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VIA ELECTRONIC FILING

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

Attn: Filing Center

RE: UM 2005—PacifiCorp's Comments

PacifiCorp d/b/a Pacific Power encloses for filing its comments in response to a set of Staff questions posted in advance of the Commission's August 25, 2020 Special Public Meeting in this 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

BEFORE THE PUBLIC UTILITY COMMISSION
OF OREGON

UM 2005

In the Matter of PUBLIC UTILITY COMMISSION OF OREGON Investigation Into Distribution System Planning.	PACIFICORP'S RESPONSE TO STAFF QUESTIONS

Staff has asked for Stakeholder comments in response to a set of Staff questions posted in advance of the Commission's August 25, 2020 Special Public Meeting in this docket. The goal is to provide stakeholder perspectives on key distribution planning (DSP) issues to help Staff develop guidance in this docket. PacifiCorp provides the following responses:

Stakeholder Questions for August 25, 2020 Special Public Meeting

1. A foundational element of DSP is establishing the current state of the grid through baseline data. Currently this baseline data is largely recorded, analyzed, utilized, and maintained by and within the utilities. Reporting this baseline data in the utilities' filed plans will help broaden understanding of the state of the distribution systems. This will be especially important in the first distribution plans utilities file. Staff asks for stakeholder feedback in response to the following question:

   What kind of actionable baseline data and system assessment information should be included in the first utility DSP plans in order to help parties reach a shared understanding of the current state of the distribution systems?

Response: While PacifiCorp agrees that a first step in DSP is establishing the current state of the grid, DSP is a complex and evolving effort that must be undertaken in a deliberately phased and thoughtful manner. To the extent the Commission seeks baseline data, it should ensure the data requested is something a utility can appropriately collect and deliver.

Most distribution grids across the country, including PacifiCorp's, currently lack the sensing and measurement tools needed for advanced grid functions, particularly those which may be especially volatile to system, market and customer changes. While PacifiCorp implemented advanced metering infrastructure in its service territory, the system may not provide the frequency and level of granularity assumed by stakeholders.

The Commission should also be mindful of customer privacy and system security concerns with respect to this effort. Unlike aggregated data used in most transmission system planning processes, DSP 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. Information about industrial customers is especially susceptible to inadvertent disclosure.

Other standards are important to keep in mind, as well. Steps must be taken to ensure that Critical Energy Infrastructure information, or CEII, remains protected. And, as PacifiCorp noted previously in this docket, Federal Energy Regulatory Commission 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.

With these important considerations in mind, PacifiCorp looks forward to engaging on efforts to bring more transparency and understanding to the state of the grid.

2. An additional foundational element of DSP is forecasting future scenarios, such as an increased peak load, or a load with greater variability, to determine how the distribution system responds to these projected scenarios. Currently utilities forecast future loads and peak demands, often at the substation and circuit level, but without including distributed energy resources (DERs). Instead, DER forecasting is included in the Integrated Resource Planning (IRP) process as a reduction to the long-term load forecast, and without being attributed to specific locations on the distribution system. Expanding current forecasting to include DERs and electric vehicles (EVs) ***with*** a locational aspect would allow a more rigorous and broad examination of potential future conditions the distribution system may face. Staff understands there are a number of ways to forecast DERs and EVs with a locational aspect, and these come with different costs and benefits. For example, a "bottom-up" DER/EV forecasting methodology may use some form of customer adoption modeling beginning at a granular level (e.g., a neighborhood), which is then aggregated up to the whole system; a "top-down" forecasting methodology may forecast quantity of DER/EVs at the system level, and then allocate amounts down to more granular levels of the system. Staff asks for stakeholder feedback in response to the following question:

   <u>When considering the first utility DSP plans, is a "bottom-up" DER/EV forecasting methodology worth the likely additional cost when compared to a "top-down" forecasting methodology? Why or why not?</u>

Response: PacifiCorp's current planning incorporates a combination of "bottom up" and "top down" planning constructed from end-use scenario development. Instead of assumptions about customer load growth, known additional customer loads and any alternative usage, trends are considered and aggregated to the distribution lines and substations. PacifiCorp's top down planning is based primarily on information about regional load trends, known interconnection requests, as well as the broader impacts of regulatory goals and policies on customer preferences. These broad trends and assumptions are helpful in informing and shaping the more granular and local projections used in DSP. In PacifiCorp's view, it is important to continue forecasting top down and bottom up, as both currently provide a utility with valuable information; the company believes it is most important that stakeholders validate the reconciliation between these directions and that they reflect credible scenarios, properly boot-strapped together. In the future, as more data becomes available over time, PacifiCorp will be able to address a wider range of scenarios that can more acutely focus anticipated outcomes of customer and policy driven changes on DERs, EVs, customer load trends and other key DSP topics, but this ability is currently limited because the relationships are not well established and thus cannot be well understood.[1] As utilities gain more data and experience, it may be appropriate to trend toward fully connected bottom up planning process, but too much complexity too early in the process is likely to undermine the planning process, increase uncertainty and drive costs up.

3. Hosting Capacity Analysis (HCA) provides benefits by identifying the amount of DERs that can be accommodated in an area of the distribution system without adversely impacting power quality or reliability under current conditions. HCA practices currently vary across utilities. Staff understands that the granularity of HCA necessitates trade-offs. For example, the more granular the analysis, the longer it takes, the more expensive, and the more useful it may be. The less granular, the less time it takes, the less expensive, and the less useful. Staff asks for stakeholder feedback in response to the following questions:

   <u>When considering the first plans utilities file, what are likely to be the best uses for HCAs, and in what ways would your organization use them? For example, to screen projects (as a partial substitute for interconnection studies)? To help utility customers understand the general state of their feeder? For researching the overall opportunity for DERs in a given area?</u>

   What form of data presentation would your use benefit from (e.g. raw, tabular data or visualized on a map)?

Response: As PacifiCorp has noted, implementing hosting capacity software would require significant investments and personnel commitments for local planning engineers, geographic information system (GIS) upgrades, data quality improvement, and other information technology upgrades. Further, it is not clear the range of resources for which HCA should be conducted. It will also take time. It would be worthwhile to conduct additional workshops specifically focused on the most useful and cost-effective way to help customers and third-party stakeholders find appropriate methods for evaluating hosting capacity for projects in the near-term.

PacifiCorp agrees with Staff's first question, which posits that an appropriate first step in DSP is to gain an understanding of the utility's system. Consistent with this concept, it may be faster and more cost effective for potential project developers to understand where higher capacity lines and existing resources exist on the current system than to wait for development of a more complex HCA as a first step (particularly given the uncertainty about the resources, their operational constraints and the capacity expectations). Moreover, PacifiCorp continues

[1] For example, future adoption of DERs or buildout cases for EV systems, particularly at a highly localized scale.

to have concerns about the cost/benefit analysis associated with adopting an expensive and complex new process as a first step without first testing its value relative to other options. The more complex a hosting capacity map, the higher the cost of maintaining that map with any level of relevance. Absent constant updating, there is a risk that developers may rely on outdated information.

This effort, like all DSP efforts, should be undertaken in a deliberately phased and thoughtful manner. Each step in the process should create a solid foundation for the next. PacifiCorp suggests a series of workshops on this issue would be a worthwhile effort.

4. The distribution system is often closer and more visible to the public than a central generation station or remote transmission line, so distribution system projects have potential to impact homes and businesses directly in day-to-day life. One way to minimize potential impact of distribution projects to homes and business is for utilities to create and implement a Community Engagement Plan to proactively engage residents, business owners and stakeholders likely to be impacted by proposed projects. Engagement of the local community might include: accessible, in-person meetings located in the impacted area; presentation of the project scope, timeline, and rationale; co-creation of solutions to distribution system needs; and public comment, particularly to understand community impacts, needs, and preferences.

   Community-based organizations (CBOs) that support local, historically underserved communities have an important role in DSP. Because DSP is locational planning, CBOs can offer insight that informs utility forecasting of technology deployment and emerging solution use-cases in underserved communities, and provide input to the utility on the methodology used in the DSP process to identify and prioritize distribution system investments. During the detailed planning phase, CBOs may be an effective partner with utilities in ensuring successful implementation of customer- sited non-wires solutions identified in the DSP plan. Staff asks for stakeholder feedback in response to the following questions:

   <u>How could a Community Engagement Plan and process lead to improved distribution project outcomes for residents, business owners, and stakeholders in impacted areas? When should community engagement around a project begin? What is a practical “project threshold” to determine which projects warrant this? What metrics, evaluation and reporting should be required? How might the PUC support utilities to develop and showcase projects co-created with community partners?</u>

Response: Community engagement is important to PacifiCorp, and the Company continually strives to improve its partnerships with residents, business owners, and other customers. Community planning efforts hold promise for positive results, and PacifiCorp looks forward to engaging further to better understand the Commission’s goals and policies with respect to effectuating the types of project outcomes articulated by Staff. At the moment, however, it is not clear precisely how such projects relate specifically to the Commission’s current DSP planning process.

Community-driven planning would appear to be non-traditional from a regulatory perspective. PacifiCorp is mindful that, under the Commission's current regulatory policies, actions taken by specific customers or groups should not cause harm to other customers—financial, operational, or otherwise. Utilities carry other obligations imposed by the Commission as well, such as the obligation to prudently plan for and operate its system, and the obligation to serve all customers in a non-discriminatory manner. For this reason, this type of community-planning effort—which at first blush would seem to be in some tension with other Commission policies—will require very specific Commission policy guidance in order to be successful. Thus, it is imperative that the Commission provide utilities with clear guidance for understanding how community-driven projects are selected and developed. In addition, parameters for project selection, as well as cost-effectiveness measures or other standards that might demonstrate a project's prudency or other eligibility for cost recovery, should be developed and clearly articulated. Finally, projects that limit a utility's flexibility to address customer electric service needs would seem counterproductive. PacifiCorp looks forward to engaging on this issue to understand the Commission's views on utility authority to bring such policy goals to fruition.

5. DSP seeks to provide insights into, and facilitate new uses of, the electrical system, and so represents a change to the way that utilities currently plan and do business. DSP implementation will benefit from careful consideration of the following: incentives supporting implementation, barriers or downsides to implementation (including perspectives from all parties), and any ways in which utility regulation should be modified in order to best accommodate implementation. Staff asks for stakeholder feedback in response to the following questions:

   <u>In what ways do stakeholders foresee DSP affecting utilities' current business model? Do these represent incentives to pursue DSP, or barriers? Are there any changes that need to be made to Oregon's approach to regulation in order to succeed at advancing DERs cost-effectively? Which barriers and uncertainties to long-term DSP are most significant from your perspective?</u>

Response: It is unclear how DSP, in and of itself, would affect the utility and the current regulatory structure. That said, if the Commission implements DSP policies that require distribution system investments to be made on behalf of specific customers or developers, that policy would represent a fundamental shift in Oregon regulatory policy, which has historically strived to ensure that all customers are treated equally. Any such shift in Commission expectations of the utility would need to be coupled with clear policy guidance addressing these expectations.

In addition, a utility currently plans its system based on its obligation to serve load safely, reliably, and affordably, and its planning is based on assessment of actual needs. If the Commission's DSP policy creates an expectation that a utility will build out its system in anticipation of future DER development, rather than to serve actual customer load, this would represent a fundamental shift in Oregon regulatory policy, which has historically strived to ensure that a utility makes investments needed to serve customer load reliably, rather than to create new opportunities for third-party developers or for customers interested in owning generation.

Other DSP policies have the potential to change the regulatory paradigm in important ways, as well, and all run the real risk of shifting costs from generation developers—third-party or otherwise—to customers. Any such policies may need to be assessed for consistency with Oregon law. Finally, PacifiCorp would reiterate that Commission DSP policy should take into account a utility's provider of last resort obligation, and the differences between DSP in a region with an independent system and market operator (such as an ISO or RTO) versus one that is not.

6. Through the course of this investigation, Staff has facilitated ongoing stakeholder feedback to express the highest-level principles and values for DSP planning, and the distribution system. Reflecting this feedback, Staff proposes the following overarching, long-term goals for the DSP process and distribution system in Oregon. Staff asks for stakeholder feedback in response to the following questions:

   <u>What are your reactions to the overarching goals below? How are your needs reflected or missing? Do you recommend changes?</u>

   1. <u>Promote the reliability, safety, security, quality, and efficiency of the distribution system for all customers.</u>
      - Reinforce our existing mission, targeted for the distribution system but also updated for security, whether physical or cyber.
      - Facilitate investment to reduce costs over time and promote system efficiencies.
      - Enable the best and highest possible uses of the distribution system, to benefit customers and utilities.

   2. <u>Be customer-focused and promote inclusion of underserved communities.</u>
      - Empower all customers with authentic choices, including access to diverse providers.
      - Create inclusive, nondiscriminatory, equitable access to opportunities across customer types, with particular attention to those that reduce energy burden.
      - Engage customers in an approachable, fully-accessible manner.
      - Provide access to detailed, real-time information on electricity use and costs to help customers manage use and costs and understand how to save.
      - Create procedural inclusion for new stakeholders traditionally not represented.
      - Promote collaboration between utilities and community based organizations to broaden perspectives and representation in planning process and outcomes.

   3. <u>Ensure optimized operation of the distribution system.</u>
      - Minimize total distribution system costs for the benefits of all customers.
      - Consider advanced technologies and opportunities with future promise of lowering system costs.
      - Promote fair competition in resource options including third-party delivery of programs and services with the best options for customers.
      - Provide justification for the customer benefits resulting from system investments.

4. Accelerate integration of DERs and other clean energy technologies.
   - Fair cost allocation and fair compensation for services and benefits provided to and by customers, and other non-utility service providers.
   - Present transparent data about system operations and characteristics, including greenhouse gas implications.
   - Enable and streamline utility co-investment in the grid for decarbonization.

5. Strive for regulatory efficiency through aligned, streamlined processes.
   - Focused, strategic reporting that enables efficient regulatory response.
   - Consistency and synchronization across related utility planning efforts.

Response: While PacifiCorp recognizes that many of the overarching goals identified by Staff are aspirational in nature, some of those goals entail broad ranging operational and policy changes that—at this stage—are not clearly understood by all parties and would benefit from significant additional discussion. Assuming these goals prove durable after such discussions, movement toward those goals should be incremental and careful. Otherwise, they could represent significant risks to customers and utilities alike. Thus, before the Commission adopts any DSP requirements beyond the utility providing some type of initial distribution system plan for review, all stakeholders and the Commission should have a clear understanding of the Commission's intended policy direction, the incremental and measurable steps that will be taken toward reaching those goals, how those goals will be implemented without harming customers, and whether any additional statutory authority would be necessary for policy implementation.

Based on the discussions in this proceeding to date, there appears to be a risk that the Commission's process may lead to increased costs for all customers, or it could lead to cost shifting to customers who do not (or cannot) participate in DER adoption.

Finally, while organized markets often include regulatory mechanisms for DER pricing and cost allocation, Oregon does not currently have the regulatory mechanisms to address all of the issues raised by stakeholders during the workshop process. While the Commission has appropriately looked to other states to provide guidance for DSP 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.

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 DER 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 DER penetration in certain areas. If distributed resource planning is intended to bring customer benefits, these operational realities must be identified and acknowledged.

Respectfully submitted this 21st day of August, 2020.

By: ______________________________
Matthew McVee
Chief Regulatory Counsel
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