BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

UM 1857

In the Matter of PacifiCorp, dba Pacific Power, Revised Draft Storage Potential Evaluation and Draft Storage Project Proposals	Staff's Comments

Staff of the Public Utility Commission of Oregon (Staff) files these comments on PacifiCorp's (PAC or Company) revised draft storage potential evaluation (SPE) and draft storage proposals filed by the Company on December 29, 2017. These initial Staff comments evaluate whether PAC's revised SPE and draft project proposals comply with the framework and guidelines established by earlier Commission orders. While Staff is encouraged by PAC's proposal, there remain significant concerns with both the SPE and individual projects that require revisions and future Staff review.

Context for Review

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 in 2015, the Commission, with substantial input from Staff and numerous stakeholders, has developed specific guidelines for projects and proposals, competitive bidding requirements, and a detailed framework for completing the system-wide storage potential evaluation required by HB 2193.

The legal standard for Commission approval of storage proposals is expressly provided in HB 2193. After considering the following three factors,[1] the Commission may authorize an electric company to develop one or more projects that include one or more qualifying energy storage systems:

A. Is the proposal consistent with the Commission project and proposal guidelines adopted in Order No. 16-504?

[1] HB 2193 (2015), Section 3(3)(a)(A)-(C), and Section 3(3)(b).

B. Does the proposal reasonably balance the value for ratepayers and utility operations that is potentially derived from the application of energy storage system technology and the costs of construction, operation, and maintenance of energy storage systems? And,

C. Is the proposal in the public interest?

Beyond the above three factors, the Commission adopted additional requirements in Order Nos. 16-504, 17-118, and 17-375. In December of 2016, the Commission adopted the following in Order No. 16-504: (1) seven *project* guidelines to help electric companies design and select projects to consider proposing; (2) fifteen *proposal* guidelines for electric companies to use when submitting formal proposals by January 1, 2018; and (3) minimum competitive bidding requirements for storage projects. All of these requirements can be found in Appendix A to Staff's Comments.

In March of 2017, Order No. 17-118 established the Commission's framework SPEs, as detailed in elements (a)-(g). All of these elements can be found in Appendix A to Staff's Comments. Also in this order, the Commission addressed the requirement that electric companies, if 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."

More recently in July of 2017, PacifiCorp filed its draft SPE. Staff determined that the draft SPE failed to comply with the framework adopted by the Commission in Order No. 17-118 and required additional work. Further, Staff stressed the importance of using the framework methodology in PacifiCorp's final filing: "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 . . ."[2]

Finally, in September of 2017, in Order No. 17-375, the Commission adopted Staff's recommendation that that PacifiCorp's final storage potential evaluation include the following revisions:[3]

- Must co-optimize the identified use cases found in Order No. 17-118.[4]
- 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

[2] Docket Nos. UM 1856 and 1867, Appendix A to Order No. 17-375 at 3-4 (Sept. 28, 2017).
[3] Docket Nos. UM 1856 and 1857, Order No. 17-375 at Appendix A 15-16 (Sept. 28, 2017).
[4] This requirement applied to both PGE and PAC.

> 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 [Energy Storage System] ESS in the final proposals."[5]

- Review the requirements of Order No. 17-118 and address each.[6]
- Include all bulk power and ancillary service use cases. Staff has confidence that DNV GL is capable of modeling these use cases if the information is provided. PAC is not free to state that this value is zero because the planning need is zero. PAC must report their bulk power number using the marginal cost from Mid-C if PAC is unable to generate an internal value.
- PAC must input a capacity value into storage modeling.
- Perform analysis on ancillary services such as spin/non-spin reserves, load following, regulation, and others. If necessary to comply with this requirement PacifiCorp needs to share production cost data or run a production cost model in support of this effort.
    - The order noted that while PacifiCorp doesn't operate in an ancillary services market, the avoided costs of providing those services can be monetized and should be provided to DNV GL.

The Commission also adopted the following procedural schedule to allow the above noted changes to be incorporated: (1) by January 1, 2018, PacifiCorp is to file a draft project proposal and an updated draft storage potential evaluation that incorporates the improvements outlined by Staff in its Report; (2) by April 2, 2018, PacifiCorp is to file final project proposals and a final storage potential evaluation; and (3) no later than April 2, 2018, the Commission will begin review of the final filings.[7]

<u>PacifiCorp's Revised SPE</u>

Staff appreciates the quality and clarity of PAC's revised SPE, which eases the difficulty of analyzing whether the Company complied with the relevant Commission orders. Further, many of the Company's responses to Staff's information requests have satisfied Staff's previous concerns about the SPE, and Staff appreciates PAC's effort to produce responses quickly. That said, Staff has a number of concerns which are outlined below.

The purpose of the SPE is to determine where on the utility's electrical system is optimal for the development of an ESS. Necessary for this determination is a systematic calculation of the costs and benefits of an ESS sited at each potential location. What naturally follows it that the Company should target the location(s) with the highest

[5] This requirement applied to both PGE and PAC.
[6] This requirement applied to both PGE and PAC.
[7] Docket Nos. UM 1856 and 1867, Appendix A to Order No. 17-375 at 17 (Sept. 28, 2017).

benefit-cost ratio(s) for ESS development. Calculating the benefits associated with a specific location requires simulating the ESS's operation to evaluate value from each of the established use cases. Further, both the costs and the benefits associated with an ESS are a function of the size of the system. While this analysis is important for the current ESS pilot development, it also serves as a model for future grid evaluation for energy storage.

However, it is unclear whether the analysis described above was sufficiently competed. For example, only four locations are listed as considered by PAC in the DNV-GL report; and an additional three locations were identified as having been analyzed in an information response.[8] By contrast, Staff expects PAC to develop a process that evaluates all feeders and substations.

Further, an 'alternative evaluation tool' was used in PAC's SPE to evaluate whether thirteen substation upgrades were viable locations for ESS installations. While PAC has provided an information response justification of the locational-specific benefits associated with its proposed Project #1, they are not compared to any other potential location.[9] Cumulated, these projects do not give Staff confidence that the highest-value location was selected for this particular ESS pilot. Accordingly, Staff has little confidence that PAC currently has the capability to fully assess its grid for future ESS opportunities. To recommend to the Commission that PAC has met the framework elements (a)-(g) required in its past order, Staff will need to see both a full comparison of potential ESS sites and the proposed project empirically demonstrated to be the most favorable location.

This level of comparison between sites is lacking in PAC's revised SPE. Any potential site will have associated costs and benefits: a project can be succinctly evaluated based on its benefit-cost ratio. PAC has calculated both costs and benefits, but not produced these ratios. While it is not a requirement that PAC demonstrate net-benefits (be larger than 1), this information is necessary for project evaluation.

The value of outage mitigation remains an important question for Staff. PAC states in an information response that no interruption costs were used for site comparison, as those benefits (or avoided costs) accrue to the customer, and not the utility (or ratepayers at large), which Staff finds appropriate.[10] In separate information responses, however, PAC describes how outage metrics were evaluated to select the highest value location.[11] These two points are mutually exclusive. The SPE must transparently evaluate the potential value of ESS deployment to all ratepayers. Whether or not PAC's SPE does this remains unclear, even after multiple direct inquiries about site selection and outage mitigation.

[8] See page 18, response to OPUC Data Request 8.
[9] See page 13, response to OPUC Data Request 1 and page 22, response to OPUC Data Request 15.
[10] See page 17, response to OPUC Data Request 3 and page 24, response to OPUC Data Request 25.
[11] See page 18, response to OPUC Data Request 8 and page 21, response to OPUC Data Request 9.

PAC has stated that there are no transmission upgrades planned at or near the proposed project, and thus there is no value of the transmission deferral use case for this project.[12] Staff believes it is certainly possible to derive some benefit over the lifetime of the ESS. In its IRP, PAC 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 provide some value. Even though this benefit will likely be marginal, Staff believes PAC could certainly improve in this area. Staff highlights the direction given in Order 17-375 that, "PAC is not free to state that this value [Bulk Power and Ancillary Service] is zero because the planning need is zero."

In summary, Staff expects a final SPE which provides:

- An explanation of why Project #1 represents the best opportunity for ESS development on all of PacifiCorp's utility network
- An explanation of how outage mitigation and/or interruption costs influenced the choice of Project #1
- The benefit-cost ratios of all sites proposed
- An evaluation of transmission deferral benefits

PacifiCorp's Draft Storage Proposals (Two Projects)

Project #1

PAC proposes to build a 2MW/6MWh ESS at an individual customer's facility, both owned and operated by PacifiCorp. A second phase is proposed to develop an additional 1MW/1MWh for participation in the Energy Imbalance Market (EIM). The costs for Phases I and II are estimated to be $4 million and $2 million, respectively. A third phase is proposed, but no size, cost, or locational information is included, and thus not considered by Staff. While there are a number of attractive attributes from this proposal, a number of issues raise concern, described below.

The quantification of the benefits associated with this project is concerning. PAC listed the benefits from ancillary services associated with an ESS, with tangible benefits listed for each.[13] However, in the energy storage use case summary, all ancillary services are described as not applicable. There are additional values in the DNV-GL report also excluded. Staff is unsure that the full amount of benefits are captured in the proposal, and requests further clarification in PAC's final submission due April 2, 2018.

Additionally, the final sizing analysis of the ESS has not been completed in PAC's draft proposal. As both the costs and benefits associated with the ESS are a function of the size of the project, the already wide spread in benefit and cost estimates are likely even wider. In the final storage proposal due April 2, Staff would expect to review a more detailed and accurate estimation of both costs and benefits from PAC, especially surrounding project size, before being able to consider recommending approval of this project.

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[12] See page 13, response to OPUC Data Request 1 and page 23, response to OPUC Data Request 22.
[13] See page 14, response to OPUC Data Request 2.

To progress from Phase I to Phase II, PAC requires a successful deployment of Phase I, continued support from its partner, and regulatory approval.[14] While the Company also states that it prefers a project benefit-cost ratio over 1, this has not explicitly been stated as a requirement to move forward. This is troubling to Staff: aside from a prudency review and a RFP compliance check, the bar to move forward to Phase II appears very low and devoid of Commission oversight. Staff recommends incorporating greater Commission involvement in determining whether the project should move forward to Phase II.

For Project #1, in the Final Project Proposal Staff expects to evaluate:

- A credible quantification of all benefits associated with each use case listed in previous orders
- A more detailed explanation and/or timeline for final sizing analysis
- A more detailed set of requirements for progressing to Phase II

Project #2
PAC proposes to design 10-20 ESSs sited at critical facilities in its network, and then fully fund the implementation of up to four of these projects. The total cost of this project is estimated to be $1.8 million dollars over eight years.

While Staff believes there is promise in this proposed program, its benefits are poorly described: Section 5.6 in the draft storage project proposal is incomplete, and the benefits are not quantified. In addition, resiliency as a concept is poorly defined. An extreme event like a Cascadia Subduction Zone event could potentially disrupt generation for significant time periods. Unless paired with renewable generation, the additional benefit of a four hour battery appears marginal. Further, Staff has reservations that the benefits will accrue to ratepayers outside of the projects themselves. Grid services will be provided, but the size of the operational reserve held for outage mitigation is unstated. If a 2MW/2MWh battery is evenly split between the two, ratepayers only benefit from a 1MW/1MWh ESS. PAC has not yet made a convincing case that the proposed projects will be worth the cost to all ratepayers.

Finally, Staff is concerned by the selection of individual locations for this project. For example, what is the demand for this service? If there are not more than twenty proposed locations, will there be any screening criteria used by PAC, or will all be accepted? The same questions could be asked of the two to four locations that PAC chooses to develop. Staff looks forward to review of the types of analyses highlighted in these comments in PAC's April 2nd filing.

For Project #2, in the Final Project Proposal Staff expects to evaluate:

- A complete explanation of the projects' benefits, including how resiliency is measured as a benefit
- A more detailed explanation and/or timeline for final sizing analysis
- A more detailed explanation of individual project evaluation and selection criteria

[14] See page 25, response to OPUC Data Request 26.

Conclusion

Staff is encouraged by PAC's draft project proposal. The quality and clarity of both the analysis and the information responses provided by PAC is appreciated. Both of PAC's proposed projects show potential, and Staff looks forward to seeing PAC incorporate the recommendations made in Staff's comments above into its final project proposal. However, there remain many concerns about the revised SPE, which is meant to identify the particular proposed projects as the highest value opportunities both in learnings and to ratepayers at large. At this time, Staff is unable to say with confidence that the results of the SPE have directed PAC to develop these two projects in particular. Staff expects PAC to develop the SPE into a tool that can be replicated in the future to identify storage opportunities as ESS cost decreases continue.

This concludes Staff's Comments.

Dated at Salem, Oregon, this 14th day of March, 2018.

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APPENDIX A TO STAFF COMMENTS

Commission Requirements for Energy Storage Proposals and Evaluations

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PROJECT GUIDELINES

The Commission adopted seven guidelines for projects[1]:

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.
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 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

The Commission adopted fifteen guidelines for proposals.[2] The Commission explained that the below proposal guidelines build on the statutory requirements; in fact, the first three guidelines are pulled verbatim from the statute,[3] and are designed to assist with the determination of whether the proposal reasonably balances the value for ratepayers and the system with the costs of the projects, and is in the public interest.[4]

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[1] Docket No. UM 1751, Order No. 16-504 at 4 (Dec. 28, 2016).
[2] Docket No. UM 1751, Order No. 16-504 at 5 (Dec. 28, 2016).
[3] Docket No. UM 1751, Order No 16-316 at 2, fn 1 (Aug. 19, 2016); HB 2193 (2015), Section 3(2)(c)(A)-(C).
[4] Docket No. UM 1751, Order No. 16-504 at 5 (Dec. 28, 2016).

Each proposal must include the following description and analysis of each proposed project:

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;
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 storage projects, explaining that the energy storage procurements under this bill would not meet the threshold for the guidelines for major resource acquisitions in docket UM 1182.[5]

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.

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

STORAGE POTENTIAL EVALUATION FRAMEWORK

The Commission adopted Staff's recommended framework for storage potential evaluations, the primary elements of which are summarized below. However, full detail can be found in Appendix A to Staff's March 21, 2017 Staff Report.[6]

a. A list of use cases or applications to be considered in the evaluation, including definitions and services, are set forth in detail in 3.21.17 Appendix A.

b. For a consistent list of definitions of key terms, the U.S. Department of Energy Glossary of Energy Terms is to be used, as well as DOE/EPRI Electricity Storage Handbook in Collaboration with NRECA, Sandia National Laboratories, Akhil, Hill et al (September 2016).

c. The time frame for the initial system analysis that is needed to define the landscape of opportunities, including potential sites for energy storage, should be 10 years. 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 are provided at 3.21.17 Appendix A.

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.

    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 found at 3.21.17 Appendix A.

g. Nine key elements that address the level of detail required in the evaluations[7]:

    1. Electric Companies should analyze each use case listed in Appendix A for each evaluated storage site.

    2. Final Storage Potential Evaluations should include detailed cost estimates for each proposed energy storage system (ESS).

[6] Docket No. UM 1751, Order No. 17-118 at Appendix A 4-9 and 15-29 (Mar. 21, 2017).

[7] 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).

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, 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.

OPUC Request 1

How were benefits specific to each location evaluated to determine optimal energy storage system (ESS) locations?

Response to OPUC Request 1

The bulk energy and ancillary services use cases represent system-wide or Oregon-wide obligations that are not specific to individual locations within Oregon. However, the value in these use cases is grossed up to account for avoided line losses, based on the interconnection voltage. For instance, generation capacity for Project 1 was grossed up by 10.06 percent to account for line losses, based on the assumption that it would be interconnected at secondary voltage.

Transmission upgrade and distribution upgrade deferral are location-specific benefits. The company has not yet identified any locations in which energy storage resources would be appropriate to defer planned transmission upgrades. The Project 1 location is expected to allow for deferral of distribution upgrades expected in 2023. The company's draft filing included distribution upgrade deferral benefits based on system average distribution upgrade costs. PacifiCorp is preparing a more comprehensive assessment of its forecasted near term distribution upgrades that could be deferred by energy storage systems and will include the results in its final filing.

Project 1 is also expected to provide outage mitigation benefits, which primarily accrue to impacted customer(s) rather than the utility and customers as a whole. Project 1 is located on a circuit that has experienced periodic outages in the past and is expected to provide opportunities to evaluate energy storage deployment and customer coordination during outage events. Distributed energy storage resources installed by customers to mitigate their own outage risk have the potential to provide value if they can be dispatched for local or system needs under specified conditions. Project 1 will provide experience that will allow this potential to be better characterized and can inform efforts to develop operating procedures and contractual terms to provide value from distributed energy storage resources to both individual customers and Oregon residents as a whole.

OPUC Request 2

Please explain how the model used for the SPE and for the projects co-optimizes the benefits associated with ESSs.

Response to OPUC Request 2

PacifiCorp first independently evaluated each of the energy storage system (ESS) use cases – assuming that an ESS was optimally dispatched for a single use case. This represents the maximum benefit a use case can provide.

The company next evaluated the overlap between the various use cases. To the extent ESS power capacity or storage capacity is reserved for one use case in a given interval, it generally cannot also be used for other uses cases in that interval. Generation capacity deferral is something of an exception, as reliably serving peak system load requires scheduled resource dispatch (i.e. energy arbitrage), ancillary services, and the ability to deliver to load in all locations (i.e. adequate transmission and distribution capacity). As a result, generation capacity benefits are generally additive to the benefits from other use cases. PacifiCorp has identified two relatively narrow exceptions to this:

- First, to account for the fact that ancillary services must be held in all hours but are only deployed under limited circumstances, the company proposed using three-hour storage capacity to determine the capacity contribution for ESSs providing ancillary services, versus four hours for ESSs providing scheduled resource dispatch (either energy arbitrage for the system, or for a specific location that allows transmission and distribution capacity upgrade deferral). To the extent the ancillary service supply exceeds the company's ancillary service obligations, any incremental ESS would receive capacity consistent with four-hour storage capacity. This circumstance is not anticipated for ESSs in Oregon under consideration in this proceeding.

- Second, generation capacity benefits may be reduced to the extent a transmission or distribution upgrade deferral application does not allow for dispatch during system peak conditions, for instance if the distribution peak is not coincident with the system peak, or if a portion of the resource's storage capacity is reserved for outage mitigation. While the applicable periods for Project 1 are relatively small, the company is incorporating these restrictions in its analysis.

The remaining use cases are mutually exclusive in any given interval. The designation of an ESS for energy arbitrage or one of the ancillary services can be modified on an hourly basis, subject to adequate energy being present in storage. On the other hand, transmission and distribution upgrade deferral requires resource availability and dispatch in all of the intervals in which a circuit would otherwise exceed its rated limits. In addition, the ESS must be adequately filled before potential exceedance events, which can restrict its availability for other uses for a period prior to dispatch.

While the annual benefits associated with distribution upgrade deferral are lower than that for the energy arbitrage or regulation use cases, the portion of the year devoted to that use case can be very low, as illustrated in the table below using the use case values from the company's Draft Storage Potential Evaluation filing. For details on the associated calculations supporting the values in the table, please refer to Attachment OPUC 2. The illustrative value of two percent usage represents four hours per day during weekdays in two months per year, which is likely higher than the requirement in many distribution upgrade deferral applications.

	Benefit $/kw-year	Annual Usage %	Avg. Benefit $/MWh
Distribution Upgrade Deferral	$12.95	2%	$73.91
Ancillary Services - Regulation	$127.37	100%	$14.54
Ancillary Services - Load Following	$86.09	100%	$9.83
Ancillary Services - Spin/Non-spin	$51.97	100%	$5.93
Energy Arbitrage - Fixed Schedules	$33.30	100%	$3.80

As indicated in the table above, distribution upgrade deferral provides the greatest benefit during the limited hours it is necessary, and leaves substantial periods available for other uses. The value for distribution upgrade deferral shown above only includes avoided distribution capacity costs, so it is appropriate to add energy arbitrage benefits when the ESS is deployed to reduce distribution circuit loading. Because these deployments are based on distribution load, rather than market price, the value may be lower than that for a resource optimized for energy arbitrage during the same period. The value is still likely to be high since many distribution feeders experience peak loading that is generally coincident with high market prices.

The remaining services can be provided during periods when an ESS is not deployed for distribution upgrade deferral and regulation service provides the next greatest benefit. Regulation service is the most flexible service so it logically represents the greatest benefit. Energy arbitrage based on fixed schedules does not allow for changes in response to updated market or system conditions, so it has the lowest value. Because the company's ancillary service obligations require that it maintain flexible capacity that is only deployed when needed, ESSs used for ancillary services have reduced costs associated with efficiency losses and storage degradation relative to energy arbitrage applications.

PacifiCorp's contingency reserve obligation is defined by NERC Standard BAL-002-WECC-2, and requires that at least half of the requirement be met with "spinning" resources that are immediately and automatically responsive to changes in frequency.[1]

[1] NERC Standard BAL-002-WECC-2: http://www.nerc.com/files/BAL-002-WECC-2a.pdf

At present, PacifiCorp's West Balancing Authority Area has a negligible quantity of non-spinning resources, so incremental spinning and non-spinning resources contribute equally to fulfilling its obligation and thus have equal value. Resources held as contingency reserve are deployed infrequently and provide limited opportunities to recharge when market prices are low, as they would need to be refilled soon after a contingency event occurred.

In contrast, resources providing load following or regulation service provide additional value by dispatching whenever they have storage available and market prices warrant. The company has interpreted load following service as non-participating resources that respond to 15-minute market (real-time pre-dispatch or RTPD) prices on an hourly basis. Because load imbalance is settled on an hourly basis, the average of the four 15-minute market prices in an hour was assumed to be used for dispatch and settlement. A resource providing the service is assumed to be dispatched up or down in 60-minute increments, based on its buy and sell bid prices and subject to its available storage capacity. PacifiCorp has interpreted regulation service as EIM participation including both 15-minute RTPD and the 5-minute real-time dispatch (RTD). A resource providing regulation service would participate in each 15-minute RTPD market interval, and would also be dispatched in 5-minute increments, in both cases based on its buy and sell bid prices and subject to its available storage capacity. Any changes from the RTPD schedule are settled at the RTD market price. Regulation service thus provides all of the value of load following service, plus additional value by providing an option for more granular dispatch.

OPUC Request 3

Outage mitigation appears to be a big driver for site selection in the SPE. Was there any attempt to combine historic outage data with interruption cost data to analyze the benefits of outage mitigation? If not, please explain why not.

Response to OPUC Request 3

PacifiCorp has not assessed interruption cost data, as this reflects customer costs and benefits rather than utility costs.

To begin understanding this benefit, general customer costs were evaluated and combined with site specific historic outage data as part of DNV GL's draft evaluation included in Appendix C and referenced in Section 4.4 on page 28 of the Revised Draft Energy Storage Potential Evaluation.

The company recognizes that customer interruption costs may be a driver for customer ownership of energy storage resources, and that this could provide benefits to customers as a whole as discussed in OPUC 1.

OPUC Request 8

Please explain in detail how the location for this site was selected, and why it was selected over other potential sites. Please list all other sites that were considered, but not selected.

Response to OPUC Request 8

The following location specific characteristics differentiate between different sites:
- Avoided line losses
- Transmission and distribution deferral
- Outage mitigation

As discussed in OPUC 1, while the potential benefits from use cases such as capacity and ancillary services can be greater than the benefits for transmission and distribution deferral, the potential for stacking transmission and distribution deferral benefits with other use cases that are not location-specific makes it a key driver.

PacifiCorp looked at transmission and distribution (T&D) location specific near-term needs as identified through the company's T&D planning studies. Through many revisions and a workshop, PacifiCorp has looked at various projects and locations where energy storage could fill one of these near term system needs and provide opportunities for stacked benefits.

Please see the following table for PacifiCorp's initial list of T&D sites as presented on May 9, 2016:

Project Title	Description	Feasibility/Review
Gleneden	Install an energy storage solution to address transmission level outages on a specific high exposure line affecting Gleneden, Oregon.	Further analysis into outage data highlighted that other locations may have a greater need.
Shevlin Park	Install energy storage solution for T&D deferral at a substation needing increased capacity.	The need for this work was not in the near term plan (post 2020) and was removed from consideration for this project. *[PacifiCorp is continuing to evaluate the potential for energy storage for this location]*
Warrenton	Install energy storage to defer replacement/upgrade of an existing transformer (T&D deferral)	Due to leaking oil and the potential environmental exposure, this transformer needed to be removed/replaced and could not be deferred. Therefore this need was eliminated and this location was removed from consideration for this particular project.
Redmond	Install energy storage to address Volt/Var concerns.	Project seemed feasible.

After initial review, many of the above projects were deemed not feasible, not within the timeframe required to meet the project requirements, or the system need was subsequently filled due to environmental requirements.

In response, PacifiCorp identified additional locations where a near-term system need, such as T&D deferral or outage mitigation, could be addressed through energy storage technology.

As a result, the following circuits were analyzed in greater detail to understand potential benefits and cost-effectiveness, described in DNV GL's Draft Energy Storage Potential Evaluation, included in Appendix C of the Revised Draft Energy Storage Potential Evaluation:

- Redmond 5D22 (existing project from first list)
- Hillview 4M182
- Independence 4M22
- Independence 4M25
- Lyons 4M70
- Lyons 4M120
- Customer Site (Project #1)

Of all of the locations analyzed above, the customer site seemed to provide the best opportunity to learn about and capture both utility and customer benefits. Additionally, the analysis completed by DNV GL showed it to be the most consistently cost-effective, highlighting it as the least risk, lowest cost option for energy storage. See Section 7.0 at 62 or Appendix C of the Revised Draft Energy Storage Potential Evaluation.

Since the inputs to the DNV GL analysis were developed, PacifiCorp has used its alternative evaluation tool (described in Section 3.0 of the Revised Draft Energy Storage Potential Evaluation) to evaluate thirteen substation capacity upgrade projects in Oregon that were identified in the company's ten year distribution system forecast.

The alternative evaluation tool identified eleven of these thirteen substation upgrade projects as viable for the installation of energy storage technology, with two of the projects being potentially cost-competitive as compared to traditional solutions. However, for these two locations, the screening tool also identified demand side management as a cost effective viable alternative. The two projects have deficiency dates beyond the 2020 horizon. PacifiCorp did not include these two projects in the Revised Draft Energy Storage Potential Evaluation due to the multiple alternatives and timing of the projects. However, PacifiCorp intends to refine the analysis and continue to consider energy storage technology as the distribution needs and deficiency dates approach.

OPUC Request 9

Please explain how and why this location was preferred over all others.

Response to OPUC Request 9

As described in OPUC 8, this location allowed energy storage technology to meet existing system needs within PacifiCorp with the potential for stacked benefits and the flexibility to co-optimize and evaluate multiple use cases. In particular, this location provided the opportunity to study both customer and utility benefits. See section 7.0 or Appendix C of the Revised Draft energy Storage Potential Evaluation.

OPUC Request 15

What are the location specific benefits at this particular site?

Response to OPUC Request 15

Project 1 is expected to be connected at secondary voltage, resulting in avoided line losses, both during normal operation and during peak periods.

Project 1 is connected to a distribution substation that is forecasted to require a capacity upgrade in 2023 as a result of load growth.

Project 1 is also expected to provide outage mitigation benefits, which primarily accrue to impacted customer(s) rather than the utility and customers as a whole. Project 1 is located on a circuit that has experienced periodic outages in the past and is expected to provide opportunities to evaluate energy storage deployment and customer coordination during outage events. Distributed energy storage resources installed by customers to mitigate their own outage risk have the potential to provide value if they can be dispatched for local or system needs under specified conditions. Project 1 will provide experience that will allow this potential to be better characterized and can inform efforts to develop operating procedures and contractual terms to provide value from distributed energy storage resources to both individual customers and Oregon residents as a whole.

For additional information, see OPUC 8 or OPUC 9 as well as section 7.0 or Appendix C of the Revised Draft Energy Storage Potential Evaluation

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OPUC Data Request 22

OPUC Request 22

Are arbitrage, load following, spin/non-spin, volt-VAR, and transmission upgrade deferral benefits included in the draft energy storage proposal? If so, where? If not, why not?

Response to OPUC Request 22

PacifiCorp evaluated the benefits associated with energy arbitrage, load following, and spin/non-spin use cases. "Results Summary" in the workpaper "Energy Storage Use Case Summary_2017 12 20.xlsx" provided with the Company's draft filing. PacifiCorp did not include any benefits associated with these use cases for Project 1 because regulation service represented a higher value use case. Please refer to PacifiCorp's response to OPUC 2.

PacifiCorp addresses volt-VAR requirements through its distribution and transmission upgrade processes so it has not separately identified benefits associated with this use case. Project 1 does not have any expected volt-VAR benefits.

PacifiCorp has not yet identified any locations in which energy storage resources would be appropriate to defer planned transmission upgrades. Project 1 does not have any expected transmission upgrade deferral benefits.

OPUC Request 25

Outage mitigation and resilience are identified as use-cases for Phase 1 but are never monetized, why?

Response to OPUC Request 25

PacifiCorp views outage mitigation and resiliency as customer specific benefits. While these benefits can provide great value, PacifiCorp focused on the benefits that accrue to the electric system and all utility customers (per Order No. 16-504, Appendix A at 16). Therefore, for this filing, PacifiCorp did not provide monetized values for these specific use cases.

PacifiCorp also recognizes that while outage mitigation is primarily a customer benefit, distributed energy storage resources installed by customers to mitigate their own outage risk have the potential to provide value if they can be dispatched for local or system needs under specified conditions. Project 1 will provide experience that will allow this potential to be better characterized and can inform efforts to develop operating procedures and contractual terms to provide value from distributed energy storage resources to both customers and ratepayers as a whole.

PacifiCorp also recognizes that for future deployment and potential cost sharing models, the monetary benefits associated with customer specific benefits can have a significant impact in cost-effectiveness of energy storage solutions. PacifiCorp intends to explore this through the implementation of pilot projects (as proposed) and field test data.

OPUC Request 26

Please list all requirements for Phases 2 and 3 of this project to happen.

Response to OPUC Request 26

For Phase II to progress to execution, the company prefers a cost to benefit ratio of 1.0 or greater and will require regulatory approval, successful deployment, integration and operation of Phase I, and continued support from the project partner. Phase II carries the additional benefits of a distributed application of energy storage, allowing the company to pilot the integration and control of the distributed energy storage devices and the potential for micro-grid formation.

For Phase III to proceed, an energy storage solution would need to be selected as the least risk, lowest cost solution either in the preferred portfolio within the Integrated Resource Plan (IRP) or through the transmission and distribution planning study process as outlined in Section 3.0 of the Revised Draft Energy Storage Potential Evaluation. The specific location for deployment of the energy storage solution (i.e. distributed storage, mid-distribution feeder, or substation) would be contingent on the specific need identified through the IRP and transmission and distribution planning processes as well as the specific characteristics of the project.

PacifiCorp is currently monitoring two forecasted projects with in-service dates of 2022 and 2023 where energy storage has the potential to be the least cost, lowest risk solution. These projects were identified through transmission and distribution studies and, subsequently, the alternative evaluation tool as described in Section 3.0 of the Revised Draft Energy Storage Potential Evaluation.

However, the initial screening selected demand side management as the preferred alternative solution for these projects. While PacifiCorp cannot commit to an energy storage solution at this time, the company will continue to monitor these projects.