Bainbridge Island Non-Wires Alternative Analysis

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TABLE OF CONTENTS

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EXECUTIVE SUMMARY

Navigant performed an assessment of the potential for Non-Wires Alternatives (NWA) to meet the range of electricity delivery needs on Bainbridge Island (BI), and provided input to Puget Sound Energy (PSE) in preparation for an upcoming Stakeholder meeting on BI, at which NWA will be a topic of discussion.

Key findings include:

- A hybrid non-wires solution[1] used to meet some portion of distribution capacity needs is technically feasible and is economically-preferable to the wired solution[2] based on the analysis of net costs used in this report.
- PSE may cost-effectively delay reaching the investment planning trigger for the 3-substation group on BI from 2020 to approximately 2030 by leveraging the ferry electric load as a curtailable resource, by installing in front of the meter storage, and expanding the non-storage DER portfolio on BI.
- PSE should launch an NWA pre-implementation analysis to validate the results presented here, specifically exploring the cost uncertainty and implementation risk associated with customer-facing programs, such as ramp-up time, necessary incentives, and stakeholder concerns.

Background and Data Review: Navigant reviewed background documentation and data from PSE to understand the situation on BI, the existing electric infrastructure and constraints and potential traditional wired solutions that have been developed by PSE. Important sources of information included the DRAFT *Bainbridge Island Electric System Needs Assessment* (May 14th, 2018) developed by PSE as well as the *DRAFT Bainbridge Island Electric System Solutions Report* (August 1st, 2018) in addition to customer and load forecast data available from PSE. Navigant also leveraged the 2017 PSE Integrated Resource Plan (IRP) and the distributed energy resources (DER) potential study that was incorporated into the IRP[3] as well as other regional sources of information (e.g., Northwest Power and Conservation Council (NPCC) 7th Plan documentation) and Navigant's own engineering experience with NWA analysis and traditional transmission and distribution (T&D) planning and engineering.

Analysis Approach: Navigant worked with PSE to define the analysis parameters and deconstruct the overall problem into components appropriate for analysis. This approach helped the team identify actions that may meet specific portions of the needs, and to understand the timing and costs of those potential actions.

- Potential Solution Elements: the NWA solution elements and measures fall into two categories:
  - DERs considered in the analysis: The specific set of DERs considered in the analysis were developed in conjunction with the PSE Team. These include: **energy efficiency (EE), demand response (DR), customer-sited solar photovoltaics (PV), energy storage, and combined heat and power (CHP)** (renewable anaerobic digesters only).

[1] A hybrid non-wired solution is defined as a solution that included both wired and non-wired components with the non-wired components dependent upon the wired components being constructed and in-service.

[2] A wired solution is defined as only traditional wired components such as poles, wires, transformers, etc.

[3] This DER potential study was titled "Conservation Potential Assessment" and was included as Appendix J of the *2017 PSE Integrated Resource Plan*. This study was performed by Navigant for PSE during 2016. The 2017 PSE IRP can be found at: https://www.pse.com/pages/energy-supply/resource-planning

  - Broader definition of NWA considered but not analyzed: in our experience, the electric utility industry defines non-wires alternatives as a non-traditional investment (e.g. DERs) to replace or defer a traditional grid-side capital investment (e.g. poles, wires, transformers). However, stakeholders may interpret the term "non-wires alternatives" more broadly. For this reason, Navigant also considered traditional utility O&M activities such as vegetation management and targeted asset replacement in our overall assessment but did not include these in the detailed analysis.

- Problem Deconstruction and Definition: Navigant deconstructed the overall problem on Bainbridge Island along two dimensions: specific *identified needs*, and *grid elements* to 1) define the specific problem being considered, and 2) identify where that problem fits in the overall picture of BI needs. This deconstruction is intended to cover the entire potential range of solutions—wired and non-wired—so that stakeholders may see and understand that PSE is pursuing a comprehensive approach to meeting specific needs.
  - Needs deconstruction: specific areas of need, based on the PSE needs analysis structure, were considered separately. These areas were: *Capacity*, *Reliability*, *Operational Flexibility*, and *Aging Infrastructure*.
  - Grid deconstruction: Deconstruction into transmission and distribution components is consistent with the existing grid architectural structure, and it was useful in this case for defining the analysis components of the overall solution.[4]

- The team used the two types of deconstruction to analyze the following solutions:
  - Traditional Wired Approach: PSE has developed and documented a traditional wired solution that has a high probability of meeting the needs but is expensive relative to many grid investment projects.
  - Exclusively Non-Wired Alternative Approach: Navigant performed a preliminary assessment of meeting the entire set of identified needs using exclusively NWAs (as broadly defined above). This approach is technically possible but not realistic given the likely overall cost (large amount of electric storage capacity required) as well as significant disruption on Bainbridge Island (requires aggressive tree trimming and removal).
  - Hybrid Non-Wired Solution Approach: Navigant used the deconstruction above to individually examine specific elements of the need that are not addressed by the wired solution components associated with the transmission loop. While meeting the entire set of needs simultaneously will require further analysis, key portions of the needs—distribution substation capacity related needs—showed promise for non-wires solution approach, and so were analyzed in more depth.

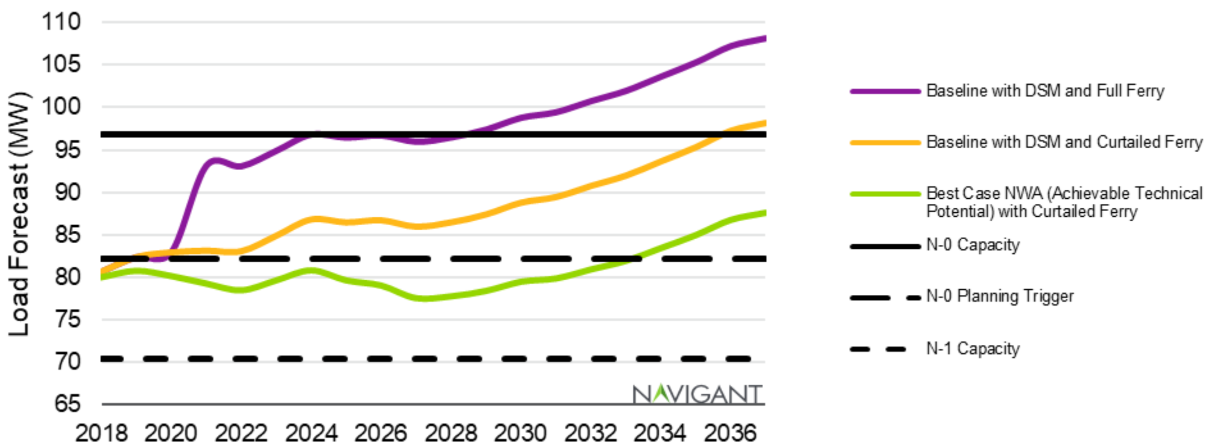
Distribution Capacity Analysis and Findings: the overall capacity needs for the grouping of three substations on Bainbridge Island drives key requirements in PSE's planning criteria. The team examined three different capacity thresholds for this three-substation grouping: *N-0 Capacity*, *N-0 Planning Trigger*,

[4] Note that additional levels of deconstruction are possible (e.g., a more granular deconstruction of the distribution grid might consider substations individually and further deconstruction could consider individual circuits). These further deconstruction levels were not explored as part of this study and are not critical to the findings presented here.

and *N-1 Capacity*. The *N-0 Planning Trigger* was selected as the key threshold for analysis focus. The other threshold values are shown in several of the graphics below for reference.

Navigant refined the analysis of baseline load forecast,[5] developed an estimate of achievable load reduction forecast using the DERs selected for the study, and examined the ferry electrification load as another key resource. The resulting load and DER forecast (excluding storage)[6] is shown in Figure 1.

Figure 1. Bainbridge Island Potential NWA Load Forecast Scenarios



Source: Navigant Analysis

Navigant's analysis concludes that PSE will likely be able to delay hitting the *N-0 Planning Trigger* for the 3-substation group on BI from 2020 to approximately 2030. The analysis made significant progress toward developing the non-wires distribution capacity solution and suggests that PSE can address local capacity needs based on a plan that:

a. Connects the ferry electrification load (10MW) as a curtailable resource

b. Incorporates storage to meet the capacity need in 2030 and provides operational flexibility between 2021 and 2029 to help provide insurance in the event that other demand-side resources don't perform as anticipated.

c. Aggressively pursues expanding the demand side management (DSM) portfolio on BI, to complement storage, as the more economical alternative to a traditional wired capacity expansion.

This analysis relies on the refined "bottom-up" calculation of load net of planned DSM programs, which includes zip-code-specific cost-effective EE savings, and recalculation of DSM capacity savings based on local substation load shapes, line losses, and power factor.

An NWA portfolio including EE, storage, renewable distributed generation (DG), and the option of DR has the potential to cost-effectively defer the wired alternative until 2030 given current load forecasts. Navigant recommends:

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[5] The IRP baseline with full DSM was re-calculated using available local information from BI and assuming the same mix of cost-effective DSM measures used in the IRP.

[6] These figures do not include storage in consideration of the "Best Case NWA" because, technically, enough storage could defer the entire need in perpetuity—although installing a battery at every customer site would not be the most cost-effective solution. Storage therefore enters the analysis in Section 3 as an economic consideration.

- Sizing the storage to meet 50% of the capacity needs in 2030.
- Designing a portfolio that allows for some operational flexibility to test assumptions about DR costs and operational parameters. Navigant's analysis indicates that a 3.3 MW, 5MWh battery would provide sufficient flexibility for PSE to study and pilot targeted DR and EE programs before DSM resources become absolutely necessary to meet the need.
- As a next step, PSE should study and develop approaches to obtaining the EE, DG, and DR portions of the NWA portfolio on BI starting as soon as feasible.

The sections below detail the analysis approach, the technical DER potential analysis and the preliminary economic analysis.

1. ANALYSIS APPROACH

Navigant worked with PSE to define the analysis parameters and deconstruct the overall problem into logical components appropriate for analysis. This approach helped the team identify actions that may meet specific portions of the needs, and to understand the timing and costs of those potential actions.

1.1 Potential Solution Elements

The NWA solution elements and measures belong in two categories:

- DERs that were quantified in the analysis: The specific set of DERs considered in the analysis were developed in conjunction with the PSE Team.
- A Broader definition of NWA considered but not quantified or analyzed in detail: given that external stakeholders may interpret the term "non-wires alternatives" more broadly, it was felt that this consideration would be valuable.

Table 1 details the DERs that were included or excluded from the analysis and the rationale behind the decision.

Table 1. Distributed Energy Resources Considered in the Analysis

Resource Name	Description	Included for BI?	Rationale
Energy Efficiency	Utility run efficiency measures	Yes	Largest and most diverse DER
Codes and Standards	A cost-free resource that make new construction more energy efficient	No	Limited additional incremental savings on top of savings estimated in IRP
Fuel Conversion	Replacing electric equipment with natural gas-consuming equipment	No	No gas access in Bainbridge
Demand Response	Flexible, price-responsive loads which can be curtailed	Yes	Potential for targeted peak curtailment
Distributed Generation – Solar PV	Customer-side solar installations	Yes	Growing resource adoption
Distributed Generation – Combustion (CHP)	Includes renewable and non-renewable combustion	Yes- Only renewable CHP	Robust option for peak reduction
Distribution Efficiency	Combination of CVR and load phase balancing	No	Waiting for full deployment of Advanced Metering Infrastructure (AMI) in region (in agreement with 2017 IRP recommendation)

Generation Efficiency	Applies to parasitic loads served by a generator	No	Not applicable to region of interest
Energy Storage	Mainly battery storage	Yes	Provides a highly flexible resource

Source: Navigant Analysis

In addition to the DER definition provided above, Navigant also considered a broader definition of NWA. The logic behind this definition is that customers and other external stakeholders may interpret the term "non-wires alternatives" more broadly than the typical electric utility industry definition. For this reason, Navigant also considered activities such as vegetation management and targeted asset replacement in this broader definition. These activities were considered in our assessment, but we did not attempt to quantify impacts of these activities or value them monetarily in our detailed analysis. Nevertheless, including them in portions of the assessment proved to be instructive.

1.2 Problem Deconstruction

To understand the specific problem being considered and analyzed, and where that problem fits in the overall picture of BI needs, Navigant deconstructed the problem along two dimensions: specific *identified needs*, and *grid elements*. This deconstruction is intended to cover the entire potential range of solutions—wired and non-wired—so that PSE and stakeholders may see that a comprehensive approach to meeting specific needs has been taken.

Needs deconstruction: specific areas of *need*, based on the PSE needs analysis structure, were considered separately. These need areas were:

1. **Capacity -** Needs consisting of distribution capacity shortfall over the next ten years including *N-0 Capacity* and *N-0 Planning Trigger* threshold considerations based on PSE planning criteria.
2. **Reliability** - Needs consisting of all transmission and distribution reliability items including applicable N-1 feeder capacity, SAIDI and SAIFI metric reduction, and transmission outages.
3. **Operational Flexibility** - Needs related to the ability to transfer load to support routine maintenance, outage management, and planned seasonal switching.
4. **Aging Infrastructure -** Needs related to equipment nearing end of useful life and reduction of loading on equipment to effectively prolong lifespan.

Grid deconstruction: Navigant performed initial grid deconstruction at Bainbridge Island and deconstructed the grid need into the transmission and distribution elements of the required solution needed to meet the needs.[7] As a first order approximation, the proposed wired solution can be separated into transmission and distribution components that operate together.

1. **Transmission Components -** The transmission components include the new loop connecting Murden Cove and Winslow Substation. At a high-level this is to provide for increased reliability and to provide more operational flexibility. In addition, rebuild of aging infrastructure to improve reliability.

[7] Additional grid levels such as distribution circuit analysis could be investigated given additional time and effort.

2. **Distribution Components -** Additional distribution capacity needed for ferry electrification and to support anticipated load growth on Bainbridge Island.

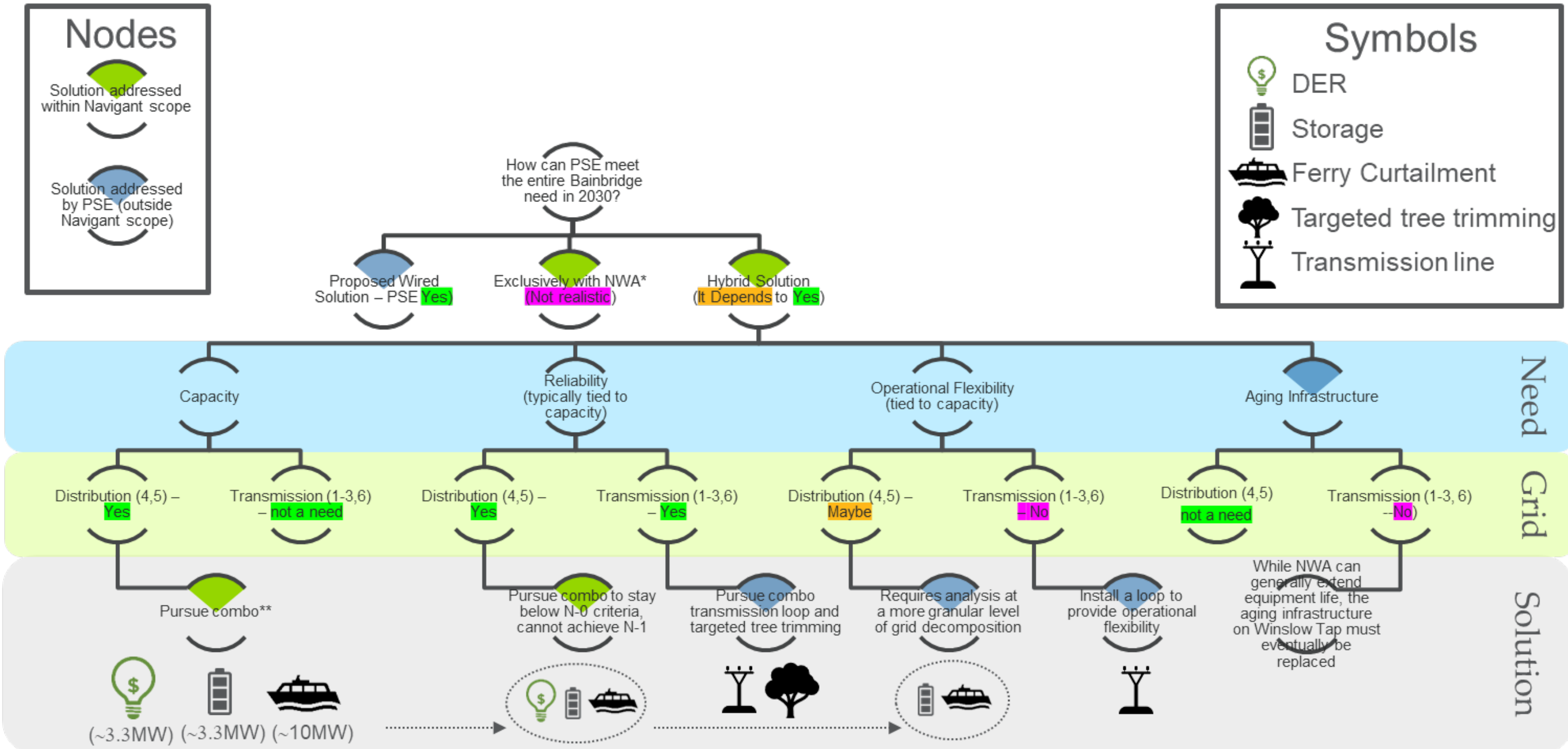
The distribution components depend upon the transmission components being constructed and in-service.[8] This deconstruction is consistent with the existing grid architectural structure, and we believe that the most significant conclusions can be drawn from this initial deconstruction.[9]

Visual Representation: a decision tree that depicts this deconstruction is shown below in Figure 2. The nodes of the decision tree represent deconstruction scenarios and are color coded to indicate which portions of the solution are addressed in the current analysis, and which are addressed outside of the current analysis. For example, PSE's analysis of traditional solutions is represented in several of the nodes by blue shading, as shown in the legend on the top-left.

[8] Typically, deconstruction of this type is more complicated, but PSE had created their proposed wired solution with input from transmission and distribution planners and tied the two together at the distribution substation level resulting in a meaningful and viable grid deconstruction.

[9] Note that additional levels of deconstruction are possible (e.g., a more granular deconstruction of the distribution grid might consider substations individually and further deconstruction could consider individual circuits). These further deconstruction levels were not explored as part of this study and are not critical to the findings presented here.

Figure 2. Bainbridge Island NWA Decision Tree



*Including all non-wire options: DER, ferry curtailment, tree trimming (not typically classified as NWA by industry)
**This combination primarily addresses capacity needs in 2030, and helps address N-1 capacity threshold for reliability needs; batteries and curtailable ferry can also provide operational flexibility
"YES" refers to a scenario in which NWA meets an element of the need (e.g., N-0), but perhaps not all elements of the need (e.g., N-1)

Source: Navigant Analysis

1.3 Solution Approaches

This overall deconstruction was used to answer the question "How can PSE meet the entire Bainbridge Island need" and to break that question down into sub-questions of "what portion of the needs can be met" by various deconstructions, leveraging different combinations of solution elements.

At the topmost level, three broad scenarios for meeting the set of identified needs are evident. These three scenarios are indicated by numbers in green boxes in Figure 2 and are:

1. **Proposed wired solution**: PSE has developed and documented a traditional wired solution based on current planning criteria and known wired components.
2. **Using exclusively NWAs** (broadly defined): Navigant considered solutions leveraging both the narrower definition of DERs and the broader definition NWAs (i.e., including vegetation management).
3. **Hybrid Non-Wired Solution**: where elements of the problem are met through traditional wired solution (or some other creative solution) and elements met through NWAs.

Navigant indicates successfully meeting the set of needs at a particular scenario node with a "YES" in Figure 2[10] and a "NO" where the meet at that node is not met, and a "MAYBE" where the situation is more nuanced and requires further explanation.

1.3.1 Traditional Scenario (Proposed Wired Solution)

Navigant reviewed the planning analysis and the traditional wired solution developed by PSE to meet Bainbridge Island transmission and distribution needs. This solution corresponds to the upper left node of the decision tree in Figure 2 and includes building a 115 kV transmission loop between Winslow and Murden Cove substations and installing a new distribution substation in the middle of the transmission loop. Sub-components with initial estimated costs of this solution are found in the *DRAFT Bainbridge Island Electric System Solutions Report* and are shown in Table 2.

Table 2. Preferred Traditional Wired Solution

	Scope of Work	2018 Unit Cost Estimate	2018 Cost Estimate	2018 Cost Estimate w/ 25% contingency
1.	Build 3 miles of new overhead 115 kV line b/w Murden Cove and Winslow on public ROW.	$2.5 M/mi.	$7.5 M	$9.4 M

[10] In some cases, this includes when NWA meets one threshold of the need (e.g. N-0 Capacity), but perhaps not all levels of the need (e.g. N-0 Planning Trigger).

2.	Expand Winslow substation bus to bring second 115 kV line. Install 2-115 kV breakers.		$1.5 M	$1.9 M
3.	Expand Murden Cove substation bus to bring second 115 kV line.		$0.8 M	$1.0 M
4.	Build new 115-13 kV distribution substation on transmission loop.		$8.0 M	$10.0 M
5.	Install 4-13 kV feeder getaways at new distribution substation.	$1.0 M/mi.	$1.0 M	$1.25 M
	TOTAL Cost.		$18.8 M	$23.6 M

Source: PSE DRAFT Bainbridge Island Electric System Solutions Report, August 1st, 2018
Note: Costs are July 2018 PSE cost estimate based on similar past projects in other areas of PSE service territory. Does not include site-specific engineering.

An additional component that PSE has categorized as a *potential upgrade* is shown in Table 3. Navigant included this in the traditional solution component consideration as an element that would clearly address some of the key transmission reliability needs that have been identified.

Table 3. Additional Components of Traditional Wired Solution

	Scope of Work	2018 Unit Cost Estimate	2018 Cost Estimate	2018 Cost Estimate w/ 25% contingency
	Potential Upgrades			
6.	Rebuild 4.5 miles of Winslow 115 kV tap. Rebuild will most likely replace all poles, relocate line and improve corridor for better access.	$2.5 M/mi. *New line construction cost estimate assumed.*	$11.25 M	$14.1 M

Source: PSE DRAFT Bainbridge Island Electric System Solutions Report, August 1st, 2018
Note: Costs are July 2018 PSE cost estimate based on similar past projects in other areas of PSE service territory. Does not include site-specific engineering.

After reviewing the needs document and solution approach, Navigant agrees that the traditional solution will meet the identified needs, as it is based on well understood, broadly used technologies and planning principles.

1.3.2 Exclusively Non-Wires Scenario

Navigant considered whether the entire set of identified needs could be met using exclusively NWAs (the scenario corresponding to item 2 in the decision tree in Figure 2) based on the two NWA definitions presented above:

- the narrower set of DERs selected for detailed analysis (Table 1 above) or
- the full range of NWAs were used (i.e., the broader definition described above including vegetation management, etc.)

Using selected DERs: In the narrower definition of NWA, we concluded that DER cannot fill the entire need or address the concerns expressed by PSE planning for the following reasons:

- Majority of the Winslow 115 kV tap design is wishbone wood cross arm construction built in the 1960s which is starting to fail (these DERs cannot prevent this aging and failure)
- PSE crews have reported poor access to certain cross-country sections of the Winslow 115 kV tap, resulting in prolonged restoration times for some transmission outages (this would require, among other things, more aggressive tree trimming and removal)
- The incidence of simultaneous outages in the two transmission lines feeding BI cannot be addressed with these DERs

Using Broader Definition of NWA: using the full range of NWAs (i.e., the broader definition described above including vegetation management, etc.) provides more flexibility and more possibilities. Again, some of the needs would be extremely hard to meet with NWAs. For example, addressing transmission reliability without the Winslow 115 kV tap rebuild and without addressing some of the aging infrastructure needs is a significant challenge.

Upon examination, Navigant concluded that while it is likely technically possible to meet the BI needs using this broader definition of NWAs, it is not a realistic solution. A detailed technical analysis using this broader definition of NWAs was not the focus of this study and was not performed. As part of the analysis of the Bainbridge Island NWA, Navigant reviewed the full projected costs for the traditional solution. Navigant also considered the varieties of needs that would be addressed by the traditional solution. Navigant found that to provide similar levels of operational flexibility and reliability as the traditional solution, additional batteries would be needed to provide grid support for four to eight hours. These batteries would be needed in addition to the batteries and other measures needed to meet the growing capacity needs. Navigant estimated that the costs for these additional batteries would be considerably more than the costs of the traditional solution related to grid flexibility and reliability. Considering the likely need for significant additional electric storage at various locations on the island, the need for aggressive tree-trimming and removal (counter to community values on Bainbridge Island), and the roll-out timeframe necessary to the meet full set of defined needs with an exclusively NWA solution, Navigant does not think such a solution could be realistically achieved.

1.3.3 Hybrid Non-Wires Solution Scenario

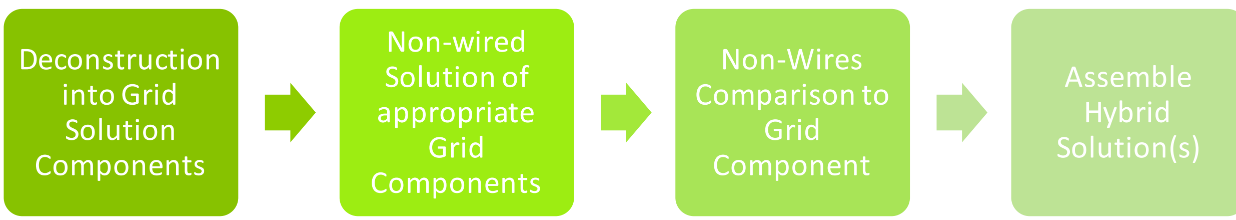
Hybrid non-wires solutions are represented on the decision tree by the 3rd node in Figure 2, node labelled “Hybrid Solution”. In a hybrid non-wires scenario, elements of the need are met through traditional wired solution (or some other unspecified means) and other elements met through NWAs.

Navigant used the more limited definition of NWA solution elements (shown in Table 1above) to adhere to the original analysis objectives, which focused on leveraging the specific set of selected DERs to meet identified needs.[11] Initial rule-of-thumb assessment of the possible capacity reductions available on BI indicated the further, detailed analysis of the potential for NWAs to meet a portion of the needs was merited. Then Navigant proceeded with a more detailed analysis of possible hybrid non-wired solutions.

The value of *completely* deferring the distribution components of the proposed wired solution is $11.25M based upon the sum of line items 4 and 5 including the 25% contingency in Table 2. For determining if the hybrid non-wires solution is economically preferred to the traditional wired solution, Navigant compared the net cost of the non-wires solution needed to meet the distribution need out to the 2030 planning horizon to the value of a complete deferral of approximately $11.25M. Given the uncertainty in load growth projections beyond ten years and uncertainty in future costs of necessary distribution upgrades, Navigant did not estimate the costs that would be incurred past 2030.[12]

The process for assembling a hybrid non-wired solution is outlined in Figure 2, and each step is described below.

Figure 3. Hybrid Non-Wired Solution Process



Source: Navigant Analysis

1. The first step of deconstruction of the preferred solution into grid components takes the components of the preferred solution, numbered 1-6 in Table 2, and maps them to the nodes on the decision tree, either transmission or distribution, under each of the need items. Based on Navigant's engineering judgment, items 1-3, and 6 are transmission components that can be cleanly separated from the distribution components 4 and 5.
2. The next step is to assess which of the DER's could replace the traditional solution component group, both across all the needs categories and within the individual needs categories.
3. As the third step, Navigant compared these DERs to the traditional solution in terms of items such as risk and reliability of the resource, to determine if there is a reason to eliminate the DER from further consideration.
4. The final step is to assemble the hybrid non-wired solution. The hybrid non-wired solution assembled by Navigant and analyzed in future sections includes the traditional solution items 1-3, and 6 to meet the transmission needs and DERs to meet the distribution capacity needs and defer or replace the cost of items 4 and 5.

[11] A more comprehensive analysis incorporating storage, or even incorporating vegetation management and other O&M approaches is possible, but was not the focus of the analysis presented here.

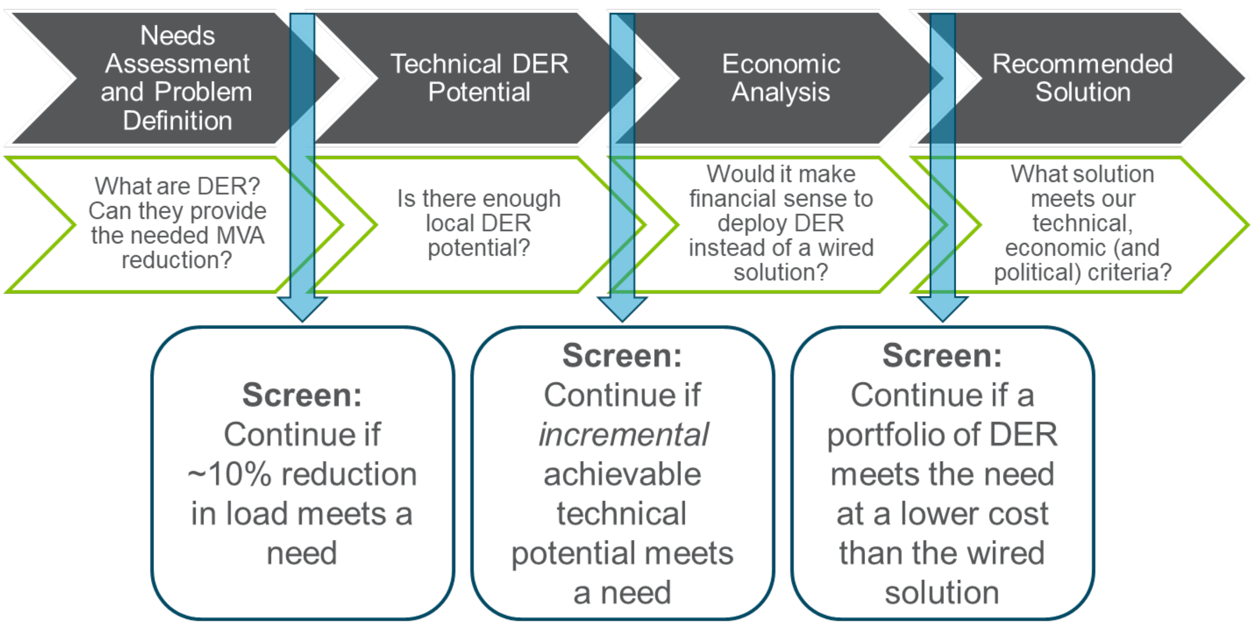
[12] For example, Navigant did not posit that this same wired solution would be built in some year after 2030, nor attempt to calculate the economic deferral value of the wired solution, which would require such an assumption.

For the transmission component in BI, the selected DERs were deemed incapable of realistically meeting the full set of needs.[13] Clearly a large amount of storage is technically capable of addressing large-scale transmission needs, but based upon Navigant's experience and engineering judgment it doesn't fit the pattern of typical non-wires solutions. However, individual transmission needs showed some promise of being addressed by NWAs and merited exploring through the screening process described in detail in the next section.

1.3.3.1 Screening Process for NWA Analysis

The next step after the hybrid non-wired solution has been assembled, is for those elements that have not yet been eliminated from further consideration to flow through the screening process as shown in Figure 4.

Figure 4. Screening Process for NWA Analysis



Source: Navigant Analysis

The first screening step is to do a simple needs assessment looking at the load growth in the area over the next 20 years. Before determining any DER potential, it is useful to consider whether a 10% reduction in demand-side load (excluding storage) can meet a need[14].

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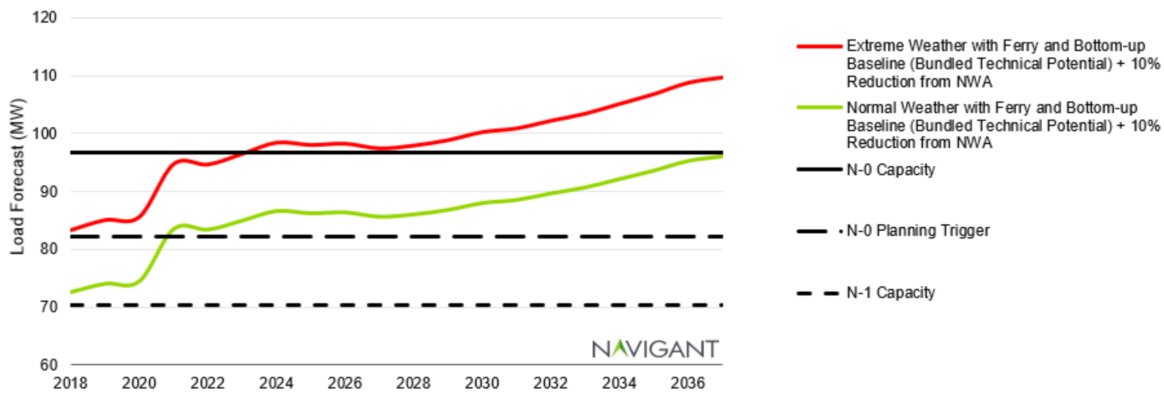
[13] Note that adding significant amounts of storage could help meet these needs, but is highly unlikely to be economically feasible in Navigant's judgement.

[14] Navigant found that a 10% reduction in peak load is a reasonable upper-bound expectation for achievable load reduction through a targeted non-storage DER-deployment. This is a general rule that may vary based on local circumstances or the presence of large curtailable loads. In this case, the electric ferry load is another, more-detailed consideration addressed in Appendix A.

Figure 5: A Comparison of Load Growth Scenarios with a Simple 10% Capacity Reduction



All scenarios assume a power factor of 97.8%; Normal weather assumes a winter peak of 23 degrees and extreme weather assumes a peak of 13 degrees; full technical potential includes DG - Renewable Combustion, DG - Solar, DR, and EE. Bundled technical potential includes DG - Renewable Combustion and EE measures in the top 3 LCOE bundles (LCOE < $70/MWh).

Source: Navigant Analysis

This step indicated potential to meet capacity needs for the distribution component of the solution—particularly with respect to the *N-0 Planning Trigger* threshold, under a load growth scenario of normal weather conditions with PSE business-as-usual DSM procurement, at least until 2021 when the ferry may become a capacity planning consideration. Navigant recommends connecting the ferry as an interruptible load, as detailed in Appendix A.

Given the inability of DER to materially impact transmission capacity and reliability on BI, and the exclusion of other non-wired solution such as tree-trimming and targeted operation and maintenance (O&M), the analysis subsequently focuses on identifying the problems on Bainbridge Island that DER can actually address, which are distribution capacity needs. The remaining steps in this process required significant analysis, which is detailed in the following three sections:

- Technical DER Potential
- Economic Analysis
- Conclusions and Recommendations

As part of this next step, Technical DER Potential, the team defined the capacity need as the *N-0 Planning Trigger* threshold (load must be below 85% of total capacity for the three-substation group on the Bainbridge Island). There are other capacity needs on BI such as N-1 capacity or circuit level N-1 capacity, but the *N-0 Planning Trigger* threshold was used for defining the amount of load reduction that the NWA must provide to successfully defer or replace the wired solution.

2. TECHNICAL DER POTENTIAL

The technical potential analysis leverages a methodology and definitions that are consistent with PSE's 2017 integrated resource plan and accepted in the Pacific Northwest. The analysis focuses on the overall capacity needs for the grouping of three substations on Bainbridge Island, which drives key requirements in PSE's planning criteria. Navigant refined the analysis of baseline load forecast, developed an estimate of achievable load reduction forecast using the DERs selected for the study, and examined the ferry electrification load as another key resource. The analysis details are described below.

2.1 Methodology and Definitions

The potential study seeks to identify all *incremental* achievable technical potential exclusive of what is already incorporated in the net load forecast. Incremental achievable technical potential (ATP) is defined as:

Incremental ATP = achievable technical potential – baseline load forecast with planned DSM

Achievable technical potential is a term used in the Pacific Northwest to represent DER potential that is achievable—considering customer economics, technology awareness, and market diffusion. Achievable technical potential is commonly referred to as "market potential" in other jurisdictions. For energy efficiency, achievable technical potential was specified as a percentage of the technical potential. The percentage of technical potential that was deemed achievable was by default 85% based on the Council's planning assumptions.[15] Navigant modeled the effects of time-dependent barriers to market adoption by applying the ramp rates provided by the Council in the Seventh Plan[16] to the maximum achievable technical potential. Navigant used a payback-based market approach in conjunction with a Bass diffusion model to forecast the adoption of PV and DR on Bainbridge Island. More details on methodology and data sources are available in the 2017 IRP Demand-Side Resource Conservation Potential Assessment Report.[17]

To define which portion of the achievable technical potential is "incremental," Navigant assumed baseline, "business-as-usual" procurement of demand-side resources by PSE, assumptions and methodology by resource type are stated below.

- EE and combustion DG- in the PSE IRP, PSE commits to pursuing levelized cost of energy (LCOE) bundles 1 through 3[18]. Navigant re-calculated the PSE net load forecast (net of demand-side resources) at the Bainbridge ZIP code level, assuming measure bundles 1-3 reach their full achievable potential. Appendix A contains more details on the baseline load forecast. The analysis of *incremental* EE and combustion DG only considers measures that were not in bundles 1 through 3 in the 2017 IRP.

[15] *Achievable Savings – A Retrospective Look at the Northwest Power and Conservation Council's Conservation Planning Assumptions*: http://www.nwcouncil.org/media/29388/2007_13.pdf.

[16] See https://www.nwcouncil.org/energy/powerplan/7/technical for the supplemental data files that accompany the Council's Seventh Power Plan.

[17] https://pse.com/aboutpse/EnergySupply/Pages/Resource-Planning.aspx

[18] The IRP "bundles" demand side resources by levelized cost of energy, from lowest (bundle 1) to highest (bundle 10). During the IRP process, resource planners decided that bundles 1-3 would be cost-effective to pursue, therefore measures in these bundles are not eligible to be pursued as an incremental non-wires alternative on Bainbridge Island.

- PV – The team assumed PSE has no business-as-usual customer incentives for distributed PV adoption—therefore all achievable technical PV potential is eligible as incremental potential for the non-wires solution.
- DR– The team assumed PSE has no immediate plans for DR on Bainbridge Island, —therefore all achievable technical DR potential is available as incremental potential for the non-wires solution. For incremental DR, 4-hour DR events were assumed.
- Storage – Technically, storage might be sized to meet essentially the entire need on Bainbridge Island. So, the *technical potential* for storage is almost limitless. Therefore, storage is primarily considered in Section 3, the Economic Analysis. See also Figure 9 for an illustration of the phased approach Navigant took to including storage in the analysis as a progressive reduction in the capacity to be provided by non-storage DER.
- Ferry – Navigant determined that the ferry should not be considered for capacity planning purposes, assuming the ferry can be connected on an interruptible rate with a sufficient number of hours of curtailment to eliminate the ferry load from capacity planning needs. For more details on the ferry load calculations, see Appendix A.

The impact of each of these resources is defined for the actual peak period on Bainbridge Island, determined through analysis of the hourly load shapes for the three substations on the island. This analysis is discussed in further detail in Appendix B.

2.2 Incremental Technical Potential Analysis

This analysis relies on the refined "bottom-up" calculation of load, net of planned DSM programs, which includes zip-code-specific cost-effective EE savings, and recalculation of DSM capacity savings based on local substation load shapes, line losses, and power factor. See Appendix A for details on how the team refined the load forecast for this analysis.

Navigant used the PSE distribution planning criteria to establish limits against which the load forecast could be compared under various assumptions. The planning criteria for the three-substation grouping of Port Madison (PMA), Murden Cove (MUR), and Winslow (WIN) on BI leads to the following winter capacity limits:

- *N-0 Capacity Limit*: When loads in an area reach 100% of capacity for a substation group of three or more, no new load can be served until additional capacity is added to support the load.
- *N-0 Planning Trigger*: When the loads in an area reach approximately 85% of existing substation capacity for a study group of two to six substations, the need for additional capacity is triggered to maintain operational flexibility.
- *N-1 Capacity Limit*: Contingency situation wherein one of the three substations is out of service and the other two substations need to serve the load.

The three substations on BI are all 25 MVA banks and are operated following the capacity limits outlined in Table 4.

Table 4. Substation Bank Capacity Limits

Single Distribution Substation Loading (25 MVA Bank)	
Operational Load (N-0)	Emergency Load (N-1)

Winter 132% of nameplate	Summer 108% of nameplate	Winter 144% of nameplate	Summer 116% of nameplate
33 MVA	**27 MVA**	**36 MVA**	**29 MVA**

Source: PSE DRAFT Bainbridge Island Electric System Needs Assessment May 14th, 2018

Given these substation bank capacity limits and the assumed power factor, the substation group planning limits used for assessing need and success are as outlined in Table 5.

Table 5. Substation Group Planning Capacity Limits

Substation Group Planning Limit	Loading	Capacity Limit (MVA)	Capacity Limit (MW)
N-0 Capacity Limit	Operational load for winter at 132% of nameplate	99 MVA	96.8 MW
N-0 Planning Trigger	85% of operational load for winter at 132% of nameplate	84 MVA	82.2 MW
N-1 Capacity Limit	Emergency load for winter at 144% of nameplate	72 MVA	70.4 MW

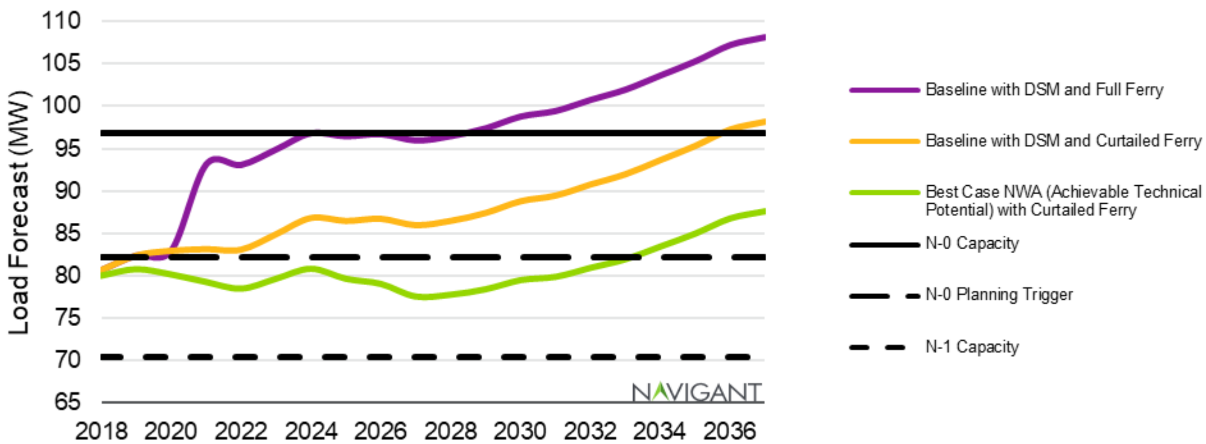
Source: PSE DRAFT Bainbridge Island Electric System Needs Assessment May 14th, 2018

These limits are included on the load forecast graphs to indicate where the projected load falls relative to each limit under the different assumptions examined. The *N-0 Planning Trigger* was selected as the key solution criteria that defines the primary capacity need for the analysis performed in this report.

As seen in Figure 6, the incremental technical potential (excluding storage) [19] brings the defined baseline load forecast below the *N-0 Planning Trigger* through at least 2033.

[19] These figures in the technical DER potential section do not include storage in consideration of the "Best Case NWA" because, technically, enough storage could defer the entire need in perpetuity—although installing a battery at every customer site would not be the most cost-effective solution. Storage therefore enters the analysis in Section 3 as an economic consideration.

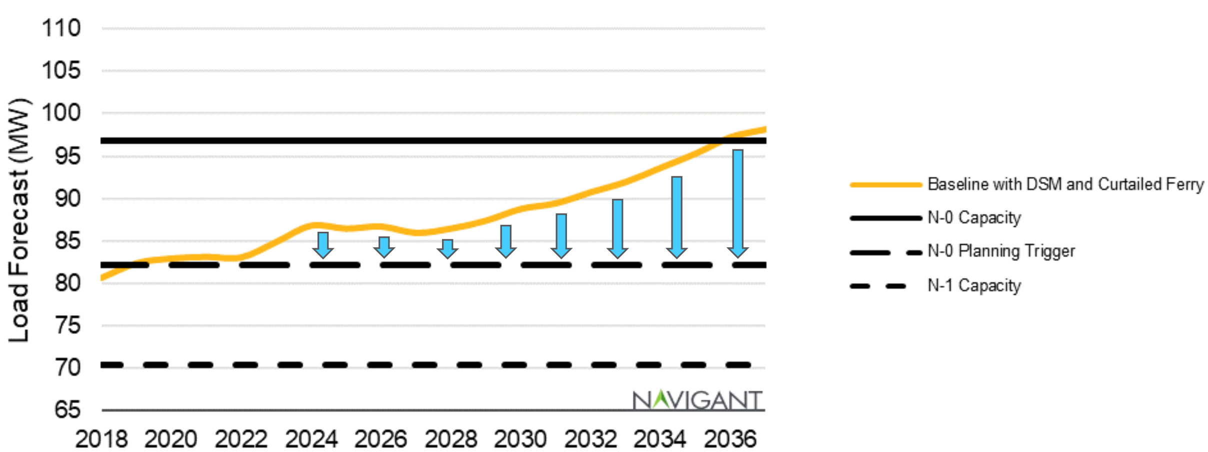
Figure 6. Effect of Incremental Technical Potential on Baseline Load Forecast



Source: Navigant Analysis

Another way to view the incremental technical potential on Bainbridge Island is to compare it to the need in the area, as illustrated in Figure 7 by the blue arrows between the defined baseline and the *N-0 Planning Trigger*.

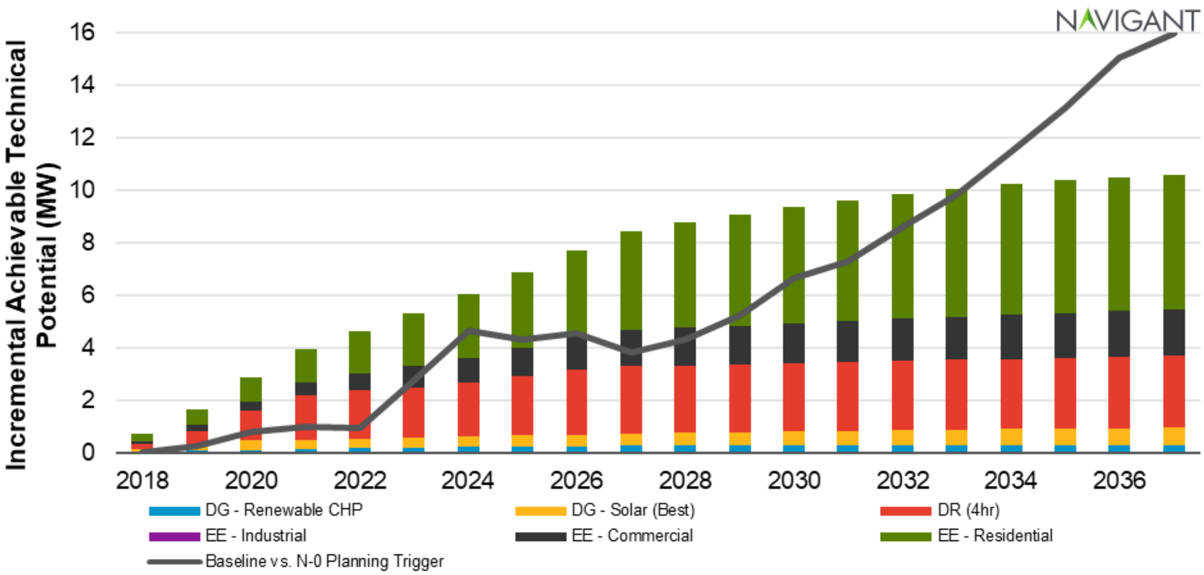
Figure 7. Illustration of Defined Need (Differed between Baseline and N-0 Planning Trigger)



Source: Navigant Analysis

This capacity need is shown as the grey line in Figure 8, where it is compared to the annual technical potential by resource type. The largest incremental achievable technical potential contribution is made by residential energy efficiency measures, followed by demand response resources.

Figure 8. Incremental Achievable Technical Potential by Resource Compared to Defined Need



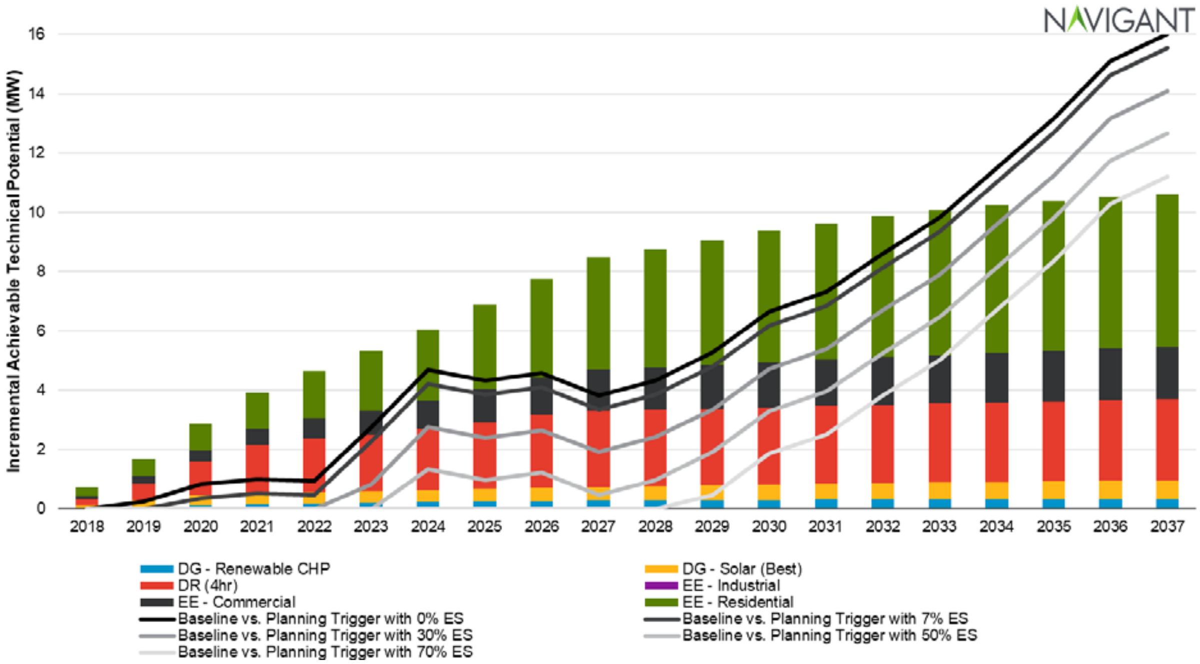
Source: Navigant Analysis

The Navigant team took a phased approach to adding storage to this analysis. At the extreme, storage can technically meet 100% of the need, as this resource is unconstrained by demand-side loads (as EE and DR are) and similarly unconstrained by fuel availability (as PV and renewable DG are). In other words, it is technically feasible to add a battery to every feeder or customer site on the island—though likely cost-prohibitive. Therefore, the team incorporated storage into the analysis using a three-step process:

1) Storage dispatch optimization. The team determined the optimal operating schedule for the storage, prioritizing dispatch of the energy in the storage by the following items in order:
    a. Three-substation group capacity deferral
    b. Bulk PSE system generation capacity deferral
    c. Energy trading based on 8,760 forecasts for PSE's avoided energy costs
2) Storage sizing. The team took a parametric approach to determining the optimal storage size, using different sizing scenarios to meet a different percentage of the capacity needs in 2030 with storage. Results of this analysis are detailed in Appendix C.
3) Layering in other DER. For each storage sizing scenario, the remaining need is then met with the least-cost DER in the economic analysis. This leads to Figure 9, a revision of Figure 8, with different levels of the need to be met by DER based on different storage sizes.

Appendix C contains the detailed assumptions and methodology behind the storage analysis.

Figure 9: Incremental Achievable Technical Potential by Resource Compared to Defined Need by Storage Scenario



Source: Navigant Analysis

Figure 8 (without storage, shown on previous page) reiterates that the analyzed incremental DER could only theoretically meet the need until 2033 without storage. However, not all resources would need to be pursued to defer the need for a shorter amount of time—until 2030 for instance—and even fewer DER would be needed depending on the amount of storage included in the portfolio (as shown in Figure 9). An economic analysis can help PSE to decide 1) what is the appropriate portfolio of DER measures and storage capacity to defer the need, and 2) what deferral timeframe makes economic sense? The following section provides a foundation for answering those questions, with a focus on a targeted deferral timeframe of 2030. As discussed in Section 4, there are uncertainties associated with this economic analysis and Navigant recommends further study of cost and benefit components of the non-wires solution before implementation.

3. ECONOMIC ANALYSIS

This section includes an economic analysis of all DER and energy storage to determine whether the DER portfolio is lower cost than the conventional wired solution. The economics of the analysis depend on the target year for deferral. Unless stated otherwise, this section assumes that a DER portfolio that meets the capacity needs in 2030 qualifies as a complete deferral of the conventional wired investment of $11.25M. Therefore, the DER portfolio is economically-preferred if the net cost is less than $11.25M.

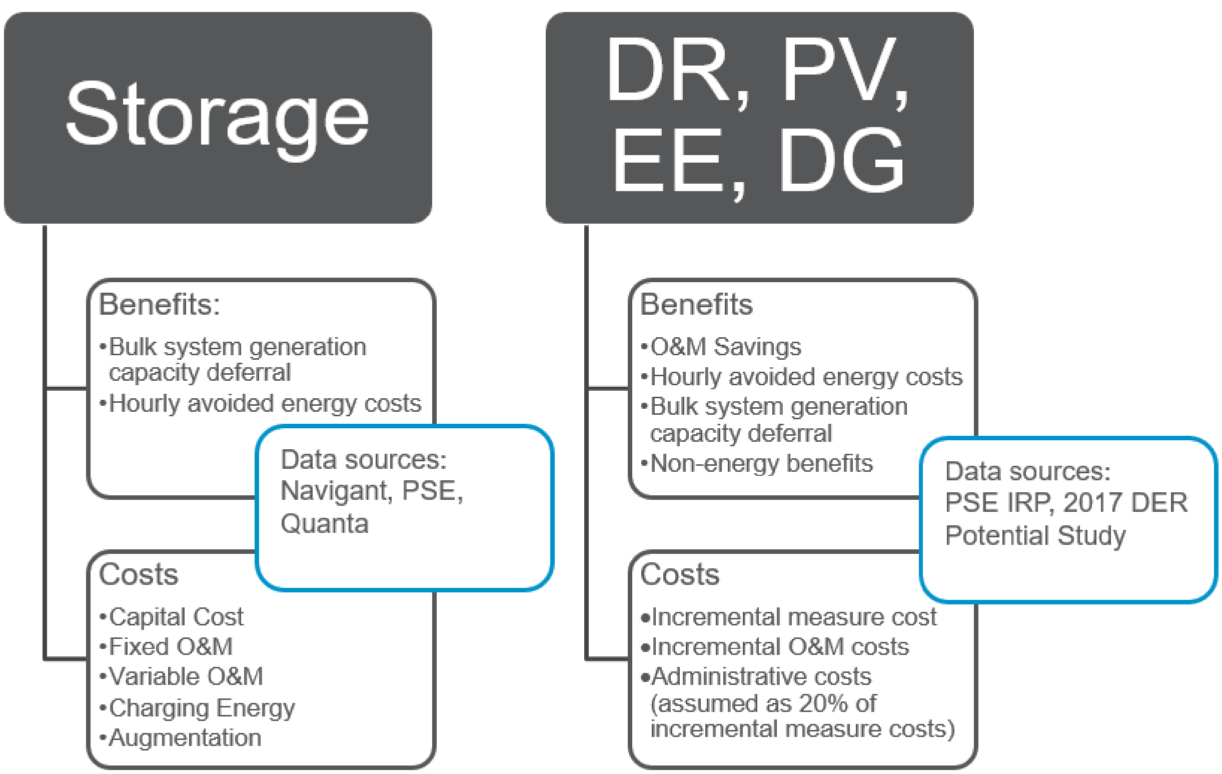
3.1 NWA Portfolio Cost Comparison

3.1.1 Levelized Cost of Capacity

To include storage and other DERs into a single optimal portfolio, Navigant developed a levelized cost of capacity (LCOC) calculation. This allows comparison of resources based on the present value of the net costs for providing local capacity deferral.

The LCOC accounts for the same costs and benefits for each measure as used in the 2017 IRP, but divided by the substation peak capacity savings of each measure rather than the annual energy savings of each measure. The team performed a congruent calculation for storage. Costs and benefits for the various resources are outlined in Figure 10.

Figure 10: Value Streams Included in LCOC Calculation



Source: Navigant Analysis

The LCOC is a net cost - considering the capital and implementation costs of the measures, net of any benefits. Costs and benefits are in present value terms (in 2020 dollars[20]) levelized over a 20-year horizon using PSE's Weighted Average Cost of Capital (WACC) (7.77%) to stay consistent with the 2017 IRP. Any monetary value for avoided T&D capacity is excluded from the calculation, so that the results can be compared directly with the costs of the distribution components of the conventional wired investment on Bainbridge Island[21].

$$LCOC\ (\$/MW) = \frac{PV\ of\ Costs\ (\$) - PV\ of\ Benefits\ (\$)}{PV\ of\ Capacity\ Savings\ (MW)}$$

The LCOC value is calculated on a measure-by-measure basis, with the value streams listed in Figure 10. Because the calculation accounts for a number of different value streams in one metric, the LCOC is best used to represent the relative value of each measure, not the absolute value of the portfolio of DER measures, and therefore caution should be used when comparing this portfolio to the cost of the wired solution.[22] For example, the actual expenditure on a portfolio of DER would be higher than the LCOC indicates, since it is a cost net of anticipated benefits. These values should be considered *preliminary*, as there may be additional costs associated with a targeted DER implementation (see Section 4 and Appendix C for a discussion of areas of further study). In addition, as discussed below, political and strategic considerations may influence which DERs (e.g. PV, DR) are included in the portfolio of DER.

3.1.2 Storage Analysis Summary

Navigant began the economic analysis by considering various storage sizes and system characteristics according to the historical substation load shape and forecast 2030 capacity needs. Figure 11 summarizes the results of this analysis, Appendix C contains the complete details of the methodology. The team concluded that, when considered alone, sizing the storage system to meet 30% of the 2030 need is the most cost-efficient system design as indicated in Figure 11 below. However, design of the optimal non-wires alternative portfolio must also consider the ability to add other non-storage DER (PV, renewable combustion generation, EE, and DR) to serve the capacity needs—which influences the optimal sizing of the storage system as discussed in the next section.

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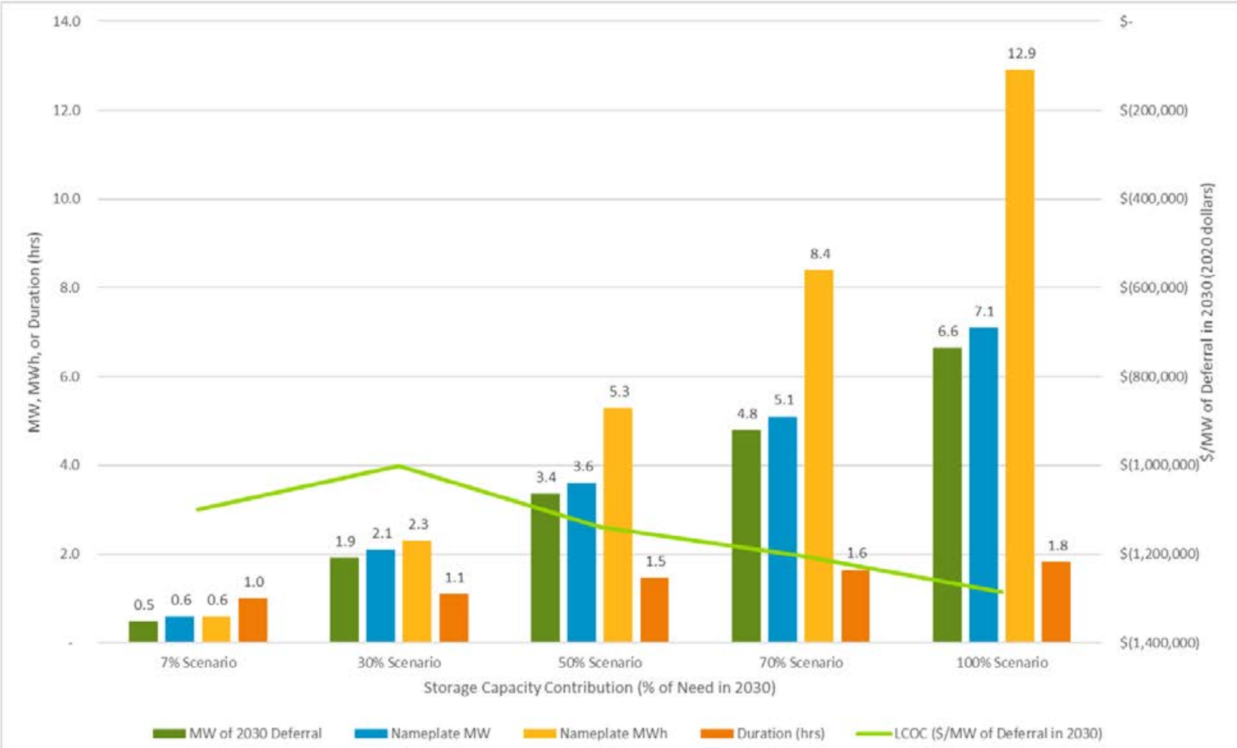
[20] Navigant assumed that the investment in a non-wires alternative portfolio—construction of storage or deployment of energy efficiency--would likely occur in 2020 due to realistic timing considerations and the fact that 2020 is the first year in which the load forecast exceeds the *N-0 Planning Trigger* threshold.

[21] The 2017 IRP did include a system-wide value of local capacity for DER on a $/MW-year basis. This non-specific value was determined by the Northwest Power and Conservation Council. Navigant did not include this value in the analysis, as these results are intended to be compared as an alternative to a specific local T&D investment.

[22] The up-front cost of the DER portfolio will be higher than the net cost which incorporates the various benefit streams generated by the portfolio.

Figure 11: Summary of Storage System Technical Characteristics and Costs



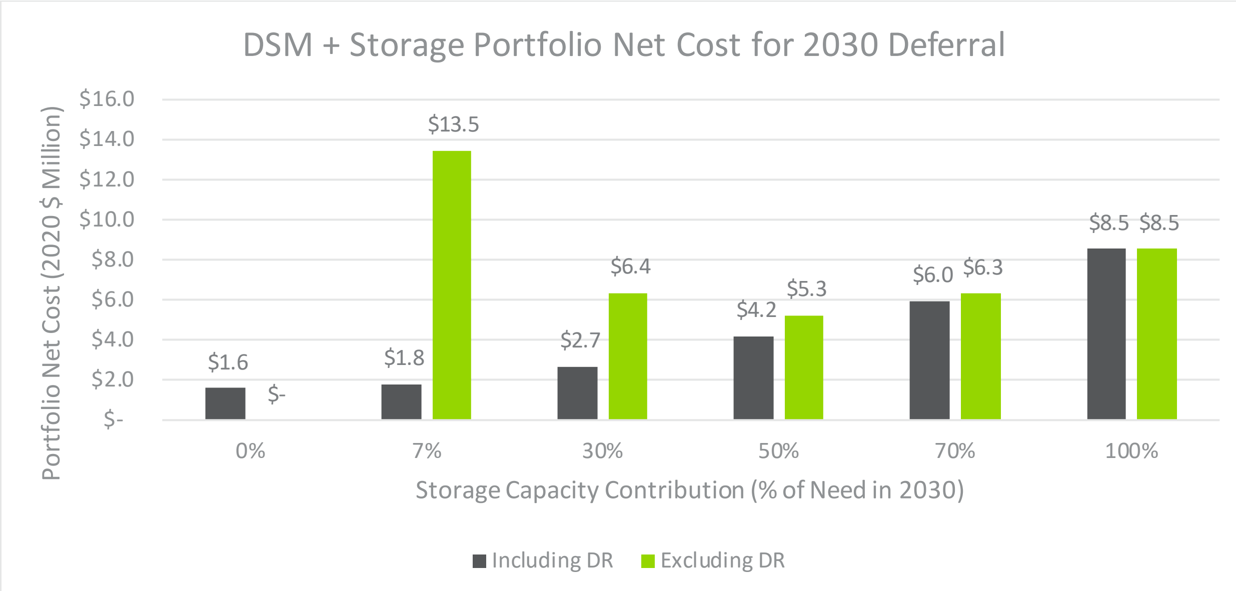
Source: Navigant Analysis

3.1.3 Developing a Portfolio of DER and Storage

When considering the LCOC calculations for all non-storage DER, the team noted that the net costs for DR potential are low and would benefit from further research. It is likely that there are some low-cost opportunities for DR on Bainbridge Island.[23] However, there is a wide range of cost and benefit uncertainty around how the DR measures were characterized for the 2017 IRP. In this report, we used data consistent with the IRP as the best available data to support this analysis. Therefore, Navigant developed two versions of the recommended solution—portfolios with and without DR. Figure 12 shows a summary of the net cost of each portfolio to defer the need until 2030. Note that it is not possible to develop a portfolio that meets the 2030 need without using DR or storage—hence there is no value for the “0% storage-excluding DR” case.

[23] A prior pilot of DR in BI concluded that a participation level of 20% could result in a possible 1 to 2 MW peak reduction. It also noted that the cost of implementing demand side conservation could be minimal, but based on the results from pilot project, demand response costs could also be sizable and may not compare favorably to other alternatives delivering similar benefits.

Figure 12: DER Portfolio Cost to meet the 2030 Capacity Need, With and Without DR



Source: Navigant Analysis

Note that with DR, the least-cost portfolio is just below $2M and includes no storage. The Navigant team recommends caution with this portfolio due to both DR measure characteristic uncertainty mentioned above, and the existence of a real yet unmonetized operational flexibility benefit provided by storage. Storage is a dispatchable resource,[24] so a certain amount of storage is beneficial to PSE to ensure the rest of the DER in the portfolio perform as planned from 2021-2029 before all resources are needed in 2030. Therefore, Navigant recommends sizing the storage to meet 50% of the capacity needs in 2030. This results in a ~$5.5M portfolio excluding DR, and a ~$4.5M portfolio including DR. So, depending on the economics of DR, PSE can expect that the *net cost* of the optimal portfolio is within this range, which is significantly less costly than the distribution components of the conventional wired upgrade (approximately $11.25M [25]). Note that the net cost does not represent the required expenditure for the non-wires solution, but the overall cost net of benefits mentioned in Section 3.1.1.

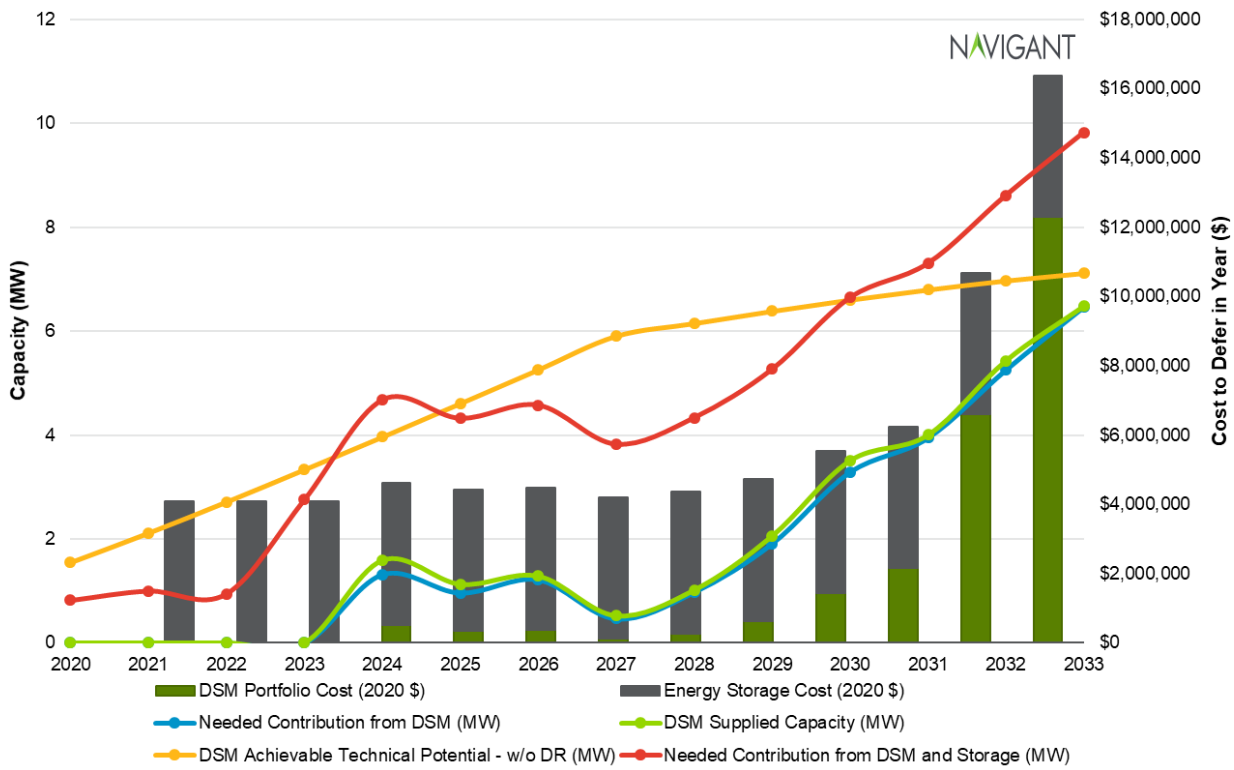
PSE may also seek to defer the need for a shorter or longer time period than 2018-2030. For example, a shorter deferral period may be less costly. Also, a shorter deferral period provides time for more information to be included in the load forecast and for updating the load forecast if necessary. PSE may also target a longer timeframe for additional planning buffer, which will increase the chances of completely avoiding the need for wired investments farther into the future. Figure 13 presents a picture of these options, excluding DR, with storage sized to meet 50% of the 2030 need. Because this scenario excludes any DR resources, Navigant believes this to be a conservative representation of the non-wires portfolio cost (in other words, if DR is pursued, it is likely to reduce the costs of the overall DER portfolio). In Figure 13 below, Navigant uses the term "DSM" as shorthand for energy efficiency (both residential and commercial) and renewable distributed generation (anaerobic digester) measures. As discussed in

[24] Note that DR is also a dispatchable resource; however its flexibility in use in extremely constrained in the number of times it can be used per year as well as how often it can be called. Thus, it provides little operational flexibility relative to battery energy storage.

[25] Note that costs are July 2018 PSE cost estimate based on similar past projects in other areas of PSE service territory. Does not include site-specific engineering.

Section 3.1.4, solar PV is not a cost-effective resource for capacity contributions to the January Bainbridge Island peak.

Figure 13. Supplied Capacity vs. Portfolio Costs over Time, with 50% Storage, Excluding DR



Source: Navigant Analysis

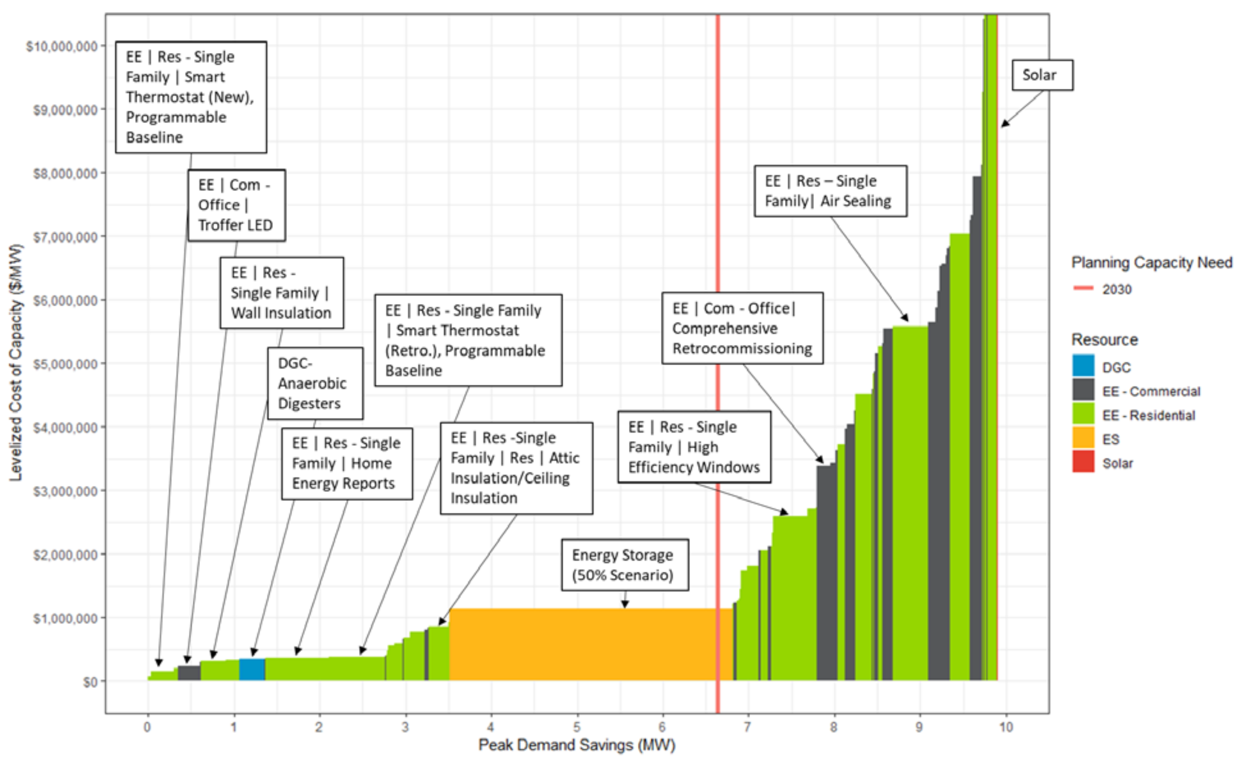
Because the incremental achievable technical potential grows over time (shown in Figure 8 and in Figure 9), and the capacity need varies in each year based on the load forecast, the net cost of the NWA portfolio depends on the number of years that PSE seeks to defer a wired investment. The bars in Figure 13 show the full cost in 2020 dollars of designing a portfolio that meets the need in each year shown on the y-axis. Figure 13 shows storage-only, if online by 2021, will meet the need at a cost of below ~$4M until 2024, when some DSM is required. Because the load forecast flattens and decreases from 2024-2028, the portfolio designed for 2024 will meet the need until 2029-2030, when the need for additional DSM increases the portfolio cost to ~$5.5M in 2030. Beyond 2030 PSE would need to acquire some of the more expensive elements of the DSM portfolio to continue to meet the capacity need, and therefore the portfolio costs increase dramatically. The needed contribution from DSM (blue line) accounts for the fact that the storage provides 3.3MW, 5MWh of deferral in each year—so that in 2030 half of the capacity is provided by storage and the other half by DSM (e.g., the green line is half of the red line).

This preliminary analysis demonstrates that a hybrid non-wired solution is technically feasible, and in most cases is economically-preferable to the wired solution—depending on the length of deferral that may be acceptable to PSE. After revisiting the NWA strategy on Bainbridge Island in light of the results of this preliminary economic analysis, PSE may decide that a more complete economic assessment and feasibility study are warranted. Further economic analysis should account for considerations associated with customer-facing programs, such as ramp-up time, program administrative costs, and stakeholder concerns—all of which may factor into the analysis as additional costs or benefits of pursing the hybrid non-wired solution.

3.1.4 DER Supply Curve

As a next step, PSE may seek to design the least-cost portfolio of DER to meet the need. To determine the specific measures that may compose this portfolio, Navigant developed a supply curve ordering DER options for capacity deferral from least cost to highest cost, shown from left to right in Figure 14 below, using a levelized cost of capacity calculation outlined in Section 3.1.1. The levelized cost of capacity (LCOC) is shown on the y-axis, while the cumulative capacity is shown on the x-axis. Figure 14 ranks all measures in the 2030 achievable technical potential estimate from lowest to highest cost—each bar represents a measure, and the width of each bar represents the three-substation group capacity savings (MW) that the measure can provide. The red vertical line is at 6.6 MW of capacity—the needed capacity in 2030.

Figure 14. DER Supply Curve (Excluding DR) Based on Levelized Cost of Winter Peak Capacity for Bainbridge Island

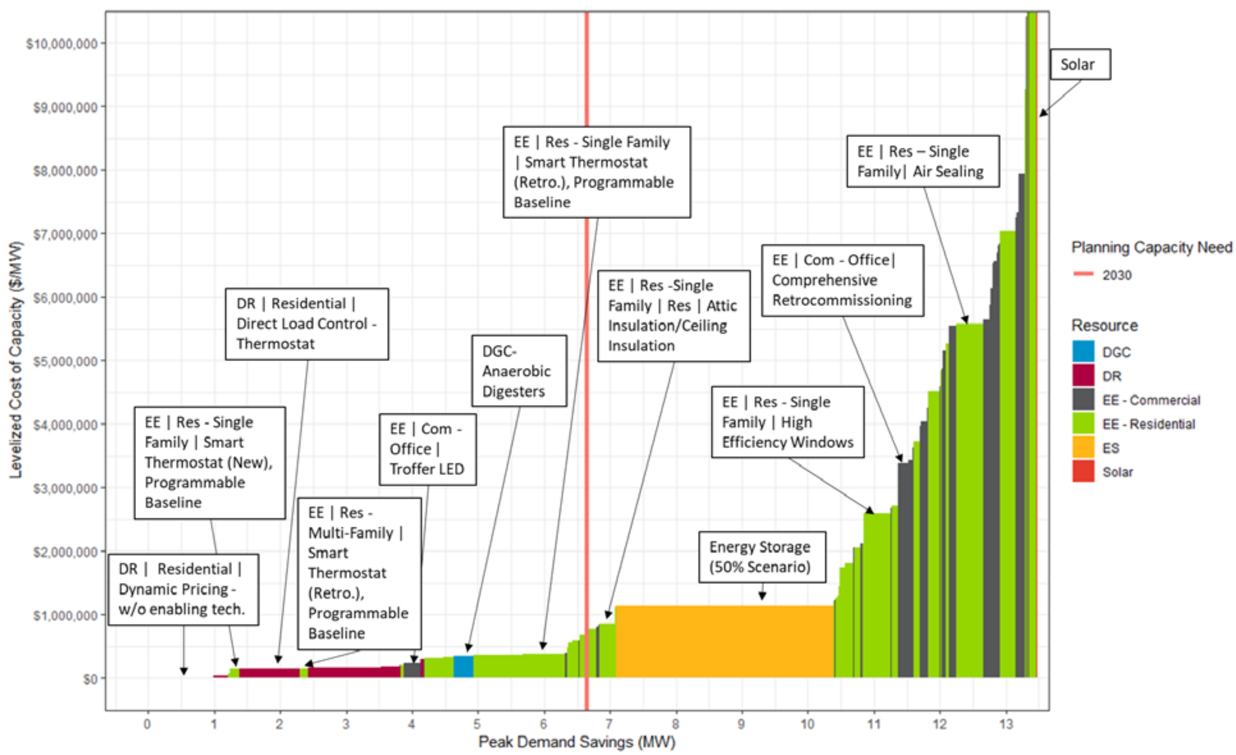


Source: Navigant Analysis

Recall that this analysis is constrained to examining *incremental* achievable technical potential only. PSE has already committed to pursuing cost-effective energy efficiency in the baseline "with DSM" net load forecast—so any negative cost demand-side resources are already being pursued and therefore not shown in this graph. Furthermore, as expected, solar makes a very small, high cost contribution to January capacity needs, which is barely visible on the far-right side of the graph.

Figure 15 shows the same graph with DR included. Note that the baseline "with DSM" forecast does not include any DR, which is why most of the low-cost DR resources appear to be lower cost than the EE in this figure—the even lower cost EE resources are already being pursued in the baseline load forecast. However, Navigant cautions against presuming that all DR on Bainbridge Island will be low-cost[26], because the resource is not well-developed in PSE territory, and therefore a conservative approach to a non-wires solution may include no DR. Note also in this scenario that the need can technically be met cost-effectively without any energy storage, yet Navigant recommends including some energy storage in the solution portfolio to maintain operational flexibility. Approximately 1 MW of DR measures on the left side of the graph have very close to $0 net cost and are therefore difficult to see on the graph.

Figure 15: DER Supply Curve (Including DR) Based on Levelized Cost of Capacity for Bainbridge Island



Source: Navigant Analysis

[26] In this preliminary analysis, Navigant leveraged data directly from the 2017 IRP to the greatest extent possible—but it is possible that the cost data for DR were not intended to be directly compared to other DER for local capacity deferral purposes. In future economic analysis, it may be prudent to continue to consider DR resources separately, or to re-characterize these resources to ensure that LCOC comparisons across all resource types are developed using a consistent set of assumptions.

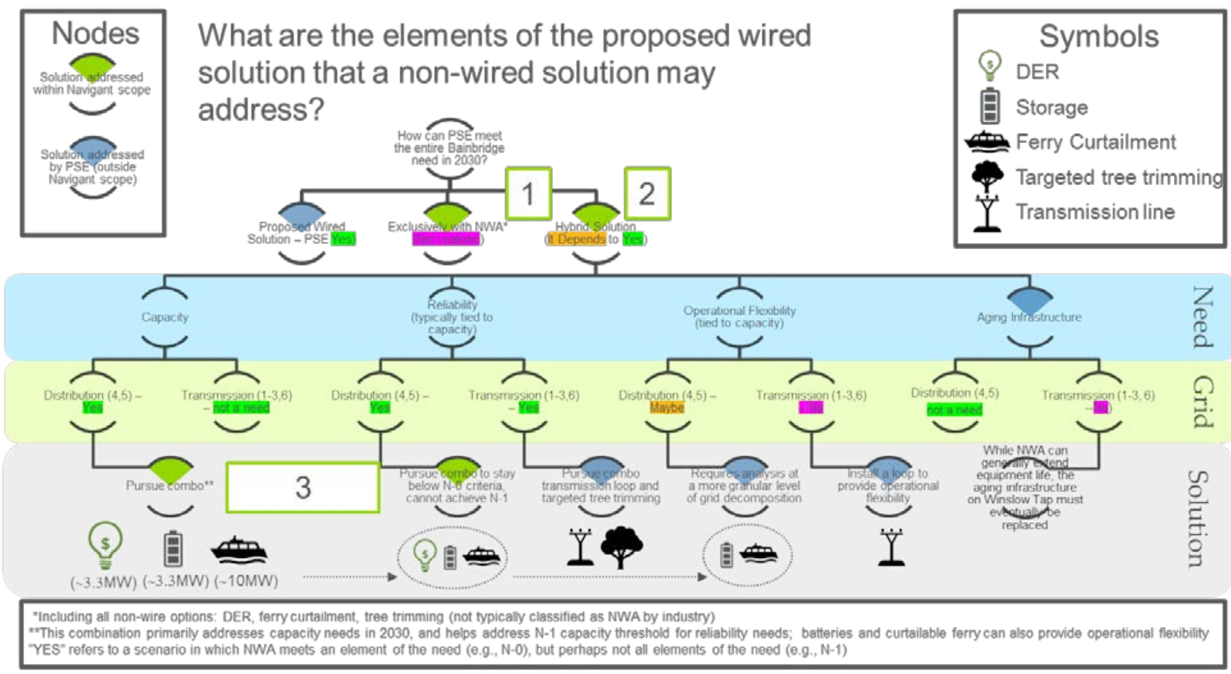
4. CONCLUSIONS AND RECOMMENDATIONS

Navigant has summarized below the conclusions and recommendations from the NWA assessment, including the DER potential assessment and economic analysis.

4.1 Conclusions

The decision tree framework introduced at the beginning of the report is useful for contextualizing the conclusions. The three numbers in Figure 16 below correspond to conclusions presented below in this section.

Figure 16. Bainbridge Island Decision Tree Including Numbered Recommendations



Source: Navigant Analysis

Navigant concluded the following:

1. It is not realistic or economically feasible for PSE to meet all the transmission and distribution needs on Bainbridge Island with solely a non-wires solution. Based on Navigant's high-level assessment and engineering judgment, however, it is likely that meeting the BI needs using the broad definition of non-wires alternatives discussed above is *technically* possible.[27] The costs and disruption on BI caused by this approach would be significant. Aging infrastructure and transmission reliability are key needs which are typically not economically feasible to address with NWAs.

[27] The broad definition includes the DERs (EE, DR, renewable CHP, PV) as well as storage and vegetation management, along with targeted O&M measures. This solution would, in our estimation, need to include an aggressive use of storage that would be very expensive, as well as aggressive tree trimming and removal that would be highly visible to residents and counter to community values on BI. Or, for example, while it is theoretically and technically possible to develop island-able microgrids for each individual neighborhood on Bainbridge Island, Navigant believes this would be cost prohibitive and highly unlikely as an acceptable solution.

2. A hybrid non-wired solution using traditional wired investment for the transmission needs, and DER (non-wires) investment for distribution capacity and reliability needs is a viable option for consideration (see #3). The specific wired solution that serves as the baseline for this hybrid solution is the transmission loop on BI that satisfies the transmission capacity and reliability aspects identified in the *BI Needs* document. Further analysis of this hybrid solution may incorporate the broader definition of NWAs, e.g., including vegetation management, which may solve additional transmission reliability elements of the identified needs.

3. PSE can delay reaching the planning trigger for the 3-substation group on BI from 2020 to approximately 2030 (possibly beyond) by leveraging the ferry electric load as a curtailable resource and by aggressively pursuing and expanding the DER portfolio on BI. Thus, distribution capacity related needs can likely be met on BI. The analysis made significant progress toward developing the non-wires distribution capacity solution and suggests that PSE can address local capacity needs based on a plan that:
    d. Connects the ferry electrification load (10MW) as a curtailable resource
    e. Incorporates storage to meet the capacity need and provide operational flexibility to help ensure that other demand-side resources perform as anticipated.
    f. Aggressively pursues expanding the DSM portfolio on BI, to complement storage, as the more economical alternative to a traditional wired capacity expansion.

The portfolio identified can help meet a portion of reliability needs as well as provide operational flexibility—primarily through ferry curtailment capability and appropriate operation of storage. However, specific details and quantification of the reliability and operational flexibility value the DER portfolio provides requires further, more granular analysis.

4.2 Recommendations and Next Steps

The conclusions presented above lead Navigant to recommend the following Bainbridge Island specific actions:

- **Connect the Ferry as a Curtailable Load:** PSE should work with relevant stakeholders to plan and operationalize the ferry as a curtailable load. Curtailing the ferry provides an opportunity to reduce the capacity needs on Bainbridge Island. These types of "big wins" involving large customers are essential to non-wires projects in our experience. Navigant's analysis of the historical loads on Bainbridge Island from 2013-2017 indicate that the ferry would need to be curtailed an average of 30 hours a year[28] to avoid planning capacity needs around the ferry. If the ferry load cannot be curtailed, then an additional 10MW of capacity will be needed to reach the same deferral targets. This would require some combination of additional DERs, likely weighted heavily towards additional DR and storage given there is no more renewable combustion potential, and the supply of additional EE would be expensive.
- **Launch a Pre-Implementation NWA Analysis to Validate the DSM portion of the Results**: An NWA portfolio including EE, storage, renewable DG, and the option of DR has the potential to cost-effectively defer the wired alternative until 2030 given current load forecasts. PSE should study and

[28] Fewer curtailment hours may be necessary, depending on the intended charging schedule of the ferry and whether that schedule is coincident with peak hours on the three-substation group. For more details on the ferry analysis, see Appendix A.

develop approaches to obtaining the EE, DG, and DR portions of the NWA portfolio on BI starting as soon as feasible.

- **Pursue Answers to Key Questions**: Future feasibility studies of the ability for PSE to pursue a cost-effective non-wires solution on Bainbridge should address the following questions:
  a. Unforeseen costs. Are there unforeseen costs associated with developing a targeted implementation of DER for Bainbridge? The measure characteristic assumptions (incremental cost, lifetimes, unit energy savings) used in this report are consistent with PSE's 2017 IRP, so represent the best available data at the PSE system level, also considering the applicable measures for Bainbridge Island based on the specific customer loads in that ZIP code. However, there may be additional cost considerations associated with implementing a targeted DR/EE program. PSE staff in Strategic System Planning could seek internal expertise on this topic by presenting Customer Energy Management staff with the measures in the recommended DER portfolio and discuss implementation considerations. Finally, there may be other grid-side costs (e.g. feeder upgrades) associated with avoiding the substation upgrade as a result of implementing the DER-based hybrid-non-wires solution.
  b. DER Derating Factor. What is the appropriate "derating" factor to apply to behind-the-meter capacity resources on Bainbridge Island? Not all customers can be guaranteed to respond to a demand response event. Similarly, load shapes for energy saving measures vary by customer. This variance may present operational considerations at the local level—a context where averaging the savings across a population of fewer customers may not result in a smooth hourly savings profile. The potential impact of customer-by-customer variance is a reason that Navigant recommends including energy storage in the portfolio to "firm up" and smooth the savings from behind-the-meter resources. Storage can be used to test DER resources in the early years (2021-2023) when the capacity needs are not as high as later years (2024, then again in 2029). This analysis assumes that all behind-the-meter resources save energy during hours typical of each measure, using load shapes vetted during development of the 2017 IRP. As the local capacity needs are not significant in early years (2018-2022), as PSE begins to implement this targeted program, PSE should perform detailed evaluation, measurement, and verification of the DER savings to understand whether the DER capacity contributions are lower or higher than modeled in the current analysis—and revise program plans accordingly.
  c. Load Forecast Refinement. PSE is consistently refining load forecasting methodology, in particular as advanced metering infrastructure becomes more prevalent in the service area. The definition of the capacity needs depends on this load forecast, so this analysis should be revisited if PSE has reason to believe the load forecast has changed significantly from that used in the *Bainbridge Needs* document.
  d. Customer Adoption. Will customers on Bainbridge Island adopt DER at a rate faster or slower than the typical power customer in the Pacific Northwest? The achievable technical potential estimate for DER is based on technology diffusion "ramp rates" developed by the Northwest Power and Conservation Council. These are region-wide adoption assumptions, which may or may not apply to BI customers. Additional customer outreach and research on BI would help to determine how receptive customers may be to targeted NWA efforts—which would allow the program implementation team to set realistic goals and lead times that ensure enough DER is installed on the necessary timeframe.
- **Leverage These Findings to Align with BI Stakeholders:** PSE staff can use the findings presented here as input for development of NWA approach alternatives on Bainbridge Island. The findings and illustrations should allow PSE to present the complexities of the decision-making process and

relevant portions of the analysis to stakeholders in a way that is congruent with PSE's broader NWA strategy on Bainbridge Island. Specifically, PSE can consider:

a. How does PSE present the information to help stakeholders understand the grid needs on Bainbridge Island?

b. How will stakeholders define "non-wires solution," is that consistent with PSE's strategy, and how can PSE manage their expectations of this definition?

c. Which aspects of the hybrid solution may be challenged by the public or local community?

In addition, Navigant recommends the following actions that are not specific to Bainbridge Island:

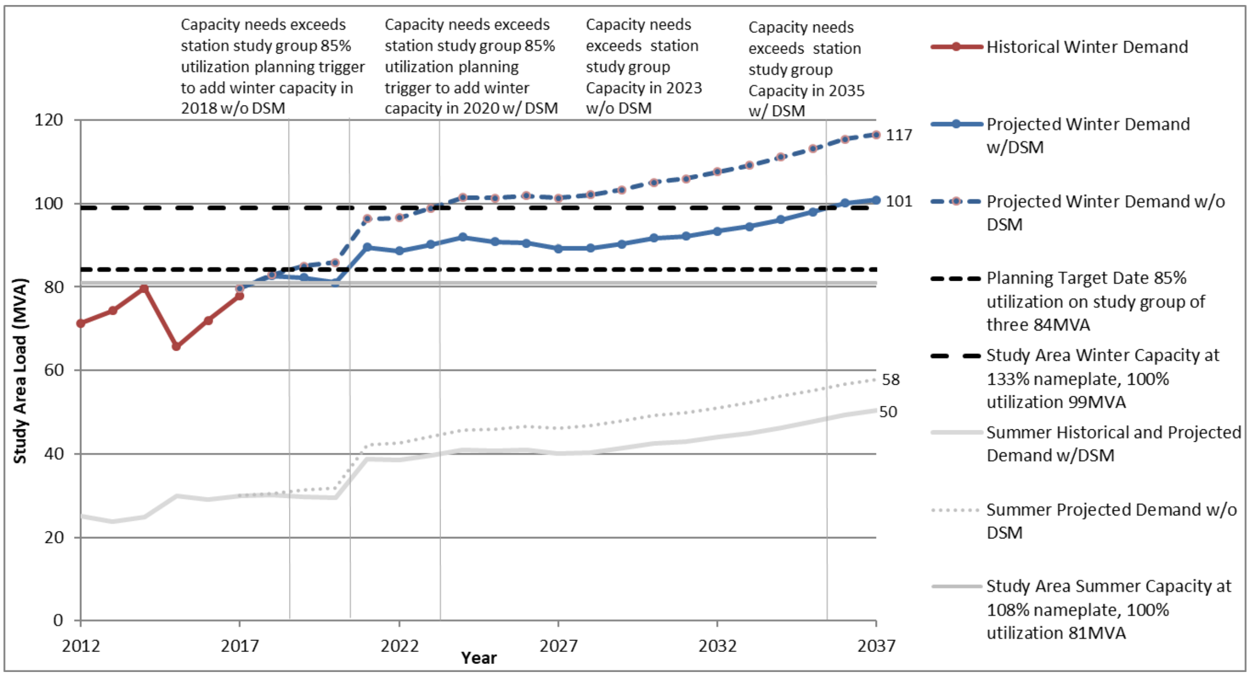
- PSE should *componentize* future wired planning solutions in a structured manner to provide flexibility in enabling wired, non-wires, and hybrid non-wires solutions. By this we mean tie the solution (transmission or distribution) to the specific need or needs addressed in the needs document. Whenever possible ensure that it is possible to decouple solutions into pieces that can be addressed using a hybrid non-wires strategy.
- PSE should select and develop a realistic non-wires pilot solution for implementation to begin to mature the non-wires process. The organizational learnings in planning and operations take time to incorporate fully and addressing low consequence non-wires or hybrid non-wires projects with enough time and pre-planned "off-ramps" will enable PSE to execute high-pressure non-wires solutions when they arrive.
- Non-wires alternative analysis requires significant quantitative complexity, considering multiple scenarios, using datasets from different divisions within PSE (Integrated Resource Planning, Strategic System Planning, Customer Energy Management, for example). PSE can use learnings from this Bainbridge Island analysis to develop a process for future NWA assessment. Such a process would require development of standardized quantitative analysis tools, and likely new processes within the organization.

APPENDIX A. BASELINE LOAD FORECAST

The baseline was developed beginning with PSE's load forecast for the substations on Bainbridge Island from the needs assessment. Forecast scenarios varied by three different variables: weather (normal or extreme), ferry (in place or not), and DSM (included or not). After several iterations, the baseline that was decided upon assumed normal weather conditions, without the Ferry, and with DSM called for in the IRP included. These iterations and decisions are discussed in more detail below.

A.1.1 Technical Adjustments

Figure A-1 PSE Initial Load Forecast



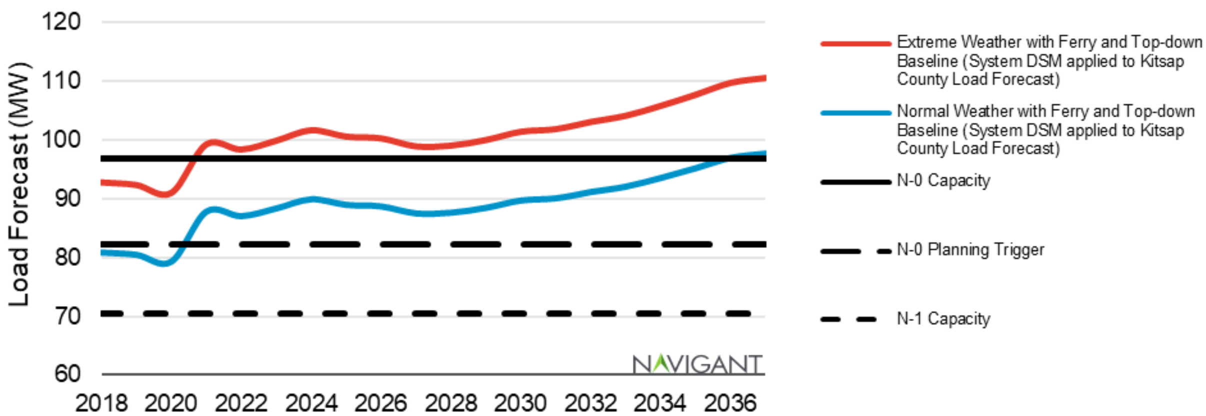
Source: Navigant Analysis

The PSE initial load forecast is shown in Figure A-1. A power factor conversion was applied on the MVA units to convert the forecast into MW load. The conversion factor was determined by comparing actual reads from the three substations on Bainbridge Island that were provided in MVA and MW. The load forecast was also disaggregated from the ferry impact, which was then included separately as a 10 MW load for the life of the ferry.

A.1.2 Winter Peak Weather

PSE-provided load forecasts based on "normal" and "extreme" winter peaks, corresponding to winter peak temperatures of 23°F and 13°F, respectively. The load forecast assuming the ferry load is included and using the top-down technical potential (assumptions discussed in sections A.1.3 below and 0 below) is shown in Figure A-2.

Figure A-2. Extreme Weather vs. Normal Weather Load Forecast



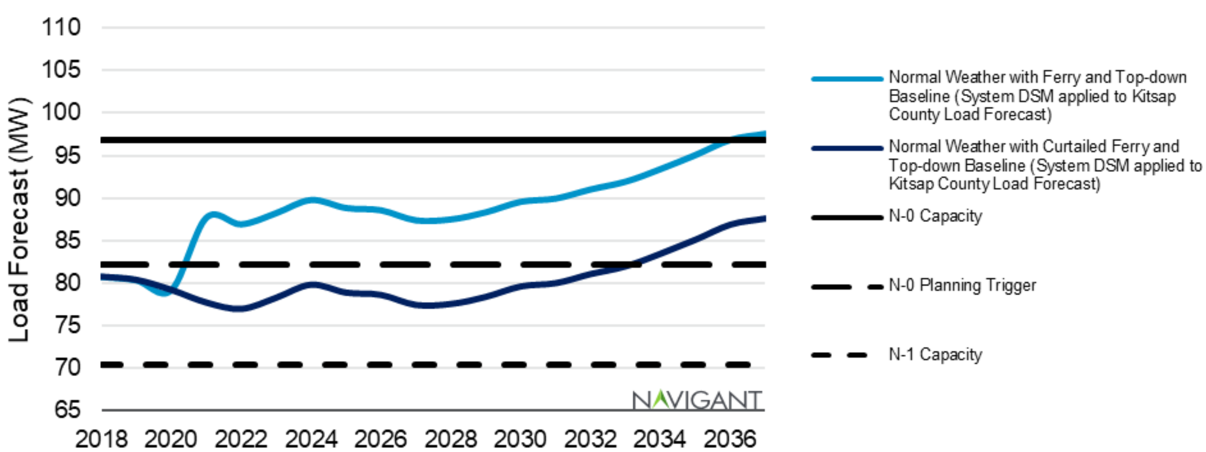
Source: Navigant Analysis

The normal weather scenario was selected as the baseline to represent a more average load forecast and remain consistent with PSE's selected load forecast.

A.1.3 Ferry Electrification

Ferry electrification in 2021 represents a large additional load (10 MW) which if not present would bring the load forecast below the N-0 Capacity threshold (assuming normal weather conditions and the top-down baseline DSM measures) and would defer the *N-0 Planning Trigger* from 2020 to 2033 or later, as seen in Figure A-3.

Figure A-3. Top-Down Baseline Forecast with and without Ferry Load

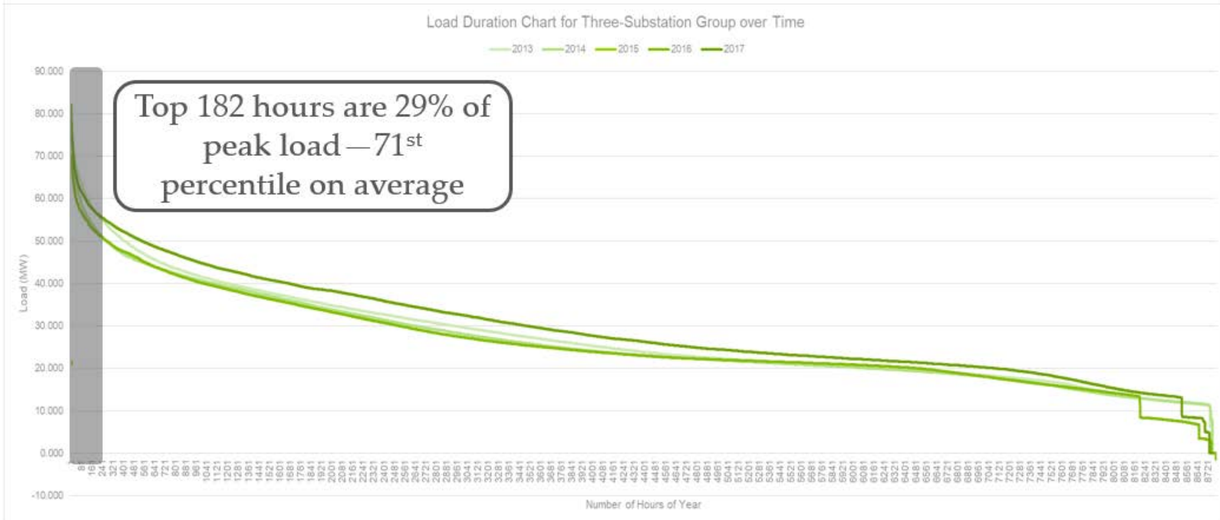


Source: Navigant Analysis

Importantly, the potential tariff structure for the ferry (Electric Tariff G, Schedule 46)[29] defines this load as interruptible for no more than 182 hours during a 12-month period. As illustrated in the load duration curve for the three-substation group below, the top 182 hours on Bainbridge Island over the past represent about 29% of the peak load.

[29] https://pse.com/aboutpse/Rates/Documents/elec_sch_046.pdf

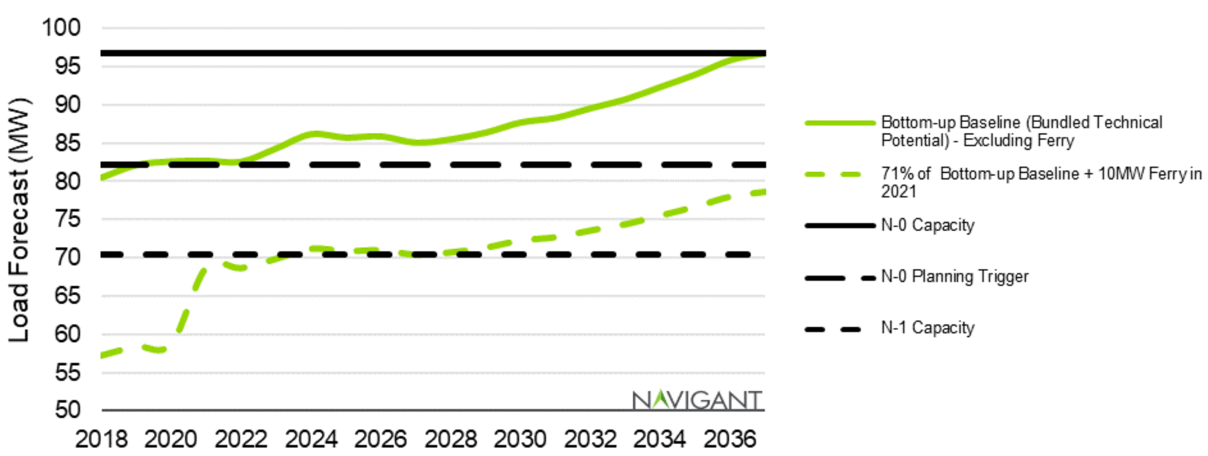
Figure A-4. Load Duration Chart and Illustrated Top 182 Hours for Three Substation Group



Source: Navigant Analysis

This means that if the ferry could be curtailed for the peak 182 hours in a year, then on the theoretical 183rd peak hour PSE would expect to supply the 10 MW ferry load plus 71% of the annual peak load. The question then becomes whether that load in the theoretical 183rd hour (71% of the peak plus the 10 MW ferry) is greater than the peak load in the top hour of the year without the ferry. As seen in Figure A-5, the peak load in the top hour of the year without the ferry is higher than the peak load in the 183rd hour, implying that with curtailment of the ferry PSE doesn't need to consider the ferry in the peak load forecast for capacity planning.

Figure A-5. Baseline Load Forecast Excluding Ferry vs. 183rd Peak Hour Plus Ferry Load

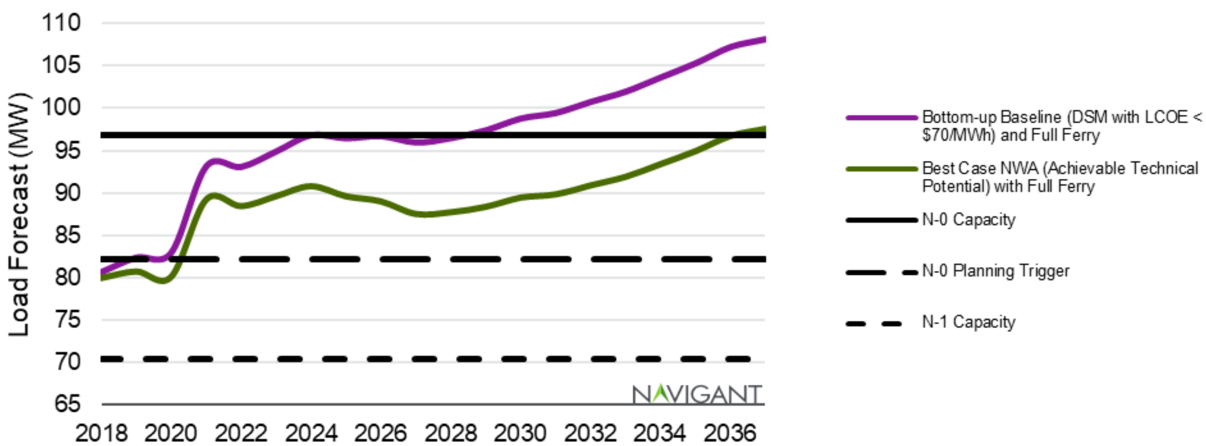


Source: Navigant Analysis

This analysis lead to the assumption that the ferry is curtailed as part of the baseline load forecast used to determine the capacity needs on Bainbridge Island.

This assumption depends on PSE's ability to utilize the ferry as a curtailable resource. One aspect that is then also important is when the decision to curtail the ferry load would need to be made. As seen in Figure A-6 (which utilizes the bottom-up baseline discussed in 0 below and the technical potential from the analyzed DER discussed in Section 2.2), the timing of the decision depends on the threshold for analysis. If the primary threshold is the *N-0 Planning Trigger* – as has been assumed throughout this work – then the DER alone would not be able to lower the load forecast when the ferry comes online in 2021, meaning that curtailing the ferry would need to be addressed from the beginning. However, if the *N-0 Capacity* threshold is considered instead, then the incremental DER could delay the need for ferry curtailment from 2023 to around 2035. Again, for this analysis the ferry was assumed to be a curtailable load starting in the near term (2020 and beyond).

Figure A-6. Baseline and Best-Case NWA Assuming the Ferry is Not Curtailed



Source: Navigant Analysis

Navigant analyzed the three-substation historical load to estimate how many hours the ferry may need to be curtailed each year. The need for the three-substation group is based on the peak load, and the ferry would add 10MW to load any time it is charging. Given that the ferry load is 10MW, the team ordered the hours from 1 to 8760 based on highest to lowest load, and identified which hour number is 10MW below the absolute peak as a proxy for how many hours the ferry may need to be curtailed. For example, on the 31st highest hour in 2013, even if the ferry was charging during that hour, the additional ferry load would not increase capacity needs on the three-substation group, because the 31st hour load + 10MW would still be less than the absolute peak load in 2013. The results in Table 6 ranged from 10-54 hours over the 5 years of historical load data, with an average curtailment of approximately 30 hours.

Table 6: Historic Analysis of a 10MW Load Reduction

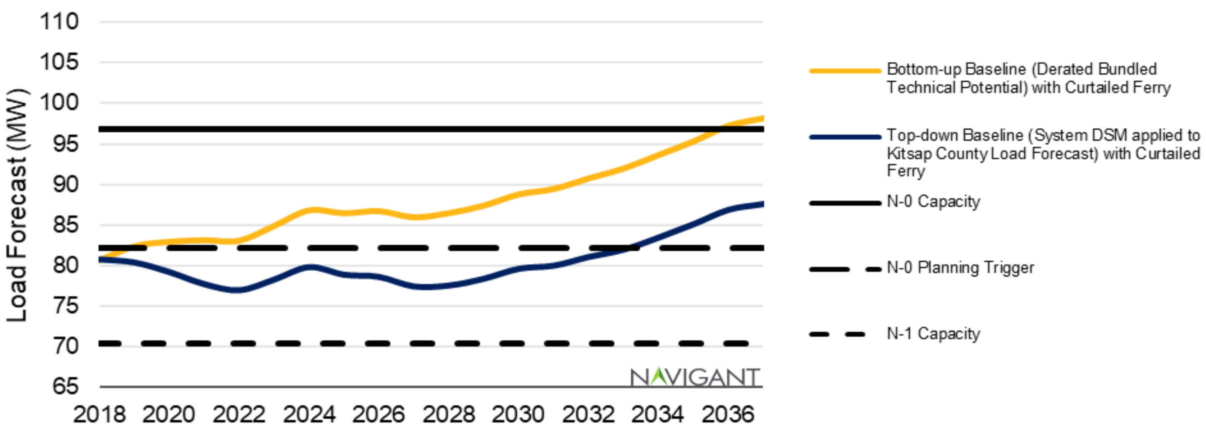
Hour ranking 10MW below annual peak load					
Average	**2013**	**2014**	**2015**	**2016**	**2017**
29.6	31	10	54	25	28

Source: Navigant Analysis

A.1.4 Business-as-Usual Measures (Top-Down vs Bottom-Up Potential Analysis)

The third variable for the baseline is inclusion of demand-side management that is already being pursued on Bainbridge Island as described in the 2017 IRP. The load forecast provided by PSE used a "top-down" method wherein system level DSM was applied to the Kitsap County Load Forecast. With access to the zip-code level data used to originally generate PSE's 2017 IRP, Navigant was able to develop a "bottom-up" forecast that analyzed resources for the 98110-ZIP code (Bainbridge Island) then sum the impact in that ZIP code for measures in the top 3 LCOE bundles (with an LCOE less than or equal to $70/MWh). As seen in Figure A-7, the "bottom-up" method or the "Bundled Technical Potential" yielded a higher load forecast for Bainbridge Island than the "top-down" method, likely because Bainbridge Island has more residential load as a fraction of overall load than average across the rest of Kitsap County, which may have led to an overestimate of commercial and industrial energy efficiency savings.

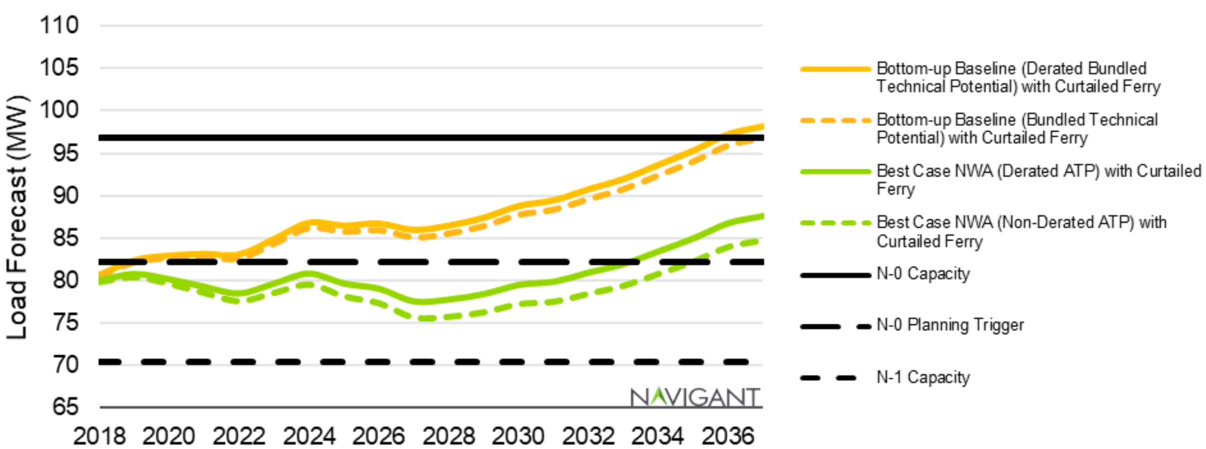
Figure A-7. "Bottom-Up" Bundled Technical Potential vs. Top-Down" DSM



Source: Navigant Analysis

When developing the bottom-up baseline, there was also a question on whether to apply an NPCC mandated achievability factor in addition to adoption factors that were already applied in the model. The NPCC dictates this achievability derating factor (typically 85%) for the service territory, which may not be suitable when developing a technical potential analysis specifically for Bainbridge Island given the demographic makeup and the urgency of the NWA program versus a typical, system-wide energy efficiency program. The decision to include the derating factor thus affects both the bottom-up baseline and the best-case NWA forecast, as can be seen in Figure A-8.

Figure A-8. Bottom-up Baseline and Best-Case NWA with and without Achievability Factor



Source: Navigant Analysis

The non-derated (dotted) lines represent a sort of best-case scenario with an achievability factor on Bainbridge Island of 100% rather than the prescribed value from the NPCC. While the difference is minor, this analysis uses the derated values to remain consistent with the NPCC, with the understanding that as incremental DER measures are pursued on Bainbridge Island the actual achievability factor can be determined.

APPENDIX B. PEAK PERIOD ANALYSIS

Using actual hourly load shape data from the three substations on Bainbridge Island over the past 5 years, the peak period was determined to be weekdays in December and January from 7:00 am to 11:00 am.

First, we analyzed the number of days each substation would surpass a given threshold for a certain hour of the day for each year, indicating the most typical peak hours, as illustrated in Figure B-1.

Figure B-1. Heat Map for 2017 Load for a Selected Bainbridge Substation and Year

Number of Days in 2017 above the Stated Threshold for each Month and Hour of Day for Selected Substation

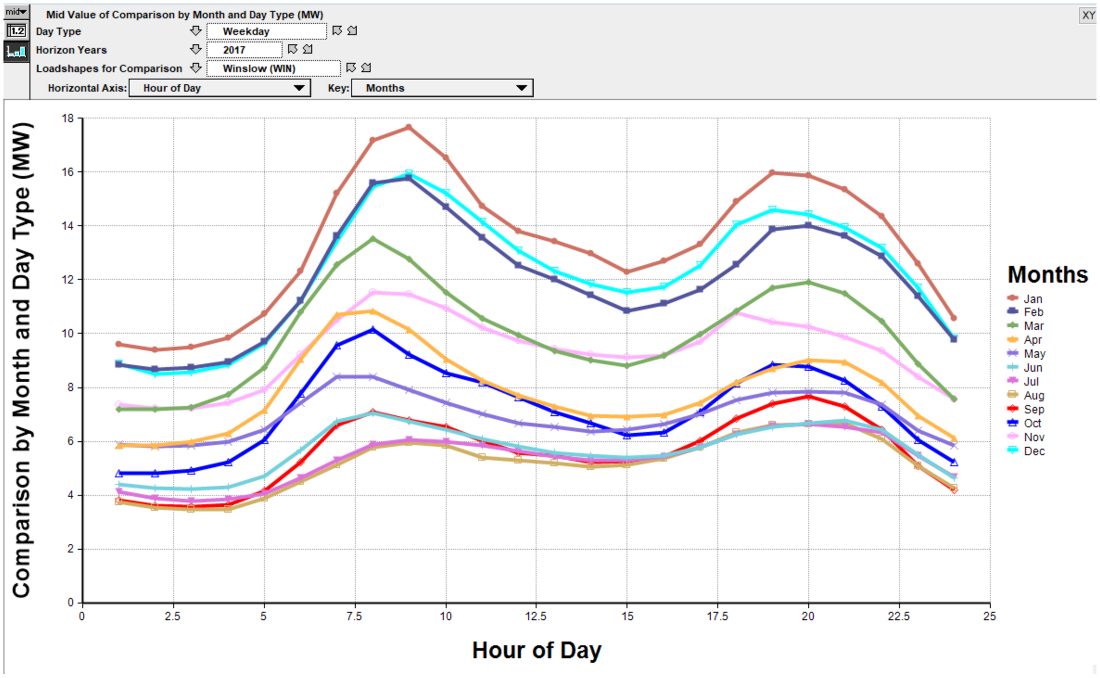
Threshold MW: 21 Top: 51 Hours; >= 77.6% of 2017 Peak Load on the Sub

Hour of Day	January	February	March	April	May	June	July	August	September	October	November	December
1:00 AM	-	-	-	-	-	-	-	-	-	-	-	-
2:00 AM	-	-	-	-	-	-	-	-	-	-	-	-
3:00 AM	-	-	-	-	-	-	-	-	-	-	-	-
4:00 AM	-	-	-	-	-	-	-	-	-	-	-	-
5:00 AM	-	-	-	-	-	-	-	-	-	-	-	-
6:00 AM	-	-	-	-	-	-	-	-	-	-	-	-
7:00 AM	2	-	-	-	-	-	-	-	-	-	-	-
8:00 AM	7	1	-	-	-	-	-	-	-	-	-	3
9:00 AM	9	1	1	-	-	-	-	-	-	-	-	4
10:00 AM	9	-	1	-	-	-	-	-	-	-	-	4
11:00 AM	3	-	-	-	-	-	-	-	-	-	-	3
12:00 PM	-	-	-	-	-	-	-	-	-	-	-	1
1:00 PM	-	-	-	-	-	-	-	-	-	-	-	-
2:00 PM	-	-	-	-	-	-	-	-	-	-	-	-
3:00 PM	-	-	-	-	-	-	-	-	-	-	-	-
4:00 PM	-	-	-	-	-	-	-	-	-	-	-	-
5:00 PM	-	-	-	-	-	-	-	-	-	-	-	-
6:00 PM	-	-	-	-	-	-	-	-	-	-	-	-
7:00 PM	1	-	-	-	-	-	-	-	-	-	-	-
8:00 PM	1	-	-	-	-	-	-	-	-	-	-	-
9:00 PM	-	-	-	-	-	-	-	-	-	-	-	-
10:00 PM	-	-	-	-	-	-	-	-	-	-	-	-
11:00 PM	-	-	-	-	-	-	-	-	-	-	-	-
12:00 AM	-	-	-	-	-	-	-	-	-	-	-	-

Source: Navigant Analysis

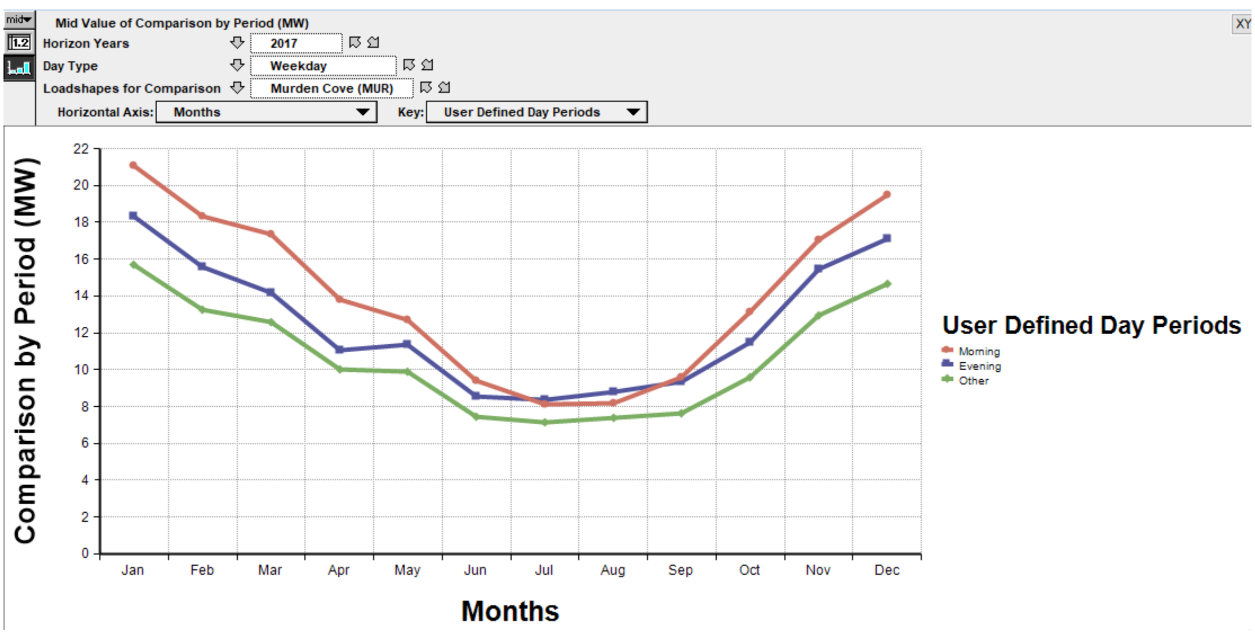
This analysis quickly indicated that mornings in January and December had the most typical peak periods, which differed slightly from PSE's system peak period which also includes the night time. Additional analysis was performed to better understand the load profile on Bainbridge Island. As illustrated in Figure B-2, Figure B-3, and Figure B-4, while there is an evening peak present on Bainbridge Island (especially in the winter), it is not as large as the morning peak. In Figure B-5, we can see that the load has remained steady on average over the past 5 years, though 2017 presented a large increase.

Figure B-2. Average Daily Load by Month for a Selected Bainbridge Substation and Year



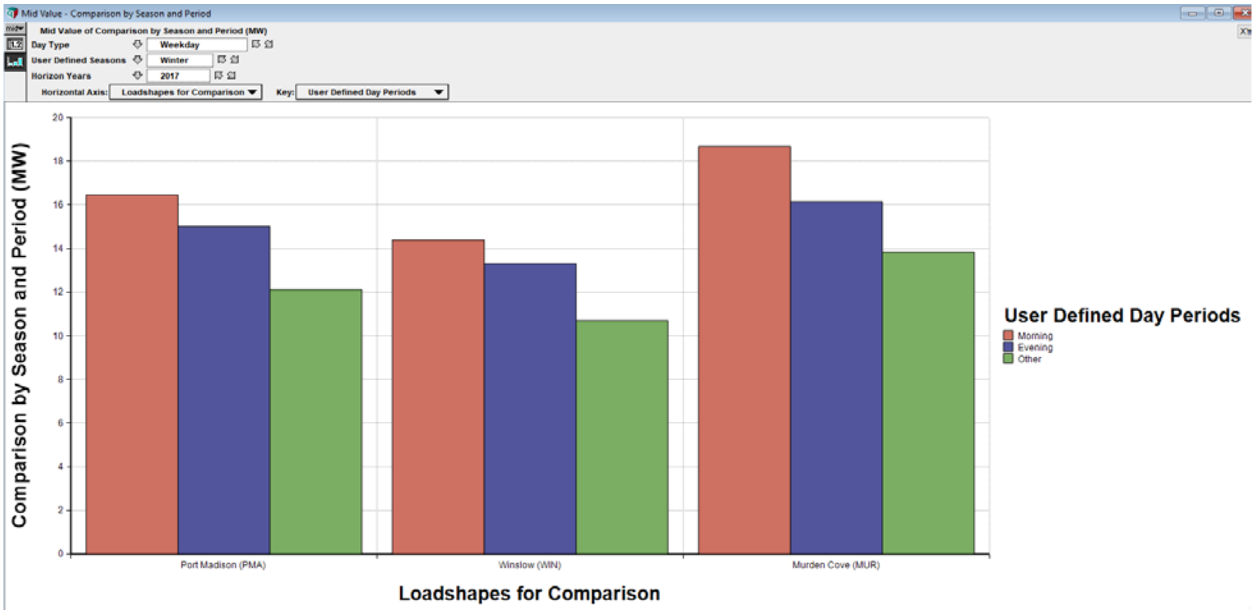
Source: Navigant Analysis

Figure B-3. Average Monthly Load by Day Period for a Selected Bainbridge Substation and Year



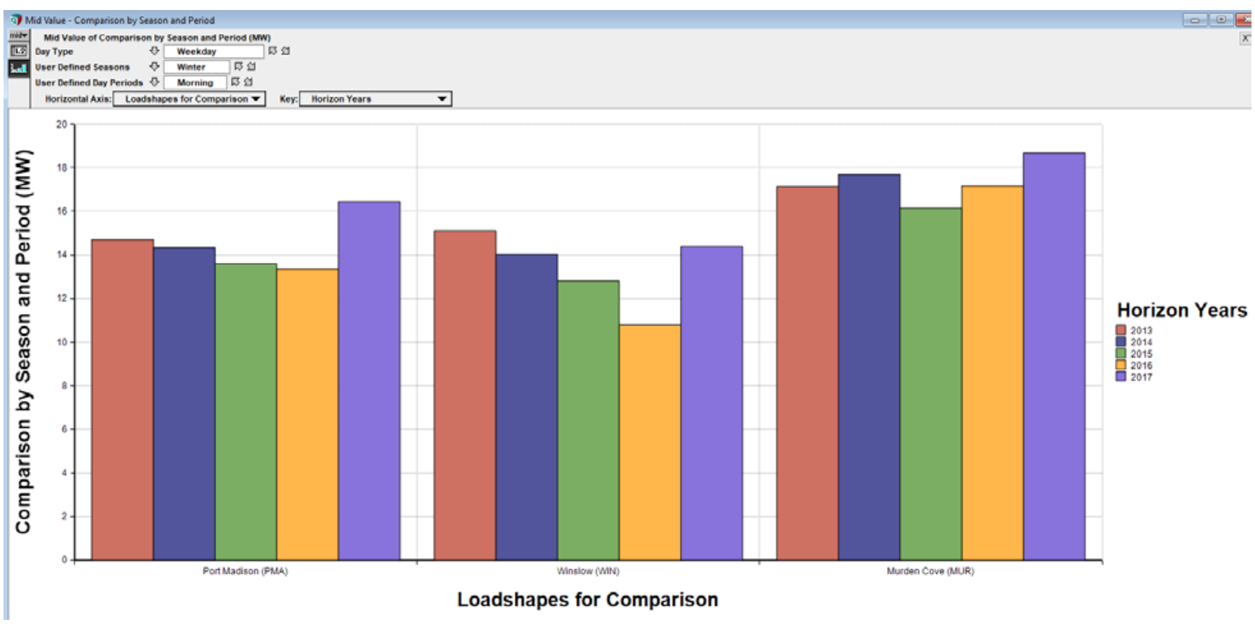
Source: Navigant Analysis

Figure B-4. Average Load by Day Period in Winter across Bainbridge Island Substations



Source: Navigant Analysis

Figure B-5. Average Winter Morning Load Over Time for Bainbridge Island Substations



Source: Navigant Analysis

This analysis indicated that mornings in December and January represent the peak period for Bainbridge Island.

APPENDIX C. ENERGY STORAGE ANALYSIS

To incorporate energy storage into the portfolio analysis, energy storage systems were assessed in incremental sizes. The approach generally followed these steps:

1. Establish inputs and assumptions
2. Size the energy storage system based upon deferral need
3. Optimize energy storage dispatch for maximum economic gain
4. Evaluate LCOC of storage based upon need met
5. Incorporate storage into portfolio

The following sub-sections describe the methodology and assumptions for each of these steps.

C.1.1 General Assumptions

Table C-1. provides an overview of the assumptions used in the energy storage analysis. The assumptions are consistent with the typical range of values for lithium-ion batteries.

Table C-1. Assumptions for Energy Storage Analysis

GENERAL	
Cycle Life	4,500 cycles (to 80% of rated energy)
Degradation	Annual degradation calculated based upon number of cycles each year. Assumed constant energy due to annual augmentation to counteract degradation.
Efficiency	90%
Equipment replacement	Annual battery augmentation (forecasted battery unit cost) to counter degradation
Financing	7.6% weighted average cost of capital
Inflation	2.5% escalation applied to operating costs and revenues
COSTS	
Capital cost[30]	$550/kW of rated power + $350/kWh of rated energy (2018 basis), decreasing annually at 8%/yr through 2022, then 4%/yr afterward
Fixed O&M	3% of capex per year, inflated annually
Variable O&M	$2/MWh
Augmentation	Cost of annual battery augmentation based upon degradation (MWh) at forecasted unit battery cost ($/MWh) in each year
Charging	Cost of charging based upon weighted average hourly energy value ($/MWh) when charging and annual energy consumed for charging (MWh)
REVENUES	
Capacity (generation)	Annual value from IRP based upon 6-11am and 5-10pm peak periods in December

[30] These costs reflect front-of-meter installed cost including a rough estimate of land lease costs for a large bulk system as well as interconnection.

Energy	Revenue from charging based upon weighted average hourly energy value ($/MWh) when discharging and annual energy export for discharging (MWh)

Source: Navigant Analysis

C.1.2 Sizing

The team sized the storage to meet the capacity needs in 2030, defined as the bottom-up with DSM load forecast, with the ferry curtailed, against the *N-0 Planning Trigger* threshold (see Appendix A for more details on the need definition).

To evaluate incremental amounts of storage within the portfolio, discrete system sizes were evaluated based upon the percentage of the 2030 need meet (7%, 30%, 50%, and 70%). The minimum power required to meet the need, adjusting for losses,[31] was rounded up to the nearest 0.1 MW. The energy rating was determined based upon the minimum energy (rounded up to the nearest 0.1 MWh) necessary to remain below the maximum load (determined by the percentage of need met) with the rated power based upon the shape of the 2017 load curve for Bainbridge Island.[32] For 2030, the load curve was scaled proportionally in each hour based upon the ratio between peak load in 2030 versus 2017.

C.1.3 Dispatch Optimization

Optimal hourly dispatch in 2030 was evaluated for each system size based upon three applications: local capacity need, system capacity need, and energy price arbitrage. Based upon the maximum load (determined by the percentage of need met), a minimum discharge power was set for each applicable interval. A maximum charge power was also set for each applicable hour to avoid exceeding the maximum load.

Hourly dispatch was optimized to maximize economic value from generation capacity (as defined above) and energy arbitrage based on PSE-provided avoided energy costs. The forecasted value of generation capacity in 2030 ($/kW-yr) was converted into an hourly value in applicable hours based upon the number of relevant hours in the year. The combined hourly energy and capacity prices were used to determine the optimal charge and discharge strategy (while meeting minimum requirements for deferral).

C.1.4 Levelized Cost of Capacity Calculation

The levelized cost of capacity was calculated based upon expected annual costs and revenues (includes avoided costs) assuming a similar dispatch profile each year over the life of the system. Capital, fixed O&M, variable O&M, charging, and augmentation costs were calculated as described in Table C-1. The energy (MWh) basis for charging, variable O&M, and augmentation costs were calculated based upon the annual storage dispatch profile.

The annual amount of deferral (MW) was calculated as the minimum of the annual deferral need (based upon the *N-0 Planning Trigger*) and the amount of need met in 2030. The amount of capacity was assumed to be constant each year and based upon the average power output during capacity hours (as

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[31] Actual need reduction, after losses, was assumed to be the square-root of the assumed round-trip efficiency (e.g., $90\%^{1/2} = 95\%$) multiplied by the rated power. This assumes equal losses during charging and discharging.

[32] The load curve was normalized as a % of annual MWh consumption occurring in each hour, such that a sum of the % values across all 8760 hours of 2017 equals 100%.

defined in Table C-1.). Energy revenue was calculated based upon the annual discharged energy (assumed to be constant) and the energy price (escalated 2.5% annually).

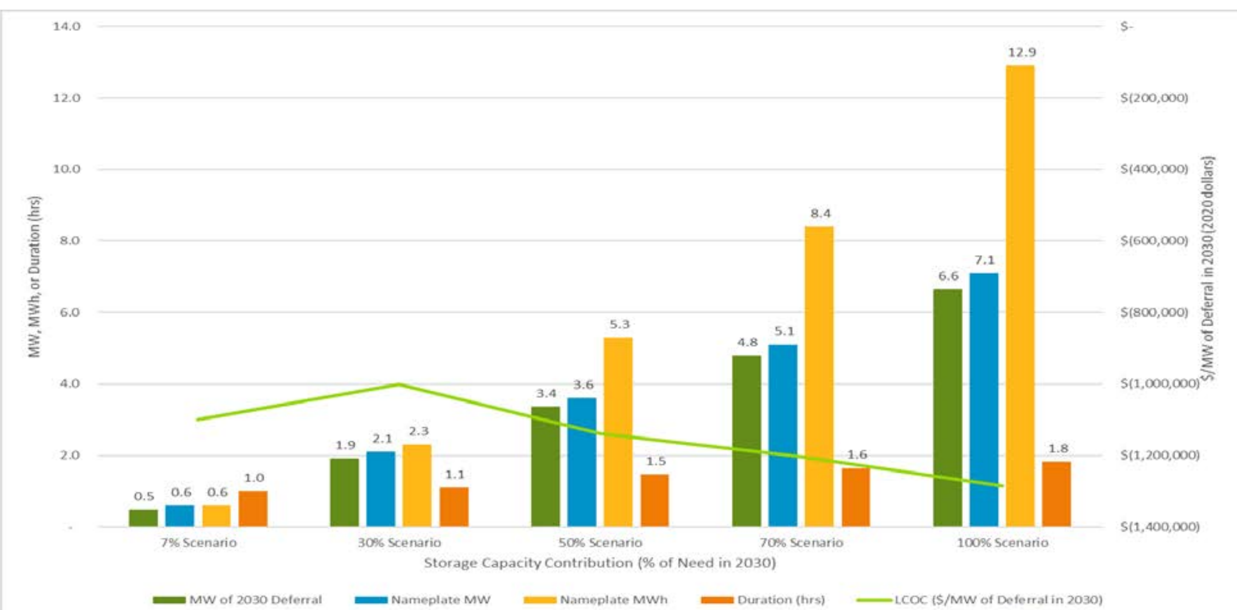
The levelized cost of capacity ($/MW) was calculated by calculating the net present value of costs and revenue ($) to 2020 dollars using a 7.6% discount rate, then dividing by the amount of need met in 2030 (MW).

The LCOC was evaluated with and without including various revenue streams. Additionally, the LCOC was evaluated using PSE's hourly avoided cost of energy in place of hourly Energy Imbalance Market (EIM) values. The dispatch optimization was calculated over one year using EIM values, and the weighted average EIM prices ($/MWh) during discharging (charging) were observed to be approximately equal to the annual average of the second highest (lowest) hourly price in a day. Thus, to approximate value based upon PSE's avoided cost of energy, weighted average discharging (charging) values were assumed to be equal to the annual average of the second highest (lowest) hourly avoided cost in a day. The amount of energy for charging and discharging was assumed to be the same.

C.1.5 Portfolio Analysis

Navigant began the economic analysis by considering various storage sizes and system characteristics according to the historical substation load shape and forecast 2030 capacity needs. Figure C-1 summarizes the results of this analysis, this section contains the complete details of the methodology. The team concluded that, when considered alone, sizing the storage system to meet 30% of the 2030 need is the most cost-efficient system design. However, design of the optimal non-wires alternative portfolio must also consider the ability to add other non-storage DER (PV, renewable combustion generation, EE, and DR) to serve the capacity needs—which influences the optimal sizing of the storage system as discussed in Section 3 of the main report.

Figure C-1: Summary of Storage System Technical Characteristics and Costs



Source: Navigant Analysis

Section 3 indicates how these results were combined with a portfolio of least-cost non-storage DER to develop the recommended non-wires solution.

C.1.6 Interpretation of Results

These results help to provide an indicative value of storage for consideration in planning. However, it should be noted that further analysis would be required before moving forward with the implementation of a specific storage system, as the actual LCOC may vary depending upon a variety of factors. The following variables and uncertainties provide examples of parameters that can significantly impact storage system sizing and LCOC:

- **Load shape** – The systems were sized to meet the need based upon the Bainbridge load shape in 2017. As other DSM strategies are employed over time, the load shape will become flatter around peak hours, requiring a longer duration (hr) of storage to meet the same need (MW), which increases the LCOC.
- **Peak load** – The systems were sized to the minimum amount necessary to meet the forecasted need (MW) in 2030. To ensure that sufficient capacity is available, in case the need is greater than forecasted, a system with greater power (MW) and a longer duration (thus higher cost in $/MW) may be prudent. It is possible that the future need may be larger or smaller than forecasted.
- **Oversizing** – To ensure that sufficient power and energy are available, the system may be oversized to mitigate uncertainty in load shape and peak load. Thus, a system with greater power (MW) and a longer duration (thus higher cost in $/MW) may be desired, which could increase the LCOC.
- **Staggered deployment** – Storage could be deployed incrementally over time to defer costs further into the future and reduce the LCOC. This would be an alternative method to help mitigate uncertainty in the load shape and load forecast.
- **Use case** – The assumed use case of storage is a utility-scale system used for deferral, generation capacity, and energy arbitrage. Alternative use cases may offer a more promising LCOC. For example, PSE may be able to utilize the storage to optimize the dispatch of its generation portfolio to lower costs, which may offer greater value than energy arbitrage. PSE could also consider additional upfront costs for islanding capabilities to increase customer benefits by improving circuit reliability.