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February 16, 2018

Via Electronic Filing and US Mail

OREGON PUBLIC UTILITY COMMISSION
ATTENTION: FILING CENTER
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RE: Docket No. UM 1856 – In the Matter of PORTLAND GENERAL ELECTRIC COMPANY, Draft Storage Potential Evaluation.

Attached is Staff Reply Testimony, Exhibit 100 to 103.
Exhibit 100 is redacted. Confidential pages 21, 22 and 39 are being mailed to parties who have signed Protective Order No 17-441.

/s/ Kay Barnes
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CERTIFICATE OF SERVICE

UM 1856

I certify that I have, this day, served the foregoing document upon all parties of record in this proceeding by delivering a copy in person or by mailing a copy properly addressed with first class postage prepaid, or by electronic mail pursuant to OAR 860-001-0180, to the following parties or attorneys of parties.

Dated this 16th day of February, 2018 at Salem, Oregon

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CASE: UM 1856
WITNESS: SETH WIGGINS

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 100

Reply Testimony

REDACTED
February 16, 2018

Q. Please state your name, occupation, and business address.

A. My name is Seth Wiggins. I am a Senior Utility Analyst for the Public Utility Commission of Oregon (Commission or OPUC). My business address is 201 High Street SE, Salem, OR 97301.

Q. Please describe your relevant work and educational experience.

A. My educational background and employment experience are set forth in my Witness Qualification Statement, which is provided as Exhibit Staff/101.

Q. How is your testimony organized?

A. My testimony is organized as follows:

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I. EXECUTIVE SUMMARY

Q. What is the purpose of this testimony?

A. The purpose of my testimony is to evaluate (1) Portland General Electric's final energy storage potential evaluation and (2) final energy storage proposals, both of which were filed in this docket on November 1, 2017. Alongside an evaluation of the potential to add storage to its grid, Portland General Electric (PGE) proposed five individual storage projects with varying sizes and purposes.

Q. What is your conclusion on PGE's proposal?

A. Staff is encouraged by PGE's submission. As described below, Staff believes there is potential for the development and building of several quality pilots which provide tangible benefits to the company and ratepayers alike. However after reviewing PGE's November 1 proposal, Staff has difficulties considering this a final version, especially given that PGE has not incorporated Staff feedback to its draft storage potential evaluation, as presented in Commission Order No. 17-375. Staff has identified several fundamental concerns with both the storage potential evaluation as well as each of the five projects. In current form, Staff cannot recommend Commission approval the storage potential evaluation or the projects. Staff believes that PGE could use the time between its rebuttal testimony (March 23) and the second settlement conference (April 2) to refine its proposal with improved projects that address Staff's concerns and adhere to the project and proposal guidelines and the storage potential evaluation framework already adopted by the Commission in Order

Nos. 16-504 and 17-118. With significant and careful revision, Staff could recommend approval of four of the projects, or PGE could treat this as an ongoing draft and revise the procedural schedule.

Q. Can you please provide an executive summary of your testimony?

A. Yes. HB 2193 (2015) encouraged the development of energy storage in the major utility networks. While the total MW capacity additions (between 5MW-1 percent of total load) were not trivial, the main purpose was to develop the capacity of both the Oregon Public Utility Commission (Commission) and the utilities to identify areas of opportunity for energy storage to be part of a risk adjusted least-cost portfolio. The legislature believed the learnings generated would justify the added ratepayer expense.

PGE submitted its storage potential evaluation and energy storage proposal well in advance of the January 1, 2018 statutory deadline. Although Commission Order No. 17-375 built in a three month window for the large electric companies to work with staff and stakeholders prior to filing their "final" storage evaluations and project proposals, PGE filed its final proposals for review on November 1, 2017. At the prehearing conference in this docket, all parties agreed to a standard contested case schedule to begin review and evaluation of PGE's filing. To be clear, two components were required in the filing. Both HB 2193 and Commission orders mandate the inclusion of (1) an evaluation of the potential to incorporate energy storage systems into the electric company's electric system (storage potential evaluation), as well as (2) detailed proposals for individual storage projects. PGE's proposed five

energy storage system (ESS) projects are widely diverse in project size, function, and ownership. If the Commission approves these five projects—ranging in total cost from $105.5 million to $189.8 million—all prudently incurred costs would be recoverable through increased electricity rates.

Staff has several concerns about PGE's storage potential evaluation, especially with regard to PGE's use of the Integrated Planning Tool (IPT) to evaluate its network for potential locations to site ESSs. First, while the IPT tool quantitatively estimates benefits of ESS deployments, Staff is concerned about its transparency. Staff has reviewed the outputs of the IPT model, but has no ability to verify that the inputs and assumptions were valid despite requesting the input data in discovery.[1] Second, there appear to be additional qualitative criteria that are utilized for site selection in the storage potential evaluation but they are at best described in insufficient detail. Third, the exclusion of both transmission and distribution (T&D) benefits and the calculation of project costs in the storage potential evaluation are troubling. Fourth, the method of quantifying benefits in the storage potential evaluation is flawed: the Commission adopted a specific framework for the calculation of the benefits associated with any proposed ESS. Despite the Commission adopting Staff's report that highlighted the insufficiencies in PGE's draft storage potential evaluation, PGE did not address the insufficiencies in this November 1 filing and has no stated plans to develop the capability to meet the Commission's requirements. Staff understands the effort required to meet the Commission's

[1] Exhibit Staff/102, Wiggins/1(PGE Response to OPUC Staff DR 2).

framework for evaluations and guidelines for proposals is substantial, however Staff believes the benefits associated with achieving those goals will surpass the cost.

With regard to PGE's energy storage proposals, Staff has concerns about each of the five proposed ESS projects. While the Power System Integration project at PGE's Coffee Creek Substation (Coffee Creek) and the Generation Kick-Start project at the Port Westward 2 generation facility (Port Westward) show the most promise, neither meets the critical components of Commission's project and proposal guidelines even in this revised version of PGE's submittal.[2] There appear to be omitted benefits from the Port Westward project, and PGE's reasoning for the specific sizing of the Coffee Creek project is not explained consistent with Commission orders. Despite these concerns, Staff believes that with minor revisions both could be considered viable projects for approval by the Commission.

Staff is more hesitant about the Power System Integration project at the (Baldock Mid-feeder (Baldock) primarily because the main stated benefit, the integration of ESS with an existing solar facility, is purely qualitative, and not explained in sufficient detail. Staff is unsure the facility's size-constrained benefits justify the estimated $4.1-7.8 million cost. However with improvements Staff could possibly recommend this pilot project for approval by the Commission. Staff is similarly concerned with the residential storage program. The project's estimated administrative costs, that are likely conservative,

[2] Docket No. UM 1751, Order No. 16-504 at 5 (Dec. 28, 2016).

leaves many technical, customer service and regulatory issues unaddressed, and provides only a portion of the quantified benefits to all ratepayers. Only with these issues resolved could Staff recommend this project for approval. Finally in the Microgrid Resiliency (Microgrid) pilot, Staff believes the benefits received by program participants far outweigh the benefits that could accrue to all ratepayers. Combined with the substantial range between the estimated $19.7-76.9 million cost, the project does not at this point appear viable.

An important consideration is that approval of PGE's proposals will allow PGE (with a prudency review) to recover the full cost of the projects in customer rates. If approved, PGE will proceed to the RFP process, with an understanding that the requested projects need not meet any level of cost effectiveness as they are pilots. If all proposed projects move forward, PGE's lowest estimates indicate they will require $55.7 million in overnight capital, with the net present value of revenue requirement totaling $90.5 million[3]. PGE's highest estimates increase those values to $97.7 million and $187.2 respectively. These costs are significant, as is the range in uncertainty associated with these estimates. Given these concerns, Staff recommends that PGE address the concerns highlighted in this reply testimony, in addition to complying with the framework and guidelines in the Commission's orders, through either rebuttal testimony or a revised evaluation and project proposals accompanying testimony addressing Staff's concerns and that is consistent with the procedural schedule adopted in this docket

[3] These lower-bound figures generally use PGE's estimates of 10-year asset lives.

II. CONTEXT FOR REVIEW

Q. Can you provide an overview of the procedural history leading up to this filing?

A. Yes. House Bill (HB) 2193 (2015) requires large Oregon electric companies to submit proposals to develop qualifying energy storage systems with the capacity to store at least 5 MWh of energy to the Commission by January 1, 2018. The bill expressly lays out specific information and analyses that must be provided for each energy storage proposal, requires a comprehensive evaluation of the potential to store energy in the electric company's system (storage potential evaluation), and includes timeline milestones to achieve procurement of Commission-approved programs by January 1, 2020. Since the bill was passed, the Commission, with substantial input from Staff and numerous stakeholders, has developed project and proposal guidelines, competitive bidding requirements, and a framework for the electric company's system-wide storage potential evaluation to assist Portland General Electric (PGE) and PacifiCorp in developing both project proposals and storage evaluations that comply with the law and Commission expectations.

In September of 2015, the Commission opened Docket No. UM 1751 for the purpose of developing energy storage guidelines by January 1, 2017, as directed by HB 2195. The Commission offered draft project and proposal guidelines, direction and timelines for the storage potential evaluations to be completed by electric companies, and draft competitive bidding requirements

specific to storage proposals in Order No. 16-316, but sought additional comments before finalization in January 2017.

The Commission received additional comments from many stakeholders and on December 28, 2016, the Commission adopted the following in Order No. 16-504: (1) final project guidelines to help electric companies design and select projects to consider proposing; (2) final proposal guidelines for electric companies to use when submitting formal proposals for approval by January 1, 2018; (3) working requirements and a timeline for development of the system-wide storage potential evaluation; and (4) final minimum competitive bidding requirements for storage projects.

Following Commission Order No. 16-504, only one component remained outstanding—the framework elements for storage potential evaluations. With direction provided by the Commission, Staff and stakeholders convened over several workshops and filed sets of comments from which Staff developed a framework of seven elements to guide the electric company's storage potential evaluations. This framework was adopted by the Commission at the March 21, 2017 public meeting and memorized in Order No. 17-118. Also in this order, the Commission addressed the requirement that electric companies, if projects are authorized by the Commission, "shall procure" one or more qualifying energy storage systems. Specifically, the Commission adopted the statutory interpretation that "shall procure" means that "contracts are in place to engineer, procure, and construct or implement the selected energy storage projects."

In July of 2017, both PGE and PacifiCorp filed draft storage potential evaluations, docketed as UM 1856 and UM 1857 respectively. Stakeholder meetings were held by the utilities and an informal comment period was opened. In its Staff Report that reviewed whether the draft storage potential evaluations complied with the storage potential evaluation framework, Staff explained that the drafts failed to meet the framework requirements spelled out in Order No. 17-118 and required additional work from both PGE and PacifiCorp. Further, Staff stressed the importance of using the framework methodology: "adherence to the methodology outlined in Order No. 17-118, the tool developed for storage assessment, is extremely important to our on-going and future assessment of storage as a potential and viable resource," and the tool "represents the understanding and consensus of the parties regarding the necessary components and information needed to produce a transparent comprehensive system evaluation . . . ."[4]

In this same Staff Report, Staff identified, and the Commission adopted, several areas that both utilities were required to address in the final storage potential evaluations, as well as a modified procedural schedule to allow the utilities to fix and finalize the evaluations.[5] The Commission adopted the following schedule: (1) by January 1, 2018, PGE and PacifiCorp were to file draft project proposals and updated draft storage potential evaluations that incorporated the improvements outlined by Staff in its Report; (2) by April 2,

[4] Docket Nos. UM 1856 and 1867, Appendix A to Order No. 17-375 at 3-4 (Sept. 28, 2017).
[5] Docket Nos. UM 1856 and 1867, Appendix A to Order No. 17-375 at 15-17 (Sept. 28, 2017).

2018, the utilities were to file final project proposals and final storage potential evaluations; (3) no later than April 2, 2018, the Commission would begin review of the final filings.[6]

PGE filed what appears to be its final project proposals and final storage potential evaluation on November1, 2017, which are the filings being evaluated in this Staff Reply testimony.

Q. What is the legal standard for Commission approval of PGE's proposals?

A. The legal standard for Commission approval of storage proposals is expressly provided in HB 2193 (2015). After considering the following three factors, the Commission may authorize an electric company to develop one or more projects that include one or more qualifying energy storage systems:

Q. Do any other requirements apply to PGE's proposals?

A. Yes. Since HB 2193 (2015) was passed, the Commission has adopted numerous requirements applicable to PGE's filing.

PROJECT GUIDELINES

The Commission adopted seven *guidelines for projects.*[7] Project guidelines cover the overall high-level expectations for the ESS projects, or portfolio of projects, submitted for Commission review proposal for ESS projects. They are:

1. Electric companies are encouraged to submit multiple projects with an aggregate capacity close to the full one percent of 2014 peak load allowed by HB 2193.

[6] Docket Nos. UM 1856 and 1867, Appendix A to Order No. 17-375 at 17 (Sept. 28, 2017).
[7] Docket No. UM 1751, Order No. 16-504 at 4 (Dec. 28, 2016).

2. Electric companies are encouraged to submit a range of projects that are differentiated by use case, application, or other differentiating factor.

3. Electric companies are encouraged to submit a portfolio of projects that balance technology maturity, technology potential, short- and long-term project performance and risks, and short- and long-term potential value.

4. Electric companies are encouraged to submit projects that can serve multiple applications.

5. Electric companies are encouraged to submit projects that are strategically located to help defer or eliminate the need for system upgrades, provide voltage control or other ancillary services, or supply some other location-specific service that will improve system operation and reliability.

6. Electric companies are encouraged to identify qualified vendors and viable energy storage technologies through a Request for Information (RFI) process.

7. Electric companies are encouraged to use established models—such as, but not limited to, the Pacific Northwest National Laboratory's Battery Storage potential evaluation Tool or the Electric Power Research Institute's Energy Storage Valuation Tool—to estimate the value of energy storage applications. Models must be transparent and auditable.

PROPOSAL GUIDELINES

Likewise, the Commission adopted fifteen guidelines for proposals.[8] The proposal guidelines establish the minimum requirements of each, individual ESS project included in an electric company's overall storage proposal. The Commission explained that the proposal guidelines build on the statutory requirements, in fact, the first three guidelines are pulled verbatim from the statute.[9] The proposal guidelines were designed to assist with the

[8] Docket No. UM 1751, Order No. 16-504 at 5 (Dec. 28, 2016).
[9] Docket No. UM 1751, Order No 16-316 at 2, fn 1 (Aug. 19, 2016); HB 2193 (2015), Section 3(2)(c)(A)-(C).

determination of whether an individual ESS project proposal reasonably balances the value for ratepayers and the system with the costs of the projects, and if the ESS project is in the public interest.[10] The proposal guidelines stated that each ESS project proposal must include the following description and analysis:

1. Technical specifications for each project, including:
    a. The capacity of the project to store energy including both the amount of energy the project can store and the rate at which it can respond, charge, and discharge as well as any other operational characteristics needed to assess the benefits of the energy storage system;
    b. The location of the project;
    c. A description of the electric company's electric system needs and the application that the energy storage system will fulfill as the basis for the project;
    d. A description of the technology necessary to construct, operate, and maintain the project, including a description of any data or communication system necessary to operate the project;
    e. A description of the types of services that the electric company expects the project to provide upon completion; and
    f. An analysis of the risk that the electric company will not be able to complete the project;
2. The estimated cost of each project, including:
    a. The estimated capital cost of the project;
    b. The estimated output cost of the project; and
    c. The amount of grant moneys available to offset the cost of the project;

[10] Docket No. UM 1751, Order No. 16-504 at 5 (Dec. 28, 2016).

3. The benefits of each project to the electric company's electric system, including:

    a. Projected in-state benefits to the electric system;

    b. Projected regional benefits to the electric system; and

    c. The potential benefits of the electric company's entire electric system if the electric company installs the energy storage system technology that is the basis for the project system-wide;

4. Reasoning for selecting chosen technology, grid location, application, and ownership structure, with supporting analysis including findings from any Request for Information (RFI) and the system-wise storage potential evaluation, identification of any criteria used to select projects and an explanation of how the criteria were applied, and any other relevant input on evaluations;

5. Comprehensive description of the project;

6. Plan for constructing, maintaining, and operating the energy storage system;

7. Comprehensive analysis of all identified costs over the life of the project to the electric system and all customers;

8. Comprehensive assessment of project risks over the life of the project;

9. Comprehensive assessment of all quantitative and qualitative benefits to the electric system and all customers over the life of the project. Assessment of larger societal benefits, where applicable, is encouraged but those assessments will not be incorporated into the cost-effectiveness calculation of the proposals;

10. Description of methodology for assessing project benefits, including the aggregation of benefits;

11. Cost-effectiveness of the energy storage system including benefit-cost ratios and net present value revenue requirements over the energy storage system lifetime, and all underling inputs and assumptions used in the calculation;

12. Projected trends in energy storage system cost and performance;

13. Strategy for large-scale deployment of the technology over time, if applicable;

14. Comparative analysis of: (1) the proposed storage solution, and (2) other storage and non-storage solutions for the proposed application; and

15. Data collection and evaluation plan with identified research objectives.

COMPETITIVE BIDDING REQUIREMENTS

The Commission adopted two competitive bidding requirements specific to HB 2193 ESS projects, explaining that energy storage procurements under this bill would not meet the threshold for the competitive bidding guidelines for major resource acquisitions in docket UM 1182.[11] The ESS competitive bidding requirements state that:

1. An electric company may award a contract for a project without competition if it determines and presents justification that only a single vendor or contractor is capable of meeting the requirements of the project.

2. Where the requirements for sole source procurement are unmet, electric companies must use a competitive process to award contracts.

    a. The electric companies will bear the burden of demonstrating that they followed a fair, competitive solicitation process to identify all vendors with the requisite expertise, experience, and capability to install viable projects.

    b. The electric companies must give the Commission and stakeholders the opportunity to review the electric companies' Request for Proposal (RFP) design and offer nonbinding input.

    c. The electric companies must summarize and report to the Commission their solicitation process and scoring approach. The report should be included with the formal project proposal submitted to the Commission, or, if bidding occurs after Commission authorization, at a special public meeting to follow.

[11] Docket No. UM 1751, Order No. 16-504 at 10 (Dec. 28, 2016).

STORAGE POTENTIAL EVALUATION FRAMEWORK

The Commission also adopted Staff's recommended framework for each utility's storage potential evaluation. The framework is summarized below. It is also provided in full detail in Appendix A to the Commission's March 21, 2017 Order No. 17-118.[12] The framework elements for an electric company's storage potential evaluation call for:

a. A list of use cases or applications to be considered in the evaluation, including definitions and services;

b. A consistent list of definitions of key terms;[13]

c. A ten-year time frame for the initial system analysis that is needed to define the landscape of opportunities, including potential sites for energy storage, for the proposal due on January 1, 2018, the analysis timeframe should be equal to the lifetime and life-cycle cost of the proposed energy storage system;

d. The valuation methodology factors, and examples, that should be included in any valuation analysis;

e. List of criteria for identifying the main opportunities for investment in storage are:

    1. Cost-effectiveness - with tolerance for proposals that are reasonable and meet statutory requirements, even if the individual proposal is not cost-effective.

    2. Diversity of ownership, of technology, and of applications.

    3. Location - the portfolio of proposals should examine the range of eligible storage systems, including those located on the customer side of the meter (i.e., behind-the-meter, or BTM), interconnected at the distribution system level, and interconnected at the transmission level.

[12] Docket No. UM 1751, Order No. 17-118 at Appendix A 4-9 and 15-29 (Mar. 21, 2017).
[13] Stakeholders decided to use, the U.S. Department of Energy Glossary of Energy Terms and the DOE/EPRI 2013 Electricity Storage Handbook for definitions.

4. Utility learning - activities that will support applications or technologies that will provide operational experience and reasonably lead to future high-value deployments;

f. Criteria to be used for identifying system locations with the greatest storage potential; and

g. Nine key elements that address the level of detail required in the evaluations[14]:

1. Electric Companies should analyze each use case for each evaluated storage site.

2. Final Storage Potential Evaluations should include detailed cost estimates for each proposed ESS.

3. When storage services can be defined based on market data, a market valuation should be used for such identified services.

4. Final evaluations submitted January 1, 2018, should provide detailed descriptions of proposed sites.

5. "Resiliency" should be defined in the form of a use case or as a unique quantifiable benefit if it is included in the Final Storage Potential Evaluation.

6. Models used in evaluations should have the following attributes:

a. Capacity to evaluate sub-hourly benefits;

b. Ability to evaluate location-specific benefits based on utility-specific values;

c. Enables co-optimization between services;

d. Capacity to evaluate bulk energy, ancillary service, distribution-level and transmission-level benefits;

e. Ability to build ESS conditions (e.g., power/energy capacity, charge/discharge rates,

[14] Significantly more detail as to these elements is found at Docket No. UM 1751, Order No. 17-118 at Appendix A 7-9 (Mar. 21, 2017).

charging/discharging efficiencies, efficiency losses) into the optimization.

7. The components of each model, including the attributes in Staff Recommendation No. 6, should be identified and documented in both the draft and final evaluations.

8. A single base year may be used for modeling purposes.

9. Staff must be able to validate the assumptions and methods used to evaluate the cost effectiveness of each proposed ESS in the final proposals.

ADDITIONAL REQUIREMENTS

Additionally, the Commission adopted Staff's recommendation that PGE and PacifiCorp's final storage potential evaluations include the following revisions[15]:

Both utilities must:

- Must co-optimize the identified use cases found in Order No. 17-118.
- Must provide the input values for each of the services modeled. This requirement addresses the call for transparency found in Order No. 17-118 and in stakeholder workgroups. This will also allow stakeholders to run other publicly available storage models with the input value information supplied by the utility. However Staff believes that we must at this early interval require transparency and avoid adopting "black box" approaches to modeling this new and important resource. Staff repeats from Order No. 17-118, "Staff must be able to validate the assumptions and methods used to evaluate the cost effectiveness of each proposed ESS in the final proposals."
- Review the requirements of Order No. 17-118 and address each.

PGE must:

- Conduct co-optimization for all use cases. Where the use case is not feasible because of battery placement or battery technical capabilities, provide supporting analysis for the justification to dismiss. Staff will not accept modeling capability short comings as a reasonable justification.

[15] Docket Nos. UM 1856 and 1857, Order No. 17-375 at Appendix A 15-16 (Sept. 28, 2017).

- Include a battery simulation with co-optimized services.
- Address the distribution modeling shortcoming mentioned in Staff's analysis of PGE's IPT distribution system modeling approaches, making sure to model all services.
- PGE must provide discrete valuation of various services, costs or benefits of the distribution system such that discrete services provided by a battery can be matched and properly valued through an avoided cost approach.
- Several of the benefits (e.g., Western Energy Imbalance Market (EIM) participation, primary frequency response, demand response, Volt-VAR, and CVR) need to be thoroughly analyzed. Where PGE has made a final assessment that these are of low value PGE needs to show their work to an extent that input values can be shared with Staff and stakeholders.
- PGE's transmission upgrade deferral value needs to be based on a more detailed assessment of the PGE system.
- Conduct a battery simulation.
- Clarify, with specific input output data, how PGE developed their assessment of a 30 percent impact of distribution-level energy storage on transmission deferral.

III. STORAGE POTENTIAL EVALUATION

Q. What is the storage potential evaluation?

A. A critical component of HB 2193 is the requirement of each large electric company to conduct an evaluation of the potential to deploy storage on its electric system. The bill clearly stated that this evaluation must include an analysis of the electric company's current operations and electric system data in order to identify opportunities to incentivize ESSs, as well as how those opportunities would pair with existing infrastructure plans. In short, the storage potential evaluation should put forth a transparent method for selecting

potential project locations, clearly explain the method of calculating the value of any proposed project, and identify the highest value locations.

Q. Has PGE filed an energy storage potential evaluation?

A. Yes. PGE submitted its draft evaluation on July 15, 2017, after which the Commission adopted Staff's recommendation, which concluded that the draft filing did not uphold "the standards set by this Commission in Order 17-118 and that additional work is necessary."[16] The Commission ordered that by January 1, 2018, PGE[17] would submit an improved draft potential evaluation (alongside its draft proposal describing ESS projects), and would have three months to work with Staff and stakeholders to modify final project proposals for submission by April 2, 2018.[18]

Q. Has PGE filed a final storage potential evaluation?

A. Yes. On November 1, 2017, PGE submitted its final UM 1856 storage evaluation and ESS project proposals. These were followed by two testimonies supporting the submissions, both of which were filed on January 5, 2018.

Q. Does Staff believe the final storage potential evaluation fulfills Commission requirements outlined in Order No. 17-118?

A. No. Despite producing a detailed analysis, in number of ways PGE's final storage potential evaluation did not fully respond to the Commission's requirements. PGE met framework requirements a-c, but need improvement in each of the following requirements (d-g). Specifically, Staff is concerned that

[16] Docket No. UM 1856, Order 17-375 at 16 (Sept. 28, 2017).
[17] The same requirement applies to PacifiCorp as well.
[18] Docket No. UM 1856, Order 17-375 at 16-17 (Sept. 28, 2017).

PGE's transparency, modeling choice, calculation of benefits, and cost estimates do not uphold these framework requirements. A revision or plan for revision is required before Staff could recommend that Commissioners approve the storage potential evaluation. Each concern is described below in the following sub-sections.

III.A. Storage Potential Evaluation Transparency

Q. Does the Commission framework mandate transparency?

A. Yes. The Commission stated that "Staff must be able to validate the assumptions and methods used to evaluate the cost effectiveness of each proposed ESS in the final proposals."[19]

Q. Does Staff have that ability?

A. No. This Commission has stated that "Proposals must appear to offer location-specific benefits (non-zero values). Proposals will receive greater weight where these locational benefits are especially high (produce at least 30 percent of the estimated benefit of the system)."[20] The Commission has previously stated that models used "…may be proprietary. However, to the extent possible, it is necessary that the evaluations be transparent."[21,22]

To describe available locational benefits, PGE used its Integrated Planning Tool (IPT) to evaluate the potential benefits associated with each sub-station and feeder on the network. While Staff has seen results from the IPT

[19] Docket No. UM 1856, Order 17-118 at 9, (Mar. 21, 2017) at 9.
[20] *Ibid* at 26.
[21] Docket No. UM 1856, Order 17-375 at 9 (Sept. 28, 2017).
[22] *Ibid* at 28.

modeling for available substations and feeders, additional criteria were clearly utilized in project selection. Some of this judgement is necessarily qualitative, but Staff has no ability to verify from PGE's submission that it was appropriate: the subjective reasoning to why the eventual selection of the five locations is not described. Staff cannot say with any confidence that these specific projects present the best available projects for the utility, ratepayers, or the industry at large.

Q. Does one of the five proposed projects serve as a good example of the lack of transparency that you have identified?

A. Yes. Coffee Creek (discussed in greater detail below) was selected to be the site of a large ESS due to a number of attractive attributes: land availability, outage mitigation, environmental characteristics, telemetry, existing equipment, and others. Each of the other projects have positive attributes described in the proposal as well. Missing however is the relative weight PGE places on these characteristics, and how these specific locations compare with others proposed. How much does say telemetry or existing space factor into deciding optimal locations for the utility?

Staff believes that PGE chose each of the prosed projects because they were the best choice based on PGE's ranking criteria. The submitted model results provide little guidance in this regard. According to the IPT results, **[BEGIN CONFIDENTIAL]** [redacted]

[redacted] **END CONFIDENTIAL]** There aren't additional costs for each location used in project selection, as Navigant's storage evaluation report stated that "This evaluation focuses on benefits, rather than costs. Cost estimates are included in PGE's Energy Storage Proposal."[23] Clearly, PGE is using other scoring metrics to determine why Coffee Creek is preferred, however Staff is unable to verify the IPT is appropriately selecting the best ESS sites. To recommend Commission acknowledgement, Staff must have a better understanding of PGE's modeling approach to selecting site locations, especially with regard to the qualitative assessments used.

III.B. Modelling Approach[24]

Q. Was PGE required to quantify ESS benefits?

A. Yes. Each and every order issued in dockets UM 1751 and UM 1856 mentions the need to accurately quantify benefits associated with each use-case from the ESS.

Q. How did PGE quantify ESS benefits?

A. PGE used the Resource Optimization Model (ROM), an in-house production-cost model designed to evaluate full costs of operation. Greatly simplified, PGE calculated the benefits associated with potential ESS installations by running

[23] PGE Testimony, PGE/101, Reihl-Brown/167.
[24] Note: This section is place under the storage potential evaluation rather than the review of projects following pg. 15 of Order No. 17-375, where co-optimization was stated as critical for storage potential evaluations.

the model twice: once with the ESS, and once without the ESS, where the reduced cost of operation is assigned as the benefit of the ESS.

Q. Does PGE's attempt at quantifying ESS benefits meet the framework set forth by the Commission?

A. No. A critical component of quantifying the ESS benefits is a thorough understanding of their source. The Commission repeatedly highlighted specific use cases that are created from an ESS. Further, specific use cases have been provided for evaluation: "Electric Companies should analyze each use case listed in Appendix A for each evaluated storage site."[25] An attractive component of ESSs is that they can often provide multiple quantifiable benefits at once. For example, the same ESS could provide value by both deferring transmission upgrades as well as peak shaving benefits. The Commission has sought to prioritize "locations where energy storage can serve multiple use cases."[26]

While 'stacking' all possible benefits seems intuitive, doing so would likely over-count the benefits. Some of these value streams are temporally mutually exclusive; a battery cannot at the same time provide energy arbitrage (storing cheap electrons then selling when expensive), while also providing reserve capacity. The Commission also clearly identified the need for utilities to develop tools that measure only feasible services, explicitly stating that: "Models used in evaluations should have the following attributes: … c. Enables

[25] Docket No. UM 1856, Order 17-118 at 7, (Mar. 21, 2017).
[26] Docket No. UM 1856, Order 17-118 at 7, (Mar. 21, 2017).

[sic] co-optimization between services."[27] ROM's modelling limitations prohibit PGE from fully co-optimizing ESS benefits.

Q. What are the limitations that prevent the full co-optimization of ESS benefits?

A. First, the granularity of the proposed ESSs makes them difficult to detect, as ROM has been developed to evaluate PGE's entire portfolio. To measure these benefits, PGE increased the size of its ESS deployment from 38 to 50MW, and benefits are assumed to scale down linearly. It is unclear whether this is a reasonable assumption, and it is also questionable whether the final size of the ESS deployment will be the full 38MW. Further, each of the individual projects are considerably smaller in capacity and duration, and it is unclear if the benefits are able to be accurately attributed across projects. It is worth repeating: each and every order issued in dockets UM 1751 and UM 1856 mentions the need to accurately quantify benefits associated with each use-case associated with the ESS.

Second, ROM is unable to confidently differentiate between use-case values. For example, Navigant noted that the benefit from Load Following (an Ancillary Service) "does not represent the value of performing Load Following Alone (i.e., without also providing Energy Arbitrage), and the isolated value is dependent upon the order in which the applications are added to the stack."[28] This lack of capability limits PGE's analysis for both the current proposal as

[27] Docket No. UM 1856, Order 17-118 at 8, (Mar. 21, 2017).
[28] Portland General Electric Proposal (hereinafter PGE Final Proposal) at 171 (filed Nov. 1, 2017).

well as all future ESS projects, as the specific benefits of potential ESS projects cannot be credibly quantified.

Q. Has PGE recognized these limitations?

A. Yes. In its initial and final proposals[29] as well as accompanying testimony[30] PGE highlighted both of these shortcomings of ROM.

Q. Are there additional reasons prohibiting full co-optimization?

A. Yes. Navigant's use of heuristics eliminated a number of use-cases[31] before they were evaluated. The Commission did allow for the case where ESS placement or technical capabilities prevented co-optimization,[32] however, in this case it is not applicable: the use-cases were believed *ex-ante* to provide little value.[33]

Q. Are these assumptions reasonable? As long as the model credibly estimates all tangible values attributable to the ESS, aren't PGE's calculations sufficient to conduct a full benefit-cost analysis on these projects?

A. Essentially yes. If this were a normal IRP today, Staff would likely find the benefit quantification done by both PGE and Navigant sufficient. PGE efficiently used the modeling capability and resources it had on hand, and

[29] PGE Final Proposal at 30-31 (filed Nov. 1, 2017), Portland General Electric Draft Proposal (hereinafter PGE Draft Proposal) at 3 (filed Jul. 14, 2017).
[30] PGE Testimony, PGE/200, Jordan – Hart - Landstrom/19.
[31] Those being voltage support, black start, and distribution congestion.
[32] Docket No. UM 1856, Order 17-375 at 15, (Sep. 28, 2017).
[33] PGE Final Proposal at 179 (filed Nov. 1, 2017).

estimating the additional value from fully co-optimizing benefits would currently not likely justify the effort it would take to perform.

Q. Then why in this case does PGE fall short?

A. To understand how PGE did not meet the Commission goals for this battery storage docket, it is useful to highlight how the Commission clearly developed rules encouraging utilities to procure ESSs even though they were not currently cost-effective. They did so with the belief that current costs would be outweighed by the future benefits of such an action. By way of background, both the variable and fixed costs of ESSs are declining, and it is thought that pace of these cost declines could be accelerated by stimulating the energy storage market. To both the Legislature and the Commission, there is a material additional benefit associated with developing this market: eventually, the lower cost barrier will allow a larger deployment of the promising technology. This view is equally applicable to the quantifying of ESS benefits, which present a significant barrier to larger ESS deployment. This represents the cutting edge of storage integration, and is critical to both the Oregon utilities themselves and to the ratepayers at large. The benefits of developing and utilizing transparent models which meet all Commission requirements extend further past the utilities as well: by accurately and completely quantifying all benefits associated with ESS deployments, Oregon utilities would help drive the development of ESS integration in the country. As Staff reported, this "would start a revolution of system modeling tools and techniques."[34] The Commission clearly and repeatedly set these difficult

[34] Docket No. UM 1856, Order 17-118 at 12 (Mar. 21, 2017).

requirements for utilities to create a positive feedback loop of cost reduction going forward, adopting the position that "Staff will not accept modeling capability short comings as a reasonable justification."[35]

Staff is treating this current opportunity as the only time when ESS pilots will be considered, after which only cost-effective ESS developments will be possible. The legislature through HB 2193 has pushed the utilities to stretch, learn, and develop their understanding of how to value benefits. The goal is that in the next IRP, their elevated level of sophistication will justify further megawatts of storage development. Though PGE's effort presents an efficient application of available models, it does not uphold the stated project goals and Commission requirements. The Commission agreed with Staff's report that noted that "the existing models do not typically examine locational value, evaluate sub-hourly benefits, or consider benefits-stacking valuation for storage deployments"[36] but that the development of such models should occur in the storage dockets. Staff believes PGE can detail a path forward to both utilize its current methodologies and either adopt current available price taker models or develop its own, and the costs of doing so will be outweighed by the future benefits.

III.C. Transmission and Distribution

Q. Was PGE required by the Commission to incorporate T&D benefits into the storage potential evaluation?

[35] 17-375 – Ap. A, pg. 15.
[36] Docket No. UM 1856, Order 17-118 at 12, (Mar. 21, 2017).

A. Yes. Proposals are "required to indicate estimated benefits from distribution or transmission deferral...."[37]

Q. How did PGE quantify the benefits of T&D deferral?

A. PGE did not, for two main reasons. First, there are no planned T&D additions in the proposed ESS locations. Second, PGE explained that system upgrades on their network are generally sudden and significant, generally caused by commercial development.

Q. Is this response appropriate?

A. No. Despite the context described above, it is certainly possible to derive some benefit for T&D deferral over the lifetime of the ESS. In its IRP, PGE projects a certain amount of load growth across its service territory. There is some probability that the ESS would defer some of this infrastructure upgrade. Multiplying the values applicable in the service area would be some value; PGE could certainly do better than this simple approach. Staff does not accepts neither that there is no benefit nor that the benefit is simply unquantifiable. This issue was raised previously in Order No. 17-375: "PGE's transmission upgrade deferral value needs to be based on a more detailed assessment of the PGE system."[38] Staff would also note that ascribes some level of T&D deferral value to energy efficiency despite the presence of the same concerns. While Staff recognizes that these two technologies are different, it is unclear if the applicability of the energy efficiency T&D benefit

[37] *Ibid* at 27.
[38] Docket No. UM 1856, Order 17-375 at 16, (Sep. 28, 2017).

methodology to ESS was explored by the Company, especially as Commission Framework g(3) calls for the use of readily available market data to establish the value of a storage service.

III.D. Project Costs

Q. Were the cost estimates of PGE's proposals reasonably created?

A. Yes. This is a rapidly changing market, with few participants and evolving technologies. PGE's presentation provided a high and low estimate based on the cheapest and most expensive response submitted in response to its RFI.

Q. If the costs are reasonably created, why does Staff have any concerns over these cost estimates?

A. The range between low and high cost estimates is significant. Staff is concerned about this uncertainty. Given that A) they represent the lowest-cost options and B) in general industry costs are declining, Staff believes that the lower cost estimate should be used as an upper-bound for any project going forward in the RFP process if the Commission approves this proposal.

IV. REVIEW OF PROJECTS

Q. Turning now to PGE's proposal, does Staff have any concerns specific to the five individual storage projects?

A. Yes. Alongside the framework for the storage potential evaluation described above, the Commission created a clear set of guidelines for each project proposal. Though some of PGE's individual projects satisfied many of the Commission guidelines, several guidelines remain unmet.

Q. To be clear, what is the connection between the project proposal guidelines and the storage potential evaluation framework?

A. The storage potential evaluation was meant to identify the highest value locations for ESS development throughout the electric company's entire system. Using that analysis, the project proposals were then meant to describe the ESS pilot project that the utility proposes to develop at those locations.

Q. Where is the size of the proposed ESS determined?

A. In the storage potential evaluation framework. As noted above, Commission in Order No. 16-504 states that draft storage potential evaluations should at a minimum "Identify system locations with the greatest storage potential."[39,40] Determining grid locations with the greatest potential for ESS development depends on the total benefits associated with each location: in the same location, those benefits can vary greatly depending on both the capacity and duration of an ESS.[41] It is important to note that a project proposal could satisfy the Commission's project guidelines while at the same time detailing the size and duration of an improperly-sized ESS.

Q. Does Staff have concerns about the sizing on the proposed projects?

A. Yes. As described below, Staff has concerns that the exact sizing of most of the proposed projects does not comport with the Commission's storage potential evaluation framework.

[39] Docket No. UM 1751, Order No. 16-504 at 8 (Dec. 28, 2016).
[40] Here Staff interprets 'potential' to mean 'greatest net-benefits' rather than 'largest possible size'. Otherwise, PGE should have merely developed one 38MW pilot.
[41] It is easy to envision an ESS dramatically over- or under-sized for the location.

Q. Are there other Commission requirements which the five individual projects do not uphold?

A. Yes. Each of the five proposed projects do not meet all of the specific guidelines, including the guideline requiring each project to fully describe the costs and benefits of each project. Again as noted above, the Commission clearly stated that each project proposal must include the full description of each.

Q. Does Staff view the learnings offered by each pilot as a critical component of the proposal?

A. Yes. As noted above, the Legislature believed the dollars spent on each project today will likely outweigh the current avoided costs. They encouraged the development of storage projects because the potential learnings would lead to a greater ESS integration, likely justifying current costs. Accordingly, the Commission agreed with Staff that it will emphasize "activities that will support applications or technologies that will provide operational experience and reasonably lead to future high-value deployments."[42] Staff views these critical learnings as part of the project's benefits.

Q. Between each of the individual pilots, are there any guidelines unmet in the project proposal?

A. Yes.

Q. Can you provide more detail about each of the individual projects, including guidelines that remain unmet?

[42] Docket No. UM 1751, Order No. 17-118 at 5 (Mar. 16, 2017).

A. Yes. Below I explain whether each individual project meets the stated Commission framework and/or guidelines for sizing the ESS, description of the project's learnings, and estimation of the associated costs and benefits.

IV.A. Coffee Creek

Q. Could you briefly describe this project?

A. Yes. PGE proposes to build one large 17-20MW/68-80MWh ESS at the Coffee Creek substation. The estimated overnight capital requirement ranges between $30-36 million, and the net present value (NPV) of revenue requirement ranges between $44.7-64.8 million.

Q. Are the learnings from this project beneficial to PGE ratepayers at large?

A. Yes. A large sub-station facility would provide an excellent learning opportunity. Measuring which use cases are valuable at what times over such a large area would be valuable. Further, developing operational efficiencies in such a significant deployment of storage would be beneficial for future projects. The PGE network has over 150 substations, meaning this the learnings from this project could be applicable on many more locations.

Q. Is the project sized appropriately?

A. Staff is not sure. PGE's lower limit of 15MW appears reasonable, given the balancing authority's requirements of dispatching resources greater than 15MW. However the upper technological limit of ~32MW is significantly larger than the interconnection-request limit of 20MW. There could be additional benefits that make an additional 6-8 month delay in procurement net positive, especially given the Commission's definition of procurement in Order 17-118.

Even if the upper and lower bounds are acceptable, determining exact sizing is important. Important to Staff, PGE has submitted no economic analysis that justifies 17-20 MW.

Q. Are there additional concerns about the calculation of project costs?

A. No.

Q. Are there additional concerns about the calculation of project benefits?

A. Staff takes issue with PGE's description of the societal benefits associated with this project, which may be significant enough to justify the procurement of non-cost-effective projects. While the Commission ordered these benefits not be included in the benefit-cost analyses, they remain tangible.

Q. If all missing elements described above were added, could this be a viable project?

A. Yes.

IV.B. Port Westward

Q. Could you briefly describe this project?

A. Yes. PGE proposes to build one 4-6MW/16-24MWh ESS at the Port Westward 2 generation facility. By integrating storage with generation, PGE could increase its spinning reserves while providing additional capacity and ancillary services. The estimated overnight capital requirement ranges between $5.9-7.7 million, and the NPV of revenue requirement ranges between $9.4-15.1 million.

Q. Are the learnings from this project beneficial to PGE ratepayers at large?

A. Yes. Integrating storage with generation presents an extremely attractive way to reduce both costs and emissions while improving reliability. As noted in a data response, the learnings of this pilot are directly applicable to the development of more ESSs in PGE's network, as this specific installation could be replicated at the eleven other reciprocating engines at the facility.[43]

Q. Is the project sized appropriately?

A. Yes, conditional on the results of the final sizing analysis.

Q. Are there additional concerns about the calculation of project benefits?

A. Staff believes there are significant additional site-specific benefits associated with this project. PGE alludes to the potential value in its proposal[44], however Staff believes they could be estimated *ex-ante*, albeit with a higher degree of uncertainty relative to other benefits.

Q. Are there additional concerns about the calculation of project costs?

A. No.

Q. If all missing elements described above were added, could this be a viable project?

A. Yes.

IV.C. Residential Storage Pilot

Q. Could you briefly describe this project?

A. Yes. PGE proposes to integrate 500 residential storage units as a dispatchable resource to provide grid services. In the event of an outage, the ESS would

[43] Exhibit Staff/103, Wiggins/1(PGE Response to OPUC Staff DR 68).
[44] PGE Final Proposal at 128 (filed Nov. 1, 2017).

provide power solely to the residence. PGE proposes two ownership models: PGE-owned, where program participants pay monthly fees for increased reliability, and customer-owned, where the participants are paid for their grid services. The estimated overnight capital requirement ranges between $2.1-6.0 million, and the NPV of revenue requirement ranges between $6.7-16.1 million.

Q. Are the learnings from this project beneficial to PGE ratepayers at large?

A. Yes. Residential storage is an appealing method of providing both grid and residential services, and provides an interesting study into the changing relationship between customer and utility. Learning how to split benefits between customer and utility could be valuable, as would be learning how to coordinate those transactions. In addition, learning how to dispatch residential storage in an economic manner could open an additional source of financing for ESS deployment with better customer service and outage mitigation.

Q. Is the project sized appropriately?

A. Unknown. PGE states that a minimum of 500 residential units are required to meet minimum viable asset size requirements, and that economies of scale reduce as the units deployed increase. PGE however sets no upper-bound. Is there an inflection point or a maximum? Additional economic analysis is required to demonstrate why 500 is the ideal number. Further, PGE proposes to cap the cost of the program, reducing the number of participants if significant cost increases are seen.[45] If 500 is the minimum number for dispatch, how

[45] PGE Final Proposal at 104 (filed Nov. 1, 2017).

would that be possible? Staff would like to see additional planning and explanation regarding this project's development.

Q. Are there additional concerns about the calculation of project benefits?

A. Staff has serious concerns about the distribution of benefits from this pilot. While these ESSs will be paid by all ratepayers, the outage mitigation benefits only apply to the receiving households. A ratepayer that does not receive an ESS could benefit from potentially lower outage mitigation costs in the future, but only if they choose to purchase one eventually. While ratepayers would benefit from increased grid services potentially provided by this residential storage pilot, Staff is concerned those learnings are not sufficient to justify the cost, especially given the disproportionate size of the benefits to the receiving households.

As noted above, outage mitigation benefits only apply to those who are enrolled in the pilot and/or purchase storage sometime in the future. Further, Staff believes the power reliability benefits should be thought of as a lower-bound only.[46]

Q. Are there additional concerns about the calculation of project costs?

A. Yes. PGE modeled a 50 percent division between customer- and PGE-owned ESS deployments, however it is not clear if that would be the actual split. These costs are very different. Additionally, it would be extremely labor

[46] There are additional, non-energy benefits associated with residential ESS: similar to having solar panels on one's roof, individuals are willing to pay a much higher amount for home storage to signal wealth and consciousness of environmental and technological trends. It is certainly outside the purview of PGE to quantify these benefits, but that are important to consider.

intensive to manage a program of 500 individual storage units: between labor challenges, space limitations, and site evaluation, these costs will be significant. Staff believes the actual administrative costs will end even higher, as with 500 households, a non-trivial number will change their residence over the lifetime of the program, necessitating more active management and a more gradual phased approach to ensure the roll-out can be staged so as to maximize lessons learned by PGE and Staff.

Staff has additional concerns about integrating storage with an existing, net-metered solar system. PGE has identified this as a potential developing market for storage, yet it is unclear how these hybrid systems would operate financially. Additionally, Staff is unclear why a mandatory, manual disconnect that must be installed for every system is necessary. The UL listing for a battery storage system would appear to cover the unnecessary or unwanted export of electricity, and Staff would want to explore this cost more with PGE and the manufacturers as installing a manual disconnect can cost of approximately $1,500/installation. Across 500 installations this could cumulatively represents a substantial program cost.

Q. If all missing elements described above were added, could this be a viable project?

A. Eventually yes. Staff believes after a thorough review PGE could address these concerns to develop a viable project, but as filed it cannot be recommended.

IV.D. Baldock

Q. Could you briefly describe this project?

A. Yes. PGE proposes to build a 2MW/4MWh ESS at a mid-feeder located at an existing solar facility. The estimated overnight capital requirement ranges between $2.8-4.1 million, and the NPV of revenue requirement ranges between $4.1-7.8 million.

Q. Are the learnings from this project beneficial to PGE ratepayers at large?

A. Staff is unsure. Two of the main benefits of this facility listed, integration with solar and public education, are qualitative in nature. Public education is a societal benefit, similar to reducing carbon emissions: certainly important, but not relevant in this current consideration. PGE has not presented a compelling case as to why the learnings associated co-locating storage with existing solar is worth the current expense.

Q. Is the project sized appropriately?

A. It is unclear. Alongside the site-selection transparency concerns stated above, Staff is additionally concerned about this location. There are identified benefits associated with a longer duration ESS, however feeder size constraints are binding. Are the potential values produced by IPT and additional selection described in the proposal for the smaller ESS better than any other possible location? Staff remains unconvinced and PGE offers no supporting evidence.

Q. Are there additional concerns about the calculation of project benefits?

A. Yes. PGE has not explained how specifically siting storage at a solar facility provides any benefit to rate-payers. If those exist, why can they not be

estimated ex ante? They would either be considered learnings or benefits, but PGE gives only cursory references to them. Similar to the argument presented above, Staff is unclear about site selection based on IPT results. Under PGE's submitted IPT model output, **[BEGIN CONFIDENTIAL]** [redacted] **END CONFIDENTIAL]** As mentioned above, PGE explained there were specific additional criteria used, but Staff has no ability to evaluate the selection criteria themselves or the relative weight placed on each.

Q. Are there additional concerns about the calculation of project costs?

A. The second paragraph describing costs (section 6.11) appears misplaced.

Q. If all missing elements described above were added, could this be a viable project?

A. Staff is unsure this project provides insufficient learnings to justify the constrained benefits it would provide. These concerns are compounded by those mentioned above applicable across all projects. To be considered viable, PGE would need to articulate the potential learnings of pairing battery storage with solar as well as demonstrate why this specific feeder with its noted limitations provides both the best value and the highest potential learnings for ratepayers. Short of this, Staff would be reluctant to believe this project viable.

IV.E. Microgrid Resiliency

Q. Could you briefly describe this project?

A. Yes: PGE proposes to build 2-5 microgrids in its service territory. Seen as an evolution to the DSG program, the microgrids would potentially serve either a

single customer or a subset, however, individual projects have not yet been developed. The estimated overnight capital requirement ranges between $12-41 million, and the NPV of revenue requirement ranges between $19.7-76.9 million.

Q. Are the learnings from this project beneficial to PGE ratepayers at large?

A. The learnings associated with the increased grid services would directly benefit ratepayers, however Staff is not at all clear how the additional learnings a project specifically focused on microgrids would be beneficial to all. A microgrid enabling critical facilities (hospitals, fire stations, etc.) would be an obvious exception, as all ratepayers benefit from the associated increased security. The benefits to ratepayers associated with maintaining power to them are likely limited in the event of a major event (such as the Cascadia Subduction-related earthquake): unless the ESS paired with a very large solar system, the additional four hours of coverage would be far surpassed by the additional outages. The benefits from smaller events are clearly important, but also limited by the likelihood of occurrence. Staff is concerned that these benefits are significantly outweighed by those benefits that accrue directly to the final recipients of the microgrid pilot, who would greatly benefit from the equipment and services that ratepayers' purchase.

Q. Is the project sized appropriately?

A. It is unclear. It may seem appropriate that PGE not solicit proposals prior to project approval, however Staff has little insight into the projects involved. Staff would have preferred a similar RFI process as was done with the Baldock,

Coffee Creek, and Generation Kick-Start projects to generate at least a cursory estimate of both the size and demand for this type of project. Are the potential values produces by IPT and additional selection described in the proposal for the smaller ESS better than any other possible location? Staff remains unconvinced because PGE provides no supporting evidence for review.

Q. Are there additional concerns about the calculation of project benefits?

A. PGE could potentially improve its proposal by tailoring the microgrid proposal to critical facilities, where the benefits could be larger.

Q. Are there additional concerns about the calculation of project costs?

A. Staff's concerns about costs are similar to the sizing concerns stated above. Further, the substantial range in cost estimates noted above is troubling. It is worth repeating that this proposal represents the final opportunity for Commission approval of the maximum cost allowed for each approved project.

Q. If all missing elements described above were added, could this be a viable project?

A. No. Staff does not believe the potential learnings from this pilot come close to justifying the associated costs, especially now in PGE's exploratory form.

V. COST RECOVERY

Q. How does PGE propose to recover costs associated with these five pilot projects?

A. PGE states in its proposal that the Renewable Adjustment Clause (RAC) is the preferred method of recovery for these costs.

Q. What is the RAC?

A. The RAC was created pursuant to SB 838, the Oregon Renewable Energy Act (Act) enacted June 6, 2007. Section 13 of the Act provided that "all prudently incurred costs associated with compliance with a renewable portfolio standard are recoverable in the rates of an electric utility" and provided that the Commission could "establish the terms of the automatic adjustment clause …."[47] In other words, the RAC was developed to provide rate recovery for utility investments in renewable resources necessary for RPS compliance, without the need for the utility to come in for a rate case.

Q. Is the RAC an appropriate method of cost recovery for PGE's storage projects?

A. No. The costs associated with the development, execution, and evaluation of ESS pilots is not for compliance with the RPS, nor does HB 2193 provide a mechanism like that expressly provided for in SB 838. Staff understands that RAC was amended by SB 1547 to include costs related to energy storage associated with renewables, however no renewable generation for the purpose of complying with RPS guidelines is being developed for these pilots.

Q. What would be a better method of cost recovery?

A. Recovery of appropriate costs should occur in a typical rate case.

VI. CONCLUSION

Q. What is Staff's conclusion regarding PGE's UM 1856 storage proposal?

A. Staff is encouraged by enthusiasm of PGE's final submitted proposal. PGE is pursuing a variety of projects with an appealing diversity that have the potential

[47] Docket No. UM 1330, Order No. 07-572 at 1 (Dec. 19, 2007).

to stimulate the regional and national ESS markets in a variety of ways. This could help develop the utility into an industry leader in ESS planning, management, and evaluation. While these specific projects are in general not likely to be cost-effective today, they could help drive down costs and increase benefits to a point in the future where they are cost-effective, the benefit of which could revolutionize the industry.

Both the Legislature in HB 2193 and the Commission in Order Nos. 16-504, 17-188, and 17-375 clearly laid out a path for project development, which PGE did not carefully follow. Further, the Commission repeatedly agreed with Staff's comments on a number of recurring issues in PGE's proposal as it progressed overtime: indeed many of Staff's arguments found above can also be found in earlier orders. A sense of collaboration and openness is certainly missing, even for a contested case. Despite this, Staff believes there is a way forward, from here towards the deployment of megawatts of storage on PGE's grid.

After addressing the shortcomings listed in this testimony to Staff and stakeholder confidence, Staff believes the Coffee Creek and Generation Kick-Start projects could be viable projects. Staff however is not yet convinced that the residential storage program fulfills the guidelines. Additional justification is required that demonstrate how the learnings and benefits are applicable to all ratepayers, and not those who make it into the program, are worth the substantial capital and administrative cost. Staff is similarly skeptical about the Baldock project, as we do not understand how the nebulous learnings of siting

storage at a solar facility align with the guidelines, especially as the benefits are physically constrained. Further, the benefits from the microgrid project appear heavily skewed towards the individual program participants, and Staff does not feel the benefits associated with the grid services provided do not justify the costs to all ratepayers.

Q. What then is Staff's proposal going forward?

A. Staff recommends that PGE address the correctable omissions identified by Staff and other stakeholders in reply testimony, adhere to each Commission guideline, and pursue the projects that best benefit current and future ratepayers. Thoughtfully making these changes in accordance with the currently adopted procedural schedule would also fit in the Commission-approved timeline set under Order No. 17-375.

Q. Does this conclude your testimony?

A. Yes.

CASE: UM 1856
WITNESS: SETH WIGGINS

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 101

Witness Qualifications Statement

February 16, 2018

WITNESS QUALIFICATIONS STATEMENT

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EDUCATION:	PhD Natural Resource Economics, West Virginia University: 2016. MS Applied Economics, Oregon State University: 2012
EXPERIENCE:	After finishing my doctorate, I taught courses in Energy and Environmental Economics at the Colorado School of Mines. In 2017 I worked briefly at both NW Natural (focusing on their IRP) and the Department of Transportation. Since January, 2018 I have been employed as a Utility Analyst at the Public Utility Commission. My current responsibilities include analysis, policy and technical support for energy resource planning related proceedings, with an emphasis on renewables, RPS compliance, integrated resource plans, and demand-side management filings.

CASE: UM 1856
WITNESS: SETH WIGGINS

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 102

Exhibits in Support
Of Reply Testimony

February 16, 2018

January 15, 2018

TO: Kay Barnes
Public Utility Commission of Oregon

FROM: Robert Macfarlane
Interim Manager, Pricing and Tariffs

PORTLAND GENERAL ELECTRIC
UM 1856
PGE Response to OPUC Data Request No. 002
Dated December 27, 2017

Request:

Please provide all output from the ROM and IPT models used to quantify benefits for each of the five projects in electronic format with cell formulae intact.

Response:

PGE objects to this request on the grounds that it is overly broad and unduly burdensome. Subject to and notwithstanding its objection, PGE responds as follows.

PGE provided the following ROM output data under Protective Order No. 17-441 in Appendix 3 of PGE Exhibit 101:

- Weekly, monthly, and annual summaries of identified operational value for 2-hour, 4-hour, and 6-hour energy storage systems simulated in ROM in the test year (2021);
- Weekly, monthly, and annual summaries of identified operational value exclusive of regulation reserve application for 2-hour energy storage system simulated in the test year (2021); and
- Test year (2021) 15-minute time series simulation results for the 2-hr storage system, including:
    - Discharging schedule (MW)
    - Charging schedule (MW)
    - State-of-charge (MWh)
    - Load following reserves provided by storage system, up and down (MW)
    - Regulation reserves provided by storage system, up and down (MW)
    - Spinning reserves provided by storage system (MW)
    - Non-spinning reserves provided by storage system (MW)

Attachment 002-A provides the IPT output data that was used to support the benefits of the substation and feeder-sited Energy Storage Projects. Attachment 002-A is confidential and subject to Protective Order No. 17-441.

UM 1856

Attachment 002-A

Provided in Electronic Format only

Protected Information Subject to Protective Order 17-441

IPT Model Outputs for Substation and Feedersited Energy Storage Systems

CASE: UM 1856
WITNESS: SETH WIGGINS

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 103

Exhibits in Support
Of Reply Testimony

February 16, 2018

January 31, 2018

TO: Kay Barnes
Public Utility Commission of Oregon

FROM: Robert Macfarlane
Interim Manager, Pricing and Tariffs

PORTLAND GENERAL ELECTRIC
UM 1856
PGE Response to OPUC Data Request No. 068
Dated January 17, 2018

Request:

On page 121 of PGE's proposal, it is stated that only Port Westward 2 units "qualified by meeting the 10 minute startup time required for spinning reserve". If this is true, then how does this qualify as a pilot? What can be learned here that would be applicable to the rest of PGE's generation fleet? How does PGE's Beaver plant operations compare to operations of Port Westward 2 units?

Response:

The Port Westward 2 Energy Storage System will be coupled with one of the twelve total reciprocating engines that make up our Port Westward 2 generating facility. The 10 minute startup requirement is only related to utilizing a relatively small energy storage system to realize the full value of spinning reserves of the off-line turbine (18.9 MW). All of the other use cases, learnings, and benefits identified in Section 8 of the proposal will apply regardless of the startup time of the generation unit.

All of the learnings from this project could be applied to additional energy storage system installations coupled with any of the other eleven reciprocating engines at Port Westward 2. With the exception of the specific learnings related to spinning reserve, the learnings from this project could be applied to other generation plant sited energy storage systems, including learnings related to the integration of storage into an existing plant control system, the utilization of existing generation assets, and operations and maintenance issues arising from generation sited energy storage.

The startup time to minimum load on Beaver units 1-6 (~30MW) is approximately 20 minutes. The startup time to full load on Beaver 8 (~23MW) is typically in the 12-15 minute range. The startup times for these units are in excess of the 10 minute requirement in order to capture

additional spinning reserve learnings, however all other use cases, learnings, and benefits identified in Section 8 of the proposal will apply to energy storage sited at any generation site.