected percent loading at the end of the study period.
- All proposed construction items. Each item requires a description, construction year, construction cost (block estimate), purpose and necessity, projected conditions/benefits, risk assessment, alternatives considered, and a sketch/map.

h. **Please include a graphic to illustrate the various plans/reports listed in this question (Section A, Question 3) and how they interact with each other.**

Response: Please refer to the following two attachments:

- **Attachment B – Report Interaction Diagram,** illustrates the interaction between the various plans/reports.
- **Attachment C – Department Interaction Diagram,** illustrates the interaction of the various departments involved in the creation of these reports.

<u>Question A.4</u>

4) **Budget process: Please describe the associated capital and operation and maintenance (O&M) budgeting processes:**

a. **Process of developing capital budgets for distribution infrastructure.**

Response: The business develops the capital budget based on multiple factors. Asset replacements due to storm, casualty, third-party damage, or failure are developed based upon volume and cost trends. Units of work which are compliance-based are budgeted on a known volume and unit-cost basis. Budgets to address new revenue are developed with economic-based regression analysis to project volume-based work on a unit-cost basis for standard growth like residential and commercial development. Large projects are budgeted on a project-by-project basis for the scope of work necessary to serve a larger facility (i.e. 1 megawatt (MW) or larger). Other specific projects budgeted for with appropriate measurement and documentation are system expansions to address load growth over time, regulatory pilots such as battery storage and EV charging stations, and contractual obligations with joint asset owners such as the Bonneville Power Administration. All of the aforementioned inputs are consolidated and balanced based on prioritization and justification for the work.

b. **Process for developing budgets for distribution O&M changes or projects, which may include, but are not limited to, information technology, communications, and shared services.**

Response: The business develops the O&M budget based on multiple factors. Operational activities such as reading meters, underground line locating, outage response, and customer connects and disconnects are developed based upon historical volume and cost trends. Units of compliance-based maintenance activities, such as field inspections, substation equipment preventative maintenance, and condition corrections, are budgeted on a known volume and historical unit-cost basis. Other specific categories of work, like right-of-way payments and maintenance of joint-owned asset are budgeted based on known contractual obligations.

c. **Process for developing New Construction Reports filed with the OPUC.**

Response: The New Construction Report is comprised of two sets of budget information: major projects greater than $10 million and projects greater than $1 million.

Listings of projects greater than $10 million (Major Projects report) are defined as those projects having a total estimated cost to completion exceeding $10 million. This information is prepared based on the detailed major project listings included in the 10-year plan and UII capital project detail. This includes generation, transmission, distribution, and general projects. Project write-ups for all of the projects greater than $10 million are also included in the filing. The project write-ups include technical specification of the project, ownership, if jointly owned, operating date, stage of construction, and other relevant information.

The New Construction Report also include a listing of projects greater than $1 million in total cost and for which construction will commence in the budget year. Information for projects greater than $1 million includes a brief project description and the project function (e.g., production, transmission, distribution, general plant, thermal, hydro, or other).

d. Timing of associated distribution system budgeting processes: Describe timing of annual distribution system planning activities and specific deadlines related to broader utility planning and budgeting processes.

Response: PacifiCorp performs planning studies annually on the distribution and sub-transmission systems to evaluate how the planned load growth over five- and 10-year planning horizons compares with PacifiCorp's current ability to deliver this load to customers and identify specific sub-transmission and distribution needs. From these various planning studies, PacifiCorp develops a list of projects needed to mitigate identified system deficiencies and incorporates the list into PacifiCorp's broader 10-year capital investment strategy as opposed to having a separate process. This ensures that the need for distribution projects is evaluated alongside all critical projects.

As the planning studies are performed on five- and 10-year planning horizons, there are not specific interim deadlines or requirements throughout the calendar year outside of PacifiCorp's annual capital budget process. Therefore, this list of distribution projects must be completed prior to the second quarter of each year to be included in the overall budget. Additionally, during the second quarter of each year, existing distribution projects are reviewed to determine if the scope and timing still aligns with the results of the five- and 10-year planning studies. Because of this timeline, it is very common for planning studies to be performed during the third and fourth quarters of each year for inclusion into the capital budget during the following calendar year.

e. Distribution system schedule i.e., is it performed on an annual basis or on some other schedule?

Response: See response to d, above.

f. Budget categories are used? For example, New Service, Asset Health, Street Lights, Substation Capacity, Reliability, Equipment Purchase, etc.

Response: Yes, PacifiCorp uses budget categories and sub-categories to budget specifically for new service, asset replacement, substation, etc. The sub-categories are generally organized by lower-level asset classes (i.e. substation regulators, substation breakers, substation transformers under asset health).

i. **Do you have construction allowances?**

Response: Construction allowances, or Extension Allowances, are addressed in Rule 13, Line Extensions. There are residential and developer fixed allowance criteria and for commercial and industrial a one-year revenue projection that determines the construction allowance.

g. **Which parts of the budget are discretionary i.e., the utility has some level of flexibility on timeframe, projects/solution, or other decision-making element? Please explain.**

Response: Potentially there are asset replacement, functional / reliability upgrades, and capacity projects with limited flexibility that can be evaluated with a risk matrix to determine options for deferral. Additionally, alternate solutions are evaluated with each project proposal to ensure the least-cost solution with the most functional outcome for the company is selected. Other non-utility options to offset projects (such as DER) are part of the evaluation process. For asset replacements or functional / reliability upgrades to be discretionary, the system risk, customer risk, and financial risk of deferring such projects can be weighed to determine feasibility of postponing such a project.

<u>Question A.5</u>

5) **Capital investments and O&M projects: Please describe the processes to identify and assess capital and O&M investments:**

a. **Assessment criteria and assessment process for reliability of grid assets (e.g., feeder, substation), condition of grid assets, and asset loading.**

i. **How do you decide what equipment to replace (e.g., age, performance, etc.)?**

Response: Generally speaking, PacifiCorp uses a range of processes and assessments to identify both capital and O&M investments. The results of these processes are able to not only identify the need for urgent investment but also provide insight into the general priority and timing of potential future investments. The mechanisms used to identify these investments combine factors such as performance, physical condition, equipment vintage and model, and test results, and can generally be grouped into one of the following categories: reliability performance, manufacturer notification/obsolescence, inspections and maintenance, and equipment misoperation.

<u>Reliability Performance:</u> PacifiCorp uses reliability metrics and trends to pinpoint location-specific and categorical investment throughout the company’s service territory. These might include hardening projects on a specific circuit due to historic outages (location specific) or a general recommendation to replace/upgrade models of equipment for enhanced features.

PacifiCorp's reliability performance projects are further contemplated and explained in the company's annual reliability report and, therefore, are not included here in detail.

Manufacturer Notification/Obsolescence: Obsolescence and manufacturer notifications involve either a piece of equipment no longer being supported by the manufacturer or notification of a major manufacturing flaw. PacifiCorp evaluates these types of notifications and puts together strategic plans to replace any obsolete equipment over time. For manufacturing defects, the defect is evaluated and a risk-based approach is taken. Usually, known flaws are replaced on a more urgent schedule as they may present elevated risk to system operations.

Inspection and Maintenance: Electric utility assets are subject to a range of environmental and loading conditions throughout their useful life. While the company uses the most up-to-date and safe construction, design, and operating standards, facilities placed in service, over time, may have various opportunities and propensities to wear, break, become damaged, or otherwise be affected, causing such facilities to fall out of compliance with the requirements and standards. Therefore, PacifiCorp's maintenance and inspection programs are tailored to perform critical maintenance and inspection activities, which qualify current operating status and identify potential conditions where investment may be either needed or beneficial to the overall system.

Such maintenance and inspection activities might include substation transformer dissolved gas analysis testing, circuit breaker maintenance or operation, visual inspections of overhead equipment, and pole strength testing. In each case, the results of the activity determine whether or not investment is recommended or required. For example, a routine dissolved gas analysis test of a substation transformer may indicate that a given transformer is operating per design and, therefore, no investment is needed. However, the test results might indicate that the transformer is nearing the end of its useful life and should be scheduled for replacement as soon as practical. Furthermore, the test results may indicate that the transformer is operating within an acceptable range but starting to trend in a negative way. In these cases, follow up maintenance may be scheduled, or a repeat analysis may be conducted in the near term to further gauge the degradation trend. Depending on the results of the follow up analysis, including the general trend and severity, the asset may be scheduled for replacement in the mid to near term.

Equipment Misoperation: As described previously, facilities placed in service, over time, may have various opportunities and propensities to wear, break, become damaged, or otherwise be affected, causing such facilities to operate outside of acceptable ranges. Generally, when a piece of equipment does not operate properly, abnormal system conditions or a fault event may occur. As a part of response and restoration efforts, PacifiCorp investigates the causes of system abnormal configurations and fault events. Oftentimes during these efforts, additional maintenance or small repairs can bring the asset back up to normal operating conditions. However, when any damage is beyond repair, the asset is replaced. Furthermore, when trends are encountered, such as multiple underground cable faults on a specific segment of underground cable in quick succession, additional adjacent assets, such as the full segment of cable, may be replaced.

ii. How do physical inspections and other operations functions inform this assessment?

Response: See response to A.5a.i, above.

b. Cost/benefit analyses the utility performs for distribution system planning:

i. For what types of investment decisions are cost/benefit analyses performed?

Response: A cost/benefit analysis is required for all capital investments having a net PacifiCorp cost of $1 million or greater after customer contribution or joint-owner share.

ii. What type of analysis is used?

Response: PacifiCorp evaluates capital investments on a present value of the revenue requirements (PVRR) basis. Revenue requirement includes return of and on capital, property and income taxes, and O&M expense over the expected life of the asset. PacifiCorp typically identifies two or more alternatives that would solve the critical issue. Based on non-monetized or hard-to-quantify benefits some of these alternatives may be given preference or deemed not feasible. The "least cost alternative", that is, the alternative with the lowest PVRR, is ordinarily selected.

iii. Which non-monetized benefits are included in these analyses (e.g., emissions reductions?)

Response: Non-monetized benefits may include: the ability to accommodate future load growth, improve reliability, flexibility to allow future system configuration changes at low cost, and so on. Non-monetized benefits or costs may result in some alternatives being preferred or deemed not feasible.

iv. Are there hard-to-quantify benefits associated with the utility's investment decisions? How are these included in your analysis?

Response: See response to A.5.b.iii, above.

v. When investments are interdependent with other investment decisions, how does your investment analysis change?

Response: Interdependent investments are evaluated as a package.

c. Alternative analysis protocols for identified needs:

i. Capital versus operating solutions: How does the utility determine whether an assessed need is best met through a capital project or through operational solutions?

Response: When reviewing capital projects for reliability performance and capacity needs operational solutions are evaluated. An example would be utilizing existing utility infrastructure, like in place switches that exist to transfer load during outages or maintenance, and using them on a permanent basis to transfer load from one feeder to another, or one substation to another. This would be an operational solution that would make use of available capacity at a neighboring substation or on a neighboring *circuit* before capital investments to increase wire size, increase transformer size, or add infrastructure.

ii. Near-term versus long-term: How does the utility consider the costs and benefits of long-versus-short-term solutions?

Response: PacifiCorp evaluates such solutions through a cost-benefit analysis taking into account budgetary constraints. In emergent scenarios, short-term solutions take precedence.

iii. Non-monetized benefits: Does the utility consider different benefits when taking alternative approaches to resolving system needs?

Response: The 2019 update of the Alternative Evaluation Tool includes modifications to account for anticipated stacked benefits of generation and storage resources. Additionally, the 2019 tool update will reflect the most current cost assumptions for generation and storage resources from the 2019 IRP analysis.

iv. Non-wires-alternative (NWA) versus traditional solutions: How does the utility consider the potential for DER or other non-wires solutions to address an assessed need or to defer or eliminate the need for a traditional capital or operating solution? Is assessment of NWA performed in a systematic or ad hoc way? If not provided in responses to Section B, please provide examples of any NWA solutions the utility has analyzed and/or implemented, if any.

Response: The Alternative Evaluation Tool is used to assess the potential of NWA solutions to T&D needs. On an annual basis, 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 T&D 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. The first step of this comparison involves a screening with the Alternative Evaluation Tool to determine which of the non-wires solutions, including energy efficiency, demand side management, DER, and energy storage technologies are technically effective and reasonably close to the cost of a facility upgrade alternative. Non-wires solutions that are initially identified by the tool as technically effective and within 25 percent of the cost of a facility upgrade alternative are then evaluated further using the specific characteristics of the site, type, scale, and other features of the non-wires solution to more accurately account for the stacked benefits of that solution.

In Oregon, the company has partnered with the Energy Trust of Oregon (ETO) to perform energy efficiency pilot programs on three locations identified through the Alternative Evaluation Tool as potentially technically effective and cost effective for energy efficiency initiatives to defer traditional capital investment solutions. The three locations include two in the mid-Willamette Valley and one in southern Oregon. Additionally, the company has participated in a pilot irrigation load control program in the Klamath Basin area of southern Oregon, in part to evaluate potential for deferring a traditional capital investment solution.

v. Identifying solutions: How are options to meeting a need identified?

Response: On an annual basis, potential projects identified in distribution planning studies are evaluated using the Alternative Evaluation Tool to compare the cost of a traditional solution such as a transformer, circuit breaker, recloser, or distribution line capacity increase against alternative solutions including energy efficiency, demand side management, DER and storage technologies.

vi. Scenario analysis: In developing solutions to an assessed need, does the utility consider multiple scenarios, including load forecasts and DER penetration? If so, what scenarios are standard?

Response: Generally, in developing solutions to an assessed need, the system is studied in its most stressed state (engineers estimate the percentage of DER that was active during the load conditions used in each study). Other load/generation levels, such as high generation with low load may be studied on an as-needed basis.

vii. Assessing NWA alternatives: What criteria or metrics are used in assessing whether a NWA can meet an identified need?

Response: The Alternative Evaluation Tool is used to assess the potential of NWAs for projects over $1 million. This tool uses projected demand to determine the feasibility and general costs of solar, battery, solar + battery, and demand side management. Each of these costs is compared to the cost of the traditional alternative. Projects within 25 percent of the cost of a facility upgrade alternative are then evaluated further.

d. **Metrics for deciding among competing proposals: For any of the applicable categories described in 5c(i) – 5c(vii), what specific metrics are used to conduct a comparison of alternative solutions? If not provided in responses to Section B, please provide an example(s) of cost-benefit studies or reports the utilities have conducted as an attachment?**

Response: Investment Appraisal Documents (IAD) are used to facilitate the financial review of capital projects over $1 million. An IAD typically includes sections describing the project purpose and necessity, project scope and outcome, alternatives considered, project delivery risk factors, target milestones for deliverables, target costs, accounting issues, customer benefit analysis, procurement, and project delivery strategy.

Question A.6

6) **Demand and system loading forecast methodologies: Please describe the demand and load forecasts that inform the utility's distribution system planning, including:**

a. **Granularity of load forecasting: To what level of granularity does the utility forecast? To what extent is the distribution system data collected by the utility reflected in load forecasts (e.g., does the utility employ an 8760-hour forecast at the substation level?)**

Response: The company performs a monthly jurisdictional forecast from which an hourly-load forecast is developed. The hourly jurisdictional long-term forecast is then disaggregated into multiple geographic locations, or load pockets. These forecasts inform the IRP process and are coordinated with the transmission planning process. Currently, these forecasts are not integrated with the distribution planning study process.

The company also performs substation bus level and distribution feeder level forecasts for winter and summer peak load conditions. These forecasts are coordinated with the transmission planning process. The substation level and distribution feeder level forecasts are built using distribution system data, including SCADA load measurements and peak demand meters that are read manually by substation operations crews during substation site visits.

The distribution feeder level forecasts act as a starting point for the simulation of all distribution level load and generation conditions. The capacity of the distribution system to handle a given amount of load or generation at some location is determined by first allocating the forecast total load across the feeder. In this way, there is a model-based granularity down to the location of the customer, even though forecasting is not performed at that granular a level. The distribution system model includes summer and winter ratings for devices throughout the system, including all cable and wire sizes and protection devices.

b. **Use of company-wide peak forecasts versus aggregation of substation or other circuit-level peaks: Does the utility use a top-down forecasting approach versus a bottom-up approach, or some combination of these approaches? Does the utility utilize peak-hour forecasts?**

Response: The company uses a combination of top-down and bottom-up forecasting approaches. The company's monthly jurisdictional forecast uses a top-down approach. The monthly jurisdictional forecast is used to develop a 20-year, 8,760 hourly forecast, which is also used to derive the company's coincident peak forecast. These top-down forecasts inform the IRP process and are coordinated with the transmission planning process. The substation bus and feeder level forecasts use a bottom-up approach to develop five-year summer peak and winter peak forecast for each substation bus and distribution feeder. These bottom-up forecasts are coordinated with the transmission planning process.

With distribution level analyses, typically the feeder load (measured, forecast, or per scenario as applicable), is used for a top-down allocation as described in part (a) above.

c. **Comparison of actual asset loading against past forecasts: Does the utility employ backcasting or ex post true-up to assess the accuracy of its forecasting process?**

Response: The substation bus and feeder level forecasts are performed on an annual basis using actual peak load data from the preceding five to eight years to determine a representative one-in-five peak.

No formal backcasting or ex post true-up process is currently in place for the distribution planning study load forecast process, but engineers do review historical forecasts as part of the process of creating a new load forecast during the study cycle.

d. **Minimum load assessments and forecasts: Does the utility measure minimum load by circuit? Does the utility utilize minimum load to assess potential impacts of distributed generation on power flows? Are minimum loads measured during peak hours or during night hours?**

Response: Minimum loads for substation buses and feeders are not forecasted system-wide but can be determined for specific study needs on a bus-by-bus and feeder-by-feeder basis by reviewing SCADA data, where available. For solar generation studies and similar evaluations, the company has used daytime minimum load data coincident with solar output. For other purposes, the company may consider minimum loads occurring during nighttime or other off-peak periods.

The company does conduct a daytime minimum load forecast, which relies on the hourly jurisdictional long-term forecast that is disaggregated into geographic locations. The daytime minimum load assessment evaluates hourly loads by geographic location for hours 8 through 16 PST. The daytime minimum load forecast incorporates the company's expectations for future private generation. This forecast is considered at the transmission load bubble level, but does not contain the resolution necessary to inform the distribution planning study process.

e. Impact on load forecasts of the projected availability of DER: What approaches and models does the utility use to forecast DERs?

i. How does the utility forecast the impact of DERs on distribution system needs?

Response: The impact of DERs on the distribution system is captured through two processes. First, the distribution impact of an individual project is reviewed during the interconnection study process. Projects are analyzed individually and in aggregate with other generating resources in the vicinity to determine if any system modifications need be incorporated to allow the project to interconnect.

Secondly, the installation of DERs will influence operational characteristics and load growth trends at the substation, feeder and bus level—which has implications on the annual substation forecast used to develop the transmissions system models that are subsequently used for various transmission planning activities, including North American Electric Reliability Corporation (NERC) reliability standards assessments and FERC-jurisdictional interconnection studies. DER installations alter operational characteristics, which impact the individual feeder load growth assumptions and other operational features that are used to determine the need for future system upgrades. During the annual substation forecast, and during the planning study process, the aggregated DERs are not singled out and analyzed for their specific impact, but their presence alters the overall operational characteristics of the entire system which then informs the assessment of future T&D system needs. Many privately owned DER are not contracted to produce a specific amount of output, and collectively their output (especially solar) does not occur at a time of day when the system is constrained by high loading. For these reasons, it is also necessary to study scenarios where generation is not producing.

ii. How is utility forecasting impacted by utility assessments on adoption and penetration of DER?

Response: The company's jurisdictional long-term forecast, which is part of the IRP process, incorporates a forecast of future private generation penetration assuming new market and incentive developments. The private generation forecast identifies expected levels of customer-sited private generation, which is then applied as a reduction to PacifiCorp's long-term load forecast. Daytime minimum loads for the system incorporates the company's expectations for future private generation.

For the load forecasting effort associated with distribution planning studies, there is not a formal adjustment made for future DER adoption. The consideration of uncertain potential DER impacts to forecasts of net load at the granular feeder level can be problematic given the dynamic and fluid nature of distribution circuits. To remain responsive to typically short timelines for distribution system upgrades in response to customer load increases, it is not practical for a provider of last resort to assume a DER adoption trend. Instead, various planning scenarios at the feeder level may need to be run to capture the range of possible load and generation profiles specific to the distribution circuit or system being evaluated. This is particularly important due to varying timelines from application to construction of new DER and the variability in actual DER energy production.

iii. Are multiple scenario forecasts developed, and if so, what are the bases of variations in scenarios?

Response: The private generation study forecasts the adoption rate of private generation at a state jurisdictional level as part of the IRP process. The study does provide multiple scenarios by developing a base case, which is considered the most likely outcome, a high case, and a low case. Fundamentally, the study is a customer adoption forecast based on payback acceptance from a customer perspective. As such, the primary variables used to differentiate the scenarios are those that impact the anticipated customer payback. The three primary variables are: 1) forecast changes to the technology costs, 2) the anticipated rate of improved performance from a technology, and 3) percentage of increase in electricity rates.

During the distribution planning study process, the objective is to ensure sufficient infrastructure exists, or can be budgeted and constructed in time, to meet system requirements based on various load and generation scenarios. Those scenarios vary according to the area and the DER penetration, but collectively lead the study engineer to have confidence that all relevant variables have been addressed by the study process and proposed infrastructure projects. Example scenarios include Light Load + High Generation, High Load + No Generation, High Load + High Generation and Light Load + No Generation. Where new loads are anticipated to come online during the study period (e.g. new retail development in Year 2), those loads are also part of the forecast and simulation. Other scenarios may also be considered.

<u>Question A.7</u>

7) Locational assessment of DER:

a. Describe whether locational DER assessments are a part of the planning process and the process for assessing this.

Response: Locational DER assessment, taken to describe the process of preemptively evaluating the potential for DER to be added at a given location or region without the submittal of an application for an interconnection, is not currently part of the distribution planning process. DER interconnections are evaluated when applications are received and necessary fees are paid.

b. What form of hosting capacity software or analysis, if any, is used in the planning process? Please describe.

Response: The company does not use hosting capacity software as part of the distribution planning process. Each generation application is formally evaluated through a study process on a case-by-case basis.

Implementing hosting capacity software would require significant investments and personnel commitments for GIS upgrades, data quality improvement, and other information technology upgrades.

c. Is hosting capacity analysis conducted system wide and/or in response to interconnection requests?

Response: Hosting capacity analysis is not conducted system wide. Interconnection requests do not prompt true "hosting capacity" analysis in the sense defined in part (a) above. Instead, the application is considered on its own merit, to see whether the proposed generation applied to the current system creates any perceivable negative consequences to the system and its customers, and potentially to provide a rough scope and cost for any improvements needed to mediate those consequences.

To clarify, true "hosting capacity" analysis could hypothetically suggest that 500 kilowatts (kW) of generation is acceptable at a given location. If an application for 400 kW is received, it will be evaluated in queue order and consequently approved. The addition of this new generation changes the characteristics of the distribution system, requiring further analysis of the capability of the system to accommodate additional generation.

Section B

In Section B of your response, please provide the following information for the current status of the utility's plans, reports, and other relevant components described in Section A. Please include information that is relevant to the utility's *Oregon* distribution systems:

Question B.1

1) The date initiated, completed, and the planning timeframe used: For each planning component (as described in Section A, Question 3a), the number of years to which it is applicable should be specified.

Response: The company does not track the date a planning study is initiated. Generally each fall, the following year's study assignments are determined, and the engineer is free to begin the study at any time so long as the due date is met.

Each study uses a five-year planning horizon. A summary of the status of current distribution studies is shown in the table below. The base year is the year used for load data. A study completed in 2019, for example, would typically utilize 2018 load data, and forecast the five years 2019-2023.

Oregon Distribution Studies				
Base Year	**Class 3**	**Class 4**	**Class 5**	**Total**
Assigned in 2019				
2005	1			1
2014		2	6	8
2015		6		6
2016	1	1		2
2018	1	1		2
2019			1	1
2019 Assigned Total:				*20*
Not assigned in 2019				
2014			1	1
2015		1	5	6
2016		7	4	11
2017	2	11	6	19
2018	1	5	10	16
2019		1		1
2019 Unassigned Total:				*54*
Grand Total	**6**	**35**	**33**	**74**

Question B.2

2) Scenarios: the range of any scenarios that were considered should be identified, e.g. high/low load forecast, high/low DER penetration.

Response: A summary of how scenarios are used for the questions in Section A is included below.

- At the distribution planning level, a strict high/low forecast is not performed. When completing a load forecast, engineers use available data to determine the state of the distribution system. Since the goal of the study is to identify likely risks and develop necessary solutions, forecasts generally include all reasonably likely load. Because the load forecast table includes load addition line items and growth rate assumptions, it is a relatively simple matter to evaluate the loading levels if a given load does not materialize.
- Engineers estimate the percentage of DER active during the load conditions used in each study in order to deduce total demand. If any given DER is not under contract to produce a guaranteed amount of power, then simulations are conducted with that generation off. Multiple scenarios may be run on an as-needed basis to evaluate likely risks, etc.
- During the process of reviewing previous studies, actual load and generation is typically compared to the old forecast to the extent possible with the available data.

Question B.3

3) System constraints and needs:

a. At a high level, what system constraints and needs have your planning processes anticipated to develop or occur within the planning period? (Further detail on system characteristics is requested in Section C)

Response: Five-year distribution planning studies typically identify projects to address the need for capacity increases or system reinforcement. Though a variety of conditions are studied, capacity increase projects are generally proposed based on customer load increases, general load growth, equipment overload concerns, or poor power factor. System reinforcement projects are generally proposed based on low voltage concerns, poor reliability, or compliance issues.

b. How have these constraints and needs been prioritized based on assessment criteria, time sensitivity, budget impact, or other criteria?

Response: Projects are generally assigned a priority based first on compliance conformity and next on risk threshold (potential customer minutes lost). Projects with field-measured performance issues (such as overloads, low voltage, or poor power factor) take precedence over projects with predicted (i.e. simulation-based) performance issues. Other factors such as budget, timeline, and seasonal loading are also taken into consideration.

<u>Question B.4</u>

4) A description of how the utility is planning for distributed generation coming online.

Response: The company identifies and plans for distribution generation in various ways throughout the planning process. Installed net meter applications are totaled by state as part of the company's annual Load and Resource Forecast development to capture any net changes to load that result from the new installations. Any distributed generation that enters the generation interconnection queued process is evaluated through a detailed study process following the company's OATT and/or applicable state and federal rules and procedures.

<u>Question B.5</u>

5) Historical and current budgets, including:

a. Historical distribution system spending: Please provide historical spending over the past five years, and to the extent possible, breakdowns of categories of expenses and budgets (such as those listed in Section A, Question 4d) for capital projects, O&M projects, information technology, communications, and shared services.

Response: Please refer to **Attachment D – Oregon's Allocated Share of Distribution Expenses** broken out by FERC account for calendar years 2014 through 2018 as reported in the company's annual Results of Operations report. Oregon distribution system budgeted expenses, budgeted capital expenditures, and historical capital expenditures for these years are not available as the company's planning process is not performed at a granular level to provide state and FERC account data in order to provide a comparison between historical (actual) costs and budgeted amounts.

b. Current distribution system spending: Please provide capital and O&M budgets over the applicable planning period, and to the extent possible, breakdowns of categories of expenses and budgets (such as those listed in Section A, Question 4d).

Response: Please refer to subpart a, above.

i. Where individual budget categories contain a substantial increase or decrease from historical levels, please explain the rationale for the change.

Response: Please refer to subpart a, above.

c. **Comparison: For each of the past five years, please provide a comparison of forecasted distribution system spending by year versus actual spending.**

Response: Please refer to subpart a, above.

<u>Question B.6</u>

6) Currently planned distribution capital projects and O&M changes and projects, including:

a. **Whether/which alternative analyses were conducted (as described in Section A, Question 5c). Please describe.**

Response: The Alternative Evaluation Tool is used to assess the potential of NWA solutions for all distribution substation capacity increase projects and feeder capacity increase projects with a projected capital cost for the traditional solution exceeding $1 million. The Alternative Evaluation Tool compares various non-wires solutions including energy efficiency, demand side management, DER, and energy storage technologies. Non-wires solutions that are initially identified by the tool as technically effective and within 25 percent of the cost of a facility upgrade alternative are then evaluated further using the specific characteristics of the site, type, scale, and other features of the non-wires solution to more accurately account for the stacked benefits of that solution.

b. **Whether future capital or O&M projects were identified using DER alternatives. Please describe.**

Response: In the 2017 and 2018 budget cycles, the company identified four projects in Oregon through the Alternative Evaluation Tool for which NWAs may provide a cost-effective solution. The four locations include two in the mid-Willamette Valley, one in the Medford area and one in the Klamath Basin area. The company partnered with the ETO to perform energy efficiency pilot programs on the Willamette Valley and Medford area locations. Additionally, the company has participated in a pilot irrigation load control program in the Klamath Basin area of southern Oregon, to further evaluate potential for deferring the traditional capital investment solution in that area.

c. **Identification of any non-monetized benefits of planned projects.**

Response: PacifiCorp is enhancing its evaluation methods to better account for energy, operating reserve, and system generation capacity benefits from NWAs. In the future, certain alternative solutions could potentially provide more flexibility during outage restoration. Customer-sited DER could assist with outage restoration in the near term, but implementation at the distribution level is not being considered at this time. T&D "wire" upgrades also have some non-monetized benefits in this analysis: the ability to accommodate future load growth, improve reliability, and flexibility to allow future system configuration changes at low cost. Depending on the outcome of these efforts, PacifiCorp may be able to calculate specific benefits for its customers.

d. **Identification of any projects that will enhance the company's future ability to integrate DER into system operations.**

Response: The data gathered through AMI may provide increased visibility to the customer usage patterns and load types that drive daily load shapes in those areas with high customer participation. This improved granularity may provide an enhanced capability to safely and reliably integrate a higher level of DER penetration in the distribution system.

e. **Which distribution projects are selected and approved within the scope of projects proposed. Please explain why.**

Response: All four projects described in response b, above, were selected and approved to move forward with further evaluation of the feasibility of implementing NWA solutions.

Section C

In Section C of your response, please provide the following information about the current status of the utility's *Oregon* distribution systems:

<u>Question C.1</u>

1) System Protection:

a. Describe types of protection schemes and devices utilized in distribution circuits, including but not limited to line reclosers, trip savers, tap fuses, outage management systems (OMS), etc.

Response: The company primarily uses substation feeder breakers, fuses, and line reclosers for protection of distribution circuits. Sectionalizers and programmable devices including Fusesavers are also deployed. Roughly 500 faulted circuit indicators (FCIs) are installed in the company's Oregon service territory, but no distribution level cFCIs have been installed in the company's Oregon service territory. In Portland, Network Protectors are employed in the secondary network system, and a vault monitoring system is used to communicate system information to the company's PI system. The company utilizes an ABB outage management suite and the OSI Monarch control system architecture.

b. Provide an estimate the amount of the system where distribution automation (DA) is deployed. Please provide any relevant context about how these technologies are distributed across the utility system and why. Please include, but do not limit responses to:

i. Volt/VAR Optimization

Response: Most regulating devices control voltage dynamically (by real and reactive power flow where appropriate). While this may be less efficient from an energy savings point of view than an advanced Volt/VAR Optimization (VVO) scheme, it is very low cost. PacifiCorp's VVO related research and pilot projects (in Washington) indicate the incremental energy savings difference between our current strategy and a VVO strategy is very small and comes with a very large cost. The AMI system being deployed in Oregon may be useful in monitoring voltage, but is not expected to be robust enough to serve in a VVO environment.

ii. Fault Detection, Isolation, and Restoration or Fault Location, Isolation, and System Restoration.

Response: The company is working to deploy by year-end 2019 a DA pilot with fault location, isolation, and service restoration (FLISR) components in the Lincoln City area. The project directly affects two distribution circuits. Lessons learned will inform future DA project decisions.

No other DA technologies are currently deployed in the company's Oregon distribution system, although the company's legacy secondary network in Portland (Lloyd District and downtown) may be thought of as having some of the attributes frequently associated with smart grids and distribution automation. This legacy secondary network has very high reliability and resiliency due to its mesh topology, but it does not operate through conditional logic the way a DA or FLISR system would.

<u>Question C.2</u>

2) Monitoring:

a. Percentage of substations and feeders that are equipped with SCADA in the utility's Oregon service area.

Response: 45-46 percent (462 out of ~1000-1020 feeders have SCADA, MV90 or revenue metering).

b. Is the utility deploying AMI technology?
  i. What is the percentage of AMI meters in the Oregon service territory?
  ii. For each customer class (e.g. commercial, residential, industrial), provide the percentage of AMI meters.

Response: Yes, the company is currently in the process of deploying AMI technology. The deployment is expected to be completed by the end of 2019. The percentage of AMI meters in the company's Oregon service territory overall and for each customer class are projected to be as follows:

- Overall – 94 percent
- Commercial 92 percent
- Industrial 85 percent
- Residential 96 percent

It should be noted, however, that these numbers are anticipated installation percentages averaged broadly across the company's Oregon service territory. Installation percentages are unlikely to be consistent across the company's largely rural, non-contiguous Oregon service territory; indeed, customers in certain areas have already indicated a greater level of interest in opting out of AMI installation than others.

c. Describe the backhaul technology the utility employs on its Oregon distribution system. Please provide any relevant context about how these technologies are distributed across the utility system and why. Please include, but do not limit responses to

Response: The communications network at PacifiCorp is focused on the transmission system to provide reliable operations of the Bulk Electric System; that is, elements of the electrical system operating at voltages higher than the typical distribution system. However, over time, communications have been expanded to distribution substations in support of load and generation interconnection projects. The majority of the infrastructure is TDM based leases (T1) from the Local Exchange Carrier with a few packet based MPLS connections. Additionally, there are select distribution locations that have been connected to the company's private microwave and/or fiber networks when adjacent to existing infrastructure that made the investment in infrastructure feasible. Finally, there is a population of distribution substations that are connected via analog and digital multiple address system (MAS) radio for SCADA polling.

d. What technology is being used to communicate with field devices as described in Question 1? Please also provide an estimate of what percentage of the Oregon distribution system is communicating with these field devices, if any.

Response: In general, most field devices are not being communicated with in real-time. The table below lists current installed distribution devices and method of communications, if utilized.

Device	**Communications**
Breakers/relays	Currently SCADA information is only communicated back to Monarch energy management system (EMS) for breakers and relays contained in substations. Communication methods from substations back to control centers where Monarch servers reside include; MAS radios, private carrier owned lease lines, fiber optic cable, microwave radios, and one location which uses a cellular solution.
Line reclosers	No line reclosers are currently set up for remote communication, but a project (Lincoln City DA) in the company is moving forward that will provide the remote SCADA capability for a small quantity (nine) of devices.
Line fuses	No communications
Sectionalizers	No communications
Fusesavers	No communications
TripSavers	No communications after installation
FCIs	No communications
cFCIs	No distribution level communicating fault indicators currently installed on the Oregon system.
Network Monitoring System	Remote monitoring and controlling capability for underground network

	system specific equipment such as network protectors via fiber networked back to respective substation SCADA installations. Similar to other SCADA installations, this communicates back to Monarch EMS to allow dispatch monitoring and control of the network protectors. Currently 80 percent capable with a 2020 plan for 100 percent capable.
Regulating devices	No communications to field installed regulating devices.
Lincoln City DA Pilot	The Lincoln City DA project will use peer-to-peer radios to communicate SCADA traffic between the field installed line reclosers and the Devils Lake substation. A radio in the peer-to-peer scheme will be installed in the substation connected to a remote terminal unit (RTU) located in the substation that will communicate back via private carrier lease line to the Monarch master for remote dispatch monitoring and control capability of the reclosers. The reclosers will be automatically monitored and operated by the automation scheme residing in the station RTU, but they will also have the ability to be monitored and controlled by dispatch.

Question C.3

3) Performance:

a. What levels of reliability and other performance factors does the utility plan for?

Response: PacifiCorp plans for reliability performance to be stable at a system (state) level, year-on-year. This recognizes that as the system changes due to new customers, aging infrastructure, environmental modifications or other factors, the reliability level at a specific location or to a specific customer may lower temporarily. However, at the same time, other locations will have equivalent improvement levels such that the system's reliability metrics, as measured by outage duration (SAIDI), outage frequency (SAIFI) and momentary interruption event frequency ($MAIFI_e$) are targeted to remain stable over time.

i. Please indicate whether metrics are mandated or driven by company practice or industry standard?

Response: Metrics that must be provided in annual reports are mandated by Oregon Administrative Rules (Chapter 860, Division 023) and also aligned with industry standards. Specific performance levels are not mandated by either rules or standards.

ii. Please provide the utility's performance across the metrics over the past 5 years?

Response: See charts below for reliability results for reliability reporting regions and state performance; the top chart shows total performance, while the lower chart shows underlying performance, i.e. performance after removing planned and pre-arranged outages and major events**.**

Excluding Major Events	SAIDI					SAIFI					MAIFIe				
OR REGION	**2014**	**2015**	**2016**	**2017**	**2018**	**2014**	**2015**	**2016**	**2017**	**2018**	**2014**	**2015**	**2016**	**2017**	**2018**
Central OR	63	60	45	52	39	1.10	0.49	0.40	0.41	0.62	2.97	2.59	2.50	3.29	2.97
CoastPlus	110	87	98	111	86	1.06	0.76	1.01	1.55	1.01	4.42	4.22	3.51	3.59	3.70
Northeast OR	108	120	87	95	129	1.18	1.04	0.66	1.05	1.71	1.37	4.41	5.34	4.63	2.92
South OR	128	133	123	106	110	1.12	0.83	1.01	0.98	1.56	3.32	4.02	3.54	4.41	3.96
Willamette Valley	172	176	157	177	124	1.32	1.66	1.76	2.02	1.23	6.88	3.16	2.79	2.70	3.22
OREGON	**123**	**120**	**111**	**114**	**98**	**1.15**	**0.94**	**1.07**	**1.26**	**1.23**	**4.23**	**3.65**	**3.23**	**3.54**	**3.59**

Including Major Events	SAIDI					SAIFI					MAIFIe				
OR REGION	**2014**	**2015**	**2016**	**2017**	**2018**	**2014**	**2015**	**2016**	**2017**	**2018**	**2014**	**2015**	**2016**	**2017**	**2018**
Central OR	99	117	74	102	83	1.26	0.88	0.70	0.56	1.09	2.97	2.59	2.50	3.29	2.97
CoastPlus	211	175	336	213	158	1.54	1.21	1.97	2.31	1.28	4.42	4.22	3.51	3.59	3.70
Northeast OR	205	289	146	147	164	1.39	1.70	0.92	1.17	1.80	1.37	4.41	5.34	4.63	2.92
South OR	146	389	184	442	166	1.26	1.28	1.38	1.85	1.83	3.32	4.02	3.54	4.41	3.96
Willamette Valley	597	240	264	371	131	2.43	1.87	2.23	2.65	1.26	6.88	3.16	2.79	2.70	3.22
OREGON	**250**	**265**	**223**	**312**	**146**	**1.57**	**1.35**	**1.59**	**1.93**	**1.47**	**4.23**	**3.65**	**3.23**	**3.54**	**3.59**

b. What is the utility's plan/process to address the various types of failures that occur on the distribution system?

Response: PacifiCorp has discussed its assessment and improvement process in response to faults (i.e. reliability events as measured by outages) on the system in response to Question A.1.vi.

c. What percentage of outages originate at the distribution level?

Response: During 2018, for underlying performance, 85.7 percent of the customer minutes of outage were attributable to distribution level outages (including distribution substations).

d. **What limits or restrictions on native load capacity, both physical and regulatory, do you currently place on the distribution system?**

Response: Distribution system capacity is limited by the physical (thermal and voltage) capabilities of the specific distribution equipment and conductors.

<u>Question C.4</u>

4) Security

a. **What controls and processes are used to secure consumer and system data, IT/communication systems, and physical infrastructure?**

Response: PacifiCorp has implemented policies necessary to ensure the confidentiality, integrity, and availability of information while it is being created, accessed, stored, transmitted or received, and provide for the security of the associated computing resources. The company's goal is to protect assets and information against unavailability, unauthorized or unintentional access, modification, destruction, or disclosure.

PacifiCorp has a 24x7 physical/cyber Security Operations Center (SOC) that performs real-time monitoring, investigation, and incident response functions that are critical to protect assets and information. The SOC is also a resource for employees to report incidents or suspicious activity, or request security assistance, to limit the potential impact or likelihood and/or expedite recovery from a physical/cybersecurity risk.

PacifiCorp has a robust and recurring security training and awareness program that educates all personnel on risks, resources, and responsibilities to protect personnel, assets, and information. This training program is responsible for bringing PacifiCorp's employee testing phishing click rate down from approximately 16 percent in mid-2016 to approximately 0.1 percent in mid-2019.

PacifiCorp has implemented the SANS "Top 20" Critical Security Controls, which includes approximately 140 specific sub-controls that enhance security across nearly all aspects of cyber systems, including:

- Documenting hardware and software inventories.
- Ensuring systems are designed and configured securely.
- Ensuring people, processes, and procedures are in place to protect assets and information.
- Verifying controls and driving continuous improvement.

b. **What protocols and cooperative arrangements with NERC, NIST or other entities are used to identify threats and available defense measures?**

Response: PacifiCorp maintains ongoing coordination and information-sharing relationships with a variety of public and private entities, including:

- National/International: the Federal Bureau of Investigation, the U.S. Department of Homeland Security, the Central Intelligence Agency, the Department of Defense Joint Intelligence Operations Centers, the Centre for Energy Advancement through Technological Innovation, the Electricity Information Sharing and Analysis Center.
- State: Fusion Centers, multiple National Guard Units.
- Local: Local law enforcement entities, other utilities.
- Public: Rewards programs, community outreach.

PacifiCorp also utilizes a variety of private threat intelligence subscription services and receives threat and vulnerability information and intelligence from Berkshire Hathaway Energy's Cyber Threat Intelligence Cell (CTIC).

The CTIC facilitates security information sharing across all Berkshire Hathaway Energy companies, and with the larger Berkshire Hathaway family of businesses. The CTIC also facilitates participation in the U.S. Department of Homeland Security's National Cybersecurity Assessments and Technical Services program, which provides actionable threat and vulnerability intelligence.

Question C.5

5) DERs:

a. What is the current and forecasted extent of DER deployment by type, size, and geographic dispersion?[4]

Response:

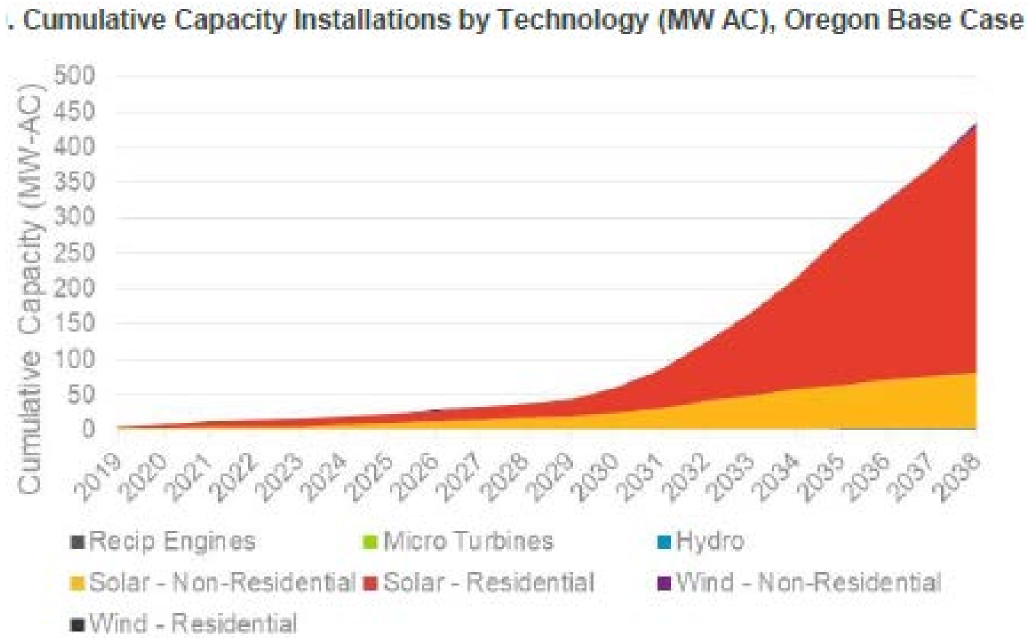
A) Distributed Generation Resources

Currently, PacifiCorp does not forecast distributed energy resources in its distribution system planning. However, as of June 30, 2019, the company has approximately 7,000 private generation projects interconnected in its Oregon service territory; resulting in approximately 70.614 MW DC of capacity.

Every two years, the company develops a private generation forecast that is used to inform PacifiCorp's IRP planning process. The purpose of this study is to project the level of private generation resources PacifiCorp's customers might install over the 20-year IRP planning horizon under low, base, and high penetration scenarios. The most recent report, conducted in 2018, forecasts approximately 435 MW AC of additional private generation will be installed in the Oregon service territory by 2038 (as illustrated below). The full report is available at: https://www.pacificorp.com/energy/integrated-resource-plan/support.html.

[4] DERs may include small generator (e.g., solar pv), distributed energy storage, demand response, energy efficiency, and EVs. However, Staff welcomes the inclusion of additional DERs that are not contemplated in this definition.

Figure 1: Cumulative Capacity Installations by Technology (MW AC), Oregon Base Case



B) Distributed Energy Storage

Currently, PacifiCorp does not forecast distributed energy resources in its distribution system planning. However, as of June 30, 2019, the company has 18 energy storage projects interconnected; resulting in 217 kW of capacity. Though the company currently has not developed forecasts of potential adoption of distributed energy storage, every two years, the company conducts a renewable resource assessment that evaluates various renewable energy resources that is used to inform PacifiCorp's IRP planning process. The purpose of this study is to conduct a screening-level of costs and includes a comparison of technical capabilities, capital costs, and O&M costs that are representative of renewable energy and storage technologies. The full report is available at: https://www.pacificorp.com/energy/integrated-resource-plan/support.html.

C) Energy Efficiency and Demand Response

Currently, PacifiCorp is developing tools to understand the potential for energy efficiency and demand response at a feeder level. The tool will enhance the PacifiCorp's existing DER Analysis Spreadsheet, which is discussed earlier in this document. Currently, for PacifiCorp, planning for all cost-effective, reliable, and feasible energy efficiency begins with its IRP. Guidance on how energy efficiency should be incorporated into resource portfolios and action plans was provided by the OPUC in 2007.[5] Consistent with these guidelines, PacifiCorp's process for identifying least cost/risk conservation resources to include in its IRP action plan.

[5] Order 07-002, Docket UM 1056, January 8, 2007.

Every two years, the company develops a Conservation Potential Assessment (CPA)[6] over a 20 year planning horizon that is used to inform PacifiCorp's IRP planning process. The CPA provides a broad estimate of the size, type, location, and cost for demand response in all states and energy efficiency in all states except Oregon. Specifically for long-term forecasting of energy efficiency in Oregon, ETO regularly models the available energy efficiency resource potential utilizing an internal Resource Assessment model (RA Model). Based on outputs from the RA Model, ETO provides a 20-year resource technical achievable potential to PacifiCorp for use in its IRP. The technical achievable potential of energy efficiency and the market potential demand response, representing potential at all costs, is provided to the IRP model for economic screening relative to supply-side alternatives.

Based on the 2017 IRP, the IRP selected the energy efficiency and demand response targets below as a least-cost, least-risk resource.

Table 1: Energy Efficiency Targets from PacifiCorp's 2017 IRP

Energy Efficiency Energy (MWh) Selected by State and Year

State	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
CA	7,450	7,340	5,130	5,250	5,190	5,070	4,800	4,590	4,420	4,000
OR	198,680	197,720	191,550	166,590	141,410	119,530	104,130	102,010	88,400	83,220
WA	44,600	34,300	36,170	33,650	38,370	35,970	34,060	34,300	31,830	28,860
UT	333,400	240,790	255,190	245,260	253,480	239,730	249,190	249,390	237,350	246,620
ID	17,570	22,950	23,060	19,200	19,920	18,630	18,160	19,280	18,640	19,220
WY	43,800	56,030	59,550	56,690	74,090	75,440	76,460	76,450	80,390	76,950
Total System	645,500	559,130	570,650	526,640	532,460	494,370	486,800	486,020	461,030	458,870

Energy Efficiency Energy (MWh) Selected by State and Year

State	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
CA	4,880	4,320	3,880	4,190	3,830	3,080	2,690	2,200	1,240	1,060
OR	82,810	76,970	73,750	73,890	71,890	74,280	68,090	67,880	72,400	72,350
WA	27,160	24,780	22,300	20,360	19,630	15,260	12,870	9,860	8,590	6,760
UT	241,950	228,310	213,700	216,120	220,390	182,340	161,080	135,140	124,270	127,670
ID	18,120	17,080	16,590	16,000	15,510	13,010	12,190	9,970	8,910	9,180
WY	69,050	62,320	62,910	58,670	56,430	47,440	40,530	36,690	36,310	36,460
Total System	443,970	413,780	393,130	389,230	387,680	335,410	297,450	261,740	251,720	253,480

[6] The CPA is available at: https://www.pacificorp.com/energy/integrated-resource-plan/support.html.

Table 2: Demand Response Targets from PacifiCorp's 2017 IRP

State/Product by Year	2028	2029	2030	2032	2033	2034	2035	Total/Products (MW)
California Load Control - Res./Com./Indust. Cooling & Wtr Htg	2.4							2.4
California Curtailment Agreements	1.2							1.2
California Load Control - Irrigation	3.7							3.7
Oregon Load Control - Res./Com./Indust. Cooling & Wtr Htg	11.4	24.7		3.3				39.4
Oregon Curtailment Agreements	35.0							35.0
Oregon Load Control - Irrigation	12.8							12.8
Washington Load Control - Res./Com./Indust. Cooling & Wtr Htg	3.8	9.2						13.0
Washington Curtailment Agreements	9.1							9.1
Washington Load Control - Irrigation	4.8							4.8
Utah Load Control - Res./Com./Indust. Cooling & Wtr Htg	68.4							68.4
Utah Curtailment Agreements	75.3		4.8			3.7		83.7
Utah Load Control - Irrigation	3.1							3.1
Idaho Load Control - Res./Com./Indust. Cooling & Wtr Htg		3.4						3.4
Idaho Curtailment Agreements		1.9						1.9
Idaho Load Control - Irrigation	10.9	3.9		3.4			3.1	21.3
Wyoming Load Control - Res./Com./Indust. Cooling & Wtr Htg	4.8							4.8
Wyoming Curtailment Agreements	40.7				3.1			43.8
Wyoming Load Control - Irrigation	1.9							1.9
Cumulative Total by Year (MW)	**289.3**	**43.1**	**4.8**	**6.7**	**3.1**	**3.7**	**3.1**	**353.6**

a. *Energy Efficiency*

For the 2019 IRP, the estimated technical achievable potential of energy efficiency over the 20 year planning period in Oregon is approximately 3.6 million megawatt-hours (MWh). The technical achievable potential, representing available potential at all costs, is provided to the IRP model for economic screening relative to supply-side alternatives.

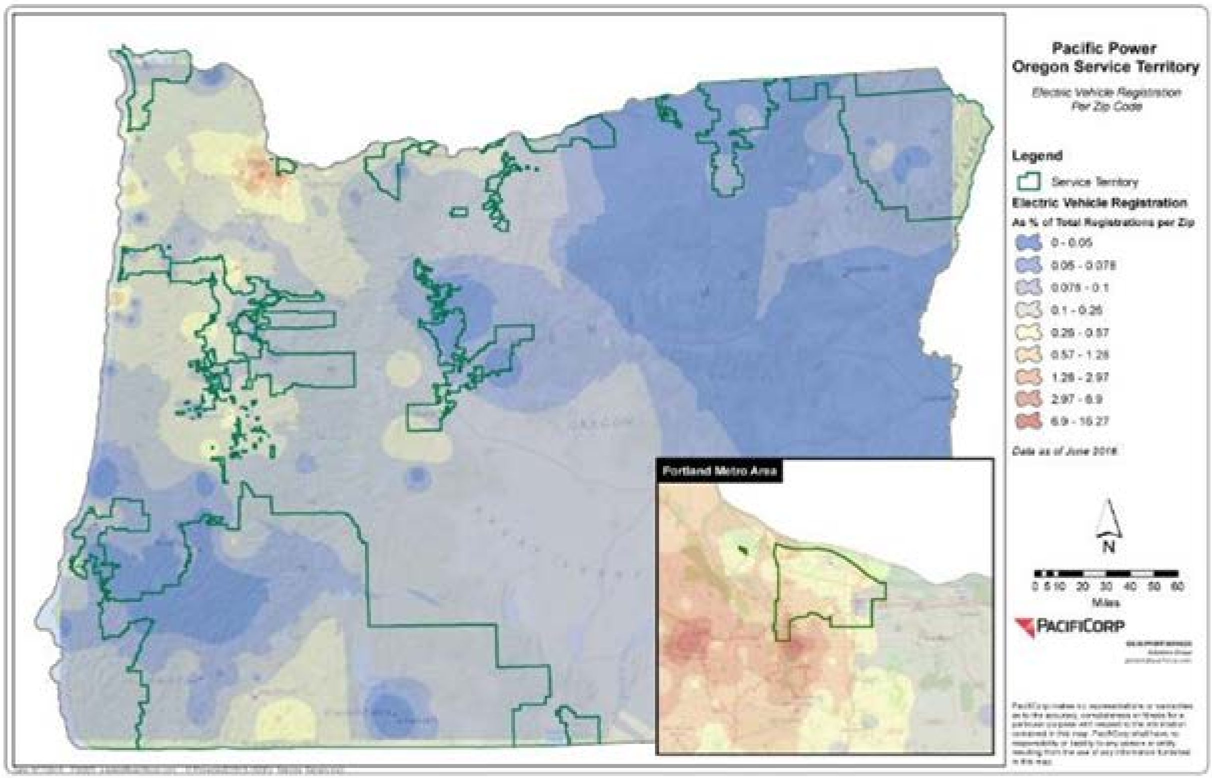
b. *Demand Response*

For the 2019 IRP, the estimated technical achievable potential of demand response over the 20 year planning period in Oregon is approximately 157 MW of summer peak and approximately 177 MW of winter peak.

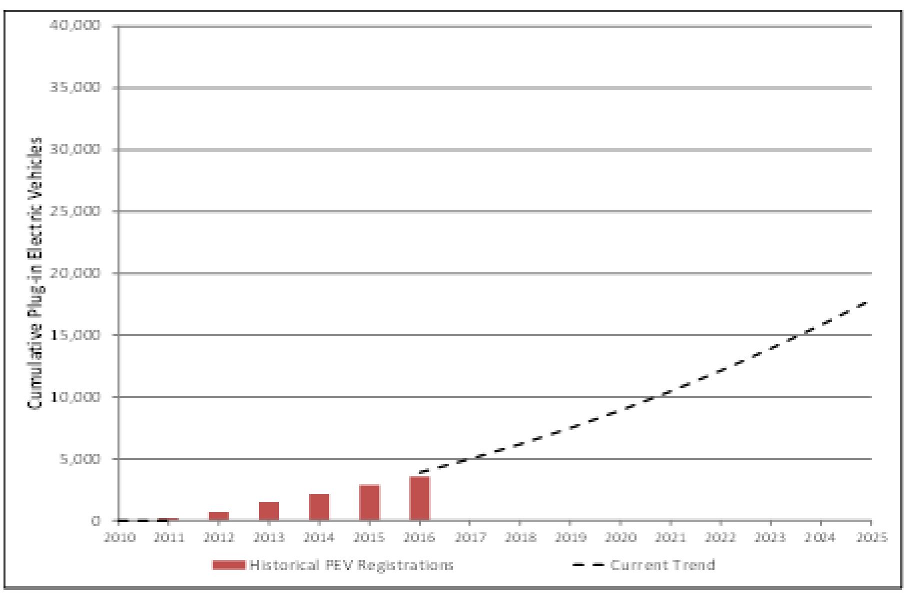
D) Electric Vehicles

Currently, PacifiCorp does not explicitly incorporate an EV load forecast in distribution planning or in its IRP. Rather, the current load forecast process relies on historical actual sales, which include EV demand, to project future demand. PacifiCorp is evaluating methodologies to estimate the potential load impacts specifically attributable to EVs at a jurisdictional-level for the 2019 IRP Update.

PacifiCorp is aware that as of December 2018, the Oregon Department of Environmental Quality (DEQ) estimates there were 3,956 residential EVs registered in PacifiCorp's Oregon service territory. In 2016, PacifiCorp received ZIP code-level registration data from DEQ, which was used to create the map below, included in the company's April 2017 Supplemental Application for Transportation Electrification, filed in docket UM 1810.



In that same filing, PacifiCorp created a forecast of EV adoption based on historical ZIP code-level registration data:



b. What is the status of small generator interconnections in the Oregon service area (< 10 MW)?

i. For each year from 2014 - 2018, please provide the number and total MW of small generators, by type, located in Oregon, interconnected to the utility, that began commercial operation in that year.

Response: This information can be found in PacifiCorp's Annual Interconnection Report, filed pursuant to OAR 860-082-0065(3).

Year	Type	Number Interconnected	Total Size (MW)
2014	NA	0	0
2015	Hydro	1	0.032
2015	Geothermal	1	1.75
2016	Solar	2	8.83
2017	Solar	6	57.9
2018	Solar	11	90.1

ii. Please provide the current number of active interconnection requests for small generators located in Oregon that have not yet executed an interconnection agreement.

Response: 23

iii. Please provide the current number of active interconnection requests for small generators located in Oregon that have an executed interconnection agreement, but have not reached commercial operation.

Response: Five

iv. Please provide the current number of small generators located in Oregon interconnected to the utility that have an executed interconnection agreement and are currently operating.

Response: 41

c. What data and information are made available to distribution-level interconnection applicants prior to making an interconnection request? How is that information provided?

Response: PacifiCorp maintains a publicly available summary sheet on its OASIS site with all prior interconnection requests. The summary sheet contains information about prior interconnection requests such as request date, size, state, county, requested point of interconnection, and fuel type. The summary sheet also contains links to any studies that were produced for the interconnection request. The studies provide all of the requirements that PacifiCorp identified for the interconnection request, as well as cost estimates and expected timelines for the completion of requirements.

Beginning September 1, 2019, as part of the UM 2000 interconnection data proceedings, Order Nos. 19-217 and 19-272, PacifiCorp will make publicly available a summary sheet on its OASIS site with the following information for the company's distribution substations and feeders in Oregon:

- For each substation:
  - Name.
  - Approximate location/County
  - Substation Voltage
  - Number of transformers
  - Transformer voltages
  - Communications – SCADA Y/N

- For each feeder:
  - Identifier
  - Peak load
  - Line Capacity at the point where it leaves the substation
  - DER connected capacity
  - DER capacity in queue

PacifiCorp remains engaged in the UM 2000 interconnection data workgroup that will help determine what additional data may be provided on that publicly available summary sheet in future revisions.

As required by OAR 860-082-0020, PacifiCorp also provides a 'Pre-Application Process' under which PacifiCorp provides information to interconnection customers regarding potential requests. This includes information such as relevant existing studies and other materials that may be used to help interconnection customers understand the feasibility of interconnecting a small generator facility to a particular point on PacifiCorp's system. Additionally, PacifiCorp also has a pre-application report process under its OATT Small Generator Interconnection Procedures that provides a similar opportunity for interconnection customers to request information about a potential interconnection point.

d. Has the utility taken any steps to implement the IEEE 1547 standard or other requirements for the interoperability of DERs and the distribution system?

Response: PacifiCorp continues to use IEEE 1547 (2003) standards to evaluate interconnection applications for distributed energy resources. The company intends to implement the advanced inverter functionalities defined in the IEEE 1547-2018 standard, however, since the process to test inverters' compliance with the revised standards have not yet been finalized, there are currently no inverters available in the market that fully comply with IEEE 1547-2018. The company has been actively involved in industry efforts to modernize IEEE 1547 and NERC interconnection standards and further collaborated with Utah State University to test and verify smart inverter capabilities. The company is currently working with the Electric Power Research Institute to study the impact of adoption of IEEE 1547 (2018) compliant inverters on the local distribution system and identify potential updates to PacifiCorp's interconnection policy designed to leverage smart inverter benefits.[7]

e. How does the utility define microgrids? Please list any microgrids in the utility's service territory.

Response: A microgrid is generally defined as a group of interconnected loads and DER, within clearly defined electrical boundaries, that act as a single controllable entity with respect to the grid and can connect and disconnect from the grid to enable it to operate in either grid-connected or islanded mode. The company does not maintain a list of microgrids connected to its system: however, it is aware of customers using back-up power to operate their facility as a microgrid. PacifiCorp is also working with Utah State University and Oregon State University investigating microgrid feasibility, implementation, and impacts on the distribution system.

<u>Question C.6</u>

6) Customer values:

a. Please describe the surveys and other market research the utility performs to understand customer values, needs, and interests related to distribution system planning.

Response:

- Mastio & Company conducts an annual survey with managed accounts (industrial and commercial) during April each year.
- JD Power conducts syndicated studies for residential and business customers. Residential surveys are conducted in 4 waves (January and February, April and May, July and August, and October and November) with final results for the year available in December. Business customers are surveyed in two different waves (February through June and July through October) with results available in November.
- Escalent (previously known as Market Strategies Inc.) conducts annual web surveys for residential and commercial customers based on agreed upon questions (standard and topic specific) as provided by PacifiCorp. Residential surveys are conducted in 4 waves (February, May, August, and November) with final results available in December. Business customers are surveyed in two different waves (May and November) with final results available in December.

In addition to these ongoing surveys, PacifiCorp conducts several other research projects during the year. Most of these studies occur on an ad hoc basis and do not have a set schedule.

[7] Electric Power Research Institute, Advancing Smart Inverter Integration in Utah: Final Report, Feb 19, 2019. Available at: https://www.epri.com/#/pages/product/000000003002015334/?lang=en-US.

i. What are the major findings from this research over the past 5 years?

Response: Over the last five years, survey results related to perceptions around utility distribution planning have remained consistent year over year. Business customers tend to be slightly more satisfied than residential customers when evaluating how well the utility does on "Efforts to develop energy supply plans for the future", "Keeping the electrical system in good working order", and "Planning for and investing in electrical facilities".

Each year PacifiCorp reviews survey results and identified the following areas of focus as follows:

- In 2015, the focus was on delivering on the basics, product and service options, and engaging customers.
- In 2016, the focus was on corporate citizenship, communications, outage information and customer service.
- In 2017, the focus was on outage communication, corporate citizenship and communications
- In 2018, the focus was on price/value, employee engagement, brand engagement, customer tools and customer solution
- In 2019, the focus is on Corporate Citizenship, Communication, Price and Product Experience.

ii. How does the utility use the results of this research?

Response: PacifiCorp conducts research with residential customers, business customers, irrigators, and opinion leaders throughout its six-state service territory. The various research projects determine customer needs and help identify ways to improve customer satisfaction. Since customer expectations continually evolve, the surveys reveal how the company compares to other utilities and measures what customers value and expect from their utility. The company analyzes the attributes and diagnostics from the studies to identify areas for improvement and uses the results to set goals, review and improve processes, and inform planning.

Section D

In Section D all interested stakeholders are asked to provide responses to the following questions:

Question D.1

1) Commission principles for distribution system planning:

a) What principles should the Commission adopt? Please explain and define.

Response: Establishing a set of principles for the distribution planning process is a critical first step in this investigation. PacifiCorp would propose the following principles for consideration:

- Maintain and enhance the safety, security, reliability, and resilience of the electric grid.
- Ensure the provision of reliable electric service at fair and reasonable costs.
- Ensure optimized utilization of electricity grid assets and resources to minimize total system costs.
- Move toward the creation of efficient, cost-effective, accessible grid platforms for new products, new services, and opportunities for adoption of new technologies.
- Enable greater customer engagement.
- Ensure continuation of utility compliance with federal regulatory requirements, including serial-queue order interconnection study requirements or an approved alternative interconnection study process that meets the utility's legal regulatory requirements by: (1) providing a fair and objective basis for conducting interconnection studies, and (2) respecting the rights of interconnection customers whose interconnections are subject to federal interconnection policies.
- Facilitate comprehensive distribution system planning.

Distribution system planning is a complex endeavor, combining long-term planning with the short-term needs of retail customers, that could theoretically involve any number of goals, any number of potential investments, and a wide range of costs, so it is important to ensure the goals and principles that guide the effort are clearly defined. New investments in the distribution system are likely to be socialized across system users, so the planning process should ensure that investments identified by the utility are the types of investments that (1) the Commission considers appropriate for investment and cost recovery, and that (2) bring value to customers that are in line with Commission objectives.

The Company looks forward to stakeholder discussions on this issue.

b) What level of specificity is most helpful to include in principles?

Response: Any meaningful distribution planning process will require the Commission to provide clear guidance to utilities. That said, each electric utility in the state is differently situated, a fact with huge significance for distribution system planning. For example, each utility has different levels of density, different geographic attributes, different existing interconnection queued requests, different load / delivery profiles, and different customer bases. Those same distinctions exist even within each utility's service territory.

As a result, a distribution system investment may be cost-effective and increase reliability in one area, while that same investment may increase system costs unnecessarily and undermine reliability if located in another area. Consequently, the most appropriate distribution system investments will vary by utility, and within a utility, will vary by location.

Thus, it may be appropriate to keep the principles themselves somewhat broad. That said, PacifiCorp is not wedded to any specific approach on this issue, so long as the principles themselves allow individual utilities to adopt plans that are most appropriate for their customers and their service territory.

Question D.

2) Maximizing customer value:

a) How you would define "maximize customer value" in the context of distribution system planning?

Response: New technologies and revived interest in customer choice are driving the need for the evolution of the distribution planning process. Nevertheless, the Commission's existing regulatory paradigm and core values provide an appropriate roadmap for determining how a utility can "maximize customer value" through distribution system planning, even when that planning involves modernization and technological change. As with other utility investments, utility distribution system planning should have the following *core principles*:

- Reliability – while distribution planning will necessarily entail accommodating a greater level of flexibility on the distribution system (and in some circumstances, may implicate the operation of the wider grid), that flexibility should not compromise the historically reliable operation of the electric system.

- Affordability – investments in the distribution system should not compromise any Oregonian's historical access to affordable electric service. There are any number of key components to ensuring affordability, but they include, for example, ensuring that locational value of generation is taken into account (including not only the value of the power itself, but also the level of investment required to accommodate delivery of distributed generation), and ensuring that customers are paying for system generation when it is needed, rather than when it is not.

- System Efficiency – the existence of new technologies makes any number of investments possible. The Commission should encourage technologies that create a more efficient system and reject those that unnecessarily encumber the utility system. Programs, technologies, or investments that undermine system efficiency will ultimately make it more difficult to operate the grid efficiently and undermine the flexibility and affordability of options going forward.

In addition to these core principles, distribution system planning should have additional objectives, including the following:

- Customer Enablement – some utility customers wish to exercise greater control over their energy choices than they have enjoyed in the past. Distribution system planning should increasingly assist such customers to better control their own energy choices. This control should not be unlimited or unconstrained, however, because individual customers do not exist in a silo—they are participants in a socially shared and deeply interconnected grid. Distribution system investments should aim to provide customers with greater flexibility and choices as the system evolves, but the core of the Commission's distribution system planning policies should focus on maximizing the value of grid investments to *all* utility customers, not just to a particular subset of customers.

- New Technology – more broadly, distribution system planning should evolve to allow a utility to better integrate distributed energy resources and clean technologies on the grid.

- Coordination – the distribution system plan should support, inform, and take input from the Integrated Resource Plan (IRP), local transmission system plans and regional transmission plans, while also respecting rights of existing queued customer load, interconnection, and transmission service requests.

- Fairness – despite the complexities associated with the greater integration of distributed energy resources on the system, the Commission should affirm its historical principle of equitably allocating system costs and avoiding cross-subsidization. As an analogous principle, third-parties who increase system costs should be financially responsible for the costs they cause.

b) What considerations (from Staff whitepaper or other thoughts) are most important to focus upon when maximizing customer value in planning for the distribution system?

Response: For distribution system planning to yield positive results for customers, the phrase "maximizing customer value" will need to be clearly defined. No planning process can be effective unless the planners know what problem they are solving for, particularly in the context of a system as complex as a multi-state electric system, with investments that generally require long-term commitments. For example, if the Commission determines that "maximizing customer value" means identifying potential upgrades that meet the core principles while taking steps to maximize the ability of the distribution system to absorb behind-the-meter customer-owned generation, that might require a different approach than if the Commission determines that "maximizing customer value" means identifying areas where commercial developers can site generation. Any number of potential planning goals could theoretically exist, and it is important to remember that the original use and design of the system may not immediately accommodate all goals that require significant investment. Such investments may result in socialized costs to all customers, depending on the applicable state or federal policies. Accordingly, in PacifiCorp's view, "maximizing customer value" should be evaluated against the core goals of the Commission's utility regulatory mission—reliability, affordability, and efficiency.

Question D.3

3) Evaluation of utility distribution system plans:

a) Which criteria or metrics should the Commission use in evaluating the proposed distribution plans (Plans)?

Response: Initially, PacifiCorp believes that the metrics used to evaluate distribution system plans should be simple and the evaluation criteria straightforward. As foundational investments on the distribution system increase and give rise to the capability for more complex grid functions, and as utilities and the Commission increase their understanding of the appropriate regulatory process and goals of distribution planning, it may be appropriate for the distribution plans to increase in complexity.

b) How will your organization evaluate and/or otherwise use the proposed Plans?

Response: PacifiCorp anticipates evaluating and using its distribution system plans using utility best practices and for their intended purposes—maintaining a safe, reliable distribution system to serve customers. That being said, PacifiCorp anticipates that the any regulatory process will not impede the core principles identified in Section 2 above.

c) How should distribution system plans be integrated with other planning activities, such as resource planning, interconnection, transmission, or others?

Response: While the answer to this question depends on the ultimate goals and content of the utility plans, as defined by the Commission, PacifiCorp does not anticipate that significant changes from its current approach are required. However, a few issues are worth noting at this point.

First, the distribution planning process has a logical connection to the Commission's IRP process in terms of informing the utility's investment decisions. That said, there are distinct differences between the planning processes (for example, the granularity of distribution system planning, the use of different models / tools for distribution system modeling, and some goals for distribution system investment). The IRP process is extensive and subject to specific timeframes. While distribution planning informs the IRP (and may ultimately inform it more deeply if deeper levels of distributed energy resource penetration are reached), it is a separate endeavor.

Second, it is critical to recognize that an increase in distributed generation, particularly for a utility with a non-contiguous system like PacifiCorp's, can have effects on energy transmission and interconnection issues beyond the distribution system. Significant behind-the-meter generation will reduce load and impact the transmission studies or require additional export.

Some circumstances could require additions to the distribution system that have significant cost impacts on the wider system, impact Federal Energy Regulatory Commission (FERC)-mandated requirements and processes, or (at some level of penetration) impact system reliability on the bulk electric system.

Third, the distribution system is inherently intertwined with the transmission system, so consistency in the rules and policies applicable to the different voltages is key. Indeed, FERC has recognized this interaction between the distribution and transmission systems when it issued its landmark orders standardizing generator interconnection procedures and agreements. For example, FERC's *pro forma* Large Generator Interconnection Procedures specifically include the potential for distribution upgrades due to an interconnection request. [8] Similarly, when establishing standardized rules for small generators,[9] FERC made a point to highlight that the *pro forma* Small Generator Interconnection Procedures and Small Generator Interconnection Agreement was consistent with NARUC's best practice suggestions, stating that "by doing so, we hope to minimize the federal-state division and promote consistent, nationwide interconnection rules."[10] In addition to FERC's recognition of this critical interaction, PacifiCorp's own queue processing approach further requires coordination because PacifiCorp's transmission function uses a single queue for all interconnection requests regardless of the voltage (distribution or transmission), generator size, or regulatory body with jurisdiction over the requested service.

Finally, there is also the potential for usage of the distribution system to facilitate wholesale power sales, triggering certain FERC requirements. Jurisdictional considerations depend on a number of factors including use of the particular facilities in interstate commerce, which can change over time.

d) What are reasonable options for stakeholder participation in the planning process: direct engagement in the development of plans, the review of draft and final plans, other?

Response: It is not unreasonable to provide for some review of a utility's distribution system plan. The key consideration is the intended purpose of the review. A distribution system plan may address longer-term system upgrades, but will also need to address reliability, load service, and customer costs. A long stakeholder process may not be appropriate to discuss technical engineering. A reasonable number of alternative scenarios could be incorporated into the planning process, similar to regional transmission planning processes, but distribution system plans may need to address detailed load service issues—raising, among other things, concerns over the confidentiality of customer usage data.

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[8] *See Standardization of Generator Interconnection Agreements and Procedures,* Order No. 2003, FERC Stats. & Regs. ¶ 31,146 (2003), order on reh'g, Order No. 2003-A, FERC Stats. & Regs. ¶ 31,160 (2004), order on reh'g, Order No. 2003-B, FERC Stats. & Regs. ¶ 31,171 (2004), order on reh'g, Order No. 2003-C, FERC Stats. & Regs. ¶ 31,190 (2005), Appendix A to Pro Forma LGIA ("Appendix A, Interconnection Facilities, Network Upgrades and Distribution Upgrades").

[9] *See Standardization of Small Generator Interconnection Agreements and Procedures*, Order No. 2006, FERC Stats. & Regs. ¶ 31,180 (2005), *order on reh'g*, Order No. 2006-A, FERC Stats. & Regs. ¶ 31,196 (2005).

[10] Order No. 2006 at P 502.

e) **How often should a utility distribution plan be submitted for Commission review?**

Response: PacifiCorp believes a logical approach would be to require a utility to submit a utility system distribution plan report for Commission review every two years to align with the IRP. The exact schedule may need to be discussed, but this would provide transparency to the Commission and stakeholders.

<u>Question D.4</u>

4) Planning Scenarios:

a) **How should the selection of scenarios used in distribution planning be determined?**

Response: A reasonable number of scenarios could be developed and selected through an open stakeholder engagement process. This input could complement the continued requirements for utilities to perform responsive engineering and planning on the distribution system to meet customer load needs in a safe, reliable manner, and would be responsive to customer requests and system conditions not covered in the scenarios evaluated in current distribution system planning.

b) **What criteria should be used by utilities to identify relevant planning scenarios?**

Response: The Company anticipates that Staff will conduct workshops that will allow the utilities to work with stakeholders to develop scenario identification and selection criteria. The selection criteria, however, should be sufficiently robust to prevent any requirement to study unrealistic scenarios that would not reflect actual operation.

<u>Question D.5</u>

5) Access to grid and planning data by customers and third parties:

Response: PacifiCorp recommends that the topics in Section 5 be discussed as part of a workshop process, similar to the workshops that have taken place in dockets UM 2000 and UM 2001.

PacifiCorp would also note that similar questions about access to grid and planning data have been raised in those dockets, as well as in docket UM 1930. In the interest of efficiency, and to avoid conflicting outcomes in dockets touching on similar issues, the outcomes of those dockets should help inform the answers to these questions about access to grid and planning data.

Finally, unlike aggregated data used in most transmission system planning processes, distribution system planning data may, by the very nature of the distribution system, rely heavily on information from specific customers. Such data may be considered highly confidential by those customers if it indicates future production or operations, so these expectations will need to be addressed. In addition, FERC standards of conduct and the prohibition on competitive disclosures of transmission capacity upgrades will need to be addressed to prevent inappropriate disclosure of non-public transmission information that could violate federal regulations or result in increased costs to customers due to speculative transmission service requests.

Throughout this process, it will be important to keep in mind the engineering complexity at issue. PacifiCorp looks forward to a discussion on the appropriate level of customer and third-party participation in the developing system plans. However, planning by committee without reasonable restrictions may lead to unintended consequences that threaten the reliability of the system or increase costs unnecessarily for customers. Stakeholder input on appropriate study scenarios can be helpful, and can provide a baseline for review of the final plan, but the utility bears the ultimate burden of maintaining reliability and serving load.

a) Discuss categories of data needed by third parties to:

i. Participate in developing system plans.

ii. Critically review proposed plans.

Response: Please see the general response to Question 5, above.

b) Identify any categories of data that may be unsuitable for access, e.g. for reasons of security, trade secret, customer privacy, or burdensomeness.

Response: Please see the general response to Question 5, above.

c) How should and in what format should the results of a hosting capacity analysis or native loading analysis be make available by utilities? Please indicate which formats are currently available and which are not currently available.

Response: PacifiCorp does not currently conduct system-wide hosting capacity analyses; please see the company's response to the utility portion of the questionnaire, Section A, Question 7.

d) How should the commission evaluate utility investments that enable more transparent interconnection data to be made available? What are the costs and benefits that the Commission should consider?

Response: Please see the general response to Question 5, above.

<u>Question D.6</u>

6) Are there other issues or topics not covered here that are relevant to discuss in distribution system planning? If so, what are they and why are they relevant?

Response: PacifiCorp looks forward to thoughtful discussions on distribution system planning going forward, but would mention a few additional points here:

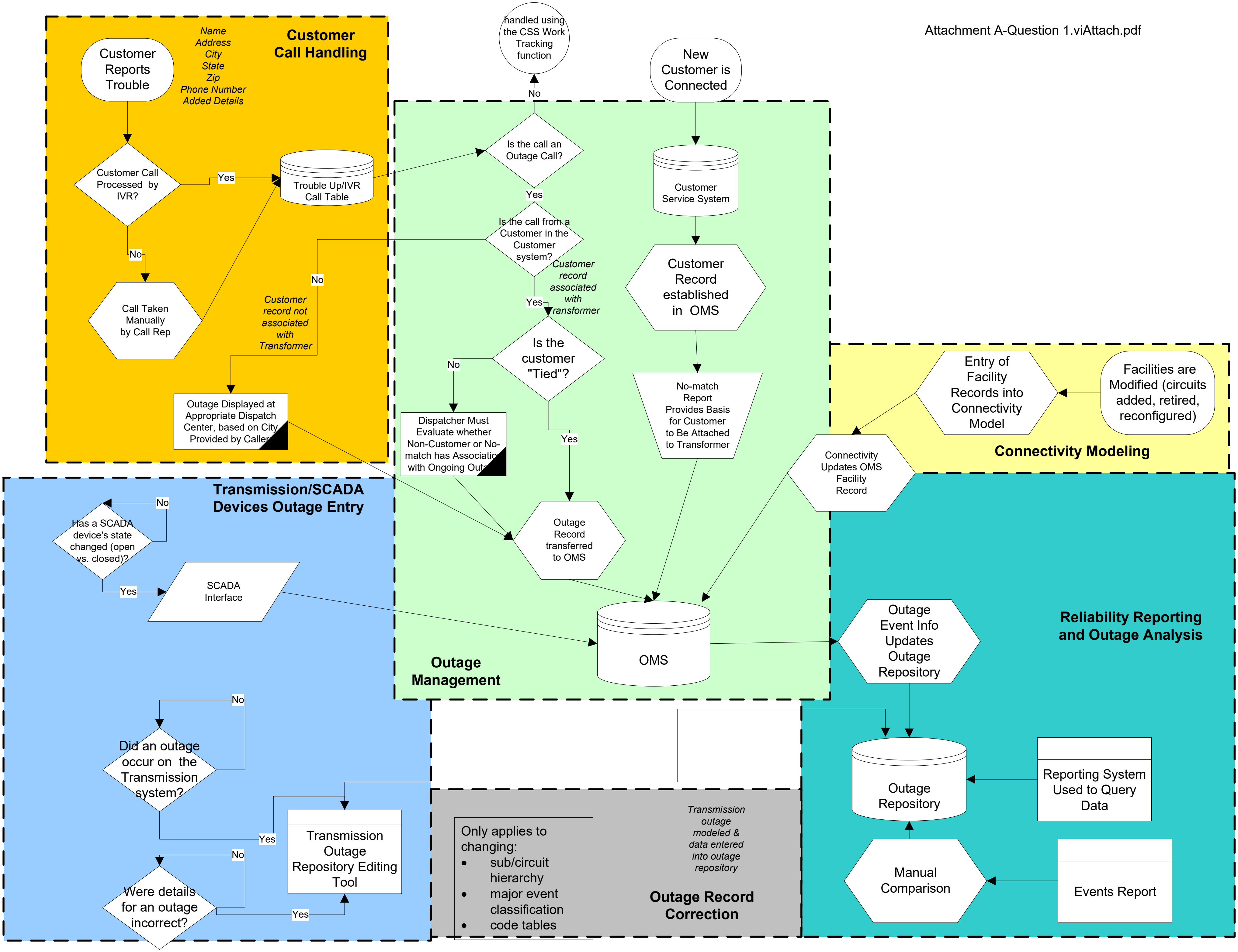
First, distribution system planning is a complex and evolving effort that must be undertaken in a deliberately phased and thoughtful manner. Each step in the process should create a solid foundation for the next. For example, most distribution grids across the country, including PacifiCorp's, currently lack the sensing and measurement tools needed for advanced grid functions. Once core goals and objectives are established, an obvious near-term step toward integrated distribution system operations would be to create a solid foundation for next-level system operations through system investments that allow for greater visibility and operational control in specific areas of PacifiCorp's system that might benefit most from such investments. This is just one example, but it is important that this effort be addressed one thoughtful step at a time.

Second, it is well recognized that at certain levels of distributed energy resource penetration, the net load characteristics at any given point on the distribution system can have material impacts not just on the distribution system, but also on the larger transmission and bulk power systems. As noted above, for a utility with a non-contiguous system like PacifiCorp's, it is possible these impacts will be seen at relatively low levels of distributed energy resource penetration in certain areas. If distributed resource planning is intended to bring customer benefits, these operational realities must be identified and acknowledged.

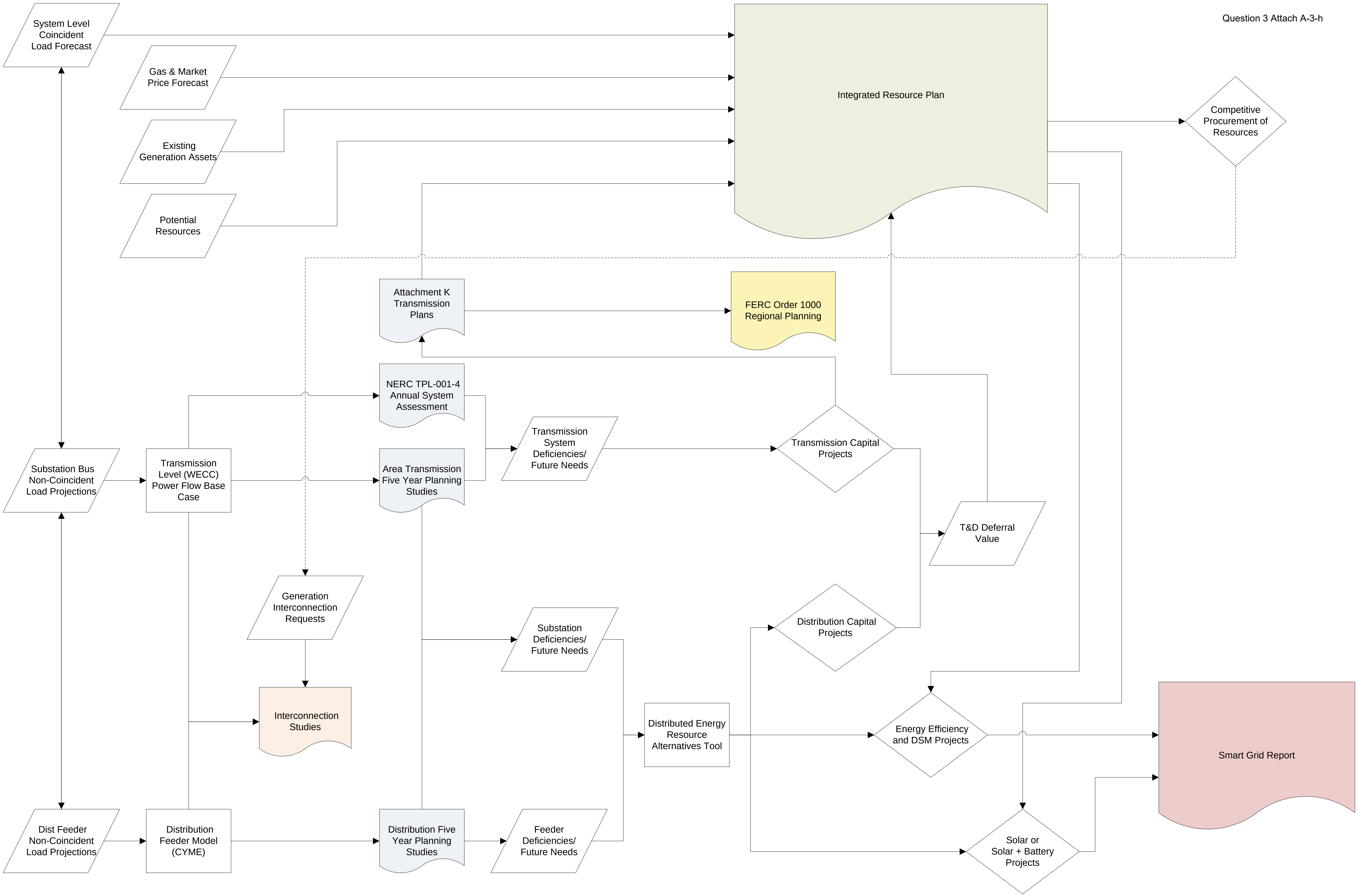
Third, while the Commission is appropriately looking to other states to provide guidance for distribution system planning efforts, PacifiCorp believes it is important for the Commission and stakeholders to identify and address the differences between risk, cost, and operational issues in regional transmission organization (RTO) and non-RTO states when RTO states are serving as the Commission model.

Attachment A

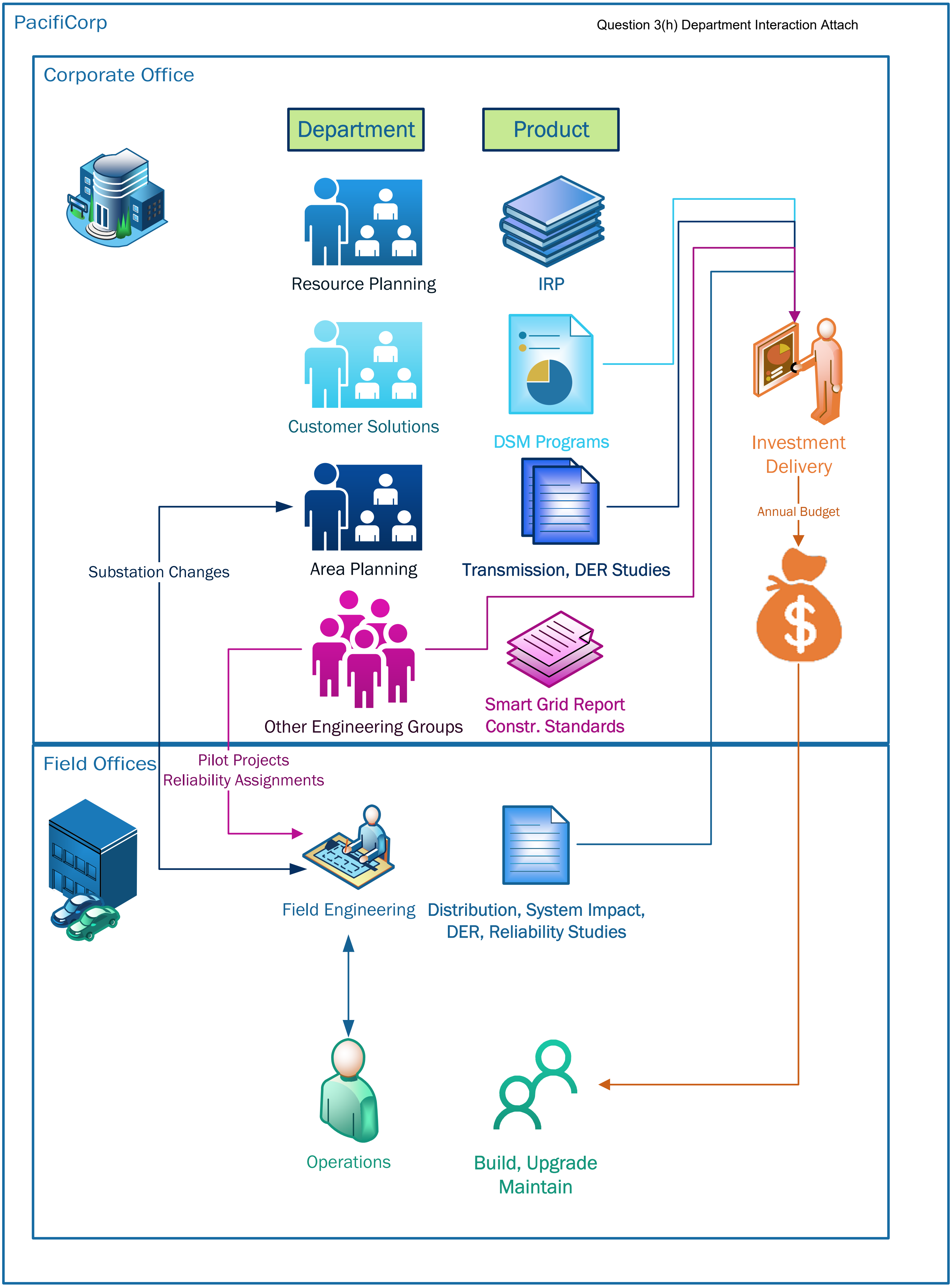
Attachment A-Question 1.viAttach.pdf



Attachment B


System Level Coincident Load Forecast
Gas & Market Price Forecast
Existing Generation Assets
Potential Resources
Integrated Resource Plan
Competitive Procurement of Resources
Attachment K Transmission Plans
FERC Order 1000 Regional Planning
NERC TPL-001-4 Annual System Assessment
Transmission System Deficiencies/ Future Needs
Transmission Capital Projects
Substation Bus Non-Coincident Load Projections
Transmission Level (WECC) Power Flow Base Case
Area Transmission Five Year Planning Studies
T&D Deferral Value
Generation Interconnection Requests
Substation Deficiencies/ Future Needs
Distribution Capital Projects
Interconnection Studies
Distributed Energy Resource Alternatives Tool
Energy Efficiency and DSM Projects
Smart Grid Report
Dist Feeder Non-Coincident Load Projections
Distribution Feeder Model (CYME)
Distribution Five Year Planning Studies
Feeder Deficiencies/ Future Needs
Solar or Solar + Battery Projects

Attachment C


PacifiCorp
Question 3(h) Department Interaction Attach
Corporate Office
Department
Product
Resource Planning
IRP
Customer Solutions
DSM Programs
Investment Delivery
Annual Budget
Area Planning
Transmission, DER Studies
Substation Changes
Other Engineering Groups
Smart Grid Report
Constr. Standards
Field Offices
Pilot Projects
Reliability Assignments
Field Engineering
Distribution, System Impact, DER, Reliability Studies
Operations
Build, Upgrade
Maintain

Attachment D

Operations & Maintenance Expense

Twelve Months Ending - December 2018
Allocation Method - Factor 2017 Protocol
(Allocated in Thousands)

Primary Account		Secondary Group Code		Alloc	Total	Oregon
5800000	OPER SUPERV & ENG	DNEX	Distribution O&M Expense	CA	44	0
5800000	OPER SUPERV & ENG	DNEX	Distribution O&M Expense	IDU	52	0
5800000	OPER SUPERV & ENG	DNEX	Distribution O&M Expense	OR	346	346
5800000	OPER SUPERV & ENG	DNEX	Distribution O&M Expense	SNPD	7,737	2,029
5800000	OPER SUPERV & ENG	DNEX	Distribution O&M Expense	UT	426	0
5800000	OPER SUPERV & ENG	DNEX	Distribution O&M Expense	WA	138	0
5800000	OPER SUPERV & ENG	DNEX	Distribution O&M Expense	WYP	105	0
5800000 Total					**8,848**	**2,375**
5810000	LOAD DISPATCHING	DNEX	Distribution O&M Expense	IDU	0	0
5810000	LOAD DISPATCHING	DNEX	Distribution O&M Expense	SNPD	11,542	3,027
5810000 Total					**11,542**	**3,027**
5820000	STATION EXP(DIST)	DNEX	Distribution O&M Expense	CA	65	0
5820000	STATION EXP(DIST)	DNEX	Distribution O&M Expense	IDU	453	0
5820000	STATION EXP(DIST)	DNEX	Distribution O&M Expense	OR	1,087	1,087
5820000	STATION EXP(DIST)	DNEX	Distribution O&M Expense	SNPD	4	1
5820000	STATION EXP(DIST)	DNEX	Distribution O&M Expense	UT	1,694	0
5820000	STATION EXP(DIST)	DNEX	Distribution O&M Expense	WA	254	0
5820000	STATION EXP(DIST)	DNEX	Distribution O&M Expense	WYP	519	0
5820000 Total					**4,076**	**1,088**
5830000	OVHD LINE EXPENSES	DNEX	Distribution O&M Expense	CA	212	0
5830000	OVHD LINE EXPENSES	DNEX	Distribution O&M Expense	IDU	430	0
5830000	OVHD LINE EXPENSES	DNEX	Distribution O&M Expense	OR	1,585	1,585
5830000	OVHD LINE EXPENSES	DNEX	Distribution O&M Expense	UT	6,165	0
5830000	OVHD LINE EXPENSES	DNEX	Distribution O&M Expense	WA	287	0
5830000	OVHD LINE EXPENSES	DNEX	Distribution O&M Expense	WYP	432	0
5830000	OVHD LINE EXPENSES	DNEX	Distribution O&M Expense	WYU	102	0
5830000 Total					**9,211**	**1,585**
5840000	UDRGRND LINE EXP	DNEX	Distribution O&M Expense	OR	1	1
5840000	UDRGRND LINE EXP	DNEX	Distribution O&M Expense	UT	1	0
5840000	UDRGRND LINE EXP	DNEX	Distribution O&M Expense	WYP	0	0
5840000 Total					**2**	**1**
5850000	STRT LGHT-SGNL SYS	DNEX	Distribution O&M Expense	SNPD	248	65
5850000 Total					**248**	**65**
5860000	METER EXPENSES	DNEX	Distribution O&M Expense	CA	91	0
5860000	METER EXPENSES	DNEX	Distribution O&M Expense	IDU	199	0
5860000	METER EXPENSES	DNEX	Distribution O&M Expense	OR	880	880
5860000	METER EXPENSES	DNEX	Distribution O&M Expense	SNPD	12	3
5860000	METER EXPENSES	DNEX	Distribution O&M Expense	UT	928	0
5860000	METER EXPENSES	DNEX	Distribution O&M Expense	WA	295	0
5860000	METER EXPENSES	DNEX	Distribution O&M Expense	WYP	310	0
5860000	METER EXPENSES	DNEX	Distribution O&M Expense	WYU	75	0
5860000 Total					**2,791**	**884**
5870000	CUST INSTL EXPENSE	DNEX	Distribution O&M Expense	CA	559	0
5870000	CUST INSTL EXPENSE	DNEX	Distribution O&M Expense	IDU	970	0
5870000	CUST INSTL EXPENSE	DNEX	Distribution O&M Expense	OR	5,107	5,107
5870000	CUST INSTL EXPENSE	DNEX	Distribution O&M Expense	UT	4,981	0
5870000	CUST INSTL EXPENSE	DNEX	Distribution O&M Expense	WA	1,300	0

Operations & Maintenance Expense
Twelve Months Ending - December 2018
Allocation Method - Factor 2017 Protocol
(Allocated in Thousands)

Primary Account		Secondary Group Code		Alloc	Total	Oregon
5870000	CUST INSTL EXPENSE	DNEX	Distribution O&M Expense	WYP	1,151	0
5870000	CUST INSTL EXPENSE	DNEX	Distribution O&M Expense	WYU	137	0
5870000 Total					**14,205**	**5,107**
5880000	MSC DISTR EXPENSES	DNEX	Distribution O&M Expense	CA	25	0
5880000	MSC DISTR EXPENSES	DNEX	Distribution O&M Expense	IDU	-2	0
5880000	MSC DISTR EXPENSES	DNEX	Distribution O&M Expense	OR	44	44
5880000	MSC DISTR EXPENSES	DNEX	Distribution O&M Expense	SNPD	834	219
5880000	MSC DISTR EXPENSES	DNEX	Distribution O&M Expense	UT	493	0
5880000	MSC DISTR EXPENSES	DNEX	Distribution O&M Expense	WA	-21	0
5880000	MSC DISTR EXPENSES	DNEX	Distribution O&M Expense	WYP	-100	0
5880000	MSC DISTR EXPENSES	DNEX	Distribution O&M Expense	WYU	-78	0
5880000 Total					**1,196**	**263**
5890000	RENTS-DISTRIBUTION	DNEX	Distribution O&M Expense	CA	55	0
5890000	RENTS-DISTRIBUTION	DNEX	Distribution O&M Expense	IDU	40	0
5890000	RENTS-DISTRIBUTION	DNEX	Distribution O&M Expense	OR	1,621	1,621
5890000	RENTS-DISTRIBUTION	DNEX	Distribution O&M Expense	SNPD	14	4
5890000	RENTS-DISTRIBUTION	DNEX	Distribution O&M Expense	UT	714	0
5890000	RENTS-DISTRIBUTION	DNEX	Distribution O&M Expense	WA	144	0
5890000	RENTS-DISTRIBUTION	DNEX	Distribution O&M Expense	WYP	507	0
5890000	RENTS-DISTRIBUTION	DNEX	Distribution O&M Expense	WYU	87	0
5890000 Total					**3,182**	**1,625**
5900000	MAINT SUPERV & ENG	DNEX	Distribution O&M Expense	CA	96	0
5900000	MAINT SUPERV & ENG	DNEX	Distribution O&M Expense	IDU	122	0
5900000	MAINT SUPERV & ENG	DNEX	Distribution O&M Expense	OR	1,100	1,100
5900000	MAINT SUPERV & ENG	DNEX	Distribution O&M Expense	SNPD	2,483	651
5900000	MAINT SUPERV & ENG	DNEX	Distribution O&M Expense	UT	1,357	0
5900000	MAINT SUPERV & ENG	DNEX	Distribution O&M Expense	WA	191	0
5900000	MAINT SUPERV & ENG	DNEX	Distribution O&M Expense	WYP	486	0
5900000 Total					**5,835**	**1,752**
5910000	MAINT OF STRUCTURE	DNEX	Distribution O&M Expense	CA	27	0
5910000	MAINT OF STRUCTURE	DNEX	Distribution O&M Expense	IDU	107	0
5910000	MAINT OF STRUCTURE	DNEX	Distribution O&M Expense	OR	453	453
5910000	MAINT OF STRUCTURE	DNEX	Distribution O&M Expense	SNPD	188	49
5910000	MAINT OF STRUCTURE	DNEX	Distribution O&M Expense	UT	786	0
5910000	MAINT OF STRUCTURE	DNEX	Distribution O&M Expense	WA	129	0
5910000	MAINT OF STRUCTURE	DNEX	Distribution O&M Expense	WYP	382	0
5910000	MAINT OF STRUCTURE	DNEX	Distribution O&M Expense	WYU	70	0
5910000 Total					**2,142**	**502**
5920000	MAINT STAT EQUIP	DNEX	Distribution O&M Expense	CA	223	0
5920000	MAINT STAT EQUIP	DNEX	Distribution O&M Expense	IDU	237	0
5920000	MAINT STAT EQUIP	DNEX	Distribution O&M Expense	OR	2,591	2,591
5920000	MAINT STAT EQUIP	DNEX	Distribution O&M Expense	SNPD	1,823	478
5920000	MAINT STAT EQUIP	DNEX	Distribution O&M Expense	UT	2,822	0
5920000	MAINT STAT EQUIP	DNEX	Distribution O&M Expense	WA	457	0
5920000	MAINT STAT EQUIP	DNEX	Distribution O&M Expense	WYP	861	0
5920000	MAINT STAT EQUIP	DNEX	Distribution O&M Expense	WYU	48	0
5920000 Total					**9,063**	**3,069**

Operations & Maintenance Expense

Twelve Months Ending - December 2018
Allocation Method - Factor 2017 Protocol
(Allocated in Thousands)

Primary Account		Secondary Group Code		Alloc	Total	Oregon
5930000	MAINT OVHD LINES	DNEX	Distribution O&M Expense	CA	7,531	0
5930000	MAINT OVHD LINES	DNEX	Distribution O&M Expense	IDU	4,428	0
5930000	MAINT OVHD LINES	DNEX	Distribution O&M Expense	OR	30,663	30,663
5930000	MAINT OVHD LINES	DNEX	Distribution O&M Expense	SNPD	1,825	479
5930000	MAINT OVHD LINES	DNEX	Distribution O&M Expense	UT	32,399	0
5930000	MAINT OVHD LINES	DNEX	Distribution O&M Expense	WA	5,198	0
5930000	MAINT OVHD LINES	DNEX	Distribution O&M Expense	WYP	6,675	0
5930000	MAINT OVHD LINES	DNEX	Distribution O&M Expense	WYU	853	0
5930000 Total					**89,571**	**31,142**
5931000	MAINT O/H LINES-LB P	DNEX	Distribution O&M Expense	CA	-152	0
5931000	MAINT O/H LINES-LB P	DNEX	Distribution O&M Expense	IDU	179	0
5931000	MAINT O/H LINES-LB P	DNEX	Distribution O&M Expense	OR	-1,296	-1,296
5931000	MAINT O/H LINES-LB P	DNEX	Distribution O&M Expense	UT	980	0
5931000	MAINT O/H LINES-LB P	DNEX	Distribution O&M Expense	WA	-150	0
5931000	MAINT O/H LINES-LB P	DNEX	Distribution O&M Expense	WYP	220	0
5931000 Total					**-220**	**-1,296**
5940000	MAINT UDGRND LINES	DNEX	Distribution O&M Expense	CA	446	0
5940000	MAINT UDGRND LINES	DNEX	Distribution O&M Expense	IDU	758	0
5940000	MAINT UDGRND LINES	DNEX	Distribution O&M Expense	OR	6,550	6,550
5940000	MAINT UDGRND LINES	DNEX	Distribution O&M Expense	SNPD	41	11
5940000	MAINT UDGRND LINES	DNEX	Distribution O&M Expense	UT	13,819	0
5940000	MAINT UDGRND LINES	DNEX	Distribution O&M Expense	WA	1,250	0
5940000	MAINT UDGRND LINES	DNEX	Distribution O&M Expense	WYP	1,602	0
5940000	MAINT UDGRND LINES	DNEX	Distribution O&M Expense	WYU	204	0
5940000 Total					**24,671**	**6,561**
5950000	MAINT LINE TRNSFRM	DNEX	Distribution O&M Expense	SNPD	975	256
5950000 Total					**975**	**256**
5960000	MNT STR LGHT-SIG S	DNEX	Distribution O&M Expense	CA	92	0
5960000	MNT STR LGHT-SIG S	DNEX	Distribution O&M Expense	IDU	102	0
5960000	MNT STR LGHT-SIG S	DNEX	Distribution O&M Expense	OR	889	889
5960000	MNT STR LGHT-SIG S	DNEX	Distribution O&M Expense	UT	1,302	0
5960000	MNT STR LGHT-SIG S	DNEX	Distribution O&M Expense	WA	166	0
5960000	MNT STR LGHT-SIG S	DNEX	Distribution O&M Expense	WYP	308	0
5960000	MNT STR LGHT-SIG S	DNEX	Distribution O&M Expense	WYU	106	0
5960000 Total					**2,966**	**889**
5970000	MNT OF METERS	DNEX	Distribution O&M Expense	CA	17	0
5970000	MNT OF METERS	DNEX	Distribution O&M Expense	IDU	35	0
5970000	MNT OF METERS	DNEX	Distribution O&M Expense	OR	181	181
5970000	MNT OF METERS	DNEX	Distribution O&M Expense	SNPD	-363	-95
5970000	MNT OF METERS	DNEX	Distribution O&M Expense	UT	278	0
5970000	MNT OF METERS	DNEX	Distribution O&M Expense	WA	33	0
5970000	MNT OF METERS	DNEX	Distribution O&M Expense	WYP	33	0
5970000	MNT OF METERS	DNEX	Distribution O&M Expense	WYU	12	0
5970000 Total					**225**	**85**
5980000	MNT MISC DIST PLNT	DNEX	Distribution O&M Expense	CA	24	0
5980000	MNT MISC DIST PLNT	DNEX	Distribution O&M Expense	IDU	70	0
5980000	MNT MISC DIST PLNT	DNEX	Distribution O&M Expense	OR	433	433

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Operations & Maintenance Expense

Twelve Months Ending - December 2018
Allocation Method - Factor 2017 Protocol
(Allocated in Thousands)

Primary Account		Secondary Group Code		Alloc	Total	Oregon
5980000	MNT MISC DIST PLNT	DNEX	Distribution O&M Expense	SNPD	2,795	733
5980000	MNT MISC DIST PLNT	DNEX	Distribution O&M Expense	UT	788	0
5980000	MNT MISC DIST PLNT	DNEX	Distribution O&M Expense	WA	169	0
5980000	MNT MISC DIST PLNT	DNEX	Distribution O&M Expense	WYP	219	0
5980000 Total					**4,498**	**1,166**
5989500	MNT DIST PLNT-ENV AM	DNEX	Distribution O&M Expense	SNPD	2,221	582
5989500 Total					**2,221**	**582**
Total Distribution					**197,248**	**60,727**

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Operations & Maintenance Expense
Twelve Months Ending - December 2017
Allocation Method - Factor 2017 Protocol
(Allocated in Thousands)

Primary Account		Secondary Group Code		Alloc	Total	Oregon
5800000	OPER SUPERV & ENG	DNEX	Distribution O&M Expense	CA	104	0
5800000	OPER SUPERV & ENG	DNEX	Distribution O&M Expense	IDU	30	0
5800000	OPER SUPERV & ENG	DNEX	Distribution O&M Expense	OR	704	704
5800000	OPER SUPERV & ENG	DNEX	Distribution O&M Expense	SNPD	7,370	1,910
5800000	OPER SUPERV & ENG	DNEX	Distribution O&M Expense	UT	522	0
5800000	OPER SUPERV & ENG	DNEX	Distribution O&M Expense	WA	128	0
5800000	OPER SUPERV & ENG	DNEX	Distribution O&M Expense	WYP	103	0
5800000 Total					**8,961**	**2,614**
5810000	LOAD DISPATCHING	DNEX	Distribution O&M Expense	SNPD	10,667	2,765
5810000 Total					**10,667**	**2,765**
5820000	STATION EXP(DIST)	DNEX	Distribution O&M Expense	CA	28	0
5820000	STATION EXP(DIST)	DNEX	Distribution O&M Expense	IDU	307	0
5820000	STATION EXP(DIST)	DNEX	Distribution O&M Expense	OR	892	892
5820000	STATION EXP(DIST)	DNEX	Distribution O&M Expense	SNPD	8	2
5820000	STATION EXP(DIST)	DNEX	Distribution O&M Expense	UT	1,693	0
5820000	STATION EXP(DIST)	DNEX	Distribution O&M Expense	WA	275	0
5820000	STATION EXP(DIST)	DNEX	Distribution O&M Expense	WYP	784	0
5820000 Total					**3,987**	**894**
5830000	OVHD LINE EXPENSES	DNEX	Distribution O&M Expense	CA	198	0
5830000	OVHD LINE EXPENSES	DNEX	Distribution O&M Expense	IDU	337	0
5830000	OVHD LINE EXPENSES	DNEX	Distribution O&M Expense	OR	1,731	1,731
5830000	OVHD LINE EXPENSES	DNEX	Distribution O&M Expense	SNPD	0	0
5830000	OVHD LINE EXPENSES	DNEX	Distribution O&M Expense	UT	4,857	0
5830000	OVHD LINE EXPENSES	DNEX	Distribution O&M Expense	WA	264	0
5830000	OVHD LINE EXPENSES	DNEX	Distribution O&M Expense	WYP	316	0
5830000	OVHD LINE EXPENSES	DNEX	Distribution O&M Expense	WYU	107	0
5830000 Total					**7,809**	**1,731**
5840000	UDRGRND LINE EXP	DNEX	Distribution O&M Expense	OR	0	0
5840000	UDRGRND LINE EXP	DNEX	Distribution O&M Expense	UT	0	0
5840000	UDRGRND LINE EXP	DNEX	Distribution O&M Expense	WYP	0	0
5840000 Total					**1**	**0**
5850000	STRT LGHT-SGNL SYS	DNEX	Distribution O&M Expense	SNPD	152	39
5850000 Total					**152**	**39**
5860000	METER EXPENSES	DNEX	Distribution O&M Expense	CA	144	0
5860000	METER EXPENSES	DNEX	Distribution O&M Expense	IDU	263	0
5860000	METER EXPENSES	DNEX	Distribution O&M Expense	OR	1,075	1,075
5860000	METER EXPENSES	DNEX	Distribution O&M Expense	SNPD	15	4
5860000	METER EXPENSES	DNEX	Distribution O&M Expense	UT	1,571	0
5860000	METER EXPENSES	DNEX	Distribution O&M Expense	WA	328	0
5860000	METER EXPENSES	DNEX	Distribution O&M Expense	WYP	671	0
5860000	METER EXPENSES	DNEX	Distribution O&M Expense	WYU	154	0
5860000 Total					**4,221**	**1,079**
5870000	CUST INSTL EXPENSE	DNEX	Distribution O&M Expense	CA	552	0

Operations & Maintenance Expense
Twelve Months Ending - December 2017
Allocation Method - Factor 2017 Protocol
(Allocated in Thousands)

Primary Account		Secondary Group Code		Alloc	Total	Oregon
5870000	CUST INSTL EXPENSE	DNEX	Distribution O&M Expense	IDU	1,042	0
5870000	CUST INSTL EXPENSE	DNEX	Distribution O&M Expense	OR	5,089	5,089
5870000	CUST INSTL EXPENSE	DNEX	Distribution O&M Expense	UT	4,716	0
5870000	CUST INSTL EXPENSE	DNEX	Distribution O&M Expense	WA	1,100	0
5870000	CUST INSTL EXPENSE	DNEX	Distribution O&M Expense	WYP	966	0
5870000	CUST INSTL EXPENSE	DNEX	Distribution O&M Expense	WYU	91	0
5870000 Total					**13,556**	**5,089**
5880000	MSC DISTR EXPENSES	DNEX	Distribution O&M Expense	CA	21	0
5880000	MSC DISTR EXPENSES	DNEX	Distribution O&M Expense	IDU	31	0
5880000	MSC DISTR EXPENSES	DNEX	Distribution O&M Expense	OR	-30	-30
5880000	MSC DISTR EXPENSES	DNEX	Distribution O&M Expense	SNPD	1,073	278
5880000	MSC DISTR EXPENSES	DNEX	Distribution O&M Expense	UT	918	0
5880000	MSC DISTR EXPENSES	DNEX	Distribution O&M Expense	WA	-23	0
5880000	MSC DISTR EXPENSES	DNEX	Distribution O&M Expense	WYP	29	0
5880000	MSC DISTR EXPENSES	DNEX	Distribution O&M Expense	WYU	-44	0
5880000 Total					**1,975**	**248**
5890000	RENTS-DISTRIBUTION	DNEX	Distribution O&M Expense	CA	69	0
5890000	RENTS-DISTRIBUTION	DNEX	Distribution O&M Expense	IDU	37	0
5890000	RENTS-DISTRIBUTION	DNEX	Distribution O&M Expense	OR	1,628	1,628
5890000	RENTS-DISTRIBUTION	DNEX	Distribution O&M Expense	SNPD	6	2
5890000	RENTS-DISTRIBUTION	DNEX	Distribution O&M Expense	UT	723	0
5890000	RENTS-DISTRIBUTION	DNEX	Distribution O&M Expense	WA	105	0
5890000	RENTS-DISTRIBUTION	DNEX	Distribution O&M Expense	WYP	516	0
5890000	RENTS-DISTRIBUTION	DNEX	Distribution O&M Expense	WYU	95	0
5890000 Total					**3,179**	**1,629**
5900000	MAINT SUPERV & ENG	DNEX	Distribution O&M Expense	CA	85	0
5900000	MAINT SUPERV & ENG	DNEX	Distribution O&M Expense	IDU	134	0
5900000	MAINT SUPERV & ENG	DNEX	Distribution O&M Expense	OR	989	989
5900000	MAINT SUPERV & ENG	DNEX	Distribution O&M Expense	SNPD	2,249	583
5900000	MAINT SUPERV & ENG	DNEX	Distribution O&M Expense	UT	1,276	0
5900000	MAINT SUPERV & ENG	DNEX	Distribution O&M Expense	WA	179	0
5900000	MAINT SUPERV & ENG	DNEX	Distribution O&M Expense	WYP	488	0
5900000 Total					**5,400**	**1,571**
5910000	MAINT OF STRUCTURE	DNEX	Distribution O&M Expense	CA	55	0
5910000	MAINT OF STRUCTURE	DNEX	Distribution O&M Expense	IDU	86	0
5910000	MAINT OF STRUCTURE	DNEX	Distribution O&M Expense	OR	947	947
5910000	MAINT OF STRUCTURE	DNEX	Distribution O&M Expense	SNPD	125	32
5910000	MAINT OF STRUCTURE	DNEX	Distribution O&M Expense	UT	721	0
5910000	MAINT OF STRUCTURE	DNEX	Distribution O&M Expense	WA	155	0
5910000	MAINT OF STRUCTURE	DNEX	Distribution O&M Expense	WYP	294	0
5910000	MAINT OF STRUCTURE	DNEX	Distribution O&M Expense	WYU	80	0
5910000 Total					**2,463**	**979**
5920000	MAINT STAT EQUIP	DNEX	Distribution O&M Expense	CA	350	0
5920000	MAINT STAT EQUIP	DNEX	Distribution O&M Expense	IDU	544	0

Operations & Maintenance Expense
Twelve Months Ending - December 2017
Allocation Method - Factor 2017 Protocol
(Allocated in Thousands)

Primary Account		Secondary Group Code		Alloc	Total	Oregon
5920000	MAINT STAT EQUIP	DNEX	Distribution O&M Expense	OR	2,273	2,273
5920000	MAINT STAT EQUIP	DNEX	Distribution O&M Expense	SNPD	1,721	446
5920000	MAINT STAT EQUIP	DNEX	Distribution O&M Expense	UT	2,469	0
5920000	MAINT STAT EQUIP	DNEX	Distribution O&M Expense	WA	517	0
5920000	MAINT STAT EQUIP	DNEX	Distribution O&M Expense	WYP	1,164	0
5920000	MAINT STAT EQUIP	DNEX	Distribution O&M Expense	WYU	-36	0
5920000 Total					**9,002**	**2,719**
5930000	MAINT OVHD LINES	DNEX	Distribution O&M Expense	CA	8,621	0
5930000	MAINT OVHD LINES	DNEX	Distribution O&M Expense	IDU	4,791	0
5930000	MAINT OVHD LINES	DNEX	Distribution O&M Expense	OR	30,116	30,116
5930000	MAINT OVHD LINES	DNEX	Distribution O&M Expense	SNPD	1,491	386
5930000	MAINT OVHD LINES	DNEX	Distribution O&M Expense	UT	28,785	0
5930000	MAINT OVHD LINES	DNEX	Distribution O&M Expense	WA	4,614	0
5930000	MAINT OVHD LINES	DNEX	Distribution O&M Expense	WYP	6,508	0
5930000	MAINT OVHD LINES	DNEX	Distribution O&M Expense	WYU	1,098	0
5930000 Total					**86,023**	**30,502**
5931000	MAINT O/H LINES-LB P	DNEX	Distribution O&M Expense	CA	-72	0
5931000	MAINT O/H LINES-LB P	DNEX	Distribution O&M Expense	IDU	448	0
5931000	MAINT O/H LINES-LB P	DNEX	Distribution O&M Expense	OR	-581	-581
5931000	MAINT O/H LINES-LB P	DNEX	Distribution O&M Expense	SNPD	-14	-4
5931000	MAINT O/H LINES-LB P	DNEX	Distribution O&M Expense	UT	834	0
5931000	MAINT O/H LINES-LB P	DNEX	Distribution O&M Expense	WA	-98	0
5931000	MAINT O/H LINES-LB P	DNEX	Distribution O&M Expense	WYP	127	0
5931000 Total					**644**	**-585**
5940000	MAINT UDGRND LINES	DNEX	Distribution O&M Expense	CA	533	0
5940000	MAINT UDGRND LINES	DNEX	Distribution O&M Expense	IDU	833	0
5940000	MAINT UDGRND LINES	DNEX	Distribution O&M Expense	OR	6,358	6,358
5940000	MAINT UDGRND LINES	DNEX	Distribution O&M Expense	SNPD	56	14
5940000	MAINT UDGRND LINES	DNEX	Distribution O&M Expense	UT	14,301	0
5940000	MAINT UDGRND LINES	DNEX	Distribution O&M Expense	WA	1,233	0
5940000	MAINT UDGRND LINES	DNEX	Distribution O&M Expense	WYP	1,839	0
5940000	MAINT UDGRND LINES	DNEX	Distribution O&M Expense	WYU	313	0
5940000 Total					**25,465**	**6,372**
5950000	MAINT LINE TRNSFRM	DNEX	Distribution O&M Expense	SNPD	970	251
5950000 Total					**970**	**251**
5960000	MNT STR LGHT-SIG S	DNEX	Distribution O&M Expense	CA	104	0
5960000	MNT STR LGHT-SIG S	DNEX	Distribution O&M Expense	IDU	115	0
5960000	MNT STR LGHT-SIG S	DNEX	Distribution O&M Expense	OR	879	879
5960000	MNT STR LGHT-SIG S	DNEX	Distribution O&M Expense	UT	1,354	0
5960000	MNT STR LGHT-SIG S	DNEX	Distribution O&M Expense	WA	145	0
5960000	MNT STR LGHT-SIG S	DNEX	Distribution O&M Expense	WYP	237	0
5960000	MNT STR LGHT-SIG S	DNEX	Distribution O&M Expense	WYU	96	0
5960000 Total					**2,931**	**879**
5970000	MNT OF METERS	DNEX	Distribution O&M Expense	CA	10	0

Operations & Maintenance Expense
Twelve Months Ending - December 2017
Allocation Method - Factor 2017 Protocol
(Allocated in Thousands)

Primary Account		Secondary Group Code		Alloc	Total	Oregon
5970000	MNT OF METERS	DNEX	Distribution O&M Expense	IDU	34	0
5970000	MNT OF METERS	DNEX	Distribution O&M Expense	OR	146	146
5970000	MNT OF METERS	DNEX	Distribution O&M Expense	SNPD	-333	-86
5970000	MNT OF METERS	DNEX	Distribution O&M Expense	UT	226	0
5970000	MNT OF METERS	DNEX	Distribution O&M Expense	WA	23	0
5970000	MNT OF METERS	DNEX	Distribution O&M Expense	WYP	21	0
5970000	MNT OF METERS	DNEX	Distribution O&M Expense	WYU	12	0
5970000 Total					**139**	**60**
5980000	MNT MISC DIST PLNT	DNEX	Distribution O&M Expense	CA	36	0
5980000	MNT MISC DIST PLNT	DNEX	Distribution O&M Expense	IDU	86	0
5980000	MNT MISC DIST PLNT	DNEX	Distribution O&M Expense	OR	141	141
5980000	MNT MISC DIST PLNT	DNEX	Distribution O&M Expense	SNPD	6,634	1,719
5980000	MNT MISC DIST PLNT	DNEX	Distribution O&M Expense	UT	662	0
5980000	MNT MISC DIST PLNT	DNEX	Distribution O&M Expense	WA	209	0
5980000	MNT MISC DIST PLNT	DNEX	Distribution O&M Expense	WYP	200	0
5980000	MNT MISC DIST PLNT	DNEX	Distribution O&M Expense	WYU	0	0
5980000 Total					**7,968**	**1,860**
5989500	MNT DIST PLNT-ENV AM	DNEX	Distribution O&M Expense	SNPD	2,065	535
5989500 Total					**2,065**	**535**
Total Distribution					**197,578**	**61,234**

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Operations & Maintenance Expense
Twelve Months Ending - December 2016
Allocation Method - Factor 2017 Protocol
(Allocated in Thousands)

Primary Account		Secondary Group Code		Alloc	Total	Oregon
5800000	OPER SUPERV & ENG	DNEX	Distribution O&M Expense	CA	41	0
5800000	OPER SUPERV & ENG	DNEX	Distribution O&M Expense	IDU	38	0
5800000	OPER SUPERV & ENG	DNEX	Distribution O&M Expense	OR	331	331
5800000	OPER SUPERV & ENG	DNEX	Distribution O&M Expense	SNPD	8,921	2,325
5800000	OPER SUPERV & ENG	DNEX	Distribution O&M Expense	UT	564	0
5800000	OPER SUPERV & ENG	DNEX	Distribution O&M Expense	WA	182	0
5800000	OPER SUPERV & ENG	DNEX	Distribution O&M Expense	WYP	135	0
5800000 Total					**10,212**	**2,655**
5810000	LOAD DISPATCHING	DNEX	Distribution O&M Expense	SNPD	11,609	3,025
5810000 Total					**11,609**	**3,025**
5820000	STATION EXP(DIST)	DNEX	Distribution O&M Expense	CA	78	0
5820000	STATION EXP(DIST)	DNEX	Distribution O&M Expense	IDU	423	0
5820000	STATION EXP(DIST)	DNEX	Distribution O&M Expense	OR	1,106	1,106
5820000	STATION EXP(DIST)	DNEX	Distribution O&M Expense	SNPD	6	2
5820000	STATION EXP(DIST)	DNEX	Distribution O&M Expense	UT	1,815	0
5820000	STATION EXP(DIST)	DNEX	Distribution O&M Expense	WA	205	0
5820000	STATION EXP(DIST)	DNEX	Distribution O&M Expense	WYP	823	0
5820000 Total					**4,456**	**1,108**
5830000	OVHD LINE EXPENSES	DNEX	Distribution O&M Expense	CA	157	0
5830000	OVHD LINE EXPENSES	DNEX	Distribution O&M Expense	IDU	398	0
5830000	OVHD LINE EXPENSES	DNEX	Distribution O&M Expense	OR	1,394	1,394
5830000	OVHD LINE EXPENSES	DNEX	Distribution O&M Expense	SNPD	0	0
5830000	OVHD LINE EXPENSES	DNEX	Distribution O&M Expense	UT	4,867	0
5830000	OVHD LINE EXPENSES	DNEX	Distribution O&M Expense	WA	261	0
5830000	OVHD LINE EXPENSES	DNEX	Distribution O&M Expense	WYP	354	0
5830000	OVHD LINE EXPENSES	DNEX	Distribution O&M Expense	WYU	152	0
5830000 Total					**7,583**	**1,394**
5840000	UDRGRND LINE EXP	DNEX	Distribution O&M Expense	OR	0	0
5840000	UDRGRND LINE EXP	DNEX	Distribution O&M Expense	UT	1	0
5840000 Total					**1**	**0**
5850000	STRT LGHT-SGNL SYS	DNEX	Distribution O&M Expense	SNPD	248	65
5850000 Total					**248**	**65**
5860000	METER EXPENSES	DNEX	Distribution O&M Expense	CA	286	0
5860000	METER EXPENSES	DNEX	Distribution O&M Expense	IDU	563	0
5860000	METER EXPENSES	DNEX	Distribution O&M Expense	OR	1,634	1,634
5860000	METER EXPENSES	DNEX	Distribution O&M Expense	SNPD	42	11
5860000	METER EXPENSES	DNEX	Distribution O&M Expense	UT	2,014	0
5860000	METER EXPENSES	DNEX	Distribution O&M Expense	WA	558	0
5860000	METER EXPENSES	DNEX	Distribution O&M Expense	WYP	780	0
5860000	METER EXPENSES	DNEX	Distribution O&M Expense	WYU	176	0
5860000 Total					**6,053**	**1,645**
5870000	CUST INSTL EXPENSE	DNEX	Distribution O&M Expense	CA	472	0
5870000	CUST INSTL EXPENSE	DNEX	Distribution O&M Expense	IDU	861	0
5870000	CUST INSTL EXPENSE	DNEX	Distribution O&M Expense	OR	5,228	5,228
5870000	CUST INSTL EXPENSE	DNEX	Distribution O&M Expense	UT	4,999	0
5870000	CUST INSTL EXPENSE	DNEX	Distribution O&M Expense	WA	1,011	0
5870000	CUST INSTL EXPENSE	DNEX	Distribution O&M Expense	WYP	848	0

Operations & Maintenance Expense
Twelve Months Ending - December 2016
Allocation Method - Factor 2017 Protocol
(Allocated in Thousands)

Primary Account		Secondary Group Code		Alloc	Total	Oregon
5870000	CUST INSTL EXPENSE	DNEX	Distribution O&M Expense	WYU	91	0
5870000 Total					**13,509**	**5,228**
5880000	MSC DISTR EXPENSES	DNEX	Distribution O&M Expense	CA	21	0
5880000	MSC DISTR EXPENSES	DNEX	Distribution O&M Expense	IDU	-10	0
5880000	MSC DISTR EXPENSES	DNEX	Distribution O&M Expense	OR	-36	-36
5880000	MSC DISTR EXPENSES	DNEX	Distribution O&M Expense	SNPD	2,597	677
5880000	MSC DISTR EXPENSES	DNEX	Distribution O&M Expense	UT	2,121	0
5880000	MSC DISTR EXPENSES	DNEX	Distribution O&M Expense	WA	-7	0
5880000	MSC DISTR EXPENSES	DNEX	Distribution O&M Expense	WYP	-52	0
5880000	MSC DISTR EXPENSES	DNEX	Distribution O&M Expense	WYU	-51	0
5880000 Total					**4,583**	**641**
5890000	RENTS-DISTRIBUTION	DNEX	Distribution O&M Expense	CA	73	0
5890000	RENTS-DISTRIBUTION	DNEX	Distribution O&M Expense	IDU	25	0
5890000	RENTS-DISTRIBUTION	DNEX	Distribution O&M Expense	OR	1,763	1,763
5890000	RENTS-DISTRIBUTION	DNEX	Distribution O&M Expense	SNPD	12	3
5890000	RENTS-DISTRIBUTION	DNEX	Distribution O&M Expense	UT	661	0
5890000	RENTS-DISTRIBUTION	DNEX	Distribution O&M Expense	WA	125	0
5890000	RENTS-DISTRIBUTION	DNEX	Distribution O&M Expense	WYP	572	0
5890000	RENTS-DISTRIBUTION	DNEX	Distribution O&M Expense	WYU	88	0
5890000 Total					**3,319**	**1,766**
5900000	MAINT SUPERV & ENG	DNEX	Distribution O&M Expense	CA	92	0
5900000	MAINT SUPERV & ENG	DNEX	Distribution O&M Expense	IDU	181	0
5900000	MAINT SUPERV & ENG	DNEX	Distribution O&M Expense	OR	886	886
5900000	MAINT SUPERV & ENG	DNEX	Distribution O&M Expense	SNPD	2,097	547
5900000	MAINT SUPERV & ENG	DNEX	Distribution O&M Expense	UT	1,394	0
5900000	MAINT SUPERV & ENG	DNEX	Distribution O&M Expense	WA	123	0
5900000	MAINT SUPERV & ENG	DNEX	Distribution O&M Expense	WYP	601	0
5900000 Total					**5,375**	**1,433**
5910000	MAINT OF STRUCTURE	DNEX	Distribution O&M Expense	CA	51	0
5910000	MAINT OF STRUCTURE	DNEX	Distribution O&M Expense	IDU	88	0
5910000	MAINT OF STRUCTURE	DNEX	Distribution O&M Expense	OR	597	597
5910000	MAINT OF STRUCTURE	DNEX	Distribution O&M Expense	SNPD	133	35
5910000	MAINT OF STRUCTURE	DNEX	Distribution O&M Expense	UT	758	0
5910000	MAINT OF STRUCTURE	DNEX	Distribution O&M Expense	WA	108	0
5910000	MAINT OF STRUCTURE	DNEX	Distribution O&M Expense	WYP	205	0
5910000	MAINT OF STRUCTURE	DNEX	Distribution O&M Expense	WYU	58	0
5910000 Total					**1,997**	**631**
5920000	MAINT STAT EQUIP	DNEX	Distribution O&M Expense	CA	418	0
5920000	MAINT STAT EQUIP	DNEX	Distribution O&M Expense	IDU	516	0
5920000	MAINT STAT EQUIP	DNEX	Distribution O&M Expense	OR	3,003	3,003
5920000	MAINT STAT EQUIP	DNEX	Distribution O&M Expense	SNPD	1,746	455
5920000	MAINT STAT EQUIP	DNEX	Distribution O&M Expense	UT	3,521	0
5920000	MAINT STAT EQUIP	DNEX	Distribution O&M Expense	WA	542	0
5920000	MAINT STAT EQUIP	DNEX	Distribution O&M Expense	WYP	853	0
5920000	MAINT STAT EQUIP	DNEX	Distribution O&M Expense	WYU	19	0
5920000 Total					**10,618**	**3,458**
5930000	MAINT OVHD LINES	DNEX	Distribution O&M Expense	CA	5,842	0

Operations & Maintenance Expense

Twelve Months Ending - December 2016
Allocation Method - Factor 2017 Protocol
(Allocated in Thousands)

Primary Account		Secondary Group Code		Alloc	Total	Oregon
5930000	MAINT OVHD LINES	DNEX	Distribution O&M Expense	IDU	4,562	0
5930000	MAINT OVHD LINES	DNEX	Distribution O&M Expense	OR	28,667	28,667
5930000	MAINT OVHD LINES	DNEX	Distribution O&M Expense	SNPD	1,567	408
5930000	MAINT OVHD LINES	DNEX	Distribution O&M Expense	UT	30,036	0
5930000	MAINT OVHD LINES	DNEX	Distribution O&M Expense	WA	4,090	0
5930000	MAINT OVHD LINES	DNEX	Distribution O&M Expense	WYP	6,986	0
5930000	MAINT OVHD LINES	DNEX	Distribution O&M Expense	WYU	1,294	0
5930000 Total					**83,044**	**29,075**
5931000	MAINT O/H LINES-LB P	DNEX	Distribution O&M Expense	CA	-55	0
5931000	MAINT O/H LINES-LB P	DNEX	Distribution O&M Expense	IDU	-534	0
5931000	MAINT O/H LINES-LB P	DNEX	Distribution O&M Expense	OR	-524	-524
5931000	MAINT O/H LINES-LB P	DNEX	Distribution O&M Expense	UT	-884	0
5931000	MAINT O/H LINES-LB P	DNEX	Distribution O&M Expense	WA	-129	0
5931000	MAINT O/H LINES-LB P	DNEX	Distribution O&M Expense	WYP	-191	0
5931000	MAINT O/H LINES-LB P	DNEX	Distribution O&M Expense	WYU	46	0
5931000 Total					**-2,272**	**-524**
5940000	MAINT UDGRND LINES	DNEX	Distribution O&M Expense	CA	600	0
5940000	MAINT UDGRND LINES	DNEX	Distribution O&M Expense	IDU	696	0
5940000	MAINT UDGRND LINES	DNEX	Distribution O&M Expense	OR	7,105	7,105
5940000	MAINT UDGRND LINES	DNEX	Distribution O&M Expense	SNPD	22	6
5940000	MAINT UDGRND LINES	DNEX	Distribution O&M Expense	UT	14,047	0
5940000	MAINT UDGRND LINES	DNEX	Distribution O&M Expense	WA	1,324	0
5940000	MAINT UDGRND LINES	DNEX	Distribution O&M Expense	WYP	1,621	0
5940000	MAINT UDGRND LINES	DNEX	Distribution O&M Expense	WYU	289	0
5940000 Total					**25,705**	**7,111**
5950000	MAINT LINE TRNSFRM	DNEX	Distribution O&M Expense	SNPD	1,076	280
5950000 Total					**1,076**	**280**
5960000	MNT STR LGHT-SIG S	DNEX	Distribution O&M Expense	CA	78	0
5960000	MNT STR LGHT-SIG S	DNEX	Distribution O&M Expense	IDU	124	0
5960000	MNT STR LGHT-SIG S	DNEX	Distribution O&M Expense	OR	953	953
5960000	MNT STR LGHT-SIG S	DNEX	Distribution O&M Expense	UT	1,534	0
5960000	MNT STR LGHT-SIG S	DNEX	Distribution O&M Expense	WA	167	0
5960000	MNT STR LGHT-SIG S	DNEX	Distribution O&M Expense	WYP	290	0
5960000	MNT STR LGHT-SIG S	DNEX	Distribution O&M Expense	WYU	94	0
5960000 Total					**3,239**	**953**
5970000	MNT OF METERS	DNEX	Distribution O&M Expense	CA	8	0
5970000	MNT OF METERS	DNEX	Distribution O&M Expense	IDU	59	0
5970000	MNT OF METERS	DNEX	Distribution O&M Expense	OR	126	126
5970000	MNT OF METERS	DNEX	Distribution O&M Expense	SNPD	-446	-116
5970000	MNT OF METERS	DNEX	Distribution O&M Expense	UT	204	0
5970000	MNT OF METERS	DNEX	Distribution O&M Expense	WA	18	0
5970000	MNT OF METERS	DNEX	Distribution O&M Expense	WYP	27	0
5970000	MNT OF METERS	DNEX	Distribution O&M Expense	WYU	9	0
5970000 Total					**6**	**10**
5980000	MNT MISC DIST PLNT	DNEX	Distribution O&M Expense	CA	37	0
5980000	MNT MISC DIST PLNT	DNEX	Distribution O&M Expense	IDU	45	0
5980000	MNT MISC DIST PLNT	DNEX	Distribution O&M Expense	OR	417	417

Operations & Maintenance Expense
Twelve Months Ending - December 2016
Allocation Method - Factor 2017 Protocol
(Allocated in Thousands)

Primary Account		Secondary Group Code		Alloc	Total	Oregon
5980000	MNT MISC DIST PLNT	DNEX	Distribution O&M Expense	SNPD	4,342	1,131
5980000	MNT MISC DIST PLNT	DNEX	Distribution O&M Expense	UT	802	0
5980000	MNT MISC DIST PLNT	DNEX	Distribution O&M Expense	WA	101	0
5980000	MNT MISC DIST PLNT	DNEX	Distribution O&M Expense	WYP	393	0
5980000 Total					**6,136**	**1,548**
Total Distribution					**196,498**	**61,502**

Operations & Maintenance Expense (Actuals)
Twelve Months Ending - December 2015
Allocation Method - Factor 2010 Protocol
(Allocated in Thousands)

Primary Account		Secondary Group Code		Alloc	Total	Oregon
5800000	OPER SUPERV & ENG	DNEX	Distribution O&M Expense	CA	33	0
5800000	OPER SUPERV & ENG	DNEX	Distribution O&M Expense	IDU	(22)	0
5800000	OPER SUPERV & ENG	DNEX	Distribution O&M Expense	OR	273	273
5800000	OPER SUPERV & ENG	DNEX	Distribution O&M Expense	SNPD	9,923	2,613
5800000	OPER SUPERV & ENG	DNEX	Distribution O&M Expense	UT	802	0
5800000	OPER SUPERV & ENG	DNEX	Distribution O&M Expense	WA	155	0
5800000	OPER SUPERV & ENG	DNEX	Distribution O&M Expense	WYP	123	0
5800000 Total					**11,288**	**2,887**
5810000	LOAD DISPATCHING	DNEX	Distribution O&M Expense	SNPD	11,746	3,093
5810000 Total					**11,746**	**3,093**
5820000	STATION EXP(DIST)	DNEX	Distribution O&M Expense	CA	59	0
5820000	STATION EXP(DIST)	DNEX	Distribution O&M Expense	IDU	324	0
5820000	STATION EXP(DIST)	DNEX	Distribution O&M Expense	OR	1,030	1,030
5820000	STATION EXP(DIST)	DNEX	Distribution O&M Expense	SNPD	15	4
5820000	STATION EXP(DIST)	DNEX	Distribution O&M Expense	UT	1,752	0
5820000	STATION EXP(DIST)	DNEX	Distribution O&M Expense	WA	204	0
5820000	STATION EXP(DIST)	DNEX	Distribution O&M Expense	WYP	852	0
5820000	STATION EXP(DIST)	DNEX	Distribution O&M Expense	WYU	(0)	0
5820000 Total					**4,236**	**1,034**
5830000	OVHD LINE EXPENSES	DNEX	Distribution O&M Expense	CA	180	0
5830000	OVHD LINE EXPENSES	DNEX	Distribution O&M Expense	IDU	334	0
5830000	OVHD LINE EXPENSES	DNEX	Distribution O&M Expense	OR	1,291	1,291
5830000	OVHD LINE EXPENSES	DNEX	Distribution O&M Expense	SNPD	5	1
5830000	OVHD LINE EXPENSES	DNEX	Distribution O&M Expense	UT	4,149	0
5830000	OVHD LINE EXPENSES	DNEX	Distribution O&M Expense	WA	286	0
5830000	OVHD LINE EXPENSES	DNEX	Distribution O&M Expense	WYP	439	0
5830000	OVHD LINE EXPENSES	DNEX	Distribution O&M Expense	WYU	125	0
5830000 Total					**6,809**	**1,292**
5840000	UDRGRND LINE EXP	DNEX	Distribution O&M Expense	OR	0	0
5840000	UDRGRND LINE EXP	DNEX	Distribution O&M Expense	SNPD	6	2
5840000	UDRGRND LINE EXP	DNEX	Distribution O&M Expense	UT	0	0
5840000 Total					**7**	**2**
5850000	STRT LGHT-SGNL SYS	DNEX	Distribution O&M Expense	SNPD	224	59
5850000 Total					**224**	**59**
5860000	METER EXPENSES	DNEX	Distribution O&M Expense	CA	169	0
5860000	METER EXPENSES	DNEX	Distribution O&M Expense	IDU	443	0
5860000	METER EXPENSES	DNEX	Distribution O&M Expense	OR	2,534	2,534
5860000	METER EXPENSES	DNEX	Distribution O&M Expense	SNPD	314	83
5860000	METER EXPENSES	DNEX	Distribution O&M Expense	UT	2,058	0
5860000	METER EXPENSES	DNEX	Distribution O&M Expense	WA	509	0
5860000	METER EXPENSES	DNEX	Distribution O&M Expense	WYP	450	0
5860000	METER EXPENSES	DNEX	Distribution O&M Expense	WYU	106	0
5860000 Total					**6,584**	**2,616**
5870000	CUST INSTL EXPENSE	DNEX	Distribution O&M Expense	CA	485	0
5870000	CUST INSTL EXPENSE	DNEX	Distribution O&M Expense	IDU	536	0
5870000	CUST INSTL EXPENSE	DNEX	Distribution O&M Expense	OR	4,158	4,158
5870000	CUST INSTL EXPENSE	DNEX	Distribution O&M Expense	UT	3,747	0
5870000	CUST INSTL EXPENSE	DNEX	Distribution O&M Expense	WA	917	0
5870000	CUST INSTL EXPENSE	DNEX	Distribution O&M Expense	WYP	647	0
5870000	CUST INSTL EXPENSE	DNEX	Distribution O&M Expense	WYU	63	0

Operations & Maintenance Expense (Actuals)
Twelve Months Ending - December 2015
Allocation Method - Factor 2010 Protocol
(Allocated in Thousands)

Primary Account		Secondary Group Code		Alloc	Total	Oregon
5870000 Total					**10,552**	**4,158**
5880000	MSC DISTR EXPENSES	DNEX	Distribution O&M Expense	CA	43	0
5880000	MSC DISTR EXPENSES	DNEX	Distribution O&M Expense	IDU	20	0
5880000	MSC DISTR EXPENSES	DNEX	Distribution O&M Expense	OR	114	114
5880000	MSC DISTR EXPENSES	DNEX	Distribution O&M Expense	SNPD	3,646	960
5880000	MSC DISTR EXPENSES	DNEX	Distribution O&M Expense	UT	929	0
5880000	MSC DISTR EXPENSES	DNEX	Distribution O&M Expense	WA	2	0
5880000	MSC DISTR EXPENSES	DNEX	Distribution O&M Expense	WYP	(52)	0
5880000	MSC DISTR EXPENSES	DNEX	Distribution O&M Expense	WYU	(32)	0
5880000 Total					**4,670**	**1,074**
5890000	RENTS-DISTRIBUTION	DNEX	Distribution O&M Expense	CA	63	0
5890000	RENTS-DISTRIBUTION	DNEX	Distribution O&M Expense	IDU	36	0
5890000	RENTS-DISTRIBUTION	DNEX	Distribution O&M Expense	OR	1,865	1,865
5890000	RENTS-DISTRIBUTION	DNEX	Distribution O&M Expense	SNPD	24	6
5890000	RENTS-DISTRIBUTION	DNEX	Distribution O&M Expense	UT	630	0
5890000	RENTS-DISTRIBUTION	DNEX	Distribution O&M Expense	WA	125	0
5890000	RENTS-DISTRIBUTION	DNEX	Distribution O&M Expense	WYP	482	0
5890000	RENTS-DISTRIBUTION	DNEX	Distribution O&M Expense	WYU	91	0
5890000 Total					**3,316**	**1,871**
5900000	MAINT SUPERV & ENG	DNEX	Distribution O&M Expense	CA	81	0
5900000	MAINT SUPERV & ENG	DNEX	Distribution O&M Expense	IDU	190	0
5900000	MAINT SUPERV & ENG	DNEX	Distribution O&M Expense	OR	1,048	1,048
5900000	MAINT SUPERV & ENG	DNEX	Distribution O&M Expense	SNPD	2,187	576
5900000	MAINT SUPERV & ENG	DNEX	Distribution O&M Expense	UT	1,455	0
5900000	MAINT SUPERV & ENG	DNEX	Distribution O&M Expense	WA	179	0
5900000	MAINT SUPERV & ENG	DNEX	Distribution O&M Expense	WYP	570	0
5900000 Total					**5,711**	**1,624**
5910000	MAINT OF STRUCTURE	DNEX	Distribution O&M Expense	CA	28	0
5910000	MAINT OF STRUCTURE	DNEX	Distribution O&M Expense	IDU	73	0
5910000	MAINT OF STRUCTURE	DNEX	Distribution O&M Expense	OR	821	821
5910000	MAINT OF STRUCTURE	DNEX	Distribution O&M Expense	SNPD	96	25
5910000	MAINT OF STRUCTURE	DNEX	Distribution O&M Expense	UT	696	0
5910000	MAINT OF STRUCTURE	DNEX	Distribution O&M Expense	WA	159	0
5910000	MAINT OF STRUCTURE	DNEX	Distribution O&M Expense	WYP	325	0
5910000	MAINT OF STRUCTURE	DNEX	Distribution O&M Expense	WYU	34	0
5910000 Total					**2,230**	**846**
5920000	MAINT STAT EQUIP	DNEX	Distribution O&M Expense	CA	534	0
5920000	MAINT STAT EQUIP	DNEX	Distribution O&M Expense	IDU	535	0
5920000	MAINT STAT EQUIP	DNEX	Distribution O&M Expense	OR	3,862	3,862
5920000	MAINT STAT EQUIP	DNEX	Distribution O&M Expense	SNPD	1,503	396
5920000	MAINT STAT EQUIP	DNEX	Distribution O&M Expense	UT	3,414	0
5920000	MAINT STAT EQUIP	DNEX	Distribution O&M Expense	WA	462	0
5920000	MAINT STAT EQUIP	DNEX	Distribution O&M Expense	WYP	1,105	0
5920000 Total					**11,414**	**4,257**
5930000	MAINT OVHD LINES	DNEX	Distribution O&M Expense	CA	6,649	0
5930000	MAINT OVHD LINES	DNEX	Distribution O&M Expense	IDU	4,962	0
5930000	MAINT OVHD LINES	DNEX	Distribution O&M Expense	OR	33,511	33,511
5930000	MAINT OVHD LINES	DNEX	Distribution O&M Expense	SNPD	1,777	468
5930000	MAINT OVHD LINES	DNEX	Distribution O&M Expense	UT	32,676	0
5930000	MAINT OVHD LINES	DNEX	Distribution O&M Expense	WA	4,059	0

Operations & Maintenance Expense (Actuals)
Twelve Months Ending - December 2015
Allocation Method - Factor 2010 Protocol
(Allocated in Thousands)

Primary Account		Secondary Group Code		Alloc	Total	Oregon
5930000	MAINT OVHD LINES	DNEX	Distribution O&M Expense	WYP	6,576	0
5930000	MAINT OVHD LINES	DNEX	Distribution O&M Expense	WYU	1,093	0
5930000 Total					**91,302**	**33,979**
5931000	MAINT O/H LINES-LB P	DNEX	Distribution O&M Expense	CA	(49)	0
5931000	MAINT O/H LINES-LB P	DNEX	Distribution O&M Expense	IDU	288	0
5931000	MAINT O/H LINES-LB P	DNEX	Distribution O&M Expense	OR	121	121
5931000	MAINT O/H LINES-LB P	DNEX	Distribution O&M Expense	UT	(271)	0
5931000	MAINT O/H LINES-LB P	DNEX	Distribution O&M Expense	WA	(43)	0
5931000	MAINT O/H LINES-LB P	DNEX	Distribution O&M Expense	WYP	281	0
5931000 Total					**326**	**121**
5940000	MAINT UDGRND LINES	DNEX	Distribution O&M Expense	CA	681	0
5940000	MAINT UDGRND LINES	DNEX	Distribution O&M Expense	IDU	718	0
5940000	MAINT UDGRND LINES	DNEX	Distribution O&M Expense	OR	5,898	5,898
5940000	MAINT UDGRND LINES	DNEX	Distribution O&M Expense	SNPD	9	2
5940000	MAINT UDGRND LINES	DNEX	Distribution O&M Expense	UT	12,480	0
5940000	MAINT UDGRND LINES	DNEX	Distribution O&M Expense	WA	1,249	0
5940000	MAINT UDGRND LINES	DNEX	Distribution O&M Expense	WYP	1,642	0
5940000	MAINT UDGRND LINES	DNEX	Distribution O&M Expense	WYU	234	0
5940000 Total					**22,911**	**5,900**
5950000	MAINT LINE TRNSFRM	DNEX	Distribution O&M Expense	SNPD	922	243
5950000 Total					**922**	**243**
5960000	MNT STR LGHT-SIG S	DNEX	Distribution O&M Expense	CA	64	0
5960000	MNT STR LGHT-SIG S	DNEX	Distribution O&M Expense	IDU	150	0
5960000	MNT STR LGHT-SIG S	DNEX	Distribution O&M Expense	OR	896	896
5960000	MNT STR LGHT-SIG S	DNEX	Distribution O&M Expense	UT	1,597	0
5960000	MNT STR LGHT-SIG S	DNEX	Distribution O&M Expense	WA	178	0
5960000	MNT STR LGHT-SIG S	DNEX	Distribution O&M Expense	WYP	285	0
5960000	MNT STR LGHT-SIG S	DNEX	Distribution O&M Expense	WYU	82	0
5960000 Total					**3,253**	**896**
5970000	MNT OF METERS	DNEX	Distribution O&M Expense	CA	33	0
5970000	MNT OF METERS	DNEX	Distribution O&M Expense	IDU	280	0
5970000	MNT OF METERS	DNEX	Distribution O&M Expense	OR	1,124	1,124
5970000	MNT OF METERS	DNEX	Distribution O&M Expense	SNPD	286	75
5970000	MNT OF METERS	DNEX	Distribution O&M Expense	UT	1,701	0
5970000	MNT OF METERS	DNEX	Distribution O&M Expense	WA	390	0
5970000	MNT OF METERS	DNEX	Distribution O&M Expense	WYP	373	0
5970000	MNT OF METERS	DNEX	Distribution O&M Expense	WYU	109	0
5970000 Total					**4,294**	**1,199**
5980000	MNT MISC DIST PLNT	DNEX	Distribution O&M Expense	CA	106	0
5980000	MNT MISC DIST PLNT	DNEX	Distribution O&M Expense	IDU	42	0
5980000	MNT MISC DIST PLNT	DNEX	Distribution O&M Expense	OR	357	357
5980000	MNT MISC DIST PLNT	DNEX	Distribution O&M Expense	SNPD	3,363	886
5980000	MNT MISC DIST PLNT	DNEX	Distribution O&M Expense	UT	821	0
5980000	MNT MISC DIST PLNT	DNEX	Distribution O&M Expense	WA	161	0
5980000	MNT MISC DIST PLNT	DNEX	Distribution O&M Expense	WYP	392	0
5980000 Total					**5,241**	**1,242**
Total Distribution					**207,035**	**68,394**

Operations & Maintenance Expense (Actuals)
Twelve Months Ending - December 2014
Allocation Method - Factor 2010 Protocol
(Allocated in Thousands)

Primary Account		Secondary Group Code		Alloc	Total	Oregon
5800000	OPER SUPERV & ENG	DNEX	Distribution O&M Expense	CA	$30	$0
5800000	OPER SUPERV & ENG	DNEX	Distribution O&M Expense	IDU	$78	$0
5800000	OPER SUPERV & ENG	DNEX	Distribution O&M Expense	OR	$266	$266
5800000	OPER SUPERV & ENG	DNEX	Distribution O&M Expense	SNPD	$8,382	$2,229
5800000	OPER SUPERV & ENG	DNEX	Distribution O&M Expense	UT	$797	$0
5800000	OPER SUPERV & ENG	DNEX	Distribution O&M Expense	WA	$107	$0
5800000	OPER SUPERV & ENG	DNEX	Distribution O&M Expense	WYP	$196	$0
5800000 Total					**$9,856**	**$2,495**
5810000	LOAD DISPATCHING	DNEX	Distribution O&M Expense	SNPD	$11,105	$2,953
5810000 Total					**$11,105**	**$2,953**
5820000	STATION EXP(DIST)	DNEX	Distribution O&M Expense	CA	$108	$0
5820000	STATION EXP(DIST)	DNEX	Distribution O&M Expense	IDU	$376	$0
5820000	STATION EXP(DIST)	DNEX	Distribution O&M Expense	OR	$1,057	$1,057
5820000	STATION EXP(DIST)	DNEX	Distribution O&M Expense	SNPD	$31	$8
5820000	STATION EXP(DIST)	DNEX	Distribution O&M Expense	UT	$1,896	$0
5820000	STATION EXP(DIST)	DNEX	Distribution O&M Expense	WA	$267	$0
5820000	STATION EXP(DIST)	DNEX	Distribution O&M Expense	WYP	$912	$0
5820000 Total					**$4,646**	**$1,065**
5830000	OVHD LINE EXPENSES	DNEX	Distribution O&M Expense	CA	$214	$0
5830000	OVHD LINE EXPENSES	DNEX	Distribution O&M Expense	IDU	$253	$0
5830000	OVHD LINE EXPENSES	DNEX	Distribution O&M Expense	OR	$1,774	$1,774
5830000	OVHD LINE EXPENSES	DNEX	Distribution O&M Expense	SNPD	$11	$3
5830000	OVHD LINE EXPENSES	DNEX	Distribution O&M Expense	UT	$2,661	$0
5830000	OVHD LINE EXPENSES	DNEX	Distribution O&M Expense	WA	$368	$0
5830000	OVHD LINE EXPENSES	DNEX	Distribution O&M Expense	WYP	$301	$0
5830000	OVHD LINE EXPENSES	DNEX	Distribution O&M Expense	WYU	$153	$0
5830000 Total					**$5,735**	**$1,777**
5840000	UDRGRND LINE EXP	DNEX	Distribution O&M Expense	OR	$0	$0
5840000	UDRGRND LINE EXP	DNEX	Distribution O&M Expense	UT	$0	$0
5840000	UDRGRND LINE EXP	DNEX	Distribution O&M Expense	WYP	$0	$0
5840000 Total					**$0**	**$0**
5850000	STRT LGHT-SGNL SYS	DNEX	Distribution O&M Expense	SNPD	$232	$62
5850000 Total					**$232**	**$62**
5860000	METER EXPENSES	DNEX	Distribution O&M Expense	CA	$217	$0
5860000	METER EXPENSES	DNEX	Distribution O&M Expense	IDU	$404	$0
5860000	METER EXPENSES	DNEX	Distribution O&M Expense	OR	$2,991	$2,991
5860000	METER EXPENSES	DNEX	Distribution O&M Expense	SNPD	$487	$129
5860000	METER EXPENSES	DNEX	Distribution O&M Expense	UT	$2,009	$0
5860000	METER EXPENSES	DNEX	Distribution O&M Expense	WA	$447	$0
5860000	METER EXPENSES	DNEX	Distribution O&M Expense	WYP	$540	$0
5860000	METER EXPENSES	DNEX	Distribution O&M Expense	WYU	$133	$0
5860000 Total					**$7,226**	**$3,120**
5870000	CUST INSTL EXPENSE	DNEX	Distribution O&M Expense	CA	$520	$0
5870000	CUST INSTL EXPENSE	DNEX	Distribution O&M Expense	IDU	$492	$0
5870000	CUST INSTL EXPENSE	DNEX	Distribution O&M Expense	OR	$4,244	$4,244
5870000	CUST INSTL EXPENSE	DNEX	Distribution O&M Expense	UT	$3,100	$0
5870000	CUST INSTL EXPENSE	DNEX	Distribution O&M Expense	WA	$998	$0
5870000	CUST INSTL EXPENSE	DNEX	Distribution O&M Expense	WYP	$668	$0
5870000	CUST INSTL EXPENSE	DNEX	Distribution O&M Expense	WYU	$60	$0
5870000 Total					**$10,082**	**$4,244**
5880000	MSC DISTR EXPENSES	DNEX	Distribution O&M Expense	CA	$29	$0
5880000	MSC DISTR EXPENSES	DNEX	Distribution O&M Expense	IDU	$2	$0
5880000	MSC DISTR EXPENSES	DNEX	Distribution O&M Expense	OR	$428	$428
5880000	MSC DISTR EXPENSES	DNEX	Distribution O&M Expense	SNPD	$5,465	$1,453
5880000	MSC DISTR EXPENSES	DNEX	Distribution O&M Expense	UT	-$145	$0
5880000	MSC DISTR EXPENSES	DNEX	Distribution O&M Expense	WA	$27	$0
5880000	MSC DISTR EXPENSES	DNEX	Distribution O&M Expense	WYP	-$64	$0
5880000	MSC DISTR EXPENSES	DNEX	Distribution O&M Expense	WYU	-$51	$0
5880000 Total					**$5,691**	**$1,882**
5890000	RENTS-DISTRIBUTION	DNEX	Distribution O&M Expense	CA	$19	$0

Operations & Maintenance Expense (Actuals)
Twelve Months Ending - December 2014
Allocation Method - Factor 2010 Protocol
(Allocated in Thousands)

Primary Account		Secondary Group Code		Alloc	Total	Oregon
5890000	RENTS-DISTRIBUTION	DNEX	Distribution O&M Expense	IDU	$30	$0
5890000	RENTS-DISTRIBUTION	DNEX	Distribution O&M Expense	OR	$1,575	$1,575
5890000	RENTS-DISTRIBUTION	DNEX	Distribution O&M Expense	SNPD	-$82	-$22
5890000	RENTS-DISTRIBUTION	DNEX	Distribution O&M Expense	UT	$425	$0
5890000	RENTS-DISTRIBUTION	DNEX	Distribution O&M Expense	WA	$96	$0
5890000	RENTS-DISTRIBUTION	DNEX	Distribution O&M Expense	WYP	$388	$0
5890000	RENTS-DISTRIBUTION	DNEX	Distribution O&M Expense	WYU	$89	$0
5890000 Total					**$2,540**	**$1,553**
5900000	MAINT SUPERV & ENG	DNEX	Distribution O&M Expense	CA	$58	$0
5900000	MAINT SUPERV & ENG	DNEX	Distribution O&M Expense	IDU	$143	$0
5900000	MAINT SUPERV & ENG	DNEX	Distribution O&M Expense	OR	$1,019	$1,019
5900000	MAINT SUPERV & ENG	DNEX	Distribution O&M Expense	SNPD	$2,670	$710
5900000	MAINT SUPERV & ENG	DNEX	Distribution O&M Expense	UT	$1,307	$0
5900000	MAINT SUPERV & ENG	DNEX	Distribution O&M Expense	WA	$136	$0
5900000	MAINT SUPERV & ENG	DNEX	Distribution O&M Expense	WYP	$549	$0
5900000 Total					**$5,883**	**$1,729**
5910000	MAINT OF STRUCTURE	DNEX	Distribution O&M Expense	CA	$74	$0
5910000	MAINT OF STRUCTURE	DNEX	Distribution O&M Expense	IDU	$88	$0
5910000	MAINT OF STRUCTURE	DNEX	Distribution O&M Expense	OR	$747	$747
5910000	MAINT OF STRUCTURE	DNEX	Distribution O&M Expense	SNPD	$168	$45
5910000	MAINT OF STRUCTURE	DNEX	Distribution O&M Expense	UT	$616	$0
5910000	MAINT OF STRUCTURE	DNEX	Distribution O&M Expense	WA	$203	$0
5910000	MAINT OF STRUCTURE	DNEX	Distribution O&M Expense	WYP	$273	$0
5910000	MAINT OF STRUCTURE	DNEX	Distribution O&M Expense	WYU	$70	$0
5910000 Total					**$2,240**	**$792**
5920000	MAINT STAT EQUIP	DNEX	Distribution O&M Expense	CA	$444	$0
5920000	MAINT STAT EQUIP	DNEX	Distribution O&M Expense	IDU	$630	$0
5920000	MAINT STAT EQUIP	DNEX	Distribution O&M Expense	OR	$3,388	$3,388
5920000	MAINT STAT EQUIP	DNEX	Distribution O&M Expense	SNPD	$2,108	$561
5920000	MAINT STAT EQUIP	DNEX	Distribution O&M Expense	UT	$3,542	$0
5920000	MAINT STAT EQUIP	DNEX	Distribution O&M Expense	WA	$670	$0
5920000	MAINT STAT EQUIP	DNEX	Distribution O&M Expense	WYP	$1,706	$0
5920000 Total					**$12,488**	**$3,949**
5930000	MAINT OVHD LINES	DNEX	Distribution O&M Expense	CA	$6,963	$0
5930000	MAINT OVHD LINES	DNEX	Distribution O&M Expense	IDU	$5,482	$0
5930000	MAINT OVHD LINES	DNEX	Distribution O&M Expense	OR	$34,711	$34,711
5930000	MAINT OVHD LINES	DNEX	Distribution O&M Expense	SNPD	$1,581	$420
5930000	MAINT OVHD LINES	DNEX	Distribution O&M Expense	UT	$34,596	$0
5930000	MAINT OVHD LINES	DNEX	Distribution O&M Expense	WA	$3,407	$0
5930000	MAINT OVHD LINES	DNEX	Distribution O&M Expense	WYP	$7,357	$0
5930000	MAINT OVHD LINES	DNEX	Distribution O&M Expense	WYU	$1,213	$0
5930000 Total					**$95,309**	**$35,131**
5931000	MAINT O/H LINES-LB P	DNEX	Distribution O&M Expense	CA	-$39	$0
5931000	MAINT O/H LINES-LB P	DNEX	Distribution O&M Expense	IDU	-$80	$0
5931000	MAINT O/H LINES-LB P	DNEX	Distribution O&M Expense	OR	-$626	-$626
5931000	MAINT O/H LINES-LB P	DNEX	Distribution O&M Expense	UT	$776	$0
5931000	MAINT O/H LINES-LB P	DNEX	Distribution O&M Expense	WA	$38	$0
5931000	MAINT O/H LINES-LB P	DNEX	Distribution O&M Expense	WYP	-$109	$0
5931000 Total					**-$41**	**-$626**
5940000	MAINT UDGRND LINES	DNEX	Distribution O&M Expense	CA	$608	$0
5940000	MAINT UDGRND LINES	DNEX	Distribution O&M Expense	IDU	$608	$0
5940000	MAINT UDGRND LINES	DNEX	Distribution O&M Expense	OR	$5,982	$5,982
5940000	MAINT UDGRND LINES	DNEX	Distribution O&M Expense	SNPD	$9	$2
5940000	MAINT UDGRND LINES	DNEX	Distribution O&M Expense	UT	$11,450	$0
5940000	MAINT UDGRND LINES	DNEX	Distribution O&M Expense	WA	$1,003	$0
5940000	MAINT UDGRND LINES	DNEX	Distribution O&M Expense	WYP	$1,524	$0
5940000	MAINT UDGRND LINES	DNEX	Distribution O&M Expense	WYU	$234	$0
5940000 Total					**$21,418**	**$5,984**
5950000	MAINT LINE TRNSFRM	DNEX	Distribution O&M Expense	SNPD	$873	$232
5950000 Total					**$873**	**$232**

Operations & Maintenance Expense (Actuals)
Twelve Months Ending - December 2014
Allocation Method - Factor 2010 Protocol
(Allocated in Thousands)

Primary Account		Secondary Group Code		Alloc	Total	Oregon
5960000	MNT STR LGHT-SIG S	DNEX	Distribution O&M Expense	CA	$86	$0
5960000	MNT STR LGHT-SIG S	DNEX	Distribution O&M Expense	IDU	$141	$0
5960000	MNT STR LGHT-SIG S	DNEX	Distribution O&M Expense	OR	$918	$918
5960000	MNT STR LGHT-SIG S	DNEX	Distribution O&M Expense	UT	$1,666	$0
5960000	MNT STR LGHT-SIG S	DNEX	Distribution O&M Expense	WA	$197	$0
5960000	MNT STR LGHT-SIG S	DNEX	Distribution O&M Expense	WYP	$279	$0
5960000	MNT STR LGHT-SIG S	DNEX	Distribution O&M Expense	WYU	$102	$0
5960000 Total					**$3,390**	**$918**
5970000	MNT OF METERS	DNEX	Distribution O&M Expense	CA	$51	$0
5970000	MNT OF METERS	DNEX	Distribution O&M Expense	IDU	$314	$0
5970000	MNT OF METERS	DNEX	Distribution O&M Expense	OR	$1,224	$1,224
5970000	MNT OF METERS	DNEX	Distribution O&M Expense	SNPD	$1,618	$430
5970000	MNT OF METERS	DNEX	Distribution O&M Expense	UT	$1,851	$0
5970000	MNT OF METERS	DNEX	Distribution O&M Expense	WA	$314	$0
5970000	MNT OF METERS	DNEX	Distribution O&M Expense	WYP	$487	$0
5970000	MNT OF METERS	DNEX	Distribution O&M Expense	WYU	$127	$0
5970000 Total					**$5,986**	**$1,654**
5980000	MNT MISC DIST PLNT	DNEX	Distribution O&M Expense	CA	$91	$0
5980000	MNT MISC DIST PLNT	DNEX	Distribution O&M Expense	IDU	$37	$0
5980000	MNT MISC DIST PLNT	DNEX	Distribution O&M Expense	OR	$306	$306
5980000	MNT MISC DIST PLNT	DNEX	Distribution O&M Expense	SNPD	$284	$76
5980000	MNT MISC DIST PLNT	DNEX	Distribution O&M Expense	UT	$859	$0
5980000	MNT MISC DIST PLNT	DNEX	Distribution O&M Expense	WA	$56	$0
5980000	MNT MISC DIST PLNT	DNEX	Distribution O&M Expense	WYP	$344	$0
5980000 Total					**$1,978**	**$381**
Total Distribution					**$206,637**	**$69,296**