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2022 PSE GENERAL RATE CASE
WITNESS: DAN'L R. KOCH

BEFORE THE
WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION

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

SEVENTH EXHIBIT (NONCONFIDENTIAL) TO THE PREFILED DIRECT TESTIMONY OF

DAN'L R. KOCH

ON BEHALF OF PUGET SOUND ENERGY

JANUARY 31, 2022

Eastside System Energy Storage Alternatives Screening Study

STRATEGEN
STRATEGIES FOR CLEAN ENERGY

Prepared for:

PSE PUGET SOUND ENERGY

MARCH, 2015

Eastside System Energy Storage Alternatives Screening Study

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Electric Power Research Institute (EPRI)

Strategen Consulting, LLC developed this report based on information received from Puget Sound Energy, who is solely responsible for this application of Energy Valuation Tool (ESVT) Version 4, with all reliance thereon to be at evaluator's sole risk without any endorsement by the Electric Power Research Institute, Inc.

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2.1 Background

Puget Sound Energy (PSE) is evaluating several possible solutions to meet reliability needs identified in PSE's Eastside transmission system located in Central King County (the Eastside) as part of PSE's annual comprehensive reliability assessment.

PSE commissioned Strategen Consulting, LLC (Strategen) to assess one of those prospective solutions: the feasibility of using energy storage – combined with other previously identified cost-effective non-wires alternatives – to meet the reliability need.

This assessment includes the following:

1) An overview of the current state of energy storage;

2) An assessment of the feasibility of energy storage paired with previously identified non-wires options to meet the Eastside's reliability need through 2021 in a manner comparable to that of a transmission solution;

3) A screening-level assessment to determine whether an energy storage system, when paired with other non-wires solutions, would be able to come online by 2017-2018 to meet the identified winter peak reduction system need and PSE planning guidelines;

4) A detailed evaluation of cost-effectiveness of whether an Eastside energy storage configuration would be cost effective as a grid resource within PSE's system.

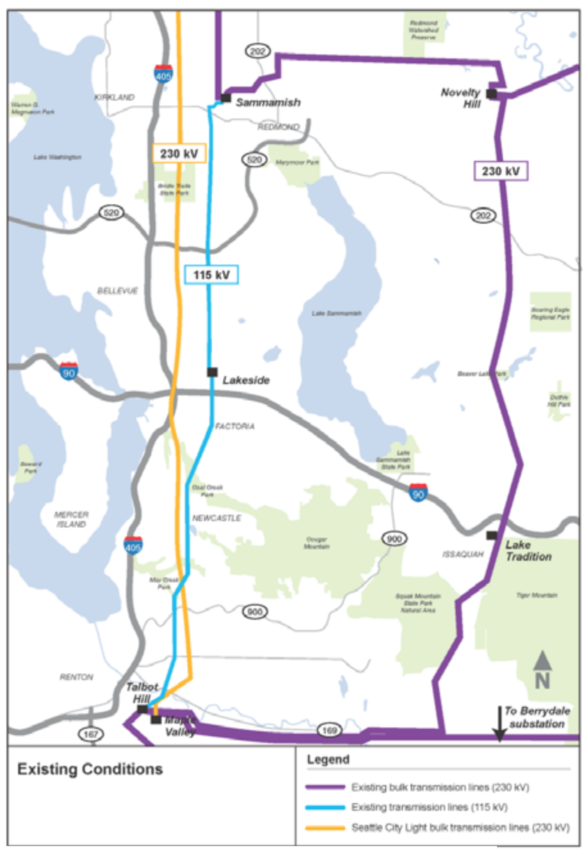


Figure 1. Eastside System

2.1.1 *Description of the Identified Eastside System Reliability Need*

PSE's 2013 Integrated Resource Plan demonstrated that PSE service territory is experiencing sustained economic growth resulting in increased electricity demand. Existing infrastructure on the eastside of King County is already strained and requires the use of corrective action plans (CAPs) to mitigate thermal violations.

In 2013 PSE commissioned the Eastside Needs Assessment Report (the "Eastside Assessment)[1] to better understand and quantify the issue. The report identified a deficiency in transmission capacity that will cause North American Electric Reliability Corporation (NERC) criteria violations and overloads in certain contingencies leading to loss of customer load at the 230 kV supply injections between Talbot Hill and Sammamish Substations.

The Eastside Assessment found that overloading of the Talbot Hill Substation 230-115 kV transformers and 115 kV transmission lines, primarily experienced during winter, will worsen as demand increases. Sammamish Substation summer overload issues will increase as well, with significant overloading projected in summer 2018. Beyond the 2017-2018 timeframe, overloads and NERC reliability violations are projected to occur and worsen at both substations even if 100% of conservation targets identified in PSE's Integrated Resource Plan (IRP) are met. The use of CAPs will have to increase as well to continue being effective, putting even more PSE customers at risk for outages.

Importantly, if not all conservation targets (identified during the IRP process) are met and/or during extreme weather events, overloads may occur before the 2017-2018 timeframe, and could be more significant in the latter years of the planning period than indicated by the IRP base case forecast.

Further detail about the Eastside situation is found in Appendix B: Description of the Eastside System Reliability Need.

2.1.2 *Summary of Proposed Transmission Solution*

Following the Eastside Assessment findings, PSE commissioned the Eastside Transmission Solutions Study[2] to rigorously evaluate potential solutions to the identified transmission needs. To be viable, a possible solution must solve the transmission issues identified in the Eastside Assessment, comply with environmental requirements, and satisfy constructability and longevity requirements. A variety of solution types were considered: distributed generation, transformer addition with minimal system reinforcements, demand side reduction, and transmission lines plus transformers.

Various solutions were evaluated based on their effectiveness at resolving the capacity deficiency, operational flexibility, potential to eliminate reliance on CAPs, and effects on adjacent grid infrastructure. After screening for feasibility and performing power flow analysis on each solution type, the addition of new transformers combined with new/upgraded transmission lines emerged as the most viable solution.

Further description of the identified transmission solution is found in Appendix C: Proposed Eastside Solutions.

[1] Quanta (2013)
[2] Quanta (2014)

2.1.3 *Non-Wires Alternatives Assessment*

To supplement PSE's work on transmission options, Energy + Environmental Economics (E3) was retained by PSE to conduct a screening analysis of "non-wires" solutions (hereafter referred to as the "Non-wires Report").[3]

The Non-wires Report evaluated the feasibility and cost-effectiveness of demand side reduction ("DSR"), including energy efficiency, demand response, and distributed generation, to defer PSE's identified need date for the Eastside transmission upgrades by maintaining peak load levels below amounts that would produce potential overloads under contingencies greater than those shown in 2017-18 in the Eastside Assessment and create the need for the upgrades.

PSE transmission planners determined that a *minimum* of 70 MW of incremental load reduction would be required for a four year deferral (2017-2021) while maintaining system reliability at 2017-2018 levels[4], assuming normal weather conditions and 100% of PSE's IRP-identified conservation measures were also successful. As much as 160 MW of incremental load reduction would be required under a higher load growth / 75% conservation scenario.

The Non-wires Report found that only 56 MW of potential non-wires alternatives in the Eastside would be cost-effective (in addition to the conservation measures identified by PSE in the IRP), and concluded that DSR alone is insufficient to address the local transmission capacity deficiency.

Additional details from the Non-wires Report are found in Appendix C: Proposed Eastside Solutions.

Because the overload reduction provided by the combined cost-effective non-wires alternatives identified in PSE's IRP and the Non-wires Report do not sufficiently meet the deferral requirement, PSE commissioned Strategen to evaluate the feasibility of energy storage to accommodate the gap between the capacity provided by the non-wires alternatives and the expected overloading.

2.2 Evaluation Summary and Results

2.2.1 *System Sizing*

PSE provided Strategen with its planning and operating requirements used to determine the power and energy rating and physical configuration of an energy storage system that both a) meets the Eastside system's reliability needs in a manner comparable to that of a transmission solution and b) is technically viable and can be built and sited when and where needed. These requirements are as follows:

[3] E3 (2014)

[4] True capacity deficits could be larger if any of the following occurred: Extreme cold weather conditions (models and forecasts are based on 23° F average), faster load growth than expected (based on prevailing economic conditions), or IRP conservation targets were implemented slower than expected.

1. The system must mitigate all Eastside line and transformer overloads to below 100% of their emergency limits in the 2021-2022 winter case and in the 2018 summer case for all required contingencies;

2. The system must reduce the duration of all line and transformer overloads in excess of 100% of their normal operating limits to no more than 8 consecutive hours; and

3. The system must be able to come online by in time to address the winter 2017-2018 peak.

PSE annual hourly data was used to determine the maximum emergency power flows on the Talbot Hill and Sammamish substations during Category C NERC contingencies (N-1-1). Using the normal and emergency line ratings for those substations, Strategen determined that in all years, Talbot Hill was the substation with the most significant normal and emergency overloads, thus Talbot Hill was the element that determined the overall need.

Strategen evaluated the power and energy requirements for an energy storage system to accomplish the above objectives.

The maximum Eastside mitigation needs required in 2021 to prevent the overloads from occurring are summarized in Table 1 and represented graphically in Figure 6 and Figure 11 on pages 70 and 79.

Table 1. Eastside Mitigation Needs

Scenario	2021 Deferral	
	Power (MWp)	Energy (MWh)
Baseline Normal Overload Reduction	76.8	491.0
Alternate #1 Emergency Overload Elimination	34.1	82.3
Alternate #2 Normal Overload Elimination	120.1	1,253.6

An energy storage configuration would have to fully address the *Normal Overload Reduction* requirement shown above in order to meet PSE's planning and operating requirements. Note that the third criterion, *Normal Overload Elimination*, was evaluated as a potential longer term solution for the Eastside, beyond the 2021 timeframe. A system sized to meet this criterion would have *eliminated* all line and transformer overloads in excess of 100% of their normal operating limits.

After accounting for an approximately 21% effectiveness factor,[5] updated NERC and PSE planning standards,[6] and assumed procurement of previously-identified, cost-effective non-wires alternatives, Strategen calculated net injection requirements for the baseline energy storage system ("ESS") meeting the first two criteria, which is summarized in Table 2.

> *Effectiveness Factor*
>
> The amount of power required is significantly more than just the localized load exceeding the Eastside transmission equipment's rating.
>
> That is due to many factors, such as: 1) the number of transformers serving the area, (2) system impedance, and 3) use of the Eastside facilities for energy transfer not related to local demand.
>
> As a result, to address one MW of actual excess localized demand, almost five MW of storage power is required; hence the important concept of effectiveness factor. For details see Chapter 6.1.

[5] See Chapter 6.1 for further description of the effectiveness factor
[6] See Chapter 6.2 for further description of updated planning standards

Table 2. Baseline Energy Storage System Net Injection Requirements

	2021 Deferral[7]		
	Power (MWp)	Energy (MWh)	Duration (hours)
Normal Overload Reduction	328.0	2,338.0	7.1

Strategen notes that the key factor driving higher net injection requirements than the Non-wires Report was the additional requirement that the ESS also eliminate the need to use Corrective Action Plans, improving reliability to more comprehensively comply with PSE planning standards through 2021.

Two alternate energy storage system configurations were also evaluated and are summarized in Table 3. The first configuration, *Emergency Overload Elimination*, would *only* meet the first criteria established by PSE, elimination of the emergency overload. This configuration is not a comparable solution to new transmission/transformer infrastructure, and would not restore reliability to the levels required by PSE's planning and operating standards. The second configuration, *Normal Overload Elimination*, would present a longer term solution than a 2021 transmission line deferral because it would completely eliminate the 2021 normal overload.

[7] Accounts for a 2% per year cell degradation rate

Table 3. Energy Storage Alternate Configurations Net injection Requirements

Scenario	2021 Deferral[8]		
	Power (MWp)	Energy (MWh)	Duration (hours)
Alternate #1 Emergency Overload Elimination	121.0	225.6	1.9
Alternate #2 Normal Overload Elimination	544.4	5,770.9	10.6

2.2.2 *Technological Readiness and Suitability*

Although the scale of bulk storage technologies (i.e. pumped hydro and compressed air) is frequently characterized by large power and energy ratings, siting limitations in the Eastside area caused Strategen and PSE to omit bulk storage options from this analysis (See Chapter 5.4 for a more detailed explanation). Chemical (battery) storage was determined to be the most appropriate and commercially-viable technology for this location and application.

Chemical storage technology is rapidly advancing (See Chapter 5.1.1), but the only system of comparable size to what PSE requires is a 100 MW/400 MWh lithium-ion ESS recently procured by Southern California Edison ("SCE"), which is not expected to be operational until 2021. The largest currently deployed and commissioned chemical storage project (by power rating) in the United States is SCE's Tehachapi Wind Energy Storage ESS, an 8 MW/32 MWh lithium ion battery.

Confidential interviews with various vendors indicate that the technology and capability exists for batteries to be deployed for this application at this magnitude. However, since no similarly-sized system has ever actually been built or commissioned, it is difficult to estimate the time necessary for development, procurement, construction and deployment. Procurement of battery cells in particular may result in long lead times, especially for the two larger systems contemplated would constitute a significant portion of the global market for batteries.[9]

2.2.3 *Siting Feasibility, Permitting, and Interconnection*

After an ESS is deemed technically feasible, to be considered an appropriate solution, it must also be permitted and sited somewhere that is acceptable to the local community. The Eastside is a dense urban area and an ESS of this scale would be very large, so this analysis focuses specifically on a substation-sited solution that minimizes both cost and potential negative community impacts.

[8] Accounts for a 2% per year cell degradation rate
[9] Tesla's "Gigafactory", for instance, is expected to produce 35 GWh/yr of lithium ion cells by 2020, approximately equal to the total estimated global lithium ion production in 2013. Assuming 2016/2017 capacity is roughly double the 2013 global capacity estimate, the largest system contemplated would require cells equal to roughly 8% of annual global production.

PSE supplied estimated acreages for ESS interconnection facilities and parking, and satellite imagery and vendor interviews provided size estimates for the enclosures to house ESS batteries and power conversion systems. ESS sizing estimates for each scenario are as follows: 5.8 acres to eliminate emergency overload, 19.6 acres to reduce normal overload, and 45.7 acres to eliminate normal overload. For frame of reference, a football field including end zones covers approximately 1.32 acres.

Acquisition of large plots of land within already developed urban areas presents economic and social challenges. Since the ESS would be sited adjacent to an existing substation, potential locations for land acquisition are severely constrained. After reviewing footprint and siting requirements,[10] PSE determined that several substation configurations would be equally effective, so Strategen assumed for the purposes of sizing the system that all storage would be located at Lakeside substation. Slightly more land would be required if the system were to be broken up between multiple substations.

The interconnection study process takes approximately 1-2 years, at which point an interconnection agreement is signed and work can begin on any necessary upgrades, which often take 6+ months to complete. The lengthy interconnection study process likely presents a barrier for an ESS beginning development in early 2015 to meet a winter 2017/2018 online date, as generally speaking, equipment procurement does not commence until a signed interconnection agreement is achieved.

Permitting also generally involves a long lead time. When evaluating locations to site a larger scale battery facility, it was assumed that the site would be within the City of Bellevue. Since large scale battery facilities are an emerging technology, they are not addressed in the City's land use regulations. It was therefore assumed that a battery facility would be categorized as something similar to a transmission switching or substation. According to the City of Bellevue, as of March 2015, Administrative CUPs averaged around 25 weeks, with Major Clear and Grade permits averaging around 65 weeks. If Design Review is triggered, those approvals averaged 90 weeks. Permits for Major Commercial Projects average around 59 weeks. PSE estimated that it would take at least two years to permit, and up to three to four years if the project triggered a comprehensive review process.

PSE indicated that it does not take the risk of contracting for major equipment before permits are in hand. PSE expects that, once permitting is complete and interconnection agreements are in hand, the project would require one-and-a-half years for major equipment lead-time, and a half-year for construction. Private developers, on the other hand, are often willing to take that risk and can accelerate the development timeframe by about one year, according to PSE.

Based on the timelines provided by PSE for permitting, interconnection, procurement and construction, we conclude that it would take approximately four years for PSE to permit, interconnect, procure equipment and build an energy storage system. Assuming the process began in 2015, it would be complete in 2019, which would not meet PSE's objective for the project to come online in time to meet the winter 2017-2018 reliability need.

[10] PSE transmission planners reviewed siting either spread evenly between Sammamish, Talbot Hill, and Lakeside substations, spread with half at Lakeside and ¼ each at Sammamish and Talbot Hill, or all at Lakeside. The 3 alternatives were found to be about equally effective.

See Chapter 6.4 through 6.7 for a more detailed explanation of siting feasibility, permitting and interconnection.

2.2.4 *Technical Feasibility*

The critical technical challenge identified for an energy storage system configured to meet the Eastside system need is the existing transmission system's available capacity to support charging of the storage system.

Strategen determined that the existing Eastside transmission system does not have sufficient capacity to charge an energy storage system configured to reduce normal overloads to a level sufficient to meet the system requirements provided by PSE (the Baseline Configuration). Specifically, the Eastside system has significant constraints during off-peak periods that could prevent an energy storage system from maintaining sufficient charge to eliminate or sufficiently reduce normal overloads over multiple days.

See Chapter 6.3.1 and 6.3.2 for detailed analysis on the transmission system's ability to support charging of various energy storage configurations.

2.2.5 *Cost-Effectiveness*

In addition to looking at the commercial readiness and technical feasibility of energy storage as a transmission deferral resource for the Eastside need, Strategen evaluated the cost effectiveness of a non-wires deferral solution that included energy storage.

Chapter 7.2 addresses the full range of benefits considered and evaluated for the cost effectiveness assessment. The most significant sources of value identified for the storage resource include: system capacity and system flexibility (which includes a broad category of functions including energy time shifting, and provision of ancillary services).

Importantly for the evaluation of the financial merits of adding *energy storage* to the overall non-wires deferral solution, the entire deferral benefit is assumed to accrue to the previously identified portfolio of cost-effective non-storage alternatives identified. That is, the total cost for the cost-effective alternatives identified was commensurate with the deferral benefit. It is also important to note that the non-storage alternatives' value for deferring the transmission solution was established based on an expectation that they would fully meet the deferral need. However, the amount of non-storage alternatives is not "effective" enough to actually allow for the deferral without the addition of energy storage. Therefore, *additional* energy storage as part of the non-wires solution was necessary to meet the deferral requirements, but was not assigned additional *value* specific to the deferral, because such benefits would have resulted in a double-counting of the value of deferral.

Therefore, benefits associated with storage that were quantified for the evaluation are not specifically related to the deferral. Rather, benefits associated with storage are for what are often referred to as "system" benefits that are related to the PSE electric supply and transmission system as a whole. While not directly related to the deferral, these benefit types are addressed quantitatively in the study and provide the sources of additional value to PSE's customers that drive the cost effectiveness results.

As Strategen determined that the baseline energy storage / non-wires solution sized to satisfy PSE's planning and operating requirements would not be technically feasible, Strategen conducted a cost effectiveness assessment on an alternate configuration, a smaller system configured to meet PSE's emergency overload planning requirements only through 2021. This configuration does seem to be cost effective to address PSE's broader system capacity and flexibility needs, with a benefit-cost ratio of approximately 1.13. Strategen did not evaluate the relative cost effectiveness of energy storage versus other types of system resources, as this would require a more robust analysis that is best suited for PSE's Integrated Resource Planning process.

2.3 Key Conclusions

Based upon the results of the study, Strategen provides the following conclusions for PSE's consideration.

- The existing Eastside transmission system does not have sufficient capacity to charge the Baseline Configuration to a level sufficient to meet PSE's operating standards. Specifically, the Eastside system has significant constraints during off-peak periods that could prevent an energy storage system from maintaining sufficient charge to eliminate or sufficiently reduce normal overloads over multiple days.
- An energy storage system with power and energy storage ratings comparable to the Baseline Configuration (large enough to reduce normal overloads) has not yet been installed anywhere in the world. Projects comparable to the more modest Alternate Configuration #1 have been contracted by other utilities.

  Based on the interconnection, permitting, procurement and construction timelines provided by PSE, project development for any configuration would take approximately four years, resulting in a mid-2019 online date. Private developers able to take on more project risk might be able to accelerate this cycle by approximately one year. However, neither approach appears capable of meeting PSE's target online date of 2017-2018.
- Strategen estimates that the Baseline Configuration to defer the Eastside transmission system upgrade through 2021 would cost ratepayers approximately $1.44 billion (in NPV terms, based on PSE's revenue requirement). Alternate Configuration #1 would cost ratepayers approximately $264 million (in NPV terms, based on PSE's revenue requirement). See Table 4 below for capital cost estimates.
- Cost-effectiveness was only evaluated for Alternate Configuration #1 because the Baseline Configuration is not technically feasible. Value was derived primarily from the system capacity, flexibility and oversupply reduction benefits for PSE's customers. GHG reduction is another benefit of energy storage, but is currently non-monetizable. Alternate Configuration #1 does not meet the reliability requirements identified by PSE, but does appear to be cost effective, with a benefit-cost ratio of approximately 1.13.
- The following Table summarizes the configurations studied:

Table 4. Energy Storage Configuration Summary

Configuration	Power (MWp)	Energy (MWh)	Duration (hours)	Est. Cost ($MM)	Includes Non-Wires Alternatives[11]	Technically Feasible	Meets Requirements
Baseline Normal Overload Reduction	328	2,338	7.1	**$1,030**	✓	×	✓
Alternate #1 Emergency Overload Elimination*	121	226	1.9	**$184**	✓	✓	×
Alternate #2 Normal Overload Elimination	545	5,771	10.6	**$2,367**	✓	×	✓

2.4 Scope Limitations

- Strategen relied on inputs from PSE provided between September 2014 and February 2015 to develop the contents of this report. Many assumptions were made as to the system costs, benefits, feasibility, and timeline that would need to be studied in a more detailed manner prior to any final determination of project feasibility. Subsequent developments, such as PSE's recent decision to join the California ISO's Energy Imbalance Market, were not studied as part of this analysis.
- The benefit analysis presumes that PSE would own and operate the energy storage assets. This scope does not assess the viability of alternative financial offerings and ownership models.
- The scope of Strategen's evaluation does not include consideration of any regulatory challenges PSE might face in adding distributed energy storage deployed as a transmission reliability asset to PSE's rate base.
- The cost effectiveness modeling evaluates the absolute cost effectiveness of energy storage in terms of system benefits versus revenue requirements. It does not evaluate the relative cost effectiveness of energy storage versus other system resources.

[11] E3 (2014)

3 Introduction and Background

Puget Sound Energy ("PSE") is developing a solution to meet reliability needs identified in PSE's Eastside transmission system located in Central King County (the "Eastside") as part of PSE's annual comprehensive reliability assessment. The goal of the solution is to avoid the risk of NERC reliability criteria violations or losses of customer load in the area.

PSE identified a number of transmission options to reinforce the Eastside system, and recently retained Energy + Environmental Economics ("E3") to conduct a non-wires alternatives screening analysis to supplement PSE's work on transmission options. This report was published in February 2014 (the "Non-wires Report"), but did not evaluate the feasibility of energy storage to cost-effectively meet a similar transmission deferral target.

PSE believes that such supplemental analysis is warranted, and hired Strategen to answer several key questions:

1) What is the current state of technology for energy storage?

    a. What energy storage technologies are currently commercially ready to provide grid services and meet utility standards to reliably meet system needs?

    b. What is the estimated cost of an energy storage solution designed to meet the Eastside's needs?

2) What are the applications for grid- connected energy storage systems? What services can energy storage provide for the bulk power system? Services of particular interest to PSE include power system stability and renewable resource integration.

3) What is the potential for energy storage systems to defer the need for new transmission in PSE's Eastside grid, either on a standalone basis, or combined with other non-wires alternatives?

4) If energy storage theoretically can meet the need to defer transmission upgrades to the Eastside grid, can it do so cost effectively (assuming all system benefits of energy storage are accounted for)?

3.1 Summary of Analysis Methodology

Strategen approached this analysis by drawing upon recent and historic publicly available research, methodologies, and cost projections, and applying that information to PSE's unique system and transmission planning requirements. The results of the analysis - particularly with respect to Sections 6 (Energy Storage Configurations and Feasibility) and 7 (Cost-Effectiveness Evaluation) - were developed based on inputs received from PSE. The results of these analyses are premised on the accuracy of the inputs provided by PSE.

3.1.1 *Overview of Analysis Objective*

The goal of this analysis is to provide information for PSE to help it determine whether energy storage is a commercially ready, technically feasible, and cost-effective as a solution to defer the need for new transmission in PSE's Eastside region. Strategen worked closely with the PSE team to determine a scope of work and objective for the assessment that were consistent with the need identified and assumptions used in PSE's transmission planning process.

3.1.2 *Literature Review*

A preliminary step in the analysis was to review relevant literature to determine the commercial viability of energy storage for the primary use case needed in PSE's Eastside system.

The list of literature reviewed is provided in Chapter 9.

3.1.3 *Overview of Energy Storage Technologies*

Based on the literature review, Strategen prepared an overview of energy storage technologies. The goal of the overview is to provide insight into which technologies are technically and commercially feasible for the primary use case. Strategen also contacted third parties to determine a more accurate and use-case relevant set of cost data for the selected configurations.

3.1.4 *Data Collection*

PSE provided a variety of data for the analysis. Specifically, this data included:

- Full hourly substation and line load duration data for Talbot Hill and Sammamish substations in the year 2012.
- Line rating and loading information at multiple substation locations
- Locational effectiveness factors for centralized energy storage systems at multiple substations and for distributed (customer-sited) energy storage.
- Flexibility values, capacity values, overgeneration reduction values, and energy cost forecasts for the relevant years customized to the system configured to mitigate emergency overloads, as well as values for systems with smaller power ratings (2 MW and 20 MW) to test the sensitivity of system sizing to system benefits.
- The underlying costs and year-by-year incremental load reduction capability of other non-wires alternatives reported in the Non-wires Report.
- Information on PSE planning and operating standards.
- Interconnection cost, land value, and permitting cost assumptions for the three studied energy storage configurations.
- Footprint assumptions for interconnection equipment associated with the three studied storage configurations.

- Assumptions needed to calculate PSE's revenue requirements for a utility-owned energy storage system.

3.1.5 *Need Identification*

In order to inform the required need for energy storage as a transmission deferral alternative, Strategen started by assuming that all cost-effective non-wires alternatives other than energy storage would be implemented according to the timeline identified in the Non-wires Report. Other non-wires alternatives include incremental energy efficiency, distributed generation, and demand response.

The remaining need was identified by running hourly power flow assessments assuming:

1. PSE is meeting 100% of its conservation and efficiency goals described in its Integrated Resource Plan;

2. Normal (1 in 2) weather conditions would set the demand forecasts

Four sets of hourly overload data were then generated based on the power flow assessment:

- Talbot Hill overloads in excess of the emergency equipment ratings

- Talbot Hill overloads in excess of the normal equipment ratings

- Sammamish overloads in excess of the emergency equipment ratings

- Sammamish overloads in excess of the normal equipment ratings

In order to completely resolve the need, the energy storage device would need to (a) eliminate the need for CAPs, improving Eastside system reliability to meet PSE planning standards, (b) eliminate all overloads in excess of the substation equipment's emergency ratings, and (c) reduce the duration of any overloads exceeding the substation equipment's normal ratings to less than or equal to 8 hours. All incrementally cost-effective non-wires alternatives identified in the prior Non-wires Report would be assumed to be implemented and contributing to PSE's necessary load reductions to help address the system need, prior to identification of the amount of incremental energy storage needed to fully resolve the above overloads.

3.1.6 *Scenario Modeling*

Strategen then developed a baseline configuration for assessment along with two alternate configurations, in consultation with PSE, to evaluate the feasibility of addressing Eastside System reliability requirements:

- The baseline configuration – "Normal Overload Reduction" - was developed to reduce the duration of all line and transformer overloads in excess of 100% of their normal operating limits to no more than 8 consecutive hours, as well as to eliminate all overloads exceeding emergency limits in the 2021-2022 winter case and in the 2018 summer case for all FERC/NERC required contingencies;

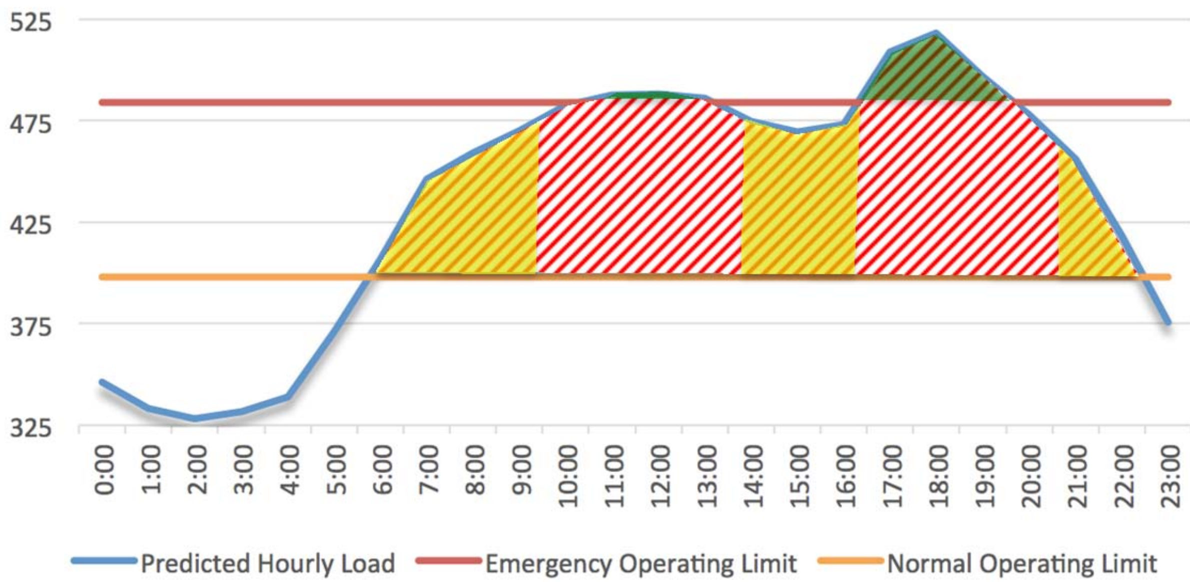
- The first alternate configuration – "Emergency Overload Elimination" - was developed to mitigate only line and transformer overloads to below 100% of their emergency limits in the 2021-2022 winter case and in the 2018 summer case for all FERC/NERC required contingencies;[12] and

- The second alternate configuration – "Normal Overload Elimination" - was developed to eliminate all line and transformer overloads in excess of 100% of their normal operating limits.

Figure 2 is a representative example of how the energy storage system would discharge under each scenario and affect a daily load profile.

[12] Configuration #1 would meet PSE planning requirements, but would not meet PSE operating requirements. This configuration was selected for the cost effectiveness modeling due to the determination that the other two configurations were not technically feasible.

Figure 2. Graphical Representation of Eastside Overload Scenarios (in MW)*



***Shading represents ESS net injection requirements to meet overload scenarios: Green -** *Emergency Overload Elimination*; **Yellow -** *Normal Overload Reduction*; **and Red -** *Normal Overload Elimination*

After accounting for an approximately 21% effectiveness factor,[13] updated NERC and PSE planning standards,[14] cell degradation, and assumed procurement of previously-identified, cost-effective non-wires alternatives, Strategen calculated net injection requirements for the ESS configurations.

Strategen evaluated customer-sited storage as a potential alternate method to meet the configuration requirements. However, the effectiveness factor of a customer-sited solution was determined by PSE to be lower than that of a substation-sited solution. In addition, the high complexity of evaluating the feasibility of contracting, permitting, and deploying customer-sited units at the scale and timeframe necessary to categorically meet PSE's 2017-2018 transmission deficiency resulted in a focus of this analysis on a centralized, substation-sited solution. Chapter 6.4.1 reviews customer-sited energy storage issues in greater depth.

3.1.7 *Cost Effectiveness Evaluation*

In addition to looking at the commercial readiness and technical feasibility of energy storage as a transmission deferral resource for the Eastside need, Strategen developed a custom spreadsheet-based model to evaluate the cost effectiveness of the modeled configuration. Because the baseline *Normal Overload Reduction* configuration was determined not to be technically feasible, Strategen modeled the smaller, alternate *Emergency Overload Elimination* configuration.

Chapter 7.2 addresses the full range of benefits studied for the cost effectiveness assessment. As energy storage devices are able to perform multiple services for the system, benefits were generally "stacked" to the extent they did not conflict. However, during the deferral period of 2017-2021, Strategen assumed that the system would not be providing system flexibility services during January or August, due to the need for it to be reserved for use as a transmission reliability resource.

Strategen did not evaluate the relative cost effectiveness of energy storage versus other types of system resources, as this would require a more robust analysis that is best suited for PSE's Integrated Resource Planning ("IRP") process.

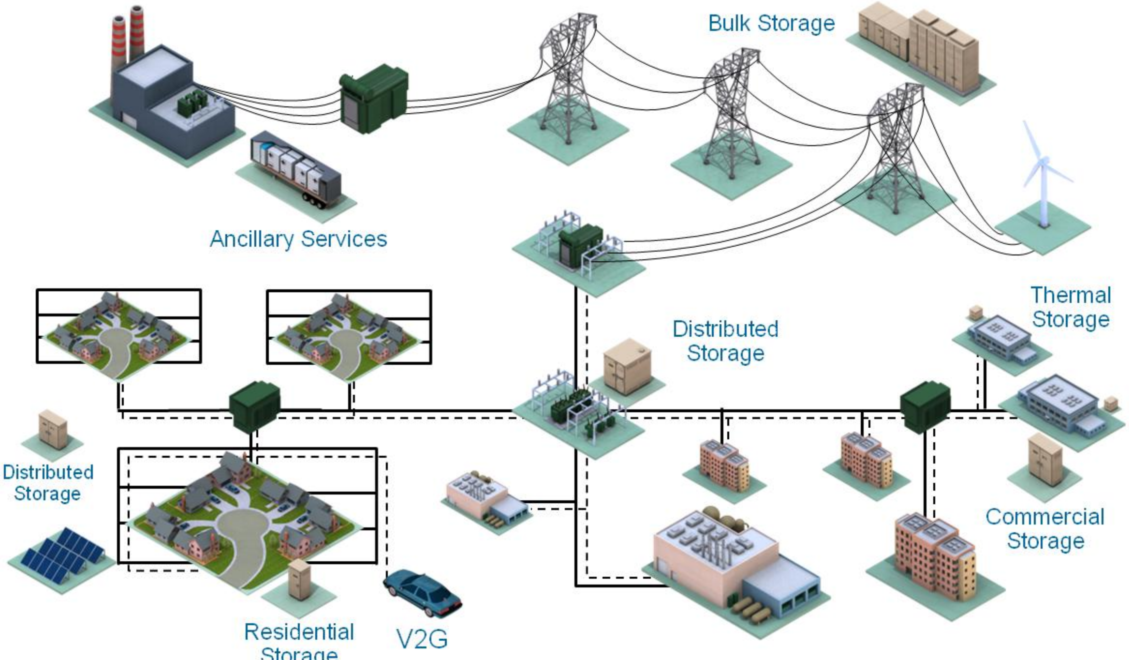
[13] See Chapter 6.1 for further description of the effectiveness factor
[14] See Chapter 6.2 for further description of PSE's planning and operating standards

4 Intro to Energy Storage, Grid Benefits & Use Cases

Energy storage is a uniquely flexible type of asset in terms of the diverse range of benefits it can provide, locations where it may be sited, and the large number of potential technologies which may be suited to provide value to the grid. Fundamentally, energy storage shifts energy from one time period to another time period. However, the value of energy stored by a resource varies highly based on its ability to control and dispatch that energy. Because the electric system operates on “just-in-time” delivery, generation and load must always be perfectly balanced to ensure high power quality and reliability to end customers. With large amounts of variable and uncertain wind and solar generation currently being deployed, guaranteeing this perfect balance is becoming an increasingly challenging issue. At very high penetrations of variable wind and solar generation, energy storage may be effective for absorbing excess energy at certain times and moving it to other times, enhancing reliability and providing economic benefits.

Figure 3 illustrates the many roles that energy storage can fill within the electric grid. Energy storage can provide large amounts of power and energy to the electric grid, as has been historically demonstrated by pumped hydropower facilities that can provide hundreds of megawatts or gigawatts of power for many hours. On the other end of the spectrum, off-grid battery systems have long been used to support electric service for small remote, residential buildings. The future may contain a spectrum of technologies, locations, and grid services, ranging from very large to very small energy storage systems capable of enhancing the reliability, economics, and environmental performance of the electric grid.

Figure 3. Overview of Energy Storage Roles on the Electric Grid[15]



In this analysis, the investigators focus on substation-sited electrical energy storage systems with a primary use case of transmission upgrade deferral (i.e. meeting identified transmission system reliability needs through a non-wires solution). Secondary use cases are also evaluated as inputs into the overall cost-effectiveness assessment, as further described below. Terminology and definitions for the grid services that energy storage could provide is not entirely uniform across the country, but the DOE/EPRI Energy Storage Handbook of 2013 provides the following list of energy storage grid services.

[15] Source: DOE-EPRI Energy Storage Handbook (2013)

Figure 4. Grid Services of Energy Storage

Bulk Energy Services
Electric Energy Time-Shift (Arbitrage)
Electric Supply Capacity

Ancillary Services
Regulation
Spinning, Non-Spinning and Supplemental Reserves
Voltage Support
Black Start
Other Related Uses

Transmission Infrastructure Services
Transmission Upgrade Deferral
Transmission Congestion Relief

Distribution Infrastructure Services
Distribution Upgrade Deferral
Voltage Support

Customer Energy Management Services
Power Quality
Power Reliability
Retail Electric Energy Time-Shift
Demand Charge Management

The following paragraphs will provide a summary of the grid services that energy storage resources may be capable of providing.

4.1 Bulk Energy Services

"**Bulk Energy Services**" refers to the potential of energy storage to avoid costs associated with generation of electricity.

Electric Energy Time-Shift (Arbitrage) refers to the ability of energy storage to store energy (charge) when the cost of electricity is low, and release energy (discharge) when the cost of electricity is high. For example, in the summer, electricity costs are typically low when demand is low at night and low marginal cost energy sources (such as hydro or wind energy) can supply a substantial portion of the load. Conversely, summer electricity costs are typically high in the late afternoon on hot days when the system's highest marginal cost resources (such as less efficient gas turbines) must be called upon to meet peak load conditions.

Electric Supply Capacity (or System Capacity) refers to a similar usage of energy storage as energy time-shift, but it refers to a different economic value. Where the arbitrage value comes from time-shifting the variable cost of electricity generation, the capacity value is an avoided fixed cost of generation. Historically, the decision to add new generation capacity (i.e. build power plants) has not been an economic one. Based on customer load growth forecasts, utilities create an integrated resource plan which determines where and when new generators are needed. This new capacity need is defined by the peak load conditions. If energy storage can reliably provide capacity during peak system load conditions, it has the potential to avoid the fixed costs of new power plants, which are typically passed through to utilities and, by extension, customers as a fixed monthly or annual payment.

4.2 Ancillary Services

"Ancillary Services" are defined as "those services necessary to support the transmission of electric power from seller to purchaser given the obligations of control areas and transmitting utilities within those control areas to maintain reliable operations of the interconnected transmission system."[16] In other words, these services are all services to the high voltage transmission system that support the reliable delivery of power and energy.

Regulation (or Frequency Regulation) is an ancillary service that ensures the balance of electricity supply and demand at all times, particularly over time frames from seconds to minutes. When supply exceeds demand the electric grid frequency increases; when demand exceeds supply, grid frequency decreases. Sensitive equipment in the United States relies on grid frequency of 60 Hertz (60 cycles / second), with very low tolerance. Because energy storage can both charge and discharge power, it has the potential to play a valuable role in managing grid frequency. Furthermore, many energy storage technologies have been demonstrated to be faster and more accurate than other grid alternatives at correcting these frequency deviations. FERC Order 755 has stipulated that independent system operators (ISOs)

[16] FERC (1995)

implement mechanisms to pay resources based upon their responsiveness to control signals. Under the new rules, energy storage resources with high speed ramping capabilities will receive greater regulation compensation than slower storage or conventional resources.

Spinning Reserves, Non-spinning Reserves, and Supplemental Reserves comprise another class of ancillary service referring to reserved excess generation capacity that is available to the electric system in the case of the worst contingency events. Spinning reserves are the fastest available reserve capacity, because the generators providing them are already "spinning", but not fully loaded. Therefore, spinning reserves can begin responding immediately to a contingency event. Non-spinning reserves typically have minutes to respond to a contingency, and supplemental reserves are intended to replace spinning and non-spinning reserves after an hour. Because many energy storage technologies can be synchronized to grid frequency through their power electronics, energy storage could provide a service equivalent to spinning reserve while idle. Furthermore, an energy storage system that is charging energy may be capable to provide a magnitude of spinning reserve equivalent to the sum of its charging and discharging power. In other words, a storage system rated at 1 megawatt capacity could provide 2 megawatts of spinning reserve, because it has the capability to move from a state of 1 megawatt charging to 1 megawatt discharging. Energy storage would be equally capable of providing non-spinning or supplemental reserves, but these services are typically lower value than spinning reserve because they are easier for traditional generators to accomplish and have lower opportunity cost.

Voltage support is an ancillary service that is used to maintain transmission voltage within an acceptable range. With alternating current (ac) power, voltage and current are transmitted as sinusoidal waves. Maximum power is transmitted when voltage and current waveforms are synchronized. Certain electric loads, particularly inductive motors, have a tendency to cause voltage to move out of sync with current by consuming reactive, or imaginary, power (aka "VARs). Due to advanced power electronics capabilities, energy storage has the capability to inject VARs and correct transmission voltages that are suboptimal or outside of acceptable bounds. Because a number of other devices are capable of providing voltage support at low cost, the value of this service for energy storage is typically considered to be low and has not received a deep level of attention.

Black start is a service typically provided by designated generators to restore the electric grid following a blackout. While this is conceptually a service that could be provided by energy storage, the exact specifications of a limited energy resource have not been well-defined. Black start is typically considered to be a low value, incremental source of value for energy storage.

4.3 Transmission Infrastructure Services

"Transmission Infrastructure Services" refer to the services, related to reliability and economics, to enable the electric transmission system to operate more optimally.

Transmission investment deferral is a service whereby a capital investment in the transmission is avoided for a period of time. For example, if power transmitted from point A to point B exceeds the power rating of a transmission transformer or power line, it may require an upgrade to a higher rated piece of equipment. However, this upgrade could be triggered by peak loads which occur relatively infrequently, perhaps only a few hours per day and a few days per year. In such cases, a sufficient quantity of energy storage may be capable to charge during low load periods and discharge during high loads periods on the load side of the overloaded piece(s) of transmission equipment and therefore to offset power flows and reduce loading experienced on that equipment. By doing so, energy storage has the ability to defer an upgrade investment for a period of time, creating economic value equal to the *time value of money* for the size of the planned transmission upgrade investment for the deferral period.

Transmission congestion relief is a similar service to transmission investment deferral. However, the economic value associated with congestion relief does not necessarily tie directly to a planned transmission upgrade. In some regions, the wholesale price of energy is defined at different geographic locations, where the congestion associated with high loads results in a higher hourly energy price. This geographically-specific energy price is called a *locational marginal price (LMP)*. In practice, energy storage would behave very similarly to how it would perform energy time-shift (arbitrage) or transmission investment deferral (i.e. charging during low load periods and discharging during high load periods), but it would optimize its charge/discharge behavior based on an hourly price signal that is jointly defined by the wholesale market price of energy and the amount of location-specific congestion specific to its geographic location in the electric system.

4.4 Distribution Infrastructure Services

"Distribution Infrastructure Services" refer to services which support the physical infrastructure of the low voltage distribution system from the substation to the customer meter. These services support delivery of electric power with high reliability and lowest cost to the electric utility customer. The costs of the electric distribution system are typically regulated by a public utility commission (PUC) or similar entity which approves electric utility spending plans and offers them a regulated return on investment for managing the reliability of the system.

Distribution investment deferral is a service similar to the aforementioned transmission investment deferral, but specific to the low voltage distribution system. To relieve overloaded distribution lines or transformers, particularly high cost substation transformers, energy storage can charge during low load period and "peak shave" the highest load periods to avoid a high cost upgrade investment for a period of time. Once again, the economic value associated with an upgrade deferral would be the time value of money for the cost of the upgrade for the achieved timeframe of deferral. The storage may only be required to perform for a relatively small number of days and hours associated with local maximum load events, which are overloading the asset in question.

Distribution voltage support refers to a service which maintains the power voltage within acceptable bounds, defined by ANSI standards (typically +/- 5% of nominal). For sensitive consumer appliances and electronics, it is important that voltage is supplied within these limits. Typically, the service voltage drops as power moves to the end of the line as customer computer and motor loads are consuming VARs (explained in the "voltage support" service description above). As a result, utilities typically install capacitor banks or voltage regulators, which boost voltage at the end of the line. However, voltage support is becoming more complicated in certain load pockets due to the increase in installed distributed solar photovoltaic (PV) systems. In areas with high distributed generation penetration rates, these systems can reverse power flow altogether at certain times, and create significant variability in local operational requirements.[17] Energy storage, with power electronics capable of injecting and absorbing both real and reactive power at different rates, conceptually provides a balance for rooftop PV installations. However, the state of research is still nascent in this area, so it is unclear how much value this service has and what the technical requirements are for energy storage to provide this service effectively.

4.5 Customer Energy Management Services

"Customer Energy Management Services" refer to the services that benefit an electric utility customer that result in lower utility bills or higher quality of electric service.

Power Quality describes a comprehensive service delivered to electric utility customers. Some elements of power quality include consistent service voltage, low harmonics, and no disruptions in service. Some customers have very high requirements for power quality, due to sensitive equipment or electronics. A well-known example is data centers. Data centers regularly use energy storage in the form of an uninterruptible power supply (UPS), which converts grid electricity from ac-to-dc-to-ac and provide acceptably high power quality for the equipment. The value of this service is highly variable, depending on the consequences and alternatives available to the customer for solving specific power quality issues. However, the ubiquity of UPS systems in data centers and critical loads is evidence of the importance of power quality for certain customers.

Reliability refers to the "uptime" of the electric grid, which is the measure of time that the grid is in operation. Outages can be caused by a number of different factors, including weather events and other unexpected contingencies, as well as unanticipated equipment failures. Because energy storage provides an inventory for electric energy, it may be able to help grid operators avoid some outages, or otherwise provide customers with backup power to ride through outages when they happen. Depending on the type of customer, their economic losses associated with outages, and the utility reliability characteristics at the customer location, economic value may be provided by an energy storage system to provide backup power. An energy storage system would need to have the appropriate capability to "island" its operation and serve the entire customer load, or a specified portion of the customer load.

Retail energy time-shift refers to charging an energy storage device during periods when the retail price of electricity is low and discharging that energy when the retail price of electricity is high. This situation is present when customers have a utility tariff with time-of-use (TOU) metering. This type of tariff is enabled by the deployment of automated metering infrastructure (AMI). The existence of TOU tariffs has existed for a long time in the commercial and industrial electricity sector, but its emergence in the residential sector is relatively new. Residential customers often opt-in for these tariffs when they purchase rooftop solar PV or electric vehicles to increase bill savings.

[17] For example, Hawaiian Electric Company cited increasing penetration rates of distributed solar as contributing to voltage stability issues on its grid that led to an April 2013 blackout for 79,000 customers on the island of O'ahu. See p. 4 in the "Hawaiian Electric State of the System" report dated April 23, 2014:
http://www.hawaiianelectric.com/vcmcontent/StaticFiles/pdf/ESS_Attachment_G_Hawaiian_Electric_State_of_the_System.pdf

Retail demand charge management refers to a service offered by energy storage, or other measures, to reduce the “demand charge” portion of a customer electric bill. A demand charge is a charge levied proportional to the peak customer instantaneous (15 minute average) demand each month. Without careful control, a customer could add a significant component to their electric bill as a result of a “peaky” load shape that causes them to pay a high monthly charge, with relatively lower average consumption. Energy storage can store energy during periods when the customer demand is low and discharge to shave off peak customer load periods, which in some cases could be infrequent and short duration. Typically the value of reducing demand charges exceeds the value of energy time-shifting, under current national tariff structures.

4.6 Summary of Grid Services for Energy Storage

The preceding section described widely accepted categories of energy storage services to the electric grid. These services span the entire scope of electric service from generation to end customer. However, it should be noted that not all of these services have been demonstrated in commercial or utility settings. Moreover, the ability to provide multiple grid services in an operational setting can be challenging, particularly when such services have the potential to be mutually exclusive. For example, an energy storage device providing a transmission reliability service must reserve its capacity during operational periods when such a reliability service is potentially needed. Providing other services during that period may not be possible.

4.7 Societal Benefits

It should be noted that energy storage may provide benefits to society in addition to its value for grid services. These benefits may include:

Greenhouse Gas and/or Pollution Reductions – Certain types of energy storage dispatch may result in reduced system-wide emissions. Cases where storage may reduce emissions include:

- **Offsetting regulation services provided by non-renewable sources** - Energy storage that provides frequency regulation service to the grid may offset heat rate (efficiency) penalties incurred by ramping traditional generators, thereby allowing the existing generator fleet to operate at a lower, overall heat rate. Large quantities of grid storage may also reduce the number of cold starts for fossil generators, allowing for more efficient grid operations.

- **Increased capture of renewable over-generation -** In cases of high renewable penetration, energy storage may charge from excess renewable generation that would otherwise be spilled or curtailed and discharge that energy at times that offset the need for traditional generation.

Job creation and/or technology leadership – Energy storage, as a rapidly developing industry, has the potential to create local jobs or establish technology leadership in the region. The complex calculation required to determine long term benefits was not part of the scope of this study.

4.8 Energy Storage Use Cases

Due to the variety of operational modes and potential locations where energy storage can be sited, energy storage has the potential to provide many different combinations of the aforementioned services. The ability of a single energy storage system to provide these services can be assessed across multiple parameters, including 1) minimum required energy storage power (capacity) and energy (duration), 2) location requirements, 3) availability requirements, both frequency and duration, and 4) flexibility and penalties of non-performance.

An energy storage use case describes a specific scenario for a single energy storage asset sited at a specific location and operated in a particular way to deliver a specific combination of grid services and benefits. The value of these services and benefits may be quantifiable to varying degrees through modeling and analysis, but not all will receive commensurate compensation under current policies.

Unlike the preceding list of individual energy storage services, which is fairly consistent and converging across the energy storage and electric industries, a comprehensive list of energy storage use cases has not yet been widely agreed upon. Due to the emerging nature of the energy storage industry, new use cases are being identified. These new use cases are often targeted to the specific needs of a utility, customer, or new wholesale electricity market opportunities.

This paper will not attempt to cover the full universe of use cases, as most use cases are not relevant to the primary service requirement of the system, which is to provide transmission investment deferral. Rather, this paper will focus on the use case of transmission-connected, utility substation-sited energy storage providing transmission infrastructure services as a primary function, with secondary functions of providing bulk energy services, ancillary services, and additional societal benefits such as greenhouse gas reduction. Neither distribution infrastructure services nor customer energy management services are relevant to this assessment due the required configuration of the system based on the need primary service requirement of the system.

Table 5 summarizes use cases for projects sited on the transmission side of the power grid.

Table 5. Use Cases for Transmission Sited Energy Storage Projects

Connection	Category	Use Case
Transmission Sited	Standalone	Rate Based (Transmission Deferral & NERC Reliability)
		Rate Based (Economic - Congestion Management, Avoiding costs of lost customer service)
		Rate Based (Policy - Renewables Integration)
		Dual Use (Partial Rate Based, Partial Market Participant)
		Market Participant - Bulk Peaker *(Energy & AS)*
		Market Participant - AS Only
	Generator Paired	Variable Energy Resource 1 (wind/solar)
		Variable Energy Resource 2 (CSP molten salt)
		Thermal + Turbine Inlet Chilling or CAES
		Hybrid Thermal + Fast Response Storage
		Thermal + Oxygen Chilling

5 Energy Storage Technology & Commercial Overview

This chapter provides a high-level overview of energy storage technologies, including their commercial viability and currently deployed utility-scale projects.

5.1 Energy Storage Technology Classes

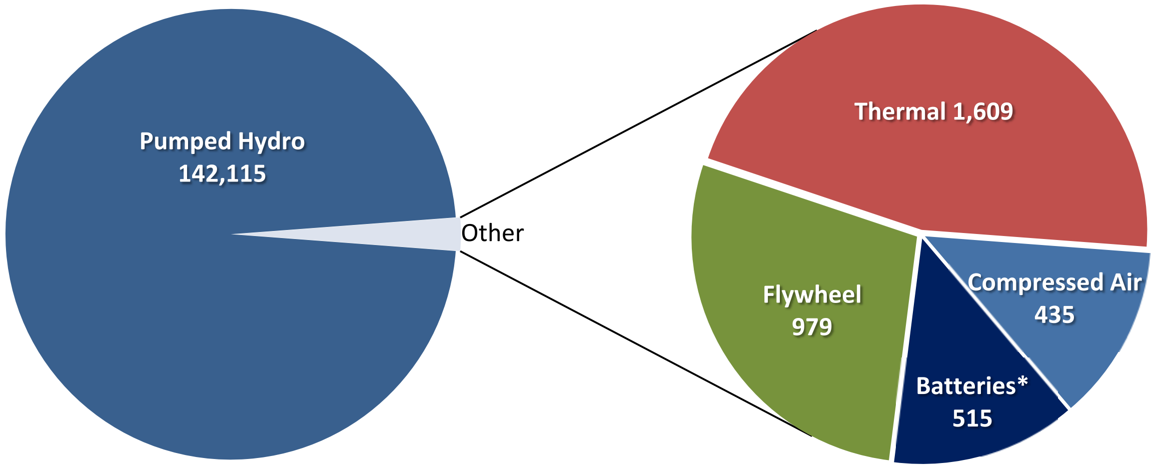
Energy storage encompasses a wide range of technologies and resource capabilities, with differing tradeoffs in cycle life, system life, efficiency, size, and other parameters.

Table 6. Energy Storage Technology Classes

Technology Class	Examples
Electrochemical Storage	Batteries, Supercapacitors
Mechanical Storage	Flywheels, Compressed Air
Thermal Storage	Ice, Molten Salt, Chilled Water
Bulk Gravitational Storage	Pumped Hydropower, Gravel

The vast majority of energy storage currently deployed in the market is pumped hydropower, as Figure 5 shows.

Figure 5. Installed Grid-Connected Energy Storage in MW, by Technology, as of 10/2014[18]



*Batteries include Flow, Lithium Ion, Sodium Sulfur, Nickel Cadmium, Lead Acid, Electrochemical Capacitors, and Ultra Batteries

Note that while much of the focus within the industry and in the press has been on advanced energy storage technologies, particularly battery technology, pumped hydro still comprises the substantial majority of grid connected energy storage (97.6%), with the remaining categories combined comprising 2.4% of installed capacity.

5.1.1 *Electro-chemical Storage (Batteries)*

This class of energy storage includes the following chemistries: advanced lead acid, lithium ion, sodium based, nickel based, flow batteries, and electrochemical capacitors. Technologies are further classified into sub-categories based on the specific chemical composition of the main components (anode, cathode, separator, electrolyte, etc.). As Table 7 summarizes, each class and sub-category is at a different stage of commercial maturity and has unique power and energy characteristics that make it more or less appropriate for specific grid support applications.

[18] DOE GESDB (October 2014)

Table 7. Characteristics of Common Chemical Energy Storage Technologies[19]

Technology Class	Advanced Lead Acid	Lithium Ion	Sodium		Nickel based	Flow Batteries	
Technology Sub-Category			Sodium sulfur	Sodium nickel chloride		Vanadium redox	Zinc bromine
Roundtrip Efficiency (%)[20]	75-90	85-98	70-90	85-90	60-80	60-85	60-75
Self-Discharge (%energy/day)	0.5-1	0.1-0.3	0.05-20	15	0.3-1	0.2	0.24
Cycle Lifetimes (cycles)	300-2.5k	1k-10k	2.5-4.5k	2.5k-4.5k	800-3.5k	12k-14k	2k-10k
Expected Lifetime (years)	6-15	5-15	5-15	10-15	5-20	5-15	5-15
Specific Power (W/kg)	75-300	230-1.5k	150-230	150-200	150-300	16-33	30-60
Specific Energy (Wh/kg)	30-50	125-250	150-240	100-200	50-75	15-50	75-85
Power Density (W/l)	90-700	1.3k-10k	120-160	250-270	75-3k	0.5-2	1-25
Energy Density (Wh/l)	30-80	250-630	150-300	150-200	200-350	20-70	65
Commercial Maturity[21]	Dem.	Dem.	Comm.	Dem.	Dem.	Pre-Comm.	Dem.

Advanced Lead Acid

Invented in the 19th century, lead acid are the most developed and commercially mature type of rechargeable battery. They are widely used in both mobile (cars, boats) and stationary consumer applications (UPS, off-grid PV), but several issues including short cycle life, slow charging rates, and high maintenance requirements have prevented widespread adoption for utility-scale grid applications.[22] A screen of the Department of Energy's Energy Storage Database identified nine currently operational projects with a power rating greater than 1 MW. These perform a wide variety of services including peak shaving, on site power, ancillary services, load following/ramping, and renewables capacity firming.

[19] Antonucci (2012), SBC Energy Institute (2013), IEA-ETSAP/IRENA (2012), IEC (2011)
[20] Cell roundtrip efficiency only; additional losses due to the system's power electronics must be accounted for as well (see Chapter 5.2)
[21] Dem. = Demonstration; Comm. = Commercial; Pre-Comm. = Pre-Commercial
[22] Navigant (2012)

Technical Details

Lead acid batteries rely on a positive, lead dioxide electrode reacting with a negative, metallic lead electrode through a sulfuric acid electrolyte. Ongoing research and development has produced several proprietary technologies falling within two categories: advanced lead acid and lead acid carbon. While technologically distinct, lead acid carbon is considered a type of advanced lead acid battery.[23]

Advanced lead acid batteries incorporate a variety of technological enhancements depending on the manufacturer. Companies such as GS Yuasa and Hitachi are developing units that improve system response times by incremental technology enhancements such as valve-regulation, solid state electrolyte-electrode configurations, and anode electrodes that include capacitors.[24]

Lead acid carbon batteries add carbon to one or both electrodes. This addresses two major historic barriers to the adoption of lead acid technology: 1) a tendency for sulfate to accumulate on the negative electrode surface which led to large decreases in capacity and cycle life and 2) slow charge/discharge rates. The addition of carbon reduces sulfate accumulation and allows faster charge and discharge with no apparent detrimental effects.[25] Research and development by Xtreme Power (now Younicos), Axion Power, and Ecoult/East Penn has led to several utility-scale deployments ranging from 1 MW to 36 MW.[26] Improvements in maintenance requirements, cycle life, and charging rates are allowing lead acid carbon systems to perform a variety of grid services that were not economically justifiable with standard lead acid.

Downsides to lead acid technology include its low power and energy density compared to other batteries, limited life ranges of approximately (6-15 years), and lead electrodes and sulfur electrolyte that are toxic and require appropriate handling and recycling.[27]

Deployments

Operational deployments total 68 MW/67 MWh in 25 projects. These have capacities ranging from 100 kW/226 kWh (2 hr 15 min duration) to 36 MW/24 MWh (40 min duration). Table 8 lists details of the five largest installations.

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[23] DOE-EPRI Energy Storage Handbook (2013)
[24] *Ibid.*
[25] *Ibid.*
[26] "Carbon-Enhanced Lead-Acid Batteries." Sandia (2012)
[27] IEC (2011)

Table 8. Five Largest Operational Lead Acid Energy Storage Projects

Owner / Project	Nominal Power / Energy (Duration)	Technology	Location	Primary Function
Duke Energy / Notrees	36 MW / 24 MWh (40 min)	Advanced lead acid	Goldsmith, TX	Renewables capacity firming
Kuroshio Power / Shiura Wind Park	4.5 MW / 10.5 MWh (2.3 hour)	Valve regulated lead acid	Aomori, Japan	Renewables capacity firming
Shonai Wind Power Generation Co. / Yuza Wind Farm Battery	4.5 MW / 10.5 MWh (2.3 hour)	Valve regulated lead acid	Yamagata, Japan	Renewables capacity firming
First Wind LLC / Kaheawa Wind Project II	10 MW / 7.5 MWh (45 min)	Advanced lead acid	Maalaea, HI	Renewables capacity firming
East Penn Manufacturing Co. / UltraBattery Demo	3 MW / 2.2 MWh (42 min)	UltraBattery®	Lyon Station, PA	Frequency regulation

In 1994, Puerto Rican Utility PREPA commissioned a 20 MW/14 MWh (40 min duration) lead acid system designed to support grid stability with frequency regulation and voltage support. The system operated for five years before being replaced by a similarly sized system that was later destroyed by fire. Metlakatla Power and Light and GNB (now Exide) installed a 1 MW/1.4 MWh (1 h 24 min duration) lead acid battery system in 1996 that successfully performed voltage regulation and frequency regulation for 12 years. It was replaced in 2008 with an identical system and is still operational.

Hitachi currently has two 4.5 MW/10.5 MWh (2 h 20 min duration) advanced lead acid field trials operating in conjunction with wind farms in Japan. The systems are performing renewables capacity firming, frequency regulation, and load following.

Recently, lead acid carbon has seen more utility deployments that other lead acid technologies. The Duke Notrees 36 MW/24 MWh (40 min duration) located in Texas has the highest power rating of any battery in the world[28]. Commissioned in 2012 with the help of a $22 million DOE grant, the system is used to firm wind energy and perform peak shifting and frequency regulation. Another Xtreme Power project adjoined to a wind farm, the Kaheawa II Project in Hawai'i features a 10 MW/7.5 MWh (45 min duration) battery. In addition to storing wind generation that would otherwise be curtailed, the unit provides ramp control, frequency regulation, and automatic generation control for Maui Electric Company.

Several smaller utility demonstration systems from different vendors are also in operation. For instance, a 500 kW/2 MWh (4 hour duration) Public Service Company of New Mexico pilot combines and coordinates two batteries of different ratings for renewable smoothing and peak shifting, while Xcel's SolarTAC project in Colorado is using a 1.5MW/1MWh (40 min

[28] Although several sodium sulfur batteries are larger when rated by *energy capacity*.

duration) for ramp control, frequency response, voltage support, and solar generation firming.

7MW/11MWh of lead acid deployments are currently either planned or under construction, 5MW of which are from three projects.[29]

Lithium Ion

First commercialized in 1991, lithium ion batteries have experienced tremendous R&D and publicity in the last few years due to their high energy density, voltage ratings, cycle life, and efficiency ratios. They have been the preferred energy storage technology for portable electronic devices, and now are being scaled up and deployed for grid services at utility scale. There are approximately 70 systems with power ratings greater than 1 MW currently operational globally. Lithium ion's adaptability to a range of power and energy ratings allows it to perform a wide variety of services. Grid scale application units range from small 1 MW/0.5 MWh (30 min duration) frequency regulation pilot projects, to large 8 MW/32 MWh (4 hour duration) and 32 MW/8 MWh (15 min duration) systems performing ramp control and shifting wind and solar generation.[30]

Technical Details

Lithium ion is a broad technology class that encompasses multiple sub-technology types based on differing chemistries, each with unique characteristics. Subtype classifications generally refer to the cathode material.[31] Some common chemistries are compared in Table 9.

Technologies are again divided by cell shape: cylindrical, prismatic, or laminate. Cylindrical cells have high potential capacity, lower cost, and good structural strength. Prismatic cells have a smaller footprint, so they are used when space is limited (i.e. mobile phones). Laminate cells are flexible and safer than the other shapes.[32]

Lithium ion batteries have several key advantages over other battery chemistries, including high energy density, high power, high efficiency, low self-discharge, lack of cell "memory", and fast response time. However, lithium ion chemistries also present a number of challenges including short life cycle, high cost, heat management issues, flammability, and narrow operating temperatures.[33]

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[29] DOE GESDB (2014)
[30] *Ibid.*
[31] Yoshio et al. (2009)
[32] Citi (2012)
[33] PNNL (2012)

Table 9. Relative Comparison of Lithium Ion Chemistries[34]

Chemistry (Shorthand)	Safety	Energy	Power	Life	Cost/ kWh	Summary
	Scale 1-5 with 5 Best					
Lithium Manganese Oxide (LMO)	3	4	3	3	4	Versatile technology with good overall performance & cost
Lithium Iron Phosphate (LFP)	3	3	4	4	3	Similar to LMO, but slightly more power & less energy
Lithium Nickel Cobalt Aluminum (NCA)	1	3	4	4	2	Good for power applications; poor safety & high cost/kWh
Lithium Titanate (LTO)	5	2	5	5	2	Excellent power & cycle life; high cost/kWh
Lithium Nickel Manganese Cobalt (NMC)	3	4	4	4	4	Versatile technology with good overall performance & cost

Deployments

Approximately 235 MW/294 MWh of lithium ion projects are currently operational and approximately 65 projects have a power rating of 1 MW or larger. These utility scale systems can generally be separated into two categories: high power, short duration projects performing frequency regulation (i.e. AES Laurel Mountain 32 MW/8 MWh) and high energy projects helping to integrate intermittent renewable generation (See Table 10).

In June 2014, Southern California Edison commissioned the largest lithium ion system (by energy rating) in the United States. The 8 MW/32 MWh (4 hour duration) project is connected to the Tehachapi Pass Wind Farm and was installed to test 13 different service/use cases. The overall goal is to improve grid performance and integrate renewables.

The three largest lithium ion projects in terms of rated power (MW) were installed by AES to provide frequency regulation services. These include the 32 MW Laurel Mountain, 20 MW Angamos, and 12 MW Los Andes projects all having between 15-20 minute duration. Laurel Mountain is adjacent to a wind farm and participates in PJM's wholesale market, while Los Andes and Angamos act to support large mining operations in Chile.

[34] Hardin (2014)

Table 10. Five Largest Operational Lithium Ion Energy Storage Projects, by energy rating

Owner / Project	Nominal Power / Energy (Duration)	Technology	Location	Primary Function
State Grid Corporation of China / Zhangbei National Wind and Solar Energy Storage and Transmission Project	6 MW / 36 MWh (6 hour)	Lithium-iron-phosphate	Hebei, China	Renewable generation shifting
Southern California Edison / Tehachapi Wind Energy Storage Project	8 MW / 32 MWh (4 hour)	Lithium ion	Tehachapi, CA	Renewable generation shifting
State Grid Corporation of China / Zhangbei National Wind and Solar Energy Storage and Transmission Project	4 MW / 16 MWh (4 hour)	Lithium-iron-phosphate	Hebei, China	Renewable generation shifting
China Southern Power Grid / Baoqing Plant Phase-1	3 MW / 12 MWh (4 hour)	Lithium-iron-phosphate	Guangdong, China	Electric energy time shift
State Grid Corporation of China / Qingdao XueJiadao Battery Pilot Project	7 MW / 10.5 MWh (1.5 hour)	Lithium-iron-phosphate	Qingdao, China	Transportati on services

There are more than 40 lithium ion projects with anticipated power ratings greater than 1 MW either planned or under construction, totaling 287 MW.[35]

Sodium Sulfur

Sodium sulfur (NaS) battery technology was invented by Ford Motors in the 1960's, but research, development, and deployment from Japanese companies like NGK Insulators and Tokyo Electric Power Company over the past 25 years established NaS as a commercially viable technology for fixed, grid-connected applications. Sodium sulfur batteries are able to provide numerous high energy grid support applications with commercially deployed systems in the 400 kW to 34 MW power rating range and system duration of roughly 6 hours.[36]

Technical Details

The battery utilizes a positive electrode of molten sulfur, a negative electrode of molten sodium, and a solid beta alumina ceramic electrolyte that separates the electrodes. Batteries require charge/discharge operating temperatures between 300-350°C, so each unit has a built in heating element. Due to high operating temperatures and hazardous materials, the systems contains various safety features including fused electrical isolation, hermetically-sealed cells,

[35] DOE GESDB (2014)
[36] DOE-EPRI Energy Storage Handbook (2013)

sand surrounding cells to mitigate fire, and a battery management system that monitors cell block voltages and temperatures.

Typical units are composed of 50 kW NaS modules and available in multiples of 1 MW/~6 MWh (generally, an approximate 6 hour duration). Units are combined in parallel to create large scale systems, typically between 2-10 MW.[37]

The advantages of sodium sulfur are its high power and long duration, good energy density (150-300 Wh/l), extensive deployment history and commercial maturity. Downsides include risk of fire, round trip efficiencies of 70-90%, and potentially high self-discharge/parasitic load values of 0.05-20% due to the internal heating element using the battery's own electricity.[38] NaS is also much less efficient for low cycle applications due to the continual energy consumption of the internal heating element.

Deployments

To date about 306 MW/1896 MWh of sodium sulfur has been deployed in approximately 220 sites globally, with systems ranging in size from 400 kW to 34 MW. Installations are predominately in Japan, but in the last ten years, eleven systems have been commissioned in the US. Peak shifting is the most frequent application, but renewables capacity firming, T&D upgrade deferral, frequency regulation and electric supply reserve capacity specified services.

The largest operational sodium sulfur battery was installed in 2008 at Rokkasho Village Wind Farm, Japan. The 34 MW/238 MWh (7 hour duration) unit is interconnected to the transmission system and stabilizes wind output, shifting it to times of peak demand.[39]

Since 2002 American Electric Power (AEP) has deployed 11 MW in 5 different locations. In 2008 a 4 MW/32 MWh (8 hour duration) unit in Texas was part of a transmission upgrade that included a new 69 kV line and autotransformer. That system is used to support aging transmission lines, supply back up power to minimize outages and provide voltage support.[40] Additionally, AEP installed three 2 MW/12 MWh (6 hour duration) units in different locations for load leveling, to alleviate transformer loading during summer peaks, capital upgrade deferral, and emergency electric supply. These units provide AEP time to make long-term decisions, and can be relocated for an estimated $115,000 if utility needs or goals change in the future.

[37] DOE-EPRI Energy Storage Handbook (2013)
[38] SBC Energy Institute (2013)
[39] DOE GESDB (2014)
[40] IEA (2014)

Table 11. Five Largest Operational Sodium Sulfur Energy Storage Projects

Owner / Project	Nominal Power / Energy (Duration)	Technology	Location	Primary Function
Japan Wind Development / Rokkasho Village Wind Farm	34 MW / 238 MWh (7 hour)	Sodium sulfur	Rokkasho Village, Japan	Renewable generation shifting
Tokyo Metropolitan Government / Morigasaki Water Reclamation Center	8 MW / 58 MWh (7.25 hour)	Sodium sulfur	Tokyo, Japan	Load leveling
Hitachi / Automotive Plant ESS	9.6 MW / 57.6 MWh (6 hour)	Sodium sulfur	Ibaraki, Japan	Load leveling
Abu Dhabi Water & Electricity Authority / BESS	8 MW / 48 MWh (6 hour)	Sodium sulfur	Abu Dhabi, United Arab Emirates	Load leveling
American Electric Power / Presidio ESS	4 MW / 32 MWh (8 hour)	Sodium sulfur	Presidio, TX	Ancillary services

In the last 3 years, Pacific Gas and Electric (PG&E) commissioned two demonstration systems of 4 MW/28 MWh (7 hour duration) and 2 MW/14 MWh (7 hour duration). PG&E is testing the units under a number of conditions and applications to better understand energy storage technologies.[41]

The DOE Global Energy Storage Database lists three deployments that are planned or under construction. All three are for Italian utility TERNA and total 35 MW/278 MWh.

Sodium Nickel Chloride

Sodium nickel chloride batteries ($NaNiCl_2$), also referred to as ZEBRA (Zero Emissions Battery Research), are similar to sodium sulfur in their operating characteristics but are still in a demonstration and limited deployment stage. General Electric and FIAMM have about 15 current operational deployments with power ratings ranging from 20 kW/70 kWh (3.5 hour duration) to 1 MW/2 MWh (2 hour duration). Systems are primarily integrating renewable generation and providing utility grid services through voltage support, load following and frequency regulation.

Technical Details

Sodium nickel chloride batteries are similar to sodium sulfur, but the cathode is composed of nickel-chloride rather than sulfur. They require operating temperatures between 260°C and 350°C and therefore feature internal thermal management components. Able to withstand limited overcharging, they are potentially safer than sodium sulfur while also having a higher

[41] DOE GESDB (2014)

cell voltage. Typical cells are 20 kWh, so system power and energy ratings are more customizable to a given application than sodium sulfur.[42]

Compared to other chemical storage technologies, advantages of sodium nickel chloride include scalability, ability to operate in a wide temperature range (-40°C to 60°C)[43], high power density (250-270 W/l), long cycle life (2k+ cycles @ 80% DOD), and easy recycling of battery materials.[44] Disadvantages include lack of commercial deployments and maturity, high cost, and thermal management.[45]

Deployments

In total, approximately 2.7 MW/5.2 MWh of sodium nickel chloride installations are operational globally.[46] Deployments include a 1 MW/2 MWh (2 hour duration) unit performing wind energy integration at the Wind Institute of Canada, a 400 kw/280 kWh (42 min duration) unit providing frequency regulation and voltage support at a Duke substation in North Carolina, and a 200 kW/140 kWh (42 min duration) unit supplementing electric supply and peak shaving in Korea.

The number of sodium nickel chloride projects, as well as the power ratings of those deployments, is far less than sodium sulfur installations. The largest current installation is a 1 MW/2 MWh (2 hour duration) unit at the Wind Energy Institute of Canada. The system was commissioned in January 2014 and primarily integrates intermittent wind generation.

The only other system with rated energy greater than 1 MW is transmission interconnected on a wind farm in Texas. Another GE Durathon unit, it also primarily performs renewable smoothing and integration.

A half dozen multi-megawatt (2-6 MW) deployments are scheduled or under construction in Italy, Japan and Africa.[47]

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[42] IEC (2011)
[43] GE Website (2014): http://geenergystorage.com/technology
[44] EUROBAT Website (2014): http://www.eurobat.org
[45] Antonucci (2012)
[46] DOE GESDB (2014)
[47] DOE GESDB (2014)

Table 12. Five Largest Operational Sodium Nickel Chloride Energy Storage Projects

Owner / Project	Nominal Power / Energy (Duration)	Technology	Location	Primary Function
Wind Energy Institute of Canada / Durathon Battery	1 MW / 2 MWh (2 hour)	Sodium nickel chloride	Prince Edward Island, Canada	Renewable generation shifting
General Electric / Wind Durathon Battery Project	0.3 MW / 1.2 MWh (4 hour)	Sodium nickel chloride	Tehachapi, TX	Renewable generation shifting
Western Power Distribution / Falcon Project	0.25 MW / 0.5 MWh (2 hour)	Sodium nickel chloride	Milton Keynes, United Kingdom	T&D upgrade deferral
Duke Energy / Rankin Substation ESS	0.4 MW / .3 MWh (42 min)	Sodium nickel chloride	Mount Holly, NC	Renewables capacity firming
State Grid Shanghai / FIAMM Battery Project	0.1 MW / 0.2 MWh (1.7 hour)	Sodium nickel chloride	Shanghai, China	Renewable generation shifting

Nickel-Based

The two main sub-technologies in the nickel-based family are nickel cadmium (NiCad), which has been in commercial use since 1915, and nickel metal hydride (NiMH), which became available around 1995. Nickel-based batteries are primarily used in portable electronics and electric vehicles do to their high power density, cycle life and roundtrip efficiency. There are only two operational projects with rated energy greater than 1 MWh, one of which provides electric supply reserve capacity in Alaska and the other performs renewable capacity firming on Bonaire Island. Although Sandia states that "Nickel-cadmium and nickel metal hydride batteries are mature and suitable for niche applications,"[48] the fact that so few grid scale operational deployments exist suggests that nickel-based technology is not currently competitive with other battery types.

Technical Details

All nickel batteries employ a cathode of nickel hydroxide. The anode composition is used to classify the sub-categories: nickel cadmium, nickel iron, nickel zinc, nickel hydrogen, and nickel metal hydride. The three former sub-categories utilize a metallic anode while the latter two use one that stores hydrogen.

Nickel cadmium chemistry is a low cost, mature technology with high energy density, but the toxicity of cadmium necessitated the search for alternatives. Nickel metal hydride was developed in response. The metal hydride chemistry is safer and has a higher specific energy than nickel cadmium, but it charges slower and does not withstand very low operating

[48] DOE-EPRI Energy Storage Handbook (2013); p. 109.

temperatures.[49] The safety of nickel metal hydride made it the battery of choice for electric and hybrid vehicles, but lithium ion is currently challenging this status.

Other nickel chemistries are in the research and development phase.

In general, the nickel family is characterized by high power density (up to 3000 W/l), a slightly greater energy density than lead acid (200-350 Wh/l), operating well at low temperatures (-20°C to -40°C) and good cycle life (800-3,500 cycles).[50]

Deployments

Total operational deployments of nickel based batteries total 31.4 MW/8.9 MWh, of which 27 MW/6.8 MWh is installed in one project. Table 13 shows the three largest nickel based projects on the DOE Global Energy Storage Database that are not systems of private citizens.

[49] Linden (2001)
[50] See Table 7

Table 13. Three Largest Nickel-Based Energy Storage Projects

Owner / Project	Nominal Power / Energy (Duration)	Technology	Location	Primary Function
Golden Valley Electric Association / Battery Energy Storage System	27 MW / 6.75 MWh (15 min)	Nickel cadmium	Fairbanks, AK	Electric Supply Reserve - Spinning
EcoPower Bonaire BV / Bonaire Wind-Diesel Hybrid	3 MW / 0.25 MWh (5 min)	Nickel cadmium	Bonaire, Netherlands	Renewables capacity firming
Okinawa Electric Power Company / Minami Daito Island	0.3 MW / 0.08 MWh (15 min)	Nickel metal hydride	Okinawa, Japan	Frequency regulation

The Golden Valley Electric Association Battery Energy Storage System is by far the largest nickel-based battery in the world. Rated at 27 MW/6.75 MWh (15 min duration), the nickel cadmium system can potentially operate at 46 MW for as long as five minutes if needed. The unit is primarily used to provide emergency reserves to give the grid operator time to ramp local generation resources should an outage occur.

According to the DOE Global Energy Storage Database, there are no megawatt scale nickel-based projects currently planned or under construction.

Flow Batteries

Flow batteries are fundamentally different than other types of electrochemical storage because the power and energy of a system are independent of one another. This feature allows systems to be tailored to specific applications and constraints. A number of megawatt-scale demonstration projects are testing the deep discharge ability, long cycle life, and easy scalability that characterize flow batteries. Some chemistries have been more extensively developed and deployed than others, and technological maturity ranges from development stage (iron-chromium, zinc-bromine) to pre-commercial (vanadium). Operational projects ranging from 5 MW/10 MWh (2 hour duration) to 250 kW/2 MWh (8 hour duration) are focused on integrating renewables, but several smaller pilots are testing different chemistries for peak shaving and ancillary services as well.[51]

Technical Details

Flow batteries have one or both of their active materials in solution in the electrolyte at any given time. In traditional flow batteries, the solution is stored in external containers and pumped to the cell stack and electrodes where an oxidation-reduction reaction occurs. This allows for independent sizing of the electrolyte tanks (energy) and cell stack (power), which in turn allows systems to be tailored to many applications.[52]

[51] DOE-EPRI Energy Storage Handbook (2013)
[52] Gyuk/ESTAP (2014)

Several chemistries have proven technologically feasible including vanadium-vanadium (V^{n+}), iron-chromium (Fe-Cr), and zinc-bromine ($ZnBr_2$). Iron-chromium's advantages are a very safe electrolyte and high abundance and low cost of materials.[53] Vanadium utilizes ions of the same metal on both sides of the reaction, thus preventing the typical crossover degradation that occurs in other flow batteries as ions try to cross the cell membrane.[54] Zinc-bromine combines features of a conventional battery and flow battery: One electrolyte is stored in an external tank and the other is stored internally in the electrochemical cell. The zinc-bromine chemistry allows higher power and energy densities than other flow batteries (See Table 7), but bromine is extremely corrosive and can lead to component degradation and failure.[55]

Deployments

As demonstrated in Table 14, Vanadium flow batteries are the most mature and commercially deployed systems. Of the approximately 18 MW/42 MWh of flow battery capacity installed globally, 17 MW/40 MWh are vanadium redox batteries.

Commissioned in 2013, the GuoDian Wind Farm is the largest flow battery by power and energy in the world. Installed by Rongke Power, it integrates wind generation, provides voltage support, and serves as reserve electric supply capacity.

The Tomamae Wind Farm was commissioned in 2005 by Sumitomo Electric Industries. It has sometimes performed over 50 charge-discharge cycles an hour while smoothing the wind output. China's Zhangbei Project was commissioned in 2011 by Prudent Energy. It firms renewable output while providing frequency regulation and load following/ramping as well.

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[53] Horne/ESTAP (2014)
[54] IEC (2011)
[55] DOE-EPRI Energy Storage Handbook (2013)

Table 14. Five Largest Operational Flow Battery Energy Storage Projects

Owner / Project	Nominal Power / Energy (Duration)	Technology	Location	Primary Function
GuoDian LongYuan (Shenyang) Wind Power Co. / GuoDian LongYuan Wind Farm VFB	5 MW / 10 MWh (2 hour)	Vanadium redox	Liaoning, China	Renewable generation shifting
State Grid Corporation of China / Zhangbei National Wind and Solar Energy Storage and Transmission Project	2 MW / 8 MWh (4 hour)	Vanadium redox	Hebei, China	Renewable generation shifting
J-Power / Tomamae Wind Farm	4 MW / 6 MWh (1.5 hour)	Vanadium redox	Hokkaido, Japan	Renewables capacity firming
Sumitomo Electric Industries / Yokohama Works VRB	1 MW / 5 MWh (5 hour)	Vanadium redox	Kanagawa, Japan	Renewable generation shifting
Prudent Energy / Gills Onions VRB	0.6 MW / 3.6 MWh (6 hour)	Vanadium redox	Oxnard, CA	Grid-Connected Commercial (Reliability & Quality)

Operational US deployments range from a 600 kW/3.6 MWh Prudent Energy vanadium unit providing power quality at a factory to a 25 kW/50 kWh ZBB zinc bromine system acting as a UPS for a data center. Non-vanadium projects are becoming more common: Enervault commissioned a 250 kW/1 MW (4 hour duration) iron chromium system adjacent to a California solar array in 2014, and Primus Power is currently constructing several identically sized zinc-bromine units.

Approximately 29 MW/110 MWh of deployments are planned or under construction globally.[56]

Supercapacitors

Also called electrochemical double-layer capacitors and ultracapacitors, this technology class bridges the gap between batteries and traditional capacitors and stores energy electrostatically. Supercapacitors are characterized by low internal resistance which allows rapid charging and discharging, very high power density (but low energy density), and high cycle life.[57] Current deployments are primarily used in voltage support, load following/ramping and regenerative braking in transportation applications and have sizes between 300 kW/3 kWh and 1 MW/17 kWh. The technology is still considered to be in demonstration phase.[58]

[56] DOE GESDB (2014)
[57] IEA-ETSAP/IRENA (2012)
[58] SBC Energy Institute (2013), DOE-EPRI Energy Storage Handbook (2013)

Technical Details

Supercapacitors use carbon electrodes with very high surface area to create a solid-liquid interface that allows electricity to be stored by the separation of charge, rather than through chemical transformation like traditional batteries.[59]

Advantages of supercapacitors include high power density (40-120 kW/l), very fast response time (<1 sec), high efficiency (80-98%), and high cycle life (10k-100k).[60] While disadvantages include low specific energy (30 Wh/kg) and corresponding high cost per kWh.

Deployments

There are 13 operational deployments listed on the DOE Global Energy Storage Database, of which 11 are 1 MW or greater. Total installed capacity is approximately 21.4 MW/0.1 MWh and the largest projects are summarized in Table 15.

[59] Badwal et al. (2014)
[60] SBC Energy Institute (2013)

Table 15. Five Largest Operational Supercapacitor Energy Storage Projects

Owner / Project	Nominal Power / Energy (Duration)	Location	Primary Function
Electrical Power worX / LIRR Malverne WESS: Ioxus	1 MW / 16 kWh (1 min)	Malverne, NY	Transportation Services
Electrical Power worX / LIRR Malverne WESS: Maxwell	1 MW / 16 kWh (1 min)	Malverne, NY	Transportation Services
Incheon Transit Corporation / Incheon Line 1 - Technopark Station	2.3 MW / 13 kWh (20 sec)	Incheon, South Korea	Transportation Services
Seoul Metro / Seoul Line 2 - Seocho Station	2.3 MW / 13 kWh (20 sec)	Seoul, South Korea	Transportation Services
Seoul Metro / Seoul Line 4 - Ssangmun Station	2.3 MW / 13 kWh (20 sec)	Seoul, South Korea	Transportation Services

Installations of supercapacitors as standalone energy storage systems are almost exclusively focused on providing near-instantaneous voltage ramping and regenerative braking for trains.

In the last two years, Maxwell Technologies and Woojin Industrial Systems have deployed nine systems that provide over 15 MW/83 kWh in support of Korean Metro operations. In New York a pilot testing two 1 MW/16 kWh units side by side was recently commissioned by Electrical Power WorX.

Supercapacitors are also being deployed in conjunction with traditional batteries. Southern Pennsylvania Transportation Authority and ABB are commissioning two hybrid units that combine lithium ion batteries with supercapacitors to provide voltage support for trains while simultaneously capturing braking energy that is sold into the frequency regulation market. Deka/EastPenn's Ultrabattery, currently in frequency regulation pilot demonstrations (See Table 8), is a packaged unit that combines a lead acid battery with a supercapacitor.

At least 11 MW/88 kWh of additional deployments are planned or under construction.[61]

5.1.2 *Mechanical Storage*

The mechanical storage technology class consists of compressed air energy storage and flywheels.

Compressed air energy storage generally makes use of off peak power to compress air and store it in a reservoir, typically either an underground cavern, or aboveground storage pipes or tanks. Compressed air energy storage is a commercially available technology for long duration storage requirements.

Underground compressed air storage facilities are generally considered less expensive than aboveground; however, siting an underground compressed air storage facility requires

[61] DOE GESDB (2014)

identification of a geologically suitable underground cavern.[62] Underground compressed air storage facilities are generally most cost effective as very long duration resources, on the scale of 8 to 26 hours.

Above ground compressed air storage facilities are more modular and less location-specific with respect to siting. The US Department of Energy states that the typical above ground compressed air storage facility is in the 3-50 MW power range, with durations of two to six hours.[63] However the incremental additional cost for above ground compressed air storage is significant, with DOE citing a cost of between $4,900-5,000/MW for a 50 MW/5 hour above ground system, and a levelized cost of slightly more than $200/MWh, or between about $380-390/kW-yr.[64]

Table 16 shows operational compressed air storage facilities.

[62] DOE-EPRI Energy Storage Handbook (2013); p. 38.
[63] *Ibid.*; p. 38.
[64] *Ibid.*; p. 39-40.

Table 16. Five Largest Operational Compressed Air Storage Facilities

Owner / Project	Nominal Power / Energy (Duration)	Technology	Location	Primary Function
E. ON / Kraftwerk Huntorf	321 MW / 642 MWh (2 hours)	In-ground Natural Gas Combustion	Elsfleth, Germany	Electric Energy Time Shift
PowerSouth Utility Cooperative / McIntosh CAES Plant	110 MW / 2,860 MWh (26 hours)	In-ground Natural Gas Combustion	McIntosh, AL	Electric Energy Time Shift
General Compression, Inc. / Texas Dispatchable Wind	2 MW / 500 MWh (250 hours)	In-ground Iso-thermal	Seminole, TX	Renewable Generation Shifting
SustainX Inc. / Isothermal Compressed Air Energy Storage	1.5 MW / 1.5 MWh (1 hour)	Modular Iso-thermal	Seabrook, NH	Renewable Generation Shifting
Highview Power Storage / Pilot Plant	.35 MW / 2.45 MWh (7 hours)	Modular	Slough, United Kingdom	Renewable Generation Shifting

Flywheels are the other mechanical energy storage technology sub-class. Flywheels are modular and can range from 22 kW in size (Stornetic's EnWheel) to 160 kW (Beacon Power). In essence, a flywheel works by accelerating a rotor (flywheel) to a very high speed in a very low-friction environment. The spinning mass stores potential energy to be discharged as necessary.

Table 17. Five Largest Operational Flywheel Facilities

Owner / Project	Nominal Power / Energy (Duration)	Location	Primary Function
European Fusion Development Agreement / EFDA JET Fusion Flywheel	400 MW / 3.3 MWh (30 sec)	Abingdon, United Kingdom	Onsite power
Max Planck Institute, EURATOM Association / ASDEX-Upgrade Pulsed Power Supply System	387 MW / 0.54 MWh (5 sec)	Bavaria, Germany	Onsite power
Spindle Grid Regulation, LLC / Beacon Power 20 MW Flywheel Plant	20 MW / 5 MWh (15 min)	Stephentown, NY	Frequency Regulation
Spindle Grid Regulation, LLC / Beacon Power 20 MW Flywheel Plant	20 MW / 5 MWh (15 min)	Hazle Township, PA	Frequency Regulation
NRStor Inc. / Minto Flywheel Energy Storage Project	2 MW / 0.5 MWh (15 min)	Ontario, Canada	Frequency Regulation

Flywheels are best for short-duration, high power, and high-cycle applications. Generally, they have a much longer cycle life than other storage alternatives. Primary competitors are supercapacitors or ultracapacitors. They are less heat sensitive than batteries and are often guaranteed for 20 years of performance (batteries are often less than 10 years). Primary use cases for flywheels on the power grid are for Voltage/VAR Support, Regulation Energy Management (REM), and improved flexible capacity.

5.1.3 *Thermal Storage*

Thermal storage comes in many forms, although perhaps the most well-known bulk thermal storage solution is molten salt. Molten salt thermal storage is paired with solar thermal generation plants and is used to improve the dispatchability of concentrated solar power (CSP) facilities through the storage of thermal energy to power steam turbines for electric generation after the solar day had ended. Molten salt is not further considered in this assessment; its need to be paired with thermal generation is incompatible with the Eastside's reliability requirements.

Table 18. Five Largest Operational Bulk Thermal Storage Facilities

Owner / Project	Nominal Power / Energy (Duration)	Technology	Location	Primary Function
Abengoa Solar / Solana Solar Generating Plant	280 MW / 1,680 MWh (6 hours)	Molten Salt	Gila Bend, AZ	Renewable Generation Shifting
Confidential / TAS Texas Cooperative	90 MW / 1,080 MWh (12 hours)	Chilled Water	Joplin, TX	Electric Supply Capacity
Acciona Energía / Nevada Solar One Plant	72 MW / 36 Mwh (30 min)	Thermal	Boulder City, NV	Renewables Capacity Firming
ACS - Cobra Group / Manchasol 2 Solar Plant	50 MW / 375 MWh (7.5 hours)	Molten Salt	Alcazar de San Juan, Spain	Renewable Generation Shifting
Ortiz - TSK -Magtel / La Africana Solar Plant	50 MW / 375 MWh (7.5 hours)	Molten Salt	Posadas, Spain	Renewable Generation Shifting

Other forms of thermal storage are typically of a distributed nature, and primarily interact with heating and cooling requirements to provide demand-side services such as demand response. Examples include ice storage technologies, which primarily shift air conditioner load, and water heater direct load control, which helps manage water heater load. Some of these technologies have already achieved widespread deployment in electrical and heating networks within certain markets. However, the mild weather in the Pacific Northwest generally limits the days that demand savings can be achieved by the customer for ice storage, and the lack of time of use pricing in PSE service territory has limited customer benefits for both ice storage and water heater direct load control in the area. Water heater direct load control was previously evaluated for its load management potential in PSE's 2013 IRP, and the Non-wires Report evaluated the potential incremental benefits of cost effective direct load control of residential room heating and water heating. Therefore, this report does not further evaluate these technologies. Furthermore, given the limited benefits to customers combined with the likely incompatibility of ice storage in addressing winter peak needs in particular, ice storage was not further evaluated.

5.1.4 *Bulk Gravitational Storage*

Bulk gravitational storage includes technologies such as pumped hydro and gravel in railcars. Pumped hydro is a mature technology that is currently used throughout North America and the world. Pumped hydro is suitable for bulk energy shifting, and the concept behind pumped hydro is that off-peak power is used to pump water from a reservoir up to a higher reservoir, where it can be released to generate electricity during peak periods.

As pumped hydro facilities generally require above ground reservoirs, the required footprint can be quite significant, is location-specific, and generally is unable to be placed near urban load centers. In addition, due to the large environmental impact, permitting of pumped hydro facilities can take many years with uncertain outcomes.

Table 19. Operational Pumped Hydro Storage Facility in Washington State

Owner / Project	Nominal Power / Energy (Duration)	Location	Primary Function
Bonneville Power Administration / John W. Keys III Pump-Generating Plant	314 MW / 25,120 MWh (80 hours)	Grand Coulee, WA	Electric Supply Capacity

The gravel/railcar storage method operates in a similar manner to pumped hydro. Typically, off peak power is used to move rail cars filled with gravel or another heavy material up a slope. When power is needed, the railcar moves down the slope, converting gravitational energy into electricity as it moves down.

An advantage of railcar/gravel energy storage over pumped hydro is that it does not require reservoirs to function. Rather, it requires a long slope of existing or new railroad track. This makes it somewhat easier to site than pumped hydro, although still not suitable for urban areas, nor is it generally suitable for segments of railroad that have existing rail traffic.

Table 20. Planned Railcar Energy Storage Facility

Owner / Project	Nominal Power / Energy (Duration)	Location	Primary Function	Status
ARES North America / Advanced Rail Energy Storage Nevada	50 MW / 12.5 MWh (15 min)	Pahrump, NV	Load Following, Voltage Support	Announced

For these reasons, bulk gravitational storage is not an appropriate technology class for the Eastside reliability requirements and has therefore not been further considered in this assessment.

5.2 Roundtrip Efficiency

Roundtrip efficiency (RTE) of energy storage technologies varies substantially based on many factors. Differences amongst technology classes can be significant, but differences due to operational profiles and the environment can be even more significant.

An interview with one vendor offering a lithium ion solution indicated, for example, that the discharge rate as a ratio of the overall energy capacity of the battery cells (the "C Rate) can have a drastic impact on RTE. Systems that slowly discharge (C rate of 0.01, or discharging 1% of capacity per hour) can operate as efficiently as 98%, while efficiency rapidly declines as discharge rate increases.

Ambient temperature can also impact RTE, particularly for chemical energy storage systems. Low temperatures can cause lithium ion, for example, to have a lower RTE, although generally power electronics have higher efficiencies at lower temperatures. Sodium sulfur systems need to be maintained at a high temperature as well in order to operate correctly. Factors such as altitude and humidity can also have a significant RTE impact.

Inverter-based technologies, such as chemical storage, also must factor in additional instantaneous and overall RTE losses that vary substantially based on inverter manufacturer, inverter size, and the device operating profile.[65] Typically efficiency is lower at lower power output as a ratio of the inverter rated maximum power output, and increases as power output increases. This is only true up to a point, however, as inverters flatten or decrease somewhat in efficiency as output nears 100%.

The State of California maintains a database of inverters that have received UL 1741 safety certification and that have developed and submitted efficiency data tested by a Nationally Recognized Testing Laboratory.[66] With 2,249 inverters currently listed, this database is perceived to be a comprehensive source of commercially available inverter power ratings and weighted operational efficiency because it is used to determine eligibility for California state

[65] Inverter capabilities also vary substantially. Certain modern "smart inverters", for example, also have the capability to actively enhance system reliability beyond simply injecting power into the grid. While these capabilities are beyond the scope of this report, such capabilities should be explored as part of PSE's future technical assessments of energy storage or other inverter-based technologies' ability to meet system needs.
[66] http://www.gosolarcalifornia.ca.gov/equipment/inverters.php

incentives. The benefits of this database are that efficiency is determined using a common and generally accepted protocol, which removes the uncertainty of relying on manufacturers' spec sheets. Per this database, modern inverters have weighted operational efficiencies in the 84.5-98.5% range, with median weighted unidirectional efficiency rated at 96%. As efficiencies are rated in a single direction, the values must be multiplied to determine approximate ac-ac RTE (e.g. if an inverter is 96% efficient, the RTE would be approximately 0.96 * 0.96 or 92.16%).

Based on this assessment, we believe that an energy storage power electronics system should be assumed to contribute to at least an additional 8-10% to overall RTE losses versus the standalone cell RTE.

5.3 Technologies Modeled

Chemical (battery) storage is the technology class the investigators determined would be most suited for further evaluation to meet the Eastside reliability needs.[67]

Strategen conducted a search of the United States Department of Energy Global Energy Storage Database[68] to assess the technical readiness of the above battery chemistries for deployment on the bulk system to provide a transmission investment deferral function.

No battery technology has yet been utilized to provide transmission or distribution reliability services at the power rating required and evaluated in this assessment, although the Rokkasho Village Wind Farm is comparable in terms of energy rating. The top 5 largest currently operational electrochemical storage projects in the world are shown in Table 21 below:

[67] Distributed thermal storage may also be suitable to meet some or all of the need. However, it was not further evaluated in this assessment as it was previously studied as a demand response resource in PSE's Integrated Resource Plan. See Chapter 5.1.3 for a complete explanation.
[68] DOE GESDB (2014)

Table 21. Largest Operational Electrochemical Storage Projects, by Power Rating

Owner / Project	Nominal Power / Energy (Duration)	Technology	Location	Primary Function
Duke Energy / Notrees	54 MW / 36 MWh (40 min)	Advanced Lead acid	Goldsmith, TX	Renewables capacity firming
Japan Wind Development / Rokkasho Village Wind Farm	34 MW / 238 MWh (7 hour)	Sodium sulfur	Rokkasho Village, Japan	Renewables capacity firming
AES / Laurel Mountain	32 MW / 8 MWh (15 min)	Lithium ion	Elkins, WV	Ancillary Services
GVEA / Battery Energy Storage System	27 MW / 6.75 MWh (15 min)	Nickel cadmium	Fairbanks, AK	Backup power
AES / Angamos	20 MW / 6.6 MWh (20 min)	Lithium ion	Mejillones, Chile	Backup power

Other notable utility-owned projects to come online recently include two substation-sited projects in California; specifically, PG&E's Yerba Buena Battery Energy Storage System Pilot Project, a 4 MW/28 MWh (7 hour duration) sodium sulfur battery system, and SCE's Techachapi Wind Energy Storage Project, an 8 MW/32 MWh (4 hour duration) lithium ion battery system. These two systems have been used in this assessment to evaluate visual impact and footprint requirements for the configuration studied herein.

It should also be noted that SCE recently announced the most significant procurement of energy storage to date (summarized in Table 22), amounting to 261 MW. While the AES project cited below has not yet been built, the facility is an in front of the meter installation (rated at 100 MW/400 MWh) and is considered by Strategen to be a comparable benchmark for this study.

Table 22. Summary of Southern California Edison's Energy Storage LCR Procurement

Seller	Resource Type	Nominal Power (MW)	Technology
Ice Energy Holdings, Inc.	Behind-the-Meter	25.6	Thermal
Advanced Microgrid Solutions	Behind-the-Meter	50	Battery
Stem	Behind-the-Meter	85	Battery
AES	In-Front-of-Meter	100	Battery
NRG Energy, Inc.	In-Front-of-Meter	0.5	Battery
TOTAL		**261.1**	

5.3.1 *Operational Energy Storage Systems for T&D Deferral*

A variety of energy storage technologies have been commercially deployed to the grid, providing substantial dispatchable generation and ancillary services resources to bulk energy systems around the world. However, using energy storage to provide a transmission or distribution reliability function *capable of deferring construction of new transmission equipment* as a primary use case is a less common use case at this point in time (with the potential exception of pumped hydro). The largest projects serving a *transmission or distribution deferral function*, per the DOE Global Energy Storage Database are shown in Table 23 below. Note that we include both operational projects and those under construction due to the limited number of projects meeting this criteria.

Table 23. Largest Projects Serving Transmission or Distribution Deferral Functions, By Power Rating

Owner / Project	Power / Energy (Duration)	Technology	Location	Status
UK Power Networks / Smarter Network Storage Project	6 MW / 10 MWh (1.67 hour)	Lithium ion	Bedfordshire, United Kingdom	Under construction
Northern Powergrid / CLNR EES1	2.5 MW / 5 MWh (2 hour)	Lithium ion	Darlington, United Kingdom	Operational
Bosch / Braderup Energy Storage Facility	2 MW / 2 MWh (1 hour)	Lithium ion	Braderup, Germany	Operational
SDG&E / Julian GRC Energy Storage Program	1 MW / 3 MWh (3 hour)	Lithium ion	Julian, California	Under construction
SDG&E / Borrego SES	1 MW / 3 MWh (3 hour)	Lithium ion	Borrego, California	Under construction

5.4 Technologies Not Further Evaluated

As discussed above, certain technology classes were not further considered in this assessment. Such technology classes and sub-classes include:

- Advanced battery technologies that do not currently have commercial deployments at grid scale, such as flow batteries, were not further considered because they may not be appropriate for a near term, large scale deployment to meet a system reliability need.

- Mechanical storage – this category, which includes flywheels and modular compressed air, was not further considered. Flywheels are optimized to provide short duration storage, typically 15 minutes or less. The primary use case under evaluation in this paper is therefore suboptimal due to the longer duration requirement. The potential use cases of modular compressed air includes the type of load shifting necessary to defer the Eastside reliability need; however, the technology is in pre-commercial demonstration phase and thus may not be appropriate for a near term, large scale deployment to meet a system reliability need.

- Bulk mechanical storage – this category was not further considered due to the unique geological requirements it has for deployment that are incompatible with siting a project in the Eastside area.

- Thermal storage – this technology was not further evaluated due to its typical application of being paired with thermal solar in the case of molten salt and hot water, in the case of direct load management of water and room heating, because it already is studied through PSE's Integrated Resource Planning process, and in the case of ice storage, because it provides benefits that are relatively unaligned with the winter peak need.

- Bulk gravitational storage – this technology class, which includes pumped hydro and rail cars, was not further considered due to the typical space requirements, which are generally more suited to be sited in rural locations, and therefore make this class unsuitable for siting a project in the Eastside area.

5.5 Commercial Models of Contracting Bulk Energy Storage

5.5.1 *Contracting Models*

Different energy storage contracting models are being utilized to address a wide range of necessary grid support applications. Contracting models include turnkey systems, power purchase tolling agreements, and demand response agreements. Each offers unique financial liabilities and operating characteristics.

Turnkey

In the turnkey model, developers are responsible for engineering, procurement, construction, testing, commissioning, start-up and performance verification. Projects could be built on either on utility or private land, and the utility agrees to acquire the system after commissioning. These utility owned systems can then be flexibly operated to deliver whatever kind of grid support the utility desires, without the operational complexity of third party involvement in the system operation. Typically, turnkey solutions come with warranties commensurate with other utility infrastructure purchases.

Examples of recent turnkey energy storage solicitations include HECO's May 2014 Request for Proposal (RFP) for 60-200 MW of energy storage (RFP# 072114-01), which requested only turn key projects. PG&E and San Diego Gas and Electric's (SDG&E) December 2014 Request for Offers (RFO) for energy storage solicited both turnkey and tolling agreements.

Energy Storage Tolling Agreements

Southern California Edison (SCE) recently developed a new style of agreement, the "Energy Storage Agreement" (ESA) for its recent solicitation to meet Southern California's Local Capacity Requirements (2013 LCR RFO). According to Les Sherman of Orrick, "SCE's pro-forma ESA will likely evolve, but is expected to become the basis for other SCE storage solicitations, as well as an example for other IOUs, and even potentially utilities in other jurisdictions."[69] This agreement was created based on SCE's standard power purchase tolling agreements (PPTA), which are "contracts to purchase power wherein the utility pays the seller a periodic payment for capacity for the length of the contract."[70] PPTAs apply to third-party owned systems and are a typical contractual arrangement for system capacity resources that have been extended to energy storage procurement where typical utility dispatch of the storage system is unknown.

[69] Sherman (2014)
[70] California Office of Ratepayer Advocate: http://www.ora.ca.gov/ppta.aspx

The commercial terms are generally structured such that the developer is fully responsible and at risk for all project development, as well as for the full operation, maintenance, and repair of the project. The buyer (utility) is typically the scheduling coordinator, and as such responsible for scheduling of all energy deliveries and dispatches, and is also responsible for all costs associated with charging, and receives all revenues from discharging. The seller's compensation is generally structured as a fixed payment for capacity, and a variable payment for operations and maintenance.

Demand Response Agreement

Utilities seeking to manage/reduce peak demand may opt for demand response agreements (DRAs). DRAs apply to distributed, customer-sited energy storage systems. A utility agrees to receive and purchase a specified amount of power and energy which the system owner agrees to deliver and sell during specific time periods.

For example, SCE solicited DRA as part of its 2013 LCR RFO.[71]

5.5.2 *Warranties & Performance Guarantees*

Performance guarantees and warranties are a critical component of energy storage procurement. Buyer protections typically include a variety of performance guarantees, damages for failure to hit pre-commercial operation milestones, testing and operations requirements that are custom to the project and technology, default provisions, capacity payment reduction mechanisms, project financing requirements, and others.[72]

Warranty terms are generally negotiated on a case-by-case basis. HECO's energy storage RFP, for example, contemplated an 18 month "performance verification" period that is mandatory for all bids, with sellers to offer warranty terms beyond the 18-month period as part of the solicitation response. HECO indicated that it preferred a single warranty wrap from the EPC contractor for the project, and expected bidders to design the system to maintain "full nameplate performance" at the end of the system's expected 15-year lifespan. [73]

PG&E's 2014 Energy Storage RFO contemplates a variety of performance guarantees. For its distribution deferral turnkey component of the RFO, PG&E's performance guarantees included guarantees on the following: Cmax (maximum charge rating), charging duration, daily efficiency, standby energy consumption, Dmax (maximum discharge rating), discharge duration, site-specific duty cycle, and emissions limits.[74]

[71] The SCE agreement can be downloaded here: https://www.sce.com/wps/wcm/connect/aac24575-6a82-439b-8da0-893638296a99/2013_LCRRFO_DR_ES_ProForma_03262014.docx?MOD=AJPERES
[72] Sherman (2014)
[73] Hawaiian Electric Company RFP (RFP# 072114-01) for 60 to 200 MW of Energy Storage for Oahu, Q&A Log: http://www.hawaiianelectric.com/vcmcontent/StaticFiles/pdf/ESS_Master_Question_and_Answer_Log_071614.pdf
[74] Exhibit F of PG&E's Energy Storage RFO protocol: http://www.pge.com/en/b2b/energysupply/wholesaleelectricsuppliersolicitation/RFO/ES_RFO2014/index.page

6 Energy Storage Configurations and Feasibility

This white paper focuses on addressing the feasibility of using energy storage combined with other cost-effective non-wires solutions to address PSE's Eastside System Reliability Needs. As such, the location and configuration of the energy storage system combined with lower cost non-wires alternatives, must be capable of meeting or exceeding the Eastside system reliability need. Importantly, it must do so with a sufficient degree of margin as to provide confidence that the system would remain reliable under system conditions that exceed the stress of PSE's more aggressive planning scenarios. This section of the report discusses the factors used as inputs to develop the configurations studied, and evaluates the feasibility of each configuration.

6.1 Effectiveness Factor

Energy storage (or any non-wires alternative) cannot offset transmission line overloads at a 1:1 ratio. Because energy flows over the power system based on the relative resistances of various lines, less than 100% of the power rating of an energy storage system will flow on the lines in the direction needed to offset load in an appropriate manner. If 1 MW of energy discharge offset 1 MW of system need, the effectiveness factor would be 100%. If 1 MW of energy discharge offsets only 0.25 MW of system need, the effectiveness factor would be 25%.

In the case of the Eastside system, PSE transmission planners modeled the impact of the load reduction via energy storage or other non-wires alternatives and determined that such load reduction would have an effectiveness factor of approximately 20-21%.[75]

6.2 Planning and Operating Standards

The Non-wires Report sought to address a 2017 transmission capacity deficiency of between 70 MW and 160 MW. That study concluded that 56 MW of non-wires (DSR) alternatives were cost-effective, and thus the overall deficiency would hypothetically be reduced but not eliminated. The Non-wires Report, though, did not reduce the need for PSE to rely on CAPs to mitigate overloads at Sammamish and Talbot substations. Discussions with PSE's transmission planners and a re-evaluation of planning criteria concluded that energy storage, if selected, must fully meet planning and operating standards in order provide a level of reliability comparable to a transmission solution.

Steady State Requirements

There were three levels of mitigation requirements to be met:

- Near Term Planning Requirements: In order to solve the transmission system capacity deficiencies indicated in the 2013 Eastside Transmission Needs Assessment, it was

[75] Based on power flow studies run by PSE, its transmission planners determined that a 29.44 MW peak overload under N-1-1 conditions in 2017 at Talbot Hill transformer #1 was offset by 135 MW of non-wires resources including storage (20.0% effectiveness). That peak overload grows to 34.07 MW by 2021, which required 170 MW of resources to offset the need (20.6%), which is within a very close margin of error when compared to the 2017 calculations.

necessary to bring loading on all lines and transformers below 100% of the emergency rating in the 2021-22 winter case and in the 2018 summer case for all FERC required contingencies.

- Long Term Solution: To be equivalent to the Bellevue 230-115 kV transformer connected to PSE's 230 kV transmission system, the battery solution would need to keep overloads below 100% in the longer term, as modeled in the 2021-22 normal winter case with 75% conservation for all FERC required contingencies.

- Operating Requirements: Day to day operations are required to keep all line and transformer loading below 100% of the emergency rating. Operations must also keep transformer loading between the normal and the emergency limit for no more than 8 consecutive hours. These limits are applicable to all cases for all FERC required contingencies. These values were provided to Strategen for reference but not required as a solution by 2021. If PSE Operations is faced with limiting 230-115 kV transformer loading above the normal limits for no more than eight hours, it may be necessary to dispatch generation, sectionalize transmission lines, or shed load, or combinations of all three.

FERC requires that PSE meet the NERC Transmission Planning Standards (TPL) for all elements in service (N-0), loss of one element (N-1), loss of a double or multiple-element site (N-2) or loss of one element followed by an adjustment then loss of a second element (N-1-1). During all of these contingencies, no elements may overload nor experience voltages out of compliance. These are included in NERC Reliability Standards TPL-001-4. PSE is not allowed to create an adverse impact on neighboring utilities during any of these contingencies.

Due to the operating characteristics of batteries, which are rated for a peak demand as well as watt-hour duration, it was necessary to consider the operating requirements as well as the planning requirements for this study. Once the battery discharges, it requires a charging period sufficient to restore its full charge prior to the next discharge cycle. Therefore the hourly load profile forecast into the future was provided to Strategen.

6.3 Defining the Size

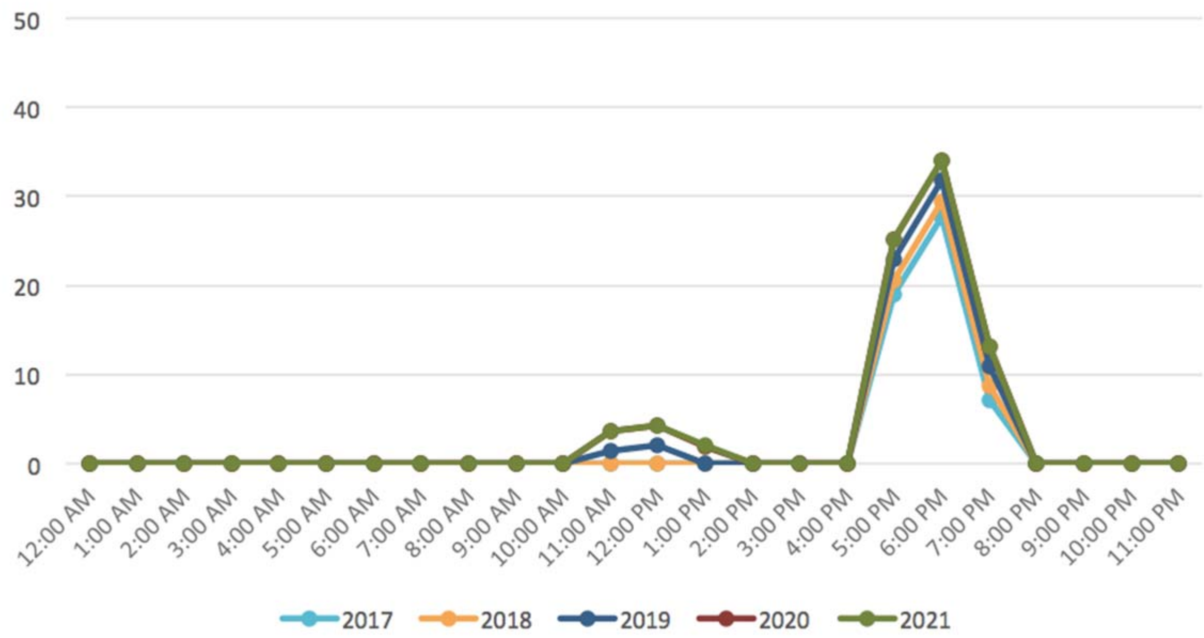
Strategen started its evaluation by looking at the maximum emergency power flows on the Talbot Hill and Sammamish substations during Category C NERC contingencies (N-1-1). This data was provided as hourly (8760 per year) data by Puget Sound Energy's transmission planning team. PSE also provided the normal and emergency line ratings for Talbot Hill and Sammamish substations. The analysis determined that in all years, Talbot Hill was the substation with the most significant normal and emergency winter overloads, thus Talbot Hill was the element that determined the overall need.

6.3.1 *Talbot Hill Emergency Overloads*

6.3.1.1 *Talbot Hill Emergency Overload Profile*

Based on the data provided by PSE, Talbot Hill's emergency rating could be exceeded on the peak day in 2017 for 3 hours, peaking at approximately 28 MW exceedance. By 2021, this increases to an overload that runs for 6 non-contiguous hours on the peak day, with a peak of 34 MW.

Figure 6. Maximum Eastside Emergency Overload Profile, from 2017 to 2021 (in MW)



The hourly overload distribution in any given year is likely to be slightly different than any other year, and could vary significantly from what was studied due to a variety of factors that include:

a) actual load growth the region will see between now and 2021 could deviate from load growth forecasts;

b) the amount of energy efficiency, distributed generation, and demand response that PSE assumes will develop in its integrated resource plan may not materialize as planned; and

c) Actual future weather conditions could drive higher or lower peak load on the system during any given year versus typical[76] winter and summer conditions.

Any of the above factors may not occur as planned. The eventual system requirements may be higher than the load reduction need identified based on the data provided by PSE.

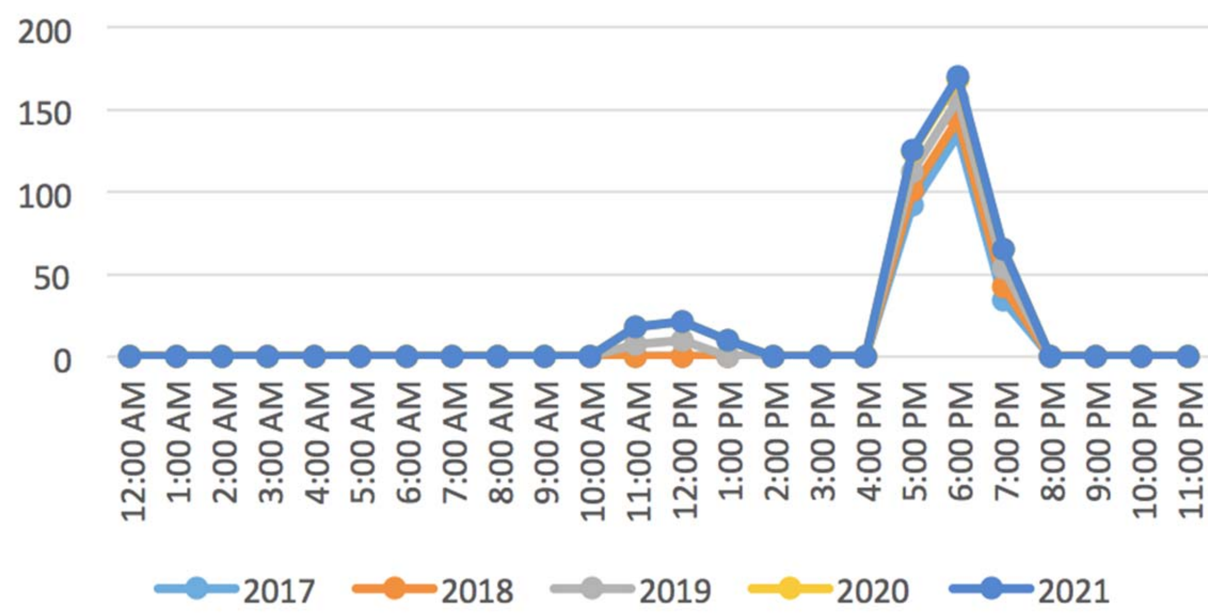
6.3.1.2 *Gross Talbot Hill Emergency Load Reduction Need*

Notwithstanding the potential for variability in actual overloads, the above data was used to determine the cumulative amount of non-wires + storage alternatives needed to address the Eastside need. As indicated in Chapter 6.1, PSE transmission planners modeled the impact of the load reduction (in the form of energy storage or other non-wires alternatives) on the overload and determined that discharged energy from the configuration would have an effectiveness factor of approximately 20-21%. In order to determine the power rating of the

[76] Typical conditions are conditions that are likely to occur in one out of every two years.

energy storage needed to meet the emergency overload need, the above overloads were multiplied by the effectiveness factor of non-wires alternatives (including energy storage) to determine the following duration and shape of load reduction requirements to offset the emergency overload on Talbot Hill:

Figure 7. Duration and Shape of Gross Non-Wires + Storage Resource Requirement by Year for Emergency Overload Elimination (in MW)



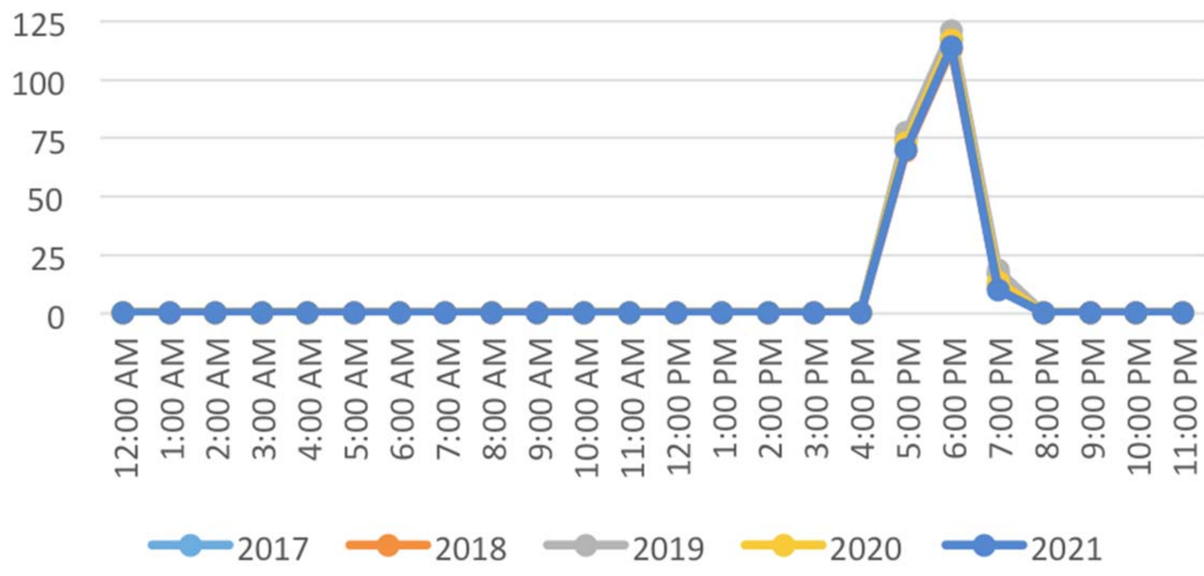
As shown on the above chart, the resulting peak need is approximately 135 MW in 2017, increasing to a peak need of 170 MW in 2021.

6.3.1.3 *Reduction in Gross Need due to Non-Wires Alternatives*

Other non-wires alternatives that were determined to be cost effective in meeting the deferral need[77] were then used to offset a portion of the identified reliability need. Figure 18, taken from the Non-wires Report[78], graphically depicts the amount of cost effective non-wires alternatives available is anticipated to increase from 2017 to 2021. The underlying data shows available non-wires resources growing from 17.7 MW in 2017 to 55.6 MW in 2021. Non-wires alternatives deemed to be cost effective include all energy efficiency, demand response, and distributed generation programs included in the Non-wires Report[79] that were not previously selected in PSE's Integrated Resource Plan. Demand Response programs deemed cost effective by PSE were already included in its integrated resource plan. The increase in other non-wires alternatives closely tracks projected growth in Talbot Hill's emergency overload, resulting in the following energy storage net injection requirements from 2017-2021:

[77] E3 (2014)
[78] *Ibid.*
[79] *Ibid.*

Figure 8. Energy Storage Net Injection Requirement by Year for Emergency Overload Elimination (in MW)



Note that the non-wires resources were effective at eliminating the overload during the first three hour peak, and reducing the emergency overload during the second peak. As the above chart shows, the peak power requirement of the energy storage system to address an emergency overload only was determined to be as follows:

2017: 117 MW

2019: 121 MW

2021: 114 MW[80]

Thus, to meet the 2021 deferral need based on the emergency rating, the system would have to be capable of having a power rating of 121 MW (to meet the 2019 peak need).

The above analysis identifies not just the power requirements of the energy storage system (i.e. MW), but also informs the *total* energy (i.e. MWh) required of the energy storage system. This was accomplished by evaluating the *duration* and *shape* of the incremental need during times when the peak capabilities of existing transmission lines are being exceeded.

Take, as an example, flow modeling that shows that over a 3-hour period, peak load exceeds line rating by 20 MW in the first hour, 30 MW in the second hour, and 10 MW in the third hour. In this case, an energy storage system would need to provide peak output of 30 MW and an energy rating of 20 MWh in the first hour, 30 MWh in the second hour, and 10 MWh in the third

[80] Note that the results show a slight drop in the 2021 power requirement versus 2019. This is driven by the projected availability of new cost effective non-wires resources in the 2019-2021 timeframe exceeding growth in line loading.

hour. This would result in an energy storage system sized to provide peak output of 30 MW and an energy rating of 60 MWh to meet the need. Depending on the chemistry of the battery used, an additional buffer may also need to be included in order to prevent the battery from completely discharging, which can have negative impacts on the life expectancy of certain batteries.

For the PSE Winter Peak Scenario, load flow analysis identified the following energy requirements:

2017: 209 MWh

2019: 216 MWh

2021: 194 MWh[81]

6.3.1.4 *Energy Storage Sizing to Meet Emergency Overload*

The investigators used the Eastside hourly overload data above as the basis to develop power and energy requirements for energy storage systems meeting the emergency overload. Chemical energy storage systems also exhibit a tendency to degrade over time as the device is charged and discharged (this is called cycling). The investigators modeled the operation of the configurations studied in a manner that conforms to a standard system degradation rate of approximately 2% per year. As such, the system meeting a 2021 deferral needs to be slightly upsized in order to account for degradation from 2017-2021. This results in a slightly greater energy requirement for the energy storage system than the 2021 injection requirement.

[81] Similar to what was noted above, the results show a slight drop in the 2021 energy requirement versus 2019.

Table 24. Emergency Overload Elimination Net Injection Requirements by Year*

	2017 Sizing for deferral through calendar year	
	2017	2021
Power (MW)	117.3	121.0
Energy (MWh)	208.8	225.6
Duration (hours)	1.8	1.9

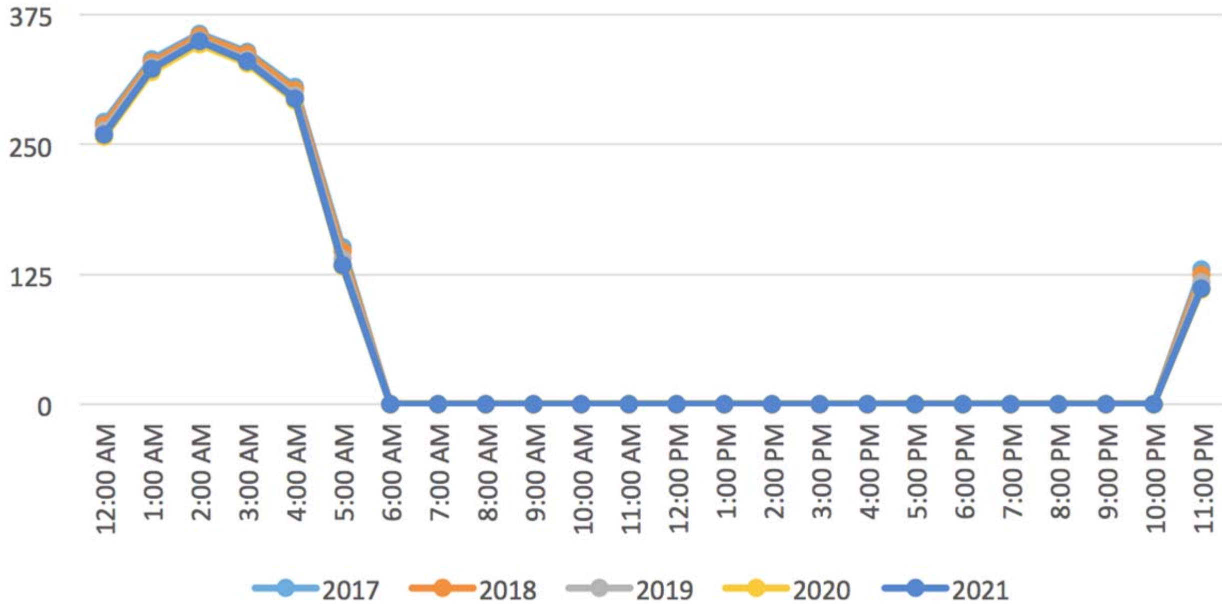
***Accounts for a 2%/year battery cell degradation**

6.3.1.5 *Charging Requirement versus Available Grid Capacity*

Available capacity on the Eastside system must also be sufficient to fully charge an energy storage device between discharge cycles without overloading equipment.

After accounting for the effectiveness factor of the energy storage and the benefits of other non-wires alternatives in alleviating the overloads, the maximum charging capacity as constrained by Talbot Hill was determined to be as follows:

Figure 9. Available Hourly Grid Capacity for ES Charging by Year (in MW)*



*Accounts for non-wires alternatives

In order to determine whether the available grid capacity is sufficient to fully charge the energy storage over the course of a day to prepare for the system's duty cycle, the charge requirement is compared against the available grid capacity. The charge requirement is determined by dividing the system's energy requirement (for discharging to the grid) by the assumed ac-to-ac roundtrip efficiency of the energy storage system. We assume an average 85% roundtrip efficiency for the studied system, which results in the following.

Figure 10. Net Energy Storage Charge Requirement vs Available Grid Capacity (in MWh)

	2017	2018	2019	2020	2021
Discharge Requirement	**208.8**	**194.1**	**216.8**	**203.4**	**194.2**
Charge Requirement	**245.6**	**228.3**	**255.1**	**239.3**	**228.5**
Capability to Charge (ex NW)*	**1886.0**	**1863.2**	**1825.9**	**1788.1**	**1802.0**
Capability to Charge (inc NW)*	**2009.6**	**2088.4**	**2074.9**	**2158.4**	**2204.2**
✓	OK	OK	OK	OK	OK

* "ex NW" = Not accounting for Non-wires alternatives, and "inc NW" = After Accounting for Non-wires alternatives"

As shown above, the Eastside system does have sufficient capacity to charge the storage system in order to meet the emergency overload discharge requirement.

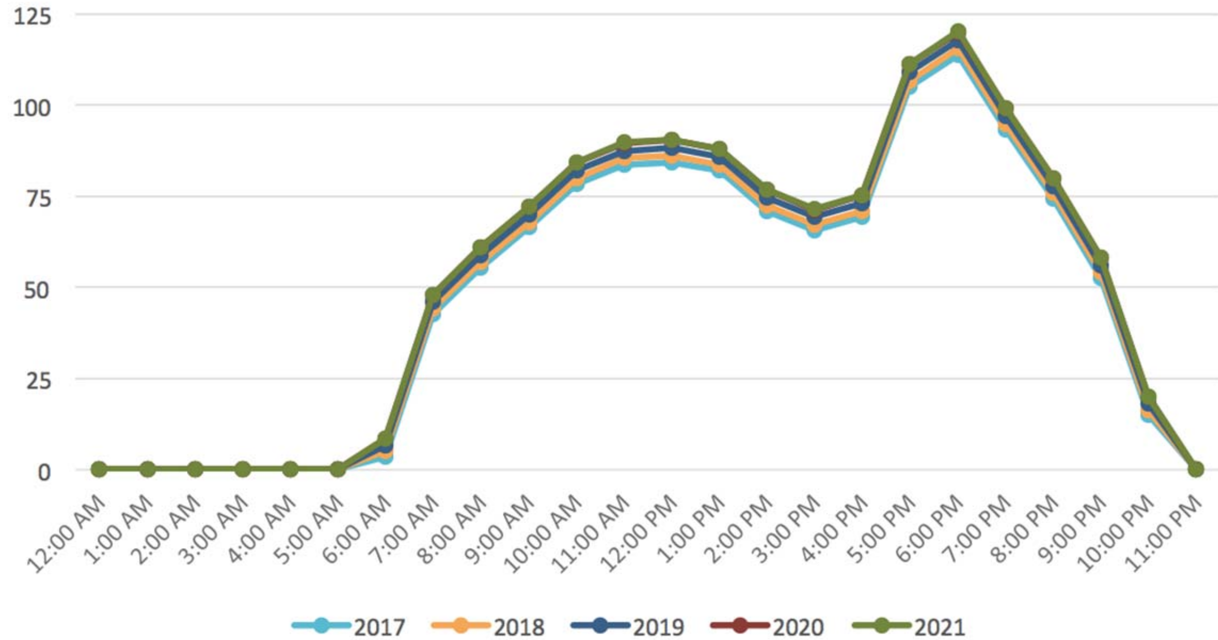
6.3.2 *Talbot Hill Normal Overloads*

6.3.2.1 *Talbot Hill Normal Overload Profile*

Based on the data provided by PSE, Talbot Hill's normal rating could be exceeded in 2017 for 17 consecutive hours. As PSE's operating standards do not allow for normal overloads to be exceeded for more than eight contiguous hours, Talbot Hill's normal overload constitutes a violation of PSE planning criteria and thus must be reduced to less than or equal to eight hours.

Talbot Hill's normal overload peaks in 2017 at approximately 114 MW exceedance. By 2021, this increases to an overload running for 17 consecutive hours with a peak of 120 MW.

Figure 11. Eastside System Maximum Normal Overload by Year (in MW)

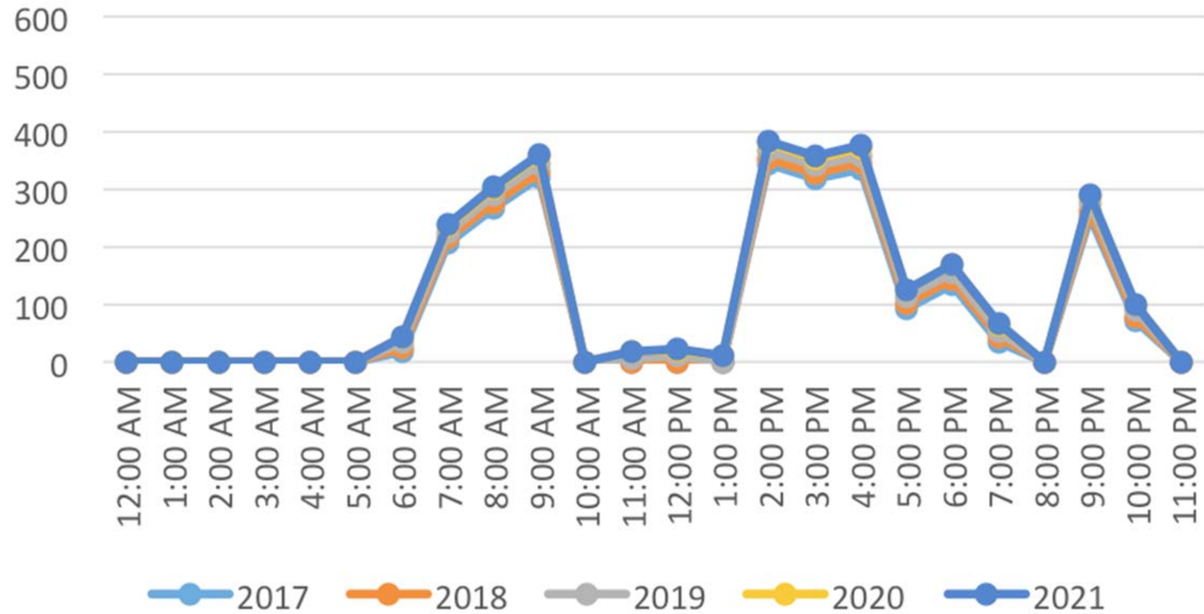


6.3.2.2 *Gross Talbot Hill Normal Load Reduction Need*

PSE data was used to determine the cumulative amount of non-wires + storage alternatives needed to address the Eastside normal overload. In order to meet PSE's planning and operating requirements, the system must both reduce the normal overload to less than or equal to eight contiguous hours, and mitigate the emergency overload during hours when the energy storage device is not also being used to address the normal overload. Due to the two-peak nature of the Eastside winter load profile, the investigators assumed that from 10:00 am – 2:00 pm and from 5:00 pm – 9:00 pm, the non-wires and energy storage solution would only be used to mitigate the emergency need; the normal overload would remain unmitigated.

The effectiveness factor of approximately 20-21% was used to determine the amount of non-wires alternatives (including energy storage) necessary to offset the normal + emergency overload on Talbot Hill. The assumed shape of the non-wires and energy storage requirement appears as such:

Figure 12. Duration and Shape of Gross Non-Wires + Storage Requirement by Year (in MW)



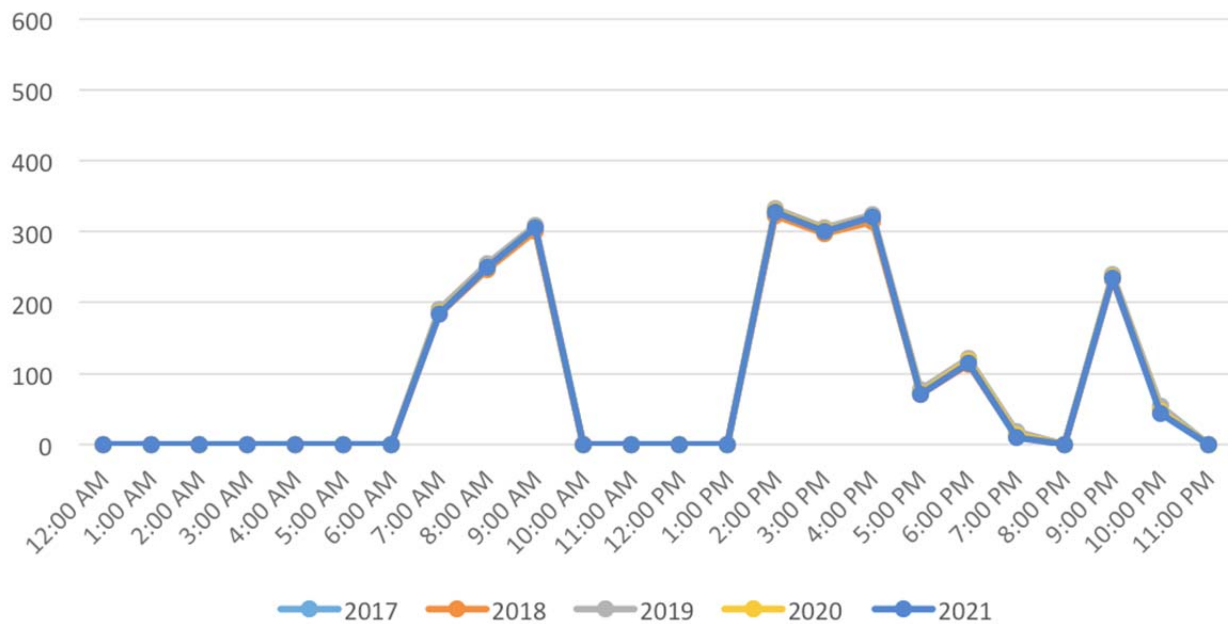
As shown on the above chart, the resulting peak need is approximately 343 MW in 2017, increasing to a peak need of 384 MW in 2021.

6.3.2.3 *Reduction in Gross Need due to Non-Wires Alternatives*

Other non-wires alternatives such as demand response, energy efficiency and distributed generation that were determined to be cost effective in meeting the deferral need[82] were then used to offset a portion of the identified reliability need, resulting in the following energy storage net injection requirements from 2017-2021:

[82] E3 (2014)

Figure 13. Duration and Shape of Energy Storage Net Injection Requirement by Year (in MW)



The above chart shows the peak power requirement of the energy storage system was determined to be as follows:

2017: 326 MW

2019: 332 MW

2021: 328 MW

Thus, to meet the 2021 deferral need in a manner that meets PSE's planning and operating requirements, the system would have to be capable of having a power rating of 332 MW (to meet the 2019 peak need). Energy requirements were identified as such:

2017: 2,184 MWh

2019: 2,224 MWh

2021: 2,160 MWh

6.3.2.4 *Energy Storage Sizing to Meet PSE Planning and Operating Requirements*

The investigators used the Eastside hourly overload data above as the basis to develop power and energy requirements for energy storage systems meeting the deferral need. Chemical energy storage systems also exhibit a tendency to degrade over time as the device is charged and discharged (this is called cycling). The investigators modeled the operation of the configurations studied in a manner that conforms to a standard system degradation rate of approximately 2% per year. As such, the system meeting a 2021 deferral needs to be slightly upsized in order to account for degradation from 2017-2021. This results in a slightly greater energy requirement for the energy storage system than the 2021 injection requirement. Note that the 2019 requirement, while higher, ends up resulting in a slightly smaller system than the 2021 requirement once degradation is accounted for. Therefore, the 2021 energy requirement with degradation is used.

Table 25. Normal Overload Reduction Net Injection Requirements by Year*

	2017 Sizing for deferral through CY	
	2017	2021
Power (MW)	326	328
Energy (MWh)	2,184	2,338
Duration (hours)	6.7	7.1

***Accounts for a 2%/year battery cell degradation**

6.3.2.5 *Charging Requirement versus Available Grid Capacity*

As discussed above, available capacity on the Eastside system must also be sufficient to fully charge an energy storage device between discharge cycles without overloading equipment.

The investigators assume an average 85% roundtrip efficiency for the studied system, which results in the following.

Figure 14: Net Energy Storage Charge Requirement versus Available Grid Capacity (in MWh)

	2017	2018	2019	2020	2021
Discharge Requirement	**2184.3**	**2136.7**	**2224.4**	**2179.8**	**2160.0**
Charge Requirement	**2569.8**	**2513.7**	**2616.9**	**2564.4**	**2541.1**
Capability to Charge (ex NW)	**1886.0**	**1863.2**	**1825.9**	**1788.1**	**1802.0**
Capability to Charge (inc NW)	**2009.6**	**2088.4**	**2074.9**	**2158.4**	**2204.2**
✓	FAIL	FAIL	FAIL	FAIL	FAIL

* "ex NW" = Not accounting for Non-wires alternatives, and "inc NW" = After Accounting for Non-wires alternatives"

As shown above, the Eastside system does not have sufficient capacity to charge the storage system in order to meet the normal overload discharge requirement. **Therefore, we have determined that it is electrically impossible for energy storage, even when paired with other non-wires alternatives, to fully mitigate the normal overload at Talbot Hill in a manner sufficient to meet Puget Sound Energy's required planning and operating standards.**

6.3.3 *Sammamish Emergency and Normal Overloads*

Strategen also evaluated the maximum emergency and normal overloads occurring at Sammamish substation. These overloads generally occurred during the summer, rather than winter, peak. However, in all circumstances, the maximum overloads were substantially less than those occurring at Talbot Hill. Thus, energy storage sized to meet the Talbot Hill overloads and sited in an appropriate location was assumed to be sufficient to meet the Sammamish overload. No further analysis was conducted on the Sammamish overloads as part of this assessment. However, further validation of this assumption would be required prior to making a definitive conclusion that both Talbot Hill and Sammamish overloads could be addressed with the studied configurations.

6.4 Ownership Model and Location

In theory, serving PSE's transmission deferral objective could be achieved independent of energy storage facility ownership model. Additionally, it could occur independent of a predetermined configuration, provided that configuration and location meets certain parameters.

For example, the need could be met by placing utility-owned energy storage devices at substations, or the utility could use a power purchase or tolling agreement with a third party for bulk system storage. The utility could develop a program wherein customer-sited energy storage systems could be used as demand response resources called upon to meet reliability needs during winter or summer peak conditions.

The analysis focused on substation-sited energy storage to address the Eastside needs. An analysis of the practical considerations of both customer-sited and substation-sited configurations are below.

6.4.1 *Customer-Sited Energy Storage*

Customer-sited energy storage is generally physically located at the customer site, but it does not necessarily require being on the customer-side of the meter. It can also include siting of energy storage at campus-level microgrids or small-scale residential-level microgrids. As such, these use cases may provide services to the customer, the utility, or both.

A conceptual advantage of a fleet of customer-sited storage is that, from a technical perspective, it provides flexibility to provide the maximum number of grid services, which are very location-specific. Additionally, energy delivered at the end-customer has the ability to avoid the line and transformer losses that occur with energy generated, transmitted, and distributed by a remote power plant. Moreover, the effectiveness factor may be higher for customer-sited storage closely aligned with load on individual circuits than for transmission level energy storage located at a substation. Power delivered from customer-sited energy storage during a system peak can simultaneously off-load T&D assets and generators, with the potential to provide multiple value streams to the owner with a simple operational objective. Additionally, due to the proximity to the customer, energy storage located at the customer site is best positioned to provide enhanced reliability and backup power during power outages. Another benefit of customer-sited systems is that a large number of distributed systems can provide redundancy and potentially leverage economies of scale in manufacturing compared to larger, more customized units.

There are, however, some potential drawbacks to customer-sited storage for this application. First is the cost associated with the small scale of the individual storage resources, should they be fully committed to transmission deferral. The fixed costs associated with installation and management of customer energy storage systems are typically higher over multiple small to mid-size energy storage resources, especially as compared to megawatt-scale systems. However, given the Eastside system deferral need is of limited frequency and duration, we do not believe this to necessarily be a constraint, as a customer-sited program in this case could potentially be cost-effectively be deployed with secondary uses benefitting retail customers.

Perhaps the more substantive issue is that transmission deferral requires a threshold minimum deployment of energy storage to achieve the needed effect depending on the load characteristics and expected growth rate. In this case, in order to address the 2017 normal need sufficiently to meet PSE planning standards, a customer-sited program would require deploying more than 4,300 commercial/industrial sized energy storage systems rated at an average of 500 kWh each between 2015 and 2017. All of these systems would need to be located appropriately in the Eastside region to provide support to the substation in need of upgrade, and the storage systems' operation would need to be managed and aggregated through secure communication and control. While not technically impossible, the development of a customer-sited storage program at this scale to meet near-term grid reliability needs is likely to be challenging given the myriad site-specific challenges that could derail or delay any individual site being developed within the fixed timeframe needed to address the reliability need. Location-specific issues such as environmental impact, community involvement in siting, electrical interconnection challenges, logistics, third party contracting or other legal challenges, would all need to be successfully resolved for enough individual customer sites in order for the reliability need to successfully be met. Locating energy storage next to a customer also requires heightened sensitivity toward safety, as compared to remotely located energy storage systems in a secure, utility-controlled area.

PSE is also obligated to meet certain reliability standards under state and federal regulations. If PSE were to proceed with a customer-sited program today and the program failed to develop enough resources to address the need, PSE would be past the 'point of no return' to move forward with a wires-based solution in time to prevent the reliability issues. Given the binary nature of this challenge, (e.g. anything less than complete success would not address the reliability need), we did not further evaluate the cost-effectiveness of customer-sited energy storage to address the Eastside reliability issues in this assessment.

While Strategen and PSE concluded that the specifically large scope of the Eastside need was not conducive for further evaluation as part of this assessment, we note that there are many circumstances where customer-sited energy storage can be a cost effective way to manage system or local peak power requirements. Strategen recommends that PSE more thoroughly evaluate the cost-effectiveness of customer-sited energy storage programs to meet long term planning objectives as part of PSE's integrated resource planning process.

6.4.2 *Substation-Sited Energy Storage*

Substation-sited energy storage is a relatively straightforward concept. Energy storage equipment would generally be sited at or near a utility substation, and would be directly connected to the substation. The device would be directly controlled by the utility as a utility asset. Such a device could be utility-owned, but it could also be owned by a third party and contracted for use by a utility under a "Power Purchase Agreement" or "Tolling Agreement" model, similar to how independently-owned power plants frequently contract with utilities.

Key advantages of substation-sited energy storage in the context of meeting the Eastside system reliability needs are as follows:

- Development of the systems would have a higher degree of certainty due to utility control over the process – comparable to that of a utility-developed transmission line,

- Significant economies of scale exist in large scale system resource development. This will result in enough purchasing power to lower battery cell cost, as well as significantly lower balance of system cost, which is defined as all of the electric infrastructure needed to interconnect the battery to the grid, convert the power from DC to AC, control the equipment, and to communicate with the grid operator, and

- PSE will have greater control over when battery cell procurement occurs, which is the component of energy storage systems that is most likely to see large cost declines during the specified timeframe. For example, the balance of system could be built to meet the full deferral need, but batteries added in a modular fashion over the 2017-2021 timeframe as costs come down and the reliability need increases.

Disadvantages include:

- Due to the changing transmission system flow patterns between winter and summer, the effectiveness of specific substation-sited storage configurations may vary between winter and summer. For example, a specified configuration may be relatively effective at meeting the winter need, but less so at meeting the summer need, because the power that the storage system injects into the transmission system is flowing on the transmission system differently.

Due to the greater certainty that substation-sited energy storage can be developed and operational in time to meet a time-sensitive reliability need, we recommended that this report focus on substation-sited configurations.

6.5 Physical Footprint of Substation-Sited Storage

After deciding to proceed with a substation sited storage solution, evaluation was made of system acreage requirements and which substation would be most appropriate for siting.

PSE supplied acreage estimates for land related to interconnection facilities and parking, while vendor interviews and satellite imagery analysis provided sizing estimates for the battery, balance of system (including power electronics and related equipment) and the building. Table 26 summarizes acreage requirements for the three modeled scenarios.

Table 26. ESS Acreage Requirement Estimates for 2021 Deferral (in acres)

Component	Baseline Normal Overload Reduction	Alternate #1 Emergency Overload Elimination	Alternate #2 Normal Overload Elimination
Battery, BOS, Building	9.6	1.3	22.7
Interconnection Facilities and Parking	10	4.5	23
TOTAL	19.6	5.8	45.7

Batteries were modeled at a combination of three centralized transmission substation locations. Battery models are not available in WECC for transmission-level interconnection, therefore batteries were modeled as a negative load at the substation bus. Negative loads were modeled as either evenly distributed between Sammamish, Lakeside and Talbot Hill, or half at Lakeside with the remainder split between the other two substations, or all at Lakeside. See Table 27 for battery distribution.

Table 27. Centralized Battery Locations Modeled

Scenario	PowerWorld Case	Amount of Storage (MW)	Locations	Split
1a	2017-18 HW SN NG	70	Sammamish, Lakeside, Talbot Hill	1/3, 1/3, 1/3
1b	2017-18 HW SN NG	70	Sammamish, Lakeside, Talbot Hill	.25, .50, .25
1c	2017-18 HW SN NG	70	Lakeside	100%
2a	2018 HS SN FG	70	Sammamish, Lakeside, Talbot Hill	1/3, 1/3, 1/3
3a	2017-18 HW SN NG	160	Sammamish, Lakeside, Talbot Hill	1/3, 1/3, 1/3
3b	2017-18 HW SN NG	160	Sammamish, Lakeside, Talbot Hill	.25, .50, .25
3c	2017-18 HW SN NG	160	Lakeside	100%
4a	2017-18 HW 75% Cons SN NG	160	Sammamish, Lakeside, Talbot Hill	1/3, 1/3, 1/3
4b	2017-18 HW 75% Cons SN NG	160	Sammamish, Lakeside, Talbot Hill	.25, .50, .25
4c	2017-18 HW 75% Cons SN NG	160	Lakeside	100%

There is little indication that any of the three options is more effective at reducing overloads; the results were roughly the same for all three scenarios studied. Therefore, for simplicity, the land use, cost, and interconnection assessments assume the system would be sited entirely at Lakeside 115kV substation.

6.6 Permitting Timeline

When evaluating locations to site a utility scale energy storage facility, it was assumed that the site would be within the City of Bellevue. Since utility scale battery storage facilities are an emerging technology, they are not addressed in the City's land use regulations. PSE therefore assumed that the facility would be categorized as something similar to a transmission switching or substation. These types of facilities are defined as Electrical Utility Facilities (§20.50.018) in Bellevue. Alternatively, PSE indicated that such a facility could be classified as a Regional Utility System (§20.50.044). If a battery facility is determined to be a Regional Utility System it would be allowed in all zoning districts, but would require a Conditional Use Permit (CUP).

Although permitted in all zoning districts, Electrical Utility Facilities are subject to additional review under Bellevue Land Use Code (§20.50.255). Approval of a battery facility as an Electrical Utility Facility could be approved through an Administrative Conditional Use Permit

(ACUP) or a CUP. Map UT-5a provided in the City's Comprehensive Plan is used to determine which permit is required. If a site is shown on the map as "sensitive," then an alternative siting analysis and CUP would be required. If the site is shown as "non-sensitive," then an ACUP would be required and alternative siting analysis would not be required. The existing Northup (0.96 ac), North Bellevue (1.11 ac), Midlakes (1.04 ac), Center (1.18 ac), Lakeside (7.82), Phantom Lake (0.92 ac), South Bellevue (1.08 ac), College (0.97 ac), Factoria (2.90 ac), and Somerset (3.15 ac) substations are designated as sites that could be expanded and are not considered sensitive. Sensitive substations sites include Clyde Hill (0.42 ac, existing), Vernell (2.87 ac), Westminster (6.15 ac), Bel-Red, Lochleven (0.75 ac, existing), Larsen, Newport, Ivy, and Lakemont.

Alternative Configuration #1 would require approximately 4.5 acres, so only the Lakeside and Westminster site are large enough to accommodate the facility. Alternative sites could be used; however, all would require alternative siting analysis and a CUP. None of the existing or future substation sites are large enough to accommodate the Baseline Configuration or Alternative Configuration #2, so additional property would need to be acquired. PSE does not own currently own property for the Bel-Red, Larson, Newport, Ivy, and Lakemont substations; therefore, an assessment to their size appropriateness cannot be made.

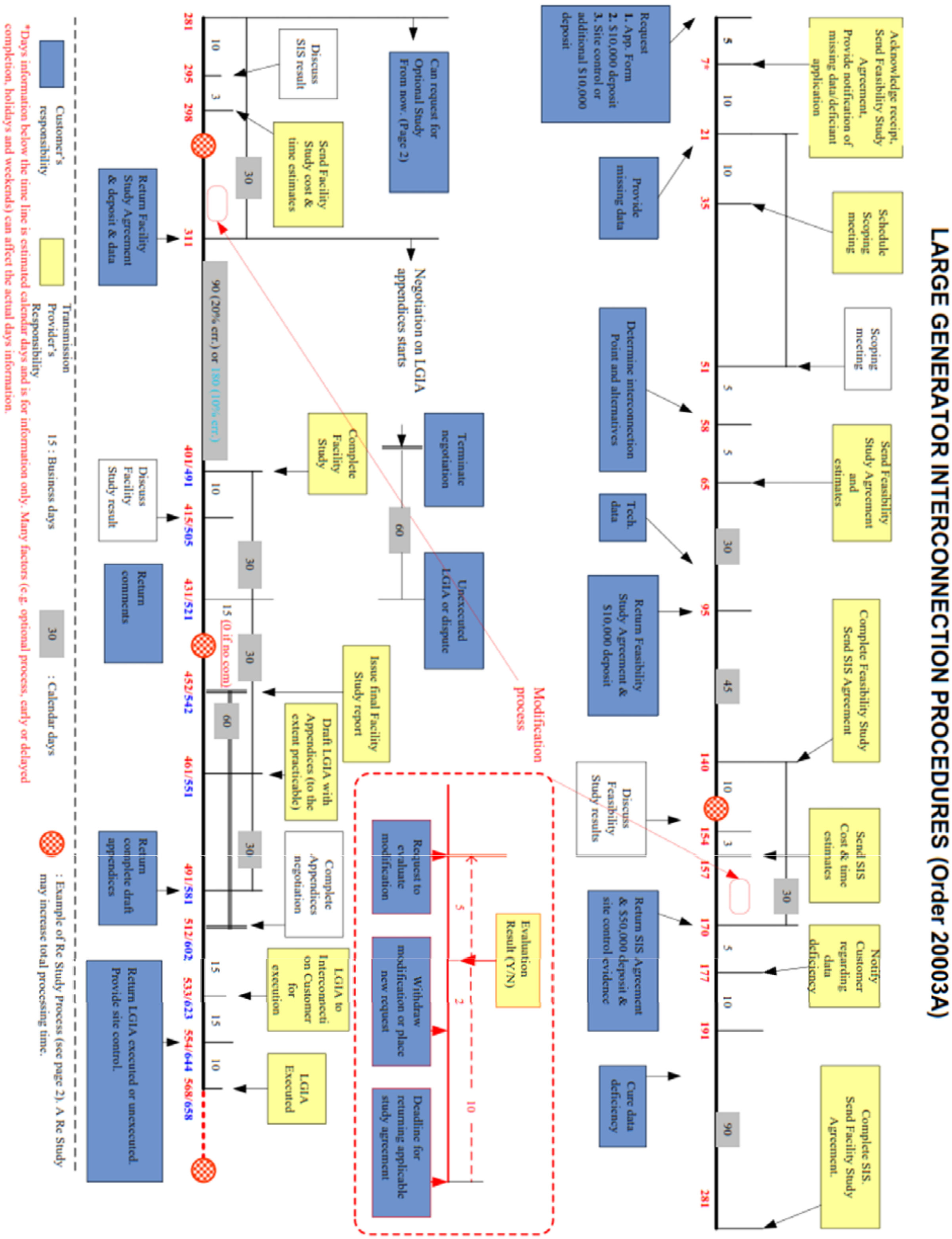
In addition to a CUP, compliance with the State Environmental Policy Act (SEPA) would be required. It is assumed that Alternative Configuration #1 would be issued a SEPA Mitigated Determination of Non-Significance (MDNS) and that the Baseline Configuration or Alternative Configuration #2 would likely receive a Determination of Significance (DS) and therefore required an Environmental Impact Statement (EIS), adding a year or more to the permitting process. Grading and building permits will also be required and if Critical Areas, such as wetlands are impacted, then additional approvals would be necessary.

According to the City of Bellevue, as of March 2015, ACUPs averaged around 25 weeks, with Major Clear and Grade permits averaging around 65 weeks. If Design Review is triggered, those approvals averaged 90 weeks. Permits for Major Commercial Projects average around 59 weeks. No data were provided for CUPs. It would be expected that Alternative Configuration #1 would take at least two years to permit with three to four years required for the Baseline Configuration or Alternative Configuration #2.

6.7 Interconnection Timeline

The interconnection process for large scale grid resource can be complicated and very time consuming. Puget Sound Energy's large generator interconnection process would be required for energy storage system interconnections with a nameplate power rating greater than 20 MW. This process is regulated by the Federal Energy Regulatory Commission and subject to open access provisions that require process standardization and transparency. PSE's process, detailed below, is fairly standard versus other utility processes.

Figure 15. Puget Sound Energy's Large Generator Interconnection Procedures



As Figure 15 above shows, the interconnection study process generally takes 1-2 years (the process has a statutory maximum of 658 days), at which point an interconnection agreement is signed and work can begin on any necessary upgrades. Interconnection facilities such as substation upgrades generally take a minimum of 6 months and (depending on equipment lead times, permitting requirements, and system clearance requirements) can take upwards of several years from the time an interconnection agreement is signed before a project can interconnect to the grid.

6.8 Land Acquisition, Procurement and Construction Timeline

PSE indicated that it expects the land acquisition, procurement and construction timeline of a utility scale energy storage system to likely be comparable with that of a simple-cycle combustion turbine project. PSE discusses this timeline in its 2013 IRP:

> *"Greenfield development requires approximately four years: two years for development and permitting, one-and-a-half years for major equipment lead-time, and a half-year for construction. PSE does not take the risk of contracting for major equipment before permits are in hand. Private developers, on the other hand, are often willing to take that risk and can accelerate the development timeframe by about one year."*[83]

Assuming the permitting and interconnection processes are started in mid-2015 and completed in parallel, we estimate that land acquisition, equipment procurement and construction could begin in mid-2017. Based on PSE's assumptions, land acquisition, procurement and construction would take approximately two years, leading to a mid-2019 online date. A third-party developed asset willing to take land acquisition and procurement risk might be able to accelerate the online date to mid-2018. However, neither alternative would meet PSE's requirement that the asset come online in time for the winter 2017-2018 reliability need.

[83] Puget Sound Energy (PSE) (30 May 2013). P. D-35

7 Cost-Effectiveness Evaluation

This chapter summarizes the scope, approach and assumptions used for the cost-effectiveness evaluation as well as the results.

7.1 Configuration Evaluated for Cost-Effectiveness

One baseline configuration and two alternate configurations were developed as described in Chapter 6.3 of this report. As discussed, in order to fully meet both PSE's planning and operating standards, energy storage would need to reduce overloading so that it does not exceed the equipment's emergency rating, and so that it does not exceed the equipment's normal rating for more than eight consecutive hours.

Given that Strategen has determined that the baseline configuration is not technically feasible (See Chapter 0), Strategen did not study cost effectiveness of the baseline configuration. Rather, Strategen focused the cost-effectiveness evaluation on the more modest Alternate Configuration #1: *Emergency Overload Elimination*, even though this configuration fails to comply with PSE's planning and operating standards.

Table 28. Energy Storage Configuration Summary

Configuration	Power (MWp)	Energy (MWh)	Duration (hours)	Est. Cost ($MM)	Includes Non-Wires Alternatives[84]	Technically Feasible	Meets Requirements
Baseline Normal Overload Reduction	328	2,338	7.1	**$1,030**	✓	✗	✓
Alternate #1 Emergency Overload Elimination*	121	226	1.9	**$184**	✓	✓	✗
Alternate #2 Normal Overload Elimination	545	5,771	10.6	**$2,367**	✓	✗	✓

[84] E3 (2014)

***Alternate Configuration #1 was evaluated for cost-effectiveness.**

7.2 Cost Assumptions

The cost of utility-scale energy storage systems is not well-established, and estimating cost is challenging because utility-owned storage other than pumped hydro is a fairly new concept. Large systems are custom built, designed and tailored for very specific, customer-identified applications and sites, so costs vary significantly.

To determine appropriate estimates for modelling system costs, Strategen reviewed publicly available cost data on utility energy storage projects, as well as research reports identifying cost trends over time, and cost estimates for projects recently contracted in California and Hawaii. Extrapolations from multiple sources were assembled to provide a realistic picture of the breakdown between battery cell costs and balance-of-system costs, while adding project-specific cost estimates for interconnection facilities, land, permitting, and operations and maintenance. Strategen also interviewed selected technology vendors to validate the accuracy of cost estimates.

After thorough review of available cost information, a generic fast-responding multi-hour lithium ion battery solution was ultimately chosen for the cost-effectiveness modeling[85]. The rationale for choosing lithium ion is that such cost estimates are the most readily available in research reports, and data is available on a spectrum of system configurations and sizes, including the relatively comparable system sizing and timing of systems announced in SCE's LCR procurement.[86]

7.2.1 *Cost Benchmarks of Utility Pilot Projects*

There are few examples of completed and planned grid scale systems for which all-in system costs can be accurately estimated.

SCE commissioned the Tehachapi Wind Energy Storage Project, an 8 MW/32 MWh lithium ion system in June 2014 with the help of a US Department of Energy grant. When the project was approved for the American Recovery and Reinvestment Act Smart Grid Demonstration Program Funding in 2010, total project cost was estimated at $50,000,000, and while actual incurred costs are unknown, it still provides a useful cost data point of $6,250/kW and $1,562/kWh. This includes batteries, BOS, interconnection, and every other component, and was probably a very conservative cost estimate that reflected 2010 component costs.

In December 2014 PSE and RES Americas announced an agreement to develop a 2 MW/4.4 MWh lithium ion project in Whatcom County to provide grid support, peak shaving, and emergency back-up power. The $9,800,000 cost equates to $4,900/kW and $2,227/kWh. Note

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[85] While lithium ion solutions have the most readily available cost estimates, flow battery technologies designed for long duration applications might present a cost-competitive alternative should PSE determine that further evaluation is warranted.

[86] In particular, Southern California Edison's procurement of a 100 MW/400 MWh lithium ion energy storage system from AES: http://www.aesenergystorage.com/2014/11/05/aes-help-sce-meet-local-power-reliability-20-year-power-purchase-agreement-energy-storage-california-new-facility-will-provide-100-mw-interconnected-storage-equivalent-200-mw/

that economies of scale are important for battery ($/kWh) costs, hence the greater cost per kilowatt-hour for PSE's system versus the SCE Tehachapi system.

In both of the above pilot projects, significant one-time integration costs occurred that likely made these projects more costly than future energy storage deployments. As a result, Strategen does not believe these are suitable as direct comparisons to what a larger scale energy storage system deployment might cost in the near future. However, they are instructive, as they show a ceiling of what currently deployed energy storage systems have cost to develop.

7.2.2 *Battery Cell Costs*

The majority of publicly-available, energy storage price research focuses on battery cell costs, especially lithium ion, due to high growth and transparency in the electric vehicle market. Brattle Group, Bloomberg New Energy Finance, Morgan Stanley, CITI Research, and Navigant Research all project lithium ion prices will decrease significantly over the next few years.[87] Price estimates for 2014 ranged from $350 to $700/kWh.

Combining and averaging these sources into one analysis, IBM Research - Australia estimated the current price (as of 2014) to be approximately $600/kWh,[88] which is further supported by a December 2014 UBS report.[89,90]

IBM Research examined future cost projections in the 2015-2020 timeframe, which vary from $200/kWh to $354/kWh. Many of the studies averaged were from 2011 and 2012, and do not reflect the steeper cost reductions actually experienced in the last few years. Since the UBS report is the most recent study, incorporates the newest 100 MW SCE/AES data point, and is well within the range of other projections, this analysis uses the UBS future projection of $250/kWh as the battery cell cost. On the one hand, this might be viewed as an aggressive estimate, because the UBS report sets this as a baseline cost in 2020 and the Eastside system would need to be operational in winter 2017-2018. However, given that Tesla estimates its current (2014) battery cell costs in the $200-300/kWh range,[91] increasingly aggressive analyst cost projections, the economies of scale that can be obtained with the size of the Eastside system, as well as a potential to incrementally add storage capacity from 2017-2021 to meet increasing system needs over that time period, Strategen believes the $250/kWh cost estimate for cells to be achievable.

7.2.3 *Balance-of-System Costs*

Batteries for grid support have a myriad of other components and costs than just batteries. Known as balance-of-system ("BOS"), these components include power electronics, control module, battery enclosure, thermal management equipment, installation labor, interconnection, permitting, land, and contingencies. The Rocky Mountain Institute estimates

[87] Brattle/Oncor (2014); PG&E/BNEF (2013); Morgan Stanley (2014); CITI Research (2012); Sam Jaffe, Navigant Research (2014)
[88] A. Vishwanath and S. Kalyanaraman (2014)
[89] UBS Global Research (2014)
[90] Sam Jaffe, Navigant Research, highlights that cost vary significantly between different types of lithium ion batteries - $600/kWh is a generic price for the lithium ion family.
[91] UBS (2014)

that 63% of the total installed cost for a 200 kW/200 kWh commercial energy storage system is BOS, with residential system BOS costs accounting for 74% of installed cost.[92]

Some vendors include enclosures in the battery purchase price, while others do not.[93] For this analysis, we assume the enclosure price is included in the battery cost.

7.2.3.1 *Power Electronics and Building Facilities*

The largest BOS costs are associated with power electronics, which includes the inverter/power conditioning system ("PCS") and control module/battery management system. UBS estimates BOS costs to be in the $400-$500/kWh range.[94] Confidential discussions with vendors suggest that BOS is better evaluated on a cost per kW basis, as power electronics tend to be based on power ratings rather than energy, and other balance of system costs tend to be relatively fixed. However, Strategen's findings correspond well to the UBS estimates for BOS costs, but on a dollars per kW basis (rather than per kWh).

Strategen views the 100 MW/400 MWh AES system recently procured by SCE as a reasonably good cost comp to the Eastside energy storage configurations. UBS estimates this project to cost roughly $1,500 per kW ($375/kWh), of which the majority of the total system cost estimates being attributable to batteries and BOS.[95] An assumed $250/kWh battery cost multiplied by a 4 hour duration gives $1,000/kW for batteries. Because the AES project is to be co-located near existing infrastructure designed to accommodate generation, we assume that land, permitting, and interconnection costs constitute a relatively small portion of remaining costs. Therefore, we assume the bulk of the remaining $500/kW as Power Electronics and Building Facilities cost, which is in line with BOS cost methodology and estimates previously identified. While using the overall project costs as a direct comp might be viewed as aggressive because the AES plant won't come online until 2021, this is counterbalanced by the fact that this analysis separately accounts for interconnection, land and permitting costs, and there is likely some (relatively small) interconnection and permitting costs blended in UBS' overall system cost estimates. Due to this counterbalancing impact, Strategen is therefore comfortable using $500/kW as the Power Electronics and Building Facilities cost in this analysis.

7.2.3.2 *Interconnection, Permitting, and Land Costs*

The costs of many system components, such as interconnection, 115 kV step-up transformers, transformer installation, land to house the equipment, and permitting, are utility and site specific.

Table 29 shows PSE-supplied cost estimates for interconnection and permitting for the three configurations.

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[92] RMI (2014)
[93] DOE-EPRI Energy Storage Handbook (2013)
[94] UBS Global Research (2014)
[95] *Ibid.*

Table 29. Interconnection and Permitting Cost Estimates

	Baseline Normal Overload Reduction	Alternate #1 Emergency Overload Elimination	Alternate #2 Normal Overload Elimination
Interconnection Facilities	$73,020,000	$28,140,000	$167,946,000
Permitting	$1,000,000	$250,000	$1,000,000

PSE supplied cost estimates for land related to interconnection facilities and parking, while vendor interviews and satellite imagery analysis provided sizing estimates for the battery and BOS which is further discussed in Chapter 6.5. Table 30 summarizes the land cost estimates for the three configurations.

Table 30. Land Cost Estimates

	Baseline Normal Overload Reduction	Alternate #1 Emergency Overload Elimination	Alternate #2 Normal Overload Elimination
Land Cost	$55,000,000	$15,000,000	$144,000,000

7.2.4 *Annual Operations and Maintenance Costs*

Systems operations and maintenance (O&M) activities and costs are divided into two categories: fixed and variable. These are usually site specific, dependent on local labor and tax rates, and vary by energy storage system specifications and specific contractual terms.

Fixed O&M refers to activities and costs that are incurred annually, unrelated to system energy requirement, and include staff to operate and maintain the building and site, property tax, insurance, routine inspections, remote monitoring/telecommunications, spare parts, and other foreseeable expenses for both the batteries and PCS.

Variable O&M refers to activities and costs that are proportional to the system's energy throughput (both charging and discharging). These costs frequently include system troubleshooting (diagnosing problems, testing components and corrective maintenance) and periodic replacement of degraded cells. However, contractual arrangements frequently wrap these costs into fixed warranty costs (thus they are already covered in Fixed O&M).[96,97]

Discussions with vendors revealed that O&M contracts are negotiable and highly sensitive. A literature review showed that cost estimates for both fixed and variable O&M vary by technology type. Fixed O&M costs ranged from approximately $2.50 to $25.20 per kilowatt-year ($/kw-year), and variable O&M costs ranged from $5 to $59 per MWh.[98,99,100] Based on discussions with utility scale developers, and given the assumption that normal system performance degradation would not be supplemented with new cell capacity, Strategen believes that fixed warranty costs will negate the need to have a separate line item for variable O&M.

Strategen assumes fixed O&M of $5.00/kW-year and no additional variable O&M costs for this analysis. Our rationale is that an ESS of this size will benefit from economies of scale for fixed costs, keeping them on the low end of the range, and that variable O&M will be wrapped under a warranty with the equipment vendor or developer. This is particularly likely given that ESS cells are not assumed to be replaced during the system life.

An annual escalator of 2.5% is applied to fixed O&M costs for the cost-effectiveness analysis.

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96 PacificCorp (2011)
97 PNNL (2010)
98 *Ibid.*
99 E. Cutter et al. (2014)
100 Black & Veatch (2012)

7.2.5 *Contingency*

Contingency is a standard assumption in large scale development assets to cover unanticipated costs during construction. Unanticipated costs could include anything from geotechnical issues, cultural resources mitigation, environmental mitigation, or any number of other issues. Strategen assumed a contingency value of 20% of the cells and power electronics + building facilities cost.

7.3 Storage System Configuration Cost Estimates

Based on the specified cost projections, Table 31 shows the total estimated capital costs for the three energy storage configurations evaluated.

Table 31. Summary of the Three Energy Storage System Configurations' Costs

Component	Per Unit Cost Projection	Baseline Normal Overload Reduction through 2021 (≤8 hours)		Alternate #1 Emergency Overload Elimination through 2021		Alternate #2 Normal Overload Elimination through 2021	
		Power (MW)	Energy (MWh)	Power (MW)	Energy (MWh)	Power (MW)	Energy (MWh)
		332	2,338	121	226	545	5,771
Cells	$250/kWh	$584,500,000		$56,500,000		$1,442,750,000	
Power Elect. & Building	$500/kW	$166,000,000		$60,500,000		$272,500,000	
Interconn. Facilities	Na	$73,020,000		$28,140,000		$167,946,000	
Land	Na	$55,000,000		$15,000,000		$140,000,000	
Permitting	Na	$1,000,000		$250,000		$1,000,000	
Contingency[101]	20% of Cells + BOS	$150,100,000		$23,400,000		$343,050,000	
TOTAL		**$1,029,620,000**		**$183,790,000**		**$2,367,246,000**	
NPV of Revenue Req'ments[102]		**$1,441,200,000**		**$264,732,000**		**$3,301,708,000**	

7.4 Benefits

This subchapter includes a characterization of the quantifiable benefits that were included in the cost-effectiveness evaluation for the *Emergency Overload Elimination* configuration (as described in Section Configuration Evaluated for Cost-Effectiveness7.1). It also includes an overview of other notable storage benefits that were not quantified or included in the cost effectiveness evaluation.

7.4.1 *Transmission & Distribution Deferral*

This analysis assumes that all cost-effective non-wires alternatives identified in the Non-wires Report are deployed. Furthermore, given the approach used in the Non-wires Report, the benefit for the amount of incremental cost-effective non-wires alternatives is assumed to

[101] Contingency is a standard assumption in large scale development assets to cover unanticipated costs during construction

[102] Fixed O&M costs ($5/kW-yr), taxes, depreciation, insurance, and required rate of return are added to the above over the 20 year life of the asset, discounted at 7.77% to determine the NPV of the configurations' revenue requirements (See Chapter 7.5.2 for further description of the financial assumptions).

absorb the entire deferral benefit.[103] Therefore, no additional financial value associated with the deferral was assigned to the energy storage system for the storage cost-effectiveness evaluation.

7.4.2 *Non-deferral Benefits Quantified*

Four non-deferral benefit types/categories are addressed quantitatively for the cost-effectiveness evaluation: 1) system capacity, 2) system flexibility, 3) oversupply reduction, and 4) greenhouse gas reduction.[104]

7.4.2.1 *System Capacity Benefit*

Introduction

The system capacity benefit provided by an energy storage system refers to the ability of the ESS to discharge during system-wide peak demand periods such that it behaves like a small-scale generator or demand response resource, thus reducing the amount of peaking generation and/or transmission capacity needed. Of particular significance is the reduced need for simple-cycle combustion turbines ("SCCTs"). System capacity is comprised of this "energy supply capacity," as well as capacity that exceeds the need for new energy supply, which is called "surplus transmission capacity" herein.

The system capacity benefit is *not* location-specific: it accrues irrespective of where the system is located.

Unlike a) generation capacity supplied by a fuel system/network, b) transmission equipment and c) demand response (that , *technically* speaking, can be called on at any time to reduce capacity requirements); *storage* is sometimes referred to as a "limited energy resource" because once all *energy* has been discharged the storage system cannot provide *power*. As such, it may not be as useful for peaking service and/or contingency events, when extended generation output is needed.

Given that major difference between storage and conventional peaking resources, the PSE Resource Planning team performed an Incremental Capacity Equivalent ("ICE") analysis to better understand the potential capacity contribution from these resources. Analysis on a storage system with two hours of sustained discharge suggested that the ICE to be 100 percent.

> **Correlation with Eastside Peaks**
>
> Given that the primary function of the storage configuration is to reduce peak load to address the Eastside transmission constraint, the capacity value must be de-rated to the extent that the system peaks are not correlated to the Eastside peaks.
>
> For this study it is assumed that there is a strong correlation between local (Eastside) and system peak demand.

[103] The non-wires alternatives' cost-effectiveness was predicated upon the value of transmission and distribution deferral benefits when the evaluation was undertaken.

[104] Greenhouse gas ("GHG") reduction benefits do not currently reflect a direct monetary benefit to PSE's customers. However, a range is provided in order to assign value to potential future scenarios where carbon reduction has direct monetary value in Washington State.

Default Peaking Capacity Resource: Simple Cycle Combustion Turbine

PSE's 2013 IRP concluded that simple-cycle combustion turbines were the least-cost resource to meet peak hour capacity needs. More specifically, the F-Class ("frame" or industrial) simple-cycle combustion turbine with a peak winter capacity of 221 MW is considered the default resource. The revenue requirement (and the net present value thereof) and levelized cost of this resource was calculated based on the following assumptions derived from PSE's 2013 IRP (see also Table 32):

- The capital cost of the SCCT is estimated to be $202.2 million or $915/kW in 2012$. This value was inflated to $228.8 million for the 2017-2018 estimated completion.[105]

- Fixed O&M costs on the SCCT are estimated to be $20/kW-yr and the book life of the asset is 35 years.

- PSE assumed that the ESS will enable it to avoid 6.55% in T&D I^2R energy losses[106,107] when compared to centralized generation. This is the assumption for avoided line losses from conservation measures at commercial and industrial customers. The effect is to increase the energy supply capacity value by that same 6.55%.

- The net present value (NPV) revenue requirement for the SCCT totaled $1,742/kW in 2017$ with a levelized cost of $146/kW-yr (also in 2017).

- The total NPV of avoided cost in 2017 is $1,829/kW and the annual (levelized) value is $153/kW-year as of 2017 (i.e., for the period 2017 to 2051).

- This year-specific annual/levelized value is escalated by 2.5% per annum to account for inflation.

---

[105] PSE (2013); p. 80, Figure 4-9.

[106] As energy is transmitted from a centralized generation facility to a customer, a portion of this energy is lost to resistance in the lines. When an energy supply capacity resource injects power close to load (or reduces load in the case of efficiency measures), as would be the case with this project, PSE would avoid slightly more than one unit of peak supply capacity by avoiding the line losses experienced while delivering peak capacity. To account for line losses an avoided loss factor of a loss factor of 6.55% was applied which is consistent with the loss factor used in PSE's energy efficiency cost effectiveness calculations for commercial and industrial programs. PSE recognizes that these losses may slightly overstate the benefits attributable to the storage resource, however PSE believes these effects are minor.

[107] The abbreviation I^2R indicates that the energy losses are a function of the square of the amount of electric current flowing (the symbol for current is I) through electrical equipment times the electrical resistance (whose symbol is R) of the equipment, hence the term pronounced I squared R.

Table 32. Energy Supply Capacity Revenue Requirement and Avoided Cost

REVENUE REQUIREMENT FOR SCCT					
Peaker Type	**Units**	**Frame SCCT**			
Capacity	MW (winter)	221			
Capex (overnight cost)	$/kW, 2012	$ 915			
Capex	$, 2012	$ 202,215,000			
Fixed O&M	$/kW-yr, 2012	$ 20			
Year Peaker Needed		2017			
NPV Revenue Req ($2017)	$/kW, 2017	$ 1,742			
Avoided Line Losses		6.55%			
Grossed-Up Avoided Cost	$/kW, 2017	$ 1,856			
Incremental Capacity Equivalent		100%			
NPV of Revenue Requirement ($/kW)	$/kW, 2017	$ 1,856			
Useful Life of SCCT	years	35			
Levelized Avoided Revenue Requirement	**$/kW-yr, 2017**	**$155.52**			
Annual Escalation Factor	2.50%				
Year	2017	20.18	2019	2020	2021
Levelized Avoided Revenue Requirement	$ 155.52	$ 159.41	$ 163.39	$ 167.48	$ 171.67

PSE advised Strategen to assume that energy supply system and local (transmission) peaks are highly correlated such that storage provides full energy supply capacity value if it is dispatched to address the local peak. Furthermore, PSE's methodology to evaluate the capacity value of resources is based on the two hour continual discharge rating of the resource. In this case, the energy storage system rated at 226 MWh would have a 2-hour continual discharge rating of 113 MW for the purpose of calculating its capacity value.

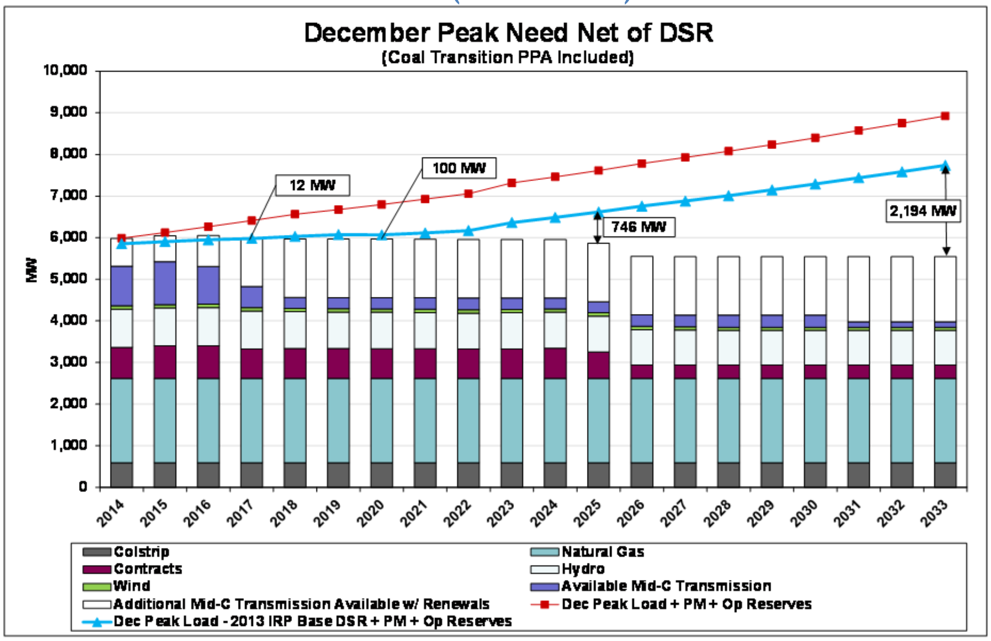
Energy Supply Capacity Needs

The Base Scenario in PSE's most recent IRP (2013) projects a system-wide peak energy supply capacity deficit of 12 MW in 2017, growing to 100 MW in 2020.

Table 33. 2013 IRP Forecast Energy Supply Capacity Deficit 2017 to 2021

Year	2017	2018	2019	2020	2021
Capacity Deficit (MW)	12	61	105	100	149

Figure 16. December Peak Need Forecast (Source: PSE)



Reduced Transmission Capacity Needs

During the first several years of storage deployment, the need for energy supply capacity is less than the storage system's power rating. During those years, the storage capacity that is not needed for energy supply capacity is assumed to enable PSE to reduce transmission capacity needs as follows: Because the storage can serve a portion of end-user demand, real-time, the amount of energy that must be delivered via the transmission system is also reduced. That frees up transmission capacity so that it can be to be used for other purposes. PSE determined that Strategen could assume the transmission capacity that is freed up (as a result of the storage operation) could be resold to provide additional revenue.[108]

The estimated value for re-sale of transmission contracts in 2014 was approximately $17.00/kW-yr. This value is escalated by 2.5% per annum to account for inflation, grossed-up for line-losses, federal income taxes, and state revenue taxes to yield the total annual value, as shown below:

[108] PSE currently relies on approximately 1,500 MW of transmission to acquire energy and capacity from the market and holds a multitude of Mid-C transmission contracts with various termination dates. These contracts only need to be renewed for 5-year terms to preserve PSE's unilateral roll-over rights in the future. In any given year, PSE has the option to renew a portion of Mid-C capacity and reevaluate the Mid-C transmission need.

Table 34. Mid-C Transmission Resale Values (Source: PSE)

	$/kW-yr				
Year	Mid-C Tx Value	Line Loss Gross up	ICE De-Rate	Gross-up for FIT *	Gross Up for State Rev Tax
2014	17.00	18.19	18.19	27.99	29.11
2015	17.43	18.65	18.65	28.69	29.84
2016	17.86	19.11	19.11	29.40	30.59
2017	18.31	19.59	19.59	30.14	31.35
2018	18.76	20.08	20.08	30.89	32.14
2019	19.23	20.58	20.58	31.66	32.94
2020	19.71	21.10	21.10	32.46	33.76
2021	20.21	21.62	21.62	33.27	34.61

* Federal Income Tax

Benefit Estimation Methodology

The system capacity benefit is estimated based on the avoided cost for energy supply capacity plus additional revenue accruing from re-sale of transmission capacity.

To the extent that PSE needs incremental new peaking energy supply capacity, the energy supply capacity contribution from the ESS is valued at the avoided cost of the default resource (F-Class SCCT) using cost and performance data from the 2013 IRP.[109]

A key premise for the evaluation of the capacity benefit is that a peaking resource must discharge for at least two hours. However, the storage system whose power rating is 121 MW is designed to discharge for 1.86 hours. Therefore, as shown in Table 32, the storage system is assumed to be able to provide 112.8 MW of energy supply capacity in 2017. The benefit estimation for energy supply capacity must account for the diminishing energy output capability of the storage system throughout its life (assumed to be 2% per year).

And, to the extent that the energy storage system provides surplus capacity in a given year beyond the energy supply capacity deficit projected in the 2013 IRP, an additional benefit is estimated for the value of the revenues associated with re-sale of surplus transmission capacity to the Mid-C based on historical bilateral transactions.

[109] To estimate the financial benefit (avoided cost) for energy supply capacity a portfolio optimization analysis, such as that done as part of the IRP process, is the most appropriate method. That is not feasible given the scope, budget and timeframe for this study. So, the estimated avoided cost for simple cycle CT was used.

Table 35. Storage System Capacity Assumptions

Year	2017	2018	2019	2020	2021
Energy Supply Capacity Deficit (MW)	12	61	105	100	149
Value at Avoided Peaker Rate (MW)	12	61	105	100	104.2
Value at Trans. Resale Rate (MW)	100.8	49.6	3.4	6.3	0
Total ESS Capacity (MWh/2)	**112.8**	**110.6**	**108.4**	**106.3**	**104.2**

7.4.2.2 *System Flexibility Benefit*

Introduction

For this evaluation PSE defines "system flexibility" as an amalgamation of four ancillary services: 1) regulation and frequency response, 2) contingency reserve obligations, 3) intra-hour energy balancing and 4) load following/ramping[110]. To the extent that storage reduces the need for those services from other resources, there is a benefit (i.e. an avoided or reduced cost).

Load fluctuations, Balancing Authority obligations to integrate scheduled interchanges, and unexpected events like forced outages all place demands on generators to provide "system flexibility." So does the need to maintain contingency reserves to assist other Balancing Authorities that may have sudden needs for help balancing loads. All generation resources provide some measure of flexibility; however, the ability of a resource to supply flexibility is constrained by unit-specific characteristics including availability, operational or environmental limitations, range, and ramp rate. These characteristics, coupled with economic dispatch generation set points, affect PSE's total supply of system flexibility.

> *Storage Power and System Benefits*
>
> Notably, some benefits associated with a specific amount of storage power may be limited because there may be more storage capacity than needed to provide the respective service.
>
> Consider an example: PSE's Contingency Reserve Obligation will soon be 3% of load plus 3% of generation. During periods when load is low and levels of market purchases are relatively high, PSE may only need to carry as little as 100 MW of reserves. During other times the requirement may be significantly higher.
>
> There are similar considerations with regard to the need for balancing and load following/ramping resources. And, usually there are operational conflicts between the various ancillary services (and with the other benefits) meaning that at any given time only one service can be

PSE often faces challenges related to system flexibility during the second quarter of the year. During this period, spring runoff often leads to high river flows which limit the operating range of hydro generators on the Columbia River (these generators are referred to collectively as the Mid-Columbia or "Mid-C"). For example, during much of the year PSE has an operating range of roughly 50 – 650 MW on its share of the Mid-C. During Q2, this range may decline to less than 100 MW. The Mid-C generators are typically used to provide frequency regulation and spinning reserves, but during periods of constrained operations, PSE often uses simple-cycle combustion turbines for spinning reserve, which incur start charges, fuel costs, and O&M costs. Year-to-year there can be high variability in hydro conditions and other factors that

[110] Source: DOE-EPRI Energy Storage Handbook (2013)

drive the costs and challenges of providing adequate flexibility. For more information on system flexibility and PSE modeling methodology, see PSE's 2013 IRP, Appendix G.

Due to their especially fast response and ramp rates, and ability to provide spinning reserve at virtually zero variable cost, battery storage systems can provide flexibility services quite well. Given that, recent FERC regulatory changes have increased compensation paid to fast-acting regulation resources such as those involving batteries and flywheel energy storage.

Indeed, many large battery storage systems deployed in the grid today are for frequency regulation services. Flexibility is a system-wide benefit and can be realized anywhere the battery is placed on the system so long as the necessary controls and communication infrastructure exist.

Benefit Estimation Methodology

The Pacific Northwest does not have a market for ancillary services such as spinning reserves and frequency regulation. Therefore, the valuation of the flexibility benefit provided by PSE involves two model-based evaluations of PSE's cost to provide system flexibility: 1) a baseline evaluation of the supply resource configuration *without* the storage system and 2) another evaluation that includes the storage system as part of PSE's electric supply resources. The flexibility benefit for storage is defined as the difference between the results from those two evaluations.

The model is consistent with modeling in the 2013 IRP, which assesses how PSE will meet its balancing obligations in the year 2018. The model uses a mixed-integer linear program in SAS-OR to simulate procuring sufficient flexible capacity from PSE generators prior to each operating hour, and then dispatching that capacity during the hour to manage load and resource variations.

The model output is a record of unit deployment for PSE's dispatchable generation that quantifies how each unit contributes to system balancing, pinpoints periods of stress, and identifies periods when the model could not balance the system.[111]

The Resource Integration Team modeled a generic battery system of 117 MW/208.8 MWh (a configuration of similar size to Alternate Configuration #1) using a subset of the 250 Aurora simulations used in the 2013 IRP, limited to the year 2018. The team has intended to use the exact size contemplated in the final report, but due to a minor sizing adjustment in the final configuration to accommodate system degradation, the former size was modeled. We do not believe this is a problem because previous modeling for smaller sizes (2MW, 18MW) yielded a similar overall value in the $100/kW-yr range. Given that the 117MW and 121MW configurations are so similar, we believe this slight inconsistency will have an insignificant impact on the overall results. For this evaluation the levelized system flexibility benefit is estimated to be $99.52/kW-yr.

[111] PSE's model prioritizes which constraints to solve (e.g., the "total energy=total demand" constraint has the highest priority), and sets an artificial price for marginal flexibility of $1,000/MW during periods when the model is unable to balance the system's flexibility needs while still solving for higher priority constraints. This may result in an artificial values being applied for system flexibility during certain periods, rather than actual market-clearing prices, which do not exist in the Pacific Northwest.

Notably, a significant portion of the flexibility benefits accrue during Q2 as that is the time of year when the significant amount of hydroelectric generation used by PSE generally is the least flexible. So, storage provides a significant portion of the total annual flexibility benefit during Q2.

Year-specific values are de-escalated or escalated at 2.5% per year throughout the study period.

The storage system is assumed to be reserved for providing the transmission reliability function (managing local transmission level winter peak demand) in January and summer peak demand during August. While the storage resource can theoretically provide multiple services such as reducing load on the transmission system and providing system flexibility, there is potential conflict during certain times when it is reserved for serving a transmission reliability function. For example, if the storage system is fully discharged in response to a transmission system overload, it can no longer be relied on for spinning reserve until recharged to a certain threshold. In these cases, other generation resources would have to be used to provide system flexibility. The data used in the system flexibility modeling is not structured in such a way to easily determine the probability that the storage system would be needed for transmission system overload relief and system flexibility concurrently.

During the transmission deferral period (2017 to 2021), PSE and Strategen agreed that the value of system flexibility should not be included for the months of January and August as a modeling assumption when the transmission overload is most likely to occur. During this period, storage receives 84.5% of the annual benefit, as 15.5% of the annual system flexibility benefit occurs in January and August. After the transmission deferral period, storage receives the entire annual benefit. This is a simplification that may result in an underestimation of the value of system flexibility provided by the storage resource, nonetheless it is a reasonable assumption for this case study.

PSE's flexibility analysis also assumes that the Eastside transmission system is capable of supporting unconstrained dispatch of the system. This may result in a possible overestimation of the flexibility benefits the storage could provide. For example, the transmission system is close to an overload situation, PSE might not be able to use the resource in full charge mode if the system needs down-balancing resources, as that might overload the transmission system. Fully resolving this issue would be complex, requiring either a study of the transmission upgrades that would be required to support unconstrained dispatch, or a study of whether current transmission constraints might limit dispatch. Such a study is beyond the scope of this assessment.

The annual values are shown in Table 36 below.

Table 36. PSE Projected Annual Flexibility Benefit

Flexibility Value for Entire Year (Post Deferral)	
Value in 2018	Total ($/kW-year)
$/Month	$11,774,364
$/kW-mo	$ 97.31
Value in 2017	Total ($/kW-year)
$/Month	$11,487,184
$/kW-mo	$ 94.94
Flexibility Value During Deferral Period	
	Include
Value in 2018	Total ($/kW-year)
$/Month	$ 9,946,467
$/kW-mo	$ 82.20
Value in 2017	Total ($/kW-year)
$/Month	$ 9,703,870
$/kW-mo	$ 80.20
Levelized Value	Total
Constant Dollars ($000)	$ 220,827
Current Dollars ($000)	$ 284,063
Present Worth* ($000)	$ 140,662
$/kW**	$ 1,162.50
$/kW-year levelized***	$ 116.37
With Energy Output Degradation	
Present Worth* ($000)	**$ 120,296**
$/kW**	**$ 994.18**
$/kW-year levelized* **	**$ 99.52**
*Based on escalation rate of 2.50%.	
*Based on discount rate of 7.77%.	
**Based on WACC of 7.77%.	

7.4.2.3 *Oversupply Reduction Benefit*

Storage can prevent "over-generation" and curtailment of generation resources (especially wind generation) in several ways including time-shifting and reduced variability served by dispatchable/thermal generation. Though modest, that benefit will be increasingly important; so Strategen included it as part of the overall value proposition for the Eastside ESS.

The estimated annual value, calculated based on data provided by PSE, is shown in **Error! Reference source not found.** below.

Table 37. Estimated Annual Oversupply Reduction Benefit, 2017

With Energy Output Degradation		
Present Worth ($000)* **	**$**	**1,687**
$/kW	**$**	**13.94**
$/kW-year levelized***	**$**	**1.40**
*Escalation Rate 2.50%		
**Discount Rate 7.77%		
***Life: 20 years, WACC (Discount Rate) = 7.77%		

7.4.3 *Other Benefits*

In order to provide a common frame of reference, it is worth noting that there are a variety of storage-related benefits that are frequently characterized differently than was done in this report. These benefits either were included as a subset of the benefit calculations above but were not studied separately, or would not accrue to storage deployed for the Eastside situation. They are summarized below and described in more detail in Appendix D: Unquantified and Partially Quantified Benefits.

Reduced GHG Emissions

Depending on the mix of fuels involved, storage can reduce overall GHG emissions in several ways, including reduced stops/starts and load following from conventional generation resources, dynamic operating benefits, more and more effective renewables integration, reduced use of the generation fleet’s most inefficient peaking resources (via energy shifting) and by allowing for better and increased use of demand response and electric vehicles.

The benefit of GHG avoidance is not currently monetized, but President Obama and the United States Environmental Protection Agency’s Clean Power Plan[112] announced in 2014 proposes “state-specific rate-based goals for carbon dioxide emissions”. Therefore, Strategen believes that it is reasonable to assume that there will be at least some actual financial benefit associated with GHG reduction.

Ascribing a cost to these avoided GHG emissions is contentious and challenging, but estimates of the social cost of carbon (“SCC”) were published by a US Government Interagency Working Group in 2010[113] and then updated in 2013.[114] PSE used a range of price estimates, including some from that analysis, for modeling different scenarios in the 2013 IRP.[115] In the 2013 IRP, PSE assumed the following:

[112] See http://www2.epa.gov/carbon-pollution-standards/clean-power-plan-proposed-rule
[113] Interagency Working Group on the Social Cost of Carbon (2010)
[114] Interagency Working Group on the Social Cost of Carbon (2013)
[115] PSE (2013); Section 4-8.

Table 38. PSE's 2013 IRP GHG Cost Assumptions

CO_2 Cost	$ per ton, 2014	$ per ton, 2033	Implied Escalation Rate
Base	$0	$0	--
Low	$6	$20	6.54%
High	$25	$80	6.31%
Very High	$75	$179	4.53%

While the amount of carbon dioxide ("CO_2") emissions that would be avoided by PSE utility-owned generation annually if the Eastside storage facility is deployed has the potential to be quite significant, calculating the regional GHG reduction impact, inclusive of all benefits and in the context of the Northwest's regional generation mix, is a very complex analysis that was out of scope for this report. In particular, the analysis would need to evaluate both the impact on PSE utility-owned generation, as well as regional changes in the market-dispatch of generation in the Pacific Northwest. The latter is likely to react to less PSE-owned generation being dispatched. This may result in imports of more market resources, the mix of which is unknown and could be comprised of renewables or conventional generation resources. Thus a broader regional analysis of GHG impacts of storage is recommended before assigning specific value to the GHG reduction benefits of storage for PSE's customers. PSE plans to conduct such an analysis as part of its 2015 Integrated Resource Plan.

Energy Time-Shifting

In essence the energy time-shift benefit is related generation/purchase of low priced/low cost electric energy when demand is low, for use or sale when demand and price are high (i.e., buy low – sell high). For the Eastside evaluation the energy time-shift benefit was included in the system flexibility benefit calculation.

Ancillary Services

Storage can be used for the full spectrum of ancillary services. Storage is especially well-suited to provide these services given how responsive most storage types are when compared to the generation resources used most often to provide these services. For the Eastside evaluation, the ancillary service benefits of frequency response, balancing and load following/ramping was included in the system flexibility benefit calculation.

Generation Dynamic Operating Benefits

Storage provides (generation fleet) dynamic operating benefits by enabling a more optimized (i.e. efficient and less variable) operation of the generation fleet by reducing the need to commit, start, ramp and operate generation at part load, which reduces fuel use and emissions (per kWh) and reduces plant wear and variable maintenance costs while extending equipment life. These benefits are captured for the Eastside evaluation in the system flexibility benefit calculation.

Reduced Need for Flexible Generation Capacity

In addition to the assessment of flexibility benefits for the *existing* electric supply resource configuration, storage could also reduce the need for *additional* "flexible capacity" (especially combustion turbines) beyond that needed to address load growth and equipment retirement. However, that benefit is likely to be limited for PSE because hydroelectric generation provides most flexibility during most of the year. These benefits are captured for the Eastside evaluation in the system flexibility benefit calculation.

Transmission Support and Voltage Control

Depending on where it is located, storage can enhance the “electrical” performance of transmission and even distribution equipment. It does that by reducing overloading and problematic current flows, offsetting/ameliorating voltage and other power quality challenges caused by renewables whose output varies, especially wind and PV, and by managing other electrical phenomena that reduce the overall effectiveness of T&D facilities such as voltage sags, excess reactance and sub-synchronous resonance and by providing means for effective Volt/VAR control and possibly even conservation voltage reduction.

Reduced T&D I^2R Energy Losses

As mentioned in the characterization of the system capacity benefits above, storage reduces real-time T&D I^2R energy losses which reduces the need for energy supply capacity (to offset the energy losses). By reducing T&D I^2R energy losses, storage also reduces the total amount of energy needed (and fuel used and GHG emissions produced) to serve PSE’s end-users.

Renewables Integration

Storage can be an important enabler of increased use of renewables whose output varies, especially wind and solar generation. Storage can also enable use of additional energy from hydroelectric generation, especially during years when precipitation is significant and/or times of the year when significant amounts of hydroelectric generated electricity is produced and demand is relatively low.

Storage does that, in part, by providing means for system operators to compensate quickly and effectively for renewables output variation and to address changes and opportunities related to reduced “oversupply” that occurs when a) the amount of generation output exceeds demand and b) most or all generation operating is not “dispatachable” (i.e., output cannot be varied without significant cost implications). Storage can also enable more deployment of distributed renewables, especially PV, by offsetting unhelpful electrical effects and by managing excess energy produced within a distribution system.

Electric Service Reliability

Beyond the “reliability-related” considerations described above (related to NERC Standards), storage can be used to improve electric service reliability in several ways such as a) improving local power quality, b) improving the overall “electrical performance” and throughput of T&D systems, c) providing “back-up” power for end-users and d) managing localized peak demand and T&D overloading.

7.5 Other Assumptions and Inputs

This subchapter provides a summary of the assumptions used for the cost-effectiveness evaluation.

7.5.1 *Evaluation Period*

The evaluation is undertaken for storage deployed in 2017-2018, to enable the deferral of the upgrade through 2021 (deferral for four years). The storage is assumed to have a service life of 20 years (through 2036).

Storage operation during the evaluation period:

- During years 2017 to 2021, the Eastside transmission-related needs- to enable the deferral- is the priority use case of the energy storage device, while the storage is assumed to be used for other system benefits during other times of the year.
- During years 2022 to 2036, transmission reliability is no longer prioritized over other applications for the energy storage device, because additional transmission is assumed to be in place to relieve the Eastside system needs.

7.5.2 *Financial and Economic*

The ultimate criterion of merit regarding cost-effectiveness is the net present value (NPV) of alternatives being assessed. The alternative with the net cost (e.g. revenue requirements minus benefits) that results in the lowest NPV is assumed to be the “best” alternative, assuming that the alternatives provide equal utility.

For the evaluation (to calculate NPV), all costs are assumed to escalate at the nominal rate of 2.5% per year.

The financial assumptions used for the evaluation are shown in Table 39. Of particular note is the pre-tax discount rate of 7.77%, which is PSE’s pre-tax weighted average cost of capital and is used in Strategen’s calculations for NPV calculations when discounting pre-tax revenue requirements.

Table 39. PSE Financial Assumptions

State Revenue Tax	3.8712%
Federal Income Tax	35.00%
Property Tax	0.4800%

PSE Capital Structure	Ratio	Cost (Pre-tax)	Weighted (Pre-Tax)	Weighted (After-Tax)
LT Debt	48.00%	6.16%	2.96%	1.92%
ST Debt	4.00%	2.68%	0.11%	0.07%
Preferred	0.00%	0.00%	0.00%	0.00%
Equity	48.00%	9.80%	4.70%	4.70%
TOTAL	**100.00%**		**7.77%**	**6.69%**

7.5.3 *Energy Storage*

The following is a summary of key storage-related assumptions.

Configuration

The storage configuration selected for evaluation is a centralized storage system located at Lakeside substation with a power rating (capacity) of 121 MW and discharge duration of approximately 1.9 hours (e.g. 226 MWh of energy can be stored).

Performance

The storage system specified is assumed to have an AC-to-AC round trip efficiency of 85%. It is also assumed that the amount of energy that can be stored degrades at a rate of 2%/year (so, at the end of the 20-year life of the system, it is able to store about 68% of its rated capacity when first deployed). Note that the system sizing when deployed was adjusted slightly upwards to account for degradation during the deferral period.[116]

No battery replacements or other significant servicing/maintenance was assumed during the 20 year evaluation period so O&M costs were assumed to fixed (under contract with the vendor) to maintain system functionality only but not to replace or add cells when overall system degradation in line with projections occurs.

Storage Cost

The PSE-specific levelized and lifecycle cost for the storage plant was calculated. Please see Appendix F: for details about the lifecycle cost estimation for storage, and Chapter 7.6 for the cost and revenue requirement assumptions used in developing the pro forma.

[116] Specifically, the need driving the 226 MW energy requirement is a 217 MW requirement in 2019. In order to meet this need, the system must be upsized to 226 MW to account for anticipated system degradation between 2017-2019.

7.6 Cost-effectiveness Evaluation Results

What follows is a detailed summary of the results of the cost effectiveness assessment of the Alternate Configuration #1: *Emergency Overload Elimination* configuration (as described in Chapter 7.1), including storage system cost, benefit values, net present value and benefit-to-cost ratio for the project.

As shown in in Table 40, the estimated NPV of storage cost is $264.2 Million and $2,183.6/kW installed, for a 20 year levelized cost of $218.6/kW-year.

Table 40. NPV of Storage Cost

Revenue Requirement ($Million)		
	$Current ($000)	414,783
	$/kW	3,428
	$NPV ($000)	**264,217**
	$/kW	**$ 2,183.61**
	$/kW-year Levelized**	**$ 218.58**
	*Discount Rate 7.77%	
	** Life: 20, WACC (Discount Rate): 7.77%	

The NPV of the energy supply capacity benefit is based on the avoided cost for the SCCT described in the characterization of the Default Peaking Capacity Resource: Simple Cycle Combustion Turbine in Chapter 7.4.2. It also reflects PSE's projected capacity needs and the diminishing energy output from storage as it ages and is used.

Shown in Table 41 below are the annual capacity needs for the first five years of storage operation, and the resulting energy supply capacity benefit from storage reflecting the 2.5%/year escalation for that benefit and the diminishing storage power available for supply capacity reflects a 2%/year decline of energy output from the storage. The resulting NPV is about $171.2 Million or $1,518/kW of storage installed, for annual levelized benefit of $152/kW-year.

Table 41. Estimated NPV of Energy Supply Capacity Benefit

		2017	2018	2019	2020	2021
Storage Power (MW)		112.8	110.6	108.4	106.3	104.2
Supply Capacity Needs		12.0	61.0	105.0	100.0	149.0
Storage Power for Supply Capacity Credit (MW)		12.0	61.0	105.0	100.0	104.2
Supply Capacity Value ($/kW-year, Capacity)		$ 156	$ 156	$ 156	$ 156	$ 156
Supply Capacity Benefit ($000 $2017)	**$ 267,687**	$ 1,866	$ 9,487	$16,330	$15,552	$16,207
Supply Capacity Benefit ($000 $Current)*	**$ 342,490**	$ 1,866	$ 9,724	$17,156	$16,748	$17,889
Supply Capacity Benefit ($000 $PW)**	**$ 171,274**	$ 1,866	$ 9,023	$14,772	$13,381	$13,263
$/kW$_{storage\ system}$	**$1,518.39**					
$/kW-year levelized***	**$ 151.99**					

*Based on escalation rate of 2.50%.
**Based on discount rate of 7.77%.
***Based on WACC of 7.77%.

The NPV of the transmission capacity benefit is based on the revenue from re-sale of unused transmission capacity, as described in the System Flexibility Benefit in Chapter 7.4.2.1.

Shown in Table 42 below are the annual values for storage power that adds to PSE's energy supply capacity surplus (and, therefore, is allows PSE to re-sell transmission in the market), starting at about 108 MW in 2017 and declining through 2020 to 6.3 MW. Those results also show the effects of 2.5%/year escalation of the benefit and the diminishing storage power available for capacity due to degradation (at a rate of 2%/year). The result is an NPV of $4.9 Million or $43.5/kW of storage installed, for an annual levelized benefit of $4.53/kW-year.

Table 42. Estimated NPV of Transmission Capacity Benefit

		2017	2018	2019	2020
Storage Power for T Capacity Credit (MW)		100.8	49.6	3.4	6.3
Transmission Capacity Value ($/kW-year$_{storage}$)		$ 31.35	$ 32.14	$ 32.94	$ 33.76
			+2.5%	+2.5%	+2.5%
T Capacity Benefit ($000 $2017)	**$ 5,079**	$ 3,160	$ 1,594	$ 113	$ 212
T Capacity Benefit ($000 $Current)*	**$ 5,079**	$ 3,160	$ 1,594	$ 113	$ 212
T Capacity Benefit ($000 $PW)**	**$ 4,906**	$ 3,160	$ 1,479	$ 97	$ 170
$/kW$_{storage\ system}$	**$ 43.49**				
$/kW-year levelized***	**$ 4.35**				

*Based on escalation rate of 2.50%.
**Based on discount rate of 7.77%.
***Based on WACC of 7.77%.

Shown in Table 43 is the NPV of the flexibility benefits for all 20 years of storage operation. The results reflect a benefit escalation of 2.5%/year and diminishing storage power due to the declining storage energy output (declining at a rate of 2%/year). The result is a NPV of $120.3 Million or $994/kW of storage installed, for an annual levelized benefit of $99.52/kW-year.

Table 43. Estimated Annual Flexibility Benefit, 2017

	Total
Constant Dollars ($000)	$220,827
Current Dollars ($000)	$284,063
Present Worth* ($000)	$140,662
$/kW**	$1,162.50
$/kW-year levelized***	$116.37
With Energy Output Degradation	
Present Worth* ($000)	**$120,296**
$/kW**	**$994.18**
$/kW-year levelized***	**$99.52**

*Based on escalation rate of 2.50%.
*Based on discount rate of 7.77%.
**Based on WACC of 7.77%.

Shown in Table 44, the estimated NPV for the oversupply reduction during the 20 years of storage operation, assuming that the benefits escalate at a rate of 2.5%/year and that the benefit declines due to the declining storage energy output at a rate of 2%/year. The NPV of those two benefits is approximately $1.7 Million or about $14/kW installed and $1.40/kW-year levelized.

Table 44. Estimated Annual Oversupply Reduction Benefit, 2017

With Energy Output Degradation		
Present Worth ($000)* **	**$**	**1,687**
$/kW	**$**	**13.94**
$/kW-year levelized***	**$**	**1.40**
*Escalation Rate 2.50%		
**Discount Rate 7.77%		
***Life: 20 years, WACC (Discount Rate) = 7.77%		

Although not included in the final benefit/cost calculus, GHG reduction benefits could also potentially be significant. The results of the cost-effectiveness evaluations are summarized in Table 45, which shows storage cost, benefits and the benefit cost ratio. The total NPV of the storage (revenue requirements) is $264.2 Million and the NPV of all benefits estimated is $298.2 Million for a net NPV of $34.0 Million and a benefit cost ratio of 1.13.

Table 45. Net Present Value Summary and Benefit Cost Ratio

Storage Cost	**Total Cost**	**$264.22**	**$2,183.61**	**$218.58**
Benefits		$ Million*	$/kW*	$/kW-year**
	Transmission Deferral***	$-	$-	$-
	Energy Supply Capacity	$171.27	$1,518.39	$151.99
	Transmission Capacity	$4.91	$43.49	$4.35
	Flexibility	$120.30	$994.18	$99.52
	Oversupply	$1.69	$13.94	$1.40
	Total Monetizable Benefits	**$298.16**	**$2,570.00**	**$257.26**
Benefit/Cost Ratio				1.13

*Values are discounted using 7.77% and are expressed in $2017.
**Based on WACC of 7.77%.
*** Assumes other non-wires alternatives fully absorb this $155/kW-year benefit

8 Conclusions and Recommendations

This chapter highlights the major conclusions and recommendations. In summary, Strategen was unable to find a solution that was both technically feasible and also meets PSE's requirements for addressing the Eastside need. Further, the timeline for interconnection and land use permitting appear render infeasible an online date in time to meet PSE's winter 2017-2018 need, and the cost of energy storage to meet the Eastside need appears prohibitive. We therefore conclude that energy storage is not a viable transmission deferral option for the Eastside need. However, we did find that energy storage in general shows promise as a potentially cost effective solution to meet other system needs, and recommend further evaluation in PSE's upcoming Integrated Resource Plan.

8.1 System Sizing

Strategen evaluated the power and energy requirements for an energy storage system to accomplish the PSE's objectives as identified in previous chapters.

Strategen calculated net injection requirements of 328.0 MW/2,338.0 MWh for an energy storage system to fully meet PSE's objectives. Alternate configurations were developed to address emergency overloads only (Alternate #1), and to create a more robust solution that would result in a longer deferral, through the elimination of all normal overloads during system contingencies (Alternate #2). A summary of key findings is contained in Table 46 below.

Table 46. Energy Storage Configuration Summary

Configuration	Power (MWp)	Energy (MWh)	Acreage	Est. Cost ($MM)	Includes Non-Wires Alternatives[117]	Technically Feasible	Meets Requirements
Baseline Normal Overload Reduction	328	2,338	19.6	**$1,030**	✓	✗	✓
Alternate #1 Emergency Overload Elimination*	121	226	5.8	**$184**	✓	✓	✗
Alternate #2 Normal Overload Elimination	545	5,771	45.7	**$2,367**	✓	✗	✓

[117] E3 (2014)

8.1.1 *Technological Readiness*

Siting limitations and commercial feasibility in the Eastside area caused Strategen and PSE to identify a chemical (battery) storage solution as the most appropriate technology for this study.

The technology and capability exists for batteries to be deployed for this application at this magnitude, however, no similarly-sized system has ever actually been built or commissioned. Therefore, it is difficult to estimate the time necessary for procurement, construction and deployment.

8.1.2 *Siting Feasibility, Permitting, and Interconnection*

The lengthy interconnection study process (1-2 years) and permitting process (2-4 years) would present significant barriers for an ESS beginning development in early 2015 to meet a Winter 2017-2018 online date. This is a particularly acute problem given that procurement of long lead items and construction are likely to take an additional 1-2 years following construction, depending on the willingness of the developer to put capital at risk for procurement before the project is fully permitted. A 2019 online date would be a more realistic expectation for any potential substation-sited storage solution to reach commercial operation.

8.1.3 *Technical Feasibility*

The critical technical challenge identified for an energy storage system configured to meet the Eastside system need is the existing transmission system's available capacity to support charging of the storage system.

Strategen determined that the existing Eastside transmission system does not have sufficient capacity to fully charge the Baseline Configuration during system contingency scenarios. Specifically, the Eastside system has significant constraints during off-peak periods that could prevent an energy storage system from maintaining sufficient charge to eliminate or sufficiently reduce normal overloads over multiple days.

8.1.4 *Cost-Effectiveness*

As Strategen determined that the Baseline Configuration would not be technically feasible, a cost-effectiveness assessment was only conducted for Alternate Configuration #1. This configuration does appear to be cost effective, with a benefit-cost ratio of approximately 1.13. Strategen did not evaluate the relative cost effectiveness of energy storage versus other types of system resources, as this would require a more robust analysis that is best suited for PSE's Integrated Resource Planning process.

8.2 **Key Conclusions**

Based upon the results of the study, Strategen provides the following conclusions for PSE's consideration.

- The Baseline Configuration (a 328 MW / 2,338 MWh storage system) is not technically feasible because the existing Eastside transmission system does not have sufficient capacity to fully charge the system.
- Based on permitting and interconnection requirements identified by PSE combined with likely procurement and construction timelines, Strategen does not believe any studied configuration could come online in time to meet a winter 2017-2018 need. A more feasible online date would be in the 2019 timeframe.
- Strategen estimates that the Baseline Configuration would have a revenue requirement of approximately $1.44 billion (discounted to reflect present value) and a physical footprint of approximately 19.6 acres.
- An energy storage system with power and energy storage ratings comparable to the Baseline Configuration (large enough to reduce normal overloads) has not yet been installed anywhere in the world. Projects comparable to Alternate Configuration #1 (a 121 MW / 226 MWh storage system) have been contracted by other utilities.
- Alternate Configuration #1, while not meeting PSE's operational requirements, does appear to be cost effective, with a benefit-cost ratio of approximately 1.13 and a revenue requirement of approximately $264 million. This configuration would require a physical footprint of approximately 5.8 acres of available land adjacent to PSE-identified substations in the Eastside.
- Strategen's analysis evaluated the absolute cost effectiveness of energy storage in terms of system benefits versus revenue requirements. While the analysis concluded that energy storage appears to be cost effective as a system resource, it did not evaluate the relative cost effectiveness of energy storage versus other types of system resources. Strategen recommends further analysis of the relative cost effectiveness of energy storage to meet PSE's system-wide needs in its upcoming Integrated Resource Plan.

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10 Appendices

Appendix A: Acronyms

AC	Alternating Current
AEP	American Electric Power
AMI	Automated Metering Infrastructure
ANSI	American National Standards Institute
AS	Ancillary Services
BOS	Balance-of-System
BPA	Bonneville Power Administration
CAES	Compressed Air Energy Storage
CAP	Corrective Action Plan
CO_2	Carbon Dioxide
CSP	Concentrated Solar Power
DG	Distributed Generation
DOD	Depth of Discharge
DOE	United States Department of Energy
DR	Demand Response
DRA	Demand Response Agreement
DSR	Demand-side Resources
E3	Energy and Environmental Economics
EE	Energy Efficiency
EPC	Engineering, Procurement and Construction
EPRI	Electric Power Research Institute
ESA	Energy Storage Agreement
ESS	Energy Storage System
ESVT	Energy Storage Valuation Tool
FERC	Federal Energy Regulatory Commission
GHG	Greenhouse Gas
GW	Gigawatt

HECO	Hawaiian Electric Company
ICE	Incremental Capacity Equivalent
IOU	Investor Owned Utility
IRP	Integrated Resource Plan
kV	Kilovolt
kW	Kilowatt
kWh	Kilowatt-hour
LCR	Local Capacity Resource
LMP	Locational Marginal Price
MMBtu	Million British Thermal Units
MW	Megawatt
MWh	Megawatt-hour
NaS	Sodium Sulfur
NERC	National Electric Reliability Council
NPV	Net Present Value
O&M	Operations and Maintenance
PCS	Power Conditioning System
PG&E	Pacific Gas and Electric Company
PPTA	Power Purchase Tolling Agreement
PSE	Puget Sound Energy
PUC	Public Utilities Commission
PV	Photovoltaic
REM	Regulation Energy Management
RFO	Request For Offer
RTE	Roundtrip Efficiency
SCC	Social Cost of Carbon
SCE	Southern California Edison Company
SDG&E	San Diego Gas & Electric Company

T&D	Transmission and Distribution
TOU	Time of Use
TPL	Transmission Planning
UPS	Uninterruptible Power Supply
VAR	Volt-Ampere Reactive

Appendix B: Description of the Eastside System Reliability Need

Puget Sound Energy's electric grid and infrastructure are facing both regional and localized supply and transmission deficiencies. This chapter summarizes the issues as identified in the 2013 Integrated Resource Plan, as well as the localized King County issues (the "Eastside) addressed in the 2013 Eastside Needs Assessment report (the "Eastside Assessment).

Load growth is straining the Eastside transmission system, and while Corrective Action Plans have mitigated the near term threat, projected growth will continue to exacerbate the risks of overloads, thermal violations and contingencies over the next ten years. Modelling demonstrates that, as early as winter 2017-2018, the PSE system will face a load level of 5,200 MW, leading to a winter peak supply deficiency and NERC contingencies on several system elements, with summer peak deficiencies and contingencies following shortly thereafter.

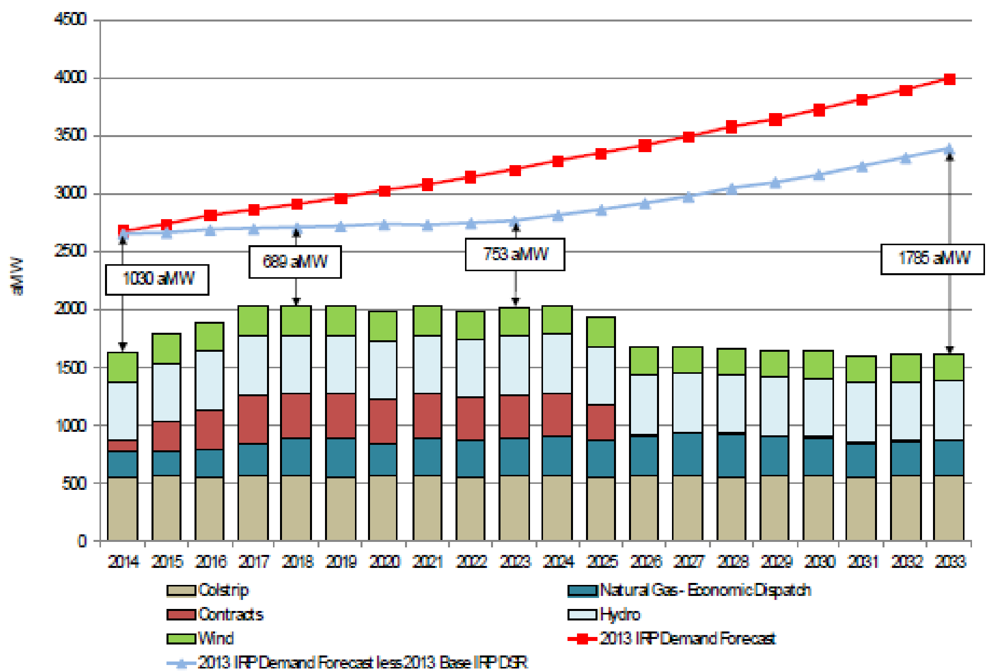
B1. Puget Sound Energy Integrated Resource Plan 2013

The amount of energy generated in the Pacific Northwest has historically been greater than the amount consumed, allowing Puget Sound Energy (PSE) many choices on how best to procure and provide reliable, low cost power to its customers. This resulted in sustained, regional economic and population growth that - in concert with the planned retirement of 2,000 megawatts of generation capacity by 2020 - will soon demand more electricity than current infrastructure can supply.

PSE's 2013 Integrated Resource Plan attempted to accurately project the regional supply-demand imbalance and determine the best way to address it while keeping customers' bills as low as possible. It examined population and economic growth rates (well correlated with electricity consumption), and projected how much electricity PSE customers will consume from 2014-2033. After better understanding customer demand and estimating annual supply capacity shortfalls (See Figure 17), PSE modeled hypothetical scenarios that combined a variety of supply resources (conservation and energy efficiency, new renewable or thermal generation, renewing transmission contracts, etc.) to see which combinations would meet customer needs at the lowest cost while also complying with renewable portfolio standards.

Results of the IRP analysis demonstrated that conservation measures and renewal of transmission contracts were least cost options that will play important roles in PSE's future electric grid. Conservation measures, also called demand-side resources (DSR), have the potential to incrementally reduce demand across PSE territory by 327 MW in 2017 and 800 MW in 2023 (represented by the difference between the red and blue line in Figure 17). The IRP substantiated previous PSE studies showing that DSR are almost always a least cost strategy, which PSE will continue to aggressively acquire. Even though PSE intends to procure as much conservation as possible, DSR alone will not reduce demand enough to balance it with supply: other resources, either new generation or transmission, will have to be secured as well.

Figure 17. Annual Energy Position for 2013 IRP Base Scenario



The IRP modelling also demonstrated that renewal of transmission contracts could potentially supply 1,141 MW and 1,407 MW of increased capacity in 2017 and 2023 respectively. In the short term (5-7 years), this is the least cost solution that, when combined with maximal DSR, allows PSE to continue reliably meeting customer demand.

While the IRP looked at the regional electric outlook and modelled the overall PSE territory, there are also specific pockets within the region where increased demand is straining existing infrastructure and presenting a more acute threat. One such pocket is PSE's Eastside system in King County.

B2. King County Transmission System

King County hosts the Seattle-Bellevue-Tacoma Metro Area. It is home to over 2 million people, of whom PSE provides electricity service to more than 500,000. The system relies on transmission interties with neighboring utilities to meet 90% of peak load.

The area load is supplied by four 500 kV substations owned by Bonneville Power Administration (BPA) in Monroe, Renton, Mill Creek, and Covington, and two 500 kV BPA switching stations in Ravensdale and south of Snoqualmie. Additional 230 kV supply is provided by five PSE substations as summarized in Table 47.

Table 47. King County Substations and Transformers

Substation	Location	Transformers (230 kV/115 kV)
Sammamish	Redmond	2
Novelty Hill	Redmond Ridge	1
Talbot Hill	Renton	2
O'Brien	Kent	2
Berrydale	Covington	1

Several studies have assessed potential risks to King County's transmission system including the 2008 Initial King County Transformation Study, 2009 PSE TPL Planning Studies and Assessment, and 2012 PSE TPL Planning Studies and Assessment. The greater Bellevue area, between Talbot Hill and Sammamish Substations, was identified as being especially at risk of potential thermal violations resulting from overloads during certain system contingency events.

A 2009 comprehensive reliability assessment confirmed the risk: given a projected 2010-2011 winter peak load of 5,329 MW,[118] a bus fault at Talbot Hill substation would cause an overload of one 230-115 kV transformer and several 230kV transmission lines if the other transformer tripped off.[119] To address the threat, PSE initiated a Corrective Action Plan (CAP) in 2009: manually switching out two 115 kV lines from Talbot Hill-Lakeside at the ~5,300 MW load level.

CAPs effectively mitigate the immediate risk of overloading at the Talbot Hill and Sammamish Substations, but negatively impact system reliability, and other issues continue to threaten local reliability. To comprehensively address those issues, quantify longer term system needs, and identify effective solutions, PSE partnered with Quanta Technology for a complete analysis of the King County Transmission system in the 2013 Eastside Needs Assessment Report.

B3. 2013 Eastside Needs Assessment Report

[118] 2009 PSE Planning Studies and Assessment TPL-001 to TPL-004 Compliance Report; P. 7.
[119] 2013 Eastside Needs Assessment Report; P. 15.

The 2013 Eastside Needs Assessment Report sought to evaluate the existing transmission infrastructure and its ability to reliably supply future load growth. The Eastside Assessment encompasses the area east of Lake Washington and west of Lake Sammamish, including Bellevue, Redmond, Mercer Island, Renton, Newcastle and Issaquah.

Compiling information from previous King County studies, incorporating the latest population and load growth projections, and accounting for energy efficiency and conservation targets set by the IRP, the report presents a comprehensive reliability analysis of the King County transmission system for 2012-2022.

Specific issues addressed include:

- Overloading of Talbot Hill and Sammamish Substation transformers
- Increasing use of Corrective Action Plans
- ColumbiaGrid recommended infrastructure reinforcements
- Risks associated with uncertain load forecasts

Talbot Hill and Sammamish Substations

The Eastside Assessment verified and elaborated the overloading issues at Talbot Hill and Sammamish Substations. The overload risks identified in 2009 have been temporarily mitigated through the use of CAPs. However, anticipated load growth in the Bellevue area will increase the number of potential future thermal violations and lead to several NERC contingencies, summarized by season in Table 48.

Transformer overloads are projected to occur in both winter and summer, but in different areas. In summer, when peak loads are forecasted to grow annually at the rate of 37 MW, overloads are possible at Sammamish Substation. This is due to regional power flowing primarily north to south and large anticipated increases in commercial loads. In winter, when power flows are reversed and load growth is expected to be 17 MW per year, the Talbot Hill Substation is at risk of overloading.

The transmission supply deficiency that results in overloading at Talbot Hill and Sammamish Substations) are projected to occur even if 100% of IRP conservation targets are met.

Table 48. Potential NERC Contingencies based on model results

Season	Est. Load	Model Year	Contingency	Elements
Winter	~5,200 MW	2017-2018	Category B (N-1) [120]	2 elements (115 kV), loading>98%
			Category C (N-1-1 & N-2)	5 elements (115 kV), loading>100%
Summer	~3,500 MW	2018	Category B (N-1)	2 elements (230 kV), loading>100% 2 elements (115 kV), loading>93%
			Category C (N-1-1)	3 elements, loading>100% 1 element, loading>99%

Risks associated with uncertain load forecasts

As with any projection of future scenarios, load forecasts are approximations based on currently available information and assumptions. The load forecast used in the analysis assumed 100% of IRP-established DSR targets are met and normal (23° F) winter weather conditions.

Analysis demonstrated that load forecasts are highly sensitive to variations in both weather conditions and actual acquired conservation levels. Using the 5,200 MW winter 2017-2018 load estimate as a reference point, models showed that if, for example, only 75% of incremental conservation targets were met, that load could occur in 2015, and overloads in the 2017-2021 period would be significantly greater than planned under the 100% conservation scenario. The overloads would also be significantly greater should extreme weather (13° F) occur, as load growth would be approximately 3.5 times greater than forecasted if the temperature on peak days were to drop from 23° F to 13° F.

The results of the Eastside Assessment rely on normal weather conditions and 100% of IRP-established DSR targets being met. If climatic conditions, planned infrastructure additions, or conservation targets deviate from assumed levels, both the magnitude and timing of transmission reliability threats could vary significantly from the report's projections.

[120] N-1 (n minus one) overloading refers to power requirements that exceed the transmission equipment's design or "normal" power rating. In addition to that normal or design rating, transmission equipment also has an "emergency" power rating. The emergency rating is the absolute maximum amount of power that should be provided – for a limited duration and very infrequently – without significant damage to the equipment and/or outages. Power flow exceeding the emergency rating when one element is taken out of service followed by another element taken out of service is referred to as N-1-1 (n minus one, minus one) overloading.

Increasing use of Corrective Action Plans

The CAPs that currently mitigates overloading at Talbot Hill and Sammamish Substations increases vulnerability across the entire transmission network, thus leaving customers vulnerable to outages.

PSE found that future load growth would require additional CAPs to be employed, thereby further degrading system resiliency and exposing up to 60,000 more customers to outage risks.

ColumbiaGrid recommended infrastructure reinforcements

ColumbiaGrid's Biennial Transmission Expansion Plan addressed Pacific Northwest regional system needs. The plan identified projects needed to buttress system reliability and reduce regional and renewable generation curtailment by installing specific infrastructure reinforcements, including additional PSE 230 kV transmission capacity in King County.

The Eastside Assessment models supported ColumbiaGrid's findings, also finding possible overloads of 230 kV lines in the future.

Appendix C: Proposed Eastside Solutions

Puget Sound Energy conducted multiple studies to identify and evaluate potential long-term solutions to the identified transmission capacity deficiencies. The Eastside Solutions Study sought to identify transmission upgrade scenarios that met the criteria for a viable alternative. The Non-wires Report estimated the potential for further demand side resources (above IRP targets) to mitigate the transmission capacity shortfall identified in King County and defer the required transmission upgrades to 2021. Results demonstrated that additional conservation, demand response, and distributed generation would be insufficient to alleviate the capacity deficiency, especially if load growth or weather conditions deviate from projections.

C1. Transmission Alternatives

Following the Eastside Needs Assessment Report findings, Puget Sound Energy conducted the Eastside Transmission Solutions Study to rigorously evaluate potential solutions to the identified transmission system issues. A variety of possible solution types and resource combinations were considered, and four principal solution types emerged: generation, transformer addition with minimal system reinforcements, demand side reduction, and transmission lines plus transformers. To be considered viable, a solution had to solve the transmission issues identified in the Eastside Needs Assessment, comply with environmental requirements, and satisfy constructability and longevity requirements.

The addition of new generation, specifically a 300 MW gas turbine, was determined to be a technically feasible solution, and three potential locations were evaluated as possible sites. However, environmental constraints - noise and atmospheric emission standards - and permitting challenges eliminated two sites, while the third, Cedar Hills, remains a potentially viable solution but would require two new transmission lines connecting Cedar Hills to both Lake Tradition and Berrydale transmission substations. This would result in building 17 miles of new 115 kV transmission lines, and rebuilding 21 miles of existing 115 kV transmission lines. In addition, according to PSE's power flow studies, generation at Cedar Hills alone did not prove enough relief to solve the identified capacity problems.

The Sammamish, Talbot Hill, and Lake Tradition substations were evaluated as sites for additional transformers, but modelling revealed that numerous overloads would occur without the additions of new lines as well. Therefore, transformers as a stand-alone solution were deemed unviable.

Potential additional demand side reduction measures were reviewed by the PSE Energy Efficiency Group. And in order to ensure full evaluation and consideration of all non-wires alternatives, PSE engaged an outside consultant to conduct an exhaustive review of non-wires solutions.

Many resource combinations were evaluated based on their effectiveness at resolving the capacity deficiency, operational flexibility, potential to eliminate reliance on CAPs, right of way assessment, and effects on adjacent grid infrastructure. After reviewing each solution type, exploring alternatives, and performing power flow analysis on each, the most viable solution type identified was the combination of new transformers and new/upgraded transmission lines. The five potential upgrades are summarized in Table 49.

Table 49. Proposed Eastside Transformer and Transmission Solutions

230 kV Line Alternative	Substation Alternative
Rebuild one Talbot Hill- Lakeside-Sammamish 115 kV line to 230 kV and loop through new substation	Westminster
Rebuild one Talbot Hill- Lakeside-Sammamish 115 kV line to 230 kV and loop through new substation	Lakeside
Build new Talbot Hill-Sammamish 230 kV line on new right of way, loop through new substation	Westminster
Build new Talbot Hill-Sammamish 230 kV line on new right of way, loop through new substation	Vernell
Build new Talbot Hill-Sammamish 230 kV line on new right of way, loop through new substation	Lakeside

C2. Non-Wires Alternatives

In February 2014 Energy and Environmental Economics (E3) provided a screening-level assessment (the "Non-Wires Report) to examine whether non-wires alternatives could effectively defer the proposed King County Transmission upgrades from winter 2017-2018 until winter 2021. Non-wires alternatives considered include energy efficiency, demand response, distributed generation, as well as solar PV, customer sited backup generation, and combined heat and power.

Need

Using the power flow case data from the Eastside Assessment, PSE planners quantified the supply capacity that would be required to defer transmission upgrades identified in the Eastside Solutions Study until 2021. Analysis focused on the 2021 winter peak load since the most significant overloads occur due to winter peak conditions. Should DSR be able to sufficiently address winter needs, summer loads would then be examined.

PSE determined that a minimum of 70 MW of incremental load reduction would be required for a four year deferral (2017-2021) while maintaining system reliability at 2017 levels,[121] assuming normal weather conditions and 100% of PSE's IRP-identified demand side reduction measures were also successful. Should load growth be higher than planned (either due to extreme weather or less than 100% success with IRP-identified demand side reduction[122]), the need could be as much as 160 MW. Analysis also showed that the incremental load reduction must be realized within the Eastside King County area, as demand reduction outside of that zone was shown to be less effective at mitigating local winter overloading.

Incremental demand reduction between 2017-2021 would maintain a system reliability level relative to that projected for 2017, however, it would not address current system overloading risks that require CAPs.[123] To reduce reliance on currently utilized CAPs, as well as those anticipated as necessary to deal with 2017 peak loads, additional load reduction would be required.

Method

The Non-wires Report considered the potential of incremental non-wires alternatives to meet the minimum 70 MW target. Two main criteria guided the evaluation: ability to reduce loads during critical peak periods[124] and cost-effectiveness.

Supply deficiencies and overloading occur at specific times, called the critical peak period, which, in PSE's winter peak, typically happens on December weekdays from 7-11 AM and 6-10 PM. Resources that would reduce demand during critical peak periods would effectively mitigate upgrade need, but technologies that produce the majority of their power outside of those periods, like solar PV, would not meet the criteria necessary for consideration as a solution.

Cost-effectiveness was determined by incorporating the incremental savings from deferring transmission upgrades (valued at $155 per kW), avoided generation and transmission supply costs (supplied by PSE and valued at the IRP 2013 Base hourly energy price), and aggregating other savings generated from DSR.[125] This results in a broader range of potentially viable non-wires alternatives

[121] True capacity deficits could be larger if any of the following occurred: Extreme cold weather conditions (models and forecasts are based on 23° F average), faster load growth than expected (based on prevailing economic conditions), or IRP conservation targets were implemented slower than expected.

[122] IRP 2014-2021 DSR targets: 550 MW of energy efficiency and distributed generation, 10 MW from distribution system efficiency, and 108 MW of demand response.

[123] The current energy storage alternatives assessment does look how to reduce reliance on CAPs, as PSE has determined that the capital investment in ESS is significant enough such that the system must restore a higher (more standard) level of system reliability. This is the key contributing factor to the higher megawatt target evaluated in this assessment.

[124] Overloading at Talbot Hill coincides with PSE's system winter peak load, so the latter was used in the analysis.

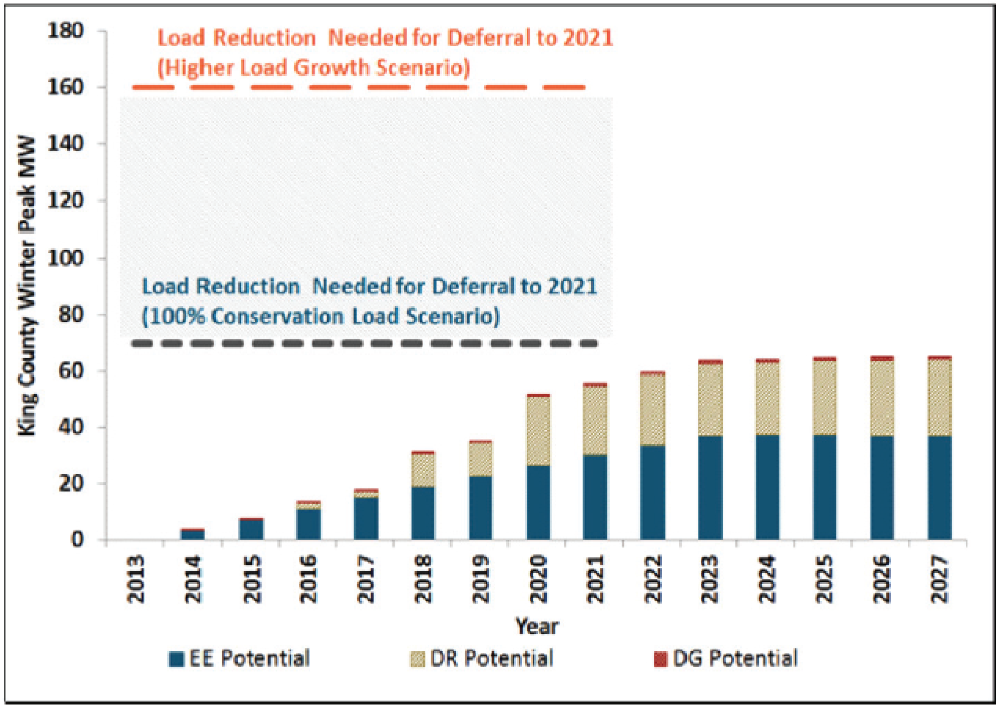
[125] Savings could include deferred need for distribution upgrades and reducing generation capacity costs.

than the IRP identified as cost-effective, because the threshold for cost-effectiveness would reflect these additional system benefits.

Results

The total non-wires alternatives achievable by 2021 and passing the necessary criteria equaled an incremental 56 MW of resources beyond those identified in the IRP. This included 30 MW of energy efficiency, 25 MW of demand response, and 1 MW of distributed generation. The cumulative, incremental acquisition of available DSR from 2013 to 2027 is displayed in Figure 18.

Figure 18. Total Non-Wires Potential in Eastside King County[126]



C3. Energy Storage Alternatives

As discussed above, Puget Sound Energy is actively studying a variety of solutions to remedy their current and projected transmission supply issues. The Eastside Solution Study identified five potential transmission alternative solutions that would effectively address overloading in summer at Sammamish Substation and at Talbot Hill in winter, alleviate transmission supply deficiencies throughout the service area, and increase overall system reliability by reducing CAP reliance. PSE estimates the costs of these projects to range from $155 million to $288 million, but they would each address all of the issues identified in the Eastside Needs Assessment. The Non-wires Report identified 56 MW of incremental cost-effective conservation, in addition to the

[126] E3 (2014)

IRP-established demand-side resource goals. By itself, this level is insufficient to meet the minimum 70 MW required to defer transmission upgrades from 2017-2021.

The Non-wires Report did not consider energy storage as an additional non-wires alternative to help manage the Eastside needs. This Eastside System Energy Storage Alternatives Screening Study builds upon the previous Non-wires Report to determine whether energy storage incremental to other non-wires alternatives would be a technically feasible, commercially viable, and cost effective solution to meet the Eastside need.

Appendix D: Unquantified and Partially Quantified Benefits

Although only a few of the prospective storage benefits and services applied to the evaluation for the Eastside, it is important to have at least cursory familiarity with the broader spectrum of benefits and services that storage can provide in the future. This appendix provides a very cursory overview of key ones. They are presented in no particular order.

Energy Time-Shifting

Energy time-shifting is perhaps the most familiar storage service. In essence the energy time-shift benefit is related generation and/or purchase of low priced/low cost electric energy when demand is low, for use or sale when demand and price are high (i.e., buy low – sell high). For the Eastside evaluation the energy time-shift benefit was included in the flexibility benefit calculation.

Ancillary Services

Given that most storage types are very responsive they are especially well-suited providing the full spectrum ancillary services including frequency regulation, load following/ramping, balancing, reserve capacity and others.

In general terms, the benefit associated with storage for ancillary services include those related to more efficacious use of generation resources (see dynamic operating benefits) and reduced opportunity cost related to use of generation for ancillary services (rather than for generating electric *energy*).

For this evaluation PSE included the value for ancillary services as part of the "flexibility benefit."

Generation Dynamic Operating Benefits

This benefit involves an overall improvement of electric generation fleet operations due to storage, use sometimes referred to as "dynamic operating benefits." Storage improves generation fleet fuel efficiency, reduces air emission and reduces maintenance cost by enabling more constant, optimized dispatch of generation. Reduced load following/ramping and part load operation and fewer startups 1) reduces equipment wear and related maintenance cost, 2) reduces fuel use and air emissions (per kWh of energy), 3) increases equipment life, and 4) increases generation asset utilization.

Ideally estimating this benefit involves "before and after" (with and without storage) production cost model runs. Furthermore, those runs would require more detailed performance data than is typically used, especially including "curves" for a) fuel efficiency, b) emissions, and c) variable O&M at various levels of operation and cost per start-up.

Reduced Need for Flexible Generation Capacity

In addition to the assessment of PSE's "flexibility benefits" for the *existing* electric supply resource configuration, storage could also reduce the need for *additional* "flexible capacity" (especially combustion turbines) beyond that needed to address load growth and equipment retirement).

However, that benefit is likely to be limited for PSE because hydroelectric generation provides most flexibility during most of the year. Nonetheless, in the future such flexible capacity will be increasingly valuable and may be part of the utility's overall approach to reducing GHG gas emissions, integration of additional renewables generation and will certainly provide generation dynamic operating benefits.

Transmission Support and Voltage Control

Storage can be used to improve the operation of transmission and distribution T&D equipment/systems and to optimize the effectiveness of those T&D assets. Storage located electrically downstream from T&D hot spots can be used to reduce power draw on T&D equipment when/if overloading occurs. Storage can provide more operational flexibility than is possible with just T&D equipment, especially when the utility must respond to existing or looming T&D-related problems. Storage can enable increased throughput of T&D equipment by giving T&D system operators means to provide more stable electricity flow. Key examples include use of storage for damping and to manage excess reactance and sub-synchronous resonance.

Storage is also likely to become an important element of utilities' increasing focus on Volt/VAR control, especially at the distribution and subtransmission levels, and may even be a part of utilities' conservation voltage reduction programs.

Reduced T&D I^2R Energy Losses

Depending on the circumstances, benefits associated with reduced T&D I^2R energy losses may be significant. The benefit accrues if storage a) is charged during night or other off-peak times when temperatures tend to be lower and power draw/current flow and I^2R losses are lowest and b) discharged such that it offsets real-time power draw by loads (i.e., during the day when temperatures, power draw/current flow and I^2R losses are highest).

The effect on capacity requirements is significant because additional equipment is needed to make-up for the energy losses, so that enough energy is delivered to end-users. Consider an example: On-peak T&D I^2R energy losses of 7.5% means that there must be an additional 7.5% of supply capacity to make up for the losses.

Generally the effect on capacity requirements is less significant the closer equipment is to end users. So at the transmission system level, I^2R energy losses may increase transmission capacity required, adding perhaps 4% to 5% to transmission capacity needs. There is a similar but somewhat lower effect at the distribution level although that would only apply to truly distributed resources.

Regarding *energy*, the “net” benefit is a function of I^2R energy losses during times when storage is charged and I^2R energy losses during times when storage is discharging. Consider an example. During peak demand times (presumably when storage is discharging) I^2R energy losses are 7.5% and during off-peak times (when storage is charging) are 4.5% the net benefit (associated with reduced T&D I^2R energy losses) is a function of the net losses avoided or 7.5% - 4.5% = 3%.

Renewables Integration

Storage can be an important enabler of increased use of renewables, especially those whose output varies (e.g., wind and solar generation). Storage can also enable use of additional energy from hydroelectric generation, especially during years when precipitation is significant and/or times of the year when significant amounts of hydroelectric generated electricity is produced and demand is relatively low.

Regarding integration of renewables with variable output: Storage enables grid system operators to compensate quickly and effectively for renewable generators’ diurnal and short duration output variation. That improves the operation of the thermal generation fleet and allows grid operators to address more localized integration challenges such as voltage fluctuations and current backflow.

And, storage can reduce electricity oversupply (and thus “curtailment” of generation output) that occurs when a) the amount of generation output exceeds demand and b) most or all generation operating is not “dispatachable” (i.e., output cannot be varied without significant cost implications), especially steam-based generation and in some cases hydroelectric generation.

This benefit is very circumstance specific, varying by location, time-of-day, day-of-week, month, and year. Furthermore, it is a composite of several other specific benefits such as increased (RE) energy value, increased (RE generation) supply capacity value, reduced need for ancillary services, (system) dynamic operating benefits (DOBs) and flexibility, improved/optimized localized Voltage and energy flow management.

Reduced GHG Emissions

Storage can reduce GHG emissions in several ways, including those addressed for the PSE Eastside evaluation: 1) reduced starts and run-time of generation and 2) more optimal generation fleet operation (i.e., for dynamic operating benefits).

Storage may also enable a) reduced use of fossil-fueled generation overall and/or b) increased generation using “cleaner” thermal generation, especially high efficiency combined cycle natural gas fueled resources, and/or c) increased use of demand response and renewables - including increased import of energy from hydroelectric generation. Storage may also help to reduce GHG emissions by enabling more use of electric vehicles.

Electric Service Reliability

The topic of reliability is quite broad and complex. However, in simple terms storage can be an important solution when electric service reliability challenges exist.

Of course end-users can use storage for "back-up power" or, in the future, utilities could provide such services.

Storage can reduce transmission and distribution related challenges that affect service reliability. Storage can improve the power quality on and throughput of T&D equipment by enabling more stable electricity flow (see transmission support below). That reduces the chance that the transmission system will be overloaded or that power quality will be unacceptable, thus reducing the likelihood of transmission related shutdowns and resulting outages. Storage can also be used to reduce peak T&D equipment loading: Even reducing power draw on the equipment by a few percentage points may be important, depending on circumstances. If nothing else it reduces the chance that T&D equipment will be overloaded, which may reduce outages.

The value for such reliability improvements is quite circumstance-specific but generally it is a function of outage-related costs that can be avoided if storage reduces service outages. Key data required to assess those avoided costs include those related to the number and duration of outages and related costs that the storage will obviate. Those costs may include: a) lost revenue during outages, b) utility equipment damage due to overloading before equipment trips off-line, c) utility response cost for outages, d) customer financial losses that the utility must cover such as food spoilage and end-use equipment damage, and e) fines/penalties if any. Significant business-related costs may accrue if outages result in lost productivity and damaged manufactured products.

Capacity for Daytime Electric Vehicle Charging

Storage may become an important element of the overall approach to enabling greater use of electric vehicles. Indeed, without storage there may be too much demand for EV charging during the day (i.e., during peak demand periods) because the existing generation and/or T&D infrastructures may not have enough capacity to serve traditional demand plus power requirements for daytime EV charging.

Appendix E: Generation Capacity Cost *Pro Forma*

PEAKER REVENUE REQUIREMENT Based on Generic SCCT from 2013 IRP

ASSUMPTIONS

Capex (2017$)	228,788,000	Book Life (yrs)	35
Annual Fixed O&M	4,978,000	Insurance Rate (%)	0.080%

CAPITAL STRUCTURE	Ratio	Pre-Tax Cost	Pre-Tax Weighted	After-Tax Weighted
LT Debt	48.00%	6.16%	2.96%	1.92%
ST Debt	4.00%	2.68%	0.11%	0.07%
Preferred	0.00%	0.0%	0.00%	0.00%
Equity	48.0%	9.80%	4.70%	4.70%
	100%		7.77%	6.70%

PEAKER BUILT IN 2017

REVENUE REQUIREMENT CALCULATION	Sum	2017 1	2018 2	2019 3	2020 4	2021 5	2022 6	2023 7	2024 8
Gross Property, Plant and Equipment ($)		228,788,000	228,788,000	228,788,000	228,788,000	228,788,000	228,788,000	228,788,000	228,788,000
Book Depreciation Expense ($)	228,788,000	6,536,800	6,536,800	6,536,800	6,536,800	6,536,800	6,536,800	6,536,800	6,536,800
Accumulated Book Depreciation ($)		6,536,800	13,073,600	19,610,400	26,147,200	32,684,000	39,220,800	45,757,600	52,294,400
Net Property, Plant and Equipment ($)		222,251,200	215,714,400	209,177,600	202,640,800	196,104,000	189,567,200	183,030,400	176,493,600
Avg. Net Property, Plant and Equipment ($)		225,519,600	218,982,800	212,446,000	205,909,200	199,372,400	192,835,600	186,298,800	179,762,000
Deferred Taxes From Depreciation ($)	(0)	714,963	3,492,792	3,058,781	2,658,402	2,286,850	1,944,126	1,626,225	1,333,148
Accumulated Deferred Taxes ($)	419,002,229	714,963	4,207,755	7,266,536	9,924,938	12,211,788	14,155,914	15,782,139	17,115,287
Average accumulated Deferred Taxes ($)	402,987,069	357,481	2,461,359	5,737,145	8,595,737	11,068,363	13,183,851	14,969,027	16,448,713
Rate Base ($)		225,162,119	216,521,441	206,708,855	197,313,463	188,304,037	179,651,749	171,329,773	163,313,287
Wtd. After-Tax Cost of Capital (%)		6.70%	6.70%	6.70%	6.70%	6.70%	6.70%	6.70%	6.70%
Return on Rate Base ($)	205,596,606	15,075,730	14,497,193	13,840,191	13,211,123	12,607,897	12,028,583	11,471,385	10,934,641
Grossed-up (for FIT) Return on Rate Base ($)	316,302,471	23,193,430	22,303,374	21,292,602	20,324,805	19,396,764	18,505,512	17,648,285	16,822,525
Depreciation ($)	228,788,000	6,536,800	6,536,800	6,536,800	6,536,800	6,536,800	6,536,800	6,536,800	6,536,800
Fixed O&M		4,978,000	5,102,450	5,230,011	5,360,762	5,494,781	5,632,150	5,772,954	5,917,278
Insurance		180,416	175,186	169,957	164,727	159,498	154,268	149,039	143,810
Property Taxes		1,066,806	1,035,429	1,004,052	972,676	941,299	909,923	878,546	847,169
Pre-Tax Revenue Requirement		35,955,452	35,153,239	34,233,423	33,359,769	32,529,142	31,738,653	30,985,623	30,267,581
Gross-up Factor for State Revenue Taxes		0.961	0.961	0.961	0.961	0.961	0.961	0.961	0.961
Revenue Requirement	**475,248,209**	37,403,423	36,568,904	35,612,045	34,703,209	33,839,131	33,016,808	32,233,453	31,486,495
NPV Revenue Requirement @ 7.77%		384,897,217							
Plant Capacity (kW, winter)		221,000							
Rev Req per Unit Capacity ($/kW)		1,742							
Levelized Cost (35 years) ($/kW-yr)		146							

REVENUE REQUIREMENT CALCULATION	2025 9	2026 10	2027 11	2028 12	2029 13	2030 14	2031 15	2032 16
Gross Property, Plant and Equipment ($)	228,788,000	228,788,000	228,788,000	228,788,000	228,788,000	228,788,000	228,788,000	228,788,000
Book Depreciation Expense ($)	6,536,800	6,536,800	6,536,800	6,536,800	6,536,800	6,536,800	6,536,800	6,536,800
Accumulated Book Depreciation ($)	58,831,200	65,368,000	71,904,800	78,441,600	84,978,400	91,515,200	98,052,000	104,588,800
Net Property, Plant and Equipment ($)	169,956,800	163,420,000	156,883,200	150,346,400	143,809,600	137,272,800	130,736,000	124,199,200
Avg. Net Property, Plant and Equipment ($)	173,225,200	166,688,400	160,151,600	153,614,800	147,078,000	140,541,200	134,004,400	127,467,600
Deferred Taxes From Depreciation ($)	1,285,102	1,284,301	1,285,102	1,284,301	1,285,102	1,284,301	1,285,102	1,284,301
Accumulated Deferred Taxes ($)	18,400,389	19,684,691	20,969,793	22,254,094	23,539,197	24,823,498	26,108,600	27,392,902
Average accumulated Deferred Taxes ($)	17,757,838	19,042,540	20,327,242	21,611,944	22,896,645	24,181,347	25,466,049	26,750,751
Rate Base ($)	155,467,362	147,645,860	139,824,358	132,002,856	124,181,355	116,359,853	108,538,351	100,716,849
Wtd. After-Tax Cost of Capital (%)	6.70%	6.70%	6.70%	6.70%	6.70%	6.70%	6.70%	6.70%
Return on Rate Base ($)	10,409,317	9,885,629	9,361,940	8,838,251	8,314,563	7,790,874	7,267,185	6,743,497
Grossed-up (for FIT) Return on Rate Base ($)	16,014,334	15,208,659	14,402,984	13,597,310	12,791,635	11,985,960	11,180,285	10,374,610
Depreciation ($)	6,536,800	6,536,800	6,536,800	6,536,800	6,536,800	6,536,800	6,536,800	6,536,800
Fixed O&M	6,065,210	6,216,840	6,372,261	6,531,567	6,694,857	6,862,228	7,033,784	7,209,628
Insurance	138,580	133,351	128,121	122,892	117,662	112,433	107,204	101,974
Property Taxes	815,793	784,416	753,039	721,663	690,286	658,909	627,533	596,156
Pre-Tax Revenue Requirement	29,570,717	28,880,066	28,193,206	27,510,232	26,831,240	26,156,330	25,485,605	24,819,169
Gross-up Factor for State Revenue Taxes	0.961	0.961	0.961	0.961	0.961	0.961	0.961	0.961
Revenue Requirement	30,761,566	30,043,102	29,328,582	28,618,103	27,911,767	27,209,678	26,511,942	25,818,668

PEAKER REVENUE REQUIREMENT

ASSUMPTIONS
Capex (2017$)
Annual Fixed O&M

PEAKER BUILT IN 2017	**2033**	**2034**	**2035**	**2036**	**2037**	**2038**	**2039**	**2040**	**2041**	**2042**	**2043**	**2044**	**2045**	**2046**	**2047**	**2048**	**2049**	**2050**	**2051**
REVENUE REQUIREMENT CALCULATION	**17**	**18**	**19**	**20**	**21**	**22**	**23**	**24**	**25**	**26**	**27**	**28**	**29**	**30**	**31**	**32**	**33**	**34**	**35**
Gross Property, Plant and Equipment ($)	228,788,000	228,788,000	228,788,000	228,788,000	228,788,000	228,788,000	228,788,000	228,788,000	228,788,000	228,788,000	228,788,000	228,788,000	228,788,000	228,788,000	228,788,000	228,788,000	228,788,000	228,788,000	228,788,000
Book Depreciation Expense ($)	6,536,800	6,536,800	6,536,800	6,536,800	6,536,800	6,536,800	6,536,800	6,536,800	6,536,800	6,536,800	6,536,800	6,536,800	6,536,800	6,536,800	6,536,800	6,536,800	6,536,800	6,536,800	6,536,800
Accumulated Book Depreciation ($)	111,125,600	117,662,400	124,199,200	130,736,000	137,272,800	143,809,600	150,346,400	156,883,200	163,420,000	169,956,800	176,493,600	183,030,400	189,567,200	196,104,000	202,640,800	209,177,600	215,714,400	222,251,200	228,788,000
Net Property, Plant and Equipment ($)	117,662,400	111,125,600	104,588,800	98,052,000	91,515,200	84,978,400	78,441,600	71,904,800	65,368,000	58,831,200	52,294,400	45,757,600	39,220,800	32,684,000	26,147,200	19,610,400	13,073,600	6,536,800	-
Avg. Net Property, Plant and Equipment ($)	120,930,800	114,394,000	107,857,200	101,320,400	94,783,600	88,246,800	81,710,000	75,173,200	68,636,400	62,099,600	55,562,800	49,026,000	42,489,200	35,952,400	29,415,600	22,878,800	16,342,000	9,805,200	3,268,400
Deferred Taxes From Depreciation ($)	1,285,102	1,284,301	1,285,102	1,284,301	(501,389)	(2,287,880)	(2,287,880)	(2,287,880)	(2,287,880)	(2,287,880)	(2,287,880)	(2,287,880)	(2,287,880)	(2,287,880)	(2,287,880)	(2,287,880)	(2,287,880)	(2,287,880)	(2,287,880)
Accumulated Deferred Taxes ($)	28,678,004	29,962,305	31,247,407	32,531,709	32,030,320	29,742,440	27,454,560	25,166,680	22,878,800	20,590,920	18,303,040	16,015,160	13,727,280	11,439,400	9,151,520	6,863,640	4,575,760	2,287,880	(0)
Average accumulated Deferred Taxes ($)	28,035,453	29,320,155	30,604,856	31,889,558	32,281,014	30,886,380	28,598,500	26,310,620	24,022,740	21,734,860	19,446,980	17,159,100	14,871,220	12,583,340	10,295,460	8,007,580	5,719,700	3,431,820	1,143,940
Rate Base ($)	92,895,347	85,073,845	77,252,344	69,430,842	62,502,586	57,360,420	53,111,500	48,862,580	44,613,660	40,364,740	36,115,820	31,866,900	27,617,980	23,369,060	19,120,140	14,871,220	10,622,300	6,373,380	2,124,460
Wtd. After-Tax Cost of Capital (%)	6.70%	6.70%	6.70%	6.70%	6.70%	6.70%	6.70%	6.70%	6.70%	6.70%	6.70%	6.70%	6.70%	6.70%	6.70%	6.70%	6.70%	6.70%	6.70%
Return on Rate Base ($)	6,219,808	5,696,119	5,172,431	4,648,742	4,184,861	3,840,567	3,556,080	3,271,594	2,987,108	2,702,621	2,418,135	2,133,648	1,849,162	1,564,675	1,280,189	995,703	711,216	426,730	142,243
Grossed-up (for FIT) Return on Rate Base ($)	9,568,935	8,763,260	7,957,586	7,151,911	6,438,247	5,908,564	5,470,893	5,033,222	4,595,550	4,157,879	3,720,207	3,282,536	2,844,864	2,407,193	1,969,521	1,531,850	1,094,179	656,507	218,836
Depreciation ($)	6,536,800	6,536,800	6,536,800	6,536,800	6,536,800	6,536,800	6,536,800	6,536,800	6,536,800	6,536,800	6,536,800	6,536,800	6,536,800	6,536,800	6,536,800	6,536,800	6,536,800	6,536,800	6,536,800
Fixed O&M	7,389,869	7,574,616	7,763,981	7,958,081	8,157,033	8,360,958	8,569,982	8,784,232	9,003,838	9,228,934	9,459,657	9,696,148	9,938,552	10,187,016	10,441,691	10,702,734	10,970,302	11,244,560	11,525,674
Insurance	96,745	91,515	86,286	81,056	75,827	70,597	65,368	60,139	54,909	49,680	44,450	39,221	33,991	28,762	23,532	18,303	13,074	7,844	2,615
Property Taxes	564,780	533,403	502,026	470,650	439,273	407,896	376,520	345,143	313,766	282,390	251,013	219,636	188,260	156,883	125,507	94,130	62,753	31,377	-
Pre-Tax Revenue Requirement	24,157,128	23,499,594	22,846,679	22,198,497	21,647,180	21,284,817	21,019,563	20,759,535	20,504,863	20,255,682	20,012,128	19,774,342	19,542,468	19,316,654	19,097,052	18,883,817	18,677,108	18,477,088	18,283,924
Gross-up Factor for State Revenue Taxes	0.961	0.961	0.961	0.961	0.961	0.961	0.961	0.961	0.961	0.961	0.961	0.961	0.961	0.961	0.961	0.961	0.961	0.961	0.961
Revenue Requirement	25,129,966	24,445,952	23,766,743	23,092,459	22,518,939	22,141,983	21,866,047	21,595,548	21,330,620	21,071,403	20,818,041	20,570,679	20,329,467	20,094,560	19,866,114	19,644,292	19,429,258	19,221,183	19,020,240

Appendix F: Storage Cost *Pro Forma*

STORAGE SYSTEM REVENUE REQUIREMENT

CAPITAL ACQUISITION

INPUTS					
System Size (kW)	121,000	Book Life (yrs)	20	System Size (MWh)	225.6
System Cost ($/kWh)	813	State Revenue Tax	4.5873%		
Hours of Discharge	1.86	Property Tax	0.4800%		
Capex ($)	183,420,000	FIT Rate	35.0%		
Fixed O&M ($/kW-yr)	5.00	Insurance Rate (%)	0.08%		
O&M Escalation	2.50%				

REVENUE REQUIREMENT CALCULATION	Sum	1	2	3	4	5	6	7	8	9	10
Gross Property, Plant and Equipment ($)		183,420,000	183,420,000	183,420,000	183,420,000	183,420,000	183,420,000	183,420,000	183,420,000	183,420,000	183,420,000
Book Depreciation Expense ($)	183,420,000	9,171,000	9,171,000	9,171,000	9,171,000	9,171,000	9,171,000	9,171,000	9,171,000	9,171,000	9,171,000
Accumulated Book Depreciation ($)		9,171,000	18,342,000	27,513,000	36,684,000	45,855,000	55,026,000	64,197,000	73,368,000	82,539,000	91,710,000
Net Property, Plant and Equipment ($)		174,249,000	165,078,000	155,907,000	146,736,000	137,565,000	128,394,000	119,223,000	110,052,000	100,881,000	91,710,000
Avg. Net Property, Plant and Equipment ($)		178,834,500	169,663,500	160,492,500	151,321,500	142,150,500	132,979,500	123,808,500	114,637,500	105,466,500	96,295,500
Deferred Taxes From Depreciation ($)	0	(802,463)	1,424,531	1,076,584	755,599	457,725	182,961	(71,901)	(306,862)	(345,380)	(346,022)
Accumulated Deferred Taxes ($)	21,349,996	(802,463)	622,069	1,698,653	2,454,251	2,911,976	3,094,937	3,023,037	2,716,175	2,370,795	2,024,773
Average accumulated Deferred Taxes ($)	21,349,996	(401,231)	(90,197)	1,160,361	2,076,452	2,683,114	3,003,457	3,058,987	2,869,606	2,543,485	2,197,784
Rate Base ($)		179,235,731	169,753,697	159,332,139	149,245,048	139,467,386	129,976,043	120,749,513	111,767,894	102,923,015	94,097,716
Wtd. After-Tax Cost of Capital (%)		6.70%	6.70%	6.70%	6.70%	6.70%	6.70%	6.70%	6.70%	6.70%	6.70%
Return on Rate Base ($)	121,331,424	12,000,728	11,365,859	10,668,083	9,992,702	9,338,039	8,702,546	8,084,784	7,483,419	6,891,210	6,300,313
Grossed-up (for FIT) Return on Rate Base ($)	186,663,730	18,462,659	17,485,937	16,412,436	15,373,388	14,366,214	13,388,532	12,438,129	11,512,953	10,601,862	9,692,789
Depreciation ($)	183,420,000	9,171,000	9,171,000	9,171,000	9,171,000	9,171,000	9,171,000	9,171,000	9,171,000	9,171,000	9,171,000
O&M		620,125	635,628	651,519	667,807	684,502	701,615	719,155	737,134	755,562	774,451
Insurance		143,068	135,731	128,394	121,057	113,720	106,384	99,047	91,710	84,373	77,036
Property Taxes		836,395	792,374	748,354	704,333	660,312	616,291	572,270	528,250	484,229	440,208
Pre-Tax Revenue Requirement		29,233,247	28,220,670	27,111,702	26,037,585	24,995,748	23,983,822	22,999,601	22,041,046	21,097,026	20,155,484
Gross-up Factor for State Revenue Taxes		0.954	0.954	0.954	0.954	0.954	0.954	0.954	0.954	0.954	0.954
Revenue Requirement		**30,638,738**	**29,577,478**	**28,415,193**	**27,289,433**	**26,197,506**	**25,136,928**	**24,105,387**	**23,100,747**	**22,111,340**	**21,124,530**

REVENUE REQUIREMENT CALCULATION	11	12	13	14	15	16	17	18	19	20	21
Gross Property, Plant and Equipment ($)	183,420,000	183,420,000	183,420,000	183,420,000	183,420,000	183,420,000	183,420,000	183,420,000	183,420,000	183,420,000	-
Book Depreciation Expense ($)	9,171,000	9,171,000	9,171,000	9,171,000	9,171,000	9,171,000	9,171,000	9,171,000	9,171,000	9,171,000	-
Accumulated Book Depreciation ($)	100,881,000	110,052,000	119,223,000	128,394,000	137,565,000	146,736,000	155,907,000	165,078,000	174,249,000	183,420,000	-
Net Property, Plant and Equipment ($)	82,539,000	73,368,000	64,197,000	55,026,000	45,855,000	36,684,000	27,513,000	18,342,000	9,171,000	-	-
Avg. Net Property, Plant and Equipment ($)	87,124,500	77,953,500	68,782,500	59,611,500	50,440,500	41,269,500	32,098,500	22,927,500	13,756,500	4,585,500	-
Deferred Taxes From Depreciation ($)	(345,380)	(346,022)	(345,380)	(346,022)	(345,380)	(346,022)	(345,380)	(346,022)	(345,380)	(346,022)	1,432,235
Accumulated Deferred Taxes ($)	1,679,394	1,333,372	987,992	641,970	296,590	(49,432)	(394,812)	(740,833)	(1,086,213)	(1,432,235)	0
Average accumulated Deferred Taxes ($)	1,852,083	1,506,383	1,160,682	814,981	469,280	123,579	(222,122)	(567,822)	(913,523)	(1,259,224)	(716,118)
Rate Base ($)	85,272,417	76,447,117	67,621,818	58,796,519	49,971,220	41,145,921	32,320,622	23,495,322	14,670,023	5,844,724	716,118
Wtd. After-Tax Cost of Capital (%)	6.70%	6.70%	6.70%	6.70%	6.70%	6.70%	6.70%	6.70%	6.70%	6.70%	0.00%
Return on Rate Base ($)	5,709,415	5,118,517	4,527,619	3,936,721	3,345,823	2,754,925	2,164,027	1,573,129	982,231	391,334	-
Grossed-up (for FIT) Return on Rate Base ($)	8,783,715	7,874,641	6,965,567	6,056,494	5,147,420	4,238,346	3,329,273	2,420,199	1,511,125	602,052	-
Depreciation ($)	9,171,000	9,171,000	9,171,000	9,171,000	9,171,000	9,171,000	9,171,000	9,171,000	9,171,000	9,171,000	-
O&M	793,812	813,658	833,999	854,849	876,220	898,126	920,579	943,594	967,183	991,363	-
Insurance	69,700	62,363	55,026	47,689	40,352	33,016	25,679	18,342	11,005	3,668	-
Property Taxes	396,187	352,166	308,146	264,125	220,104	176,083	132,062	88,042	44,021	-	-
Pre-Tax Revenue Requirement	19,214,414	18,273,828	17,333,738	16,394,157	15,455,097	14,516,571	13,578,593	12,641,176	11,704,335	10,768,083	-
Gross-up Factor for State Revenue Taxes	0.954	0.954	0.954	0.954	0.954	0.954	0.954	0.954	0.954	0.954	0.954
Revenue Requirement	**20,138,214**	**19,152,406**	**18,167,118**	**17,182,363**	**16,198,155**	**15,214,506**	**14,231,431**	**13,248,945**	**12,267,062**	**11,285,796**	**-**

Revenue Requirement, Scaled ($Million)	
$Current ($000)	414,783
$/kW	3,428
$NPV ($000)*	**264,217**
$/kW*	**$2,183.61**
$/kW-year Levelized*	**$218.58**

* Life: 20 years, WACC (Discount Rate): 7.77%

Appendix G: About Strategen

Strategen Consulting brings the insight and hands-on experience required to make intelligent decisions about clean energy and advanced grid solutions.

Strategen Expertise

The Strategen team, including its extended network of senior advisors, has extensive experience in the electric power system, energy markets, renewable energy, energy storage, and smart grid technology:

T&D/Electric Infrastructure Planning:

- California, WECC and FERC Order 1000 interregional transmission planning processes
- Load and system resource planning
- NERC reliability criteria
- Transmission & distribution deferral, and non-wires alternatives analysis
- Resource interconnection processes
- FERC and state regulation

Wholesale Energy Markets:

- Market design & regulatory policy
- Ancillary Services
- System, Local and Flexible Capacity
- GHG Pricing / Cap & Trade
- CAISO Energy Imbalance Market (EIM)

Energy Storage:

- Storage value proposition and cost-effectiveness analysis (including both customer sited as well as distribution and transmission interconnected projects)
- Storage regulatory landscape
- Storage project/business due diligence
- Storage project development and financing
- Storage contracting and bid strategies

Renewable Energy:

- Solar project development and financing
- Solar regulatory landscape
- Solar value proposition analysis
- Solar technology/business due diligence
- Wind project development and financing
- Integrated solar + energy storage project development

Corporate Strategy:

- Related corporate diversification
- Venturing within large organizations
- White-space business and program development

Related Energy Industry:

- Utility programs and regulation
- Electric distribution system automation
- Energy controls systems
- Advanced sensors and metering
- Demand response

Supporting Functional Expertise:

- Strategic planning/vision development
- Energy regulatory strategy development
- Strategic marketing and sales forecasting
- Financial risk modeling and evaluation
- Project team development and recruitment