ISSUED: December 3, 2020

# BEFORE THE PUBLIC UTILITY COMMISSION

# OF OREGON

UM 2005

| In the Matter of the<br><br>PUBLIC UTILITY COMMISSION OF OREGON<br><br>Investigation Into Distribution System Planning. | REVISED DSP GUIDELINES<br>AND<br>NEXT STEPS |
|---|---|

Revised Guidelines
Staff announces revised Distribution System Planning (DSP) Guidelines. Included with this announcement are revised and red-line versions of the Introduction, and revised and red-line versions of the Guidelines. For stakeholder convenience red-line versions indicate the major changes Staff made to the draft documents as a result of stakeholder feedback.

A Staff Memo will replace the Introduction document when the Guidelines are considered for approval at the December 15, 2020 Public Meeting. An additional summary of stakeholder comments and Staff response will accompany the Staff Memo. Both documents will be posted next week.

Stakeholder Comment
Staff welcomes written comment on the revised Guidelines but will not formally respond to comment. Stakeholders should submit comments no later than Thursday, December 10, 2020. Comment may be provided in the following ways:

- By email – puc.publiccomments@state.or.us
  Please include "COMMENTS – DOCKET NO. UM 2005" in the subject line, so they may be properly filed in this docket.
- By Phone – 503-378-6600 or 800-522-2404 or TTY 800-648-3458, weekdays from 8 a.m. - 5 p.m. Pacific

Participation in December 15, 2020 Public Meeting
Staff requests those who wish to speak at the December 15, 2020 Public Meeting provide notification via email no later than Friday, December 11, 2020. Please direct email to nick.sayen@state.or.us.

Next Steps
Below is the anticipated timeline for next steps in the investigation.

- Week of December 7, 2020: Staff Memo and stakeholder comment summary posted
- Thursday, December 10, 2020: Deadline for comment on revised Guidelines

- Friday, December 11, 2020: Notify Staff of interest in speaking at December 15, 2020 Public Meeting
- Tuesday, December 15, 2020: Commission consideration to adopt revised DSP Guidelines at Public Meeting

Questions and comments can be directed to Nick Sayen at nick.sayen@state.or.us or 503-510-4355.

# Distribution System Planning Guidelines

# Introduction

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## 1. Purpose

This document provides an overview of the Distribution System Planning (DSP) Guidelines in Docket UM 2005. The Public Utility Commission of Oregon (OPUC) issued Order No. 19-104 March 22, 2019, opening an investigation to “develop a transparent, robust, holistic regulatory planning process for electric utility distribution system operations and investments.”[1] The draft Guidelines (attached) outline requirements for the initial utility DSP Plan (Plan) filings to be submitted by Oregon’s investor-owned electric utilities to the Commission in 2021 and 2022.

A new regulatory structure for DSP will enable utilities to better identify system needs and evaluate the evolving range of opportunities that can meet those needs. Staff seeks to maximize customer value by ensuring that the utilities’ approach to managing and operating the distribution system is evolving in a least-cost, least-risk manner. Staff sees grid modernization as a foundation for higher levels of customer access and interaction, and integration of variable resources. The proposed DSP process supports these aims and advances State and OPUC policy goals.

The Commission envisions DSP as a critical step in modernizing the grid to accommodate developing industry trends and support new policy objectives. Since 2013, Oregon’s investor-owned electric utilities have filed biennial Smart-Grid Reports, which provide important insight into innovative grid modernization projects. The DSP Guidelines are designed to further expand and evolve this reporting framework.

Informing Staff’s proposal for DSP Guidelines are Senate Bill (SB) 978 (2017) and Governor Brown’s Executive Order No. 20-04.[2] With SB 978, the Oregon Legislature tasked utilities and the OPUC with exploring new expectations for the electric grid, highlighting the clear importance of clean energy, inclusivity, and customer options in addition to the core mission of the OPUC.

The OPUC’s 2018 legislative report notes that the Commission had previously acknowledged the need for an investigation into distribution system planning.[3] The report cites distribution system resources and management technologies as one of four key themes within the technology trends and impacts most significant for Oregon’s electric sector.[4] The report encourages increased transparency in distribution system planning.[5] Importantly, the report outlines new efforts to create an environment of procedural inclusion for underserved communities including low-income, environmental justice and community-based organizations.[6]

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[1] See UM 2005, Order No. 19-104, March 22, 2019 at https://apps.puc.state.or.us/orders/2019ords/19-104.pdf.
[2] See Executive Order No. 20-04 (EO 20-04, March 10, 2020), at [https://www.oregon.gov/gov/Documents/executive_orders/eo_20-04.pdf](https://www.oregon.gov/gov/Documents/executive_orders/eo_20-04.pdf).
[3] See *SB 978: Actively Adapting to the Changing Electricity Sector* September 2018, page 17, at: https://www.oregon.gov/puc/utilities/Documents/SB978LegislativeReport-2018.pdf.
[4] Ibid, at page 10.
[5] Ibid, at page 21.
[6] Ibid, at page 19.

EO 20-04 sets new science-based greenhouse gas (GHG) emissions goals for Oregon and directs state agencies to identify and prioritize actions to meet those goals.[7] The EO directs the Commission to use any and all authority at its discretion to help reduce the emission of greenhouse gases to at least 45 percent below 1990 levels by 2035 and 80 percent below 1990 levels by 2050.[8] Section 5(A) first finds that: "It is in the interest of utility customers and the public generally for the utility sector to take actions that result in the rapid reduction of GHG emissions, at reasonable costs, to levels consistent with the GHG emission goals set forth in [this EO], including transitioning to clean energy resources and expanding low carbon transportation choices for Oregonians." Staff's proposed DSP Guidelines support the GHG emissions goals of the EO by enabling efficient grid integration of distributed energy resources (DERs) and other clean energy technologies.

## 2. Drivers

Staff's whitepaper on distribution system planning (2019) identified two proactive drivers for the UM 2005 investigation:

- Insight (procedural driver): The near-term need to establish visibility and holistic engagement in utilities' distribution-level investments.
- Optimization (operational driver): The longer-term need to ensure the operation of the changing distribution system maximizes operational efficiency and customer value.[9]

Historically, utility investments in the distribution system were understood to be sufficient for reliable operations, or to serve increased or new load. That investment was typically in equipment to support one-directional flow of power and communication, and to serve predictable load patterns. This traditional type of investment was generally regarded as necessary and prudent, for example when reviewed in general rate cases.

However, changes in state and federal public policy, evolving digital technology, and rapidly decreasing costs of DERs[10] have led to a host of new investments in the grid by utilities and customers. These include the utilization of advanced metering infrastructure (AMI), increasing adoption of solar PV and battery storage, and increasing adoption of electric vehicles and installation of charging stations. These changes have led to new and increased demands on the distribution system in order to "keep the lights on," and new opportunities for the distribution system to deliver value. Customers and utilities can benefit through grid services that enable higher levels of intermittent DERs, provide carbon-free energy for transportation, and serve to reduce GHG emissions as directed by EO 20-04.

[7] See Executive Order No. 20-04 (EO 20-04, 2020), Section 2, page 5 at https://www.oregon.gov/gov/Documents/executive_orders/eo_20-04.pdf.
[8] Ibid, Section 3.A. page 5.
[9] Staff Whitepaper: A Proposal for Electric Distribution System Planning, March 2019, https://edocs.puc.state.or.us/efdocs/HAU/um2005hau15477.pdf.
[10] For the purposes of these guidelines "distributed energy resource" includes distributed generation resources (either net metering or Qualifying Facilities), distributed energy storage, demand response, energy efficiency, and electric vehicles that are connected to the electric distribution power grid. U.S. Department of Energy, Modern Distribution Grid Volume I: Customer and State Policy Driven Functionality, page 7, https://gridarchitecture.pnnl.gov/media/Modern-Distribution-Grid_Volume-I_v1_1.pdf.

As a result, the distribution system will need to evolve to leverage the two-way flow of power and communication, to handle increased levels of intermittent power generation, and to harness the potential for highly flexible load patterns. The types and amount of investment in the distribution system are expected to change as well. In other states, investment in the distribution system has already been significantly transformed. As a critical step in advancing the state's expectations for a modern grid, a new DSP framework will help ensure distribution system investments are planned and customer value maximized. Without the transparency from planning, there is risk of erratic grid development with uneven benefits. A robust DSP process can advance a modern and reliable system—one positioned to form a foundation for higher levels of customer access and interaction, and higher levels of generation and load variability.

## 3. Goals and Principles

**Long-Term Goals**

In developing this proposal, Staff has been guided by the following overarching goals for Oregon's long-term DSP process. These overarching goals were developed collaboratively with parties through the course of the investigation.[11]

- Promote the reliability, safety, security, affordability and quality of the distribution system and utility services 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; and
- Strive for regulatory efficiency through aligned, streamlined processes.

**Guiding Principles**

Staff also utilized the following guiding principles to inform development of the initial DSP Guidelines. The principles of practicality, transparency and inclusion address the investigation's procedural driver of "insight." The principles of flexibility, efficiency and transparency address the operational driver of "optimization."

| Principle | Does the requirement or activity… |
|---|---|
| Flexibility | Allow for plans to evolve as the state of the distribution system changes? Allow for variance among utilities? Accommodate changes over time in variables such as technology and costs? |
| Practicality | Deliver information that is usable by utilities and stakeholders? Appropriately weigh complexity and cost? Streamline regulatory efforts? |

[11] See https://edocs.puc.state.or.us/efdocs/HAH/um2005hah145318.pdf.

| Principle | Does the requirement or activity… |
|---|---|
| Efficiency | Achieve efficient integration of distributed energy resources (DERs) and accelerate decarbonization? Lead to more efficient operation of the distribution system? |
| Transparency | Yield results that improve insight? Deliver information needed to holistically understand long-term distribution system plans? Reveal how customer and competitive options can provide value? |
| Inclusion | Meaningfully include a broader range of participants? Remove barriers to public participation to ensure all voices are heard in the decision-making process? |

## 4. Planning Interactions and Streamlining

To achieve focused and strategic reporting for DSP, current related regulatory requirements will change. The changes below are anticipated; specific requirements are included in the Plan Guidelines.

a. Smart Grid Report (SGR). This biennial report is the current regulatory requirement with the largest focus on the distribution system. Conceived nearly 10 years ago, the SGR has played a critical role, but it is not a planning document. In order to allow for utilities to shift focus from the SGR to DSP, Staff recommends temporarily suspending the next Smart Grid Report filing cycle requirement as established in Docket UM 1460, Order No. 17-290 (currently PGE – June 1, 2021, Pacific Power – August 1, 2021, Idaho Power – October 1, 2021). As the DSP process becomes established, Staff anticipates requesting that Order Nos. 12-158 and 17-290, issued in Docket UM 1460, be revised or these orders may be superseded by new requirements adopted in this docket.

   Staff recommends continuing several forward-looking aspects of the SGR and integrating these into the DSP Guidelines section of Long-term Distribution System Plan. These include:[12]
   - C.1. (any distribution system plan strategies, goals or objectives, and their alignment with State and Commission policies),
   - C.2.b. (a description of upcoming investment options across a range of categories)
   - C.3 a-c. (Smart Grid opportunities)

b. Transportation Electrification (TE) Plan. This biennial plan presents the utility's long-term strategy to accelerate transportation electrification in its Oregon service territory. The TE Plan serves numerous important purposes. Staff recommends it continue to be separately produced, though information reported in the TE Plan may be sourced from the Distribution System Plan.

[12] See Order No. 12-158.

Because transportation electrification has the potential for such a large impact on the distribution system, Staff recommends the Distribution System Plan be used to develop several elements currently required in the TE Plan. Specifically, Staff recommends developing and including the following information in the Distribution System Plan:

- OAR 860-087-0020(3)(a)(C) (existing data on the availability and usage of charging stations)
- (D) (number of EVs in the service territory and projected number of EVs in the coming years)
- (E) (other related infrastructure, if applicable)
- (G) (Distribution system impacts and opportunities for efficient grid management).

Once developed and provided in the Distribution System Plan, a utility can include that data in its TE Plan. As the DSP process becomes established Staff will consider recommending changes to the requirements of OAR 860-087-0020.

Staff recommends utilities include the elements referenced above within the DSP Guidelines sections of Baseline and System Assessment, and Forecasting of Load Growth, DER Adoption, and EV Adoption.

c. Annual Net Metering Reports. This report conveys important information in understanding the distribution system and DERs. Staff recommends Annual Net Metering Reports continue separately from the Distribution System Plan. Each Plan should include the most recent Annual Net Metering Report. Staff recommends possible integration of these reports into future Plan filings.

   Annual Small Generator Reports. This report also conveys important information in understanding the distribution system and DERs. Staff recommends Annual Small Generator Reports continue separately from a Distribution System Plan. Each Plan should include the most recent Annual Small Generator Report. Staff recommends possible integration of these reports into future DSP filings.

d. Annual Reliability Reports. This report conveys information vital to understanding the distribution system's performance in delivering reliable service to customers. However, this report serves other important purposes as well, and Staff recommends Annual Reliability Reports continue separate from a Distribution System Plan, with each Plan including the most recent reliability report.

e. Demand response (DR) reporting. Utilities currently report the performance of demand response programs in numerous dockets.[13] These reports cover important and detailed aspects of DR program operation and efficacy. The sum, system-wide capability and results of DR can affect the distribution system, and so Staff recommends high-level DR reporting be included in the Plan, while current, detailed DR reporting continue separate from a Distribution System Plan.

[13] For examples see ADV 242 for annual reports on Pacific Power's Irrigation Load Control Pilot, or UM 1708 for evaluations of various PGE demand response pilots.

f. Integrated Resource Plan. Staff recognizes the significant time and effort required for the Integrated Resource Planning (IRP) process, and welcomes suggestions on how best to synchronize this effort with the Distribution System Planning process. In order to inform any future synchronization, in the DSP Guidelines section, Long-term Distribution System Plan, utilities should include a discussion of how the IRP and Plans are coordinated. This should include related inputs and outputs such as data sets or prices, and assumptions such as macro-economic policies or growth rates.

g. Hosting Capacity Analysis. Direction on hosting capacity analysis technical requirements (such as minimum daily load calculation, assumptions about DER generation profiles, treatment of solar plus storage in interconnection analysis, and other factors that determine the DER penetration thresholds that trigger system upgrades) will be established in Docket No. UM 2111, Staff Investigation into Interconnection Process and Policies.

## 5. Data Privacy and Security

It is important that utility data be provided to the Commission and to stakeholders, as appropriate, at the necessary level of detail to ensure a sound review process. Staff recognizes that some information should not be widely distributed to the public in every instance, such as personally identifiable customer information or critical infrastructure information. Utilities should provide as detailed a Plan as possible.

## 6. Cost Recovery

Utility costs:

- Staff recognizes some additional expenses may be incurred as a result of Plan development and compliance. If the result of these activities is a significant increase in expense, cost-recovery mechanisms are available to utilities and can be addressed outside of this proceeding. Pilots specified within these Guidelines may allow utilities cost recovery mechanisms.

Stakeholder costs:

- Participation in this process places an increased burden on the time and resources of involved citizens and organizations. Staff will explore opportunities to support community-based organization participation. As described in section 9.1, Staff plans to provide educational materials and public workshops. Staff supports resourcing as necessary of these organizations to inform decision-making.

## 7. Regulatory Development

OPUC recognizes the need for ongoing conversations about how DSP activities align or interact with the utilities' existing business models and regulatory approaches. Utilities and stakeholders should explore whether an alternative regulatory framework would assist in aligning incentives for utility long-term DSP investment and DER development, is in customers' interest, and aligns with the clean energy vision articulated by the State of Oregon. To address the changes that utilities may make in implementing the DSP process, the OPUC may explore new regulatory mechanisms that may better align with utilities' efforts to plan and invest in DSP over the long-term.

## 8. Vision for Distribution Planning Evolution

The initial Plan filings required herein will be the first stage in an evolving multi-stage process. Staff anticipates that the forming, filing and acceptance of the initial Plans will educate all parties and identify areas for continuous improvement. Table 1 illustrates Staff's expected evolution from the Initial Requirements put forward in these Guidelines to more advanced stages.

To ensure progress toward long-term goals and reflect guiding principles, each element of the Guidelines includes "Initial Requirements" and a description of "Expected Evolution." Staff proposes the "Initial Requirements" for the first utility Plans, while "Expected Evolution" includes potential benchmarks for future stages. This structure provides utilities a firm foundation of guidance for the first Plans, while introducing a flexible vision for the future that may be adapted based on new information. Achievement of Stages 2 and 3 may be accelerated depending on circumstances and readiness of utilities and participants.

**Table 1**

| **Distribution System Planning Evolution Framework** | | |
|---|---|---|
| Stage 3 | | Achieving the long-term vision for distribution system planning capabilities and outcomes |
| Stage 2 | | Advancing requirements incrementally to better match growing utility capabilities and evolving grid, customer and community needs |
| Stage 1 | Beginning with Initial Requirements of Utility DSP Filings, providing a foundation for future stages | |
| | 2021-2022 | 2023 and beyond |

Staff anticipates lessons from the filing process and Plan review will inform an assessment of the Guidelines. Guideline revision is discussed further in Section 9.

### 8.1. Insights Provided by Parties and Subject Matter Experts

The vision for DSP in Oregon relies heavily on the input provided to Staff by diverse parties and subject matter experts throughout the 2020 workshop series. Robust stakeholder participation across 12 workshops and webinars explored distribution system planning approaches, best practices from across the country, and related OPUC policies. The active participation of utilities and stakeholders in this investigation, from more than 40 parties, has provided new insight on a range of topics. These include the capabilities, needs and future of Oregon's distribution systems, distributed energy resources, and the customers and communities they serve.[14] The impact of this input on the DSP Guidelines is substantial, initiating a new era of transparency, rigor and opportunity for DSP in Oregon.

## 9. Plan Submission and Commission Action

Utilities will develop and file their initial Plans in two parts, the first part in Fall 2021 and the second part in Summer 2022. Plans will be presented at a Public Meeting between three to five months following each filing, after a period of stakeholder and Staff review. The Commission may accept the Plans and may provide additional guidance for future Plan filings. As used in the Guidelines, "acceptance" means the Commission finds that the Plan meets the criteria and requirements of these Guidelines and does not constitute a determination on the prudence of any individual actions discussed in the Plan. Non-acceptance means that the Plan does not meet the criteria or requirements of the Guidelines.

Following the issuance of the final Commission orders, the DSP Guidelines will be formally reopened with a stakeholder process identifying Guideline improvements for future Plan filings.

Staff anticipates that the second "round" of DSP will follow a two-year cycle. The second round should commence after Commission acceptance of both parts of the initial Plan. The second Plan will likely be submitted in an integrated fashion, rather than in two parts.

### 9.1. Plan Development Support

Staff will host a public workshop prior to the filing of each part of the initial Plan. These workshops may be formatted to respond to utility and stakeholder requests to support Plan completion. Topics may include cybersecurity, community outreach, regulatory development or data transparency. A technical working group may be formed to assist utilities in vetting new materials or products needing stakeholder feedback.

### 9.2. Transition and Implementation

Staff recognizes that utilities will invest in new systems and processes to meet these Plan Guidelines. A transition period is expected in which legacy processes and data will be implemented while new systems are developed. For the first Plan filings, legacy planning studies and data may be submitted when more current data is not available.

[14] Records from the workshops are available online through the UM 2005 investigation docket https://apps.puc.state.or.us/edockets/DocketNoLayout.asp?DocketID=21850. Records from the webinar series are located in the Webinar Archive on the OPUC Distribution System Planning Webpage, as well as in the UM 2005 docket, https://www.oregon.gov/puc/utilities/Pages/Distribution-System-Planning.aspx.

# Distribution System Planning Guidelines

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# 1. Process and Timing

The following development and review process will guide the initial utility filing of a Distribution System Plan (Plan) for a utility's service territory in Oregon.

a) Each electric utility[1] must file the first portion of its Plan (Part 1) on October 15, 2021 or an alternative date designated by Commission order.
b) Each utility must file the second portion of its Plan (Part 2), on August 15, 2022 or an alternative date designated by Commission order.
c) Subsequent Plans will be filed in their entirety, combining Parts 1 and 2.
d) Each utility must file a subsequent Plan within two years of the Commission order for Part 2.

For both Part 1 and Part 2 of the utility Plan:

e) During Plan development, prior to filing, each utility must hold at least two workshops with stakeholders to ensure a range of community perspectives are heard and considered. Each utility must hold additional community meetings during development of pilot projects.
f) Each utility will present the results of each filing to the Commission at a separate public meeting.
g) Upon each filing, the Commission will set a procedural schedule under which interested parties will have the opportunity to provide comment and make recommendations on the filing.
h) The Commission will generally consider comments and recommendations on a utility's filing at a public meeting three to five months after it is filed. The Commission will consider whether to accept the filing as meeting the objectives of these Guidelines. The Commission may provide guidance on the development and content of future Plans.
i) The Commission may provide the utility an opportunity to revise the filing before making its decision.

The design and implementation of this proposed process will serve the long-term regulatory efficiency goals through aligned, streamlined processes, inclusion, and transparency.

# 2. Commission Action

A utility must file its Plan as provided in Guideline 1. The Commission will consider whether to accept the filed Plan (or Plan Part) as meeting the objectives of these Guidelines. As used in this Guideline, "acceptance" means the Commission finds the Plan meets the criteria and requirements of these Guidelines. 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.

Commission acknowledgement of a Plan may be premature given that the DSP process is in its initial stage of development. At later stages, the Commission may revisit this topic and address whether subsequent Plans may be considered for Commission acknowledgement.

[1] "Electric utility" or "utility" for purposes of these guidelines 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. Scope

An electric utility will file the initial utility Distribution System Plan in two sections:

Part 1 (October 2021)
- Baseline Data and System Assessment
- Hosting Capacity Analysis
- Community Engagement Plan
- Long-Term Plan
- Plan for Development of Part 2

Part 2 (August 2022)
- Forecasting of Load Growth, DER Adoption, and EV Adoption
- Grid Needs Identification
- Solution Identification
- Near-Term Action Plan

# 4. Part 1

## 4.1. Baseline Data and System Assessment

To foster transparency and enable effective decision-making, Distribution System Plans should provide a fundamental understanding of the current physical status of the utility distribution systems, recent investment in those systems, and the level of distributed energy resources (DERs) currently integrated into those systems.[2] Figure 1 introduces the initial requirements and expected evolution for baseline data and system assessments.

[2] For the purposes of these guidelines "distributed energy resource" includes distributed generation resources (either net metering or Qualifying Facilities), distributed energy storage, demand response, energy efficiency, and electric vehicles that are connected to the electric distribution power grid. U.S. Department of Energy, Modern Distribution Grid Volume I: Customer and State Policy Driven Functionality, page 7, https://gridarchitecture.pnnl.gov/media/Modern-Distribution-Grid_Volume-I_v1_1.pdf.

**Figure 1**

| Baseline Data and System Assessment | | |
|---|---|---|
| Stage 3 | | Refine asset financial planning processes and strengthen relationships with DER planning and integration processes. |
| | | Use software systems to proactively monitor and support operation of the distribution system and DERs. |
| Stage 2 | | Share asset financial planning processes and show relationships with DER forecasting and planning processes. |
| | | Leverage remote sensing technologies to provide detailed insight on physical infrastructure to support efficient operation of the distribution system. |
| Stage 1 | Identify existing grid equipment inventory and financial data, as well as DER-related data with locational granularity. | |
| | 2021-2022 | 2023 and beyond |

**Initial Requirements**

In initial Distribution System Plans, a utility is required to identify the existing grid equipment inventory, management and monitoring practices, financial data, and DER data. This requirement consolidates reporting requirements currently effective under the Smart Grid Reports, Transportation Electrification Plans, and others. This data may come from the utility or from other sources, and should be the most recent data available. The utility should provide, at minimum:

a) A description of any currently used internal baseline and system assessment practices (such as system reliability baseline, system asset health baseline, etc.) that includes:
   i) Method and tools used to develop the baseline and assessment
   ii) Forecasting time horizon(s)
   iii) Key performance metrics
b) A summary of the utility's distribution system assets including:
   i) Asset classes
   ii) Number of assets in each class
   iii) Average age of assets in each class
   iv) Age range of assets in each class
   v) Industry life expectancy of assets in each class
c) A discussion of distribution system monitoring and control capabilities including:
   i) Number of feeders
   ii) Number of substations
   iii) Monitoring and control technologies (such as SCADA, AMI, etc.) currently installed, and the percentage of substations, feeders, and other applicable equipment with each technology
   iv) A description of the monitoring and control capabilities (for example, percentage of system with each technology, resulting capacity, such as remote fault detection or power quality monitoring, and what time interval measurements are available)

d) A discussion of any advanced control and communication systems (for example: distribution management systems, distributed energy resources management systems, demand response management systems, outage management systems, field area networks, etc.). Include a description of system visibility and capabilities, the percentage of system reached with each capability, the percentage of customers reached with each capability, and any utility programs utilizing each capability.
e) Historical distribution system spending for the past five years, in each category:
   i) Age-related replacements and asset renewal
   ii) System expansion or upgrades for capacity
   iii) System expansion or upgrades for reliability and power quality
   iv) New customer projects
   v) Grid modernization projects
   vi) Metering
   vii) Preventative maintenance
f) Net Metering and Small Generator information:[3]
   i) Total existing net metering facilities and small generator facilities interconnected to the distribution grid (or to the transmission system, as appropriate for small generator facilities) at time of filing, by feeder.
      (1) The total number of net metering facilities by resource type
      (2) The total estimated rated generating capacity of net metering facilities by resource type
      (3) The total number of small generator facilities by resource type
      (4) The total nameplate capacity of small generator facilities by resource type
   ii) The total number and nameplate capacity of queued net metering facilities and small generator facilities at time of filing, by feeder, broken down by resource type
   iii) A map, in electronic format, identifying locations of net metering facilities and small generator facilities interconnected to the distribution grid (or to the transmission system, as appropriate for small generator facilities) at time of filing.
g) Total number of electric vehicles (EVs) of various sizes served by the utility's system at time of filing
h) Number of EVs added to the utility's system in each of the last five years
i) Total number of charging stations on the utility's system, broken down by type, ownership, and feeder
j) Total number of charging stations added to the utility's system in each of the last five years, broken down by type
   i) Data on the availability and usage patterns of charging stations
k) Summary data of other transportation electrification infrastructure, if applicable
l) A high-level summary of demand response (DR) pilot and/or program performance metrics for the past five years including:[4]

[3] A utility that is exempt from the Annual Net Metering Report requirement pursuant to OAR 860-039-0070 is not required to report net metering data required in section f).
[4] For example see Table 26 on page 101 of Appendix 1 of 2019 PGE Smart Grid Report, https://edocs.puc.state.or.us/efdocs/HAQ/um1657haq15635.pdf.

i) Number of customers participating by residential and business customer class, and combined total
ii) By winter and summer demand response season:
(1) Maximum available capacity of DR by residential and business customer class, and combined total
(2) Season system peak
(3) Available capacity of DR, expressed as a percentage of the season system peak

m) Plans should include the utility's most recently filed Annual Net Metering Report and the most recently filed Annual Small Generator Report, each as an appendix to the Plan.

n) Plans should include the utility's most recently filed Annual Reliability Report as an appendix to the Plan. Any descriptions of reliability challenges and opportunities in the Distribution System Plan should cross-reference underlying data and information contained in the Annual Reliability Report.

**Expected Evolution**

This investigation identified numerous opportunities for gaining greater insight into the utility distribution systems and the DERs contributing to and relying on those systems. Staff's 2019 Whitepaper on Distribution System Planning laid out the vision for a transition to a modern grid, including a desire for automated system operations and real-time system visibility.[5] Additionally, at the February 26, 2020 workshop, utilities provided an overview of their existing DSP processes, including monitoring and automation practices.[6, 7, 8] Presentations highlighted that each utility has different capabilities and system needs, which guide their planning and related outcomes.

Based on the insights gained through the investigation, for stages 2 and 3 of utility Plans, a utility should meet the benchmarks identified in Figure 1.

## 4.2. Hosting Capacity Analysis

Hosting Capacity Analysis (HCA) provides information about the ability of a distribution system to support new DER integration without system faults. To date, analyses of a system's hosting capacity has become an important piece of DSP in Minnesota, New York, Hawaii, Nevada and California.[9] The following requirements are intended to initiate hosting capacity analysis in Oregon with the ultimate aim of informing grid investment decisions made by the utilities, while also informing siting decisions made by DER developers. Figure 2 introduces the initial requirements and expected evolution for hosting capacity analysis.

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[5] Staff Whitepaper: A Proposal for Electric Distribution System Planning, March 2019, https://edocs.puc.state.or.us/efdocs/HAU/um2005hau15477.pdf.
[6] *Distribution System Highlights*, Portland General Electric, February 26, 2020, https://edocs.puc.state.or.us/efdocs/HAH/um2005hah16124.pdf.
[7] *Idaho Power: Current Distribution System and Small Scale Generation*, Idaho Power, February 26, 2020, https://edocs.puc.state.or.us/efdocs/HAH/um2005hah14343.pdf.
[8] *Current Distribution System: Questionnaire Section C*, Pacific Power, February 26, 2020, https://edocs.puc.state.or.us/efdocs/HAH/um2005hah9537.pdf.
[9] *Distribution Planning Regulatory Practices in Other States*, Lisa Schwartz, Berkeley Lab, May 21, 2020, https://www.oregon.gov/puc/utilities/Documents/DSP-Schwartz-Presentation.pdf.

**Figure 2**

| Hosting Capacity Analysis | |
|---|---|
| Stage 3 | Comprehensive hosting capacity considering both distribution and transmission. |
| | Increased level of detail regarding distribution constraints, asset performance, and DER performance metrics. Address emerging technology development. |
| | Maps indicate node/section-level hosting capacity. |
| | Update and publish hosting capacity maps and datasets sufficiently accurate and frequent to streamline interconnection. |
| | Conduct system-wide hosting capacity evaluations to inform Grid Needs Identification. |
| Stage 2 | If determined through Docket UM 2111, conduct hosting capacity analysis inform stakeholders of potential interconnection challenges, or replace portions of interconnection studies; publish hosting capacity maps with greater detail over time. Update areas with greater/faster DER adoption more frequently. |
| | Include distribution-level impacts to the substation and transmission system. |
| | Conduct hosting capacity evaluations to inform Grid Needs Identification. |
| Stage 1 | Conduct a system evaluation to identify areas of limited DER growth. |
| | Provide a plan to conduct hosting capacity evaluations in the near-term which may inform Grid Needs Identification, inform stakeholders of potential interconnection challenges, or replace portions of interconnection studies. Plan may address options that may provide more approachable and instructive data for communities. |
| | 2021-2022 / 2023 and beyond |

**Initial Requirements**

Under these Guidelines, for initial Distribution System Plans, each utility should conduct system evaluations to identify generation constrained areas where it is difficult to interconnect DERs without system upgrades. Each utility should present the results through an unredacted map that the utility should make available on its website on a continuing basis. In addition, a utility should include an Options Analysis for investing in more sophisticated HCA capabilities in the near-term. Specific requirements include:

a) Upon Commission adoption of these Guidelines each utility should begin conducting a system evaluation to identify areas where it is difficult to interconnect DERs without system upgrades. Each utility should present the results through an unredacted map that is continuously available on the utility's website.[10]

[10] This requirement is not grounded in the Commission's net-metering administrative rules. Any utility exemptions from net-metering administrative rules do not correspond to an exemption from to this requirement.

i) A utility should adopt the methodology underlying PGE's Net Metering Map, as presented in UM 2099, for calculating and identifying areas where it is difficult to interconnect DERs without system upgrades.[11]
   (1) If this methodology is not feasible, a utility should present an alternative methodology with documentation of why it is necessary, and an explanation of any ways in which it may be different from the methodology utilized by PGE.

ii) The resulting system-evaluation map should:
   (1) At minimum, meet the level of functionality of PGE's Net Metering Map.[12]
   (2) Label feeders serving Public Safety Power Shutoff areas.

b) Each utility should analyze three options to meet future HCA needs consistent with Figure 2. This analysis should be included in Part 1 of the Plan. At minimum, a utility shall develop cost and timeline estimates for each of the following three options. A utility should identify any data security, cost, result validation, or implementation concerns and/or barriers for each of the three options. Each utility should recommend a preferred timeline and development path for achieving the vision set forth in Figure 2, accounting for the relative strengths of Options 1, 2 and 3 below. The Commission will consider these cost and timeline estimates, concerns, and recommendations in adopting a path forward for HCA in Oregon.

i) Option 1: The primary use of HCA is to inform Grid Needs Identification (see Section 5.2) and includes the following parameters:
   - Methodology: stochastic modeling / EPRI DRIVE modeling
   - Geographic granularity: circuit
   - Temporal granularity: annual minimum daily load
   - Data presentation: web-based map for the public and available tabular data
   - Annual refresh
   - Planned/queued generation details such as number and size of projects, description and costs of upgrades assigned to planned generation

ii) Option 2: The two main uses are to inform Grid Needs Identification and to share regularly updated results publicly to inform stakeholders of potential interconnection challenges.[13] Option 2 includes the following parameters:
   - Methodology: same as Option 1
   - Geographic granularity: feeder
   - Temporal granularity: monthly minimum daily load
   - Data presentation: same as Option 1
   - Monthly refresh
   - Planned/queued generation details: same as Option 1

iii) Option 3: The two main uses are to inform Grid Needs Identification and to replace portions of the interconnection studies.[14] Option 3 includes the following parameters:
   - Methodology: iterative modeling
   - Geographic granularity: line segment
   - Temporal granularity: hourly assessment
   - Data presentation: same as Option 1
   - Monthly refresh

[11] See *PGE Reply Comments*, Docket UM 2099, (September 22, 2020) pages 6 and page 8: https://edocs.puc.state.or.us/efdocs/HAC/um2099hac154013.pdf.
[12] https://www.portlandgeneral.com/business/power-choices-pricing/renewable-power/install-solar-wind-more/net-metering/net-metering-map
[13] Xcel Minnesota performs HCA implementation that illustrates some of these parameters.
[14] California utilities perform HCA implementation that illustrate some of these parameters.

- Planned/queued generation details: same as Option 1

Beyond these requirements, any utility may seek to accelerate its testing and deployment of new hosting capacity analysis through a pilot or demonstration. A utility that proposes to do so should detail the pilot objectives, plan, budget, and evaluation method in the Plan.

**Expected Evolution**

This investigation identified numerous opportunities for hosting capacity analysis in Oregon. Given that hosting capacity and the related analysis have multiple definitions and best practices are continuously evolving, it is important for stakeholders to identify and prioritize use cases for the analysis. Multiple jurisdictions incorporate hosting capacity analysis into distribution system planning because the analysis and outputs can support DER adoption and flag potential interconnection issues.[15] Over time, hosting capacity analysis may reduce the need for interconnection studies.[16, 17]

Based on these insights gained through the investigation, for stages 2 and 3 of utility Plans, a utility should meet the benchmarks identified in Figure 2.

## 4.3. Community Engagement Plan

A utility should involve the public in the preparation and implementation of each utility Distribution System Plan. Involvement includes opportunities to contribute information and ideas, as well as to receive information, similar to the public input process in an IRP. Interested parties must have an opportunity to make relevant inquiries of the utility formulating the Plan. These guidelines for community engagement are intended to foster a developing process that supports a human-centered approach to DSP.

Community-based organizations (CBOs) may play an integral role in DSP-related community engagement. CBOs can offer insight to inform the utility's bottom-up forecasting of technology deployment, especially in vulnerable communities. CBOs can provide input to the utility on the methodology to identify and prioritize distribution system investments and project development. CBOs can also identify or support implementation of customer-sited non-wires solutions.

In the *Connectivity Means Community* presentation, presenters noted five approaches to engagement: inform, consult, involve, collaborate, and defer to.[18, 19] Each of these approaches should be incorporated into a robust community engagement plan and ongoing process. Further, best practices for community engagement highlighted during the May 20, 2020 workshop include:

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[15] *Hosting Capacity - Lessons Learned*, Steve Steffel, Pepco Holdings, May 6, 2020, https://www.oregon.gov/puc/utilities/Documents/DSP-Hosting-Capacity-SSteffel.pdf.
[16] *OPUC Hosting Capacity Overview*, Aram Shumavon, Kevala Analytics, May 6, 2020, https://www.oregon.gov/puc/utilities/Documents/DSP-Shumavon-Presentation.pdf.
[17] UM2005 Distribution System Planning, Webinar #9, OPUC Policies and Practices, June 10, 2020, https://www.oregon.gov/puc/utilities/Documents/DSP-Webinar9-PUC-Presentation.pdf.
[18] *Connectivity Means Community - Distributed System Planning for Humans*, Oriana Magnera and Charity Fain, Verde and Community Energy Project, May, 20, 2020, https://www.oregon.gov/puc/utilities/Documents/DSP-Magnera-Fain-Presentation.pdf.
[19] *The Spectrum of Community Engagement to Ownership*, Rosa Gonzalez, Facilitating Power, https://movementstrategy.org/b/wp-content/uploads/2019/09/Spectrum-2-1-1.pdf.

- Be easy;
- Be trusted;
- Be adaptable;
- Be flexible;
- Be positive;
- Be equitable; and
- Be a great ally.[20]

Grounded in these insights and conclusions, Figure 3 introduces the initial requirements and expected evolution for community engagement.

**Figure 3**

| **Community Engagement** | |
|---|---|
| Stage 3 | Utilities collaborate with CBOs and environmental justice communities so that community needs inform DSP project identification and implementation. "Community needs" could address energy burden, customer choice and resiliency. |
| Stage 2 | Reflecting UM 2005 outreach requirements, utility holds ongoing community stakeholder meetings during grid needs assessment, solution identification, and action planning. |
| | Utilities and OPUC agree on community goals, project tracking and coordination activities. |
| | Conduct baseline study to increase detailed knowledge of service territory communities. Engage CBO experts to inform co-created community pilot(s). |
| | Consult with communities to understand identified needs and opportunities, then seek to co-develop solution options, documenting longer-term needs. |
| Stage 1 | Hold four public pre-filing workshops with stakeholders on Plan development. |
| | Utilities create a collaborative environment among all interested partners and stakeholders. Utilities document community feedback and utility's responses. |
| | OPUC prepares accessible educational materials on DSP with consultation from CBOs and utilities. |
| | Prepare a draft community engagement plan as part of Plan. |
| | Utilities conduct focused community engagement for planned distribution projects. |
| | OPUC to host quarterly public workshop and technical forums after Plan filings. |
| 2021-2022 | 2023 and beyond |

[20] *Connectivity Means Community - Distributed System Planning for Humans*, Oriana Magnera and Charity Fain, Verde and Community Energy Project, May, 20, 2020, https://www.oregon.gov/puc/utilities/Documents/DSP-Magnera-Fain-Presentation.pdf.

### Initial Requirements

Community engagement should occur during the Distribution System Plan development and throughout Plan implementation with detailed documentation included in the Plan. Specific requirements for utilities, unless noted as OPUC activities, are:

a) During Plan Development
   i) A utility should host at least two stakeholder workshops prior to filing each Part of the utility's Plan, for a minimum total of four workshops. These workshops should be held at a stage in which stakeholder engagement can influence the filed Plan. The workshops may include presentation of the Plan outline, data and assumptions under consideration or challenges encountered, and the utility's approach to the Community Engagement Plan, described in (b). During stakeholder workshops, a utility must invite community members to share their relevant needs, challenges and opportunities.
   ii) A utility should develop a Community Engagement Plan. A utility should plan to engage community members and CBOs during development of pilot concept proposals required in Solutions Identification requirement (Part 2, Section 5.3. (d)). The planned process should include the following activities. A utility should implement these activities as part of the development of pilot proposals prior to filing Part 2 of the Plan:
      (1) Proactively engage stakeholders regarding proposed pilots in impacted communities. Engagement of the local community may include in-person meetings located in the community; presentation of the project scope, timeline, rationale; and solicitation of public comment, particularly to understand community needs and opportunities.
      (2) Document stakeholder comments and utility response, including comments that were heard but not implemented.
      (3) Collaboratively develop and share datasets and metrics to guide community-centered planning.
      (4) Refer to Section 5.3. (d, i-vi) for the community-centered questions that should be addressed through the process above, and during development of pilot proposals described in Part 2, Solutions Identification.
   iii) Utilities should aim to create a collaborative environment among all interested CBO partners and stakeholders. To support collaboration between all interested parties, Staff plans to host public workshops and a technical working forum. These are in addition to the utility workshops required during Plan and pilot development.
   iv) With consultation from utilities and stakeholders, OPUC will prepare accessible, non-technical educational materials on DSP to support public engagement.

### Expected Evolution

The investigation identified numerous opportunities for community engagement in Oregon. In addition to the content presented in the workshop series, stakeholder comments in the investigation frequently spoke to community engagement needs. In comments filed in preparation for the August 25, 2020 Special Public meeting, the Oregon Citizens' Utility Board (CUB), Energy Trust of Oregon, Northwest Energy Coalition (NWEC), and Oregon Solar Energy Industries Association (OSEIA) each commented on the need for solutions to be co-developed with CBOs and stakeholders. Some spoke of the need to acknowledge, value, and compensate CBOs as technical experts in the planning process.[21, 22, 23, 24]

Based on these insights gained through the investigation, for stages 2 and 3 of Plans, a utility should meet the benchmarks identified in Figure 3.

### 4.4. Overarching Requirement - Long-term Distribution System Plan

This section of the Distribution System Plan will consist of the utility's long-term distribution system investment plan and inform broader goals related to maximizing reliability, customer benefits, and efficient operation of the distribution system. A utility should include:

a) The utility's vision for the distribution system over the next 5-10 years, including any strategies, goals or objectives, and their alignment with State law and OPUC policies. These goals may include increased reliability, effective integration of DERs, broader greenhouse gas emissions reduction, or others.
b) Roadmap of the utility's planned investments, tools and activities to advance the long-term DSP vision, using a 5-10-year planning horizon.
    i) Assessment of investment options to enhance the grid across the following range of areas, including relative costs and benefits:
        (1) Substation and distribution network and operations enhancements
            (a) Plans for conservation voltage reduction
        (2) Distributed resource and renewable resource enhancements
            (a) Penetration and activation/utilization of smart inverters
        (3) Transportation Electrification enhancements
        (4) Customer information and demand-side management enhancements
            (a) Plans to continue to expand customer benefits resulting from investments in advanced metering infrastructure
        (5) General business enhancements
            (a) Communications and supporting systems
            (b) Interoperability of systems and equipment
            (c) Work-management systems
            (d) Other enhancements
        (6) As applicable, any transmission network and operations enhancements
    ii) Explanation of how the investments reduce customer costs, improve customer service, improve reliability, facilitate adoption of demand-side and renewable resources, and convey other system benefits
    iii) Long-term assumptions, and impacts of Action Plan investments, etc.
    iv) Forecasting future technical and market potential of DERs
    v) Plans to further build community needs assessment and co-created community solutions into DSP roadmap

[21] Energy Trust of Oregon UM 2005 Responses to Stakeholder Questions for August 25 Special Public Meeting, August 21, 2020, https://edocs.puc.state.or.us/efdocs/HAC/um2005hac75744.pdf.
[22] Responses of the Oregon Citizens' Utility Board for Aug. 25, 2020 Special Public Meeting, August 20, 2020, https://edocs.puc.state.or.us/efdocs/HAC/um2005hac17184.pdf.
[23] Oregon Solar Energy Industries Association Response to Stakeholder Questions for August 25, 2020 Special Public Meeting discussion, August 21, 2020, https://edocs.puc.state.or.us/efdocs/HAC/um2005hac17748.pdf
[24] Northwest Energy Coalition Stakeholder Questions for August 25, 2020 Special Public Meeting discussion, August 21, 2020, https://edocs.puc.state.or.us/efdocs/HAC/um2005hac163634.pdf.

   vi) Transitional planning and operational activities underway in the organization to build capabilities in DSP-related functions
   vii) Key barriers or constraints the utility faces to advancing investment (whether financial, technical, organizational) and mitigation plans

c) Smart Grid investment[25] opportunities
   i) List and describe smart-grid opportunities that the utility is considering for investment over the next 5-10 years and any constraints that affect the utility's investment considerations
   ii) Describe evaluations and assessments of any smart-grid technologies, applications, pilots, or programs that the company is monitoring or plans to undertake

d) Key opportunities and possible benefits for distribution system investment
e) Research and development the utility is undertaking or monitoring
f) Future policy and planning intersections:
   i) Discussion of how planned investments fit with the utility's IRP
   ii) Discussion of how planned investments fit with the utility's annual construction budget for major distribution and transmission investments
   iii) Discussion of how distribution system planning may be coordinated in the future with other major policy and planning efforts discussed in these Guidelines. At a minimum, address the IRP and transmission planning, including: how the Distribution System Plan filing is coordinated with each policy or planning effort, related inputs and outputs such as data sets or prices, and assumptions such as macro-economic policies or growth rates

g) Plans to monitor and adapt the long-term Distribution System Plan

## 4.5. Plan for Part 2 Development

As Part of its Part 1 filing each utility should prepare for the upcoming transition period and include a high-level summary to discuss:

a) How legacy distribution planning practices will be transitioned to the requirements of Part 2
b) Whether all legacy distribution planning practices will be transitioned in time for filing Part 2, and if not, the expected timeframe for that eventual transition
c) Efforts to synchronize IRP activities with requirements of Part 2

[25] Smart grid investments were defined in Order No. 11-172 and that definition is retained here. Smart grid investments are utility investments in technology with two-way communication capability that will (1) improve the control and operation of the utility's transmission or distribution system, and (2) provide consumers information about their electricity use and its cost and enable them to respond to price signals from the utility either by using programmable appliances or by manually managing their energy use. Smart grid technologies include sensors and remote control switches at the distribution system level, synchrophasors and flexible AC transmission system devices at the transmission level, and information displays and appliance control circuits at the consumer level.

# 5. Part 2

## 5.1. Forecasting of Load Growth, DER Adoption, and EV Adoption

Accurately forecasting load growth, a critically important exercise utilities have done for decades, enables the distribution system to reliably meet future energy, demand and ancillary grid service needs. As DER and EV adoption grows, forecasting must advance to better account for their impact on load, as well as the ability of these resources to productively modify load. The following requirements aim to improve the accuracy and granularity of forecasting by requiring DER and EV growth forecast at the substation level. This in turn should improve the accuracy and granularity of existing and anticipated constraints on the distribution system revealed in Grid Needs Identification. Figure 4 introduces the initial requirements and expected evolution for the forecasting of load growth, DER adoption and EV adoption.

**Figure 4**

| **Forecasting of Load Growth, DER Adoption, and EV Adoption** | | |
|---|---|---|
| Stage 3 | | Refine hybrid forecast approach to allow more granular locational and temporal forecasts, aiming for consistent outputs across utilities. |
| Stage 2 | | Identify potential locational system benefit from strategic placement of DERs on the distribution grid. |
| | | Examine data to better understand opportunities for customer participation by energy-burdened households. |
| | | Leverage both top-down forecasts and bottom-up customer models to build forecasts (approaches may be specified). |
| Stage 1 | Allocate system-wide DER forecasts from utility IRP filings to greater locational granularity. | |
| | Document forecasting process and indicate existing and anticipated constraints on the distribution system. | |
| | 2021-2022 | 2023 and beyond |

### Initial Requirements

These Guidelines require a utility to document in the Distribution System Plan current utility load forecasting processes for distribution service. Plans should build on that foundation with forecasts of DER adoption and EV adoption as follows:

a) Discussion of current utility processes for distribution system load growth forecasting including:
   i) Forecasting method and tools used to develop the forecast
   ii) Forecasting time horizon(s)
   iii) Data sources used to inform the forecast
   iv) Locational granularity of the load forecast
b) Forecast of DER adoption and EV adoption by substation
   i) The forecast should include high/medium/low scenarios for both DER adoption and EV adoption

   ii) A utility should fully describe its methodologies for developing the DER forecast, EV forecast, high/medium/low scenarios, and geographical allocation in its plan (for example methods and tools, time horizons, data sources).
   iii) For the initial Plan, the methodology for geographical allocation (to the substation) is at the utility's discretion. The Commission may provide direction for subsequent Plans.
   iv) A utility may consider leveraging information such as: historical utility program trends, historical customer adoption trends, data from Energy Trust of Oregon, data from Transportation Electrification Plans and pilots, or studies on DER technical and economic potential used in other dockets. Utilities should use the most recent data available.
c) Results of forecasting load growth, DER adoption, and EV adoption
   i) Document existing and anticipated constraints on the distribution system

**Expected Evolution**

This investigation identified numerous opportunities for improved creation and use of more granular forecasting of load growth, and DER and EV adoption. The presentation *Forecasting load on distribution systems with distributed energy resources* from the National Renewable Energy Laboratory (NREL) identified several approaches and tools for top-down and bottom-up DER forecasts, including the use of historical trends, program-based approaches, and customer adoption models.[26] In comments filed in response to Staff's questions for the August 25, 2020 Special Public Meeting, numerous parties suggested that the OPUC apply multiple approaches to calibrate and refine forecasts over time.

Based on these insights gained through the investigation, for stages 2 and 3 of Plans, utilities should meet the benchmarks identified in Figure 4.

## 5.2. Grid Needs Identification

Grid needs identification compares the current capabilities of a distribution system and the demands on that system to infer its future needs.

At its core, a grid needs identification answers the question of what technical requirements must be addressed to ensure a safe, reliable and resilient system that provides adequate power quality to the customers it serves. Adding to this core, a holistic approach to grid needs identification anticipates DER adoption by customers, as well as the social and economic needs of the communities that depend on distribution systems and the contributions they can make to strengthen it.

Figure 5 introduces the initial requirements and expected evolution for grid needs identification.

[26] See https://www.oregon.gov/puc/utilities/Documents/DSP-Sigrin-Presentation.pdf for more detail.

**Figure 5**

| Grid Needs Identification | | |
|---|---|---|
| Stage 3 | | Identify grid needs and present a summary of prioritized grid constraints, utilizing prioritization criteria such as community priorities, equity analysis, constraints on DER adoption, and evolving public policy goals. |
| | | Provide new datasets and analysis responsive to OPUC, community inputs and policy evolution. |
| Stage 2 | | Develop robust “future state” data needs, including inputs in the following categories: |
| | | Perform equity analysis overlaying customer geographic and socio-economic data relative to system reliability and customer options. Make findings publicly available. |
| | | Needs identification includes results of community needs assessments, DER forecasting, and equity analysis. |
| | | Identify grid modernization needs and present a summary of prioritized grid constraints and opportunities publicly. |
| Stage 1 | Present summary of prioritized grid constraints publicly, including criteria used for prioritization. | |
| | Document process and criteria used to identify grid adequacy and needs. Discuss criteria used to assess reliability and risk, and methods and modeling tools used to identify needs. | |
| | 2021-2022 | 2023 and beyond |

**Initial Requirements**

A utility, in its Distribution System Plan, should:

a) Document the process used to assess grid adequacy and identify needs.
b) Discuss criteria used to assess reliability and risk, and methods and modeling tools used to identify needs.
c) Present a summary of prioritized grid constraints publicly, including criteria used for prioritization.
d) Provide a timeline by which the grid need(s) must be resolved to avoid potential adverse impacts.

In fulfilling these requirements, each Plan should cross-reference Plan sections of Baseline Data and System Assessments; Community Engagement; and Forecasting of Load Growth, DER Adoption, and EV Adoption.

**Expected Evolution**

This investigation identified numerous opportunities for grid needs identification in Oregon. In the *Connectivity Means Community* presentation, presenters highlighted the need for community engagement and responsiveness to community needs in relation to grid needs identification.[27] A human-focused approach to identifying grid needs, implemented in partnership with communities and CBOs, can create value-adding investments for communities, and align the energy system with community priorities.

Based on these insights gained through the investigation, for stages 2 and 3 of utility Plans, a utility should meet the benchmarks identified in Figure 5.

## 5.3. Solution Identification

Solution identification proposes the equipment, technology or program(s) the utility will advance to meet identified grid needs. Previously, a Distribution System Plan would rely on traditional hardware solutions (such as substation upgrades, reconductoring, additional transformer deployment). These Guidelines advance more holistic distribution system planning, calling for consideration of a wider range of potential solutions (for example increased system monitoring automation, expanded switching capability, distributed energy resources).

Experts contributing to the OPUC’s workshops on Non-Wire Solutions and Distributed Energy Resource Valuation suggested that Solution Identification include a comprehensive exposition of the options available to serve grid needs. This section of the Plan should weigh the pros and cons of each option across standardized criteria, with inclusive approaches to weighing the cost and benefits of each path forward.

Figure 6 introduces the initial requirements and expected evolution for solution identification.

[27] *Connectivity Means Community - Distributed System Planning for Humans*, Oriana Magnera and Charity Fain, Verde and Community Energy Project, May, 20, 2020, https://www.oregon.gov/puc/utilities/Documents/DSP-Magnera-Fain-Presentation.pdf.

**Figure 6**

| Solution Identification | |
|---|---|
| Stage 3 | Co-develop solutions with communities and community-based organizations. |
| | Streamline and refine non-wires solutions and aggregations of non-wires solutions to defer distribution system upgrades. |
| Stage 2 | In assessing options for distribution system pilots and projects, engage community organizing experts to gain input from potentially impacted communities. |
| | Prior to filing, publicly present data used to identify distribution system investments, and understand data most useful to stakeholders. |
| | Co-develop solutions with communities and community-based organizations. |
| | Utilize non-wires solutions to defer distribution system upgrades. This includes harnessing DERs for voltage support and frequency event support. |
| Stage 1 | Stakeholders provide feedback on what data would be useful to them. OPUC determines if additional datasets are necessary and may direct utilities to submit them in the next Distribution System Plan filing. |
| | Provide summary and description of data used in distribution system investment decisions such as: feeder level details (including customer types on feeder, loading information), DER forecasts and adoption. |
| | Document the process to identify a range of possible solutions to address grid needs. For larger projects, engage with communities early in solution identification. Facilitate discussion of proposed investments that allow for mutual understanding of the value and risks associated with resource investment options. |
| 2021-2022 | 2023 and beyond |

**Initial Requirements**

The utility should assess proposed solutions to address grid needs. Specific requirements include:

a) Document the process to identify the range of possible solutions to address priority grid needs.
b) For each identified Grid Need provide a summary and description of data used for distribution system investment decisions including: discussion of the proposed and various alternative solutions considered, a detailed accounting of the relative costs and benefits of the chosen and alternative solutions, feeder level details (such as customer types on the feeder; loading information), DER forecasts and EV adoption rates.
c) For larger projects (this may exclude, for example, regular maintenance projects, or inspection projects), engage with impacted communities early in solution identification. Facilitate discussion of proposed investments that allow for mutual understanding of the value and risks associated with resource investment options.

d) Evaluate at least two[28] pilot concept proposals in which non-wire solutions would be used in the place of traditional utility infrastructure investment. The purpose of these pilots is to gain experience and insight into the evaluation of non-wire solutions to address priority issues such as the need for new capacity to serve local load growth, power quality improvements in underserved communities. These pilots will prepare utilities to achieve the goals listed in Stages 2 and 3 of Figure 6.

In its pilot concept proposals, a utility should discuss the grid need(s) addressed, various alternative solutions considered, and provide detailed accounting of the relative costs and benefits of the chosen and alternative solutions. The pilot concept proposals should be reasonable and meet the Guidelines, even if the individual proposal may not be cost-effective. In addition, evaluation of pilot concept proposals should utilize the community engagement process developed in Section 4.3. (a) (ii) and address:

i) Community interest in clean energy planning and projects
ii) Community energy needs and desires
iii) Community barriers to clean energy needs, desires, and opportunities
iv) Energy burden within the community
v) Community demographics
vi) Any carbon reductions resulting from implementing a non-wires solution rather than providing electricity from the grid's incumbent generation mix

The pilot concept proposal should include a process in which the utility works with stakeholders to set equity goals, as may be appropriate for the pilot.

**Expected Evolution**

This investigation identified numerous opportunities for solutions identification in Oregon. The need to co-develop distribution system solutions with communities and CBOs remains a priority throughout the DSP evolution. Beyond community engagement, the regulatory framework, utility processes and structures, and procurement practices also need to evolve to enable implementation of non-wires solutions.[29] As non-wires solutions are constructed and their performance in serving grid needs and deferring grid upgrades is better understood, valuation methods may be needed to compare non-wires solutions to traditional utility hardware (for example substation upgrades, additional transformer deployment).[30]

Based on these insights gained through the investigation, for stages 2 and 3 of utility Plans, a utility should meet the benchmarks identified in Figure 6.

## 5.4. Overarching Requirement - Near-Term Action Plan

In this section of the Plan, a utility should present the utility's proposed solutions to address grid needs, as well as other investments in the distribution system. Specific requirements include:

[28] 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.

[29] *Non-wires Solutions: Context, Rationale, and Opportunity*, Jason Prince, Rocky Mountain Institute, May 13, 2020, https://www.oregon.gov/puc/utilities/Documents/DSP-Prince-Presentation.pdf.

[30] Refer to *Valuation of Distributed Energy Resources* presentation from Debra Lew for details on approaches to valuing non-wires solutions and distributed energy resources, https://www.oregon.gov/puc/utilities/Documents/DSP-LewPresentation.pdf.

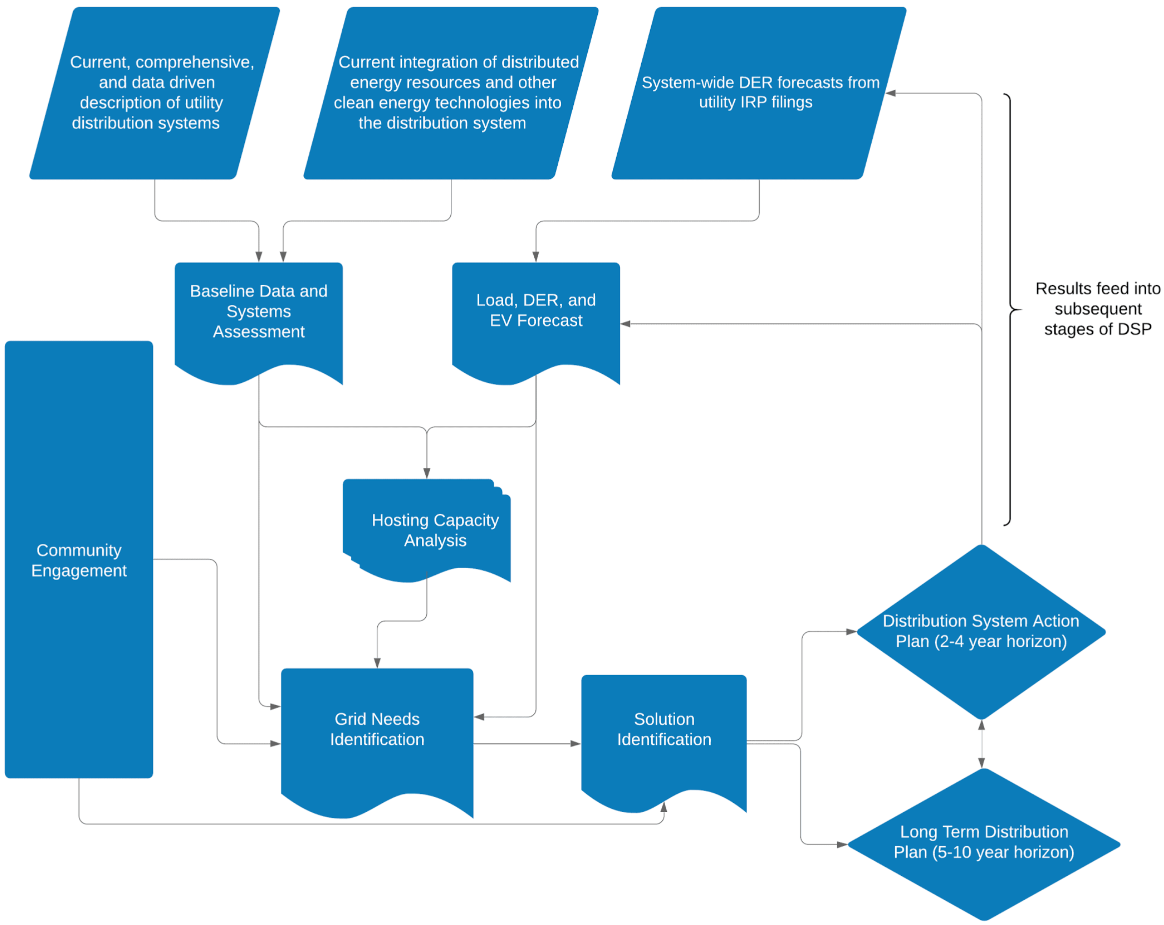
a) Action Plan: Provide a 2-4 year plan consisting of the utility's proposed solutions to address grid needs and other investments in the distribution system
b) Projected spending: Disclose projected system spending to implement the action plan, timeline for improvement, and anticipated requests for a cost recovery mechanism
c) Relation to other investments: As applicable, the Action Plan should identify areas of relation and interaction with other investments such as transmission projects and demand response programs
d) Document current innovations and pilots being conducted to improve, modernize, and/or enhance the grid beyond its current capabilities

## 6. Overview of the Distribution System Planning Process

The elements of Distribution System Planning described in these Guidelines must be integrated and used iteratively to form a holistic planning process to meet Oregon's needs. These Guidelines specify the initial requirements for utility Distribution System Plan filings, and identify baseline expectations for how these requirements may evolve over time. Figure 7 depicts this process in a conceptual manner. Figure 7 does not address the respective timing of these elements as outlined in these Guidelines.

**Figure 7**

**Oregon Public Utilities Commission Distribution System Planning Process Diagram**




Key conceptual relationships depicted in Figure 7 include:

- Baseline Data and System Assessments are informed by current information and data on the current state of utility distribution systems and the DERs already contributing to and depending on those systems. The initial Plan requirements are primarily a consolidation of this information and data from other existing reports.
- Load, DER and EV Adoption Forecasts are informed by system-wide forecasts utilized currently in each utility's Integrated Resource Planning. The allocation of those forecasts to the substation level represents an incremental advance beyond current practices introduced by these Guidelines.
- In the future, Hosting Capacity Analysis will compare the capabilities of the system and the demands on the system, as recognized by forecasts of load growth, and DER and EV adoption. As depicted in this figure, the hosting capacity analysis will inform distribution planning as an input into the Grid Needs Identification.

- Grid Needs Identification will compare the capabilities of, and demands on, the system, and will utilize the improved forecasting of load growth, and DER and EV adoption noted above.
- The Plan's Solution Identification should show how the utility intends to meet the needs identified in the preceding step. The requirement of non-wire solutions pilot concept proposals is an incremental advance beyond current practices introduced by these Guidelines.
- The integration of community engagement is also an incremental advance beyond current practices introduced by these Guidelines. Each Plan should seek and account for community input in identifying Solutions.
- Each Plan's Near-Term Action Plan will be derived from its Solution Identification, providing specific steps the utility will take to secure identified solutions within the next 2-4 years, as well as proposed deadlines, milestones and projected costs.
- Each Plan's Long-term Plan affords the utility an opportunity to explain how its Action Plan represents a step toward its envisioned long-term modernization of the distribution system.
- Finally, recognizing the iterative nature of planning, each Plan's Action Plan and Long-term Plan will provide a basis for subsequent phases of DSP.

Together, a utility's successful integration of these elements should amount to a transparent, robust and holistic distribution planning system.

# Distribution System Planning Guidelines

## Introduction

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## 1. Purpose

This ~~Introduction~~document provides ~~context for~~an overview of the ~~accompanying draft~~ Distribution System Planning (DSP) Guidelines ~~for Oregon's investor-owned electric utilities, under Oregon~~ in Docket UM 2005. The Public Utility Commission ~~Docket UM 2005.~~ of Oregon (OPUC) issued Order No. 19-104~~, issued~~ March 22, 2019, open~~ed~~ing an investigation to "develop a transparent, robust, holistic regulatory planning process for electric utility distribution system operations and investments."[1] The draft Guidelines (~~Appendix 1~~attached) outline requirements for the initial utility DSP Plan (Plan) filings to be submitted by Oregon's investor-owned electric utilities to the Commission in 2021 and 2022.

~~Staff believes a~~A new regulatory structure for DSP will enable utilities to better identify system needs and evaluate the evolving range of opportunities that can meet those needs. ~~Staff wants to advance least-cost investments to modernize the grid as a foundation for optimization of the distribution system, in order to foster higher levels of customer access and interaction, and integration of variable resources.~~ Staff seeks to maximize customer value by ensuring that the utilities' approach to managing and operating the distribution system is evolving in a least-cost, least-risk manner. Staff sees grid modernization as a foundation for higher levels of customer access and interaction, and integration of variable resources. The proposed DSP process supports these aims and advances State and OPUC policy goals.

~~Staff envisions DSP as a critical step in advancing the state's expectations for a modern grid. Staff foresees an eventual transition to a more responsive platform capable of minimizing the frequency and impact of outages, supporting decarbonization, optimizing system performance, and enabling customers to deploy distributed energy resources in a manner that minimizes their costs while maximizing system benefits.~~

The Commission envisions DSP as a critical step in modernizing the grid to accommodate developing industry trends and support new policy objectives. Since 2013, Oregon's investor-owned electric utilities have filed biennial Smart-Grid Reports, which provide important insight into innovative grid modernization projects. The DSP Guidelines ~~will~~are designed to further expand and evolve this reporting framework.

Informing Staff's proposal for DSP Guidelines are Senate Bill (SB) 978 (2017) and Governor Brown's Executive Order No. 20-04~~ (EO 20-04) of March 10, 2020.~~.[2] With SB 978, the Oregon Legislature tasked utilities and the OPUC with exploring new expectations for the electric grid, highlighting the clear importance of clean energy, inclusivity, and customer options in addition to the core mission of the OPUC.

The OPUC's 2018 legislative report ~~in 2018~~notes that the Commission had previously acknowledged the need for an investigation into distribution system planning.[3] The report cites

[1] ~~See~~ See UM 2005, Order No. 19-104, March 22, 2019 at https://apps.puc.state.or.us/orders/2019ords/19-104.pdf.
[2] See Executive Order No. 20-04 (EO 20-04, March 10, 2020), at https://www.oregon.gov/gov/Documents/executive_orders/eo_20-04.pdf.
[3] See *SB 978: Actively Adapting to the Changing Electricity Sector* September 2018, page 17, at: https://www.oregon.gov/puc/utilities/Documents/SB978LegislativeReport-2018.pdf.

distribution system resources and management technologies as one of four key themes within the technology trends and impacts most significant for Oregon's electric sector~~, requiring regulatory attention~~.[4] The report encourages increased transparency in distribution system planning.[5] Importantly, the ~~agency~~report outlines new efforts to create an environment of procedural inclusion for underserved communities including low-income, environmental justice and community-based organizations.[6]

EO 20-04 sets new science-based greenhouse gas (GHG) emissions goals for Oregon and directs state agencies to identify and prioritize actions to meet those goals.[7] The EO directs the Commission to use any and all authority at its discretion to help reduce the emission of greenhouse gases to at least 45 percent below 1990 levels by 2035 and 80 percent below 1990 levels by 2050.[8] Section 5(A) first finds that: "It is in the interest of utility customers and the public generally for the utility sector to take actions that result in the rapid reduction of GHG emissions, at reasonable costs, to levels consistent with the GHG emission goals set forth in [this EO], including transitioning to clean energy resources and expanding low carbon transportation choices for Oregonians." Staff's proposed DSP Guidelines support the GHG emissions goals of the EO by enabling efficient grid integration of distributed energy resources (DERs) and other clean energy technologies.

## 2. Drivers

Staff's whitepaper on distribution system planning (2019) identified two proactive drivers for the UM 2005 investigation~~ that carry forward:~~:

- Insight (procedural driver): The near-term need to establish visibility and holistic engagement in utilities' distribution-level investments.
- Optimization (operational driver): The longer-term need to ensure the operation of the changing distribution system maximizes operational efficiency and customer value.[9]

Historically, utility investments in the distribution system were understood to be sufficient for reliable operations~~ and maintenance~~, or to serve increased or new load. That investment was typically in equipment to support one-directional flow of power and communication, and to serve predictable load patterns. This traditional type of investment was generally regarded as necessary and prudent, for example when reviewed in general rate cases.

[4] Ibid, at page 10.
[5] ~~See *SB 978: Actively Adapting to the Changing Electricity Sector* September 2018, pages 9-11, available at: https://www.oregon.gov/puc/utilities/Documents/SB978LegislativeReport-2018.pdf.~~ Ibid, at page 21.
[6] Ibid, at page 19.
[7] See Executive Order No. 20-04 (EO 20-04, 2020), Section 2, page 5 at https://www.oregon.gov/gov/Documents/executive_orders/eo_20-04.pdf.
[8] Ibid, Section 3.A. page 5.
[9] Staff Whitepaper: A Proposal for Electric Distribution System Planning, March 2019, ~~https://edocs.puc.state.or.us/efdocs/HAU/um2005hau15477.pdf.~~https://edocs.puc.state.or.us/efdocs/HAU/um2005hau15477.pdf.

However, changes in state and federal public policy, evolving digital technology, and rapidly decreasing costs of ~~distributed energy resources (~~DERs~~)~~[10] have led to a host of new investments in the grid by utilities and customers. These include the utilization of advanced metering infrastructure (AMI), increasing adoption of solar PV and battery storage, and increasing adoption of electric vehicles and installation of charging stations. These changes have led to new and increased demands on the distribution system in order to "keep the lights on," and new opportunities for the distribution system to deliver ~~new~~ value ~~to customers~~. Customers and utilities can benefit through ~~enabling~~grid services that enable higher levels of intermittent DERs, provid~~inge~~ carbon-free energy for transportation, ~~serving to decarbonize the utility sector and~~and serve to reduce GHG emissions as directed by EO 20-04~~, and other grid services~~.

As a result, the distribution system ~~should~~will need to evolve to leverage the two-way flow of power and communication, ~~greatly~~to handle increased levels of intermittent power generation, and to harness the potential for highly flexible load patterns. The types and amount of investment in the distribution system are expected to change as well. In other states, investment in the distribution system has already been significantly transformed. As a critical step in advancing the state's expectations for a modern grid, a new DSP ~~planning~~ framework ~~in Oregon~~ will help ensure distribution system investments are planned and customer value maximized. ~~In contrast to unplanned,~~ Without the transparency from planning, there is risk of erratic grid development ~~of the system~~ with uneven benefits~~, a~~. A robust DSP process ~~will~~can advance a modern and reliable system~~,~~—one positioned to form a foundation for higher levels of customer access and interaction, and higher levels of generation and load variability.

## 3. Goals and Principles

### Long-Term Goals

In developing this proposal, Staff has been guided by the following overarching goals for Oregon's long-term DSP process. These overarching goals were developed collaboratively with parties through the course of the investigation.[11]

- Promote the reliability, safety, security, affordability and quality of the distribution system and utility services 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; and

[10] For the purposes of these guidelines "distributed energy resource" includes distributed generation resources~~,~~ (either net metering or Qualifying Facilities), distributed energy storage, demand response, energy efficiency, and electric vehicles that are connected to the electric distribution power grid. U.S. Department of Energy, Modern Distribution Grid Volume I: Customer and State Policy Driven Functionality, page 7, ~~https://gridarchitecture.pnnl.gov/media/Modern-Distribution-Grid_Volume-I_v1_1.pdf.~~https://gridarchitecture.pnnl.gov/media/Modern-Distribution-Grid_Volume-I_v1_1.pdf.

[11] ~~See https://edocs.puc.state.or.us/efdocs/HAH/um2005hah145318.pdf.~~ See https://edocs.puc.state.or.us/efdocs/HAH/um2005hah145318.pdf.

- Strive for regulatory efficiency through aligned, streamlined processes.

**Guiding Principles**

Staff also utilized the following guiding principles to inform development of the initial DSP Guidelines. The principles of practicality, transparency and inclusion address the investigation's procedural driver of "insight." The principles of flexibility, efficiency and transparency address the operational driver of "optimization."

| Principle | Does the requirement or activity… |
|---|---|
| Flexibility | Allow for plans to evolve as the state of the distribution system changes? Allow for variance among utilities? Accommodate changes over time in variables such as technology and costs? |
| Practicality | Deliver information that is usable by utilities and stakeholders? Appropriately weigh complexity and cost? Streamline regulatory efforts? |
| Efficiency | Achieve efficient integration of distributed energy resources (DERs) and accelerate decarbonization? Lead to more efficient operation of the distribution system? |
| Transparency | Yield results that improve insight? Deliver information needed to holistically understand long-term distribution system plans? Reveal how customer and competitive options can provide value? |
| Inclusion | Meaningfully include a broader range of participants? Remove barriers to public participation to ensure all voices are heard in the decision-making process? |

~~To ensure progress toward long-term goals and reflect guiding principles, each element of the Guidelines includes "Initial Requirements" and a description of "Expected Evolution." Staff proposes the "Initial Requirements" for the first utility Plans, while "Expected Evolution" includes potential benchmarks for future phases. (See section 8 for a further discussion.) This structure provides utilities a firm foundation of guidance for the first Plans, while introducing a flexible vision for the future that may be adapted based on new information put forward by the utilities and stakeholders.~~

~~Guidelines will be revised after the first utility Plan filings and the resultant Commission orders, reflecting stakeholder input and learnings. Staff anticipates lessons from the filing process and Plan review will inform an assessment of the Guidelines.~~

## 4. Planning Interactions and Streamlining

To achieve focused and strategic reporting for DSP, current related regulatory requirements will change. The changes below are anticipated; specific requirements are included in the Plan Guidelines.

a. Smart Grid Report (SGR). This biennial report is the current regulatory requirement with the largest focus on the distribution system. Conceived nearly 10 years ago, the SGR has played a critical role, but it is not a planning document. In order to allow for utilities to shift focus from the SGR to DSP, Staff recommends temporarily suspending the next Smart Grid Report filing cycle requirement as established in Docket UM 1460, Order No. 17-290 (currently PGE – June 1, 2021, Pacific Power – August 1, 2021, Idaho Power – October 1, 2021). As the DSP process becomes established, Staff anticipates requesting that Order Nos. 12-158 and 17-290, issued in Docket UM 1460, be revised or these orders may be superseded by new requirements adopted in this docket.

   Staff recommends continuing several forward-looking aspects of the SGR and integrating these into the DSP Guidelines section~~s~~ of Long-term Distribution System Plan~~, and Planning Interactions and Streamlining.~~. These include~~ (from Order No. 12-158):~~ :[12]

   - C.1. (any distribution system plan strategies, goals or objectives, and their alignment with State and Commission policies~~) and~~ ),
   - C.2.b. (a description of upcoming investment options across a range of categories~~).~~)
   - C.3 a-c. (Smart Grid opportunities)

   ~~a.~~

b. Transportation Electrification (TE) Plan. This biennial plan presents the utility's long-term strategy to accelerate transportation electrification in its Oregon service territory. The TE Plan serves numerous important purposes~~, and~~. Staff recommends it continue to be separately produced, though information reported in the TE Plan may be sourced from the Distribution System Plan.

   Because transportation electrification has the potential for such a large impact on the distribution system, Staff recommends the Distribution System Plan be used to develop several elements ~~that will also be included~~currently required in the TE Plan~~,~~. Specifically, Staff recommends developing and including the following information ~~currently required in TE Plans~~ in the Distribution System Plan:

   - OAR 860-087-0020(3)(a)(C) (existing data on the availability and usage of charging stations~~),~~ )
   - (D) (number of EVs in the service territory and projected number of EVs in the coming years~~),~~ )
   - (E) (other related infrastructure, if applicable~~), and~~ )
   - (G) (Distribution system impacts and opportunities for efficient grid management).

   Once developed and provided in the Distribution System Plan, a utility can include that data in its TE Plan. As the DSP process becomes established Staff will consider recommending changes to the requirements of OAR 860-087-0020.

   Staff recommends utilities include the elements referenced above within the DSP Guidelines sections of Baseline and System Assessment, and Forecasting of Load~~, Distributed Energy Resources~~ Growth, DER Adoption, and EV ~~Forecast~~Adoption.

[12] See Order No. 12-158.

~~c.~~ Annual Net Metering Reports. This report conveys important information in understanding the distribution system and DERs. ~~In order to integrate this information into~~ Staff recommends Annual Net Metering Reports continue separately from the Distribution System Plan~~, while requiring it be reported only once, Staff recommends a waiver temporarily suspending~~. Each Plan should include the ~~next annual~~most recent Annual Net Metering Report ~~filing cycle requirement as established in OAR 860-039-0070(2) (currently April 1, 2021). As the DSP process becomes established~~. Staff ~~will consider recommending changes to the requirements~~recommends possible integration of ~~OAR 860-039-0070.~~these reports into future Plan filings.
~~Staff recommends continuing reporting net metering data and integrating this information into the DSP Guidelines section Baseline and System Assessment. These reference: OAR 860-039-0070(2)(a) (total number of net metering facilities by type), (b) (total estimated rated generating capacity of net metering facilities by type), and (3) (upon request each utility must file maps, records and reports to identify, locate and summarize net metering facilities).~~

~~d.~~ Annual Small Generator Reports. This report also conveys important information in understanding the distribution system and DERs. ~~In order to integrate this information into the Distribution System Plan, while requiring it be reported only once, Staff recommends a waiver temporarily suspending the next annual report filing cycle requirement as established in OAR 860-082-0065(3) (currently May 30, 2021). As the DSP process becomes established Staff will consider recommending changes to the requirements of OAR 860-082-0065.~~
Staff recommends Annual Small Generator Reports continue separately from a Distribution System Plan. Each Plan should include the most recent Annual Small Generator Report. Staff recommends possible integration of these reports into future DSP filings.
~~Staff recommends continuing reporting small generator data and integrating this information in the DSP Guidelines section Baseline and System Assessment. These include: OAR 860-082-0065(3)(a) (number of complete small generator interconnection applications received), (b) (number of small generator facility interconnections completed), (c) (types of small generator facilities applying for interconnection and the capacity of the facilities), (e) (for each Tier 3 and Tier 4 small generator interconnection approval, the basic telemetry configuration, if applicable), (f) (for each Tier 4 small generator interconnection approval), (A) (interconnection facilities required to accommodate the interconnection of a small generator facility and the estimated costs of those facilities), and (B) (system upgrades required to accommodate the interconnection of a small generator facility and the estimated costs of those upgrades).~~

~~e.~~c. Annual Reliability Reports. This report conveys information vital to understanding the distribution system's performance in delivering reliable service to customers. However, this report serves other important purposes as well, and Staff recommends Annual Reliability Reports continue separate from a Distribution System Plan, with each Plan including the most recent reliability report.

~~f.~~ d. Demand response (DR) reporting. Utilities currently report the performance of demand response programs ~~on an annual basis.~~ in numerous dockets.[13] These reports cover important and detailed aspects of ~~their~~ DR program operation and efficacy. ~~Overall DR~~ The sum, system-wide capability and results of DR can affect the distribution system, and so Staff recommends ~~summary~~ high-level ~~demand response~~ DR reporting be included in the Plan, while current ~~and~~, detailed DR reporting continue separate from a Distribution System Plan.

~~g.~~ e. Integrated Resource Plan. Staff recognizes the significant time and effort required for the Integrated Resource Planning (IRP) process, and welcomes suggestions on how best to synchronize this effort with the Distribution System Planning process. In order to inform any future synchronization, in the DSP Guidelines section, Long-term Distribution System Plan, utilities should include a discussion of how the IRP and Plans are coordinated. This should include related inputs and outputs such as data sets or prices, and assumptions such as macro-economic policies or growth rates.

f. Hosting Capacity Analysis. Direction on hosting capacity analysis technical requirements (such as minimum daily load calculation, assumptions about DER generation profiles, treatment of solar plus storage in interconnection analysis, and other factors that determine the DER penetration thresholds that trigger system upgrades) will be established in Docket No. UM 2111, Staff Investigation into Interconnection Process and Policies.

## 5. Data Privacy and Security

It is important that utility data be provided to the Commission and to stakeholders, as appropriate, at the necessary level of detail to ensure a sound review process. Staff recognizes that some information should not be widely distributed to the public in every instance, such as personally identifiable customer information or critical infrastructure information. Utilities should provide as detailed a Plan as possible.

## 6. Cost Recovery

Utility costs:

- ~~The OPUC will aim to provide utilities with guidance on reasonable levels of spending for upfront costs to identify and plan for risks. This should include new resources needed to meet requirements for community engagement and planning not currently recovered through rates.~~
- ~~This process requires incremental progress. Staff recognizes current utility performance and the uncertainty that utilities will take on throughout the process.~~
- ~~Associated pilots~~ Staff recognizes some additional expenses may be incurred as a result of Plan development and compliance. If the result of these activities is a significant increase in expense, cost-recovery mechanisms are available to utilities and can be

[13] For examples see ADV 242 for annual reports on Pacific Power's Irrigation Load Control Pilot, or UM 1708 for evaluations of various PGE demand response pilots.

addressed outside of this proceeding. Pilots specified within these Guidelines may allow utilities cost recovery mechanisms.

Stakeholder costs:

- Participation in this process places an increased burden on ~~involved organizations'~~the time and resources~~.~~ of involved citizens and organizations. Staff will explore opportunities to support community-based organization participation. As described in section 9.1, Staff plans to provide educational materials and public workshops. Staff supports resourcing as necessary of these organizations to inform decision-making.

## 7. Regulatory Development

OPUC recognizes the need for ongoing conversations about how DSP activities align or interact with the utilities' existing business models and regulatory approaches. Utilities and stakeholders should explore whether an alternative regulatory framework would assist in aligning incentives for utility long-term DSP investment and DER development, is in customers' interest, and aligns with the clean energy vision articulated by the State of Oregon. To address the changes that utilities may make in implementing the DSP process, the OPUC may explore new regulatory mechanisms that may better align with utilities' efforts to plan and invest in DSP over the long-term.

## 8. Vision for Distribution Planning Evolution

The initial ~~DSP~~ Plan filings required herein will be the first stage in an evolving multi-stage process. Staff anticipates that the forming, filing and acceptance of the initial Plans will educate all parties and identify areas for continuous improvement. Table 1 illustrates Staff's expected evolution from the Initial Requirements put forward in these Guidelines to more advanced stages.

To ensure progress toward long-term goals and reflect guiding principles, each element of the Guidelines includes "Initial Requirements" and a description of "Expected Evolution." Staff proposes the "Initial Requirements" for the first utility Plans, while "Expected Evolution" includes potential benchmarks for future stages. This structure provides utilities a firm foundation of guidance for the first Plans, while introducing a flexible vision for the future that may be adapted based on new information. Achievement of Stages 2 and 3 may be accelerated depending on circumstances and readiness of utilities and participants.

**Table 1**

| **Distribution System Planning Evolution Framework** | |
|---|---|
| Stage 3 | Achieving the long-term vision for distribution system planning capabilities and outcomes |
| Stage 2 | Advancing requirements incrementally to better match growing utility capabilities |

| **Distribution System Planning Evolution Framework** | | |
|---|---|---|
| | | and evolving grid, customer and community needs |
| Stage 1 | Beginning with Initial Requirements of Utility DSP Filings, providing a foundation for future stages | |
| | 2021-2022 | 202~~9~~3 and beyond |

~~Utilities will develop and file their initial Plans in Fall 2021, resulting in Commission orders that may accept the Plans and may provide additional guidance for future plan filings. As used in the Guidelines, "acceptance" means the Commission finds that the Plan meets the criteria and requirements of these Guidelines and does not constitute a determination on the prudence of any individual actions discussed in the Plan. Non-acceptance means that the Plan does not meet the expectations of the Guidelines.~~

~~Following the issuance of these initial Commission orders, Staff will work with parties to identify improvements to DSP Guidelines and processes for future filings.~~
Staff anticipates lessons from the filing process and Plan review will inform an assessment of the Guidelines. Guideline revision is discussed further in Section 9.

### 8.1. Insights Provided by Parties and Subject Matter Experts

The vision for DSP in Oregon relies heavily on the input provided to Staff by diverse parties and subject matter experts throughout the 2020 workshop series. Robust stakeholder participation across 12 workshops and webinars explored distribution system planning approaches, best practices from across the country, and related OPUC policies. The active participation of utilities and stakeholders in this investigation, from more than 40 parties, has provided new insight ~~into~~on a range of topics. These include the capabilities, needs and future of Oregon's distribution systems, distributed energy resources, and the customers and communities they serve.[14] The impact of this input on the DSP Guidelines is substantial, initiating a new era of transparency, rigor and opportunity for DSP in Oregon.

## 9. Plan Submission and Commission Action

Utilities will develop and file their initial Plans in two parts, the first part in Fall 2021 and the second part in Summer 2022. Plans will be presented at a Public Meeting between three to five months following each filing, after a period of stakeholder and Staff review. The Commission may accept the Plans and may provide additional guidance for future Plan filings. As used in the

[14] Records from the workshops are available online through the UM 2005 investigation docket ~~https://apps.puc.state.or.us/edockets/DocketNoLayout.asp?DocketID=21850.~~https://apps.puc.state.or.us/edockets/DocketNoLayout.asp?DocketID=21850. Records from the webinar series are located in the Webinar Archive on the OPUC Distribution System Planning Webpage, as well as in the UM 2005 docket, ~~https://www.oregon.gov/puc/utilities/Pages/Distribution-System-Planning.aspx.~~https://www.oregon.gov/puc/utilities/Pages/Distribution-System-Planning.aspx.

Guidelines, "acceptance" means the Commission finds that the Plan meets the criteria and requirements of these Guidelines and does not constitute a determination on the prudence of any individual actions discussed in the Plan. Non-acceptance means that the Plan does not meet the criteria or requirements of the Guidelines.

Following the issuance of the final Commission orders, the DSP Guidelines will be formally reopened with a stakeholder process identifying Guideline improvements for future Plan filings.

Staff anticipates that the second "round" of DSP will follow a two-year cycle. The second round should commence after Commission acceptance of both parts of the initial Plan. The second Plan will likely be submitted in an integrated fashion, rather than in two parts.

## 9.1. Plan Development Support

Staff will host a public workshop prior to the filing of each part of the initial Plan. These workshops may be formatted to respond to utility and stakeholder requests to support Plan completion. Topics may include cybersecurity, community outreach, regulatory development or data transparency. A technical working group may be formed to assist utilities in vetting new materials or products needing stakeholder feedback.

## 9.2. Transition and Implementation

Staff recognizes that utilities will invest in new systems and processes to meet these Plan Guidelines. A transition period is expected in which legacy processes and data will be implemented while new systems are developed. For the first Plan filings, legacy planning studies and data may be submitted when more current data is not available.

# Distribution System Planning Guidelines

~~Appendix 1~~

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## 1. Process and Timing

~~Staff proposes the~~The following development and review process ~~for~~will guide the initial utility filing of a Distribution System Plan (Plan~~).~~) for a utility's service territory in Oregon.

a) ~~Utilities~~Each electric utility[1] must file ~~a Distribution System~~the first portion of its Plan ~~every two years,~~(Part 1) on October 15, 2021 or an alternative date designated ~~through~~by Commission order.
b) Each utility must file the second portion of its Plan (Part 2), on August 15, 2022 or an alternative date designated by Commission order.
c) Subsequent Plans will be filed in their entirety, combining Parts 1 and 2.
d) Each utility must file a subsequent Plan within two years of the Commission order for Part 2.

For both Part 1 and Part 2 of the utility Plan:

~~b)~~e) During Plan development, prior to filing~~ a Plan, utilities~~, each utility must hold at least two workshops with stakeholders to ensure a range of community perspectives are heard and considered. Each utility must hold additional community meetings during development of pilot projects.
~~c)~~f) ~~Utilities~~Each utility will present the results of ~~its filed Plan~~each filing to the Commission at a separate public meeting.
~~d)~~g) Upon each filing, the Commission will set a procedural schedule under which interested parties will have the opportunity to provide comment and make recommendations on ~~a utility's Plan.~~ the filing.
~~e)~~h) The Commission will generally consider comments and recommendations on a utility's ~~Plan~~filing at a public meeting three to five months after it is filed. The Commission will consider whether to accept the ~~Plan~~filing as meeting the objectives of these Guidelines~~, and issue an order accordingly~~. The Commission may provide guidance on the development and content of future Plans.
~~f)~~i) The Commission may provide the utility an opportunity to revise the ~~Plan~~filing before ~~issuing an order~~making its decision.

~~Staff's~~The design and implementation of this proposed process will ~~achieve Staff's~~serve the long-term ~~goals or guiding principles of~~ regulatory efficiency goals through aligned, streamlined processes, ~~and~~ inclusion, and transparency.

## 2. Commission Action

~~Initial~~A utility must file its Plan ~~filings will be reviewed for~~as provided in Guideline 1. The Commission will consider whether to accept the filed Plan (or Plan Part) as meeting the objectives of these Guidelines. As used in this Guideline, "acceptance~~, rather than acknowledgement. Staff understands there is much to learn for all parties, and that~~" means the Commission finds the Plan meets the criteria and requirements of these Guidelines. Acceptance does not constitute a determination on the prudence of any individual actions discussed in the

[1] "Electric utility" or "utility" for purposes of these guidelines 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.

Plan. A decision to not accept a Plan means that the Plan does not meet the criteria or requirements of the Guidelines.

Commission acknowledgement of a Plan may be premature given that the ~~state of~~ DSP process ~~maturity.~~is in its initial stage of development. At later stages, ~~Staff proposes to~~the Commission may revisit this topic and address whether subsequent Plans ~~are filed~~ may be considered for Commission acknowledgement.

## 3. Scope

~~Initial~~An electric utility will file the initial utility Distribution System ~~Plans will address and provide the following:~~Plan in two sections:

Part 1 (October 2021)

- Baseline Data and System Assessment
- ~~Load, Distributed Energy Resource (DER), and Electric Vehicle (EV) Adoption Forecasts~~
- Hosting Capacity Analysis
- Community Engagement Plan
- Long-Term Plan
- Plan for Development of Part 2

Part 2 (August 2022)

- Forecasting of Load Growth, DER Adoption, and EV Adoption
- Grid Needs Identification
- Solution Identification
- Near-Term Action Plan ~~and Long-Term Plan~~

## 4. Part 1

### ~~3.1.~~4.1. Baseline Data and System Assessment

To foster ~~understanding~~transparency and enable effective decision-making, Distribution System Plans should provide a fundamental understanding of the current physical status of the utility distribution systems, recent investment in those systems, and the level of distributed energy resources (DERs) currently integrated into those systems.[2] Figure 1 introduces the initial requirements and expected evolution for baseline data and system assessments.

[2] For the purposes of these guidelines "distributed energy resource" includes distributed generation resources (either net metering or Qualifying Facilities), distributed energy storage, demand response, energy efficiency, and electric vehicles that are connected to the electric distribution power grid. U.S. Department of Energy, Modern Distribution Grid Volume I: Customer and State Policy Driven Functionality, page 7, https://gridarchitecture.pnnl.gov/media/Modern-Distribution-Grid_Volume-I_v1_1.pdf.

**Figure 1**

| Baseline Data and System Assessment | | |
|---|---|---|
| Stage 3 | | Refine asset financial planning processes and strengthen relationships with DER planning and integration processes. |
| | | Use software systems to proactively monitor and support operation of the distribution system and DERs. |
| Stage 2 | | Share asset financial planning processes and show relationships with DER forecasting and planning processes. |
| | | Leverage remote sensing technologies to provide detailed insight on physical infrastructure to support efficient operation of the distribution system. |
| Stage 1 | Identify ~~the~~ existing grid equipment inventory and financial data, as well as DER-related data with locational granularity~~, and DER-related data.~~ . | |
| | 2021-2022 | 202~~9~~3 and beyond |

**Initial Requirements**

~~Stage 1~~In initial Distribution System Plans~~ are~~, a utility is required to identify the existing grid equipment inventory, management and monitoring practices, financial data~~ with locational granularity~~, and ~~include related~~ DER data~~ (e.g., number of connected systems and generation capacity).~~. This requirement consolidates reporting requirements currently effective under the Smart Grid Reports, Transportation Electrification Plans, ~~Annual Net Metering Reports, Annual Small Generator Reports, and others. (See section 4, Planning Interactions and Streamlining, for further detail).~~and others. This data may come from the utility or from other sources, and should be the most recent data available. The utility should provide, at minimum:

a) A description of any currently used~~, relevant,~~ internal baseline and system assessment practices (such as system reliability baseline, system asset health baseline, ~~system DER penetration baseline,~~ etc.) that includes:
   i) Method and tools used to develop the baseline and assessment
   ii) Forecasting time horizon(s)
   iii) Key performance metrics

b) A summary of the utility's distribution system assets including:
   i) Asset classes
   ii) Number of assets in each class
   iii) Average age of assets in each class
   iv) Age range of assets in each class
   v) Industry life expectancy of assets in each class

c) A discussion of distribution system monitoring and control capabilities including:
   ~~b)~~i) Number of feeders
   ~~c)~~ii) Number of substations
   ~~d)~~iii) ~~Percentage of~~ Monitoring and control technologies (such as SCADA, AMI, etc.) currently installed, and the percentage of substations, feeders, and other applicable equipment with ~~monitoring and control capabilities~~each technology

~~e) Number of AMI meters by customer class, and a count of customers without AMI meters~~

~~f)~~iv) A ~~summary~~description of the ~~measurement of the performance of the distribution system (feeder-level and time interval), resulting from equipment with~~ monitoring and control capabilities~~, and AMI meters, including information on~~ (for example, percentage of system with each ~~level of visibility (ex. max/min, daytime/nighttime, monthly/daily reads, automated/manual)~~ technology, resulting capacity, such as remote fault detection or power quality monitoring, and what time interval measurements are available)

~~g) Advanced~~A discussion of any advanced control and communication systems~~,~~ (for example: distribution management systems, distributed energy resources management systems, demand response management systems, outage management systems, field area networks, etc~~.~~

~~h)~~d) ~~A summary~~.). Include a description of system visibility~~,~~ and capabilities~~ of these advanced control and communication systems, including information on~~, the percentage of system reached with each capability, the percentage of customers reached with each capability, ~~the~~and any utility programs utilizing each capability~~, etc~~.

~~i) A summary of the utility's distribution system assets including the following:~~

~~i) Asset classes~~

~~ii) Average age of assets in each class~~

~~iii) Age range of assets in each class~~

~~iv) Industry life expectancy of assets in each class~~

~~j)~~e) Historical distribution system spending for the past five years, in each category:

i) Age-related replacements and asset renewal

ii) System expansion or upgrades for capacity

iii) System expansion or upgrades for reliability and power quality

iv) New customer projects

v) Grid modernization projects

vi) Metering

vii) Preventative maintenance

~~viii) Vegetation management~~

~~ix) Other~~

f) ~~Existing distributed generation resources and distributed energy storage systems~~Net Metering and Small Generator information:[3]

~~k)~~i) Total existing net metering facilities and small generator facilities interconnected to the distribution grid (or to the transmission system, as appropriate for small generator facilities) at time of filing, by ~~substation~~feeder.

~~i)~~(1) The total number of net metering facilities by resource type

~~ii)~~(2) The total estimated rated generating capacity of net metering facilities by resource type

~~iii)~~(3) The total number of small generator facilities by resource type

~~iv)~~(4) The total nameplate capacity of small generator facilities by resource type

[3] A utility that is exempt from the Annual Net Metering Report requirement pursuant to OAR 860-039-0070 is not required to report net metering data required in section f).

- ~~v) The total number, and nameplate capacity, of other distributed generation resources and distributed energy storage systems not included as net metering or small generators, by resource type~~

~~l) Distributed generation resources and distributed energy storage systems interconnected to the distribution system (or to the transmission system, as appropriate for small generator facilities) for each of the five prior years, by substation~~

- ~~i) The total number of net metering facilities by resource type~~
- ~~ii) The total estimated rated generating capacity of net metering facilities by resource type~~
- ~~iii) The total number of net metering facilities that had interconnection denied, by resource type~~
- ~~iv) The total number of complete small generator interconnection applications received~~
- ~~v) The total number of small generator facility interconnections completed~~
- ~~vi) The types of small generator facilities applying for interconnection and the nameplate capacity of the facilities~~
- ~~vii) For each Tier 3 and Tier 4 small generator interconnection approval, the basic telemetry configuration, if applicable~~
- ~~viii) For each Tier 4 small generator interconnection approval:~~
  - ~~(1) The interconnection facilities required to accommodate the interconnection of a small generator facility and the estimated costs of those facilities~~
  - ~~(2) The system upgrades required to accommodate the interconnection of a small generator facility and the estimated costs of those upgrades~~
- ~~ix) The number, and nameplate capacity, of other distributed generation resources and distributed energy storage systems not included as net metering or small generators, by resource type~~
- ~~x) The total number, and estimated rated generating capacity, of net metering facilities, small generator facilities, and other distributed generation resources and distributed energy storage systems not included as net metering or small generators, by resource type by substation~~
- ~~m)~~ii) The total number and nameplate capacity of queued net metering~~, small generator, or other distributed generation resources and distributed energy storage systems not included as net metering or small generators,~~ facilities and small generator facilities at time of filing, by feeder, broken down by resource type
- ~~n)~~iii) A map, in electronic format, identifying locations of net metering~~, small generator, and any other distributed generation resources and distributed energy storage systems~~ facilities and small generator facilities interconnected to the distribution grid (or to the transmission system, as appropriate for small generator facilities) at time of filing.

~~o)~~g) Total number of electric vehicles (EVs) of various sizes served by the utility's system at time of filing

~~p)~~h) Number of EVs added to the utility's system in each of the ~~prior year~~last five years

~~q)~~i) Total number of charging stations on the utility's system, broken down by type, ownership, and ~~substation location~~feeder

~~r)~~j) Total number of charging stations added to the utility's system in each of the ~~prior year~~last five years, broken down by type

i) Data on the availability and usage patterns of charging stations

~~s)~~k) Summary data of other transportation electrification infrastructure, if applicable

~~t)~~l) A high-level summary of demand response (DR) pilot and/or program performance metrics for the past five years including:[4]

i) Number of customers participating by residential and business customer class, and combined total

ii) By winter and summer demand response season:

(1) Maximum available capacity of DR by residential and business customer class, and combined total

(2) Season system peak

(3) Available capacity of DR, expressed as a percentage of the season system peak

m) ~~Distribution System~~ Plans should include the utility's most recently filed Annual Net Metering Report and the most recently filed Annual Small Generator Report, each as an appendix to the Plan.

n) Plans should include the utility's most recently filed Annual Reliability Report as an appendix to the Plan ~~filings~~. Any descriptions of reliability challenges and opportunities in the Distribution System Plan should cross-reference underlying data and information contained in the Annual Reliability Report.

**Expected Evolution**

This investigation identified numerous opportunities for gaining greater insight into the utility distribution systems and the DERs contributing to and relying on those systems. Staff's 2019 Whitepaper on Distribution System Planning laid out the vision for a transition to a modern grid, including a desire for automated system operations and real-time system visibility.[5] Additionally, at the February 26, 2020 workshop, utilities provided an overview of their existing DSP processes, including monitoring and automation practices.[6,7,8] Presentations highlighted that each utility has different capabilities and system needs, which guide their planning and related outcomes.

Based on the~~se~~ insights gained through the investigation, for stages 2 and 3 of utility Plans, ~~the utilities~~a utility should meet the benchmarks identified in Figure 1.

## ~~3.2. Load, Distributed Energy Resource, and EV Forecasting~~

~~Accurate load forecasting enables the distribution system to reliably meet energy, demand and ancillary grid service needs. As DER and EV adoption grows, load forecasting must better account for its impact on load, as well as the ability of these resources to productively modify~~

[4] For example see Table 26 on page 101 of Appendix 1 of 2019 PGE Smart Grid Report, https://edocs.puc.state.or.us/efdocs/HAQ/um1657haq15635.pdf.

[5] Staff Whitepaper: A Proposal for Electric Distribution System Planning, March 2019, https://edocs.puc.state.or.us/efdocs/HAU/um2005hau15477.pdf.

[6] *Distribution System Highlights*, Portland General Electric, February 26, 2020, https://edocs.puc.state.or.us/efdocs/HAH/um2005hah16124.pdf.

[7] *Idaho Power: Current Distribution System and Small Scale Generation*, Idaho Power, February 26, 2020, https://edocs.puc.state.or.us/efdocs/HAH/um2005hah14343.pdf.

[8] *Current Distribution System: Questionnaire Section C*, Pacific Power, February 26, 2020, https://edocs.puc.state.or.us/efdocs/HAH/um2005hah9537.pdf.

~~load. Figure 2 introduces the initial requirements and expected evolution for load, DER and EV forecasting.~~

**~~Figure 2~~**

| **~~Load, DER, and EV Forecasting~~** | | | |
|---|---|---|---|
| ~~Stage 3~~ | | | ~~Refine hybrid to allow more granular locational and temporal forecasts, aiming for consistent outputs across utilities.~~ |
| ~~Stage 2~~ | | ~~Identify potential locational system benefit from strategic placement of DERs on the distribution grid.~~ | |
| | | ~~Examine data to better understand opportunities for customer participation by energy-burdened households.~~ | |
| | | ~~Leverage both top-down forecasts and bottom-up customer models to build forecasts (approaches may be specified).~~ | |
| ~~Stage 1~~ | ~~Allocate system-wide DER forecasts from utility IRP filings to greater locational granularity.~~ | | |
| | ~~Document forecasting process and indicate existing and anticipated constraints on the distribution system.~~ | | |
| | ~~2021~~ | ~~2023-2027~~ | ~~2029 and beyond~~ |

**~~Initial Requirements~~**

~~These Guidelines require that initial Distribution System Plans document existing utility load forecasting processes for distribution service. Plans should build on that foundation with forecasts of DER and EV adoption as follows:~~

- ~~a) Discussion of current distribution system load forecasting process including:~~
  - ~~i) Forecasting method and tools used to develop the forecast~~
  - ~~ii) Forecasting time horizon(s)~~
  - ~~iii) Data sources used to inform the forecast~~
  - ~~iv) Locational granularity of the load forecast~~
- ~~b) Forecast of DER adoption and EV adoption with a locational aspect.~~
  - ~~i) The forecast should include high/medium/low scenarios for both DER adoption and EV adoption.~~
  - ~~ii) A utility should fully describe its methodologies for developing the DER forecast, high/medium/low scenarios, and geographical allocation in its plan (e.g., methods and tools, time horizons, data sources).~~
  - ~~iii) For the initial Plan, the methodology to apply a locational aspect, and the granularity of the locational aspect for DER and EV forecasts, are at the utility's discretion. The Commission may provide direction for subsequent Plans.~~
  - ~~iv) Utilities may consider leveraging information such as: historical utility program trends, historical customer adoption trends, data from Energy Trust of Oregon, data from Transportation Electrification Plans and pilots, or studies on DER technical and economic potential used in other dockets.~~
- ~~c) Reported results of load, DER, and EV forecasting.~~
  - ~~i) Document existing and anticipated constraints on the distribution system.~~

~~**Expected Evolution**~~

~~This investigation identified numerous opportunities for improved creation and use of more granular load, DER and EV adoption forecasts. The presentation *Forecasting load on distribution systems with distributed energy resources* from the National Renewable Energy Laboratory (NREL) identified several approaches and tools for top-down and bottom-up DER forecasts, including the use of historical trends, program-based approaches, and customer adoption models.[9] In comments filed in response to Staff's questions for the August 25, 2020 Special Public Meeting, numerous parties suggested that the OPUC apply multiple approaches to calibrate and refine forecasts over time.~~

~~Based on these insights gained through the investigation, for stages 2 and 3 of Plans, utilities should meet the benchmarks identified in Figure 2.~~

### ~~3.3.~~4.2. Hosting Capacity Analysis

Hosting Capacity Analysis (HCA) provides information about the ability of a distribution system to support new DER integration without system faults. To date, analyses of a system's hosting capacity has become an important piece of DSP in Minnesota, New York, Hawaii, Nevada and California.[10] ~~Figure 3~~The following requirements are intended to initiate hosting capacity analysis in Oregon with the ultimate aim of informing grid investment decisions made by the utilities, while also informing siting decisions made by DER developers. Figure 2 introduces the initial requirements and expected evolution for hosting capacity analysis.

[9] ~~See https://www.oregon.gov/puc/utilities/Documents/DSP-Sigrin-Presentation.pdf for more detail.~~

[10] *Distribution Planning Regulatory Practices in Other States*, Lisa Schwartz, Berkeley Lab, May 21, 2020, https://www.oregon.gov/puc/utilities/Documents/DSP-Schwartz-Presentation.pdf.

**Figure ~~3~~2**

| Hosting Capacity Analysis | |
|---|---|
| Stage 3 | Comprehensive hosting capacity considering both distribution and transmission. |
| | Increased level of detail regarding distribution constraints, asset performance, and DER performance metrics. Address emerging technology development. |
| | Maps indicate node/section-level hosting capacity. |
| | Update and publish hosting capacity maps and datasets sufficiently accurate and frequent to streamline interconnection. |
| | Conduct system-wide hosting capacity evaluations ~~as a planning use case to guide DSP investments~~to inform Grid Needs Identification. |
| Stage 2 | If determined through Docket UM 2111, conduct hosting capacity analysis ~~as an~~inform stakeholders of potential interconnection ~~use case~~challenges, or replace portions of interconnection studies; publish hosting capacity maps with greater detail over time. Update areas with greater/faster DER adoption more frequently. |
| | Include distribution-level impacts to the substation and transmission system. |
| | Conduct hosting capacity evaluations to inform ~~distribution system investment plans, and to enhance distribution system visibility when determining locations for future DER~~Grid Needs Identification. |
| Stage 1 | Conduct a system evaluation to identify areas of limited DER growth. |
| | Provide a plan to conduct hosting capacity evaluations in the near-term ~~considering both the planning use case for DSP investments, and~~which may inform Grid Needs Identification, inform stakeholders of potential interconnection ~~use case.~~challenges, or replace portions of interconnection studies. Plan may address ~~alternate tool~~ options that may provide more approachable and instructive data for communities. |
| 2021-2022 | 202~~9~~3 and beyond |

**Initial Requirements**

Under these Guidelines, for initial Distribution System Plans, ~~utilities~~each utility should conduct system evaluations to identify ~~areas of limited DER growth, and refers to the methodology underlying PGE's Net Metering Map.[11]~~generation constrained areas where it is difficult to interconnect DERs without system upgrades. Each utility should present the results through an unredacted map that the utility should make available on its website on a continuing basis. In addition, ~~Plans should provide a plan, or roadmap, to conduct hosting capacity analysis~~ a utility should include an Options Analysis for investing in more sophisticated HCA capabilities in the

~~[11] https://www.portlandgeneral.com/business/power-choices-pricing/renewable-power/install-solar-wind-more/net-metering/net-metering-map~~

near-term ~~considering both planning, and interconnection use-cases. (Staff notes aspects of the analytical exercise may be shared between the two use-cases and suggests Plans note this when applicable.)~~. Specific requirements include:

a) ~~Utilities~~Upon Commission adoption of these Guidelines each utility should ~~conduct~~begin conducting a system evaluation to identify areas ~~of limited DER growth.~~where it is difficult to interconnect DERs without system upgrades. Each utility should present the results through an unredacted map that is continuously available on the utility's website.[12]
   i) ~~Utilities~~A utility should adopt the methodology underlying PGE's Net Metering Map, as presented in UM 2099, for calculating and identifying areas ~~of limited DER growth.~~[13]where it is difficult to interconnect DERs without system upgrades.[14]
      (1) If this methodology is ~~unworkable, utilities~~not feasible, a utility should present an alternative methodology with documentation of why it is necessary, and an explanation of any ways in which it may ~~prove deficient to~~be different from the ~~proposed~~ methodology~~.~~ utilized by PGE.
   ii) The ~~result~~resulting system-evaluation map should~~, at~~:
      ~~ii)~~(1) At minimum, meet the level of functionality of PGE's Net Metering Map.[15]
      (2) ~~Stochastic~~Label feeders serving Public Safety Power Shutoff areas.

~~b) Utilities should prepare a roadmap to implement HCAs for a planning use-case, as part of the utility's future distribution system planning process (e.g., HCA is conducted, load growth and DER are forecasted, system needs are identified). The utility may prepare an additional roadmap for an alternative analytical approach for comparison to HCA, if the utility believes the alternative approach may provide greater benefits than HCA, or the same benefits as HCA at lower costs. The roadmap(s) should include:~~
   ~~i) Analysis of integrating hosting capacity as an input into the utility's distribution system planning practices, as well as project plans with: a summary of scope, a timeline with milestones, consideration of validation requirements, identification of any existing barriers to implementing hosting capacity analyses, forecast of the time and resources needed to overcome these barriers, estimated costs, as well as any additional relevant information to help inform the project.~~
   ~~ii) Identified plans, costs, and barriers should be identified for the types of analyses and parameters listed below in section d).~~

~~c) Utilities should prepare a roadmap to implement HCAs for an interconnection use-case, in order to provide customers information about the conditions of the distribution system to assist DER site selection and project design. The utility may prepare an additional roadmap for an alternative analytical approach for comparison to HCA, if the utility believes the alternative approach may provide greater benefits than HCA, or the same benefits as HCA at lower costs. The roadmap should include:~~

[12] This requirement is not grounded in the Commission's net-metering administrative rules. Any utility exemptions from net-metering administrative rules do not correspond to an exemption from to this requirement.
~~[13] See *PGE Reply Comments*, Docket UM 2099, (September 22, 2020) pages 6 and page 8: https://edocs.puc.state.or.us/efdocs/HAC/um2099hac154013.pdf.~~
[14] See *PGE Reply Comments*, Docket UM 2099, (September 22, 2020) pages 6 and page 8: https://edocs.puc.state.or.us/efdocs/HAC/um2099hac154013.pdf.
[15] https://www.portlandgeneral.com/business/power-choices-pricing/renewable-power/install-solar-wind-more/net-metering/net-metering-map

- ~~i) Analysis of utilizing hosting capacity as a tool to inform customers of distribution system conditions, as well as project plans with: a summary of scope, a timeline with milestones, consideration of validation requirements, identification of any existing barriers to implementing hosting capacity analyses, forecast of the time and resources needed to overcome these barriers, estimated costs, and additional relevant information to help inform the project.~~
- ~~ii) Identified plans, costs and barriers should be identified for the types of analyses and parameters listed below in section d).~~

~~d) Types of analyses and parameters HCA roadmaps should consider:~~

~~i) Modeling methodology~~

b) Each utility should analyze three options to meet future HCA needs consistent with Figure 2. This analysis should be included in Part 1 of the Plan. At minimum, a utility shall develop cost and timeline estimates for each of the following three options. A utility should identify any data security, cost, result validation, or implementation concerns and/or barriers for each of the three options. Each utility should recommend a preferred timeline and development path for achieving the vision set forth in Figure 2, accounting for the relative strengths of Options 1, 2 and 3 below. The Commission will consider these cost and timeline estimates, concerns, and recommendations in adopting a path forward for HCA in Oregon.

- i) Option 1: The primary use of HCA is to inform Grid Needs Identification (see Section 5.2) and includes the following parameters:
  - ~~(1)~~ Methodology: stochastic modeling
  - ~~(2)~~● ~~Iterative~~ / EPRI DRIVE modeling
  - ~~(3) EPRI Distribution Resource Integration and Value Estimation (DRIVE) modeling~~
  - ~~(4) Alternative methodologies considered that are not listed above~~
  - ~~ii)~~● Geographic granularity: circuit
  - ~~(1) Circuit level~~
  - ~~(2) Main trunk~~
  - ~~(3) Line segment~~
- ~~iii)~~ Temporal granularity
  - ~~(1) Peak assessment~~
  - ~~(2)~~● ~~Hourly~~: annual ~~assessment~~minimum daily load
- ~~iv)~~ Data presentation
  - ~~(1) Tabular/spreadsheet presentation only~~
  - ~~(2)~~● ~~Tabular/spreadsheet presentation with output~~ : web-based ~~on customer application (for example ComEd's Small Generator Pre-Application Form and Report)~~map for the public and available tabular data
  - ~~(3) Map-based visual presentation~~
  - ~~(4) Raw data via Open API~~
- ~~v) Refresh timing~~
  - ~~(1) Refresh biennially~~
  - ~~(2) Refresh annually~~
  - ~~(3) Refresh every six months~~
  - ~~(4) Refresh weekly~~
  - ● Annual refresh
- ~~vi)~~ Planned/queued generation
  - ~~(1) Number~~ details such as number and size of projects
  - ~~(2) Proposed frequency of refreshing planned generation information~~

- ~~(3)~~● ~~Description,~~, description and costs~~,~~ of upgrades assigned to planned generation

ii) Option 2: The two main uses are to inform Grid Needs Identification and to share regularly updated results publicly to inform stakeholders of potential interconnection challenges.[16] Option 2 includes the following parameters:
- Methodology: same as Option 1
- Geographic granularity: feeder
- Temporal granularity: monthly minimum daily load
- Data presentation: same as Option 1
- Monthly refresh
- Planned/queued generation details: same as Option 1

iii) Option 3: The two main uses are to inform Grid Needs Identification and to replace portions of the interconnection studies.[17] Option 3 includes the following parameters:
- Methodology: iterative modeling
- Geographic granularity: line segment
- Temporal granularity: hourly assessment
- Data presentation: same as Option 1
- Monthly refresh
- Planned/queued generation details: same as Option 1

Beyond these requirements~~ of all Distribution System Plans~~, any utility may seek to accelerate its testing and deployment of new hosting capacity analysis through a pilot or demonstration. A utility ~~wishing~~that proposes to ~~take advantage of this opportunity~~do so should detail the pilot objectives, plan, budget, and evaluation method in the~~ Distribution System~~ Plan.

**Expected Evolution**

This investigation identified numerous opportunities for hosting capacity analysis in Oregon. Given that hosting capacity and the related analysis have multiple definitions and best practices are continuously evolving, it is important for stakeholders to identify and prioritize use cases for the analysis. Multiple jurisdictions incorporate hosting capacity analysis into distribution system planning because the analysis and outputs can support DER adoption and flag potential interconnection issues.[18] Over time, hosting capacity analysis may reduce the need for interconnection studies.[19, 20]

Based on these insights gained through the investigation, for stages 2 and 3 of utility Plans, a utility should meet the benchmarks identified in Figure ~~3~~2.

### ~~3.4.~~4.3. Community Engagement Plan

A utility should involve the public in the preparation and implementation of each utility Distribution System Plan. Involvement includes opportunities to contribute information and

[16] Xcel Minnesota performs HCA implementation that illustrates some of these parameters.
[17] California utilities perform HCA implementation that illustrate some of these parameters.
[18] *Hosting Capacity - Lessons Learned*, Steve Steffel, Pepco Holdings, May 6, 2020, https://www.oregon.gov/puc/utilities/Documents/DSP-Hosting-Capacity-SSteffel.pdf.
[19] *OPUC Hosting Capacity Overview*, Aram Shumavon, Kevala Analytics, May 6, 2020, https://www.oregon.gov/puc/utilities/Documents/DSP-Shumavon-Presentation.pdf.
[20] UM2005 Distribution System Planning, Webinar #9, OPUC Policies and Practices, June 10, 2020, https://www.oregon.gov/puc/utilities/Documents/DSP-Webinar9-PUC-Presentation.pdf.

ideas, as well as to receive information, similar to the public input process in an IRP. Interested parties must have an opportunity to make relevant inquiries of the utility formulating the Plan. These guidelines for community engagement are intended to foster a developing process that supports a human-centered approach to DSP.

Community-based organizations (CBOs) may play an integral role in DSP-related community engagement. CBOs can offer insight ~~that can~~to inform the utility's bottom-up forecasting of technology deployment, especially in vulnerable communities~~;~~. CBOs can provide input to the utility on the methodology ~~used in the DSP process~~ to identify and prioritize distribution system investments and project development~~; and~~. CBOs can also identify or support implementation of customer-sited non-wires solutions.

In the *Connectivity Means Community* presentation, presenters noted five approaches to engagement: inform, consult, involve, collaborate, and defer to.[21, 22] Each of these approaches should be incorporated into a robust community engagement plan and ongoing process. Further, best practices for community engagement highlighted during the May 20, 2020 workshop include:

- Be easy;
- Be trusted;
- Be adaptable;
- Be flexible;
- Be positive;
- Be equitable; and
- Be a great ally.[23]

Grounded in these insights and conclusions, Figure ~~4~~3 introduces the initial requirements and expected evolution for community engagement.

[21] *Connectivity Means Community - Distributed System Planning for Humans*, Oriana Magnera and Charity Fain, Verde and Community Energy Project, May, 20, 2020, https://www.oregon.gov/puc/utilities/Documents/DSP-Magnera-Fain-Presentation.pdf.
[22] *The Spectrum of Community Engagement to Ownership*, Rosa Gonzalez, Facilitating Power, https://movementstrategy.org/b/wp-content/uploads/2019/09/Spectrum-2-1-1.pdf.
[23] *Connectivity Means Community - Distributed System Planning for Humans*, Oriana Magnera and Charity Fain, Verde and Community Energy Project, May, 20, 2020, https://www.oregon.gov/puc/utilities/Documents/DSP-Magnera-Fain-Presentation.pdf.

**Figure 43**

| Community Engagement | |
|---|---|
| Stage 3 | Utilities collaborate with ~~community-based organizations~~CBOs and environmental justice communities so that community needs inform DSP project identification and implementation. "Community needs" could address energy burden, customer choice and resiliency. |
| Stage 2 | Reflecting UM 2005 outreach requirements, utility holds ongoing community stakeholder meetings during grid needs assessment, solution identification, and action planning. |
| | Utilities and OPUC agree on community goals, project tracking and coordination activities. |
| | Conduct baseline study to increase detailed knowledge of service territory communities. ~~Utilize paid~~Engage CBO experts to inform co-created community pilot(s). |
| | Consult with communities to understand identified needs and opportunities, then seek to co-develop solution options, documenting longer-term needs. |
| Stage 1 | Hold ~~two~~four public pre-filing workshops with stakeholders on Plan development. |
| | Utilities create a collaborative environment among all interested partners and stakeholders. Utilities document community feedback and utility's responses. |
| | OPUC prepares accessible educational materials on DSP with consultation from CBOs and utilities. |
| | Prepare a draft community engagement plan as part of Plan. |
| | Utilities conduct focused community engagement for planned distribution projects. |
| | OPUC to host quarterly public workshop and technical forums after Plan filings. |
| 2021-2022 | 202~~9~~3 and beyond |

### Initial Requirements

Community engagement should occur during the Distribution System Plan development and throughout Plan implementation~~.~~ with detailed documentation included in the Plan. Specific requirements for utilities ~~include the following~~, unless noted as OPUC activities, are:

a) During Plan Development
   i) ~~Hold~~A utility should host at least two stakeholder workshops prior to filing each Part of the utility's Plan~~.~~, for a minimum total of four workshops. These workshops should be held at a stage in which stakeholder engagement can influence the fi~~na~~led Plan. The workshops may include presentation of the Plan outline, data and assumptions under consideration or challenges encountered, and the utility's approach to the

Community Engagement Plan, described in (~~iii). Stakeholder~~b). During stakeholder workshops, a utility must invite community members to share their relevant needs, challenges and opportunities.

~~ii)~~ A utility should ~~Create a collaborative environment among all interested CBO partners~~develop ~~and stakeholders. To support collaboration between all interested parties, Staff plans to host quarterly public workshops and technical working forums.~~

~~iii) With consultation from utilities and stakeholders, OPUC will prepare accessible, non-technical educational materials on DSP to support public engagement.~~

~~iv)~~ii) ~~Provide~~ a ~~draft~~ Community Engagement Plan ~~as part of the Distribution System Plan filed with the Commission. The Community Engagement Plan~~. A utility should ~~detail plans~~plan to engage community members and CBOs during ~~project~~ development of ~~pilots~~ pilot concept proposals required in ~~Grid Needs Assessment and~~ Solutions Identification ~~requirements.~~requirement (Part 2, Section 5.3. (d)). The planned process should include the following activities. A utility should implement these activities as part of the development of pilot proposals prior to filing Part 2 of the Plan:

~~b) During Project Development~~

~~i)~~(1) Proactively engage stakeholders regarding proposed p~~r~~ilo~~jec~~ts in impacted communities. Engagement of the local community may include in-person meetings located in the community; presentation of the project scope, timeline, rationale; and solicitation of public comment, particularly to understand community needs and opportunities.

~~ii)~~(2) Document stakeholder comments and utility response, including comments that were heard but not implemented.

~~iii)~~(3) Collaboratively develop and share datasets and metrics to guide community-centered planning.

(4) Refer to Section 5.3. (d, i-vi) for the community-centered questions that should be addressed through the process above, and during development of pilot proposals described in Part 2, Solutions Identification.

iii) Utilities should aim to create a collaborative environment among all interested CBO partners and stakeholders. To support collaboration between all interested parties, Staff plans to host public workshops and a technical working forum. These are in addition to the utility workshops required during Plan and pilot development.

iv) With consultation from utilities and stakeholders, OPUC will prepare accessible, non-technical educational materials on DSP to support public engagement.

**Expected Evolution**

The investigation identified numerous opportunities for community engagement in Oregon. In addition to the content presented in the workshop series, stakeholder comments in the investigation frequently spoke to community engagement needs. In comments filed in preparation for the August 25, 2020 Special Public meeting, the Oregon Citizens' Utility Board (CUB), Energy Trust of Oregon, Northwest Energy Coalition (NWEC), and Oregon Solar Energy Industries Association (OSEIA) each commented on the need for solutions to be co-developed with CBOs and stakeholders. Some spoke of the need to acknowledge, value, and compensate CBOs as technical experts in the planning process.[24, 25, 26, 27]

Based on these insights gained through the investigation, for stages 2 and 3 of Plans, a utility should meet the benchmarks identified in Figure ~~4~~3.

## ~~3.5. Grid Needs Identification~~

~~Grid needs identification compares the baseline capabilities of a distribution system and the demands on that system to infer its future needs.~~

~~At its core, a grid needs identification answers the question of what technical requirements must be addressed to ensure a safe, reliable and resilient system that provides adequate power quality to the customers it serves. Adding to this core, a holistic approach to grid needs identification anticipates the social and economic needs of the communities that depend on distribution systems, as well as the contributions they can make to strengthen it.~~

~~Figure 5 introduces the initial requirements and expected evolution for grid needs identification.~~

**~~Figure 5~~**

| **~~Grid Needs Identification~~** | |
|---|---|
| ~~Stage 3~~ | ~~Identify grid needs and present a summary of prioritized grid constraints, utilizing prioritization criteria such as community priorities, equity analysis, constraints on DER adoption, and evolving public policy goals.~~ |
| | ~~Provide new datasets and analysis responsive to OPUC, community inputs and policy evolution.~~ |
| ~~Stage 2~~ | ~~Develop robust "future state" data needs, including inputs in the following categories:~~ |
| | ~~Perform equity analysis overlaying customer geographic and socio-economic data relative to system reliability and customer options. Make findings publicly available.~~ |
| | ~~Needs identification includes results of community needs assessments, DER forecasting, and equity analysis.~~ |
| | ~~Identify grid modernization needs and present a summary of prioritized grid constraints and opportunities publicly.~~ |

[24] Energy Trust of Oregon UM 2005 Responses to Stakeholder Questions for August 25 Special Public Meeting, August 21, 2020, https://edocs.puc.state.or.us/efdocs/HAC/um2005hac75744.pdf.
[25] Responses of the Oregon Citizens' Utility Board for Aug. 25, 2020 Special Public Meeting, August 20, 2020, https://edocs.puc.state.or.us/efdocs/HAC/um2005hac17184.pdf.
[26] Oregon Solar Energy Industries Association Response to Stakeholder Questions for August 25, 2020 Special Public Meeting discussion, August 21, 2020, https://edocs.puc.state.or.us/efdocs/HAC/um2005hac17748.pdf
[27] Northwest Energy Coalition Stakeholder Questions for August 25, 2020 Special Public Meeting discussion, August 21, 2020, https://edocs.puc.state.or.us/efdocs/HAC/um2005hac163634.pdf.

| ~~Grid Needs Identification~~ | | | |
|---|---|---|---|
| ~~Stage 1~~ | ~~Pilot grid needs assessment with CBO expertise to increase learnings about community needs within service territory.~~ | | |
| | ~~Present summary of prioritized grid constraints publicly, including criteria used for prioritization.~~ | | |
| | ~~Document process and criteria used to identify grid adequacy and needs. Discuss criteria used to assess reliability and risk, and methods and modeling tools used to identify needs.~~ | | |
| | ~~2021~~ | ~~2023-2027~~ | ~~2029 and beyond~~ |

**~~Initial Requirements~~**

~~Utility Distribution System Plans should:~~

- ~~a) Document the process used to assess grid adequacy and identify needs.~~
- ~~b) Discuss criteria used to assess reliability and risk, and methods and modeling tools used to identify needs.~~
- ~~c) Present a summary of prioritized grid constraints publicly, including criteria used for prioritization.~~
- ~~d) Provide a timeline by which the grid need(s) must be resolved to avoid potential adverse impacts.~~
- ~~e) Pilot a grid needs assessment process with CBO input and expertise to increase learnings about community needs within the service territory. Pilots should address:~~
  - ~~i) Status of community planning~~
  - ~~ii) Challenges facing the community~~
  - ~~iii) Energy burden within the community~~
  - ~~iv) Community energy needs and desires~~
  - ~~v) Community interest in clean energy planning and projects~~
  - ~~vi) Ongoing engagement with community members on a schedule determined by the community~~
  - ~~vii) Community demographics~~

~~In fulfilling these requirements, each Plan should cross-reference Plan sections of Baseline Data and System Assessments; and Load, DER and EV Adoption Forecasts.~~

**~~Expected Evolution~~**

~~This investigation identified numerous opportunities for grid needs identification in Oregon. In the *Connectivity Means Community* presentation, presenters highlighted the need for community engagement and responsiveness to community needs in relation to grid needs identification.[28] A human-focused approach to identifying grid needs, implemented in partnership with communities and CBOs, can create value-adding investments for communities, and align the energy system with community priorities.~~

~~Based on these insights gained through the investigation, for stages 2 and 3 of utility Plans, a utility should meet the benchmarks identified in Figure 5.~~

~~[28] *Connectivity Means Community - Distributed System Planning for Humans*, Oriana Magnera and Charity Fain, Verde and Community Energy Project, May, 20, 2020, https://www.oregon.gov/puc/utilities/Documents/DSP-Magnera-Fain-Presentation.pdf.~~

## ~~3.6. Solution Identification~~

~~Solution identification complements a Distribution System Plan grid needs identification by proposing the equipment, technology or program(s) the utility will advance to meet identified grid needs. Traditionally, a Distribution System Plan would rely on traditional hardware solutions (e.g., substation upgrades, reconductoring, additional transformer deployment). These Guidelines advance more holistic distribution system planning, calling for consideration of a wider range of potential solutions (e.g., increased system monitoring automation, expanded switching capability, distributed energy resources).~~

~~Experts contributing to the OPUC's workshops on Non-Wire Alternatives and Distributed Energy Resource Valuation suggest Solution Identification include a comprehensive exposition of the options available to serve grid needs, weighing of the pros and cons of each option across standardized criteria, and inclusive approaches to weighing the cost and benefits of each path forward.~~

~~Figure 6 introduces the initial requirements and expected evolution for solution identification.~~

**~~Figure 6~~**

| **~~Solution Identification~~** | |
|---|---|
| ~~Stage 3~~ | ~~Co-develop solutions with communities and community-based organizations.~~ |
| | ~~Streamline and refine non-wires solutions and aggregations of non-wires solutions to defer distribution system upgrades.~~ |
| ~~Stage 2~~ | ~~In assessing options for distribution system pilots, projects, engage community organizing experts to gain input from potentially impacted communities.~~ |
| | ~~Prior to filing, publicly present data used to identify distribution system investments, and understand data most useful to stakeholders.~~ |
| | ~~Co-develop solutions with communities and community-based organizations.~~ |
| | ~~Utilize non-wires solutions to defer distribution system upgrades. Includes harnessing DERs for voltage support and frequency event support.~~ |
| ~~Stage 1~~ | ~~Make detailed datasets publicly available and host a listening session/workshop describing data used in investment decisions. Stakeholders provide feedback on what data would be useful to them. OPUC determines if additional datasets are necessary and may direct utilities to submit them in the next Distribution System Plan filing.~~ |
| | ~~Provide summary and description of data used in distribution system investment decisions such as: feeder level details (e.g., customer types on feeder, loading information), DER forecasts and adoption.~~ |

| ~~Solution Identification~~ | | | |
|---|---|---|---|
| | ~~Document the process to the range of possible solutions to address grid needs. For larger projects, engage with communities early in solution identification. Facilitate discussion of proposed investments that allow for mutual understanding of the value and risks associated with resource investment options.~~ | | |
| | ~~2021~~ | ~~2023-2027~~ | ~~2029 and beyond~~ |

**~~Initial Requirements~~**

~~This section should identify the utility's proposed solutions to address grid needs. Specific requirements include:~~

- ~~a) Document the process to identify the range of possible solutions to address priority grid needs.~~
- ~~b) For larger projects, engage with impacted communities early in solution identification. Facilitate discussion of proposed investments that allow for mutual understanding of the value and risks associated with resource investment options.~~
- ~~c) Provide a summary and description of data used for distribution system investment decisions such as: a detailed accounting of the relative costs and benefits of the chosen and alternative solutions, feeder level details (e.g., customer types on the feeder; loading information), DER forecasts and adoption rates.~~
- ~~d) Make detailed datasets publicly available and host listening sessions and/or workshops to describe data used in investment decisions. Stakeholders will provide feedback on data that would be useful to them. OPUC will determine if publication of additional datasets is necessary and may direct utilities to submit them in the next Plan filing.~~
- ~~e) Submit to the Commission at least two proposals for pilots in which non-wire solutions are used in the place of traditional utility infrastructure investment. Provide detailed accounting of the relative costs and benefits of the chosen and alternative solutions, including estimated greenhouse gas emissions impacts. Pilots should prioritize community engagement to accelerate and expand the benefits of the pilot to communities in need.~~

**~~Expected Evolution~~**

~~This investigation identified numerous opportunities for solutions identification in Oregon. The need to co-develop distribution system solutions with communities and CBOs remains a priority throughout the DSP evolution. Beyond community engagement, the regulatory framework, utility processes and structures, and procurement practices also need to evolve to enable implementation of non-wires solutions.~~[29] ~~As non-wires solutions are constructed and their performance in serving grid needs and deferring grid upgrades is better understood, valuation methods may be needed to compare non-wires solutions to traditional utility hardware (e.g., substation upgrades, additional transformer deployment).~~[30]

~~Based on these insights gained through the investigation, for stages 2 and 3 of utility Plans, a utility should meet the benchmarks identified in Figure 6.~~

[29] ~~*Non-wires Solutions: Context, Rationale, and Opportunity*, Jason Prince, Rocky Mountain Institute, May 13, 2020, https://www.oregon.gov/puc/utilities/Documents/DSP-Prince-Presentation.pdf.~~

[30] ~~Refer to *Valuation of Distributed Energy Resources* presentation from Debra Lew for details on approaches to valuing non-wires solutions and distributed energy resources, https://www.oregon.gov/puc/utilities/Documents/DSP-LewPresentation.pdf.~~

### ~~3.7. Overarching Requirements and Explanation~~

#### ~~3.7.1. Near-Term Action Plan~~

~~This section of the Plan should present the utility's proposed solutions to address grid needs, as well as other investments in the distribution system. Specific requirements include:~~

- ~~a) Action Plan: Provide a 2-4 year plan consisting of the utility's proposed solutions to address grid needs and other investments in the distribution system.~~
- ~~b) Projected spending: Disclose projected system spending to implement the action plan, timeline for improvement, and anticipated cost recovery mechanism.~~
- ~~c) Relation to other investments: As applicable, the Action Plan should identify areas of relation and interaction with other investments such as transmission projects and demand response programs.~~
- ~~d) Document current innovations and pilots being conducted to improve, modernize, and/or enhance the grid beyond its current capabilities.~~

### ~~3.7.2.~~4.4. Overarching Requirement - Long-term Distribution System Plan

This section of the Distribution System Plan will consist of the utility's long-term distribution system investment plan and inform broader goals related to maximizing reliability, customer benefits, and efficient operation of the distribution system. ~~It~~A utility should include:

a) The utility's vision for the distribution system over the next 5-10 years, including any strategies, goals or objectives, and their alignment with State law and OPUC policies. These goals may include increased reliability, effective integration of DERs, broader greenhouse gas emissions reduction, or others.

b) Roadmap of the utility's planned investments, tools and activities to advance the long-term DSP vision, using a 5-10-year planning horizon.
  - i) Assessment of investment options to enhance the grid across the following range of areas, including relative costs and benefits:
    - (1) Substation and distribution network and operations enhancements
      - (a) Plans for conservation voltage reduction
    - (2) Distributed resource and renewable resource enhancements
      - (a) Penetration and activation/utilization of smart inverters
    - (3) Transportation Electrification enhancements
    - (4) Customer information and demand-side management enhancements
      - (a) Plans to continue to expand customer benefits resulting from investments in advanced metering infrastructure
    - (5) General business enhancements
      - (a) Communications and supporting systems
      - (b) Interoperability of systems and equipment
      - (c) Work-management systems
      - ~~(d) Any other business enhancements~~
      - ~~(e)~~(d) Other enhancements
    - (6) As applicable, any transmission network and operations enhancements
  - ii) Explanation of how the investments reduce customer costs, improve customer service, improve reliability, facilitate adoption of demand-side and renewable resources, and convey other system benefits
  - iii) Long-term assumptions, and impacts of Action Plan investments, etc.

iv) Forecasting future technical and market potential of DERs
v) Plans to further build community needs assessment and co-created community solutions into DSP roadmap
vi) Transitional planning and operational activities underway in the organization to build capabilities in DSP-related functions
vii) Key barriers or constraints the utility faces to advancing investment (whether financial, technical, organizational) and mitigation plans

c) Smart Grid investment[31] opportunities
  i) List and describe smart-grid opportunities that the utility is considering for investment over the next 5-10 years and any constraints that affect the utility's investment considerations
  ii) Describe evaluations and assessments of any smart-grid technologies, applications, pilots, or programs that the company is monitoring or plans to undertake

~~c)~~d) Key opportunities and possible benefits for distribution system investment ~~supported by company executives~~

~~d)~~e) Research and development the utility is undertaking or monitoring

~~e)~~f) Future policy and planning intersections:
  i) Discussion of how planned investments fit with the utility's IRP
  ii) Discussion of how planned investments fit with the utility's annual construction budget for major distribution and transmission investments
  iii) Discussion of how distribution system planning may be coordinated in the future with other major policy and planning efforts discussed in ~~Guideline requirements.~~these Guidelines. At a minimum, address the IRP and transmission planning, including: how the Distribution System Plan filing is coordinated with each policy or planning effort, related inputs and outputs such as data sets or prices, and assumptions such as macro-economic policies or growth rates.

~~f)~~g) Plans to monitor and adapt the long-term Distribution System Plan

## 4.5. Plan for Part 2 Development

As Part of its Part 1 filing each utility should prepare for the upcoming transition period and include a high-level summary to discuss:

a) How legacy distribution planning practices will be transitioned to the requirements of Part 2
b) Whether all legacy distribution planning practices will be transitioned in time for filing Part 2, and if not, the expected timeframe for that eventual transition
c) Efforts to synchronize IRP activities with requirements of Part 2

[31] Smart grid investments were defined in Order No. 11-172 and that definition is retained here. Smart grid investments are utility investments in technology with two-way communication capability that will (1) improve the control and operation of the utility's transmission or distribution system, and (2) provide consumers information about their electricity use and its cost and enable them to respond to price signals from the utility either by using programmable appliances or by manually managing their energy use. Smart grid technologies include sensors and remote control switches at the distribution system level, synchrophasors and flexible AC transmission system devices at the transmission level, and information displays and appliance control circuits at the consumer level.

# 5. Part 2

## 5.1. Forecasting of Load Growth, DER Adoption, and EV Adoption

Accurately forecasting load growth, a critically important exercise utilities have done for decades, enables the distribution system to reliably meet future energy, demand and ancillary grid service needs. As DER and EV adoption grows, forecasting must advance to better account for their impact on load, as well as the ability of these resources to productively modify load. The following requirements aim to improve the accuracy and granularity of forecasting by requiring DER and EV growth forecast at the substation level. This in turn should improve the accuracy and granularity of existing and anticipated constraints on the distribution system revealed in Grid Needs Identification. Figure 4 introduces the initial requirements and expected evolution for the forecasting of load growth, DER adoption and EV adoption.

**Figure 4**

| Forecasting of Load Growth, DER Adoption, and EV Adoption | |
|---|---|
| Stage 3 | Refine hybrid forecast approach to allow more granular locational and temporal forecasts, aiming for consistent outputs across utilities. |
| Stage 2 | Identify potential locational system benefit from strategic placement of DERs on the distribution grid. |
| | Examine data to better understand opportunities for customer participation by energy-burdened households. |
| | Leverage both top-down forecasts and bottom-up customer models to build forecasts (approaches may be specified). |
| Stage 1 | Allocate system-wide DER forecasts from utility IRP filings to greater locational granularity. |
| | Document forecasting process and indicate existing and anticipated constraints on the distribution system. |
| | 2021-2022 / 2023 and beyond |

### Initial Requirements

These Guidelines require a utility to document in the Distribution System Plan current utility load forecasting processes for distribution service. Plans should build on that foundation with forecasts of DER adoption and EV adoption as follows:

~~d)~~a) Discussion of current utility processes for distribution system load growth forecasting including:
   i) Forecasting method and tools used to develop the forecast
   ii) Forecasting time horizon(s)
   iii) Data sources used to inform the forecast
   iv) Locational granularity of the load forecast

b) Forecast of DER adoption and EV adoption by substation
   ~~v)~~i) The forecast should include high/medium/low scenarios for both DER adoption and EV adoption

- ~~vi)~~ii) A utility should fully describe its methodologies for developing the DER forecast, EV forecast, high/medium/low scenarios, and geographical allocation in its plan (for example methods and tools, time horizons, data sources)
- ~~vii)~~iii) For the initial Plan, the methodology for geographical allocation (to the substation) is at the utility's discretion. The Commission may provide direction for subsequent Plans
- iv) A utility may consider leveraging information such as: historical utility program trends, historical customer adoption trends, data from Energy Trust of Oregon, data from Transportation Electrification Plans and pilots, or studies on DER technical and economic potential used in other dockets. Utilities should use the most recent data available.

c) Results of forecasting load growth, DER adoption, and EV adoption
- ~~viii)~~i) Document existing and anticipated constraints on the distribution system~~.~~

**Expected Evolution**

This investigation identified numerous opportunities for improved creation and use of more granular forecasting of load growth, and DER and EV adoption. The presentation *Forecasting load on distribution systems with distributed energy resources* from the National Renewable Energy Laboratory (NREL) identified several approaches and tools for top-down and bottom-up DER forecasts, including the use of historical trends, program-based approaches, and customer adoption models.[32] In comments filed in response to Staff's questions for the August 25, 2020 Special Public Meeting, numerous parties suggested that the OPUC apply multiple approaches to calibrate and refine forecasts over time.

Based on these insights gained through the investigation, for stages 2 and 3 of Plans, utilities should meet the benchmarks identified in Figure 4.

## 5.2. Grid Needs Identification

Grid needs identification compares the current capabilities of a distribution system and the demands on that system to infer its future needs.

At its core, a grid needs identification answers the question of what technical requirements must be addressed to ensure a safe, reliable and resilient system that provides adequate power quality to the customers it serves. Adding to this core, a holistic approach to grid needs identification anticipates DER adoption by customers, as well as the social and economic needs of the communities that depend on distribution systems and the contributions they can make to strengthen it.

Figure 5 introduces the initial requirements and expected evolution for grid needs identification.

[32] See https://www.oregon.gov/puc/utilities/Documents/DSP-Sigrin-Presentation.pdf for more detail.

**Figure 5**

| Grid Needs Identification | |
|---|---|
| Stage 3 | Identify grid needs and present a summary of prioritized grid constraints, utilizing prioritization criteria such as community priorities, equity analysis, constraints on DER adoption, and evolving public policy goals. |
| | Provide new datasets and analysis responsive to OPUC, community inputs and policy evolution. |
| Stage 2 | Develop robust “future state” data needs, including inputs in the following categories: |
| | Perform equity analysis overlaying customer geographic and socio-economic data relative to system reliability and customer options. Make findings publicly available. |
| | Needs identification includes results of community needs assessments, DER forecasting, and equity analysis. |
| | Identify grid modernization needs and present a summary of prioritized grid constraints and opportunities publicly. |
| Stage 1 | Present summary of prioritized grid constraints publicly, including criteria used for prioritization. |
| | Document process and criteria used to identify grid adequacy and needs. Discuss criteria used to assess reliability and risk, and methods and modeling tools used to identify needs. |
| | 2021-2022 / 2023 and beyond |

### Initial Requirements

A utility, in its Distribution System Plan, should:

~~f)~~a) Document the process used to assess grid adequacy and identify needs~~.~~
~~g)~~b) Discuss criteria used to assess reliability and risk, and methods and modeling tools used to identify needs~~.~~
~~h)~~c) Present a summary of prioritized grid constraints publicly, including criteria used for prioritization~~.~~
~~i)~~ Provide a timeline by which the grid need(s) must be resolved to avoid potential adverse impacts~~.~~
~~j) Pilot a grid needs assessment process with CBO input and expertise to increase learnings about community needs within the service territory. Pilots should address:~~
   ~~i) Status of community planning~~
   ~~ii) Challenges facing the community~~
   ~~iii) Energy burden within the community~~
   ~~iv) Community energy needs and desires~~
   ~~v) Community interest in clean energy planning and projects~~
   ~~vi) Ongoing engagement with community members on a schedule determined by the community~~
~~vii)~~d) ~~Community demographics~~

In fulfilling these requirements, each Plan should cross-reference Plan sections of Baseline Data and System Assessments; Community Engagement; and Forecasting of Load Growth, DER Adoption, and EV Adoption.

**Expected Evolution**

This investigation identified numerous opportunities for grid needs identification in Oregon. In the *Connectivity Means Community* presentation, presenters highlighted the need for community engagement and responsiveness to community needs in relation to grid needs identification.[33] A human-focused approach to identifying grid needs, implemented in partnership with communities and CBOs, can create value-adding investments for communities, and align the energy system with community priorities.

Based on these insights gained through the investigation, for stages 2 and 3 of utility Plans, a utility should meet the benchmarks identified in Figure 5.

## 5.3. Solution Identification

Solution identification ~~complements a Distribution System Plan grid needs identification by~~ proposes the equipment, technology or program(s) the utility will advance to meet identified grid needs. Previously, a Distribution System Plan would rely on traditional hardware solutions (such as substation upgrades, reconductoring, additional transformer deployment). These Guidelines advance more holistic distribution system planning, calling for consideration of a wider range of potential solutions (for example increased system monitoring automation, expanded switching capability, distributed energy resources).

Experts contributing to the OPUC's workshops on Non-Wire Solutions and Distributed Energy Resource Valuation suggested that Solution Identification include a comprehensive exposition of the options available to serve grid needs. This section of the Plan should weigh the pros and cons of each option across standardized criteria, with inclusive approaches to weighing the cost and benefits of each path forward.

Figure 6 introduces the initial requirements and expected evolution for solution identification.

[33] *Connectivity Means Community - Distributed System Planning for Humans*, Oriana Magnera and Charity Fain, Verde and Community Energy Project, May, 20, 2020, https://www.oregon.gov/puc/utilities/Documents/DSP-Magnera-Fain-Presentation.pdf.

**Figure 6**

| Solution Identification | |
|---|---|
| Stage 3 | Co-develop solutions with communities and community-based organizations. |
| | Streamline and refine non-wires solutions and aggregations of non-wires solutions to defer distribution system upgrades. |
| Stage 2 | In assessing options for distribution system pilots and projects, engage community organizing experts to gain input from potentially impacted communities. |
| | Prior to filing, publicly present data used to identify distribution system investments, and understand data most useful to stakeholders. |
| | Co-develop solutions with communities and community-based organizations. |
| | Utilize non-wires solutions to defer distribution system upgrades. This includes harnessing DERs for voltage support and frequency event support. |
| Stage 1 | Stakeholders provide feedback on what data would be useful to them. OPUC determines if additional datasets are necessary and may direct utilities to submit them in the next Distribution System Plan filing. |
| | Provide summary and description of data used in distribution system investment decisions such as: feeder level details (including customer types on feeder, loading information), DER forecasts and adoption. |
| | Document the process to identify a range of possible solutions to address grid needs. For larger projects, engage with communities early in solution identification. Facilitate discussion of proposed investments that allow for mutual understanding of the value and risks associated with resource investment options. |
| 2021-2022 | 2023 and beyond |

**Initial Requirements**

The utility should assess proposed solutions to address grid needs. Specific requirements include:

~~f)~~a) Document the process to identify the range of possible solutions to address priority grid needs~~.~~

b) For each identified Grid Need provide a summary and description of data used for distribution system investment decisions including: discussion of the proposed and various alternative solutions considered, a detailed accounting of the relative costs and benefits of the chosen and alternative solutions, feeder level details (such as customer types on the feeder; loading information), DER forecasts and EV adoption rates~~.~~

~~g)~~ For larger projects (this may exclude, for example, regular maintenance projects, or inspection projects), engage with impacted communities early in solution identification. Facilitate discussion of proposed investments that allow for mutual understanding of the value and risks associated with resource investment options~~.~~

c) ~~Make detailed datasets publicly available and host listening sessions and/or workshops to describe data used in investment decisions. Stakeholders will provide feedback on~~

~~data that would be useful to them. OPUC will determine if publication of additional datasets is necessary and may direct utilities to submit them in the next Plan filing.~~

d) Evaluate at least two[34] pilot concept proposals in which non-wire solutions would be used in the place of traditional utility infrastructure investment. The purpose of these pilots is to gain experience and insight into the evaluation of non-wire solutions to address priority issues such as the need for new capacity to serve local load growth, power quality improvements in underserved communities. These pilots will prepare utilities to achieve the goals listed in Stages 2 and 3 of Figure 6.

In its pilot concept proposals, a utility should discuss the grid need(s) addressed, various alternative solutions considered, and provide detailed accounting of the relative costs and benefits of the chosen and alternative solutions. The pilot concept proposals should be reasonable and meet the Guidelines, even if the individual proposal may not be cost-effective. In addition, evaluation of pilot concept proposals should utilize the community engagement process developed in Section 4.3. (a) (ii) and address:

i) Community interest in clean energy planning and projects
ii) Community energy needs and desires
iii) Community barriers to clean energy needs, desires, and opportunities
iv) Energy burden within the community
v) Community demographics
vi) Any carbon reductions resulting from implementing a non-wires solution rather than providing electricity from the grid's incumbent generation mix

The pilot concept proposal should include a process in which the utility works with stakeholders to set equity goals, as may be appropriate for the pilot.

**Expected Evolution**

This investigation identified numerous opportunities for solutions identification in Oregon. The need to co-develop distribution system solutions with communities and CBOs remains a priority throughout the DSP evolution. Beyond community engagement, the regulatory framework, utility processes and structures, and procurement practices also need to evolve to enable implementation of non-wires solutions.[35] As non-wires solutions are constructed and their performance in serving grid needs and deferring grid upgrades is better understood, valuation methods may be needed to compare non-wires solutions to traditional utility hardware (for example substation upgrades, additional transformer deployment).[36]

Based on these insights gained through the investigation, for stages 2 and 3 of utility Plans, a utility should meet the benchmarks identified in Figure 6.

[34] 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.

[35] *Non-wires Solutions: Context, Rationale, and Opportunity*, Jason Prince, Rocky Mountain Institute, May 13, 2020, https://www.oregon.gov/puc/utilities/Documents/DSP-Prince-Presentation.pdf.

[36] Refer to *Valuation of Distributed Energy Resources* presentation from Debra Lew for details on approaches to valuing non-wires solutions and distributed energy resources, https://www.oregon.gov/puc/utilities/Documents/DSP-LewPresentation.pdf.

### 5.4. Overarching Requirement - Near-Term Action Plan

In this section of the Plan, a utility should present the utility's proposed solutions to address grid needs, as well as other investments in the distribution system. Specific requirements include:

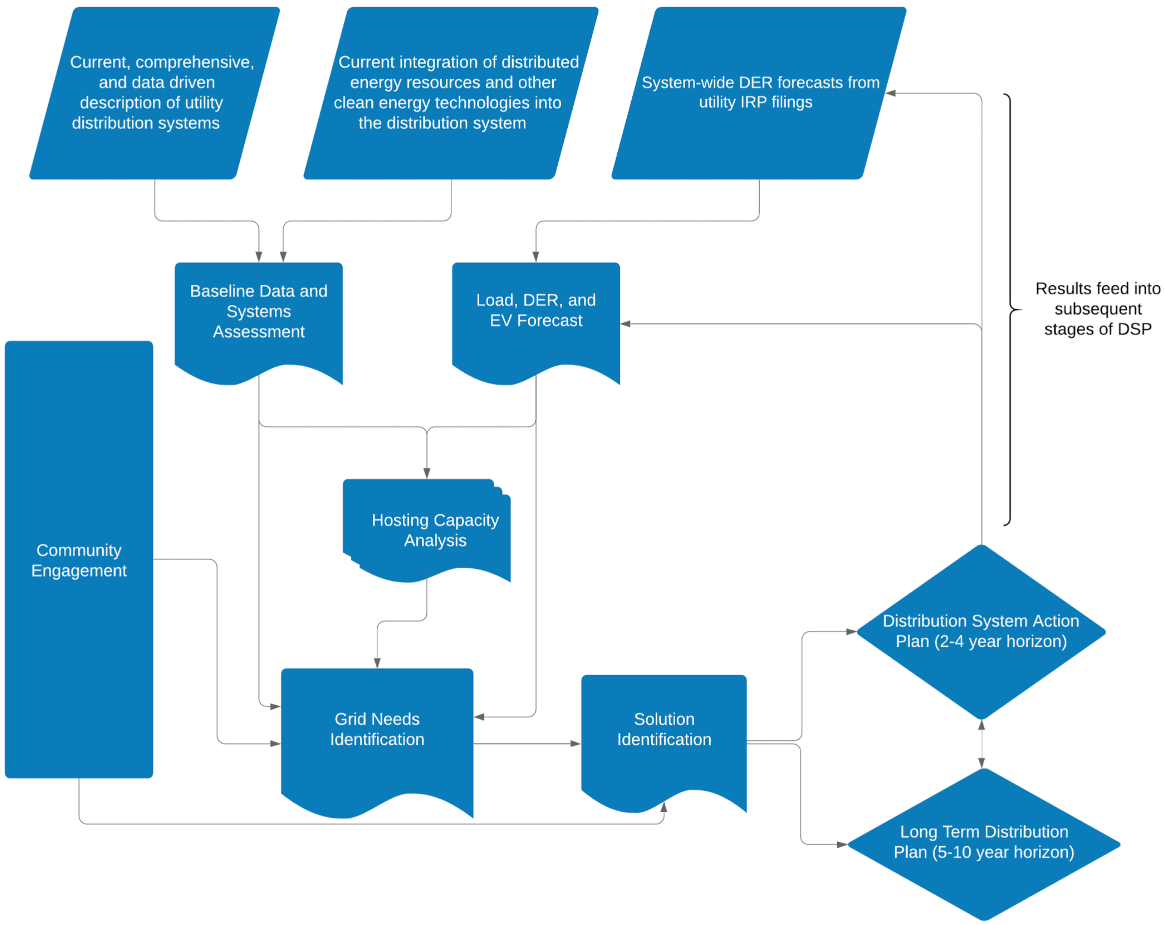
- ~~e)~~a) Action Plan: Provide a 2-4 year plan consisting of the utility's proposed solutions to address grid needs and other investments in the distribution system~~.~~
- b) Projected spending: Disclose projected system spending to implement the action plan, timeline for improvement, and anticipated requests for a cost recovery mechanism
- ~~f)~~c) Relation to other investments: As applicable, the Action Plan should identify areas of relation and interaction with other investments such as transmission projects and demand response programs~~.~~
- d) Document current innovations and pilots being conducted to improve, modernize, and/or enhance the grid beyond its current capabilities~~.~~

## ~~4.~~6. Overview of the Distribution System Planning Process

The elements of Distribution System Planning described in these ~~g~~Guidelines must be integrated and used iteratively to form a holistic planning process to meet Oregon's needs. ~~Therefore, in addition to specifying~~These Guidelines specify the initial requirements for utility Distribution System Plan filings, and identify baseline expectations for how th~~o~~ese requirements ~~will~~may evolve over time~~, these Guidelines suggest how those pieces fit together.~~. Figure 7 depicts this process in a conceptual manner. Figure 7 does not address the respective timing of these elements as outlined in these Guidelines.

**Figure 7**

**Oregon Public Utilities Commission Distribution System Planning Process Diagram**




Key conceptual relationships depicted in Figure 7 include:

- Baseline Data and System Assessments are informed by current information and data on the current state of utility distribution systems and the DERs already contributing to and depending on those systems. The initial Plan requirements are primarily a consolidation of this information and data from other existing reports.
- Load, DER and EV Adoption Forecasts are informed by ~~current~~ system-wide forecasts utilized currently in each utility's Integrated Resource Planning. The allocation of those forecasts to ~~distribution planning area~~the substation level represents an incremental ~~step~~advance beyond current practices introduced by these Guidelines.
- ~~Beginning in Stage 2~~In the future, Hosting Capacity Analysis will compare the capabilities of the system ~~as presented in the baseline data and system assessment~~ and the demands on the system, as recognized by forecasts of load~~,~~ growth, and DER and EV adoption. As depicted in this figure, the hosting capacity analysis will inform distribution planning as an input into the Grid Needs Identification.

- ~~In its~~ Grid Needs Identification~~, each Plan should draw on the Baseline Data and System Assessments, Forecasts of load, DER and EV Adoption, as well as insights gained through community engagement. By comparing~~ will compare the capabilities of, and demands on, the system, ~~Plans should infer future needs of their respective grids. Two new requirements are introduced by these Guidelines:~~
- ~~Grid Needs~~and will ~~be assessed using locationally-specific forecasts~~utilize the improved forecasting of load~~,~~, growth, and DER and EV adoption ~~represents an incremental step introduced by these Guidelines;~~noted above.
  - ~~Grid Needs will be determined with input from community engagement.~~
- ~~Progressing forward, each~~The Plan's Solution Identification should show how the utility intends to meet the needs identified in the preceding step. The requirement ~~that~~of non-wire solutions ~~be considered among the options represents~~pilot concept proposals is an incremental ~~step~~advance beyond current practices introduced by these Guidelines.
- ~~An additional~~The integration of community engagement is also an incremental ~~requirement~~advance beyond current practices introduced by these Guidelines ~~is the integration of community engagement.~~. Each Plan should seek and account for community input in identifying ~~Grid Needs and~~ Solutions.
- Each Plan's Near-Term Action Plan will be derived from its Solution Identification, providing specific steps the utility will take to secure identified solutions within the next 2-4 years, as well as proposed deadlines, milestones and projected costs.
- Each Plan's Long-term Plan affords the utility an opportunity to explain how its Action Plan represents a step toward its envisioned long-term modernization of the distribution system.
- Finally, recognizing the iterative nature of planning, each Plan's Action Plan and Long-term Plan will provide a basis for subsequent phases of DSP.

Together, a utility's successful integration of these elements should amount to a transparent, robust and holistic distribution planning system.