EXH. CAK-5 (Apdx. B)
DOCKETS UE-22___/UG-22___
2022 PSE GENERAL RATE CASE
WITNESS: CATHERINE A. KOCH

BEFORE THE
WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION

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

APPENDIX B (NONCONFIDENTIAL) TO THE FOURTH EXHIBIT TO THE PREFILED DIRECT TESTIMONY OF

CATHERINE A. KOCH

ON BEHALF OF PUGET SOUND ENERGY

JANUARY 31, 2022

Grid Mod – Virtual Power Plan

Seeking Initiation Funding

Corporate Spending Authorization (CSA)

Before starting: Contact the Capital Budget team (CSA-TeamMail@pse.com) for any clarification needed and review the CSA Standard when completing this template.

The sections provided expand / are not limited to one row. **Ensure you provide adequate information and back-up documentation to support your business case.** If a section or item is not applicable, enter N/A; if unknown, enter TBD. The gray fields are provided as prompts; do not leave these fields with instructions visible.

Date Submitted:	4/19/2021
Officer Sponsor:	Booga Gilbertson/Margaret Hopkins
Project Director:	Cathy Koch
Responsible Cost Center:	1224

I. Project Overview

Update each section with high level information as applicable, noting any changes from the previous request/Gate.

Business Need:	PSE needs to manage increasing clean, distributed energy resources in a way that is cost effective and operationally efficient. According to the 2021 IRP preferred portfolio, PSE will acquire 634 MW of distributes batteries, distributed solar, and demand response by 2030. This portfolio is expected to leverage existing DER capacity and add new capacity though a variety of customer programs and PSE owned DERs. With the DER RFP release anticipated in late 2021, PSE expects to acquire or promote installation of hundereds of MWs of DERs over the next several years. PSE needs to establish a platform for managing these resources in a way that is safe in the field, efficient for System Operations and the Load Office, and can support firm capacity and energy requirements.
Proposed Solution:	A Virtual Power Plant establishes a platform by which aggregated DERs can be forecast, controlled, and dispatched by PSE. A Virtual Power Plant is a software tool that enables PSE to utilize diverse types of DERs at desired at magnitudes meaningful for the load office and market dispatch. There are increasing numbers of solar panels, residential batteries, customer level load managing systems with demand response capabilities and EVs being installed at increasing rates on PSE's system. Establishing a Virtual Power Plant will provide the ability to continuously acquire clean energy resources as customers and PSE develop resources to meet customer and portfolio needs.
Project Outcome/Results:	Aggregated distributed energy resources (DER) made accessible to PSE's System operations, Load office and Market as dispatchable resources in the scale of hundereds of MW.
OCM, Process & Training Impact:	○ N/A ○ Low Impact ○ Medium Impact ◉ Significant Impact

A Virtual Power Plant would add Distribution functionality that presently does not exist. Due to the nature of incorporating new functionality into the business, there is going to be need for clarity of roles & responsibilities, process development, training and overall change management. Several target areas for consideration are:

- Clarity of ownership of the VPP functionality within the business
- Product development and enabling the functional capability in a way that is used and useful.
- Load Office Integration (People training for application and Process development)
- System Operations (people training for application and Process development)
- IT systems integration (Process development for architecture and maintenance and systems management)
- Vendor integration for aggregate DER resources (Process & People)
- Internal PSE integration for aggregate DER resources (Process & People)

Primary ISP Alignment:	Energy Supply	ISP strategy descriptions	
Portfolio Description:	Strategic	Capital Allocation Definitions	
Project Complexity:	○ Straightforward and well understood	○ Complex and well understood	● Complex and not well articulated

II. Key Schedule and Financial Information

Expected Start Date If Funded:	06/2021
Expected In-Service Date:	05/31/2023

High-Level Schedule *Enter Expected # of Years and Months*

Duration				
Planning	**Design**	**Execution**	**Total Project**	**Anticipated Closeout date**
2021	**2022**	**2023**	**2 year project.** **Operationalized Q2 2023**	05/2023

Initial Estimated Funding % by Phase as of 04/7/2021: *Enter values to include both O&M and Capital in the cells below for percentage of funding to be used in each phase of the project.*

Initiation	Planning	Design	Execution	Closeout
0%	**5%**	**25%**	**50%**	**20%**

Initial Grand Total Estimate (contingency included and in $000s): [Contingency Standard]	**Capital: $8,002,500** **(NOTE - $200K for the Planning phase in 2021 in order to develop the RFP and select a vendor)**	**OMRC/Project O&M: $82,683** (Not including O&M Tail)

Estimated Five Year Allocation: *Enter values in the cells below for years anticipated, up to five years, plus any expected future years. Change "Year 1, Year 2, etc. to the relevant years for this project. Ongoing O&M begins after project close-out.*

Category:	**Year 1 2021**	**Year 2 2022**	**Year 3 2023**	**Total**
Capital (contingency included)	**$200,000**	**$5,962,737**	**$1,839,763**	**$8,002,500**
OMRC / Project O&M	**$0**	**$61,627**	**$21,056**	**$82,683**

III. Ongoing Benefits

Summary Benefits (see Benefits realization plan for details):	The details of the benefits to be realized are to be determined as part of the Initiation and Planning process within 2021. At a high level the objective is to be able to make clean DERs already existing on PSE's system, and new DERs that will be acquired accessible in a way that can be materally support PSE's resource needs. Acquiring this platform prior to the implementation of PSE DER programs will ensure that there will be a single platform for dispatch and settlement, and PSE will not need to rework integrations as new DER programs and specific resources are acquired over time. Also, it establishes the direct relationship with the customer. As the penetration of DERs increase on the system through customer adoption and PSE programs, PSE has control of aggregated resources in our territory. (Note: This table below will be filled out as part of the Initiation and Planning stage)

Category:	**Year 1**	**Year 2**	**Year 3**	**Year 4**	**Year 5**	**Total**
Ongoing O&M (to be funded by business)	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**
Ongoing O&M (requesting $'s)	**$0**	**$0**	**$344,922**	**$485,607**	**$485,607**	**$1,316,136**
Benefits	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**
Net impact (= Benefits – O&M)	**N/A**	**N/A**	**N/A**	**N/A**	**N/A**	**N/A**
* Payback in Years	Years = Total Costs / Annual Cash Benefits					

* Enter positive amount or Not Applicable

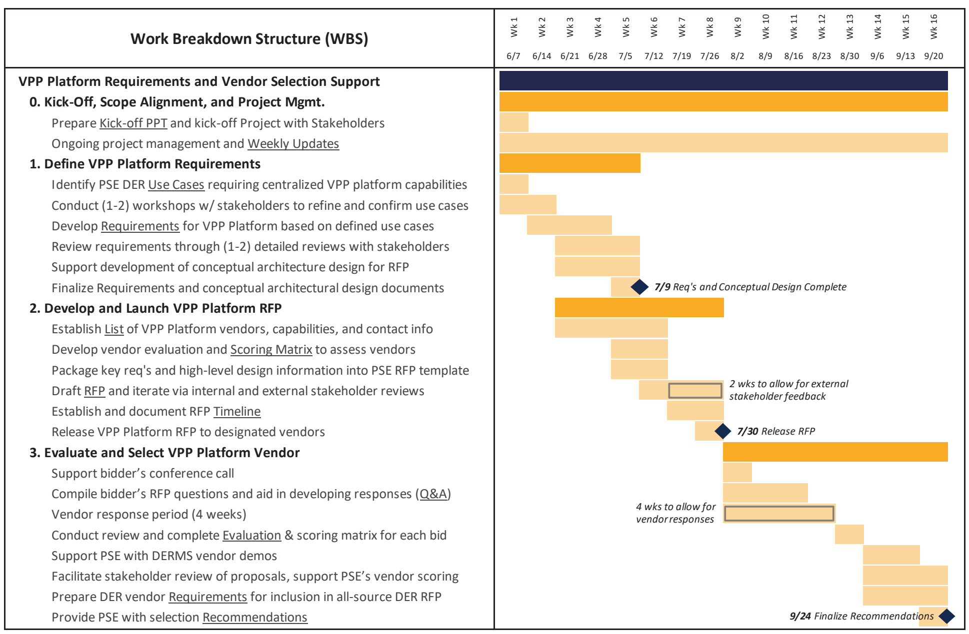
IV. Risk Management Summary

Identify high level risk categories expected for the project. Consider Project Dependency, Project Timing and Resourcing, as well as Regulatory Risk.

Summary of high level risks sentence:	1) IT Security. The VPP provider will need to have an acceptable SOC 2 Type 2 audit. 2) Business Integration and Operationalization of a new Software that is usable by the load office and system ops (IT Architecture) 3) Capacity for the Change Management of the organizations that will be impacted 4) Organizational alignment (what are the different department ownerships with regards to the operation and maintenance of the VPP)

V. Phase Gate Change Summary

Use this section for changes from: ***Planning to Design***, ***Design to Execution*** *or* ***Execution to Closeout*** *phases. To have a history of the changes at each phase gate change,* ***copy/paste the table below above the previous table.***

Phase:	Initiating to Planning
Scope:	This is the first stage of the overall development process of the Virtual Power Plant. The Budget, Schedule and Benefits are only representative of the **"Initiating to Planning"** phase as that is what is known at the moment. The scope is to: 1) Develop the SOW for the Consultants that will help with the RFP development for a Virtual Power Plant (Complete) 2) Define the VPP Platform Requirements and Success Criteria 3) Develop the RFP 4) Launch the VPP RFP 5) Evaluate and select the top vendor canditat for a VPP 6) Submit the plan for the Design and Execution of the VPP Software Platform for funding approval for 2022 and 2023.
Budget:	$200,000 capital for the development of the RFP and selecting the software vendor. This includes the cost for consultants to develop the RFP and the PSE resources involved as part of the Core Team for the RFP development. $8,000,000 capital and $500,000 OMRC for the Integration and Execution of the VPP.
Schedule:	
Benefits:	This first stage of Initiating and Planning will lay the foundations of longterm success in the implementation and operation of a Virtual Power Plan. There will be a lot of collaboration with the consultants who have experience with Virtual Power Plan integration and will give a lot of exposure to what is available in the industry. The intentional approach in the "Initiation and Planning" phase lays the foundations for success in the following Design and Execution phases. This scope of work will involve shaping the requirements for the DER RFP Nov 15 2021.

Prepared by:	Kevin Gowan and Elaine Markham

VI. CSA Approvals

*Add/remove rows as needed in the table below. Email approval is acceptable. To maintain a history of the changes at each phase gate change, **copy/paste the table below above the previous table.** Send to the Capital Budget team at CSA-TeamMail@pse.com. For a project in the Strategic Project Portfolio (SPP) review the* Escalation Criteria *for appropriate escalation and approvals.*

For guidance on approval authority levels, follow CTM-07 Invoice Payment Approval Exhibit I Invoice/Payment Approval Chart

Project Phase	Select Phase			
Approved By	**Title**	**Role**	**Date**	**Signature**
Margaret Hopkins	VP	IT Executive		
Booga Gilbertson	VP	Executive Sponsor		
Cathy Koch	Director	*Director Sponsor	5/7/2021	Catherine Koch
Dan Koch	Director	Other Key Director		
Shauna Tran	Director	Other Key Director		

*Director Sponsor attests that all considered documentation has been approved.

Please direct any questions to either:
1. The Capital Budget team at CSA-TeamMail@pse.com, or
2. The Enterprise Project and Performance Project Practices team at EPP-ProjectPracticesTeam@pse.com

Geospatial Load Forecasting
Planning and Design to Execution
Gate change to Execution
Corporate Spending Authorization (CSA)

Before starting: Contact the Capital Budget team (CSA-TeamMail@pse.com) for any clarification needed and review the CSA Standard when completing this template.

The sections provided expand / are not limited to one row. **Ensure you provide adequate information and back-up documentation to support your business case.** If a section or item is not applicable, enter N/A; if unknown, enter TBD. The gray fields are provided as prompts; do not leave these fields with instructions visible.

Date Submitted:	8/31/2021
Officer Sponsor:	Dan Koch/Joshua Jacobs
Project Director:	Cathy Koch / Phillip Popoff
Responsible Cost Center:	System Planning / Load Forecasting

I. Project Overview

Business Need:

As customers demand more energy choices, from Distributed Energy Resources (DER) to Electric Vehicles (EV), load patterns are changing. As a result, System Planning practices must adapt to include additional drivers beyond seasonal system peaks or else instability and decreases in reliability may become a greater concern. If planned and dispatched strategically, the new elements described below can be added onto the grid to address the system challenges presented by non-wires alternatives and changing demand patterns. These tools will enable planners to use a more granular, small-area forecast that brings together planning and operation across a time-series basis. This approach is imperative to provide better system visibility, increase planning accuracy, confidence, and more economically plan projects.

PSE spent approximately $1 million on consultants to perform non-wires alternative (NWA) analysis on three projects in 2019. It is the regulatory mandate to perform NWA analysis; PSE currently has identified an additional 38 areas to be evaluated for NWA projects but does not have the tools to independently perform the analysis at a pace that keeps up with the demand.

The proliferation of DERs driven by the Clean Energy Transformation Act (CETA) poses two questions to PSE planners:

- How does PSE plan the systems to accommodate the upcoming DERs
- and EVs?
  How much DER of what type should PSE install in its
- system to meet the CETA requirements?

A robust circuit-level forecast and DER optimizer will enable PSE to make sound, data driven decisions when addressing those questions.

Proposed Solution:

LoadSEER, developed by Integral Analytics, is a spatial load forecasting tool which is used by electric distribution system planners to predict load and power changes, where on the grid the loads will occur, how Distributed Generation (DG) changes the load shape, and when it must be supplied. LoadSEER spatial load forecasts address both short-term circuit trends and long-term grid expansion, while remaining consistent with the system-level corporate load forecast for energy and peak demand. The resulting forecast provides system planners with substation, circuit and small-area resolution time-series load growth and load shape changes.

LoadSEER also has a built-in data-scrubber that cleans up data inputs from Supervisory Control and Data Acquisition (SCADA) historian and weather stations, which can potentially benefit other groups besides Planning and Load Forecasting that use those data as inputs for analytics.

As one of the key features of LoadSEER, the DER Optimizer module is the application of targeted DER and demand-side management (DSM) program spend, by DER type, by circuit, by year. It creates the ability for PSE to create locational (community/municipal/circuit/zonal) portfolios of DER or DSM program initiatives that will maximize savings, reliability or clean attributes by targeting the correct DER mix to achieve the objective measure, mathematically optimized. The DER Optimizer will serve as a powerful tool for non-wires alternative analysis by providing optimal DER mix by costs while meeting the granular forecasted 8760 load profile by feeders.

LoadSEER is the only commercial tool in the market that employs a hybrid forecasting approach which combines advanced statistical trending and rule-driven growth simulation analysis through spatial electric load forecasting. It combines the capability of using extensive data from GIS, CIS, satellite imagery, load research, historical loads, customer class modeling, historical weather, etc to enable itself to provide both short-range and long-range forecasts. It also provides the flexibility for planners to apply growth assumptions and rule sets for individual feeders or across an entire service territory, preserving old parameters for comparison and calibration. LoadSEER's simulation engine enables planners to run any number of growth scenarios created from sets of specific assumptions to cope with uncertainty.

LoadSEER's 8760 profile forecast includes loads, all types of DERs, and DSRs, at thefeeder level, taking into consideration smart grid controls, government or utility incentives and new load types. The granular analytic capability along with its DER economic optimizer, which is unique amongst all commercial tools in the market, will enable utilities like PSE to perform non-wires alternative analysis independently.

The package is customized by the software developer for each specific user based on the data they have available and the scope of the forecast desired. Pioneering utilities in grid modernization like PSE will benefit from helping to shape the tool's capability and interface as it continues to evolve with the regulation and customer requirements for the power industry.

Utilities that have experience utilizing LoadSEER include Duke Energy, PacifiCorp, Nashville Electric Service, Pacific Gas and Electric (PG&E), Seattle City Light, and Northern Virginia Electric Cooperative (NOVEC).

Project Outcome/Results:	It is System Planning's goal to bring the non-wires alternative analysis process in-house, which would require tools for load data processing, load and DER forecasting, DER valuation and optimization, and time-series generation/load simulations. Modern tools that combine the functions of 8760 feeder-level load/DER/EV forecasting, a data scrubber, and a DER optimization engine will significantly

reduce its operation costs on NWA project RFP/Contract Services requests and dependence on consultants for NWA projects, and set a foundation for standardizing the NWA analysis process within PSE.

The zip-code level conservation potential assessment that is rolled into the Integrated Resource Plan (IRP) (Appendix J) is currently done by a consultant. Feeder-level forecasts, once approved and accepted internally and by the Conservation Resource Advisory Group (CRAG), could potentially reduce PSE's cost in the IRP potential assessment process. The EV and solar adoption forecasts could potentially eliminate the need for market research by vendors.

The feeder-level forecasting tool automatically allocates by scientific methods the load growth/decline at the desired level for the planner to review and make adjustments as needed.

Overall, feeder-level geospatial forecasting supports PSE's Grid Modernization Roadmap as an enabling tool for DER and DSM program integration and implementation across a wide range of use cases, including NWA analysis and clean energy implementation planning as required by the Clean Energy Transformation Act.

OCM, Process & Training Impact:	○ N/A ○ Low Impact ○ Medium Impact ◉ Significant Impact
Primary ISP Alignment:	Processes & Tools — ISP strategy descriptions
ISP Strategy Description:	Process & Tools - Streamline processes to drive effectiveness and efficiency
Portfolio Description:	Strategic — Capital Allocation Definitions
Project Complexity:	○ Straightforward and well understood ◉ Complex and well understood ○ Complex and not well articulated

II. Key Schedule and Financial Information

Initial Expected Start Date If Funded:	10/2020
Initial Expected In-Service Date:	05/31/2021

Actual Start Date:	02/2021
Current Expected In-Service Date:	12/31/2021

High-Level Schedule

Duration				
Planning	**Design**	**Execution/Close out**	**Total Project**	**Anticipated Closeout date**
7 months	**2 months**	**2 months**	**11 months**	12/2021

Initial Estimated Funding % by Phase as of 08/31/2021:

Initiation	Planning	Design	Execution	Closeout
0%	20%	15%	60%	5%

Initial Grand Total Estimate (contingency included and in $000s): Contingency Standard	**Capital: $1,627,245** (including on-going capital tail from 2021 to 2024) **Capital: $880,545** (Project implementation only – includes 2021 SAAS licensing cost and SAAS maintenance cost)	**Project O&M: $172,328** (Not including O&M Tail)

Estimated Five Year Allocation:

Category:	2021	2022	2023	2024	2025	2026	Total
Capital (contingency included)	$1,960,748.50	$0	$0	$0	$0	$0	$1,960,748.50
OMRC / Project O&M/Ongoing O&M	$0	$53,138.00	$53,138.00	$53,138.00	$53,138.00	$35,425.00	$247,977.00

III. Ongoing Benefits:

Summary Benefits (see Benefits realization plan for details):	This tool will provide a fundamentally new capability, and will support compliance with regulatory requirements related to CETA and non-wires alternatives. It will also support customer program design for DERs, targeted DSM, and transportation electrification. 1. Enables granular, consistent, circuit-level load/DER forecasting for System Planning to make more precise capital investments on system upgrades. 2. Enables in-house, circuit-level targeted non-wires alternative analysis to reduce consultant services and improve analysis results. Predicted annual avoided costs based on reduction in consulting services: $500,000-$1,000,000 3. Distribution CAPEX optimization for DER accommodation; Capital deferral by balancing EV charging, load shifting, grid support; Predictive transformer load management.

Category:	2021	2022	2023	2024	2025	2026 - 8 months	Total

Ongoing O&M (to be funded by business) Cost Center 1815 (Lorin Molander) FTE support with new tool.	$0	$82,170	$41,085	$41,085	$41,085	$27,390	$232,815
Ongoing OPEX (to be funded by business) Cost Center 4210 (Electric System Planning) FTE support with new tool.	$0	$82,170	$41,085	$41,085	$41,085	$27,390	$232,815
Ongoing O&M (to be funded by 1231) Cost Center 25% FTE IT support with new tool.	$0	$31,720	$31,720	$31,720	$31,720	$21,147	$148,027
Ongoing O&M (requesting $'s) SAAS (LoadSeer) Annual Maintenance and Support fee (cost for 2021 : included in Project Capital Cost)	$0	$53,138	$53,138	$53,138	$53,138	$35,425	$247,977
Total **Ongoing OPEX/O&M** and **Ongoing OMRC**	$0	$249,198	$167,028	$167,028	$167,028	$111,352	$861,634
Benefits (avoided costs) Cost Center 4022	$0	$500,000	$1,000,000	$1,000,000	$1,000,000	$670,000	$ 4,170,000
Net impact (= Benefits – Ongoing O&M & Capital)	$0						$1,347,617.50
* **Payback in Years**		3.39					

* Enter positive amount or Not Applicable

Years = Total Capital and O&M Costs / Annual Cash Benefits

Benefits $4,170,000 minus O&M $861,634 and Capital $1,960,748.50 = $1,347,617.50

Capital $1,967,748.50

O&M $861.634.00

Total $2,829,382.50

Benefits $4,170,000 / 5 = $834,000.00 Annual cash benefits

3.39 years

IV. Risk Management Summary

Identify high level risk categories expected for the project. Consider Project Dependency, Project Timing and Resourcing, as well as Regulatory Risk.

Summary of high level risks sentence:	The data mapping from PSE source systems to the LoadSEER product is critical to the success of the project. There is a project dependency on the DER PowerClerk to SAP project. Currently the project timelines are synchronized, but if there is a delay to the DER PowerClerk to SAP project there would be an impact to this project schedule.

V. Phase Gate Change Summary

*Use this section for changes from: **Planning to Design**, **Design to Execution** or **Execution to Closeout** phases. To have a history of the changes at each phase gate change, **copy/paste the table below above the previous table.***

Phase:	Planning to Design
Scope:	No change
Budget:	The 2021 budget was increased by $1,080,203.50 via PCR1 to capitalize the SaaS software
Schedule:	The scheduled was updated from the initial assumption of 8 months with deployment in May of 2021, to 11 months and deployment in December of 2021.
Benefits:	No change

Prepared by:	Patty Griffith and Laurent Sayer

VI. CSA Approvals

Add/remove rows as needed in the table below. Email approval is acceptable. To maintain a history of the changes at each phase gate change, ***copy/paste the table below above the previous table.*** *Send to the*

Capital Budget team at CSA-TeamMail@pse.com. For a project in the Strategic Project Portfolio (SPP) review the Escalation Criteria for appropriate escalation and approvals.

For guidance on approval authority levels, follow CTM-07 Invoice Payment Approval Exhibit I Invoice/Payment Approval Chart

Project Phase	**Planning to Design**			
Approved By	**Title**	**Role**	**Date**	**Signature**
Jens Nedrud	Manager, Electric System Planning	Key Benefit Owner	9/7/2021	PDF Geospatial Load Forecasting Tool - U
Lorin Molander	Manager, Load Forecasting and Analysis	Key Benefit Owner	9/7/2021	PDF Geospatial Load Forecasting Tool - U
Phillip Popoff	Director, Resource Planning and Analytics	*Director Sponsor	10/11/2021	PDF Geospatial Load Forecasting Tool - U
Cathy Koch	Director, Planning	*Director Sponsor	10/5/2021	PDF Geospatial Load Forecasting Tool - U
Brian Fellon	Director, IT Applications	*Director Sponsor	8/31/2021	PDF Geospatial Load Forecasting Tool - U
Dan Koch	VP Operations	Officer Sponsor	12/2/2021	PDF Geospatial Load Forecasting Tool - U
Joshua Jacobs	VP Clean Energy Strategy	Officer Sponsor	11/1/2021	PDF Geospatial Load Forecasting Tool - U
Margaret Hopkins	VP & Chief Information Officer	Officer Sponsor	10/18/2021	PDF Geospatial Load Forecasting Tool - U

Project Phase	Initiation Funding			
Approved By	**Title**	**Role**	**Date**	**Signature**
Jens Nedrud	Manager, Electric System Planning	Key Benefit Owner	4/29/2020	Re LoadSEER CSA Approval Requested
Lorin Molander	Manager, Load Forecasting and Analysis	Key Benefit Owner	4/29/2020	RE Geospatial Load Forecasting CSA Che
Irena Netik	Director, Energy Supply Planning and Analytics	*Director Sponsor	4/29/2020	RE Geospatial Load Forecasting CSA Che
Cathy Koch	Director, Planning	*Director Sponsor	5/14/2020	RE LoadSEER CSA Approval Requested
Brian Fellon	Director, IT Applications	*Director Sponsor	5/14/2020	RE Review Approve CSA Geospatial Loac
Booga Gilbertson	VP	Officer Sponsor		
David Mills	VP	Officer Sponsor		
Margaret Hopkins	VP	Officer Sponsor	5/26/2020	MH_Approval.JPG

*Director Sponsor attests that all considered documentation has been approved.

Please direct any questions to either:

1. The Capital Budget team at CSA-TeamMail@pse.com, or
2. The Enterprise Project and Performance Project Practices team at EPP-ProjectPracticesTeam@pse.com

Hosting Capacity Analysis, Map, and Customer Portal

Seeking Initiation Funding

Corporate Spending Authorization (CSA)

Before starting: Contact the Capital Budget team (CSA-TeamMail@pse.com) for any clarification needed and review the CSA Standard when completing this template.

The sections provided expand / are not limited to one row. **Ensure you provide adequate information and back-up documentation to support your business case.** If a section or item is not applicable, enter N/A; if unknown, enter TBD. The gray fields are provided as prompts; do not leave these fields with instructions visible.

Date Submitted:	5/3/2021
Officer Sponsor:	Booga Gilbertson/Margaret Hopkins
Project Director:	Cathy Koch
Responsible Cost Center:	Enter Responsible Cost Center

I. Project Overview

Update each section with high level information as applicable, noting any changes from the previous request/Gate.

Business Need:

One of the objectives of grid modernization is to enable the distribution grid to incorporate or integrate new technologies such as distributed energy resources (DERs). Similar to loads, DERs impact the operating conditions of the grid, and when the operating points fall outside the standard acceptable ranges, system reliability and power quality are jeopardized. These violations can be identified by System Planners through system studies as part of the standard interconnection process. These studies are time-consuming and cause delays to the interconnections. Studies often need to be repeated at multiple locations to seek available capacity and sometimes projects are ultimately cancelled due to unanticipated system upgrades that would be required for interconnection. The preferred portfolio in PSE's 2021 IRP includes 405 MW of distributed solar PV and battery energy storage by 2030.

Hosting Capacity is the amount of DERs that can be accommodated on the distribution system at a given time and at a given location under existing grid conditions and operations. While several analysis tools exist for hosting capacity analysis (HCA), PSE does not perform HCA at a system level today. Therefore, PSE does not provide visibility to available hosting capacity to customers or developers as other utilities have begun to do when managing high volumes of interconnection requests. Visibility to hosting capacity can help customers and developers avoid loss of time and application fees for planned projects that turn out infeasible.

In coordination with feeder-level load forecasting, HCA enables proactive investments that support PSE's strategic goals and likely customer DER and EV installations. Without HCA, Planners do not have information on areas where system upgrades can be co-optimized for system needs and DER/EV accommodation. When system upgrades are identified and costs are passed to customers through the current interconnection process, they are implemented in reactive mode and costs may not be allocated in a fair manner across all parties.

Another business need comes from the best DER planning practices as required by *RCW 19.280.100 Distributed energy resources planning*.

Three of the goals placed on the utility in the RCW include:

1. Identify data gaps including enhanced planning simulation tools that would allow the utility to quantify the locational and temporal value of resources on the distribution system/

2. Plan to avoid reactive investments due to unanticipated growth of DERs.

3. Use a transparent planning process.

Finally, recently proposed legislation for performance based ratemaking includes rapid integration of renewable resources as a factor that WUTC will evaluate as a possible performance metric for future rate plans. Other states with PBR include time to interconnect as a performance metric.

Hosting Capacity Analysis is a necessary input for the evaluation of DERs' temporal and locational values and supports proactive investment in the distribution system. When HCA results are made visible to customers and developers, it will result in a more transparent process and faster interconnection of DERs.

Streamlining and guiding DER interconnections in sizing and siting using HCA is necessary to accomplish our CETA goals, comply with DER planning regulations, and prepare for future performance metrics.

Proposed Solution:

Hosting Capacity Analysis based on powerflow modeling and technical criteria can be automated for the majority of interconnection application reviews. The result of the analysis can indicate whether an interconnection should be approved, rejected, or required further analysis due to project complexity.

An associated hosting capacity heatmap provided to customers and developers provides transparency to participants and locational value in relative terms. It would also reduce time and cost for the interconnection applicants, number of applications that may require further studies, and free up PSE's planning resources from interconnection projects that are infeasible due to inadequate hosting capacity.

To further provide permanent digital records and queuing information of the interconnection process to customers and to automate internal departmental review for DER interconnections, a customer-facing portal shall be implemented. Through this portal, customers can enter interconnection requests with project information, such as location, DER type, capacity, etc. For applicants who are existing PSE customers, this portal can import customer information from the GIS.

The output of geospatial forecasting tool (LoadSEER) will be part of the HCA inputs to provide hosting capacity information for better planning for customers/developers on a broader time horizon.

As a next step to meet the expectation of WUTC in providing temporal and locational DER value evaluation, a fully integrated DER value assessment will be built on the customer portal with HCA as the back-engine performing the required calculations.

We expect this project to be delivered in 3 phases:

	1) Hosting Capacity Analysis Tool 2) Hosting Capacity Map 3) Enhanced Interconnection Portal
Project Outcome/Results:	1. An automated HCA program that is integrated with GIS and Distribution Planning process and refreshes its results at a user-defined frequency, for example, monthly or annually. Hosting capacity data on map directs customers and developers to areas easier to accommodate new DERs to compare suitability of multiple candidate locations, reduce speculative projects and to avoid point-of-interconnection that requires more complex study. 2. A web-based, published hosting capacity heatmap that presents the hosting capacity value at every section of PSE's entire distribution circuit. The advanced version will present the hourly hosting capacity at every location maximizing the usefulness of the map. 3. An Interconnection Customer Portal that takes DER information and automatically checks the technical feasibility of the interconnection at the locations chosen by customers and provides instant feedback on whether the interconnection is Approved, Rejected, or Needs Further Analysis by PSE. It increases customer accountability and responses in providing complete information for interconnection applications, reduces DER application processing time, queue congestions, and costs or better messaging of cost expectations. 4. An automated, digital interconnection process, timeline, and queuing tracking system with notifications for all PSE contributors and customers/developers.
OCM, Process & Training Impact:	○ N/A ○ Low Impact ● Medium Impact ○ Significant Impact
	It is estimated that up to 80% of current DER interconnection requests can be automatically processed with a customer portal supported by hosting capacity analysis. The projected results of an expedited DER interconnection application review process in terms of organizational changes, work process changes, and training requirements are as follow: 1. Stakeholder engagement with customers/developers, customer service team, planning, and engineering. Estimated a minimum of two external meetings with developers and commission staff, and on-going internal stakeholder engagement activities. 2. Integration of HCA and customer portal into existing DER interconnection process flow. 3. Influx of DER field installation, which will require construction work process improvement and re-prioritization. 4. Resources to be allocated to clean up and maintain the distribution network model, manage and maintain the HCA program and customer portal for software updates, criteria setting changes, tool evaluation, feature improvements. 5. Increased DER penetration will require all DERs to be modeled in distribution planning, for their aggregated impacts on not only capacity, but also reliability and power quality. 6. Static hosting capacity saturation that will happen at some point in the future, which will require dynamic hosting capacity analysis for hosting capacity enhancement to maximize network utilization. 7. Gradually increased system stability challenges with growing DER penetration requires System Operations' awareness, tools and corresponding training for appropriate controls for DERs.
Primary ISP Alignment:	Customer — **ISP strategy descriptions**
Portfolio Description:	Strategic — **Capital Allocation Definitions**

Project Complexity: ○ Straightforward and well understood ● Complex and well understood ○ Complex and not well articulated

II. Key Schedule and Financial Information

Expected Start Date If Funded:	05/2021
Expected In-Service Date:	08/31/2022

High-Level Schedule *Enter Expected # of Years and Months*

Duration				
Planning	**Design**	**Execution**	**Total Project**	**Anticipated Closeout date**
3 months	**3 months**	**10 months**	**16 months**	09/2022

Initial Estimated Funding % by Phase as of 04/29/2021**:** *Enter values to include both O&M and Capital in the cells below for percentage of funding to be used in each phase of the project.*

Initiation	Planning	Design	Execution	Closeout
5%	**20%**	**30%**	**40%**	**5%**

Initial Grand Total Estimate (contingency included and in $000s): [Contingency Standard]	**Capital: $3,500,000**	**OMRC/Project O&M: $ IT to provide by May 15th** (Not including O&M Tail)

Estimated Five Year Allocation: *Enter values in the cells below for years anticipated, up to five years, plus any expected future years. Change "Year 1, Year 2, etc. to the relevant years for this project. Ongoing O&M begins after project close-out.*

Category:	Year 1	Year 2	Year 3	Year 4	Year 5	Total
Capital (contingency included)	**$ 3,500,000**	**$30,000**	**$30,000**	**$30,000**	**$30,000**	**$3,620,000**
OMRC / Project O&M	**$ IT to provide by May 15th**					**$**

III. Ongoing Benefits

Summary Benefits (see Benefits realization plan for details):	**1.** Regulatory requirement fulfillment and better interconnection data collection and reporting. **2.** Reduced costs for application process and interconnection review currently by 80+ subject matter experts: • Avoided withdrawn projects due to inadequate HC per year which account for 20% of the overall applications: 20% X 1000 emails/project X 30min/email X projected 15 of prjects in the year 2022 X $100/hr = $150,000/year • Communication and technical review efforts avoided by automated approval for basic DER projects, which is estimated to be 30% initially: 30% X (1000 emails/project X 30min/email + 3 days of FTE) X projected 15 prjects in the year 2022 X $100/hr = $235,800/year • Email communication for guiding customers/developers to complete applications, setting up and completing review process with proper SMEs for the remaining 50% proceeding applications – estimated 90% reduction (avg. 50% X 1000 emails/project X 30min/email X projected 15 projects in the year 2022 X $100/hr X 90%= $337,500/year) • Reduced alternative DER system configurations that lead to 50% fewer hours for interconnection studies, assuming all projects beyond the automated approval process require further anlysis: 50% X 15 X 500 hours saved X $100 = $375,000/year **3.** Greater customer self-service and grid transparency and better project decisions: • Reduced customer planning, siting time, and commute time and fuel consumption (unable to track) • Increased application success rate • Avoided application fees for infeasible projects: 20% X projected 15 projects in 2022 X $300 (minimum application fee) = $900/year **4.** Accelerated interconnection process and increased application volume to help reaching the CETA goals.

Category:	Year 1	Year 2	Year 3	Year 4	Year 5	Total
Ongoing O&M (to be funded by business)	$ **IT to provide by May 15th**	$	$	$	$	$
Ongoing O&M (requesting $'s)	$	$	$	$	$	$
Benefits	$	$	$	$	$	$
Net impact (= Benefits – O&M)	$	$	$	$	$	$
* Payback in Years	Years = Total Costs / Annual Cash Benefits					

* Enter positive amount or Not Applicable

IV. Risk Management Summary

Identify high level risk categories expected for the project. Consider Project Dependency, Project Timing and Resourcing, as well as Regulatory Risk.

Summary of high level risks sentence:	1. Timely decision on which HCA tool to use. Different tools present different cost structures and schedules due to the differences in program architecture. Decision factors include tool familiarity, efforts required for program integration, timelines, hardware costs, licensing costs, map refreshing frequency, etc. 2. Timely decision on customer portal service provider. Collaboration and coordination with the Customer Renewables team on timeline and program features is required. 3. Potential technical issues with integrations of multiple large data applications that can affect map/portal data quality and user experience. 4. Result accuracy depends on applied impact factors, accuracy of model inputs, and choice of map refreshing triggers and the transition is a time-consuming effort. 5. Data security related to grid data.Regulatory requirements may differ from PSE's vision for the HCA program.

V. Phase Gate Change Summary

*Use this section for changes from: **Planning to Design**, **Design to Execution** or **Execution to Closeout** phases. To have a history of the changes at each phase gate change, **copy/paste the table below above the previous table.***

Phase:	Choose an item
Scope:	Describe the Scope changes since last submission/Phase Gate.
Budget:	Describe the Budget changes since last submission/Phase Gate.
Schedule:	Describe the Schedule changes since last submission/Phase Gate.
Benefits:	Describe the Benefits changes since last submission/Phase Gate.

Prepared by:	Kincheiu Wei

VI. CSA Approvals

*Add/remove rows as needed in the table below. Email approval is acceptable. To maintain a history of the changes at each phase gate change, **copy/paste the table below above the previous table.** Send to the*

Capital Budget team at CSA-TeamMail@pse.com. For a project in the Strategic Project Portfolio (SPP) review the Escalation Criteria for appropriate escalation and approvals.

For guidance on approval authority levels, follow CTM-07 Invoice Payment Approval Exhibit I Invoice/Payment Approval Chart

Project Phase	Select Phase			
Approved By	**Title**	**Role**	**Date**	**Signature**
Booga Gilbertson	SVP & COO	Executive Sponsor		
Margaret Hopkins	SVP & CIO	Executive Sponsor		
Will Einstein	Director, New Product Development	Other Key Director		
Cathy Koch	Director, Planning	*Director Sponsor	5/7/2021	Catherine Koch
Jens Nedrud	Manager, System Planning	Key Benefit Owner		
Heather Mulligan	Manager, Customer Energy Renewables	Key Benefit Owner		

*Director Sponsor attests that all considered documentation has been approved.

Please direct any questions to either:
1. The Capital Budget team at CSA-TeamMail@pse.com, or
2. The Enterprise Project and Performance Project Practices team at EPP-ProjectPracticesTeam@pse.com

Grid Modernization

Corporate Spending Authorization (CSA) – Operational Program

Date Submitted:	5/7/2021
Officer Sponsor:	Booga Gilbertson
Completed By:	Jens Nedrud, Elaine Markham, Nick Coulson
Responsible Cost Center:	Operations

I. Program Overview

Operational Program Description:	*The Grid Modernization* operational program refers to an all-encompassing strategy to address the electric grid's reliability, resiliency, flexibility and smart capability. The key programs that support this strategy include energy conservation (conservation voltage reduction and volt-var optimization), Grid Automation (which includes Distribution Automation, Transmission Automation, and circuit enablement for electric vehicles, DERs, and Microgrids), Substation SCADA, Cable Remediation, High value electric system upgrades (including Worst Performing Circuits – WPC and targeted capacity/reliability upgrades), Pole replacement program, Substation Replacement Program, WSDOT and King County Clear Zone Pole Programs, Central Bellevue district automation, Smart Meter Technology, Resilience Enhancements, and Data Lake and Data Lake Analytics. All the subprograms of grid modernization are designed to collectively deliver key reliability and resiliency, (specifically SAIDI), objectives and enable customer energy options of choice. There are 7 SubCSAs within this Operational CSA, including Cable Remediation, WPC, Targeted Capacity, Targeted Reliability, Pole Replacement Program, Hosting Capacity Analysis, and Virtual Power Plant.
Operational Program Objectives:	Reliability Objectives: • Improve reliability of remaining worst performing circuits of 135 identified by 50% • Improve reliability to highest priority non-WPC problem areas • Replace 402 miles of cable • Achieve 117 - 121 minutes SAIDI by 2026 Resiliency Objectives: • Address priority pole and substation assets and levelize ongoing program • Address high and highest priority wildfire risk areas • Enable grid automation at 110 locations Grid Capability (Smart and Flexible) Objectives: • Enable grid visibility and control across 40 substations and 15% of distribution circuits, which enables DER integration, higher solar penetration and microgrids • Support buildout of EV program with adequate infrastructure reinforcement and technology • Enable remote meter reconnect/disconnect at all electric meters • Implement grid energy efficiency optimization on 30 circuits (volt-var optimization and conservation voltage reduction).
Primary ISP Alignment:	**Processes & Tools** **ISP strategy descriptions**

ISP Strategy Description:	Please see the Cable Remediation, Worst Performing Circuit Program, Targeted Capacity, Targeted Reliability, Pole Replacement Program, Hosting Capacity Analysis, Map, and Customer Portal, and Virtual Power Plant SubCSAs for more detail regarding those specific programs. Below are the 15 business cases that support this CSA:

2021 Update_TARGETED (	2021 Update_TARGETED I	2021 Update_WPC PROGRAM Business	CVR PROGRAM Business Case 2021_
CVR PROGRAM Business Case 2021_	DA PROGRAM Business Case 2021 .	FUSESAVERS PROGRAM Business	PROACTIVE FEEDER UG CONVERSION PF
RECLOSERS PROGRAM Business	Submarine Cable Business Case_Final.	SUBSTATION RELIABILITY PROGRA	SUBSTATION SCADA PROGRAM Bı
T&D STRATEGIC POLE PROGRAM Bus	TRANSMISSION AUTOMATION PROC	Wildfire PROGRAM Business Case 2021-	

Process & Tools - System reliability and integrity

II. Key Benefits: *Please provide key metrics you track/measure to ensure that you are running business efficiently with the funding you're receiving.*

Metrics related to number of projects, completion of projects/miles/substations/locations can be measured immediately after completion. Metrics related to reliability and circuit performance are backcasted or tested 3 years after project has been completed in order to relicate similar circuit events over time.

Benefit Description	Metric (average annual)	Metric Type	Target (2022 - 2026)
Primary Reliability – outage duration	SAIDI reduction	Quantitative	117-121 SAIDI by 2026
Reliability – non-MED CMI	CMI	Quantitative	134 million CMI Saved (avg. 26.9M/year)
WPC projects completed	# projects / circuits	Quantitative	All 135 WPC (~100 WPC projects)
Substation SCADA installed	# substations	Quantitative	106
Distribution automation completed	# circuits	Quantitative	416
Reclosers installed	# reclosers	Quantitative	200
Fusesavers installed	# fusesavers	Quantitative	600
Cable Remediated	# miles	Quantitative	402
Transmission Automation completed	# transmission lines	Quantitative	23
Targeted Capacity Upgrades	# circuits	Quantitative	75
Targeted Reliability Upgrades	# circuits	Quantitative	446
OH converted to UG	# miles	Quantitative	36
Poles inspected	# inspected	Quantitative	~30,000 dist/yr ~3,000 trans/yr

Poles Replaced	# replaced	Quantitative	~500 – 1,600/yr
Substation assets replaced	# equipment	Quantitative	330

III. Year-to-Year Operational Metrics and Costs:

Different reliability strategies are applied under this program, including tree wire, underground conversions, overhead rebuilds, adding new feeder ties and distribution automation and more recently considering non-wire alternatives such as energy storage solutions. Because of the unique issue and solution, per unit analysis is not relevant. Primary changes in cost are associated with timing of projects, changing jurisdictional requirements for hard surface restoration, locational requirements, and general inflation/contract increases.

	Prior Year (2020)	Current Year (2021)	Change
Number of units or distance	N/A	N/A	N/A
Per unit cost ($/unit or $/distance)	N/A	N/A	N/A
Capex (total $)	N/A	$207,307,260	
Per unit cost driver	N/A		

IV. Estimated Five Year Allocation:

The 2022-2026 estimated five year allocation and breakdowns are shown below. The high level changes from last year's 2021-2025 five year allocation include:

- Minimal changes to 2022 budget
- Added Wildfire and Submarine Cable requests for 2023-2026
- Additional specificity within the DER circuit enablement bucket including:
  - High solar penetration circuit enhancement (visibility, control and dispatch)
  - VVO implementation
  - IT grid mod platform support (VPP, DER Valuation Tool, DERMS)
- Additional budget for Resilience Enhancement including:
  - Operational flexibility enhancement for radial circuits
  - Physical security for key DER locations
  - Cybersecurity
  - T&D asset monitoring and risk reduction
- Increased budget for distribution capacity work
  - Assumptions related to EV penetration, electric new customers, and electrification build-out
- Additional budget for DER/Substation property acquisition and expanded ROW acquisition

Category:	**Year 1**	**Year 2**	**Year 3**	**Year 4**	**Year 5**	**Total**
	2022	**2023**	**2024**	**2025**	**2026**	
Capital (contingency included)	$227,699,190	$285,094,263	$317,283,699	$323,158,245	$345,118,394	**$1,498,353,791**
OMRC/Ongoing O&M	$11,185,755	$12,726,786	$11,155,008	$11,468,736	$12,071,743	**$58,608,028**

*OMRC/Ongoing O&M is estimated at an average of 5% across all programs in the WBS Level 3 inclusion below except Substation SCADA, Cable Remediation, Pole Replacement Program, King County/WSDOT Clear Zone Pole Programs, Distribution Automation, Transmission Automation, Reclosers, WPC/RRM, UG System, Fusesavers, and Hosting Capacity and LoadSeer. These programs either have a separate budgeted WBS or an estimated average using historical data. The Pole Program OMRC/Ongoing O&M is estimated as high as 17%

and the WSDOT King County Clear Zone Pole Program is estimated as high as 14%. Years 2022 – 2023 also include $300,000 of O&M dollars to closeout the CVR program.

WBS Level 3 inclusion.
CETA compliance impact is indicated across the portfolio in the last column. An empty circle indicates no impact, while a fully filled circle indicates a key investment for CETA compliance.

Category:	**Year 1**	**Year 2**	**Year 3**	**Year 4**	**Year 5**	**CETA Compliance**
	2022	**2023**	**2024**	**2025**	**2026**	
Conservation Voltage Reduction (CVR)/Volt-Var Optimization (VVO)	$1,225,000	$1,225,000	$3,750,000	$3,750,000	$3,750,000	◑
Grid Automation	$29,500,000	$42,000,000	$56,950,000	$71,250,000	$86,050,000	See breakdown below
Substation Scada (not incl IP SCADA – IT)	$11,250,000	$15,000,000	$20,000,000	$20,000,000	$20,000,000	◑
Cable Remediation	$30,500,000	$40,000,000	$40,000,000	$40,000,000	$40,000,000	○
Electric System Upgrades (incl WPC)	$99,550,000	$111,080,000	$126,080,000	$116,080,000	$125,580,000	See breakdown below
Electric System New Distribution	$10,618,000	$10,000,000	$10,000,000	$10,000,000	$10,000,000	○
Pole Replacement Program	$27,898,540	$20,868,435	$10,529,394	$10,529,394	$10,529,394	○
Substation Replacement Program	$9,000,000	$30,000,000	$30,000,000	$30,000,000	$30,000,000	○
King County Clear Zone Pole Program	$3,212,000	$3,212,000	$3,212,000	$3,212,000	$3,212,000	○
WSDOT Clear Zone Pole Program	$2,750,000	$2,750,000	$2,750,000	$2,750,000	$2,750,000	○
Central Bellevue District	$650,250	$2,653,020	$2,706,081	$2,760,202	$2,700,000	○
Smart Meter Technology	$20,400	$20,808	$21,224	$21,649	$22,000	○
Resilience Enhancement	$1,025,000	$4,525,000	$9,525,000	$9,525,000	$9,525,000	●
Data Lake and Data Analytics	$500,000	$1,760,000	$1,760,000	$3,280,000	$1,000,000	◑

Grid Automation Breakdown

Category:	Year 1	Year 2	Year 3	Year 4	Year 5	CETA Compliance
	2022	2023	2024	2025	2026	
Distribution Automation	$9,000,000	$12,000,000	$20,000,000	$28,000,000	$35,000,000	○
Transmission Automation	$2,000,000	$2,000,000	$4,000,000	$4,000,000	$4,000,000	○
Reclosers	$3,000,000	$3,000,000	$3,000,000	$3,000,000	$3,000,000	○
DER Circuit Enablement – DERs & Microgrids	$2,500,000	$15,000,000	$17,500,000	$22,500,000	$27,500,000	●
DER Circuit Enablement – IT Grid Mod Platform*	$2,500,000	$1,500,000	$1,500,000	$1,000,000	$2,500,000	●
Circuit Enablement Electric Vehicle	$6,700,000	$7,600,000	$10,700,000	$12,500,000	$13,800,000	●*
Living Lab	$3,800,000	$900,000	$250,000	$250,000	$250,000	○
Total	**$29,500,000**	**$42,000,000**	**$56,950,000**	**$71,250,000**	**$86,050,000**	

*IT Grid Mod Platform – the VPP SubCSA is included in this bucket
*Electric Vehicle - CETA compliance varies due to reliance on alternative compliance.

Electric System Upgrades (incl WPC) Breakdown

Category:	Year 1	Year 2	Year 3	Year 4	Year 5	CETA Compliance
	2022	2023	2024	2025	2026	
WPC	$45,000,000	$23,000,000	$15,000,000	$0	$0	○
Other Reliability	$39,200,000	$49,000,000	$65,000,000	$61,000,000	$70,000,000	○
UG System	$0	$15,000,000	$25,000,000	$25,000,000	$25,000,000	○
Fuse Savers	$3,000,000	$3,000,000	$3,000,000	$3,000,000	$3,000,000	○
Fault Location	$250,000	$250,000	$250,000	$250,000	$250,000	○
Hosting Capacity and LoadSeer	$3,500,000	$30,000	$30,000	$30,000	$30,000	●
Mobile DG	$2,000,000	$4,000,000	$500,000	$500,000	$500,000	○
Root Cause Analysis	$2,600,000	$5,200,000	$5,200,000	$5,200,000	$5,200,000	○
Submarine Cable	$2,000,000	$4,000,000	$4,000,000	$12,500,000	$12,500,000	○
Wildfire	$2,000,000	$2,000,000	$2,500,000	$3,000,000	$3,500,000	○
Property Acquisition – expanded ROW and DER/Substation property	$0	$5,600,000	$5,600,000	$5,100,000	$5,600,000	◑
Total	**$99,550,000**	**$111,080,000**	**$126,080,000**	**$116,080,000**	**$125,580,000**	

PSE PUGET SOUND ENERGY
The Energy To Do Great Things

V. CSA Approvals

Add/remove rows as needed in the table below. Email approval is acceptable. To maintain a history of the changes at each phase gate change, ***copy/paste the table below above the previous table.*** *Send to the Capital Budget team at CSA-TeamMail@pse.com. For a project in the Strategic Project Portfolio (SPP) review the* Escalation Criteria *for appropriate escalation and approvals..*

Project Phase	Select Phase			
Approved By	**Title**	**Role**	**Date**	**S**
Catherine Koch	Director Planning	*Director Sponsor	05/7/2021	DocuSigned by: Catherine Koch D3835A30CBC142D...
Roque Bamba	Director Project Delivery	Other Key Director	05/7/2021	BC203E4E58BB426...

*Director Sponsor attests that all considered documentation has been approved.

Please direct any questions to either:
1. The Capital Budget team at CSA-TeamMail@pse.com, or
2. The Enterprise Project and Performance Project Practices team at EPP-ProjectPracticesTeam@pse.com

DER AND MICROGRID CIRCUIT ENABLEMENT

ENERGY TYPE: ELECTRIC

1. SHORT DESCRIPTION

A grid modernized distribution circuit is one that permits transactive energy from sources that either produces (i.e. solar photovoltaics or wind turbines) or stores energy (i.e. battery storage). In either scenario, there are multiple use-cases that improves electric system performance when used for peak load shaving, demand response, and back-up power during outages. This translates to non-wire alternatives, SAIDI & SAIFI savings, and new customer plans inclined towards renewable energy. With the enactment of the state's Clean Energy Transformation Act (CETA), this has accelerated PSE's grid modernization efforts to meet the clean energy targets. Consequently, the Distributed Energy Resources (DER) and Microgrid circuit enablement plan will tackle constraints on the electric system in order to enable behind-the-meter (BTM) and front-of-the-meter (FTM) assets at scale.

2. BACKGROUND

The electric grid has seen a growth in DERs both in front and behind the meter. In FTM, PSE installed various battery systems in the cities of Glacier and Poulsbo. PSE is in the process of engineering more systems that involve batteries/solar PV in Tenino, Bainbridge Island, and Samish Island. Conversely, PSE has two behind-the-meter demonstrations on Bainbridge Island to study the effects of DERs to utility operations. In addition, there are 11,046 BTM DER systems in PSE's service territory recorded (since 2010) through PSE's net-metering program. The net-metering program has seen in total ~88.8 MW of power export from customers onto the electric grid.

The number of these systems will rapidly expand to match the CETA enacted by the state of Washington and PSE's Integrated Resources Plan (IRP) which call for 80% of electric sales (delivered load) to be met by non-emitting/renewable resources by 2030. Ultimately, this presents two unique challenges: 1) How to increase BTM and FTM DER penetration to achieve the goals laid out by CETA/IRP and 2) Developing microgrids that can bring customers more system reliability and resiliency.

3. STATEMENT OF NEED

Over the past decade, net-metering trends point to approximately 500% growth rate over PSE's service territory. The number of these systems will be compounded by the Clean Energy Implementation Plan (CEIP) and the results of PSE's DER request for proposals (RFP) put in place in response to CETA. The table below (derived from the IRP) outlines the DER additions in order to meet CETA standards.

	Incremental Resource Additions			Total
	2022-2025	2026-2031	2032-2045	
Distributed Energy Resources				
Battery Energy Storage	25 MW	175 MW	250 MW	450 MW
Solar	80 MW	180 MW	420 MW	680 MW
DSP Non-Wire Alternatives*	22 MW	28 MW	68 MW	118 MW
Total	127 MW	383 MW	737 MW	1248 MW

*DSP Non-wire alternatives are resources such as energy storage systems and solar generation that provide specific benefit on the transmission and distribution systems and simultaneously support resource needs

PSE is beginning to implement tools such as Hosting Capacity Analysis and LoadSeer, which models the effects of DERs on a circuit-by-circuit basis. As the DER portfolio scales, the peak capacity output for DERs on a circuit will be clamped by the existing grid infrastructure, as the system does not accept high amounts of reverse power flow. This is a prevalent condition in 56% of distribution circuits (or 179 distribution substations) where low transformer loading conditions exist. Moreover, primary and/or secondary conductors on distribution feeders pose as chokeholds to DER capacity in both aggregated/non-aggregated instances. Lastly, voltage imbalances caused by DER production onto the grid impacts reliability, which in turn limits available hosting capacity. The grid will require dynamic voltage control and visibility to operate DERs effectively across the system.

PSE is actively engaging in two microgrid pilot projects in the Tenino and Samish Island areas to realize the benefits of microgrids. The on/off grid use-cases being observed point to a potential increment in reliability and resiliency benefits. As value streams are defined using results of the microgrid pilots, non-wire alternative studies and customer plans will scale microgrids. Subsequently, key technology deployments are needed to develop the microgrid controls over DER assets on the grid.

3.1. Need Drivers

- **Grid Modernization**
  - **Reliability –** The current grid infrastructure limits the ability for mass DER export. Managing the diverse energy portfolio with intermittent resources whilst being able to maintain reliable utility power creates new operating parameters on the grid. Close studies of the circuits with higher DER penetration shall address circuit infrastructure constraints and create a path forward to enable them for DERs and Microgrids.
  - **Safety** – Grid modernization needs to occur in order to effectively manage DERs and microgrids for worker and customer safety. This plan achieves this by implementing technology/equipment to ensure power backfeed is sectioned off appropriately during normal/abnormal events as well as managing their intended behaviors.

- **Resiliency** – DERs and Microgrids provides opportunities for backup power during system outage events. By modernizing the grid, this plan can expand those opportunities to greater parts of the system thus increasing resiliency.

3.2. Integrated Strategic Plan (ISP) Alignment

This plan aligns primarily with the Processes & Tools category of the ISP:

- Streamline processes to drive effectiveness and efficiency:

  Enabling DERs and Microgrids on the circuit will drive integration efforts to other enterprise-wide technologies such as Advanced Distribution Management System (ADMS), Virtual Power Plant (VPP), and Distribution Energy Resource Management System (DERMS). The landscape of the electric grid is vastly altered when sources can stem from DERs and utility power. Leveraging multiple technologies requires tactful engineering and training to maintain grid stability.

  The DER and microgrid circuit enablement plan will also serve as a platform oncoming customer renewable programs that are driven through systems such as VPP and DERMS. A capable circuit that is primed for DERs and Microgrids is one that can maintain power quality from impacted DER energy capacity and the ability to sectionalize itself for resiliency. In turn, customers gain a clear process to seamlessly interconnect DERs to the grid as well as an option to explore a microgrid in their community.

- System Reliability and Integrity: An electric system that can accommodate increased DERs and microgrids at scale will see in return additional available energy capacity. This translates to creating more headroom for system operations when needing to "pickup" customers during non-storm/unplanned outages. Electric dispatch and repair times will shrink due to remote operations of DER energy dispatch and automatic forming of microgrids. Lastly, as DERs are continually adopted across the service territory, the ability to call upon DERs leads to energy supply portfolio optimization.

- Extract and leverage value from existing technology and assets: The DER and Microgrid circuit enablement plan lays a foundation for multiple technologies on the grid modernization roadmap. ADMS, VPP, DERMS, and AMI are all systems that tie into the infrastructure set forth by this plan.

4. PLAN DETAIL

4.1. Plan Size/Population

The exact plan scope is subject to three major factors: 1) Hosting Capacity Study Results 2) The CEIP and 3) The DER strategy. Nonetheless, as DER initiatives and non-wires alternatives ramp-up penetration over time, the plan work will be set to follow targeted areas. Below are key tasks to achieve DER and Microgrid circuit enablement:

- Upsizing of assets such as conductors and service transformers to accommodate additional renewable energy capacity
- Additional line capacitors/regulators and/or substation transformer upgrades for voltage regulation
- Additional reclosers and protective relays to form microgrids
- Substation upgrades such as smart circuit breakers, 115 kV circuit switchers, or communications to protect system from higher fault currents
- Improving communication networks for granular loading data

Plan population size and data shall ultimately be determined by hosting capacity studies, the CEIP, and the DER strategy. Although a range of factors can contribute to limited hosting capacity, lightly-loaded substation circuits pose as key investment areas for infrastructure upgrades. Initial studies point to 179 distribution substations out of 320 total using low transformer loading criterion. Transformer peak winter/summer ratings are individually measured and ranked in this category if loading is between 0-50 percent of nameplate rating. By enabling these circuits, DERs and microgrids are able to add value in more parts of PSE's service territory, thus extending benefits to all of PSE's customers.

4.2. Proposed Completion Date

This plan shall be ongoing to match the needs of the CETA and PSE's IRP. Current plans are through 2026.

4.3. Summary of Plan Benefits

a) A new process that addresses DERs and Microgrids at scale

The current battery storage and solar PV projects at PSE target specific needs such as delivering capacity using a non-wires alternative or concept demonstrations for peak-shaving, demand-response, and resiliency use cases. By instantiating this plan, PSE is proactively addressing circuit constraints that limit DER penetration and microgrids.

b) Improved Customer Satisfaction/Experience

This plan aims to create more opportunities for customers seeking to interconnect DERs or form microgrids by proactively enabling circuits that are limited in hosting capacity/microgrid capabilities.

c) Grid Modernization

PSE is able to further its grid modernization efforts by increasing system visibility, automation, and flexibility. Furthermore, this plan plays a role in creating new operating practices/policies when interfacing with customers adding DERs or microgrids onto the grid.

4.4. Primary iDOT Categories

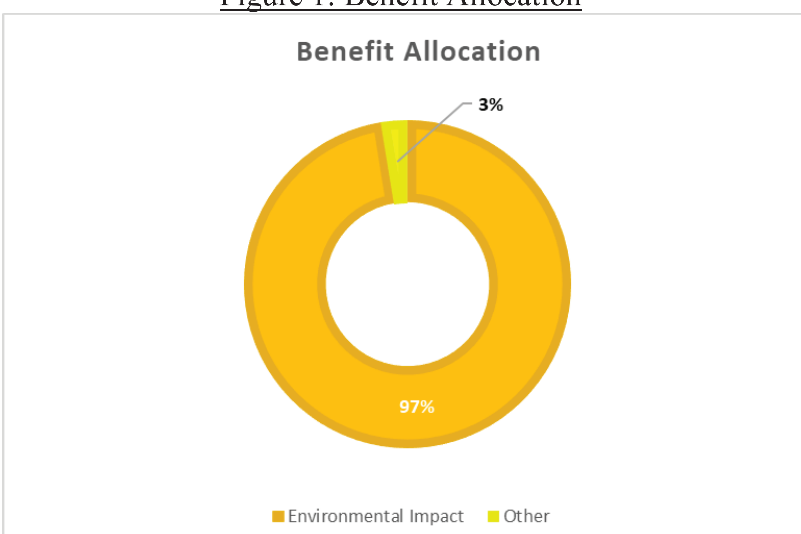
The primary iDOT Categories related to this plan are:

- TBD

Table 3: Summary of Plan Benefits and Population

2022-2026	Number of Projects	Budget ($M)[1]		NPV ($M)[2]	iDOT B/C Score[3]
		Capital	OMRC	Total Benefits	
Total	**67**	**85**	**0**	**744.32**	**10**

Figure 1: Benefit Allocation[4]



[1] Budget indicate are sum of future year budget as it is allocated for that specific year
[2] Benefits indicated are Net Present Value (NPV) sum of future year benefits allocated for that specific year
[3] B/C Score uses NPV of Benefits and Budget
[4] Risk of not achieving budget and expected benefits is 11.0%

4.5. Estimated Total Costs

DER and microgrid circuit enablement costs vary based on location and quantity. In worse-case scenarios, replacement of a substation equipment to provide voltage regulation and short-circuit current breaking capabilities average ~$1.5M. This figure can vastly change depending on coordination with other capital or O&M projects. The initial estimated cost is set at $85M to enable 179 substations and their associated circuits. More accurate details is to be determined pending on the results of the DER RFP and CEIP.

5. ALTERNATIVES

5.1. Solution alternatives

No Action – Failure to implement this plan puts PSE at risk to comply with CETA. The lack of targeted infrastructure improvements hinders the ability for DERs and microgrids to scale and provide benefits to all of PSE's customers.

Place a moratorium for DER and microgrids connections until a circuit enablement program is in place – this is not feasible as customers can still connect DERs without a way for the utility manage it.

Curtail customer DER output – this is a much more costly solution that uses a separate communication infrastructure to control and monitor customer DER devices.

5.2. Funding alternatives

Increase Funding from Proposed – Invest into modelling tools (LoadSEER, Hosting Capacity Analysis, and internal resources) to better identify impacted areas. Develop tools geared towards customers such as DER interconnection maps that show available hosting capacity across system. In addition, build similar tools to gauge customer interest in community microgrids based on current grid modernization capabilities.

Decrease Funding from Proposed –Decreased funding will delay DER interconnections which presents a bottleneck to achieving the goals set out by CETA.

6. PLAN DOCUMENT HISTORY

The current version of the project summary supersedes all previous versions.

Date	Reason(s) for Update	Summary of Significant Change(s)	Modified By
11/12/2021	Initial Plan	Initial document	Joseph Do

7. SUPPORTING DOCUMENTATION

Document Name
FINAL 2021 INTEGRATED RESOURCE PLAN, CHAPTERS 2/3/4/8/APPENDIX M

RESILIENCE ENHANCEMENT – EXPANDED

ENERGY TYPE: ELECTRIC

1. SHORT DESCRIPTION

The Resilience Enhancement Program aims to implement proactive monitoring of the electric system with better real-time insight into condition in order to limit outage consequences. The intent is to monitor and predict equipment failures and to reduce the effect on our customers. It is currently divided into three focus areas: Line asset monitoring, Radial feeder improvements, and Transformer Health monitoring. These programs are specifically targeted to improve reliability, and resiliency during extreme events. Improvements align with the CEIP customer benefit indicators and considers named communities for both HIC and VP in its prioritization.

Line asset monitoring consists of improvements in predicting and replacing failing equipment in the transmission and distribution lines. Develop conductor, splice, and insulator replacement by utilizing in-house drones to perform LiDAR, Infrared (IR), and visual scanning of the transmission and distribution system. This program also seeks to accelerate #6 copper replacement in high-risk areas, monitor the underground transmission sections, and replace obsolete yellow-jacket feeder getaways from the substation.

Radial feeder improvements consist of evaluating and improving the reliability of radially-fed distribution feeders which have no other means of backup for power service. This will include evaluation of distributed generation and battery systems that could run in an island configuration to reduce outage duration and severity. This program will coordinate with the distributed generation enablement that PSE is already performing.

Transformer health monitoring consists of online dissolved gas analysis (DGA) monitors on substation distribution transformers to measure the transformer health by measuring gases dissolved in the transformer mineral oil. PSE is also evaluating other online monitoring such as bushing monitors and this program will coordinate with the next generation transformer controllers currently in development. The final aim is to integrate complete transformer monitoring systems into asset management software packages to create real-time holistic transformer risk ratings to drive a condition-based maintenance program

2. BACKGROUND

Resiliency Enhancement efforts align with PSE's larger efforts to mature our asset management system to better manage the electrical system. A robust asset management system requires up-to-date condition data and integration into a holistic analysis solution. Improved monitoring and equipment assessment is an important step in reducing system outages for our customers, addressing both safety and reliability effects.

Ground-based line inspection is labor intensive, slow, and produces incomplete results by necessarily being far away from the high voltage connections and insulators. Vegetation work is performed on a cyclic basis, line equipment is replaced on a reactive basis, and problems are not identified until after they cause outages or ignitions.

Currently, distribution transformers and tap-changer compartments are sampled manually by substation inspectors on 6- and 12-month cycles. This frequency changes by model type and equipment condition. The sampling process is labor intensive, the laboratory turn-around time is slow, the manual samples are somewhat inconsistent, evaluation of the results is manual, and the data is entered into a health database in a manual, labor-intensive manner.

Additionally, the need to address extended outage times for customers connected by radial feeders addresses the consequence of outages. PSE is actively working on enablement for distributed generation facilities as part of CETA efforts and aligned with our overall integrated resource plan, and utilizing distributed generation/storage solutions to solve these issues is aligned with the Grid Modernization efforts already underway.

3. STATEMENT OF NEED

Robust, real-time monitoring of the condition of system assets is essential as PSE continues to develop a mature asset management system capable of predicting the best use of maintenance and replacement dollars to minimize outages and system downtime for our customers. The Resilience Enhancement Program aims to fill the largest gaps in system monitoring and to address the consequences of system outages to improve reliability.

3.1. Need Drivers

- **Grid Modernization –**
  - **Safety** – Reacting to a fault after the fact adds significant safety concerns to the public and drives a need to develop predictive assessment of the line assets. With better real-time monitoring, we can identify degrading assets and prevent outages.
  - **Resiliency** – The resiliency efforts are focused on high-impact, low-frequency (HILF) events. The outages occurring on radially-fed lines are generally longer and lead to a higher SAIDI than the system as a whole.
  - **Smart & Flexible** – The integration of distributed generation and storage into the electrical system to fill missing components aligns with the larger PSE strategy of flexibility

3.2. Integrated Strategic Plan (ISP) Alignment

This program aligns primarily with the Processes & Tools category of the ISP:

- **System Reliability and Integrity**: This program specifically addresses a missing monitoring component of a mature asset management solution to drive better reliability for our customers.
- **Streamline Processes to Drive Effectiveness and Efficiency:** The Asset Management program development relies on holistic, real-time data acquisition in order to predict maintenance and replacement needs ahead of equipment failures. The
- **Extract and Leverage Value from Existing Technology and Assets:** To achieve the most value from the lifecycle of our assets requires a robust asset management solution fed by real-time and consistent data.

4. PROGRAM DETAIL

4.1. Program Size/Population

- Line asset monitoring
  - Drone inspections with infrared (IR) and LIDAR scanning of transmission lines and distribution circuits to identify failing hardware, maintenance needs, clearance encroachments, vegetation concerns, etc.
  - Transmission switches
  - UG Transmission monitoring
  - Distribution SCADA switch maintenance. Connect switch to a monitoring system to drive proactive maintenance. The switches need high availability to be functional for distribution automation, and to allow the flexibility needed for DER enablement. With the ever expanding fleet of SCADA switches, maintenance must be coordinated with a condition-based program and not reactively after failure.
- Radial Feeder Improvements
  - There are approximately 37 radially fed circuits that have opportunity for distributed generation/storage to mitigate outages.
  - There are several possible solutions to the issue of radial feeders. The traditional method is to loop into adjacent circuits with feeder ties. In the more remote regions of the system, this is not often possible. A possible solution would be a mobile generation facility that could be quickly deployed during outage events. This can help bring back power before the line is able to be fully repaired, but the outage still occurs and deployment may not be significantly faster than the original repair. A more enticing solution is to develop a micro-grid on the feeder where generation and/or storage are employed to immediately source power in the case of a fault detaching the feeder from the main system.
  - PSE is currently developing a demonstration micro-grid projects in Tenino and Samish Island.
  - This program seeks to continue the research and development needed for successful micro-grid installations and to implement solutions as the need is identified.
- Distribution Transformer Health Monitoring
  - Following the successful installation of online DGA (dissolved gas analysis) monitors on the fleet of distribution transformers, PSE proposes to evaluate and install Online DGA
    - 250 Transformers with OLTC
    - 110 Transformers without OLTC

- Including remote access communications
- Integrated into maintenance server and asset management software

4.2. Proposed Completion Date

This phase of the program is for five years of system improvements to address the highest concerns. Ongoing benefit evaluation will determine the effectiveness of program to with evaluation on scope, and benefits for future program continuation.

4.3. Summary of Plan Benefits

Current ground-based line inspection and post-event, reactive maintenance does not address the growing problems of aging infrastructure and the cumulative effects of environmental wear and equipment degradation. Drone-based aerial inspections and LiDAR/IR scanning will allow significantly more line distance to be covered annually and provide close-up visual inspection along with thermal imaging. The intent is to identify failing splices, insulators, cross-arms, and pole-tops and to route this work to the appropriate department for repair/replacement. The LiDAR mapping will assist with identifying vegetation concerns.

The radially-fed circuits pose a higher consequence of failure than other parts of the electric system as they require significantly longer restoration. Customers on these circuits experience higher SAIDI than other customers. Addressing this gap will realize a reliability benefit for these customers, allowing them to be back-fed from adjacent circuits or providing closed-system islanding with batteries or distributed generation. This program will work hand-in-hand with existing distributed generation programs underway at PSE.

Online transformer monitoring is part of a larger integrated transformer health monitoring system. After successfully deploying online dissolved gas analyzers on the transmission-level transformers, this program seeks to expand to the distribution-class transformers. Dissolved gas analysis (DGA) examines the gases produced inside a transformer, and dissolved into the mineral oil, to identify overheating, insulation degradation, arcing, and partial discharge events that can lead to transformer failure. Online DGA provides numerous benefits over traditional manual sampling. The frequency of manual samples is 6-12 months, whereas online samples occur every 4 hours. The samples are taken with identical consistency and analyzed immediately as opposed to a 2-week laboratory turn around. The online monitor can be integrated with other real-time monitoring (bushing power factor, motor current, tap wear, temperature) and integrated into holistic asset management software to identify problems early and predict failures long before they occur. This allows for maintenance efforts to repair equipment or to replace a unit in a planned capital project as opposed to an unplanned event following an outage.

4.4. Primary IDOT Categories

The primary IDOT Categories related to this program are:

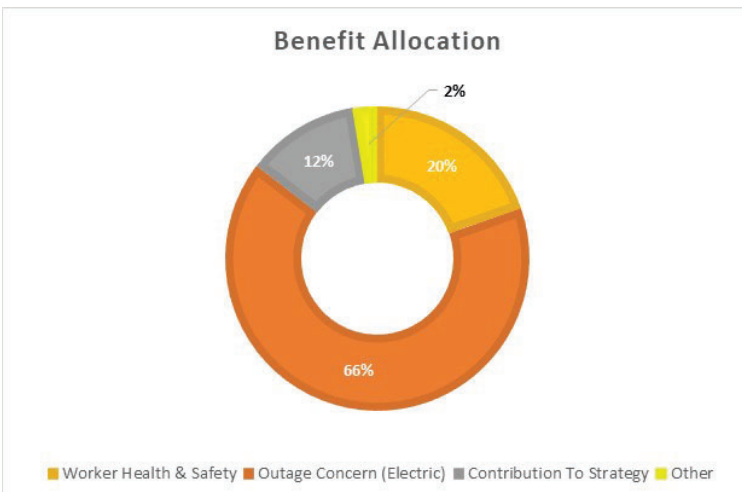
- Outage Concern
- Safety
- Contribution to Strategy

Table 2: Summary of Program Benefits, Population, and IDOT B/C Score per Year

2022-2026	Number of assets	Budget ($M)[1]		NPV ($M)[2]	iDOT B/C Score[3]
		Capital	OMRC	Total Benefits	
Total	**120** (DGA monitors) See note	**20.1**	**0**	**114.63**	**6.23**

Note: Also includes 4 Radial feeder improvements, additional drone inspection hardware, and 180 miles of drone inspection per year.

Figure 1: Benefit Allocation



4.5. Estimated Total Costs

Over the next five years, the Reliability Enhancement Program costs is estimated to be $20 million in Capital and $2 million in OMRC.

For Electric System Planning estimated costs are generated based off of historical costs on similar types of projects, allows for variations in project scope, increase in project cost due to

[1] Budget indicate are sum of future year budget as it is allocated for that specific year
[2] Benefits indicated are Net Present Value (NPV) sum of future year benefits allocated for that specific year
[3] B/C Score uses NPV of Benefits and Budget

inflation, and added contingency to account for unforeseen conditions associated with the project.

Total estimated cost are based on:

$2.5M for installation of generator on radial feeder.
$35k for installation of DGA (dissolved gas analysis) monitoring units on substation transformers.

5. ALTERNATIVES

5.1. SOLUTION ALTERNATIVES

No Action – No action would lead to lost opportunity for monitoring and trending health conditions for assets. PSE remains reactive instead of proactive in addressing reliability SAIDI and SAIFI. This decreases PSE's ability meaningful improve key CEIP customer benefit indicators related to energy resiliency in named communities.

5.2. FUNDING ALTERNATIVES

Increase Funding from Proposed – Increased funding has the opportunity for expanded and accelerated scope of these efforts. The current 5-year proposal is for phase 1 efforts that have the highest benefit. Enabling this effort more quickly brings benefits sooner to customers and allows for additional efforts to the next phase of locations.

Decrease Funding from Proposed – Decreased funding would result in reduced and delayed scope of effort. PSE would see a delay in realizing the benefits.

6. PLAN DOCUMENT HISTORY

The current version of the project summary supersedes all previous versions.

Date of Project Summary Revision	Reason(s) for Update	Summary of Significant Change(s)	Modified By
07/01/21	Initial Plan	Initial document	Josh Pelman

7. SUPPORTING DOCUMENTATION

Document Name
NONE