LISA D. NORDSTROM
Lead Counsel
lnordstrom@idahopower.com

August 30, 2019

VIA ELECTRONIC FILING

Attention: Filing Center
Public Utility Commission of Oregon
201 High Street SE, Suite 100
P.O. Box 1088
Salem, Oregon 97308-1088

Re: Docket No. UM 2005
Investigation into Distribution System Planning – Idaho Power Company's Utility Survey Responses

Filing Center:

Attached for filing is an electronic copy of Idaho Power Company's responses to Public Utility Commission of Oregon Staff's Utility Survey questions.

Please contact me at (208) 388-5825 or Senior Regulatory Analyst Kelley Noe at (208) 388-5736 with any questions regarding this filing.

Sincerely,

Lisa D. Nordstrom

Lisa D. Nordstrom, OSB #973528

LDN:csb
Attachment

IDAHO POWER COMPANY'S
RESONSES TO STAFF'S UTILITY SURVEY QUESTIONS
August 30, 2019

Section A
<u>Current Distribution Planning Processes</u>

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:

<u>STAFF'S UTILITY SURVEY – QUESTION A1</u>:

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?**
- **b.** **Provide a general description of how the utility plans for:**
  - **i.** **Load growth**
  - **ii.** **Aging infrastructure (replacement)**
  - **iii.** **Increased penetration of the various types of DERs—What does the utility do to accommodate DER penetration in its distribution system?**
  - **iv.** **Climate change impacts on the system**
  - **v.** **Advances in equipment (e.g. controls, communications, awareness)**
  - **vi.** **Reliability**
- **c.** **How does the utility define "distribution system"?**
- **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).** [3,4]

[3] Commission Order No.19-104.

[4] Attachments are encouraged but should not replace substantive, narrative answers.

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

IDAHO POWER COMPANY'S RESPONSE TO STAFF'S UTILITY – QUESTION A1:

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?

Idaho Power Company's ("Idaho Power" or "Company") goal for the distribution system is to safely, reliably, and cost-effectively meet near- and long-term load service requirements. The primary objectives that support this are: forecasting long-term electrical demands for each service region, developing community advisory based electrical plans, jurisdictional adoption of the electrical plan in their comprehensive plans, forecasting near-term electrical demand, and developing near-term local area plans that are constructible prior to electrical demand increases that overload facilities or result in reduced service quality. Idaho Power's secondary objective is to create a flexible system that may adapt to increased demand, technology changes, and distributed energy resources.

b. Provide a general description of how the utility plans for:

i. Load growth

Seasonal peak demand is tracked on distribution circuits and substation transformers where supervisory control and data acquisition ("SCADA") is available. The seasonal peak demand values are adjusted to account for large load changes, load transfers, and intermittent distributed generation. The seasonal peak demand values are also adjusted to reflect a 95^{th} percentile temperature event. The growth forecast for each asset is calculated from a cubic regression model using the adjusted historical peak demand values. Infrastructure investments are scheduled for construction when planning capacity is forecasted to be exceeded.

When load growth is most efficiently served with a new substation, Idaho Power references the area electrical plan to begin the site-selection process.

ii. Aging infrastructure (replacement)

Idaho Power developed an asset replacement strategy to provide a comprehensive, long-range plan for managing the replacement of aging and/or condition-based transmission, distribution, and station assets. To develop the replacement strategy, assets are prioritized within each asset class based on condition and criticality as the primary replacement drivers. The data provided in the tables below lists the information used to develop the asset replacement strategy. Table 1 lists the factors that may be considered to determine both condition and criticality, while Table 2 lists the asset classes included in the study and Table 3 lists the distribution asset replacement drivers.

Furthermore, on an annual basis, asset managers identify and include asset replacements/improvements in their budget requests for the respective asset classes.

These replacement/improvement projects are then prioritized against and/or combined with other capital project requirements.

Table 1 – Condition and Criticality Factors

Condition Factors Considered	Criticality Factors Considered
Age	Customer outage impact
Test and inspection results	Public and employee impact
Equipment environment	Environmental impact
Past equipment performance	Operational impact
	Megawatt ("MW") transfer capability impact
	Strategic (technology)

Table 2 – Asset Classes Included in Asset Replacement Strategy

Distribution	Stations
Overhead circuits (poles and conductor)	Transformers
Underground cable	Circuit breakers
Line equipment (regulators, capacitors, reclosers, transformers)	Protective relays
Porcelain line switches	Instrument transformers
Distribution relays	Batteries
Pole-top switches	Communication equipment

Table 3 – Asset Replacement Drivers

Asset Class	Primary Replacement Drivers
Overhead circuits (poles and conductor)	• Customer reliability programs • Condition (patrol inspections)
Underground cable (pre-1989)	• Unjacketed cable • Material condition
Service transformers	• Material condition • Incorporate with other replacement projects
Distribution regulators, capacitors, reclosers	• Regular inspections to identify condition
Porcelain line switches and pole-top switches	• Material condition • Incorporate with other replacement projects
Station distribution transformers	• Condition based on diagnostic testing
Station circuit breakers	• Criticality • Material condition/age of breaker and metalclad models • Oil breakers
Station instrument transformers	• Oil condition
Station batteries	• Age/criticality
Communication equipment	• Changes in technology • Factory support
Protective relays	• Factory support • Condition/based on test results • Age/criticality

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

DER penetration in the Idaho Power distribution system falls into two main categories: (1) in front of the meter utility scale generation interconnections and (2) behind the meter customer generation (customer on-site generation).

For the larger scale generation interconnects, Idaho Power follows IEEE 1547 and UL 1741 (SA). IEEE 1547 allows reactive compensation to keep circuit voltage within limits. This is implemented through Volt/VAr control. This can result in minimizing upgrades to the system at a given generation capacity. UL 1741 (SA) has anti-islanding requirements that enable inverter-based generation to utilize an active anti-islanding scheme. This minimizes the special circuit protection requirements and communication assisted protection. DER penetration upper limits are set at the feeder load planning limits based on circuit voltage; 10 Mega Volt Amp ("MVA") for 12.47 kilovolt ("kV") and 20 MVA for 34.5 kV.

For customers proposing on-site generation, Idaho Power uses an automated feasibility study process. Applications are screened based on customer on-site generation limits, service transformer capacity, and distribution circuit capacity. For applications that exceed the distribution circuit capacity, Idaho Power utilizes advanced modeling to study the impact and determine if the proposed application can be installed while maintaining safe and reliable circuit operation within accepted parameter limits. Additionally, a system-wide hosting capacity study is in progress.

iv. Climate change impacts on the system

Idaho Power is not currently making any assumptions on climate change outcomes in its local load forecasting processes. However, trends in changing climate are captured by using rolling 40-year peak temperature data. Idaho Power tracks the average temperature on the peak day of each season. Models are used to determine the relationship of temperature to load.

If climate change is impacting more recent years, the use of the 95th percentile temperature adjusted forecasting process (as described in the Company's response to Section A Question 1.b.i above) will incorporate the changes within the load forecast.

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

One of the key tenants of Idaho Power's grid modernization planning considerations is to provide distribution system conditional awareness and control. Idaho Power accomplishes this through SCADA monitoring and controls at substations and some line reclosers. In addition, Idaho Power is currently building a new Integrated Volt-Var Control system ("IVVC") that will provide awareness and control of substation load-tap-changes (LTC), line voltage regulators, and capacitors using a new licensed 700 megahertz ("MHz') field area network. The Company also has a distribution relay replacement program where legacy electro-mechanical feeder relays are being replaced with microprocessor-based relays for added control and visibility of the system.

vi. Reliability

Idaho Power uses the planning capacities on distribution circuits, which are more limiting than thermal capacities, allowing the Company to provide operational flexibility to accommodate load transfers. Most distribution circuits have a thermal capacity of 12.5 MW and a planning capacity of 10 MW, reserving 2.5 MW. This reserve capacity allows adjacent distribution circuits to restore load to customers during planned and unplanned outages. The Company also utilizes standard asset sizes and voltages to facilitate speedy restoration of service during maintenance and after unplanned outages.

Idaho Power plans for the ability to serve peak demand whether or not the largest distributed generator on each distribution circuit or substation transformer is generating.

Additionally, the Company's response to Section C, Question 3.b describes how Idaho Power plans for asset replacement and improves reliability on worst-performing circuits.

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

The primary distribution system is composed of medium voltage circuits that range from 12.47 to 34.5 kilovolt ("kV'). The secondary distribution system is comprised of the service transformers and service drops that range from 240 volts up to but less than the primary distribution voltage.

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).* [footnotes omitted]

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

Idaho Power believes the U.S. DOE definition is sufficiently broad and succinct in defining DER. The NARUC definition only adds how DER interacts with the customer and grid. Please note that a microgrid is not a DER but the interconnection of one or more DER(s) and load operating in isolation from the larger grid.

<u>STAFF'S UTILITY SURVEY – QUESTION A2</u>:

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?**
- **b.** **What advanced tools and other planning resources is the utility investing in?**
- **c.** **Applicable engineering standards**
- **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.**
  - **ii.** **Please provide an overview of roles and responsibilities.**

<u>IDAHO POWER COMPANY'S RESPONSE TO STAFF'S UTILITY SURVEY– QUESTION A2</u>:

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?*

The Transmission and Distribution ("T&D") Planning department developed an in-house application to track and forecast seasonal peak demand on substation transformers and distribution circuits. The application is called the Load Forecasting Tool. The tool retrieves demand data from the SCADA data historian system and allows entry and tracking of load transfers, distributed generation, and new large load requests. It produces a demand forecast from the historical peak demand, entries described in the Company's response to Section A, Question 1.b.i, and scaling to reflect 95th percentile extreme temperature events (extreme peak demand). These forecasts inform the timing for infrastructure investments.

A community advisory committee process helps determine the physical location of new substations. This long-range planning process utilizes zoning and future land use information that is tracked in ArcGIS. ArcGIS also enables the combining of zoning and load data to produce land-based buildout scenarios.

Additionally, Idaho Power utilizes the following modeling software to analyze generation interconnection requests, customer on-site generation requests, and perform special studies exploring DER capability, operation, and impact. These are discussed further in the Company's response to Section 2b below:

- Time-series analysis (EPRI OpenDSS)
- Hosting Capacity analysis (EPRI DRIVE)
- DER Modeling (NREL SAM, SNLGridPV)
- Distribution Modeling (DNV GL Synergi, EPRI OpenDSS)
- Sub-transmission Modeling (PowerWorld Simulator)

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

Idaho Power invests in subscription-based services to maintain and enhance the general tools utilized for distribution planning. Idaho Power invests in research-based firms like GreenTech Media (GTM) that will provide insight to future planning scenarios.

Additionally, Idaho Power is investing time and resources in the following advanced modeling tools:

- Open Source Distribution System Simulation ("OpenDSS"). An Electric Power Research Institute ("EPRI") comprehensive electrical power system simulation tool primarily for electric utility power distribution systems. It supports nearly all frequency domain (sinusoidal steady-state) analyses commonly performed on electric utility power distribution systems. In addition, it supports many new types of analyses that are designed to meet future needs related to smart grid, grid modernization, and renewable energy research.

- Distribution Resource Integration and Value Estimation ("DRIVE"). An EPRI capacity evaluation application to determine the ability to host resources on distribution feeders without causing adverse impacts to power quality or reliability. DRIVE was created to determine the distribution system ability to accommodate DERs such as PV and energy storage on a feeder-by-feeder basis.

- GridPV Toolbox ("GridPV"). A Georgia Tech Research Corporation and Sandia Corporation developed MathWorks MATLAB toolbox that is able to model and simulate the integration of distributed generation into the electric power system and to determine the impacts on the distribution system for highly variable generation.

- System Advisor Model ("SAM"). A National Renewables Laboratories ("NREL") computer model that calculates performance and financial metrics of renewable energy systems. SAM's advanced simulation options facilitate parametric and sensitivity analyses, and statistical analysis capabilities are available for Monte Carlo simulation and weather variability studies.

- Synergi Electric. A DVN GL software program that simulates, analyzes, and plans power distribution feeders, networks, and substations. The simulation engine is an object-oriented design that consists of highly detailed models for power system devices such as lines, transformer banks, regulator banks, capacitors, and active generators.

c. Applicable engineering standards

- Idaho Power follows the voltage standards specified in ANSI C84.1.

- DER interconnections are required to comply with Institute of Electrical and Electronics Engineers ("IEEE") Standard 154.7.

- Idaho Power customers are required to adhere to IEEE Standard 519, which details power quality requirements.

- Transformer purchase specifications reference the current versions of IEEE Standard C57, IEEE Standard C37, and IEEE Standard 693 as well as accepted standards and practices of the National Electrical Manufacturers Association ("NEMA"). Existing equipment typically complies with the standard and practice in place at the time of manufacture.

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.

There were 15 in-house employees and three supervisors that focused on distribution system planning full- or part- time since 2014.

ii. Please provide an overview of roles and responsibilities.

A six-member team provides load service interconnection requirements for loads that exceed 1 MW and provide near-term and long-range load service plans, which include transmission systems 138 kV and below, substations, and distribution systems. Four employees focus on distribution level generation interconnection analysis and provide non-wire solution analyses and recommendations. A team of eight provides load service interconnection requirements for loads less than 1 MW and supplies distribution models.

STAFF'S UTILITY SURVEY – QUESTION A3:

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.**
  - **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.**
- **b.** **Frequency with which the utility conducts the distribution system planning processes.**
- **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.**
- **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?**
- **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?**
- **f.** **How do IRPs, resource RFPs, Smart Grid Reports, transmission planning, and interconnection studies inform distribution system planning?**
- **g.** **What is the outcome of your distribution planning process? A plan/report? Budget by field area/region?**
- **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.**

IDAHO POWER COMPANY'S RESPONSE TO STAFF'S UTILITY SURVEY– QUESTION A3:

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.*

  - *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.*

    The following information details the distribution system planning processes of Idaho Power:

    - Seasonal peak demand checks inform distribution circuit and substation transformer forecasts through the 10-year planning horizon. The forecasts include projected load growth from known large load additions as well as residential and commercial growth.

- Small area studies cover single distribution substations with associated substation transformers and distribution circuits. These studies include power flow analyses with the goal of ensuring sufficient capacity to serve future load growth.

- Electrical plans are long-term plans developed with local jurisdictions and customers. Idaho Power, in collaboration with community advisory committees creates electrical plans to identify preferred locations to construct new substations and transmission lines to meet future demand.

- Protection coordination studies review settings between distribution circuit protective equipment such as breakers, reclosers, and fuses. The studies are performed at a five-year interval unless triggered by large load or DER development.

- Fault analyses and power quality studies are performed when needed for fault events or customer compliance verification with IEEE 519.

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

- Seasonal peak demand checks occur every spring and fall following the seasonal peak demands.

- Small area studies are completed on a three-year rotation or as the system changes to serve new customers or distributed generation additions, address reliability or power quality concerns, and replace aging assets.

- Protection coordination studies are completed at a minimum of once every five years.

- Fault analyses and power quality studies are performed when needed for fault events or customer compliance verification with IEEE 519.

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.*

Planning study update frequencies are described above. Planning study revisions may be triggered by large load additions, system configuration changes, reliability or power quality concerns, aging asset replacements, and new distributed generation.

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?*

The results of previous plans inform new plans where relevant. The time horizon for distribution system planning is 10 years, with small area studies being updated a minimum of every three years.

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?*

- <u>IRP</u>. Distribution system planning affects the calculation of the T&D deferral value included in the energy efficiency cost-effectiveness test. It also affects the calculation of the T&D deferral value of distributed energy systems in the IRP resource stack.

- <u>Smart Grid Reports</u>. Small area studies identify capacity constraints. When capacity constraints can be cost-effectively addressed with non-wire alternatives, the alternatives may be included in the Smart Grid Report.

    - An example is the potential Jordan Valley Energy Storage Project or Jordan Valley Microgrid. To address a transformer capacity constraint at the Jordan Valley substation, Idaho Power is considering installing energy storage to shift peak demand.

- <u>Transmission local planning</u>. Electrical plans produced from distribution system planning directly inform the need and location of transmission lines and substations. Small area studies inform the timing of transmission system capacity additions.

- <u>Resource RFPs</u>. It has been many years since a resource RFP was released and it was for a large single site resource that could not be accommodated by the distribution system.

- <u>Interconnection studies</u>. Distribution plans are evaluated when generation developers request interconnection to a distribution circuit.

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

- To the extent that IRPs identify distributed generation in the resource action plan, local load forecasts and the distribution plan would be adjusted based on the anticipated peak demand reduction.

- To the extent that distributed generation resource RFPs are issued, local load forecasts and the distribution plan would be adjusted based on the anticipated peak demand reduction. Elements of the Smart Grid Report are generated from distribution system plans.

- Transmission planning informs available locations for substations.

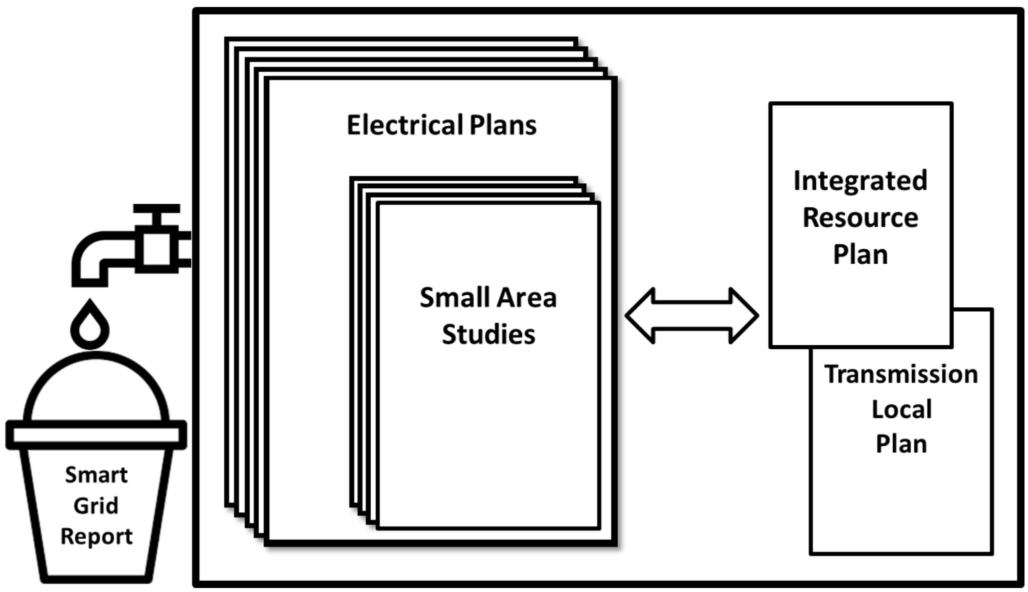
- Interconnection studies inform the local load and resource forecasts and the distribution plan may be adjusted based on frequency and size of both load and resource interconnection requests

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

- Small area studies are internally published plans and the information is shared with regional personnel, grid operations, management, and transmission planning. These plans generate projects that are included in present and future capital budgets (Idaho Power's capital budget is centrally managed).

- Electrical plan reports are published on [Idaho Power's public website](). Idaho Power seeks to incorporate language from the electrical plans into jurisdictional comprehensive plans.

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.*



STAFF'S UTILITY SURVEY – QUESTION A4:

Budget process: Please describe the associated capital and operation and maintenance (O&M) budgeting processes:

- **a. Process of developing capital budgets for distribution infrastructure.**
- **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.**
- **c. Process for developing New Construction Reports filed with 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.**
- **e. Distribution system schedule i.e., is it performed on an annual basis or on some other schedule?**
- **f. Budget categories are used? For example, New Service, Asset Health, Street Lights, Substation Capacity, Reliability, Equipment Purchase, etc.**
  - **i. Do you have construction allowances?**
- **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.**

IDAHO POWER COMPANY'S RESPONSE TO STAFF'S UTILITY SURVEY – QUESTION A4:

Budget process: Please describe the associated capital and operation and maintenance (O&M) budgeting processes:

a. Process of developing capital budgets for distribution infrastructure.

Idaho Power utilizes an annual capital budget process. Capital budgets are generally project based. Managers submit capital project proposals for senior management review. The capital projects are reviewed and approved by the executive management team. From that information, the capital budgets are created and then reviewed and approved by the Idaho Power Board of Directors.

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.

Idaho Power utilizes an annual O&M budget process. O&M budgets are generally based on historical cost center/cost element spend with adjustments for known changes. Managers submit O&M budget requests for senior management review. The budgets are then reviewed and approved by the executive management team and the Idaho Power Board of Directors.

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

The Idaho Power Board-approved budget for the current year is analyzed to identify major projects totaling more than $10 million and smaller projects totaling over $1 million but less than $10 million. Additionally, the projects are categorized as Production, Transmission, Distribution, and General Plant.

For major projects, the total spend prior to the reporting budget year, the anticipated spend for the budget year, and the anticipated spend for the two subsequent budget years is identified. Idaho Power's percentage of ownership is identified and a narrative describing the nature and potential benefit(s) of the project is provided. Idaho Power provides the spend for each Production and General Plant project. Due to Federal Energy Regulatory Commission Standards of Conduct requirements, Idaho Power presents transmission projects in total, and without year-by-year amounts. Distribution projects are presented without narrative, instead being categorized into components of distribution.

Smaller projects, greater than $1 million but less than $10 million are prepared similarly to the major projects, including identifying prior spend, anticipated spend for the budget year, and the anticipated spend for the subsequent budget years. Idaho Power includes an in-service date and a narrative describing the nature and potential benefit(s) of the project.

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.*

<u>May and June</u>. Capital projects are gathered and reviewed by managers.
<u>July</u>. Capital projects are reviewed by senior managers.
<u>August</u>. Capital projects are reviewed and approved by executives.
<u>September</u>. O&M budgets requested by cost center managers
<u>October</u>. O&M budgets are reviewed and approved by senior managers and executives.
<u>November</u>. Capital and O&M budgets are reviewed & approved by Idaho Power Board of Directors.

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

Idaho Power utilizes an annual O&M and capital budgeting process.

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

The capital budget utilizes the following plant type for categorizing distribution projects: 15, Interconnect Facilities - Distribution Lines; 40, Underground Reconstruction; 41, Distribution Stations; 42, Overhead New Business; 43, Overhead Reconstruction; 44, Underground Duct Vault; 45, Underground New Business; 46, Nightguard Lighting; 47, Street Lighting; 48, Transformer Purchases; and 49, Meter Purchases.

The O&M budget does not utilize a categorization to separate distribution system expenses from other types of expenses.

i. *Do you have construction allowances?*

No.

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.*

Idaho Power does not have flexibility for customer request and restoration projects. Idaho Power does have some flexibility on the timing of system maintenance and other projects; however, consideration is given to the potential risks of delaying such projects with regard to impacts on system reliability.

STAFF'S UTILITY SURVEY – QUESTION A5:

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

- **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.)?**
  - **ii.** **How do physical inspections and other operations functions inform this assessment?**
- **b.** **Cost/benefit analyses the utility performs for distribution system planning:**
  - **i.** **For what types of investment decisions are cost/benefit analyses performed?**
  - **ii.** **What type of analysis is used?**
  - **iii.** **Which non-monetized benefits are included in these analyses (e.g., emissions reductions?)**
  - **iv.** **Are there hard-to-quantify benefits associated with the utility's investment decisions? How are these included in your analysis?**
  - **v.** **When investments are interdependent with other investment decisions, how does your investment analysis change?**
- **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?**
  - **ii.** **Near-term versus long-term: How does the utility consider the costs and benefits of long-versus-short-term solutions?**
  - **iii.** **Non-monetized benefits: Does the utility consider different benefits when taking alternative approaches to resolving system needs?**
  - **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.**
  - **v.** **Identifying solutions: How are options to meeting a need identified?**
  - **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?**
  - **vii.** **Assessing NWA alternatives: What criteria or metrics are used in assessing whether a NWA can meet an identified need?**
- **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?**

IDAHO POWER COMPANY'S RESPONSE TO STAFF'S UTILITY SURVEY – QUESTION A5:

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

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.)?*

Idaho Power assesses projects on the physical condition, performance metrics, preventive maintenance, and/or obsolescence of the equipment. For example, if upon inspection a pole is deemed to be hollow, it would be accelerated to be replaced. If upon inspection or failure parts for a switch are no longer available, or if a communication radio is no longer supported by the manufacturer, it will be replaced with the current technology.

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

A physical inspection may delay or accelerate the replacement decision based on the physical inspection or performance metrics of the equipment. For example, if a transformer is cracked and has poor performance, It would need to be replaced. If the same transformer is in good physical condition but has poor performance, it would be rebuilt.

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

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

Large distribution projects are evaluated to determine the least-cost solution for an identified investment need; i.e., load service reliability or safety.

ii. *What type of analysis is used?*

A revenue requirement model which factors in the cost of capital, ongoing O&M expenses, taxes, depreciation, and the time value of money is used to analyze investment decisions.

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

Non-monetized benefits are not included in the cost-benefit analysis.

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

Yes, however, non-quantifiable benefits are not included in the cost-benefit analysis. However, they are considered when choosing an investment option.

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

Idaho Power evaluates to determine if it can sync multiple smaller interdependent projects into one larger project to minimize the impact on the system and maximize resources.

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 general, Idaho Power utilizes cost-effective operational solutions that align with future load service plans prior to making significant capital investments. The following are considered in the determination of cost-effectiveness: ongoing maintenance and equipment replacement costs, initial expenses, and reliability impacts.

ii. Near-term versus long-term: How does the utility consider the costs and benefits of long-versus-short-term solutions?

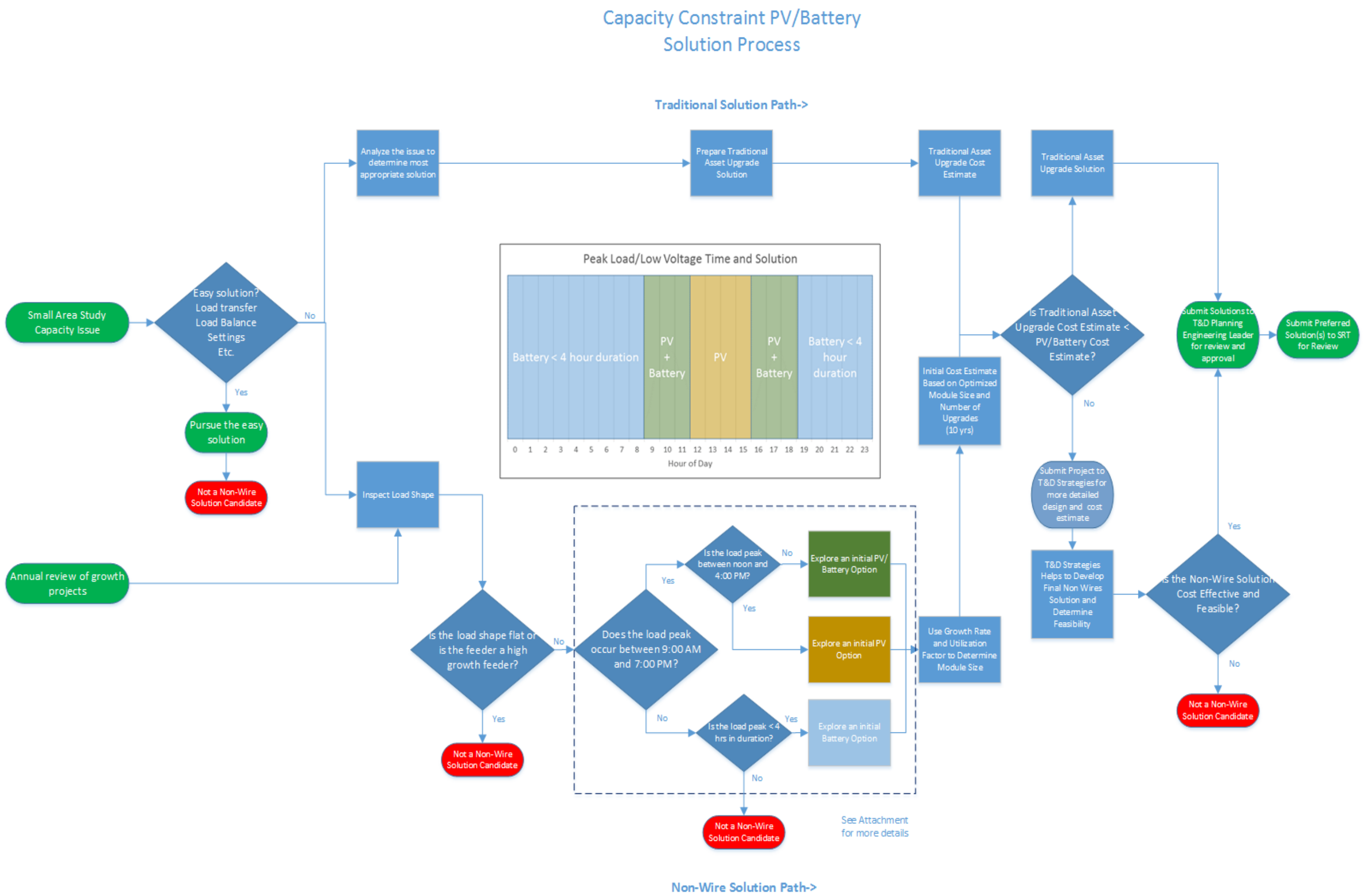
The costs, including ongoing maintenance, from each alternative are quantified, as well as when and how often the costs occur. The net present value of these costs is compared over a similar period.

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

Yes, non-monetized benefits are considered. Some of these include experience gained implementing new solutions, future flexibility, and customer satisfaction.

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.

Idaho Power has a systematic process to evaluate NWA. The identified NWA is then compared to a traditional solution. The most cost-effective solution is selected. The image below depicts the process Idaho Power goes through to evaluate traditional vs. NWA solutions.



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

When the Company is identifying solutions, NWA options are identified based on the load shape for the assets involved.

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?

Idaho Power will develop multiple scenarios when circumstances dictate the need to do so. For example, in a current electrical plan, Idaho Power is considering the impacts of the electrification of transportation and heating, DER penetration, and energy efficiency measures.

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

Idaho Power's current process checks for load shape, time of peak, and growth of the area to identify potential solutions. The NWA solution and the traditional solution are compared for cost-effectiveness.

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?*

For large distribution projects where there is more than one solution, Idaho Power would perform a cost-benefit analysis from the perspective of the revenue requirement impact on customers. An example of a cost-benefit analysis that Idaho Power performed for a large distribution project is the automated metering infrastructure ("AMI") project that was filed with the Public Utility Commission of Oregon in Docket UM 233.

STAFF'S UTILITY SURVEY – QUESTION A6:

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?)

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?

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?

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?

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

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

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

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

IDAHO POWER COMPANY'S RESPONSE TO STAFF'S UTILITY SURVEY – QUESTION A6:

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?)

For local load service planning, the use of winter and summer peak demands suffice for distribution circuit and substation transformer load forecasting. Hourly models (8,760-hour models) are utilized to determine hosting capacity for DERs and interconnection studies.

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?

Idaho Power tracks Company-wide seasonal peaks for the purpose of the IRP and other system-level planning efforts. Distribution system forecasting focuses on distribution circuit and substation transformer level seasonal peak demand. Local peak times often deviate significantly from the system peak time. For most distribution circuits and substation transformers, data is available such that the local peak is easily determined. Where data is not available, a top-down approach can be utilized to estimate the local peak demand. No efforts are made to roll local peaks up to the system level as coincident system-level peaks are readily available.

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?

Yes. To determine the most accurate load forecasting methodology, Idaho Power reviewed 10 years of historical peak data on approximately 700 distribution circuits and 300 substation transformers Company-wide. The first seven years were used to calibrate the forecast. The last three years were used to measure the accuracy of each trending methodology. Through the process, it was determined that a cubic regression with horizon loads most accurately represented actual load growth in the one- to seven-year timeframe that is most critical for infrastructure budgeting.

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 is measured and recorded by Idaho Power's SCADA system. All 8,760 hourly load measurements are used to determine the impact of DERs.

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

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

Given current DER penetration levels, the Company does not currently forecast the impact of DER on the distribution system. However, Idaho Power is currently developing scenarios reflecting DER penetration and adoption as well as increased electrification of transportation and buildings for use in its various electrical plans.

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

Please see the Company's response to Question 6.e.i above.

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

Please see the Company's response to Question 6.e.i above.

STAFF'S UTILITY SURVEY – QUESTION A7:

Locational assessment of DER:

a. Describe whether locational DER assessments are a part of the planning process and the process for assessing this.
b. What form of hosting capacity software or analysis, if any, is used in the planning process? Please describe.
c. Is hosting capacity analysis conducted system wide and/or in response to interconnection requests?

IDAHO POWER COMPANY'S RESPONSE TO STAFF'S UTILITY SURVEY – QUESTION A7:

Locational assessment of DER:

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

Yes. Idaho Power submitted a T&D locational capacity deferral value analysis in Docket UM 1911, *Idaho Power Resource Value of Solar,* on July 18, 2019. The analysis can be found at: https://edocs.puc.state.or.us/efdocs/HAD/um1911had164825.pdf.

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

Idaho Power is using DRIVE, developed by EPRI, to calculate hosting capacity. DRIVE is a capacity evaluation application to determine the ability to host resources on distribution feeders without causing adverse impacts to power quality or reliability. DRIVE was created to determine the distribution system ability to accommodate DERs such as PV and energy storage on a feeder-by-feeder basis.

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

A system-wide hosting capacity analysis is currently in progress. The study is expected to be completed by the end of the 2019.

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:

STAFF'S UTILITY SURVEY – QUESTION B1:

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

IDAHO POWER COMPANY'S RESPONSE TO STAFF'S UTILITY SURVEY – QUESTION B1:

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

> *[Section A, Question 3a: A description of the various distribution system planning processes, reports and other components utilized.]*

The summer 2018 peak demands were reviewed for all 54 distribution circuits and 29 substation transformers in Oregon in August 2018. Winter 2018-2019 peak demands were reviewed in April 2019. Seasonal peak demands are reviewed every spring and fall. They are used to inform peak demand forecasts.

Small area studies typically take one to six months to complete and are sometimes done concurrently. Of the 10 small area studies in Oregon, one was last updated in 2017, three in 2018, and six have been or will be updated in 2019. Each small area study forecasts 10 years from the date of completion of the study and is applicable for three years or until another study is triggered.

Protection coordination studies typically take one to six months to complete and can be done concurrently. Protection coordination studies are completed on a five-year cycle. Of the 54 distribution circuits in Oregon, four studies were last updated in 2016, 17 in 2017, 15 in 2018, nine are planned in 2019, and seven are planned in 2020. Each coordination study is applicable for five years or until another study is triggered.

<u>STAFF'S UTILITY SURVEY – QUESTION B2</u>:

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

<u>IDAHO POWER COMPANY'S RESPONSE TO STAFF'S UTILITY SURVEY – QUESTION B2</u>:

Current local short-term plans do not include multiple scenarios. DERs and large loads are studied when interconnection is requested. For low and high growth rates, identified solutions can be deferred or accelerated within the budget.

The current long-term electrical plan (Western Treasure Valley Electrical Plan) is adjusted to account for energy efficiency, but, at the time it was completed in 2011, no DER or electrification scenarios were considered. An update to the electrical plan is scheduled in 2021.

<u>STAFF'S UTILITY SURVEY – QUESTION B3</u>:

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)

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

<u>IDAHO POWER COMPANY'S RESPONSE TO STAFF'S UTILITY SURVEY – QUESTION B3</u>:

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)

From the 10 small area studies, four planning capacity increases are scheduled to address anticipated needs within the next 10 years.

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

All projects, including projects with growth, reliability, and asset replacement drivers, are ranked based on the costs and drivers associated with the project. Once ranked, the list is reviewed to ensure the ranking is accurate and all projects fit within budgeting, timing, and resource constraints.

STAFF'S UTILITY SURVEY – QUESTION B4:

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

IDAHO POWER COMPANY'S RESPONSE TO STAFF'S UTILITY SURVEY – QUESTION B4:

For generators that have indicated an intent to come on-line, Idaho Power has implemented software and processes for analyzing DER (customer on-site generation and Public Utility Regulatory Policies Act of 1978 ("PURPA") projects) distribution integration requests to ensure safe and reliable circuit operation within accepted parameter limits.

STAFF'S UTILITY SURVEY – QUESTION B5:

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.**
- **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).**
  - **i.** **Where individual budget categories contain a substantial increase or decrease from historical levels, please explain the rationale for the change.**
- **c.** **Comparison: For each of the past five years, please provide a comparison of forecasted distribution system spending by year versus actual spending.**

IDAHO POWER COMPANY'S RESPONSE TO STAFF'S UTILITY SURVEY – QUESTION B5:

Please see the attached Excel spreadsheet.

STAFF'S UTILITY SURVEY – QUESTION B6:

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

- **a.** **Whether/which alternative analyses were conducted (as described in Section A, Question 5c). P lease describe.**
- **b.** **Whether future capital or O&M projects were identified using DER alternatives. Please describe.**
- **c.** **Identification of any non-monetized benefits of planned projects.**
- **d.** **Identification of any projects that will enhance the company's future ability to integrate DER into system operations.**
- **e.** **Which distribution projects are selected and approved within the scope of projects proposed. Please explain why.**

IDAHO POWER COMPANY'S RESPONSE TO STAFF'S UTILITY SURVEY – QUESTION B6:

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

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

Each planned project was analyzed as described in the Company's response to Section A, Question 5.c (capital vs. O&M, near-term vs. long-term, non-monetized benefits, NWA). As an example, the alternatives analyzed at Jordan Valley were to install a larger transformer, add a battery storage bank, or install a solar and storage microgrid.

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

Every capital project is screened for non-wire alternatives. At Jordan Valley, a battery solution to shift peak demand was determined to be a cost-effective way to address a capacity constraint. Idaho Power is actively looking for other NWA solutions.

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

Idaho Power was considering a small solar plus storage microgrid at Jordan Valley. Non-monetized benefits included:

- Expertise in coordinating generation, storage, and demand;
- Experience with battery technology;
- Providing power during transmission outage events to critical loads in a small, remote community; and
- Customer satisfaction.

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

Idaho Power plans to require smart inverter installations with DER integration consistent with the yet to be finalized IEEE 1547 standards. The use of smart inverters will allow for additional DER penetration.

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

Of the 23 projects currently scheduled in Oregon, eight are capacity related and the remaining 15 will replace aged assets. These projects are necessary to serve new load growth as well as improve reliability as Idaho Power maintains its electrical system.

Section C
<u>Current Distribution System</u>

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

<u>STAFF'S UTILITY SURVEY – QUESTION C1</u>:

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

<u>IDAHO POWER COMPANY'S RESPONSE TO STAFF'S UTILITY SURVEY – QUESTION C1</u>:

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.*

Idaho Power utilizes an over-current based protection scheme on its distribution system. The distribution protection system starts at the high side (transmission source) of the substation transformer and uses breaker/relays in most substations and fuses on small substation transformers. The protection devices at the distribution class voltage level include the feeder breaker/relays in the substations and distribution feeder (circuit) devices, including reclosers, sectionalizers, and fuses (including both inline and tap fuses).

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*

Idaho Power is currently constructing a system-wide IVVC. A successful pilot with a single substation and five-feeders was completed in 2018. The Company has commenced a three-year buildout plan that will expand the IVVC system to 78 additional substations and 367 distribution feeders (circuits) across Idaho Power's five-region service territory. This represents 55 percent of the distribution circuits that serve nearly 80 percent of Idaho Power's customers. The three-year buildout is scheduled to be complete by the end of 2021 and is to replace the legacy Automated Capacitor Control system ("ACC") that has been in operation since the mid 1990's.

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

Faults on the Idaho Power distribution system are automatically detected by protective devices on the system, including relays, reclosers and fuses. There are currently 587 feeder breakers, 93 substation reclosers, 1,040-line reclosers and over 27,000 line fuses on the distribution system. Idaho Power does not have any fully automated Fault Location, Isolation, and System Restoration (FLISR) schemes. The Company does have 11 automated tie switches in operation primarily at large industrial customers, including one in Oregon. Idaho Power also uses fault indicators on a limited, situational basis to troubleshoot and indicate faults on both the overhead and underground distribution systems. There are currently 258 fault indicators installed across the distribution system.

<u>STAFF'S UTILITY SURVEY – QUESTION C2</u>:

Monitoring:

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

b. Is the utility deploying AMI technology?

i. What is the percentage of AMI meters in the Oregon service territory?

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

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 *[SIC - INCOMPLETE IN ORIGINAL]*

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.

<u>IDAHO POWER COMPANY'S RESPONSE TO STAFF'S UTILITY SURVEY – QUESTION C2</u>:

Monitoring:

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

There are 26 distribution stations (owned by Idaho Power serving retail customers at 34.5 kV or below) with 62 feeders in Oregon. Fourteen of these stations (56 percent) with 43 feeders (72 percent), have one or more power system devices which can be remotely controlled and monitored. Please note that this includes only stations in the state of Oregon and does not include stations located in Idaho but with feeders that cross into Oregon.

b. Is the utility deploying AMI technology?

Idaho Power deployed AMI technology in its Oregon service territory in 2010. The system currently covers approximately 92 percent of Idaho Power's customer base within the state of Oregon. Idaho Power is currently in the design phase to expand the AMI system; expanding the AMI footprint to cover about 99 percent of the Oregon customer base. This project is scheduled to be completed by 2020.

i. What is the percentage of AMI meters in the Oregon service territory?

In Idaho Power's Oregon service territory, 92 percent of the meter population leverages AMI technology. The remaining 8 percent of customers are served via manually read meters.

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

- Commercial: 89 percent AMI
- Residential: 94 percent AMI
- Irrigation: 87 percent AMI

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* ***[SIC – INCOMPLETE IN ORIGINAL]***

Idaho Power has AMI and SCADA at 14 distribution substations and AMI only at one distribution substation in Oregon. Fifteen distribution substations in Oregon have no AMI and no SCADA. Idaho Power also has SCADA at two transmission stations, one switching station, two metering stations, two interconnection stations, one compensation station, and two power plants in Oregon.

For Idaho Power-owned infrastructure serving some of the sites mentioned above, there are seven microwave hops into three microwave sites, two power plants, two transmission stations, and one switching station in Oregon. Two more transmission stations in Oregon are connected to an adjacent microwave site via fiber optic cables. The microwave hops typically have between 100 and 360 megabits per second bandwidth. The fiber connected transmission stations are connected via gigabit Ethernet to the adjacent microwave site but are limited by the microwave site's bandwidth to the rest of the system. Currently, there are no plans to build more Idaho Power-owned infrastructure in Oregon except as detailed in the Company's response to Question 2.d below.

The rest of Idaho Power's connectivity to the stations mentioned above uses telecommunications carrier services. The services used from these carriers include analog leased lines, Digital Data Service leased lines, T1 leased lines, and Metro Ethernet leased services.

Currently, in Oregon, there is one distribution line recloser remotely controlled via a point-to-point radio frequency link, one recloser on a cell phone SCADA connection, and four substations have one-way communications from the substations to distribution line capacitors as part of our legacy ACC. ACC is being replaced in Idaho Power's Oregon area in 2020. Please see the Company's response to Section C, Question 1.b.i for additional information.

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.*

Idaho Power has plans to install a private Field Area Network ("FAN") around 16 substations and its associated distribution systems. This FAN is comprised of narrowband Ethernet radios operating in the 700 MHz region. Idaho Power acquired a small amount of 700 MHz spectrum in the secondary market in 2016 specifically for this FAN. The system is constructed with strategically placed base stations to communicate out to some electrical distribution elements. Coverage of the Oregon feeders is estimated to be 50 percent at project completion.

STAFF'S UTILITY SURVEY – QUESTION C3:

Performance:

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

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

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

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

c. **What percentage of 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?**

IDAHO POWER COMPANY'S RESPONSE TO STAFF'S UTILITY SURVEY – QUESTION C3:

Performance:

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

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

Idaho Power uses industry standard metrics defined in IEEE 1366 including:

- System Average Interruption Frequency Index ("SAIFI")
- System Average Interruption Duration Index ("SAIDI")
- Customer Average Interruption Duration Index ("CAIDI")
- Customers Experiencing Multiple Interruptions ("CEMI")
- Momentary Average Interruption Event Frequency Index ("MAIFI-E")

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

Year	SAIDI	SAIFI	CAIDI	MAIFI-E	CEMI-3
2014	3.43	1.63	2.10	2.48	26.1%
2015	6.18	1.95	3.17	3.86	24.1%
2016	2.88	1.05	2.74	2.83	14.5%
2017	3.69	1.23	3.00	3.82	15.6%
2018	2.49	0.96	2.59	3.30	7.3%

In addition, the Company files its annual Electric Service Reliability Report, under Docket RE 90.

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

Idaho Power uses outage data analytics to track the various outage causes. Idaho Power has tools to track and evaluate trends in failures that result in sustained outages

(SAIFI) and momentary interruptions (MAIFI). Idaho Power uses regularly scheduled line patrols and detailed emergency response patrols to identify specific failure points on the distribution system such as damaged insulators, cross arms, poles, arrestors, and other equipment. Line maintenance is then done on areas identified in patrols and inspections.

Distribution reliability programs focus on identifying the worst-performing feeders (circuits). Work is then done on an annual basis to harden distribution circuits to prevent outages and to reduce the outage exposure to customers by adding protection and sectionalizing devices such as reclosers, sectionalizers, and fuses.

Idaho Power has an extensive vegetation management program. Distribution feeders are on a three-year vegetation management cycle. Areas with fast growing trees near lines are trimmed on a shorter cycle, even annually when necessary.

The Company also has asset replacement programs where aging or obsolete equipment is replaced to prevent future outages. Idaho Power currently has programs to replace transformers, breakers, relays, switches, poles, and underground cable.

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

YEAR	**CI***	**CHO****	**% Dist CI**	**% Dist CHO**
2014	30,113	65,059	46.8%	57.0%
2015	36,336	115,301	68.0%	57.2%
2016	19,868	54,244	63.2%	65.8%
2017	23,114	69,216	71.8%	75.2%
2018	18,024	47,002	79.9%	68.7%
Total	**127,455**	**350,823**	**64.6%**	**63.6%**

*CI: Customer Interruptions
**CHO: Customer Hours Out

Please note these are system values.

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

Idaho Power designs, evaluates, and operates the distribution system voltage service to the American National Standards Institute (ANSI) C84.1 voltage standard. The Company also manages loads to prevent thermal overloads on lines and equipment on the distribution system. Customers are required to comply with IEEE 519, the Practices and Requirements of Harmonic Control in Electric Power Systems.

Per Rule K in the Idaho Power's Oregon tariff, customers are also required to give the Company notice prior to making any significant change in either the amount or electrical character of the customer's load, thereby allowing the Company to determine if any changes are needed in the Company's equipment or distribution system.

<u>STAFF'S UTILITY SURVEY – QUESTION C4</u>:

Security

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

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

<u>IDAHO POWER COMPANY'S RESPONSE TO STAFF'S UTILITY SURVEY – QUESTION C4</u>:

Security

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

Idaho Power has physical security controls in place to deter, detect, deny, and/or delay access to Idaho Power facilities, including data centers, substations, and operations centers. Idaho Power also utilizes various policies, standards, and processes and procedures for securing data and systems, such as change management, system security plans, and baselines. Finally, from a technology standpoint, Idaho Power utilizes a defense in depth approach for securing Idaho Power networks, applications, data, and workstations.

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

Idaho Power has aligned its cyber security program with National Institute of Standards and Technology ("NIST") guidance. The Company has reviewed, selected, and documented all controls that would be applicable. Additionally, the Company has developed a formal threat model that identifies threats, related impacts, and controls in place to mitigate the threats. These threats are based on the NIST 800-53 standards and evaluation of Idaho Power-specific risks. The threat model provides Cyber Security, management, and the Board of Directors more insight into current threats, the qualitative review of Idaho Power resiliency, and residual risks identified.

The Company is engaged with various industry organizations (E-ISAC, EEI, WEI, WECC, etc.), Idaho Fusion Center (DHS), InfraGard (FBI), Cybersecurity and Infrastructure Security (CISA), and other utility partners.

<u>STAFF'S UTILITY SURVEY – QUESTION C5</u>:

DERs:

- **a. What is the current and forecasted extent of DER deployment by type, size, and geographic dispersion?**
- **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.**
  - **ii. Please provide the current number of active interconnection requests for small generators located in Oregon that have not yet executed an interconnection agreement.**
  - **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.**
  - **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.**
- **c. What data and information are made available to distribution-level interconnection applicants prior to making an interconnection request? How is that information provided?**
- **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. How does the utility define microgrids? Please list any microgrids in the utility's service territory.**

<u>IDAHO POWER COMPANY'S RESPONSE TO STAFF'S UTILITY SURVEY – QUESTION C5</u>:

DERs:

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

Idaho Power does not forecast DER deployment on its distribution system. As described in the Company's response to Section A, Question 1.b.i, seasonal peak demands are adjusted to account for distributed generation, among other things.

While DER deployment is not forecast on a granular level, Idaho Power's system load forecast does include the impact of on-site generation.

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

Idaho Power has 20 PURPA qualifying facilities ("QF") that are 10 MW or less under contract in its Oregon service area. Of these 20 QFs, fifteen are on-line, totaling 117 MW. Four QFs, totaling 11.75 MW, are scheduled to be online in 2019, and one QF of 3 MW is scheduled to be on-line in 2022. These totals do not include QFs 10 MW and less that are interconnected to other utilities but deliver generation to the Idaho Power system under Oregon PURPA Energy Sales Agreements.

Idaho Power has 60 projects under contract and on-line totaling 0.46 MW in the Oregon Solar volumetric incentive rate (VIR) pilot program.

Idaho Power has 57 Oregon projects connected under its Net Metering tariff totaling 1.19 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.*

	PURPA			**Oregon Solar VIR Pilot**		
	Resource	**Projects**	**MW**	**Resource**	**Projects**	**MW**
2014	N/A	N/A	N/A	Solar	6	0.05
2015	N/A	N/A	N/A	Solar	7	0.06
2016	Solar	6	49.5	N/A	N/A	N/A
2017	Wind	5	50	N/A	N/A	N/A
2018	N/A	N/A	N/A	N/A	N/A	N/A

Customer Generation (all projects installed between 2014 to 2018 were solar).

	Solar Projects	**Solar MW**
2014	3	0.21
2015	10	0.24
2016	5	0.25
2017	13	0.15
2018	10	0.14

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

- Idaho Power has eight applications for Oregon net metering projects.
- There are two active interconnection requests (projects < 10MW) and both are 3 MW nameplate capacity.

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.*

There are four projects (<10 MW) that have an executed interconnection agreement but have not reached commercial operation. Three projects each at 3 MW nameplate capacity and one at 2.75 MW of nameplate capacity.

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.*

Please see the Company's response to Question 5.b above.

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

The Idaho Power website (https://www.idahopower.com/about-us/doing-business-with-us/generator-interconnection/) has links to the interconnection requirements and interconnection process documents. Furthermore, Order No. 19-217 in Docket UM 2001 outlines the additional data Idaho Power will make publicly available by September 1, 2019.

For behind the meter customer generation, there are several informational documents, as well as rules for Oregon customers. For larger in front of the meter primary distribution connected generation, both PURPA and non-PURPA interconnection rules and processes can be found on Idaho Power's website. Additionally, the processes outline a pre-application subprocess that can be used to obtain the following information for a $300 fee:

- Total substation/area bus, bank, or circuit capacity
- Existing aggregate generation capacity
- Aggregate queued generation capacity
- Available substation/area bus, bank, or circuit capacity
- Substation nominal voltage
- Approximate circuit distance between the proposed point of interconnection and the substation
- Estimated or actual peak load and minimum load data
- Number and rating of protective devices and regulating devices between the proposed point of interconnection and the substation
- Number of phases
- Limiting conductor ratings
- Proposed point of interconnection circuit type (network, radial, spot)
- Existing or known constraints

A link to the interconnection queue is also available on Idaho Power's website.

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?

Yes, Idaho Power exchanges data with PURPA projects to enable external Volt/VAr set point control.

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

Today, there are no planned or operating microgrids. As referenced in the Company's response to Section B, Question 6.c, a microgrid is being considered in Jordan Valley. Idaho Power views microgrids as a community or group of customers in an area that can be isolated electrically and operate independently from the rest of the grid for a period of time. Typically, generation and/or storage is required to effectively run a microgrid.

<u>STAFF'S UTILITY SURVEY – QUESTION C6</u>:

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.**
  - **i.** **What are the major findings from this research over the past 5 years?**
  - **ii.** **How does the utility use the results of this research?**

<u>IDAHO POWER COMPANY'S RESPONSE TO STAFF'S UTILITY SURVEY – QUESTION C6</u>:

Customer values:

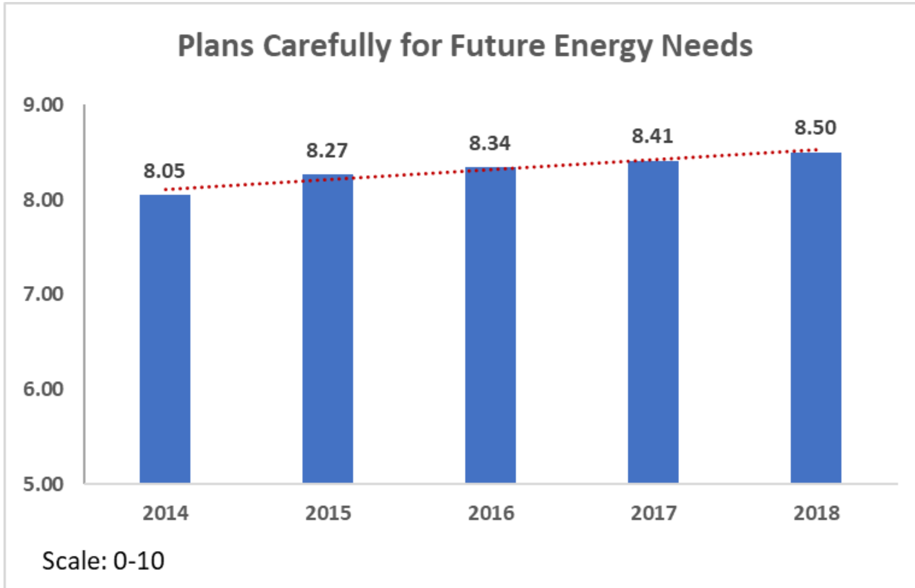
a. Please describe the surveys and other market research the utility performs to understand customer values, needs, and interests related to distribution system planning.

Idaho Power conducts proprietary relationship surveys with all customer groups on a quarterly basis. These survey groups include residential, small to medium commercial, large commercial and industrial, and irrigation customers. Surveys are primarily conducted over the telephone. The purpose of this survey is to measure the overall relationship the customer has with Idaho Power and therefore is not focused specifically on distribution system planning. However, in the survey, all respondents are asked one question that is somewhat related to distribution system planning: "How much would you agree or disagree that Idaho Power considers the needs of all customers in planning for future energy needs?"

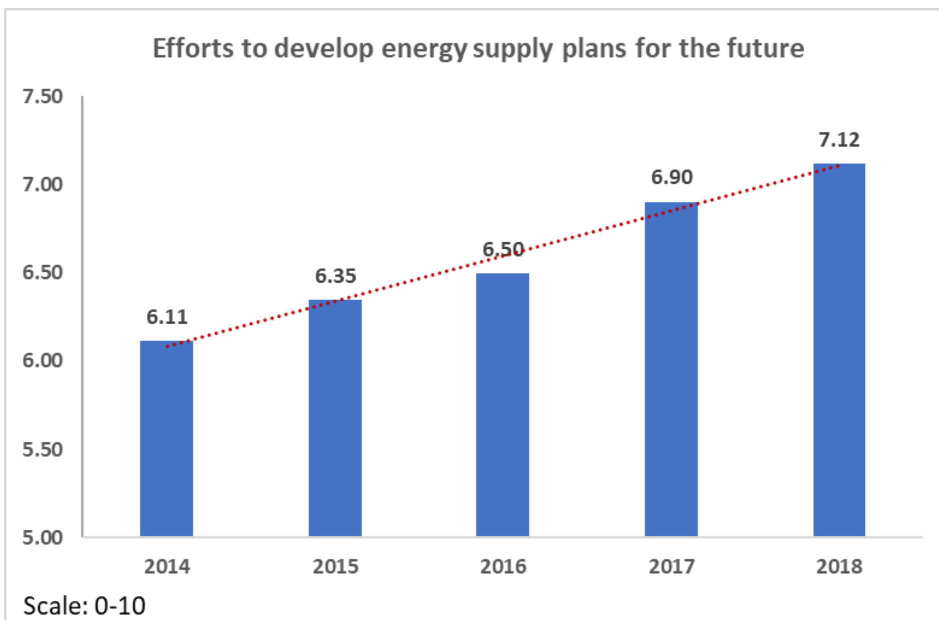
Additionally, Idaho Power subscribes to the annual J.D. Power and Associates Electric Utility **Residential** Customer Satisfaction Study. This survey is conducted with online panelists. The intent of this study is also as a relationship study with residential customers only and thus is not focused specifically on distribution system planning. However, this study also includes a question somewhat related to distribution system planning: "How would you rate Idaho Power on efforts to develop energy supply plans for the future?"

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

Below are the overall mean scores for all customer segments in the Idaho Power proprietary research for the attribute "Plans carefully for future energy needs" over the last five years.



Below are the overall mean scores for the J.D. Power and Associates Electric Utility Residential Customer Satisfaction study for the attribute "Efforts to develop energy supply plans for the future" over the last five years.



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

Idaho Power monitors the mean scores of the associated attributes on both the proprietary research and the J.D. Power and Associates study on a quarterly basis to ensure that customers are aware of Idaho Power's efforts to plan for future energy needs. Customer awareness of Idaho Power's efforts have steadily increased in both studies over the last five years.

Section E
<u>Energy Trust of Oregon</u>

Energy Trust of Oregon, as a nonprofit third-party administrator of energy efficiency and small scale renewable programs in Portland General Electric and PacifiCorp's Oregon territory, please provide the following information. Note: Idaho Power (IPC) will include DER responses in their reply to Utility Survey Section C because Energy Trust does not provide these services in IPC's service territory.

<u>STAFF'S UTILITY SURVEY – QUESTION E1</u>:

Program results: For both electric energy efficiency and small scale renewable programs:

- **a.** **Provide annual savings / generation for years 2014-2018 for PGE and PAC service territories.**
- **b.** **At what level of granularity are these results available? Locational? Hourly?**
- **c.** **What program result details are shared regularly with utilities?**
- **d.** **What level of certainty do you have in those results? Estimated? Metered/measured? Pre/post evaluation?**
- **e.** **Are there different levels of certainty associated with results for different types of measures and resources? If so, please explain.**

<u>IDAHO POWER COMPANY'S RESPONSE TO STAFF'S UTILITY SURVEY – QUESTION E1</u>:

Program results: For both electric energy efficiency and small scale renewable programs:

- *a.* *Provide annual savings / generation for years 2014-2018 for PGE and PAC service territories.*

Idaho Power System Demand-Side Management ("DSM") Energy Efficiency Savings

Year	Idaho Power Program Savings* (kWh)	NEEA Saving* (kWh)	Total savings* (kWh)
2014	118,670,113	26,805,600	145,475,713
2015	140,633,155	23,038,800	163,671,955
2016	146,218,758	24,352,800	170,529,352
2017	167,819,395	24,440,400	192,259,795
2018	158,556,721	24,966,000	183,377,834

*Savings are reported without line losses.

Idaho Power Orgon DSM Energy Efficiency Savings

Year	Idaho Power Program Savings* (kWh)	NEEA Saving* (kWh)	Total savings* (kWh)
2014	5,777,306	1,000,000	6,777,306
2015	6,304,727	1,095,000	7,399,727
2016	6,073,512	1,230,780	7,304,292
2017	6,140,511	1,182,600	7,323,111
2018	5,283,897	1,248,300	6,532,197

*Saving are reported without line losses.

b. *At what level of granularity are these results available? Locational? Hourly?*

Energy savings from DSM programs are reported annually by jurisdiction. Idaho Power filed its *Demand-Side Management 2018 Annual Report* on April 2, 2019, in Docket UM 1710.

c. *What program result details are shared regularly with utilities?*

N/A

d. *What level of certainty do you have in those results? Estimated? Metered/measured? Pre/post evaluation?*

Idaho Power reports estimated DSM energy efficiency savings.

e. *Are there different levels of certainty associated with results for different types of measures and resources? If so, please explain.*

Idaho Power uses industry-standard protocols for its internal and external evaluation of DSM energy efficiency programs and measures, including the National Action Plan for Energy Efficiency—Model Energy Efficiency Program Impact Evaluation Guide, the California Evaluation Framework, the International Performance Measurement and Verification Protocol (IPMVP), the Database for Energy Efficiency Resources, and the Regional Technical Forum's evaluation protocols.

Timing of impact evaluations are based on protocols from these industry standards with large portfolio contributors being evaluated more often and with more rigor. Smaller portfolio contributors are done less often and require less analysis as most of the program measure savings are deemed savings from the Regional Technical Forum (RTF), the Company's Technical Resource Manual (TRM), or other sources. Realized savings of programs evaluated by third-party contractors between 2017 and 2018 ranged between 84 and 101 percent. The savings weighted average realized savings over the same period is 100 percent.

<u>STAFF'S UTILITY SURVEY – QUESTION E2</u>:

Planning and program design:

- **a.** **How are program results forecasted?**
- **b.** **At what level of granularity are program impacts forecasted? Broadly across the service territory or by region? By location?**
- **c.** **How is planning data shared with utilities?**
- **d.** **Use of program targeting to meet specific utility system needs as a non-wires alternative.**
- **e.** **How do you incorporate customer accessibility and inclusivity into program planning and design?**

<u>IDAHO POWER COMPANY'S RESPONSE TO STAFF'S UTILITY SURVEY – QUESTION E2</u>:

Planning and program design:

a. How are program results forecasted?

DSM energy efficiency results are forecast based on historic performance and the most recent conservation potential assessment (CPA) conducted by a third-party contractor.

b. At what level of granularity are program impacts forecasted? Broadly across the service territory or by region? By location?

DSM energy efficiency results are forecast by service area and allocated to jurisdictions.

c. How is planning data shared with utilities?

N/A

d. Use of program targeting to meet specific utility system needs as a non-wires alternative.

DSM energy efficiency resources are not used for locational utility system's needs. demand response programs are used to defer or avoid the building of new supply-side resources.

e. How do you incorporate customer accessibility and inclusivity into program planning and design?

Idaho Power has DSM energy efficiency and demand response program programs available to all customer classes and has two energy efficiency programs specifically targeted at low-income customers.

The Company has an Energy Efficiency Advisory Group ("EEAG") which was formed in 2002 to provide input on implementing and planning energy efficiency programs and enhancing existing DSM programs. The EEAG consists of members from Idaho Power's service area and the Northwest. EEAG meetings are open to the public and consist of members representing a cross-section of customers from the residential, industrial, commercial, and irrigation sectors, and technical experts, as well as representatives from low-income households, environmental organizations, state agencies, county and city governments, and public utility commissions of Idaho and Oregon. The EEAG meets quarterly and, when necessary, Idaho Power facilitates conference calls and/or webinars to address special topics.

ATTACHMENT - RESPONSE TO STAFF'S UTILITY SURVEY - SECTION B, QUESTION 5

Distribution Plant - Capital
5)a.Historical distribution System Spending

	Capital ACTUAL					
Plant Type	2014	2015	2016	2017	2018	Comments
15 - Interconnect Fac - Dist Lines	-306,774	-5,873,750	2,344,550	2,909,259	-238,727	
40 - Underground Reconstruction	14,982,469	15,729,754	18,130,121	20,789,069	20,841,949	
41 - Distribution Stations	6,711,270	18,765,187	14,604,317	19,341,364	22,099,029	
42 - Overhead New Business	3,683,000	1,379,347	4,865,222	2,824,939	4,747,044	
43 - Overhead Reconstruction	20,677,511	23,272,507	27,759,151	28,918,214	30,362,009	
44 - Underground Duct Vault	873,310	261,836	9,179	7,733	48,144	
45 - Underground New Business	601,082	2,166,355	2,447,642	2,503,359	-4,511,779	
46 - Nightguard Lighting	6,113	723	0	0	0	
47 - Street Lighting	56	0	-8	0	0	
48 - Transformer Purchases	-811,491	-1,326,178	-1,522,916	-1,593,332	-1,213,945	
49 - Meter Purchases	4,595,623	3,185,330	4,606,016	5,045,247	4,974,278	
Distribution Plant Total	51,012,168	57,561,110	73,243,273	80,745,852	77,108,002	

	O&M ACTUAL				
Operation	**2014**	**2015**	**2016**	**2017**	**2018**
(580) Operation Supervision and Engi	4,028,859	4,289,300	4,226,094	4,208,616	4,550,906
(581) Load Dispatching	3,643,133	3,897,253	4,026,028	4,166,896	4,354,562
(582) Station Expenses	1,180,321	1,339,544	1,544,740	1,555,734	1,565,905
(583) Overhead Line Expenses	3,138,798	3,968,009	3,606,076	4,916,620	3,896,819
(584) Underground Line Expenses	2,525,008	2,889,346	3,076,757	3,615,140	3,392,139
(585) Street Lighting and Signal Syste	76,902	87,956	82,633	118,675	157,861
(586) Meter Expenses	4,424,696	4,769,220	4,717,443	4,904,919	4,570,706
(587) Customer Installations Expense	694,859	784,157	897,759	1,276,382	1,287,251
(588) Miscellaneous Expenses	5,788,865	6,041,032	7,518,466	6,886,864	4,939,645
(589) Rents	466,127	262,071	305,059	381,320	1,203,806
TOTAL Operation	25,967,569	28,327,887	30,001,053	32,031,165	29,919,600
Maintenance					
(590) Maintenance Supervision and E	16,451	10,627	-1,554,525	-1,643,939	604,934
(591) Maintenance of Structures	0	0	0	0	-1,048
(592) Maintenance of Station Equipm	3,950,824	3,630,618	3,870,899	3,887,158	4,482,318
(593) Maintenance of Overhead Lines	13,906,165	14,203,471	14,975,930	13,818,925	17,401,297
(594) Maintenance of Underground L	630,375	604,456	868,712	748,181	703,795
(595) Maintenance of Line Transform	148,125	36,603	28,581	23,843	45,593
(596) Maintenance of Street Lighting	531,740	486,847	588,626	554,421	589,313
(597) Maintenance of Meters	735,448	767,988	873,691	982,875	911,444
(598) Maintenance of Miscellaneous	418,635	289,620	380,105	240,442	214,170
TOTAL Maintenance	20,337,764	20,030,231	20,032,019	18,611,906	24,951,817
TOTAL Distribution Exp	46,305,333	48,358,119	50,033,072	50,643,072	54,871,417

ATTACHMENT - RESPONSE TO STAFF'S UTILITY SURVEY - SECTION B, QUESTION 5

5)b. Current distribution System Spending

	Capital Budgets					
Plant Type	2014	2015	2016	2017	2018	Comments
15 - Interconnect Fac - Dist Lines			20,006	3,164	27,671	
40 - Underground Reconstruction	14,820,308	14,693,938	18,072,542	18,455,810	19,763,417	
41 - Distribution Stations	6,206,998	18,160,597	15,728,761	19,343,873	24,605,453	the increase was driven by System Growth
42 - Overhead New Business	4,056,648	3,849,380	3,087,477	3,161,609	3,113,006	
43 - Overhead Reconstruction	20,411,043	24,462,716	26,527,474	31,323,120	30,201,788	
44 - Underground Duct Vault	131,744	134,821			50,000	
45 - Underground New Business	4,712,382	4,919,655	3,817,611	3,796,758	3,766,490	
46 - Nightguard Lighting	0	0	0	0	0	
47 - Street Lighting	0	0	0	0	0	
48 - Transformer Purchases	-750,000	-750,000	-788,000	-875,000	-1,050,000	
49 - Meter Purchases	3,363,551	2,160,344	4,098,224	3,954,581	5,600,274	
Distribution Plant Total	52,952,674	67,631,451	70,564,095	79,163,916	86,078,099	

The O&M Budget does not utilize a categorization to separate system expenses from other types of expenses

5)c. Comparison distribution System Spending

	Capital Comparison				
Plant Type	2014	2015	2016	2017	2018
15 - Interconnect Fac - Dist Lines	-306,774	-5,873,750	2,324,543	2,906,095	-266,398
40 - Underground Reconstruction	162,161	1,035,816	57,579	2,333,259	1,078,532
41 - Distribution Stations	504,272	604,590	-1,124,444	-2,509	-2,506,424
42 - Overhead New Business	-373,647	-2,470,033	1,777,745	-336,670	1,634,038
43 - Overhead Reconstruction	266,468	-1,190,209	1,231,678	-2,404,906	160,222
44 - Underground Duct Vault	741,566	127,014	9,179	7,733	-1,856
45 - Underground New Business	-4,111,301	-2,753,299	-1,369,969	-1,293,399	-8,278,269
46 - Nightguard Lighting	6,113	723			
47 - Street Lighting	56	0	-8		
48 - Transformer Purchases	-61,491	-576,178	-734,916	-718,332	-163,945
49 - Meter Purchases	1,232,072	1,024,985	507,793	1,090,666	-625,996
Distribution Plant Total	-1,940,505	-10,070,341	2,679,178	1,581,936	-8,970,097

The O&M Budget does not utilize a categorization to separate system expenses from other types of expenses and therefore an O&M Comparison is not available.