ITEM NO. RA3

PUBLIC UTILITY COMMISSION OF OREGON
STAFF REPORT
PUBLIC MEETING DATE: March 8, 2022

REGULAR __X__ CONSENT ____ EFFECTIVE DATE ______March 9, 2022______

DATE: February 28, 2022

TO: Public Utility Commission

FROM: Nick Sayen

THROUGH: Bryan Conway, JP Batmale, and Sarah Hall **SIGNED**

SUBJECT: OREGON PUBLIC UTILITY COMMISSION STAFF:
(Docket Nos. UM 2196, UM 2197, UM 2198)
Acceptance of Distribution System Plans - Part One.

STAFF RECOMMENDATION:

Accept Distribution System Plans - Part One filings by Idaho Power, Portland General Electric, and Pacific Power as meeting the objectives of the Distribution System Planning (DSP) Guidelines established in Order No. 20-485.

DISCUSSION:

Issue

1. Whether the Commission should accept Idaho Power Company's (Idaho Power) Distribution System Plan – Part One filing (Plan) filed October 15, 2021, in UM 2196 as meeting the objectives of the DSP Guidelines established in Order No. 20-485.

2. Whether the Commission should accept Portland General Electric's (PGE) Distribution System Plan – Part One filing (Plan) filed October 15, 2021, in UM 2197 as meeting the objectives of the DSP Guidelines established in Order No. 20-485.

3. Whether the Commission should accept Pacific Power's (dba as PacifiCorp or PAC) Distribution System Plan – Part One filing (Plan) filed October 15, 2021, in UM 2198 as meeting the objectives of the DSP Guidelines established in Order No. 20-485.

Applicable Rule or Law

ORS 756.040 describes the general powers of the Commission to supervise and regulate every public utility, and to do all things necessary and convenient in the exercise of that authority.

Under ORS 756.105(1), "Every public utility or telecommunications utility shall furnish to the Public Utility Commission all information required by the commission to carry into effect the provisions of ORS chapters 756, 757, 758 and 759."

In Order No. 19-104, the Commission opened Docket No. UM 2005 to "develop a transparent, robust, holistic regulatory planning process for electric utility distribution system operations and investments."

Order No. 20-485 established procedural and substantive DSP planning requirements, including Part One and Part Two DSP Plans as well as the process for Commission review of the Plans. The Part One Guidelines require that utility's Plan provide the following:

- A baseline understanding of the current physical status of the distribution system, including recent investment in the system and the level of Distributed Energy Resources (DERs) currently integrated into the system;
- A web-based map which identifies generation constrained areas of the system;
- An estimate of costs, timelines, and barriers to implementing Hosting Capacity Analysis (HCA);
- An overview of how stakeholders were engaged in the development of the Plan and how the utility is creating a collaborative environment;
- A Community Engagement Plan for implementation during development of non-wires solutions pilot concept proposals in Part Two; and
- A vision for the distribution for the next 5-10 years, and a roadmap of planned investments to support that vision.

Analysis

In this memo, Staff reviews procedural history and summarizes the DSP Guidelines and DSP planning goals. Staff then reviews each utility Plan and stakeholder comments. Staff concludes with a discussion of an evolving policy landscape and regulatory next steps.

Procedural History

The Commission issued Order No. 19-104 on March 22, 2019, opening Docket No. UM 2005 and an investigation to "develop a transparent, robust, holistic regulatory planning process for electric utility distribution system operations and investments."[1] Staff led a year-long process of robust stakeholder engagement. This included extensive efforts to improve understanding of distribution system planning for all parties and resulted in Staff's proposed draft DSP Guidelines (Guidelines) for public comment. The draft Guidelines were revised, utilizing the comment received and the Commission issued Order No. 20-485 on December 15, 2020, adopting Guidelines for electric utilities[2] for distribution system planning.[3] As specified by the Guidelines, utilities filed Part One DSP Plans on October 15, 2021, with Part Two to be filed August 15, 2022.

Utilities began preparing their Plans in 2021. The preparations included numerous workshops with stakeholders and members of the communities served by utilities. The workshops provided education and insight into the utilities' planning processes. In the workshops, utilities provided opportunities for stakeholder engagement to influence the Plans and share community perspectives. Staff led a Technical Working Group to provide a forum for utilities, stakeholders, and Staff to discuss issues that arose as utilities prepared their Plans.

While utilities developed their Part One Plans, the Oregon legislature passed several transformative energy policies including House Bill (HB) 2021 and HB 2475. These policies cover a range of utility investments and activities that will decarbonize the energy sector in a manner that is just, equitable, and inclusive. Staff discusses the intersection of DSP and these bills later in this memo.

After utilities filed their Plans, Staff solicited comment on utility Plans through a request-for-comment posted to the DSP dockets.[4] Staff also conducted a workshop on December 10, 2021, to solicit verbal comment from parties who did not submit written comment. Staff received comment from the following organizations and individuals:

- Joint comments from Verde and the Institute for Market Transformation (IMT) (submitted prior to the Plans being filed);

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[1] See Docket No. UM 2005, Order No. 19-104, https://apps.puc.state.or.us/orders/2019ords/19-104.pdf.

[2] "Electric utility" or "utility" for purposes of distribution system planning means an electric company that is engaged in the business of distributing electricity to retail electricity consumers in this state and that owns and operates a distribution system connecting the transmission grid to the retail electricity consumer.

[3] See Docket No. UM 2005, Order No. 20-485, https://apps.puc.state.or.us/edockets/orders.asp?OrderNumber=20-485.

[4] See Docket No. UM 2005, https://edocs.puc.state.or.us/efdocs/HAH/um2005hah131122.pdf.

- Joint comments from Coalition of Communities of Color (CCC), Verde, and IMT;
- Community Energy Project (CEP);
- Interstate Renewable Energy Council (IREC);
- NW Energy Coalition (NWEC);
- Joint comments from Oregon Coast Energy Alliance Network (OCEAN) and Oregon Solar + Storage Industries Association (OSSIA);
- WeaveGrid;
- Oregon Citizens Utility Board (CUB);
- Renewable Northwest;
- Multnomah County;
- Oregon Department of Energy (ODOE);
- Aharown Luke; and
- Hood River County Energy Council (HRCEC).

Staff received nearly ninety comments on PGE's Plan and more than 110 comments on Pacific Power's Plan. Feedback on Idaho Power's Plan was limited to several verbal comments in the December 10 workshop. Broadly speaking, comments provided positive feedback on the Plans, as well as critical feedback largely focused on future improvements. Staff encourages the utilities to review and consider all comments when considering improvements to their Plans.

DSP Guidelines Overview
The Guidelines establish timing of utility filings, processes for utilities to engage stakeholders in development of the Plans, and processes for Commission activity once Plans are filed. The Commission will consider whether to "accept" the filed Plan if the Commission finds the Plan meets the criteria and requirements of the Guidelines.[5]

The Guidelines aim to evolve utilities' legacy practices for distribution system planning towards a transparent stakeholder process, a substantive new practice. In addition, several requirements of the Guidelines – estimation of hosting capacity analysis (HCA) costs and timelines, developing plans for and implementing community engagement, and forecasting of distributed energy resources (DERs) and electric vehicles (EVs) to the substation – advance legacy practices in new ways. The Part One DSP Plan

[5] The Guidelines also articulate that acceptance does not constitute a determination on the prudence of any individual actions discussed in the Plan. A decision to not accept a Plan means that the Plan does not meet the criteria or requirements of the Guidelines.

focuses on creating transparency into the utilities' current system and long-term investment plans, and includes five sections:

1. Baseline and System Assessment: Description of the current physical status of the distribution systems including monitoring and control capabilities, recent investment in those systems, and the level of DERs currently integrated.
2. Hosting Capacity Analysis: Requires a system evaluation to identify areas where it is difficult to interconnect DERs without system upgrades, and present results on a web-based map.[6] Additionally, utilities are required to estimate costs and timelines for implementing HCA with varying levels of rigor. The Guidelines do not require estimates of benefits for these versions of HCA, nor do they require utilities to begin implementation of HCA.
3. Community Engagement: Requires utilities to conduct stakeholder workshops prior to Plan development, and to develop a Community Engagement Plan for implementation in Part Two.
4. Long-term Distribution System Plan: Requires utilities to articulate a 5-10 year vision for the distribution system, prepare a roadmap of planned investments, and discuss future policy and planning intersections.
5. Plan for Development of Part Two: Requires utilities to prepare a high-level summary of how legacy distribution planning practices will be transitioned to the requirements of Part Two.

Part Two of DSP Plans requires utilities to document current load forecasting processes and build on that foundation with forecasts of DER adoption and EV adoption by substation. The second section requires utilities to document the process by which they compare the current capabilities of their system, and future demands on that system to infer future "grid needs." The third section requires utilities to document assessment of proposed solutions to address grid needs. In addition, utilities must evaluate at least two pilot concept proposals utilizing non-wires solutions.[7] The final section requires utilities to present selected, proposed solutions to address grid needs.

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[6] This evaluation is not the same as conducting hosting capacity analysis. Instead, it is a simplified analysis using already developed methodology, utilizing data the utilities already provided through OASIS, and presenting the results visually through a map. For background on the current methodology see Docket No. UM 2099, PGE Reply Comments, https://edocs.puc.state.or.us/efdocs/HAC/um2099hac154013.pdf.

[7] An electric utility that makes sales of electricity to retail electricity consumers in an amount that equals less than three percent of all electricity sold to retail electricity consumers may evaluate one pilot concept proposal.

After utilities file Part Two Plans, Staff anticipates a stakeholder process to identify improvements to the Guidelines. Staff discusses possible areas of focus for this 2023 process later in the memo.

Goals of Distribution System Planning in Oregon
Reviewing foundational goals that guided the process of developing Oregon's DSP Guidelines provides context for the decision before the Commission today, as well as for Staff's recommendation. First, Staff notes two drivers behind the need for distribution planning.[8] The first, increased insight, is a procedural driver grounded in the near-term need for increased visibility into utility planning processes and holistic engagement in utility distribution-level investments. The second, optimization, is an operational driver grounded in the longer-term need to ensure the evolving distribution system maximizes operational efficiency and customer value.

Staff also notes a set of DSP goals developed collaboratively with parties through the course of the UM 2005 investigation.[9] These overarching goals serve Staff as useful lenses in considering utility Plans:

- Promote the reliability, safety, security, and quality of the distribution system for all customers.
- Be customer-focused and promote inclusion of underserved populations, including frontline, environmental justice communities.
- Ensure optimized operation of the distribution system.
- Enable efficient integration of DERs and other clean energy technologies.
- Strive for regulatory efficiency through aligned, streamlined processes.

Staff and Stakeholder Review of Utility Plans
Staff reviewed each utility Plan and provides a summary, Staff comment, discussion of select public comment, and Staff's recommendation. Part One filings reflect each utility's unique starting point with respect to DSP, its systems, and service territories.

<u>Portland General Electric Plan - Summary</u>
PGE's Plan is ambitious in scope and depth, consisting of eight chapters and running 169 pages. The Plan has well-articulated vision with chapters structured around this vision. It includes helpful chapter "readers guides" and a Guidelines compliance

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[8] See Docket No. UM 2005, Staff Whitepaper: A Proposal for Electric Distribution System Planning, https://edocs.puc.state.or.us/efdocs/HAU/um2005hau15477.pdf.
[9] See Docket No. UM 2005, https://edocs.puc.state.or.us/efdocs/HAH/um2005hah145318.pdf.

checklist. The Plan, and additional information including maps, can be found on PGE's DSP website.[10]

The Plan begins with a discussion of the current distribution system, and this discussion provides rich context for distribution planning broadly to aid the lay reader. Chapter two documents how corporate strategy informs PGE's DSP vision – a 21st century community-centered distribution system – and how that vision in turn informs high-level goals, which informs strategic initiatives. These strategic initiatives represent subsequent chapters in the Plan. Chapter three presents the Company's framework for community engagement best practices. The chapter also presents activities to evolve the status quo to a more human-centered distribution system. Finally, Chapter three conveys the Company's evolving understanding of energy justice and journey towards diversity, equity, and inclusion. Chapter four discusses a framework for modernizing the grid, and the Company's alignment with the U.S. Department of Energy's Modern Distribution Grid (DSPx) approach to justify modernization. The chapter walks through various grid capabilities evaluating the Company's own "maturity" with respect to that capability.

Chapter four also presents the Plan's roadmap and planned investments. The roadmap includes a discussion of costs, which includes costs through 2021, estimates for 2022, and some omissions. The roadmap does not include a forecast of future costs. Costs of note in 2022 include:

- $2M for next-generation planning tools,
- $1M for project scoping and software for a DER measure database (these costs do not have a year associated with them in the Plan),
- $40M for grid management systems,
- $8M for distribution automation systems, and
- $3M for field area network systems.

PGE's approaches to customer infrastructure resilience, PGE infrastructure resilience, and PGE operational resilience are discussed in Chapter five. The Plan delves into HCA in Chapter six, including results of the Company's work to identify areas where it is difficult to interconnect DERs, and develop estimates for HCA implementation. Finally, the Plan provides context and framework for a discussion of regulation and public policy that affects distribution system investments in Chapter seven.

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[10] See https://portlandgeneral.com/about/who-we-are/resource-planning/distribution-system-planning.

Staff Comment on PGE's Plan

Hosting Capacity Analysis

PGE developed the Company's Distributed Generation Evaluation Map, and this exceeded the Guideline requirement to conduct a system evaluation to identify areas where it is difficult to interconnect DERs without system upgrades. Because the Guideline was modeled on methodology PGE developed to create its net metering map, PGE's status quo would have been compliant. Instead, PGE worked with stakeholders to revamp the Company's net metering map and the underlying data. The new Distributed Generation Evaluation Map presents substantially more information about PGE's distribution system than the net metering map's "Generation Limited Feeders." The new map includes, for example, details about substations, individual feeders, and net daytime minimum load. Staff views the Distributed Generation Evaluation Map as an important step forward in distribution system transparency. PGE also included demographic layers such as income, ethnic identification, and other parameters. In addition to an improved map and data, Staff believes parties benefitted from developing the improved map, through initial HCA discussions about data, analyses, and visual presentation. Staff appreciates the effort to exceed the Guideline requirements.

PGE also met the requirement of developing cost and timeline estimates for, and identifying potential barriers to, implementing HCA with varying levels of rigor. Staff notes the significant jump in estimated cost from the mid-rigor option to the high-rigor option: ~$2.6M to ~$58.4M. The Plan notes that over half of the $58M estimate – ~$38.7M (based on ~645,000 hours of labor) – is rooted in setup activity. This analysis will be informative for starting discussions of HCA and considering future options.

The Plan notes that PGE intends to conduct HCA twice annually and lays out the Company's operating assumptions to do so. Staff notes that stakeholders raised concerns around PGE's intentions, discussed in the next section, and as a result PGE is slowing its approach. Staff notes the risk of PGE investing ratepayer funds before the Commission considers whether HCA minimum standards and calculation methodologies should be established.

Finally Staff recommends that utilities collaboratively engage stakeholders to assess effectiveness of the distribution system maps developed, and identify and implement best practices to improve the representation of distribution system data, including HCA. Staff proposes the DSP Work Group take this up as a potential next step. Ratepayers, and Oregon in general, would benefit from having one conversation that leads to agreement on minimum expectations on what distribution system data is made available, regardless of the utility in question.

Community Engagement Plan

PGE's effort to engage stakeholders in the development of the Plan was substantial, conducting eight workshops covering a broad range of high-level and detailed topics. PGE's work evolved, engaging a wide mix of stakeholder interest, making improvements in the workshops, and course-correcting after receiving participant feedback on workshop operating agreements, inclusion, structure, and timing.

In developing its Community Engagement Plan, PGE partnered with Coalition of Communities of Color (CCC), Community Energy Project (CEP), and Unite Oregon in this work. The Community Engagement Plan is broad, thorough, includes a high-level framework for community engagement, and details best-practices for community engagement.

PGE's Community Engagement Plan represents significant progress in a short amount of time. Staff suggests new questions for consideration during the 2023 stakeholder Guidelines review:

- Will PGE be able to replicate best practices throughout the Company?
- Will Community Engagement Plan learnings around outreach and communicating technical information drive Part Two pilot concept development?

Finally, there is a need for evaluating meaningful community engagement by all utilities. In simple terms, metrics are needed to evaluate whether ratepayer funds result in good, adequate, or insufficient engagement on DSP Plan development. These metrics can be issued to assess communities impacted by larger projects, and non-wires solutions implementation. Further there is an opportunity to continue OPUC efforts to improve engagement and accessibility, including opportunities to coordinate similar activities across dockets. This topic would likely benefit from additional stakeholder perspectives in the 2023 Guidelines review.

Long-term Distribution System Plan

PGE's Plan devotes more than two chapters to meeting the Long-term DSP requirements. The Company's vision informs three goals: advance environmental justice goals, accelerate DER adoption, and maximize grid benefits. The Company has developed five strategic initiatives to execute on these goals: empowered communities, modernized grid, resilience, "plug and play," and evolved regulatory framework.

Staff notes that the vision in the Plan is considerable and meets the intent of the Guideline. However, Staff observes additional detail in the roadmap discussion may be warranted in the future to better quantify the costs and benefits of the roadmap investments. Several examples include:

- Should cost-benefit discussions include more detail about specific items, timing, and whether benefits are expected to outweigh costs?
- To what extent can plans be aggregated to achieve some level of spending forecast? The level of detail provided for the planned near-term investments varies as Staff noted.
- Should there be a requirement for the Long-term Plan to consider asset health provided in the Baseline data? Examples include associated risks, opportunities, or anticipated investments.

Utility Concerns Directed to Staff
PGE's Plan explores the regulatory framework that impacts the distribution system. The sweeping discussion in Chapter seven includes Federal and State policy, legislation from the Oregon 2021 regular legislative session, and PUC regulatory matters. Staff notes its comments to the following points:

- DER cost-effectiveness: Staff appreciates this discussion and notes its possible inclusion in the 2023 Guideline revision process.
- Interconnection regulations: Staff values this discussion, and notes that the PUC has resumed activity in Docket No. UM 2111.
- Aligning EV regulation across vehicles classes: Staff thanks PGE for raising this topic, and notes development of the TE Investment Framework in AR 654 as an opportunity to advance the discussion.
- Comparable treatment of non-wires solutions and traditional utility investments: Similar to DER cost-effectiveness, Staff appreciates this discussion, and notes its possible inclusion in the 2023 Guidelines revision process.
- Docket integration for operational efficiency: Staff appreciates this discussion as a reminder that additional progress can be made.

PGE also discusses these topics in greater depth:

- Aligning utility incentives to scale DER programs: Staff appreciates PGE's research on examples from other states that have made progress on this topic.
- Regulatory Guidance on enabling inverter-based generation: Staff recognizes PGE's work to date developing tools to forecast and analyze conditions on the grid which allow for consideration of proactive investments to remove barriers for DER adoption.

Revision of utility incentives and proactive grid investments are topics that will require deliberate discussion and consideration by Staff, stakeholders and the Commission.

Public Comment on PGE's Plan

In this section Staff discusses public comment on PGE's Plan in specific Plan areas.

Baseline Assessment

- NWEC and OCEAN/OSSIA noted that recent investments have more than doubled from 2016 to 2020 and ask whether PGE anticipates the current overall higher levels will continue going forward. Staff anticipates that the Action Plan filed in Part Two should answer this question in the short-term and notes the Long-term Plan requirements may benefit from greater specificity on spending forecast.
- NWEC noted that PGE transformers have a current average life of 38 years with an expected average life of 55 years. NWEC asked whether PGE is taking special steps to accelerate replacement, if so, what financial impact might that have. Staff is interested in whether the Part Two Action Plan engages in these kinds of system conditions.

Hosting Capacity Analysis and Interconnection

- IREC commented that PGE's intention to conduct HCA before the Commission makes key decisions about the design of HCA would circumvent the Commission's decision-making process. Such key design decisions include methodology, granularity, update frequency, and methods of public access to the data. Further, IREC contends the Commission should not approve or acknowledge PGE's proposed HCA as the design (providing feeder-level results and updating results at an infrequent interval) would provide scant value to customers. Renewable Northwest echoed the comment. Staff agrees there is risk for PGE to implement HCA before the Commission considers key decisions about design. Responding to this feedback during the December 10 workshop, PGE stated the Company heard the need to slow down on HCA and will slow down.
- IREC commented that PGE's cost estimate for the high-rigor HCA is an order of magnitude higher than Pacific Gas and Electric's reported costs, despite having fewer feeders. OCEAN/OSSIA echoed this comment. Without commenting on the estimates, Staff notes the initial cost estimates will be informative for starting discussions of HCA and considering future options.
- NWEC, OCEAN/OSSIA, Renewable Northwest, and CUB expressed preference for additional stakeholder workshops on HCA. OCEAN/OSSIA also requested

Staff confer with counterparts at the California PUC regarding HCA. Staff recommends that further discussion of HCA in DSP pause, until the plan for the Docket No. UM 2111 Investigation into Interconnection Process and Policies is final. Once that plan is final, Staff recommends DSP stakeholders consider continuing discussions of HCA. If there is bandwidth and interest, Staff will work with stakeholders to determine next steps and scope that compliments efforts in the UM 2111 investigation. Staff is open to consultation with other state Commissions.

- Finally, CCC/Verde/IMT call on the PUC to require utilities to include in the DSP Part Two filing interconnection practices that encourage DERs and cost allocation. Staff notes the UM 2111 investigation as a more appropriate venue for revising interconnection practices, as discussed later in this memo.

Distribution System Data

- IREC commented that in the interim, while consideration of key decisions about HCA is underway, the Commission should authorize and encourage utilities to organize, validate, and publish basic distribution system data.[11] Staff agrees this is a pragmatic approach and proposes the DSP Work Group take this up as a potential next step to augment the maps utilities have already created.
- CCC/Verde/IMT, OCEAN/OSSIA, Renewable Northwest, and Multnomah County affirmed the importance of including equity indicators in distribution system maps and HCA maps. Staff notes PGE has made some progress by including demographic layers noted previously. Staff proposes the DSP Work Group take this up as a potential next step to augment existing utility maps.
- The Oregon Department of Energy encouraged that, when possible and appropriate, data underlying the mapping tools be made available such that data is as accessible as possible to public users and integrated with other spatial data. Staff appreciates this comment and is supportive of the proposed approach as distribution system data, and HCA guidance is further defined. Staff also finds that PGE could begin discussions with ODOE about making the underlying data to the Distributed Generation Evaluation Map available through "mapping services."
- While noting that Pacific Power has already begun to include reliability data in the Company's map, Staff will explore the possibility of further integrating reliability data into utility maps.[12]

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[11] See Docket No. UM 2197, https://apps.puc.state.or.us/edockets/edocs.asp?FileType=HAC&FileName=um2197hac153720.pdf.
[12] See Docket No. RE 113 for PGE, https://apps.puc.state.or.us/edockets/docket.asp?DocketID=18326.

Community Engagement Plan

- CCC/Verde/IMT noted that PGE's Plan does not afford an avenue for community input to be translated into technical recommendations, or put into practice through process changes to planning, operation, or investment. Multnomah County echoed the need to improve process towards community-centering. Staff anticipates greater opportunity for community input and recommendations in Part Two, particularly in the development of the non-wires solutions pilot concept proposals. However, the comment is a reminder that an engineering-centric process is in the early stages of evolution, and as the process gradually shifts towards community-centering, identifying such openings for community input will require attention.
- CCC/Verde/IMT noted there is a lack of transparency on how feedback is valued or integrated in the current Plan. Staff encourages utilities to strive for a transparent "feedback loop" for stakeholders input moving forward.
- CCC/Verde/IMT commented that funds should be directed to the PUC to distribute to community based organizations (CBOs). Staff notes the Commission is implementing a process to make available resources established by HB 2475, discussed later in this memo.

Long-term Distribution System Plan

- OCEAN/OSSIA noted provisions in the Plan show "limited generation feeders" not being upgraded until 2025 and asked that PGE begin upgrading these areas now. Staff notes that the Part Two filing will demonstrate the utility's process to identify grid needs, assess and propose solutions to needs. Staff anticipates all parties will better understand costs and benefits at that time. Further, Staff notes that the Commission recently extended the two-meter solution for new net-metering customers through December 31, 2022, which may alleviate some of the constraint on the feeders in question.[13]
- OCEAN/OSSIA noted extreme concern that PGE is using the resource value of solar (RVOS) in developing its cost-effectiveness tool and urge the Commission to immediately request PGE revisit their cost-effectiveness methodology for DERs with a stakeholder process. Staff notes that during the December 10 workshop PGE stated the Company is not using RVOS as part of cost-effectiveness calculations.

Docket No. RE 171 for Pacific Power, https://apps.puc.state.or.us/edockets/docket.asp?DocketID=20141, and Docket No. RE 90 for Idaho Power, https://apps.puc.state.or.us/edockets/docket.asp?DocketID=17818.

[13] See Docket No. UM 2099, Order No. 21-493, https://apps.puc.state.or.us/edockets/orders.asp?OrderNumber=21-493.

Metrics for Community Benefits, and Evaluating Investments

- CCC/Verde/IMT call on the PUC to develop a "Community Benefits Test" in partnership with utilities, CBOs, and other stakeholders to identify, track, and achieve metrics regarding energy burden and other community benefits. The parties cited requirements of HB 3141 for public purpose charge-funded incentives, HB 2021 for clean energy investments and the charges of the Utility Equity Advisory bodies, and HB 2475 with regard to energy affordability. The comment was echoed by OCEAN/OSSIA and Multnomah County. Staff appreciates this comment and is ready to collaborate to explore this concept and to meet legislative requirements.
- OCEAN/OSSIA commented that Staff should have resources regularly available to provide independent assessment of grid planning and investment done on behalf of ratepayers. Staff appreciates this comment and agrees with the need for resources to be able to assess such planning and investment.
- OCEAN/OSSIA requested the Commission strongly consider enforcement mechanisms to the DSP and urge the Commission to closely monitor PGE's investments to ensure maximum benefits for communities. Staff notes the Guidelines are currently structured as a planning process and disagrees that enforcement mechanisms are needed. Instead, the Commission has other potential procedural pathways to evaluate prudent investments.

<u>Staff Recommendation: Acceptance of PGE's Plan</u>

Staff recommends the Commission accept PGE's Plan. The Plan represents significant advancement of PGE's distribution planning practices towards the drivers and long-term goals identified during the development of the Guidelines in 2020. PGE's Plan generated substantial insight into the Company's distribution planning. Its development included workshops which addressed multiple topics, technologies, and policies, and included meaningful engagement by Staff and stakeholders while striving to reach new communities.

Staff finds the Plan meets the criteria and requirements of the Guidelines by:

- Providing a baseline understanding of the current physical status of the distribution system, including recent investment in the system and the level of DERs currently integrated into the system.
- Identifying generation constrained areas of the system and presenting those areas through a web-based map.
- Presenting estimated costs, timelines, and barriers to implementing HCA

- Engaging stakeholders in the development of the Plan and creating a collaborative environment.
- Developing a Community Engagement Plan for implementation during development of non-wires solutions pilot concept proposals in Part Two
- Presenting a vision for the distribution for the next 5-10 years, and a roadmap of planned investments to support that vision

Pacific Power Plan - Summary

Pacific Power's Plan consists of seven chapters, runs 98 pages, and includes a helpful Guidelines Reference. It is grounded in a clear overview of the legacy system, its management, and future enabling investments. The Plan, and additional information including maps, can be found on Pacific Power's DSP website.[14]

The Company provides a rich discussion of Pacific Power's current operations, programs, practices, and data addressing Baseline requirements in Chapter one. Pacific Power also provided this baseline data in an electronic, supplemental workpaper. Next, the Plan discusses the future distribution system, and suggests the Company is in early phases of developing DSP strategy, and the planning approach that it will entail. Pacific Power describes the Company's Community Engagement Plan in Chapter three. The Community Engagement Plan proposes utilizing a Community Input Group (CIG). The Group, a coalition of CBOs, businesses, individuals, social justice groups, agencies, and other interested parties, will aim to ensure equitable and inclusive consideration of community interests in the development process of the DSP. The Plan discusses foundational aspects of planning process, data, and HCA in Chapters four and five.

The Plan presents near term activities leading to the filing of Part Two, integration with the next IRP, and high-level future plans, including cost estimates in Chapter six. The cost estimates are presented as one-time and annual costs, and include components of the Long-term Plan and HCA. (Staff discusses HCA costs below.) One-time costs of note are $2.75M for substation supervisory control and data acquisition (SCADA) build out, $8.7M for deployment of fiber communications to substations, and $3.3M for LoadSEER software license. Annual costs of note are $1.5M to expand DA/FLISR pilots, and $4.3M for core DSP activities.[15]

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[14] See https://www.pacificorp.com/energy/oregon-distribution-system-planning.html.

[15] See Docket No. UM 2198, https://apps.puc.state.or.us/edockets/edocs.asp?FileType=HAA&FileName=um2198haa12716.pdf, Table 26: DSP Cost Estimates, including HCA Options, page 94.

Staff Comment on Pacific Power's Plan

Baseline Assessment

Staff appreciates the Company providing baseline data in a supplemental workpaper; this is a rich resource of information. To the extent practical, Staff encourages the workpaper be given a fuller narrative description in subsequent Plans.

Hosting Capacity Analysis

Pacific Power met the requirement of a system evaluation, with presentation of results via map. The Company did not stop there however and included in the map additional features such as contextual information for distributed generation planning, Low-Income Energy Affordability Data (LEAD), and 2020 reliability data. Staff appreciates the effort to exceed the Guideline requirements and developing additional data elements for stakeholders and Staff to consider in HCA implementation discussions.

Pacific Power also met the requirement of developing cost and timeline estimates for, and identifying potential barriers to, implementing HCA with varying levels of rigor. Staff notes the significant jumps in estimated cost for each level of rigor: low-rigor ~$500k, mid-rigor ~$10.1M, high-rigor ~$64M. While Pacific Power did not include labor-hour estimates, Staff notes the majority of costs for the mid- and high-rigor levels were for System Availability Work, which based on the tasks described, Staff assumes to be set-up work. Staff believes this analysis will be informative for starting discussions of HCA and considering future options.

Finally Staff recommends that utilities collaboratively engage stakeholders to assess effectiveness of the distribution system maps developed, and identify and implement best practices to improve the representation of distribution system data, including HCA. Staff proposes the DSP Work Group take this up as a potential next step. Ratepayers, and Oregon in general, would benefit from having one conversation that leads to agreement on minimum expectations on what distribution system data is made available, regardless of the utility in question.

Community Engagement

Pacific Power's effort to engage stakeholders in the development of the Plan was considerable. Through five workshops, the Company communicated holistically the current state of Pacific Power's system, approaches to managing the system, and how the Company was beginning to evolve that current state in response to Guideline requirements. Staff notes that workshop participants did not often include community representatives or CBOs, but more often stakeholders already engaged in DSP. Staff understands the Company is aware of this circumstance and is taking steps to increase the scope of community representatives engaged in DSP.

Pacific Power's Community Engagement Plan represents valuable progress in developing new strategies to engage communities the Company serves. Like PGE and Idaho Power, Pacific Power was covering new ground. The development of a CIG seems likely to provide the Company valuable input, particularly if composed of individuals representing broad interests such as CBOs, business, and environmental justice groups. Staff comments that many outreach methods and feedback channels in the Plan are technology focused (for example, web-based information sources, email and or social media). While a benefit of this approach is lower costs, a risk is the omission of those less able or inclined to engage via technology. Staff encourages Pacific Power to consider options to bridge the "digital divide" to minimize this risk.

Finally, Staff comments that, broadly speaking, much of the content provided by Pacific Power to-date has been technical in nature. While there are benefits to providing data-rich information, a downside is reduced accessibility for some stakeholders, and less transparency generally. Staff encourages the Company to be cognizant of audiences, and continually consider whether material is appropriately technical, or more complicated than it needs to be.

Staff reflects that, as with PGE, there are now new questions about community engagement that need answering:

- Will Pacific Power be able to replicate best-practices throughout the Company?
- Will learnings from Part One translate into success in developing Part Two pilot concepts?

Finally, as noted with PGE, there is a need for evaluating meaningful community engagement. In simple terms, metrics are needed to be able to evaluate whether ratepayer funds resulted in good, adequate, or insufficient engagement on DSP Plan development, communities impacted by larger projects, and non-wires solutions implementation. Further there is an opportunity to continue PUC efforts to improve engagement and accessibility, including opportunities to coordinate similar activities across dockets. This topic would likely benefit from additional stakeholder perspectives in the 2023 Guideline review.

Long-term Distribution System Plan
Staff notes discussion of the Long-term Plan is stretched across all but one chapter. Staff comments that Chapter 2 suggests Pacific Power envisions itself at very early phases of developing DSP strategy. The Company is beginning to develop a methodology for DSP that it will eventually be able to discuss with stakeholders when deciding and developing strategy in the future. This has the potential to be a robust and

transparent process; Staff encourages the Company to follow this plan and to identify whenever possible concrete actions to provide customer benefits. As the Company follows this plan, and further develops its strategy, Staff sees opportunity for a more well-articulated, cohesive Long-term Plan in future filings and will suggest in the 2023 guideline revision process that all utilities' Long-term Plans be updated before the end of 2024 with new information and lessons learned.

Staff also notes several instances where the Long-term Plan could have additional discussion and detail about how technologies can be used to support the Company's vision.

- The AMI discussion notes current capabilities, and that the Company wants to be better able to identify potential power quality issues, but what about facilitating new types of time-based pricing, or other approaches to reduce peak load?
- The *CYME* section discusses how the software may help identify least-cost options to meet load or avoid the need for new distribution lines, but the discussion of plans is vague.
- The discussion on self-healing distribution-automation pilots presents a promising way to improve resiliency. However, despite two such projects underway now, the Plan doesn't really share a vision for using this technology in the next 5-10 years.

Staff appreciates Table 26 as a first step to consider DSP cost estimates.[16] Staff looks forward to discussing the Company's assumptions and development of the estimates, as well as the implementation schedule. As with PGE's Plan, Staff observes additional detail in the roadmap may be warranted in the future. Improving the Long-term Plan requirements may be included in the scope of the 2023 revision process.

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[16] See Docket No. UM 2198, https://apps.puc.state.or.us/edockets/edocs.asp?FileType=HAA&FileName=um2198haa12716.pdf, Table 26: DSP Cost Estimates, including HCA Options, page 94. Table 26 describes various aspects of the costs associated with fully implementing Long-term Plan Components. This implementation includes one-time costs for substation supervisory control and data acquisition (SCADA) build out, for deployment of fiber communications to substations, for LoadSEER software licensing and implementation, for integrating PowerClerk software, and for developing the communications plan. Table 26 also includes annual costs: to expand DA/FLISR pilots, to implement the communications plan, and for core DSP activities.

Public Comment on Pacific Power's Plan

In this section, Staff discusses public comment on Pacific Power's Plan in specific Plan areas. Many comments on Pacific Power's Plan echoed those on PGE's Plan, and Staff's responses are similar. For brevity Staff indicates when that is the case.

Baseline Assessment

- As with PGE's Plan, NWEC noted that recent investments have more than doubled from 2016 to 2020 and ask whether the current overall higher levels will continue. Staff again anticipates that the Action Plan filed in Part Two should answer this question in the short-term and notes the Long-term Plan requirements may benefit from greater specificity on spending forecast.
- As with PGE's Plan, NWEC notes Pacific Power transformers have a current average life of nearly 47 years with an expected average life of 53 years; is the Company taking special steps to accelerate replacement, if so, what financial impact might that have? Staff again is interested in whether the Part Two Action Plan engages in these kinds of system conditions.

Hosting Capacity Analysis and Interconnection

- HRCEC commented that data going into HCA, and the criteria to determine suitability (such as minimum load) needs to be made available, feeder lines should be clearly labeled, individually identifiable, and include information on existing load and current hosting capacity for additional DERs. Staff notes these elements are important aspects of HCA. However, Staff recommends pausing HCA discussions within DSP until further development of the plan for Docket No. UM 2111 Investigation into Interconnection Process and Policies.
- As with PGE's Plan, NWEC, OCEAN/OSSIA, Renewable Northwest, and CUB expressed preference for additional stakeholder workshops and engagement on HCA. OCEAN/OSSIA also request Staff confer with counterparts at the California PUC regarding HCA. If there is bandwidth and interest, Staff will work with stakeholders to determine next steps that compliment efforts in Docket No. UM 2111. Staff is open to consultation with other state Commissions.
- As with PGE's Plan, CCC/Verde/IMT call on the PUC to require utilities to include in the DSP Part Two filing interconnection practices that encourage DERs and cost allocation. Staff notes Docket No. UM 2111 is a more appropriate venue for revising interconnection practices, as discussed later in this memo.

Distribution System Data

- As with PGE's Plan, CCC/Verde/IMT, OCEAN/OSSIA, Renewable Northwest, and Multnomah County affirmed the importance of including equity indicators in distribution system maps and HCA maps. Staff notes Pacific Power has made some progress by including LEAD layers noted previously. Staff proposes the DSP Work Group take this up as a potential next step to augment maps utilities have already created.

- As with PGE's Plan, the ODOE submitted comment encouraging the data underlying the mapping tools be made available such that data is as accessible as possible to public users and integrated with other spatial data. Staff appreciates this comment and is supportive of the proposed approach as distribution system data, and HCA guidance is further defined. Staff also finds that Pacific Power could begin discussions with ODOE about making the underlying data to Pacific Power's Distribution System Planning Map available through "mapping services."
- While noting that Pacific Power has already begun to include reliability data in the Company's map, Staff will explore the possibility of further integrating reliability data into utility maps.[17]

Community Engagement Plan

- CEP and NWEC commented that key aspects of the CIG, such as membership and roles, have not been identified and this is important as the CIG is a core element of the Outreach Plan. NWEC also complimented the concept of the CIG but noted more clarity is needed for how the CIG will engage community, how community may participate, and how the CIG will engage in DSP work. Staff notes that the Plan identifies development of the CIG is in early stages and encourages the Company to consider this input as it moves forward.
- CEP, NWEC, and OCEAN/OSSIA comment that the Plan should include engaging community directly and should address new audiences. HRCEC echoed this comment. Staff notes Pacific Power's territory is non-contiguous, urban, suburban, and rural, which present unique challenges to engagement. Nonetheless, Staff appreciates these comments and encourages the Company to strive for opportunities to engage community directly and consider the costs and benefits each opportunity presents.
- CEP and HRCEC commented that workshops so far have been technical and that moving engagement forward should be appropriate for intended audiences, focus on how the Plan relates to community, and facilitate dialogue and input. CEP notes CBOs can help reach desired outcomes, for example making

[17] See Docket No. RE 113 for PGE, https://apps.puc.state.or.us/edockets/docket.asp?DocketID=18326, Docket No. RE 171 for Pacific Power, https://apps.puc.state.or.us/edockets/docket.asp?DocketID=20141, and Docket No. RE 90 for Idaho Power, https://apps.puc.state.or.us/edockets/docket.asp?DocketID=17818.

technical information more accessible. Staff reiterates encouragement to be cognizant of audiences, and whether material is appropriately technical.
- As with PGE's Plan, CCC/Verde/IMT noted Pacific Power's Plan does not afford an avenue for community input to be translated into technical recommendation or implemented through process changes to planning, operation, or investment. OCEAN/OSSIA echoed the comment. Multnomah County echoed the need to improve process towards community-centering. Staff anticipates greater opportunity for community input and recommendations in Part Two, particularly in the development of the non-wires solutions pilot concept proposals. However, the comment is a reminder that an engineering-centric process is in the early stages of evolution, and as the process gradually shifts towards community-centering, identifying such openings for community input will require attention.
- As with PGE's Plan, CCC/Verde/IMT noted there is a lack of transparency on how feedback is valued or integrated in the current Plan. Staff encourages utilities to strive for a transparent "feedback loop" for stakeholder input.
- As with PGE's Plan, CCC/Verde/IMT commented that funds should be directed to the PUC to distribute to CBOs. Staff notes the Commission is implementing a process to make available resources established by HB 2475, discussed later in this memo.

Metrics for Community Benefits, and Evaluating Investments
- OCEAN/OSSIA noted the potential for systemic underserving of marginalized communities is enhanced in areas where SCADA has not been deployed, and that an aggressive strategy for universal SCADA deployment be prioritized. Staff is interested in an accounting of costs and benefits of such investment.
- As with PGE's Plan, OCEAN/OSSIA comment that Staff should have resources to provide independent assessment of grid planning and investment. Staff appreciates this comment and concurs on the need for resources to be able to assess such planning and investment.
- As with PGE's Plan, CCC/Verde/IMT call for development a "Community Benefits Test" in partnership with utilities, CBOs, and other stakeholders. Interest in a community benefits test was echoed by OCEAN/OSSIA, and from Multnomah County. Staff appreciates this comment and is ready to collaborate to continue OPUC efforts to improve engagement and accessibility, including opportunities to coordinate similar activities across dockets.

<u>Staff Recommendation: Acceptance of Pacific Power's Plan</u>
Staff recommends the Commission accept Pacific Power's Plan. The Plan represents noteworthy advancement of the Company's distribution planning practices towards the

drivers and long-term goals identified during the development of the Guidelines in 2020. The Plan's development included numerous workshops which addressed multiple topics and technologies and included meaningful engagement by Staff and stakeholders.

Staff finds the Plan meets the criteria and requirements of the Guidelines by:

- Providing a baseline understanding of the current physical status of the distribution system, including recent investment in the system and the level of DERs currently integrated into the system.
- Identifying generation constrained areas of the system and presenting those areas through a web-based map.
- Presenting estimated costs, timelines, and barriers to implementing HCA.
- Engaging stakeholders in the development of the Plan and creating a collaborative environment.
- Developing a Community Engagement Plan for implementation during development of non-wires solutions pilot concept proposals in Part Two.
- Presenting a vision for the distribution for the next 5-10 years, and a roadmap of planned investments to support that vision.

Idaho Power Plan - Summary
Idaho Power's Plan is concise, with six main sections structured around the Guideline requirements, and runs 54 pages. The Plan and additional information including maps can be found on Idaho Power's DSP website.[18]

The Plan begins with rich context for the Company's service territory, and then walks through the Company's current distribution system providing insights highly in line with the Guideline Baseline requirements. For example, while just over half of the Company's substations are equipped with SCADA, those substations represent nearly 95 percent of customers in Oregon. The HCA discussion includes a proposal to move ahead with implementation in late 2022. Next, the Company discusses Community Engagement and notes that Idaho Power utilizes workgroups and committees in many of its planning efforts, but has not yet created a dedicated DSP group. The section explains the Company's steps in lieu of an established group.

Finally, The Long-term Plan includes a vision that clearly states areas of focus for DSP:

- Forecasting near- and long-term electrical demands for each service region.

[18] See https://www.idahopower.com/energy-environment/energy/planning-and-electrical-projects/oregon-distribution-system-plan/.

- Developing community advisory-based electrical plans.
- Developing proactive near-term local area plans that are achievable and executable before electrical demand overloads facilities or results in reduced service quality.

Staff notes that while the Long-term Plan includes a roadmap of planned investments across varying technologies and levels of development, it does not include estimated costs.[19]

<u>Staff Comment on Idaho Power's Plan</u>
Baseline Assessment
Staff notes that some key equipment has advanced average age. Such equipment includes substation transformers, circuit breakers, and electromechanical relays. Staff wonders about the impact of construction delays in the Boardman to Hemingway transmission line has on this data. Staff requests Idaho Power include in the submission of Part Two an updated Appendix B with an alternate scenario of asset age were Boardman to Hemingway just placed into service.

Hosting Capacity Analysis
Idaho Power met the requirement of a system evaluation, with presentation of results via a map. The Company also met the requirement of developing cost and timeline estimates for, and identifying potential barriers to, implementing HCA with varying levels of rigor. Staff notes Idaho Power discusses implementing HCA in late 2022. In doing so, as was the case with PGE, there is some risk investing ratepayer funds to implement HCA before the Commission considers minimum standards. However Staff understands from the Plan that the primary implementation costs would be $70k in labor, and so the risk of a sizable investment becoming a "stranded asset" seems minimal.

Finally Staff recommends that utilities collaboratively engage stakeholders to assess effectiveness of the distribution system maps developed, and identify and implement best practices to improve the representation of distribution system data, including HCA. Staff proposes the DSP Work Group take this up as a potential next step. Ratepayers, and Oregon in general, would benefit from having one conversation that leads to agreement on minimum expectations on what distribution system data is made available, regardless of the utility in question.

[19] See Docket No. UM 2196, https://apps.puc.state.or.us/edockets/edocs.asp?FileType=HAA&FileName=um2196haa161347.pdf, Long-term Distribution System Plan Chapter, page 42.

Community Engagement
Idaho Power met the requirement of holding two workshops with stakeholders in developing their Plan. Workshops were responsive to participants' interests, and the Company took away useful learnings, for example, suggestions about how to best approach customers and communities to achieve greater engagement.

While Staff is encouraged to see that the Company plans to engage CBOs to gain more representative and diverse public input in preparing Part Two, Staff notes the Community Engagement Plan, as outlined in requirement 4.3.a.ii, is only a high-level summary of intended next steps. Staff hopes this lack of specificity does not impede development of a successful non-wires solutions pilot concept proposal in Part Two.

Staff suggests there are new questions about community engagement that need consideration, such as how to evaluate meaningful community engagement by all utilities. In simple terms, metrics are needed in order to evaluate whether ratepayer funds resulted in good, adequate, or insufficient engagement on DSP Plan development, communities impacted by larger projects, and non-wires solutions implementation. Further there is an opportunity to continue OPUC efforts to improve engagement and accessibility, including opportunities to coordinate similar activities across dockets. This topic would likely benefit from additional stakeholder perspectives in the 2023 Guideline review.

Long-term Distribution System Plan
Staff is pleased to see the Long-term Plan includes a vision that clearly states the three areas of focus for DSP noted earlier. The discussion on Planned Improvements is helpful in showing Idaho Power's strategy. However, discussion of costs and benefits of the technologies is vague. As noted with PGE and Pacific Power's Plans, additional detail in the Long-term Plan section may be warranted in the future. Improving the Long-term Plan requirements may be included in the scope of the 2023 revision process.

Idaho Power notes that its service territory in Eastern Oregon may not evolve at the pace of other Oregon regions. Staff comments that while the rural nature of the grid is an important consideration in DSP, some aspects of DSP, such as non-wires solutions, may be more cost-effective in a region where wires need to be long to reach remote locations. Staff notes that development of a non-wires solutions pilot concept proposal for Part Two may further inform this question.

<u>Public Comment on Idaho Power's Plan</u>
There was no written public comment submitted on Idaho Power's Plan. At the December 10 workshop, Renewable Northwest lauded Idaho Power for its 100 percent

clean energy goal and wondered if it was achievable faster. Also during the Workshop, IREC commented that the use of *estimated* minimum daytime load in HCA can produce more restrictive results than using *actual* minimum daytime load.

Staff Recommendation: Acceptance of Idaho Power's Plan
Staff recommends the Commission accept Idaho Power's Plan. The Plan represents advancement of the Company's distribution planning practices towards the drivers and long-term goals identified during the development of the Guidelines in 2020. The Plan provides insight into the Company's distribution planning, established long-term and short-term vision, and engaged stakeholders and Staff.

Staff finds the Plan meets the criteria and requirements of the Guidelines by:

- Providing a baseline understanding of the current physical status of the distribution system, including recent investment in the system and the level of DERs currently integrated into the system.
- Identifying generation constrained areas of the system and presenting those areas through a web-based map.
- Presenting estimated costs, timelines, and barriers to implementing HCA.
- Engaging stakeholders in the development of the Plan and creating a collaborative environment.
- Developing a Community Engagement Plan for implementation during development of non-wires solutions pilot concept proposals in Part Two.
- Presenting a vision for the distribution for the next 5-10 years, and a roadmap of planned investments to support that vision.

Looking Forward
Coordination with Planning Processes and Regulatory Efficiency
In this section, Staff discusses emerging policies and planning processes that intersect with DSP, identifying important areas for increased coordination and attention moving forward. At the time the Commission launched UM 2005, the planning framework centered on the Integrated Resource Plan (IRP), which examines utilities' resource

strategies at the bulk level.[20,21] Since that time, major changes in the planning landscape have evolved the conversation about how DSP should fit into the utility planning landscape. These changes include Clean Energy Plans, Utility Community Benefits and Impacts Advisory Groups (UCBIAG), Wildfire Protection Plans, Flexible Load and Demand Response Planning, and Transportation Electrification Plans.

Clean Energy Plans and Integrated Resource Planning
HB 2021 establishes an ambitious emissions-based clean energy framework and requires PGE, Pacific Power, and electricity service suppliers to decarbonize their retail electricity sales by 2040 in a manner that provides direct benefits to local communities to the extent practicable. Clean Energy Plans, one of the bill's major parts, are to include a robust set of requirements including annual goals/actions that make progress towards the clean energy targets. Clean Energy Plans are to be based on, or included in, an IRP.

The introduction of the Clean Energy Plans has forced a near-term conversation about where DSP should fit into the broader planning framework. What was previously a question of how IRPs and DSPs would successfully align inputs, outputs, and high-level assumptions, is now a conversation about how the IRP and DSP will feed into the Clean Energy Plan to convey the utility's overall decarbonization strategy. This is not just a question about the flow of data, assumptions, and actions. This new landscape requires discussion about community and stakeholder touchpoints and how to create meaningful engagement opportunities within this complex framework, including the UCBIAG.

Further, it is important to note the timing of the DSP, IRPs, and Clean Energy Plans. The current expectation for the first Clean Energy Plan from both Pacific Power and PGE is as early as March 2023, although they may come later in the year. Under the current DSP Guidelines, the second DSP filings in 2024 will come after the Clean Energy Plan and IRP filings. While the second, more mature DSPs will not be able to inform the first Clean Energy Plans or the next IRP, discussion in Docket No. UM 2225

[20] The IRP process scrutinizes whether a utility has planned sufficiently to provide enough power for the system overall, and whether it has done so in a way that minimizes both risk and cost. The IRP is a well-established process in Oregon that strives for transparency and stakeholder participation and occurs on an approximately 2-year cadence. The OPUC's IRP Guidelines can be found in Commission Order Nos. 07-047 and 08-339.

[21] The planning framework also included an informational Smart Grid Report (See Docket Nos. UM 1657, UM 1667, UM 1675) and newly implemented Transportation Electrification Plans (See Docket Nos. UM 1810, UM 1811, UM 1815).

will consider what additional analysis or inputs are needed for the first Clean Energy Plans.[22]

Finally, the new planning framework will consider the introduction of the Wildfire Protection Plan and the requirement for the Clean Energy Plan to examine risk-based resiliency opportunities that includes costs, consequences, outcomes and benefits. This will require consideration of where resiliency-related risks and utility actions will be examined throughout the planning framework.

Many significant questions about maintaining consistency and synchronization within broader planning landscape have been surfaced since the DSP Guidelines were adopted in December 2020, but Docket No. UM 2225 is in the initial stages of tackling them. As the Commission considers the Part One Plans, and looks to the Part Two Plans in August, the position and timing of DSP analysis in the broader planning framework is in a state of flux. Changes related to Clean Energy Plans that impact the current DSP processes may be brought before the Commission before Part Two is filed or considered for acceptance.

Utility Community Benefits and Impacts Advisory Groups are another of HB 2021's major parts. Staff recommends continuing OPUC efforts to improve engagement and accessibility, including opportunities to coordinate similar activities across dockets. This could reduce workload for both utilities and stakeholders, and result in outcomes that more meaningfully reflect stakeholder and community input. For example, OCEAN/OSSIA commented that refining the IRP and DSP processes should ensure that stakeholder input is integrated at the beginning of more intertwined processes.

Flexible Load and Demand Response Planning
PGE's Flexible Load Plan (FLP) covers a broad scope of interrelated, flexible load (or demand response) activities.[23] The FLP includes portfolio-level multi-year planning, budgeting, and reporting of flexible load activities. On January 25, 2022, the Commission approved a two-year portfolio budget – referred to as the Multi-Year Plan – of approximately $24.5M for five flexible load activities.[24]

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[22] See Docket No. UM 2225, https://apps.puc.state.or.us/edockets/DocketNoLayout.asp?DocketID=23160.
[23] See Docket No. UM 2141, https://apps.puc.state.or.us/edockets/DocketNoLayout.asp?DocketID=22696.
[24] See Docket No. UM 2141, Order No. 22-023, https://apps.puc.state.or.us/edockets/orders.asp?OrderNumber=22-023.

The FLP will intersect with DSP in the following ways: PGE's DSP process will develop tools to model the capabilities of DERs and will identify location-specific needs in the distribution system. This will inform PGE's strategy to deploy and dispatch flexible load resources to meet those system needs, and inform PGE's testing of flexible load resources. PGE's experience dispatching flexible load resources will then inform DSP modeling tools.[25]

This will require coordination between the FLP and DSP processes. In a hypothetical timeline, the DSP would convey location-specific distribution system needs, and possibly flexible load resources to meet those needs. At that point, the FLP could then formulate budgets, and plan and execute deployment of flexible load resources to meet those needs. The FLP budgets and resources could be used to inform the IRP of the amount of resources available, at the given prices. Staff recommends that once the timing of Clean Energy Plans, IRPs and DSPs is resolved, PGE consider action to realign the FLP's Multi-Year Plan to best fit identified needs.

FLP cost-effectiveness methodology is a second topic requiring coordination. As noted in Staff's memo addressing the FLP Multi-Year Plan, Staff is encouraged by PGE's work on the cost-effectiveness methodology for FLP to date. DSP, however, will have to consider EE, DERs and non-wires solutions beyond flexible load resources. So whatever FLP cost-effectiveness methodology is used, it must provide for comparisons across additional resources and technologies. Staff will begin exploring valuation frameworks for grid investments.

Demand response is an evolving resource for Pacific Power as well. Staff notes that the Company's 2021 IRP indicates a major increase in acquisition of this resource in the next several years. Pacific Power will also face the challenge of integrating demand response in its planning processes.

Transportation Electrification
Transportation Electrification (TE) is a policy area and nascent market undergoing substantial change. The forecast increases in EV adoption in Oregon represents significant new load and challenges for the distribution system. Also driving this change is the passage of HB 2165, and the Commission's decision to explore the adoption of a proposed TE Investment Framework in Oregon to support utility investment in TE.[26]

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[25] See UM Docket No. UM 2141, Flexible Load Plan Section 3.9, https://apps.puc.state.or.us/edockets/edocs.asp?FileType=HAA&FileName=haa125814.pdf.
[26] See Docket No. UM 2165, Order No. 21-484, https://apps.puc.state.or.us/edockets/orders.asp?OrderNumber=21-484.

Staff has opened a formal rulemaking to revise Division 87 TE Planning rules, with completion goal of July 2022. Utilities will file their next TE Plans later in 2022.

Staff understands TE and DSP to intersect in the following ways:

- Beyond new load, EV adoption may also represent an opportunity to manage load through improved grid integration. This includes EV charging equipment enabled to participate in flexible load programs, or to respond to off-peak "smart" charging rates.
- Staff anticipates the analytical exercises required in the upcoming DSP Part Two filings will provide insight into TE-related grid impacts and inform the value and use of improved grid integration strategies noted above.
- As noted earlier in this memo, the DSP Guidelines require utilities to forecast EV adoption by substation, as part of the holistic load and DER forecasting processes conducted as part of their distribution planning.
- Staff anticipates that utility investments in the distribution system of the general-customer driven variety will be proposed through the DSP. Such investments might include construction of residential auxiliary dwelling units in a concentrated area. Investments of the EV-customer driven variety will be proposed through TE Plans. Such investments may include neighborhood-cluster EV adoption.

The utilities sufficiently discussed interactions of DSP and TE in their current Plans. Staff expects additional discussion of DSP and TE interactions moving forward.

Interconnection Reform and HCA Implementation Next Steps
Staff released a draft scope and near-term process for Docket No. UM 2111 Investigation into Interconnection Process and Policies on February 11, 2022.[27] Following receipt of public comment and a future March 2022 workshop, Staff will present its plan for moving forward with the docket at the April 5, 2022, Public Meeting. Staff has proposed the following priority issues within the investigation:

- Analytical methods and threshold levels used to identify the need for system upgrades in interconnection process.
- Adopting IEEE 1547-2018 (IEEE Standard for Interconnection and Interoperability of Distributed Energy Resources with Associated Electric Power Systems Interfaces) and policies needed to incorporate advanced inverters into existing interconnection rules and practices.

[27] See Docket No. UM 2111, https://edocs.puc.state.or.us/efdocs/HAH/um2111hah13246.pdf.

- Integrating storage, islanding, and other modern configurations more explicitly into interconnection rules, policies, and practices.

Staff sees the division of efforts between UM 2111 and DSP as follows:

Docket No. UM 2111	DSP
Focus on underlying interconnection practices	Focus on transparency of system data
Examine the underlying data sources that will be used in the interconnection screening and study process	Consider the system data that is published
Examine the underlying methodologies that will be used in the interconnection screening and study process	How the system data is published
	System investments required to collect and publish the system data

Consideration of these topics in DSP will be most impactful if they provide information that reflects the screening thresholds and analyses examined in UM 2111. As noted, Staff recommends that further discussion of HCA in DSP pause until the plan for the Docket No. UM 2111 is final. Staff recommends DSP stakeholders then consider continuing discussions of HCA. If there is bandwidth and interest, Staff will work with stakeholders to on next steps that are coordinated with Docket No. UM 2111.

Expanded Intervenor Funding
House Bill 2475 expands the type of entities that are eligible for intervenor funding. The bill expands eligibility for such funding to include organizations that represent interests of low-income residential customers and residential customers that are members of environmental justice communities. The legislation requires that the Commission promulgate rules that will allow effective implementation of these agreements. Consistent with the schedule outlined in Docket No. AR 652, final rules are expected July 2022. Earlier this year, the Commission adopted an interim funding agreement until the final rules are in place.[28]

Staff anticipates this additional funding will provide resources to groups that have participated in DSP proceedings. This may enable these groups and others to assist utilities to develop and execute community engagement plans. This would be valuable

[28] See Docket No, UM 2211, Order No. 22-043, https://apps.puc.state.or.us/edockets/orders.asp?OrderNumber=22-043.

in pursuit of long-term DSP goals such as promoting inclusion of underserved populations including frontline, environmental justice communities.

Next Steps in DSP Planning
Utilities will file DSP Part Two Plans August 15, 2022. Staff expects that the review process for Part 2 will be similar to the process for Part 1, concluding in 2022. Staff anticipates the Part Two filings may be more technical than Part One filings. Staff notes there will be a need for increased discussion with utilities to help stakeholders understand the technical material. Staff expects a great amount of learning will result from the Part Two filings, including the following high-level lessons:

- How and where utilities are forecasting load growth, DER, and EV adoption.
- How and where utilities identify areas of the distribution system which need investment.
- How utilities consider and evaluate various investments to address grid needs.
- How utilities have evaluated non-wires solutions pilot concept proposals.
- How utilities' community engagement plans were implemented.
- And finally, what investments utilities are planning in the next several years.

Once Part Two filings have been filed and implementation learnings are available, Staff plans to turn to the process of revising and improving the Guidelines, likely in 2023. Guideline revisions may reflect outcomes from the evolving policy landscape, as well as Guideline updates, revisions, and corrections. Additionally, parties have begun to flag topics for inclusion in the process. Some of these include:

- A standardized valuation framework for selecting and prioritizing DERs.
- A regime for evaluating non-wires solutions investments and conventional infrastructure investments.
- Development of community engagement metrics to be able to evaluate whether ratepayer funds resulted in good, adequate, or insufficient engagement.
- Policy guiding distribution system-level data and related customer data issues.

Staff notes this list is incomplete, and the scope of the 2023 revision process will have to account for still-to-come learnings from the Part Two filings, as well as outcomes currently being determined, or that will be determined, by the nascent policies and processes discussed previously in this section.

Thoughtful planning processes are the foundation of the Commission's decision-making practice. DSP exists within the Commission's broader planning framework and is a key example of how the framework is evolving to meet the changing landscape.

Conclusion

The DSP Guidelines were established with high-reaching, broad goals for the process. The Part 1 Plans reflect each utility's starting point with respect to DSP, systems, and service territory. The Plans demonstrate that distribution planning is evolving to meet high-reaching and broad goals though the process will take time, as expected. Staff finds that each Plan meets the criteria and requirements of the Guidelines.

PROPOSED COMMISSION MOTION:

Accept Distribution System Planning Part One Reports filed by Idaho Power, Portland General Electric, and Pacific Power as meeting the objectives of the DSP Guidelines established in Order No. 20-485.

UM 2196, UM 2197, UM 2198 – DSP Part One Filings