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UM 2005 Investigation into Distribution System Planning: Staff Responses to Section F

1. **Planning. Discuss the current regulatory oversight process for utility distribution system planning related to:**
    a. **Grid modernization**
    b. **Distributed energy resources**
    c. **Efficient integration of distributed energy resources**
    d. **Load growth**
    e. **Bulk system planning**
    f. **Maintaining system reliability and safety**

Grid Modernization – Currently the three electric utilities overseen by the OPUC submit biennial Smart Grid reports.[1] The reports detail the strategy, objectives, and associated investments for each utility's smart grid activities as part of an informal process. Originally launched under Order No. 11-172 and further refined in Order No. 12-158, the goal of these reports are to foster utility investments in real-time sensing, communication, control, and other smart-grid measures that are cost-effective and achieve enhanced reliability, energy savings, and development of renewables. The smart grid reports are only meant to report on activities and plans, but are not substantive "planning" documents where stakeholders, Staff and the Commission can impact investments. When reviewing Smart Grid Reports, Staff looks at compliance with the reporting requirements set forth in the Smart Grid guidelines. Many of the activities reported in the Smart Grid report are also reviewed by Staff in other proceedings related to elements such as cost recovery or approval of specific pilot programs.

Distributed Energy Resources (DERs) – Staff interprets this category as utility planning for the deployment of DERs on the system—whether utility, consumer, or third-party driven. DER covers a broad range of technologies from roof-top solar and smart thermostats to energy efficiency and demand response pilots.[2] Currently, the utilities' integrated resource plans (IRP) are the only dockets in which Staff looks holistically at utility planning for the deployment of DERs. When reviewing these, Staff submits information requests regarding cost, load, and market penetration effects on a case-by-case basis and makes recommendations based on its review. In the IRP, utilities forecast the deployment of DERs to account for reductions,

[1] Smart Grid investments were defined in Order No. 11-172 as "…utility investments in technology with two-way communication capability that will (1) improve the control and operation of the utility's transmission or distribution system, and (2) provide consumers information about their electricity use and its cost and enable them to respond to price signals from the utility either by using programmable appliances or by manually managing their energy use."
[2] For Staff's definition of DER, see March 21, 2019 Public Meeting, Regular Agenda Item #1, Request to Open Investigation (UM 2005), Appendix, Staff Whitepaper, "A Proposal for Distribution System Planning," February 19, 2019 pg.1.

increases, or other shifts in energy or capacity needs. Much of this work is performed through third-party studies. Staff analyzes whether the methodologies are sound and confirms whether the outputs of these DER forecasts adhere to the IRP guidelines for least-cost, least-risk planning.

Staff finds that there are challenges in overseeing this aspect of utility planning. First, integrating DERs into the utilities' IRPs is new. The past penetration rate of DERs have been small enough to warrant minimal discussion around integration at the IRP level. Second, IRPs historically lacked the tools to model the two-way interaction between demand and supply enabled by smart grid investments. Finally, Senate Bill (SB) 1547 introduced new guidance directing the utilities to acquire all cost-effective, reliable, and feasible energy efficiency and all cost effective demand response before acquiring new resources.[3]

The preferred regulatory oversight process for the deployment of DER technologies are investigations and are generally labeled under the utility miscellaneous or "UM" docket designation. These investigations generally cover the application, policy contours, compensation, and the overall planning of many of these technologies. In other cases, rulemaking is used and regular reports are submitted by the utilities to ensure compliance.

Efficient integration of DERs – Staff interprets this to include the efficient interconnection and valuation of DERs. Currently, the OPUC governs net metered interconnections, where customer-sited generation serves the customer's load directly and may export excess generation onto the utility's distribution system. The OPUC also governs Oregon-jurisdictional small generator interconnection, where third-party generator facilities under 10 MW export power to the distribution system. [4,5] The Commission's rules governing interconnection focus on the utility process to review interconnection requests and determine whether safe, reliable interconnections are possible. Sometimes disputes arise in this area and can be addressed at the Commission through the complaint process or other proceedings.

Similar to the increasing complexity of DER technologies considered in IRPs, an increasing number of investigations and other dockets related to the integration of DERs are underway at the Commission. These look at new pilots and programs, methodologies to value DERs, new planning or reporting processes for specific DERs, and more. While linked and interdependent, these dockets are not currently considered under a comprehensive umbrella. Staff notes that this is not an exhaustive list, but offers the following examples:

- Smart Grid Reports (UM 1657, UM 1667, UM 1675)
- Transportation Electrification Plans and Programs (AR 609, UM 1810, UM 1811, UM 1815)
- New Construction Budget Reports (RE 18, RE 35, RE 43)
- Energy Storage Pilots (UM 1856, UM 1857)
- Demand Response Pilots (UM 1708)
- Resource Value of Solar (UM 1910, UM 1911, UM 1912)
- Energy Efficiency Avoided Cost (UM 1893)
- PURPA Implementation (UM 2000, UM 2001)
- Annual Reliability Reports (RE 90, RE 113, RE 171)

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[3] See ORS 757.054
[4] See OAR Chapter 860, Division 39.
[5] See OAR Chapter 860, Division 82.

<u>Load Growth</u> – Staff has limited opportunity to review utilities' distribution-level plans and investments driven by load growth. Staff's primary opportunity to review utility load growth forecasts in a planning context is within the IRP. As mentioned above, the IRP load forecasts incorporate DER forecasts (distributed generation and storage, energy efficiency, demand response, and electric vehicle adoption). However, these forecasts and associated investments are provided at the aggregate system level. IRPs do not include feeder or other more granular distribution-level load forecasts that drive distribution-level planning and investments. The smart grid reports, transportation electrification plans, and pilots looking at geographically targeted energy efficiency investments offer additional insights into planning for load growth, but they contain few tools to directly impact the relationship between distribution-level load growth and investments.

<u>Bulk System Planning</u> – There is no formal regulatory oversight process for the interaction between utility distribution system planning and bulk system planning. When new investments in the bulk energy system are proposed, Staff reviews non-wires alternatives as part of our least-cost, least-risk planning process. High-voltage transmission lines generally associated with bulk system planning are reviewed in IRPs or rate cases. The Commission and Staff have also participated in the Northern Tier Transmission Group (NTTG) bulk system planning process. Members of NTTG include utilities, state commissions, and public service commissions. The group coordinates transmission systems operation, products, business practices, and high-voltage transmission network planning. Though certain distribution system investments may impact the bulk electric system, Staff does not anticipate bulk system planning to play a significant role in DSP.

<u>Maintaining system reliability and safety</u> – Utility IRPs address system-level resource adequacy but do not specifically address system reliability and safety performance. *See # 2 below for additional context.*

2. Current utility system operations and maintenance. Discuss the current regulatory oversight process for utility operations and maintenance of the distribution system including:

a. System reliability and safety

b. Efficient integration of distributed energy resources

Below are some of the ways that the OPUC reviews investor-owned utility (IOU) system reliability and safety:

- IOUs are required to file a report on their reliability performance for the previous year by May 1st each year. Safety Staff reviews utilities' reliability reports and assesses them. Staff verifies that the reports comply with the reporting requirements of OAR 860-023-0151 and further investigates trends in reliability indices and tries to get explanations or context for those trends. Staff also compares Oregon IOU indices with national benchmarks published by the Institute of Electrical and Electronics Engineers (IEEE).

- Every summer, Safety personnel perform vegetation audits on IOU distribution lines that consist of investigating tree trimming practices. Safety Staff verifies the implementation of the utilities' vegetation plans and confirms that the vegetation clearance requirements outlined in OAR 860-024-0016 are being met. Subsequent to Staff audits, Staff compiles findings of the vegetation audits and forwards those reports to the utilities and requests that utilities correct all vegetation clearance violations within an agreed upon timeline.

- OAR 860-024-0050 requires IOUs and consumer-owned utilities (COUs) to report on incidents that involve serious injury to persons or property that occurred within the utilities' facilities. Safety Staff receives the reports and documents them. If Safety Staff determines that the incident requires investigation, then it makes inquiries about the incident to understand the circumstances of the incident and whether safety rules were violated; Staff also explores ways to prevent similar incidents. Staff shares summaries of incident reports with members of the Oregon Utility Safety Committee (OUSC) in regular meetings and in an effort to raise awareness of safety issues. When Staff identifies trends in safety performance, it first works directly with the utility. If safety at the utility doesn't improve, Staff escalates through management and the Commission to drive action at the utility.

- ORS 401.054 requires the OPUC to designate a liaison to the Office of Emergency Management (OEM). Our role is to support the state when an emergency or disaster exceeds the capability of a local jurisdiction and that jurisdiction turns to the state for support. Safety Staff gathers the status (number of customers impacted and estimated recovery time) of all energy utilities (IOU, COUs, and local distribution companies or LDCs) as well as main telecommunication providers and reports that information to the state. Every agency designated to support OEM is providing similar information about other vital state systems. OEM compiles that information into a single report. The frequency of this reporting is at minimum daily. It can be multiple times a day in a dynamic situation. We develop a picture of the condition of the state related to energy and telecom, which can be used by the Commission Chair and the Governor to set priorities in the event of a major disaster. Additionally, in the liaison role, Safety Staff are the conduit for utilities to obtain resources. We participate in drills, development of statewide emergency plans, and general education about the capabilities of the system when there are outages in transmission or distribution.

- OAR 860-024-0010, in conjunction with OAR 860-024-0011 require electric utilities to construct and maintain their facilities in accordance with the 2017 edition of the National

Electric Safety Code (NESC). These rules also require IOUs to inspect all distribution system facilities in a maximum span of ten years. Safety Staff performs NESC audits and looks into compliance with clearance requirements, joint use requirements, construction standards, etc. Subsequent to Staff audits, Staff compiles findings of the NESC audits and forwards those reports to the utilities and requests that utilities correct all NESC violations in accordance with the timing requirements of OAR 860-024-0012. Staff also performs post audit verifications to ensure that utilities have corrected the violations accordingly.

- Customer complaints about power quality or outage response by a utility is one of Safety Staff's key views into the utility's day to day operations. Investigating those complaints have helped Staff identify poor-performing circuits that needed to be replaced or repaired, inadequate field staff to respond to downed lines and other safety concerns. Utilities are required to file reports on outages that meet the threshold in OAR 860-024-0050. Staff reviews those reports to determine if the utility has conducted thorough root cause analysis and if there are any proposed actions to minimize similar type outages in the future. Staff also reviews the outage reports for trends. Staff works informally and formally with the utility to clarify incomplete or inadequate reports and asks the utility to file a corrected report.

- Regarding efficient integration of DERs, distinctive types of DERs are handled separately through separate dockets. As mentioned above, through participation in the IRP, Staff reviews studies on distributed energy integration and how they impact load and capacity need. Historically, OPUC Staff has been quite engaged in safety and reliability issues of the distribution system but has had limited exposure to individual distribution system planning investments greater than $10 million and collective expenses represented in rate cases. As utilities expand their distribution system planning expertise, Staff expects that the transparency into utility investment decision-making will evolve. Staff is seeking to identify all of the possible components of DER integration with the help of stakeholders in order to tease out the key components of a unified design. Staff believes process harmonization is an important building block to transparency.

3. **Cost Recovery. Discuss the current typical regulatory process for utility recovery of costs related to the distribution system including:**
    a. **Grid modernization**
    b. **Replacement of aging infrastructure**
    c. **Operations and maintenance**
    d. **d. System expansion for load growth**
    e. **e. R&D and programs**

Grid modernization, replacement of aging infrastructure, and system expansion for load growth typically require capital investment. Utilities, as they build the related capital projects, charge the costs to Work-In-Process (WIP), and once the project is complete, the utility transfers it from WIP to Fixed Assets (FA). In a rate case, the utility would seek recovery of these capital costs by including them in the test year rate base. Staff reviews the facts and circumstances particular to each investment included in the test year rate base subsequent to the last rate case. Staff determines whether the investment was prudently incurred and if it is currently used and useful in providing utility service to Oregon customers. The Company does not earn a return on investment until the effective date of rates in the rate case, so there is a lag between the utility's capital investment spending and recovery in customer rates, known as "regulatory lag."

Under special circumstances, the utility is sometimes allowed by the Commission to "track in" capital costs between general rate cases (i.e. through automatic adjustment clauses). However, these mechanisms historically have not been used as a ratemaking tool for the recovery of distribution costs in between rate cases.

Operations and maintenance costs and research and development (R&D) costs are normal operating costs that are typically expensed on the utility's books and fall into the category of "cost of service" for ratemaking purposes (e.g. recurring ordinary expenses incurred in providing service to customers). In a rate case, the utility forecasts the test year cost of service expense. The utility's costs are often time determined by reference to actual operating expense for a historical base year and adjusted for known and measurable changes resulting in a future "test year" amount to be included in utility base rates. The utility is free to propose increases or decreases in the base year spending level. In a rate case, Staff scrutinizes the utility's proposed cost of service and customarily recommends adjustments based on Staff's analysis, Commission policy, or Commission precedent. Staff's review focuses on whether the proposed test year costs will result in rates that are fair, just, and reasonable. Regulatory lag also applies to variances in spending above and below what was included in the rate case versus the utility's current spending. Annually, each utility reports its actual results of operations. Staff reviews these reports for over earning within limits previously approved by the Commission.

Finally, pursuant to ORS 757.259, a utility may file an application requesting to establish a deferred account for a specific expense or revenue between rate cases for future ratemaking consideration. Deferred accounts (also referred to as "deferrals") act as an exception to the rule against retroactive ratemaking, which is allowed only to the extent authorized by statute. There are two steps to achieving ratemaking treatment for a deferred account: (1) a Commission order authorizing creation of the deferred account, which preserves the applicant's opportunity to make an argument at a future date that recovery of the balance in the deferred account is appropriate, and (2) a subsequent order authorizing amortization of the deferred amount. The Commission recently determined that it does not have the statutory authority to defer capital costs, and there is currently an investigation docket (UM 2004) open to explore the implications of this decision.

4. 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 relevant?

Staff believes there are a few other topics relevant to DSP that should be covered in greater depth by any process going forward:

- The communications infrastructure associated with the distribution system. The utilities are either making or will have to make substantive investments in secure two-way communications. As with any other utility investment, the Averch-Johnson effect plays a role.
- Utilities still operate based on tariffs. For DSP to make an impact, complementary tariffs will be needed if the goal is to enable non-discriminatory access to the grid (like the transmission system) and economically-efficient, equitable approaches to distribution system investments along with the dispatch of those investments.
- The equity and accessibility of OPUC processes continues to remain an important discussion across Commission activities. Staff finds that these elements should be considered when designing a DSP framework.