October 4, 2024

Via Electronic Filing

Public Utility Commission of Oregon
Attention: Filing Center
PO Box 1088
Salem, OR 97308-1088

Re: Docket No. UM 2005, Investigation into Distribution Planning, Proposed Guideline Revisions

Filing Center:

Portland General Electric Company (PGE), PacifiCorp d/b/a Pacific Power (PacifiCorp), and Idaho Power Company (Idaho Power) (collectively, the Joint Utilities) appreciate the opportunity for further comment on Public Utility Commission of Oregon (OPUC or Commission) Staff's (Staff) proposed guideline revisions for Distribution System Plans (DSP) in Docket No. UM 2005.

The Joint Utilities thank Staff for their continued engagement with stakeholders, including the utilities, in the development of the proposed guideline revisions. We appreciate the additional comment periods and public workshop provided as part of this process. The enhanced discussion, dialogue and associated revisions have led the Joint Utilities to have greater confidence that we are operating with a shared understanding of the guidelines and Staff's expectations of utility DSPs going forward.

In the spirit of striving for that shared understanding, the Joint Utilities offer minimal, discrete edits to the proposed guideline language, included here as redlines in Attachment A, to enhance clarity and to align with the discussions we have had with Staff, collectively and individually, over the past several months. We respectfully request Staff consider adopting these redlines for their final recommendation to the Commission for the planned November 14, 2024 Public Meeting.

Our suggested redlines are intended to clarify:

- The level of detail expected in grid needs analysis, solution identification, and Action Plan project descriptions (both near and long term);
- The frequency and mechanisms required for utilities to update that information; and
- How Staff expects to use the information utilities provide within their DSPs in subsequent cost-recovery proceedings.

In addition, we offer suggested redlines to clarify development and treatment of potential non-wires solutions.

We further ask that Staff review the following statements from the Joint Utilities regarding our understanding of Staff's intent in the matters bulleted above and confirm in the public meeting memo or with further guideline revisions that our interpretation of the proposed guidelines is correct.

DSP principles and relationship to cost recovery

1. Staff does not intend for the Commission's acceptance of the DSP to represent any sort of finding on prudency. Measures planned or expenditures projected in the DSP will be reviewed for prudency only if the utility subsequently implements them and includes them in a general rate case (GRC).

2. The DSP is forward-looking, so projected grid needs and responsive measures and strategies are subject to change as circumstances, priorities, economic and market conditions, and customer plans change. It follows that expenditures projected in the DSP Action Plan and individual project plans are necessarily reasonable estimates based on the information available at the time the plan is prepared.
3. Expenditures for which the utility seeks cost recovery in a GRC, however, reflect actual costs after implementation and are likely to vary from reasonable planning estimates.
4. In addition, customer needs, utility financial constraints, regulatory requirements and other changed circumstances may mean the utility is obliged to undertake capital projects that were not anticipated in the DSP, or to cancel or reschedule capital projects that were included in the DSP. Thus, costs included for recovery in a GRC may not have previously been projected in a DSP, and costs projected in a DSP may not subsequently appear in a GRC. Utilities should make every effort to keep Staff apprised of these changes in periodic formal or informal DSP summary progress reports, on a cadence agreed upon with Staff as outlined in the draft guidelines.
5. Staff has stated in draft guidance that:
    a. a utility's DSP investments are expected to be generally responsive to identified grid needs and solutions identified,
    b. the prioritized list of investments and projected spending in the Action Plan should guide DSP implementation and provide a preview of investments/expenditures in future rate cases, and
    c. the utility should be prepared to explain in the cost recovery process any deviation from the grid needs, solutions, and investments/spending described in the DSP.
6. In light of points 1-4 above, 5 a, b and c and similar points made elsewhere in Staff's guidance do not carry a presumption that an expenditure for which recovery is sought in a GRC is imprudent if it does not appear in or varies materially from what was projected in the DSP. Rather, Staff's intent is simply that utilities will prepare their DSPs carefully and implement them in good faith, and that the DSP will provide useful context, background, and reasonable planning estimates for Staff's evaluation of expenditures proposed for recovery in subsequent GRCs. Reasonable and substantive utility explanations for variations in the GRC from projected investments/expenditures in the DSP, however, will also inform Staff's prudency determinations with no negative presumption simply because costs or projects implemented varied from projections.

We note also that Staff's best point of reference in understanding investments for which utilities request recovery in a GRC will likely be the most recent formal or informal DSP summary progress reports provided by the utilities, and not necessarily the potentially stale elements of the DSP document itself. Our attached suggested redlines reflect this relationship and would clarify that utilities should be prepared to provide context for GRC investments that illustrates continuity or explains variation from its most recent summary progress reports.

Details of project summaries

Staff has noted in discussions with the utilities and in its September 24th public workshop that the description in the guidelines of content for the summaries of investments/expenditures estimated to cost more than $2 million encompasses detailed information that may not be available or relevant for all projects. We would like to confirm that there is no expectation utilities will use the categories in the guidelines (i thru vii) as a template, but rather that utilities will use their best judgment to provide relevant and sufficient detail, generally within the bounds of the kinds of information described, to allow Staff to understand the anticipated purpose, scope, cost, benefits and timeline associated with each project.

Regarding the $2 million project threshold, PGE further asks that Staff consider revising the threshold to $3 million. This would simplify reporting and comparison of projects between the DSP and the GRC by aligning the DSP reporting requirement with information provided in UE 435, PGE's current GRC. Movement of the threshold upward to $3 million will cover over 90 percent of capital projects.

Conclusion

The Joint Utilities thank Staff for their consideration of the above comments and look forward to reviewing the final proposed guideline revisions. Please do not hesitate to contact us if Staff requires clarification or has questions regarding these comments.

Respectfully,

/s/ Riley Peck

Riley Peck,
Senior Manager, Regulatory Strategy and Engagement
Portland General Electric

/s/ Alison Williams

Alison Williams,
Regulatory Policy & Strategy Leader
Idaho Power

/s/ Matthew D. McVee

Matthew D. McVee
Vice President, Regulatory Policy and Operations
PacifiCorp

Cc: UM 2005 Service List
Nick Sayen
Sarah Hall

Attachment A: Joint Utilities' suggested redlines to Staff's proposed guideline revisions

Attachment A: Joint Utilities' Suggested Redlines to Staff Proposed Distribution System Planning (DSP) Guideline Revisions

September 2024

Clean version

New changes are shown with yellow highlight. For guiding context for these revisions, please see Staff's September 17, 2024, Update and Response to Stakeholder Feedback, posted to Docket No. UM 2005 separately.

Distribution System Planning Guidelines

Table of Contents

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 utility[1] must file its next Plan on or before the following dates, or an alternative date designated by Commission order.

Idaho Power: March 6, 2026
Portland General Electric: April 1, 2025
Pacific Power: March 31, 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.

[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.

f) 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

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

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 updated guidelines for community engagement are intended to foster a process that has continued to develop since DSP Guidelines were adopted in 2020, and 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.

Local governments and Tribal nations may also play an important role in DSP-related community engagement, and can provide input to the utility on policies intersecting with distribution system planning.

Specific requirements for utilities include:

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, while maintaining accessible engagement forums, and integrate

[2] 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 host at least two stakeholder workshops.

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, and 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 that may have a reasonable expectation of impacting surrounding communities. Larger projects may exclude, for example, regular maintenance projects, or inspection projects. The Community Engagement Plan should include the activities described below.

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 information, for example datasets and metrics to guide community-centered planning of the possible non-wire solutions or larger projects.

iii) Consider engagement of local governments and Tribal nations for input on possible non-wire solutions, larger projects, as well as on other policies intersecting distribution system planning. Examples of such policies may include micro-grids and other resiliency planning, or local environmental and climate plans such as fleet-electrification and building-electrification efforts.

e) Utilities should aim to create a collaborative and accessible 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.

Recognizing that some asset information is relatively static, a utility may refer to or include asset information provided in a prior DSP. The utility should provide, at minimum:

a) A summary description and table of the utility's distribution system assets including:

i) Asset classes

[3] For the purposes of these guidelines "distributed energy resource" includes distributed generation resources, 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.

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

b) 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)

c) 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

ii) The percentage of system reached with each capability, the percentage of customers reached with each capability

iii) Any utility programs utilizing each capability

d) Historical distribution system spending for the past five years, in categories that reflect Company project management and financial management practices, and have been shared with Staff prior to filing.

e) Net Metering and Small Generator information:[4]

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.

f) 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, or other properly cited, publicly available data source.

g) Plans should include high-level summary data on electric vehicles (EV) and EV charging, or link to such data if it is provided through other utility planning practices or publicly available

[4] 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).

sources. If not provided through other utility planning practices or publicly available sources, the data should include:

i) Total number of EVs of various sizes served by the utility's system at time of filing

ii) Number of EVs added to the utility's system in each of the last five years

iii) Total number of charging stations on the utility's system, broken down by type, ownership, and feeder

iv) Total number of charging stations added to the utility's system in each of the last five years, broken down by type

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

vi) Summary data of other transportation electrification infrastructure, if applicable

h) Plans should include high-level summary data on demand response/flexible load pilot and/or program performance metrics for the past five years, or link to such data if it is provided through other utility planning practices. If not provided through other utility planning practices, the data should include:

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

~~i)~~ Utilities should propose a cadence for ~~S~~summary-level progress reporting on activities included in the last-filed DSP. The proposed progress report may be formal or informal. The intent is to clearly communicate substantive developments (for example new project initiation, project advancement, completion, or delay) that may occur between DSP filings and may appear in the recovery process.~~of:~~

i) ~~Investments/expenditures from the Long-term Plan~~

ii) ~~Investments/expenditures from the Near-term Action Plan~~

j) Data and information assembled for the Current System Data and Assessment requirement should be submitted to the Commission in electronic format and without protective order when appropriate. Utilities may take necessary action to protect confidential or sensitive information that is sought in this electronic submission, such as anonymizing customer data or critical infrastructure.

5. 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 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:

a) Forecast of load growth to a granularity of, at a minimum, the substation level, including discussion of:

- i) Forecasting method and tools used to develop the forecast
- ii) Forecasting time horizon(s)
- iii) Data sources used to inform the forecast (sources and vintage should be clearly identified in DSP filings)
- iv) The load forecast should include data, inputs, and assumptions from the Company's most recent IRP/CEP, or from the most current and accurate sources at the time. Sources should be consistent with those used in other Company planning practices at the time. Examples include but are not limited to:
  - (1) System modeled scenarios decomposed to the distribution system
  - (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.

b) Forecast of DER adoption and EV adoption to a granularity of, at a minimum, the substation level, including discussion of:

- i) Forecasting method and tools used to develop the forecast
- ii) Forecasting time horizon(s)
- iii) Data sources used to inform the forecast (sources and vintage should be clearly identified in DSP filings)
- iv) The forecast should include high/medium/low scenarios for both DER adoption and EV adoption
- v) The DER adoption and EV adoption forecasts should include data, inputs, and assumptions from the Company's most recent IRP/CEP or from the most current and accurate sources at the time. Sources should be consistent with those used in other Company planning practices at the time. Examples include but are not limited to:
  - (1) Community based renewable energy (CBRE) forecast, potential study, RFP, needs assessment, etc.
  - (2) Small scale renewable (SSR) forecast, potential study, RFP, needs assessment, etc.
- vi) The methodology for geographical allocation is at the utility's discretion. The Commission may provide direction for subsequent Plans.

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:

- i) Explain the reasons for completing the exercise for a portion of the system
- ii) Describe for how much of the system the exercise was completed, in terms of customers, load, substation count, and feeder count
- iii) Discuss whether and how the utility plans to complete the exercise in future DSPs

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 utility-owned or third-party 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 considered. Grid needs identification should be comprehensive and inclusive, identifying the biggest drivers and trends behind needed investments~~ and operational budgets~~. A utility's DSP investments are expected to be generally responsive to identified grid needs. ~~Where investments do not align with identified grid needs, a~~ A utility should be prepared to explain in its summary progress report (see guideline 4. i)) the change in needs and circumstances requiring substantial divergence from the last filed DSP~~ as part of the cost recovery process~~.

A utility's Distribution System Plan should:

a) Describe any currently used system assessment processes and practices (such as system reliability assessments, system asset health assessments, etc.) that are utilized in assessing grid adequacy and identifying grid needs and evaluating possible solutions, which may include:

i) Criteria, methods, and tools used to develop the assessment
ii) Forecasting time horizon(s)
iii) Key performance metrics

b) Discuss and identify anticipated grid needs, to the extent such identification does not violate customer privacy or NERC/CIP protections, including the following:

i) Replacement 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 identified through other utility planning processes including, as relevant:

(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
(5) Annual reliability reporting, and any related performance issues

v) Timing of grid needs

c) Provide a summary table of each identified grid need, and specify the timing of each need.

7. 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, 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). A utility's DSP investments are expected to be generally consistent with identified solutions. ~~Where investments do not align with the solutions identified, a~~ A utility should be prepared to explain in its summary progress report the information and circumstances that informed the selection of an investment inconsistent with identified solutions in the last filed DSP~~ as part of the cost recovery process~~.

The utility should assess grid needs to determine solutions as follows:

a) Document the process to identify the range of possible solutions to address grid needs.
b) Identify at a project- or program-level processes or approaches to employing no or low-incremental cost options to resolve a grid need without capital projects (examples may include rebalancing distribution loading through switching and phase balancing, or other actions).
c) Assess each identified grid need for possible traditional solutions, alternative solutions, and for low-cost solutions.

~~i) Document possible solutions in Near-term Action Plan investment/expenditure summaries.~~

d) If a utility has candidates that reasonably could be considered for non-wires solutions, ~~Evaluate at least two non-wires solutions pilot~~ a concept proposal~~s~~ should be developed. If no candidate is identified, a utility should describe what investments would be necessary to enable NWS in its service area.
In the~~se~~ NWS concept proposals, non- wire solutions would be used in the place of traditional utility ~~investment/expenditure~~infrastructure. 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, or power quality improvements in underserved communities.

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. A utility may propose regulatory investment and cost-recovery treatment for the proposed project. In addition, pilot concept proposals should utilize the utility's Community Engagement Plan 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.

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. The Near-term Action Plan should include a prioritized list of investments/expenditures, investment/expenditure summaries, and projected spending. These elements should guide DSP implementation and provide a preview of investments/expenditures for which cost recovery may be sought in future general rate cases. ~~Where a utility's implementation of the Near-term Action Plan does not align with the Near-term Action Plan contained in the DSP,~~ ~~a~~A utility should be prepared to explain in its summary progress report where a utility's implementation of the Near-term Action Plan does not align with the Near-term Action Plan contained in the last filed DSP ~~its rationale for deviation in the~~ to inform the cost recovery process.

The utility should use best efforts to include the content identified below, or provide an explanation for why it was not included~~Specific requirements include~~:

a) Prioritized list of the utility's proposed solutions (investments/expenditures) over the next five years to address identified grid needs.
b) A summary of each planned investment/expenditure estimated to cost more than $2 million. Each summary should be no more than one page in length and should include:

i) Project narrative including the asset classes and unit counts of proposed solution, and as available, foundational assumptions and key barriers or constraints (for example financial, technical, organizational) and mitigation plans
ii) Estimated timeframe
iii) Estimated project cost/expenditure amount
iv) Description of the criteria and methods the utility used to prioritize the investment/expenditure in Guideline 8a, including consideration of if, and how the investment/expenditure advances State policies and goals and PUC objectives, including but not limited to:[5]

- Reliability
- Safety and security
- Customer benefits and promoting inclusion of underserved populations
- Optimized operation of the system
- Efficient integration of DERs

When possible, the description should include quantification of the improvement in the goal[6] and should demonstrate improvement by using cited, publicly available data, for example a utility's Annual Reliability Report. Should a planned investment/expenditure advance a goal not included above, a utility should explain the rationale for the investment/expenditure, and when possible, include quantitative outcomes.
v) Where available, ~~D~~description of alternative solutions considered (for example, traditional utility solutions, low-cost solutions, and if applicable any non-wires solutions the utility may have considered)~~ including the proposed asset classes and unit counts, and estimated project cost/expenditure amount for each alternative~~.
vi) Description of if, and how the investment/expenditure 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).
vii) Description of if, and how the proposed investment/expenditure interacts with non-distribution asset strategies (for example, transmission strategies), whether alternatives to distribution investment were considered, and if made, what impact does the proposed investment/expenditure have on other network assets.

c) Projected spending: Provide a table of the projected annual cost and timeline to implement the Action Plan. Provide a description of anticipated requests for cost recovery.

---

[5] These high-level goals were developed collaboratively with parties through the course of the Docket No. UM 2005 investigation.
[6] Examples may include but are not limited to:
Reliability – reduction in outages or duration
Safety and security – reduction in equipment failures, or vulnerabilities
Customer benefits, and promote inclusion of underserved populations – improvement in customer service, increased program participation in underserved populations
Optimized operation of the system – reduction in operating costs
Efficient integration of DERs – increased adoption of demand-side and renewable resources

9. Long-term Plan

This section of the Plan consists of the utility's long-term investment plan. The Long-term Plan should include a 10-year vision, a ~~list~~ narrative description of investments/expenditures the utility expects to make in years 6 through 10 (an extension of the Near-term Action Plan)~~, and investment/expenditure summaries~~. These elements should present investments/expenditures a utility anticipates pursuing, recognizing that grid needs, circumstances, and State polices may change over the planning horizon. These elements should provide Staff and stakeholders with a preview of investments/expenditures that may be seen in future distribution system plans~~, and possibly in future general rate cases~~. Staff anticipates that a utility's actions should remain consistent with its 10-year vision for the distribution system. However, refinement of the list of expected investments/expenditures will likely be necessary. A utility should be prepared to explain evolution of its Long-term Plan in each distribution system plan.

Specific requirements include:

a) The utility's vision for the distribution system for the next 10 years, and a discussion of if, and how, it aligns with State policies and goals and PUC objectives, including but not limited to:[7]

- Reliability
- Safety and security
- Customer benefits and promoting inclusion of underserved populations
- Optimized operation of the system
- Efficient integration of DERs

~~b) Prioritized list of investments/expenditures the utility expects to make in years 6 through 10 in order to advance the 10-year vision.~~

~~c)~~b) A summary of ~~each~~ the planned investment/expenditure ~~which should be no more than one page in length~~to advance the 10-yr vision, and include the following, as available:

i) Project narrative including, as available, foundational assumptions and key barriers or constraints (for example financial, technical, organizational) and mitigation plans.

ii) Estimated timeframe

~~iii) Estimated project cost/expenditure amount~~

~~iv) Description of the criteria and methods the utility used to prioritize the investment/expenditure in Guideline 9b, including consideration of if, and how the investment/expenditure advances policies/goals/objectives identified in Guideline 9a, and consideration of any connections to, and impacts on, Near-term Action Plan projects.~~

~~v)~~iii) Description of if, and how the investment/expenditure fits with the utility's other planning processes (such as the most recent IRP/CEP, Wildfire Mitigation Plan, TE Plan, and DR/Flexible Load Plan).

[7] These high-level goals were developed collaboratively with parties through the course of the Docket No. UM 2005 investigation.