EXH. RBB-1T
DOCKETS UE-240004/UG-240005
2024 PSE GENERAL RATE CASE
WITNESS: ROQUE B. BAMBA

BEFORE THE
WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION

WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION, **Complainant,** **v.** **PUGET SOUND ENERGY,** **Respondent.**	**Docket UE-240004** **Docket UG-240005**

PREFILED DIRECT TESTIMONY (NONCONFIDENTIAL) OF

ROQUE B. BAMBA

ON BEHALF OF PUGET SOUND ENERGY

FEBRUARY 15, 2024

PUGET SOUND ENERGY

PREFILED DIRECT TESTIMONY (NONCONFIDENTIAL) OF ROQUE B. BAMBA

CONTENTS

PUGET SOUND ENERGY

PREFILED DIRECT TESTIMONY (NONCONFIDENTIAL) OF ROQUE B. BAMBA

LIST OF EXHIBITS

PUGET SOUND ENERGY

PREFILED DIRECT TESTIMONY (NONCONFIDENTIAL) OF ROQUE B. BAMBA

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, Vegetation Management, Construction Performance Management, 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 System Planning, Engineering, Finance, Accounting, and Regulatory, so projects and programs are well-coordinated across the Company.

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

A. First, 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 during PSE's operations, such as unanticipated weather events, new economic development needs, and emerging public policy priorities.

Second, I describe how PSE's project and program management methodology applies in practice by discussing certain major projects in greater detail. I explain the differences in project and program profiles and the need for limited and reasonable modifications to PSE's general project and program management methodology. I illustrate PSE's need for flexibility in applying project and program management structures and in utilizing capital and operating and maintenance budgets to fulfil PSE's public service obligations over the multiyear rate plan. This flexibility is crucial for PSE to provide safe and reliable utility service.

Third, I demonstrate how PSE has complied with the requirements of the multiparty settlement approved in PSE's last general rate case, Dockets UE-220066/UG-220067 et al. ("2022 General Rate Case"), regarding PSE's Advanced Metering Infrastructure ("AMI") investment, and why full recovery of PSE's remaining AMI investment is now appropriate. PSE is requesting final recovery of all remaining investments in its AMI program, including its full return on that investment.

Lastly, I describe the Bainbridge Island and Sedro Woolley – Bellingham #4 115kV Reconductor Transmission Line major projects that will be placed in service during the multiyear rate plan. I explain how the projects are prudent and why recovery for these projects is appropriate.

II. PSE'S DELIVERY SYSTEM EXECUTION PROCESS

A. Overview

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. PSE's System Planning organization, led by David J. Landers, is responsible for monitoring, identifying, and analyzing Delivery System needs and planning solutions. Mr. Landers describes PSE's Delivery System Planning process in his Prefiled Direct Testimony, Exh. DJL-1T. For planned work by the Delivery System Planning organization, PSE's Project Delivery organization, which I oversee, is responsible for executing Delivery System plans and performing project and program management to deliver plans on schedule, scope, and budget.

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

A. PSE defines a "project" as a limited task undertaken to provide a unique service or result. Projects are temporary and typically end 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 generally not available from managing them individually.

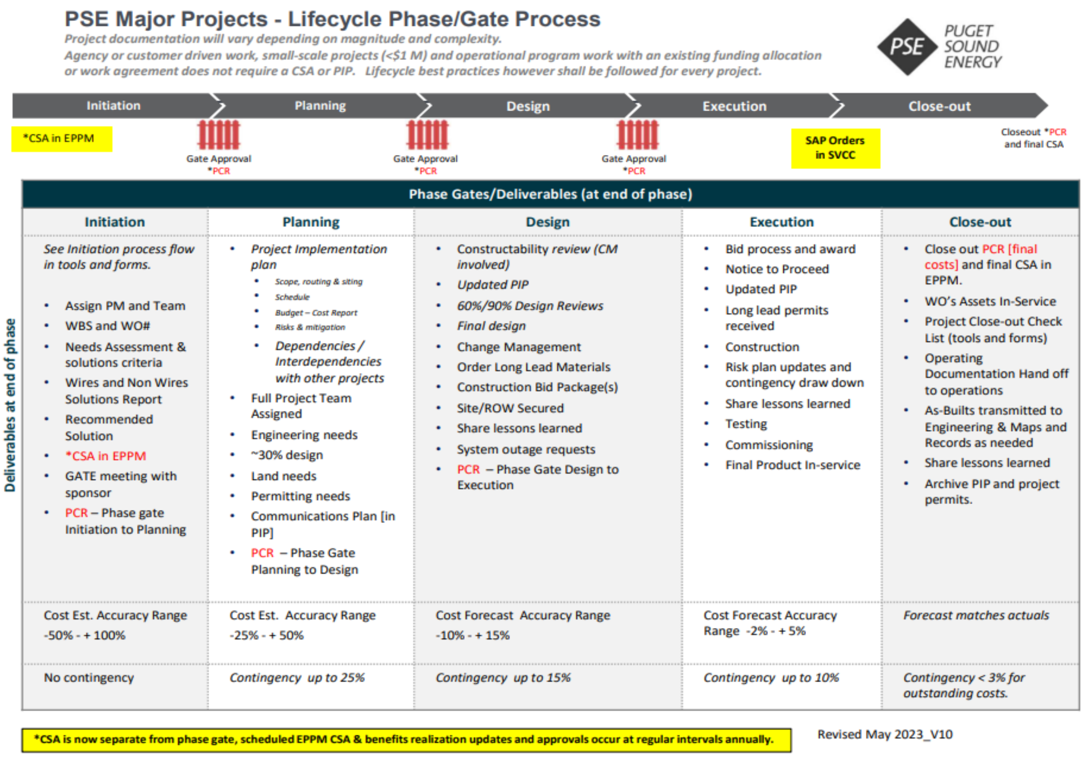
<u>B. Project and Program Methodology</u>

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

A. Generally, most projects follow a similar process with varying degrees of complexity. At a high level, a project manager is assigned to the project and manages it from inception through closeout. This project manager oversees the "triple constraints" of schedule, cost, and scope, coordinating with external and internal team members across engineering, procurement, and construction. The project manager and team members orchestrate designs developed by engineers which are peer reviewed and approved for compliance with standards, accuracy, and cost effectiveness. Designs are reviewed so that identified constructability challenges are proactively addressed prior to the start of construction. Project managers deploy construction management personnel to monitor compliance with the engineering design and address field issues that arise.

PSE's project management process follows industry best practices 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 and provide a governance model for managing a wide range of infrastructure projects. 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.



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

A. Generally, for programmatic work, a program manager is assigned to a collection of projects. They oversee delivery of program objectives over the many specific individual projects, applying the same project management principles described above. To maximize benefits for customers and to adapt to changes, programs are managed around core objectives, allowing for risk-based adjustments of projects within a core objective and across years. 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.

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, such as the Project Management Institute, which is a professional association for project professionals worldwide and a leading authority on project management approaches. The Project Management Institute 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 Project Management Institute 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, contractor performance meets or exceeds expectations, and benefits that result from the Company's investments are optimized. 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, decisions can be made, and issues can be addressed quickly and efficiently.

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. 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. 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 Baker River Hydro re-grouting project is a major capital project with sophisticated engineering needs and correspondingly complex procurement and contractor oversight requirements. Please see the Prefiled Direct Testimony of James P. Hogan, Exh. JPH-1CT, who provides an update regarding PSE's plans concerning the refurbishment of the

Baker River Hydro facility in his testimony. Such projects receive additional scrutiny and management attention, as needed for the project.

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-1CT, 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 respond to unexpected events quickly and effectively 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. Can you provide an example?

A. In 2023, Infrastructure Program Management collaborated across programs to maximize resource productivity, efficiency, and benefits realization. For example, instead of the Substation Reliability projects annual portfolios being comprised of only the highest value construction-ready projects in a given year, all work in a given substation was considered as a comprehensive construction work package. By doing so, PSE was able to complete 114 percent more substation work in 2023 than in 2022 by completing all planned work at a given substation in a single mobilization.

Q. Please describe program management cost controls.

A. Infrastructure Program Management conducts budgetary conceptual cost estimates prior to design, and design-based estimates at 90 percent design, prior to permitting and easement acquisition.

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.

Q. Please describe Program Management schedule controls.

A. Managing individual project and program schedules is important for logistics, portfolio management, and budget forecasting. Most projects are tracked using a Gantt format schedule which lists the major task start and end dates which allows for the effective tracking of multiple projects in one document. Schedule controls must also manage plant closings timely as customer rates have been set based on scheduled plant closing plans as described by PSE witnesses Susan E. Free, Exh. SEF-1T and Joshua A. Kensok, Exh. JAK-1CT. PSE program managers monitor plant closing reports every month to review what has been closed and where closing schedule changes may occur to manage the portfolio as effectively as possible.

Q. Please describe program management benefit realization controls.

A. Program management establishes a scorecard of projects to complete and a subset of contingency projects each year to ensure enterprise targets are met. Program schedules and status reports are regularly published which allow management and stakeholders to make risk and opportunity-based adjustments throughout the year as the projects advance. Three or more years after commissioning a project, PSE performs improvement verification analysis to determine whether the project provided the projected benefit. To collect enough data for an analysis, investments are typically reviewed three or more years after implementation with a focus on programs that are ongoing. For each project, where data is available, actual performance is compared to projected performance from the project scope. The improvement verification analysis information can be used to adjust predicted benefits for future projects and can help to identify where there might be issues with benefit assumptions, project implementations, system operation, or data accuracy. PSE tracks benefits as investments are executed to inform decisions and make execution or investment adjustments as needed. This backward-looking review informs PSE's ongoing planning process.

Q. Has PSE made any changes to its planning and program management processes since its last multiyear rate plan?

A. Yes. Planning and Program Management have refined our approach to project scoping and pre-design project assessment to ensure that new project scopes, schedules, and forecasts accurately reflect cost trends and project complexities from completed projects in the recent past. Additionally, multi-year portfolio coordination has been expanded to optimize resource efficiency, maximize benefits realization, and improve portfolio flexibility.

C. Equity

Q. Has PSE incorporated equity into its project and program management processes?

A. Yes. Equity in project and program management begins with PSE's Delivery System Planning process. As explained in the Prefiled Direct Testimony of David J. Landers, Exh. DJL-1T, PSE has incorporated equity into its planning processes including:

- Performing system planning to achieve an equitable distribution of benefits and burdens to all customers, including vulnerable populations and highly impacted communities.
- Investments in system reliability and resiliency are evaluated and prioritized utilizing PSE's investment decision optimization tool (iDOT), which has been enhanced to include equity-related costs and benefits.
- Where appropriate, prioritizing emergency repairs in areas of vulnerable populations and highly impacted communities.
- Consulting with PSE's Equity Advisory Group on further incorporating equity into Delivery System Planning processes.

Once Delivery System Planning has determined which projects and programs to pursue (taking into account equity considerations), PSE Project Management then executes on and manages the projects and programs using an equity lens so that the scope, design, schedule, funding, logistics, and communications minimizes potential detrimental effects on vulnerable populations and highly impacted communities. For example:

- PSE utilizes a Geographic Information System (GIS) to identify where PSE's projects will impact communities during alternative analysis and siting phases of a project.

- PSE coordinates with local municipalities to identify opportunities to partner on utilizing the right of way use permit process to improve coordination, reduce traffic impacts, noise, and general disruption in the communities we serve, including and especially vulnerable populations and highly impacted communities.
- For permitting processes that involve public comment and general project communications, PSE is taking measures to help facilitate broader public participation, including providing multilingual materials, and scheduling the time, location and format for public hearings and engagement events so it is reasonably accessible for all.

PSE is committed to executing and managing projects and programs equitably across its customer base. PSE's incorporation of equity into its project and program management processes is ongoing and will continue to evolve and advance over time. Please see the Prefiled Direct Testimony of Troy A. Hutson, Exh. TAH-1T, for further discussion of PSE's equity efforts across the Company.

III. PSE'S AMI DEPLOYMENT IS COMPLETE AND FULL RECOVERY OF ITS AMI INVESTMENT IS WARRANTED

A. AMI Program Background

Q. What is AMI?

A. AMI is a meter reading technology that allows for two-way communication between the meter and a utility. The components of the AMI system include individual meters (for electric) or modules (for gas) which automatically transmit customer energy usage meter reads over a network to the utility. Additionally, AMI technology allows the utility to communicate with the meter, including, for example, to obtain additional usage information or to even turn off a meter. AMI is contrasted with PSE's prior meter reading technology—Automated Meter

Reading ("AMR")—which provided only a one-way energy usage read communication from the meter to the utility. As described in more detail below, the two-way communication capabilities of AMI make it a critical technology in PSE's progression toward achieving its clean energy goals and in complying with clean energy laws, such as the Clean Energy Transformation Act ("CETA").[1]

Q. Please describe PSE's AMI investment.

A. In 2016, PSE began replacing its AMR system with AMI across PSE's electric and gas service territory. PSE started installing the AMI network in 2016 and meter and module replacement started in 2018. PSE completed the last mass deployment meter installation in December 2023. In total, PSE has deployed over 7,400 network devices, and over 1.2 million electric meters and 840,000 gas modules. PSE has invested approximately $456 million[2] in capital in the AMI communication network and metering equipment. An additional $17 million in operations and maintenance expense, mostly associated with the software system that collects meter data and the effort to enable conservation voltage reduction, brings the total investment to $473 million.

Q. Why did PSE transition to AMI?

A. As described in PSE's testimony and supporting documents provided in PSE's 2019 and 2022 General Rate Cases, PSE transitioned from AMR to AMI because

[1] Chapter 19.405 RCW.
[2] Financial numbers are represented as nominal dollars.

PSE's AMR system was obsolete in 2016 and had reached the end of its useful life. PSE's AMR system was installed between 1998 and 2001 with a design life of 15 years. Because of AMR system obsolescence, PSE was experiencing unacceptable system failure and was unable to obtain replacement equipment causing PSE to rely on refurbished equipment which was unreliable and unsustainable. PSE determined that transitioning to AMI would significantly improve meter reliability while saving customers $230 million in avoided capital AMR investment and associated operations and maintenance expense. In addition, transitioning to AMI would provide significant benefits to customers including the ability to expand voltage reduction for energy savings for customers, serve as a foundational technology in grid modernization, and enable customer access to more granular energy use information, among other benefits.

Q. Is the AMI system providing service to customers now?

A. Yes. There is some misconception surrounding when AMI began serving customers. PSE has been providing service to customers with installed AMI equipment on a rolling basis since meter installation began in 2018. Thus, for many customers, the AMI system has been in-service and providing benefits for years. Now that deployment is complete, the AMI system is providing service to all customers across PSE's territory, except for any opt out customers.

B. The 2019 and 2022 General Rate Case Orders on AMI

1. The Commission withheld full rate recovery for AMI in the 2019 General Rate Case.

Q. Did PSE seek recovery for its AMI investment in its 2019 General Rate Case?

A. Yes. PSE requested recovery for the in-service AMI investments installed between October 1, 2016 and December 31, 2018, in its 2019 General Rate Case. PSE submitted testimony and supporting exhibits in that case, describing and documenting the obsolescence of PSE's AMR system, PSE's business decision to implement AMI, and the benefits to customers in transitioning to AMI. PSE demonstrated that PSE's decision to transition from AMR to AMI was prudent, that the portion of the AMI system installed at the time was in service and benefiting customers, and as result, PSE requested full rate recovery for its AMI investment to date.

Q. Did the Commission agree that PSE's decision to transition to AMI was prudent?

A. Yes. The Commission rejected arguments from interveners that PSE prematurely abandoned its AMR system, noting that PSE provided "ample testimony and evidence related to the obsolescence of its AMR system" and "testimony and exhibits documenting its business case, including each of the systems it considered before it elected to install AMI. . . . Therefore, we determine based on the record evidence that the operational decision to install AMI was prudent."[3]

Q. Did the Commission agree with PSE that AMI is the industry standard?

A. Yes. The Commission agreed with PSE that "moving to a smart meter platform has become the industry standard, and the Company is appropriately on pace to keep up with this evolving technology."[4]

Q. Did the Commission allow PSE to recover its AMI investment to date, including a return on that investment?

A. Not entirely. Even though the Commission found that PSE's decision to transition to AMI was "operationally" prudent and the correct decision, the Commission allowed PSE to only recover its AMI investment to date but denied PSE any return on that investment.[5]

Q. Why did the Commission deny PSE a return on its investment?

A. The Commission determined that notwithstanding that PSE made the correct decision to transition to AMI, PSE also needed a plan for achieving certain additional benefits. As explained by the Commission:

> PSE has not yet satisfactorily demonstrated the benefits of the AMI system as a whole. The Company represented at hearing that it is planning to pursue additional benefits, but has yet to put forth any formal plan or proposal. . . . As such, PSE has not yet made a showing that would justify

[3] *WUTC v. Puget Sound Energy*, Dockets UE-190529/UG-190530 et al., Final Order 08/05/03 ¶ 153 (July 8, 2020).
[4] *Id.*
[5] *Id.* ¶ 155.

> authorizing the Company to recover a return on any portion of its AMI investment made thus far.
>
> Going forward, the Commission will evaluate the portion of AMI investment for which PSE seeks recovery in rates, but will require the continued deferral of the *recovery of the return on* each portion of the investment until the AMI project is complete. Our decision recognizes that PSE will not be able to demonstrate a significant portion of AMI benefits until the system is fully deployed. In light of these circumstances, we will reserve a final determination of prudency on the project as a whole until the AMI installation is complete and all customer benefits can be presented for evaluation. The final prudency determination thus rests on PSE's ability to live up to its promises of multiple customer benefits.[6]

Q. What was the Commission's explanation for withholding PSE's ability to earn a return on its AMI investment to date?

A. In the 2019 General Rate Case Final Order, the Commission referenced a *Utility Dive* article which described certain AMI use case benefits that had not been subject to discovery or presented as evidence in the case.[7] The *Utility Dive* article was first referenced by the Commission at the evidentiary hearing. In its Final Order, the Commission conditioned PSE's return on its AMI investment on PSE's ability to achieve the benefits referenced in the article, including:

- Real-time energy use feedback to customers.
- Behavior-based programs with customer feedback and insights.
- Time-of-use rates.
- Program targeting, marketing, and technical assistance using insights from data disaggregation.
- Grid-interactive efficient buildings.

[6] *Id.* ¶¶ 155-56.
[7] *Id.* ¶ 157.

- Conservation voltage reduction or volt/VAR optimization.[8]

Q. Since the 2019 General Rate Case Final Order, has the Commission provided further guidance on rate recovery for an AMI investment?

A. Yes. In the Commission's Final Order in Avista's recent general rate case, Dockets UE-200900/UG-200901 et al. ("Avista General Rate Case"), the Commission provided the following guidance on recovery for AMI investment:

- Maximization of the ACEEE six use cases referenced above, "in addition to further information or metrics that demonstrate AMI's benefits to customers."[9]
- A "substantial" completion of an AMI deployment.[10]
- Demonstration of "a significant portion of benefits," including the ability to "adequately demonstrate or quantify the associated benefits."[11]
- A plan or proposal for achieving the associated benefits.[12]
- "[M]ust be able to present all customer benefits for evaluation, not that all customer benefits must have already been realized. We also refrain from such unrealistic expectations that a utility must demonstrate all benefits that might be realized by AMI in the future before recovery on its investment in rates."[13]
- A description of any unquantifiable benefits.[14]
- "Develop and report further analyses of the use cases," "[c]raft and report plans for achieving benefits through application of each of the use cases, above," and "[d]evelop and propose AMI performance-based regulation metrics and measurements that the Commission might apply, and

[8] *Id.*
[9] *WUTC v. Avista Corp.*, Dockets UE-200900/UG-200901 et al., ¶ 218 (Sept. 27, 2021).
[10] *Id.* ¶ 222.
[11] *Id.* ¶ 223.
[12] *Id.* ¶ 224.
[13] *Id.* ¶ 225.
[14] *Id.* ¶ 226.

specifically such metrics and measurements for each of the use cases, above."[15]

Q. Since the 2019 General Rate Case and the Avista General Rate Case, has PSE taken measures to comply with the Commission's requirements as described in those cases?

A. Yes. As described in more detail below, PSE has worked diligently to complete deployment of the AMI system on time and on budget and to maximize its use of AMI, consistent with the Commission's direction.

2. <u>In its 2022 General Rate Case, PSE agreed to defer final recovery of AMI until the current case.</u>

Q. Did PSE request full recovery of its AMI investment to date in its 2022 General Rate Case?

A. Yes. Based on the framework set forth by the Commission in the 2019 General Rate Case and in the Avista General Rate Case described above, in its 2022 General Rate Case, PSE presented significant testimony and supporting evidence demonstrating that it had met the Commission's requirements for fully recovering its AMI investment to date, including:

- **"Substantial" deployment.** At the time of its 2022 General Rate Case filing, the AMI network was fully installed and over 1.1 million PSE customers were using AMI meters and modules to measure their energy use. For perspective, at that time, PSE had installed more than *2.5 times* the AMI assets that Avista had installed when it was allowed to recover on its AMI investment.
- **Customer benefits.** PSE's testimony and exhibits demonstrated that the AMI system was already benefiting PSE customers including reductions

[15] *Id.* ¶ 228.

in operations and maintenance expense, reductions in power costs, and the avoided benefit of expensive AMR obsolescence costs. Experts from the Brattle Company also provided a benefits report describing and projecting the benefits that would be realized from 38 AMI benefit use cases, including the benefits referenced in the *Utility Dive* article. This includes both quantifiable and non-quantifiable benefits.

- **Plan for achieving benefits.** PSE provided a detailed plan and timeline for further maximizing the benefits identified.
- **Performance metrics.** PSE also provided performance-based metrics and measurements that the Commission might apply.

Q. Based on the above, was full recovery of AMI investment to date, including return on its investment, appropriate?

A. Yes. At the time of its 2022 General Rate Case filing, based on the above, PSE had met the Commission's requirements for earning a full return on its AMI investment to date.

Q. Why else did PSE believe that full recovery of its AMI investment to date was appropriate?

In addition to its efforts to maximize its AMI investment, in 2021, the law changed surrounding general rate cases which now requires utilities to file multiyear rate plans. RCW 80.04.250 now allows recovery of investments that will be used and useful during the multiyear rate plan period. Given that AMI deployment would be complete during the multiyear rate plan, full recovery of the investment over the course of the multiyear rate plan should have been authorized.

Q. What was the outcome of PSE's AMI request in the 2022 General Rate Case?

A. As a compromise with case parties, PSE agreed to settle its AMI request as part of a multiparty settlement, that was accepted by the Commission, under the following terms:

- PSE had adequately demonstrated utility system benefits of AMI.[16]
- PSE will continue deferring recovery of its return on equity of AMI but is permitted to recover the debt component of return on rate base.[17]
- PSE is entitled to recovery of its AMI plant put into service through December 31, 2021.[18]
- PSE will not receive a final determination of prudency on the AMI project until the AMI installation is complete, and PSE provides an AMI benefits progress report. PSE will file a final AMI benefits progress report as a compliance filing no later than the filing of its next multiyear rate plan. The report will provide an update describing how PSE has continued efforts to maximize company and customer benefits realized under the program and PSE's plans to continue such maximization benefits, as well as any new company or customer benefit use cases identified. The benefit progress report will also update its AMI reporting metrics, including equity considerations.[19]

Q. What portion of the AMI investment remains unrecovered?

A. PSE has yet to recover its full return on AMI plant in service to date. Since its inception in early 2019, PSE has been deferring its full return on AMI plant, but only on balances in service at the time of prior proceedings. In the 2022 General Rate Case, for the first time, PSE was authorized to recover only the debt

---

[16] *WUTC v. Puget Sound Energy*, Dockets UE-220066/UG-220067 et al., Settlement Stipulation and Agreement on Revenue Requirement and All Other Issues Except Tacoma LNG and PSE's Green Direct Program, at 5 (Dec. 22, 2022).

[17] *Id.*

[18] *Id.* at 6.

[19] *Id.*

component of its allowed return on estimated balances through 2024. But it is still deferring the equity return on balances through 2021. In this rate proceeding, PSE is requesting a full return on AMI for 2025 and 2026, in addition to amortization of the outstanding equity portion of its authorized rate of return on net AMI plant in service since March 2019. Please see the Prefiled Direct Testimony of Susan E. Free, Exh. SEF-1T, for a further detailed discussion regarding the regulatory history regarding the recovery of PSE's AMI investment.

C. A Final Determination that PSE's AMI Investment Is Prudent Is Warranted

Q. Is a final prudency determination of its AMI investment appropriate in this case?

A. Yes, it is. As agreed in the 2022 General Rate Case settlement summarized above, a final prudency determination was warranted when the Company had completed deployment of the AMI system and had filed the AMI benefits progress report. As noted above, AMI deployment was substantially complete in December 2023. PSE filed its AMI benefits progress report in the 2022 General Rate Case docket. It is also provided as Exh. RBB-3 to my testimony.

Q. Does PSE's AMI investment meet the Commission's prudency standard?

A. Yes, it does. PSE's AMI investment meets all of the requirements of the Commission's historical prudency standard and the additive requirements the Commission has imposed for AMI investments as articulated in the 2019 General Rate Case and the Avista General Rate Case.

Q. What is the Commission's prudency standard?

A. In the 2022 General Rate Case, the Commission reaffirmed its long-established prudency standard, which is a reasonableness standard, typically evaluated by the following factors:

> (1) The Need for the Resource: The utility must first determine whether new resources are necessary. Once a need has been identified, the utility must determine how to fill that need in a cost-effective manner. When a utility is considering the purchase of a resource, it must evaluate that resource against the standards of what other purchases are available, and against the standard of what it would cost to build the resource itself.
>
> 2) Evaluation of Alternatives: The utility must analyze the resource alternatives using current information that adjusts for such factors as end effects, capital costs, dispatchability, transmission costs, and whatever other factors need specific analysis at the time of a purchase decision. The acquisition process should be appropriate.
>
> 3) Communication With and Involvement of the Company's Board of Directors: The utility should inform its board of directors about the purchase decision and its costs. The utility should also involve the board in the decision process.
>
> 4) Adequate Documentation: The utility must keep adequate contemporaneous records that will allow the Commission to evaluate the Company's decisionmaking process. The Commission should be able to follow the utility's decisionprocess; understand the elements that the utility used; and determine the manner in which the utility valued these elements.[20]

PSE's AMI investment meets all of these requirements.

[20] *WUTC v. Puget Sound Energy*, Dockets UE-220066/UG-220067 et al., Final Order 24/10 ¶ 204 (Dec. 22, 2022).

Q. Did PSE demonstrate a need for the AMI investment?

A. Yes, it did. In its 2019 General Rate Case, PSE presented significant evidence demonstrating that PSE's existing AMR system was obsolete and needed to be replaced. In its order from that case, despite opposition from case parties, the Commission agreed that the AMR system was obsolete and needed to be replaced.[21]

Q. Did PSE correctly select AMI after appropriately evaluating alternatives?

A. Yes, it did. In its 2019 General Rate Case, PSE presented significant evidence demonstrating that transitioning to AMI was the appropriate and correct decision compared to the alternatives.[22] In its order from that case, again, despite opposition from case parties, the Commission agreed that "the operational decision to install AMI was prudent."[23] The Commission endorsed PSE's decision to transition to AMI by stating that AMI was industry standard and that PSE was correctly keeping up with "this evolving technology."[24]

Q. Was the Board of Directors or management involved in the AMI decision?

A. Yes. The Board of Directors and PSE management were closely involved in the decision to implement AMI and the decision to convert to AMI was reaffirmed by the Board and management on several occasions. No party has ever challenged

---

[21] *WUTC v. Puget Sound Energy*, Dockets UE-190529/UG-190530 et al., Final Order 08/05/03 ¶ 153 (July 8, 2020).
[22] *Id.*
[23] *Id.*
[24] *Id.*

that PSE satisfied this prudency factor nor did the Commission conclude otherwise in its 2019 General Rate Case Final Order.

Q. Did PSE provide contemporaneous documentation regarding PSE's AMI decision making process?

A. Yes, it did. In its 2019 General Rate Case order, the Commission found that PSE had provided "ample testimony and evidence related to the obsolescence of its AMR system" and "testimony and exhibits documenting its business case, including each of the systems it considered before it elected to install AMI."[25] No party has ever challenged that PSE satisfied this prudency factor nor did the Commission conclude otherwise in its 2019 General Rate Case Final Order.

Q. Is the AMI investment in-service now and otherwise "used and useful"?

A. Yes, it is. As described above, because AMI meter and module installation started in 2018, thousands of PSE customers have been using their AMI meters for years. However, PSE substantially completed deployment of the AMI system in December 2023. The entire system is in-service now and is "used and useful."

---

[25] *WUTC v. Puget Sound Energy*, Dockets UE-190529/UG-190530 et al., Final Order 08/05/03 ¶ 153 (July 8, 2020).

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

A. No. Full deployment was completed on schedule in December 2023 and under budget by about $15 million.

Q. What were the total final costs of the AMI deployment?

A. PSE's total investment in the AMI deployment was $456 million in capital and $17 million in operations and maintenance expense related to capital for a total investment of $473 million. PSE's investment was within 0.22 percent of the costs estimated in 2016.

Q. Under the Commission's prudency standard, is full recovery of PSE's investment appropriate?

A. Yes, it is. Rate recovery is appropriate when utility plant is used and useful and was a prudent investment. In this case, the AMI system is used and useful and was a prudent investment. The Company also completed the project on time and on budget. Accordingly, based on the Commission's prudency standard, any remaining recovery of both the investment and the return on that investment is appropriate now.

D. PSE Has Met the Commission's Additive Requirements for AMI Recovery

Q. In addition to the Commission's prudency standard for rate recovery of plant investments described above, has PSE satisfied the additional requirements the Commission imposed on PSE in the 2019 General Rate Case before it could earn a return on its AMI investment?

A. Yes, it has. The Commission's 2019 General Rate Case Final Order and the further guidance provided by the Commission in the Avista General Rate Case required PSE to have a plan for maximizing its use of AMI, including the benefit use cases noted by the Commission from the *Utility Dive* article. The AMI benefits progress report filed with my testimony, Exh. RBB-3, describes how PSE is maximizing AMI and its plans for continuing to do so.

Q. Please summarize PSE's AMI benefits progress report.

A. PSE's AMI benefits progress report addresses the requirements agreed to by the parties as part of the 2022 General Rate Case settlement including:

- PSE's efforts to maximize Company and customer benefits realized under the program.
- PSE's plans to continue maximizing Company and customer benefits realized under the program.
- New Company or customer benefit use cases identified.
- Updated AMI reporting metrics, including equity considerations.[26]

[26] *WUTC v. Puget Sound Energy*, Dockets UE-220066/UG-220067 et al., Settlement Stipulation and Agreement on Revenue Requirement and All Other Issues Except Tacoma LNG and PSE's Green Direct Program, at 5 (Dec. 22, 2022).

Q. Please summarize PSE's efforts to maximize company and customer benefits realized under the program.

A. PSE's AMI benefits progress report describes 58 AMI "use cases" that are in varying stages of development and implementation, including the use cases identified by the Commission in its 2019 General Rate Case Final Order. These use cases help advance a broad scope of Company objectives including customer energy management, Company operational efficiency, customer bill management, Company resource planning and investment, revenue assurance and financial analysis, field and customer safety, and grid performance. Collectively, these use cases are estimated to deliver over $1.3 billion in Company and customer benefits with additional qualitative benefits over the anticipated life of the AMI system.

Q. Please describe PSE's plans to continue maximizing Company and customer benefits realized under the program.

A. Each AMI benefit use case discussed in the AMI benefits progress report describes the development status of each use case and the estimated implementation timeline, where applicable. PSE will continue to advance these use cases within the broader context, budget, prioritization process, and planning associated with PSE's overall project portfolio.

Q. What new Company or customer use cases has PSE identified?

A. The AMI benefits progress report identifies and discusses 32 new and emerging use cases since PSE's 2022 General Rate Case. They include:

- Improved Customer Engagement with Data
- Bill Payment (Pre-Paid)
- Meter Asset Health (Accurate Meter Type Installation)
- Phase Identification
- Non-Wires Alternatives
- Sizing Transformers
- Transformer Asset Health (Voltage Anomalies)
- Model Validation (Voltage)
- Enhanced Power Flow Modeling
- Masked Load Identification
- Fixed Capacitor Monitoring
- Secondary Circuit Parameter Estimation
- Battery Incentives
- Electric Vehicle/Battery Charging Capacity Map
- Smart Inverter Connection
- Alternative Transportation Electrification Rate Schedules
- Interconnection Commissioning
- Customized Program Engagement and Optimization
- Cost of Service Studies
- Unsafe Condition (Photo Voltaic Backfeed)
- Downed Live Wire Notification
- Improved Customer Safety (Fire Notification)
- Communications for Methane Detection
- Momentary Outages/Power Quality

- Voltage Compliance (Real-Time Operations)
- Predictive Analytics for Operations
- Reliability Index Validation
- Outage Cause Prediction
- Cold Load Pickup Prevention
- Extreme Event Strategic Load Shedding
- Meter Sampling

Q. What AMI reporting metrics have been updated and how has equity been considered?

A. Appendix A of the AMI benefits progress report reports on the AMI metrics agreed to in the 2022 General Rate Case. Four of those metrics related to equity. Moving forward, PSE proposes to consolidate its AMI metrics into one metric calculating the percentage of automated billing data received by the Company using the AMI system. This performance metric is included in the Customer Satisfaction table presented in the Prefiled Direct Testimony of Aaron A. August Exh. AAA-1T.

Q. How do you propose that the calculation of this metric be modified?

A. PSE proposes to sum the number of successful electric plus gas customer automated meter reads to be used for billing purposes for all billing cycles, and this number divided by the total number of electric plus gas customer meter bills for all billing cycles multiplied by 100.

Q. Why is it appropriate to change the calculation of this metric in the context of this rate plan?

A. Using actual numbers instead of averages will be a more accurate accounting of network performance and allow PSE to better identify trends that might indicate concerns around billing accuracy.

Q. Has PSE met the additive requirements for AMI recovery described in the Commission's Final Order in PSE's 2019 General Rate Case and as further described in the Avista General Rate Case?

A. Yes. As described above, AMI deployment is substantially complete, and PSE has completed and filed the AMI benefits progress report showing how PSE is maximizing its use of AMI. PSE has also reported on and updated its AMI reporting metrics, including equity. PSE has satisfied the additive requirements in the 2022 General Rate Case settlement, and full recovery of PSE's AMI investment appropriate now.

IV. MAJOR PROJECTS GREATER THAN $15 MILLION THAT WILL BE PLACED IN SERVICE BETWEEN JANUARY 1, 2025 AND DECEMBER 31, 2026

Q. Please describe the major projects with capital costs greater than $15 million that will be placed in service between January 1, 2025 and December 31, 2026, about which you are testifying.

A. I am providing testimony on two major projects with capital costs greater than $15 million that will be placed in service between January 1, 2025 and December

31, 2026: (a) the Bainbridge Island project and (b) the Sedro Woolley – Bellingham #4 115kV Reconductor Transmission Line project. The table below summarizes the capital investment during the multiyear rate plan. Recovery for these investments during the multiyear rate plan is appropriate.

Description	W_R.10019.01.01.02: Bainbridge Trans WIN-MUR Loop CSA0001 / Bainbridge Tlines Trans In-Service Date: In-Service Date / October 2027	W_R.10019.01.01.03: E Rebuild Winslow Tap CSA0177 / Winslow Tap 115kV Transmission Line Rebuild In-Service Date: In-Service Date / October 2025	W_R.10019.01.01.04: E Bainbridge Energy Storage Battery / CSA0015 / Bainbridge Island Energy Storage Battery / In-Service Date: In-Service Date / December 2026	W_R.10054.01.01.01: E Bellingham Sedro 4 115Kv Recond Tline CSA0018 / BHM-SED #4 115 kV Line In-Service Date: In-Service Date / December 2026
Capex - Inception through In-Service	$ 27,493,197	$ 9,989,246	$ 10,533,683	$ 13,962,097
AFUDC	4,447,185	1,033,193	1,383	1,703,873
Amont still in CWIP	(31,940,382)			
Amount forecasted to close during MYRP	$ -	$ 11,022,438	$ 10,535,067	$ 15,665,970
	0	0	0	0

A. The Bainbridge Island Project

Q. Please describe the Bainbridge Island project.

A. The Bainbridge Island project is located on Bainbridge Island in Kitsap County. This project consists of three components that address each of the identified system needs separately with a hybrid solution: 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 with permanent access and clearing vegetation to standard width; third, installation of an approximate 3.3 MW 5MWh battery energy storage system and implementation of an approximate 3.3 MW distributed energy resource portfolio. Exh. RBB-4 contains the CSA for the Bainbridge Island project.

Q. What is the timeline and status of the Bainbridge Island project?

A. This project was initiated in 2019. The timeline and status of each component of the project are as follows:

- Permit submittal for the new 115kV transmission line between the Winslow and Murden Cove substations is estimated to be in 2025 with the line completed in 2027/2028. The Winslow substation upgrade project for the 115 kV loop will be completed in 2028.
- The Murden Cove substation upgrade project, which includes installation of a battery energy storage system, is in design and permits are targeted to be submitted in the third quarter 2024 with construction completion in 2026.
- Land use and environmental permits have been submitted and are under review for the Winslow Tap 115 kV line rebuild project. That project and the new 115 kV transmission line project require code amendments with the City of Bainbridge Island which may not be processed until 2025 based on the City Council's current policy to wait until after the Comprehensive Plan periodic review update is completed. The team is also preparing for easement acquisition for the Winslow Tap rebuild project. Construction permits cannot be issued until after the city codes have been amended, extending permit issuance into 2026. The Winslow Tap rebuild is projected to be completed by the end of 2027.
- An objective of adding approximately 3.3 MW distributed energy resource portfolio involves customer side resources such as energy efficiency, renewable distributed generation and potential of demand response along with connecting the new ferry electrification charging load (10 MW). Customer enrollment campaigns are underway.

Q. Was the Bainbridge Island project discussed in PSE's 2022 General Rate Case?

A. Yes. I filed testimony on the Bainbridge Island project in that case because at the time, it was anticipated that the project would be complete and the various components described above would be in-service by the end of 2025, which was the last year of PSE's proposed three-year multiyear rate plan as originally filed. The parties ultimately reached a settlement in that case for a two-year rate plan, and the in-service date of the project fell out of the current multiyear rate plan.

Q. Has the in-service date for this project changed?

A. Yes. As mentioned above, the projected completion and in-service date for the entire project is 2028.

Q. What was the original projected cost of the Bainbridge Island project and has it changed since the last case?

A. The projected final cost of the project in my testimony from the 2022 General Rate Case was $48.82 million without AFUDC.

Q. What was the original system need for the project and has that changed at all?

A. The need for the project has not changed since my testimony in the last case. 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 14.6 MW was identified on Bainbridge Island within the 10-year planning horizon to support general load growth of 4.6 MW.

Q. What were the alternatives considered before selecting this project and has any re-evaluation been done?

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 percent 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. For the 2018-2023 period, Winslow substation had 16 outages (14 of these outages were Winslow Tap related).

Twenty-nine of these 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, including the adjusted timelines and costs since the last case.

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. How has equity been incorporated into the project?

A. With regard to equity considerations for the Bainbridge Island project, the alternatives analysis and scoping phase was completed in 2019 prior to the incorporation of equity into our formal planning processes. These projects will, however, provide capacity and reliability benefits for the entire island including named communities within it. The specific Customer Benefit Indicators addressed by the Bainbridge Island project include improved Resilience due to infrastructure improvements and Enabling Cleaner Energy via increased distribution capacity for the island, including the four circuits identified as serving highly impacted communities.

The construction phase logistics and customer communication will be done with careful consideration of named communities. There are no targeted equity scope elements benefiting only named communities as part of these projects.

Q. What is PSE's request in this case for the Bainbridge Island project?

A. PSE requests to recover in rates the Winslow tap rebuild at a cost of $11,022,438 and the Murden Cove Substation Energy Storage System at a cost of $10,535,067, both without AFUDC. These figures do not include the WIN-MUR 115 kV loop which is scheduled to be completed in 2028.

B. The Sedro-Woolley – Bellingham #4 115kV Project

Q. Please describe the Sedro-Woolley – Bellingham #4 115kV ("Sedro #4") project.

A. 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, and to replace/rebuild the pole structures to PSE's 115 kV configuration in the current corridor alignment as well as rebuild the 12.5 kV underbuilt distribution. 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 is being constructed in four phases:

- Phases A and B, approximately 11.5 miles of line in Skagit County, are operating and in service and were included and recovered in PSE's prior general rate cases.
- Phase C, approximately six miles of line in Skagit and Whatcom Counties. Pre-construction will begin in 2024, with construction scheduled for 2025.
- Phase D, approximately six miles of line in Whatcom and Bellingham Counties. Pre-construction will take place in 2024/2025, with construction scheduled for 2026. Prior testimony on Sedro #4 referenced a Phase E; this has been absorbed into Phase D.

Phases C and D are before the Commission in this case as part of PSE's multiyear rate plan. Exh. RBB-5 contains the CSA for Sedro #4.

Q. What is the timeline and status of Sedro #4?

A. In PSE's 2022 General Rate Case, I provided testimony on Sedro #4, which projected that Phases C would be completed and in service in 2024, and that Phase D (and E), would be completed and in service in 2025. At the time both were in the design phase of the Project Lifecycle Model. Due primarily to portfolio prioritization, the current project schedule is to complete Phase C in 2025 and Phase D in 2026, with final closeout and restoration to be completed in 2027.

Q. What was the original projected cost of Phases C and D of Sedro #4 and has it changed since the last case?

A. As I reported in my testimony in the 2022 General Rate Case, the expected final cost of the entire project remains approximately $23 million without AFUDC. Eight million in costs associated with Phases A and B were recovered in prior rate cases and are not before the Commission in this case. The remaining cost to complete, including closeout by 2027 is $15,665,970 with AFUDC.

Q. What was the original system need for the project and has that changed at all?

A. The Sedro #4 line has constrained line ratings that cause the line to exceed its allowable capacity for several contingencies and limit generation capacity in Whatcom and Skagit Counties. Aging infrastructure on the system has resulted in extended outages. Since the 1990s, PSE has had to protect the line from loading above its allowable limits by automatically opening the Sedro Woolley substation circuit breaker. This can occur when various outages and system conditions cause high power flows on the line. This results in lower system reliability for the Norlum and Alger substations. It also results in taking out of service one of the two 115 kV lines that ties the Whatcom County and Skagit County 115 kV systems together.

The overall need has not changed but there is one scope addition in June 2019 which included adding a three-phase 12.5 kV voltage regulator on the ALG-12 distribution circuit as part of the overall 12.5 kV system rebuild to stabilize power quality.

Q. What were the alternatives considered before selecting this project and has any re-evaluation been done?

A. Several alternatives were originally evaluated as described below. The best solutions were evaluated in-depth, including the selected alternative. PSE's solution criteria required all identified needs be addressed.

1. **Rebuild the 115 kV transmission line.** 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.** 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. This project results in system capacity and reliability improvements due to increased conductor size and the replacement of aging infrastructure. The line is critically important in keeping electric service to most of Whatcom County. If the Portal Way Substation 230-115 kV transformer were out of service and then a fault occurred at Bellingham's Substation, there would be only the Sedro-Bellingham #3 and #4 115 kV lines left to connect PSE's entire Whatcom County transmission system to BPA's main grid. Therefore, the higher capacity and improved reliability will result in reduced outage frequency and improved bulk power delivery in the region.

Q. Describe how PSE kept management informed during this project, including the adjusted timelines and costs since the last case.

A. Using PSE's Project Lifecycle Model and phase-gate process, management provided review and approval of the project. This project was most recently reviewed by management in the five-year budget approval process (2024-2028) and a capital spending authorization in 2023. The project currently has funding in the approved 2024-2028 funding plan for completion in 2025-2027.

Q. How has equity been incorporated into the project?

A. With regard to equity considerations for Sedro #4, the alternatives analysis and scoping phase was completed prior to the incorporation of equity into our formal planning processes. However, this project will provide capacity and reliability benefits for multiple distribution systems that include named communities served within it. The specific Customer Benefit Indicators addressed by Sedro #4 include improved Resilience due to infrastructure improvements and Enabling Cleaner Energy via increased transmission capacity for all the customers fed from the line, which includes two substations where all circuits have customers that are identified as highly impacted communities and vulnerable populations.

The construction phase logistics and communication for this project will be done with careful consideration of customers in named communities.

Q. What is PSE's request in this case for Sedro #4?

A. PSE is seeking recovery for the amounts identified in the table above.

V. CONCLUSION

Q. Does this conclude your testimony?

A. Yes, it does.