PACIFIC POWER
A DIVISION OF PACIFICORP

825 NE Multnomah, Suite 2000
Portland, Oregon 97232

May 31, 2024

Nick Sayen
Oregon Public Utility Commission
201 High St. SE, Suite 100
Salem, OR 97301-3398
Nick.SAYEN@puc.oregon.gov

RE: **PacifiCorp Comments re Staff's Proposed Distribution System Planning Guideline Revisions**

Please find enclosed PacifiCorp's ("the Company") Comments with respect to Commission Staff's Proposed Distribution System Planning ("DSP") Guideline Revisions issued on April 26, 2024. The Company appreciates the opportunity to provide feedback and comment on the Proposed DSP Guideline Revisions and to work with Staff, stakeholders, and fellow utilities on this next phase of DSP Guideline refinement while continuing to execute on the action plan outlined in the Part 2 filing. The Company applauds Staff for creating an environment for collaboration and open discussion through the proceedings to date. It is in that spirit of collaboration that the Company submits its comments. The Company anticipates making its next DSP filing on or before March 31, 2026.

The Company believes it understands Staff's high-level goals and objectives regarding the revised guidelines and seeks to find common ground where possible. The Company therefore proposes engaging in a round of workshops, and additionally requests the ability to submit a second round of comments prior to presenting the revised guidelines to the Commission.

The Company's attached comments address specific revisions and line items in Staff's proposed DSP Guidelines that cause concern for the Company, along with associated recommendations. In the Company's review of the proposed revisions several areas of concern emerged:

(1) <u>Thru-Line from DSP Guidelines to Future General Rate Cases, Direction of Company Decision Making re Investment for Distribution Assets, and Ten Year Going-Forward Projections</u>

The Company is concerned that Staff's Proposed DSP Guideline Revisions express an intent that the DSP information provided by the Company link directly to future general rate cases and "lay the groundwork for rate recovery." The Company is also concerned that Staff's revised Guidelines appear to step well beyond offering "input" for the utility to consider in its processes and decision-making and move toward directing Company decisions and investments prior to implementation—moving toward de facto management of utility decisions. Examples of proposed Guideline revisions to this effect include:

- Staff Proposed DSP Guideline 6(d): "Provide a summary table of each identified grid need by asset class and specifying the timing of need. ***The summary table should aid***

Staff and stakeholders in finding a thru-line from grid needs reported in a DSP to investments seen in future general rate cases." (Emphasis added.)

- Staff Proposed DSP Guideline 7: "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). ***The solutions identified should correspond to future general rate cases***." (Emphasis added.)

- Staff Proposed DSP Guideline 8(c): "The Action Plan prioritized list (Guideline 8 a) i)) and discussions (Guideline 8 a) ii)), as well as the projected spending (Guideline 8 b)) should aid Staff and stakeholders in finding a ***thru line from the Near-term Action Plan to investments seen in future general rate cases***. Further, ***when pursuing recovery in a general rate case, utilities should prepare to provide materials assembled for the DSP filing as well as additional materials*** such as documentation of proposed and various alternative solutions considered, and a detailed accounting of the relative costs and benefits of the chosen and alternative solutions, such as engineering reports, feeder level details (such as customer types on the feeder; loading information), DER forecasts and EV adoption rates." (Emphasis added.)

- Staff Proposed DSP Guideline 9(b)(iii): "The Long-term Plan Roadmap prioritized list (Guideline 9 b) i)) and discussions (Guideline 9 b) ii)) should aid Staff and stakeholders in ***finding a thru-line from the Long-term Plan to investments seen in future general rate cases***." (Emphasis added.)

Staff's April 26, 2024, Executive Summary to the Proposed DSP Guideline Revisions notes that Staff "seeks to focus the next round of plans on vetting core investment planning information to directly inform the rate recovery process." Staff further notes that the next round of plans will focus on a "thorough review of the Companies' proposed grid investments and operational plans to (1) allow participants to influence decisions prior to their implementation; and (2) lay the groundwork for rate recovery" that will "require the utilities to provide detailed and comprehensive information about planned operational budgets and system investments, along with a clear rationale for prioritizing these expenses to maintain, improve, or avoid investments in the grid." Staff continues by explaining that "[f]or large distribution projects Staff will continue to prioritize the DSP as the primary venue for utility accountability . . ." Staff's Executive Summary proposes that the "Guideline revisions . . . focus DSP on grid needs, expenditure decision making and prioritization, and proposed investments and expenditures."

The Company finds proposed guidelines that establish a "thru-line" between DSP submissions and future general rate cases to be problematic. The Company's concern is that the DSP Guideline process will function as a de facto preview of the Company's general rate cases, or as a "pre-prudence" or "dual prudence" inquiry. This does not align with how capital planning and investment function in the Company's normal operations or rate cases. That is, that capital investments only become subject to review once they are used and useful and filed for inclusion in rate base.[1] This concern is heightened in light of Section 9 of Staff's Proposed DSP Guideline revisions calling for "[t]he utility's vision for the distribution system for the next 10 years . . ." Distribution system planning and procurement, considered on a ten-year going-forward basis, involves a high degree of speculation, outside the Company's normal business planning methodology, and is susceptible to a variety of contingent factors outside of the Company's control (*e.g.*, shifting system needs, population changes, weather events, unplanned disturbances, etc.). These factors require a contemporaneous approach and flexibility to meet ever-evolving system demands. Staff's statement that "when pursuing recovery in a general rate case, utilities should prepare to provide materials assembled for the DSP filing" suggests that DSP proceedings could operate prescriptively, could bind the Company and, in effect, represent a "pre-prudence" or "dual prudence" inquiry.

The Company is also concerned that the revised DSP Guidelines appear to directly influence Company decision making regarding proposed distribution investments and expenditures. Directing Company investment decisions in a planning proceeding is problematic on a number of levels. Most importantly, the utility is a private entity providing a service that has to manage both its operations and financial health to provide that service. Failure to address both aspects has consequences. The Company believes that directing utility action is beyond the scope of this DSP process, could put the utility at financial risk, and could result in unnecessarily higher rates. From the Company's perspective, Commission direction to plan or invest in a certain manner would have to be associated with preapproval of any assets because the Commission would usurp the utility's ability to manage its finances. Such direction, even in the context of a general rate case, is contrary to established precedent.[2] *See, e.g.*, proposed guidelines 8(a)(ii)(4) and 9(a).

---

[1] *See, e.g.*, *In re Nw. Nat. Gas Co.*, Docket No. UM 125, UP 38, Order No. 87-1044 at 536–37 (Oct. 5, 1987) ("Will the Public Utility Commission of Oregon in these dockets undertake to render a decision in advance of construction with respect to the prudence of Northwest Natural Gas Company to develop an underground natural gas storage facility[?] . . . The answer to this question is 'no' . . . Decisions of this type by utility management are reviewed in the context of applications to recover costs of plant which is in service, not projects in the planning stage. Any decision by a utility to undertake a construction project involves some risk that the project, if completed, will not meet expectations. However, that risk and the risk of noncompletion is upon the company alone. The Commission only has authority to determine whether the plant is used and useful when a request is made to reflect its costs in utility rates."); *see also In re Application of Nw. Nat. Gas Co. for A Gen. Rate Revision*, Docket No. UG 132, Order No. 99-697 at 52 (Nov. 12, 1999) ("Prudence in planning and constructing a plant is relevant for determining the valuation of the facility once placed in rate base.").

[2] *See, e.g.*, *City of Portland Complainant*, Docket No. UM 1262, Order No. 06-636 at 6 (Nov. 17, 2006) ("The Oregon Supreme Court observed that the Commission's role is not to manage the utility, but to consider the utility's management and its effect on rates. 'The determination of what is reasonable in conducting the business of the utility is the primary responsibility of management. If the commission is empowered to prescribe the terms of contracts and the practices of utilities and thus substitute its judgment as to what is reasonable for that of management, it is empowered to undertake the management of all utilities subject to its jurisdiction. It has been repeatedly held, however, that the commission does not have such power.'") (*citing Pac. Tel. & Tel. Co. v. Flagg*, 189 Or. 370, 395–96 (1950)); *see also In re Pacificorp, DBA Pac. Power Request for A Gen. Rate Revision*, Docket No. UE 246, Order No. 12 493 at 25 (Dec. 20, 2012) ("[N]or is it appropriate for the [commission] to merely substitute its best judgment for the judgments made by the company's managers. The company's conduct should be judged by asking whether the conduct was reasonable at the time, under all circumstances, considering that the company had to solve its problems prospectively . . .").

(2) <u>Expansion of Scope under Proposed DSP Guideline Revisions</u>

Several of Staff's Proposed DSP Guideline Revisions would expand the scope of the DSP process far beyond distribution-focused assessments and stray into other areas of the Company's management. For example, proposed guideline 6(c)(iv)(1)-(5) states that a utility's DSP should "(c) Discuss and identify anticipated grid needs, including the following: . . . (iv) Grid needs to address other relevant utility plans including (1) IRP/CEP; (2) Wildfire Mitigation Plan, including but not limited to identified increased risk, either in geographically targeted areas, or at a system-level; (3) Transportation Electrification Plan; (4) Geographically targeted efforts of any demand side programs/DER programs; and (5) Annual reliability reporting, and any related performance issues." As revised, this proposed guideline would bring each of these broad areas of Company operation under the purview of the DSP process. Other similar examples of revised guidelines that would greatly expand the scope of the DSP process include proposed guidelines 4(g), 8(a)(ii)(5), and 9(b)(ii)(6).

(3) <u>Increased Granularity and Detail of Data Requested under Proposed DSP Guideline Revisions, Areas of Incongruity between Guidelines and Company Data, and Confidentiality</u>

Certain of Staff's Proposed DSP Guideline Revisions substantially increase the granularity and level of detail to be included in DSP beyond what was provided in Part 2 and beyond what is reasonably feasible for the Company to provide. For example, proposed guidelines 4(e)(i)-(vii) seek "historical distribution system spending for the past five years" for seven categories of spending that were initially requested and provided by the Company in Part 1, but that proved to be extraordinarily burdensome to derive (the requests sought data outside of the Company's existing accounting structure). Following discussions between Company representatives and OPUC Staff held on December 2, 2022, it was agreed that the Company would provide information based on its existing accounting structures and categorization in its Part 2 submissions. *See* PacifiCorp's Responses to OPUC Data Requests 8-11, Docket UM 2198, dated December 12, 2022. For example, OPUC Data Request No. 8(c) sought project level spending data "for any projects begun in prior years, for each of the years 2023, 2024, 2025, and 2026." In response to this request the Company explained that:

> "[T]he forecast was not constructed using project level details. As such, large portions of the forecast expenditures are contained in Program level budgets within the forecast horizon. Specific projects will be managed from these Program budgets, but project level details were not used in the development of Figure 53. Larger projects that are not part of a Program may have a specific line item in the forecast. In such instances, the project expenditures have been identified by category for projects started before 2022 and for projects that started after 2021."

Proposed guidelines 8(a) (Near-Term Plan) and 9(a) (Long-Term Plan) seek a similar level of detail and categorization to proposed guidelines 4(e)(i)-(vii) on a going-forward basis. Particularly in the context of the 10-year going-forward nature of the Long-Term Plan, project-level and even program-level cost projection figures will be subject to significant change as operational needs and contingencies evolve. Moving forward, the Company proposes providing a level of detail and categorization like what was provided in response to OPUC Data Request No. 8 for its Part 2 filing.

In other areas, Staff's proposed Guideline revisions seek data that does not align with categories of data that the Company maintains in its normal course of business. For example, revised guideline 6(b) (regarding grid needs) asks the Company to "Discuss criteria, methods, and tools used to identify needs by asset class." Similarly, revised guideline 6(d) (also regarding grid needs) asks the Company to "Provide a summary table of each identified grid need by asset class and specifying the timing of need." However, the Company does not in its normal operations identify grid needs by asset class. Another example of incongruity between the revised guidelines and data categorization maintained by the Company is found in revised guideline 8(b) (regarding the Near-Term Action Plan). This guideline seeks "Projected spending: Provide the projected cost and timeline by asset class to implement the Action Plan. Provide a description of anticipated requests for cost recovery." However, the Company does not make cost and timeline projections by asset class. As was done for its Part 2 filing, the Company hopes to work collaboratively with Staff to find solutions to these areas of data incongruity that are acceptable for Staff and feasible for the Company.

Lastly, the Company continues to have concerns regarding the confidentiality, privacy, and security of personally identifiable customer information as well as PacifiCorp's sensitive, confidential, and/or proprietary business information, particularly in the context of project-level data. In the above-referenced discussions between OPUC Staff and the Company in December 2022, Staff clarified that the Company would provide responses to information requests in a manner that did not contain confidential or protected information for ease of sharing. Moving forward, the Company would like to continue with this understanding in place as it provides data in response to the revised guidelines (*e.g.*, through performing redactions, removing certain sets of sensitive and/or confidential information as needed, etc.).

(4) Load Forecasting: Staff Recommends OPUC and Stakeholders Conduct Workshops re Forecasting Methodology & Approach in Advance of Adopting New Requirements

Staff's proposed guideline 5 generally seeks to "require a utility to document in its Plan current utility load forecasting processes for distribution service and forecasting processes for DER adoption and EV adoption." The Company believes it would be most productive, with respect to this revised guideline, for the OPUC to organize a workshop to discuss forecasting methodology and/or approaches before adopting any new requirements. Generally speaking, circuit-level forecasts reflect macro-level assumptions and trends from IRP, CEP, and TE plans. However, circuit forecasts are focused on local conditions, circuits characteristics, and constraints. Circuit level forecasts will therefore reflect the conditions that place the greatest demand on the local circuit. That timing and set of conditions is very unlikely to correspond to peak conditions contained in IRP or system-level forecasts. The Company believes a workshop could best address these issues and how the guidelines could be revised to better reflect this operational reality.

(5) <u>Non-Wires Analysis Criteria in the Context of Near-Term and Long-Term Plans: Projections Subject to Change</u>

Revised guideline 7 seeks, in part, that "[a]ll identified utility traditional and non-wires solutions . . . be documented in the Long-term and Near-term Plans as appropriate." Non-wires solutions reflect new and evolving technology solutions. The Company is not certain about the successful nature of individual potential non-wires solutions. As such, a recitation of plans involving non-wires solutions, particularly in the context of the near-term and long-term plans on a going forward basis (and specifically in the context of any thru-line to rate recovery) would be subject to a significant level of change and evolution. This is a challenge the Company would like an opportunity to clarify with OPUC Staff in advance of any requirement that non-wires solutions be integrated into the near-term and short-term planning methodology.

In closing, the Company fully supports and anticipates a continued open and collaborative approach to the DSP planning and guideline process, and shares the views expressed by the OPUC Commissioners and PGE (during the Special Public Meeting held on February 28, 2024) that: DSP planning should stay at an appropriate level of detail to support the evolution of and foundational improvements to DSP; and (2) that refinements to DSP guidelines should encourage the core values of innovation, open and frank discussion, and pragmatism. To that end, the Company believes workshops are needed to collaborate on a revised set of guidelines addressing the Company's concerns as expressed in the attached line-item comments. The Company looks forward to continued discussions with all stakeholders regarding innovative and pragmatic solutions to DSP issues.

If you have any questions, please call me at (503) 813-5817 (desk) or (503) 730-6276 (cell).

Sincerely,

<u>/s/ *Daniel J. Teimouri*</u>

Daniel J. Teimouri
Assistant General Counsel
PacifiCorp
(503) 813-5817
daniel.teimouri@pacificorp.com

OPUC Staff Proposed DSP Guideline Revisions (4/29/2024)

ID	Section/Requirement	Comment/Notes
1	**Process and Timing**	
	The following development and review process will guide the utility filing of a Distribution System Plan (Plan) for a utility's service territory in Oregon.	
a)	Each electric utility1 must file its next Plan on or before the following dates, or an alternative date designated by Commission order: Idaho Power: Month, Day, Year Portland General Electric: Month, Day, Year Pacific Power: Month, Day, Year	PacifiCorp (The Company) intends to file it's next plan on or before March 31st, 2026.
b)	The date and cadence of filing subsequent Plans will be set in the next Guideline revision process, or by Commission order.	
c)	Each utility will present the results of the filing to the Commission at a public meeting.	
d)	Upon 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.	
e)	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.	
f)	The Commission may provide the utility an opportunity to revise the filing before making its decision.	
2	**Commission Action**	
	The Commission will consider whether to accept the filed Plan 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.	
3	**Community Engagement**	
	Intro not included in excel version - see PDF or Word version for introduction language	
	Specific Community Engagement Requirements for utilities include:	

ID	Section/Requirement	Comment/Notes
a)	During Plan development a utility should host at least four stakeholder workshops prior to filing the utility's Plan.2 These workshops should be held during Plan development, at a stage in which stakeholder engagement can influence the filed Plan. The workshops may include in- person meetings located in a community, and may include presentation of the Plan outline, data and assumptions under consideration or challenges encountered, and the utility's approach to community engagement. During stakeholder workshops, a utility must invite community members to share their perspectives, relevant needs, challenges, and opportunities or novel solutions for the grid.	
b)	To engage stakeholders and community on distribution system planning, a utility should leverage best practices, and lessons learned from engagement efforts from prior Plans, and other planning processes. A utility should also leverage ongoing community and stakeholder engagement processes, and integrate distribution system planning engagement to the full extent it is beneficial to do so. Ongoing processes may include but are not limited to Clean Energy Planning, regional or local-area planning exercises.	
c)	During preparation and implementation of a DSP, a utility should document community and stakeholder comments and feedback and utility response, including comments and feedback that were heard but not implemented. This documentation should be included in the utility's Plan when filed.	
d)	A utility should maintain a Community Engagement Plan, as developed in the Company's prior DSP. The Community Engagement Plan should describe actions the utility will implement in order to engage community members and CBOs if it needs to develop and implement non- wire solutions to address grid needs, or if it needs to engage communities around implementing larger projects. Larger projects may exclude, for example, regular maintenance projects, or inspection projects. The Community Engagement Plan should include the activities described below.	The Company has consolidated the community engagement plan under the Clean Energy Plan (CEP) and Community Benefits and Impacts Advisory Group (CBIAG). DSP actively participates in the community engagement under thse initiatives. DSP continues to conduct local engagement as outlined in the DSP Near-Term Action Plan and when necessary to collaborate with communities on potential non-wires solutions.
i)	Proactively engage stakeholders regarding possible non-wire solutions or larger projects in impacted communities. Engagement of the local community may include in-person meetings located in the community; presentation of the project scope, timeline, rationale; discussion of proposed utility projects and the value and risks associated with options; and solicitation of public comment, particularly to understand community needs and opportunities.	
ii)	Collaboratively develop and share *datasets and metrics* to guide community-centered planning of the possible non-wire solutions or larger projects.	*Recommend strike "datasets and metrics" and replace with "information."*
iii)	The Plan should consider engagement of local governments and Tribal nations for input on possible non-wire solutions, larger projects, as well as input on other policies intersecting distribution system planning. *These may include opportunities or interest in micro-grids and other resiliency planning, or local environmental and climate plans such as fleet-electrification and building-electrification efforts* .	*Recommend striking the last sentence of the requirement that includes "may" items.*

ID	Section/Requirement	Comment/Notes
e)	Utilities should aim to create a collaborative environment among all interested CBO partners and stakeholders.	

4	**Current System Data and 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 and equipment, progress of investment in those systems, the level of distributed energy resources (DERs) currently integrated into those systems,3 and management and monitoring practices of those systems.	
	The Utility should provide at a minimum:	
a)	A description of any currently used system assessment practices (such as system reliability assessments, system asset health assessments, etc.) that are utilized in identifying grid needs and evaluating possible solutions, which may include:	
i)	Method and tools used to develop the assessment	
ii)	Forecasting time horizon(s)	
iii)	Key performance metrics	
b)	A summary description and table 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)	Life expectancy of assets in each class	
vi)	Percentage of assets in each class at or beyond the end of expected life	
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.). The discussion should include:	
i)	a description of system visibility and capabilities	

ID	Section/Requirement	Comment/Notes
ii)	the percentage of system reached with each capability, the percentage of customers reached with each capability	
iii)	any utility programs utilizing each capability	
e)	Historical distribution system spending for the past five years, in each category:	The Company proposes to strike the categories outlined below and to report based on the categories that were provided in the PacifiCorp DSP Part 2 filing and subsequent Data Responses related to investment categories. Please refer to concern (3) in the attached letter regarding communications with staff for prior data requests that are related to this requirement.
i)	Age-related replacements and asset renewal	See above
ii)	System expansion or upgrades for capacity	See above
iii)	System expansion or upgrades for reliability and power quality	See above
iv)	New customer projects	See above
v)	Grid modernization projects	See above
vi)	Metering	See above
vii)	Preventative maintenance	See above
f)	Net Metering and Small Generator information:	
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	
g)	Plans should include the utility's most recently filed Annual Reliability Report as an appendix to the Plan.	
i)	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	The Company proposes Commission Staff organize workshops to collaborate on a revised set of requirements for 4(g)(i-ii) to further define the intent and scope. See concern (2) in the attached letter regarding expansion of scope.
ii)	Any proposed investments based in whole, or in part, on reliability improvements must demonstrate those improvements by cross-referencing underlying data and information contained in the Annual Reliability Report	See above
h)	Summary progress report on activities included in the most recently filed DSP to clearly communicate advancement or completion of:	
i)	Investments, expenditures, and activities from the Long-term Plan	
ii)	Investments, expenditures, and activities from the Near-term Action Plan	
i)	Data assembled for this requirement should be prepared in electronic format, and submitted to the Commission for public review	The Company has concerns regarding the level of detail and confidentiality being requested by this requirement. Please refer to concern (3) in the attached letter. The Company proposes striking this requirement until workshops take place to further define parameters of the data being requested.

ID	Section/Requirement	Comment/Notes
5	**Forecasting of Load Growth, DER Adoption, and EV Adoption**	
	(Initial two sentences of this text excluded from this section for brevity) The updated requirements aim to improve the accuracy and granularity of forecasting. This in turn is intended to improve the accuracy and granularity of existing and anticipated constraints on the distribution system revealed in the engineering analysis to identify Grid Needs.	
	The Guidelines require a utility to document in its Plan current utility load forecasting processes for distribution service, and forecasting processes for DER adoption and EV adoption as follows:	The Company proposes to strike this entire section until joint workshops can be convened to collaborate on a revised set of requirements for this section. Please refer to concern (4) in the attached letter.
a)	Forecast of load growth by feeder including discussion of:	See above
i)	Forecasting method and tools used to develop the forecast	See above
ii)	Forecasting time horizon(s)	See above
iii)	Data sources used to inform the forecast	See above
iv)	The load forecast should include data, inputs, and assumptions from the Company's most recent IRP/CEP, which should be clearly listed in the DSP. Examples include but are not limited to:	See above
-1	System modeled scenarios decomposed to the distribution system	See above
-2	Discussion of how IRP/CEP forecasting is decomposed to, and reconciled with, geographic areas of the distribution system, and identification of those specific geographic areas. Examples of such areas may include transitional planning areas.	See above
b)	Forecast of DER adoption and EV adoption by feeder including discussion of:	See above
i)	Forecasting method and tools used to develop the forecast	See above
ii)	Forecasting time horizon(s)	See above
iii)	Data sources used to inform the forecast	See above
iv)	The forecast should include high/medium/low scenarios for both DER adoption and EV adoption	See above
v)	The DER adoption and EV adoption forecasts should include data, inputs, and assumptions from the Company's most recent IRP/CEP, which should be clearly listed in the DSP. Examples include but are not limited to:	See above
-1	Community based renewable energy (CBRE) forecast, potential study, RFP, needs assessment, etc.	See above
-2	Small scale renewable (SSR) forecast, potential study, RFP, needs assessment, etc.	See above
vi)	The methodology for geographical allocation is at the utility's discretion. The Commission may provide direction for subsequent Plans.	See above
c)	If a utility does not complete forecasting for its entire distribution system and instead completes forecasting for a portion of its distribution system, it must state so clearly and:	See above
i)	explain the reasons for completing the exercise for a portion of the system	See above
ii)	describe for how much of the system the exercise was completed, in terms of customers, load, substation count, and feeder count	See above
iii)	discuss whether and how the utility plans to complete the exercise in future DSPs	See above

ID	Section/Requirement	Comment/Notes
6	**Grid Needs**	
	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, grid needs identification should include constraints related to forecast of customer and front-of-the-meter DER. Additionally, the social and economic needs of the communities that depend on distribution systems, and the contributions they can make to strengthen it should be addressed. Grid needs identification should be comprehensive and inclusive, identifying the biggest drivers and trends behind needed investments and operational budgets.	The Company proposes to strike the highlighted text unless Staff can provide clarification that can be reviewed prior to presentation to the Commision.
	A utility's Distribution System Plan should:	
a)	Document processes used to assess grid adequacy and identify grid needs	
b)	Discuss criteria, methods, and tools used to identify needs by asset class	The Company proposes to strike this requirement. See concern (3) in the attached letter regarding categorization by asset class.
c)	Discuss and identify anticipated grid needs, including the following:	
i)	Renewal needs based on asset condition	
ii)	Grid needs to address forecasted load growth, DER adoption, EV adoption	
iii)	Grid needs to address customer needs such as new service, additional service, or service quality	
iv)	Grid needs to address other relevant utility plans including	The Company proposes to strike this entire section until joint workshops can be convened to collaborate on a revised set of requirements for this section. See concern (2) in the attached letter.
-1	IRP/CEP	See above
-2	Wildfire Mitigation Plan, including but not limited to identified Increased risk, either in geographically targeted areas, or at a system-level	See above
-3	Transportation Electrification Plan	See above
-4	Geographically targeted efforts of any demand side programs/DER programs	See above
-5	Annual reliability reporting, and any related performance issues	See above
v)	Timing of grid needs	
d)	Provide a summary table of each identified grid need by asset class and specifying the timing of need. The summary table should aid Staff and stakeholders in finding a thru-line from grid needs reported in a DSP to investments seen in future general rate cases.	The Company proposes to strike this requirement. The Company does not track grid needs by asset class. See concerns (1) and (3) in the attached letter regarding concerns with the DSP serving as a thru-line to the GRC and the level of detail requested.
7	**Solution Identification**	

ID	Section/Requirement	Comment/Notes
	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, and 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). The solutions identified should correspond to future general rate cases.	The Company proposes to strike this entire section until joint workshops can be convened to collaborate on a revised set of requirements for this section. In the attached letter, please refer to concern (1) regarding concerns with DSP serving as a thru-line to the GRC and concern (5) regarding non-wires solution criteria.
	The utility should assess grid needs to determine **cost effective** solutions as follows:	See above
a)	Document the process to identify the range of possible solutions to address grid needs and discuss how this process was applied to identify the proposed solutions in the Long-term and Near-term Plans	See above
b)	First, the utility process should assess each identified grid need to identify opportunities for no or low-incremental cost grid solutions such as rebalancing distribution loading through switching and phase balancing, or other actions	See above
c)	Second, if a specific grid need cannot be addressed by b) the utility should identify both a traditional solution and screen the grid need for suitability of a non-wires solution, if the cost for the traditional solution is $1 million or more	See above
i)	Determine the suitability of a non-wires solution based on the following screening criteria:	See above
-1	Grid need is not a redundant supply to a radial load;	See above
-2	Grid need is not a maintenance, asset condition, or safety need;	See above
-3	Grid need is not a stability or short circuit problems; or	See above
-4	Grid need must be addressed within two years	See above
ii)	If a grid need is suitable for a non-wires solution and comparatively cost-effective to the traditional solution, then the utility should identify the proposed non-wires solution(s) program, pricing, and/or procurement.	See above
d)	All identified utility traditional and non-wires solutions should be documented in the Long-term and Near-term Plans as appropriate.	See above
8	**Near Term Action Plan**	
	In this section of the Plan, a utility should present the utility's proposed solutions to address near-term grid needs. Specific requirements include:	
a)	Action Plan: Provide a 5 year plan of the utility's proposed solutions to address identified grid needs. The Action Plan should include:	The Company proposes to strike this entire section until joint workshops can be convened to collaborate on a revised set of requirements for this section. Please see concern (3) in the attached letter regarding increased granularity and detail being requested.
i)	Prioritized list of investments, expenditures, and activities	See above
ii)	A discussion of each planned investment/expenditures/activity estimated to cost more than $2 million. Each discussion should include:	See above

ID	Section/Requirement	Comment/Notes
-1	Project narrative including foundational assumptions and key barriers or constraints (including financial, technical, organizational) and mitigation plans	See above
-2	Timeframe	See above
-3	Investment/expenditure amount	See above
-4	Description of the criteria and methods the utility used to prioritize the investment/expenditure/activity, including explicit consideration of how the investment/expenditure/activity advances **State policies and goals and PUC objectives**, including but not limited to:5	See above
(a)	Reliability	See above
(b)	Safety and security	See above
(c)	Customer benefits and promoting inclusion of underserved populations	See above
(d)	Optimized operation of the system	See above
(e)	Efficient integration of DERs	See above
	When possible, the description should include quantification of the improvement in the goal.6 Should a planned investment/expenditure/activity advance a goal not included in (a)-(e), a utility should explain the rationale for the investment/expenditure/activity, and when possible, include quantitative outcomes.	See above
-5	Explanation of how the investment/expenditure/activity is coordinated with the utility's other planning processes (such as the most recent IRP/CEP, Wildfire Mitigation Plan, Transportation Electrification (TE) Plan, and DR/Flexible Load Plan).	See above. Please refer to concern (2) in the attached letter.
-6	Any proposed investments/expenditures which address a grid need previously identified as a non-wires solution opportunity by the non-wires solutions screen should be identified and include a summary of the range of possible alternatives analyzed, the analysis results, and discussion of why the non-wires solution was not selected.	See above
-7	Discussion of whether the proposed investment/expenditure/activity interacts with non-distribution asset strategies, whether alternatives to distribution investment were considered, and if made, what impact does the proposed investment/expenditure/activity have on other network assets.	See above
b)	Projected spending: Provide the projected cost and timeline by asset class to implement the Action Plan. Provide a description of anticipated requests for cost recovery.	See above

ID	Section/Requirement	Comment/Notes
c)	The Action Plan prioritized list (Guideline 8 a) i)) and discussions (Guideline 8 a) ii)), as well as the projected spending (Guideline 8 b)) should aid Staff and stakeholders in finding a thru- line from the Near-term Action Plan to investments seen in future general rate cases. Further, when pursuing recovery in a general rate case, utilities should prepare to provide materials assembled for the DSP filing as well as additional materials such as documentation of proposed and various alternative solutions considered, and a detailed accounting of the relative costs and benefits of the chosen and alternative solutions, such as engineering reports, feeder level details (such as customer types on the feeder; loading information), DER forecasts and EV adoption rates.	Please see concern (1) in the attached letter, regarding DSP serving as a thru-line to the GRC.

ID	Section/Requirement	Comment/Notes
9	**Long Term Plan**	
	This section of the Distribution System Plan consists of the utility's long-term investment plan. This section of the plan should include:	
a)	The utility's vision for the distribution system for the next 10 years, aligned with State policies and goals and PUC objectives, including but not limited to:7	The Company proposes to strike this entire section until joint workshops can be convened to collaborate on a revised set of requirements for this section. Please see concern (3) in the attached letter regarding increased granularity and detail being requested.
i)	Reliability	See above
ii)	Safety and security	See above
iii)	Customer benefits and promoting inclusion of underserved populations	See above
iv)	Optimized operation of the system	See above
v)	Efficient integration of DERs	See above
b)	Roadmap of the utility's planned investments, expenditures, and activities to advance the distribution system vision, for a 10-year planning horizon. The roadmap should include:	See above
i)	Prioritized list of long-term investments, expenditures, and activities	See above
ii)	A discussion of each planned investment/expenditures/activity including:	See above
-1	Project narrative including foundational assumptions and key barriers or constraints (including financial, technical, organizational) and mitigation plans	See above
-2	Estimated timeframe	See above
-3	Estimated investment/expenditure	See above
-4	Description of the criteria and methods the utility used to prioritize the investment/expenditure/activity, including explicit consideration of how the investment/expenditure/activity advances policies/goals/objectives identified in a) i)-v). When possible, the explanation should include quantification of the improvement in the goal.8 Should a planned investment/expenditure/activity advance a goal not included in a) i)-v), a utility should explain the rationale for the investment/expenditure/activity, and when possible, include quantitative outcomes.	See above
-5	Any connections to, and impacts on, Near-term Action Plan projects	See above

ID	Section/Requirement	Comment/Notes
-6	Explanation of how the investment/expenditure/activity fits with the utility's other planning processes (such as the most recent IRP/CEP, Wildfire Mitigation Plan, Transportation Electrification (TE) Plan, and DR/Flexible Load Plan) including how the investment/expenditure/activity is coordinated with each planning process with respect to related inputs and outputs such as data sets and prices, and assumptions such as macro-economic policies and growth rates.	See above. Please refer to concern (2) in the attached letter.
iii)	The Long-term Plan Roadmap prioritized list (Guideline 9 b) i)) and discussions (Guideline 9 b) ii)) should aid Staff and stakeholders in finding a thru-line from the Long- term Plan to investments seen in future general rate cases.	Please see concern (1) in the attached letter regarding DSP serving as a thru-line to the GRC.