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

August 30, 2019

Public Utility Commission of Oregon
Attn: Filing Center
201 High Street, S.E.
P.O. Box 1088
Salem, OR 97308-1088

RE: UM 1856 2019 Annual Energy Storage Update

Pursuant to Public Utility Commission of Oregon (OPUC or Commission) Order No. 18-290, Portland General Electric Company (PGE) submits its first annual report on the progress of its energy storage proposal which includes: Baldock, Coffee Creek, Microgrid pilot, Port Westward 2 (PW2), Residential Storage pilot, and the controls for the energy storage systems. During operation of the projects, PGE will submit comprehensive evaluations in the third, sixth, and tenth operating year, along with annual progress updates. The following report details each project and includes progress, challenges, and preliminary learnings (as available). In addition, included as Appendices are the filings submitted over the past 12 months that are referenced throughout this report.

History of Energy Storage Docket

The Commission opened Docket No. UM 1751 in September 2015 to implement House Bill 2193, which requires Oregon electric companies (PGE and PacifiCorp) to submit proposals by January 1, 2018, to procure qualifying energy storage systems with capacity to store at least five megawatt hours of energy. In Commission Order No. 16-504, the Commission adopted guidelines and requirements for energy storage proposals and a framework for the Energy Storage Potential Evaluations.

PGE filed its energy storage proposal and final Energy Storage Potential Evaluation on November 1, 2017, which were reviewed in this docket. Order 18-290 partially approved and modified the stipulation and provided conditional approval on the following projects:

- **Energy Storage Potential Evaluation** – Prior to moving forward with any of the projects, PGE will submit a detailed written explanation of a plan to improve its energy storage modeling capability to estimate all energy storage benefits as directed in Order Nos. 17-118 and 17-375. This will be submitted to OPUC Staff (Staff) where they will evaluate and determine approval to allow PGE to move forward with all projects.

- **Baldock Mid-Feeder Project** – Submit a site analysis to Staff where they will evaluate and determine whether adequate evidence has been provided to allow PGE to move forward with the project.
- **Coffee Creek Substation Project** – Similar to Baldock, submit a site analysis for evaluation by Staff. In addition, PGE is to submit a justification for utility ownership.
- **Residential Storage Pilot** – Submit an addendum that details how PGE will optimize learnings and mitigate risks to Staff where they will evaluate and determine whether adequate evidence has been provided to allow PGE to move forward with the pilot.

PGE filed its plan to improve energy storage modeling in October 2018, which is provided as Appendix A. Staff submitted their feedback in an informational filing in May 2019, which is provided as Appendix B.

Baldock Mid-Feeder Energy Storage System

This project will develop and build a 2 MW, two-hour energy storage system adjacent to PGE's Baldock Solar facility and will be interconnected to the Canby-Butteville feeder. The final project energy rating (MWh) will be determined based on the proposal pricing received and space availability.

The project received conditional approval from the Commission on the site-specific benefits analysis. Pursuant to the condition outlined in the stipulation, PGE filed its site analysis in February 2019, provided as Appendix C. Based on initial discussions with Oregon Department of Transportation, the current plan is to locate the energy storage system inside the existing site boundary for the Baldock Solar Facility. This includes the space within the existing fence and the access road to the north of the project site. PGE is engaged with Staff on their feedback on the site analysis. In the meantime, PGE is preparing the Request for Proposal (RFP) for this project in preparation for Staff's feedback.

If Staff provides favorable feedback, PGE will move forward with the project by issuing the RFP. Currently, the first RFP deliverables, including the technical specifications, have been received and are under review. The bidders list has been developed from the request for information (RFI) results the RFI was issued to 43 vendors and 26 responses were received and evaluated. PGE plans to issue the RFP to 11 bidders from the RFI evaluation.

RFP development is underway with the goal to issue to the selected bidder list in September 2019. RFP evaluation and bidder selection will continue into the first quarter of 2020.

PGE's Coffee Creek Substation Energy Storage System

This project will develop and build a 17-20 MW, four-hour energy storage system sited and interconnected at PGE's Coffee Creek Substation. The final project rated capacity will be determined based on the proposal pricing received.

The project received conditional approval from the Commission on the site-specific benefits analysis. Pursuant to the condition outlined in the stipulation, PGE filed its site analysis in January 2019, provided as Appendix D. Staff filed comments stating the filing fulfilled the requirements in the stipulation.[1] The RFP evaluation team has developed bid scoring criteria. Pursuant to the competitive bidding requirements in UM 1751, PGE filed the RFP in May 2019, with the OPUC and invited stakeholder feedback within 30 days. The draft RFP that was submitted is provided in Appendix E. PGE then issued the RFP in June 2019 to 12 bidders that were identified in the same RFI described above. Bids were received on August 16 and are currently under review.

The interconnection application was submitted and permitting meetings were held with both Washington County and the City of Wilsonville. PGE's conditional use permit application will be submitted to Washington County once additional project details are defined by the selected vendor.

Microgrid Pilot

This project will develop and build two to five microgrids and will serve either single customers or a subset of customers.

PGE and the City of Beaverton have signed an agreement to deploy the first energy storage microgrid at the Beaverton Public Safety Center. The project will consist of a 250 kVA, four-hour battery and will be energized by April 2020. Pursuant to the competitive bidding requirements in UM 1751, PGE submitted the RFP for stakeholder review in May 2019, provided as Appendix F, and then issued the RFP in June 2019.

PGE is negotiating its second energy storage microgrid, which we anticipate will also be energized by the end of 2020. Both projects are designed to support community resiliency.

PGE's Port Westward 2 (Generation Kickstart) Energy Storage System

This project will develop and build a 4-6 MW, two-to-four-hour energy storage system at PGE's PW2 Generating Station. This energy storage system will be coupled with one of PW2's reciprocating engines. The project will enable the combined resource (i.e. the

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[1] See Appendix B of this report.

energy storage system and a PW2 reciprocating engine) to qualify as spinning reserve, even when the engine is not running.

When called upon for spinning reserves, the energy storage system will immediately deliver full output to the grid while the adjacent PW2 engine starts and synchronizes to the grid (within 10 minutes), thereby providing the full 18.9 MW required. This will reduce the wear and tear, operation and maintenance expense, and carbon footprint of the PW2 engine while providing ancillary services.

Pursuant to the competitive bidding requirements in UM 1751, PGE submitted the RFP for stakeholder review in May 2019, provided in Appendix E, and issued the RFP in June to 12 bidders that were identified in the same RFI described above. RFP bids were received on August 16 and are currently under review. The site certificate amendment request has been submitted to Oregon Department of Energy and is currently under review.

Residential Storage Pilot

PGE's residential storage pilot will integrate residential storage units as a dispatchable resource providing grid services. During grid outages, the energy storage system could provide power to participating residences. PGE will offer a PGE-owned storage option and a customer-owned option in which participants are paid for grid services.

This pilot received conditional approval from the Commission directing PGE to submit a plan on how the pilot would mitigate risks and how PGE will optimize learnings. Pursuant to the condition outlined in the stipulation, PGE filed an addendum in January 2019 discussing risk mitigation and learning optimization, provided as Appendix G. However, after recent discussions with OPUC Staff regarding their feedback on the pilot, PGE is updating the approach to the pilot, within the bounds of the stipulation, and will present the update to Staff and other stakeholders before end of 20192019. A consultant has been retained to help with technical specifications and to identify risk mitigation strategies. If Staff and stakeholders do not object to the approach, PGE will file an operating tariff to implement the pilot.

Please direct any questions regarding this filing to Kalia Savage at (503) 464-7432. Please direct all formal correspondence and requests to the following email address pge.opuc.filings@pgn.com

Sincerely,

Karla Wenzel
Manager, Pricing and Tariffs

Enclosures

Appendix A

PGE's Plan to Advance Energy Storage Modeling Capability

Portland General Electric
121 SW Salmon Street • Portland, Ore. 97204
PortlandGeneral.com

October 25, 2018

Public Utility Commission of Oregon
Attn: Filing Center
201 High Street, S.E.
P.O. Box 1088
Salem, OR 97308-1088

Re: UM 1856 PGE's Plan to Advancing its Energy Storage Modeling Capability

Pursuant to Public Utility Commission of Oregon (OPUC or Commission) Order No. 18-290 filed in OPUC Docket No. UM 1856 (PGE's Energy Storage Proposal), Portland General Electric Company (PGE or Company) hereby submits its plan, which includes incremental next steps to advancing its energy storage modeling capability to credibly estimate all benefits associated with the proposed energy storage systems as directed in Commission Order Nos. 16-504 and 17-532.

Should you have any questions or comments regarding this filing, please contact Kalia Savage at (503) 464-7432.

Please direct all formal correspondence and requests to the following email address pge.opuc.filings@pgn.com.

Sincerely,

Karla Wenzel
Manager, Pricing & Tariffs

Enclosure
KW:np

UM 1856 - PGE's Plan to Advance its Energy Storage Modeling Capability

Introduction

Portland General Electric Company ("PGE" or "Company") files this detailed explanation to comply with the Stipulation approved in Public Utility Commission of Oregon ("OPUC" or "Commission") Order No. 18-290 filed in Docket No. UM 1856, to advance storage modeling. Specifically, the Stipulation states:

> Prior to implementing any of the five projects agreed to in this Stipulation, PGE will file in this docket a detailed written explanation of its plan, including incremental next steps, to advance its energy storage modeling capability to credibly estimate all benefits associated with the proposed energy storage systems as directed in Commission Order Nos. 17-118 and 17-375. PGE's plan must set clear milestones with explanations regarding the analysis or tool development necessary to advance its methodologies to the forefront of [energy storage system] benefit modeling; then PGE must implement those methodologies for future [energy storage system] proposals made outside of the [Integrated Resource Planning] process.

One critique of PGE's Energy Storage Potential Evaluations ("Potential Evaluations") was that PGE did not quantitatively co-optimize benefits across all potential benefits of energy storage resources on its system. PGE's Resource Optimization Model ("ROM")[1] analysis included quantitative co-optimization across the following benefits: energy arbitrage, load following, regulation, spinning reserves, and non-spinning reserves. The consulting firm, Navigant, applied heuristics to approximate the interaction and co-optimization between these applications and locational and customer applications.

Background: Energy Storage Law, PGE's Proposal, and Order 18-290

The Commission opened Docket No. UM 1751 in September 2015 to implement House Bill ("HB") 2193,[2] which requires large Oregon electric companies to submit proposals to the Commission by January 1, 2018; the proposals would identify how PGE would develop qualifying energy storage systems with the capacity to store at least five megawatt hours ("MWh"). The total capacity may not exceed one percent of PGE's 2014 peak load,[3] which equates to 38.7 megawatts ("MW"). The Commission adopted specific guidelines and requirements, in Commission Order No. 16-504, for Pacific Power ("PAC") and PGE's energy storage project proposals on December 28, 2016. Then on March 21, 2017, the Commission adopted a framework in Commission Order No. 17-118 for PAC's and PGE's Potential Evaluation that includes seven elements. PGE filed its Draft Potential Evaluation on July 14, 2017. OPUC Staff ("Staff") and stakeholders reviewed this draft and made recommendations to the Commission through a Staff Report. Commission Order No. 17-375 adopted the following schedule: (1) by January 1, 2018, PGE and PAC were to file draft project proposals and updated draft potential evaluations that incorporated the improvements outlined by Staff in its Report; (2) by April 2, 2018, the utilities were to file final project proposals and final potential evaluations; and (3) no later than April 2, 2018, the Commission was to begin review of the final

[1] ROM is a multistage sub-hourly production cost model of PGE's resource portfolio.
[2] 2015 Oregon Laws Chapter 312.
[3] See HB 2193, Section 2(a).

filings. PGE's Energy Storage Proposal and Potential Evaluation resulted in a partial stipulation among most of the Parties (i.e. PGE, Staff, CUB, AWEC, NIPPC and RNW), with no party objecting to the stipulation. The stipulation was approved August 13, 2018

Co-optimization Analysis

To further improve upon the method used in the Potential Evaluation and to improve the transparency of its analysis, PGE plans to use the Electric Power Research Institute's ("EPRI's") Storage Value Estimation Tool ("StorageVET®") with PGE-specific input data to co-optimize benefits across all Bulk Energy, Ancillary Services, Transmission and Distribution Services, and Customer Energy Management Services for future analysis of small energy storage projects or programs.

With the assistance of EPRI, PGE will prepare an energy storage valuation method, incorporating applicable learnings from other participant utilities[4] investing in energy storage. PGE will achieve this outcome through participation in the EPRI supplemental program, "Energy Storage Analysis: Finding, Designing, and Operating Projects."

To advance PGE's energy storage modeling capability and credibly estimate potential benefits associated with proposed energy storage systems, as directed in Commission Orders 17-118 and 17-375, PGE, with EPRI, will conduct a deep analysis of storage operation using time-series analysis and dispatch models to address stacked benefits. In addition, PGE and EPRI will fully model and understand how storage systems are likely to influence grid operation under various conditions across the lifetime of the project. The outcome will report effective and efficient methods to perform the necessary economic dispatch optimization of small storage and other distributed energy resources ("DER"), as well as the required time-series analyses to assess integration with the grid. PGE will use these learnings to validate and refine the locational system benefits and impacts of energy storage systems to integrate future storage resources and other DER into distribution capacity planning.

While the EPRI StorageVET® supports analyses, which co-optimize the economic dispatch of all stacked benefits based on user inputs, some potential benefits have "pre-dispatch" carve-outs (e.g. T&D deferral) which prioritize reliability over economic benefits. These pre-dispatch constraints and dispatch priorities are customizable for each case, depending on the intended application of the energy storage system.

For each of PGE's proposed energy storage projects specified in Order 18-290, PGE will identify and assign the primary service and/or issue that the energy storage application is intending to address at the customer, distribution, or transmission level, along with any associated learnings the projects are intended to achieve for the various scenarios proposed. By deploying storage in a manner which considers a variety of applications, PGE will gain a broader set of learnings to be used when considering future deployments. The StorageVET® time-series analyses will co-optimize and stack all potential benefits/value streams compatible with the intended application to quantify the total value represented by the project. This approach is consistent with the method that EPRI uses in its StorageVET® model when evaluating co-optimized benefits for energy storage at other partner utilities.

Data Needs

PGE will provide a list of applicable value streams and a corresponding value for the StorageVET® to perform the co-optimization analysis in consultation with EPRI. For this

[4] Includes each of the utilities which elected to subscribe to EPRI's supplemental project on Energy Storage, "Energy Storage Analysis Finding, Designing, and Operating Projects."

evaluation, the applicable value streams include Bulk Energy, Ancillary Services, Transmission Services, Distribution Services, and Customer Energy Management Services.[5]

Generation Capacity Value

To determine generation capacity value to incorporate into StorageVET®, PGE will use the Renewable Energy Capacity Planning ("RECAP") model. Consistent with Commission Order No. 16-326, PGE has used RECAP in PGE's Integrated Resource Plan ("IRP") to determine the effective load carrying capability ("ELCC") of renewable resources to quantify capacity contributions and capacity values. Capacity contributions from RECAP have also been applied to Qualifying Facilities and were included in PGE's Resource Value of Solar in OPUC Docket No. UM 1912. In the 2016 IRP, PGE presented a preliminary analysis of the ELCC of energy storage resources in RECAP and the Company plans to advance this work in future IRPs to inform both resource portfolio planning and future analysis specific to energy storage projects and programs.

Bulk Energy and Ancillary Services Value

Bulk energy and ancillary service values include energy arbitrage, load following reserves, regulation reserves, spinning reserves, non-spinning reserves, voltage support, and black start. To co-optimize across applications, StorageVET®, and other price-taker energy storage evaluation tools, require time series information about the value of providing each of these services to the system. For an energy storage system that operates within an organized energy and ancillary services market, the value of the resource is typically estimated by calculating the maximum revenue that could be collected in the market given hourly historical, or forecasted, energy and ancillary service price streams. Because PGE does not operate within an organized energy and ancillary services market, PGE has estimated the value of providing energy and ancillary services with energy storage resources as the reduction in variable costs[6] that can be achieved with the resource, as simulated in ROM. This approach more accurately reflects the value of an energy storage operating within PGE's resource fleet than alternative methods.[7]

To provide additional insight regarding the co-optimized bulk energy and ancillary service value of energy storage resources, PGE will conduct additional analysis to estimate the time-varying marginal value of providing bulk energy and ancillary services within its system. For a system that does not operate within an organized market, the hourly value of providing a given service can be estimated by the shadow price of the constraint associated with that service. For example, in each hour the system is required to hold a specified amount of regulation reserves. The shadow price of the regulation reserve constraint is equal to the marginal cost of providing the last increment of regulation reserves to meet that constraint. This regulation reserve shadow price provides an analog to the price that a resource may be paid if it were selected to provide regulation reserves in an organized market. The hourly shadow prices for each bulk energy and ancillary service constraint can therefore serve as a proxy for the hourly market prices in a price-taker model like StorageVET®. Production cost models like ROM[8] can be configured to export shadow prices when they solve for the commitment and dispatch of a resource portfolio. PGE plans to use ROM to provide shadow prices for energy and ancillary services for use in StorageVET® to enable co-optimization across these and other services. Because PGE has not undertaken this type of exercise in the past, this analysis may require multiple iterations to ensure accuracy and consistency with PGE's system needs and true marginal costs.

[5] See Commission Order No. 17-375 and Commission Order 18-290 Appendix A at 5-6.
[6] Variable costs include fuel, start-up costs, and variable operation and maintenance costs across PGE's resource fleets as well as net costs associated with market purchases and sales and potential future carbon costs.
[7] Providing this accuracy requires more modeling complexity, which could be viewed as reducing transparency.
[8] ROM is a tool designed to investigate operational cost trade-offs over short time scales and with a high degree of rigor with respect to PGE's portfolio.

Ancillary services that are not currently modeled in ROM include frequency response, voltage support, and black start service. PGE will work with EPRI to identify best practices for quantifying these value streams in a way that is transparent and allows for co-optimization.

This plan does not include efforts to substantively modify ROM to incorporate non-bulk energy and ancillary service value streams. Due to the complexity of power system operations and planning, all models of power systems are designed to best serve their specific purpose with practical and computational trade-offs in mind. In the case of ROM, PGE has prioritized temporal resolution over geographical resolution. This allows ROM to resolve value streams related to operations in very short timescales and those associated with time-varying operating constraints on PGE's resource portfolio that are challenging to model (like generator unit constraints). In contrast, distribution planning tools, like the Integrated Planning Tool, prioritize geographical resolution over temporal resolution because locational value is primarily dependent on geographic placement of the resource and its connectivity to the local T&D infrastructure. While an ideal model might attempt to resolve energy storage value streams at high resolution with respect to both temporal factors and geographical factors at the same time, current computational limitations in both industry and research prevent such a model from being practical at scale (i.e. for more than a small number of locations). This proposal allows PGE to use its existing models to focus on what they do well, and for StorageVET® to leverage the resulting simplified output information (like shadow prices from ROM) to consider problems that are complex across both time and geography.

Transmission Value

The following transmission values will be calculated:

- Transmission Reliability – This will be calculated based on the potential for an energy storage system to offset transmission reliability/resiliency-based investments (e.g. the value to PGE for transmission outage avoidance/mitigation). The Transmission Reliability value requires a commitment to reserve energy storage capacity to provide this service as the primary use case during all times during which the system may be exposed to a potential reliability event.
- Transmission Capacity and Loss Reduction – PGE will forecast potential changes in transmission system losses due to the presence and availability of a DER portfolio (e.g. storage) of varying penetration levels to offset system demand during a four-hour system peak. The results will be extrapolated to consider the per-unit transmission system loss reduction available and corresponding value for this mode of operation across 365 days per year.
  - Concurrent with the transmission loss reduction value, PGE will consider the same mode of operation for a DER portfolio to offset transmission system capacity needs during the four-hour system peak. PGE will calculate the forecasted transmission system capacity investment needed to support general system demand at the time of the peak, as identified per compliance with the North American Electric Reliability Committee ("NERC") TPL-001 reliability standard. In addition, PGE will assign a pro-rata transmission capacity value to the DER based on the size of the resource and its proportionate ability to influence transmission system flow in the area(s) of identified transmission capacity needs. The Transmission Capacity value and Loss Reduction value require a commitment to reserve energy storage capacity to provide these services as the primary use cases during the time of the daily system peak (compatible with the Distribution Capacity and Loss Reduction use case).

Distribution/Locational Value

The following Distribution and Locational values will be calculated:

- Distribution Voltage Management – This will be calculated based on the potential for an energy storage system to offset investments otherwise needed to support feeder voltage profile management, especially pertaining to Volt-Var Optimization ("VVO") and Conservation Voltage Reduction ("CVR") programs. For screening purposes, PGE will assign an average cost-per-feeder for the investment needed to support CVR and will calculate a pro-rata value for an energy storage system's ability to offset these investments. In future project proposals, the value considered for Distribution Voltage Management may be revised to reflect specific costs and benefits for the feeder in which the planned DER will interconnect.
- Distribution Reliability & Power Quality – This will be calculated based on the potential for an energy storage system to offset distribution reliability/resiliency-based investments. This includes the value to PGE for customer outage avoidance/mitigation minus the integration cost of necessary microgrid control. The Distribution Resiliency value requires a commitment to reserve energy storage capacity to provide this service as the primary use case during all times during which the system may be exposed to a potential reliability event.
- Distribution Capacity & Loss Reduction – PGE will forecast what change in distribution system losses may be available given the presence and availability of a DER portfolio of varying penetration levels to offset system demand during a four-hour system peak. The studies will be extrapolated to consider the per-unit distribution system loss reduction available and corresponding value for this mode of operation across 365 days per year.
    - Concurrent with the distribution loss reduction value, PGE will consider the same mode of operation for a DER portfolio to offset distribution system capacity needs during the four-hour system peak. PGE will calculate the forecasted distribution system capacity investment needed to support general system demand at the time of the peak and assign a pro-rata distribution capacity value to the DER based on the size of the resource and its proportionate ability to influence distribution system flow in the area(s) of identified distribution capacity needs. The Distribution Capacity value and Loss Reduction value require a commitment to reserve energy storage capacity to provide these services as the primary use cases during the time of the daily system peak (compatible with the Transmission Capacity and Loss Reduction use case).

Customer Value

The following customer values will be calculated for behind the meter projects:

- Time-of-Use ("TOU") Optimization – PGE will use TOU rates as potential value streams in areas where those optional rates are available for customers. For residential applications, this will use TOU rates. For nonresidential applications, PGE's Schedules 32 ("Small Non-Residential Standard Service") and 38 ("Large Non-Residential Optional TOU Service") rates will be used.
- Demand Charge Reduction – For nonresidential customers, PGE will test the ability to manage peak demand against relevant demand charges.

Interactions with Other Planning Processes

Integrated Resource Planning

Consistent with Order 18-290, PGE will use the Storage Potential method, adopted by the Commission in Order 17-375, when considering energy storage resources outside of the IRP. PGE draws this distinction for both technical and logistical reasons.

- Technical considerations – The third-party tools available for energy storage evaluation, including StorageVET®, are not consistent with the frameworks and methodologies used in the IRP. StorageVET® and other third-party energy storage evaluation tools are price-taker models, which assume that the behavior of the resource being modeled does not impact the prices of the services that it provides. This assumption is generally valid for smaller resources (e.g. a 10 MW energy storage system) relative to the total size of the system (e.g. the size of PGE's resource portfolio). However, as the size of the resource (or resource fleet) grows, it can fill larger shares of the system needs, reducing prices and marginal value, and eventually saturating the system. This effect is important in portfolio planning efforts, like the IRP, which consider major resource actions. These effects may be less important for small individual projects, e.g., a small distribution- or customer-sited energy storage project. For this reason, PGE will continue to pursue production cost modeling in the IRP while investigating the potential to use price-taker models such as StorageVET® in applications that are not expected to materially impact PGE's generation portfolio.

- Logistical considerations – The production cost modeling that occurs within the IRP is highly data- and time-intensive. In the effort to enable energy storage resources that are cost-effective for customers, PGE does not wish to burden each individual distribution- or customer-sited storage resource with the same level of analysis (regarding bulk energy and ancillary service value) that major resource actions, including large energy storage projects and/or programs, require in the IRP. The plan, as described here, would allow for PGE to update bulk energy and ancillary service inputs into a tool, StorageVET®, after each IRP so that the Company could conduct more nimble analysis of specific projects between IRPs.

Within the IRP, PGE will continue to advance its modeling capabilities for capturing the value of flexible and distributed resources like energy storage. While not occurring within the IRP, the analysis described in this plan will provide helpful learning that, over time, may inform future IRPs. In determining how the learnings from this analysis may inform future IRPs, PGE will use the IRP stakeholder engagement process to work toward applying new methodologies, or frameworks, in ways that ensure that resource options are compared on a consistent basis, as required by the IRP Guidelines.

Transmission and Distribution Planning

From a Transmission and Distribution ("T&D") Planning standpoint, the EPRI StorageVET® price-taker model may be used to quantify locational value of future energy storage applications until a given location reaches saturation. Saturation in the T&D Planning context will be identified through a system-wide hosting capacity analysis which identifies an "upper bound" for DERs specific to each defined location, after which the locational value for any incremental resource will be offset to some degree by a corresponding system integration cost.

Customer Program Planning

The StorageVET® output may be used to identify a mix of potential use cases from behind-the-meter storage resources. This may aid in the design of programs in understanding the balance between customer value propositions and grid value. It may also help identify where locational deployment of programs would be appropriate.

Timelines and Key Milestones

In accordance with Order 17-375, PGE established energy storage potential value streams. In addition, in PGE's Potential Evaluation, PGE calculated draft shadow prices (i.e. arbitrage, load following, regulation, and spin/non-spin reserves) as well as draft values for specific transmission, distribution, and customer benefits. Going forward, PGE will develop internal capabilities to use the EPRI StorageVET® tool to evaluate and quantify potential benefits of energy storage systems and benchmark the StorageVET® reported value for Bulk Energy, Ancillary Services, and Capacity Value against those values derived in the ROM model through PGE's IRP process.

To maintain the validity of the transmission and distribution values attributed to energy storage through participation in the EPRI Supplemental project, PGE plans to create incremental FTE positions in PGE's Distribution Planning department. These resources will periodically review and update a system-wide Hosting Capacity Assessment and will perform ongoing time-series analyses to support the accuracy of the assigned locational values.

Table 1, below, provides PGE's timeline for developing and updating the valuation methodology for energy storage systems.

Table 1: PGE's Timeline for Developing and Updating Energy Storage Valuation Methodology

Action	Completed By
1. PGE provides input values for StorageVET®	1/1/2019
2. EPRI StorageVET® output delivered	6/1/2019
3. PGE completes running StorageVET®	8/1/2019
4. Method developed to validate/refine input values to StorageVET®	10/1/2019
5. Benchmark StorageVET® output against IRP	1/1/2020
6. EPRI to compile and deliver co-optimized benefits report/recommendations	6/1/2020
7. Finalize valuation methodology	12/1/2020

Appendix B

Staff Comments Informational Filing on May 9, 2019

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

UM 1856

In the Matter of PORTLAND GENERAL ELECTRIC COMPANY, Draft Storage Potential Evaluation and Coffee Creek Pilot	Staff Comments Informational Filing Only

The Public Utility Commission of Oregon Staff (Staff) offers these comments as a status update and for informational purposes.

BACKGROUND

On August 13, 2018, the Commission issued Order No. 18-290 in this docket, adopting a partial stipulation (Stipulation)[1] that outlined an agreed approach to the development of five energy storage projects, as well as revisions to the Storage Potential Evaluation (SPE) methodology, proposed by Portland General Electric Company (PGE) pursuant to HB 2193 and corresponding Commission orders.

In particular, the adopted Stipulation required that the following additional analyses and filings be made by PGE:

- **SPE Improvements:** PGE is required to file a detailed written explanation of a plan to improve its energy storage modeling capability to estimate all of the energy storage benefits as directed in Order Nos. 17-118 and 17-375. The parties agreed that Staff would review and approve PGE's revised modeling plan for compliance with Order Nos. 17-118 and 17-375. Additionally, the Stipulation requires all future energy storage projects proposed by PGE to credibly estimate the value of all listed benefits in Order Nos. 17-118 and 17-375, and PGE must explain how the locational value of energy storage resources are considered in

[1] Docket No. UM 1856, Partial Stipulation filed May 22, 2018.

the IRP planning process.

- **Coffee Creek:** To proceed with this project, the parties agreed that PGE must first present an analysis to Staff, supported by adequate evidence, that Coffee Creek is the best site for the Energy Storage System (ESS) based on the universe of available substation sites within PGE's system.[2]

- **Baldock:** Similarly, to proceed with this project, the parties agreed that PGE must first present an analysis to Staff demonstrating that Baldock is the best site to locate the energy storage system given the universe of available feeders on PGE's system.[3]

- **Residential Project:** Last, the Stipulation requires PGE to present a revised project design to Staff with evidence demonstrating that PGE will manage risk and optimize learnings.[4] PGE's revised project proposal must include specificity on how the individual energy storage systems will be aggregated and dispatched as outlined in PGE's original application.

In the comments below, Staff responds to PGE's plan to improve its energy storage modeling capability and PGE's justification for the selection of the Coffee Creek location.

STORAGE POTENTIAL EVALUATION

In the summer of 2018, PGE began working with Staff to develop a revised SPE methodology. In August 2018, Staff received a draft of PGE's updated SPE, which included changes to the methodology and software. On October 25, 2018, PGE filed a final version of their revised SPE in UM 1856.

A key component to PGE's revised SPE is the use of the Electric Power Research Institute's (EPRI) StorageVet modeling tool. The StorageVet model is a publicly available, open-source energy storage valuation tool that has been used nationally and by the California Public Utilities Commission. StorageVet's development was partially funded by the California Energy Commission. It functions as a price-taker model (values are given to it) and can be run to co-optimize benefits, evaluate hourly data and benefits, and evaluate location-specific benefits. These capabilities found in StorageVet addressed Staff's concerns regarding the shortcomings of PGE's originally proposed SPE approach. Based on the information provided by PGE, a conversation with PGE staff on March 15, 2019, and additional supporting materials provided by PGE, it

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[2] In the event that Staff does not agree that adequate evidence has been provided, the Parties agree that the Commission should determine whether PGE can move forward with the project.
[3] In the event that Staff does not agree that adequate evidence has been provided, the Parties agree that the Commission should determine whether PGE can move forward with the project.
[4] In the event that Staff does not agree that adequate evidence has been provided, the Parties agree that the Commission should determine whether PGE can move forward with the project.

appears that the StorageVet model should allow PGE to effectively estimate the energy storage benefits required by Commission Order Nos. 17-118 and 17-375.

Staff is satisfied that EPRI's StorageVet model positions PGE to meet the requirements of applicable Commission orders and the adopted Stipulation in UM 1856. Staff plans to continue to be engaged with PGE on the values and data used by the SPE model and how it is applied.

Sometime later this year, Staff recommends that PGE provide a demonstration of the StorageVet for Staff. Additionally, because the Stipulation calls for any future proposed energy storage project to include an estimate of all benefits, Staff requests that the demonstration occur prior to any new storage proposal submissions. Further, Staff suggests that the StorageVet tool be used to analyze the benefits of the Coffee Creek and Baldock projects as test cases.

COFFEE CREEK LOCATION

On January 4, 2019, Staff received PGE's analysis to justify the selection of the Coffee Creek substation for an energy storage pilot. This analysis was called for by Commission Order No. 18-290 and also included a feasibility assessment of third-party operation and ownership of the energy storage system at this site. As part of the Stipulation for this docket, all parties agreed that PGE must first present an analysis to Staff, supported by adequate evidence, that Coffee Creek is the best site for the Energy Storage System (ESS) based on the universe of available substation sites within PGE's system, before it could proceed with the project.

In Staff testimony, we expressed reservations regarding PGE's rationale for selecting the Coffee Creek substation for an energy storage system pilot. Staff's position centered on three main concerns:

- Not meeting the required project and proposal guidelines per Order No. 16-504;
- Indeterminate reasoning for the size of project given the location; and
- Unknown scoring metrics.[5]

Based on the information that PGE originally submitted with its filing on July 14, 2017, it was unclear why Coffee Creek – among PGE's 140 potential substation locations – was selected as the optimal location for a 17 MW ESS project at a cost of over $30 Million.

Site selection is a crucial component to an ESS pilot. A pilot's location and size determine the extent to which ESS operations can both test and subsequently co-optimize the multiple potential end-use case benefits of an ESS.[6] Improper location and size limit the learnings that can be more broadly applied. Therefore, Staff pushed for

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[5] *See* UM 1856 Staff Reply Testimony, Staff/100 Wiggins, 2/16/18, pgs. 5, 21, 22, and 32.

[6] Using data from PNNL, Staff testimony established 14 end-use cases for an ESS and pushed for pilots that could test and co-optimize these multiple benefits so as to apply "lessons learned" in the evaluation of ESS investments by PGE or in the market signals given by the Company in rates to third-parties.

supporting evidence for this project location, which was incorporated into the multi-party Stipulation and adopted by the Commission.

In PGE's January 2019 filing to address the location choice, they addressed Staff's concerns in two ways. First, PGE made their selection criteria more transparent. Staff was better able to understand how implementation risks tempered and shaped the original substation rankings from PGE's Integrated Planning Tool (IPT) outputs. Second, PGE explained in more detail why other substation sites that received a higher IPT ranking than Coffee Creek were eliminated from consideration.

Staff is satisfied, based on the information provided by PGE, that Coffee Creek is a satisfactory site for the proposed ESS project and does not object to PGE moving forward with the project.

Staff does not take a positon on third-party ownership at the Coffee Creek location at this time.[7]

OTHER PROJECTS

Staff's review of the remaining outstanding requirements of the adopted Stipulation is forthcoming.

This concludes Staff's status update and informational filing.

Dated at Salem, Oregon, this 9th of May, 2019

JP Batmale
Division Administrator
Energy Resource Planning Division

[7] A position on this issue is not required by the Stipulation.

Appendix C

PGE's Baldock Site Analysis

Portland General Electric
121 SW Salmon Street • Portland, Ore. 97204
PortlandGeneral.com

February 1, 2019

Public Utility Commission of Oregon
Attn: Filing Center
201 High Street, S.E.
P.O. Box 1088
Salem, OR 97308-1088

RE: **UM 1856 – PGE's Baldock Mid-Feeder Site Analysis**

Pursuant to Public Utility Commission of Oregon (OPUC or Commission) Order No. 18-290, enclosed is Portland General Electric Company's (PGE's) site analysis for its Baldock Mid-feeder proposal. Per the Stipulation, paragraph 28, PGE requests that OPUC Staff express its agreement that PGE presented adequate evidence that Baldock Mid-Feeder is the best site for the energy storage system based on the universe of available feeder sites within PGE's system.

The Commission opened Docket No. UM 1751, in September 2015, to implement House Bill 2193. This House Bill requires large Oregon electric companies (i.e. Pacific Power or PAC, and PGE) to submit proposals by January 1, 2018, to develop qualifying energy storage systems with the capacity to store at least five megawatt hours. In UM 1751, the Commission adopted specific guidelines and requirements for energy storage project proposals, in late 2016, and a framework for PAC's and PGE's Energy Storage Potential Evaluations (Potential Evaluations) in March 2017.

PGE filed its Energy Storage Proposal and Final Potential Evaluation on November 1, 2017, which were investigated in the subsequently opened Docket No. UM 1856. Following multiple rounds of testimony and numerous data requests, workshops and a settlement conference, stakeholders and PGE reached a Partial Stipulation and submitted Joint Testimony in support of the Stipulation. The stipulation resolved nearly all the issues in the proceeding.

Attachment A provides the site analysis for PGE's Baldock Mid-Feeder proposal to comply with Item No. 02 of Order No. 18-290. Attachment B provides a list of all PGE feeders and the site selection for the energy storage system. Attachment B is confidential and subject to Protective Order No. 17-441 and sent to Staff via US Mail.

PGE looks forward to working with OPUC Staff in determining the adequacy of evidence in the site analysis. Should you have any questions or comments regarding this filing, please contact Kalia Savage at (503) 464-7432.

Please direct all formal correspondence and requests to the following email address pge.opuc.filings@pgn.com

Sincerely,

Karla Wenzel
Manager, Pricing & Tariffs

Enclosures
Cc: UM 1856 Service List

Attachment A

Provided in Electronic Format only

Baldock Mid-Feeder Site Analysis

Attachment A - Baldock Mid-Feeder Energy Storage Site Analysis

Introduction

Portland General Electric Company ("PGE" or "Company") files this document to comply with Public Utility Commission of Oregon ("OPUC" or "Commission") Order No. 18-290 which states "to be able to proceed with this project, PGE must first present an analysis to Staff, supported by adequate evidence, that Baldock is the best site to locate the energy storage system given the universe of available feeders on PGE's system." This document provides a procedural background, describes the site selection process for the Baldock mid-feeder project, and provides a detailed review matrix regarding the site selection.

Background: Storage Law, PGE's Proposal, and Partial Stipulation

The Commission opened Docket No. UM 1751 in September 2015 to implement House Bill ("HB") 2193 (2015 Regular Legislative Session), which requires large Oregon electric companies to submit proposals to develop qualifying energy storage systems with the capacity to store at least five megawatt hours ("MWh") the Commission by January 1, 2018. On December 28, 2016, the Commission adopted specific guidelines and requirements, in Order No. 16-504, that encourage Pacific Power's ("PAC's") and PGE's energy storage project proposals. On March 21, 2017, in Order No. 17-118, the Commission adopted a framework for PAC's and PGE's Energy Storage Potential Evaluations ("Potential Evaluations") that includes seven elements. On July 14, 2017, PGE filed its Draft Potential Evaluation. Staff and stakeholders reviewed this draft and made recommendations to the Commission through a Staff Report. In Order No. 17-375, the Commission adopted the following schedule: (1) by January 1, 2018, PGE and PAC were to file draft project proposals and updated draft potential evaluations that incorporated the improvements outlined by Staff in its Report; (2) by April 2, 2018, the utilities were to file final project proposals and final potential evaluations; and (3) no later than April 2, 2018, the Commission would begin review of the final filings. PGE's submitted Proposal and Potential Evaluation resulted in a partial stipulation among most of the Parties (i.e. PGE, OPUC Staff, CUB, AWEC, NIPPC and RNW), with no party objecting to the stipulation.

As part of the stipulation, Parties agreed that PGE would present its analysis to Staff that the Baldock mid-feeder is the best site for the mid-feeder energy storage system based on the options of available feeders on PGE's system. The stipulation further provided that if Staff did not agree, the Commission would determine whether PGE could move forward with the project. In adopting the stipulation, the Commission clarified that its involvement in a dispute on whether the evidence is adequate would not occur until a prudence determination is made as part of a cost recovery proceeding.

Mid-Feeder Project Benefits

Baldock is the mid-feeder project identified in PGE's Energy Storage Proposals submitted November 1, 2017. The mid-feeder project is intended to explore the specific benefits an energy storage system can provide in supporting potential feeder reliability and power quality issues stemming from high penetrations of distributed solar. Applicable learnings will help PGE evaluate energy storage systems for their suitability as a non-wires alternative to traditional Transmission and Distribution infrastructure investments, and the degree to which any co-optimized benefits can enhance the Energy Storage system's value in this context. With this objective in mind, PGE sought PGE feeders with high penetrations of distributed solar which could present associated reliability and/or power quality concerns.

PGE regularly deploys voltage control devices at its substations. These devices can raise or lower voltage at the substation, with a goal of maintaining distribution system voltages within an acceptable bandwidth. In general, the measured voltage at any point along a distribution feeder decreases in proportion to the distance from the substation, especially as load[1] on the feeder increases. Utilities may also deploy additional voltage control and other reactive devices (e.g. feeder regulators, feeder capacity banks) at selected locations along a feeder (outside of the substation) to improve the feeder voltage profile for the range of expected system conditions.

One of the challenges utilities have with integrating large sums of distributed solar on its distribution feeders has to do with the impact these solar facilities can have on the distribution feeder voltage profile. Distributed energy resources, such as solar, can have the effect of raising voltages on the feeder when energy output is high. When compensating adjustments cannot be made to the substation voltage control devices without negatively impacting distribution system voltages elsewhere on the feeder, additional investment may be needed for downstream (outside of the substation) voltage control and reactive devices to better manage the feeder voltage profile.

Another challenge utilities can have with integrating large sums of distributed solar on its distribution feeders has to do with the loading capability, or capacity, of the distribution feeder. When energy production is high, reverse flow can occur on the distribution feeders to the point where the power flow in a given location can exceed the feeder's capacity. Distribution feeder capacity is generally limited by thermal constraints, and capacity can be increased with a distribution feeder reconductor of larger size wire.

For the mid-feeder project, PGE is exploring the use of energy storage to facilitate the integration of high penetration solar as a mitigating resource in lieu of investment in more traditional downstream voltage control and reactive devices or feeder reconductor projects. The mid-feeder project also affords PGE the opportunity to explore the prospect of direct coupling utility scale solar with storage as a combined resource.

Mid-Feeder Site Selection Analysis

The determination that the Baldock mid-feeder was the best among feeders for energy storage started with the ranking of distribution feeders based on the site-specific outage mitigation benefits (also known as the locational value) as identified by the Integrated Planning Tool ("IPT").[2] PGE evaluated all 589 radial distribution feeders using the IPT and ranked them from highest locational value to lowest locational value for a two-hour energy storage system.

The following steps were taken to filter the IPT results and identify the best site for a mid-feeder project, with consideration for high T&D value, per the IPT, and potential for learnings affecting the integration of Distributed Energy Resources (DER) on high-penetration feeders. Please see Confidential Attachment B, "Feeder Energy Storage Site Selection," for the detailed site review matrix for the feeder site selection process described in this section.

1. **Highest value:** The first screening mechanism considered the availability of locational value as calculated in the IPT:

   The IPT results were sorted based on largest to smallest on the dollar per kilowatt hour ("kWh") benefit for a two-hour energy storage system.[3] This can be seen in column H of the site selection

[1] While this is generally true of loads with a lagging power factor, the inverse can be true for a load with a leading power factor.

[2] The details of the IPT modeling and analysis are covered in OPUC Docket No. UM 1856 PGE Exhibit 101, Section 2.2(a) and Appendix 2 and PGE Exhibit 200, page 18.

[3] The highest site-specific benefits were seen with a two-hour system, but the overall benefits were maximized with a four-hour system due to the stacked benefits available from the Bulk Energy & Ancillary Services value streams.

spreadsheet. Further review of potential sites was prioritized starting at the top of this list with the locations demonstrating the highest potential value as indicated by the IPT model.

2. **Feeder Configuration** was then considered, and feeders demonstrating adequate connectivity to adjacent feeders were removed from consideration due to their suitability for the implementation of lower cost options for outage mitigation. Most feeders on PGE's system are designed in a manner where load can be transferred from one feeder to another, especially in response to an outage. In some instances, it is not practicable to construct adequate feeder ties especially in more rural locations. Feeders without adequate ties to adjacent feeders are considered better candidates for alternative outage mitigation measures, such as implementation of energy storage to support outage mitigation.
3. **High Solar Penetration** was then considered, and feeders were reviewed with respect to the level of distributed solar penetration as a percentage of peak load. PGE reviewed a study, compiled by the National Renewable Energy Laboratory ("NREL")[4], in which research showed that the maximum Photovoltaic penetration allowable on an average feeder without negatively impacting voltages or overcurrent protection devices was typically at least 30% of the peak load. PGE ranked its 589 distribution feeders using the Active Generator List[5] to determine which feeders had the greatest penetration of solar resources.

The following steps were taken to filter the results of the Active Generator List and identify the short list of potential sites. Attachment A "Active Generators for Energy Storage" provides the detailed site review matrix for the mid-feeder site selection process described in this section.

The first screening mechanism considered the penetration level of distributed solar as a percentage of feeder peak load.

1. All distributed solar installations in PGE's service territory were grouped by feeder to sum the total nameplate capacity (kW) of connected solar on each distribution feeder.
2. PGE then identified the hourly-averaged peak load (kW) recorded for each feeder as of the Summer 2017 operating season.
3. The total nameplate capacity of connected solar was divided by the hourly-average peak load, by feeder, to identify the percent penetration of solar by feeder. The feeders were ranked from highest penetration of solar to lowest penetration of solar.
4. Feeders which reported solar penetration less than 30% were omitted from further analysis since the NREL analysis indicated that these low-penetration feeders are less likely to experience reliability and power quality constraints resulting from connected solar installations.
5. The remaining high-penetration feeders provide PGE with a selection of feeders from which PGE can collect and evaluate unique benefits in optimizing and integrating energy storage coupled with renewable generation for solar firming, feeder reliability, and power quality management given a high penetration of solar resources.

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[4] Hoke, Anderson, et al. "Maximum Photovoltaic Penetration Levels on Typical Distribution Feeders." *IEEE Transactions on Sustainable Energy*, July 2012, www.nrel.gov/docs/fy12osti/55094.pdf.

[5] The Active Generator List is a compilation of all known distribution-connected, customer-owned generation resources existing within PGE's service territory.

After applying the filters listed above for feeders with high (>30%) penetration of distributed solar, the universe of available feeders on PGE's system was winnowed to three remaining candidate feeders for the short-list evaluation:

- Canby-Butteville feeder
- Amity-13 feeder
- Amity-Bellevue feeder

Implementation risks were then considered, and sites were removed based on the following implementation risks:

1. **Readiness of Communications Infrastructure.** Each of the remaining high-penetration feeders were evaluated for their access to existing telecommunications infrastructure, such as fiber available on the feeder and in proximity to the proposed mid-feeder project site. PGE estimates the unloaded cost to install fiber on an existing distribution feeder to be approximately $50,000 per mile.

2. **Other Considerations:** The more proximate a major source of distributed solar is to the mid-feeder project, the greater is the potential to access specific learnings around feeder reliability and power quality as affected by high penetrations of distributed solar. The Baldock solar facility is the largest distributed solar resource on the Canby-Butteville feeder, and the site was reviewed to determine its suitability to incorporate an energy storage system.
   - Environmental Review – An internal review of the environmental considerations indicated there are no major concerns with a proposed energy storage project at the Baldock site.
   - Permitting/Land Use Review – An internal review of the permitting and land use indicated there are no major concerns regarding permitting requirements and timeframes as well as zoning changes due to the proposed use for an energy storage project at the Baldock site.
   - Available space – Available space on the existing PGE parcel for the Baldock site was reviewed to determine if there was enough physical space to locate the proposed energy storage system. Additional costs for land preparation or additional land purchase or leases would have a negative impact on the project economics.

Final Feeder Selection

The short-list evaluation resulted with the selection of the Baldock site on the Canby-Butteville as the optimal site for the mid-feeder project. The specific benefits that led to the selection of Baldock includes the high penetration of distributed solar allowing the testing and direct integration of solar and energy storage at the site, the presence of existing telecommunications infrastructure available to support the project, and existing space at the facility to readily integrate an energy storage system, which facilitates an accelerated deployment on the timeline necessary to fulfill the requirements of HB 2193.

Detailed Site Review Matrix

Confidential Attachment B provides a detailed review matrix for the feeder site selection process.

Appendix D

PGE's Coffee Creek Site Analysis and Utility Ownership Justification

Portland General Electric
121 SW Salmon Street • Portland, Ore. 97204
PortlandGeneral.com

January 4, 2019

Public Utility Commission of Oregon
Attn: Filing Center
201 High Street, S.E.
P.O. Box 1088
Salem, OR 97308-1088

RE: **UM 1856 – PGE's Coffee Creek Substation Site Analysis and Feasibility of Third-Party Operation and Ownership**

Pursuant to Oregon Public Utility Commission (OPUC or Commission) Order No. 18-290, enclosed is Portland General Electric Company's (PGE's) site analysis and feasibility of third-party operation and ownership for its Coffee Creek Substation proposal. Per the Stipulation, paragraph 24, PGE requests that OPUC Staff express its agreement that PGE presented adequate evidence that Coffee Creek is the best site for the energy storage system based on the universe of available substation sites within PGE's system.

The Commission opened Docket No. UM 1751, in September 2015, to implement House Bill 2193. This House Bill requires large Oregon electric companies (i.e. Pacific Power or PAC, and PGE) to submit proposals by January 1, 2018, to develop qualifying energy storage systems with the capacity to store at least five megawatt hours. In UM 1751, the Commission adopted specific guidelines and requirements for energy storage project proposals, in late 2016, and a framework for PAC's and PGE's Energy Storage Potential Evaluations (Potential Evaluations) in March 2017.

PGE filed its Energy Storage Proposal and Final Potential Evaluation on November 1, 2017, which were investigated in the subsequently opened Docket No. UM 1856. Following multiple rounds of testimony and numerous data requests, workshops and a settlement conference, stakeholders and PGE reached a Partial Stipulation and submitted Joint Testimony in support of the Stipulation. The stipulation resolved nearly all the issues in the proceeding.

Attachment A provides the site analysis and feasibility of third-party operation and ownership for PGE's Coffee Creek Substation proposal to comply with Item No. 02 of Order No. 18-290. Attachment B provides a list of all PGE substations and the site selection for the energy storage system. Attachment C provides a short-listed substation site evaluation matrix. Attachment B and C are confidential and subject to Protective Order No. 17-441.

PGE looks forward to working with OPUC Staff in determining the adequacy of evidence in the site analysis. Should you have any questions or comments regarding this filing, please contact Kalia Savage at (503) 464-7432.

Please direct all formal correspondence and requests to the following email address pge.opuc.filings@pgn.com

Sincerely,

Karla Wenzel
Manager, Pricing & Tariffs

Enclosures
Cc: UM 1856 Service List

Attachment A

Provided in Electronic Format only

Coffee Creek Substation Site Analysis and Feasibility of Third-Party Operation and Ownership

Attachment A - PGE's Coffee Creek Energy Storage Site Analysis

Introduction

Portland General Electric Company ("PGE") files this document to comply with Public Utility Commission of Oregon ("OPUC" or "Commission") Order No. 18-290 which states "consistent with the stipulation, [PGE] will develop analysis justifying the Coffee Creek site selection. As part of that analysis and in the review of other potential locations, [PGE] must consider the feasibility of third-party ownership and operation." This document provides procedural background, the site selection process for the Coffee Creek energy storage system, a detailed review matrix regarding the site selection, the intended project use cases, operation, and applicable learnings. In addition, the document describes why third-party ownership and operation of an energy storage device which is integrated as part of a substation network as proposed at Coffee Creek would not be feasible, and is distinguished from energy devices interconnected, but not integrated, into substations or other points on the transmission and distribution system.

Background: Storage Law, PGE's Proposal, and Partial Stipulation

The Commission opened Docket No. UM 1751 in September 2015 to implement House Bill ("HB") 2193 (2015 Regular Legislative Session), which requires large Oregon electric companies to submit proposals to develop qualifying energy storage systems with the capacity to store at least five megawatt hours ("MWh") the Commission by January 1, 2018. On December 28, 2016, the Commission adopted specific guidelines and requirements, in Order No. 16-504, that encourage Pacific Power's ("PAC") and PGE's energy storage project proposals. On March 21, 2017, in Order No. 17-118, the Commission adopted a framework for PAC's and PGE's Energy Storage Potential Evaluations ("Potential Evaluations") that includes seven elements. On July 14, 2017, PGE filed its Draft Potential Evaluation. Staff and stakeholders reviewed this draft and made recommendations to the Commission through a Staff Report. In Order No. 17-375, the Commission adopted the following schedule: (1) by January 1, 2018, PGE and PAC were to file draft project proposals and updated draft potential evaluations that incorporated the improvements outlined by Staff in its Report; (2) by April 2, 2018, the utilities were to file final project proposals and final potential evaluations; and (3) no later than April 2, 2018, the Commission would begin review of the final filings. PGE's submitted Proposal and Potential Evaluation resulted in a partial stipulation among most of the parties (i.e. PGE, OPUC Staff, CUB, AWEC, NIPPC and RNW), with no party objecting to the stipulation.

As part of the stipulation, Parties agreed that PGE would present its analysis to Staff that the Coffee Creek Substation is the best site for the substation energy storage system based on the options of available substations sites in PGE's system. The stipulation further provided that if Staff did not agree, the Commission would determine whether PGE could move forward with the project. Additionally, the stipulation carved out the issue of third-party ownership as the remaining issue to be litigated. In adopting the stipulation, the Commission declined to direct PGE to expand its request for proposals to third-party owned and operated projects. Instead, the Commission directed PGE to address the feasibility of third-party ownership and operation at the possible alternative locations. The Commission noted that it would closely examine any ownership limitations in future ratemaking proceedings.

Substation Site Selection Analysis

A substation sited energy storage system is important because of the variety of learnings produced. The available learnings are unique to a substation-sited energy storage project as opposed to residential, commercial, mid-feeder, and generation sites. These learnings include the ability to provide Transmission and Distribution ("T&D") integrated locational value through outage mitigation and deferred distribution investment. Thus, PGE sought to identify a location where high potential of T&D locational value was present and there were minimal implementation risks for that location.

The determination that the Coffee Creek Substation was the best among substations for energy storage started with the ranking of substation sites based on the desired site-specific outage mitigation benefits that the sites offered. PGE ranked the list, filtering it using both quantitative[1] and qualitative[2] metrics to establish a shortlist of ideal locations for substation-sited storage on PGE's system. Finally, this shortlist was evaluated on additional physical and operational criteria that resulted in Coffee Creek as the preferred site.

PGE evaluated all 140 PGE-owned distribution substations using the Integrated Planning Tool ("IPT")[3] to determine the site-specific outage mitigation benefits (also known as the locational value) available due to the reduction of system risks from a two-hour, four-hour, and infinite duration energy storage system. The IPT considers the reliability and economic life of T&D assets at PGE substations and calculates a likelihood of component failure which could result in customer outages. A consequence of failure is then calculated, which considers how widespread the resulting outage could be and what customers would be impacted. A total risk value is monetized, which is aggregated from the asset likelihood of failure multiplied by the consequence of failure. PGE uses the IPT to identify where best to make system investments to address system risk in areas of the system which demonstrate the highest risk per the calculation. These IPT results are the input to the site selection process described in this document. For the IPT modeling and analysis details, please see PGE's Proposal.

The following steps were taken to filter the IPT results and identify the short list of potential sites, with consideration for high T&D value per the IPT and minimal barriers to project implementation. Please see Confidential Attachment B "Substation Energy Storage Site Selection" for the detailed site review matrix for the substation site selection process described in this section.

Highest value: The first screening mechanisms considered the availability of locational value as calculated in the IPT:

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[1] Quantitative metrics include the IPT analysis, SCADA availability, existing near-term planned substation projects, and existing substation reverse power flow protection.
[2] Qualitative metrics include property availability and environmental considerations.
[3] The details of the IPT modeling and analysis are covered in OPUC Docket No. UM 1856 PGE Exhibit 101, Section 2.2(a) and Appendix 2 and PGE Exhibit 200, page 18.

- The IPT results were sorted based on largest to smallest on the dollar per kilowatt hour ("kWh") benefit for a two-hour energy storage system.[4] This can be seen in column D of the site selection spreadsheet. Further review of potential sites was prioritized starting at the top of this list with the locations demonstrating the highest potential value as indicated by the IPT model.
- PGE eliminated sites with ongoing near-term upgrade projects (i.e. substation sites with transmission and distribution upgrades not modeled in the IPT). This can be seen in column K of the site selection spreadsheet. Once the upgrades are completed, the site-specific benefits for these sites will be greatly reduced, thereby minimizing the potential IPT value that an energy storage system could otherwise provide. When considering the pending construction projects identified at these substations, the resulting impact to the system risk profile for each substation is reduced to sufficiently drop them out of the top quartile of high-risk substations identified in the IPT.

Implementation risks were then considered, and sites were removed based on the following implementation risks:

1. **SCADA.** The list was culled to eliminate sites that did not have existing Supervisory Control and Data Acquisition ("SCADA") systems. This can be seen in column J of the site selection spreadsheet. Substation sites with a SCADA system communicate with PGE's System Control Center in real time. This means that there is existing telecommunication infrastructure in place to support the real time control of an energy storage system without the need for additional upgrades and additional project costs. The decision to eliminate substations without SCADA was based on financial and timeline considerations. PGE estimates the unloaded cost of a substation SCADA upgrade to range from $500,000 to $1.5 million. Furthermore, the resulting substation upgrades associated with introducing SCADA to an older substation could take two years to plan and execute, representing a risk to the energy storage project schedule. The locational value that an energy storage system could provide at non-SCADA sites evaluated in the IPT is calculated to be less than $500,000 for each site. Since the cost to include SCADA at these sites exceeds the locational value that an energy storage system can contribute, in addition to the associated timeline which is needed to support a project at non-SCADA sites, PGE removed non-SCADA sites from consideration.
2. **Transformer Protection.** The list was limited to sites that had existing transformer protection equipment that met PGE's standards to allow for reverse power flow from the distribution system to the transmission system. This can be seen in column L of the site selection spreadsheet. This decision was also based on financial and timeline considerations. Substation sites with fuse protection on the high side of the transformer would require the addition of high-side circuit switchers and an upgraded transformer protection scheme to properly protect the grid if an energy storage system was located at that site. As designed,

[4] The highest site-specific benefits were seen with a two-hour system, but the overall benefits were maximized with a four-hour system due to the stacked benefits available from the Bulk Energy & Ancillary Services value streams.

sites with high-side fuses properly protect the grid in the typical situation where power is flowing in one direction from the transmission system to the distribution system but result in coordination issues for the reverse power flow from an energy storage system. PGE estimates the unloaded cost of a substation transformer protection upgrade to range from $200,000 to $500,000. Furthermore, the resulting substation upgrades associated with introducing protection upgrades to an older substation could take two years to plan and execute, representing a risk to the energy storage project schedule. Given the small contribution of site-specific benefits to the overall benefits of a substation-sited storage (as identified in the Potential Evaluation) and the additional costs and timeline needed to support a project at these sites, these sites were removed from consideration.

3. **Other Considerations.** Three sites were removed from consideration for other reasons, as shown in column M of the site selection spreadsheet.
    a. Durham – Physical space constraints at this site were identified in the initial evaluation phase and it was determined that there was no room for an energy storage system; and
    b. Grand Ronde and Kelly Point – Both of these sites have existing customer Dispatchable Standby Generation which is not modeled in the IPT and results in a reduced risk profile for these substations. When considering the availability of customer on-site backup generation for major customers served by these substations, the resulting risk profile for these substations per the IPT analysis places them outside of the top quartile ranking of high risk substations.

After applying the filters listed above, there were six sites remaining for the additional short list evaluation which are provided in Confidential Attachment C.

Short List Evaluation and Final Site Selection

The final short list evaluation consisted of a detailed site review of the following elements:

- Substation transformer loadings – The transformer loading data was reviewed as an initial indicator of the potential energy storage system size. Some substations serve load from multiple transformers which would impact the energy storage system design criteria in that PGE would need to consider if the energy storage system should be large enough to provide backup service to feeders from a single transformer, or if multiple energy storage systems should be deployed to provide backup capabilities for multiple substation transformers.
- Environmental Review – An internal review of the environmental considerations was conducted for each of the short-listed sites to identify potential environmental concerns.
- Permitting/Land Use Review – An internal review of the permitting and land use was conducted for each of the short-listed sites to identify permitting requirements and timeframes as well as zoning changes due to the proposed use.
- Substation Operations considerations – An internal review was conducted for each of the short-listed sites by PGE Substation Operations to identify any site-specific concerns from an engineering and operations standpoint.
- Available space on Existing PGE Parcel – Available space on the existing PGE parcel for each site was reviewed to determine if there was enough physical space to locate the proposed energy

storage system. Additional costs for land preparation or additional land purchase or leases would have a negative impact on the project economics.

The short list evaluation resulted with the selection of Coffee Creek Substation as the final site. The specific benefits that led to the selection of Coffee Creek are the large amount of space available outside of the identified wetland area on the property, the standard permitting process required by Washington County, and no identified operational concerns at that location.

Table 1 includes the results of this final short list evaluation. After taking into consideration all the different risks for each potential project site, Coffee Creek emerged as the best location for a substation sited project.

Feasibility of Third-Party Ownership and Operation

An energy storage resource intending to directly operate and control utility infrastructure in a substation microgrid, thereby providing direct distribution services and power quality management to all utility customers residing within the substation service area, must remain under the direct operational control of the utility. Third-party ownership of the facility may be feasible, but only to the degree that the utility retains exclusive operational control and dispatch of the energy storage resource and its distribution control functions. The contractual arrangements necessary to award the utility exclusive operational control and dispatch of the resource, as well as all maintenance decisions and design upgrades or modifications to the facility and its controls, and coordination with system protection schemes, would be overly burdensome, time consuming, and are not appropriate for consideration under the HB 2193 timeline[5].

A core mission of the public utility is to provide non-discriminatory access for all customers within its defined service territory. In carrying out this mission, the utility strives to provide standardization in the application of safety, reliability, security, and power quality measures governing distribution service, inclusive of service to both customer loads and interconnected resources. A utility has the obligation to consistently uphold T&D quality of service standards to all customers in its service territory, irrespective of the energy provider(s). The function of providing these distribution services in a fair and transparent manner is characteristically performed by the local area grid operator, a role which is best serviced by a single entity for any given area under the regulation of the Commission.

The role of a substation within the T&D system is to provide a reliable connection to the transmission network, to step down voltages from the transmission level to a safe distribution level, and to provide distribution services such as voltage management and power factor management for distribution feeders as connected customer loads change throughout the day.

[5] HB 2193 requires a minimum of 5 MWh of energy storage to be in procurement by January 1, 2020. The process to develop and issue an RFP, and to award a bid for a substation-sited energy storage system could take 9-12 months. Work on development of an RFP will not commence until a substation site is agreed upon between OPUC Staff and PGE.

In Order No. 17-375, the Commission directed electric companies to "analyze each use case listed in Appendix A for each evaluated storage site and that each use case should be considered at each site with a brief justification provided when not evaluated." Two of the energy storage use cases identified by Staff include "Distribution Upgrade Deferral" and "Outage Mitigation." In the context of the substation-sited energy storage system, Distribution Upgrade Deferral relates to the energy storage system's ability to regulate system voltages as an integrated part of the substation control package. The Outage Mitigation use case is recognized when the energy storage system can operate as a microgrid, thereby operating utility grid infrastructure and providing power and grid services to all customers served by the selected substation during times when service from the substation is unavailable because of transmission system outages or substation component failure. The locational value for Outage Mitigation is calculated per the IPT, and this value is available only if the energy storage system is designed to operate as an integral part of the substation and distribution grid. Other potential sites such as commercial or industrial properties interconnecting with the grid act much more a standalone device and are not integral parts of a complex substation system and can avail themselves to third party ownership.

Interconnected versus Integrated and Grid-following versus Grid-forming

There is a difference between a third-party owning and operating a substation-integrated storage system, versus when a third party is interconnecting a resource to the grid.

PGE has mechanisms in place to maintain the safety and reliability of the T&D system when interconnecting third-party owned resources. PGE considers these interconnected resources as grid-following. This means that they require the grid operator (i.e. PGE) to retain control and management of the grid reliability and power quality functions (e.g. frequency control, voltage control, grid protection systems). To protect PGE's customers from inadvertent operation of the distribution plant from a non-utility provider, PGE regularly installs protection systems complete with high-speed communications to automatically disconnect third-party power resources from the grid when microgrid conditions or equipment failure may occur.

Conversely, a utility-owned grid-forming resource can mitigate outages by independently establishing the utility control functions necessary for reliable operation of the distribution system without any connection back to the main grid. To ensure PGE's customers are provided with a consistent quality of electric service when served by the substation microgrid, PGE's distribution plant residing within the microgrid will remain compliant with the Commission service standards governing Quality of Electric Service and subject to applicable regulatory authority of the Commission (Chapter 860 Division 23). Utility grid control functions, such as system protection, feeder voltage profile management, and power quality management, affect service quality to all distribution customers directly served by the grid-forming resource, the management of which is the sole responsibility of the utility provider. These necessary control functions are incremental to the energy services which can otherwise be provided by an interconnected (grid-following) resource.

As an example, an energy storage system which independently serves all substation customers, such as a microgrid, would have the direct impact of controlling system voltages and system frequency delivered to all customers residing within the microgrid. The energy storage system will also have the direct impact of altering the response of all downstream utility protective devices and will be responsible for coordinating with the downstream protective devices to ensure proper protection with respect to safety, equipment damage, and system reliability (e.g. SAIDI and SAIFI), along with public and worker safety. Allowing a third-party owner or operator of a substation storage system as a grid-forming resource could have that owner/operator either intentionally or unintentionally affect safety and service quality to distribution customers.

As a grid-forming resource, any liability resulting from off-nominal voltage or frequency deviations will appropriately be borne by the owner and operator of the energy storage system and connected substation microgrid facilities. This includes safe and reliable operation of the substation microgrid, as well as the safe and reliable return to normal by synchronizing back to the main grid upon restoration of the transmission source without exposing customers to the risk of equipment damage or unnecessary outages.

In addition to the energy storage project serving as a grid-forming resource, PGE has identified potential additional legal impediments regarding third-party ownership of this project that warrant consideration by Staff. The integrated operation of the energy storage system as a grid-forming resource for substation outage mitigation would place the energy storage system in the position to control, operate, and manage energy deliveries across the electrical infrastructure serving all customers residing within the substation microgrid. This includes the independent control and operation of PGE distribution facilities serving over 480 PGE customers connected to the two distribution feeders sourced by Coffee Creek substation. In the event of a complete outage to the Coffee Creek substation, the owner/operator of the substation microgrid will also need sufficient visibility into the distribution system to coordinate implementation of a black start procedure which isolates and systematically brings sections of the distribution feeders into the microgrid as system conditions allow. Thus, PGE raises the question as to whether the owner of the energy storage system would become a public utility during microgrid operation as defined by statute.[6] Such question presents a potential barrier to third-party ownership/operation of the substation-sited energy storage system and introduces complexities in contracting that likely delays execution and may impede PGE’s meeting the UM 1856 implementation timeline as directed in Order 18-290.

Alternatively, if third-party ownership or operation were a requirement for this energy storage system, PGE would treat it as a customer interconnection which provides energy services as a grid-following resource; therefore, not allowing the resource to establish a utility microgrid for outage mitigation. As a third-party owned and operated resource, the energy storage system would not be permitted to operate in a manner which establishes the primary utility grid control functions comprising system protection and power quality management across the utility microgrid. Rather, the functions of a third-party owned and operated resource would be limited during microgrid operations to only supplementing the utility microgrid by contributing energy deliveries and responding within set parameters to grid voltage

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[6] ORS 757.005(1)(A) defines a public utility as “any corporation, company, individual, association of individuals, or its lessees, trustees or receivers, that owns, operates, manages or controls all or a part of any plant or equipment in this state for the production, transmission, delivery or furnishing of heat, light, water or power, directly or indirectly to or for the public, whether or not such plant or equipment or part thereof is wholly within any town or city.” Exceptions to this definition exist for qualifying facilities under ORS 758.505 and for electricity service suppliers under ORS 757.600; however, these entities only deliver energy as grid-following resources and do not control, operate, or manage the delivery of these resources across the utility electrical infrastructure to its end-use customers.

measurements. This would remain the case regardless of whether the third-party owned energy storage system was located at a utility substation or elsewhere within PGE's distribution system. PGE would need to incur additional investment to implement standalone utility-owned devices and control functions necessary to establish a utility microgrid for PGE to allow a third-party resource to feed power back onto the utility microgrid while disconnected from the main grid. This additional investment would most likely need to be in the form of a utility-owned energy resource to exercise the primary control of the utility microgrid. The utility grid-forming resource likely needs to be larger than any singular grid-following resource for the utility grid-forming resource to can exercise primary control over the utility microgrid, a responsibility belonging exclusively to the public utility.

Per the IPT analysis, PGE identifies value in establishing microgrid functionality for the proposed energy storage system at the Coffee Creek substation in its ability to reduce outage risks affecting the Coffee Creek substation asset by enhancing reliability to the local distribution system. This pilot project affords PGE the opportunity to test the microgrid use case and validate assumptions made in the IPT analysis and affords PGE the opportunity to gain learnings which may be applied to future microgrids on the distribution system.

Embedded substation controls and operation

The value of a substation-sited energy storage system is that it enables PGE to evaluate the operational benefits of integrating energy storage into the substation design, control, and protection schemes as a T&D asset supporting distribution reliability and power quality. As a distribution reliability resource, the energy storage system will be integrated into the distribution substation equipment complete with the appropriate and automatic modification to substation control settings necessary to ensure the safety, reliability, and power quality of service to the downstream distribution feeders are maintained. This design, which automatically modifies PGE substation protection and control settings, establishes the energy storage resource as an embedded distribution system asset in a comparable fashion to other, more traditional T&D infrastructure assets (e.g. transformers, regulators) which are owned and operated only by the utility provider.

By properly integrating the storage system into the utility-owned voltage control devices, there will create a linkage from the energy storage system to the inner operations of the distribution substation. These substations represent the backbone of the retail service system. An energy storage resource which is integrated into the backbone of the utility retail system is a sensitive proposition, but a highly valuable learning opportunity which can provide guidance standards for anticipated future interconnections.

Third-party ownership of an energy storage system which is directly integrated into the inner operations of the distribution substation presents a potential risk to customers in that the integrated programming and control protocols could affect substation operations, particularly around voltage control and power quality. Voltage control and power quality are important to many industrial and commercial customers, some of which take service from Coffee Creek substation.[7] PGE would need latitude to respond quickly when changes to the programming and controls are necessary to mitigate/address identified voltage control and power quality issues. If owned by a third party, any modifications to the programming and control protocols would require additional paid assistance, permission, work, and coordination with the third-party owner. The ability to modify the energy storage system operations in real-time may be

[7] Commercial and industrial customers served by Coffee Creek substation include: Mentor Graphics Corp, Optimim LLC, Tyco Electronics, Hartung Glass, Fujimi Corporation, and Pacific Foods.

something to consider in a contract, but PGE fears the practical outcome could cause unintended consequences particularly around access to not only the physical energy storage plant and its interconnection, but also to its management systems. More appropriately, any arrangement for a third-party owned resource would cause PGE to take a much more conservative approach to this pilot project to assure the distribution system and our customers are appropriately protected from unknown or unanticipated contingencies.

Through utility ownership and control; however, PGE can conduct various activities and system modifications in an unfettered manner to best understand how to effectively integrate and manage energy storage systems into the inner operations of the distribution substation. Regular modifications to the energy storage system programming and control protocols will allow PGE to understand how best to optimize the operation of utility voltage control devices including: substation distribution capacitor banks, transformer load-tap changers (LTC), and other voltage regulating equipment. PGE would need latitude to try various programming and control protocols to maximize learnings and best understand how to proceed with future integration of new energy storage systems. The learnings we will obtain from utility ownership of an energy storage system integrated into the distribution substation controls will be used to inform the development of interconnection standards to reliably address any currently unknown issues for this mode of operation and may also influence future substation design and operating practices.

Conclusion

The Coffee Creek substation is the best location to pilot a substation-sited energy storage system based on the high locational value available at this site for outage mitigation (as calculated by the IPT), and the reduced risks identified for project implementation.

For this pilot, the substation-sited energy storage project should be operated by PGE for the following reasons:

1. Locational value for outage mitigation is only available in the presence of a grid-forming resource, which delivers utility grid services and power quality control affecting all customers residing within the microgrid.
2. Managing and controlling all or a part of a utility microgrid (substation and connecting feeders) introduces potential legal impediments to third-party ownership and operation.
3. The incremental learnings for full substation integration, including feedback controls to utility substation devices, are only achieved reliably, safely, and timely under HB 2193 through full utility operational control.

Attachment B

Provided in Electronic Format Only

Protected Information Subject to Protective Order 17-441

Substation Energy Storage Site Selection

Attachment C

Provided in Electronic Format only

Protected Information Subject to Protective Order 17-441

Substation Site Evaluation Matrix

Appendix E

PGE's Energy Storage RFP Draft for the Coffee Creek Substation and PW2 Energy Storage Systems

Portland General Electric
121 SW Salmon Street • Portland, Ore. 97204
PortlandGeneral.com

May 01, 2019

Public Utility Commission of Oregon
Attn: Filing Center
201 High Street, S.E.
P.O. Box 1088
Salem, OR 97308-1088

RE: UM 1856 PGE's Energy Storage Request for Proposal Drafts for the Coffee Creek Substation and Port Westward 2 Energy Storage Systems – Inviting Stakeholder and Commission Review

Pursuant to Oregon Public Utility Commission (OPUC or Commission) Order Nos. 16-504 and 18-290, enclosed is Portland General Electric Company's (PGE's) request for proposal (RFP) drafts for the Coffee Creek energy storage system project and the Generation Kickstart energy storage system project located at PGE's Port Westward 2 (PW2) generation plant. By copy of this to the OPUC Docket No. UM 1856 service list, we invite stakeholders to review and offer comments to the RFP designs by May 31, 2019.

History of Energy Storage Docket
The Commission opened Docket No. UM 1751, in September 2015, to implement recently passed legislation, House Bill 2193. House Bill 2193 requires PGE and PacifiCorp to submit proposals by January 1, 2018, for qualifying energy storage systems with capacity to store at least five megawatt hours. In Commission Order 16-504, the Commission adopted guidelines and requirements for energy storage project proposals, in late 2016, and a framework for PAC's and PGE's Energy Storage Potential Evaluations.

PGE filed its Energy Storage Proposal and Final Potential Evaluation on November 1, 2017, which were investigated in UM 1856. Pursuant to Commission Order No. 18-290, filed in UM 1856 on October 25, 2018, PGE filed its plan to advance its energy storage modeling cability. On April 9, 2019, Staff approved this filing via electronic mail, enabling the PW2 project to move forward. In addition, on April 29, Staff found that PGE had provided adequate evidence in its site analysis for the Coffee Creek project; thus PGE is also filing the draft RFP for stakeholder review.

PGE now seeks stakeholder input to the RFP designs for the energy storage systems located at PGE's Coffee Creek Substation and PW2. The Commission's competitive bidding requirements for House Bill 2193 projects are as follows:

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' RFP design and offer nonbinding input* (emphasis added).
   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.

Attachment A provides the draft RFP for the energy storage system that will be located at PGE's Coffee Creek Substation.

Attachment B provides the draft RFP for the energy storage system that will be located at PGE's PW2.

PGE is seeking stakeholder feedback within the next 30 days. Feedback should be directed to: puc.filingcenter@state.or.us

Should you have any questions or comments regarding this filing, please contact Kalia Savage at (503) 464-7432.

Please direct all formal correspondence and requests to the following email address pge.opuc.filings@pgn.com

Sincerely,

Karla Wenzel
Manager, Pricing and Tariffs

Enclosures

Attachment A

Draft Request for Proposal for the Coffee Creek Substation Energy Storage System

May 1, 2019

PORTLAND GENERAL ELECTRIC COMPANY

Coffee Creek Energy Storage System Project

DRAFT Energy Storage System Project Technical Specification

TABLE OF CONTENTS

Acronyms and Abbreviations

AC	Alternating Current
ACI	American Concrete Institute
AHJ	Authority Having Jurisdiction
ANSI	American National Standards Institute
ASME	American Society of Mechanical Engineers
ASTM	American Society for Testing and Materials
°C	degrees Celsius
CAD	Computer-aided design
CT	Current Transformer
DART	Days away, restricted or transferred
DC	Direct Current
EMI	Electromagnetic Interference
EMR	Experience Modification Rate
E-Stop	Emergency Stop
ESIC	Energy Storage Integration Council
FAT	Factory Acceptance Testing
HMI	Human Machine Interface
HV	High Voltage
HVAC	Heating, Ventilation, and Air Conditioning
IEEE	Institute of Electrical and Electronic Engineers
IFC	Issued for Construction
LV	Low Voltage
MV	Medium Voltage
NEC	National Electrical Code
NEMA	National Electrical Manufacturers Association
NETA	InterNational Electrical Testing Association
NFPA	National Fire Protection Association
OSHA	Occupational Safety and Health Administration
PCS	Power Conversion System
PDF	Portable Document Format
PF	Power Factor
psi	pounds per square inch
PT	Potential Transformer
QA/QC	Quality Assurance/Quality Control
QC	Quality Control
RTU	Remote Terminal Unit
SAT	Site Acceptance Test
SCADA	Supervisory Control and Data Acquisition
SEC	Site Energy Controller
SOC	State of Charge or Energy: Nominal Energy Remaining / Nominal Full Pack Energy Available
Specification	Project Technical Specification
TRIR	Total Recordable Incident Rate
UL	Underwriters Laboratories
UPS	Uninterruptible Power Supply
VPN	Virtual Private Network

Scope

This Project Technical Specification (Specification), including Appendices, comprise or constitute requirements to design, fabricate, ship, assemble, test, startup, commission, warrant and make ready for service a fully functional energy storage system complete with accessories as required by the Agreement. This Specification defines specific engineering, operating and performance requirements for the Project that is intended for installation on the Owner's electric system. The Project is to be designed to be in a restricted access setting and configured to meet applicable standards required of other Owner equipment with respect to safety, operations, maintenance and environmental impact.

1.0 CONFORMANCE TO SPECIFICATION

1.1 Applicable Documents

Except as modified herein, the Project, including the energy storage technology, power conversion system (PCS), and site energy controller (SEC) shall be designed, manufactured, and tested in compliance with the latest versions (including any issued revisions) of the applicable standards of American National Standards Institute (ANSI), Institute of Electrical and Electronic Engineers (IEEE), National Electrical Code (NEC), National Electrical Manufacturers Association (NEMA), Occupational Safety and Health Administration (OSHA), American Society for Testing and Materials (ASTM), American Society of Mechanical Engineers (ASME), National Fire Protection Association (NFPA), and Owner safety practices. See Appendix A for applicable standards and codes.

1.2 Safety

- The Project must be compliant with all applicable provisions of IEEE 1547, Underwriters Laboratories (UL) 1642, UL 1741 Supplement A, UL 1973, and NFPA Codes. The Project must be able to protect itself from internal failures and utility grid disturbances. As such, the Project must be self-protecting for alternating current (AC) or direct current (DC) component system failures. In addition, the Project must be able to protect itself from various types of external faults and other abnormal operating conditions on the grid.
- The Project must be designed in compliance with applicable federal, state, and local safety standards and regulations regarding construction and potential exposure to chemicals and regarding container or enclosure resistance to hazards such as ruptures and exposure to fire.
- All Project systems and equipment must be grounded in accordance with the NEC and adhere to the guidelines in IEEE 80 and IEEE 142.
- For all Project equipment, Contractor shall provide information on all known or reasonably foreseeable safety issues related to the equipment, including appropriate responses on how to handle the Project in case of an emergency, such as fires or module ruptures.
- The Project must be designed such as to minimize risk of injury to the workforce and public during installation, maintenance, and operation.
- Visual and audible fire alarms should be included as necessary per all applicable fire and safety codes.

- A physical Emergency Stop (E-Stop) button is required to be installed at all entrances and exits of the buildings or containers. The E-Stop button shall have the ability to open contactors/breakers to the inverter and batteries isolating the DC and AC potential.
- Contractor to submit a copy of Corporate Safety Plans and a comprehensive site-specific safety plan (at least 30 days prior to the start of the Work) that the Contractor and all Subcontractors will understand and follow during execution of the Work. The site-specific safety plan shall incorporate, at a minimum, plans and policies that are at least as stringent as federal, state, and Owner safety regulations and policies. (i.e. include reference to Contractor Safety Program and all Owner Safety Plans/Policies).
- Designated safety personnel during construction of the Project shall have a minimum of five years of safety experience or an equivalent level of skill through a training certification or professional degree.
- Contractor and all Subcontractors must submit historical safety data for review prior to start of the Work: previous three years of safety stats: Total Recordable Incident Rate (TRIR); Days Away, Restricted or Transferred (DART); Experience Modification Rate (EMR) on official letterhead; and OSHA inspection history and any OSHA citation history. Contractor shall use the following benchmarks for TRIR (less than or equal to 2.0, DART less than or equal to 1.0, EMR less than 1.0) and membership with ISN. Inspections and citations should be evaluated on case-by-case basis. If TRIR, DART, EMR are outside of recommended benchmarks, a risk mitigation plan is required.
- At minimum, Contractor's Site-Specific Safety Plan shall include provisions with respect to:
  - Daily job planning
  - Activity Hazards Analysis
  - Analysis of Utility locations (proper mark-out for underground facilities)
  - Incident reporting procedures
  - Project safety statistics tracking and reporting
  - Personal Protective Equipment
  - Emergency Plans to include evacuations and inclement weather
  - Fire Management (i.e. Fire Safety)
  - Excavation plans
  - Sanitation (hand wash/temporary toilets)
  - Demolition activities (if applicable)
  - Procedures for a Regulatory Visit (should one occur)
  - Deficient Project Safety Performance (recovery plan)
  - Site Safety Orientation requirements
  - Security of work zones, material yards, etc.
  - Behavioral Based Safety Plan
  - HAZCOMM

- OSHA

1.3 Environmental Requirements

- Contractor and its Subcontractors and vendors engaged in the performance of the Work shall comply with all Applicable Laws.
- All Project equipment must be installed in the Owner's local resource area. The project is in the Willamette Valley near the confluence of the Columbia and Willamette rivers and is subject to extended periods of fog (fresh water), rain, dampness and seismic activity.
- Spill Prevention Control and Counter Measure Plan - Proper site containment when equipment has equal to or greater than 1,320 gallons of liquid.
  - Containment shall include Petro pipe and a lockable drain valve.
  - All containment basins shall include grating as required to access and maintain equipment located in the containment area.
- The Project shall be designed for proper operation without de-rating for the following conditions and limits:
  - During and after an earthquake the system must maintain functionality (operational).
  - Ambient temperature range as defined in Schedule A.2, Site Specific Information – Site Specific Information.
  - Zero gas emissions during normal operating conditions.
  - Noise produced by any Project operation shall comply with applicable local noise codes.
  - The Project must be designed to minimize risk of harm to the environment including land contamination or disturbance (footprint), water contamination or diversion, and air emissions, as required by permitting and best Industry Standards.
  - Contractor must provide sufficient information specific to their product and the Project to facilitate utility personnel training and communications with emergency response and environmental agencies. Safety Data Sheets shall be provided, as applicable.

1.4 Seismic

- The structural and nonstructural components of all buildings, Control Shelters/Rooms, free standing structures, structural equipment supports, and all associated foundations and anchorages shall be designed and constructed to withstand the effects of earthquake motions and seismic loading in accordance with the requirements of the 2014 Oregon Structural Specialty Code and American Society of Civil Engineers 7-10 with supplements No. 1 and 2 with the following parameters:
  - Risk Category IV
  - Seismic Design Category D
  - Site Soil Class D, unless otherwise determined by the Geotechnical Engineer
  - Ip is 1.5

- All electrical equipment shall be designed to the ‘High Seismic Qualification Level’ in accordance with IEEE 693 Standard.
- For all anchors embedded into concrete that resist seismic loading, the cracked concrete provisions of American Concrete Institute (ACI) 318-11, Appendix D must be considered.
- Anchor design must be governed by ductile yielding of a steel element (anchor or attachment), unless the exceptions of ACI 318-11, Appendix D are met.
- Post-installed anchors installed into hardened concrete must be an International Building Code Compliant Anchor for Seismic Design Category D and shall be designed and installed in accordance with the cracked concrete provisions

1.5 Specification Interpretation

- Contractor, if in doubt as to the meaning of any part of this Specification, or if Contractor finds discrepancies in or omissions in this Specification, may submit a request for a written interpretation or correction of the Specification. Any request for a written interpretation should be made to the Owner Representative.
- Any interpretation or correction of the Specification will be given in writing by the Owner Representative.

2.0 GENERAL REQUIREMENTS

2.1 Workmanship

All Work must be done and completed in a thorough, workmanlike manner by personnel skilled in their various trades, notwithstanding any omission from drawings or this Specification. All parts of the Work shall be constructed accurately to standard gauge so that renewals and repairs may be made when necessary with the least possible expense.

2.2 Design and Material

All materials used in the Project shall be new and of the specified quality. All components and workmanship must be free from physical and electrical flaws and imperfections. The design shall not only be effective in engineering characteristics, it must comply with the finish requirements stated herein.

2.3 Document Submittals

The Contractor shall provide electronic Portable Document Format (PDF), and one computer-aided design (CAD) file in AutoCAD/dwg format for the Project required by this Specification for the Owner’s review. As part of Substantial Completion, final set drawings shall be provided in AutoCAD .dwg format. The review drawings shall be forwarded and be accompanied by a transmittal letter identifying all drawings by drawing number, revision number, and drawing description (title). A list of the drawing numbers, descriptions, revisions, revision dates and types of format shall be provided in a Microsoft Excel format for full tracking of all drawings/documents to be reviewed. This may be used in part as an identification of the listed drawings of the transmittals.

To coordinate the progress of the Project design and to verify that the design complies with the Statement of Work, the Contractor shall submit to the Owner design review drawings, calculations and associated documentation at the 30% and 90% completion levels. The review documents shall include, but not be limited to the following design activities: site development, footing and foundation design, conduit, grounding, structural calculations, seismic qualification reports and seismic outline drawings, equipment drawings, design calculations and drawings for the enclosure containing the batteries, and indoor and outdoor wiring and schematics. These drawings shall be marked “for review” and shall be submitted in the sequence of preparation in order that the design review may be performed in an orderly sequence.

Intermediate partial review data may be submitted at any time in the Project when the Contractor needs clarification of design requirements or to meet the Substantial Completion Guaranteed Date.

The preliminary drawings submitted (30% review) shall be accompanied by design memoranda which shall provide, when applicable, all data, calculations, and information necessary for an engineering review and understanding of the proposed design. The 30% review level is defined as drawings and documents that define the design concept. Examples of documents to be submitted at the 30% level include but are not limited to:

- Site Plan Layout
- AC Single-line Drawing(s)
- DC Single–line Drawing(s)
- Grounding Plan
- PCS Layout and Details
- Energy Storage Layout and Details
- Architectural Drawings
- Foundation Plan
- Heating, Ventilation, and Air Conditioning (HVAC) Drawings and Details
- Fire System Drawings and Details
- Grading and Drainage Plan
- Storm Water Pollution Prevention Plan
- Equipment Specification List
- Control System Diagrams / Logic Diagrams
- Communication System Block Diagrams
- Access Road Plan, Cross Sections, and Details
- Site Fencing Drawing
- Electrical Load Flow and Short Circuit Calculations
- Purchase Specs or Data Sheets for Long Lead Items
- Equipment Seismic Qualification Reports
- Enclosure/Building Structural Calculations

Owner review of drawings will be limited to a review for constructability and compliance with the Specification. The Contractor shall be responsible for the quality control (QC) of its drawings and documents and consistency between design documents and compliance to codes. The Contractor shall continue with design work while preliminary drawings are being reviewed.

The Owner shall have the right to require the Contractor to make design alterations for conformance to the design requirements of the Statement of Work without additional costs to the Owner. The review of such alterations shall not be construed to mean that the drawings have been checked in detail, shall not be accepted as justification for an extension of time, and shall not relieve the Contractor from the responsibility for the correctness of the drawings and compliance to the Statement of Work. The Contractor shall make, at his own expense, any revisions needed to correct the drawings for any errors or omissions which may be found by the Owner. The Contractor shall submit for review multiple packages of final drawings ready for construction (90% review). Calculations and drawings shall be submitted together. After review, the Contractor shall stamp the final drawings “Issued for Construction”, or IFC, to indicate that these drawings will be the official drawings used for construction activities. Drawings submitted at 90% review shall include, but are not limited to:

- Site Plan Layout
- AC Single-line Drawing
- AC Three-Line Drawings
- DC Single–line Drawing
- DC Three-Line
- Uninterruptible Power Supply (UPS) drawings for black start / islanding systems (if applicable)
- Drawings Grounding Plan and Details
- PCS Layout and Details
- Energy storage Layout and Details
- Building/Enclosure Drawings and Details:
  - Structural
  - Architectural
  - Plumbing
  - Mechanical
  - Electrical
  - Fire
- Grading and Drainage Plan and Details
- Foundation Drawings, Plans and Details
- Raceway Plan and Details
- Storm Water Pollution Prevention Plan, if required
- Equipment and Materials List / Bill of Materials listing major Equipment and Materials
- Control System Diagrams / Logic Diagrams

- Communication System Block Diagrams
- Access Road Plan, Cross Sections, and Details
- Site Fencing Drawing
- Electrical Load Flow and Short Circuit Calculations
- Control Input/Output List
- Supervisory Control and Data Acquisition (SCADA) Points List
- Purchase Specs or Data Sheets for All Equipment
- Site Logistics
- Labels and Signage
- Section 2.6 Study Reports
- Communication Network Documents
- Communication Network Block Diagrams
- Equipment Seismic Qualification Reports
- Structural Calculations
- Commissioning and Testing Documents
- Operations and Maintenance Documents

A final set of signed "IFC" drawings for each sub-system shall be available on-site before construction of that sub-system may proceed. To the extent required by Applicable Laws, and/or the Authority Having Jurisdiction (AHJ) over Project permits, construction issue drawings shall be signed and stamped by an Oregon registered professional engineer involved in the Project. Electronic registered professional engineer stamps shall be provided for electronic issues.

- The following information shall be shown on each drawing submitted:
  - Contractor's name.
  - Owner contract and release number.
  - Owner equipment number if indicated in the Agreement or Contractor's equipment number if not indicated in the Agreement.
  - Description of drawings (Title).
  - Latest revision and date.
- Construction submittals shall be reviewed by Contractors' registered engineer or architect (as applicable) and, to the extent required by Applicable Laws, and/or the AHJ over Project permits, shall bear review stamp from Contractor's registered engineer or architect (as applicable), or the registered engineer/architect's designee, where appropriate. Documentation provided by equipment manufacturers shall not require additional stamp by a registered engineer if those equipment manufacturer documents are included in a 30%, 90% or IFC submittal package. These reviewed submittals shall be submitted to the Owner at a minimum for the following items:
  - As-built drawing markups delivered after completion of Work.

- Drilled pier construction work plan (if applicable).
- Backfilling materials.
- Structural concrete mix design and associated material certifications.
- Complete reinforcing bar fabrication, details, and bar setting drawings.
- Anchor bolts.
- Structural steel shop fabrication drawings.
- CMU block including certification of compliance with appropriate design ASTM standards.
- Welding procedure specifications, qualifications, and QC plan.
- Disposal site for exported soil material.
- Masonry mortar mix.
- Grout mix and procedures.
- Roof deck erection drawings.
- Completed manufacturer application for roof guarantee along with shop drawings of the roofs showing all dimensions, penetrations and details. The roof guarantee shall contain all technical information including: Deck types, roof slopes, base sheet and/or insulation assemblies (with method of attachment and fastener type) and manufacturers membrane assembly proposed for installation. The roof guarantee should contain accurate and complete information including: Proper names, addresses, zip codes, and telephone numbers.
- Roof membrane guarantee, 20-year labor and materials membrane / system guarantee.
- Roofing material submittals, product data information and material certifications.
- Layout and attachment of insulation indicating fastener and adhesive patterns per the manufacturer's installation requirements to meet Factory Mutual Global tested wind uplift resistance.
- Certification from roof manufacturer that board insulation materials are acceptable with roof membrane and included in roof manufacturer 20-year system guarantee.
- Copy of manufacturer's warranty and installers warranty for control shelter.
- Doors, frames and hardware.
- Louvers
- Paints
- Sealant
- Cable cut sheets and testing results.
- Transformer testing results.
- Inverter testing results.
- Conductors and grounding rods.

- Exothermic welds and grounding connections.
- Conduit, tray, and conduit fittings.
- Mandrel

- Within 15 Business Days after receipt of the drawings by the Owner for review, reviewed drawings will be returned to the Contractor. If reasonably required in the opinion of the Owner Representative, or if requested by the Contractor, a design review meeting will be held at Owner offices or other mutually agreed upon location with the Contractor's engineer within one week following return of the reviewed drawings to the Contractor. Contractor shall be provided with at least one week notice in advance of such design review meeting. The Contractor's maintained Critical Path Schedule shall provide for the submittal reviews as noted for all submittals. If practicable, any such meeting may be held via conference call for submittals other than the 30%, 90% and IFC submittal packages.
- Electronic comments in PDF or clearly legible scans of drawing will be returned to the Contractor with a letter designating the review status of each drawing. The review status given to a drawing by the Owner will be one of the following: "No Comments", "Furnish as Corrected" or "Correction Required." Review by the Owner shall in no way abrogate the requirements of the Specification. The Contractor shall be totally responsible for furnishing a complete, coordinated and integrated design which, when finished, is to be workable and consistent with the requirements of the Statement of Work. Review of any corrected documents will be completed by the Owner within 10 business days of receipt.
- If a drawing is designated "No Comments", the Contractor may proceed with the Work covered by the drawing.
- If a drawing is designated "Furnish as Corrected", the Contractor may proceed with the Work covered by the drawing and the corrections shown. However, the Contractor shall promptly revise the drawing in accordance with the requirements of the Statement of Work and submit electronic copies of the revised drawing to the Owner. If paper copies are requested, they shall follow the delivery of such electronic copies.
- If a drawing is designated "Correction Required", the Contractor shall revise the drawing to comply with the requirements of the Statement of Work and resubmit electronic copies of the revised drawing and related CAD file for review before proceeding with the work covered by the drawing.

2.4 Record Drawings

The Contractor shall maintain a record drawing set on-site always with clear markings on the drawings indicating it as the record set. The record set shall be available for Owner review always during performance of the Work. The Contractor shall furnish record drawings to reflect any changes including red line drawings made during or after installation and commissioning of the Project. One set of marked-up paper print drawings all with a new revision number shall be forwarded within six weeks from the Substantial Completion Date. A transmittal letter shall accompany the mailing itemizing the revised drawings.

2.5 Project Specific – Operations and Maintenance Manual

No later than six weeks from the Substantial Completion Date, the Contractor shall furnish two complete identical set of detailed Operation and Maintenance Manuals in both print and digital (i.e. PDF) formats for the Project. These manuals shall be accompanied by a letter of transmittal and shall have a table of contents, contain all illustrations, assembly drawings, outline drawings, wiring diagrams, replacement parts list that includes part number identification, a list of recommended spare parts, and instructions necessary for storing, installing, operating and maintaining the Project. The illustrated parts shall be numbered for identification. Additionally, these books shall contain instructions and test procedures for integrating the Project into Owner control and monitoring computer networks. All information contained therein shall apply specifically to the Equipment and Materials furnished and shall not include instructions that are not applicable. All illustrations shall be incorporated within the print of the page to form a durable and permanent reference book. Binding holes of all Table of Contents pages, illustrations and drawings bound into the book shall be reinforced with nylon circlets to prevent this information from being torn out of the book.

The Owner will inform the Contractor six weeks after receipt of the Operation and Maintenance Manuals either that there are “No Comments”, “Furnish as Corrected” or “Correction Required”. If there are “No Comments”, the Contractor shall promptly furnish two additional sets identical to the submitted copy. If there are corrections needed, one set will be returned to the Contractor by the Owner. The corrections shall be promptly incorporated in the Operation and Maintenance Manuals and a total of four complete, identical sets of such revised Operation and Maintenance Manuals shall be furnished to the Owner in both print and digital formats.

One additional, identical Operation and Maintenance Manual shall be kept in control shelter.

2.6 Study Reports and Calculations

The Contractor shall submit all design study, calculations, dynamic modeling simulation, shake table testing, and field test reports to the Owner in a timely manner. All reports and calculations shall be signed by an Oregon registered professional engineer and shall list assumptions, study methods, results, significant findings and conclusions.

The Contractor shall prepare the following study reports and calculations as specified below:

- **Seismic and Wind Loading Calculations**: The Contractor shall provide seismic and wind loading calculations for all buildings, structures, nonstructural components, equipment and structural supports, and all associated foundations and anchorages as specified in Section 1.4.
- **Seismic Qualification Report**: Contractor shall prepare a report demonstrating the Project’s compliance with the seismic standards specified in Section 1.4 for the following:
  - Battery racks IEEE-693-2005-Annex J
  - Batteries – IEEE 693-Annex J
  - Switchgear-IEEE 693-Annex M
  - Step-Up Transformer-IEEE 693-Annex D
  - Inverters (including rack mount)-IEEE 693- Annex L
  - Medium Voltage (MV)/High Voltage (HV) Breaker, IEEE 693- Annex C

- MV/HV Disconnect Switch IEEE 693-Annex E
- MV/HV Termination and Support Structure, IEEE 693-Annex N
- Pad-mount Isolation Transformers (Anchorage Only), IEEE 693-Annex D
- Electronic Devices, Panels, Switchboards, solid-state rectifiers-IEEE 693 Annex L

- **Structural Calculations**: The Contractor shall provide structural calculations for all structural supports and foundations, the building enclosing the batteries, and shelters, Control Shelters/Rooms, and equipment foundations and all nonstructural components in accordance with Oregon Structural Specialty Code requirements as specified in Section 1.4 of this document.
- **Grounding System Study**: The Contractor shall perform soil resistivity measurements and studies as necessary to determine the parameters for the Project's grounding system. Grounding studies shall identify step and touch potentials, as applicable, for each facility where new equipment is added as part of the Project scope. The Project grounding system shall be designed to function independently of the adjacent grounding system. The grounding system for the Project may be connected to the ground grid for the adjoining substation at the discretion of the Owner at Contractor's cost. If connected to the adjoining grounding system, the contractor shall perform a study to verify that step and touch potential are within tolerable limits. Connections to and routing of ground cables to connect the ground grid of the adjoining grounding system shall be provided by the Contractor. Grounding for all multi-component outdoor structures shall include two or more independent ground connections. The Project grounding system shall also be designed in such a way as to reduce electromagnetic interference (EMI) coupled to the grounding system from power electronic converters, such as through single-point grounding systems. Designs and study shall adhere to IEEE 80, IEEE 81 and IEEE 142 where applicable.
- **Electrical Studies**: The Contractor shall provide electrical studies as required to determine control response and settings, including load flow, short circuit, cable ampacity, arc flash analysis, and voltage drop using industry-standard engineering software agreed-upon by the Owner. For the purposes of the system electrical studies, the Contractor shall provide inputs data for an accurate power flow and dynamic simulation model of the Project compatible with the Owner's CYME database and software. Contractor shall perform dynamic simulations, utilizing CYME.
- **Relay and Control Settings:** The Contractor shall provide complete documentation of all protective relay and Project control settings for the Project's batteries, inverters, control systems, and AC systems up to the point of interconnection. Such documentation shall include a protection and control criteria document (separate protection and control criteria documents are acceptable), all calculations and time current coordination curves used in the development of the settings.

2.7 Testing and Test Reports

- The Contractor shall, within 30 days prior to any on-site testing, submit a "Master Test Plan and Procedures" document indicating the order in which the tests will be conducted, and the test method being used along with required instrumentation for Owner approval.
- The Contractor shall furnish, at the Contractor's own expense, necessary facilities and test equipment for the required tests.
- The Contractor shall notify the Owner not less than two weeks in advance of the day when:

  - Manufacture, fabrication and integration starts for the batteries, inverters, controls and transformers of each major deployment.
  - The batteries, inverters, controls, transformers and other major components allocated for each major deployment are ready for testing and inspection prior to packaging for shipment.
- Should the Owner elect to waive the right of inspection or of witnessing tests and accept certified test reports instead, the Owner will notify Contractor no later than three business days ahead of the scheduled inspection or test.
- Witnessed factory tests shall be made in the presence of Owner personnel. The test procedures shall be subject to review and acceptance by the Owner prior to arrival at testing location, provided that non-acceptance of any part of the procedures is consistent with the Statement of Work. The Contractor shall bear all costs of such testing except for the compensation and expenses of Owner personnel. If scheduling such tests to accommodate the Owner causes schedule delays, then said delays will be accommodated on a day for day basis to the extent they negatively impact the critical path.
- One copy of the certified reports of all tests shall be furnished to the Owner in digital and print formats for review. The Owner will inform the Contractor within two weeks after the receipt of the certified test reports either that there are no exceptions noted or that the test results show noncompliance with the Specification. Contractor shall provide the test data for a representative sample of each of the major components.

2.8 Factory Acceptance Testing Requirements

The Contractor shall be responsible for compliance with all standard factory test procedures that check the quality and performance of the Equipment and Materials.

The Contractor shall perform those tests specified below and in other sections of this Specification. The Contractor shall propose additional tests to be conducted if required. Where appropriate, tests should conform to those contained in ANSI, NEMA, ASME, NEC, ASTM and IEEE standards and guidelines. Where standards are not suitable or applicable, other common industry procedures and mutually acceptable methods shall be used.

If certain tests are performed by firms other than the Contractor, the Contractor shall furnish the test reports and certify that the necessary testing has been performed.

2.8.1 Factory Acceptance Testing of the Battery/Cells

The Contractor shall test and submit test data for the cells designated for use on this Project. At a minimum, the following tests shall be performed:

- Amp hour capacity
- UL 1642 Certificates (if applicable)
- As applicable, maximum noxious and toxic material release rates for same cell design but not necessarily a specific production lot.

The Contractor shall propose a test plan for all required cell tests. Required tests may be proposed as a percentage of the cells in production lots. Test data for production lots other than those being supplied for this Project are not acceptable.

2.8.2 Factory Acceptance Testing of the PCS and Control System

The Contractor shall develop and submit for Owner approval of a Factory Acceptance Test (FAT) Plan. The FAT Plan shall be in general accordance with Appendix C of this Specification. The supplier shall work cooperatively with the Owner to develop a formal FAT Plan based on the appendix.

At a minimum, sufficient tests shall be conducted to demonstrate that all controls, protective functions and instrumentation perform as designed and follow this Specification. Successful tests performed on scale models or analog simulators will be deemed to meet the intent of this paragraph. The tests shall demonstrate that the PCS is capable of synchronizing with and operating in parallel with the utility connection. A report along with graphs of each test and a data file will be provided by the Contractor to the Owner upon completion of the FAT. This file should be captured at a minimum of 512 samples per cycle resolution.

Witness test shall demonstrate the following, at a minimum:

- Normal and failure mode operating sequence and protective functions.
- Verification of accuracy of measured input/output voltage and currents.
- Verification of dynamic power factor (PF) control via SCADA system (e.g. Communications Protocol).
- Verification of power curtailment via SCADA system (e.g. Communications Protocol).
- Verification of islanding and black start capabilities.

2.9 Site Acceptance Test

The Site Acceptance Test shall be in accordance with Appendix F of this Specification. Owner will assist Contractor during the Site Acceptance Test process. In addition, the Contractor shall demonstrate that all aspects of the System integrate and coordinate as intended. At a minimum, the Contractor shall demonstrate that all control and management systems, including but not limited to, all levels of energy storage management system, PCS controls, and overall site controls, interact as intended. Other balance-of-plant systems shall be tested in conjunction with the overall system tests (e.g. HVAC, fire alarm, lighting, security).

2.9.1 Actual Operating Experience

It may not be possible due to system constraints to test all facets of the Project function as part of the performance verification tests specified above. The actual operating experience of the Project through Final Completion shall be deemed an extension of the performance verification tests.

Actual operating experience will be documented through Owner-furnished sequence of event recorders, oscillographs, digital fault recorders and other system monitoring equipment capable of identifying system disturbances and associated Project performance. Additional information may be provided by monitoring equipment installed by the Owner at other locations. Operation may also be documented with the Contractor-furnished power quality meters, as determined by the Owner.

2.9.2 Other Compliance Tests

The Contractor is responsible for obtaining both before (or with all equipment de-energized) and after Project installation, measurements to ensure the Project complies with this Specification in the following areas. The Owner reserves the right to perform (or request others to perform), at Owner expense, identical compliance test measurements for the following:

- Broadband frequency signal strength and noise voltage.
- Harmonic voltages and currents adhering to IEEE 519.
- Audible noise measurements adhering to AHJ requirements.

2.10 Spare Parts

The Project specific Operations and Maintenance Manual provided by Contractor will list the required spare parts to be furnished with the Project by Contractor. Each spare part shall be interchangeable with and shall be made of the same material and workmanship as the corresponding part included with the product furnished under these Specifications. Enclosed storage space for spare parts required on site shall be provided for by Contractor. If climate-controlled space is required, additional space shall be included in the Control Shelter or energy storage system enclosure(s).

2.11 Special Tools

The Contractor shall furnish a complete set of any special tools, lifting devices, templates and jigs, which are specifically necessary for installation and/or maintenance of the Project. Any accessories normally furnished with this system required for satisfactory operation of the Project, and not specified herein, shall also be furnished by the Contractor. All tools furnished shall be new and plainly marked for identification. One complete set of tools shall be furnished for the Site.

2.12 Cleaning and Painting

All waterproof enclosures shall be thoroughly cleaned of rust, welding scale, and grease, and shall be treated to affect a bond between the metal and paint which shall prevent the formation of rust under the paint. A priming coat shall be applied immediately after the bonding treatment. The final finish shall consist of two coats of paint of specified color and type. Contractor shall submit painting specifications and procedures for Owner approval.

Waterproofing is the combination of materials or systems that prevent water intrusion into structural elements of the buildings or its finished spaces.

2.13 Shipping Requirements

- The Contractor shall prepare Equipment and Materials for shipment in such a manner as to protect from damage in transit. Each item, box or bundle shall be plainly and individually identifiable for content according to item number, Owner contract number, Contractor's identifying number, and complete shipping address. The Contractor shall pay attention to the proper packaging and bracing of the apparatus to assure its safe arrival.

- Systems, equipment, materials and components shall be transportable from the designates port at normal speeds over North American highways and railways and meet all United States Department of Transportation hazardous materials and other requirements. System components may be shipped separately as needed and assembled on-site. Battery shipments shall adhere to the requirements of Title 49 Code of Federal Regulations Part 173.185.
- A complete itemized bill of lading, which clearly identifies and inventories each assembly, subassembly, carton, package, envelop, etc., shall be furnished and enclosed with each item or items at the time of shipment.

2.14 Installation

The Contractor shall be responsible for quality of construction to meet best Industry Standards and design requirements.

2.14.1 Civil/Structural

The Project shelters and required foundations and structures (including the building that will house the batteries) shall be designed by and under the supervision of a qualified Oregon registered professional engineer and Oregon registered architect. All designs shall be in accordance with seismic design requirements as specified in Section 1.4 of this Specification.

The Contractor shall gain access to the Site from existing public and private roads. Existing roads shall not be blocked or restricted without prior approval of the Owner and local agencies. The Contractor shall be responsible for any damage to public roadways or walkways resulting from the Work.

Existing structures and utilities that are adjacent to or within the limits of the Project area shall be protected against damage. The Contractor shall be fully responsible to property owners for all repairs in the event of removal or damage of any existing structure, equipment or systems that are intended to remain in place.

2.14.2 Geotechnical testing

The Contractor shall perform geotechnical investigations and geotechnical report shall be in accordance with the Oregon State Building Code and contain information necessary to complete civil/structural and grounding design. A copy of any report resulting from any geotechnical investigations performed by Contractor must be provided to the Owner. Geotechnical testing, site monitoring and as-built reporting shall be performed during construction and submitted to Owner on a weekly basis.

2.14.3 Site Development

The Contractor shall perform all necessary studies and calculations for hydrology and drainage, erosion control, landscaping, National Pollutant Discharge Elimination System (Stormwater Pollution Prevention Plan) and site grading to comply with local agency regulations. The Contractor shall be responsible for all surveys (e.g. topographic, Dig Alert, potholing) required to attain an accurate design.

Drainage structures and piping within the Project boundaries should be grounded if constructed of materials capable of conducting electricity.

2.14.4 Excavation

The Contractor shall perform all common and deep excavation necessary for installation of all foundations and utilities. All excavation shall be in accordance with Oregon OSHA regulations and the geotechnical report performed or to be performed by Contractor. Excavation spoils shall be the Contractor's responsibility and may be used for backfilling or embankment if suitable for this application as directed by the project geotechnical report/ engineer. Unsuitable or excess excavated material shall be disposed of properly.

The Contractor shall verify that earth material exposed in excavations is consistent with those assumed for the Contractor's foundation designs.

2.14.5 Construction Surveying

The Contractor shall furnish all labor, equipment, material and services to perform all surveying and staking essential for the completion of the Project in conformance with Contractor's design and the Statement of Work. Survey information shall be included in Project as-builts.

The Contractor shall retain qualified survey crews knowledgeable in proper and up-to-date survey techniques and shall use these qualified survey crews when conducting the survey. Such crews shall be under the supervision of a professional land surveyor licensed in the state of Oregon.

2.14.6 Fills

Earth fill material adjacent to and below structures shall conform to the design requirements for the structure and the geotechnical report performed or to be performed by Contractor. Contractor prepared specifications and drawings shall indicate the types of soil to use for fills and compaction requirements.

Fill shall be placed as uniformly as possible on all sides of structural units. Fill placed against green concrete or retaining walls shall be placed in a manner which will prevent damage to the structures and will allow the structures to assume the loads from the fill gradually and uniformly.

2.14.7 Fencing

Site perimeter fencing is required for the Project. Such fencing shall comply with the Owner substation fence standard (to be provided upon request).

2.14.8 Lighting

Lighting shall be provided for all indoor and outdoor areas of the project. The lighting system shall provide personnel with illumination for operation under normal conditions and means of egress under emergency conditions. Luminaries shall be LED type, mounted so they are easily accessible for maintenance and lamp change out, to the maximum extent practical; for both interior and exterior. Emergency lighting shall be powered from self-contained batteries, with chargers, within a self-contained emergency lighting unit.

The power supply for the lighting system shall generally be from low voltage (LV) lighting panelboards. The emergency egress lighting shall consist of self-contained battery lanterns. Outdoor lighting shall be limited to providing fixtures mounted on building, container, or light standards. Light fixtures shall be Dark Sky compliant to help preserve the night sky from light pollution.

The lighting levels shall be designed in accordance with the Illuminating Engineering Society to provide proper illumination levels recommended. Minimum level in the energy storage system area shall be 30-foot candles (323 lux) at 30 inches (762 millimeters) above plane, when occupied, and adequate levels for illumination for video and security equipment when unoccupied; 3.0-foot candles (22 lux) at 30 inches (726 millimeters). Minimum level in the control room and maintenance area shall be 50-foot candles (538 lux) at 30 inches (762 millimeters) above floor plane.

Follow state and local lighting energy efficiency standards, as applicable. Electric power to light fixtures shall be switched with motion sensors in energy storage system rooms. When unoccupied sensors shall reduce levels to minimum for security. Motion sensors with built-in override function shall be provided in areas where the light can be completely turned off; such as store rooms, switchgear rooms, and maintenance area. Wall mounted switches and sensors shall be provided at the latch side of the door entrance.

Electric power to outdoor light fixtures shall be switched with motion or heat detectors to keep lights off when not required. Convenience outlets and switches throughout shall be industrial grade rated for standard voltages and amperes per country standards. Convenience outlets located outdoors shall be provided with weatherproof snap-action covers. Outlets shall be spaced in the energy storage area such that there is a maximum 100 feet (30 meters) distance to a receptacle outlet, unless codes allow or require otherwise. As a minimum, an accessible receptacle outlet shall be reachable within 25 feet (7.6 meters) from each HVAC unit. Provide outdoor receptacles protected by ground fault interrupters, and interior receptacles in locations as required by codes. In finished areas, general-purpose power outlets shall be located on each wall and in no case shall they be located more than 10 linear feet (3.0 meters) apart.

2.14.9 Jersey Barriers

Jersey Barriers are required to protect the Project if installed within 20 feet of public thoroughfares. Jersey barriers may be removed after construction at the instruction of the Owner.

2.14.10 Control Enclosure (if control room not provided in building-based solution)

For container-based solutions, the Contractor shall design, engineer, and provide a shelter suitable for use to house the Project controls and all indoor components common to the Site. The Shelter shall be designed to comply with the Oregon building code requirements. The Contractor shall provide the shelter required to accommodate the Project controls commensurate with the Project design life, including but not limited to seismic events, wind loads or other controlling criteria.

The Project shelter and containers shall be designed with the appropriate insulation to meet local building codes and ensure an energy efficient operation of the HVAC and/or ventilation system. Control shelter will be installed on a graded pad and all components mounted thereon shall be designed for and anchored sufficiently for transportation to the jobsite. Control shelter shall be designed without shipping splits. The control shelter shall be made from either steel (galvanneal), aluminum or stainless steel. The control shelter shall have doors to accommodate installation and replacement of equipment housed in the structure. The roof shall have a pitch design with a minimum slope of 0.25 inch per linear foot and shall be designed to support interior or exterior loads of 100 pounds per linear foot without compromising the roof load design.

The control shelter shall be equipped with DC cabinet, AC panels and disconnects (480/240/120), lights, switches, receptacles, controls rack, fire suppression, HVAC units, push buttons, HVAC controls, cable tray, wireway, grounding system and conduit.

Exit and fire door hardware shall conform to UL specifications. Installation of exits shall conform to NFPA No. 80.

2.14.11 Project Building (if applicable to proposed system)

The Contractor shall design, engineer, and provide a building suitable for use to house all indoor components of the Project. The building shall be designed to comply with the Oregon State Building Code requirements. The Contractor shall provide the building required to accommodate the Project commensurate with the Project design life, including but not limited to seismic events, wind loads, or other controlling criteria as specified in Section 1.4.

The building shall be designed with the appropriate insulation to meet local building codes and ensure an energy efficient operation of the HVAC and/or ventilation system. Exit and fire door hardware shall conform to UL specifications. Installation of exits shall conform to NFPA No. 80.

2.14.12 Structural Steel and Connections

All structural steel shall comply to the following applicable materials standards:

- Wide Flange Shapes - ASTM A992
- Angles and Channels - ASTM A36
- Plates - ASTM A572 Grade 50
- High Strength Structural Bolts - ASTM A325N Type 1, or A490
- Washers - Hardened steel, ASTM F436
- Nuts - Heavy hex, ASTM A563
- Welded stud anchors shall be headed arc-welded mild steel studs conforming to ASTM A108, Type B having minimum yield strength of 51,000 pounds per square inch (psi) and a minimum tensile strength of 65,000 psi.
- Anchor Bolts - ASTM F1554 Hex Head, Grade 36 or Grade 55
- Electrodes for Welding - Electrodes shall be E70XX 70ksi tensile strength, minimum.
- All structural steel shall be hot-dipped galvanized in accordance with ASTM 123 and all mill certifications shall be available. Structures shall be fabricated such that double dipping is not required.
- Bolted connections shall be ASTM A325 with hardened washer and heavy hex nuts installed as snug-tightened in accordance with the Research Council on Structural Connections Specification for Structural Joints Using ASTM A325 or A490 Bolts.

- All welding shall comply with the requirements of AWS D1.1, Structural Welding Code - Steel. Welders and welding processes shall be qualified in accordance with AWS D1.1.

2.14.13 Foundations and Concrete Work

The Contractor shall furnish all labor, equipment, materials and services to layout, design and construct all foundation and concrete work required for the Project. The Contractor shall provide foundations for all equipment and structures, as appropriate, including but not limited to shelters, containers, buildings, transformers, switches, breakers and instrument transformers.

ACI 318 and Oregon Structural Specialty Code shall be used for the design of foundations. All concrete exposed to weather or in contact with soil shall be designed to be compatible with the life of the Project.

The appropriate manufacturer shall specify the quantity, size, and location of anchor bolts for enclosures and equipment per seismic qualification reports. Embedded steel items shall be hot dip galvanized. Anchor bolts and embedded steel items subject to corrosive action shall be fabricated from stainless steel.

Concrete shall be batched, mixed and delivered in accordance with the requirements of ACI 301. Reinforcing shall be detailed and fabricated in accordance with ACI 315. Details of concrete reinforcement not covered in ACI 315 shall be in accordance with the CRSI manual. Concrete placing methods shall conform to the requirements of ACI 301, 304, and 318.

The Contractor shall provide the services of an independent testing agency to perform tests on concrete material such as compressive strength, slump, concrete mix designs, during the Work. Testing, evaluation and acceptance of concrete shall be done in accordance with the requirements of Chapters 16 and 17 of ACI 301. Any concrete that does not meet the requirements shall be replaced with no increase to the Purchase Price.

2.14.14 Mechanical

All exposed surfaces (inside or outside) of ferrous parts shall be thoroughly cleaned, primed, and painted or otherwise suitably protected to survive outdoor conditions for the design life of the Project.

The building housing the energy storage system and any other outdoor enclosures or shelters shall be waterproof and capable of surviving, intact, under the Site environmental conditions for the design life of the Project. Flat Roofs are not allowed – minimum roof slope shall be 0.25 inch per linear foot.

Components mounted inside of the building and any other enclosure shall be clearly identified with suitable permanent designations that also shall serve to identify the items on drawings provided.

- The Project shall include an HVAC or ventilation system for the building(s) housing the energy storage system(s) and control shelter which shall be seismically anchored. All design shall be in accordance with seismic design requirements as specified in Section 1.4 of this Specification.
- The Project shall be designed to maintain component temperatures within design limits for all modes of planned Project operation. The HVAC system shall be sized to maintain ambient temperatures in the building to 25 degrees Celsius (°C) +/- 5 °C during all operating modes and ambient conditions.

Communications and Control Technology

Communications and control technology shall make use of the best Industry Standard components and be compatible with the Owner's existing environment for substation communications infrastructure.

2.15 Quality Assurance / Quality Control

2.15.1 Quality Control Program

- The Contractor shall establish, implement, and maintain a comprehensive QC Program, which shall be reviewed for approval by the Owner prior to implementation. This program shall include provision of a qualified, on-site Quality Assurance / Quality Control (QA/QC) support staff for the duration of the Project.
- The QC Program shall clearly establish a QA/QC Manager and/or staff with the responsibility and authority to inspect the Work, to enforce the quality requirements of the Statement of Work and the Agreement, and to verify the effectiveness of problem resolutions and corrective actions.
- The QC Program shall be capable of assuring that the design, construction, purchasing, manufacturing, shipping, storage, testing, inspection and examination of all equipment, materials, procedures, and services shall comply with the requirements of the Agreement and building code requirements. Reports generated under the QC program must be submitted to the Owner within three days of receipt.
- The Contractor shall provide all equipment, materials, and labor required to perform all Work in support of QA/QC. As a minimum, this applies to soil density, concrete, welding, and any laboratory tests. Any Subcontractors or third-party inspectors hired by Contractor to perform any Work in support of QA/QC shall be subject to the approval of the Owner.
- The Owner shall have the right to independently review and inspect all Work associated with the Project that occurs or will occur at the Site. This may include review and inspection by third parties and contractors of the Owner.

2.15.2 Quality Assurance Manual

The QC Program shall consist of one or more bound sets of documents comprising a single Quality Assurance Manual. The form and format of the Quality Assurance Manual is at the discretion of Contractor and its Subcontractors. Upon review and final approval by the Owner, it shall become the sole guide for Contractor and all its Subcontractors for quality performance of all Work on the Project. The content of the Quality Assurance Manual shall include written descriptions of QA/QC policies, procedures, methods, instructions, exhibits, or other quality assurance descriptions. An uncontrolled copy of Contractor's corporate QC manual shall be provided to the Owner Representative. The Owner shall always have access to all QA/QC documentation and shall be provided copies upon request.

The Contractor's Quality Assurance Manual shall include, at a minimum, control procedures or methods to assure the following:

- The establishment of on-site QA/QC staff.
- A plan for receipt inspection, in-progress inspection, examination, and testing of the equipment and material installed by Contractor.

- A description of the authority and responsibilities of the persons in charge of the quality assurance program.
- Current and accurate maintenance of design documents, drawings, specifications, quality assurance procedures, records, inspection procedures, and purchase control documents.
- Conformance of purchased materials, equipment and services to the requirements of the Agreement.
- Proper performance of receipt and in-process inspections as well as equipment examinations, testing, corrections as well as checkout procedures.
- The inclusion of adequate inspection and quality of all Contractor's subcontracted work and shop fabricated components.
- Shop inspections are performed and documented at an adequate frequency rate.
- Assurance that the quality of all special processes such as welding, and any other nondestructive testing is properly inspected, verified, and documented.
- Assurance that the proper methods are employed for qualifying all personnel performing welding and non-destructive testing.
- Assurance that inspection hold points are identified and monitored in coordination with the Owner Representative.
- All deviations and non-conformance will be communicated to the Owner in writing within three days.

2.16 Required Training Courses

The training courses described below, with accompanying written text, shall be a live presentation at an Owner facility with the Owner having the right to video tape the training course. Such taped training will be used only for training of new personnel and will be subject to confidentiality agreements, and other protections of Contractor's Intellectual Property. The training course shall cover all aspects of installing the Project, a pictorial breakdown of the energy storage subassemblies, procedures related to emergency response (ruptured modules, fire, etc.), and operation and control of the Project.

2.16.1 General

The Contractor shall provide training for the Project as specified below. The Contractor shall determine the content and duration for each training session. The suggested class durations in this Specification are meant to illustrate the level of training expected. Performance evaluation testing of all trainees (i.e., a written test) is required for all classes except the orientation training.

2.16.2 Orientation Training

The Contractor shall provide two orientation training sessions. It is anticipated that each session will last half a day. These sessions shall be suitable for managers, supervisors, professional and technical personnel. Each session will be limited to a maximum of 20 people.

The orientation training sessions shall be scheduled before commencing Acceptance Testing. An outline for this orientation training shall be submitted to the Owner 90 days ahead of the actual date of training.

Approval of this outline shall be obtained from the Owner. The Owner will provide comments and/or approval at least 30 days before the scheduled training date.

2.16.3 Operator Training

The Contractor shall provide the necessary training in proper operation of the Project and related equipment. This training shall be conducted after successful completion of the Acceptance Testing, but before system commissioning. It is anticipated that this session will last one to two days. This session will be limited to a maximum of 20 people. Emphasis shall be placed on hands-on operating experience interspersed with the critical background as necessary, including switching procedures and emergency response training.

2.16.4 Maintenance and Diagnostic Training

The Contractor is responsible for providing necessary training on energy storage and inverter diagnostic software which includes a set of the necessary cables to diagnose these issues. This training shall be completed onsite using the Owner's field personnel equipment. Documentation of the software and steps needed to communicate with various equipment will be supplied by the vendor.

3.0 FUNCTIONAL REQUIREMENTS

3.1 General

The Project will can serve multiple purposes, each represented by a control mode. These modes will all be supported within the system capabilities and self-protection requirements. The Project shall be able to move freely between each mode of operation at any time.

The Contractor shall specify the method used to determine the point where further discharge is no longer practical or safe and the storage media must be recharged before further use. All modes will be limited by the Contractor specified discharge limit to avoid damage to the Project. Termination of any operating scenario by the discharge limit, without reaching rated capacity discharge, will be included in the availability calculation unless the discharge was initiated with the energy storage partially discharged.

The Project shall be capable of functioning in the modes currently available within the Contractor's software.

For all modes, except modes that respond to abnormal system conditions, the Project shall ramp to the required output at an Owner selectable rate. Following a rated discharge or termination of the mode command, the Project shall ramp to zero at an Owner selectable rate suitable to allow other generation to follow. The total energy delivered shall be inclusive of the energy required to ramp the system to zero. Termination of operating modes due to reaching the discharge limit shall consider the ramp down energy required.

3.2 Control Modes

The following sections describe the control/operational modes and sources of commands for the Project. Contractor shall work with the Owner to ensure that the appropriate command and source hierarchy are enforced by the Project. Clarification on specific SEC behavior, relating to these modes, is provided in Section 4.12 and Appendix E.

3.2.1 Integration to Other Owner Control Systems

The Project shall be capable of being integrated with other Owner control systems. Integration with the Owner Ovation control system and the Owner Distributed Energy Management System (DERMS) will be required.

3.3 Permissive Operation States (applies only to Islandable Systems)

A system of operational states shall permit the use of each mode of operation of the Project. Permissions will be granted by the Owner via an Owner-specified process. The operational states are Island and Blackstart. The descriptions are in the following sections.

3.3.1 Island

Island permission shall authorize the energy storage system to operate in Voltage and Frequency mode, in island with the utility grid. All necessary switching of islandable and non-islandable load and disconnection from the grid shall be done automatically by the Owner's distribution switch controller. Only after grid voltage is restored for the specified delay time, and all necessary switching back to normal has been completed, shall the system be allowed to reconnect with the operator's permission and operate in the Parallel state.

3.3.2 Blackstart

Blackstart permission shall authorize the energy storage system to blackstart from a de-energized state, operate in Voltage and Frequency mode and island from the utility grid. All necessary switching of islandable and non-islandable load shall be done automatically by the Owner's distribution switch controller. Only after grid voltage is restored for the specified delay time, and all necessary switching back to normal has been completed, shall the system be allowed to reconnect with the operator's permission and operate in the Parallel state.

4.0 TECHNICAL REQUIREMENTS

4.1 General

The Project shall include the energy storage system, PCSs (inverter), pad-mount transformers, cabling, shelters, all associated control and communication interface systems, all switchgear and other interconnection equipment and any auxiliary loads necessary to support its operation to the point of interconnection with the utility.

All loads necessary to operate and protect the Project, such as controls, cooling systems, fans, pumps, and heaters, are considered auxiliary loads internal to the system.

The “Point of Interconnection” shall be defined per the Schedule A1 of the request for proposal.

4.2 Storage Capacity

The Project shall be rated in terms of net delivered power and energy to the Point of Interconnection. All system loads and losses, including wiring losses, losses through the contactor/static switch, power conversion losses, auxiliary loads, and chemical/ionic losses are considered internal to the Project and ratings are net of these loads and losses as measured (or calculated if not measured) to the Point of Interconnection.

In such cases where auxiliary loads (such as cooling systems) are periodic in nature, ratings may be described for conditions in which these loads are active in the worst-case conditions (or alternatively provide sufficient supplementary information such that ratings under these worst-case conditions may be easily determined).

The Supplier shall scale the reported State of Charge of the energy storage system so that 0-100% represents the maximum range of energy storage capacity available to the Owner regardless of the actual state of charge of the system. A reported 0% state of charge shall indicate that no further discharge of the system is permitted, and a reported 100% state of charge shall indicate that no further charging of the system is permitted. This range shall permit the Owner to fully realize the rated energy storage capacity of the system (i.e. for a 1.0-megawatt hour [MWh] system, the Owner shall be able to discharge 1.0 MWh of energy when discharging from a reported 100% to a reported 0% state of charge).

4.3 Ratings

Following are fundamental Project unit ratings. Note that power, energy, and ampacity ratings apply through the full operating temperature range, as defined for the Site unless otherwise noted.

4.3.1 AC Voltage

Nominal interconnection voltage is 12.47 kV [±5%]

Plant-side distribution voltages shall be 12.47 kV for interconnection with the local utility substation.

4.3.2 Round-trip Efficiency

The roundtrip AC-AC energy efficiency, measured at the Point of Interconnection, shall be provided and include parasitic and auxiliary losses under worst case conditions prescribed in the FAT Plan.

The calculation is as follows:

$$\eta = \frac{kWh_{out}}{kWh_{in}} \times 100\% = \frac{(rated\ discharge\ power) \times (discharge\ time)}{(rated\ charge\ power) \times (charge\ time) + losses} \times 100\%$$

In which the discharge time is from a fully charged to fully discharged energy storage, and charge time is from a fully discharged to fully charged energy storage. If the auxiliary power is provided by a separate connection from the energy storage, these measured values should be reflected in the losses term in the equation.

4.3.3 Parasitic Losses

The total Energy Storage System unit losses shall be determined for standby operation, including power electronics and any environmental controls such as HVACs.

4.3.4 Self-Discharge

Supplier shall provide self-discharge characteristics.

4.3.5 Basic Insulation Level

The Energy Storage System AC system equipment shall have a Basic Insulation Level in accordance with as required by IEEE for each piece of equipment.

4.3.6 Inrush Capability

It may be advantageous to the Owner for the Project to have short time overload capabilities. This may occur for power system disturbances in which both real and reactive power is required for a short period of time to control both frequency and voltage excursions.

The Contractor shall provide a curve showing the inherent overload capability (if any) of the Project as a function of time. It is not a requirement of the Specification to design specific overload capability into the Project.

When islanded, the Energy Storage System shall also have capability for 1.5 x rated kW/MW and 1.5 x rated kVA/MVA for one minute. This inrush duty will be four times per hour on top of continuous, full load.

4.3.7 Auxiliary Voltage

Auxiliary voltage will be site specific and captured within Schedule A2 of the request for proposal.

4.3.8 Power and Energy

System ratings are defined in kVA (i.e. AC) or MVA (i.e. AC) and kWh (i.e. AC) or MWh (i.e. AC) as measured at the Point of Interconnection.

4.3.9 Design Ambient Temperature Range

Reference Schedule A2 for site specific information.

4.3.10 Audible Noise

The maximum sound level generated from the Project and any associated equipment supplied by the Contractor under any output level within the Project operating range, shall be limited to levels specified by Applicable Laws. The Contractor shall comply with all Applicable Laws that may apply to the Project installation as determined by the jurisdiction applicable to the site.

The audible noise level in the Project control room if separate from areas housing inverters, cooling equipment, etc. shall meet OSHA requirements for normally occupied areas.

Compliance Measurements

The Contractor shall make audible noise measurements before and after commissioning of the Project for verifying adherence and compliance with the local ministerial ordinance and requirements. The measurements shall be made at various locations using a Type 1 sound level meter that complies with the requirements of ANSI S1.4-1983 "American National Standard Specification for Sound Level Meters."

4.3.11 Broadband Interference

The Contractor shall take necessary precautionary measures to ensure that there will be no mis-operation, damage or danger to the Project due to broadband interference and effects. The Contractor shall ensure that there are no discharge sources from the Project and related equipment that could cause interference with radio and television reception, wireless communication systems, or microwave communication systems per the 47 Code of Federal Regulations Part 15. The Contractor shall propose any necessary mitigation to ensure that communication is not adversely affected.

The Contractor shall make measurements before (or with all equipment de-energized) and after commissioning of the Project for verifying compliance with the broadband interference requirements.

All broadcast signals, radio noise, television interference and broadband interference measurements shall be made with instruments that comply with the latest revision of ANSI C63.2, "American National Standard for Electromagnetic Noise and Field Strength Instrumentation, 10 Hz to 40 GHz - Specification." IEEE Standard 430, "IEEE Standard Procedures for the Measurement of Radio Noise from Overhead Power Lines and Substations" defines the measurement procedures that shall be used.

4.3.12 Interference and Harmonic Suppression

The PCS shall not produce EMI that will cause mis-operation of instrumentation, communication, or similar electronic equipment within the Project or on the Owner system. The PCS shall be designed in accordance with the applicable IEEE standards to suppress EMI effects.

The Project must meet the harmonic specifications of IEEE 1547 and IEEE 519 and comply with requirements outlined in the Energy Storage Integration Council (ESIC) technical specifications spreadsheet located in Appendix G. Harmonic suppression may be included with the PCS or at the Project AC system level. However, the Contractor shall design the Project electrical system to preclude unacceptable harmonic levels in the Project auxiliary power system.

4.4 External AC Power Interface(s)

4.4.1 Termination

All terminations and locations of terminations shall be pre-approved by the Owner and specified in the appropriate submitted drawings. The Project shall comply with any applicable owner interconnection standard.

4.4.2 Isolation/Disconnect

The Project shall be equipped with a means to isolate the power conditioning system from the substation. This may be accomplished through a lockable breaker.

A 12.47 kV interconnection isolation disconnect switch shall be placed directly on the line side of each metering section. The disconnect switch shall be lockable and have a visible break. The device does not have to be rated for load break nor provide over-current protection. The Owner shall have full access and control over this device.

A LV source side isolation contactor shall be provided. The disconnect breaker shall be lockable and have a visible break. It shall be capable of breaking the full rated power of the system. The contactor will be operated by the energy storage system control and will also have provisions to be operated manually. The utility will have full access and control over this device

4.4.3 Use for Auxiliary power

The auxiliary power system shall include, but is not limited to, all step-down transformers, breakers, fuses, motor starters, relaying, panels, enclosures, junction boxes, conduits, raceways, wiring and similar equipment, as required for the Project operation.

4.4.4 Power Quality Metering and Telemetry

Contractor shall provide its own Current Transformer's (CT) for protection and internal metering, and controls for Project operation. Contractor to provide local utility compliant metering and telemetry. Contractor to provide Potential Transformer (PT) connection points for synching and telemetry. Contractor to provide one revenue grade power quality meter installed on the line side of the main breaker to validate system performance.

4.4.5 System Protection Requirements

Contractor shall adhere to rules and regulations described on the Owner's Electric Distribution System Interconnection or Generation Interconnection Handbook if available. For the avoidance of doubt, the requirements of the applicable Interconnect Handbook shall apply to all aspects of the project and not just the system protection. If Owner Handbook is unavailable the contractor shall adhere to IEEE and Manufacturer device setting recommendation for protective system settings.

Protection and coordination for the "plant-side" system including batteries, DC combiner panels, inverters, AC combiner panels, transformers, auxiliary systems, and switchgear (where applicable) shall adhere to IEEE 242.

Protection relays for the interconnection shall be utility grade and shall meet the minimum requirements specified in IEEE C37.90 (latest edition) including requirements for EMI and surge withstand according to applicable standards for the intended location of the Project. A complete protective relaying system based on Industry Standards shall be a part of the AC system. The protective relaying and metering shall be integrated with the Project control system and communications channel to the Owner SCADA system. However, integration into the Project control system shall not circumvent normal protective relaying functions.

All protective equipment and schemes shall be properly coordinated with the Owner protection engineering department. The Contractor shall use Schweitzer Engineering Laboratories microprocessor-based protection equipment to the extent practical. The interconnection relay shall be a Schweitzer Engineering Laboratories relay with Mirror Bit capability. The low side bus and cable shall be protected by multifunction feeder protection relays. Testing of protection equipment shall be conducted by InterNational Electrical Testing Association (NETA) certified technicians. The NETA certification number of the tester shall be documented on all test reports.

4.5 Coordination of Controls

The Contractor shall provide a communications channel with Owner relaying at the interconnection distribution switch. This communications channel will provide permissions to island, black start and operate in parallel. See sample table Appendix E.

4.6 Instrument and Control Wiring

In general, and where practicable, control and instrumentation wiring shall be designed and installed to minimize all electrical noise and transients. All cabling shall be new and continuous for each run; splices are not acceptable. All conductors shall be copper.

All cabling which may be exposed to mechanical damage shall be placed in conduit, wireway, overhead tray, or other enclosures suitable to the Owner. Wires shall have identifying labels or markings on both ends. The labels shall identify the cable tag, and opposite end destination. Each wire in the system must have an accompanied drawing and location reference.

Control and instrumentation wiring shall be separated from power and HV wiring by use of separate compartments or enclosures or by use of separate wireways and appropriate barrier strips within a common enclosure as required by the NEC.

Project and PCS control and instrumentation system wiring shall be bundled, laced and otherwise laid in an orderly manner. Where cable is in wiretrays, waterfalls shall be used, as necessary. Wires shall be of sufficient length to preclude mechanical stress on terminals. Wiring around hinged panels or doors shall be extra flexible (Class K stranding or equivalent) and shall include loops to prevent mechanical stress or fatigue on the wires.

Cable insulation material shall be thermoset composition rated for 90˚C during normal operation. Insulation and jackets shall be flame retardant and self-extinguishing and shall be capable of passing the flame test of IEEE Standard 383 or IEEE 1202. Raceway and cable systems shall not block access to equipment by personnel.

Where appropriate, Fiber Optic Cable used for instrument and/or control shall be ruggedized indoor/outdoor breakout, riser rated, orange jacket, four fiber, 50/125um MM giga link 600 fibers, 2.5 mm, RoHS, standard strip.

4.7 Modular Replacement

The Project PCS, control, batteries and current sensors shall be connected in a manner that enables field replacement. It is expected that most maintenance will be accomplished while maintaining partial service.

The physical and electrical arrangement shall permit module replacement with the isolation breaker/contactor closed and the PCS disconnected.

Owner shall not be required to provide additional space or resources to accommodate the battery module replacement or supplementation. Contractor shall reserve the appropriate spacing and clearance per NESC into the design of the Project to accommodate battery module replacement and supplementation.

4.8 Physical Characteristics

The Project shall meet all applicable OSHA, NEC, IEEE, ANSI, and NFPA requirements for electrical and fire safety.

The Project shall be designed to minimize footprint and volume. The Project may also be designed to include subsurface components or modules, provided relevant operating and environmental factors normally addressed for submersible equipment are considered to assure full life-cycle performance requirements are met.

The Project components located outdoors shall be contained within weatherproof, tamper resistant, metal enclosures suitable for mounting outdoors on concrete pads with a minimum NEMA 3R rating. NEMA 3R: Types 3R, 3RX: Rain-tight, sleet-resistant. Indoor or outdoor use. Same protection as Type 1 but adds a degree of protection against ingress of falling dirt, rain, sleet and snow; also protects against damage due to external ice formation. Rust-resistant. The "X" designation indicates corrosion-resistance.

Any enclosures shall be dust tight to at least the NEMA 3R rating, except as designed to allow forced air exchange with the atmosphere.

Project Modules PCS, and controls shall be accessible and removable for replacement. The Project shall be designed to operate with minimal maintenance for at least five years.

A nameplate shall be provided including:

- Manufacturer Name
- Connection diagram
- ESS ratings; Power, energy, voltage, BIL
- Specimen data; serial number, date of manufacture
- The nameplate shall meet the requirements of IEEE C57.12.00

All necessary safety signs and warnings as described in ANSI Z535-2002 (entire series from Z535.1 through Z535.6) shall be included on the building, shelter or each enclosure. All necessary signs and warnings for identification of hazardous materials as described in NFPA 704 shall be included on the building, shelter or each enclosure.

4.9 Cycle Life

The energy storage system must be designed to achieve a minimum lifetime of 10 years. End-of-life is defined as when the energy storage system reaches 80% of the rated capacity at the time of installation. If the energy storage system is subject to capacity degradation, the design must accommodate future augmentation or replacement as required to maintain rated capacity, taking into consideration the specified operating profile. See the ESIC technical spreadsheet in Appendix G for cycle life requirements to various depths of discharge over the anticipated energy storage system lifetime.

The Contractor shall provide a graph or set of graphs that displays the relationship between depth of discharge, discharge energy throughput, operating temperature, C-rate, resting state-of-charge, and other relevant parameters and the corresponding capacity degradation experienced by the energy storage system.

Cycle counting shall be accomplished by applying a filter for each of the specified depth of discharge levels or based on other methodology proposed by the Contractor and agreed to by Owner. Contractor shall propose a methodology for tracking all other parameters that effect energy storage system capacity.

4.10 Battery Management System (if applicable)

As a subcomponent of a Project, a Battery Management System shall be included to manage the operational health of the Project, provide cell-by-cell diagnostics information and assure its safe and optimal performance of the energy storage system as an interconnected asset to the Owner's electrical system. Primary functions include but are not limited to:

- Monitoring:
  - State of Charge
  - State of Health
  - Voltage/Current
    - String
  - Temperature
    - Module Internal
    - Various Ambient
  - Status
  - Energy Throughput
- Maximum charge/discharge current or power
- Balancing
  - Cell voltage
- Warning and alarms
- Internal protective measures
- Logs of operations
- Management of any software versions
- Cyber Security management of the device itself
- Provide data exchange to the SEC

- Contribute to functional safety of overall Project

4.11 Power Conversion System

The PCS shall be listed to UL 1741 Supplement A. The PCS shall be capable of operating in all four power quadrants at rated power (20 MVA). Any combination of kW/MW and kVAr/MVAr output that results in the following equation being true: $\text{kVA}_{rated}=\sqrt{\text{kW}^2+\text{kVAr}^2}$ and as defined by the inverter P-Q capability curve, provided that at the system level there may be restrictions on reactive power output if the setpoint is chosen to boost system voltage that is already higher than nominal or reduce system voltage that is already lower than nominal.

The PCS shall be a static device (non-rotational) using solid-state electronic switch arrays in a self-commutated circuit topology. Line-commutated systems or systems that require the presence of utility voltage or current to develop an AC output are not acceptable. Only commercially proven switch technology and circuit designs are acceptable.

The PCS, in conjunction with the Project control system, shall be capable of completely automatic unattended operation, including self-protection, synchronizing and paralleling with the utility, and disconnect functions.

The control of the PCS shall be integrated with the overall Project control system. However, the PCS also shall include all necessary self-protective features and self-diagnostic features to protect itself from damage in the event of component failure or from parameters beyond safe range due to internal or external causes. The self-protective features shall not allow the PCS to be operated in a manner that may be unsafe or damaging. Faults due to malfunctions within the PCS, including commutation failures, shall be cleared by the PCS protection device(s) or external protection devices.

All PCS components shall be designed to withstand the stresses associated with steady state operation, transient operation and overload conditions as implied by this Specification. The Contractor shall be responsible to demonstrate that all relevant aspects of overvoltage stresses have been considered.

The PCS system shall include provisions for disconnection on both the AC and DC terminal(s) for maintenance work. Conductor separation must adhere to the requirements of the Owner’s Generator Interconnection Handbook, the Owner’s Distribution Interconnection Handbook, or IEEE recommendations. These disconnects shall be capable of being locked open for maintenance work. Any PCS capacitors shall be provided with bleeder resistors or other such means of discharging capacitors to less than 50 volts within five minutes of de-energization per UL1741 requirements.

The PCS or battery system must have DC bus pre-charging functionality or other means of arc mitigation during switching of the DC disconnect devices.

Outdoor located PCS electronic compartments shall be NEMA 4 and the overall enclosure rating shall be NEMA 3R. PCS shall meet IEEE 519 for harmonic content. Total harmonic distortion shall not exceed IEEE 519 requirements.

PCS cooling system shall not be susceptible to particle contamination and require minimal maintenance. The PCS shall be furnished with nameplates or stickers that are suitable for the environment. Nameplates shall be located to be visible with equipment installed and operating. Each nameplate shall indicate the following information:

- Nameplate ratings
- Component name
- Manufacturer's name
- Serial number
- Year built (or may be found in a reference document based on serial number)

4.12 Site Energy Controller

The Project shall include all necessary software applications and supporting hardware required to meet the specified functional requirements. Software algorithms, external data input capabilities, and user interfaces shall provide for user specified variable input or set point values, as well as external data value streams required by programs directing the Project operations.

The Project shall include the necessary communication and telemetry hardware, and support communications protocols, to effectively provide the required services. No single mode of failure shall result in loss of power to the control and data acquisition module. The control shall include provisions for an orderly and safe shutdown in the absence of utility power.

4.12.1 Operations and Control Functions

The SEC shall be the primary dispatching location for local monitoring and control command functions, and is responsible to perform the following by priority in this order:

- Protect itself (isolate for any internal fault)
- Remain within power constraints (transformer and Project ratings)
- Remain within frequency constraints
- Remain within voltage constraints
- Remain within operating temperature constraints
- Isolate in response to system anomalies
- Charge/discharge Real Power and Reactive Power in response to SEC programs or external commands
- Communicate status and diagnostic data

The SEC shall respond to commands issued remotely or locally, including but not limited to:

- Change Modes (e.g. charge, discharge)
- Startup/Shutdown
- Change Status (enable/disable)
- Reset Alarms
- System Reset/Restart

The SEC shall respond to the following modes of operation:

- Controller must be able to transition from one mode to any other mode without ceasing operation (current source to voltage source mode changes, excluded). Changing of output from an existing inverter setpoint to any other setpoint as a transition step (e.g. returning inverter to 0 output) before executing next command will be considered unacceptable.
- The controller must have the capability to limit system output based on an external signal. This will allow the unit to output to the limit of the circuit at any time. (e.g. if a circuit is rated for 10 MW and the current load is 5.5 MW unit should limit its maximum charge rate to 4.5 MW. Furthermore, we will feed the controlled the current circuit load in a register and it will do the math internally to determine the new system limits.)
- Controller must be able to transition from one setpoint within a given mode of operation to another setpoint within the same mode without ceasing operation. Changing of output from an existing inverter setpoint to any other setpoint as a transition step (e.g. returning inverter to 0 output) before executing next command will be considered unacceptable.
- Controller must be able to accept and validate a given setpoint command prior to executing a given operation mode. For example, if the Owner sends a command for the BESS to discharge at 1.0 MW in constant real power output mode, the controller must be able to validate and accept the 1.0 MW setpoint prior to it initiating constant real power output mode. Setpoint validation will vary depending on the control mode command but may include limits associated with state of charge, facility ratings, ramp rates, system operating conditions, etc.
- Controller must be able to switch from current source mode to voltage source mode and back via a single remote-control point ("Voltage Source Inverter Mode"), as well as a local point on the Human Machine Interface (HMI).
- Controller must be able to operate inverter breakers/contactors via remote control points ("Start" equals 1 is close command for breakers/contactors and "Start" equals 0 is open command for breakers/contactors), as well as a local point on the HMI.
- Controller must be able to reset all applicable system alarms via a remote-control point.
- Controller must be able to conduct real and reactive power operations completely independently of one another until the apparent power limit of the asset is reached.
- Controller shall allow for the prioritization of either real power setpoints over reactive power setpoints or reactive power setpoints over real power setpoints once the apparent power limit of the asset is reached. Prioritization shall be indicated via remote commands from the Owner.
- Controller shall allow the operator to "Idle" or "Standby" real or reactive power from the system while still operating the other.
- Controller shall NOT have a real power mode command which ceases any reactive power mode operation or vice-versa.
- Controller shall consider assign a positive sign convention to system real power output information when the system is discharging (real power).
- Controller shall assign negative sign convention to system real power output information when the system is charging (real power).
- Controller shall assign a positive sign convention to system information when the system is injecting reactive power (acting like a capacitor). This should be considered a leading PF.

- Controller shall assign a negative sign convention to system information when the system is absorbing reactive power (acting like an inductor). This shall be considered a lagging PF.
- Controller sign convention for real and reactive power commands shall match the desired convention assigned to system information reporting. In other words, positive real power commands refer to discharging, negative real power commands refer to charging, positive reactive power commands refer to injecting vars, and negative reactive power commands refer to absorbing vars.
- Specific to the Target State of Charge or Energy (SOC) operational mode, the Controller shall ensure the system reaches the commanded SOC setpoint and then not dispatch the system until after the SOC falls outside the commanded SOC deadband.

4.12.2 Permissive Operational States

As stated in the functional requirements, the Owner will permit the use of the Project in specific operational states remote signals. The Project must be able to integrate with the dispatch center to allow for and acknowledge each operational state. A command table must be submitted by the Contractor and approved by the Owner prior to the acceptance of the controller and FAT.

4.12.3 User Settable Limits

User settable limits shall be provided for the parameters listed below. These limits should have the capability to be changed either through the HMI and/or a remote setpoint. If a limit is reached an alarm or warning should alert the operator to the condition:

- Global Real Power Limit
- Global Reactive Power Limit
- Global Apparent Power Limit
- Mode-Specific Real Power Limit (unique limit for each mode)
- Mode-Specific Reactive Power Limit (unique limit for each mode)

The SEC shall enforce whichever limit is most restrictive for the current mode of operation, either the mode-specific limit or the global limit.

4.12.4 Human Machine Interface

A local HMI shall be provided to permit local monitoring and control. All settings must be viewable and settable, statuses viewable, operating parameters viewable, and logs configurable and viewable. Local password protection is required. Different login accounts shall be set up to allow for a hierarchy of operators: (i.e. observer: read, operator: read/write, admin).

Meaningful control buttons and indicating lights shall be provided for monitor and control status and operations. All control and alarm functions available remotely shall also be available locally.

A data entry screen shall be provided in the HMI to allow input of all user settable parameters, such as ramp rates, real and reactive power limits, and PF limits. This data entry screen shall require admin login rights. Display screens shall be developed for each of the control modes. Each screen shall display the mode, setpoint(s), actual value(s), deviation(s) from setpoint, and any applicable limits or configuration parameters.

The HMI shall include alarm screens, including alarm summaries, alarm details, and alarm logging. Alarms screens shall be provided for balance of plant type information (e.g. HVAC, fire alarms, UPS) in addition to energy storage system information.

An E-Stop button or equivalent shall be provided in the HMI to allow the operator to quickly shut down a unit. The E-Stop button shall have the ability to open contactors/breakers to the inverter and batteries isolating the DC and AC potential.

4.12.5 Remote Operations

The Project shall provide a single interface with which the Owner can communicate. All commands, feedbacks, information, statuses, and alarms from all system components or subsystems (fire suppression and/or HVAC included) should be conveyed via said interface. Single interface must have a minimum of four fiber ports and four copper ports or a network switch which provides the specified number of ports.

The SEC shall be able to respond to manual commands that are issued remotely by an external supervisory controller using a secure internet-based protocol. Commands sent to the SEC may come from other applications within a larger Distributed Energy Resource hierarchy.

The Project shall remain functional in the absence or loss of communication from the remote controller. The Project shall continue its current mode of operation for a set period (variable setting, 15-minute default). On expiration of the time, the Project shall standby.

During an interruption to communications, the remote controller will make repeated attempts to re-establish communications at a set time interval (variable setting, default of five minutes). When communications have been re-established, the Project and remote controller shall make any necessary updates to resume performance.

A “Local/Remote” control function shall be provided in the HMI so that the operator may allow or inhibit remote commands. The SEC shall log the source of each command (i.e. HMI/Operator Name, Remote). The source of the current active command shall also be displayed in the HMI.

4.12.6 Monitoring, Data Logging, Alarms, and Status

Alarms

- Alarms shall be provided for all critical energy storage system parameters (see Appendix E for more details).
- Alarms shall be provided for all critical balance of plant system parameters (see Appendix E for more details).
- The operator shall be able to assign criticality or importance to alarms and filter the alarms so that only the most critical are displayed on the HMI.
- Operator shall have the ability to acknowledge alarms.
- An alarm log with time stamps shall be provided.

- Details or help screens shall be provided for each alarm.
- An alarm matrix shall be provided to show the relationship and hierarchy of all alarms.

The SEC shall provide relevant status information, for feedback to the utility supervisory control system. The telemetry points should include:

- Operation Control
- Operation Status
- System Information
- AC/DC Status
- Counters
- Status
- Device Status and Error Codes (Alarms)
- Data Logging:
  - Log of Operations for one year on-site. Life-of-project duration for off-site log.
  - Historical data and trending for one year on-site for a limited set of parameters as-agreed with the Owner. Life-of-project duration for off-site data.

For full list of required information, please see Appendix E.

4.13 Network Communications

The Project and all its subcomponents required for operation shall be configured to be on its own sub-network, separate from any Owner communications network.

- Communication between the energy storage system and any Owner IP network shall be accomplished using a managed point of interconnection between the Contractor-provided energy storage system and any Owner IP-based network. The Contractor connectivity solution shall use a barrier technical control, such as a firewall. The Contractor shall configure the Contractor barrier technical control to deny IP traffic by default and allow authorized IP traffic by exception. The Owner shall configure its own barrier technical control between Owner networks and the Contractor-configured barrier technical control and shall configure the Owner barrier technical control to deny IP traffic by default and to allow authorized IP traffic only by exception.
- A modern IP-based protocol shall be used for external communications between Owner networks and the Contractor's energy storage systems. Other protocol options shall be implemented only by agreement between the Owner and the Contractor and are subject to Owner's Information Assurance Program.
- A secure, encrypted site to site IP virtual private network (VPN) tunnel may be established between the Owner and the Vendor to allow the Vendor remote access to the energy storage system for monitoring and support purposes. The Owner firewall will deny IP traffic by default and allow authorized IP traffic only by exception. Vendor will provide a detailed list of devices and protocols that require access for remote support.

- The Owner shall provide IP subnet assignments using private RFC 1918 address space for use in the energy storage system network. If required, a separate IP subnet assignment will be provided by the Owner for site to site VPN remote access purposes. If network address translation is required, it is the responsibility of the Vendor to configure translation on their side of the connection.
- Any additional Contractor or Vendor external communications to the energy storage system are prohibited. This includes analog lines, cellular modems, wired or wireless communications circuits, internet connections, or any other connection methods. If the Contractor requires alternate external communications, these must be submitted to the Owner for review. If the Owner grants approval, it is the sole responsibility of the Contractor to provide, install, secure, and maintain. The Contractor shall pay all installation costs and reoccurring charges for approved communications. For cybersecurity purposes, the Owner will not interconnect any Vendor network that has Internet access with any Owner routed IP network or networked device.

  The Project's HMI for control shall be able to be controlled by the Owner electric control centers using a TCP/IP routable protocol specified by the Owner.
- The Project's SCADA and historian information shall be able to be accessed by the Owner electric control centers using a TCP/IP routable protocol specified by the Owner.

Contractor shall provide its proposed network and communications documentation to include identifying all serial and network cables.

The solution shall use wired connections for communications. If the Contractor wishes to include wireless communications in the proposal, these must be submitted to the Owner for review. The Contractor shall provide a list of any proposed wireless communications devices, security methods and encryption standards, the associated protocols, and a list of endpoint devices that would be connected.

Contractor provided communications equipment shall be suitable for the intended purpose and the environment where it is installed. Contractor shall use hardened devices that support extended temperature and humidity where required. For key system communications, the equipment should have built in high availability or redundancy capabilities, or separate redundant devices should be used.

Any Contractor-provided LAN switch implemented as a part of the Project shall have a switch port configured as a SPAN port, to which an Owner network anomaly detection appliance shall be attached to span the traffic to identify and alert on apparent cybersecurity issues.

The proposed solution shall provide communications for any required security and fire alarm systems, including fire and first responders, in compliance with all Applicable Laws and Owner standards. The solution shall be capable of communicating with Owner-selected Remote Terminal Unit (RTU) via currently-supported protocols and cabling types, as assisted by an Owner Interface.

The solution shall be capable of communicating with the Owner-selected Automated Dispatch System Gateway via currently-supported protocols and cabling types, as assisted by an Owner Interface. The solution shall be capable of communicating with the Owner-selected Owner Metering via currently-supported protocols and cabling types for both the systems load and auxiliary load, as needed. The energy storage site metering system shall be implemented to support polling via the Owner's specified protocol, as assisted by an Owner Interface.

The Project shall support selection of control modes between local HMI, remote Owner, Automated Dispatch System, and AGC control sources, as assisted by an Owner Interface. The Project shall be capable of integration with the Owner enterprise control system, as assisted by an Owner Interface. Any Contractor-provided LAN switch implemented as a part of the Project shall have a switch port configured as a SPAN port, to which an Owner network anomaly detection appliance shall be attached to span the traffic to identify and alert on apparent cybersecurity issues.

The Project must be able to interoperate with either a RTU local to the site, or a RTU that the Owner may locate at a central location and communicate to over Owner-owned WAN communications for aggregation of multiple sites to a single RIG before transport of data between the Owner and the local utility/transmission owner.

The Project's Owner-facing network and firewall equipment shall be interoperable with Owner Networks LAN switches, routing, and firewalls, to include static routing, MPLS, OSPF, and 802.1q VLAN trunking.

4.14 Information Security

4.14.1 Contractor

Contractor shall design the Project to be hardened against willful attack or human negligence using Cybersecurity industry best practices and incorporating technical controls as applicable to the Project as outlined in the NISTIR 7628 Framework. The reference for these controls can be found through the NIST government publications for the Framework NISTIR 7628 – Guidelines for Smart Grid Cyber Security: Vol. 1, Smart Grid Cyber Security Strategy, Architecture, and High-Level Requirements. A summary of these controls is listed in Appendix G.

4.14.2 Account Management

The Contractor shall design the Project to support integration with the Contractor's centrally managed Active Directory instance. The Contractor's control system solution will authenticate through LDAP or OAuth, as assisted by an Owner Interface.

4.14.3 Application Partitioning

The Contractor shall design the Project to support integration with Role-based Access Controls, as assisted by an Owner Interface. For example, functions necessary to administer databases, network components, workstations, or servers, and typically requires privileged user access. The separation of user functionality from information system management functionality is either physical or logical.

4.14.4 Audit Logging and Reporting Mechanisms

The Contractor shall design the Project to provide logging capabilities. Preferably the logging mechanism is in a standard format like Syslog that can easily integrate with the Owner Security Integration and Event Management system.

4.14.5 Authentication and Authorization Controls

- The Contractor shall design the Project to provide the following authorization controls:

- Log account access events, such as failed login, login, logout, session timeout.
- Display an approved system use notification message or banner before granting access to the system that provides privacy and security notices consistent with all Applicable Laws, Executive Orders, directives, policies, regulations, standards, and guidance.
- Prevent non-privileged users from executing privileged functions to include disabling, circumventing, or altering implemented security safeguards/countermeasures.

4.14.6 Authenticator Feedback

The Contractor shall design the Project to obscure feedback of authentication information during the authentication process to protect the information from possible exploitation/use by unauthorized individuals. For example, do not display a separate error message for an invalid username versus an invalid password.

4.14.7 Baseline Configuration and Configuration Settings

The Contractor shall provide a checklist of security configuration requirements / system hardening requirements for all IT assets deployed as part of the Project, as assisted by an Owner Interface.

4.14.8 Boundary Protection System

The Contractor shall segment trust zones using a barrier technical control such as a firewall. The barrier technical control shall be configured to deny network communications traffic by default and allow network communications traffic by exception.

4.14.9 Cryptographic Key Establishment and Management

The Contractor shall provide certificates that support at least SHA-2, SHA-1 certificates are not permitted. Wildcard certificates like *.example.com are not permissible and certificates must be for specific (list) of sub-domains. All PKI certificates must support SHA-256 or higher. The Contractor will provide cryptographic keys from a Certificate Authority approved by the Owner.

4.14.10 Device Identification and Authentication

The Contractor shall provide an asset inventory containing all IP addressable devices in the Project. The asset inventory will include the following fields: Device Name, Network Name, IP Address, MAC Address, Building Location, Rack Location, Firmware version / software version, Device Description.

4.14.11 Information Input Validation

The Contractor shall provide a solution that validates user input and network input for malicious content and unstructured data within the Project. For example, user interfaces should not be susceptible untrusted user inputs.

4.14.12 Information System Backup

The Contractor shall provide the Project with a solution that is scheduled to conduct periodic backups of user and system-level information and protect the confidentiality, integrity, and availability of the backups.

4.14.13 Information system Monitoring

The Contractor shall allow the Owner to monitor network traffic leveraging SPAN ports on switches and routers provided as part of the Project.

4.14.14 Least Functionality

The Contractor shall configure information systems to provide only essential capabilities, open ports, protocols, and services as part of the Project.

4.14.15 Malicious Code Protection

The Contractor shall provide malicious code Endpoint protection software on all assets that support it in the Project and provide a method for updating the software. The Contractor shall configure the Endpoint protection software to perform periodic scans of the information systems and real-time scans of files that are downloaded, opened or executed. The malicious code protection software will block malicious code, quarantine malicious code and send alerts to administrators of the system. Enforced Whitelisting of system software and operation may be considered an alternative to Endpoint protection.

4.14.16 Password-Based Authentication

The information system shall offer provisions for a password-based authentication. These features should include, but are not limited to, the following:

- Enforce password complexity to include case sensitivity, a minimum of eight characters, mix of upper-case letters, lower-case letters, numbers, and special characters.
- Stores and transmits only encrypted representations of passwords.
- Enforces password minimum and maximum lifetime restrictions of specific defined numbers for lifetime minimum, lifetime maximum.
- Prohibits password reuse for 10 generations.
- Allows the use of a temporary password for system logons with an immediate change to a permanent password.
- Employs automated tools to determine if password authenticators are sufficiently strong as related to above criteria of password authentication requirements.

4.14.17 Protection of Information at Rest

As part of the Project, the Contractor shall implement Information Systems that:

- Protects the confidentiality and integrity of information at rest.
- Implements cryptographic mechanisms to prevent unauthorized disclosure and modification of information on information system components.
- Securely stores off-line storage.

4.14.18 Remote Access Policy

The Contractor should leverage a two-factor authentication solution architecture to remotely access the Project, as assisted by an Owner Interface.

4.14.19 Session Authenticity

As part of the Project, the Contractor shall implement Information Systems that:

- Invalidates session identifiers upon user logout or other session termination.
- Generates a unique session identifier for each session with randomness and recognizes only session identifiers that are system-generated.
- Only allows the use of certificate authorities for verification of the establishment of protected sessions.

4.14.20 Transmission Confidentiality and Integrity

As part of the Project, the Contractor shall implement cryptographic mechanisms to prevent unauthorized disclosure of information during data transmission (e.g. VPN Tunnel).

4.14.21 Unique Identification and Authentication

As part of the Project, the Contractor shall provide the means to uniquely identify and authenticate organizational users (or processes acting on behalf of organizational users) such as Multifactor authentication. Shared user accounts shall not be permitted.

4.14.22 3rd Party Assessment

Contractor shall contract information/cyber security scans and penetration tests by an Owner-approved third-party security company, prior to Substantial Completion.

The Contractor will provide the Owner with a copy of the original report from the 3rd party security company. The Owner reserves the right to perform its own internal security testing in addition to the Contractor's testing.

Contractor shall develop a cybersecurity plan that addresses and mitigates the critical vulnerabilities inherent in both the hardware and software that comprise the control and data acquisition systems. The cybersecurity plan will include regular qualified software patches and service packs to Windows and Linux based operating systems, the underlying software and device firmware. The patches will be applied at least every 90 days with an expedited method for highly critical vulnerabilities (Common Vulnerability Scoring System Score of 10).

4.14.23 Portable Media and Laptops

As part of the Project, the Contractor shall disable all mass storage device capabilities for Windows and Linux based servers and workstations (USB drives, SD Cards, CD-ROMs, External Portable HDDs and Floppy disk drives).

Any portable device (or variant) such as process control service laptops will be regularly managed by policy to ensure it is inspected and found to be free from malicious code. Using latest version Endpoint protection with regular updates no older than 30 days. Portable devices will be restricted from connecting to a secondary network while connected to the Process Control network. The Owner may request logs and audit access to review system scans, patching and management tools to ensure compliance.

4.14.24 Unused Network Ports

As part of the Project, the Contractor shall disable all unused network ports on switches, routers and firewalls.

4.15 Containment

4.15.1 Lightning Protection

Provide a UL Master Label lightning protection system for all buildings, shelters and other structures per the requirements of NFPA 780 and UL 96A.

4.15.2 Cooling Systems

The Site temperatures and the effect of temperature on component life shall be considered in developing the thermal design for all components, including the batteries and PCS. There may be several separate heat removal systems to accommodate the needs of Project components and subsystems (e.g. PCS, transformers). The heat removal and/or cooling system may include vapor-compression cooling system or other conventional environmental conditioning equipment. Final rejection of all waste heat from the Project shall be to the ambient air.

Air handling systems shall include filters to prevent dust intrusion into the Project. Exterior wall make-up air inlet louver shall be sized to avoid water penetration. HVAC system(s) efficiency and control requirements needs to comply with applicable local and national codes. HVAC system(s) for energy storage cooling shall include three or more stages. Sufficient redundancy shall be considered in the design such that no single component failure will shut-down the system.

HVAC and ventilation systems shall be seismic braced/anchored. All design shall be in accordance with local and national seismic design requirements.

Evaporator coil coating shall also be required if outside air is draw-in from the exterior. Indirect waste from the HVAC system(s) shall be disposed per local and national plumbing codes. HVAC/ventilation design shall comply with all Applicable Laws. HVAC/Ventilation shall require interlock to the shelters fires alert system for shut-down.

4.15.3 Fire Protection

The Contractor shall provide fire protection system for the complete energy storage system including modification of existing site fire protection system to meet all applicable codes including the 2nd DRAFT release of the new NFPA 855 "Standard for the Installation of Stationary Energy Storage Systems" and the latest approved revision of the applicable local fire protection codes.

EPC contractor shall comply with NFPA coordination, design, installation, commissioning, testing, training and startup requirements. This shall include all other requirements as outlined in this specification. Fire Protection system design shall include, but not be limited to, the following:

- emergency vehicle access and fire hydrants per applicable local and national codes;
- Hazard Mitigation Analysis to defend and gain alignment for the system design with all key stakeholders before the design is finalized (e.g. risk mitigation for runaway prevention);
- Shelter design in accordance with NFPA requirements for location, separation, materials of construction, ventilation, smoke or flammable conditions detection, fire suppression, communications/alarms, training, commissioning, permitting, and documentation
- The fire alarm control panel shall provide supervised addressable relays for HVAC shutdown. The HVAC Engineer shall design and specify startup and testing services to support the interface with the Fire Protection System and ensure that the HVAC is de-energized as designed. Alarms shall clearly annunciate location of detected condition within building or by individual container.
- Startup and testing of the Fire Protection System will be provided by the fire protection contractor in accordance with NFPA requirements.
- Option pricing for an off-gas sensing system that will detect off-gassing at the cell level. This system shall be integrated into the Contractor's control system and/or site controller.

Contractor will provide the potential combustion products and quantities for the batteries (or other storage media) selected to be used with the energy storage system.

4.16 Station DC system and Uninterruptible Power Supply

The Project shall be equipped with a Station DC system and/or a UPS to power essential functions in the event of a total failure of auxiliary supply systems(s) if required for orderly shutdown. The UPS system shall provide backup support for all control and communication equipment necessary for black start and island operation. The provided DC system/UPS shall comply with the applicable standards. In no case shall the UPS have less than eight hours of back-up power for power essential functions. Protective relays shall have no less than 72 hours of backup power. Owner's preference would be to have this UPS function provided by the primary Energy Storage System.

4.17 Energy Storage System Design

The Contractor shall design, furnish and install an energy storage system that meets all the requirements of the Agreement, including this Specification.

4.17.1 Cells and Modules (if applicable)

The energy storage shall consist of cells of proven technology designed for the type of service described herein. For the purposes of this Specification, proven technology shall be defined as cells that have been in successful commercial service in similar type applications for a period sufficient to establish a service life and maintenance history. Only cells that are commercially available or for which suitable (not necessarily identical) replacement cells (or modules or strings) can be supplied on short notice throughout the Project life will be allowed. Cells shall be listed to UL 1642 and manufacturer must provide UL certificate prior to shipment to Project Site.

The cells may be supplied as separate, individual units or as group of cells combined into modules. Modules shall be listed to UL 1973, and UL 9540A and manufacturer must provide UL certificate prior to shipment to Site.

Cell construction and accessories (as applicable) shall be sealed to prevent electrolyte seepage. Post seals shall not transmit stresses between the cover or container and the posts. Cell terminals and interconnects shall have adequate current carrying capacity and shall be designed to withstand short circuit forces and current generated by the energy storage. Safety features shall be designed into each cell in accordance with UL 1642, UL 1973, and UL 9540A.

DC Contactors will disconnect the string from the circuit during high temperature conditions but will reconnect once the cell temperatures reach an acceptable range and other conditions are met allowing reconnection. Labeling of the cell (or modules) shall include manufacturer’s name, cell type, nameplate rating and date of manufacture, in fully legible characters or QR code. Contractor shall provide a list showing all the modules by their unique identification number along with their corresponding physical location within the project site. The unique identification numbers shall correspond to their identification within the Project so to provide easy location of all cells or modules.

The energy storage subsystem and as individual cells shall be designed to withstand seismic events as described herein. The batteries may consist of one or more parallel strings of cells.

DC wiring shall be sized per NEC Article 310 or based on UL standards and be appropriately braced for available fault currents. Protection shall include a DC breaker, fuse or other current-limiting device on the energy storage bus. This protection shall be coordinated with the PCS capabilities and energy storage string protection and shall consider transients and the Inductance/Resistance (L/R) ratio at the relevant areas of the DC system. The Project shall operate no higher than 1,500 Volts DC.

The Contractor shall provide information on the impact that weak or failed cells have on the life and performance of the entire string. The Contractor shall specify critical parameters, such as temperature variation limits between cells of a string. The Contractor shall provide a means of monitoring critical parameters to ensure the limits are being met.

Cells, wiring, switchgear and all DC electrical components shall be insulated for 2,000 Volts DC. The Contractor shall have overall responsibility for the safety of the electrical design and installation of the Project. The Project shall include a monitoring/alarm system and/or prescribed maintenance procedures to detect abnormal cell conditions and other conditions that may impair the ability of the Project to meet performance criteria.

The energy storage monitoring system shall be capable of balancing the voltages across cells automatically and independently without any input from the operator or the SEC. Cell monitoring system shall be specified to alert the proper personnel in a timely manner that an abnormal cell condition exists or may exist. Abnormal cell conditions shall include over- and under-cell voltage. Temperature is not expected to be monitored at the individual cell level.

The monitoring/alarm system will record data on the number and general location of failed modules, to expedite maintenance and cell replacement. This data shall be stored in non-volatile memory. Such monitoring/alarm system shall be integrated into the overall control system.

The Project shall include racks or shall consist of stackable modules of batteries. Aisle spaces shall be set to permit access for equipment needed for easy removal and replacement of failed modules. The lengths and widths of aisles shall conform to all applicable codes and facilitate access by maintenance personnel. As applicable, the racks shall provide sufficient clearance between tiers to facilitate required modules maintenance, including modules testing and inspection, and replacement.

Rack-mounted modules shall have all connections located on the front of the enclosure or module. Modules shall not be required to be removed from the racks during regular maintenance. All racks and metallic conductive members of stackable modules shall be solidly grounded. Racks shall be seismically designed based on the requirements of Section 1.4 and shall include means to restrain cell movement during seismic events. All design shall be in accordance with seismic design requirements as specified in Section 1.4 of this Specification.

4.18 Medium Voltage Switchgear

Metal-enclosed switchgear shall be designed, constructed and tested per IEEE C37.20.3. Metal-clad switchgear shall be designed, constructed and tested per IEEE C37.20.2. Design test results shall be provided to the Owner prior to shipment to the Site.

4.18.1 Field Tests

Contractor shall:

- High-potential test each breaker in accordance with IEEE C37.20.2, Table 1 and part 6.5. Apply test voltage to each pole of the breaker for one minute.
- Test and record contact resistance on each phase from bus to load terminal through a closed breaker.
- Record operation counter reading.
- Perform vacuum integrity test.

The MV switchgear lineup shall be rated to continuously carry nominal Project generation. The lineup shall contain power metering and voltage transformers, fused switches and circuit breakers as necessary to collect and interconnect full plant generation.

Switchgear shall include an auxiliary compartment containing all instrument transformers associated with the protective relays and a 120/240 Volt Control Power Transformer. The Control Power Transformer shall be fused and able to disconnect. The Control Power Transformer shall be sized to supply the expected continuous load, with approximately 20 percent margin for future load growth. The transformers shall be air-cooled, dry type, with a 150 °C rise. Alternatively, site DC backup power may be used.

Switchgear shall be provided with a metering section containing provisions for utility meters. Consistent with the Owner's Electric Distribution System Interconnection Handbook, the metering section includes cable pull sections, bus bars for metering CT/PT insertion; disconnect switches, a metering panel, a meter socket(s), and accommodations for test switches/test blocks. A set of visible disconnect switches, or rack-able breaker, shall be placed directly on the line side of each metering section as well as a set of disconnect switches for the metering PTs (accessible by Owner personnel only) per the Owner's service requirements. In addition, a set of disconnect switches shall be placed on the load side of the meter or at the point of generator output. Disconnect switches and rack-out breakers must accommodate locking devices to allow the Owner to lock-out services or net-generation points when necessary.

Protective relaying, metering, and control parameters shall be in accordance with the Owner Electric Distribution System Interconnection Handbook and reviewed and approved by Owner prior to construction. All design shall be in accordance with seismic design requirements as specified in Section 1.4 of this Specification.

4.19 3 Phase, Liquid-Filled or Dry-Type Pad-Mount Transformer

The nominal high-side voltage shall be 12.47 kV, unless noted otherwise by the Owner. Transformer LV windings shall be per Inverter manufacturer's recommendations. Percent impedance voltage shall be according to the inverter manufacturer's recommendation. Transformers shall be rated for continuous operation of the Inverters.

Transformers shall be configured as Wye high side, Delta low side. This transformer will also require a high side neutral (HO) bushing with ground strap connected to the neutral. The aux transformer will require an electric meter socket. This can be designed in to the transformer or a pedestal with a meter socket can be used to meter site aux load. Transformers are required to have load interruption capabilities on the low side to isolate the energy storage equipment (e.g. inverters, storage media).

Liquid filled transformers shall be designed, constructed and tested in conformance with IEEE C57.12.00. Liquid filled transformers shall contain a UL-listed and Factory Mutual Global Approved less-flammable dielectric coolant meeting the requirements of NEC Section 450-23 and the requirements of the National Electrical Safety Code, Section 15. Transformer shall be suitable for indoor or outdoor use as applicable. Routine test results shall be provided to the Owner prior to shipment to the Site. All design shall be in accordance with seismic design requirements as specified in Section 1.4 of this Specification.

4.19.1 Field Testing

- Verify nameplate data.
- Coordinate and perform instrument transformer tests on CTs with transformer assembly.
- Winding Tests:
  - Transformer Turns Ratio at all no-load taps.

- Megger winding to ground.
- Megger winding to winding.
- Set HV taps at positions determined by Engineer.

- Check and measure equipment ground; ground shall not be more than one ohm.
- Check insulating fluid for clear or pale amber color and report any variance to the Owner. Other colors may indicate contamination from decomposition of insulation, foreign material, carbon, or other substances.
- Test oil samples from each transformer with standard AC test in accordance with ASTM D1816. Notify the Owner if breakdown voltage is less than 30 kV.
- Check liquid level in tanks, and in bushings of the liquid-filled type, and check nitrogen content in inert gas sealed oil preservation systems.
- Check that all valves are open between the transformer tank and cooling equipment.
- Check operation of cooling equipment and cooling controls before energizing transformer.
- Check calibration of pressure relief device, top oil temperature relay, and hot spot temperature relay.
- Pressure test the sudden pressure relay in accordance with the manufacturer's instructions to verify proper operation of device and electrical contacts.
- Alarm Sensor Testing: Induce the device to operate with proper input medium (heat, cooling, pressure, vacuum, voltage, current, etc.) and verify operation of the device at the correct input medium level by monitoring the output contacts with an ohmmeter.
- Annunciator Testing: Check each unit of annunciators by closing or opening the trouble contact and observing operation of control board.
- Check all annunciator lamps, bell cutoff, and reset operation.
- Test all gauges including level, temperature, and pressure gauges.

4.20 Dry Type Transformers

Dry type transformers shall be designed, constructed and tested in conformance with IEEE C57.12.01. Dry type transformers shall be ventilated dry-type cast coil, Class AA suitable for indoor or outdoor use as applicable. All design shall be in accordance with seismic design requirements as specified in Section 1.4 of this Specification.

4.20.1 Field Testing

- Verify nameplate data.
- Winding tests:
  - Transformer Turns Ratio at all taps.
  - Megger winding to winding.

- Megger winding to ground.

- Check equipment ground to assure continuity of connections. Notify the Owner if ground is more than one ohm.
- Check electrical neutral of the transformer. This connection shall be a copper wire connection to the station ground grid.
- Check for proper operation of the winding temperature gauge and cooling fans.
- Set HV taps at positions determined by Engineer.
- Check connections for tightness; clean out dust and other foreign material.

No Load taps labeled per IEEE Std C57.12.34. Full-capacity taps in high-voltage winding:

- Two 2.5% taps above rated voltage.
- Two 2.5% taps below rated voltage.
- Transformer compartments shall have provisions for padlocking.
- High-voltage compartment shall contain terminations for dead-break elbows, and provisions for entrance of multi-conductor high-voltage, insulated, shielded, power cable. Provide terminations with stress relief devices.
- Transformer shall be equipped with a load-break switch that is oil immersed in transformer tank. The handle shall be located on the exterior tank wall. The switch shall be operable without exposure to any live circuits.

Include accessories as follows:

- Dial-type thermometer with contacts for high-temperature warning and alarm levels
- Magnetic liquid level gauge with alarm contact for low level.
- Pressure/vacuum gauge with alarm contacts.

4.21 Raceways

4.21.1 Conduit

- Contractor shall install all conduit, bends, accessories, fittings, junction boxes, mounting hardware, etc., to produce the complete system.
- Conduit shall be sized and installed in accordance with the NEC.
- In general areas, Electrical Metallic Tubing can be used for all feeders hidden from view above ceilings and in walls. Electrical Metallic Tubing fittings shall all be compression-type fittings. Set-screw fittings shall not be utilized.
- Flexible Metal Conduit or Liquid-tight Flexible Metal Conduit shall be used for connections to motors, transformers, machinery, lighting, and for other equipment subject to vibration.
- Rigid Metal Conduit or Intermediate Metal Conduit shall be used as allowed in the NEC.

- Plastic conduit, elbows, couplers and other fittings for underground application shall be Schedule 40 PVC, UL or ETL Listed. Fabrication, testing, and installation shall be per NEMA TC-2. Direct buried conductors will not be allowed. Each underground conduit package shall include at least one spare conduit.
- Threaded or compression fittings shall be used with all raceway types. Set-screw fittings are not permitted.
- All conduit shall be sealed.

4.21.2 Tray

- Tray shall be fabricated, tested, and installed per NEMA VE1, NEMA VE2, and the NEC.
- Aluminum: Straight section and fitting side rails and rungs shall be extruded from Aluminum Association Alloy 6063 and all fabricated parts shall be made from Aluminum Association Alloy 5052, in accordance with ASTM B221 and ANSI H35.1.
- Pre-galvanized Steel: Straight sections, fitting side rails, rungs, and covers shall be made from steel meeting the minimum mechanical properties and mill galvanized in accordance with ASTM A653 SS, Grade 33, coating designation G90.
- Hot-dip Galvanized Steel: Straight section and fitting side rails and rungs shall be made from steel meeting the minimum mechanical properties of ASTM A1011 SS, Grade 33 for 14 gauge and heavier, ASTM A1008, Grade 33, Type 2 for 16 gauge and lighter, and shall be hot-dip galvanized after fabrication in accordance with ASTM A123. All hot-dip galvanized after fabrication cable trays and components must be returned to point of manufacture after coating for inspection and removal of all icicles and excess zinc to mitigate damage to cables and/or injury to installers.
- Hardware shall be zinc plated in accordance with ASTM B633, SC1. If aluminum cable tray is to be used outdoors, then hardware shall be Type 316 stainless in accordance with ASTM F593 and F-594.
- Any exterior tray shall include a cover.
- All design shall be in accordance with seismic design requirements as specified in Section 1.4 of this Specification.

4.22 Medium Voltage Cable

- Cable shall be listed to UL 1072 and adhere to NEC requirements.
- Cable furnished shall be suitable for installation in underground ducts and conduits, trays, underground structures, and in outdoor applications of direct underground burial or for use in suitable supported aerial applications. Cable shall be rated for wet and dry locations.
- Insulation shall be thermosetting compound with minimum ratings for normal conductor temperatures of 90 °C, 140 °C for emergency operation condition, and 350 °C for short circuit conditions.
- Cable shall be tested at the factory and reports delivered to the Owner prior to shipment. Once test results are provided to the Owner, it will have five business days to review testing reports.

Contractor shall not ship cables until the Owner approves the test reports or the review period expires.

4.22.1 Field Tests

- Field high potential test in accordance with NEMA WC 74 (ICEA S-93-639), Table F-1, DC Test Voltages After Installation and NETA ATS, Table 100.6, Medium-Voltage Cables Acceptance Test Values, as follows:

		DC TEST VOLTAGE (KV)	
RATED VOLTAGE (KV, PHASE-PHASE)	CONDUCTOR SIZE AWG OR KCMIL	100% INSULATION	133% INSULATION
2,001 – 5,000	8 – 1,000	28	28
2,001 – 5,000	1,001 – 3,000	28	36
5,001 – 8,000	6 – 1,000	36	44
5,001 – 8,000	1,001 – 3,000	36	44
8,001 – 15,000	2 – 1,000	56	64
8,001 – 15,000	1,001 – 3,000	56	64
15,001 – 25,000	1 – 3,000	80	96
25,001 – 28,000	1 – 3,000	84	100
28,001 – 35,000	1/0 – 3,000	100	124
35,001 – 46,000	4/0 – 3,000	132	172
46,001 – 69,000	4/0 – 3,000	N/A	195

- The initially applied DC voltage shall be not greater than 3.0 times the rated AC voltage of the cable.
- The duration of DC voltage test shall be 15 minutes.
- Do not test cables with an AC test set. Disconnect from all equipment during testing. Testing cable on the reel will not be acceptable. Perform tests after installation, but before final connection to equipment. Make high potential tests between each conductor and shield, or between conductor and armor with shield or armor grounded.

4.23 2.0 kV Cable

- Cable shall be listed to UL 44 and adhere to NEC requirements.
- Cable shall be rated for use in conduit, underground ducts, and cable tray.
- Insulation shall be thermosetting compound with minimum ratings for normal conductor temperatures of 90˚C.
- Field Tests
  - Megger insulation resistance testing is required prior to energization.

4.23.1 Field Tests

- All field tests shall be performed by a certified third-party testing company.

- In addition to the tests specified previously, the following tests shall be conducted:
  - LV breakers 100A and greater shall be trip tested.

5.0 APPENDIX A APPLICABLE STANDARDS AND CODES

NO.	STANDARDS	CODE
1	ANSI/IEEE C2	National Electric Safety Code
2	IEEE 519	IEEE Recommended Practices and Requirements for harmonic Control in Electrical Power Systems
3	IEEE 1547	IEEE Standard for Interconnecting Distributed Resources with Electric Power Systems
4	IEEE 1547.1	Standard Conformance Test Procedure for Equipment Interconnecting Distributed Resources with Electric Power Systems
5	IEEE 1547.2	Interconnecting Distributed Resources with Electric Power Systems
6	IEEE 1547.3	Guide for Monitoring, Information Exchange, and Control of Distributed Resources Interconnected with Electric Power Systems
7	ANSI Z535	Product Safety Signs and Labels
8	ANSI C57/IEEE	Transformer Standards, whenever applicable
9	ANSI C37/IEEE	Surge withstand capabilities, whenever applicable
10	UL 1642/IEC 62133	Applicable sections related to battery cell safety, where applicable
11	UL 1741	Standard for Inverters, Converters, Controllers and Interconnection System Equipment for Use with Distributed Energy Resources
12	NFPA 704	Standard System for the Identification of the Hazards of Materials for Emergency Response
13	UL 1778	Underwriters Laboratories' Standard for Uninterruptible Power Systems for up to 600 Volts AC
14	UL 1973	Standards for Batteries for Use in Light Electric Rail Applications and Stationary Applications
15	UL 9540/9540A	Standard for Energy Storage Systems and Equipment
16	Electric Tariff Rule 21	Generating Facility Interconnections
17	NISTIR 7628	Guidelines for Smart Grid Cyber Security
18	NEC	National Electric Code
19	NESC	National Electric Safety Code
20	ASHRAE	American Society of Heating, Refrigerating and Air-Conditioning Engineers
21	CAA	Clean Air Act and Amendments
22	CERCLA	Comprehensive Environmental Response, Compensation, and Liability Act of 1980
23	EPA	Environmental Protection Agency regulations
24	FAA	Federal Aviation Administration regulations
25	FERC	Federal Energy Regulatory Commission regulations
26	FPA	Federal Power Act
27	RCRA	Resource Conservation and Recovery Act
28	SDWA	Safe Drinking Water Act
29	SWDA	Solid Waste Disposal Act
30	TSCA	Toxic Substances Control Act
31	ADA	Americans with Disabilities Act
32	MBTA	Migratory Bird Treaty Act
33	CWA	Clean Water Act
34	ANSI	American National Standards Institute
35	IEEE	Institute of Electrical and Electronics Engineers
36	NEMA	National Electrical Manufacturers Association
37	ASTM	American Society for Testing and Materials
38	ASME	American Society of Mechanical Engineers
39	IEEE 1881	Standard Glossary of Stationary Battery Terminology
40	IEEE 519	Recommended Practice and Requirements for Harmonic Control in Electric Power Systems

NO.	STANDARDS	CODE
41	**IEEE 142**	Recommended Practice for Grounding of Industrial and Commercial Power Systems
42	**IEEE 242**	Recommended Practice for Protection and Coordination of Industrial and Commercial Power Systems
43	**IEEE 2030.3**	Standard Test Procedures for Electric Energy Storage Equipment and Systems for Electric Power Systems Applications
44	**EPRI 3002009313**	Energy Storage Integration Council Energy Storage Test Manual 2016
45	**IEEE 1881**	Standard Glossary of Stationary Battery Terminology
46	**Owner S-76**	Below Grade Substation Standards
47	**MESA**	Open Standards for Energy Storage
48	**NFPA 855**	Standard for the Installation of Stationary Energy Storage Systems
49	**OSSC**	2014 Oregon Structural Specialty Code
50	**International Building Code**	2012 International Building Code
51	**ACI-318**	American Concrete Institute 318-11
52	**AWS**	American Welding Society D1.1 Structural Welding Code - Steel

6.0 APPENDIX B CONCEPTUAL ONE-LINE DIAGRAM

7.0 APPENDIX C ENERGY STORAGE SYSTEM FACTORY ACCEPTANCE TESTING PROCEDURE

8.0 APPENDIX D STATE MATRIX

		STANDBY	RUN	CURRENT SOURCE ENABLE	SYNC REQUEST	BLACK START ENABLE	INVERTER READY	INVERTER RUNNING	ISLAND READY	SYNCH READY
1	Standby	1	0	0	0	0	1	0	0	0
2	Island	1	1	0	0	0	1	1	1	0
3	Synch request	1	1	0	1	0	1	1	1	1
4	Black Start	1	1	0	0	1	0	0	0	0

9.0 APPENDIX E SUPERVISORY CONTROL AND DATA ACQUISITION INTERFACE

Overview

The following is information of the data objects being used by the Owner for controlling and monitoring storage systems via a communications gateway. Contractor will appropriately deploy or provide an interface which implements a TCP protocol. Additionally, Contractor will implement multiple points list, simultaneously, including Owner Points List as specified below.

Note the alarms list for each system has not been listed, as systems provide a multitude of alarms. In all cases, the complete set of all possible alarms must be conveyed via alarm word points at each level, System and Subsystems (Inverters and Energy Storage Banks). Each bit of a given word must be mapped to a single alarm (fault or warning). Multiple alarms words can be utilized at every level if the number of alarms exceed the number of bits available in a single alarm word.

Alarm words at the System level should have a single bit representing the presence of alarms on each subsystem (Inverter or Energy Storage Bank) that make up the energy storage system.

Consider a System comprised of two inverters and two energy storage banks. Energy storage bank one and inverter two each have a single active alarm present. The System level alarm word should have a bit for each of the subsystems, in this case, two inverters and two energy storage banks, representing the existence of present alarms. If the last four bits (28-31) were reserved for this (one for each subsystem), the other 28 bits are available to represent System level alarms.

It should be also noted that any other device capable of generating alarms within the energy storage system should have its alarms passed to the Owner's gateway via the same, single interface described in this section. Any resettable alarms, for any device capable of generating alarms, must be able to be reset via the same, single interface, as well.

Data Object List

Inputs and outputs are broken down into categories and subcategories. The Owner considers energy storage system to be distinct based on their aggregate, head-end controller. For example, if there are separate head-end controllers within a given designated area, points belonging to one of these systems will follow the Gateway naming structure:

[SES][Head-end Controller/System number]_[Category abbv.]_[Point Name]

Category abbreviations are as follows. If more than one category is defined, the category abbreviation will come first, followed by a number starting from 1 and going up sequentially. All names and sequence number assignments are managed by the Owner as part of system deployment planning and provisioning.

Example:

SES1_SYS_CHRG_KW_LIMIT

SES2_INV1_AC_BRKR_STATUS

When being defined at the Historian, the following nomenclature will be followed:

[Designated area abbv.]_[Gateway Point Name]

Points of different types are expected to follow standard units, signs, and data sizes. The tables shown below provide a guide to be followed when reporting data via the Owner interface. Table F.3 and supplementary material will indicate the expected units for all points. Notice units are generally specified within point names. If there are questions around the configuration of a given data point, consult the tables below and then reach out to the Owner for further clarification.

Points with the suffix "_OUT" are control/command points being issued from the Owner to the head-end controller

Points with the suffix "_FB" are confirmations of all control/command points being sent from the Owner to the head-end controller. The Contractor must echo received control/command points from the Owner back to the Owner, so it is understood whether the head-end controller has received them.

Points are split up into Analog Inputs (AI), Binary Inputs (BI), and Analog Outputs (AO). All specified points take the perspective of the Owner. For example, Analog Inputs are Inputs to the Owner.

TABLE F.1 EXPECTED UNITS, SIGN CONVENTION, AND SIZE

POINT TYPE	UNITS	UNSIGNED/SIGNED TWO'S COMPLEMENT	INTEGER/FLOAT
Real Power	kW	Signed Two's Complement	Float
Reactive Power	kVAr	Signed Two's Complement	Float
Amperes	A	Signed Two's Complement	Float
Frequency	Hz	Unsigned	Float
AC Voltage	kV	Unsigned	Float
DC Voltage	kV	Unsigned	Float
Real Power Ramp Rate	kW/s	Signed Two's Complement	Float
Reactive Power Ramp Rate	kVAr/s	Signed Two's Complement	Float
SOC	Percentage	Unsigned	Float
Energy	kWh	Unsigned	Float
Power Factor	Decimal	Signed Two's Complement	Float
Temperatures	Celsius	Signed Two's Complement	Float
Cell Voltage	V	Unsigned	Float

10.0 APPENDIX F CONTROL SYSTEM ACCEPTANCE TEST

11.0 APPENDIX G ESIC TECHNICAL SPECIFICATION SPREADSHEET

12.0 APPENDIX H SITE SPECIFIC INFORMATION

Attachment B

Draft Request for Proposal for the Port Westward 2 Energy Storage System

May 1, 2019

PORTLAND GENERAL ELECTRIC COMPANY

Port Westward 2 Energy Storage System Project

DRAFT Energy Storage System Project Technical Specification

Table of Contents

1 Project Location and Overview

1.1 Project site

Port Westward 2 Generation Project:
81566 Kallunki Road
Clatskanie, Oregon 97016

Coordinates: 46°10'40.3"N 123°10'20.9"W

1.2 Owner

Portland General Electric Company (PGE)

1.3 Schedule

Refer to requirements outlined in schedule provided in the commercial portion of this request for proposal.

1.4 Battery Energy Storage System Description

The Bidder shall be responsible for all aspects of a turn-key project; design, procurement, delivery, construction (including wiring, grounding, and communications), commissioning, and ongoing maintenance of an energy storage system. This specification defines a factory built, fully functioning energy storage system with batteries, Power Conversion System (PCS), enclosure(s), energy storage system switchgear, transformer(s), Battery Management System (BMS), Energy Management System, fire detection and suppression, environmental systems, control system, site controller, internal wiring, communication and software, and all required programming for integration with Owner's existing Supervisory Control and Data Acquisition (SCADA) system.

Owner shall provide oversight during the Engineering, Procurement and Construction process. Without limiting the foregoing, the following shall be the responsibility of the Bidder.

1.5 Conflicting Requirements

In cases where requirements contained within the Agreement conflict the more stringent shall apply, unless otherwise approved by Owner.

1.6 Critical Features

Owner requires the energy storage system to have the following critical features:

1. The energy storage system shall provide up to 5MW of AC at the Point of Interconnection (POI) for a minimum duration of one hour. It is at the Bidder's discretion to provide alternate bids for durations of two and/or four hours.
2. POI is defined as the connection to the Owner's 13.8kV switchgear. See provided one-line diagram for POI.
3. The primary performance requirement is that the Project must be capable of operating safely, reliably and continuously at all ranges of power output and ambient conditions. The energy storage system shall have monitoring from several customer-owned SCADA systems

but will not be staffed for constant operations and maintenance (O&M). The energy storage system must be designed to be completely automated and report failure problems via SCADA to PGE Operators.

4. The energy storage system must be capable of performing the services defined by Owner. See 1.6 Services for details.
5. The Bidder must provide a minimum 10-year energy storage system performance guarantee. See 2.13 Warranty and Performance Guarantee for details.
6. Modular-Based design. The energy storage system shall consist of multiple battery cells in series and parallel to store from and discharge to the power grid in appropriately rated enclosure(s).
7. Fire Suppression shall be able to contain the fire within the energy storage system enclosure and prevent thermal runaway. Fire suppression shall electrically disconnect and isolate the container automatically in the event of a detected fire. Fire suppression shall contain fire for an adequate amount of time to allow emergency services to arrive on site (assume 40 minutes).
8. Bidder shall provide appropriate spill containment in accordance with Environmental Protection Agency (EPA) and Oregon Department of Environmental Quality (ODEQ) requirements. Owner shall not provide any additional containment.
9. The auxiliary (station service) power system shall be 120/240Vor 480V. Auxiliary power must be provided within the Bidder's scope of supply. It must include provisions for the black start service which will require Uninterruptable Power Supply (UPS) standby power if the 13.8kV bus is de-energized. Bidder may provide a standalone UPS or utilize energy stored in the energy storage system batteries for this function.
10. The maximum sound level of the energy storage system and any associated equipment is 65 dBA at 50 feet in any direction generated for the full range of the energy storage system's operation measured from any individual component of the system.

1.7 Services

The following is a list of services that shall be offered by the energy storage system:

1.7.1 Spinning Reserve

The energy storage system shall provide energy during the 10-minute ramp up time of a co-located reciprocating internal combustion engine (RICE) plant used for spinning reserves. The battery energy discharged during the ramp up period of the RICE allows the RICE to be designated as spinning reserve even when it is not spinning.

For this service, the energy storage system must respond from an idle state to a request for spinning reserve within 2 seconds of receiving the command. From that time, the battery output must ramp at a rate of 250kW per second until a full output of 5MW (1.0 power factor) is achieved. Ramp signals will be provided from PGE's Plant Programmable Logic Controller (PLC). The energy storage system must be able to keep up with that ramp. 5MW output shall be maintained until a ramp-down and stop command is issued. When ramp-down and stop is received, within two seconds the energy storage system will ramp down at a rate of 250kW per second and then return to an idle state.

When the RICE is shutdown or reaches an output below 5MW, the energy storage system will recharge at a rate of 500kW until the state of charge or energy (SOC) setpoint is achieved. The control for this service will reside in the PGE plant PLC. The Bidder's controls must respond to a setpoint for MW and keep up with the requested ramp rate.

This service will be dispatched up to 50 times per year.

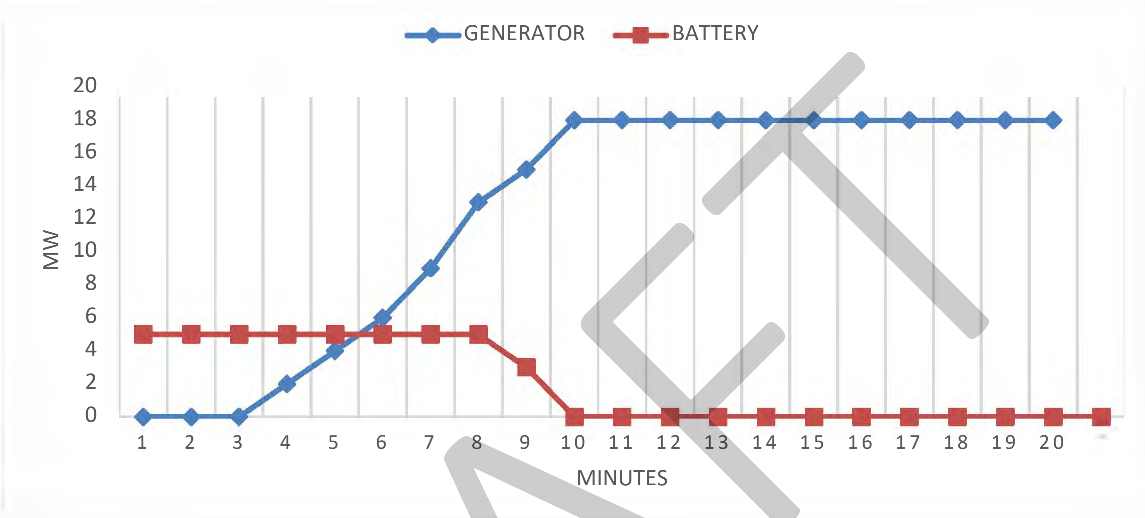


Figure 1 Generator Start up Curve vs. Battery Discharging

1.7.2 Non-spinning Reserve

For this service, the energy storage system must respond from an idle state to a request for non-spinning reserve within two seconds of receiving the command. From that time, the battery output must ramp up at a rate of 250kW per second until a full output of 5MW is achieved. 5MW output shall be maintained until a ramp-down and stop command is issued. When ramp-down and stop is received, within two seconds the energy storage system will ramp down at a rate of 100kW per second until the MW output is less than or equal to 500kW.

Once the energy storage system output is less than or equal to 500kW, the energy storage system will recharge at a rate of 500kW until the SOC setpoint is achieved.

The control for this service will reside in the PGE plant controller. The Bidder's controls must respond to a setpoint for MW and keep up with the requested ramp.

This service will be dispatched up to eight times per year.

1.7.3 Frequency Response

For this service, the energy storage system must respond from an idle state to a request for frequency response within two seconds of receiving the command. From that time, the battery output must ramp at a rate of 500kW per second until a full output of 5MW is achieved. 5MW output shall be maintained for three minutes and then the energy storage system output will ramp down at a rate of 25kW per second. When energy storage system output gets to zero kW, the energy storage system will recharge at a rate of 500kW until the SOC setpoint is achieved.

The control for this service will reside in the PGE plant controller. The Bidder's controls must respond to a setpoint for MW.

This service shall be provided up to 50 times per year, and sometimes within the same 8-hour period.

Figure 2 Energy Storage System Frequency Response

1.7.4 Regulation

The energy storage system must be capable of performing regulation according to Area Control Error (ACE) signals. The control for this service will reside in the PGE plant controller. The Bidder's controls must respond to a setpoint for MW. The energy storage system must be able to respond to these MW signals within four seconds or less. Response is defined as the time it takes from the time the Bidder's energy storage system controller receives a MW setpoint until the point when that MW output is achieved.

MW setpoints shall be both positive and negative and may be of any magnitude up to 100% of the system's real power rating. Over time, these MW setpoints are intended to be energy neutral (no net gain or loss in energy) but if the battery capacity is at a level at which the battery can no longer respond (either positive or negative), the energy storage system shall be sent signals only of the polarity to which it can respond until the battery SOC reaches 50%. When battery capacity reaches 50%, the energy storage system will resume responding to signals of both polarities.

The energy storage system shall be operated in regulation mode 24 times per year (190 hours total per year).

Bidders must stipulate clearly how the thermal limitations of their system would impact this service.

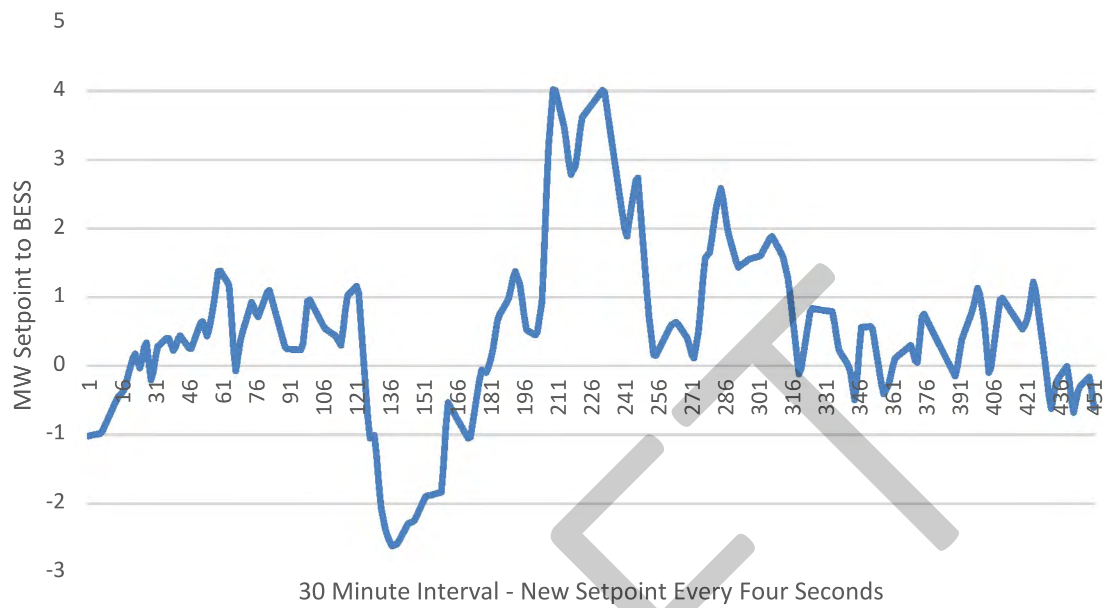


Figure 3 Energy Storage System Response to ACE

1.7.5 Black Start

The energy storage system must be capable of performing black start. Owner will provide control power to the energy storage system via UPS. This excludes environmental systems (i.e. Heating, Ventilation, and Air Conditioning or HVAC). The energy storage system must be capable of regulating voltage and frequency and closing to a dead 13.8kV bus and serving load up to 2MW. From an off state to serving load must occur within 60 seconds. Voltage regulation must be within +/- 1.0% of nominal and frequency regulation must be 60Hz +/- 0.5%. energy storage system must serve load for 30 minutes. If during this time, service to the energy storage system HVAC is necessary, the energy storage system must provide its own capacity to HVAC. Within 30 minutes, Port Westward 2 generator(s) will come on line and synchronize to the bus. Within one second of the Port Westward 2 unit closing to the bus, the energy storage system must revert to current regulation mode and begin ramping down output at a rate of 250kW per second.

This service shall be provided less than one time per year.

Bidders will clearly stipulate in their proposals the additional cost for providing black start service (including the cost of maintaining control power in an outage).

1.7.6 Voltage Support

In this service, the energy storage system will respond to a kVAr setpoint from the PGE plant controller. It may be a steady kVAr request or it may be regulating to maintain a voltage using closed-loop PI control. The system must be able to regulate kVAr to within +/- 1% of setpoint from 100kVAr to full nameplate rating. The kVAr controller resides within the energy storage system control system. kVAr setpoints originate from the Owner's plant controller. Depending on the service(s) being requested at any given time, the energy storage system may be asked to provide voltage support simultaneous with being in standby for another service such as frequency response or spinning reserve or voltage support may be operated simultaneously with other services providing that the kVA capacity of the system will allow it.

The only limitations on the energy storage system for providing this service must be the kVA rating of the system.

1.7.7 Generation Capacity

The other use cases; Generation Capacity, Economic Dispatch and Load Following are all energy capacity use cases, meaning that the energy storage system shall be asked to charge and discharge according to requests from PGE's Energy Management System. These commands (setpoints) will come to the Bidder's master controller from PGE's plant PLC. The power output or input setpoint should be assumed to be a constant 5MW for these services with depth of charge and discharge being 100%. Assume the rates of recharging to be 250kW.

This service should be expected to operate 240 times per year.

1.7.8 Standby

When the energy storage system is in frequency response mode, spinning reserve or non-spinning reserve, it may spend long amounts of time in standby mode. In standby, the energy storage system is expected to maintain a SOC of 100% (or other SOC setpoint as provided from the PGE controller) and be prepared to respond to a signal for discharge within the specified time. When in idle mode, the energy storage system will maintain a requested SOC within +/-1%. It is expected that the energy storage system will spend 92% of its time in standby mode.

2 Energy Storage System Scope of Work

2.1 Engineer/Design

1. All engineering and design shall meet the specifications outlined in Section 4 of this Document.
2. All engineering and design shall meet the codes and standards outlined in Section 5 of this document.
3. Bidder shall be responsible for detailed design and engineering provided by their Engineer of Record (EOR) licensed for the Project location, for an energy storage system that will dispatch power, both real and reactive, negative and positive when requested for duration(s) and ramp rates as outlined in the energy storage system Electrical Requirements.
4. The design shall include providing technical requirements (e.g. ratings, phasing) for all balance of plant (BOP) equipment up to the POI.
5. The drawings, studies and engineering reports shall be stamped and signed by the EOR, or other licensed professional engineers performing under the supervision of the EOR.
6. Engineer an equipment grounding system compliant with industry standards and meeting the Owner's requirements. The system shall be adequate for the measurement, detection

and clearing of ground faults within the energy storage system by direct measurement (not by calculation).

7. Shall provide fault current information to Owner for short circuit, coordination and grounding study.
8. Provide AC and DC Arc Flash Hazard Analysis and labeling of supplied equipment.
9. Shall be responsible for coordinating protective relaying with Owner including using Owner's relay settings as stipulated by Owner.

2.2 Procurement

1. Bidder shall be responsible for procurement and assembly of all components required to provide an energy storage system to Owner at project site of specified size.
2. Bidder shall review all major material costs with Owner prior to purchase.
3. Bidder shall purchase all equipment and materials, consumables, and services to complete the Project except for Owner provided equipment and services as specifically defined herein.
4. Equipment and materials purchased for the Project shall be new and unused, and intended for industrial service typical of power plant environments (Prudent Utility Practices).

2.3 Bidder Procurement shall consist of:

1. Battery system, composed of cells, modules, and strings connected to the PCS DC Side.
2. PCS.
3. BMS.
4. Step-up transformers (Bidder Specified-Y/13.8kV-Δ). A minimum of two transformers may be required to maintain acceptable fault current levels. Bidder should assume fault current magnitude of 110 kA on the low side of the transformer(s).
5. Necessary control and communication devices and architecture to allow the integration of the Bidder's control system and site controller to integrate with the Owner's SCADA system.
6. Necessary HVAC, fire suppression, fire alarm and electrical wiring. Fire alarm system will include both detection and suppression system status.
7. All communications, power, grounding, and aux power conduit and/or cables and/or conductors as required up to the POI.
8. Supply recommended spare parts for three years of operation. In addition, spare parts shall be available on demand for 10 years.
9. Required protection, controls and metering equipment of the energy storage system.
10. Bidder will provide all conductors and raceway to the POI including lugs and hardware.

2.4 Deliveries

Bidder shall be responsible for all transportation, shipping, loading, unloading, tarping, etc. associated with project to deliver a fully operational energy storage system to Owner's project site. Bidder shall be limited to a lay-down area shown in the General Arrangement (GA) as the energy storage system site. The site is the extent to which lay-down is available. If the Bidder requires covered laydown, or other protection from the weather, it is the Bidder's responsibility to provide that space. Scheduling deliveries is the responsibility of the Bidder. Owner will not make special accommodation for storage based upon Bidder's scheduling needs.

All deliveries will be scheduled between 8:00 AM and 5:00 PM on weekdays. Owner shall be given 24-hours' notice in advance of large truck deliveries.

1. The Bidder shall prepare materials and equipment for shipment to protect them from damage while in transit.
2. The Bidder shall submit a shipment plan detailing the contents of each shipping section including weights and dimensions.
3. The Bidder shall use typical transportation means such as tractor trailers, or trucks on roadways. Any special permits and arrangements required for transportation shall be the responsibility of the Bidder.
4. The delivery shall be coordinated with the PGE Project Manager, PGE Representative, and/or the PGE Construction Manager.
5. The equipment furnished shall be delivered and installed onto pad foundations at Site if no lay down area designated.
6. The bidder shall include all rigging arrangements for transport and setting the equipment on the foundations.

2.5 Construction

The Bidder shall be responsible for all Construction of items procured and delivered to site for assembly of the energy storage system project. This shall include the following:

1. Provide all labor to install "Turn-Key" energy storage system to Owner.
2. Earthwork and new foundations for the energy storage system.
3. Construction of site ground grid according to Owner's design and specifications.
4. Assembly and installation of the energy storage system and BOP.
5. All control and relaying equipment to be supplied and installed.
6. All conduits, wiring and communications equipment.
7. All conduits, wiring, terminations and other equipment required for interconnection at the POI.
8. Provide toilet and wash facilities per Occupational Safety and Health Administration (OSHA) and Owner's requirements.

2.6 Testing and Commissioning

1. Bidder shall be responsible for start-up, testing, initial operation, and performance verification of the energy storage system to the satisfaction of the Owner.
2. Bidder shall provide Method of Procedures (MOPs) to Owner 60 days prior to first energization. Owner shall be allowed to comment and revise MOP's in cooperation with Bidder. Both Bidder and Owner will identify commissioning managers prior to first energization. Each MOP must be signed and dated by both commissioning managers prior to acceptance of the energy storage system by Owner.
3. Bidder shall provide all test reports related to Institute of Electrical and Electronics Engineers (IEEE) standard number IEEE1547-2018 including type testing, production testing and project (field) tests.
4. Bidder must provide commissioning report listing compliance with contracts, manufacturer recommendations, and industry accepted minimum standards. Any non-compliant issues

must be addressed prior to final payment. Bidder will provide a post-commission testing procedure to test and verify capacity and round-trip efficiency.

5. The Bidder shall perform material suppliers recommended Factory Acceptance Tests (FATs) on all subsystems. Subsystem FAT shall be performed prior to shipment to the job site.
6. Owner may elect to send representatives to witness such testing or inspection of subsystems.
7. The Bidder shall provide notice to Owner at least 15 business days prior to any FAT or inspection activity.
8. The Bidder shall perform a factory witness test prior to shipment. This test is a functional test to confirm proper operation of the energy storage system, PCS, and Control System prior to energization. Owner will not provide authorization to ship (See 2.9.14b) prior to successful completion of this test. This factory witness test may be performed on a subset of the total system depending upon the supplier's system architecture. This system subset must be a minimum of 250kW and must be either grid connected or connected to a grid simulator. Grid connection can be at 480VAC. The following tests shall be required, and results shall demonstrate that equipment meets product datasheet specifications and project performance requirements:
    a. Battery capacity
    b. Battery internal resistance verification
    c. System round-trip efficiency at rated power
    d. PCS time response to a power reference step, from zero to PCS nameplate rating
    e. Demonstrate to Owner that the battery protection and control system and Human Machine Interface (HMI) perform all intended functions as designed such as start, stop, idle, black start, real and reactive power outputs according to supplier's specifications of four-quadrant operation.
    f. Bidder will provide all metering including power quality metering and an oscilloscope.
    g. Bidder will provide an oscilloscope analysis of power quality on the DC bus.
    h. Bidder will provide a complete power quality analysis on the AC bus.
    i. If the Bidder uses isolation transformers, power quality may be measured on the utility side of the isolation transformers.
    j. Communication verification testing with Owner provided controller
9. The Bidder shall provide an example project that utilizes the same Battery, PCS, and Switchgear components proposed for this project, and that is fully operational. If this cannot be demonstrated, the Bidder shall perform an end-to-end test of proposed major equipment (Battery, PCS, and Switchgear) to ensure interoperability and compatibility of the equipment.
10. Programming and commissioning of the PCS and control system is by the Bidder.
11. The Bidder shall coordinate with Owner for commissioning of the communications system and interconnection facilities.
12. The Bidder shall perform a wiring continuity test to confirm all wiring is complete and correct, and that all wire labels are correct and easily readable. Wiring should have point-to-point continuity with parallel paths disconnected, unless required for battery design.
13. Bidder will verify torque of all bolted connections.
14. Bidder will perform an infrared inspection on all bolted cable and bus connections.

15. Battery and BMS supplier must provide a specification for power quality requirements on the DC bus. During witness testing, DC power quality shall be measured at full inverter output. Battery and BMS supplier will provide a written statement guaranteeing the performance of the BMS under these power quality conditions.
16. If BMS is supplied or manufactured by a vendor that is different from the battery cell manufacturer, bidder must specify.

2.7 Maintenance

Provide minimum 10-year Maintenance and Capacity contract for Energy Storage System. Provide system complete with all recommended spare parts for three years of operation and specialty installation tools. In addition, spare parts shall be available on demand for length of performance guarantee. See Commercial terms for further details.

2.8 Participation

Participate in the following manner with regards to meetings with Owner during the design phase and construction period:

1. Participate in bi-weekly design meetings
2. Participate in weekly construction update meetings
3. Generate an agenda or dashboard 24 hours in advance of the meeting
4. Provide summary notes of those meetings within 48 hours of hosting the meeting
5. Provide a system for tracking risks/issues and their resolutions
6. Retain and if requested by Owner, provide at least the following: summary notes for Project Meetings with subcontractors, Communication Plans, Project Kick-Off, Design Reviews, Testing Overview, and Conference Calls.
7. Provide a competent management and site supervisory staff always during construction.
8. Provide all labor to install "Turn-Key" energy storage system to PGE.
9. Provide Safety watch personnel during construction.
10. Appropriately staffing the site always with managerial, supervisory (including safety) personnel, fluent in English, and capable of communicating with all workers on-site. In the case that personnel across the site are not fluent in English, the Bidder shall have a representative that is bilingual to ensure effective communication always.

2.9 Bidder Documentation and Deliverables

See the Document Delivery List for Project Deliverables.

The record of this project shall include the following:

1. Method of Procedure (MOP) -The Bidder shall submit for approval a detailed MOP. This MOP shall detail all elements of mobilization, installation, testing, and demobilization. The MOP is due to Owner 90 calendar days after Notice to Proceed (NTP). The review time for the MOP by Owner will take 15 business days.
2. Energization and de-energization plans -The Bidder shall submit for approval a detailed energization and de-energization plan for safe operation of the Project. The Bidder shall coordinate with all applicable parties to review the energization plan. Energization and de-

energization plans shall be submitted to Owner for review no less than 20 business days before the energization date. The Bidder shall hold a meeting before energization to walk through the energization/de-energization plans.

3. Project Specific Safety Plan (PSSP) –Shall be the most important aspect of this project. Bidder shall not allow any individual to remain on job site during this project that will not follow the Bidder's Safety Plan. Said PSSP shall identify project specific safety hazards that may be encountered during the performance of construction and describe a mitigation plan that minimizes or eliminates these hazards by defining all safety protocols to be incorporated into the project, and how the PSSP shall be implemented. Said PSSP shall be due to Owner for review and approval within 90 calendar days after the Successful Bidder has received the NTP. The review time for the PSSP by Owner will take 15 business days.
4. Documents requiring submittal to Owner will be itemized in a transmittal email. The documents shall be in portable document format (PDF) or .docx format as required and transmitted electronically. Each PDF file shall contain only one submitted document.
5. All Computer Aided Design and Drafting System drawings shall be delivered in Owner Specified Format per Drawing Standards section of this document. Drawings that contain multiple sheets can be consolidated in one PDF file provided that the drawing number is the same for each sheet.
6. Preliminary, Issued for Construction and As-Built Design Documents – The Bidder is required to submit 30%, 60% and 90% design review, Issued for Construction and As-Built packages.
    a. To facilitate the Owner's technical review and submittal of design documents the Bidder shall meet the following submission requirements. All transmittals are to clearly indicate the following:
        i. Owner's name
        ii. Project Name
        iii. Facility Name
        iv. Owner Project Number (i.e. AWO)
        v. Bidder contract number (i.e. Owner Purchase Owner number)
        vi. How submittal is being transmitted (e.g. electronically via SharePoint, hard copy)
        vii. Reason for submittal (for review, for construction, for permitting, as-built)
        viii. Date of transmittal
    b. The Bidder shall assume 15 business days for Owner's review of the said documents. All of Owner's comments shall be incorporated into the next issued set, or if not incorporated, the Bidder shall provide a reasonable explanation for not incorporating Owner's comments within 10 business days. Review of drawings by Owner does not relieve Bidder of responsibility for errors, correctness of details or conformance with these specifications.
    c. As-Built Drawings – The bidder is required to submit As-Built drawings in accordance with PGE's Power Supply Engineering Services (PSES) Computer-aided Design (CAD) Standards 30 calendar days after completion of the project. Submittal of As-Built drawings shall include:
        i. Drawings in AutoCAD 2018 format (i.e. .DWG)
        ii. Xref files used in Drawings in native format
        iii. 2D/3D Models provided in Autodesk Navisworks format
7. Field Document Control

a. The Bidder is responsible and liable for ensuring all construction meets the requirements of the most recent set of prints.
b. Owner's site personnel shall be issued half size and full-size drawing sets for field work with new revisions slip-sheeted in as issued.
c. When new revisions are issued, the old issues should be collected from the site construction staff at the same time the new drawings are issued. All project drawings shall be collected, and new drawings issued at the same time.
d. Bidder will maintain all Owner copies using the same document control structure as for construction.

The Bidder shall issue three-month report to Owner, no later than 15 calendar days after the end of each three-month period from NTP, describing the project activity that occurred during the quarter, including but not limited to:

e. A narrative summarizing project activities, risks and issues mitigated, and lessons learned
f. The project milestones met to date and anticipated in the subsequent quarter (e.g. through a project Gantt Chart schedule provided quarterly in Microsoft Project format showing actual progress to date along with the baseline schedule developed at project kickoff)
g. The project expenditures to date and anticipated in the next quarter
h. This section shall consist of a concise summary of all technical activities performed and anticipated under the contract during the reporting period. A summary showing planned and actual start and completion dates for each task, percent complete, and schedule variances shall be provided. Schedule variances shall be highlighted in the narrative with options for correcting problems as appropriate. Specific areas of interest shall include difficulties encountered during the reporting period and corrective actions taken, lessons learned, a statement of activity anticipated during the subsequent reporting period, and a schedule showing accomplishments versus planned activities (e.g. through a project Gantt Chart schedule provided during the reporting period in Microsoft Project format showing actual progress to date along with the baseline schedule developed at project kickoff). The report shall include any changes of key personnel concerned with the project, and number and type of equipment present during the reporting period and anticipated during the next reporting period on site.
i. Financial: This section shall provide the following information to assess the financial status of the project:
j. Baseline for actual expenditures, project expenditures to date, available estimated costs and costs anticipated in the subsequent reporting period.
k. Cumulative invoiced amounts
l. Estimated budget variances and a plan for corrective actions, if applicable
m. A detailed explanation of the basis for any cost variances that exceed 15% as of the reporting date.
n. Subcontracts: This section shall list all subcontracts awarded monthly by title, contractor, and dollar value

8. Bi-Weekly Design and Construction Status Reports. The Bidder shall prepare and submit to Owner bi-weekly progress reports for the work performed during the previous week and anticipated (look-ahead) in the next two weeks. The purpose of these reports shall be to

inform Owner of the status of the projects and to call attention to any departures from the applicable management and work plans.

9. Final Report - The Bidder is required to submit a Final Report 30-calendar days after completion of the project. This report shall include a narrative of all significant events defined by segment of work, photographs of operations, dates for milestones achieved, and all charts representing as-laid positioning.
10. Training – The Bidder shall provide training literature to Owner on all installed components to Owner employees. It shall contain the following:
    a. Training course outline and objective
    b. Detailed lesson plans
    c. Training manual
    d. Preliminary training schedule
    e. List of training aids
    f. Equipment Overview
    g. Major component description
    h. Controls: Including flow paths, instrumentation, controls and interlocks.
    i. Principal of operation including operating parameters, start-up, normal operation, normal shutdown, emergency shutdown, infrequent operation modes, and maintenance.
    j. Support systems needed for operation
    k. Visual aids of equipment and system design.
11. Provide a description of battery thermal management and cooling consisting of specification of internal temperature distribution during operation. Bidder shall also identify any additional AC auxiliary power requirements.
12. Provide a description of battery fire suppression plan including specification of equipment used and training provided to local fire department personnel.
13. Provide quality assurance documentation/program in effect always to verify that all components, equipment, material, and services, including subcontracted components, equipment material, and services comply with the requirements of the Contract, and applicable codes, standards, and regulations. The Bidder's Quality Assurance / Quality Control (QA/QC) shall clearly establish the authority and responsibility of those responsible for the QA/QC program. Persons performing quality functions shall have defined responsibility and authority to enforce quality requirements; to identify, initiate, recommend, and provide solutions to quality problems; and to verify the effectiveness of the solution. If the QA/QC program is found to be ineffective or inadequate in providing acceptable QA/QC, Owner reserves the right to require the necessary revisions.
14. Reporting/plans
    a. Report any shortage or damaged materials, in writing, to Owner within 48 hours of receipt of materials, associated with the Owner Supplied Equipment.
    b. If shortage and/or damage reports are not furnished to Owner within 48 hours after receipt of materials by Bidder, the cost of the shortage and/or damage shall be borne by Bidder, if not otherwise collectable.
    c. Implement and maintain an Erosion and Sediment Control Plan (ESCP) that meets the requirements of a 1200-C application during the Work. The ESCP shall be provided for Owner's review before the start of the construction and shall be available for adaptation throughout construction. A final ESCP shall be provided as

part of the turnover documentation capturing any residual maintenance requirements

d. Develop a Hazardous Materials Management and Monitoring Plan that addresses the handling of hazardous substances, the measures implemented to prevent site contamination, and how implementation of the plan shall be documented.
e. Develop and maintain a detailed Project Schedule in Microsoft Project format that integrates related activities and complies with required milestones
f. Any significant changes in the schedule shall be reported, reasons stated, and recommendations made for appropriate action.
g. Bidder shall be required to submit all Material Safety Sheets on all material brought on site to Owner.
h. Provide an independent third-party testing laboratory, approved by the Owner, for sampling, testing and certifying the materials and installation are in conformance with the requirements.

15. Shipping/Delivery Documentation Requirements
    a. Prior to shipment of the energy storage system from the manufacturer, the Owner Project Administrator shall have received and approved the FAT test reports.
    b. Authorization to Ship - Upon approval of the Project Engineer, Owner will release an Authorization to Ship to the Bidder at which time the energy storage system may be shipped from the manufacturer to the.
    c. Shipping Arrangements for all Bidder provided materials shall be coordinated, managed and implemented by the Bidder. The Bidder shall arrange for shipping in a timely manner so that all Bidder provided materials are available and ready at the start of Construction of the Project.
    d. Bidder will supply with his bid approximate gross weights, together with the overall physical dimensions of equipment of subassembly as packed for shipment, and a written proposal describing, briefly, the design, contents and number of shipping units.
    e. Before transportation of batteries or electrolyte, a spill prevention plan must be submitted to Owner. It is the Bidder’s responsibility to ensure that any battery or electrolyte fluid does not enter the environment. Bidder is responsible for all cost associated with any “clean-up” of battery or electrolyte fluid.
16. The Bidder shall make a test schedule form and record the results of the testing, as outlined above. The test results shall be submitted to Owner, for review and acceptance before the energy storage system gets shipped to the site. This procedure shall be coordinated with Owner so that the scheduled delivery date will not be delayed.
17. O&M Manual Requirements
    a. Fully indexed, the content shall conform to the requirements described in this article and shall be complete and specific to all the systems, auxiliary systems and equipment supplied.
    b. Material and information that does not contribute to the understanding of the design, operation and maintenance of the equipment shall be excluded from the manuals. Information that does not apply shall be removed from the manual or redacted. Drawings, diagrams, pictures or photographs shall be used to add to the understanding of the text. Where manufacturer's standard brochures are available in a suitable form and relating specifically to the equipment supplied, these may be

used, provided the brochures are edited to remove irrelevant material and are integrated into the overall manual.

c. The manuals shall contain information suitable for personnel who have received a basic training and/or have a knowledge and experience of similar equipment.
d. The manuals shall alert the operating staff to any hazard inherent in the equipment or likely to arise in the implementation of operating or maintenance procedures.
e. The O&M manual shall be organized by sections, if the overall quantity of information is greater than a four-inch binder the manual shall be organized in multiple volumes. The manual should be arranged to enable normal operation of the equipment without undue reference to other documents.
f. O&M manuals shall be provided in both hard copy and electronic PDF file. The PDF file shall be bookmarked and capable of electronic searching of the material.

2.10 Key Personnel

Provide the names and resumes for the key personnel proposed to work on this project. Provide a plan that identifies the percentage of time the individuals performing the roles identified below to be present on-site during construction will do so. State if any of the roles identified below to be present on-site during construction shall be shared between the same individual and how you plan to minimize any impact to safety and quality during construction in case of a role sharing. Show all applicable training, certificate, and work experience relevant to this project. Key Personnel should include the following:

1. Project Manager
2. Design Engineer(s)
3. CAD Manager
4. Site Superintendent (on site during construction)
5. Materials Representative (on site during construction)
6. Field Quality Control Manager (on site during construction)
7. Safety Manager (on site during construction)
8. Safety Watcher(s) (on site during construction)

2.11 Operator Training

Bidder shall supply training and appropriate instructional literature on all installed components to Owner personnel.

1. Training of Owner's personnel (or other employees or agents of Owner) shall be given by Bidder prior to the Project Commercial Operation Date as required by the Specification, in accordance with a timetable to be agreed upon with Owner prior to the Project Commercial Operation Date and shall include onsite and classroom training covering the O&M of the energy storage system. Such training shall be conducted by trainers who are experienced in the O&M of the energy storage system's components, equipment, and systems. Bidder shall coordinate the overall program, which shall be developed to familiarize the O&M personnel with each of the various operating systems, the major mechanical equipment, and the control systems. The training shall provide control and operating philosophy to allow

Owner's personnel to safely and reliably start up, operate, and shut down all components, equipment, and systems.

2. The Program plan shall be based on a maximum number of 20 personnel in the training session. Bidder shall provide a person to coordinate and lead the program.
3. Bidder shall furnish Owner with complete instruction, O&M manuals for all components, equipment, and systems furnished by Bidder. The information shall be separated into logical groups or sections with identifying tabs. Each instruction/O&M manual shall have an index listing all leaflets in the same order as they appear in the manual. Providing only the various sub-suppliers' instruction books and other documents is not acceptable. Furthermore, providing generic instruction manuals for equipment that has been substantially modified is not acceptable. Two preliminary copies of the final instruction/O&M manual for all components, equipment, and systems furnished by Bidder shall be submitted for comments eight weeks before final issue of the manuals.
4. After Bidder's receipt and resolution of Owner's comments, two bound sets and one electronic version of the Final O&M Manuals shall be submitted to Owner. The electronic version shall include hyperlinks to the various documents included in the Final O&M Manuals.
5. The training sessions shall be comprised of both formal classroom and hands-on training. The hands-on training means utilizing installed equipment and actual O&M procedures to familiarize the O&M personnel with the components, equipment, and systems: their locations in the energy storage system; and their operation and maintenance.
6. It is anticipated that each training session should include discussions on such topics as equipment construction, a process overview/description, and specific equipment/system operations including start-up, normal operation, abnormal operation, and shutdown.
7. Bidder shall provide fire suppression training to local fire department personnel to adequately prepare for any fire suppression characteristics or techniques that are unique to the specific chemistry and technology provided by the bidder.
8. The Program is normally scheduled for one week, of eight-hour days, for five business days per week with an hour lunch. A formalized training schedule shall be developed, which shall outline the actual sessions, topic arrangement, and time when the sessions shall be conducted.
9. The training schedule shall be submitted to Owner for review. If Owner decides that additional training is necessary after review of the schedule, Bidder shall incorporate Owner's comments and resubmit for Owner's approval.
10. Further On-The-Job-Training shall be provided as Owner's O&M staff supports the Commissioning program by operating equipment and systems during initial start-up and operation

2.12 Decommissioning Plan

Bidder shall be responsible for a plan to decommission the Project and the restoration of the site at the end of the energy storage system service life. Decommissioning Plan shall include developing and implementing a program for the recycling or proper disposal of installed infrastructure and mitigation or remediation of all environmental impacts arising from or associated with the Project. The Bidder shall describe its decommissioning plan, including programs for recycling of installed infrastructure, if any and how the respondent will remediate or mitigate the environmental impacts in compliance with all applicable Environmental Laws in effect at the time of decommissioning so that the Site is returned to the condition it was in immediately prior to implementation of the Project. No underground materials may be abandoned in place.

2.13 Warranty and Performance Guarantee

1. Bidder shall provide support to Owner during an 18-month performance verification period, to begin after the energy storage system has been commissioned and has begun commercial operations.
2. The energy storage system shall have an equipment warranty available for a minimum of three years, and a performance guarantee for a minimum 10 years. Length of warranty shall be considered in bidding process.
3. The Product Warranty shall include the monitoring and evaluation of the energy storage system to identify any indication of premature degradation and/or potential underperformance, including any circumstances that reasonably could be expected to result in a claim under any manufacturer warranty. Owner will be notified of any discoveries orally as soon as possible after identification and shall submit a written root cause or other reasonably appropriate analysis of the situation within a reasonable period not to exceed fifteen 15 calendar days after identification. Bidder shall immediately undertake activities to increase capacity to satisfy the technical specifications within a reasonably appropriate period not to exceed 30 calendar days of problem identification.
4. Additionally, Bidder is requested to provide a 10-year minimum Performance Guarantee which will include replacement and performance criteria. At any time during the 10-year term that, as reasonably required to maintain Guarantied Capacity or otherwise as defined by the technical specifications, the repair of the energy storage system requires a replacement component, Bidder will bear all of the cost of shipment and installation of new components and any related equipment, materials, and/or parts, and Bidder will bear the risk of loss of module, equipment, materials and/or parts until installation in the energy storage system.
5. During the 10-year minimum Performance Guarantee Period (PGP), if capacity of the energy storage system project falls below the Guaranteed Capacity, Service Provider shall immediately undertake activities to increase capacity to satisfy the technical specifications.
6. The energy storage system Bidder shall perform warranty services to minimize interference and/or other disruption with the energy storage system and Owner's operation and maintenance of its electric distribution system. No warranty services requiring an electrical line or outage will begin without the prior written consent of Owner.
7. The energy storage system Bidder unconditionally warrants that the energy storage system Bidder shall perform all services in accordance with professional standards and skill, expertise and diligence of professionals regularly involved in the maintenance of large Battery Storage Systems projects like the energy storage system and otherwise in full compliance with all requirements of this Agreement, and all Services shall be free from any defect or error whatsoever, including in design and workmanship.

3 Construction Specifications

Bidder shall procure, deliver, construct and commission the energy storage system per the schedule provided.

3.1 Shipment

All transportation logistics and cost from manufacturing facilities to project site is the responsibility of the Bidder.

1. Loading onto and off the transportation equipment is the Bidder's responsibility.
2. Receiving, inspecting, unloading and storing (including all equipment and rigging required) of Owner and Bidder supplied equipment and materials. Inspection of the material shall be the responsibility of the Bidder, of which the Owner may witness
3. All disconnected wires shall be clearly identified, bundled, coiled, and secured. All fasteners required for reassembly shall be arranged in clearly marked packages with invoice attached. These packages shall be shipped securely as an integral part of the energy storage system
4. components, so they shall be immediately accessible for reassembly.
5. The energy storage system components shall be shipped in a manner preventing damage to or degradation of the components due to ambient environmental conditions
6. Bidder shall not use any Owner employee to load batteries or electrolyte material into the energy storage system modular containers.
7. Any machined surfaces shall be fully wrapped and protected from impact damage in shipment.
8. Moving Parts shall be braced as needed or as recommended by Vendor to avoid shipping damage.
9. Providing all temporary surfaces for safe and efficient offload, storage and erection, in accordance with crane manufacturer and the energy storage system supplier requirements.
10. Bidder shall be required to remove all debris from project site caused or created by the un-crating and assembly of the energy storage system. Bidder must separate recyclable materials from the solid waste stream to the extent practicable, deliver or sell those materials to a recycling project.

3.2 Construction

1. Bidder shall not require Owner to instruct Bidder on how to accomplish the bid work.
2. Bidder's installation personnel shall follow Bidder PSSP that must be approved by Owner.
3. Provide quality control. Bidder shall be responsible for inspection, oversight, review and documentation of the Bidder's work as well as the work of its subcontractors and suppliers. Materials to be uploaded as they become available not later than five business days after delivery and inspection – no materials to be retained and uploaded en masse at or near turnover.
4. Provide covered trash dumpsters or other suitable containers for proper disposal and/or recycling of construction debris, garbage, food wastes and other similar trash created from Bidder's work.
5. Providing all temporary power and communication requirements for the Work, including all permits, fees and applications required.

6. Supplying all potable and non-potable water required for the duration of the Work.
7. Traffic & parking
    a. Bidder shall direct its employees and Subcontractor's employees to park only in those areas specifically approved by Owner.
    b. Providing all traffic control, including access to the site. In the case of shared access Bidder shall coordinate with other contractors on-site.
    c. Returning roads or highway infrastructure both on and off-site to their original state (or better) – reversing necessary alterations, when required, or repairing damage due to construction activities.
8. Bidder shall erect a temporary barrier to demarcate energized equipment for the duration of the project construction.
9. Maintaining all dust control measures in compliance with local and permit requirements.
10. Signs and Labelling
    a. Supply and install construction identification, warning, and information signs as necessary to inform the public of the project and warn them of potential hazards during construction.
    b. Supply, install, and maintain temporary signs to assist delivery and emergency medical responders in locating access roads.
    c. Access roads and project components shall be identified clearly with permanent signs readable from a reasonable distance.
    d. Label all cable and equipment as specified
    e. Installing warning tape in all trenches
    f. Furnish and install bollards and warning flags around Generator Step-Up Transformers, medium voltage Switchgear, fiber splice boxes and junction boxes as required.
    g. Installing four feet tall above-ground fiberglass cable route markers at an interval of no more than 500 feet, at crossings and at changes of direction.
11. All disassembled components shall be clearly piece marked for ease in field assembly.
12. Equipment and material
    a. Maintain equipment so that it does not leak oil, hydraulic fluids, fuels, greases, cutting oils, antifreeze or other chemicals.
    b. All materials shall be new and free from defects.
    c. All materials and equipment shall be installed or applied in accordance with the Manufacturer's instruction documentation.
13. Providing all site security, including for Owner Supplied Equipment and materials, throughout the duration of the Project. All security breaches shall be reported to the Owner immediately, but in no case more than 24 hours after said breach has occurred.
14. Compliance with all environmental, archaeological, cultural and wildlife requirements specified in Project permits, Applicable Laws, codes or regulations.
15. In the event of an inadvertent discovery (a cultural resource found unexpectedly during construction), call Owner within two hours (503-464-2663)
16. Bidder shall document all spills during construction and provide documentation demonstrating appropriate clean up to Owner. Notify Owner immediately of any non-incidental spills.
17. Locating all underground utilities and providing sufficient and timely notification to the required parties prior to the start of work.

18. All doors and hatches shall be installed following a plan coordinated with the Owner accounting for accessibility, environmental conditions, and safety in windy conditions.
19. Implement and manage lock-out/tag-out program from mobilization through Substantial Completion.
20. Bidder will not leave holes open overnight. Open holes are to be properly covered and/or fenced.
21. Any deviation from the Manufacturer's installation instructions shall be approved by the manufacturer of the materials or equipment in writing.
22. Supplying and installing all rebar, anchor bolts, anchor bolt nuts, templates, embedment rings and shims required for complete foundations.
23. Supplying, installing and stripping all formwork required. Patching and sealing of all exposed concrete after stripping of forms.
24. Supplying concrete and grout that complies with the approved plans, specifications and manufacturer's recommendations.
25. Providing all welding required to complete the Work.
26. Civil Work
    a. Trenching, excavation and backfill required to complete the Work.
    b. Conforming to any Owner provided preliminary survey, performing any required remaining surveying and establishing and maintaining survey control points for the duration of the Work.
    c. Removal and disposal of all top-soil, vegetation, organic material, rock, earth, sand and debris required to complete the Work. Soils shall not be relocated throughout the project site, unless approved by Owner.
    d. Installing fill material free of organic and or foreign material (e.g. debris, concrete, metal).
    e. Placing fill in lifts, maximum thickness specified by the Bidder's EOR, to allow for proper compaction throughout the fill. Density and moisture tests shall be taken at regular intervals in the field during compaction to verify installation is meeting the design standards.
    f. Grading adjacent to all equipment and structures so that it is smooth, matches existing grade and provides proper elevation and drainage, sloped away to maintain positive drainage.
    g. Restoring all temporarily disturbed areas prior to the completion of the Work. This shall include all crane paths, crane pads, lay down areas, storage areas, road shoulders, collection system trenches, temporary access roads, etc. which should be fully remediated including decompaction as necessary.
    h. Construction operations shall be conducted to prevent any unnecessary scarring or defacing of the natural vegetation and surroundings near the work. Construction methods shall be designed to limit, so far as reasonable, erosion or subsidence.
    i. Identify and repair drain tiles damaged during construction.
27. Sealing of all conduit ends and enclosure entries to prevent water, rodent, and insect intrusion.
28. Minimizing any outages to existing utilities and operating facilities while completing the Work. Bidder shall anticipate performing the work with the existing lines energized, when crossing existing lines.
29. Providing suitably rated electrical and equipment enclosures.

30. Furnish and install a fiber optic grounding kit at each end of each fiber optic cable. This includes at all energy storage systems, splice boxes, patch panel within substation.
31. Not attempting any repairs to damaged material or equipment without the prior approval of the Owner unless additional damage would be created by waiting for approval.
32. Bidders shall comply with Owner site certificate requirements (attached but subject to change. Site Certificate provided at time of construction shall be considered valid).
33. Bidder shall provide all construction equipment such as portable generators, load banks, man-lifts, cranes, and excavation equipment Owner will not provide equipment for construction, loading or unloading.

3.3 Civil Site Work

This section describes the civil site work along with the design basis for yard facilities and infrastructure. The scope of this work shall involve all items to engineer, procure, construct, commission, and bring into service the required Project and shall include, but is not limited to the following items:

1. Site clearing and grubbing, and disposal of non-hazardous waste
2. Stripping and stockpiling of topsoil
3. Installation and maintenance of construction parking and laydown areas. Construction parking and laydown areas shall be reclaimed at the end of the project and returned to their original state
4. Excavation for subgrade utilities
5. Construction and management of temporary and permanent drainage facilities, including, if necessary, storm detention pond or basins
6. Providing temporary erosion and sediment control during earthwork
7. Providing permanent erosion and sediment control and surface water runoff as required during and after construction
8. Final Site grading and cleanup
9. Roads, paving, associated road fixtures and landscaping
10. Landscaping and fencing
11. Security of Bidder controlled areas
12. Compliance with all EPA and PGE requirements

Bidder shall be responsible to inspect the Site, obtain all necessary Site data, and perform all required geotechnical and/or survey investigations for the design and construction of the Project.

3.3.1 Surveying

PGE shall provide a complete American Land Title Association and topographic survey of the Site, easements, and other existing structures prior to design and development.

Bidder shall install permanent benchmarks as control points for construction.

The Bidder shall be responsible for obtaining any required surveying outside of the Site boundary.

3.3.2 Geotechnical Investigation

Initial Geotechnical analysis has been conducted by PGE for the Bidder's reference and the results are made available as an attachment to this request for proposal. If additional studies are needed the Bidder shall be responsible for obtaining all comprehensive and detailed soil investigation deemed necessary to complete engineering and design of the Facilities.

Geotechnical information is provided as-is and is representative for the region. Any additional bores specifically required by the EOR for structural design are within the scope of the Bidder. Specifications may contain wind specific elements that are not applicable to a battery application. Any requirements in question should be clarified by the Bidder. Equipment specifications are representative and will have to be updated for local conditions by the EOR maintaining the same technical requirements.

Bidder shall be responsible for completing all required geotechnical investigations for the Project and shall maintain all liability and responsibility regarding the accuracy and applicability of geotechnical data.

If additional geotechnical investigation and analysis are performed by the Bidder, they shall consist of a subsurface exploration program, field testing and sampling, laboratory testing, and engineering analysis and evaluation with the results presented in report form to the Bidder.

3.3.3 Erosion and Sediment Control

The Bidder must not cause more than one acre of ground disturbance to perform the work, including any ground disturbance at the location of the energy storage system and disturbance associated with potential spoils disposal onsite. If spoils disposal occurs onsite the disturbance limitation applies to the spoils, grading area, and area needed to maneuver equipment. Total disturbance for the project must be under one acre because the project is not permitted to receive a National Pollutant Discharge Elimination System General Stormwater Discharge Permit 1200-C without going through a Site Certificate amendment; therefore, the criteria for requiring a permit must not be triggered.

Nevertheless, Bidder shall provide for erosion control during and after construction in accordance with applicable Laws and local practice. Best Management Practices (BMPs) identified in the ODEQ Construction Stormwater BMPs Manual that are applicable to the construction activities and site conditions shall be used during construction to minimize erosion. Bidder shall prepare and submit to PGE for approval an ESCP, that meets the requirements of a 1200-C application. Weekly ESCP inspections are required during construction.

BMPs shall be utilized in the design and location of all erosion and sediment control devices prior to any land disturbance activity. The plans shall be prepared using a phased approach including clearing phase, grading phase, and final phase. These phased drawings shall ensure proper controls are in place at each phase of construction to mitigate erosion and to prevent silt from leaving the Site.

Temporary BMP devices shall be provided by the Bidder for control of erosion and turbid runoff during clearing operations and from graded areas until they are stabilized. Temporary BMPs shall be acceptable to PGE.

The Bidder shall provide permanent BMPs as required for ditches and slopes, such as riprap, headwalls, rock surfacing and slope pavement.

3.3.4 Containment

Containment measures must be designed to hold at least 110% of the volume of liquids stored within them. If transformers contain more than 55 gallons of oil, they must be in spill containment that holds at least 110% of the volume of oil stored within them and the volume of precipitation that might accumulate during a 100-year return frequency storm. All fuel and chemicals used for construction must be kept in spill containment areas designed to hold at least 110% of the volume of liquids stored within them.

3.3.5 Civil Management During Construction

During the construction phase, temporary erosion and sediment control measures shall be installed, maintained, relocated and modified, as required. These shall be removed when no longer required or incorporated into the permanent construction if properly designed for long-term service.

3.3.6 Civil Management During Operation

Non-contact storm water shall be diverted from the Site using the natural drainage courses.

Storm water that contacts process equipment or secondary containments with potential oil contact shall either be contained and removed from the Site via suitable truck transport and disposal or shall be diverted to an oil/water separator before being discharged with process waste water.

3.3.7 Grading

Grades shall be established to minimize the amount of earthwork required to construct the Project. Graded areas shall be smooth, compacted, free from irregular surface changes, and sloped to drain. Final earth grade adjacent to equipment and buildings shall be below the finished floor slab and shall be sloped away from the building to maintain proper drainage.

Permanent unprotected slopes in cut or fill shall generally be no steeper than 3H:1V. The minimum grading slope in the main Project complexes shall be 1%, or as appropriate for surface type, conveying storm water runoff away from permanent equipment. If spoils are disposed of at an onsite disposal area, the spoils must blend into the existing topography and have a gentle, reasonable slope.

3.3.8 Backfill and Compaction

Areas to be backfilled shall be prepared by removing unsuitable material before placing the fill. The bottom of the excavation shall be examined to reveal loose, soft or otherwise unsuitable areas. Such areas shall be excavated fully and backfilled with compacted fill. Backfilling shall be done in uniform layers. Soil in each layer shall be properly moistened to obtain its specified density. To verify compaction, representative field density and moisture-content tests shall be made during compaction.

Structural fill under inverters, roads, and parking areas subjected to heavy or cyclical loads shall be compacted to a minimum of 95% of the Modified Proctor maximum dry density in accordance with American Society for Testing and Materials (ASTM) D 1557. General backfill shall be compacted to at least 80% of Modified Proctor. The backfill and compaction requirements identified as part of the geotechnical evaluation shall be incorporated, as appropriate.

3.3.9 Surfacing

Surfaces surrounding buildings and equipment shall be graded to direct surface water away with material to prevent soil erosion and surface treated for dust abatement. Such surface shall maintain structural integrity during periods of precipitation.

The materials selected for road construction shall be of adequate strength and durability to meet the design requirements for the whole of the design life. The materials of construction and required thickness of the roadways shall be identified in the geotechnical evaluation.

3.3.10 Roads

Contractor is responsible for the following:

1. No new roads will be constructed as part of this project. All access to site will be provided by roads previously constructed by PGE.
2. Conducting a survey to document the existing conditions of the roads to be utilized prior to the start of and after the completion of the construction activities. This survey shall include video of the roads and Bidder will coordinate with PGE to obtain the agreement of the Authority Having Jurisdiction (AHJ) that the survey accurately reflects the road status at each milestone.
3. Ongoing regular maintenance of all project and public roads as needed throughout the Work, to include grading, dust control, and snow removal as needed
4. Construction of
    a. Crane pads
    b. Public road improvements, as necessary
    c. Delivery road improvements (e.g. jug handles, increased radii), as necessary.
    d. The energy storage system staging area(s), as required.
    e. Adhering to all public road use agreements, as applicable.

All site entrances/exits shall have a system in place (e.g. rumble strips) to prevent tracking of mud and other debris onto the public way.

4 Energy Storage System Performance Requirements

1. Nameplate rating of 5 MVA AC for a duration of one, two, or four hours.

2. The energy storage system shall perform at a minimum the nameplate ratings for a minimum operational period of 10 years given the stated use cycles herein.
3. Over-building, augmentation or replacement can be utilized as required to meet expected performance guarantee.
4. The energy storage system shall support a charging and discharging rate within the range of 0 degrees Celsius (°C) to nameplate rating. The battery vendors should specify both charge (C) and discharge (E) ratings in relation to the SOC.
5. The energy storage system shall provide more than 98% system availability on forced and planned outages during PGP.
6. Equivalent Availability Factor (EAF) over a calendar year must be greater than 90%. EAF shall be calculated according to IEEE 762-2006: Standard Definitions for Use in Reporting Electric Generating Unit Reliability, Availability, and Productivity.
7. Depth of discharge shall be 100% of system nameplate rating for the PGP.
8. End of Life shall be defined as when the energy storage system capacity is 80% of Beginning of Life capacity at standard testing conditions. Testing shall be performed in accordance with "*5.0 Test Methods and Procedures of Protocol for Uniformly Measuring and Expressing the Performance of Energy Storage Systems – PNNL – April 2016*".
9. Replacement of individual modules shall not interrupt the energy storage system availability to the grid.

5 Material Specifications and Requirements

5.1 Approval of Manufactured System

1. The energy storage system shall be a demonstrated technology with at least five deployments of the same model of 10 MWh or greater in aggregate.
2. Bidder will review all major material costs with Owner prior to purchase.

5.2 Electrical Requirements

1. 5MVA AC for a minimum of one hour.
2. PCS shall be capable of true four-quadrant operation.
3. Nominal sustained voltage at POI 0.9 per unit (minimum) and 1.1 per unit (maximum) in voltage regulation mode.
4. Nominal frequency at 60 Hz with normal deviation of +/- 0.2 Hz in voltage regulation mode.
5. Frequency design tolerance of 50.0 Hz – 66.0 Hz
6. Bidder shall supply all DC power and controls power requirements of the energy storage system.
7. Bidder shall supply all AC auxiliary power for the energy storage system separate from the power charge/discharge path separately metered.
8. Minimum AC round trip efficiency of the energy storage system, including auxiliary power, measured at POI of 75% for Flow systems and 85% for Li-ion systems.
9. Total Harmonic Distortion less than 5% per spec IEEE 519.
10. Basic Insulation Level (BIL) required for each discipline shall be coordinated to minimize damage due to potential overvoltage conditions per IEEE 1313.2.
11. All electrical clearances shall be met.

5.3 Physical Arrangement Requirements

1. Bidder shall follow PGE Substation Standard 13004, Layout Design Requirements, for layout design.
2. Bidder shall conform with the version of the National Electric Safety Code (NESC), American National Standards Institute (ANSI) ANSI C2 in force at design NTP date for clearance to exposed energized parts.
3. Enclosures shall be at least 7 feet from the fence, preferably 10 feet.
4. Bidder shall follow driving space specified in Table 2 of PGE Substation Standard 13004.
5. Bidder shall provide a minimum of 30 feet between the outside of oil filled power transformers (PTs) and any enclosure that can accommodate people or ensure that the wall of the enclosure facing the transformer is a two-hour rated firewall per IEEE 979-1994, Section 4.4.

5.4 Energy Storage System Enclosure Characteristics

Operating temperature range of -2 to 40 °C.

1. Compressor driven air conditioning system as required. System must operate in an ambient temperature range of -2 to 40 °C.
2. The PCS shall be installed in a weather-proof, rodent-proof, corrosion-resistant enclosure. Alternately, the PCS may be outdoor-rated, but must be weather-proof and corrosion resistant. Joining surfaces shall be sealed with waterproof non-hardening compound and/or gaskets. Doors and access cover plates shall be provided with gaskets and suitably fitted to ensure a weather tight structure against blowing rain.
3. The energy storage system shall be installed in a weather-proof, rodent-proof, corrosion-resistant enclosure. Joining surfaces shall be sealed with waterproof non-hardening compound and/or gaskets. Doors and access cover plates shall be provided with gaskets and suitably fitted to ensure a weather tight structure against blowing rain.
   The energy storage system should be designed and implemented in a manner that minimizes the risk that surrounding equipment shall be adversely affected by the energy storage system's radiated and conducted emissions.
4. There shall be zero gas emissions during normal operations. The energy storage system Supplier shall provide an enclosure gas monitoring system, gas detector and alarm. All wiring and internal connections shall be completed by the energy storage system Supplier.
5. All components of the energy storage system shall be accessible and removable for replacement or maintenance. The design will allow for OSHA compliant operation and maintenance, and safe working clearances with regards to National Fire Protection Association (NFPA) standard number NFPA-70E arc-flash considerations
6. Disconnect switches shall be installed such that Owner personnel can locally and manually isolate the battery modules from the PCS (DC switch) and locally and manually isolate the PCS from the step-up transformer (AC switch). These disconnect switches shall be gang-operated, lockable in the open position and have a visible break.
7. The energy storage system Supplier shall provide an appropriate HVAC system for the energy storage system including any external connections. All wiring, piping, ducting and internal connections shall be completed by Bidder.

8. There shall be emergency shutdown pushbuttons easily accessible for both PCS and the energy storage system receptacles shall be installed as follows:
    a. At least one Ground Fault Interrupter receptacle is required in the energy storage system Switchgear.
    b. Relay test receptacles. Number and location shall be such that no breaker, transformer or relay panel is more than 100 feet from a receptacle.
9. Emergency lights shall be installed on exterior switchgear, controlled by timer switch fed from the DC panels.
   Telephone line and/or other communications equipment shall be installed to establish communication with the fire alarm equipment in the energy storage system.
   The control enclosure(s) shall be connected to the ground grid in two locations. Reference PGE Standard S14006, Metal Building Grounds, for details. 4.4 PCS Specification.
10. All enclosures and their contents and all other structures within the Bidder's scope of supply must be seismically rated to withstand a seismic event as detailed in Table 5-1 below.

5.5 Power Conversion System

1. The energy storage system shall be capable of charge and discharge at a rate equal to the nameplate rating of the PCS. The Bidder shall meet this requirement through appropriate sizing of the energy storage system or approved strategy.
2. Bidder shall supply a four-quadrant PCS compliant with UL1741A and like those compliant with IEEE 1547-2018, allowing for extended high and low voltage (LV) ride through as well as voltage and frequency grid support. Bidder shall supply all PCS performance characteristics.
3. The ramp rate of charging and discharging of the energy storage system shall be programmable or set to a defined value by manually entering a value into the energy storage system HMI or by the Owner system communication a ramp rate set point.
4. The power quality to the grid shall meet the harmonic requirements as indicated in IEEE 519.
5. Disconnect switches shall be installed such that personnel can locally and manually isolate the battery from the Power Distribution Control System (PDCS) (i.e. DC Switch) and locally and manually isolate the PCS from the step-up transformer (i.e. AC Switch). These disconnect switches shall be gang-operated, lockable in the open position and have a visible break.
6. PCS shall be able to transition from an off state to an idle current regulating state (on-line) within 10 seconds.
7. PCS must be capable of controlling MW output to within 1% of setpoint.
8. PCS must be capable of controlling MVAr output to within 1% of setpoint.
9. PCS shall be capable of high voltage (HV), LV, high frequency and low frequency ride through as required in IEEE1647-2018.
10. Inverters should be self-commutated so as not to cause any harmonic disturbance.
11. Inverters must be islanding capable to support black start operations.

5.6 Controls

5.6.1 Master Site Controller System Specifications

1. The master site controller shall be able to operate outlined use cases.

2. Monitor points shall have the ability to be recorded at a minimum of one second, with the capability for instantaneous collection of data when data is outside of set parameters.
3. System should have the ability to remotely access and monitor the data as well as have a 30-calendar day on-site memory storage capacity.
4. The master site controller shall provide remote and local means for resetting the energy storage system alarms.
5. The master site controller shall be designed to provide for automatic, unattended operation of the energy storage system. However, the control system design also shall provide for local manual operation, remote operation, or dispatch of the energy storage system from Owner's Communication system or remote access point.
6. The master site controller shall be capable of installing additional operating functions in the future, if needed.
7. The master site controller shall have the necessary hardware and software (i.e. firewalls and malware detection) such that it is compliant with the latest Owner standards at the time of commissioning for control system security requirements.
8. Master site controller and other controls and systems shall be designed for isolation, testing, diagnostic monitoring, and removal without interruption of the energy storage system availability to the grid.
9. The master site controller system shall be capable of communication with Owner Communications via a compatible network medium/protocol.
10. Communications must meet applicable North American Electric Reliability Corporation (NERC) Critical Infrastructure Protection (CIP) Standards, and PGE's NERC CIP Cyber Security Policy.
11. Master site controller ingress or egress communication from a location outside of Port Westward is required to be controlled and have a documented business justification as specified in PGE's NERC CIP Low Impact Plan.
12. Master site controllers must be in an area that is controlled as specified in PGE's NERC CIP Low Impact Plan.
13. Master site controller shall have the ability to communicate to the transformer high side circuit breaker protection scheme to protect the energy storage system from system abnormities such as faults, under frequency, over frequency, etc.
14. Local control shall include automatic and manual operation of the energy storage system. Automatic control shall be performed by the PGE plan PLC. Manual control shall be performed through the HMI and manual control switches. At a minimum the following control switches are required: open/close switch for the PCS AC breaker(s), open/close switch for the PCS DC breaker(s), open/close switch for the interconnection breaker, and auto/manual selector switches.
15. Remote control shall be performed by Owner's SCADA system through an interface with the local logic controller.
16. The Bidder's proposal shall fully describe and demonstrate how the proposed master site controller will operate.
17. Each battery container will require high-speed fiber optic or ethernet communications to the master the energy storage system controller
18. The master site controller shall have the ability to interface with the PCS controller(s).
19. Any operating function shall be capable of being remotely and dynamically selected and prioritized

20. The master site controller will receive a single integer watchdog word from and to PGE's local logic controller. The master site controller will add 5_{10} to this integer and send the single integer back to PGE's local logic controller. A timer within the master site controller will determine when communications are lost between the two controllers.
21. The master site controller will have a similar watchdog feature to all network devices that it interfaces with to determine when communication failures occur.
22. The energy storage system Monitor Points shall include but not be limited to:
    a. Complete battery voltage, current, temperature, useful energy, SOC, battery capacity, State of Health (SOH) and IR.
    b. Cell/module voltage, temperature and SOC, SOH and IR.
    c. Rack and container voltage, current, temperature, SOC, SOH and IR.
    d. Actual system limitation (voltage, power and time) due to low energy or low/high temperature and any other system derating.
    e. All monitoring points shall be available for indication to the Owner Communications.
    f. Monitor if the energy storage system is operating in local or remote.
    g. Each module status (Charge, Discharge, Idle, Sleep, Error).
    h. To study the battery usage, the idle time of the system shall be monitored.
    i. To monitor the energy flow of the battery, the monitoring system shall provide the cumulative total MWh charged and discharged separately at complete system, container and rack level.
    j. Cooling and/or heating system status.
    k. Cell and/or module balancing system status.
    l. Each contactor status and as a redundant measure the voltage after contactors.
    m. Error and warning status.
    n. Insulation monitoring system that periodically will check the correct insulation of the battery.
    o. Any other monitoring points required to track or evaluate equipment warranties.

5.6.2 The Power Conversion System monitoring system shall include:

1. Each inverter DC voltage, current and power.
2. Each inverter AC voltage, current, active power and reactive power.
3. Grid frequency.
4. Each inverter status, errors and warnings.
5. The energy storage system shall be equipped with a BMS that controls and protects the system at the cell, module, rack, and container level.

5.7 Protection

1. Intertie protection shall be provided by a SEL-700GT by Schweitzer Engineering Laboratories. Any other protective relays shall be microprocessor-based digital type, manufactured by Schweitzer Engineering Laboratories. Protective relays shall be time synchronized using a dedicated System Master Clock.
2. The protection system shall be designed that in the event of faults occurring, the faulty systems/equipment are safely disconnected, while continuity of supply consistent with system stability is maintained. The selection and setting of protection devices for the auxiliary systems shall be based upon the following major requirements:

   a. Faults on systems/equipment items shall be interrupted as quickly as possible to minimize damage.
   b. Faults external to major power sources, e.g. the transformer shall only open the circuit breaker controlling these power sources after all other protection nearest the fault has failed.
   c. Faults internal to major power sources shall cause their circuit breakers to open as fast as possible to ensure that the transmission system can restore itself within the limits of stability.
3. The protection shall be designed to be stable in transient conditions such as motor starting and shall not operate for current surges caused by faults external to the auxiliary system, for which the main generator would recover, and the item of equipment protected would not be damaged.
4. Protection of systems/equipment shall be designed to match the systems/equipment operating characteristics and provide discrimination with other systems/equipment
5. Local control shall include automatic and manual operation of the energy storage system. Automatic control shall be performed by the logic controller. Manual control shall be performed through the HMI and manual control switches. At a minimum the following control switches are required: trip/close switch for the PCS ac breaker(s), trip/close switch for the PCS dc breaker(s), trip/close switch for the interconnection breaker, and auto/manual selector switch.
6. Remote control shall be performed by Owner’s SCADA system through an interface with the local logic controller.
7. If a direct transfer trip is issued from PGE to the energy storage system, the system shall lock out and the 86 Lock-Out function must be reset manually only at the site. Lock-out switch shall be Electroswitch Type 24 Lockout Relay (LOR) or equivalent.

5.8 Metering

1. Revenue Energy Metering; the energy storage system power output shall include dedicated electrical revenue metering utilizing revenue grade PT’s (ANSI C57.13-2015, 0.3 accuracy) and CT’s (ANSI C57.13.6-2005, 0.15S accuracy) and primary/backup meters (ANSI C12.20, 0.2 accuracy) connected via ethernet to the energy storage system network at each metering point.
2. Energy metering shall be provided and shall be compliant with the Owner’s energy management requirements of power exports onto the power transmission system.
3. Energy shall be metered using solid state, high precision, digital display meters compliant with the 0.2 accuracy class contained within ANSI C12.20-2010, Underwriters Laboratories (UL) listings, SEL-735 (part number x735Bx1094xEGxDxxx161xxxx). Metering shall be provided for gross power output/input and auxiliary power.
4. Each meter shall provide, as a minimum, two pulsed KYZ outputs proportional to each of the following energy measurements:
5. Generator Net, Gross and Auxiliary MW-hr energy
6. Generator Net, Gross and Auxiliary MVar-hr energy
7. MW-hr energy consumed by Project auxiliaries
8. Pulsed outputs shall be transmitted to the Project SCADA/AGC remote terminal unit (RTU) in real time.

9. All data collection, metering and data recording facilities shall have provisions for time stamping of measurements using a source signaling system that uses the IRIG-B or GPS nationally recognized time reference source as a basis.

5.9 Communications, Network and Data

1. All system components must be individually addressable by separate and unique host IP addresses. This includes BMS, PCS, meters, HMI, Master Controller and all other Ethernet accessible devices including power supplies, UPS's.
2. Bidder shall provide two data networks with separate network IP addresses. One network is for data to be monitored such as volts, amps, watts, SOC, system status, etc. This is called the "Monitor" network. The other network is for control data such as start, stop, kW setpoint, kVAr setpoint, feedback for closed loop control, etc. This is called the "Control" network. An RJ-45 Ethernet port shall be provided in each of these networks for attachment of PGE's network devices.
3. Bidder will provide a network switch for each network with a minimum of two unused RJ45 ports for Owner's use; two extra ports on the monitor network and two extra ports on the control network.
4. Bidder will provide a complete tag list with all system parameters for Owner to monitor. Data shall be provided down to the cell level.
5. A Honeywell Notifier fire alarm panel shall be provided at the energy storage system location by the Bidder and networked with the existing panel within the Port Westward 2 control room provided by Owner. Port Westward 2 operators must be able to receive, acknowledge and silence fire, trouble and system status alarms.
6. Owner will provide a list of IP network and host ID's after Bidder provides a list of all network devices.
7. Bidder's communication protocol shall be Modbus over TCPIP except for ungrounded DC systems which may utilize CAN protocol. CAN protocol must be converted to Modbus over TCPIP to connect to either the Monitor or Control networks.
8. Bidder will utilize CAT6 ethernet cable as a standard.
9. Bidder will utilize RJ-45 connectors as a standard throughout the system.

5.10 Cable and Conduit

1. Equipment where the manufacturer determines the layout and provides the wiring diagram shall have wire terminations according to industry standards and shall be subject to Owner approval.
2. Each control wire end shall be clearly labeled with the address to which the other end of the wire is terminated. Use labeling convention from S14410, Control Wiring, for cable connections to plant equipment.
3. No butt splices shall be used in control wiring within the entire scope of supply.
4. Control wires connecting low level signals to and from SCADA transducers or PLC terminals shall be Switchboard Wire (SIS) 18 American Wire Gauge (AWG) minimum. All other connections, including Current Transformer (CT) and PT circuits, shall use SIS 14 AWG. All wire shall be stranded and rated for 600V. Outdoor multiconductor control cables shall be #10 AWG. Reference PGE standard S14420 Control and Power Cables for details.

5. Current and potential circuits shall use States Co. Type NT blocks, with sliding links. A maximum of two wires may be connected to each termination stud with non-insulated ring tongues crimped on.
6. Test switches shall be applied to isolate relays, breaker trips circuit, and CT/PT circuits for testing. Reference PGE Standard 14415, Test Switches for details.
7. For specific functions the wire colors indicated shall be used:

a. 120/240V Single-Phase Power	X	Black
	Y	Red
	Z (or Neutral)	Blue (with White Tape for Neutral)
	GRD	Orange (with Green Tape for ground)
b. All Three-Phase Connections	A	Black
	B	Red
	C	Blue
	COM	Orange (with white Tape for Neutral)
c. DC Power	Positive	Red
	Negative	Black

8. Primary cables shall be installed per PGE Substation Standard S14430. Also reference PGE Underground Standard Section 220 and 225 for ampacity, bend radius, and termination.
9. Secondary and service cables shall reference PGE Underground Standard Section 240 and 245 for ampacity, bend radius, and termination.
10. Outdoor conduit of low-voltage (below 600V) wires shall follow PGE Substation Standard S14600, Conduit Systems.
11. Splices for control cable shall followed Substation standard S14450, Splice Junction Box.
12. CTs for relaying shall be relaying accuracy with a CT ratio such that the maximum secondary fault current does not exceed 20 times rated secondary current. Refer to PGE Substation Standard S11601, CTs for details.
13. Voltage transformer for relaying shall be relay accuracy but shall cover all letter designation per Table 3, Standard Burdens for Voltage Transformers, in PGE Substation Standard S11602. Secondary voltage transformer circuit shall be grounded at one point.

5.11 Grounding

1. Bidder shall follow Substation Standard 14000, Grounding System Design, for grounding design of all equipment, structure, and fencing.
2. All buildings shall be grounded per Substation Standard S14006, Metal Building Grounds. Outdoor enclosures and cabinets shall be grounded per Substation Standard S14012.
3. Fence and gate shall be grounded per Substation Standard S14015, Fence and Gate Grounding. Barb wires shall be grounded per Substation Standard 14016.
4. Ground grid shall be extended per Substation Standard S14021, Ground Grid and structure.
5. Instrument transformer and PTs shall be grounded per Substation Standard S14024, Instrument Transformer Grounding, and S14031, PT Grounding, respectively.
6. Switch handle and operator shall be grounded per Substation Standard S14027, Switch Handle and Operators.

5.12 Fencing

1. Bidder shall follow Substation Standard 12000, Fencing Design, for design, material, and construction of all fences.
2. Fencing clearance to exposed live parts shall follow Substation Standard S12030, Fence Safety Clearance.
3. Safety signs shall be installed on the fence per Substation Standard S12020, Safety Signs.

5.13 Meteorological and Seismic Data

The project site is in the northwest temperate climate zone. The BOP facilities and equipment being supplied under this Agreement shall be designed to operate satisfactorily within the following ranges of site ambient conditions. Outdoor BOP facilities and equipment shall be designed and constructed to operate continuously within the design basis data as listed below. Summer and winter indoor design temperatures for plant equipment and the outdoor design dry bulb and wet bulb temperatures for HVAC systems are specified in the Space Conditioning System Definition.

- Outdoor Extreme Summer Temperature 104 F
- Summer Design Temperature 95 °F
- Average High Summer Temperature 74 °F
- Annual Average Outdoor Temperature 51 °F
- Average Low Winter Temperature 33 °F
- Winter Outdoor Design Temperature 15 °F
- Winter Outdoor Extreme Temperature 0 °F
- Average Relative Humidity 78%
- Design One Hour Duration Rainfall 2 inches / hour
- Design 24 Hour Duration Rainfall 4 inches / day
- Average Annual Precipitation 58 inches / year
- Plant Site Elevation 18 feet above MSL
- Plant Site Barometric Pressure 14.691 psia
- Maximum Design Wind Speed: As determined by local governing building code for this area as noted below.

Work shall be designed according to the building code and site conditions shown in Table 5-1.

Table 5-1. Building Code and Site Conditions	
General Design Data:	
Building Code	County's current version of the Oregon Structural Specialty Code and related codes in effect upon enactment of the first permitting submittal.
Occupancy Category	III
Site Elevation (Mean Sea Level), ft (m)	18 (NGVD29)
Wind Design Data:	
Basic Wind Speed, V, Nominal 3 second gust wind speed at 33 ft (10 m) above ground for Exposure C category, mph (m/s)	95
Exposure Category	C
Topographic Factor, Kzt	1.0
Importance Factor (Wind Loads), I	1.15
Snow Design Data:	
Ground Snow Load, Pg, lb/ft2 (kN/m2)	25
Importance Factor (Snow Loads), I	1.1
Ice Design Data:	
Nominal Ice Thickness, t, Due to freezing rain at a height of 33 ft (10 m), inches (mm)	0.25
Concurrent Wind Speed, Vc, mph (m/s)	30
Importance Factor (Ice Loads – Ice Thickness), Ii	1.25
Importance Factor (Ice Loads – Concurrent Wind), Iw	1.0
Seismic Design Data:	
Short Period Mapped Spectral Acceleration, Ss	0.88
One Second Period Mapped Spectral Acceleration, S1	0.41
Site Class	F
Importance Factor (Seismic Loads), I	1.25

5.14 Transformer

1. Transformers shall comply with the following standards:
    a. American National Standards Institute (ANSI) or Institute of Electrical and Electronic Engineers (IEEE):
        i. C57.12.00 General Requirements;
        ii. C57.12.26 Construction;
        iii. C57.12.28 Enclosure integrity;
        iv. C57.12.34 Pad-mounted, Three-Phase Distribution Transformers;
        v. C57.12.70 Terminal Markings and Connections;
        vi. C57.12.80 Terminology;
        vii. C57.12.90 Test Code;
        viii. C59.147 Natural Ester Fluids in Transformers;
        ix. IEEE Standard 386 Separable Connectors';
        x. IEEE Standard 519 Harmonic Control in Power Systems;

2. Transformers shall be three-phase, 60-Hz, fluid-filled KNAN, self-cooled, 65 °C average winding temperature rise above 40 °C ambient, dead front, radial feed, pad-mounted, compartment-type transformer.
3. Transformer kVAr-rating shall be determined by the maximum available steady-state output of aggregated inverters. Each transformer shall be rated at no more than 3,000kVAr to reduce breaker fault current and replacement lead time.
4. Primary HV voltage shall be $13.8kV_{LL}$ ungrounded Delta.
5. Transformer secondary shall be grounded for all three phases.
6. The HV coil BIL rating shall be at least 95kV. LV coil BIL shall be at least 30kV.
7. Impedance value shall be 5.75% nominal; with a minimum value of 5.32%, and maximum value of 6.18%.
8. There shall be five primary taps (nominal voltage, ±2.5%, and ±5%).
9. Transformer shall be capable of serving a capacitive or inductive load at 100% nameplate, under steady-state conditions.
10. Transformer shall be capable of serving an overload of 125% for 4 hours.
11. Transformer excitation shall be <1% at nameplate rating, under 100% and 110% voltage conditions.
12. Bidder shall use a K-factor>3.
13. Transformer shall be designed to serve a 60Hz load with a Total Harmonic Distortion not to exceed 3%.
14. Transformer shall be protected on the primary by thermal fuses.

5.15 Foundations

Except as otherwise specified, the Bidder shall be responsible for all building and equipment foundations. The scope of foundation work shall include the design, furnishing and installation of all anchor bolts and embedments. Foundation design shall follow PGE Substation Standard S12310.

A permanent Project benchmark shall be established on the Project Site by the Seller.

5.15.1 General Criteria

Foundations shall be designed using reinforced concrete slabs on grade, spread footings, steel piles, or ballasted material to resist the loading imposed by the building, structure, or equipment being supported. The foundation design shall consider the following:

1. Soil bearing capacities
2. Deep foundation capacities
3. Lateral earth pressures
4. Fluid pressures and impact loads
5. Allowable settlements
6. Structure, equipment, and environmental loadings
7. Equipment performance criteria
8. Access and maintenance
9. Temporary construction loading
10. Where piled foundations are to be used, the Bidder shall conduct a pile load test program.

All foundation floor elevations shall be above the 100-year flood plain. Floor elevation of buildings and the top of foundation for major outdoor equipment shall be a minimum of six inches above the high point of finished grade elevation and sloped to drain and shall not pond water.

11. Slab on grade concrete foundations with thickened edges (i.e. grade beams around perimeter) shall be provided for all equipment such as inverters, medium voltage step-up transformer(s), HV step-up transformer(s) and all other required equipment subject to adequate soil capacity and equipment tolerance of anticipated frost movement. Soil below the slab on grade shall be over excavated down to frost level, and then backfilled with an engineered fill in accordance with the Geotechnical Engineer’s recommendations. If slab on grade foundations are deemed inadequate for equipment loads or serviceability criteria due to frost concerns specific to the project site, cast-in-place concrete drilled piers shall be used;
12. All foundations shall be made of concrete mixture not less than 8 inches thick or as required for structural considerations and will contain rebar reinforcing steel or steel cages. All foundations shall be designed to meet the requirements of the local ground conditions as defined in the Geotechnical investigations;
13. The concrete shall be reinforced using rebar both horizontal and vertical. All foundations shall meet the requirements and specifications of the equipment Contractor. All foundations drawings shall be stamped by a Professional Engineer licensed in the State of the Project;
14. All foundations shall be designed to meet all applicable municipal, state and federal building codes and regulations;
15. Foundations shall be designed with required electrical grounding considerations;
16. Bidder shall provide, maintain and operate all equipment necessary to dispose of water that interferes with foundation construction. Water shall be removed from excavations before depositing concrete, except where under-water concrete placement is allowed for drilled piers. Bidder shall comply with all applicable discharge codes, regulations and practices for the project location;

17. Pier or pile design shall be based on specific site Geotechnical conditions such as resistance factors, moisture, corrosiveness, and frost depth and will account for freeze stress, allowable deflection at ground surface, compression, tension and lateral forces. All piles including additional hardware shall have proper corrosion resistant treatment, hot dip galvanizing or anodizing to withstand 25-year service life time in consideration of the local climate conditions and installed conditions of the Project site. Galvanization shall be to ASTM A123 specification with a minimum coating of 3.3 mils. Final galvanizing coating thickness shall be assessed and verified by a registered Corrosion Engineer in the state that the project is located in. This verification shall be based on in-situ soil corrosion tests. Site touch-ups of the corrosion protection shall be done consistent with Good Utility Practices, ASTM A780 (for galvanized materials). Factory end cut surfaces that come from the manufacturer in a healed state shall not be touched up onsite, unless deemed necessary by racking vendor or Independent Engineer structural review. All field drilled holes, site modifications, field welds, shipping damage, etc. shall be touched up onsite.
18. Pull out load test for the Project shall be performed with the specific pile design to ensure load assumptions are accurate and pile design is adequate. The Bidder shall perform proof tests on a minimum of one pile per one hundred (100) of the production piles installed. The test procedures shall conform to ASTM D3689. Tension test shall be performed in lieu of compression tests up to the design load provided by the racking manufacturer. The production piles shall sustain the compression, horizontal and tensile design capacities with deformations within the acceptable limits specified by the racking manufacturer. If a pile test fails to meet the acceptance criteria, the Subcontractor shall proof test another pile in the vicinity. For failed piles and further construction of other piles, the Bidder shall modify the design, the construction method and procedure, or both to remedy such failure. The Bidder shall submit the proposed modifications for review and acceptance by the Buyer;
19. Piles shall be designed to meet or exceed a 25-year service life. Pile installation records shall be kept and provided to the Buyer upon request. Installation records will include:
    a. The type and make of hammer and its stroke or rated energy (where driven piles are used);
    b. The pile location, size and length;
    c. The pile driving sequence;
    d. The final embedment depth and the tip and head elevations;
    e. Inspection of verticality; and
    f. Any difficulties or unusual conditions encountered during driving.
20. Pier or pile design and selection shall take into consideration all reasonable geotechnical conditions at the site including but not limited to clay, rock, swamp areas and water table depth, and corrosion.
21. All foundation methods and designs shall require design approval of the PGE or PGE's representative.
22. Pile / foundation design and selection is required for a minimum of 25-year service life period.
23. Oil-filled transformer foundations shall have an integral reinforced concrete spill containment area compliant with Spill Control and Countermeasures criteria. Exposed surfaces of foundations exposed to contact with petroleum products due to spray, spills, drips, etc., shall receive an appropriate coating system to prevent absorption and staining of the concrete.

24. The Bidder shall maintain records of inspection and testing of soils to ensure compliance with design assumptions and shall comply with the requirements of the state and local authorities regarding notification and inspection.
25. All slab foundations shall have notches or cutouts for cable/conduit entry. Embedding conduits in concrete is not acceptable.

5.15.2 Concrete

Except as otherwise specified, or where precast structural elements can reduce cost and meet or exceed cast-in-place reinforced concrete performance, all concrete shall be reinforced cast-in-place concrete designed in accordance with American Concrete Institute (ACI) 318, *Building Code Requirements for Reinforced Concrete* and other applicable structure specific Codes and standard.

Materials for concrete shall comply with applicable ACI Committee publications. Materials shall be handled and stored as recommended industry codes and standards.

Table 1 Concrete Classes

Class	Use	F'_c 28 Day Strength, psi
A	Mud slabs, fill, duct bank	3,000
B	General	4,500
Grout	Structure to concrete bearing surfaces	5,000 (or as required by Equipment manufacturers)
Material	Usage	Requirements
Cement	In accordance with mix Design, local supply	ASTM C150, Type I (unless soils, process water, and mixing water contain sulfates that exceed Type I sulfate limits. Use ASTM C150, Type II or V as required by ACI 318).
Admixtures and Pozzolan	Cement reduction, heat and crack control, workability	Fly ash, slag, plasticizers, and other admixtures are permitted if included in mix designs submitted to Buyer; air entrainment to be used in all concrete exposed to the atmosphere
Water	In accordance with mix Design, local supply	Potable, or clean and free of deleterious materials.
Aggregate	In accordance with mix Design, local supply	ASTM C33. (verify that local aggregates are not reactive)
Reinforcing Steel, main	As required by Design	ASTM A615, Grade 60.
Reinforcing Steel, ties and stirrups	No. 4 or as required by Design	ASTM A615, Grade 60.
Welded wire fabric	As required by Design	ASTM A185.
Forms	All exposed concrete surfaces (not flatwork)	Plywood or modular steel

1. Construction of all reinforced concrete foundations required to complete the Project, including but not limited to energy storage system(s), PMT(s), Main Power Transformer(s), electrical equipment (under the Bidder supplied and/or PGE supplied), sub-station building(s) and control building(s).
2. Supplying and installing all rebar, anchor bolts, anchor bolt nuts, templates, embedment rings and shims required for complete foundations.

3. Surveying of all foundation locations, by a 3rd party surveyor, to validate the center pin of the foundations. Surveyor shall verify the XYZ coordinates for all foundations.
4. Supplying, installing and stripping all formwork required.
5. Patching and sealing of all exposed concrete after stripping of forms.
6. Supplying concrete and grout that complies with the approved plans, specifications and manufacturer's recommendations.
7. Providing an independent 3rd party testing laboratory, approved by the AGR, for sampling, testing and certifying the materials and installation are in conformance with the requirements.
8. Providing all welding required to complete the Work.

5.16 Protective Coatings and Painting

1. Exposed surfaces at the Facilities shall receive a protective coating system. All surfaces damaged during delivery or installation or otherwise left unprotected for construction purposes shall be coated or touched-up on Site after the installation is complete.
2. Coating systems shall be inspected and documented by a qualified NACE level II inspector or equivalent.
3. Structural and miscellaneous support steel shall be galvanized in accordance with ASTM A123, ASTM A153 and ASTM A385.
4. Structural steel, structural components and miscellaneous steel Work shipped to the Site for a pre-engineered building (PEB) shall have a manufacturer's applied zinc-rich primer. PEB components shipped to the Site with a top coat (final finish) shall have a coating System that meets or exceeds the requirements listed below. In all cases, the completed PEB building shall have a coating system that meets or exceeds the requirements listed below.

Table 2 Protective Coating and Painting

Material	Criteria
Structural Steel, steel piping, Equipment: High moisture, extremely corrosive environment	Surface preparation per referenced standards; hot-dipped galvanized. Note: connection materials shall be coated the same; welded connections not allowed.
Structural Steel, steel piping, Equipment: Exterior/exposed, and/or Interior, moderately corrosive environment	Surface preparation as recommended by the paint manufacturer; a primer coat (2-4 mils) of two component inorganic zinc; and a finish coat (4-6 mils) of semi-gloss polyamide epoxy paint.
Structural Steel, steel piping, Equipment: Moderate chemical exposure (acidic, alkaline) environment	Surface preparation as recommended by the paint manufacturer; primer coats (4-6 mils) of polyamide epoxy paint; and a finish coat (2-3 mils) of acrylic aliphatic polyurethane paint.
PV Tracker / Rack steel piles	Hot Dip Galvanize per Corrosion Engineer's requirements specific to the soils at the project.
Externally exposed metal surfaces with service temperatures at or above 450°F	SSPC SP10 surface preparation; a primer coat (2-2.5 mils) of silicone paint or inorganic zinc silicate paint; and a finish coat (1.5 mils) of silicone aluminum paint.
Environmentally controlled areas with interior concrete and concrete masonry that require painting	Surface preparation that is clean, dry and free of contaminants; a primer coat thickness rate per paint manufacture) of masonry filler; an intermediate coat (2-3 mils) of low gloss acrylic latex; and a finish coat (2-3 mils) of low gloss acrylic latex.
Exterior and non-environmentally controlled areas with concrete and concrete masonry components requiring painting	Surface preparation that is clean, dry, and free of contaminants; a primer coat (thickness rate as recommended by the paint manufacturer) of masonry filler; an intermediate coat (2-3 mils) of water-borne acrylic paint;

Material	Criteria
	and a finish coat (2-3 mils) of water-borne acrylic paint. Split face concrete masonry shall be coated with a clear penetrating sealer.

6 Codes and Standards

All Construction must satisfy the requirements of applicable local, state, and federal building, mechanical, plumbing, fire energy and barrier-free codes.

Compliance with the Americans with Disabilities Act of 1990 28 C.F.R. Part 35 shall be required.

The energy storage system furnished under this specification, except where specifically stated otherwise, shall conform to industry standards, the AHJ and the latest applicable standards of:

- UL 1741SA with interoperability features unlocked (capable of operation in accordance with California Rule 21)
- American National Standards Institute (ANSI)
- American Society of Civil Engineers (ASCE)
- American Society of Mechanical Engineers (ASME)
- Institute of Electrical and Electronics Engineers (IEEE)
- Insulated Cable Engineers Association (ICEA)
- National Fire Protection Association (NFPA)
- National Electric Code (NEC)
- National Electrical Safety Code (NESC)
- National electrical Manufacturers Association (NEMA)
- Occupational Safety and Health Administration (OSHA)
- Underwriters Laboratories (UL)
- North American Electric Reliability Corporation (NERC)
- International Building Code (IBC)

Specific Requirements to be followed but not limited to:

• UL 9540	Energy Storage Systems and Equipment
• NFPA 855	(Proposed Standard)
• IEEE 2030.2 Electric	Interoperability of Energy Storage Systems Integrated with the Power Infrastructure
• ANSI Z535	Product safety signs and labels
• FCC Class A	Industrial and commercial, emissions requirements
• IEEE 1547-2018	Interconnection for distributed resources with electric power systems
• IEEE 519-1992	Power quality and harmonic control in electrical power systems
• IEEE C62.41. (0,1,2)	Lightning/Surge protection
• NESC	National Electrical Safety Code latest adopted edition
• NFPA-70	National Electrical Code (NEC) latest adopted edition

- UL 1741-2010 Static inverters and charge controllers for distributed energy resources
- UL 1973 (in process) Standard for Batteries for Use in Stationary, Vehicle Auxiliary Power and Light Electric Rail (LER) Applications
- UL 508C General safety for power conversion equipment
- UL 9540 Compliant Standard for Energy Storage Systems and Equipment
- CIP-003-7 Security Management Controls

7 Abbreviations

AC	Alternating Current
ACI	American Concrete Institute
AHJ	Authority Having Jurisdiction
ANSI	American National Standards Institute
ASTM	American Society for Testing and Materials
AWG	American Wire Gauge
BIL	Basic Insulation Level
BOP	Balance of Plant
BMP	Best Management Practice
BMS	Battery Management System
°C	degrees Celsius
CAD	Computer-aided Design
CIP	Critical Infrastructure Protection
CT	Current Transformer
DC	Direct Current
EOR	Engineer of Record
EPA	Environmental Protection Agency
ESCP	Erosion and Sediment Control Plan
°F	degrees Fahrenheit
FAT	Factory Acceptance Test
GA	General Arrangement
HMI	Human Machine Interface
HV	High Voltage
HVAC	Heating, Ventilation, and Air Conditioning
IEEE	Institute of Electrical and Electronics Engineers
IR	Internal Resistance
LV	Low Voltage
MOP	Method of Procedure
NERC	North American Electric Reliability Corporation
NFPA	National Fire Protection Association
NTP	Notice to Proceed
ODEQ	Oregon Department of Environmental Quality
O&M	Operations and Maintenance
OSHA	Occupational Safety and Health Administration
PCS	Power Conversion System
PDF	Portable Document Format
PGP	Performance Guarantee Period
PGE	Portland General Electric Company
PLC	Programmable Logic Controller
PMT	Pad mounted transformer
POI	Point of Interconnection
PSES	Power Supply Engineering Services
PSSP	Project Specific Safety Plan
PT	Power Transformer
QA/QC	Quality Assurance/Quality Control
RICE	Reciprocating Internal Combustion Engine
SCADA	Supervisory Control and Data Acquisition
SOC	State of Charge or Energy: Nominal Energy Remaining / Nominal Full Pack Energy Available
SOH	State of Health
UL	Underwriters Laboratories
UPS	Uninterruptable Power Supply

8 Safety Material

The energy storage system shall include eyewash station(s) in the battery area as applicable. In general, the energy storage system shall be designed with personnel safety as the top priority.

1. The energy storage system thermal management system and fire protection system shall be complete and failsafe. The energy storage system associated equipment shall have complete and failsafe fire detection/extinguishing system, compliant with applicable current specifications and standards.
2. Fire extinguishers and first aid kits shall be supplied as required.
3. All safe working clearances between equipment shall be met.
4. Interlock switches that create a safe environment shall be provided on all access ports/doors/panels to hazardous voltages and or currents. The energy storage system shall go into an alarm state and shutdown when one of these ports is opened.
5. The energy storage system shall be able to shut down safely in all conditions (e.g. ground fault, programmed)
6. The energy storage system labeling shall be highly visible, no smaller than 14 pt. font in uppercase sans serif typeface, to identify major equipment and associated components or protection.

9 Bid Submission Documents

Each Bidder is required to provide the following documentation as a part of their bid submission. It is at the Bidder's discretion to provide alternate bids for durations of 2 and/or 4 hours.

1. BMS system description and functional specifications.
2. Detailed product data sheets and specifications for all components.
3. The energy storage system typical one-line diagram
4. The energy storage system typical physical arrangement
5. A power quadrant diagram showing the energy storage system real and reactive power capabilities in each quadrant.
6. Scope of Supply – including any field assembly requirements.
7. Proposed Project Schedule & Milestones.
8. (3) Reference projects, capabilities, experiences, and qualifications from within the last 5 years that are within 50% of Project proposed size and of the same the energy storage system model/make.
9. O&M plan as well as procedures/manuals, including but not limited to the following:
    a. A document describing Lock-Out Tag-Out procedures for normal maintenance and component replacement. This document should describe the specific points at which lock-outs must be made and the device used for receiving a lock.
    b. A written procedure for bringing a battery block up to nominal operating voltage should that block inadvertently be discharged below permissible operating voltage.
10. The Bidder shall provide requirements for specialized test equipment and any spare equipment recommended having in stock.
11. Description of performance monitoring, periodic maintenance requirements and replacement/spare parts. In addition, the maintenance program should include routine testing of the battery system and of other systems installed to monitor the energy storage system.

12. Description of DC ground fault detection system.
13. Capacity Augmentation (or replacement) Plan if applicable.
14. Detailed pricing breakdown that includes proposals for three-year Product Warranty and 10-year Performance Guarantee, including the methodology for its verification.
15. Pricing breakdown for black start capabilities and associated costs.
16. Decommissioning Plan
17. QA/QC Plan - Description of QA/QC procedure.

10 Attachments

1. Document Delivery List.
2. Example one-line diagram
3. Example GA
4. Technical Specification Adherence Spreadsheet
5. Reference Specifications
    a. PGE's NERC CIP Low Impact Plan
    b. PGE's Underground cable/conduit standards
    c. PGE's Substation Standards
    d. PGE's Metering Standards
    e. PGE's CAD/Drawing Standard
    f. PGE's Construction Site Safety Requirements
    g. PGE's Civil Standards
    h. PGE's QAQC Program Requirements
6. Port Westward Geotech report; Geotechnical information is provided as-is and is representative for the region. Any additional bores specifically required by the EOR for structural design are within the scope of the Bidder.
7. Port Westward 2 the energy storage system Control Diagram
8. Port Westward Site Certificate; Site Certificate provided represents current site conditions. Updated Site Certificate provided at time of construction will be considered valid.

11 Drawing Standards

1. All drawings prepared by the bidder or any of its subcontractors shall meet the following requirements:
    a. All drawings shall be in AutoCAD 2018 format.
    b. All drawings shall be in the English language.
    c. All drawings created or modified for this Project shall be vector based.
    d. All drawings created or modified shall be per PSES CAD standards.
    e. Measurement system used shall be the U.S. Customary System.
    f. All drawings and dimensions shall be to scale. Non-scale dimensions on drawings shall not be permitted on scalable drawings. A scale bar shall be included on scaled drawings to permit use following photo-reduction.
    g. All drawings shall be sized and formatted ANSI D (22" x 34") in paper space.
    h. All drawings shall be on a PGE PSES standard title block and given a PGE provided drawing number. Vendor drawing numbers may be included in addition to the PGE provided drawing number.

i. Each CAD file shall only contain a single sheet.
j. Typical depiction of designs is not allowed. Each representation of a system or entity shall be shown as many times as it's used. Express written permission from Owner is required for deviating from this requirement.
k. Revision Clouds around any changes from the previous revision.
l. Equipment drawings shall have the equipment name and tag number clearly displayed.

2. GA drawings shall meet the following requirements
    a. Indicate at a minimum three perspective views of the subject matter, (plan view, elevation view, and side view). Additional views or sections shall be provided to clearly indicate the extents and features of the subject.
    b. Include the details of the Work and that of all sub-vendors that are incorporated into the Work. Consolidate all information from suppliers onto the GA drawings.
    c. Pull spaces and maintenance removal zones shall be indicated on the GA drawings. Indicate any areas that require more than three feet of clearance around the equipment boundary on the GA drawings for access or maintenance requirements.
    d. Provide information regarding the location of access doors or view ports.
3. Outline drawings shall depict graphically and dimensionally the configurations, profile, and limitations of parts and assemblies. Perspectives and reference points shall be indicated clearly for each view.
4. Anchor bolt drawings shall provide templating dimensions in sufficient detail to facilitate the preparation of foundation design drawings and to determine the sizes and types of fasteners and other installation devices required. The load shown in anchor bolt drawings shall include all load cases (e.g. Dead load, Live Load, Wind Load, Seismic Load, Thermal Load, Operation Load, Dynamic Load) and load combination for all equipment support point or building column, also interface detail between foundation and equipment support/column (i.e. thickness of grout, shear key, anchor bolt projection) shall be provided.
5. Foundation plans shall provide sufficient dimensional and configuration details to facilitate foundation design. The drawings shall also include recommendations for installation methods and materials if germane. Provide the following:
    a. Overall dimensions, embed and block out requirements, bolt/anchor bolt locations, sizes, and details
    b. Recommended/required mounting details clearly depicting bolting location, size, material, and projection requirements
    c. Equipment Weights, Operating Loads, and Center of Gravity
    d. Either actual or "not-to-exceed" foundation interface design loads, and their points of application, based on loading combinations (e.g. dead load, live load, operating load, test load, wind, seismic, dynamic)
    e. Identification of loading directions, magnitudes, and any other permanent data required for the foundation design. For rotational or reciprocal machinery, include the mass center and dynamic operating frequencies
6. Wiring, connection and interconnection diagrams shall show the electrical connections of an installation or its component devices and parts. Schematics and connection diagrams, such as one line and three-line diagrams, may also be included in this category. Drawings supplied under this category shall provide such detail as is necessary to make or trace the connections involved. The drawings may cover internal or external connections, or both.

7. Cross sectional drawings shall present a view of an object in a perspective that cuts away all or part of an object to show its shape and construction at the cutting plane. Cross section drawings shall be provided where the construction or hidden features of an object cannot be shown clearly by outside views.
8. Fabrication drawings shall provide, in detail appropriate to the nature or complexity of the items, configuration and dimensional data, required processes, procedures, sequences and materials required to fabricate the required items. The information shall be indicated directly on the drawing or by reference to other documents.
9. Detail drawings shall depict complete item requirements for the parts depicted on the drawings including, as applicable, configuration, dimensions, tolerances, materials, mandatory processes, surface finish, protective coatings and symbols.
10. Each assembly drawing shall show the relationship of parts, components, and assemblies to each other. Subordinate parts or components shall be called out on the field of the drawing, by part or finding numbers, and reference shall be made to related drawings and listed as required.
11. Erection drawings shall show the procedures and operations sequences required for erection or assembly of individual items and/or of assembly of component parts of total items or facilities.

Appendix F

PGE's Energy Storage RFP Draft for a Microgrid Pilot

Portland General Electric
121 SW Salmon Street • Portland, Ore. 97204
PortlandGeneral.com

May 02, 2019

Public Utility Commission of Oregon
Attn: Filing Center
201 High Street, S.E.
P.O. Box 1088
Salem, OR 97308-1088

RE: UM 1856 PGE's Energy Storage Request for Proposal Draft for a Microgrid Pilot Energy Storage System – Inviting Stakeholder and Commission Review

Pursuant to Oregon Public Utility Commission (OPUC or Commission) Order Nos. 16-504 and 18-290, enclosed is Portland General Electric Company's (PGE's) request for proposal (RFP) draft for one of the energy storage systems, located in Beaverton as part of the Microgrid pilot. By copy of this to the OPUC Docket No. UM 1856 service list, we invite stakeholders to review and offer comments to the RFP design by May 16, 2019.

History of Energy Storage Docket

The Commission opened Docket No. UM 1751, in September 2015, to implement recently passed legislation, House Bill 2193. House Bill 2193 requires PGE and PacifiCorp to submit proposals by January 1, 2018, for qualifying energy storage systems with capacity to store at least five megawatt hours. In Commission Order 16-504, the Commission adopted guidelines and requirements for energy storage project proposals, in late 2016, and a framework for PAC's and PGE's Energy Storage Potential Evaluations.

PGE filed its Energy Storage Proposal and Final Potential Evaluation on November 1, 2017, which were investigated in UM 1856. Pursuant to Commission Order No. 18-290, filed in UM 1856 on October 25, 2018, PGE filed its plan to advance its energy storage modeling cability. On April 9, 2019, Staff approved this filing via electronic mail, enabling the Microgrid pilot to move forward.

PGE now seeks stakeholder input to the RFP design for an energy storage system used in the Microgrid pilot. The Commission's competitive bidding requirements for House Bill 2193 projects are as follows:

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' RFP design and offer nonbinding input* (emphasis added).
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.

Enclosed is the draft RFP for one of the energy storage systems that will be used in the Microgrid pilot.

PGE is seeking stakeholder feedback within the next 30 days. Feedback should be directed to: puc.filingcenter@state.or.us

Should you have any questions or comments regarding this filing, please contact Kalia Savage at (503) 464-7432.

Please direct all formal correspondence and requests to the following email address pge.opuc.filings@pgn.com

Sincerely,

Karla Wenzel
Manager, Pricing and Tariffs

Enclosures

Draft Request for Proposal for a Microgrid Pilot Energy Storage System (Located in Beaverton)

May 2, 2019

PORTLAND GENERAL ELECTRIC COMPANY

Energy Storage System Customer Microgrid Project

DRAFT Microgrid Energy Storage System Specification

Contents

1 Scope

Portland General Electric Company (PGE and Owner) plans to procure and install an energy storage system behind a PGE customer's meter (Customer). The Customer is a municipality building, which is a new three-story office building in an urban area. The energy storage system will be owned by PGE although located on the Customer's property and connected to the Customer's 480VAC (nominal) main bus. This energy storage system will provide services to the Area Electric Power System (EPS) while grid connected and will provide reliability and microgrid functions when intentionally islanded. The Energy storage system must be capable of black start to recover the local EPS after an unscheduled intentional islanding event and must be capable of regulating voltage and frequency on the local EPS when intentionally islanded. The energy storage system must also be capable of switching to current regulation mode while islanded. In grid connected mode the energy storage system must be current regulating.

The Customer's microgrid also includes 320 kW of AC coupled photovoltaic (PV) solar and a 1,000kW synchronous diesel generator. All three of these energy resources must operate in either grid-connected mode or islanded mode, individually and in coordination according to site conditions. The PV must operate as part of the microgrid, but it is not a grid-forming resource. Only the energy storage system and the diesel generator can regulate voltage and frequency. The Customer's building load is approximately 200 kW peak.

The scope of supply for Bidders on this Request for Proposals (RFPs) includes:

1. Four-hour modular battery system with Battery Management System (BMS).
2. 250 kW (nominal) Power Conversion System (PCS).
3. Microgrid Energy Management System (MEMS) capable of coordinating the operation of the grid, the energy storage system, the PV and the diesel generator in either grid-tied operation or islanded operation.
4. Fire detection and suppression related to the energy storage system equipment (see Section V. for details).
5. Disconnecting and lock-out means for the energy storage system equipment.
6. Environmental containment in accordance with Environmental Protection Agency (EPA) and Oregon Department of Environmental Quality (ODEQ) requirements.
7. Heating, cooling or other environmental controls required by the energy storage system.
8. All shipping, freight and delivery to Customer's site in Beaverton, Oregon.
9. Installation consultation and supervision as necessary.
10. Bidder will assemble any components on-site that are shipped separately.
11. Installation quality inspection and certification.

12. System commissioning and testing.
13. Demonstration of all functions of the energy storage system and MEMS.
14. Ongoing system maintenance including both preventative corrective maintenances.
15. Ten-year full-coverage warranty of system operation and performance specifications.

2 Basic Energy Storage System Electrical Requirements

Specification Parameter	**Definition**	**Units**	**Value**
Rated Continuous Discharge Power	The rate at which the energy storage system can continuously deliver energy for the energy storage component's entire *specified State of Charge (SOC)* range.	kW	250
Rated Apparent Power	The real or reactive power (leading and lagging) that the energy storage system can provide into the AC grid continuously without exceeding the maximum operating temperature of the energy storage system.	kVA	Bidder shall state the rated kVA that allows for 250kW and 250kVAR
Rated Continuous Charge Power	The rate at which the energy storage system can capture energy for the energy storage component's entire SOC range.	kW	250
Rated Continuous AC Current	The AC current that the energy storage system can provide into the grid continuously and can be charged by the grid continuously without exceeding the maximum operating temperature of the energy storage system.	A	Cannot exceed 320A
Output Voltage Operating Range	The range of AC grid voltage under which the energy storage system will operate in accordance with the energy storage system specification.	V	422V to 528V
Enter-Service Voltage	The range of voltage in which the inverter may enter service	V	422V to 509V (adjustable)
Enter-Service Frequency	The range of frequency in which the inverter may enter service	Hz	59.0 to 61.0Hz (adjustable)
Total Response Time	The response time measured in accordance with figure below starting when the signal (command) is received at the energy storage system boundary and continuing until the energy storage system discharge power output (electrical or thermal) reaches 100 ± 2% of its rated power.	seconds	< 1 second
System Round Trip Efficiency	Total round trip efficiency from beginning of life to end of life, defined as the ratio of the delivered output	%	No less than 89%

Specification Parameter	Definition	Units	Value
	energy of the energy storage system to the absorbed input energy required to restore it to the initial state of charge under specified conditions.		
Ramp Rate	The maximum rate that the energy storage system can change its input and output power.	kW/sec	100
Enclosure Type	A description of the system enclosure including that supplied with the system, provided as a part of the site installation and/or comprised of building assemblies associated with the installation. Examples include building, containerized–both stationary and transportable.	n/a	All enclosures related to the system shall be outdoor rated (National Electrical Manufacturers Association [NEMA] 3R minimum). This includes the BMS, PCS and MEMS enclosures.
Equipment Footprint	Length x Width (LxW) of equipment only (Includes energy storage system and all ancillary units as required) in intended layout.	$Ft.^2$	Total equipment footprint shall not exceed 300 sq. ft. (10' X 30')
Height	Equipment height plus safe clearance distances above the equipment.	Feet	10
Weight	Weight per individual sub-system (e.g. PCS, energy storage system, accessories), including maximum shipping weight of largest item that will be transported to the project site.	Pounds	20,000
Grid Communication Protocols/Standards	List of codes/standards with which the energy storage system is compliant.	MEMS must be capable of communicating via Sunspec Modbus to PGE's plant Programmable Logic Controller (PLC). Within the plant, the system may communicate via Modbus protocol. Entire system must be compliant with Underwriters Laboratories (UL) UL1741SA.	

Specification Parameter	**Definition**	**Units**	**Value**
General Description of Energy Storage	Energy storage technology type (e.g. battery type, flywheel, etc.).	Energy storage shall be via Lithium-ion battery technology (Lithium-Nickel Manganese Cobalt Oxide, LiFePO4 or Nickel-Cobalt-Aluminum)	
Rated Discharge Energy	Specify the accessible energy that can be provided by the energy storage system at its AC terminals when discharged at its beginning of life and end of life.	kWh	1,000
Minimum Charge Time	The minimum amount of time required for the energy storage system to be charged from minimum SOC to its rated maximum SOC.	Hr	4
Typical Recharge Time	This should include any time for rest a period needed between a full or partial charge or discharge cycle.	Hr	4
Expected Availability of System	Percentage of time that the system is in full operation performing application specific functions (including standby) considering both planned and unplanned down-time.	Hr/yr (%)	8670 (99%) of at least partial availability (>50%)
Synchronization voltage step change	The allowable amount of step change in voltage during synchronization	V (pu)	5%

Energy storage systems shall be Category B.1 as defined by Institute of Electrical and Electronics Engineers (IEEE) 1547-2018.

Energy storage systems shall comply with UL1741SA with the interoperability features of that standard fully enabled.

The energy storage system PCS shall be capable of operation in all four quadrants of the power circle. The PCS shall produce at least 250kVA at any location of the power circle and real power output of 250kW anywhere between +0.9pf and -0.9pf. For all angles θ, where pf = -0.9 to +0.9, S=250kW/0.9=278kVA. For all other angles, 0 to 359^{o}, P = 250kVA*Cosθ, where P = energy storage system real power output and θ is the phase angle between current and voltage; and Q=250kVA*Sinθ.

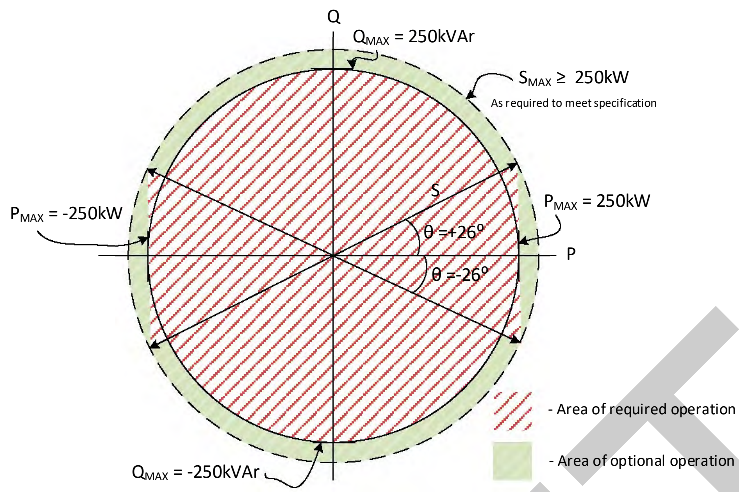


Illustration of Power Quadrants

3 Microgrid Energy Management System (MEMS) Capability

The MEMS may be a standalone controller or may be integrated into the Bidder's Plant Controller. It must be interoperable with the utility grid, the Customer's PV system, the energy storage system, the diesel generator's control system and the Customer's building energy management system.

The MEMS will optimize the operation of all the energy resources according to dispatch priorities provided by the Owner's plant PLC. The MEMS shall communicate with the Owner's plant PLC via Sunspec Modbus protocol utilizing Category 6 ethernet cable and RJ45 connections. The MEMS will reside on a network with various other components such as the PGE plant PLC, diesel generator controller, various meters such as Ion 8,650 revenue meters, PV inverter, Human Machine Interface (HMI), protective relays and the Customer's building energy management system. Owner will provide a switch for the connection of these devices.

The Bidder shall provide a MEMS containing a full color HMI with minimum dimensions of 16"X16" and a touch screen. The HMI may be built onto the controller enclosure or may be a separate console. The HMI shall display the operating status of all energy resources including on/off status, breaker position, power flow (real and reactive), voltage, current related to all nodes. The HMI shall display basic power quality information about the local area EPS (frequency and voltage).

The HMI shall display in graphical format the historical and real-time values for power flows from the energy resources and status of the grid connection (connected or islanded).

The HMI shall clearly display the optimization program being executed and the service being performed in real time and historical.

The HMI shall have no greater than a one second update time.

The HMI shall provide a login screen according to security level:

1. Viewing – no login required
2. Local Operator – Ability to move between basic states such as entering Storm Avoidance mode or Maximum Energy Reservation, placing the system in standby.
3. Owner operations – All Local Operator functions plus ability to change basic operating constants and parameters
4. Developer – highest level security allowing access to modify all parameters and program functions`

All security levels shall have an inactivity time-out.

In addition to the local HMI, the Customer is providing a large screen high-resolution monitor in a public space. Bidder will provide a connection to this monitor to display live screens illustrating and interpreting the MEMS for laypersons visiting the building. These screens are within the Bidder's scope, and the screens must be reviewed and approved by the Customer and Owner.

MEMS shall employ a watchdog system to the Owner's plant PLC, the diesel generator controller, the energy storage system, the Customer's PV system and the Customer's building energy management system to alarm upon loss of communications.

MEMS must be capable of remote monitoring via a web app. Communication to the web may be wireless or ethernet through the Customer's building network but will not communicate through the plant Modbus network.

The MEMS hardware platform may be either a PLC or an embedded fanless and diskless computer.

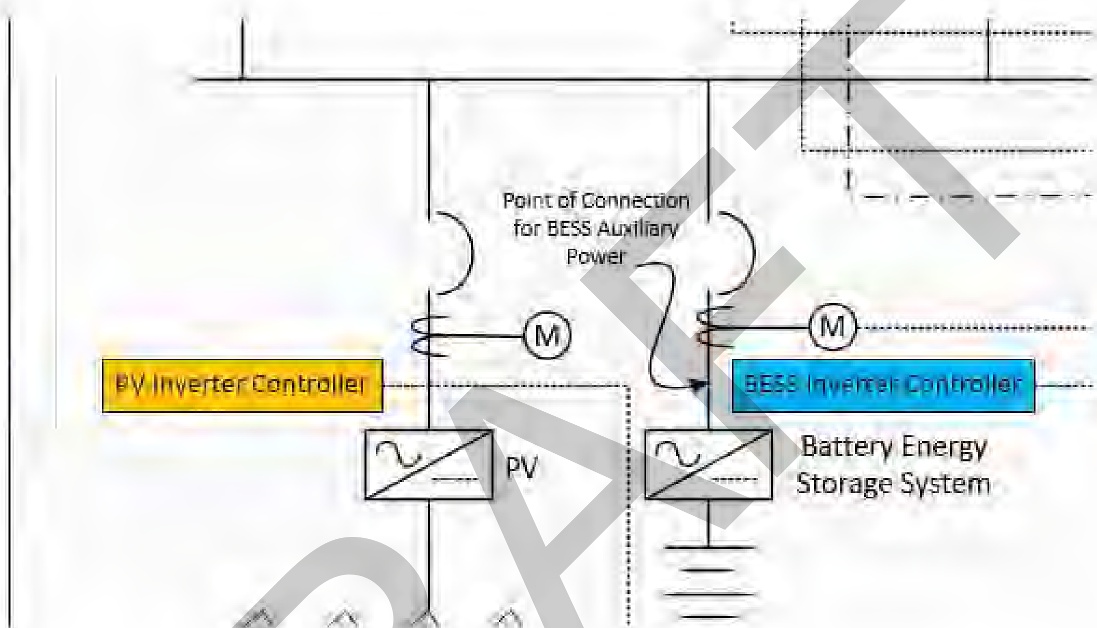
The Owner must be able to communicate directly with a Modbus connection to the MEMS. Access through a web application or API is not sufficient.

4 Auxiliary Power

The energy storage system auxiliary power system shall be 120/240Vor 480V. Auxiliary power must be provided within the Bidder's scope of supply. It must include provisions for the black start service which will require Uninterruptable Power Supply (UPS) standby power. Bidder may provide a standalone UPS or utilize energy stored in the energy storage system batteries for this function. Neither the Customer nor the Owner will provide UPS power for black start.

Energy storage systems auxiliary power must consume less than 22,000kWh of energy annually.

Auxiliary power must be connected at a point between the energy storage system equipment and the Ion8650 revenue meter so that auxiliary power is unmetered and remains in the efficiency loss for billing.



Energy Storage System Aux. Power is Connected Between the Energy Storage System and the Revenue Meter

5 Fire Detection and Suppression

Bidder must provide an integral fire detection and suppression system. The detection must be capable of integration into the Customer's fire alarm panel. The suppression system must be capable of extinguishing the worst-case thermal runaway scenario, containing the fire within the battery enclosure. Fire detection and suppression system must automatically shut down and electrically disconnect the energy storage system from Customer's bus.

The fire detection and suppression system must meet the requirements of UBC and the local Authority Having Jurisdiction (AHJ). It also must meet the minimum best practices for the energy storage industry.

Bidder must provide an off-gas sensing system integrated with the energy storage system plant controller that will detect off-gassing at the individual cell level.

6 Warranty and Performance Guarantee

A. Bidder shall provide support to Owner during a twelve (12) month performance verification period, to begin after the energy storage system has been commissioned and has begun commercial operation. This support includes tuning of the optimization algorithms and consulting by phone, e-mail and web meeting regarding operations and maintenance of the energy storage system.
B. The energy storage system shall have an Equipment Warranty for a minimum of (3) years, and a Performance Guarantee for (10) years.
C. The Equipment Warranty shall include periodic evaluation of the energy storage system to identify any premature degradation and/or potential underperformance. Owner will be notified of evaluation results as soon as possible.
D. Bidder shall provide a (10) year minimum Performance Guarantee which will include replacement of battery modules as necessary to maintain guaranteed energy storage capacity and efficiency. At any time during the (10) year term that, as reasonably required to maintain guaranteed capacity or otherwise as defined by the technical specifications, the repair of the energy storage system requires a replacement component, Bidder will bear all the cost of replacement and any related equipment, materials, and/or parts.
E. Energy storage system Bidder shall perform all services in accordance with professional standards and skill, expertise, safety and diligence of professionals regularly involved in the maintenance of energy storage system projects and otherwise in full compliance with all requirements of this Agreement, and all Services shall be warranted against any defect or error whatsoever, including in design and workmanship.

7 Seismic Rating

The energy storage system will be installed in an area exposed to seismic hazards potentially exceeding 9.0. The energy storage system is intended for use in a microgrid after such an event. Therefore, the entire system including ancillary components must be designed to survive and function after an event of the following seismic criteria.

SEISMIC CRITERIA		
RISK CATEGORY	IV	
SEISMIC DESIGN CATEGORY	D	
SITE CLASS	D	
IMPORTANCE FACTOR	IE = 1.5	
MCE SPECTRAL ACCELERATION	Ss = 0.98	S1 = 0.43
SITE COEFFICIENT	Fa = 1.10	Fv = 1.56
DESIGN SPECTRAL ACCELERATION	SDS = 0.728	SD1 = 0.45
ANALYSIS PROCEDURE	EQUIVALENT LATERAL FORCE PER ASCE 7-10, SECTION 12.8	

8 Standards

The energy storage system must be designed, built and installed according to the following standards:

- IEEE 1547-2003
- UL 1741SA with interoperability features unlocked (capable of operation in accordance with California Rule 21)
- American National Standards Institute (ANSI)
- American Society of Mechanical Engineers (ASME)
- Institute of Electrical and Electronics Engineers (IEEE)
- Insulated Cable Engineers Association (ICEA)
- National Fire Protection Association (NFPA)
- National Electric Code (NEC)
- National Electrical Manufacturers Association (NEMA)
- Occupational Safety and Health Administration (OSHA)
- Underwriters Laboratories (UL)
- Uniform Building Code (UBC) or International Building Code as required by the local AHJ
- Cells, modules and racks must have undergone testing according to UL9540A and that report must be made available to Owner.

9 Sound Level

The maximum sound level of the energy storage system and any associated equipment is 65 dBA measured at 50 feet in any direction generated for the full range of the energy storage system's operation.

10 Modes of Operation

The energy storage system and MEMS must provide the following operations:

10.1 Grid connected:

10.1.1 General

Connecting and Disconnecting – energy storage system must be capable of automatically connecting and disconnecting from the grid based on a remote signal.

Standby – must be capable of remaining synchronized with and electrically connected to the grid neither charging nor discharging capable of responding to a remote command within one second. In standby mode (neither charging nor discharging), the energy storage system, not including auxiliary power, must maintain a power output or input below 5kVA.

Except for reserving 100kWh for customer reliability, the microgrid will give precedence to all utility services over customer services while grid connected. If customer services can be provided without interfering with utility services, then they will be performed as a second priority. Performing utility services shall have no detrimental effects on the Customer's bill beyond what billing would occur if no energy storage system were connected.

10.1.2 Customer Services

PV self-generation – energy storage system will maximize the local EPS utilization of Customer's PV generation.

Minimum energy reservation – in grid connected mode, the energy storage system will maintain 100kWh for the Customer in the event of an unscheduled intentional island (utility outage).

10.1.3 Utility Services

The energy storage system will provide each of the following utility services: Frequency Regulation, Contingency Reserve, Voltage and Var Support, Demand Response, and Mitigation of Cold Load Pick-up. Detailed descriptions of each utility service are included in Section 11.

11 Description of Utility Services

Utility services are only provided when the energy storage system is operating in parallel with the utility. Management of these services and setpoints are provided by Owner's Plant PLC. The Owner's Plant PLC will communicate with the MEMS via Modbus to send setpoints for real power, reactive power, ramp rates and state of charge (SOC). The descriptions of utility services below are intended for use by the bidder to develop performance specifications and warranty provisions.

11.1 Frequency Response

For this service, the energy storage system must respond from an idle state to a request for frequency response within two seconds of receiving the command. From that time, the battery output must ramp at a rate of 100kW per second until a full output of 250kW is achieved. 250kW output shall be maintained for three minutes and then the energy storage system output will ramp down at a rate of 25kW per second. When energy storage system output gets to less than or equal to 25kW, the energy storage system will recharge at a rate of 25kW until the SOC setpoint is achieved.

The control for this service will reside in the PGE plant controller. The Bidder's controls must simply respond to a setpoint for kW.

This service shall be provided up to 50 times per year, and sometimes within the same eight-hour period.

Example of Frequency Response

11.2 Contingency Reserve

For this service, the energy storage system must respond from an idle state to a request for contingency reserve within two seconds of receiving the command. From that time, the battery output must ramp up at a rate of 100kW per second until a full output of 250kW is achieved. 250kW output shall be maintained until a ramp-down and stop command is issued. When ramp-down and stop is received, within two seconds the energy storage system will ramp down at a rate of 25kW per second until the kW output is less than or equal to 25kW.

Once the energy storage system output is less than or equal to 25kW, the energy storage system will be commanded by the PGE plant PLC to recharge at a rate of 25kW until the SOC setpoint is achieved.

The control for this service will reside in the PGE plant controller. The Bidder's controls must simply respond to a setpoint for kW, keep up with the requested ramp and manage SOC.

This service shall be provided up to eight times per year.

11.3 Voltage and VAr Support

In this service, the energy storage system will respond to a kVAr setpoint from the PGE plant controller. It may be a steady kVAr request or it may be regulating to maintain a voltage using closed-loop proportion integral (PI) control. Depending on the service(s) being requested at any given time, the energy storage system may be asked to provide voltage or VAr support simultaneous with being in standby for another service such as frequency response or spinning reserve or voltage support may be operated simultaneously with other services providing that the kVA capacity of the system will allow it.

The only limitations on the energy storage system for providing this service must be the kVA rating of the system.

11.4 Demand Response

Demand Response (DR) is a service scheduled by the Owner normally a day in advance. DR occurs on days with the highest system load. A demand response event is scheduled for a preset number of hours, typically two. When this schedule is set in PGE’s Plant Controller, PGE’s Plant Controller will assume that 900kWh of energy will be available for that event. A setpoint of 250kW will be given to the MEMS for the DR service. If for some reason, available energy is less than 900kWh, then a lower kW setpoint will be calculated. For example, if 400kWh are expected to be available and two hours is the scheduled duration of the event, PGE’s Plant Controller will calculate a kW setpoint of 400kWh/2h = 200kW and this setpoint will be given to the MEMS as a DR setpoint. If 900kWh of energy are available, but the duration of the event is scheduled to be four hours, then PGE’s Plant Controller will calculate the kW setpoint to be 900kWh/4hrs. = 225kW.

This service will be dispatched 20 times per year.

11.5 Mitigation of Cold-Load Pick-up

Energy storage system must be able to reduce cold load pick-up after a utility outage. This is accomplished by the MEMS setting the return to grid timer to zero in both the energy storage system PCS and the PV inverter. The energy storage system must adjust to a kW output setpoint delivered by the Owner’s plant controller. To mitigate cold load pick-up, the energy storage system will return to grid with no delay once utility power is restored and ramp up to a real power setpoint established by the Owner’s plant controller. The MEMS will operate with the Customer’s building energy management system to delay starting large loads such as chillers and other Heating, Ventilation, and Air Conditioning (HVAC) equipment until two minutes after the site returns to utility power. Bidder shall assume that the real power setpoint will be the full nameplate rating. This output is maintained for an hour and then the energy storage system will ramp down at a rate of 25kW/second and return to its normal operation.

This service will be dispatched once per year.

12 Intentionally Islanded:

12.1.1 General

Energy storage system will manage the microgrid for maximum reliability, maximum utilization of renewable energy and minimum operating cost. While intentionally islanded, the energy storage system must regulate voltage within nominal +/- 5% and frequency at 60Hz within +/- 0.2Hz.

12.1.2 Customer Services

The MEMS shall cause the diesel generator and/or the energy storage system to serve load as appropriate for optimization of on-site fuel consumption. PV is current regulating only and shall be utilized to the highest possible degree (maximized to serve either load or charge the energy storage system) during an unscheduled intentional island with the goal to minimize energy from the diesel generator.

The MEMS shall utilize the energy storage system to operate the diesel generator in baseload mode at a level recommended by the generator manufacturer to avoid wet-stacking.

During times of ample photonic insolation (meaning the PV and the battery together can serve load without diesel generation), the MEMS shall put the generator in standby mode and utilize only the solar and energy storage system to serve load.

The MEMS will automatically return to grid after an adjustable return-to-grid time. The return-to-grid timer shall be remotely adjustable from 0 to 600 seconds. Return to grid shall be a closed transition.

13 Interconnection

The energy storage system shall interconnect to the Customer's 480V main bus via a 400A, 480V 3-phase breaker located in the Customer's switchgear. The lugs on that breaker define the point of connection (POC) for the energy storage system and the reference point of applicability for performance measurements.

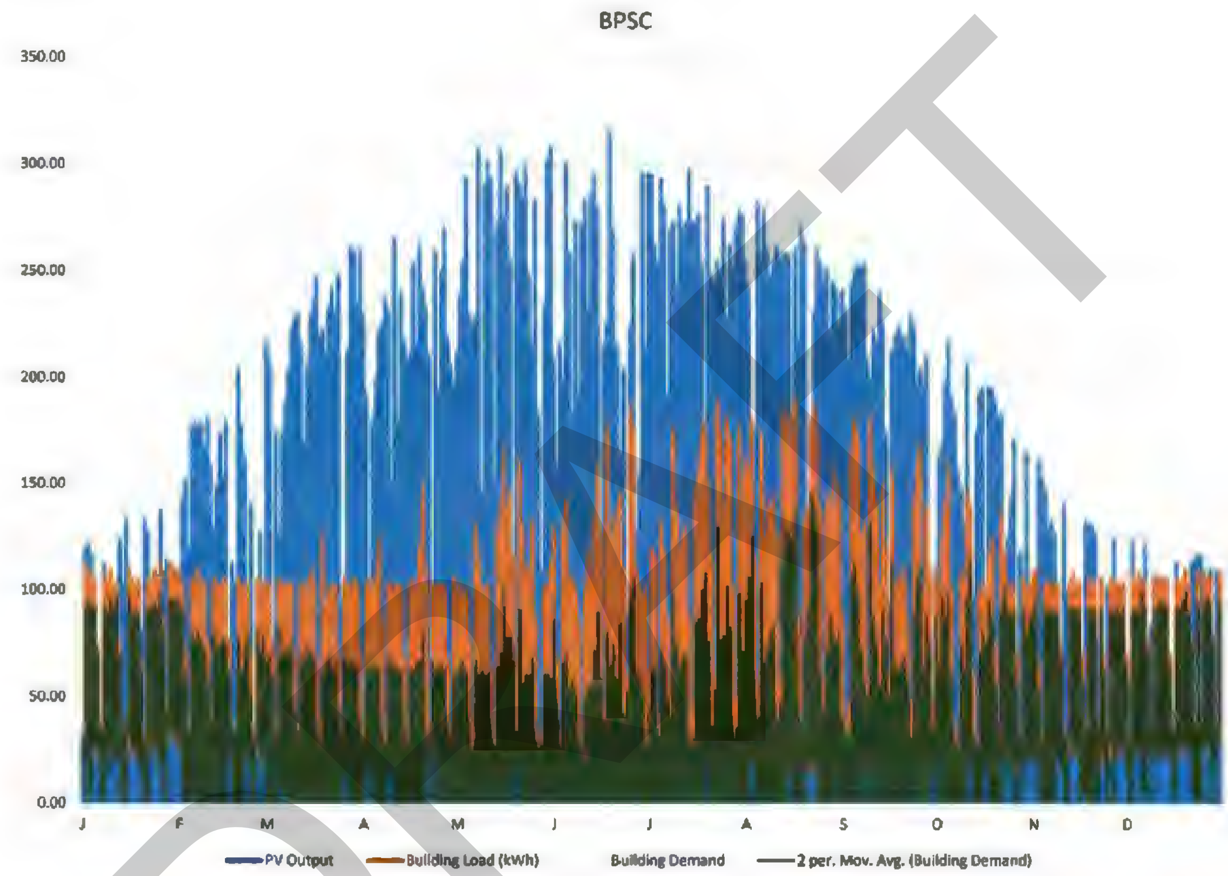
Energy storage system will be connected through a EUSERC rated metering enclosure per PGE service requirements. Metering section to be provided by others.

Bidder shall clearly state all site installation requirements such as pad dimensions and locations of mounting bolts; electrical connection requirements including conductor sizes and lug sizes.

Bidder will provide all electrical specifications of the system including available fault current, voltage ranges of operation and current ratings.

Refer to the drawing E-701, E702 and E-703 for a single-line drawing of the project.

14 Projected Building Load And PV Output



15 Quality Assurance

The supplier shall use its established Quality Management System (QMS) for the design, production, packaging and shipping of its items and/or services to the PGE. The QMS may be either registered/accredited by an external agency or approved by PGE via an on-site assessment or review of supplier's proposal. Bidder shall state its proposed quality assurance program to the Owner clearly within the proposal. This program shall include procedures for quality assurance of all design, manufacturing and construction activities. As a minimum, it shall address the following:

1. Responsibilities and authorities

2. Document control
3. Design verifications
4. Subcontractor assessment and control
5. Calibration requirements
6. Traceability
7. Non-conformance control
8. Inspection and test plans
9. Internal audits
10. Records

16 Commercial

16.1 Bidder Information

Provide the following details regarding your company:

- Exact legal name of the firm
- Form of legal entity under which business is conducted
- Mailing address
- Federal Tax Identification Number
- Key contact information - the name, phone number, and email address of the individual who will serve as a primary point of contact with your company for the purposes of this RFP

16.2 Schedule

The RFP will be issued on May 16, 2019

Responses to this RFP are required no later than June 7, 2019.

A purchase order shall be issued by July 15, 2019.

The energy storage system with all its components will be delivered to the Customer's site no later than December 20, 2019.

The system will be commissioned (complete) no later than Feb. 28, 2020.

All punch list items will be corrected no later than April 15, 2020.

16.3 Transportation

Bidder shall be responsible for all transportation, shipping and loading associated with project to deliver a fully operational energy storage system to Owner's project site including any subsystems or components from sub-suppliers. Scheduling deliveries is the responsibility of the Bidder. Owner will not make special accommodation for storage based upon Bidder's scheduling needs.

All deliveries will be scheduled between 8:00 AM and 5:00 PM on weekdays. Owner (or Owner's representative) shall be given 24-hours' notice in advance of large truck deliveries. If a crane or other special equipment is required for unloading, seven-days' notice must be provided to the Owner.

The Bidder shall prepare materials and equipment for shipment to protect them from damage while in transit.

The delivery shall be coordinated with the PGE Project Manager. Unloading at the site will be by the Owner's contractor.

Construction will be performed by the Owner's electrical contractor according to drawings and installation instructions provided by the bidder. The Bidder will provide construction assistance as necessary for successful installation.

16.4 Expansion

Bidders should address in their proposal the capability of expanding the storage components of the system. With maintaining a power rating of 250kW nominal, bidders shall describe what features of the proposal would allow for easy expansion of storage beyond four hours. This should include provisions for electrical connection, controls, cooling systems, safety systems, mechanical connections, etc.

16.5 Information to Be Included in Proposal

Bidders must include a description of all components within the offering including:

- Basic system architecture
- Battery cell supplier quantity and chemistry
- PCS supplier and model number
- BMS supplier, basic architecture and control hardware
- DC ground fault protection hardware and design

- System dimensions including all ancillary equipment such as control cabinets and isolation transformer
- Weight of battery module container and mounting requirements
- Description of expansion provisions
- Clear description of major components that are sourced from a third party such as batteries, BMS, PCS, MEMS
- Specification sheets for all major system components
- A list of similarly sized systems operating in a microgrid configuration with a description of services provided (both grid services and customer services)
- One or more reference contacts from previous or current customers
- One or more operational sites where the owner would be agreeable to a site visit by PGE
- Basic pricing for conformance with the RFP
- Separate pricing for performance warranty, ongoing maintenance and shipping
- Pricing for any options that are offered
- Clearly describe any exceptions to the RFP

It is the Owner's preference to purchase a complete energy storage system and MEMS as a package. The Owner will consider proposals structured as a partnership if necessary. Owner will also consider proposals that include only the energy storage system or MEMS, but such a proposal must clearly explain how issues of integration will be dealt with. Owner will not consider purchasing a battery without a PCS.

17 Abbreviations

AC	Alternating Current
AHJ	Authority Having Jurisdiction
BMS	Battery Management System
DC	Direct Current
EPA	Environmental Protection Agency
EPS	Electric Power System
HMI	Human Machine Interface
IEEE	Institute of Electrical and Electronics Engineers
kV	Kilovolts
kVAr	Kilovar
kW	Kilowatt
kWh	Kilowatt Hours
MEMS	Microgrid Energy Management System
ODEQ	Oregon Department of Environmental Quality
PCS	Power Conversion System
PGE	Portland General Electric Company
PLC	Programmable Logic Controller
PV	Photovoltaic
RFP	Request for Proposal
SOC	State of Charge or Energy: Nominal Energy Remaining / Nominal Full Pack Energy Available
UL	Underwriters Laboratories
UPS	Uninterruptable Power Supply

18 Attachment A - Single-Line Drawings E-701, E-702 And E-703

19 Attachment B - A Graphic Depiction of The Microgrid Controls Hierarchy

20 Attachment C - Microgrid State Definitions

Attachment A

Single Line Drawings E-701, E-702, and E-703

Draft Request for Proposal for a Microgrid Pilot Energy Storage System (Located in Beaverton)

KEY NOTES:

1. PROVIDE (2) 3" C PROVISION FOR FUTURE DESIGN/BUILD BESS. REFER TO SITE PLAN FOR ADDITIONAL INFORMATION.

2. PROVIDE (2) 4" C FOR MEDIUM VOLTAGE DISTRIBUTION. PGE TO PROVIDE CONDUCTORS. REFER TO SITE PLAN FOR ADDITIONAL INFORMATION.

3. REFER TO GROUNDING SYSTEM DETAIL 2, SHEET E-601 FOR GROUNDING ELECTRODE CONDUCTOR SIZES.

4. GENERATOR REMOTE ANNUNCIATOR PANEL. MOUNT IN LOBBY. SEE FLOOR PLANS FOR LOCATION.

5. CO-LOCATE MICROGRID REMOTE HMI WITH GENERATOR ANNUNCIATION PANEL IN LOBBY. SEE FLOOR PLANS FOR LOCATION.

6. PROVIDE (8) 3" C PROVISION FOR SERVICE LATERAL. PGE TO PROVIDE CONDUCTORS. SEE GROUNDING SYSTEM DETAILS ON SHEET E-601 FOR ADDITIONAL INFORMATION.

7. BREAKERS TAGGED WITH "E" SHALL BE EQUIPPED WITH ELECTRICALLY OPERATED CHARGED SPRING, TRIP AND CLOSE MECHANISMS TO PERMIT CONTROL BY THE MICROGRID SYSTEM CONTROLLER.

8. ALL BREAKERS IN MAIN AND SUB-MAIN DISTRIBUTION BOARDS 4MDP & 4SDP SHALL BE EQUIPPED WITH SOLID STATE TRIP DEVICES WITH INTEGRAL POWER METERING.

9. PROVIDE SEL-700G RELAY OR APPROVED ALTERNATIVE. RELAY MUST BE SPECIFIED WITH COMMUNICATIONS OPTIONS TO BE INTEROPERABLE WITH MICROGRID CONTROL SYSTEM.

10. PROVIDE (1) 2" C AND PULL STRING BETWEEN PGE REMOTE METER BANK AND PGE SCADA RACK IN THE MAIN ELECTRICAL ROOM. COMMUNICATIONS CABLING TO BE INSTALLED BY PGE.

11. PROVIDE MODIFIED DIFFERENTIAL GROUND FAULT PROTECTION FOR ALL SOURCE INTERCONNECTIONS WITHIN 4MDP.

12. PROVIDE SEL-351S RELAY OR APPROVED ALTERNATE. RELAY MUST BE SPECIFIED WITH COMMUNICATION OPTIONS TO BE INTEROPERABLE WITH MICROGRID CONTROL SYSTEM.

13. FUTURE CONTAINERIZED BESS INCLUDING PSC, ISLOATION TRANSFORMER AND REQUIRED OCPDS TO BE PROVIDED BY PORTLAND GENERAL ELECTRIC.

14. LOCATE EMERGENCY POWER OFF BUTTONS WITHIN MAIN AND EMERGENCY ELECTRICAL ROOMS AND ANY ADDITIONAL LOCATIONS AS REQUIRED BY THE AHJ. EPO BUTTON PRESS SHALL TRIGGER MICROGRID STATE TRANSITION TO "SS6". SEE DETAILS 1 AND 2 ON SHEET E-603 FOR ADDITIONAL INFORMATION.

15. PROVISION TWO SPACES IN 4SDP FOR FUTURE 600A BREAKER FRAMES.

16. PROVISION TWO SPACES IN 4SDP FOR FUTURE 225A BREAKER FRAMES.

17. MICRODGRID DESIGN BUILD CONTRACTOR SHALL INCORPORATE UPS AND ANY OTHER ELECTRICAL DISTRIBUTION EQUIPMENT AS NEEDED TO MEET DESIGN/BUILD INTENT. RACK SHALL INCORPORATE 24VDC UPS BACKED POWER SUPPLY OR BATTERY.

18. SOURCE BREAKER CONTROL POWER FROM DC STATION BATTERY.

19. PROVIDE FT-1 TEST SWITCHES AS REQUIRED TO SATISFY PORTLAND GENERAL ELECTRIC DSG DESIGN CRITERIA. SEE PGE DSG DESIGN CRITERIA APPENDIX E.

20. SWITCHBOARD MANUFACTURER TO SIZE SURGE PROTECTION DEVICE OVERCURRENT PROTECTION.

21. PGE SCADA RACK AND EQUIPMENT SHALL BE SPECIFIED, FURNISHED AND INSTALLED BY PORTLAND GENERAL ELECTRIC. SEE SHEET E-501 FOR UPDATED SCADA RACK LOCATION IN THE GENERATOR YARD.

22. PROVIDE (1) 2" C BETWEEN MICROGRID CONTROL RACK AND EACH ELEVATOR CONTROLLER. DAISY-CHAINING CONDUITS IS ACCEPTABLE. CABLING BY MEMS DESIGN-BUILD CONTRACTOR.

23. PROVIDE (2) 2" C BETWEEN MICROGRID CONTROL RACK AND PGE SCADA RACK. CABLING BY MEMS DESIGN-BUILD CONTRACTOR.

24. PROVIDE (2) 2" C BETWEEN MICROGRID CONTROL RACK AND SECTION "RELAY" IN 4MDP. CABLING BY MEMS DESIGN-BUILD CONTRACTOR.

25. PROVIDE (1) 2" C BETWEEN MICROGRID CONTROL RACK AND EACH ATS IN THE EMERGENCY ELECTRICAL ROOM. DAISY-CHAINING CONDUITS AND CONTROL CABLING IS ACCEPTABLE. CABLING BY MEMS DESIGN-BUILD CONTRACTOR.

26. PROVIDE (1) 4CC #14 AWG BETWEEN "ATS-LS" AND THE GENERATOR ENCLOSURE FOR LIFE SAFETY GENERATOR START CONTROL.

27. PROVIDE (1) 4CC #14 AWG (1) 2" C BETWEEN GENERATOR ENCLOSURE AND PORTABLE GEN DOCKING STATION FOR CONTINUATION OF LIFE SAFETY GENERATOR START CONTROL.

28. GENERATOR SHALL BE EQUIPPED WITH EMCP 4.2 CONTROLLER OR APPROVED EQUIVALENT TO FACILITATE SYNCHRONIZATION AND PARALLELING WITH PGE GRID BATTERY ENERGY STORAGE SYSTEM (BESS).

29. PROVIDE (1) 1" C BETWEEN MICROGRID CONTROL RACK AND FOA-101 IN THE BOILER ROOM. CABLING BY MEMS DESIGN-BUILD CONTRACTOR.

30. PROVIDE (1) 1" C AND PULL STRING BETWEEN MICROGRID CONTROL RACK AND BMS CONTROLLER ENCLOSURE. MICROGRID DESIGN-BUILD CONTRACTOR TO MAKE DETERMINATION REGARDING OPTION A OR B TO TRIGGER MECHANICAL RESILIENCY OPERATION MODE (MROM). SEE DETAIL 2, SHEET E-703 FOR ADDITIONAL INFO. CABLING BY MEMS DESIGN-BUILD CONTRACTOR.

31. PROVIDE (1) 1" C WITH PULL STRING BETWEEN MICROGRID CONTROL RACK AND REMOTE HMI. CONFIRM REMOTE HMI LOCATION WITH ARCHITECT. CABLING BY MEMS DESIGN-BUILD CONTRACTOR.

32. MEMS DESIGN-BUILD CONTRACTOR TO PROVIDE RS-485 PLTC CABLE (BELDEN 9841 OR EQUAL) WITHIN MICROGRID CONTROL RACK TO CO-LOCATED PV COMMUNICATIONS GATEWAY.

33. PV SYSTEM COMMERCIAL COMMUNICATIONS GATEWAY (CCG) PROVIDED BY THE PV DESIGN BUILD CONTRACTOR.

34. PROVIDE (1) 1" C AND PULL STRING BETWEEN MICROGRID CONTROL RACK AND PV SYSTEM INVERTER #3 LOCATED IN THE GENERATOR YARD. PV INVERTERS BY PV DESIGN BUILD CONTRACTOR. PV DESIGN BUILD CONTRACTOR TO PROVISION RS-485 PLTC CABLE AND DAISY-CHAIN TERMINATIONS BETWEEN CCG AND ALL PV INVERTERS ON SITE.

35. PROVIDE (1) 2" C AND PULL STRING(S) BETWEEN MICROGRID CONTROL RACK AND FUTURE BESS CONTAINER PAD. CONTRACTOR TO LOCATE PULL-BOXES AS NEEDED.

36. PROVIDE (2) 2" C AND PULL STRING(S) BETWEEN MICROGRID CONTROL RACK AND GEN ENCLOSURE. CONTRACTOR TO LOCATE PULL-BOXES AS NEEDED.

37. PARALLELING GENERATOR CONTROLLER TO BE PROVIDED BY MICROGRID DESIGN BUILD CONTRACTOR. GENERATOR CONTROLLER SHALL HAVE PROVISIONS FOR COMMUNICATIONS TO MICROGRID CONTROLLER. BASIS OF DESIGN IS WOODWARD EASYGEN-3200-XT-P1 OR APPROVED ALTERNATE.

38. PROVIDE (1) 3" C (SCHED. 40 PVC) WITH (2) 1" SDR SMOOTH WALL INNER DUCTS WITH PULL TAPE IN EACH. INCLUDE (1) #12 AWG THWN-2 COPPER CONDUCTOR WITH ORANGE INSULATIVE JACKET TO SERVE AS A LOCATE TRACER. ALL 90° BENDS MUST BE 36" SWEEPS. STUB-UP IN ELEC ROOM 131 WITHIN PGE SCADA RACK.

39. SEE PANEL 2-S-1A SCHEDULE SHEET E-804 FOR OPTIONAL STANDBY BRANCH CIRCUIT TO PGE SCADA RACK.

40. PROVIDE SHARK REVENUE METER AND CT ENCLOSURE FOR PGE DSG BUILDING LOAD METERING.

41. PROVIDE (2) 2" C WITH PULL STRING FROM MICROGRID CONTROL RACK TO 4MDP FOR COMMUNICATIONS. COMMUNICATION/CONTROL CONDUCTORS BY MICROGRID DESIGN-BUILD CONTRACTOR.

42. GENSET MANUFACTUER TO PROVIDE 15KVA, 480-208Y/120V STEP DOWN TRANSFORMER AND BRANCH PANEL WITHIN GENSET ENCLOSURE. MINI POWER CENTER OR EQUIVALENT.

43. PROVIDE 480Y/277V, 1600A PORTABLE GENERATOR DOCKING STATION CABINET. TRISTAR OR APPROVED EQUAL.

44. MICROGRID CONTROLLER SHALL BE WIRED TO FUEL OIL HOLDING TANK LOW LEVEL ALARM PANEL (FOA-101) TO RECEIVE FUEL TANK LEVEL AND LEAK STATUS DATA.

45. SEE DETAIL 2, SHEET M-703 FOR ADDITIONAL INFORMATION REGARDING MICROGRID CONTROL OVER MROM.

46. PROVIDE (1) 1" C MINIMUM FOR 120V, 20A RECEPTACLE BRANCH CIRCUIT POWER FROM THE PGE SCADA RACK UPS TO EACH PGE REMOTE METER . SEE PGE DSG DESIGN CRITERIA APPENDIX B FOR ADDITIONAL INFORMATION.

47. PROVIDE 24VDC STATION BATTERY, RACK (2-TIER, SINGLE ROW) WITH SEISMIC HOLD DOWN RAILS. BASIS OF DESIGN FOR RACK IS ALCAD RSL24N1-2. CONTRACTOR TO CALCULATE BATTERY ENERGY REQUIREMENT IN CONSULTATION WITH PGE. LOCAL 24VDC BEST BATTERY SCHEME IS RECOMMENDED.

48. PROVIDE BATTERY CHARGER WITH 120VAC INPUT AND 24VDC OUTPUT. CHARGER SHALL BE EQUIPPED WITH STATUS I/O OR MODBUS COMMUNICATIONS.

49. SWITCHGEAR RELAY SECTION SHALL BE PROVISIONED WITH BACK PANEL TERMINAL BLOCKS FOR PT AND CT SECONDARIES, RELAY CONTROLLED BREAKER TRIP AND CLOSE COILS AND DC POWER. MEMS DESIGN-BUILD CONTRACTOR TO PROVIDE COMPLETE THREE-LINE WIRING AND CONTROL DIAGRAMS FOR APPROVAL.

50. PROVIDE (1) 1"C BETWEEN MICROGRID CONTROL RACK AND STATION BATTERY CHARGER FOR COMMUNICATIONS. CABLING BY MEMS DESIGN-BUILD CONTRACTOR.

51. SWITCHBOARD 4MDP SHALL BE SERVICE ENTRANCE RATED WITH CONTINUOUS NEUTRAL, 100% RATED THROUGHOUT.

52. PROVIDE (1) 1" C BETWEEN BESS SAFETY SWITCH STRUCTURE AND FUTURE BESS PAD. COORDINATE CONDUIT STUB-UP AT BESS PAD WITH PGE.

53. PROVIDE (1) 2" C BETWEEN THE PGE SCADA RACK AND SECTION "RELAY" IN 4MDP. MEMS DESIGN-BUILD CONTRACTOR TO PULL AND CONNECT (1) MM FIBER OPTIC FOR MIRRORED BIT AND (1) CAT6A FOR ETHERNET. MEMS DESIGN-BUILD CONTRACTOR TO COORDINATE TERMINATIONS WITH PGE.

54. PROVIDE (1) 4CC #14 IN (1) 1" C BETWEEN GEN-DP AND THE MICROGRID CONTROL RACK FOR STATUS OF GENERATOR FEEDER BREAKER POSITION.

55. MEMS DESIGN-BUILD CONTRACTOR TO PROVIDE KEYED SWITCH WITHIN MICROGRID CONTROL RACK. SWITCH ACTIVATION SHALL DISABLE GENERATOR PARALLELING WITH PGE UTILITY GRID.

56. PROVIDE (1) 2" C SPARE CONDUITS BETWEEN GEN ENCLOSURE AND BESS PAD. COORDINATE CONDUIT STUB-UP AT BESS PAD WITH PGE.

57. PROVIDE (1) 1-1/4" C AND PULL STRING FOR PT AND CT SECONDARIES. USE ONLY 24" MIN. SWEEPS AT STUB-UPS. COORDINATE LOCATION OF PT/CT CONDUIT STUB-UP WITHIN EUSERC CT SECTIONS WITH PRIMARY FEEDER CONDUIT LOCATIONS. REVIEW ALL STUB-UPS WITHIN EUSERC SECTIONS WITH PGE.

58. PROVIDE (1) 2" CONDUIT AND PULL TAPE BETWEEN PGE SCADA RACK AND THE BESS PAD. COORDINATE CONDUIT STUB-UPS AT SCADA RACK AND BESS PAD WITH PGE. CONDUIT PROVISION FOR COMMUNICATIONS.

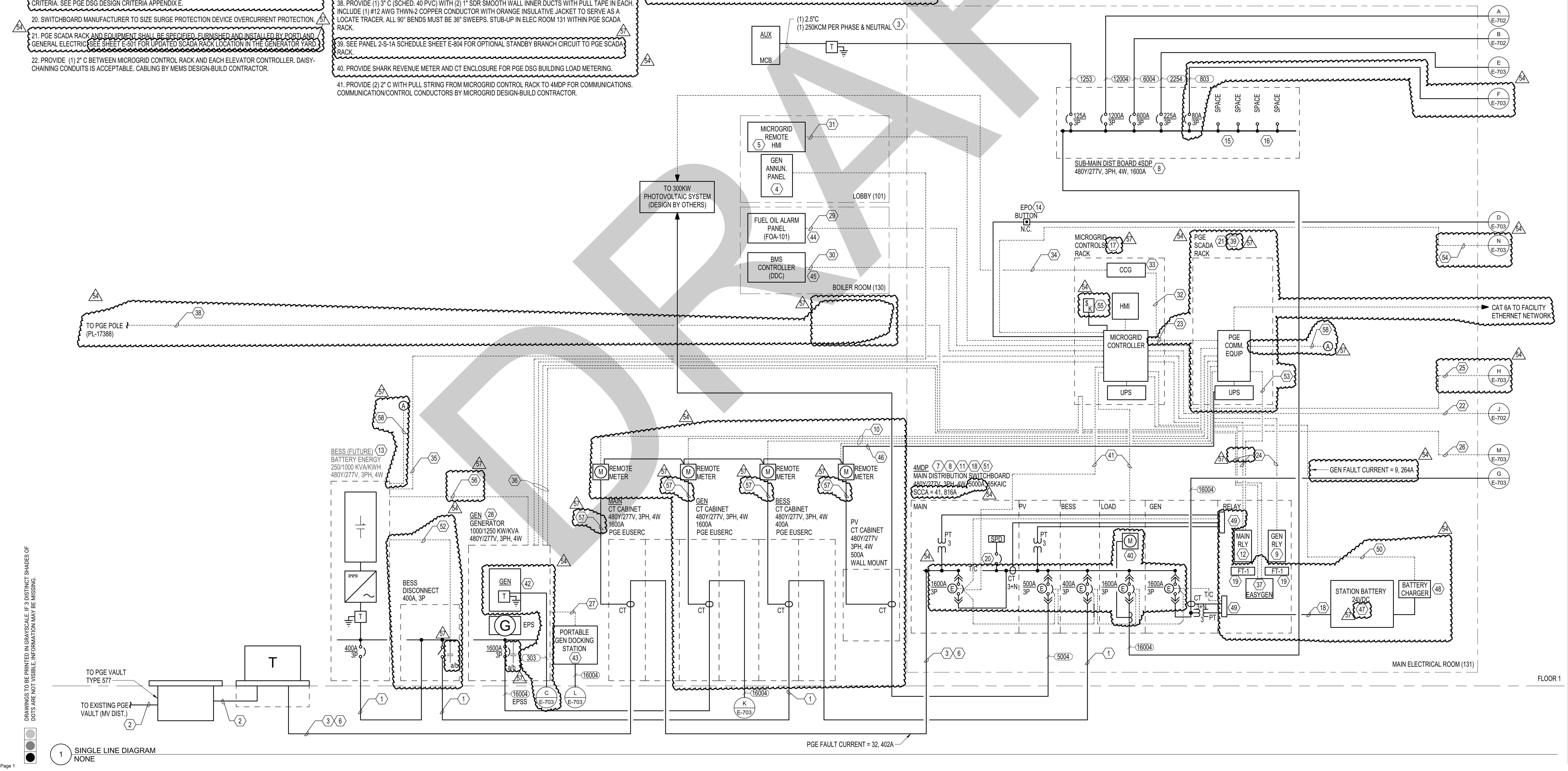
GENERAL NOTES:

A. PROVIDE POWER AND DATA CONNECTION TO EACH POWER METER EQUIPMENT. VERIFY REQUIREMENTS WITH APPROVED METER MANUFACTURER.

B. SEE PANEL SCHEDULES FOR PANEL BUS BRACING RATINGS.

C. UNLESS OTHERWISE NOTED, PROVIDE 225A FRAME SPACE WHERE "SPACE" IS INDICATED ON DISTRIBUTION BOARDS.

D. SEE SHEET E-702 FOR FEEDER TAG SCHEDULE.



1 SINGLE LINE DIAGRAM
NONE

DRAWINGS TO BE PRINTED IN GRAYSCALE. IF 3 DISTINCT SHADES OF DOTS ARE NOT VISIBLE, INFORMATION MAY BE MISSING.

DRAFT

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BEAVERTON POLICE DEPARTMENT
COURAGE COMPASSION INTEGRITY

#	DESCRIPTION	DATE
15	ELEC PR1	11/6/18
28	ASI 006	1/14/19
54	PR 19	04/22/19
57	PR 19_R1	04/25/19

BEAVERTON PUBLIC SAFETY CENTER

CITY OF BEAVERTON POLICE DEPARTMENT

12500 SW Allen Boulevard
Beaverton, OR 97005

APPROVED:	KPH
DRAWN:	ASH
DATE:	08.31.2018
PROJECT NUMBER:	240717

SINGLE LINE DIAGRAM - POWER SOURCES

E-701
PERMIT/BID SET

KEY NOTES:

1. REFER TO GROUNDING SYSTEM DETAIL 2, SHEET E-601 FOR GROUNDING ELECTRODE CONDUCTOR SIZES.
2. VERIFY ELECTRICAL TRIP RATING AND SERVICE SIZE WITH SUBMITTED EQUIPMENT PRIOR TO ELECTRICAL EQUIPMENT PURCHASE.
3. PROVIDE SLIM "I-LINE" STYLE OR EQUIVALENT.
4. VERIFY ELECTRICAL TRIP RATING AND FEEDER SIZE WITH SUBMITTED EQUIPMENT PRIOR TO ELECTRICAL EQUIPMENT PURCHASE. IF FEEDER IS INSTALLED UNDERGROUND, CONDUIT SHALL BE MINIMUM 1".
5. PROVIDED BY ELEVATOR CONTRACTOR.
6. PROVIDE (1) 2" C BETWEEN MICROGRID CONTROL RACK AND EACH ELEVATOR CONTROLLER. DAISY-CHAINING CONDUITS AND CONTROL CABLING IS ACCEPTABLE. CABLING BY MEMS DESIGN-BUILD CONTRACTOR.

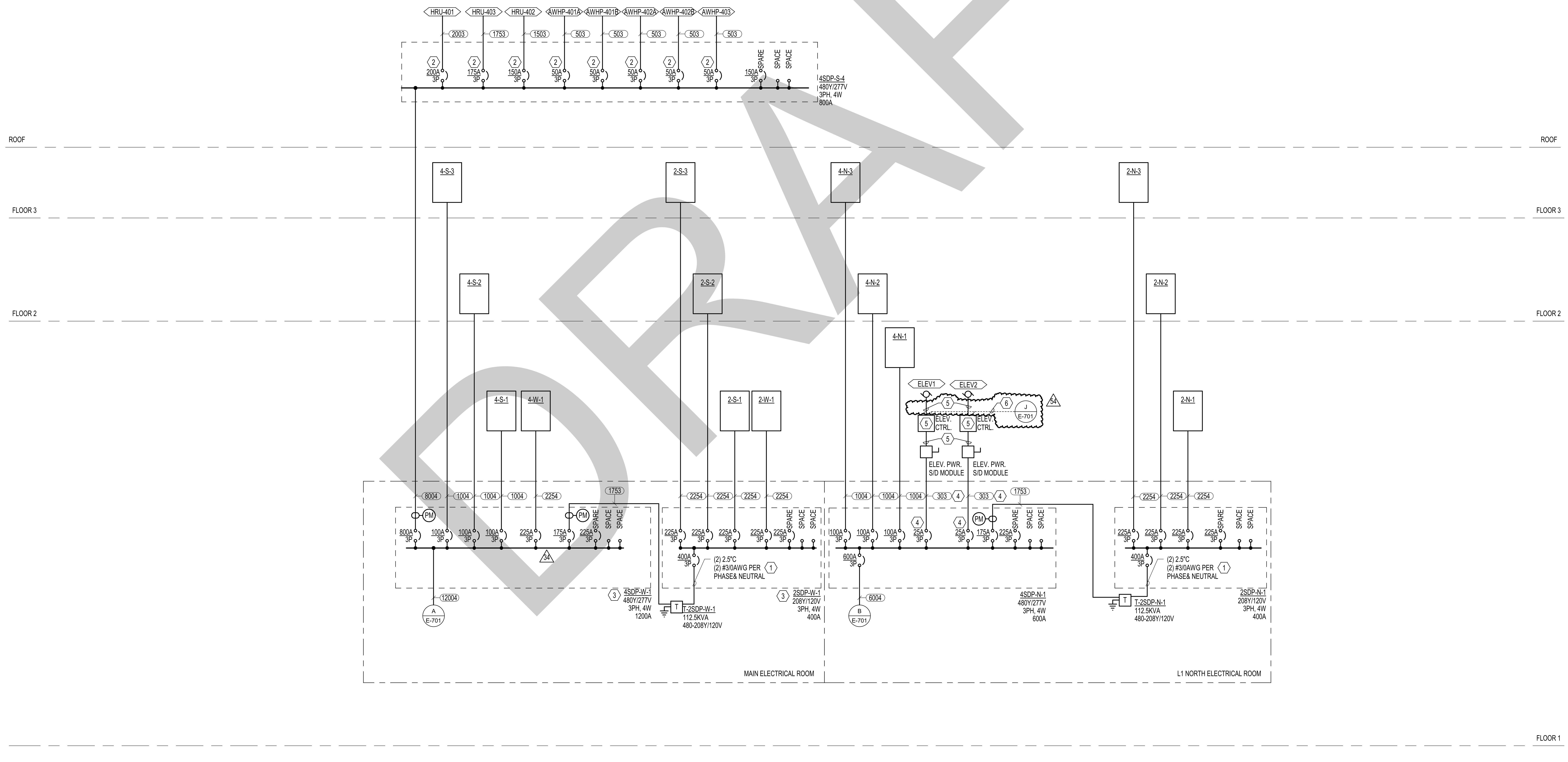
GENERAL NOTES:

A. PROVIDE POWER AND DATA CONNECTION TO EACH POWER METER EQUIPMENT. VERIFY REQUIREMENTS WITH APPROVED METER MANUFACTURER.

B. SEE PANEL SCHEDULES FOR PANEL BUS BRACING RATINGS.

C. UNLESS OTHERWISE NOTED, PROVIDE 225A FRAME SPACE WHERE "SPACE" IS INDICATED ON DISTRIBUTION BOARDS.

FEEDER SCHEDULE COPPER: 3 PHASE, 3 WIRE + GROUND					FEEDER SCHEDULE COPPER: 3 PHASE, 4 WIRE + GROUND				
TAG	NOMINAL AMPACITY	CONDUIT SIZE (MIN)	PHASE CONDUCTORS	GROUND CONDUCTOR	TAG	NOMINAL AMPACITY	CONDUIT SIZE (MIN)	PHASE & NEUTRAL CONDUCTORS	GROUND CONDUCTOR
203	20	1/2"	(3) #12	#12	204	20	1/2"	(4) #12	#12
303	30	1/2"	(3) #10	#10	304	30	3/4"	(4) #10	#10
403	40	3/4"	(3) #8	#10	404	40	3/4"	(4) #8	#10
503	50	3/4"	(3) #6	#10	504	50	1"	(4) #6	#10
603	60	3/4"	(3) #6	#10	604	60	1"	(4) #6	#10
703	70	1"	(3) #4	#8	704	70	1 1/4"	(4) #4	#8
803	80	1 1/4"	(3) #3	#8	804	80	1 1/4"	(4) #3	#8
903	90	1 1/4"	(3) #3	#8	904	90	1 1/4"	(4) #3	#8
1003	100	1 1/4"	(3) #2	#8	1004	100	1 1/4"	(4) #2	#8
1103	110	1 1/2"	(3) #1	#6	1104	110	1 1/2"	(4) #1	#6
1253	125	1 1/2"	(3) #1	#6	1254	125	1 1/2"	(4) #1	#6
1503	150	1 1/2"	(3) #1/0	#6	1504	150	2"	(4) #1/0	#6
1753	175	2"	(3) #2/0	#6	1754	175	2"	(4) #2/0	#6
2003	200	2"	(3) #3/0	#6	2004	200	2"	(4) #3/0	#6
2253	225	2"	(3) #4/0	#4	2254	225	2 1/2"	(4) #4/0	#4
2503	250	2"	(3) #4/0	#4	2504	250	2 1/2"	(4) 250KCM	#3
3003	300	2 1/2"	(3) 250KCM	#4	3004	300	3"	(4) 350KCM	#2
3503	350	2 1/2"	(3) 350KCM	#3	3504	350	3 1/2"	(4) 500KCM	#1
4003	400	(2) 2"	(6) #3/0	(2) #3	4004	400	(2) 2"	(8) #3/0	(2) #3
4503	450	(2) 2"	(6) #4/0	(2) #2	4504	450	(2) 2 1/2"	(8) #4/0	(2) #2
5003	500	(2) 2"	(6) #4/0	(2) #2	5004	500	(2) 3"	(8) 250KCM	(2) #1
6003	600	(2) 2 1/2"	(6) 250KCM	(2) #1	6004	600	(2) 3"	(8) 350KCM	(2) #2/0
8003	800	(2) 3"	(6) 500KCM	(2) #1/0	8004	800	(3) 3"	(12) 350KCM	(3) #2/0
10003	1000	(3) 3"	(9) 500KCM	(3) #2/0	10004	1000	(3) 4"	(12) 500KCM	(3) #2/0
12003	1200	(4) 3"	(12) 350KCM	(4) #3/0	12004	1200	(4) 4"	(16) 500KCM	(4) 250KCM
16003	1600	(4) 4"	(12) 750KCM	(4) #4/0	16004	1600	(5) 4"	(20) 500KCM	(5) #4/0



DRAWINGS TO BE PRINTED IN GRAYSCALE. IF 3 DISTINCT SHADES OF DOTS ARE NOT VISIBLE, INFORMATION MAY BE MISSING.

1 SINGLE LINE DIAGRAM
NONE

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BEAVERTON POLICE DEPARTMENT — COURAGE COMPASSION INTEGRITY

#	DESCRIPTION	DATE
15	ELEC PR1	11/6/18
28	ASI 006	1/14/19
34	ASI 10	2/5/19
54	PR 19	04/22/19

BEAVERTON PUBLIC SAFETY CENTER

CITY OF BEAVERTON POLICE DEPARTMENT

12500 SW Allen Boulevard
Beaverton, OR 97005

APPROVED:	Approver
DRAWN:	Author
DATE:	08.31.2018
PROJECT NUMBER:	240717

SINGLE LINE DIAGRAM - NORMAL DISTRIBUTION

E-702

PERMIT/BID SET

GENERAL NOTES:

A. PROVIDE POWER AND DATA CONNECTION TO EACH POWER METER EQUIPMENT. VERIFY REQUIREMENTS WITH APPROVED METER MANUFACTURER.

B. SEE PANEL SCHEDULES FOR PANEL BUS BRACING RATINGS.

C. UNLESS OTHERWISE NOTED, PROVIDE 225A FRAME SIZE WHERE "SPACE" IS INDICATED ON DISTRIBUTION BOARDS.

D. SEE SHEET E-702 FOR FEEDER TAG SCHEDULE.

KEY NOTES:

1. REFER TO GROUNDING SYSTEM DETAIL 2, SHEET E-601 FOR GROUNDING ELECTRODE CONDUCTOR SIZES.

2. PROVIDE SLIM "I-LINE" STYLE OR EQUIVALENT.

3. SWITCHBOARD MANUFACTURER TO SIZE SURGE PROTECTION DEVICE OVERCURRENT PROTECTION.

4. ATS EQUIPMENT SHALL BE CLOSE-TRANSITION TYPE AND EQUIPPED WITH RE-TRANSFER DELAY ENABLE FUNCTION AND FULL SUITE OF STATUS CONTACTS.

5. BREAKERS SHALL BE INTERLOCKED VIA KIRK-KEY MECHANISM.

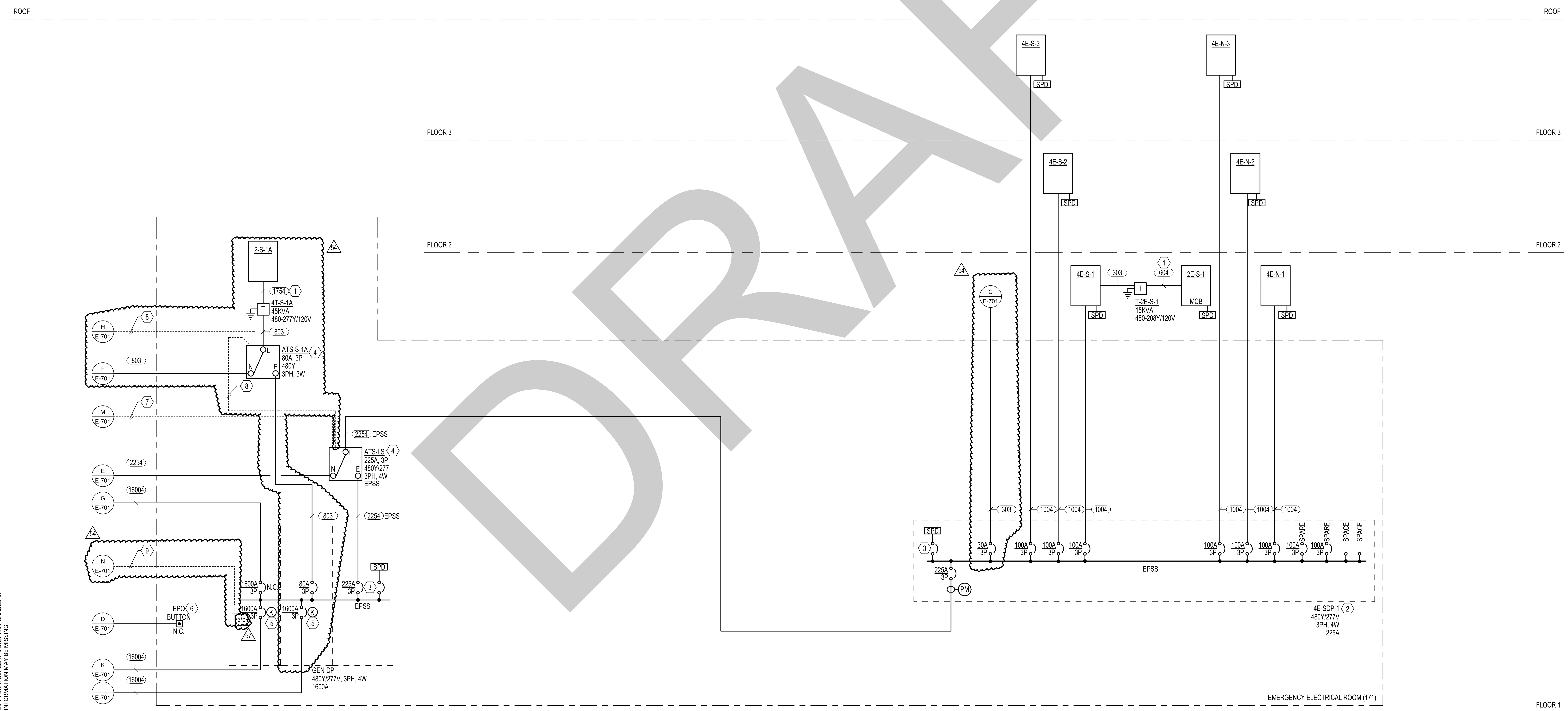
6. LOCATE EMERGENCY POWER OFF BUTTONS WITHIN MAIN AND EMERGENCY ELECTRICAL ROOMS AND ANY ADDITIONAL LOCATIONS AS REQUIRED BY THE AHJ. EPO BUTTON PRESS SHALL TRIGGER MICROGRID STATE TRANSITION TO "SS6". SEE DETAILS 1 AND 2 ON SHEET E-603 FOR ADDITIONAL INFORMATION.

7. PROVIDE (1) 4CC #14 BETWEEN "ATS-LS" AND THE GENERATOR ENCLOSURE FOR LIFE SAFETY GENERATOR START CONTROL.

54

8. PROVIDE (1) 2" C BETWEEN MICROGRID CONTROL RACK AND EACH ATS IN THE EMERGENCY ELECTRICAL ROOM. DAISY-CHAINING CONDUITS AND CONTROL CABLING IS ACCEPTABLE. CABLING BY MEMS DESIGN-BUILD CONTRACTOR.

9. PROVIDE (1) 4CC #14 IN (1) 1" C BETWEEN GEN-DP STRUCTURE 1 AND THE MICROGRID CONTROL RACK FOR STATUS OF GENERATOR FEEDER BREAKER POSITION.



1 SINGLE LINE DIAGRAM
NONE

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SINGLE LINE DIAGRAM - LIFE SAFETY DISTRIBUTION

E-703

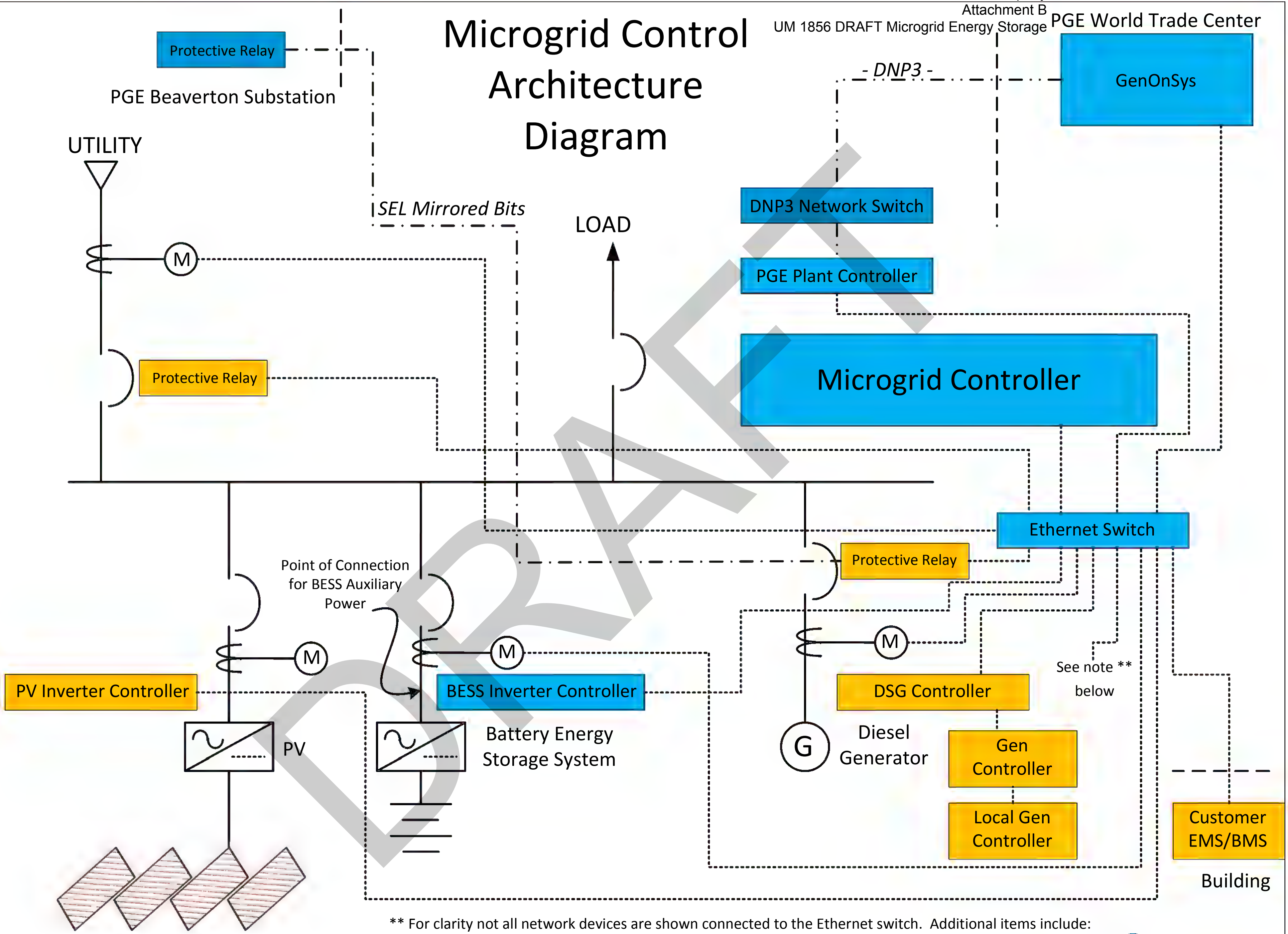
PERMIT/BID SET

Attachment B

A Graphic Depiction of The Microgrid Controls Hierarchy

Draft Request for Proposal for a Microgrid Pilot Energy Storage System (Located in Beaverton)

Microgrid Control Architecture Diagram



** For clarity not all network devices are shown connected to the Ethernet switch. Additional items include:

- Remote HMI
- Fuel Oil Alarm Panel, modbus
- BMS Controller, modbus (likely requires converter to BACNET or modbus card addition at BMS)
- Power circuit breakers for power and status monitoring, modbus

- PGE
- Customer

* Assume all comms are Modbus unless noted DNP3 or SEL Mirrored Bits

Attachment C

Microgrid State Definitions

Draft Request for Proposal for a Microgrid Pilot Energy Storage System (Located in Beaverton)

Definition of Microgrid States and Services

1 Microgrid States

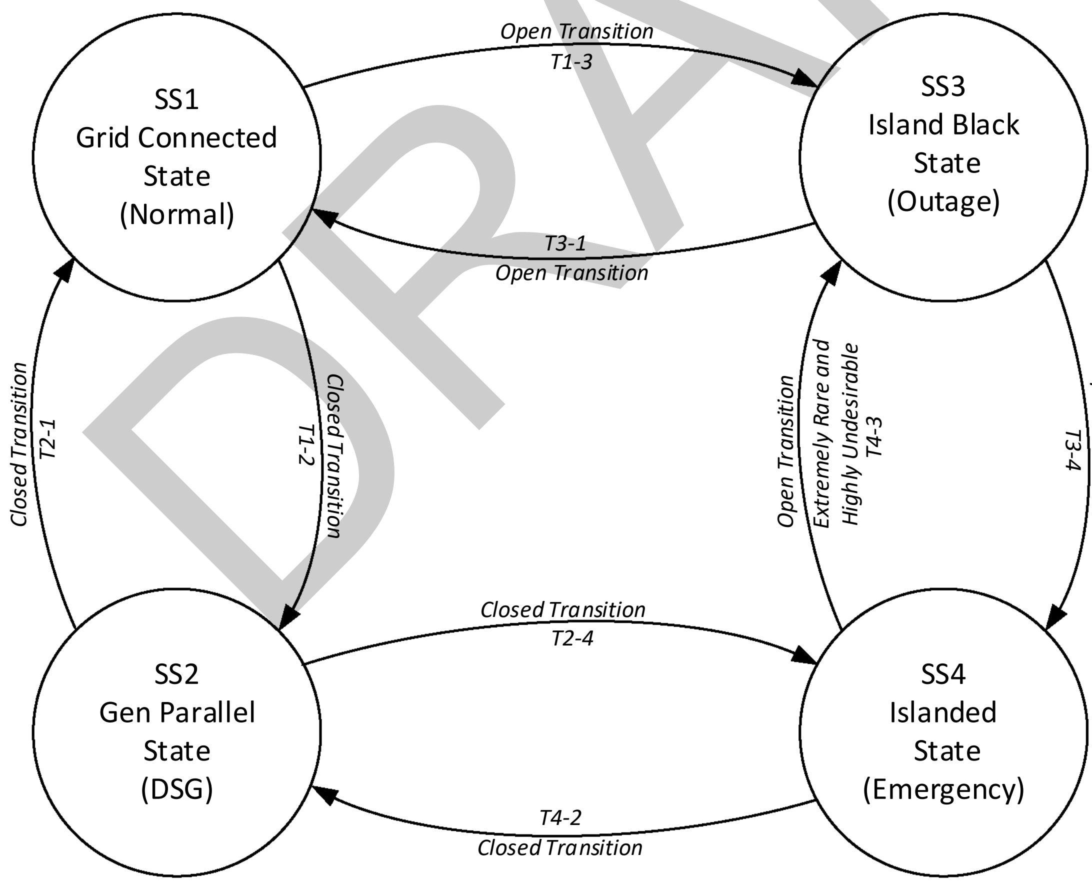
There are four different states within which the microgrid can operate. These states are:

SS1: Grid Connected State (Normal)

SS2: Gen Parallel State (DSG)

SS3: Island Black State (Outage)

SS4: Islanded State (Emergency)



Basic Illustration of Microgrid States and Transitions

Within these four states, the microgrid can perform various functions or "services" to accomplish operational goals for both the site and for the utility. All the services for the benefit of the utility that the BESS and PV perform are accomplished in either **SS1: Grid Connected State** or **SS2: Gen Parallel State**. Services performed for the benefit of the utility by the diesel generator are performed only in **SS2: Gen Parallel State**.

Most services of the microgrid performed for the Customer's benefit are performed in **SS4: Islanded State.** The exceptions are PV self-generation optimization which is also performed in **SS1: Grid Connected State** and **SS2: Gen Parallel State,** and 100kW energy reservation with is performed in all states except **SS3: Island Black**.

SS3: Island Black State is an undesirable mode wherein only battery-backed UPS services are operating. The controls must immediately transition from this state to a state where the Local Area EPS is energized.

<u>SS1: Grid Connected State</u>

Grid-Connected State is the normal operating mode. The system should be in this mode more than 99% of the time.

In Grid-Connected State, the utility is serving the customer's load, the PV is generating according to available insolation connected to the Local Electric Power System (EPS), the generator is not connected to the Local EPS. The Battery Energy Storage System (BESS) is connected to the Local EPS and is available to respond to utility commands. The PV is also capable of responding to utility commands according to the interoperability standards associated with UL1741-SA, specifically Ramp Rate, Specified Power Factor, Volt/Var Mode, Frequency Watt and Volt Watt.

- The Utility Main circuit breaker is closed
- The Gen breaker is open
- The utility regulates voltage and frequency
- The microgrid controller will reserve a minimum of 100kW for use in a utility outage
- Both PV and the BESS are operating in current regulation

From this state, the system may transition directly to **SS3: Island Black State** and **SS2: Generator Parallel State**.

SS2: Generator Parallel State (Local and Remote DSG)

Functionally, this mode is the same as PGE's Dispatchable Standby Generator (DSG) mode. This mode may be entered by either a local command from the HMI or from a remote command from PGE's downtown command center. PGE will initiate this test remotely once per month for one hour. This mode can also be initiated by PGE without notification due to a utility system emergency (a DSG dispatch). The customer may enter this mode for testing at their choice using the local HMI after notifying PGE. During this mode, the generator starts, synchronizes to the grid and closes the Gen breaker. The generator output then ramps up to the baseload setpoint which can be entered either locally or remotely.

To exit this mode and return to **SS1: Grid Connected**, the stop command is issued either locally or remotely. The generator will follow a prescribed ramp down to a minimum power output, then the Gen breaker will open and the generator will enter cooldown mode for five minutes. After cooldown, the generator will shut down.

In this state, the BESS and PV operate the same as in **SS1: Grid Connected**.

- The Utility Main circuit breaker is closed
- The Gen breaker is closed
- The utility regulates voltage and frequency
- The microgrid controller will reserve a minimum of 100kW for use in a utility outage
- The PV, the BESS and the diesel generator are operating in current regulation

From this state, the system may transition directly to **SS1: Grid Connected State** or **SS2: Islanded State**. The transition to **SS2: Islanded State** occurs when there is a utility outage during **SS2: Generator Parallel State**. The system will perform a closed transition to Islanded mode by opening the Utility Main breaker and allowing the generator to remain connected through the Gen breaker. The generator must then regulate voltage and frequency. Then, the microgrid controller may ramp down the diesel generator and stop it provided the BESS SOC is adequate.

SS3: Island Black

This mode is undesirable and should only occur briefly after a utility outage. The Utility Main breaker will open immediately upon sensing a utility outage. Then, the microgrid controller must transition the system quickly from **SS3: Island Black** to **SS4: Islanded,** or if utility power returns prior to this transition occurring, the system should return to **SS1: Grid connected State**. During **SS3: Island Black**, all microgrid functions are suspended.

SS4: Islanded State

SS4: Islanded State automatically occurs immediately after an unplanned utility outage. When an unplanned utility outage occurs, the system first transitions to **SS3: Island Black** by opening the utility main breaker, and then immediately transitions to **SS4: Islanded**. Most often, when transitioning from **SS3: Island Black State to SS4: Islanded State**, the BESS is employed to energize the Local Area EPS and regulate frequency and voltage, not the diesel generator. Based on system conditions, like a low BESS state of charge (SOC), the diesel generator may be utilized in **SS4: Islanded State** to form the grid (regulate voltage and frequency).

SS4: Islanded State can also occur when the Owner elects to enter "Generator Test with Load" mode or "Storm Avoidance" mode. These two functions are the same. They cause **SS4: Islanded State** to operate solely with the diesel generator. To reach this state (from **SS1: Grid Connected State only**), the system transitions to **SS2: Generator Parallel State.** This is achieved by starting the diesel generator, waiting for it to synchronize with the main bus and then closing the Gen breaker. Once the diesel generator is parallel with the grid, its output is ramped up to equal the utility load (facility load minus PV output). The main utility breaker is then opened. The BESS can charge in this mode but not to discharge. Output from the PV is ramped down to near-zero and prevented from further output.

"Generator Test with Load" mode or "Storm Avoidance Mode" can only be selected when the system is in **SS1: Grid Connected State**. To leave this mode of operation, "Return to Grid" must be selected locally". The system will transition to **SS2: Generator Parallel** State by synchronizing across the utility main breaker. Then the generator will follow a prescribed ramp down to a minimum power output. Then the Gen breaker will open and the generator will enter cooldown mode for five minutes. After cooldown, the generator will shut down. The system will then be in **SS1: Grid Connected State.**

Another way that the system can enter **SS4: Islanded State** is by local selection of "Island Microgrid". This can only be selected when the system is in in **SS1: Grid Connected State**. In this mode, the battery is switched from current regulation in **SS1: Grid Connected State** to voltage regulation. The battery output will be ramped up to a level equal to utility load (facility load minus PV). The utility main breaker will then open leaving the system to operate as an islanded microgrid (**SS4: Islanded State**).

When intentionally entering **SS4: Islanded State**, the transition is always closed, meaning the site does not experience an outage.

- The Utility Main circuit breaker is open
- The Gen breaker is open unless the diesel generator is being utilized
- The battery regulates voltage and frequency except in "Generator Test with Load" or "Storm Avoidance" mode
- The microgrid controller will only allow the battery to reach a minimum of 100kW before the diesel generator comes online to supply the Local Area EPS and to recharge the battery in baseload mode
- If the BESS is unavailable, the generator must regulate voltage and frequency

These four states and their transitions are most often controlled by the microgrid controller with the following exceptions:

1. **Transition T1-2** and **Transition T2-1** between **SS1: Grid Connected State** and **SS2: Gen Parallel State** is controlled by the Generator Paralleling Controls.
2. The Customer's site includes two Automatic Transfer Switches (ATS's) for fire and life safety loads. Either of these ATS's may perform a generator start independently of all other controls. The ATS's should be put on a five second delay to give the other controls the opportunity to react prior to the ATS's sending the generator start command. This prevents the ATS's from cycling unnecessarily.
3. If the microgrid controller is entirely out of service, the generator controller (Woodward EasyGen) will create an island and serve the Local Area EPS with the diesel generator. This is considered the last line of defense in the event of an outage. If absolutely every other control system fails to achieve emergency mode with the generator, the EasyGen will accomplish the task.

2 Microgrid Services

The various resources and controllers associated with the microgrid are intended to provide beneficial services to both the electric utility and to the site. What service is being provided at any given time depends upon what state the microgrid is operating in at the time and what service is being requested from the hierarchy of microgrid controls.

In general, services for the benefit of the electric utility can only be performed when the microgrid is connected to the utility grid. Services for the benefit of the site are mostly performed when the microgrid is disconnected from the utility grid. Two exceptions to this are:

1. Maximizing PV Self-Generation
2. Minimum Energy Reservation

These two services are performed for the benefit of the site when the microgrid is connected to the utility grid.

The table below describes all the services provided by the microgrid controller and in which state each service shall function.

Service	State(s) in Which This Service Can Function	For the Benefit of?	Resource(s) Employed	Service Requested From
Frequency Response	SS1 and SS2 (Connected)	Utility	BESS	Local Control - PGE Plant PLC
Contingency Reserve	SS1 and SS2 (Connected)	Utility	Gen and BESS	Remote Control - PGE Plant PLC
Volt/VAr Support	SS1 and SS2 (Connected)	Utility	BESS and PV	Local Control - PGE Plant PLC
VAr or pf support	SS1 and SS2 (Connected)	Utility	BESS and PV	Remote Control - PGE Plant PLC
Demand Response	SS1 and SS2 (Connected)	Utility	BESS	Remote Control - PGE Plant PLC
Mitigation of Cold Load Pick-up	SS1 and SS2 (Connected)	Utility	BESS	Local Control - PGE Plant PLC
PV Self-Generation	SS1, SS2 and SS4 (Islanded and Connected)	Site	PV and BESS	Local Control - Microgrid Controller
Minimum Energy Reservation	SS1, SS2 and SS4 (Islanded and Connected)	Site	BESS	Local Control - Microgrid Controller
Maximum Energy Reservation	SS1 and SS2 (Connected)	Site	BESS	Local Control - Microgrid Controller
Maximize Reliability	SS1, SS2, SS3 and SS4 (All Conditions)	Site	BESS and Gen	Local Control - Microgrid Controller and DSG Controller
Economic Optimization	SS4 (Islanded)	Site	BESS, PV and Gen	Local Control - Microgrid Controller
Test with Load/Storm Avoidance	SS4 (Islanded)	Site	BESS, PV and Gen	Local Control - Microgrid Controller and DSG Controller
Test Island	SS4 (Islanded)	Site	BESS, PV and Gen	Local Control - Microgrid Controller and DSG Controller

List of Microgrid Services

3 Detailed Description of Services

Utility Services

Utility services are only provided when the BESS is operating in parallel with the utility. Management of these services and setpoints are provided by Owner's Plant PLC. The Owner's Plant PLC will communicate with the microgrid controller via Modbus to send setpoints for real power, reactive power, ramp rates and state of charge (SOC). The descriptions of utility services below are intended for use by the bidder to develop performance specifications and warranty provisions.

Whenever the BESS is operating connected to the utility, Utility Services take precedence over any other service. Services for the benefit of the site are always lower priority when the BESS is grid-connected.

The sole exception is the microgrid controller's role to maximize reliability of the site. Under all conditions, site reliability is paramount.

3.1 Frequency Response

For this service, the BESS must respond from an idle state to a request for frequency response within 2 seconds of receiving the command. From that time, the battery output must ramp at a rate of 100kW per second until a full output of 250kW is achieved. 250kW output shall be maintained for three minutes and then the BESS output will ramp down at a rate of 25kW per second. When BESS output gets to less than or equal to 25kW, the BESS will recharge at a rate of 25kW until the SOC setpoint is achieved.

The control for this service will reside in the PGE plant controller. The Bidder's controls must simply respond to a setpoint for kW.

This service shall be provided up to 50 times per year, and sometimes within the same 8-hour period.

Example of Frequency Response

3.2 Contingency Reserve

For this service, the BESS must respond from an idle state to a request for contingency reserve within 2 seconds of receiving the command. From that time, the battery output must ramp up at a rate of 100kW per second until a full output of 250kW is achieved. 250kW output shall be maintained until a ramp-down and stop command is issued. When ramp-down and stop is received, within two seconds the BESS will ramp down at a rate of 25kW per second until the kW output is less than or equal to 25kW.

Once the BESS output is less than or equal to 25kW, the BESS will be commanded by the PGE plant PLC to recharge at a rate of 25kW until the SOC setpoint is achieved.

The control for this service will reside in the PGE plant controller. The Bidder's controls must simply respond to a setpoint for kW, keep up with the requested ramp and manage SOC.

This service shall be provided up to 8 times per year.

3.3 Volt/VAr Support

In this service, the BESS will respond to a request for Volt/VAr support. Depending on the service(s) being requested at any given time, the BESS may be asked to provide Volt/VAr support simultaneous with being in standby for another service such as frequency response or spinning reserve or voltage support may be operated simultaneously with other services providing that the kVA capacity of the system will allow it. When Volt/VAr is requested, the BESS will respond with a pre-established Volt/VAr curve.

The only limitations on the BESS for providing this service must be the kVA rating of the system.

3.4 VAr or Power Factor Support

In this service, the BESS will respond to a kVAr setpoint or power factor setpoint from the PGE plant controller. Depending on the service(s) being requested at any given time, the BESS may be asked to provide VAr or power factor support simultaneous with being in standby for another service such as frequency response or spinning reserve or voltage support may be operated simultaneously with other services providing that the kVA capacity of the system will allow it.

The only limitations on the BESS for providing this service must be the kVA rating of the system.

3.5 Demand Response

Demand Response (DR) is a service scheduled by the Owner normally a day in advance. DR occurs on days with the highest system load. A demand response event is scheduled for a preset number of hours, typically two. When this schedule is set in PGE's Plant Controller, PGE's Plant Controller will assume that 900kWh of energy will be available for that event. A setpoint of 250kW will be given to the microgrid controller for the DR service. If for some reason, available energy is less than 900kWh, then a lower kW setpoint will be calculated. For example, if 400kWh are expected to be available and two hours is the scheduled duration of the event, PGE's Plant Controller will calculate a kW setpoint of 400kWh/2h = 200kW and this setpoint will be given to the microgrid controller as a DR setpoint. If 900kWh of energy are available, but the duration of the event is scheduled to be 4 hours, then PGE's Plant Controller will calculate the kW setpoint to be 900kWh/4hrs. = 225kW.

This service will be dispatched 20 times per year.

3.6 Mitigation of Cold-Load Pick-up

BESS must be able to reduce cold load pick-up after a utility outage. This is accomplished by the microgrid controller setting the return to grid timer to zero in both the BESS PCS and the PV inverter. The BESS must adjust to a kW output setpoint delivered by the Owner's plant controller. To mitigate cold load pick-up, the BESS will return to grid with no delay once utility power is restored and ramp up to a real power setpoint established by the Owner's plant controller. The microgrid controller will operate with the Customer's building energy management system to delay starting large loads such as chillers and other HVAC equipment until two minutes after the site returns to utility power. Bidder shall assume that the real power setpoint will be the full nameplate rating. This output is maintained for 1 hour and then the BESS will ramp down at a rate of 25kW/second and return to its normal operation.

This service will be dispatched once per year.

Site Services

Site services are mostly provided when the BESS is operating islanded from the utility. Management of these services and setpoints are provided by microgrid controller.

3.7 PV Self-Generation

For the benefit of the site, the microgrid will always be operated in such a way that solar PV self-generation is maximized. The microgrid controller will use current system status as well as historical data to determine the best times to charge the BESS to facilitate this service.

3.8 Minimum Energy Reservation

Whether grid-connected or islanded, the microgrid controller will always maintain 100kWh of energy as an emergency reserve for the site.

3.9 Maximum Energy Reservation

While grid-connected, the customer may select on the local HMI to reserve 100% SOC for a potential emergency. Under this mode, the microgrid controller will use the utility source to charge the battery to 100% SOC and then hold that in reserve until this mode is de-selected.

3.10 Maximize Reliability

Under all conditions, the microgrid controller will maximize the reliability of the site. This means that open transitions will be limited to events of utility power failure. All other transitions shall be closed transitions.

3.11 Economic Optimization

When islanded, the system will always utilize solar PV or stored energy from the BESS as a preference over the diesel generation.

3.12 Test with Load/Storm Avoidance

The local site operator may choose to manually test the generator at full load. This service will cause the generator to start and synchronize with the grid. The generator breaker will close and the generator will take over all load. BESS power and PV power will be disabled during this service so that the generator power is maximized.

3.13 Test Island

The local site operator may select “Island Microgrid”. In this mode, the site will disconnect from the grid and be islanded. The island will be served by the most economically optimized way.

Appendix G

Addendum to PGE's Residential Storage Pilot

Portland General Electric Company
121 SW Salmon Street • Portland, Oregon 97204
PortlandGeneral.com

January 25, 2019

Public Utility Commission of Oregon
Attn: Filing Center
201 High Street, S.E.
P.O. Box 1088
Salem, OR 97308-1088

RE: **UM 1856 – Addendum to PGE's Residential Storage Pilot**

Pursuant to Oregon Public Utility Commission (OPUC or Commission) Order No. 18-290, enclosed is Portland General Electric Company's (PGE's) addendum to its Residential Storage Pilot for OPUC Staff review. The addendum presents a revised project design with evidence demonstrating that PGE will manage risk and optimize learnings.

Per paragraph 18 of the Partial Stipulation filed in Docket No. UM 1856, PGE requests that Staff express its agreement as provided in the Stipulation.

The Commission opened Docket No. UM 1751, in September 2015, to implement House Bill 2193. This House Bill requires large Oregon electric companies (i.e. Pacific Power or PAC, and PGE) to submit proposals by January 1, 2018, to develop qualifying energy storage systems with the capacity to store at least five megawatt hours. In UM 1751, the Commission adopted specific guidelines and requirements for energy storage project proposals, in late 2016, and a framework for PAC's and PGE's Energy Storage Potential Evaluations (Potential Evaluations) in March 2017.

PGE filed its Energy Storage Proposal and Final Potential Evaluation on November 1, 2017, which were investigated in the subsequently opened UM 1856. Following multiple rounds of testimony and numerous data requests, workshops and a settlement conference, stakeholders and the company reached a Partial Stipulation and submitted Joint Testimony in support. The stipulation resolved nearly all the issues.

Attachment A provides an addendum to the Residential Storage Pilot proposal to comply with Item Nos. 18 and 19 of the Partial Stipulation. This addendum includes a revised pilot project design that:

- Aggregates and dispatches residential storage units as a single resource;
- Manages and details mitigation strategies for all program deployment[1] and life cycle risks;
- Optimizes learnings (shared control between the participant and PGE and shared benefits of the system with its participant); and
- Contains a data collection and a program evaluation plan.

PGE looks forward to working with Staff as they review this filing in accordance with Order 18-290. Should you have any questions or comments regarding this filing, please contact Kalia Savage at (503) 464-7432.

Please direct all formal correspondence and requests to the following email address pge.opuc.filings@pgn.com

Sincerely,

Karla Wenzel
Manager, Pricing & Tariffs

Enclosure
cc: UM 1856 Service List

[1] See PGE's Application in UM 1856 at page 107.

Attachment A
UM 1856 - Addendum to PGE's Residential Storage Pilot

UM 1856 – Attachment A: Addendum to PGE's Residential Energy Storage Pilot

The following Addendum supplements PGE's original residential storage proposal to comply with the stipulation approved as part of PGE's application in UM 1856. We first discuss what other pilots informed our approach. We then discuss how we plan to study aggregation and dispatch of residential storage including the platforms we will use. Following these, we provide a discussion of the identified risks and how PGE plans to mitigate them as well as how we plan to optimize the learnings from this pilot. We conclude this Addendum with a discussion of the learning objectives, data collection plan and finally an evaluation of the pilot. PGE recommends, following Staff's review of this Addendum, that Staff make the required finding that PGE has demonstrated it will manage risk and optimize learnings of the Residential Energy Storage Pilot.

7.11 Learning Objectives & Evaluation Plan

7.1(a) Insights Inform Approach, Lessons and Risk

PGE conducted a meta-study of program proposals and offerings by other utilities for residential behind-the-meter storage. At the time of writing, residential energy storage programs were offered only by a small number of utilities, including Green Mountain Power (GMP) in Vermont, Liberty Utilities in New Hampshire (Liberty), and Consolidated Edison (Con Ed) in New York. The successes and failures of these program structures have informed PGE's approach and are discussed below.

<u>GMP</u>

GMP was an early utility entrant into the residential energy storage market. GMP, a vertically-integrated utility serving over 270,000 customers in Vermont, received approval from its regulator in 2016 to explore a residential storage offering. Many factors led the Vermont Commission to grant approval for the programs. While many of these factors are unique to Vermont, the customer value proposition and impact on grid operations are important considerations in Oregon and to PGE.

GMP serves many Vermont customers. Vermont customers have been adopting roof top solar in large part because the Vermont grid experiences more resiliency issues than other areas of the country. This is due, in part, to the rural nature of the state. Additionally, Vermont has been a difficult place to site supply-side generation. Thus, GMP is more exposed to market prices and long-term contracts than utilities in neighboring states. This has led Vermont regulators to champion customer energy solutions, such as energy efficiency and self-generation or distributed generation—also called grid edge resources.

PGE is similarly interested in understanding DER development as a valuable addition to our broader energy portfolio. This notion underlies PGE's interest in creating a residential storage program that produces a cycle of benefits for the participating customer, the grid, and all customers. Thus, the customer value proposition is nested in the grid value proposition. GMP's concept for a residential storage program is informative, and there are lessons learned from GMP's experiences that PGE hopes to leverage.

GMP's residential storage program offers 2,000 units of the Tesla Powerwall 2.0 at a one-time fee of $1,500 or $15 per month.[a] Tesla is responsible for marketing to customers, enrolling customers, preparing site designs, and installing the batteries.[b,c]

PGE views this approach as problematic. While Tesla understands its product better than any other entity, Tesla does not necessarily understand utility customers and how to synthesize the customer value proposition with utility grid operations. Additionally, both the Vermont residential storage market and the Oregon storage market are too small for Tesla to develop a unique service territory approach. Thus, by April of 2018, GMP only had a few hundred units in place, although Tesla is expecting nearly two thousand units by early 2019.[d]

Liberty Utilities

Liberty proposed a pilot project like PGE's Residential Storage Pilot to its regulators in 2017.[e] New Hampshire Public Utilities Commission Staff denied the pilot proposal requesting Liberty return with a revised proposal with additional detail on marketing and outreach, emphasizing the need for program design that includes adequate resources and planning for customer acquisition and program administration. On November 19, 2018, a settlement was reached where the first phase of the pilot Liberty will offer 200 Tesla Powerwalls. Participating customers would be required to install two utility-owned batteries and controller software for a one-time, upfront installed fee of $4,866 or a monthly fee of $50 per month for ten years.[f,g] The second phase, under special conditions outlined in the settlement, will allow Liberty to install up to an additional 300 batteries which will include third parties to install up to 500 batteries through a Bring Your Own Device option.

PGE finds Liberty's proposal to pilot utility and third-party owned assets to be a productive way to evaluate which ownership models best address 'customers' needs.

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[a] Trabish, Herman K. "New Hampshire settlement moves 'cutting-edge' utility BTM storage pilot forward." *Utility Dive*, 27 November 2018, https://www.utilitydive.com/news/new-hampshire-settlement-moves-cutting-edge-utility-btm-storage-pilot-for/542866/.
[b] Pre-filed testimony of Elizabeth R. Nixon on behalf of Liberty Utilities. May 2018. www.puc.state.nh.us/Regulatory/Docketbk/2017/17-189/TESTIMONY/17-189_2018-05-03_STAFF_DTESTIMONY_NIXON.PDF.
[c] Green Mountain Power recently added a program that allows customer to participate with other storage devices, including offerings from Sonnen, Sunverge, and SolarEdge ("Battery Systems." *Green Mountain Power*, accessed on 9 Oct. 2018, greenmountainpower.com/bring-your-own-device/battery-systems/.)
[d] Pre-filed Testimony of Joshua Castonguay on Behalf of Green Mount Power. April 13th, 2018. https://greenmountainpower.com/wp-content/uploads/2018/05/2018-04-13-Castonguay-Testimony.pdf
[e] Liberty Utilities. "Direct Testimony of Heather M. Tebbetts." Docket No. DE 17-189. November 20, 2017. http://puc.nh.gov/Regulatory/Docketbk/2017/17-189/INITIAL%20FILING%20-%20PETITION/17-189_2017-12-01_GSEC_DTESTIMONY_TEBBETTS.PDF
[f] Ibid, Footnote A.
[g] Liberty Utilities. "Technical Statement of Heather M. Tebbetts." Docket No. DE 17-189. November 15, 2018. http://www.puc.state.nh.us/Regulatory/Docketbk/2017/17-189/LETTERS-MEMOS-TARIFFS/17-189_2018-11-19_GSEC_TECH_STATEMENT_TEBBETTS.PDF

PGE plans to explore additional value streams beyond the local network services (LNS), regional network services (RNS), and forward capacity markets (FCM) described in Liberty's proposal by operating the proposed residential storage assets as a true virtual power plant (VPP). PGE also plans to remain the aggregator of both utility and third-party-owned residential storage assets to enable PGE to integrate the VPP into grid operations and more fully explore potential value streams by aggregating across resource types (e.g. distributed storage, demand response). Based on PGE's experience with third-party aggregators (e.g. ENERNOC), PGE also recognizes contractual risk when a third-party provider retains the contract with PGE's customers. In the case of ENERNOC, PGE had to renegotiate demand response contracts with each of its customers after the relationship with ENERNOC expired and PGE chose to not renew. By directly establishing contracts between the customer and the utility, PGE can avoid contractual risk and provide stability in connecting the entity providing grid services to the entity using the grid services.

Con Ed

Con Ed, serving New York City, proposed the Clean Virtual Power Plant Pilot which was designed to address distribution congestion by achieving 1.8 MW (or 4 MWh) of residential storage. In addition, Con Ed offered to install solar plus storage, with the customer paying a monthly lease payment to a third-party for the solar system and a monthly payment to Con Ed for resiliency services.[h] Con Ed sought to explore three pricing frameworks: (1) resiliency payment as a percentage of expected solar savings; (2) resiliency payment as a percentage of their current utility bill; and (3) resiliency payment as a dollar value. Unfortunately, Con Ed's program was not deployed due to barriers presented by outdated building code standards which necessitated difficult and expensive upgrades to the residential circuit panels to incorporate energy storage devices.[i] PGE has identified this issue and has been working with new home builders on a storage-ready building specification. By modeling this code in new buildings, like market transformation strategies employed by the Northwest Energy Efficiency Alliance (NEEA), PGE is seeking to demonstrate and address how best to incorporate on-site residential energy storage.

7.1(b) Aggregated Dispatch

In PGE's Proposal and in the Stipulation, approved in Commission Order No. 18-290, PGE committed to aggregate and dispatch residential energy storage will as a fleet. For this pilot, PGE will explore two approaches to storage market adoption which include a BYOD and PGE owned model. Three platforms for aggregating and dispatching units, including the Enbala DER management platform, GenOnSys, and energy storage system vendor-specific DER management platforms (for PGE owned models) will be under consideration.

[h] ConEdison. "REV Demonstration Project Outline – Clean Virtual Power Plant". July 1st, 2015. http://origin-states.politico.com.s3-website-us-east-1.amazonaws.com/files/CONEDDEMO3.pdf

[i] ConEdison. "REV Demonstration Project – Clean Virtual Power Plant 2017 1Q Quarterly Progress Report – Notice of Temporary Suspension of the Clean Virtual Power Plant Project." April 28th, 2017. http://documents.dps.ny.gov/public/Common/ViewDoc.aspx?DocRefId=%7B6512D405-FA94-4BA6-B89D-732E53206358%7D

PGE uses the Enbala DER management platform to control business and government DR resources individually or as a fleet. While currently used for DR resources, PGE can have the Enbala platform incorporate energy storage into their platform in the coming year at low cost. To test this functionality and proof of concept, PGE will integrate a pilot energy storage system at City of Portland's Fire Station One by the end of 2019 through the Energy Partner program. Incorporating lessons learned on the commercial implementation will aide in our approach incorporating residential units into a "virtual power plant" platform as means to dispatch resources. PGE will be able to not only dispatch the energy storage system but aggregate them with existing DR resources. Dispatching energy storage and DR resources together can enhance the value of aggregated resources by increasing the total aggregate resource size.

As an industry leader in control of distributed resources, PGE operates a custom-built management platform built on generic control software, provided by Schneider Electric, to dispatch and control a fleet of customer-owned dispatchable standby generators.[j,k] The platform, GenOnSys, is currently dispatching over 115 MW of distributed, customer-sited back-up generators (i.e. DER) as a fleet. In a PGE internal pilot study, PGE used GenOnSys to dispatch customer-sited residential energy storage devices. The study revealed that the GenOnSys is currently capable of supporting additional DERs aside from back-up generation.

PGE may also use a DER management platform provided by the energy storage system vendor. PGE has already piloted this with the Sunverge platform since the summer of 2017 with a single customer-sited residential energy storage device. PGE has successfully dispatched the energy storage device during summer demand response events and has also dispatched the energy storage for peak shaving and has seen other successful implementations from leading providers such as Tesla.[l] Even if this is not the primary dispatch platform, it is likely that one of the above-mentioned management systems would need to integrate with the manufacturer provided dispatch platform.

Any one of these aggregation platforms (or some combination of them) would allow PGE to send commands to a fleet of residential energy storage devices. The logic that determines which command is sent, and when, to obtain the value of each use case will be common to the control logic for all energy storage. PGE plans to determine the best aggregation platform from these three options after selecting the vendor for the residential energy storage devices. With this approach, PGE will be positioned to evaluate a vendor-specific platform and will proceed with the best platform available for aggregating the specific residential energy storage devices.

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[j] Portland General Electric. "Dispatchable Standby Generation." Accessed on October 9th, 2018. https://www.portlandgeneral.com/business/get-paid-to-help-meet-demand/dispatchable-standby-generation

[k] AVEVA. "Portland General Electric – Dispatchable Standby Generation (DSG) Links 32 Generators at 21 Customer Sites Ensuring Grid Reliability at Peak Power Demands." Access October 9th, 2018. https://sw.aveva.com/success-stories/portland-general-electric

[l] Green Mountain Power. "GMP Launches New Comprehensive Energy Home Solution from Tesla to Lower Costs for Customers." May 12th, 2017. https://greenmountainpower.com/press/gmp-launches-new-comprehensive-energy-home-solution-tesla-lower-costs-customers/

The intent of dispatching the residential energy storage devices as a fleet is to address the potential use cases[m] in order of value. PGE recognizes the primary value of residential energy storage is Bulk Energy[n], followed by Ancillary Services. Localized T&D grid services are of incremental value. These values can be co-optimized to enhance the total potential value represented by a residential energy storage device, but only to the degree that the resource is of sufficient size to participate in delivering Bulk Energy and Ancillary Services (i.e. minimum of 1 MW).

PGE power operations dispatches in 1 MW increments. Using a Tesla Powerwall 2 as a benchmark resource would take approximately 300 operational units to meet this minimum requirement for a 4-hour period (the defined minimum to defer generation capacity).[o] Understanding that customers may prefer to reserve a portion of the energy storage capacity exclusively for backup purposes, the actual number of residential deployments may need to be larger than 300 units if PGE is to secure access to a minimum aggregate of 1 MW capacity to be made available for utility grid services. Charging of the batteries will be managed by the battery inverter system in coordination with signals from PGE's control system. To manage risk and maximize learnings, we recommend procuring sufficient capacity to provide PGE power operations with a usable resource while also retaining incremental capacity to support and test use cases associated with localized T&D grid services as defined in Order 17-375. For all these reasons, PGE is recommending integrating approximately 525 units.

In aggregate, fleet operation will be significant enough for grid operations to see the effects of the resource as it moves from the grid edge into distribution operations and up into the bulk system. Once PGE understands how best to design a controls hierarchy which co-optimizes the aggregate resource while retaining appropriate localized value for individual units, we will be better positioned to incorporate residential programs into the planning efforts in support of attaining localized T&D benefits. This represents a major learning for PGE which can also inform PGE's efforts to valuate and effectively integrate other DERs into T&D grid planning and operations. In the meantime, PGE will ensure customers receive the back-up power services they expect form their energy storage resources by reserving a portion of the energy storage capacity.

7.1(c) Risk Mitigation and Learnings Optimization

In Sections 7.5 and 7.6, PGE identifies program deployment and life cycle risks and mitigation strategies. Risks and mitigation strategies are further explored below.

Risk of Personal Injury and Property Damage

Safety of customers, employees and members of the public is our number one priority. New technologies, especially those that store large amounts of energy in our customer's homes, must be piloted in a way that minimizes the risk of personal injury and property damage.

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[m] The energy storage potential use cases available to PGE are defined in Order 17-375 in Docket UM 1756.
[n] The "Bulk Energy" value stream includes Generation Capacity/Resource Adequacy value and Energy Arbitrage.
[o] The Powerwall 2 has an effective energy capacity of 13.5 kWh. Dividing by 4 hours gives and average production of 3.375 kW per unit, resulting in need for 297 units to operate at 1 MW for 4 hours.

Minimizing these risks will be achieved by implementing mitigation strategies during energy storage system procurement, installation, and operation, and end-of-life. During procurement, PGE plans to only evaluate bids from vendors that have received: 1) all applicable Underwriters Laboratories, or equivalent listings; 2) have demonstrated that their devices can be installed in our service territory in accordance with all relevant codes and standards; 3) have successfully deployed energy storage systems in over 100 homes in the US; 4) are capable of detecting unsafe conditions and automatically shutting down equipment; and 5) have not had any instances of personal injury or property damage.

When installing energy storage systems, PGE will only contract with licensed installers that have been approved and trained by the energy storage system vendor. Installation will adhere to PGE indemnification policies and support customer claims. All systems will only be deemed ready for operation after receiving all applicable inspections and permits from all relevant jurisdictions and after PGE's interconnection team has inspected and performed all necessary testing. PGE will require installers to train customers in the safe operation and emergency shut-off of all equipment and disconnect devices will be accessible to PGE personnel.

Energy storage has well-developed and autonomous control systems that monitor for abnormal electric currents and temperatures. PGE is not aware of any case where a Li-Ion type battery fire occurred in a stationary application.[p] Even electric vehicle battery fires are rare and typically only occurred in a crash where a violent mechanical event occurred to the battery. The average residential battery has about one-half therm of stored energy, or about the amount in a half-gallon of propane. The safety measures implemented in energy storage systems and in all likely failure modes protect and mitigate against damage to the home. PGE plans to require the manufacturers to assume liability for damages caused by the failure of their product design and its implementation.

The program O&M budget includes an annual 30-minute electrician post-installation visit per unit to ensure the system has not been physically damaged and is performing as expected. The electrician will conduct a visual inspection of all equipment, check energy storage system performance parameters via a software diagnostic tool and test all emergency safety systems for proper functionality. In addition, during system operation, PGE will require the energy storage system vendor to monitor all systems remotely and notify PGE immediately if any safety-critical errors are received. Customers will also have access to energy storage system performance data via web-based and/or mobile applications.

The most common failure modes are detected by control login in the operating system on site. When an abnormal condition is discovered, a fault message is dispatched to the vendor and, if possible, PGE at the same time. Upon receipt of a safety message and/or abnormal telemetry data, the vendor will remotely shut down the equipment if shutdown has not already occurred. PGE or the vendor will dispatch a local crew to determine the root cause and take appropriate action to address the issue.

[p] There are of course, non-battery related fire risks associated with potentially faulty wiring. Per the code, residential installations must adhere to NESC and NFP 855 code requirements.

At energy storage system end-of-life, PGE will only use licensed and approved technicians to remove equipment. PGE will dispose of all equipment in accordance with local regulations and seek to recycle equipment where possible.

Associated Learnings

To ensure that PGE captures all relevant findings, we will document issues that arise in the installation, maintenance, and decommissioning of the units as well as the resolution strategy implemented. These will be documented both in internal project tracking as well as through stakeholder interviews from the evaluator.

Risk of Power Quality or Reliability Impacts

Installation of power electronics behind-the-meter could potentially result in power quality issues if the control systems are not properly configured and managed. Additionally, failure of the energy storage system could potentially have reliability impacts on the host customer.

PGE will actively monitor power quality and reliability on the host sites through its energy storage management platform and will ensure that alarms are in place to alert the operators to any issues that arise as soon as possible (we have piloted this monitoring through R&D installations at employee homes). Our budget allows for the deployment of electricians to host sites if issues require immediate on-site assistance, though most should be able to be resolved remotely through the management platform.

Associated Learnings

The data historian for the management system will allow PGE to track all issues as they arise. These data will be available for our program evaluator to capture the incidence and trajectory of issues through the pilot. These will help inform PGE on what to expect from systems in the field and will allow us to better understand what level of support may be needed to assure power quality is appropriately maintained.

Integration Risk

There are many issues that can arise in the integration of any DER into utility system operations. These include infrastructural barriers as well as software integration issues.

On the power systems side, limited hosting capacity can hamper DER deployment. While we do not anticipate hosting capacity to be an issue for this pilot, particularly given the small size of the individual energy storage systems, PGE will continue to develop expertise in performing hosting capacity assessments as-needed to support program deployment.

Communications infrastructure can also present an issue where systems rely on utility networks. While work is still being done to expand our field area network communications, we anticipate these systems initially being connected through a customer broadband internet connection or cellular modem. Maintaining this connection will be a requirement of participation and PGE will monitor communications uptime through its management platform.

Another issue is maintaining integration between software systems. Regardless of the management system utilized, there will likely be an integration maintained between the energy storage management system at the customer site and a central control system. PGE has included budget for controls that includes maintenance of these integrations whether it be by ensuring over-the-air updates take place for any firmware upgrades or updated integrations between platform application programming interfaces.

Associated Learnings

As part of the reporting and evaluation work, PGE will identify and record learnings. Learnings on working around hosting capacity issues will be captured in project documentation and through stakeholder interviews. PGE will also gain applicable learnings around smart inverter settings for customer-connected devices and will explore how different settings can affect hosting capacity. Communications downtime will be monitored through PGE's management platform and recorded in the data historian. Software integration issues will be documented as necessary.

Risk of Inopportune Timing

There is some risk that our deployment timeline may be misaligned with customer needs and/or system needs. This may be due either to some external project that may look to leverage rebates for residential energy storage (e.g. community energy initiative) or some development taking place that could potentially look to install many units in a single instance (e.g. a resilience-minded planned housing development). PGE will monitor these opportunities as they arise and assess the impacts to the pilot of participating, including impacts on cost, timeline, and project risks. PGE will keep communication open with OPUC Staff throughout the pilot and will consult with them on these issues as necessary.

Associated Learnings

Unexpected events can present great opportunities for new learnings. PGE will monitor these events as they come up and be sure to document them in the process evaluation. Where they present cases for program adjustments, we will analyze the impacts of these adjustments and consult with OPUC Staff on the prudency of moving forward with them.

Risk of Low Enrollment

Achieving the desired learnings from this pilot requires a large and diverse pool of participants (e.g. load profile). PGE will design participant selection to ensure a representative sample of PGE customers to the extent possible. Whatever the final total enrollment, control of the group will be analyzed to determine what minimum levels in a future program are required to extract value for any use case.

GMP successfully demonstrated strong customer interest in a program where the cost of the energy storage system is shared, so we expect a future program will reach the critical mass needed for any use case. Their first residential energy storage program, in which Tesla Powerwall 1 energy storage systems were leased to customers for $37.50 per month, quickly reached the 500 units maximum program size and began to accumulate a waiting list of interested customers.[q,r] Building on this successful program, GMP released a second program where customers can lease a Tesla Powerwall 2 for $15.00 per month with a program cap of 2,000 units.[1] The Powerwall 2 program launched in August 2017.

PGE will also evaluate program growth monthly, adjusting marketing and outreach resources as necessary to achieve the desired participation levels. PGE is also exploring integrating our residential energy storage pilot with the proposed Testbed pilot.[s] The pilot can provide additional outreach and marketing resources, potentially including an energy storage program as part of a larger, bundled offering.

Associated Learnings

PGE will track and report program enrollment throughout the pilot. The process evaluation will include review of marketing materials, benchmarking of similar programs, stakeholder interviews, and customer surveys. These tools will provide critical information on customer adoption of energy storage systems, and what works/what doesn't in marketing energy storage programs to residential customers. If differentials exist in enrollment between ownership models, it will be important to track customer motivations between the two options as reported in participant surveys.

Risk of High Enrollment

Another possible issue that could arise would be high and rapid uptake of the program offerings. While this would be an important finding for the pilot, this would need to be managed to ensure that rollout does not happen so quickly that it hampers the pilot's ability to adjust to other risks that may arise (as outlined in the other parts of the section) or exceeds the budget. PGE will closely monitor uptake at the onset of the program and be sure to space out installations if it seems that the program will be subscribed too quickly.

If after the first year the program implementation is running smoothly, the evaluation findings indicate that the program has been successful, and economic analysis presents an opportunity for a cost-effective rollout, then PGE would engage with OPUC staff to discuss the possibility of expanding the program. This would be like PGE's recent expanded DR programs, such as its residential thermostat program.

Associated Learnings

PGE will track program enrollment throughout the pilot. The process evaluation will include review of marketing materials, benchmarking of similar programs, stakeholder interviews, and customer surveys. These tools will provide critical information on the barriers to customer adoption and what works/what doesn't in marketing energy storage programs to residential customers. If differentials exist in enrollment between ownership models, it will be important to track customer motivations between the two options as reported in participant surveys.

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[q] Conversations with Josh Castonguay, Vice President and Chief Innovation Executive at Green Mountain Power.
[r] GMP – Tesla Powerwall Innovative Pilot Program Rider (filled with Vermont Public Service Board on December 3, 2015).
[s] See PGE Advice No. 18-14 Attachment A.

Risk of Partner Failure

Residential energy storage systems are still an emerging technology with many product offerings coming from newer businesses with unproven business models. To mitigate the risks associated with key vendors no longer being able to perform their agreed-upon duties, PGE will require vendors to submit their credit information during the procurement process and only partner with organizations that present a low level of financial risk (this is already standard practice for PGE).

PGE will also seek to procure energy storage systems that adhere to open communications protocols and have discrete and serviceable components. If a vendor can no longer support portions of the energy storage system or software platform, components can be swapped out by licensed technicians and aggregation platforms changed to ensure program continuation. The use of discrete and serviceable parts also ensures the cost-effective repair of components like inverters, communications gateways, and batteries.

PGE will mitigate the risk of a vendor not meeting program delivery timelines and goals through deliverables-based contracting and the evaluation of back-up providers that can step in quickly should a vendor fail to meet their duties.

Associated Learnings

PGE will use this pilot to assess the performance of the hardware, software, aggregation, and operations and maintenance vendors contracted. In cases where vendors fail to perform duties we will adjust as necessary and conduct a post-failure analysis to understand the cause of that failure. Accounts of failures will also be documented by the evaluator through stakeholder interviews with key program staff at PGE and with its partners to understand all perspectives on critical issues.

Risk of Supply Chain Failure

As the energy storage market is still growing at a rapid pace, supply chain deals such as committing production to a single subscriber are not uncommon. These may be on the manufacturer side or be upstream on the battery cells or even raw materials. These delays could hamper our ability to rollout the pilot on the intended timeline. PGE will seek to mitigate this by engaging with vendors early to plan deployment, securing production and delivery guarantees, and managing customer expectations. If supply chain problems exist, PGE will pursue alternate vendors as appropriate.

Associated Learnings

Reasons for delays, where observed, will be recorded and mitigated where possible. Through stakeholder interviews, the evaluator will capture issues observed and recommend mitigation strategies for wider program deployments. Supply times observed in the pilot will be used to update program planning assumptions for future offerings.

Risk to Technological Obsolescence

Energy storage systems are still an emerging technology and product offerings that are state of the art today may become outdated within the program lifetime. To mitigate the risk of our offering no longer appealing to our customers, we will require vendors to provide product roadmaps during the procurement process, helping ensure that vendors will be able to provide updated product offerings.

PGE will also require vendors to guarantee support for all products for the duration of the pilot so that all assets remain usable. PGE may also select products with discrete components that are capable of being upgraded to maintain viability as technology progresses.

<u>Associated Learnings</u>

Where PGE observes rapid changes in product capabilities, these will be captured in the process evaluation. If major changes are observed in the pilot period, we will incorporate obsolesces assumptions into future models for program planning and cost-effectiveness.

Risk of dispersal

PGE understands that a few hundred units offered across the service territory are not likely to concentrate in one area of the distribution system at levels high enough for PGE to collect enough operational data and experience to directly learn about the T&D locational benefits of multiple batteries installed on one feeder or substation. PGE is preparing a strategy whereby a residential energy storage device could be first offered first to Test Bed participants with the hope of identifying and creating a cluster of residential batteries within the Test Bed to accelerate our learnings from the Residential Energy Storage pilot. Therefore, the Test Bed application maps of each substation in the Test Bed identifying the location of self-generation and roof-top PV. If this strategy yields too few enrollments, we will then expand to a wider population.

<u>Associated Learnings</u>

If successful targeted deployment is achieved, PGE will be able to demonstrate localized use cases directly at the Test Bed substations. These will be reported specifically for the residential batteries in the evaluation of this pilot as well as in aggregate with DR resources in the Test Bed evaluation report.

7.1(d) Learning Objectives

PGE aims to use this pilot program to gain experience in residential energy storage program design, procurement, customer acquisition, deployment, operation, maintenance, and end-of-life.

In broad strokes, this pilot would require evaluation of the following topics:

Table 36: Evaluation Topics (Residential Pilot)

Project	Quantitative Topics					Qualitative Topics				
	Bulk Energy	Ancillary Services	Transmission Services	Distribution Services	Customer Energy Management Services	Resiliency	Procurement	Infrastructural Readiness	Organizational Readiness	Customer Engagement
Microgrid	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓
Substation	✓	✓	✓	✓			✓	✓	✓	
Mid-Feeder	✓	✓	✓	✓			✓	✓	✓	
Residential	✓	✓	✓	✓	✓		✓	✓	✓	✓
Generation	✓	✓					✓	✓	✓	

The pilot will inform future program design elements, including but not limited to:

- BIS design, power output, and energy storage specifications;
- Effective capacity available for behind-the-meter systems;
- Customer acquisition and enrollment strategies;
- Differences in enrollment and operations between customer and utility owned systems;
- Procurement, installation, and commissioning best practices;
- Operational strategies;
- Fleet command software design; and
- BIS maintenance and end-of-life.

PGE also seeks to answer the following research questions:

- How can PGE most effectively leverage distributed energy storage to optimize benefits for generation, transmission, and distribution operations while also providing a compelling customer value proposition?
- What program improvements can be made to support successful dispatch of the aggregated BIS fleet to provide capacity, energy and ancillary services, and transmission deferral services?
- What additional services can the aggregate BIS fleet provide, and how can these benefits be best included in future program designs?
- What are PGE customers willing to pay for enhanced and power reliability?

- In what proportion should storage capacity be shared between PGE and customers to maximize total benefits?
- What business model is most compelling for the customer between utility and customer owned?
- What operations and maintenance issues arise from BIS operation, and how will that affect program maintenance costs?
- How will distributed energy storage contribute to PGE's broader set of distributed flexibility resources (such as DR and DSG)?

PGE also intends to evaluate program costs, realized system benefits, realized customer benefits and willingness to pay, and equipment ownership structure.

7.1(e) Data Collection Plan

Throughout the pilot, PGE will collect and maintain the following types of data:

- Battery state of charge, Volts, Amps, Watts at a 15-minute basis if not more frequent
- Battery reported charge/discharge rate
- Control signals sent from PGE to batteries
- Data on times when PGE system would benefit from battery charge/discharge and how much
- Alarms reported by storage management system(s)
- Customer AMI data, including kW, kWh, and service voltage at 15-minute increments.
- Customer rooftop solar production data (where relevant and available)
- Customer outage data
- Agreements between customers and PGE concerning storage device control
- Program tracking data
- Program marketing materials
- Participant survey data
- Stakeholder interviews
- Literature review of comparable programs

7.1(f) Evaluation Plan

For the residential program, PGE plans to engage a third-party evaluator to document and analyze program impacts and processes.

For the impact evaluation, there are three main areas in which problems could arise between the expected capabilities of the batteries and their actual performance for PGE system benefit:

- Do the batteries meet the expected capabilities? Is the degradation over time and with temperature changes greater or less than expected?
- When called, do the batteries' control systems respond as expected?

- How much of the theoretical maximum PGE system benefit can be gained given the need to reserve sufficient capacity to also provide specific customer benefit?
    - Do customers need to have units providing some minimum level of backup?
    - How does the balance between customer needs and system needs change seasonally, i.e., summer (low outage incidence) and winter (higher outage incidence)?
    - How do systems purely solar-fed (customer-owned systems subject to the investment tax credit) respond differently than those that are grid fed?

Area of Inquiry	Data used	Analysis Method
Do the batteries meet the expected capabilities? Is the degradation over time and with temperature changes greater or less than expected?	State of charge, battery-reported charge/discharge rate, customer AMI data.	Compare battery's nameplate charge/discharge rate with that observed by AMI. Compare observed changes in storage capacity with manufacturer guidance.
When called, do the batteries' control systems respond as expected?	PGE control signals, battery-reported charge/discharge rate, AMI.	Compare what PGE control signals call for the batteries to do versus the observed charge/discharge rate in AMI.
How much of the theoretical maximum PGE system benefit can be gained given realistic operation (e.g. imperfect foresight on charging/discharging; need to also provide customer benefit)?	Data on times when PGE system would benefit from charge/discharge and how much; control signals sent to batteries.	During periods when PGE is attempting to use the batteries in the way that it would with an at-scale battery program, compare control signals sent to batteries with data on potential PGE system benefit had the batteries been charged/discharged.

PGE's method of inquiry for the process evaluation include qualitative analysis of information gained from PGE in documentation, interviews, and analysis of other utilities' experience. The evaluator will conduct a thorough review of all program tracking data and marketing materials to ensure that they follow industry best practices. They will benchmark program outcomes and process against comparable utility programs to ensure to illuminate any ways that PGE and/or its customers deviated from what's commonly observed.

The program evaluator will implement a program logic model early in the process to document the intended causal model of the program and identify metrics to evaluate effectiveness at each step in the process. This will be critical in identifying where each data collection mechanism and associated metric will inform program design.

The process evaluation will use primary data collected from participant surveys and stakeholder interviews to answer research questions such as:

- How effective was the program at addressing customer needs and wants with respect to energy storage?
- What were the biggest barriers to implementation?
- What were the biggest factors in program success?
- How satisfied were participants with the program? Did this change over time?
- Were there any issues with the following processes:
  - Customer acquisition?
  - Installation?
  - Commissioning?
  - Calling events?
  - Ongoing operations/communications?
  - Operation in backup mode?
- What marketing messages/channels were most effective?
- Were there differences in how customers responded to different ownership models?
- How can PGE identify customer propensity to adopt, and did different types of customers adopt one model over another?
- What adjustments should be made from the pilot that would lead to a more effective program at scale?

7.1(g) Conclusion

PGE submits this addendum to its initial proposal, which includes a revised pilot project design that:

- Aggregates and dispatches residential storage units as a single resource;
- Manages and details mitigation strategies for all program deployment and life cycle risks;
- Optimizes learnings (shared control between the participant and PGE and shared benefits of the system with its participant); and
- Contains a data collection and a program evaluation plan.