**EXH. RBB-1T**
**DOCKETS UE-22___/UG-22___**
**2022 PSE GENERAL RATE CASE**
**WITNESS: ROQUE B. BAMBA**

**BEFORE THE**
**WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION**

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| **WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION,**<br><br>**Complainant,**<br><br>**v.**<br><br>**PUGET SOUND ENERGY,**<br><br>**Respondent.** | **Docket UE-22____**<br>**Docket UG-22____** |

**PREFILED DIRECT TESTIMONY (NONCONFIDENTIAL) OF**

**ROQUE B. BAMBA**

**ON BEHALF OF PUGET SOUND ENERGY**

**JANUARY 31, 2022**

**PUGET SOUND ENERGY**

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## I. INTRODUCTION

**Q. Please state your name, business address, and position with Puget Sound Energy.**

A. My name is Roque B. Bamba. My business address is 355 110th Ave. NE, Bellevue, WA 98004. I am the Director of Project Delivery with Puget Sound Energy ("PSE" or the "Company").

**Q. Have you prepared an exhibit describing your education, relevant employment experience, and other professional qualifications?**

A. Yes, I have. Please see Exh. RBB-2.

**Q. Please describe your responsibilities as Director of Project Delivery.**

A. I am responsible for overseeing the management and execution of capital infrastructure projects and programs within PSE's Operations organization. Project Delivery is comprised of Major Projects, Infrastructure Program Management, AMI Program, and Project Controls. My responsibilities include providing for safe and effective delivery of PSE's infrastructure projects and programs, resolution of complex operational challenges, and project-related customer and stakeholder inquiries. Additionally, I am responsible for adherence to and ongoing refinement of PSE project and program governance standards and policies. In my role, I work closely with PSE System Planning, Engineering, Finance, Accounting, and Regulatory so projects and programs are well-coordinated among all stakeholders.

**Q. Please summarize the purpose of this prefiled direct testimony.**

A. My testimony provides an overview of how PSE manages the capital infrastructure projects and programs needed to deliver safe, reliable, and affordable energy to customers. I describe the methodical approach that guides PSE project and program management and how through this approach, PSE invests customer funds wisely and optimizes the benefits flowing from each project or program selected for development and execution. I also describe how optimizing benefits may, from time to time, require PSE to alter the way projects and programs are sequenced to reflect unexpected conditions that unfold naturally in the course of PSE's operations, such as unanticipated weather events, new economic development needs, and emerging public policy priorities.

I then describe how PSE's methodology applies in practice by discussing certain major projects in greater detail. I explain that differences in project and program profiles imply the need for limited and reasonable modifications to PSE's general project and program management methodology. I illustrate the need for flexibility in applying project and program management structures.

**Q. What is PSE requesting in your testimony?**

A. PSE is requesting recovery of costs associated with the three major backbone infrastructure projects with capital costs greater than $10 million placed in service between January 1, 2019 and June 30, 2021: i) Lake Hills – Phantom Lake 115kV

Transmission Line; ii) Bellingham Substation; and iii) distribution upgrades related to Tacoma Liquid Natural Gas ("LNG") project. My testimony describes these projects and the prudence of investing in them.

In addition, my testimony provides an explanation for PSE's need for flexibility in applying capital and Operating and Maintenance ("O&M") budgets to fulfilment of our public service obligations over the multiyear rate plan. This flexibility is crucial for PSE to provide safe and reliable utility service.

## II. PSE'S OPERATIONS DELIVERY APPROACH

**Q. Please describe how PSE is organized to plan and manage work.**

A. There is significant and necessary collaboration between many functions within PSE to plan and manage work. For planned discretionary work, PSE's Project Delivery organization, which I oversee, is responsible for executing discretionary plans and performing project and program management to deliver plans on schedule, scope, and budget. PSE's Delivery System Planning organization, led by Catherine A. Koch, is responsible for monitoring, identifying, and analyzing delivery system needs and building solutions that address performance issues and identified needs. Ms. Koch describes PSE's Delivery System Planning process in her Prefiled Direct Testimony, Exh. CAK-1T.

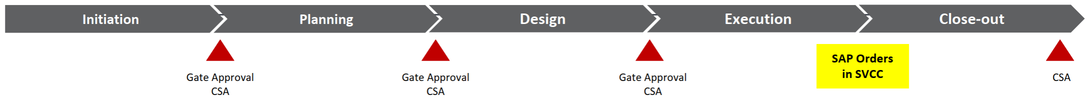
**Q. Please explain projects and programs at a high level.**

A. PSE defines a project as a temporary endeavor undertaken to provide a unique service or result. Projects are temporary and close down upon completion of the work they were chartered to deliver. In contrast, PSE defines a program as the coordinated organization, direction, and implementation of a collection of related projects and complex activities which, when executed together, achieve outcomes and realize benefits not available from managing them individually.

**Q. Please explain how PSE manages projects at a high level.**

A. PSE's project management process follows industry best practices and is based on PSE's Infrastructure Project Lifecycle Phase/Gate Model ("Project Lifecycle Model"), which includes five phases: Initiation, Planning, Design, Execution, and Close-out. For a given project, each phase includes deliverables to provide that scope, schedule, and budget are controlled, risks are managed, benefit realization plans are updated, and the overall solution is re-evaluated as the project progresses through each phase by way of phase gate approvals. The Project Lifecycle Model is designed to deliver consistency and scalability. Guided by the Project Lifecycle Model, each project maintains ongoing governance documentation in the form of Corporate Spending Authorizations ("CSA") and Project Change Requests. The PSE Project Lifecycle Model is illustrated in Figure 1, below.

**Figure 1: PSE Project Lifecycle Model**




| Phase Gates/Deliverables (at end of phase) | | | | | |
|---|---|---|---|---|---|
| | Initiation | Planning | Design | Execution | Close-out |
| Deliverables at end of phase | *See Initiation process flow in tools and forms.*<br>• Assign PM and Team<br>• WBS and WO#<br>• Needs Assessment & solutions criteria<br>• Wires and Non Wires Solutions Report<br>• Recommended Solution<br>• Benefits Realization defined<br>• GATE meeting with sponsor<br>• CSA – Initiation to Planning | • *Project Implementation plan*<br>  • *Scope, routing & siting*<br>  • *Schedule*<br>  • *Budget – Cost Report*<br>  • *Risks & mitigation*<br>• Full Project Team Assigned<br>• Engineering needs<br>• ~30% design<br>• Land needs<br>• Permitting needs<br>• Communications Plan<br>• CSA – Updated for Planning to Design | • *Constructability review (CM involved)*<br>• *Updated PIP*<br>• *60%/90% Design Reviews*<br>• *Final design*<br>• Long lead permits received<br>• Change Management<br>• Order Long Lead Materials<br>• Construction Bid Package(s)<br>• Site/ROW Secured<br>• Risk Register w/ details in PIP<br>• Track Lessons Learned<br>• Dependencies / Interdependencies with other projects<br>• System outage requests<br>• Gate review meeting with management<br>• CSA – For Design to Execution | • Bid process and award<br>• Notice to Proceed<br>• Updated PIP<br>• Construction<br>• Risk plan updates and contingency draw down<br>• Testing<br>• Commissioning<br>• Final Product In-service | • Close out CSA and benefits realization<br>• WO's Assets In-Service<br>• Project Close-out Check List (tools and forms)<br>• Operating Documentation Hand off to operations<br>• As-Builts handed off to Engineering & Maps and Records as needed<br>• Track and summarize Lessons Learned |
| | Cost Est. Accuracy Range<br>-50% - + 100% | Cost Est. Accuracy Range<br>-25% - + 50% | Cost Forecast Accuracy Range<br>-10% - + 15% | Cost F'cast Accuracy Range<br>-2% - + 5% | *Forecast matches actuals* |
| | No contingency | *Contingency up to 25%* | *Contingency up to 15%* | *Contingency up to 10%* | *Contingency < 3% for outstanding costs.* |

**Q. Please explain how PSE manages programs at a high level.**

A. PSE's program management process follows industry best practices and is based on PSE's Infrastructure Program Management model. This methodology includes deliverables to provide that scope, schedule, and budget are controlled, risks are managed, and benefits are optimized as a portfolio on an ongoing basis. Robust project controls are in place to manage individual project costs, which are used by Program Management to optimize portfolio benefits. An example of PSE's Program Management capability is the Gas Cost Recovery Mechanism, which includes programs such Dupont Pipe Replacement where PSE has consistently delivered on plan since its inception.

**Q. Does PSE's project and program management methodology align with industry standards?**

A. Yes. PSE's methodology for managing and overseeing projects and programs is based on guidance from industry best practices, PSE Enterprise Program Management Organization standards, and the Project Management Institute ("PMI"), which is a professional association for project professionals worldwide and a leading authority on project management approaches. The PMI maintains a resource called the Project Management Book of Knowledge ("PMBOK") that serves as a standard and is used widely across many industries.

PSE's Project Lifecycle Model approximates the flow of project development that the PMI advises. For example, project development actions that take place in the Initiating, Planning, and Design phases of PSE's projects align with practices described in the PMBOK's Initiation and Planning project phases. PSE's Execution-phase project development encompasses the activities described in the PMBOK Execution, Monitoring, Controlling, and Close-out phases. This includes rigorous project oversight so that PSE projects are managed to mitigate risk effectively, that contractor performance meets or exceeds expectations, and to optimize benefits that result from the Company's investments. In addition, PSE's methodology contains extensive communications and governance guidance so that project and Company executive management are apprised of challenges as they arise so that decisions can be made, and issues addressed quickly and efficiently.

**Q. Please describe PSE's Project Lifecycle Model in more detail.**

A. The Project Lifecycle Model provides a consistent and scalable framework and governance model for managing a wide range of infrastructure projects. This methodology provides that PSE consistently applies project management best practices, governance, and the appropriate level of rigor and oversight based on the complexity and overall risk of each project.

**Q. Is this methodology applied rigorously for every Operations project that PSE undertakes?**

A. This model is generally applied for every major project PSE pursues. However, each project has unique characteristics and may require specific means and methods to address the project's needs. Projects may have varying degrees of initiation, planning, design, and execution project management as required for successful mitigation of delivery risk.

**Q. Please describe what features would cause PSE to apply the Project Lifecycle Model in a manner that deviates from the Company standard.**

A. Some large projects are so unique that they require additional rigor and a highly customized approach. For example, PSE's Tacoma LNG project, the Energize Eastside transmission project, and the Baker River Hydro regrouting project are major capital projects with sophisticated engineering needs and correspondingly complex procurement and contractor oversight requirements. Please see the Prefiled Direct Testimony of Ronald J. Roberts, Exh. RJR-1CT, for a detailed description of the Tacoma LNG project. Please see the Prefiled Direct Testimony of Dan'l R. Koch, Exh. DRK-1CT, for a comprehensive discussion of the Energize Eastside Project. And please see the Prefiled Direct Testimony of Ryan P. Blood, Exh. RPB-1T, who discusses PSE's plans concerning the refurbishment of the Baker River Hydro facility in his testimony. Such projects receive additional scrutiny and management attention.

**Q. Please describe what happens in PSE's Initiation Phase of project development.**

A. During the Initiation Phase of the PSE Project Lifecycle Model, PSE evaluates and confirms the project's need, analyzes alternatives including, when feasible, non-wires options, and recommends a specific solution that accounts for risks in execution, benefits that will be achieved, and associated costs. A Project Manager ("PM") and team are assigned, and a preliminary scope is developed. This preliminary scope consists of a project description and "Work Breakdown Structure" that defines the key objectives and any interdependencies. At this point in a project, the costs are typically estimated using a range that reflects the considerable uncertainty, i.e., -50 to +100 percent.

**Q. Please describe what happens in PSE's Project Planning Phase of project development.**

A. The PM assigned to a project leads a rigorous project implementation planning process throughout the project Planning Phase of the PSE Project Lifecycle Model. This involves detailed scope definition, identification of engineering, permitting, and resource needs; assembly of a team with representation from various corporate areas with project expertise; and the development of a communications plan so that internal and external stakeholders are apprised of project development milestones and challenges.

**Q. Please describe what happens in PSE's Design Phase of project development.**

A. PSE's Design Phase includes detailed engineering design with typical reviews including constructability at 30, 60 and 90 percent engineering design completion milestones. This stage of project development is when procurement activities begin to significantly inform the Project Implementation Plan ("PIP"). The PIP documents all aspects of the project plan and is maintained throughout the project lifecycle. When necessary, PSE defines commercial and contracting strategies and conducts market outreach to determine whether there is sufficient competition to hold a competitive procurement for contracted support.

In addition, during the Design Phase, the PM pursues and secures all necessary environment and land use permits and Rights of Way ("ROW"). With all permits and ROWs established, the PM documents project and program plans and seeks PSE management approval to proceed to the Execution Phase. At this point, a project's scope is understood to a much greater degree than in earlier phases. Project costs for known and knowable scope can be estimated to within approximately 15 percent by the close of the Design Phase and is considered the baseline lifetime budget. Contingency budgets are also set at approximately 15 percent of cost estimates to reflect remaining uncertainty.

**Q. Please describe what happens in PSE's Execution Phase of project development.**

A. The Execution Phase of the project is focused on contractor selection, construction, and commissioning activities. Procurements for contractor services and professional support are conducted in a manner consistent with PSE's procurement guidance at the beginning of the Execution Phase. Please see the Prefiled Direct Testimony of Dawn M. Reyes, Exh. DMR-1T, for a detailed description PSE's Procurement process. The project team works closely with PSE's Procurement team throughout the contractor selection process and makes a final award recommendation to PSE Management. Construction activities are initiated once the contract has been awarded and fully executed. Throughout construction, all project risks are actively managed and associated oversight mechanisms are in place. These include onsite Environmental Managers, Construction Managers, Quality Assurance and Quality Control, and materials testing necessary to insulate the project and customers from construction activity risks. Once the construction work is complete, PSE conducts all necessary testing and commissioning activities, and the project is placed in service.

**Q. Please describe what happens in PSE's Close-out Phase of project development.**

A. In this phase, the asset and all supporting documentation are officially transferred to the appropriate business owners and all project records are reviewed and filed for future reference. Any open action items, punch lists, or ongoing program-level activities can be officially closed or assigned to the appropriate support organization.

**Q. Are projects ever re-prioritized?**

A. Yes. Projects are part of the broader PSE portfolio and are subject to re-prioritization or re-sequencing which may result in deferring project activities for a period of time. Additionally, projects may be re-prioritized as the result of external factors such as unexpected weather conditions, permitting delays, public opposition, legal challenges, or broader economic circumstances.

Successful program management requires the flexibility to adjust for individual project variability by continuously monitoring and adjusting projects so that emergent needs are met and program-wide benefit targets are achieved. PSE's program management methodology is structured to make necessary adjustments for impacts that delay individual projects and affect the program benefit targets.

This kind of reprioritization is common due to unexpected events such as weather anomalies or other exogenous factors that cannot be accurately predicted. The Prefiled Direct Testimony of Joshua A. Kensok, Exh. JAK-1T, discusses how the Company's financial management and associated governance practices address this kind of challenge. PSE's project/program management approach is similarly designed to be flexible to allow PSE to quickly and effectively respond to unexpected events when they occur. For example, in the event a specific program focused on reliability benefits experiences disproportionate impacts related to external factors, PSE will evaluate, reprioritize, and accelerate other programs focused on reliability benefits so that overall benefits are achieved.

**Q Please describe Program Management cost controls.**

A. Infrastructure Program Management conducts budgetary cost estimates with a basis and level of granularity that is particular to the project maturity at the time of the estimate.

Costs basis typically include historic estimates, which are used at an early level of project maturity, and detailed estimates, which are used when the project design is nearly complete or at completion. A historic-based estimate is predicated on an average of comprehensive actualized costs per high-level scoping unit (mileage, quantity of structures, etc.) of past projects with a percentage multiplier to account for relative complexity and risk.

A detailed estimate is based on a robust database of typical cost items, including hourly rates from different roles throughout the Company, material cost items, consultant support, and construction crew contract rates.

The level of project maturity and cadence for which estimates are conducted can vary between programs depending on the complexity of budgeting the projects within the program's portfolio.

## III. MAJOR BACKBONE INFRASTRUCTURE PROJECTS GREATER THAN $10 MILLION THAT WERE PLACED IN SERVICE BETWEEN JANUARY 1, 2019 AND JUNE 30, 2021

**Q. Please describe the major backbone infrastructure projects with capital costs greater than $10 million placed in service between January 1, 2019 and June 30, 2021.**

A. There are three major backbone infrastructure projects with capital costs greater than $10 million placed in service between January 1, 2019 and June 30, 2021: i) Lake Hills – Phantom Lake 115kV Transmission Line; ii) Bellingham Substation; and iii) distribution upgrades related to Tacoma LNG project. For each project, my testimony describes the need, alternatives considered, how management was informed, and any major changes during the project lifecycle following the project management process described above.

### A. Lake Hills – Phantom Lake Transmission Line Project

**Q. Please describe the Lake Hills – Phantom Lake 115kV Transmission Line project.**

A. The Lake Hills – Phantom Lake 115kV Transmission Line project is located in east Bellevue in central King County. The project consisted of installing 2.5 miles of new 115 kV transmission line extending from the Lake Hills substation to the Lakeside – Phantom Lake transmission line. This eliminates three substations from being radially fed and provides increased reliability in the Bellevue-Redmond area. Exh. RBB-3 contains the CSA for the Lake Hills – Phantom Lake 115kV Transmission Line project.

**Q. Is Lake Hills – Phantom Lake 115kV Transmission Line project operating and providing service to customers?**

A. Yes.

**Q. What was the timeline for the completion of Lake Hills – Phantom Lake 115kV Transmission Line project?**

A. This project was initiated in 2006. After engaging the neighboring communities on route alternatives, PSE moved forward with Lake Hills – Phantom Lake 115kV Transmission Line project in 2011 by starting the City of Bellevue permitting process. 2011 through 2019 was spent on permitting and easement acquisition. Work associated with the Lake Hills – Phantom Lake 115kV Transmission Line project was completed and placed in service October 2020 with final site restoration to be completed in early 2022.

**Q. What was the final cost of Lake Hills – Phantom Lake 115kV Transmission Line?**

A. The cost of the project was $15.9 million without allowance for funds used during construction ("AFUDC") as of July 1, 2021. PSE recovered $5 million in the 2019 general rate case. Final mitigation and closeout costs are expected to be an additional $4.15 million resulting in an overall cost of $20.1 million.

**Q. Describe the system need for Lake Hills – Phantom Lake 115kV Transmission Line.**

A. The primary need for the project was to improve the reliability of the Phantom Lake, Lake Hills, and College substations which are serving a total of over 12,000 customers. Each substation was fed radially. Any transmission outage on the radial feeds resulted in an extended outage to one or two of these substations. The larger area between Redmond and Eastgate along the west side of Lake Sammamish also benefited from the new transmission line. Six substations serving 23,000 customers were served by an existing transmission line. The line resulted in a third feed to Ardmore, connecting Ardmore to the Lakeside Switching Station, allowing for automated switching between the Sammamish and Lakeside substations and increasing reliability for these six substations.

**Q. Describe the alternatives evaluated and how this solution was chosen.**

A. Two alternatives, including the selected alternative, were evaluated. PSE's solution criteria required all identified needs be addressed, specifically the customer reliability objectives and PSE's long-term transmission reliability objectives in the Bellevue-Redmond area.

1. **Construct Westminster Switching Station and a new Pickering – Phantom Lake 115kV Line** – This alternative considered construction of a new Westminster switching station and building a new six mile transmission line from the existing Pickering substation to the Phantom Lake substation. This alternative was rejected because it did not meet the reliability objectives, and the Lake Hills – Phantom Lake line would inevitably still be needed to relieve loading issues and maintain reliability in the Bellevue-Redmond area.

2. **Construct a new 115kV line between the Lakeside – Phantom Lake Line and Lake Hills Substation** – This alternative was selected because it fully met the project needs of transmission reliability. The new line limited the customer outages for the 12,000 customers served by the three substations. This also supported the long-term planning efforts for the Bellevue-Redmond area with a full automatic switching scheme from the Sammamish to Lakeside substations resulting in reliability improvements for six substations.

**Q. What benefits does the Lake Hills – Phantom Lake 115kV Transmission Line provide for customers?**

A. This project improved reliability for over 12,000 customers by adding a second feed to each of the three radially fed substations and improved bulk power supply reliability by adding a third feed to Ardmore substation.

**Q. Describe how PSE kept management informed during this project.**

A. Using PSE's Project Lifecycle Model, management provided review and approvals for the project. This project was reviewed by management to proceed to the project design phase in June 2014. The project was approved for construction funding in 2019. However, due to permitting delays, construction did not start until 2020 which was also communicated to and approved by management. The Lake Hills – Phantom Lake 115kV Transmission Line project was tracked within PSE's Strategic Project Portfolio and Project Change Request processes throughout the execution phase of the project.

**Q. Were there any material changes that impacted the project scope, schedule or budget? If so, describe.**

A. Yes. At the execution approval, the estimate was $13.2 million without AFUDC. The major changes to the project that increased the cost from $13.2 million to the estimated final expenditure of $20.1 million are as follows:

- $1.8 million for increased costs of necessary easements, legal support of easement acquisition, transmission line design changes to include engineered foundations, and increased consultant support for additional trees that were identified for removal and the associated permitting;

- $600,000 for permit delays that impacted the schedule;
- $1.2 million for design revisions to include installation of service to the motor operated transmission switches, permit conditions that required police traffic escorts for pole site delivery, COVID-19 "Stay Home, Stay Safe" orders that extended the construction schedule, and additional equipment necessary for vegetation removal; and
- $3.2 million for increased landscape mitigation that was a result of plant availability and unforeseen permit conditions and increase in resources to address six new permits required to document changes to mitigation and restoration areas.

**Q. Have the benefits from the Lake Hills – Phantom Lake 115kV Transmission Line been realized?**

A. Yes. As described above, this project is providing improved operational flexibility and transmission reliability to approximately 12,000 customers in the Bellevue-Redmond area.

## B. Bellingham Substation Project

**Q. Please describe the Bellingham Substation project.**

A. The Bellingham Substation project is located in the Bellingham area of Whatcom County. The Bellingham Substation project consisted of rebuilding the existing 115 kV switching station to a breaker-and-a-half bus configuration and included construction of a new station control house and perimeter fencing for station expansion. Exh. RBB-4 contains the CSA for the Bellingham Substation project.

**Q. Is the Bellingham Substation project operating and providing service to customers?**

A. Yes.

**Q. What was the timeline for the Bellingham Substation project?**

A. This project was initiated in 2006 with an anticipated need date of 2010. The project was delayed due to: (i) a change in growth projections in 2009 caused by a change in development plans for the area and (ii) the need to focus on another capacity project. The project resumed in 2014 but was deferred for higher priority reliability and capacity projects until 2018. The Bellingham Substation project was completed and placed in service in July 2019.

**Q. What was the final cost of the Bellingham Substation project?**

A. The final cost of the project was $27.8 million without AFUDC.

**Q. Describe the system need for the Bellingham Substation project.**

A. There were several needs for this project. First, the substation is the central switching station for the region, and the layout of the previous substation created reliability concerns that would cause loss of service to 20,000 customers and the Encogen generating plant. Second, the capacity of several portions of the substation infrastructure was not able to serve long term capacity needs for the Bellingham area. Third, and more specifically, the capacity of the bus would be beyond the NERC allowable limits for certain transmission system contingencies (or outages) and anticipated load growth. Last, there is a significant amount of aging infrastructure in the substation between degrading, low-capacity oil breakers and electro-mechanical relays.

**Q. Describe the alternatives evaluated and how this solution was chosen.**

A. Four alternatives, including the selected alternative, were evaluated. PSE's solution criteria required all identified needs be addressed.

1. **Rebuild bus to breaker-and-a-half configuration** – This alternative consisted of constructing a breaker and a half bus configured substation in the former Bellingham substation 55kV yard and demolishing the existing Bellingham 115kV substation. This alternative was selected because it fully met the project needs, including improved reliability in the Bellingham area, met long-range capacity needs for the Bellingham area, and addresses future capacity compliance.

2. **Rebuild bus with two bus section circuit breakers and an aux bus with bus tie circuit breaker** – This alternative consisted of constructing a main bus with two bus section circuit breaker and an auxiliary bus with a bus tie circuit breaker in the former Bellingham substation 55kV yard. This alternative was rejected because it did not offer the same reliability benefits of a breaker-and-a-half configuration at a similar cost.

3. **Rebuild the existing 115kV substation** – This alternative consisted of rebuilding both bus sections one bus section at a time and installing two bus section breakers with a new auxiliary bus and bus tie circuit breaker. This alternative was rejected because it offered lower reliability than the selected option at a similar cost. This option also presented the added risk of outage coordination during construction and building adjacent to energized infrastructure.

4. **Do nothing** – This alternative consisted of not upgrading any portion of the substation or replacing any aging infrastructure. This alternative was rejected because it did not address any of the existing and future system deficiencies.

**Q. What benefits does the Bellingham Substation project provide for customers?**

A. This project improved Bellingham area reliability for 20,000 customers and the Carolina substation is now connected to the new 115kV bus eliminating outages for 4,236 customers. The improvement also allows for the future capacity needs of expected growth in the Bellingham area.

**Q. Describe how PSE kept management informed during this project.**

A. Using PSE's Project Lifecycle Model, management provided review and approval of the project. This project was reviewed by management in April 2015 to proceed to the Design Phase. The project was also reviewed by management in June 2016 to proceed to the Execution Phase. The Bellingham project was tracked within PSE's Strategic Project Portfolio and Project Change Request processes throughout the execution phase of the project.

**Q. Were there any material changes during execution that impacted the project scope, schedule, or budget? If so, describe.**

A. Yes. Prior to execution, the project estimate was $21.4 million without AFUDC. The major changes to the project that increased the cost from $21.4 million to the actual expenditure of $27.8 million are as follows:

- $1.7 million for support of efforts related substantial permitting, new substation security installations, updated costs for new control house, updated costs for transmission pole foundation installations and removal of existing spill prevention, and control and countermeasures;
- $3.2 million for increased costs associated with removal of unsuitable soils and replaced with clean imported fill, design revisions that required deeper foundations and associated installation costs, removal of existing duct bank, additional conduit due to inadequate existing asbestos concrete conduit and additional grounding due to lack of existing grounding; and
- $1.5 million for construction crew overtime to maintain energization schedule, construction coordination, and safety watch support for contractor installations.

**Q. Have the benefits from this project been realized?**

A. Yes. System reliability has been increased for the Bellingham substation and for each of the nine interconnected substations. Aging infrastructure has been removed from the stations prior to failure. This project also provided additional station capacity on the 115kV bus meeting the needs of the Bellingham area and NERC requirements.

## C. Tacoma LNG Project Distribution Upgrades

**Q. Please describe the distribution upgrades related to the Tacoma LNG project.**

A. The dual-use Tacoma LNG project at the Port of Tacoma was constructed for use by PSE as a peak day resource for natural gas customers and by Puget LNG, a subsidiary of Puget Energy, as a source of LNG for transportation fuel for the maritime and trucking industries. There were three primary upgrades necessary to connect the Tacoma LNG project to the PSE gas distribution system. First, four miles of new piping and a meter station to connect the Tacoma LNG Facility to the PSE natural gas distribution system. Second, the existing Frederickson Gate Station was rebuilt. Third, one mile of 12-inch-high pressure piping was installed along Golden Given Road East, and installation of the new Golden Given Limit Station. Please see Roberts, Exh. RJR-1CT, for additional information about this project.

**Q. Are all three upgrades operating and providing service to customers?**

A. Yes.

**Q. What was the timeline for distribution upgrades related to the Tacoma LNG project?**

A. The three upgrades were planned for construction to be completed over the course of three years with final completion in advance of the original in-service date for the Tacoma LNG Facility, which was planned for early 2019. Construction of the four miles of new piping was placed into service in October 2017. The meter station was placed into service in December 2020. Construction of the Frederickson Gate Station rebuild was completed and placed into service in September 2017. Due to permitting delays related to the Tacoma LNG Facility, construction of the one mile of 12-inch-high pressure piping and new Golden Given Limit Station was deferred until 2020; those facilities were placed in service in October 2020.

**Q. What was the final cost of the distribution upgrades related to the Tacoma LNG project?**

A. The final cost of the distribution upgrade projects related to the Tacoma LNG Facility is $46.4 million without AFUDC. This includes $30 million for the four miles of new pipe and meter station connecting the Tacoma LNG Facility to the PSE natural gas distribution system, $4.1 million for the Fredrickson Gate Station, and $12.3 million for the one mile of 12-inch-high pressure piping and new Golden Givens Limit Station. Consistent with Docket UG-151663,[1] the costs

[1] *In the Matter of the Petition of Puget Sound Energy, Inc. for (i) Approval of a Special Contract for Liquefied Natural Gas Fuel Service with Totem Ocean Trailer Express, Inc. and (ii) a Declaratory Order Approving the Methodology for Allocating Costs Between Regulated and Non-regulated Liquefied Natural Gas Services*, Docket UG-151663, Final Order 10 (Oct. 31, 2016).

related to the four miles of new pipe and meter station connecting the Tacoma LNG Facility to the PSE distribution system were charged to the Tacoma LNG Project costs. The costs of the Fredrickson Gate Station and the Golden Givens Limit Station were charged to PSE distribution system costs. The Prefiled Direct Testimony of Jon A. Piliaris, Exh. JAP-1T, provides further explanation of the allocation of these costs between the Tacoma LNG project and the PSE distribution system.

**Q. Describe the system need for distribution upgrades related to the Tacoma LNG project.**

A. First, the four miles of new piping and meter station are utilized to supply natural gas to the Tacoma LNG Facility for liquefaction and to transport vaporized natural gas from the Tacoma LNG Facility to the distribution system. These four miles of new piping and the meter station support both uses of the Tacoma LNG Facility, PSE's use for system peaking and Puget LNG's use of LNG as transportation fuel.

Second, prior to adding the peaking service to be provided by the Tacoma LNG Facility, the Fredrickson Gate Station had a delivery capacity of 2,356,000 standard cubic feet per hour ("SCFH"). The peak design day required 92 percent of this capacity, and the addition of the volumes for the Tacoma LNG Facility would have exceeded the capacity of the Fredrickson Gate Station. This required the Frederickson Gate Station to be rebuilt to serve 6,000,000 SCFH to meet anticipated loads.

Finally, the Tacoma natural gas distribution system was served from the North Tacoma high pressure line and the South Tacoma high pressure line. These two lines operated independently, both serving limit stations that feed the remainder of the North and South Tacoma distribution systems. The addition of the Tacoma LNG Facility natural gas load would exceed the capacity of the North Tacoma high pressure line unless reinforcement actions were taken to increase system capacity. The installation of the 12-inch-high pressure line along Golden Given Road East and the new limit station connect the North Tacoma high pressure line and the South Tacoma high pressure line, allowing the South Tacoma high pressure line to support more of the load and increase overall system capacity. The need for the Fredrickson Gate Station and the new line and limit station connecting the North Tacoma high pressure line to the South Tacoma high pressure line was driven by the peaking service to be provided by the Tacoma LNG Facility and therefore, benefit the PSE distribution system.

**Q. Describe the alternatives evaluated and how this solution was chosen.**

A. Two alternatives, including the selected alternative, were evaluated. PSE’s solution criteria required all identified needs to be addressed and met.

1. **Upgrade the North Tacoma supply system** – This alternative consisted of upgrading the North Tacoma supply system by looping the existing system with five miles of 16-inch pipe. This alternative also included the four-mile pipeline to connect the Tacoma LNG project to the gas distribution system. This alternative was rejected because of higher estimated costs and additional risk of a river crossing and steep hill to complicate construction.
2. **Increase capacity of the existing South Tacoma supply system** – This alternative consisted of increasing capacity of the existing South Tacoma

> supply system and providing a connection to the North Tacoma supply system. In addition to the work already identified in the area, this alternative would require the installation of a one-mile connector pipeline, a pressure regulating station, and rebuild of the Frederickson gate station. This alternative also included the four-mile pipeline to connect the Tacoma LNG project to the gas distribution system. This alternative was accepted because it was the most cost-effective solution.

**Q. What benefits do the distribution upgrades related to the Tacoma LNG project provide for customers?**

A. The improvements made to the distribution system outside of the Port of Tacoma improved existing low pressure issues in the Dupont, Steilacoom, University Place and Fircrest areas. These upgrades also support PSE providing reliable service in Tacoma and surrounding areas.

**Q. Was PSE management informed and involved during development and construction of the upgrades related to the Tacoma LNG project?**

A. Yes. The distribution upgrades related to the Tacoma LNG project were part of a much larger dual-use project. Roberts, Exh. RJR-1CT, describes the efforts that were undertaken to involve PSE management and the PSE Board of Directors in decisions related to development and construction of the larger Tacoma LNG project. See Exh. RJR-3 for a detailed narrative timeline of the process by which PSE developed and the PSE Board of Directors approved the Tacoma LNG project.

**Q. Were there any material changes during execution that impacted the project scope, schedule or budget? If so, describe.**

A. No. The upgrades related to the Tacoma LNG project were initially estimated at $49.26 million and the final cost for the upgrades was $46.4 million.

**Q. Have the benefits from this project been realized?**

A. Yes, the improvements made to the distribution system outside of the Port of Tacoma improved existing low-pressure issues in the Dupont, Steilacoom, University Place and Fircrest areas as well as increased reliability in the Tacoma area. Additional benefits will be realized when the PSE distribution system relies on the Tacoma LNG Facility to meet peaking needs, through the increased capacity at the Fredrickson Gate Station and the connection of the North Tacoma high pressure line to the South Tacoma high pressure line.

## IV. MAJOR BACKBONE INFRASTRUCTURE PROJECTS THAT WILL BE PLACED IN SERVICE BETWEEN JULY 1, 2021 AND DECEMBER 31, 2025

**Q. Please describe the major backbone infrastructure projects with capital costs greater than $10 million currently in progress.**

A. The projects described in this section are not in-service. However, they are underway and have a lifetime cost above $10 million. The table below summarizes these projects including phase, estimated budget, and planned in service year.

**Table 1: Major Backbone Infrastructure Projects with Capital Costs Greater than $10 million Currently in Progress**

| Project | Current Lifecycle Phase | Lifetime Budget (EST) | Project In Service Year (EST) |
|---|---|---|---|
| Sammamish - Juanita 115kV Transmission Line | Design | $30.1M | 2023 |
| Electron Heights - Enumclaw 55/115kV Conversion | Execution | $21.2M | 2024 |
| Bainbridge Island | Planning | $48.82M | 2025 |
| Tono Substation | Planning | $17M | 2022 |
| Lynden Substation | Planning | $9.6M | 2024 |
| Sedro Woolley - Bellingham #4 | Design | $23M | 2025 |
| Vashon – Gig Harbor Long Term Solution | Planning | $35.3M | 2026 |

**A. Sammamish – Juanita 115kv Transmission Line Project**

**Q. Please describe the Sammamish – Juanita 115kV Transmission Line project.**

A. The Sammamish – Juanita 115kV Transmission Line project ("Sammamish - Juanita") is located in the Moorlands area of King County. The Sammamish – Juanita project consists of installing 4.65 miles of new 115 kV transmission line and upgrading another 0.15 miles of existing 115kV transmission line to connect Sammamish and Juanita substations. The project will also loop through the existing Totem Lake substation, removing it from being radially fed from the Sammamish – Vituli 115kV transmission line. Exh. RBB-5 contains the CSA for this project.

**Q. Is the Sammamish – Juanita 115kV Transmission Line operating and providing service to customers?**

A. No.

**Q. What is the timeline for the Sammamish – Juanita 115kV Transmission Line project?**

A. This project was initiated in 2007. After considering alternatives to the project, PSE moved forward with the Sammamish – Juanita 115kV Transmission Line project in 2008 seeking community, City of Kirkland, and City of Redmond input on five route alternatives. The project team has been working with the City of Redmond and City of Kirkland since on specifics of the route and permitting. Easement acquisition started in 2021 with anticipated construction in 2022.

**Q. What is the final projected cost of the Sammamish – Juanita 115kV Transmission Line project?**

A. The expected final cost of the project is $30.1 million without AFUDC.

**Q. Describe the system need for the Sammamish – Juanita 115kV Transmission Line.**

A. The primary need for the project is to increase transmission capacity and reliability in the Moorlands area. The existing Moorlands area infrastructure serves 56,000 customers from twelve substations supported by three transmission lines. The summer and winter peak capacity of the substations exceeds the capacity limit for two of the transmission lines and approaches capacity limits of the third. The area load is already higher than the capacity of the existing lines and PSE has instituted plans to drop load, if necessary, to prevent overloads. This reduces customer reliability in operating the transmission system to meet capacity requirements. Finally, outage scenarios can cause one line in the area to support the twelve substations. Adding the Sammamish – Juanita 115kV Transmission Line would reduce the likelihood of this occurrence.

**Q. Describe the alternatives evaluated and how this solution was chosen.**

A. Five alternatives, including the selected alternative, were evaluated. PSE's solution criteria required all identified needs be addressed.

1. **Build new 115kV transmission line between Sammamish and Juanita substations with loop through of Totem substation** – The Sammamish – Juanita 115kV Line will result in three of the twelve substations being moved off of the three existing transmission lines, reducing the total load served by the three transmission lines. This alternative will also allow for a future line to be extended from the Juanita substation to the Moorlands substation. This was the preferred alternative because it improves both reliability and capacity while allowing for future development.

2. **Build new 115kV transmission line between Sammamish and Moorlands substations with loop through of Juanita substation** – This alternative included construction of a new transmission line from the Sammamish substation through the Juanita substation (Alternative 1) to the Moorlands substation. This would create a four-line system with better reliability than the existing three-line system and improve reliability for the three substations that would be removed from the three-line system. While this expansion may be necessary in the future, this option was rejected in favor of doing the project individually.

3. **Rebuild three lines serving Moorlands with Bittern conductor** – This alternative consisted of rebuilding and reconductoring the Sammamish – Vitulli, Vitulli – Brightwater, and Sammamish – Moorlands #1 lines to Bittern conductor. This alternative was rejected because it only addresses the capacity needs of the area and does not resolve the reliability need.

4. **Build new underground 115kV transmission line between Sammamish and Juanita substations with loop through to Totem substation** – This alternative is similar to Alternative 1 and addresses the

capacity and reliability need. This alternative was rejected due to higher cost than standard overhead construction.

5. **Do nothing** – This alternative consisted of no new line construction. This alternative was rejected because it did not address the reliability or capacity needs in the Moorlands area.

**Q. What benefits does the Sammamish – Juanita 115kV Transmission Line provide for customers?**

A. This project will improve Moorlands area reliability for 56,000 customer that would have been impacted by line overloads. Serving two of the twelve substations with a separate line will reduce capacity required of the existing three-line system by approximately 40 MW. This will lower the potential for outages on these three lines and allow for increased load growth in the area.

**Q. Describe how PSE kept management informed during this project.**

A. Using PSE's Project Lifecycle Model, management provided review and approval of the project. This project was reviewed by management in May 2014 to proceed to the planning phase. The project was reviewed by management in August 2019 for scope updates. The project was reviewed by management in May 2020 to proceed to the design phase. Finally, the project was reviewed by management in November 2021 for budget and schedule updates.

**Q. Describe the current state of the Sammamish – Juanita 115kV Transmission Line project.**

A. The project is currently in the design phase of the Project Lifecycle Model. PSE is pursuing easements and permits consistent with the designs for anticipated construction and in service in 2022.

## B. Electron Heights – Enumclaw 55/115kV Conversion Project

**Q. Please describe the Electron Heights – Enumclaw 55/115kV Conversion project.**

A. The Electron Heights – Enumclaw 55/115kV Conversion project ("Electron Heights – Enumclaw") is primarily located in the Wilkeson and Buckley areas of Pierce County and Enumclaw area of King County. The Electron Heights – Enumclaw project consists of converting the 22-mile existing Electron Heights – Stevenson 55kV transmission line to a 115kV transmission line and 0.5 mile of existing transmission between Stevenson and the Enumclaw substation. This will require upgrading the 55kV breaker at the Electron Heights substation to 115kV, rebuilding the transmission side of the Wilkeson substation to 115kV infrastructure, relocating the Buckley substation to be rebuilt at 115kV, and adding a new deadend tower and circuit switcher at the Enumclaw substation to allow for the new loop through. Exh. RBB-6 contains the CSA for the Electron Heights – Enumclaw project.

**Q. Is the Electron Heights – Enumclaw 55/115kV Conversion operating and providing service to customers?**

A. No.

**Q. What is the timeline for Electron Heights – Enumclaw 55/115kV Conversion project?**

A. This project was initiated in 2008. The first phases consisted of rebuilding the transmission line for 115kV between the Electron Heights substation and

Stevenson switching station. The remaining substation and transmission upgrades to be completed in the final phase were deferred because of budget constraints. The project was started again in 2017 evaluating location alternatives for the Buckley substation and Enumclaw area alternatives with respective jurisdictions. The project is currently working through the permitting process and easement acquisition with construction scheduled to start in 2022 and be completed by the end of 2024.

**Q. What is the final projected cost of the Electron Heights – Enumclaw 55/115kV Conversion project?**

A. The expected final cost of the final phase of the project is $21.2 million without AFUDC.

**Q. Describe the system need for Electron Heights – Enumclaw 55/115kV Conversion project.**

A. There are several needs for this project. First, this project will support capacity needs for the Krain Corner substation and eliminate overloading existing 115kV to 55kV transformers at Krain Corner and Electron Heights and the White River – Krain Corner 55kV transmission line in certain outage conditions. Second, this will remove aging infrastructure from various substations including the Electron Heights, Wilkeson, and Buckley substation transformers. Finally, the project brings increased reliability for the Enumclaw and Buckley areas by 1) providing a 115kV loop to the Enumclaw substation opposed to current radial service and 2) installing 115kV midline breakers at the new Buckley substation with communications to Krain Corner to improved fault isolation and clearing times for the Buckley area.

**Q. Describe the alternatives evaluated and how this solution was chosen.**

A. Six alternatives, including the selected alternative, were evaluated. PSE's solution criteria required all identified needs be addressed.

1. **Convert Electron Heights – Enumclaw from 55kV to 115kV** – This alternative was selected because it is the least cost alternative (estimated $11-15 million) that meets the capacity needs for the Krain Corner substation.

2. **Convert White River – Krain Corner 55kV to 115kV** – This alternative was rejected because it was a larger cost alternative (estimated $30-40 million) due to jurisdictional requirements for a seven-mile section of the line.

3. **Build a new 115kV transmission line between Berrydale and Krain Corner substations** – This alternative was rejected because it was a larger cost alternative (estimated $35-50 million) due to construction of 19.7 miles of new transmission line and upgrades to various substations.

4. **Build new substation west of Buckley substation and install a three winding transformer to provide 115kV** – This alternative was rejected because it did not fully meet project needs and it was a larger cost alternative (estimated $24-48 million) due to building two new transmission line segments and new substation.

5. **Install new 115/55kV transformer at Krain Corner and Electron Heights** – This alternative was rejected because PSE is working to eliminate 55kV infrastructure from the system.

6. **Do nothing** – This alternative was rejected because of possible future conflicts with NERC compliance and continued risk of outages for customers.

**Q. What benefits does Electron Heights – Enumclaw 55/115kV Conversion provide for customers?**

A. This project will increase reliability for the 9,962 customers served by the line in the various areas. The overload scenarios required at Krain Corner that result in an outage for 29,000 to 45,000 customers will be eliminated with this project.

**Q. Describe how PSE kept management informed during this project.**

A. Using PSE's Project Lifecycle Model, management provided review and approval of the project. This project was reviewed by management in April 2014 to proceed to the design phase. The project was reviewed by management in May 2020 for scope updates. The project was reviewed by management in January 2022 to proceed to the execution phase.

**Q. Describe the current state of the Electron Heights – Enumclaw 55/115kV Conversion.**

A. The project is currently in the execution phase of the Project Lifecycle Model. PSE is acquiring permits and easements consistent with the designs for anticipated construction and in service in 2024.

## C. Bainbridge Island Project

**Q. Please describe the Bainbridge Island project.**

A. The Bainbridge Island project is located on Bainbridge Island in Kitsap County. The Bainbridge Island project consists of three components that address each of the identified system needs separately: First, constructing a 115kV transmission line between the Winslow and Murden Cove substations with upgrades at each station that allow for the new transmission interconnection; second, rebuilding the existing 4.5 mile Winslow Tap 115kV transmission line; third, installation of an approximate 3.3 MW 5MWh energy storage battery and implementation of an approximate 3.3 MW distributed energy resource portfolio. Exh. RBB-7 contains the CSA for the Bainbridge Island project.

**Q. Is the Bainbridge Island project operating and providing service to customers?**

A. No.

**Q. What is the timeline for the Bainbridge Island project?**

A. This project was initiated in 2019. The project is currently working through design and preparing for easement acquisition and permit submittals. The Winslow Tap replacements are scheduled to be completed by the end of 2023. The energy storage battery and distributed energy resources are scheduled to be completed by the end of 2023. The new transmission line between the Winslow and Murden Cove substations is scheduled to be completed by the end of 2025.

**Q. What is the projected final cost of the Bainbridge Island project?**

A. The expected final cost of the project is $48.82 million without AFUDC.

**Q. Describe the system need for the Bainbridge Island project.**

A. There are several needs for this project. First, the Winslow Tap transmission line was built in 1960 with wishbone crossarm construction. PSE has started to see wishbone crossarms of similar vintage failing in other parts of PSE's service area and considers this type of construction to be a reliability risk. An inspection of this transmission line in early 2019 indicated that nearly half of the wishbone crossarms will require replacement. Second, two of the three substations on Bainbridge Island, the Winslow and Murden Cove substations, are radially fed substations with no operating flexibility at the transmission level and no back up feed. When managing transmission outages to either of these two substations, customers are switched to adjacent substations. This switching is time consuming and complex. During winter when customer demand is highest, some customers on the affected transmission line and its substation may not be transferred and can experience extended outages. Third, Bainbridge Island and the north Kitsap County substations are at the end of the transmission system serving the Kitsap peninsula. Studies of various contingencies in compliance with federal reliability requirements have found that certain multiple contingencies on the transmission system off-island on Kitsap peninsula may cause low voltage or overloading of the transmission lines on the peninsula. Under such contingencies, PSE may be forced to shed load by de-energizing some or all of Bainbridge Island substations. Finally, a distribution substation group capacity need of 14.6MW was identified on Bainbridge Island within the 10-year planning horizon to support general load growth of 4.6 MW.

**Q. Describe the alternatives evaluated and how this solution was chosen.**

A. Several alternatives were evaluated and classified in three categories: conventional wires alternatives, non-wires alternatives, and hybrid alternatives.

Of these three categories, the best solutions were evaluated in-depth, including the selected alternative. PSE's solution criteria required all identified needs be addressed.

1. **Wires Alternative** – This alternative included rebuilding Winslow Tap transmission line, constructing a 115kV transmission line between Winslow and Murden Cove substations, and building a new 25MVA substation in south Bainbridge Island. This alternative was not selected because it cost more, required building a substation that other alternatives did not require, and possibly over-built capacity needs.

2. **Non-Wires Alternative** – This alternative consisted of five batteries to be installed at locations around Bainbridge Island. This alternative was not selected because of the higher cost relative to other alternatives.

3. **Hybrid Solution** – This alternative included a new transmission line between Murden Cove and Winslow substations, a battery sized to meet 50% of the capacity needs, and rebuilding the Winslow Tap 115kV transmission line. This alternative was selected because it is the least cost alternative that addresses reliability issues, provides transmission operation flexibility on Bainbridge Island by making the Murden Cove and Winslow substations no longer radial substations, and addresses distribution capacity with a non-wires alternative.

4. **Do nothing** – This alternative included only replacing aging infrastructure on the Winslow Tap transmission line because of safety and overall reliability considerations. This alternative was not selected because it does not address future capacity needs of Bainbridge Island and does not address the transmission reliability need of the Winslow Tap. Customers fed from this station will continue to see a high frequency of interruptions from the transmission source. With the limited group capacity operating flexibility this load cannot be shifted to other substations resulting in lengthy outages.

**Q. What benefits does the Bainbridge Island project provide for customers?**

A. This project will increase the reliability for customers on Bainbridge Island. The Winslow substation has experienced 21 transmission outages in a five-year test period between 2013 and 2017. Fifteen of those outages involved loss of radial transmission taps serving Winslow and Murden Cove substations, with the loss of

Winslow Tap transmission line as the primary cause. Rebuilding this line and redundancy of connecting the Winslow and Murden Cove substations will dramatically reduce the number of outages. The added capacity will meet load growth for Bainbridge Island.

**Q. Describe how PSE kept management informed during this project.**

A. Using PSE's Project Lifecycle Model, management provided review and approval of the project. This project was reviewed by management in November 2019 to proceed to the planning phase. The project was reviewed by management in June 2021 for scope, schedule and cost updates. The Winslow Tap rebuild was approved by management to proceed to the design phase in June 2021.

**Q. Describe the current state of the Bainbridge Island project.**

A. The Winslow Tap upgrades are currently in the design phase of the Project Lifecycle Model, preparing final designs and preparing for permit submittals and easement acquisition. The energy storage battery and distributed energy resources are in the planning phase preparing initial designs. The new transmission line between the Winslow and Murden Cove substations is in the planning phase and recently completed the route selection process.

## D. Tono Substation Project

**Q. Please describe the Tono Substation project.**

A. The Tono Substation project is located near Centralia in Lewis County. The Tono Substation project consists of replacing the four single 500/115kV transformers with two new three phase 500/115kV transformers. One transformer has already exceeded allowable hydrogen levels and is currently offline to prevent service failure, and the other two transformers are projecting failure within five years. The project will also replace two 115kV oil circuit breakers and electromechanical relays within Tono substation. Exh. RBB-8 contains the CSA for Tono Substation project.

**Q. Are the upgrades to the Tono Substation operating and providing service to customers?**

A. No.

**Q. What is the timeline for the Tono Substation project upgrades?**

A. The Tono Substation project started evaluating project needs in 2019. Since 2020, the project team has been working on material procurement, design, and permitting. The project is scheduled to be placed in service in 2022.

**Q. What is the expected final cost of Tono Substation project?**

A. The expected final cost of the project is $17 million without AFUDC.

**Q. Describe the system need for the Tono Substation project.**

A. The Tono 500/115kV transformers serve as PSE's only Extra High Voltage ("EHV") source into the Thurston County South region and is one of three EHV sources supporting Thurston County. Sustained outages of the Tono substation EHV source can significantly degrade reliability, resiliency, and operability of Thurston County and neighboring electric systems. The Tono substation has additional maintenance concerns due to aged infrastructure equipment operating beyond their recommended service life.

**Q. Describe the alternatives evaluated and how this solution was chosen.**

A. Nine alternatives, including the selected alternative, were evaluated. PSE's solution criteria required all identified needs be addressed.

1. **Replace failing transformer with one in-kind transformer** – This alternative consisted of replacing the failing transformer with one new or used in-kind transformer. This option was rejected because of the difficulty of matching the existing transformer impedance and requires a custom order to match the impedances. This option was also rejected because it did not support the long-term holistic solution strategy, as the two other transformers are showing signs of failure with an estimated five years or less of remaining service life.

2. **Replace failing transformer with one in-kind transformer and purchase and store a spare in-kind transformer** – This alternative consisted of replacing the failing transformer with one new or used in-kind transformer and purchasing a second new or used unit to store as a spare in-kind transformer. This option was rejected because of the difficulty of matching the existing transformer impedance. In addition, this alternative did not support the long-term holistic solution strategy, as the two other transformers are showing signs of failure with an estimated five years or less of remaining service life.

3. **Replace with four in-kind single-phase transformers** – This option consisted of replacing the existing transformers with four new single phase in-kind transformers, with one being a non-connected spare. This option was not selected because of the slightly higher costs and design and construction issues related to clearance requirements for the configuration of three transformers within the existing layout of the substation.

4. **Replace failing transformers with two new 500/115kV transformers** – This option consisted of replacing the existing single-phase transformers with two new three phase transformers with one being a non-connected spare. This option was the preferred option because it replaces all aging infrastructure. It is a lower cost alternative and is a more feasible design and construction configuration given the existing layout of the substation. This option also supported the long-term holistic solution strategy.

5. **Replace failing transformers with two three phase 500/230kV transformers and one three phase 230/115kV transformer** – This option consisted of replacement with two new three-phase 500/230kV transformers with one being a non-connected spare and a used or new three phase 230/115kV transformer. This option was not selected due to higher costs and the extensive rebuild necessary to add a 230kV section with physical constraint concerns, including spacing limitations and topological concerns.

6. **Acquire and connect to BPA Big Hanaford Substation** – This option included acquiring BPA's Big Hanaford substation, which is currently de-energized, and interconnecting the substation to the existing Transalta 500kV transmission line to Centralia 500kV switching station. A 500/230kV transformer would be added at Big Hanaford substation and a new 0.7 mile, 230kV transmission line built from Big Hanaford Substation to Tono Substation. A 230/115kV transformer would be installed at Tono Substation. This option was rejected because of the elevated cost and nine-year estimated project schedule.

7. **Add a three phase 230/115kV transformer at Tono substation and add double circuit 230kV transmission line tap to existing Transalta 230kV transmission line** – This option consists of looping the Transalta 230kV transmission line into Tono Substation with two 0.5-mile 230kV transmission lines and adding a 230/115kV transformer to Tono Substation. A reconductor of 2.2 miles of the Transalta 230kV line would be necessary to increase its capacity rating for this connection. This option was rejected because of the capacity deficiencies, an extended three to five year estimated schedule, and higher cost.

8. **Connect to Transalta 230kV Startup Substation at Centralia Generating Station** – This option consisted of connecting a 0.9-mile 230kV transmission line from Tono Substation to the existing Centralia Generating Startup substation. A reconductor of 2.5 miles of Transalta's transmission line from the Startup Substation to the existing tap point on BPA's Chehalis – Covington 230kV transmission line would be needed to increase the capacity rating. This option was rejected because of the capacity deficiencies, an extended three to five year estimated schedule, and higher cost.

9. **Add 500/230kV transformer at Transalta Centralia 500kV switching station and add 230kV transmission line to Tono substation** – This option consisted of acquiring land next to Transalta's Centralia 500kV Switching Station to expand the Transalta Centralia 500kV substation and add a new 500/230kV transformer there and add a 230/115kV transformer at Tono Substation. A new 0.5-mile 230kV transmission line would be run from the Tono Substation to the existing Centraila Switching Station. This

option was rejected because of the extended 15+ year estimated project schedule due to needing to go through Transalta's interconnection process and higher cost.

**Q. What benefits does Tono Substation upgrades provide for customers?**

A. The Tono substation serves as PSE's EHV for the southern region of Thurston County. This provides reliability for approximately 40,000 customers. Similarly, Tono substation serves as one of three PSE EHV sources for Thurston County. The upgrades provide improved reliability for approximately 129,000 customers.

**Q. Describe how PSE kept management informed during this project.**

A. Using PSE's Project Lifecycle Model, management provided review and approval of the project. This project was reviewed by management in August 2020 to proceed to the planning phase. The project was reviewed by management in June 2021 for budget updates.

**Q. Describe the current state of the Tono Substation project.**

A. The project is currently in the planning phase of the Project Lifecycle Model, where PSE is preparing designs and permit submittals.

## E. Lynden Substation

**Q. Please describe the Lynden Substation project.**

A. The Lynden Substation project is located in the City of Lynden in Whatcom County. The Lynden Substation project consists of expanding the substation footprint and rebuilding the substation, adding a 115kV circuit breaker for the

BPA Bellingham – Lynden transmission line. Exh. RBB-9 contains the CSA for the Lynden Substation project.

**Q. Is the Lynden Substation project operating and providing service to customers?**

A. No.

**Q. What is the timeline for Lynden Substation project?**

A. The Lynden Substation project started evaluating project needs in 2019. Since 2020, PSE has been working on project design and evaluating permitting requirements. The project is scheduled to be placed in service in 2024.

**Q. What is the expected final cost of Lynden Substation project?**

A. The expected final cost of the project is $9.6 million without AFUDC.

**Q. Describe the system need for Lynden Substation project.**

A. There are several needs for this project. First, there are several pieces of equipment that are beyond their economic life and in need of replacement. Second, the BPA Bellingham – Lynden transmission line terminating at the Lynden substation does not terminate at a circuit breaker. Without a circuit breaker on this line, a fault on this 5.8-mile line segment results in a full station outage at Lynden. Third, the unique layout of the substation and physical spacing constraints would require an extended period of time for replacement of the Bank #2 transformer and regulator because there is not enough space in the present configuration as well as challenging crews' ability to work efficiently and safely.

Finally, there are distribution reliability and operation concerns at the station, as there is no bus tie switch between the two 12.5kV feeder structures and substation controls are spread between two control houses.

**Q. Describe the alternatives evaluated and how this solution was chosen.**

A. Seven alternatives, including non-wires alternatives, were evaluated. This includes the selected alternative. PSE's solution criteria required all identified needs be addressed.

1. **Improvements on existing site** – This option evaluated the existing site for how much improvement could be obtained without expanding the substation site. This option was rejected because of space limitations in the existing substation, it is not possible to address replacing Bank #2 and install a 115kV circuit breaker for the BPA Bellingham – Lynden transmission line.

2. **Expand and rebuild substation with 115kV main bus and install one metalclad feeder** – This option expands the substation footprint for upgrading the substation with an open-air 115kV bus. This option was rejected because it did not provide the reliability benefits of two metalclad alternatives while having similar cost requirements.

3. **Expand and rebuild substation with 115kV main bus and install two metalclad feeders** – This option expands the substation footprint for upgrading the substation and replaces both open air feeder structures with metalclad switchgear. This alternative was selected because it was the lowest cost alternative that met reliability and operability concerns with replacement of aging infrastructure.

4. **Expand substation with 115kV ring bus and two metalclad feeders** – This option expands the substation footprint for installing a 115kV ring bus and two metalclad feeders. This alternative was rejected because of the cost impacts related to expanding the substation beyond other alternatives.

5. **New substation at new site with 115kV ring bus and 2 metalclad feeders** – This option included relocating the substation to a new site located within one mile of the existing substation. This alternative was rejected because of the cost and schedule risks of finding an alternative site and relocating the existing transmission and distribution systems.

6. **Remove transformer, perform distributed energy resources measures and reduced scope of work in existing substation footprint** – This non-wires alternative was rejected because of the increased costs associated with the solution.

7. **Do nothing** – This option consists of replacing the Bank #2 transformer upon failure. This will require an extended outage for the work to enable proper installation of the equipment to integrate a load-tap-changing transformer. This option was rejected because it did not provide a circuit breaker on the BPA Bellingham – Lynden transmission line, address other aging infrastructure within the station, or substation operating limitations.

**Q. What benefits does the Lynden Substation project provide for customers?**

A. The project will improve reliability for the 6,300 customers served by the Lynden substation and reduce risks for momentary or sustained outages to another 15,700 customers in northern Whatcom County.

**Q. Describe how PSE kept management informed during this project.**

A. Using PSE's Project Lifecycle Model, management provided review and approval of the project. This project was reviewed by management in January 2021 to proceed to the planning phase. The project was reviewed by management in June 2021 for funding updates.

**Q. Describe the current state of the Lynden Substation project.**

A. The project is currently in the planning phase of the Project Lifecycle Model, preparing initial designs and evaluating permitting requirements.

## F. Sedro Woolley – Bellingham #4 115kV

**Q. Please describe the Sedro Woolley – Bellingham #4 115kV project.**

A. The Sedro Woolley – Bellingham #4 115kV Reconductor Transmission Line project ("Sedro #4") is located in western Whatcom and Skagit Counties serving Burlington and Sedro Woolley. Sedro #4 consists of rebuilding and reconductoring the existing 24-mile-long Sedro Woolley-Bellingham #4 115 kV line. The line helps connect the Skagit County and Whatcom County 115 kV systems together and directly feeds two distribution substations, Alger and Norlum. To coordinate concurrent distribution system upgrades, this project will be constructed in five phases: Phase A, which was completed in February 2018, included approximately four miles of the line in Skagit County; Phase B, which was completed in December 2018, included approximately seven and a half miles of the line in Skagit County; Phase C includes approximately six miles of the line in Skagit and Whatcom Counties; Phase D includes approximately six miles of the line in Whatcom County; and Phase E includes rebuilding the final a half mile of the line in Skagit County. Exh. RBB-10 contains a Mid-Phase Change Request prior to project deferment in 2019.

**Q. Is Sedro #4 operating and providing service to customers?**

A. Partially. Phases A and B are operating and providing service to customers. Phases C, D and E are not.

**Q. What is the timeline for Sedro #4?**

A. The Sedro #4 project was initiated in 2010. Phase A was constructed and placed in service February 2018. Phase B was constructed and placed in service December 2018. In 2019 and 2020, the remaining phases were deferred for higher priority reliability and capacity projects. The project team is working on evaluating existing designs prior to acquiring remaining permits and easements. Phase C construction is planned to be completed and in service in 2024. Phases D and E are planned to be constructed and in service in 2025.

**Q. What is the estimated final cost of Sedro #4?**

A. The expected final cost of the project is approximately $23 million without AFUDC. The $8 million costs associated with Phases A and B were recovered in the 2017 and 2019 general rate cases.

**Q. Describe the system need for Sedro #4.**

A. There are several needs for this project. First, the low capacity line ratings could cause the line to exceed its allowable ratings for several contingencies and limit generation capacity in Whatcom and Skagit Counties. The small copper wires also could cause high line losses and the aging infrastructure would lead to extended outages. Second, the low capacity of the Bellingham-Sedro Woolley #4 line has caused constraints on regional power flows for over twenty years due to the parallel higher-voltage transmission line, which requires PSE to protect the line from overloading by automatically opening the Sedro Woolley substation circuit breaker. Opening this circuit breaker reduces system reliability in both Whatcom and Skagit Counties, including the Norlum and Alger substations. Customers served by Norlum and Alger substations are at an increased risk of outage during this time as each substation has only one transmission source. Third, the aged equipment of the line contributed to 27 momentary outages and four sustained outages in the five years prior to construction of Phases A and B.

**Q. Describe the alternatives evaluated and how this solution was chosen.**

A. Three alternatives, including the selected alternative, were evaluated. PSE's solution criteria required all identified needs be addressed.

1. **Rebuild the 115 kV transmission lin**e – This alternative was selected because it addressed both the capacity deficiency and the reliability problems related to the aging infrastructure for the most economical cost. This option includes replacing all of the aging wood poles and reconductoring the line to a larger conductor size.
2. **Maintain existing transmission line, replace aging transmission poles and keep Corrective Action Plan ("CAP")** – This alternative was rejected because it does not decrease the number of line outages, results in increased maintenance activities and costs, and does not address line overloading issues.
3. **Build a new 115 kV transmission line** – This alternative was rejected because of its high cost from purchasing land and easements for a new right-of-way and the associated permitting challenges with a new right of way. In addition, this alternative did not address the aging infrastructure of the existing transmission line.

**Q. What benefits does Sedro #4 provide for customers?**

A. Replacement of the aging infrastructure reduces the likelihood of unplanned customer outages for the 6,240 customers served by Norlum and Alger substations. Similarly, with the increased line capacity, PSE will be able to remove an automatic tripping scheme that opens the south end of the line when system events cause the line to overload, which decreases exposure of the customers to subsequent line outages and strengthens the transmission system between Whatcom and Skagit Counties.

**Q. Describe how PSE kept management informed during this project.**

A. Using PSE's Project Lifecycle Model, management provided review and approval of the project. This project was reviewed by management in February 2011 for the substation work to proceed to the design phase. The transmission line work was approved to proceed to the design phase in June 2014. The project budget was reviewed and approved by management in June 2015, October 2018, and June 2019.

**Q. Describe the current state of the Sedro #4 project.**

A. The project is currently in the design phase of the Project Lifecycle Model for Phases C, D and E, evaluating existing designs prior to acquiring remaining permits and easements.

## G. Vashon – Gig Harbor Long Term Solution Project

**Q. Please describe the Vashon – Gig Harbor Long Term Solution project.**

A. The Vashon – Gig Harbor Long Term Solution project ("Marine Crossing") is located between Des Moines, Gig Harbor, and Vashon Island. Currently, there is a single gas supply from the mainland that serves customers on Vashon Island and in Gig Harbor. This single feed includes two subsea marine crossings of parallel pipelines that run approximately 11,000 feet from Des Moines underwater to Vashon Island (the East Passage), and 9,000 feet from Vashon Island underwater to Gig Harbor (the Colvos Passage). These pipelines were designed and installed to rest on the seafloor. Sections of unsupported pipeline have occurred as a result of seafloor movement and third-party analysis has indicated that the pipelines may be approaching the end of their useful lives. The Marine Crossing project consists of implementing a long-term supply to customers on Vashon Island and the Gig Harbor area. Exh. RBB-11 contains the CSA for the Marine Crossing project.

**Q. Is the Marine Crossing operating and providing service to customers?**

A. No.

**Q. What is the projected timeline for the Marine Crossing project?**

A. The Marine Crossing project was approved by management for the planning phase in June 2020. Since 2020, PSE has engaged in a needs assessment and the evaluation of solution alternatives. The long-term solution is anticipated to be placed in service by 2026.

**Q. What is the current lifetime cost estimate of the Marine Crossing project?**

A. The current lifetime cost estimate of the project is $35.3 million without AFUDC.

**Q. Describe the system need for the Marine Crossing project.**

A. A third-party analysis showed that tidal flow around the exposed pipelines originally installed in 1969 may induce stresses that ultimately lead to failure of the pipe. The analysis recommended that PSE further assess pipeline conditions and develop a plan of ensuring long-term gas supply to existing customers.

Damage to the pipeline could result in sustained outages for customers on Vashon Island and Gig Harbor.

**Q. Describe the alternatives being evaluated.**

A. Various alternatives are being evaluated between replacement and reinforcement, alternative routing, and non-pipe solutions to address the long-term needs. A preferred alternative has not yet been finalized. PSE's solution criteria require that all identified needs are addressed.

**Q. What benefits does the Marine Crossing project provide for customers?**

A. The completion of a solution will reduce risk of disruption to natural gas supply to PSE's existing customers thereby increasing reliability of natural gas service for 13,000 customers.

**Q. Describe how PSE kept management informed during this project.**

A. Using PSE's Project Lifecycle Model, management provided review and approval of the project. This project was reviewed by management and approved in June 2020 to proceed to the planning phase. The project was reviewed and approved by management in April 2021 for budget updates.

**Q. Describe the current state of the Marine Crossing project.**

A. The project is currently in the planning phase of the Project Lifecycle Model. PSE is analyzing alternatives for a long-term solution while completing technical feasibility analyses and designs.

## V. CONCLUSION

**Q. Does this conclude your testimony?**

A. Yes, it does.