**Portland General Electric**
121 SW Salmon Street · Portland, Ore. 97204

# UM 2005 - Distribution System Planning

## Section A
## Current Distribution Planning Processes

**In Section A of your response, please provide the following information about the current distribution plans, reports, and other relevant components of distribution system planning:**

1) **Strategy: Please include an overview of the utility's approach to distribution system planning, including:**
   a. **What are the utility's planning goals? What are the major planning objectives? Which objectives are primary vs secondary?**

      *Distribution planning goals are to deliver a system that can be operated safely and reliably. To meet these goals, various drivers are identified to determine which parts of the system may be the most vulnerable or in need of attention. Planning drivers can include either load growth (natural, or customer driven) or additional requirements focused on asset risk, reliability, and safety.*

      *Load Growth / Design Criteria: PGE's system is designed to serve existing customer load with adequate reserved capacity to ensure service continuity in the event of a device failure. For distribution studies, a device failure includes the loss of a single distribution feeder or a distribution power transformer.*

      *Reliability: Planning studies ensure that PGE operates within reliability metrics for SAIDI. A risk-based approach provides the ability to determine the relative changes in potential project value due to calculation of non-asset risk per each presented option.*

      *Asset Risk: Each project evaluates existing assets, including cost of ownership of these assets, to determine feasibility of including improvements to reduce these inherent costs while maintaining net positive benefit.*

      *Safety: Each project is vetted by a team of technical, environmental, and security experts to ensure that the proposed project meets all criteria required to operate the new system in a safer manner.*

   b. **Provide a general description of how the utility plans for:**
      i. **Load growth**

         *Load growth is factored in planning studies based on either lumped load additions or natural growth. Currently, load growth is factored utilizing a top-down approach in which projected coincidental loading is* *forecasted at the system-wide level, and then allocated across distribution feeders based on historical loading patterns.*

ii. **Aging infrastructure (replacement)**

*PGE considers replacement of aging substation and distribution assets by utilizing a risk-based approach. With this approach, an asset's value is determined by evaluating risk of an asset's likelihood of failure along with the resulting consequence of the asset's failure. Although an asset's age is a significant factor, other factors include the magnitude of customer impact, safety implications, environmental impacts, and total economic value.*

iii. **Increased penetration of the various types of DERs—What does the utility do to accommodate DER penetration in its distribution system?**

*DER penetration is currently considered inherent with the system forecast and existing DER is considered within the bounds of the planning study. The utility has not actively assembled a project to accommodate DER penetration outside of the bounds of OAR Rule 860.*

iv. **Climate change impacts on the system**

*The utility has not actively incorporated climate change within its distribution planning process.*

v. **Advances in equipment (e.g. controls, communications, awareness)**

*System visibility is a key component to distribution planning, and PGE makes every effort to add or enhance communications, monitoring, and to substations and field communicating devices.*

vi. **Reliability**

*Each planning project considers improvement in reliability in the form of non-asset risk reduction. The replacement of aging assets coupled with optimal system reconfiguration allows for disturbance reduction due to external events as well as reducing restoration time if an event occurs.*

c. **How does the utility define "distribution system"?**

*A distribution system is a mechanism used to provide electric power to each connected consumer. PGE's Application for Support to Reclassify Plant in*

*Service filing in UM 2031 goes into detail of determining distribution facilities.*[1]

d. **In its whitepaper launching the DSP investigation, Staff cited the U.S. Department of Energy's definition of distributed energy resources (DER):**

> **Distributed generation resources, distributed energy storage, demand response, energy efficiency, and electric vehicles that are connected to the electric distribution power grid**

**Staff is also considering adopting the National Association of Regulatory Utility Commissioner (NARUC's) definition of a DER for this investigation:**

> **A DER is a resource sited close to customers that can provide all or some of their immediate electric and power needs and can also be used by the system to either reduce demand (such as energy efficiency) or provide supply to satisfy the energy, capacity, or ancillary service needs of the distribution grid. The resources, if providing electricity or thermal energy, are small in scale, connected to the distribution system, and close to load. Examples of different types of DER include solar photovoltaic (PV), wind, combined heat and power (CHP), energy storage, demand response (DR), electric vehicles (EVs), microgrids, and energy efficiency (EE).** [2],[3]

**Does either definition align with the utility's definition of DERs or are there modifications that the utility would suggest?**

*Both definitions align with the utility's definition of DER.*

2) **Resources: Please describe the general distribution planning tools and other resources utilized, including:**
   a. **Types of planning and modeling software used and for what specific purpose. For example, does the utility make use of GIS technology in distribution system planning?**

      *Distribution Planners at PGE primarily use CYME Power Flow software for modeling and analysis of the distribution system. Distribution system topology and associated equipment is extracted from the existing GIS system into the CYME platform.*

   b. **What advanced tools and other planning resources is the utility investing in?**

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1 https://apps.puc.state.or.us/edockets/edocs.asp?FileType=HAA&FileName=haa161923.pdf&DocketID=22081&numSequence=1

2 National Association of Regulatory Utility Commissioners, Manual on Distributed Energy Resources Rate Design and Compensation, p. 45.https://pubs.naruc.org/pub/19FDF48B-AA57-5160-DBA1-BE2E9C2F7EA0#page=46

3 NARUC's definition includes a caveat that diesel-fired backup generators may also fit in this definition and the individual jurisdiction should determine whether to include in its definition of DER.

*The utility is currently investing in an Automated Distribution Management System (ADMS).*

c. **Applicable engineering standards**

*IEEE, ANSI, NFPA, IEC, NEMA.*

d. **Personnel commitment: What personnel resources are involved in distribution system planning? Please include utility personnel as well as contracted services.**

i. **Please provide the number of personnel involved in distribution system planning per year, for the period of 2014 – 2018, identify whether in-house or contract staff.**

*In-house staff includes the following (average # of during calendar year)*
*2014: 4.3 FTE (Full-time equivalent) average*
*2015: 5.4 FTE average*
*2016: 5.5 FTE average*
*2017: 4.5 FTE average*
*2018: 5.1 FTE average*

ii. **Please provide an overview of roles and responsibilities.**

*Perform engineering studies and analyses on PGE's distribution system. Prepare engineering solutions to mitigate system risk and optimize system investments. Document study results, make recommendations, and foster project scoping/estimating process when preparing capital funding requests. Job responsibilities include system evaluation, managing planning related activities within bounded regional areas, coordinating activities with internal workgroups for project development, and maintaining distribution system models.*

3) **Planning description: Please provide an overview of the distribution planning schedules and process, including:**

a. **A description of the various distribution system planning processes, reports and other components utilized.**

- *Verify ratings and loadings for each distribution power transformer and feeder within the service territory*
- *Perform assessment of heaviest loaded distribution power transformers in each distribution region*
- *Identify heavily loaded distribution power transformers and feeders, determine plans for mitigation*

i. **Planning elements or considerations included (or not included) in regular updates and revisions and a description of each. For example: circuit or substation data, power flow analysis, power quality analysis, fault analysis, load and demand forecasts,**

**external policy and regulations, etc.**

*Review and updates to PGE system data include substation and feeder mainline elements, source impedance data, and ratings information.*

b. **Frequency with which the utility conducts the distribution system planning processes.**

*Distribution system planning has adopted an annual process for project planning and submission. Recently, PGE has made efforts to instill a more fluid process related to project development and submission.*

c. **Frequency of planning updates or revisions: Are updates dependent on a set timing frequency (i.e. every 1, 2, 5, or 10 years) or are there events that may trigger a more frequent planning cycle or revision? If so, please explain.**

*Updates or revisions to general assessment documents are performed semi-annually. Updates to more formal documents (white papers) are performed periodically or at request.*

d. **Iterative updates and/or new plans: Are planning processes based on continuations of past plans, new planning cycles, or some combination? How long is each planning cycle's time horizon?**

*Customer-driven plans are immediately added to the planning process. Other types of projects (reliability driven, resiliency driven, etc.) fall into the annual process based on the complexity of the project. More complex projects may require an additional year of study, scoping, etc.*

e. **Integration of existing planning processes: How do the distribution plans inform the Integrated Resource Plans (IRPs), competitive procurement of generating resources (resource RFPs), Smart Grid Reports, transmission planning, and interconnection studies?**

*Distribution planning provides some technical insights that drive potential results with initiatives described in the IRP. Existing planning processes currently do not inform the IRP or overall generation procurement.*

*Distribution planning and transmission planning collaborate on specific projects (large load additions or transmission reliability related) to ensure that needs (such as compliance requirements) are met. This is also reflective of the interconnection studies in which verification of transmission requirements are included.*

f. **How do IRPs, resource RFPs, Smart Grid Reports, transmission planning, and interconnection studies inform distribution system planning?**

*For IRPs, and Smart Grid Reports, distribution system planning plays a role in performing analysis and providing data for the associated updates to the proposals or reports. DSP does align with the goals that are set forth as a result in these documents. Distribution Planning has not yet developed criteria for procurement of generating resources.*

*At PGE, the distribution planning and transmission planning functions are in the same department. Projects with significant elements of both functions are collaborative, and both the distribution and transmission planner will lead efforts to assemble initial project scope, identify risks, determine benefits, and refine the project with subject matter experts.*

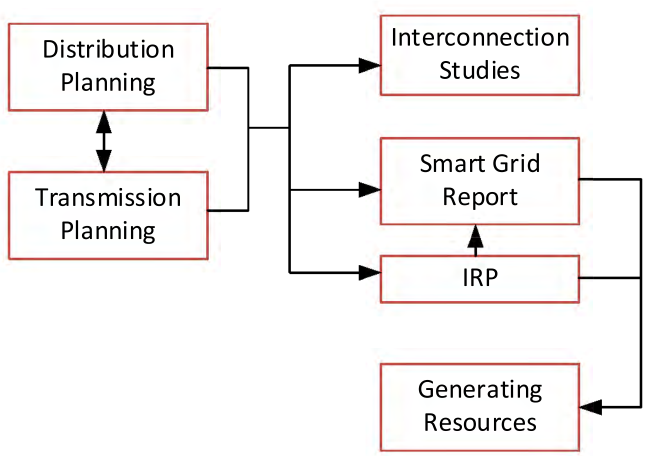
*Interconnection studies performed by the Distribution System Planning group at PGE include parts of the system impact study. Distribution System Planning is in the process of adopting existing interconnections as well as reviewing queued interconnections when performing new studies.*

**g. What is the outcome of your distribution planning process? A plan/report? Budget by field area/region?**

*A project indicating upgrades due to deficiencies in either capacity, reliability, or both will result in a report which includes analysis results, options, justification, B/C analysis, and recommendation. Project budgets are not separated by areas/regions as some projects span several areas within T&D. Budgets are generally assembled by project types (i.e., load additions, reliability, aging infrastructure, etc.)*

**h. Please include a graphic to illustrate the various plans/reports listed in this question (Section A, Question 3) and how they interact with each other.**

*The graphic below represents T&D Planning and their direct influences/contributions to interconnection studies, Smart Grid Report, and the IRP- which in turn influence the future of utilizing generating resources.*



4) **Budget process: Please describe the associated capital and operation and maintenance (O&M) budgeting processes:**
    a. **Process of developing capital budgets for distribution infrastructure.**

        *Capital budget development is a function set by the Capital Review Group (CRG) and the Business Services Group (BSG). Total T&D Budget is set per Corporate Planning based on depreciation of distribution assets as well as customer and shareholder impacts. Capital projects are submitted to the BSG as part of the T&D Portfolio, in which the volume of proposed projects exceed the allowable budget and available resources. Based on value criteria, BSG decides which projects will ultimately be funded.*

    b. **Process for developing budgets for distribution O&M changes or projects, which may include, but are not limited to, information technology, communications, and shared services.**

        *O&M budgets can be set for multiple years depending on the project's function- whether it's programmatic or routine. This budget will be based on historical failure rates and set appropriately.*

    c. **Process for developing New Construction Reports filed with the OPUC.**

        *PGE generates the report using three datasets: historical project actuals using the working forecast, current years data using approved budgets for the year, and working forecasts for future years. Multipliers for each year come from Global Insights. Trojan decommissioning projections are updated annually. Project narratives are pulled from PGE's project justifications. The information is compiled and summarized in the report to the OPUC.*

    d. **Timing of associated distribution system budgeting processes: Describe timing of annual distribution system planning activities and specific deadlines related to broader utility planning and budgeting processes.**

        *The annual budgeting process begins in the June preceding the year of new project funding or construction. A bulk of the T&D Projects are vetted during this time. In addition to the annual process, projects are also proposed on a rolling basis as needed. These projects are presented during the monthly CRG meetings and are approved accordingly by the BSG based on updated timelines, and current or forecasted budget.*

    e. **Distribution system schedule i.e., is it performed on an annual basis or on some other schedule?**

        *The capital distribution system schedule is updated on a continuous basis to depict current and future activities during various design and construction phases. This schedule does undergo a major revision during the annual budgeting process as new projects are proposed and either approved or* *deferred. Ongoing programs are built on separate schedules.*

f. **Budget categories are used? For example, New Service, Asset Health, Street Lights, Substation Capacity, Reliability, Equipment Purchase, etc.**

*Budget Categories include Substation Upgrades and Rebuilds, T&D Upgrades and Rebuilds, Communications Upgrades and Rebuilds, Misc. Materials Equipment and Fleet, and Customer / Other.*

i. **Do you have construction allowances?**

*Yes. PGE's line extension policy is provided in PGE Rule I. The amounts are provided in PGE Schedule 300.*

g. **Which parts of the budget are discretionary i.e., the utility has some level of flexibility on timeframe, projects/solution, or other decision-making element? Please explain.**

*Any discretionary funding is determined by PGE's Business Sponsor Group or PGE's Capital Review Group. Funding is allocated for new customer connects regardless of volume. Previously funded projects may be reduced in scope or deferred based on individual risk, cost/benefit, etc.*

5) **Capital investments and O&M projects: Please describe the processes to identify and assess capital and O&M investments:**

*Drivers to determine capital assessments include new large customer/lump load additions, changes or expansion to the urban growth boundary, zoning changes, and periodic system assessments.*

a. **Assessment criteria and assessment process for reliability of grid assets (e.g., feeder, substation), condition of grid assets, and asset loading.**

i. **How do you decide what equipment to replace (e.g., age, performance, etc.)?**

*Assets are primarily evaluated based on the total risk as determined based on customer types, number of customers, aging and degradation, equipment test results, failure rates, etc.*

ii. **How do physical inspections and other operations functions inform this assessment?**

*Initial assessments are based on tabular models of the entire distribution system. If physical inspections or monitoring programs are present, these are built into the equipment models.*

b. **Cost/benefit analyses the utility performs for distribution system planning:**

i. **For what types of investment decisions are cost/benefit analyses**

**performed?**

*Cost/benefit analyses are performed for most distribution-related projects.*

ii. **What type of analysis is used?**

*PGE creates a Risk Register that is a compilation of significant assets in the T&D system, indicating their likelihood of service failure and their consequence of service failure. PGE remediates risks by proposing projects that address high concentrations of risk, as identified in the Risk Register. Projects are prioritized for execution based on their risk reduction potential, the value of the proposed risk reduction work, and implementation constraints. There are several types of projects generally resulting from the Risk Register approach.*

iii. **Which non-monetized benefits are included in these analyses (e.g., emissions reductions?)**

*Equipment test data (e.g., DGA), external equipment data (e.g., transformer bushings or monitoring equipment), failure data, hazardous material content, etc.*

iv. **Are there hard-to-quantify benefits associated with the utility's investment decisions? How are these included in your analysis?**

*Soft benefits that are hard to quantify (e.g., increased safety) are included in overall analyses with their own scoring metrics.*

v. **When investments are interdependent with other investment decisions, how does your investment analysis change?**

*Projects are reviewed holistically either within a bounded area, or as a certain program. If an investment depends on a separate investment decision, plans/timelines are assembled initially to perform all involved projects- at times, these projects are segmented to accomplish baseline goals, and reviewed to determine additional benefits.*

c. **Alternative analysis protocols for identified needs:**

i. **Capital versus operating solutions: How does the utility determine whether an assessed need is best met through a capital project or through operational solutions?**

*In most cases, a capital project is assembled to mitigate an operational deficiency. Operational solutions are usually temporary but can be effective in delaying a capital investment. At times, a capital investment will be coupled with a front-end operational solution.*

ii. **Near-term versus long-term: How does the utility consider the**

**costs and benefits of long-versus-short-term solutions?**

*Capital projects are designed to reap long term benefits. In the event that a long term solution reaps similar benefits to several short term solutions, they will be evaluated and compared.*

iii. **Non-monetized benefits: Does the utility consider different benefits when taking alternative approaches to resolving system needs?**

*The utility does review non-monetized benefits as part of the project evaluation process.*

iv. **Non-wires-alternative (NWA) versus traditional solutions: How does the utility consider the potential for DER or other non-wires solutions to address an assessed need or to defer or eliminate the need for a traditional capital or operating solution? Is assessment of NWA performed in a systematic or ad hoc way? If not provided in responses to Section B, please provide examples of any NWA solutions the utility has analyzed and/or implemented, if any.**

*The utility has not yet included NWA as part of its systemic planning process.*

v. **Identifying solutions: How are options to meeting a need identified?**

*Options are identified as basis of system need while differentiating levels of these needs. A base option is identified to provide minimal benefit, but additional options are determined and studied to determine additional operational or reliability benefits.*

vi. **Scenario analysis: In developing solutions to an assessed need, does the utility consider multiple scenarios, including load forecasts and DER penetration? If so, what scenarios are standard?**

*Limited scenarios are considered when developing solutions/options. These scenarios currently include forecasted peak loading periods.*

vii. **Assessing NWA alternatives: What criteria or metrics are used in assessing whether a NWA can meet an identified need?**

*NWA alternatives have not yet been vetted within Distribution Planning.*

d. **Metrics for deciding among competing proposals: For any of the applicable categories described in 5c(i) – 5c(vii), what specific metrics are used to conduct a comparison of alternative solutions? If not provided in responses to Section B, please provide an example(s) of cost-benefit studies or reports the utilities have conducted as an attachment?**

*Overall asset and non-asset risk reduction drive the hard benefits for most capital projects. Options analyses provide a clear picture of which project(s) will yield the greatest benefits.*

6) **Demand and system loading forecast methodologies: Please describe the demand and load forecasts that inform the utility's distribution system planning, including:**

a. **Granularity of load forecasting: To what level of granularity does the utility forecast? To what extent is the distribution system data collected by the utility reflected in load forecasts (e.g., does the utility employ an 8760-hour forecast at the substation level?)**

*The utility has not adopted an 8760 hour forecast.*

b. **Use of company-wide peak forecasts versus aggregation of substation or other circuit-level peaks: Does the utility use a top-down forecasting approach versus a bottom-up approach, or some combination of these approaches? Does the utility utilize peak-hour forecasts?**

*Load forecasts use a top/down approach via the corporate used for net system load. Peak coincidental loading for summer and winter seasons are allocated per each distribution power transformer and scaled for future seasons and severity of the loading.*

c. **Comparison of actual asset loading against past forecasts: Does the utility employ backcasting or ex post true-up to assess the accuracy of its forecasting process?**

*Backcasting is performed under rare circumstances.*

d. **Minimum load assessments and forecasts: Does the utility measure minimum load by circuit? Does the utility utilize minimum load to assess potential impacts of distributed generation on power flows? Are minimum loads measured during peak hours or during night hours?**

*Minimum load assessments are determined on a case-by-case basis for interconnection related studies. These minimum loads are measured during daytime hours.*

e. **Impact on load forecasts of the projected availability of DER: What approaches and models does the utility use to forecast DERs?**

*The utility has piloted a DER forecast via third party, but has not implemented a related process.*

i. **How does the utility forecast the impact of DERs on distribution system needs?**

*DER forecasts are not currently performed.*

ii. **How is utility forecasting impacted by utility assessments on adoption and penetration of DER?**

*The utility forecast inherently includes DER penetration as part of its net system load but does not provide a breakdown of DER versus load.*

iii. **Are multiple scenario forecasts developed, and if so, what are the basis of variations in scenarios?**

*For the corporate forecasts, scenarios are seasonal (peak summer and peak winter) and include temperature adjusted peaks scenarios for these seasons.*

7) **Locational assessment of DER:**

a. **Describe whether locational DER assessments are a part of the planning process and the process for assessing this.**

*Locational assessment of DER is not yet part of the planning process.*

b. **What form of hosting capacity software or analysis, if any, is used in the planning process? Please describe.**

*PGE is an EPRI participant and has utilized the DRIVE tool to perform some hosting capacity analyses; however, hosting capacity has not yet been included in the planning process.*

c. **Is hosting capacity analysis conducted system wide and/or in response to interconnection requests?**

*Hosting capacity analyses are performed on a case by case basis as a response to interconnection requests upon request.*

## Section B
## Current Distribution System Plans

**In Section B of your response, please provide the following information for the current status of the utility's plans, reports, and other relevant components described in Section A. Please include information that is relevant to the utility's *Oregon* distribution systems:**

1) **The date initiated, completed, and the planning timeframe used: For each planning component (as described in Section A, Question 3a), the number of years to which it is applicable should be specified.**

   *Various processes are performed either annually or semi-annually to help inform areas of focus. Related deliverables for 2019 include the following:*

   - *Peak Loading Assessment Report (2/7/19 – 4/19/19; 9/6/19 – 11/4/19)*
   - *Heavily Loaded Equipment Reports (4/29/19 – 5/7/19; 11/14/19 – 11/29/19)*
   - *10-year load forecasting (02/19 – 05/19)*

2) **Scenarios: the range of any scenarios that were considered should be identified, e.g. high/low load forecast, high/low DER penetration.**

   *Currently, scenarios are based on peak load forecasting.*

3) **System constraints and needs:**
   a. **At a high level, what system constraints and needs have your planning processes anticipated to develop or occur within the planning period? (Further detail on system characteristics is requested in Section C)**

      *These processes are used to identify potential future loading constraints within certain areas in the distribution system.*

   b. **How have these constraints and needs been prioritized based on assessment criteria, time sensitivity, budget impact, or other criteria?**

      *These constraints have been prioritized based on likelihood of failure due to future load growth (year(s) violations may occur). Risk analyses are performed to determine overall project value.*

4) **A description of how the utility is planning for distributed generation coming online.**

   *The QF process provides analysis to determine impacts to each DG which is coming online in the future.*

5) **Historical and current budgets, including:**
   a. **Historical distribution system spending: Please provide historical**

**spending over the past five years, and to the extent possible, breakdowns of categories of expenses and budgets (such as those listed in Section A, Question 4d) for capital projects, O&M projects, information technology, communications, and shared services.**

*See Attachment A for O&M historical system spending.*

*See below for capital project historical system spending:*

| | **2014 Actuals** | **2015 Actuals** | **2016 Actuals** | **2017 Actuals** | **2018 Actuals** |
|---|---|---|---|---|---|
| Base Business | $ 128,187,381 | $141,893,552 | $169,125,238 | $ 177,292,740 | $ 188,475,893 |
| Infrastructure Resiliency | [redacted] | | | $ 43,406,771 | $73,042,576 |
| Strategic-Projects Funded Directly by Board Resolution | $ 33,021,484 | $15,358,198 | $14,346,406 | $35,217,871 | $ 43,449,884 |
| **Total** | **$ 161,208,865** | **$ 157,251,750** | **$ 183,471,644** | **$ 255,917,382** | **$ 304,968,353** |
| **% Change from Previous Year** | | -2% | 17% | 39% | 19% |

b. **Current distribution system spending: Please provide capital and O&M budgets over the applicable planning period, and to the extent possible, breakdowns of categories of expenses and budgets (such as those listed in Section A, Question 4d).**

*See Attachment A for O&M current year spending.*

*See below for capital project current year spending:*

| | **2019 YTD Actuals+Forecast 7+5** |
|---|---|
| Base Business | $222,280,956 |
| Infrastructure Resiliency | $ 88,294,240 |
| Strategic-Projects Funded Directly by Board Resolution | $9,259,148 |
| **Total** | **$ 319,834,344** |
| **% Change from Previous Year** | 5% |

i. **Where individual budget categories contain a substantial increase or decrease from historical levels, please explain the rationale for the change.**

O&M
*See Attachment A.*

*Capital Spending*
*2015-2016 Increase: Primary driver is the Distribution Customer and System projects, which increased approximately $9.3M between 2015 and 2016.*

*2016-2017 Increase: In 2017, Distribution began the Transmission and Distribution Resiliency Initiative, a five-year project to modernize aging infrastructure that had a high risk of customer impact if it failed. To support the program, PGE increased the capital portfolio to enable the program.*

*2017-2018 Increase: Primary driver is Transmission and Distribution Resiliency initiative, with projects moving from planning in 2017 into execution in 2018 and new projects beginning planning and detailed design for 2019 execution.*

**c. Comparison: For each of the past five years, please provide a comparison of forecasted distribution system spending by year versus actual spending.**

*O&M*
*See Attachment A.*

*Capital*
*Note: Over or underspend by Distribution in Base Business and Infrastructure Resiliency is offset by tradeoffs in PGE's capital portfolio.*

| **2014** | | | |
|---|---|---|---|
| | **BOD Budget** | **Acutals** | **Variance (Over)** |
| Base Business | $ 115,894,843 | $ 128,187,381 | $ (12,292,538) |
| Infrastructure Resiliency | [redacted] | | |
| Strategic-Projects Funded Directly by Board Resolution | $ 54,326,284 | $ 33,021,484 | $ 21,304,800 |
| **Total** | **$ 170,221,127** | **$ 161,208,865** | **$9,012,262** |

*Base $12.3M over. Significant Variances:*
- *L&G Remote Disconnect Meters $5.8M*

*Strategic: $21.3M under. Significant Variances:*
- *LED Streetlight Replacement. $12.2M*

- *Sewell - Easements $5.4M*

| 2015 | | | |
|---|---|---|---|
| | **BOD Budget** | **Acutals** | **Variance (Over)** |
| Base Business | $ 148,400,587 | $ 141,893,552 | $ 6,507,035 |
| Infrastructure Resiliency | | | |
| Strategic-Projects Funded Directly by Board Resolution | $ 12,301,746 | $15,358,198 | $ (3,056,452) |
| **Total** | **$ 160,702,333** | **$ 157,251,750** | **$ 3,450,583** |

*Base $19.8M over. Significant Variances:*

- *Distribution Customer and System Construction $14.1M*

*Strategic $3.6M under. Significant Variances:*

- *Construct Marquam Substation $3.9M*

| 2016 | | | |
|---|---|---|---|
| | **BOD Budget** | **Acutals** | **Variance (Over)** |
| Base Business | $ 149,302,773 | $ 169,125,238 | $ (19,822,465) |
| Infrastructure Resiliency | | | |
| Strategic-Projects Funded Directly by Board Resolution | $17,951,029 | $ 14,346,406 | $3,604,623 |
| **Total** | **$ 167,253,802** | **$ 183,471,644** | **$ (16,217,842)** |

*Base $19.8M over. Significant Variances:*

- *Distribution Customer and System Construction $14.1M Over*

*Strategic $3.6M under. Significant Variances:*

- *Construct Marquam Substation $3.9M Under*

| 2017 | | | |
|---|---|---|---|
| | **BOD Budget** | **Acutals** | **Variance (Over)** |
| Base Business | $ 145,116,175 | $ 177,292,740 | $ (32,176,565) |
| Infrastructure Resiliency | $ 94,997,387 | $ 43,406,771 | $ 51,590,616 |
| Strategic-Projects Funded Directly by Board Resolution | $ 22,484,569 | $ 35,217,871 | $ (12,733,302) |
| **Total** | **$ 262,598,131** | **$ 255,917,382** | **$ 6,680,749** |

*Base: $32.2M over. Significant Variances:*

- *Distribution Customer and System Construction $26.1M*

*Infrastructure Resiliency $51.6M under. Significant Variances:*
- *T&D Substation Reliability Upgrades $36.1M*

*Strategic: $12.7M over. Significant Variances:*
- *Construction Marquam Substation $12.8M*

| 2018 | | | |
|---|---|---|---|
| | **BOD Budget** | **Acutals** | **Variance (Over)** |
| Base Business | $ 162,592,795 | $ 188,475,893 | $ (25,883,098) |
| Infrastructure Resiliency | $ 77,588,928 | $ 73,042,576 | $ 4,546,352 |
| Strategic-Projects Funded Directly by Board Resolution | $ 16,537,481 | $ 43,449,884 | $ (26,912,403) |
| **Total** | **$ 256,719,204** | **$304,968,353** | **$ (48,249,149)** |

*Base $25.9M over. Significant Variances:*
- *T&D Major System Inspect, Replacement $11.0M*
- *Replace Failed Underground Cables $5.9M*
- *McGill Sub Capacity Additions $5.2M*

*Infrastructure Resiliency $4.5M under. Significant Variances:*
- *Harborton Reliability Project $9.8M.*

*Strategic: $12.7M over. Significant Variances:*
- *Construct Marquam Project $11.7M*

| 2019 | | | |
|---|---|---|---|
| | **BOD Budget** | **Acutals+Forecast (7+5)** | **Variance (Over)** |
| Base Business | $183,068,648 | $ 222,280,956 | $ (39,212,308) |
| Infrastructure Resiliency | $ 90,291,759 | $ 88,294,240 | $ 1,997,519 |
| Strategic-Projects Funded Directly by Board Resolution | $ 4,375,858 | $ 9,259,148 | $ (4,883,290) |
| **Total** | **$277,736,265** | **$ 319,834,344** | **$ (42,098,079)** |

*Base: $39.2M over. Significant Variances:*
- *T&D Major System Inspect, Replacement $13.6M*

- *Replace Failed Underground Cables $4.5M*
- *Sensus DT34 Meter Exchanges $4.8M*
- *Roseway Substation Expansion $4.1M*

**6) Currently planned distribution capital projects and O&M changes and projects, including:**

- *Stephens substation 11 to 13kV conversion*
- *Marquam substation feeder addition*
- *Redland Substation Upgrades*
- *Rock Creek Substaiton Construction*
- *Roseway Substation Expansion*
- *North Portland Conversion*
- *Mt Pleasant Substation Upgrades*
- *Silverton Substation Capacity Addition*
- *Centennial Substation Upgrades*
- *Willbridge Substation 11 to 13kV conversion*

**a. Whether/which alternative analyses were conducted (as described in Section A, Question 5c). Please describe.**

*Each project had option analyses conducted and were ranked based on Cost/Benefit, risk, and non-quantifiable benefits.*

**b. Whether future capital or O&M projects were identified using DER alternatives. Please describe.**

*For this grouping of projects, none were identified in utilizing DER alternatives.*

**c. Identification of any non-monetized benefits of planned projects.**

*Considered non-monetized benefits include workforce readiness, efficient operations, safety, impacts to organizational change, environmental stewardship, sustained growth, and customer satisfaction.*

**d. Identification of any projects that will enhance the company's future ability to integrate DER into system operations.**

*There are currently no Distribution Planning sponsored projects aimed at enhancing the ability to integrate DER into system operations.*

**e. Which distribution projects are selected and approved within the scope of projects proposed. Please explain why.**

*Within the scope of projects proposed, those that meet both economic benefits and non-monetized benefits are first to be selected and approved due to their overall benefits to PGE's system and its customers. Customer-driven projects will supersede most other projects in order to meet customer construction timelines and associated goals.*

## Section C
## Current Distribution System

**In Section C of your response, please provide the following information about the current status of the utility's *Oregon* distribution systems:**

1) **System Protection:**
    a. **Describe types of protection schemes and devices utilized in distribution circuits, including but not limited to line reclosers, trip savers, tap fuses, outage management systems (OMS), etc.**

    *Protective devices on distribution circuits include feeder breakers, reclosers, fuses, trip savers, and sectionalizers. PGE has also been building out distribution automation via use of automated reclosers.*

    b. **Provide an estimate the amount of the system where distribution automation (DA) is deployed. Please provide any relevant context about how these technologies are distributed across the utility system and why. Please include, but do not limit responses to:**
        i. **Volt/VAR optimization**

        *Distribution automation does not provide benefits to volt/var optimization. PGE piloted a CVR project at two stations in 2015 in which volt/var optimization was employed to determine benefits.*

        ii. **Fault Detection, Isolation, and Restoration or Fault Location, Isolation, and System Restoration.**

        *Currently, PGE has three active DA schemes which include eleven different feeders. This is approximately 2% of PGE's service territory.*

2) **Monitoring:**
    a. **Percentage of substations and feeders that are equipped with SCADA in the utility's Oregon service area.**

    *About 80% of PGE's stations are equipped with SCADA.*

    b. **Is the utility deploying AMI technology?**
        i. **What is the percentage of AMI meters in the Oregon service territory?**

        *PGE has 100% deployment of AMI meters.*

        ii. **For each customer class (e.g. commercial, residential, industrial), provide the percentage of AMI meters.**

        *Commercial – 12.3%*
        *Residential – 87.7%*

*Industrial – 0.03%*

c. **Describe the backhaul technology the utility employs on its Oregon distribution system. Please provide any relevant context about how these technologies are distributed across the utility system and why. Please include, but do not limit responses to**

*PGE deploys a variety of technologies to backhaul telecommunication traffic. PGE owns an extensive fiber network that connects to its buildings, communication sites, generation plants, and a large number of our high value transmission and distribution substations. PGE uses SONET and Ethernet on its fiber to transport data. Off its fiber, PGE uses leased services from local Telcos, PGE Owned microwave systems, or cellular services to bring the traffic to its network.*

d. **What technology is being used to communicate with field devices as described in Question 1? Please also provide an estimate of what percentage of the Oregon distribution system is communicating with these field devices, if any.**

*Field devices use the same mix of technology. Depending on their location, PGE uses fiber, microwave, leased services or cellular services for communications. PGE is communicating with most of these devices.*

3) **Performance:**

a. **What levels of reliability and other performance factors does the utility plan for?**

*PGE uses the industry standard metrics SAIDI, SAIFI, MAIFI and CAIDI to track reliability performance. PGE also uses the IEEE 2.5 Beta method defined in IEEE 1366-2012 to identify major event days and normalize values.*

i. **Please indicate whether metrics are mandated or driven by company practice or industry standard?**

*PGE's calculation and reporting of SAIDI, SAIFI, and MAIFI metrics are mandated by the Oregon Public Utility Commission. PGE has additional reliability metrics (e.g. CAIDI) that are driven by company practice.*

ii. **Please provide the utility's performance across the metrics over the past 5 years?**

*See table below.*

| Outage Year | SAIDI | SAIFI | MAIFI | CAIDI |
|---|---|---|---|---|
| 2014 | 95 | 0.70 | 1.3 | 136 |
| 2015 | 75 | 0.48 | 1.2 | 156 |
| 2016 | 97 | 0.59 | 1.1 | 163 |
| 2017 | 113 | 0.62 | 1.4 | 181 |
| 2018 | 88 | 0.52 | 1.3 | 172 |

**b. What is the utility's plan/process to address the various types of failures that occur on the distribution system?**

*The company addresses reactive failures as they occur and are identified on the distribution system. These types of failures include both outages to customers and assets identified as failing to adhere to compliance requirements. For customer outages, the company dispatches a line crew to repair or replace the asset and restore power. With respect to compliance failures, PGE has ongoing OH and UG FITNES programs for many T&D assets that are inspected for NESC compliance over a 10-year span via the Facility Inspection and Treatment to the National Electric Safety Code (NESC). The amount of assets replaced or repaired depends on what is found in the field. Capital and O&M funding associated with these programs is currently based on meeting or getting ahead of those compliance targets each year. In addition to NESC compliance inspections, PGE is piloting full a wood pole inspections program for T&D assets with the goal for the program to be ongoing. Similar to FITNES programs, the amount of poles to be replaced depends on what is found during the inspection.*

*In addition to addressing reactive failures, the company has an Asset Management program with the goal to cost effectively avoid asset failures. PGE uses economic life models for a subset of asset classes to inform asset replacement/repair timing or non-asset mitigation strategies to protect the equipment from failure as a result of vegetation, weather, animals, or other events happening to the asset. These models optimally balance maintenance cost & risk of operating the existing asset compared to cost of replacing or repairing the asset. The company uses these models to standup programs such as: proactive cable replacement, tree wire, distribution automation, and tapline reliability improvement program; to identify and mitigate the greatest outage risk to customers located in PGE's service territory.*

**c. What percentage of outages originate at the distribution level?**

*99% of customer outages originate at the distribution level.*

**d. What limits or restrictions on native load capacity, both physical and regulatory, do you currently place on the distribution system?**

*PGE establishes facility ratings for all T&D equipment, which identify the thermal loading capabilities of load-serving facilities. PGE does not permit any* *equipment to load beyond its maximum thermal loading capability as established by the facility ratings methodology and T&D standards. Furthermore, PGE reserves load-serving capacity on feeder mainlines, transmission circuits, and major equipment to assure that no system element will exceed its maximum thermal loading capability following disruption to any other single T&D element. This approach provides backup capability to quickly restore service to customers following an outage, and is a NERC requirement for transmission facilities.*

*PGE also evaluates additional measures (e.g. voltage drop, voltage flicker, voltage stability, transient stability, etc) to determine if a system element may be physically limited beyond what has otherwise been defined as its thermal loading capability. When modeled or demonstrated performance violates PGE's standards for power quality and reliability, PGE sets a capacity limit to mitigate concerns of power quality or reliability otherwise being compromised.*

**4) Security**

**a. What controls and processes are used to secure consumer and system data, IT/communication systems, and physical infrastructure?**

*PGE deploys controls based on a system's location as well as the sensitivity level of the data that is transmitted, processed, viewed, or stored on a given system or asset. Host systems are deployed with virus and malware protections and host-based firewall functions enabled. Encryption is enabled to protect data at rest and utilize secure protocols (ex. TLS for user interfaces & system integrations) to protect data being transmitted. PGE's network provides additional layers of protection using both traditional firewalls and application firewalls, which provide inspection and protection against malicious commands. As part of the application firewalls, data transformation protections are in place to protect against common attacks on databases and applications, such as XML and SQL injections. PGE also deployed intrusion detection and prevention systems in key network areas.*

**b. What protocols and cooperative arrangements with NERC, NIST or other entities are used to identify threats and available defense measures?**

*PGE has a strong working relationship with regulatory partners, peer utilities, and industry leaders in order to continually update our understanding of current threats which affect the utility industry, and how to safeguard against them. These include, but are not limited to:*

- *National Information Sharing and Analysis Centers (ISACs)*
- *InfraGard (a partnership with the Federal Bureau of Investigation)*
- *The SANS Institute Industrial Control Systems (ICS) Initiative*
- *The US Department of Homeland Security (DHS)*
- *Dragos*
- *The Electric Power Research Institute (EPRI)*
- *The National Institute of Standards and Technology (NIST)*
- *The Edison Electric Institute (EEI).*

**5) DERs:**

**a. What is the current and forecasted extent of DER deployment by type, size, and geographic dispersion?**[4]

Information on the current and forecasted amount of DER for the various categories mentioned in staff's survey definition are presented below.[5]

Note that in response to Staff's comments that utilities are welcome to present data on additional DERs outside of those defined, PGE has no additional definitions to recommend at this time.

**Current DER extent**

*Table 1. Current DER Extent by Type*

| DER Type | Value | Units |
|---|---|---|
| Small Generators (<10MW) | | |
| *Diesel* | 152.2 | MW |
| *Solar PV* | 117.3 | MW |
| *Other* | 5.6 | MW |
| Distributed Energy Storage | 81 | Batteries |
| Demand Response | 35.4 | MW (as of May 2019) |
| Energy Efficiency | 368,713 | MWh at bus bar (2018) |
| Electric Vehicles | 13,894 | Vehicles (year end 2018) |

Geographic information is available to PUC staff in the form of excel files with all of the individual customer data, but it has not been provided here with that level of detail.

Similarly, the breakdown of DER by size is difficult due to the heterogeneous nature of the different DER resources.

**Forecasted DER extent**

The most recent forecast information for DERs that PGE has available is the Navigant Distributed Resource and Flexible Load Study (included as Appendix L of the Company's draft 2019 IRP). Below is a table summarizing the forecasted adoption across a sampling of years.

[4] DERs may include small generator (e.g., solar pv), distributed energy storage, demand response, energy efficiency, and electric vehicles. However, Staff welcomes the inclusion of additional DERs that are not contemplated in this definition.
[5] For Energy Efficiency, please reference the Energy Trust survey response as they maintain the most up-to-date records for that type of DER.

*Table 2. DER MW Forecast from Navigant DER and Flexible Load Study - Base Case scenario*

| DER Type | Units | 2020 | 2025 | 2030 | 2035 | 2040 | 2045 | 2050 |
|---|---|---|---|---|---|---|---|---|
| Res Solar | MW | 50.0 | 70.0 | 92.0 | 122.0 | 158.0 | 200.0 | 244.0 |
| Res Storage | MW | 0.0 | 1.0 | 4.0 | 8.0 | 14.0 | 22.0 | 32.0 |
| Res Demand Response | MW | 55.9 | 124.5 | 133.7 | 141.5 | 147.2 | 151.9 | 156.2 |
| Res Smart Charging (EV DLC) | MW | 4.0 | 15.0 | 35.0 | 60.0 | 89.0 | 121.0 | 152.0 |
| *Residential (Subtotal)* | *MW* | *109.9* | *210.5* | *264.7* | *331.5* | *408.2* | *494.9* | *584.2* |
| C&I Solar | MW | 38.0 | 59.0 | 95.0 | 146.0 | 214.0 | 301.0 | 405.0 |
| C&I Storage | MW | 0.2 | 1.0 | 4.0 | 8.0 | 14.0 | 22.0 | 32.0 |
| C&I Demand Response | MW | 26.7 | 36.2 | 38.2 | 39.9 | 41.6 | 43.3 | 45.0 |
| *Business (Subtotal)* | *MW* | *64.9* | *96.2* | *137.2* | *193.9* | *269.6* | *366.3* | *482.0* |
| **Grand Total** | | **175** | **307** | **402** | **525** | **678** | **861** | **1,066** |

And below is the Electric Vehicle forecast from the same study:

*Table 3. Electric Vehicle Forecasts from Navigant DER and Flexible Load Study - Base Case scenario*

| EV Type | Units | 2020 | 2025 | 2030 | 2035 | 2040 | 2045 | 2050 |
|---|---|---|---|---|---|---|---|---|
| LDV | Vehicles | 27,691 | 99,216 | 225,105 | 371,310 | 537,329 | 715,463 | 874,865 |
| MHDV | Vehicles | 28 | 741 | 4,749 | 11,803 | 21,888 | 35,097 | 51,136 |
| | | | | | | | | |
| LDV | Ports | 29,043 | 100,820 | 221,486 | 353,380 | 494,100 | 634,954 | 748,419 |
| | | | | | | | | |
| LDV | MWh | 86,304 | 303,252 | 689,558 | 1,143,404 | 1,665,372 | 2,236,702 | 2,764,163 |
| MHDV | MWh | 1,601 | 38,279 | 260,183 | 674,254 | 1,270,459 | 2,048,426 | 2,992,945 |

**b. What is the status of small generator interconnections in the Oregon service area (< 10 MW)?**

**i. For each year from 2014 - 2018, please provide the number and total MW of small generators, by type, located in Oregon, interconnected to the utility, that began commercial operation in that year.**

- *2014: 1 (Hydro) - 0.225 MW-ac*
- *2015: 7 (Solar) - 3.885 MW-ac*
- *2016: 0*
- *2017: 6 (Solar) - 13.2 MW-ac*
- *2018: 4 (Solar) - 8.8 MW-ac*

**ii. Please provide the current number of active interconnection requests for small generators located in Oregon that have not yet executed an interconnection agreement.**

*18.*

iii. **Please provide the current number of active interconnection requests for small generators located in Oregon that have an executed interconnection agreement but have not reached commercial operation.**

*58.*

iv. **Please provide the current number of small generators located in Oregon interconnected to the utility, that have an executed interconnection agreement and are currently operating.**

*41.*

c. **What data and information are made available to distribution-level interconnection applicants prior to making an interconnection request? How is that information provided?**

Currently, customers can access information about distribution-level interconnection requests by going to PGE's website: https://www.portlandgeneral.com/business/power-choices-pricing/renewable-power/install-solar-wind-more/sell-power-to-pge.

The website has instructions about what it takes to meet project eligibility criteria, compliance rules, and important definitions with links to the FERC webpage where customers can learn more about QF rules and history. PGE has compiled an FAQ about the interconnection process that is available via the website above.

Customers can navigate to the interconnection request portal using this website to submit a small generator interconnection request via PowerClerk. On the PowerClerk landing page the customer can create a login, view the process flow of the interconnection process, and obtain necessary contact information for relevant PGE departments.

In addition, PGE provides a link to a Clean Power Research video about setting up a PowerClerk account and submitting projects.

Later this year, there will be much more information made available on PGE's OASIS site (http://www.oasis.oati.com/pge/) under the Generation Interconnection folder. Currently this information pertains mostly to Transmission and large generator interconnection. The following is a summary of what will be provided in the coming months:

- Oregon small gen jurisdictional interconnection queue
- Oregon small gen jurisdictional interconnection study reports
- Other various technical information, i.e., transformer and feeder ratings and distribution interconnection standards

**d. Has the utility taken any steps to implement the IEEE 1547 standard or other requirements for the interoperability of DERs and the distribution system?**

**e.**

*PGE's technical interconnection requirements are substantially based on interconnection standards of the Institute of Electrical and Electronics Engineers, Inc. (IEEE) 1547-2003, 1547.1-2005, and 1547-2018, as well as NFPA, UL, NERC, WECC, and NWPP standards, principals, and practices. With regard to IEEE interconnection standards, PGE reserves the right to follow IEEE 1547-2018 (or later) standards where appropriate to protect the safety and reliability of the PGE System, consistent with good utility practice. This right is irrespective of whether OPUC interconnection rules set forth in Oregon Administrative Rules (OAR) have yet been updated to adopt the IEEE 1547-2018 (or later) standards at the time PGE applies the technical requirements.*

**f. How does the utility define microgrids? Please list any microgrids in the utility's service territory.**

*PGE has not adopted a specific definition of microgrid, though there are multiple references to microgrids throughout the UM1856 Energy Storage Pilot filing and other areas.*

*As part of the Microgrid Resiliency Project, PGE defined a microgrid as such:*

> *"A small-scale electric grid that operates in conjunction with the electrical grid through a network of onsite generation, energy storage, and integrated controls. Under normal conditions it is connected to the main grid. During a grid disturbance, the microgrid resources would provide stability support to the main grid. In the event the main grid experiences an outage, the microgrid would isolate itself and operate independently ("islanding")."*

*In the Energy Storage Pilot filing, PGE described two scenarios with respect to microgrids that it would consider studying:*

1. *Single Customer Microgrid: serves a single customer metered site (single building, facility, or campus). The single customer has on-site generation to sustain power during an outage.*

2. *Community Microgrid (partial feeder microgrid): serves a subset of customers on a feeder; a segment of the feeder is isolated during an outage event. This could be a neighborhood or otherwise closely located facilities on the same feeder section.*

*In addition, PGE is considering other definitions that would lend more consistency with other parties in the industry, such as the US DOE's definition:*

*"a group of interconnected loads and distributed energy resources within clearly defined electrical boundaries that acts as a single controllable entity with respect to the grid. A microgrid can connect and disconnect from the grid to enable it to operate in both grid-connected or island mode."* (Source: DOE Microgrid Report here)

*PGE has 52 single customer microgrids that are enrolled under the DSG program and meet the single-customer microgrid definition as defined above.*

*PGE has explored providing community microgrid capability with the Salem Smart Power Center, but has not ultimately enabled such functionality and to date has no community microgrids on its system.*

**6) Customer values:**

**a. Please describe the surveys and other market research the utility performs to understand customer values, needs, and interests related to distribution system planning.**

*PGE collects data from its customers across several sources, including satisfaction surveys, appliance saturation surveys, program evaluation surveys, and domain-specific ad hoc research (for instance, surveys on DR awareness). We also purchase and/or collect data from third party sources, such as on customer demographics, building characteristics, company firmographics, vehicle ownership, Energy Trust program participation, etc.*

**i. What are the major findings from this research over the past 5 years?**

*The below list states in general terms the major findings related to distribution system planning surfaced by the research described above:*

- *Providing better reliability and shorter outage are important to customers*
- *Getting customers real time information about outages; causes and restoration times is a modern-day expectation.*
- *Customers believe it is PGE's responsibility to enable renewables integration, stop Cyber-attacks of the grid, upgrade the grid for population and business growth, and assure increasing technical reliability (surges, sag, frequency).*

**ii. How does the utility use the results of this research?**

*PGE incorporates findings from customer research into these areas as part of its ongoing business and operational planning. Findings specific to distribution resource planning are contemplated alongside a variety of other additional customer needs and strategic imperatives.*

## Section D
## All Stakeholders

In Section D all interested stakeholders are asked to provide responses to the following questions:

**1) Commission principles for distribution system planning:**

**a) What principles should the Commission adopt? Please explain and define.**

*PGE appreciates the opportunity to provide input on the process. Commission staff has laid out the important factors to consider in its DSP white paper. PGE agrees with Staff's comments that the process should be robust, aligned, strategic, adaptive, inclusive and regular. These factors are important to PGE for the following reasons:*

- *Robust: Plans should adhere to best practices and models should be tested against a wide range of scenarios.*
- *Aligned: The utilities and staff should ensure that the planning process serves priorities agree upon in the DSP docket.*
- *Strategic: The plans should advance several strategic priorities, balancing short term versus long terms needs and considering the synergies between needs on the bulk power system, transmission and distribution grid, and the needs of retail electricity customers.*
- *Adaptive: The DSP process should be a framework sufficiently detailed to address priorities while not so prescriptive as to exclude potential changes to technology, economics, or methodologies. Lessons learned should be incorporated on an ongoing basis while not expecting any individual plan be perfect, but that it incrementally improve on past plans.*
- *Inclusive: The distribution system planning process should engage a wide swath of stakeholders to potentially include those that have not been as active in the integrated resource planning process, such as DER solution providers and advocates, academia and/or the national labs, and municipal/community advocates.*
- *Regular: Given the pace of change in the energy sector, particularly with distributed energy resources, DSPs should occur on a frequent and somewhat predictable basis.*

*PGE also agrees that the approach should maximize customer value by being transparent, rigorous, interactive and advanced. PGE's perspective on each of these factors:*

- *Transparent: Where possible, the utilities and stakeholders should be empowered to share data and results with each other to improve the distribution system planning process and outcomes.*
- *Rigorous: Planning methods should be well vetted and incorporate the latest best practices, while not precluding the opportunity to test new methods/tools as they become available.*
- *Interactive: PGE would appreciate the opportunity to incorporate stakeholder in "real-time" throughout the process. Particularly for the distribution system, conditions and technologies change rapidly. The sooner feedback and data can be gathered, the more quickly PGE can include it in its DSP.*
- *Advanced: The DSP is likely to involve highly technical solutions, not just from an engineering perspective, but also from a modeling and software perspective.*

*While these principles will be largely sufficient for the distribution planning process, we would add* *a few more principles that are important as we move forward. PGE believes a modern distribution planning process should be:*

- *Resilient: The DSP should anticipate uncertainties and rare events in its design. This means anticipating reliability events that may occur very infrequently, but have significant impacts on the grid. Additionally, the process should anticipate structural changes that may occur to policy, market, or technology.*
- *Equitable: A DSP should consider the impact to all customer, not just those able to provide upfront time or capital to participate. The plan should clearly articulate how customers are included and benefit from investments in the grid, whether a traditional solution or a non-wires alternative.*
- *Secure: The DSP process and plans must consider potential threats, either physical or cyber, to the grid. This means understanding threats or protections introduced by a given solution and understanding how best to share data in way that does not introduce new vulnerabilities to the system.*

**b) What level of specificity is most helpful to include in principles?**

*It is important that these principles are used to evaluate the plans and underlying processes holistically. For each principle, a DSP plan should meet, and ideally exceed, the current state with respect to each principle. For instance, the utilities' DSPs should be at least more transparent, rigorous, interactive, and advanced as their current planning processes.*

*As to the question of whether each principle should be evaluated in greater detail, PGE believes that in order to anticipate changes in the planning and policy context, adherence to the principles should be evaluated qualitatively but not tied to specific metrics. This may change in the future, but for now commitment to specific quantitative criteria is unnecessary.*

**2) Maximizing customer value:**

**a) How you would define "maximize customer value" in the context of distribution system planning?**

*Distribution system planning creates value for customers across a number of dimensions, including reliability and economic efficiency.*

**b) What considerations (from Staff whitepaper or other thoughts) are most important to focus upon when maximizing customer value in planning for the distribution system?**

*PGE believes that the most important considerations from Staff's white paper and PGE's corporate imperatives are that the planning process should be:*

- *Inclusive*
- *Adaptive*
- *Transparent*
- *Resilient*

**3) Evaluation of utility distribution system plans:**

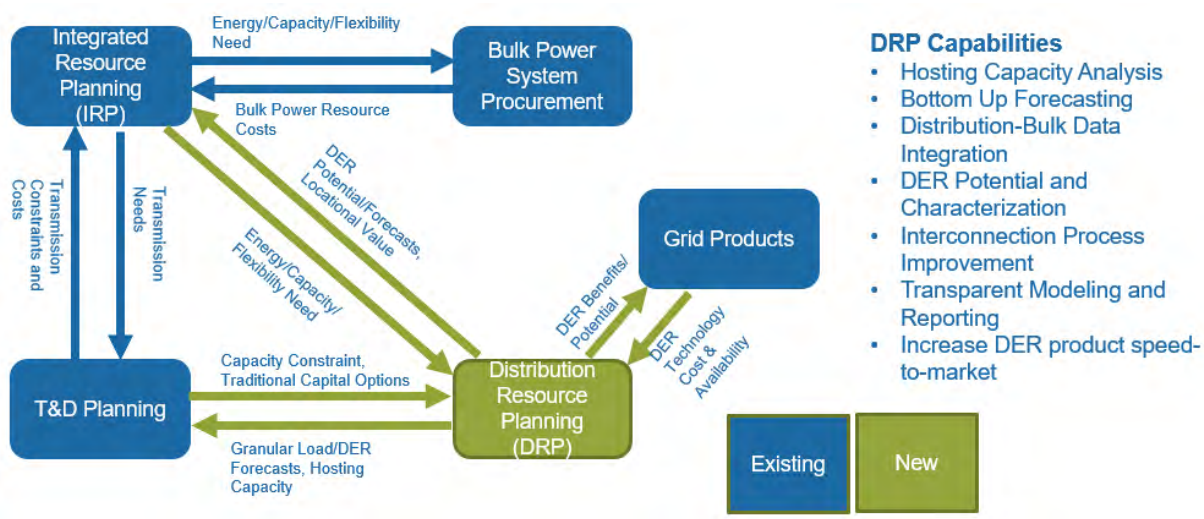
**a) Which criteria or metrics should the Commission use in evaluating the proposed distribution plans (Plans)?**

**b) How will your organization evaluate and/or otherwise use the proposed Plans?**

*PGE plans, and is already beginning to prepare, to deeply operationalize the processes and tools developed through the distribution system plans, similarly to how we incorporate analysis and tools from our IRP throughout the organization. PGE has begun to engage internal stakeholders on how operational efficiencies or investment decisions might improve with a more robust and transparent distribution system planning process.*

**c) How should distribution system plans be integrated with other planning activities, such as resource planning, interconnection, transmission, or others?**

*PGE sees tremendous synergies with other parts of the organization. A Distribution Resource Planning (DRP) group was started that would be responsible to develop the plan, manage the development and implementation of supporting analysis, and operationalize these tools within the respective business units. The diagram below describes at a high level how we see this group and its plan interacting with other parts of the organization.*




*As suggested in the figure above, a very tight integration between the distribution system plans and the integrated resource plans is envisioned. While some states have sought to combine these processes, at PGE, they iteratively inform each other. Given the hierarchical, but functionally distinct, needs of the distribution and bulk power systems, it makes sense to keep these processes separate.*

**d) What are reasonable options for stakeholder participation in the planning process: direct engagement in the development of plans, the review of draft and final plans, other?**

*As PGE has done with the IRP process, there should be robust and inclusive stakeholder engagement in the planning process. Stakeholders should be given the opportunity to comment and present relevant feedback throughout plan development and provide formal comments upon submission of the plans.*

**e) How often should a utility distribution plan be submitted for Commission review?**

*A reasonable utility distribution plan cadence would be every other year, with abbreviated updates in off years. IRPs can take place in the off years of DSPs and vice versa. Having the plans submitted in alternating years would ensure that each plan can utilize assumptions from the other that are no more than one year old. This will allow the utilities, staff, and stakeholders to maintain a DSP process that is adaptive and robust to changes to the system, resource mix, stakeholder priorities, and/or market context.*

**4) Planning Scenarios:**

**a) How should the selection of scenarios used in distribution planning be determined?**

*The current process used for selecting scenarios in the IRP is well suited for the DSPs. That said, we recognize that we will need to expand the granularity and specificity of these scenarios to address the specific concerns of the distribution system.*

**b) What criteria should be used by utilities to identify relevant planning scenarios?**

*We should identify scenarios based on the following factors:*

- *System impact: How are costs and benefits incurred and how might they be distributed (by customer segment, bulk power, transmission, distribution)?*
- *Relevance to policy: What policy decisions are likely to be considered, particularly within the action plan window?*
- *Sources of uncertainty: What inputs are the most uncertain in the planning period? What structural changes might occur that would impact investment decisions?*
- *Relevance to stakeholders: What areas are most critical for stakeholders, both in terms of outcomes and decision criteria?*
- *Source of risk: What conditions lead to the biggest impacts on reliability and safety? What drivers lead to cascading impacts on the system?*

**5) Access to grid and planning data by customers and third parties:**

**a) Discuss categories of data needed by third parties to:**

**i. Participate in developing system plans.**

**ii. Critically review proposed plans.**

**iii. Prepare commercial projects in response to plans.**

**b) Identify any categories of data that may be unsuitable for access, e.g. for reasons of security, trade secret, customer privacy, or burdensomeness.**

*PGE's main areas of concern are limited to cases of personally identifiable information (PII) or where physical or cyber system vulnerabilities are exposed. We don't believe these limitations will in any way impede the planning process or the ability of third parties to provide input on the process.*

**c) How should and in what format should the results of a hosting capacity analysis or native loading analysis be make available by utilities? Please**

**indicate which formats are currently available and which are not currently available.**

*We believe that the results of hosting capacity could and should be made available publicly through web accessible displays of GIS outputs, similarly to what has been provided by the California utilities. The granularity of results will depend on the method and tools used by the utilities.*

**d) How should the commission evaluate utility investments that enable more transparent interconnection data to be made available? What are the costs and benefits that the Commission should consider?**

*PGE believes that these investments should be treated as distribution investments and should be evaluated based on their impact on the speed and effectiveness of interconnections on the utilities' systems.*

**6) Are there other issues or topics not covered here that are relevant to discuss in distribution system planning? If so, what are they and why are they relevant?**

*PGE believes that any discussion of alternatives to traditional investments (such as non-wires alternatives) would be incomplete without also a discussion of alternative incentive mechanisms as discussed in SB 978. Non-wires alternatives replace well-tested capital planning wherein the utility is compensated for its investment with a more complex and dynamic set of resources that are (in many cases) treated as expense. PGE sees great promise in these technologies, but believes that a discussion of targeted, relevant incentive mechanisms must be included (as they have been in states like NY, CA, and MN) in order to mitigate possible asymmetries between parties bearing risk and those bearing financial upside.*

/s/ Rob Macfarlane for Jay Tinker
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