PGE

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July 14, 2017

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Public Utility Commission of Oregon
Attn: OPUC Filing Center
201 High St. SE, Suite 100
P. O. Box 1088
Salem, OR 97308-1088

Re: **UM ____ – PGE's Draft Storage Potential Evaluation**

In accordance with Commission Orders No. 16-504 and 17-118, enclosed is PGE's Draft Storage Potential Evaluation. Attachment A is the Draft Storage Potential Evaluation, designed to meet the guidelines outlined in Order 17-118. Attachment B is PGE's Summary of Energy Storage Request for Information (RFI), designed to meet item 2.g. in the Storage Potential Evaluation Guidelines set forth in Order No. 16-504.

To provide broader context for the study included as Attachment A, this letter outlines how PGE proposes to use this evaluation to propose energy storage projects to the OPUC, and summarizes the strengths and shortcomings of the three primary models used to inform the evaluation.

This evaluation in the context of UM 1751

The study provided herein demonstrates the potential benefits of different energy storage systems interconnected with PGE's electric system at various locations (i.e., storage "use cases"). The study does not identify or even contemplate potential costs of the storage systems required for each use case. Cost information will be included in the final evaluation submitted in concert with PGE's proposal of specific storage projects.

Importantly, the costs required to achieve the benefits outlined in the attached study go beyond the cost of the storage system itself, i.e., the cost of engineering, procuring and constructing the storage system. In some cases, achieving the benefits identified require whole system upgrades – for example, to achieve the power reliability benefits identified for storage located at customer sites requires site-specific engineering studies, site upgrades, and commissioning to enable the customer to effectively island some or all of its load from the grid during an outage. Another example is the need for energy storage communications and control platforms that enable PGE to automate and optimize dispatch of aggregated storage systems across the system in order to realize many of the benefits described. These broader system upgrades might provide broader benefits to PGE than those related to the storage project itself. For example, storage control platforms can provide learning and early frameworks that might enable broader benefits from other smart grid projects, like demand response and conservation voltage reduction.

Moreover, simply comparing the quantified benefits of storage systems to their total costs will not be sufficient for determining the most valuable storage projects for PGE to pursue in context of UM 1751. Consistent with OPUC Order No. 16-504, PGE plans to propose "a portfolio of projects that balance technology maturity, technology potential, short- and long-term project performance and risks, and short- and long-term potential value." Doing so presents the best opportunity to pursue projects that offer the greatest potential benefits for PGE customers.

Strengths and shortcomings of ROM, IPT, and NVEST

From a high level, the science and art of evaluating the potential for energy storage is nascent. Tools exist to do this work, but they are all in their early stages and will continue to evolve as the industry understanding and operational experience with energy storage systems mature. PGE has learned a tremendous amount about the potential of energy storage to serve grid needs from its Salem Smart Power Center. Such real-world examples, however, are too few and have thus far provided too little operational data to fully validate the work that the evaluation models used by Navigant and others attempt.

As the attached study describes in more detail, Navigant primarily relied upon three models to determine the benefits of the storage use cases. Two of these models – the Resource Optimization Model (ROM) and the Integrated Planning Tool (IPT) – are PGE models that historically have served other purposes and have been amended to evaluate energy storage. The Navigant Valuation of Energy Storage Tool (NVEST) took inputs from ROM, IPT, and other data sources (PGE data or typical industry values) to determine the potentially monetizable value of various storage applications and use cases. Each of the three primary models – ROM, IPT, and NVEST – used for the evaluation have their relative strengths and shortcomings, as described below.

<u>ROM</u>

ROM –first used to model energy storage in the 2016 IRP – is generally considered a best-in-class approach to identifying the benefits of introducing energy storage into a utility's total resource portfolio. PGE's ROM methodology was highlighted in the Energy Storage Association's 2016 primer on energy storage modeling in IRPs, and PGE was invited to present the analysis at industry and policy forums, including the Western Energy Institute's Integrated Resource Planning Forum and the North Carolina Sustainable Energy Association's Energy Storage Working Group. Moreover, at a May 24th Pacific Coast Distributed Energy Summit, Staff from the California PUC indicated that they were urging the utilities in California to essentially adopt a ROM-like approach to determine the benefits of energy storage to a utility's existing resource portfolio.

ROM has, however, two meaningful drawbacks. The first is that in order to actually identify overall benefits to storage, the storage system must be large – at least 50 MW (larger than the cap in HB 2193). Accordingly, the enclosed study assumed that the benefits ROM identified for a 50 MW system scale perfectly to systems of smaller sizes. This assumption may or may not be true.

A second complicating factor is that ROM holistically looks at how a total portfolio of resources acts to provide all of the following services: energy arbitrage, regulation, load following, and spinning/non-spinning reserves. ROM looks at one portfolio without storage and then an identical portfolio with storage. The improved performance of the latter portfolio represents the operational value of the storage system. The identified benefits encompass all of the applications listed above, accounting for the fact that operational decisions to provide one application necessarily have implications for the ability of the system to provide other applications. While this framework captures the total potential operational value, it does not lend itself easily to parsing individual operational benefits. As detailed in the attachment, PGE did some additional analysis to attempt to better isolate values of the unique energy and ancillary services captured by ROM, but such work is preliminary.

<u>IPT</u>

The IPT – a project valuation tool co-developed by PGE and BIS Consulting – is typically used to calculate and compare the economic merit of T&D system investments in different parts of PGE's service area. The IPT does this by comparing the cost of proposed T&D investments to their benefit. The benefit is calculated by determining the reduced risk of an outage to a customer.

The IPT draws on an array of foundational risk models used by T&D's Strategic Asset Management group (SAM) for long-range risk management planning. SAM calculates "risk" from the customer's perspective. In other words, while "risk" includes the direct costs of an outage to PGE and the cost of asset replacement (if required), the primary driver of risk in the T&D system is the economic impact of an outage on customers should an outage occur. Thus, the drivers of risk in the T&D system include the likelihood of an outage, the duration of an outage should an outage occur, the load affected in an outage, and the economic impact of the outage on the residential, commercial, and industrial customers that have lost power.

For this analysis, SAM's IPT tool was slightly modified to identify the best locations for energy storage; rather than calculating a benefit/cost ratio (which requires a cost input), the IPT simply looked at the reduction in baseline risk that was achievable should a battery be placed in the array of system locations identified for analysis (at the substation, on the feeder, etc.). The goal was to ascertain where in the system a reduction in outage duration would have maximum risk reduction benefit – in other words, where in PGE's system customers would most benefit from the outage mitigation benefits of a storage investment.

For substation and feeder-sited energy storage systems, this risk reduction benefit was interpreted as a potential avoided cost because it theoretically provides the opportunity to defer or avoid other investments in the distribution system. Importantly, these distribution benefits estimated in the report are based on statistical analysis over a large number of locations on the grid and are not representative of specific sites. Potential distribution benefits at specific sites will depend on the infrastructure, risks, and operational considerations at that specific site. For customer-sited systems in the report, the risk reduction benefit is interpreted as an individual customer benefit because those systems are modeled as behind-the-meter for simplicity. Installations at customer sites that are in front of the meter may blend distribution and utility customer benefits, but such determinations would be highly site- and configuration-specific.

Analysis of the benefits of energy storage in the distribution grid at other utilities has focused on identifying specific transformers or other distribution assets for which replacement due to load growth can be deferred. Such an approach was deemed insufficient for this analysis because of PGE's load growth profile. Within our territory, load growth tends to be clustered, meaning it is sudden and significant (e.g., a new server farm). Typically, this type of growth requires the installation of significant new infrastructure that could not be deferred through the installation of energy storage alone. Moreover, there are no incremental upgrades pending in PGE's system for which energy storage was deemed an adequately reliable and appropriate alternative to asset replacement.

To our knowledge, this evaluation is the first attempt to use such an approach to identify the distribution-level benefits of energy storage. PGE has received generally positive feedback from a number of stakeholders – including those well-versed in energy storage modeling – on the use of the IPT for this purpose. Our hope is that this approach to identifying the outage mitigation benefits of energy storage will be as appreciated as the use of ROM to identify energy and ancillary service benefits.

One drawback of the use of the IPT for this analysis is that it was built to compare the relative merits of projects across the T&D system as opposed to calculating the financial value of a specific project installation. Put another way, the values used to calculate outage impact costs to customers are not customer-specific; rather, they were taken from a generalized study of average outage costs to customers at the customer-class level (residential, commercial, industrial). In suit, the IPT is useful for determining the outage mitigation benefits of energy storage to a large number of customers, but when energy storage is located at a specific customer site to provide a power reliability benefit, generalized outage costs may not accurately represent the value these customers place on reliable power. In short, while the IPT outputs have been used to calculate posited power reliability benefits for customers, specific customers might (and likely will) value battery installation differently than calculated by the IPT. As such, the power reliability benefits identified in this report should be considered illustrative, not indicative.

NVEST

Finally, Navigant's NVEST model was used to combine inputs from ROM, IPT and other data sources and optimize different storage use cases. This model was used previously by, among others, five California utilities for compliance with the requirements of AB 2514, which established energy storage procurement targets. As desired by most stakeholders, the model is well established and transparent.

PGE appreciates the opportunity presented by HB 2193 and UM 1751 to continue to investigate energy storage. We believe that the attached evaluation represents an important next step toward understanding the potential benefits of energy storage to the system. At the same time, PGE acknowledges that energy storage technologies and deployments are still immature relative to more established grid technologies, as are the modeling tools used to evaluate them.

PGE is committed to continuing to refine its own modeling capabilities and to take advantage of continued improvements in third party tools over time. Perhaps more importantly, PGE looks forward to gaining more operational experience through the procurement of energy storage resources. This knowledge will help PGE to improve the understanding and evaluation of energy storage resources in its system and prepare for the deployment of cost effective energy storage resources at larger scales.

If you have any questions or require further information, please call me at (503) 464-8954. Please direct all formal correspondence and requests to the following email address: pge.opuc.filings@pgn.com.

Sincerely,

Robert Macfarlane

Robert Macfarlane
Regulatory Affairs

cc: Jason Salmi Klotz, OPUC

Energy Storage Potential Evaluation

Prepared for:

Portland General Electric

Oregon Public Utilities Commission Docket – UM 1751

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TABLE OF CONTENTS

DISCLAIMER

EXECUTIVE SUMMARY

This Draft Energy Storage Potential Evaluation report has been prepared by Navigant for Portland General Electric (PGE) in compliance with the requirements set forth by Oregon House Bill 2193 (HB 2193) and Docket UM 1751.

This report contains the results of analysis of the expected benefits to PGE's system and to individual customers resulting from deploying energy storage systems at different locations on PGE's network (e.g., transmission, distribution, and customer level) for different grid applications (e.g., energy arbitrage, load following, demand charge reduction). Under the specific conditions evaluated across a variety of different use cases, the results indicate that system benefits (socialized benefits that are distributed across all customers) vary from roughly \$200/kW to more than \$2,300/kW on a net present value (NPV) basis, while individual customer benefits (those that accrue only to one specific customer range from \$0/kW to more than \$2,400/kW. These benefits will be considered in light of energy storage system (ESS) costs in the Final Energy Storage Potential Evaluation, which will evaluate proposed deployments of energy storage systems at specific locations on PGE's network.

Section 1 introduces the requirements set forth by HB 2193 and UM 1751 and their relation to the content contained herein and to the approach used to evaluate the potential benefits of energy storage within PGE's territory. This information provides context for understanding the chosen methodology, which is described in Section 2. Appendix A provides further supporting information, identifying how the approach complies with requirements set forth within HB 2193 and UM 1751.

Section 2 provides an overview of the methodology used to evaluate storage potential, including the high level approach, the models used, the use cases considered, and the approach for considering various technologies. This section provides context to understand and interpret the results provided in Section 3. The approach considers all applications explicitly specified by the Oregon Public Utility Commission (OPUC). Various models and inputs were used to assess the value of individual applications. The PGE Resource Optimization Model (ROM) generated values for energy and ancillary services benefits by optimizing the use of energy storage in combination with PGE's generation fleet. The PGE Integrated Planning Tool (IPT) generated values for using energy storage as backup power to reduce the cost of maintaining distribution infrastructure and to reduce customer impacts resulting from network outages. A variety of PGE inputs and typical industry parameters were used to determine the value of all other applications, such as the benefits from deferred transmission investments.

The Navigant Valuation of Energy Storage Tool (NVEST)—which uses a framework that was initially developed for the US Department of Energy and has been peer-reviewed by industry stakeholders—was used to assess the value of five different use cases of energy storage:

(1) A 20 MW transmission-level ESS

(2) A 10 MW ESS at a distribution substation

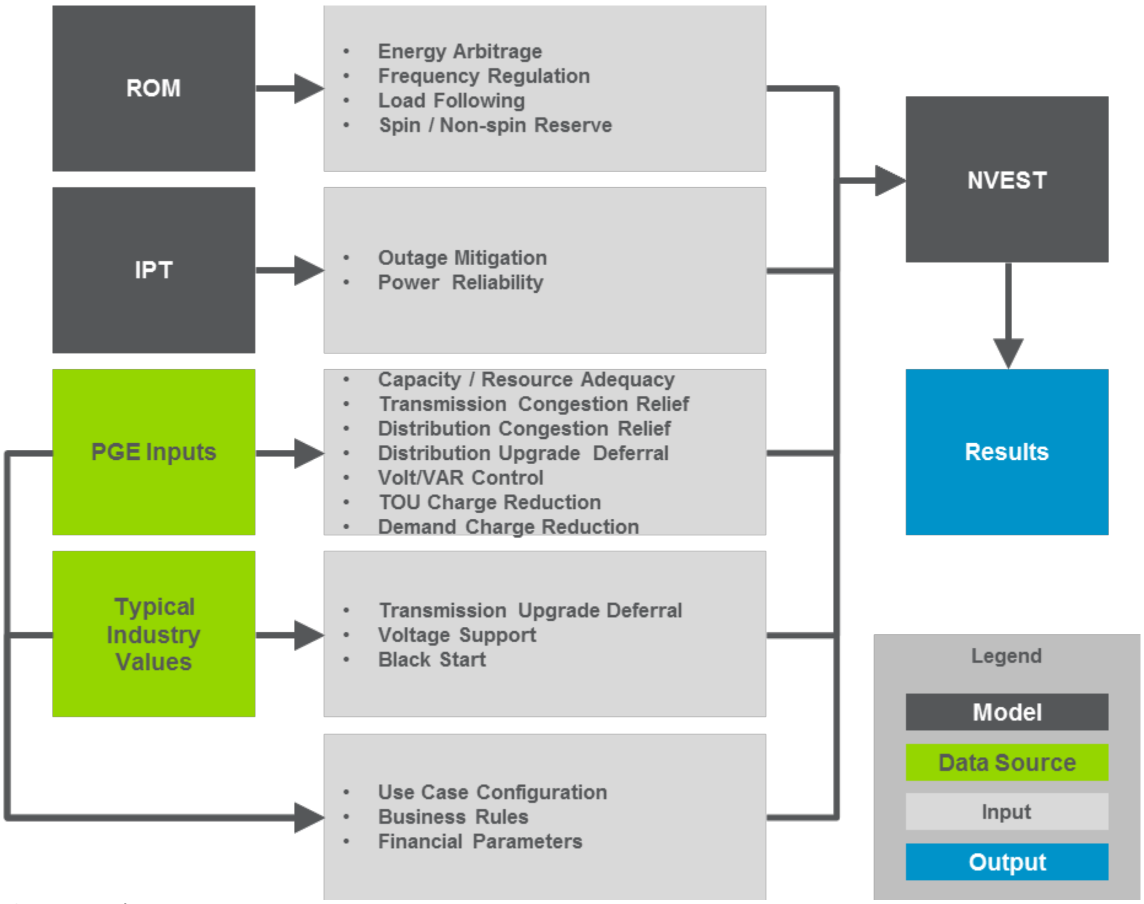
(3) A 2 MW ESS along a distribution feeder

(4) 1 MW of aggregated ESSs located at medium and large commercial and industrial (C&I) customer sites

(5) 1 MW of aggregated ESSs located at residential and small C&I customer sites

Figure 1 summarizes the modeling approach.[1]

Figure 1-1. Modeling Approach



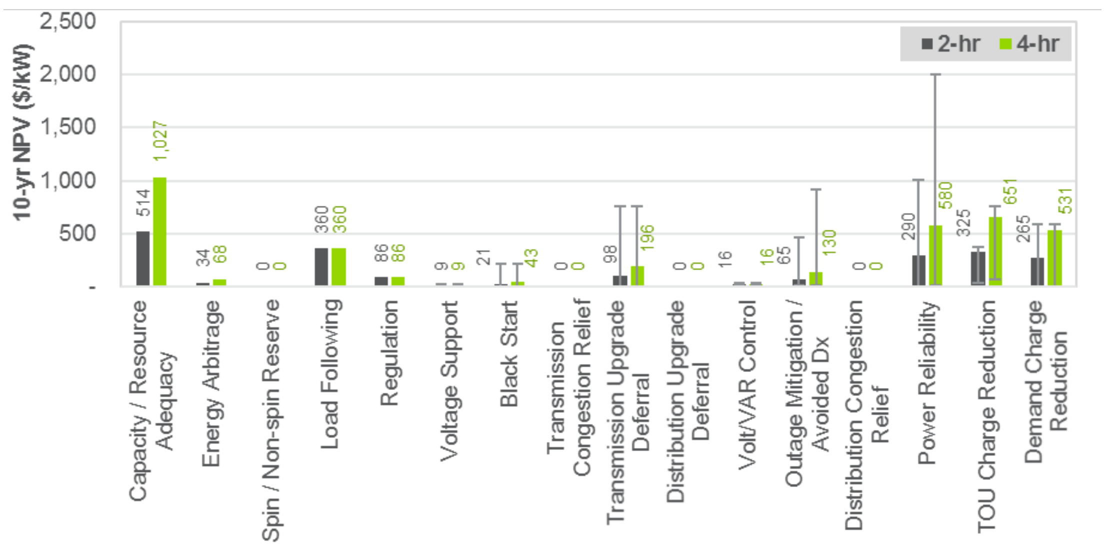
Source: Navigant

Within a given use case, different scenarios were considered with different ESS durations (i.e., 2 hour and 4 hour), as well as different business rules for determining how the ESSs would be dispatched to serve multiple applications.

Section 3 provides the results of the analysis. First, benefits were evaluated for individual applications (Figure 2). These results helped to guide the use case configuration, as applications were selected for each use case based upon their benefit values and their compatibility with one another. Low value applications were not included in the use cases.

[1] Appendix B provides additional details regarding the ROM, IPT, and NVEST models.

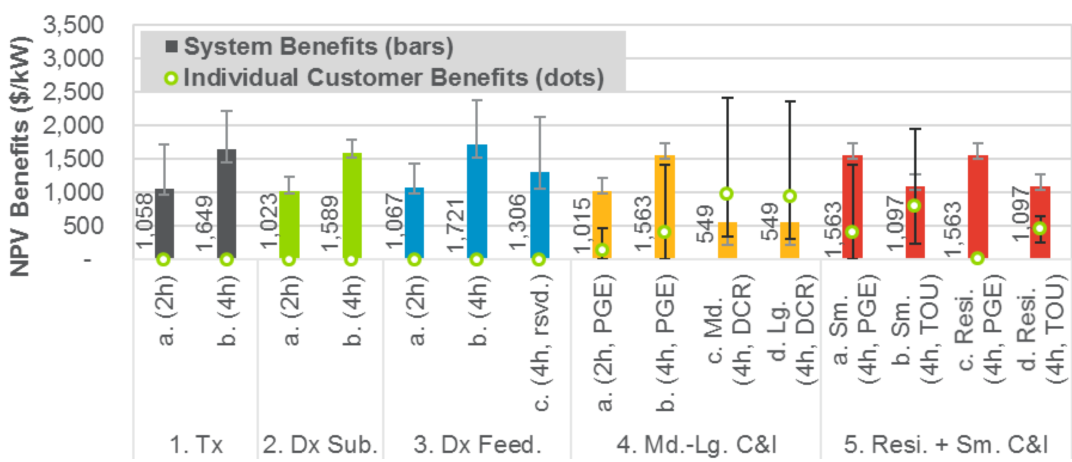
Figure 1-2. 10-year Benefits of Each Application[2]



Source: Navigant

The analysis for each use case provides a summary of the benefits under each of the associated scenarios, including results under low, base, and high conditions. These conditions help to provide an indicative range of potential benefits due to variability associated with particular benefit streams (e.g., differences in the cost of deferred transmission capacity and the period over which investments may be deferred). The range of potential system benefits is similar between use cases to the range between different scenarios within the same use case (Figure 3). Accordingly, the duration of the ESS and the business rules for dispatch are just as important of considerations as the location of the ESS on PGE's network.

Figure 1-3. Summary of Results for all Use Cases

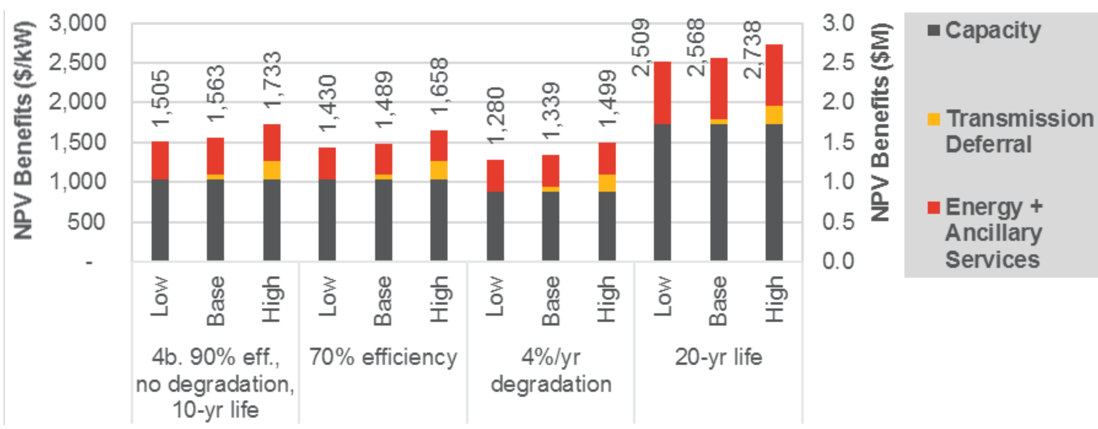


Source: Navigant

[2] Error bars are provided only for applications with significant uncertainty/variability in benefits.

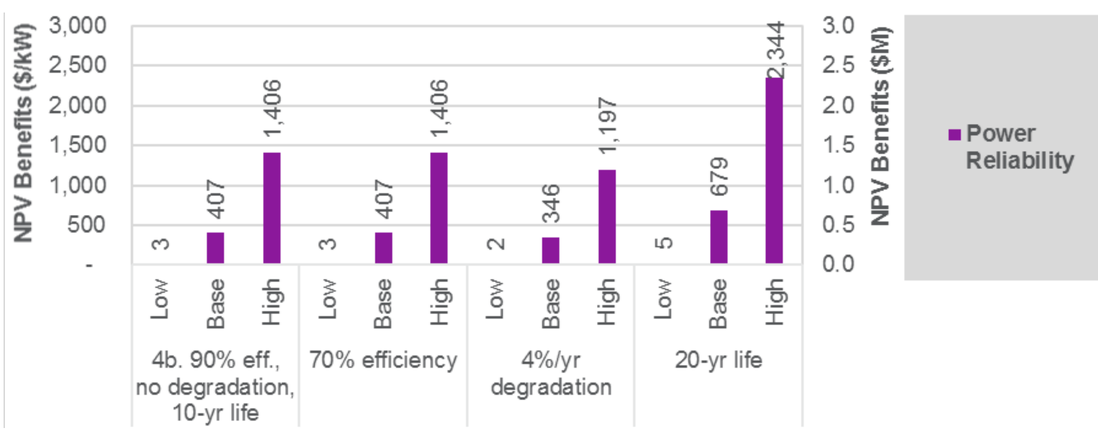
The analysis is intentionally technology-agnostic, as PGE intends to consider bids from a variety of different technologies when procuring ESSs. Key parameters associated with storage technologies (including efficiency, degradation rate, and lifetime) can vary significantly not only between different types of technologies (e.g., Li-ion vs. flow) but also within a family of technologies (e.g., Li-ion batteries from different suppliers). Thus, to evaluate the impact of technology, the analysis focused on the impact of specific parameters rather than assumed parameters associated with different technologies (Figure 4 and Figure 5). Round-trip efficiency was found to have a modest impact on the results. While round-trip efficiency can have a significant impact for value streams requiring frequent charge and discharge (e.g., energy arbitrage, load following, regulation), many of the benefit streams only require occasional dispatch (e.g., capacity, transmission deferral, outage mitigation). Degradation of the technology over time reduces the available power and energy capacity available to support different applications, which can reduce the net present of benefits by 15% or more. Extending the lifetime of the technology can have a profound impact on the results. A 20-year ESS was found to produce over 60% greater NPV benefits relative to a 10-year ESS. This result is largely tied to PGE's relatively low cost of capital.

Figure 1-4. Impact of Technology Parameters on System Benefits



Source: Navigant

Figure 1-5. Impact of Technology Parameters on Individual Customer Benefits



Source: Navigant

This analysis provides a foundation for PGE to consider specific deployments of energy storage at specific locations on its network, which will be considered and assessed in the Final Energy Storage Potential Evaluation report.

1. INTRODUCTION

Oregon House Bill 2193 (HB 2193) requires Portland General Electric Company (PGE) to submit a proposal to develop energy storage systems (ESSs) and to procure any authorized projects by January 1, 2020. The Oregon Public Utility Commission (OPUC) UM 1751 sets guidelines and requirements for the implementation of HB 2193, including a requirement to deliver a draft storage potential evaluation. This report presents Navigant's storage potential evaluation findings.

This section provides an overview of the requirements for the evaluation, which were set forth by HB 2193 (Section 1.1) and the resulting proceedings in Docket UM 1751 (Section 1.2), including the specific applications of energy storage to be considered in this analysis (Section 1.3). This information provides context for understanding the chosen methodology, which is described in Section 2. Appendix A provides further details regarding individual requirements for the potential evaluation and the compliance of this analysis with those requirements.

Section 2 provides an overview of the methodology used to evaluate storage potential, including the high-level approach, the models used, the use cases conducted, and the approach for considering various technologies. This section provides context to understand and interpret the results provided in Section 3. The results include benefits associated with individual applications, the benefits associated with using the ESS for multiple applications within a given use case, and the impact of technology parameters on those benefits.

1.1 HB 2193

HB 2193[3] directs large Oregon electric companies, including PGE, to submit proposals for qualifying ESSs with the capacity to store at least 5 MWh of energy. The bill caps the total capacity of the ESSs procured by each electric company at one percent of the company's peak load in 2014, with an exception for a project of statewide significance. The electric companies adopted proposal guidelines by January 1, 2017 and must submit ESS proposals by January 1, 2018.

HB 2193 outlines several requirements for the energy storage proposals:

1. Each proposal must be accompanied by a comprehensive evaluation of the potential to store energy in the electric company's system.
2. Specific analysis must be provided in the proposal including technical specifications for the project, the estimated cost, and the benefits to the electric grid.
3. Each proposal must be evaluated to determine whether it: (a) is consistent with the guidelines; (b) reasonably balances the value for customers, utility operations, and the costs of construction, operation, and maintenance; and (c) is in the public interest.

The following report presents Navigant's storage potential evaluation to determine the potential value of energy storage systems at different locations on PGE's system. If the OPUC authorizes a storage project, the electric company has until January 1, 2020 to procure the qualifying ESS. HB 2193 specifies that the electric companies may recover in rates all costs prudently incurred in procuring qualifying ESSs under this program, including any above-market costs associated with procurement.

[3] House Bill 2193, https://olis.leg.state.or.us/liz/2015R1/Downloads/MeasureDocument/HB2193.

1.2 UM 1751

UM 1751[4] sets the guidelines and requirements for the implementation of HB 2193 by adopting the following:

1. Project guidelines to help the electric companies design and select projects to propose for development.
2. Proposal guidelines for the electric companies to submit proposals for authorization.
3. Storage evaluation requirements to help electric companies conduct the mandated system-wide storage potential evaluation.
4. Competitive bidding requirements for HB 2193 programs.

This report achieves compliance with third item, requiring that electric companies file a draft system-wide storage evaluation with the OPUC. The Storage Potential Evaluation includes an analysis of operations and system data, an examination of how storage would complement the electric company's existing action plans, and identification of areas with opportunity to partner with customers for the use of energy storage at their locations. Evaluation requirements for this study are provided in Appendix A.

This report represents PGE's draft system-wide storage evaluation. The electric companies will file final versions of their evaluations with their formal project proposals by January 1, 2018.

1.3 Potential Evaluation Requirements

The March 21, 2017 public meeting staff report[5] outlines the applications for consideration in the draft system-wide storage evaluation. These applications are provided in Table 1-1 and evaluated in the following energy storage potential study. Appendix A provides tables that detail how the evaluation framework, key evaluation elements, and modeling attributes map to the requirements set forth by the OPUC.

Table 1-1. OPUC Storage Applications Evaluated[6]

Category	Application	Description
Bulk Energy	Capacity/ Resource Adequacy	The ESS is dispatched during peak demand periods to supply energy and shave peak demand. The ESS reduces the need for new peaking power plants.
	Energy Arbitrage	Trading in the wholesale energy markets by buying energy during low-price periods and selling it during high-price periods.

[4] UM 1751, Implementing Energy Storage Program Guidelines pursuant to House Bill 2193, http://apps.puc.state.or.us/orders/2016ords/16-504.pdf.

[5] Public Utility Commission of Oregon Staff Report, Implementing an Energy Storage Program – Staff Report Pursuant to Order No. 16-504, http://apps.puc.state.or.us/orders/2017ords/17-118.pdf.

[6] Application descriptions reflect the language in the OPUC Staff Report and do not necessarily reflect PGE's or Navigant's definitions of these grid services for PGE specifically. PGE operates its system consistent with all applicable NERC/WECC standards.

Category	Application	Description
Ancillary Services	Regulation	An ESS operator responds to an area control error to provide a corrective response to all or a segment portion of a control area.
	Load Following	Regulation of the power output of an ESS within a prescribed area in response to changes in system frequency, tie line loading, or the relation of these to each other, to maintain the scheduled system frequency and/or established interchange with other areas within predetermined limits.
	Spin/ Non-spin Reserve	Spinning reserve represents capacity that is online and capable of synchronizing to the grid within 10 minutes. Non-spin reserve is offline generation capable of being brought onto the grid and synchronized to it within 30 minutes.
	Voltage Support	Voltage support consists of providing reactive power onto the grid to maintain a desired voltage level.
	Black Start	Black start service is the ability of a generating unit to start without an outside electrical supply. Black start service is necessary to help ensure the reliable restoration of the grid following a blackout.
Transmission Services	Transmission Congestion Relief	Use of an ESS to store energy when the transmission system is uncongested and provide relief during hours of high congestion.
	Transmission Upgrade Deferral	Use of an ESS to reduce loading on a specific portion of the transmission system, thus delaying the need to upgrade the transmission system to accommodate load growth or regulate voltage or avoiding the purchase of additional transmission rights from third-party transmission providers.
Distribution Services	Distribution Upgrade Deferral	Use of an ESS to reduce loading on a specific portion of the distribution system, thus delaying the need to upgrade the system to accommodate load growth or regulate voltage.
	Volt/VAR Control	In electric power transmission and distribution, volt-ampere reactive (VAR) is a unit used to measure reactive power in an AC electric power system. VAR control manages the reactive power, usually attempting to get a power factor near unity.
	Outage Mitigation	Outage mitigation refers to the use of an ESS to reduce or eliminate the costs associated with power outages to utilities.
	Distribution Congestion Relief	Use of an ESS to store energy when the distribution system is uncongested and provide relief during hours of high congestion.
Customer Energy Management Services	Power Reliability	Power reliability refers to the use of an ESS to reduce or eliminate power outages to utility customers.
	TOU Charge Reduction	Reducing customer charges for electric energy when the price is specific to the time (season, day of week, time of day) when the energy is purchased.
	Demand Charge Reduction	Use of an ESS to reduce the maximum power draw by electric load to avoid peak demand charges.

Source: Public Utility Commission of Oregon Staff Report Public Meeting Date: March 21, 2017

2. METHODOLOGY

This section summarizes Navigant's methodology for conducting the storage potential evaluation as required by OPUC UM 1751. The following sections provide detail on key aspects of the analysis, including:

- Storage potential evaluation approach
- Models and data sources used for the analysis
- Use cases evaluated
- Energy storage technologies considered

Section 2.1 describes the general approach used to determine the value of each individual application. Section 2.2 describes the models and data sources used in the analysis, along with other inputs and assumptions. Section 2.3 first describes the considerations used in determining how to construct the use cases, then describes the inputs and assumptions associated with each use case. Next, Section 2.4 describes the technology parameters associated with the use case analysis (results in Section 3.2), as well as the approach to analyzing the impact of technology on benefits (results in Section 3.3).

2.1 Storage Potential Approach

Navigant determined the typical benefits for each of the applications reflected in the Oregon framework established by the Commission in the March 21, 2017 stakeholder meeting. Our analysis includes values that reflect PGE-specific information to the extent possible. As described in Section 3.1, benefit values may vary within or between use cases, and not all benefits accrue to the same entity. Some applications provide system benefits to PGE (which are socialized across customers), while others provide individual customer benefits to single customers.

Table 2-1. Storage Potential Valuation Methodology by Application

Category	Application	Methodology & Data Sources
Bulk Energy	Capacity/ Resource Adequacy	Calculated as the net cost of a new Generic Capacity resource, consistent with the 2016 IRP. This capacity value is applied to the maximum discharge power that can be sustained for 4 hours.
	Energy Arbitrage	Determined from an energy-only energy storage dispatch simulation with 15-min prices from the 2016 IRP Reference Case. This represents the value of Energy Arbitrage in the absence of ancillary service opportunities.

Category	Application	Methodology & Data Sources
Ancillary Services	Spin/ Non-spin Reserve	While the total operational value used in this evaluation is inclusive of the ability to provide contingency reserves, the Resource Optimization Model (ROM) analysis suggests that the value of providing additional contingency reserves is very small relative to other operational applications. Thus this value is assumed to be negligible. See Appendix B for more information.
	Load Following	Determined by comparing ROM results with Energy Arbitrage, Spin / Non-spin Reserve, and Load Following to the isolated Energy Arbitrage value. This value represents the marginal benefit of adding Load Following to the application stack after Energy Arbitrage and Spin/ Non-spin Reserve. Note that the value does not represent the value of performing Load Following alone, and the value is dependent upon the order in which applications are added to the stack. Load Following is inclusive of forecast error mitigation and sub-hourly flexibility down to five minutes. See Appendix B for more information.
	Regulation	Determined from ROM results. This value represents the marginal benefit of adding Regulation to the application stack after Energy Arbitrage, Spin/ Non-spin Reserve, and Load Following. Note that the value does not represent the value of performing Regulation alone, and the value is dependent upon the order in which applications are added to the stack. See Appendix B for more information.
	Voltage Support	Navigant looked at typical market values in wholesale for this service where voltage support markets exist. However, the value is effectively zero for PGE, as the Reactive Demand Program with the Bonneville Power Administration was discontinued in 2014, and PGE no longer pays reactive demand charges. Thus PGE does not have a need for additional Voltage Support services.
	Black Start	Navigant looked at typical market values for this service where Black Start markets exist. However, the value is effectively zero for PGE, as it does not have a need for additional Black Start services. To comply with the EOP-005 NERC Compliance Standard, PGE maintains an official Black Start plan which includes the existence of adequate resource to provide Black Start capability. The introduction of new energy storage resources (distributed or other) would not be considered as a replacement for PGE's existing Black Start resource.
Transmission Services	Transmission Congestion Relief	At present, PGE transmission system modeling suggests limited congestion issues on its transmission system, leading to no meaningful basis to monetize benefits.
	Transmission Upgrade Deferral	This value is based upon representative capital costs of transmission ($125/kW) assuming a 1-year deferral period with 2% inflation, a fixed charge rate of 8%, and an ESS with 5% of the capacity (kW) of the transmission equipment being deferred.[7]

[7] T&D Upgrade Deferral. Energy Storage Association. http://energystorage.org/energy-storage/technology-applications/td-upgrade-deferral.

Category	Application	Methodology & Data Sources
Distribution Services	Distribution Upgrade Deferral	Opportunities for distribution investment deferrals on the PGE system are primarily driven by aging infrastructure for two reasons. Historically, PGE has constructed a distribution system to reliably serve all customers during peak loading conditions, even when a single asset is out of service (i.e., N-1 redundancy). Secondly, at present new load growth tends to be caused by significant commercial or industrial demand that is inherently clustered (e.g., a server farm), requiring significant new infrastructure. PGE prioritizes investments in distribution system upgrades based on a probabilistic analysis of potential component failure. The value of potential avoided distribution investments is encompassed within the Outage Mitigation category. The method is described more fully in Section 2.2.3.
	Volt/VAR Control	This value is representative of a recent investment in Volt/VAR equipment by PGE and reflects an avoided cost in similar equipment.
	Outage Mitigation	The values were calculated using the Integrated Planning Tool (IPT), as described in Section 2.2.3, and are representative of avoided investments in distribution infrastructure. The model outputs, which reflect the NPV over an infinite period, were adjusted to reflect 10-year benefits.[8] These values vary significantly depending on the location of the ESS, and different ranges of values were calculated at the substation level and feeder level.
	Distribution Congestion Relief	PGE does not have significant congestion issues on its distribution system, so there is no meaningful basis from which to monetize benefits.
Customer Energy Management Services	Power Reliability	Power Reliability benefits were calculated in a similar fashion to the Outage Mitigation benefits (see above), but these benefits are specifically for customer-sited systems and applied only to a single customer. The benefits are based upon customer value of service ranges, which were generated from surveys and used as inputs in the IPT model, as described in Section 2.2.3.
	TOU Charge Reduction	The range was calculated based upon the margin between peak and off-peak retail price of electricity for rate schedules 7, 32, 83, and 85.[9] The analysis assumes one cycle per weekday with 90% round-trip efficiency.
	Demand Charge Reduction	The range was calculated based upon monthly demand charges per kW for rate schedules 7, 32, 83, and 85.

Source: Navigant

2.2 Models

Figure 2-1 summarizes the modeling approach utilized in this analysis. The Navigant Valuation of Energy Storage Tool (NVEST) was used to run each of the use cases described in Section 2.3. The inputs and assumptions for the NVEST model were determined from a variety of sources:

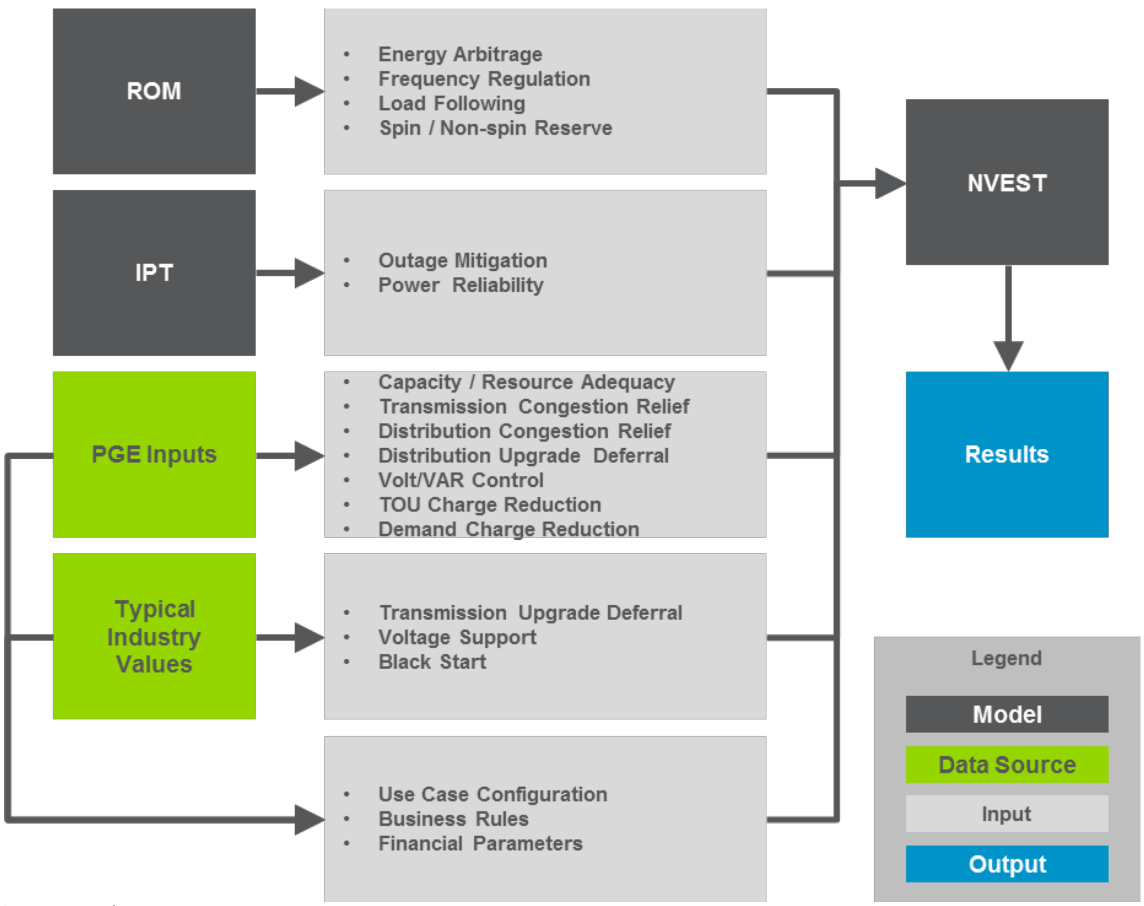
- ROM was used to determine the co-optimized value of energy arbitrage, regulation, Load Following, and Spin/Non-spin Reserve (see Section 2.2.2 below).
- IPT was used to determine the value of Outage Mitigation (inclusive of avoided distribution investments) and Power Reliability benefits as described in Section 2.2.3.

[8] According to BIS Consulting, which performed the IPT analysis, the 10-year value is approximately 70% of the infinite-life value.

[9] Rate schedules 7, 32, 83, and 85 are representative of residential, small C&I, medium C&I, and large C&I customers, respectively.

- PGE provided input values for Transmission Congestion Relief, Distribution Upgrade Deferral, Distribution Congestion Relief, Volt/VAR Control, TOU Charge Reduction, and Demand Charge Reduction (DCR) as indicated in Table 2-1.
- Typical industry values were obtained for Transmission Upgrade Deferral, Voltage Support, and Black Start (Table 2-1).
- The use case configuration (including the size, location, applications, etc.), business rules and assumptions for dispatching the ESS, and the financial parameters (e.g., escalation rates, cost of capital, lifetime) were developed in coordination with PGE and informed by representative industry values and assumptions (see Section 2.3).

Figure 2-1. Modeling Approach



Source: Navigant

2.2.1 Navigant Valuation of Energy Storage Tool

NVEST is based upon a tool originally developed by Navigant in 2008 for the US Department of Energy (DOE) to evaluate the potential of energy storage in various grid applications across the United States. The comprehensive framework provides a methodology that maps applications to benefits with monetized values (Figure 2-2). This framework was later peer-reviewed, evaluated by many industry stakeholders, and adopted by the DOE for use by the recipients of the Smart Grid Demonstration program. A detailed description of the basic methodology is publicly available online.[10]

Figure 2-2. NVEST High-level Framework

Source: Navigant

Since 2008, Navigant has built upon this framework using the Excel-based NVEST model to execute our framework and valuation methodology, resulting in a net present value (NPV) analysis. This framework has been used to support regulatory filings by other utilities, including five utilities in California for compliance with the requirements of AB2514.[11]

Appendix B provides greater detail regarding the NVEST model and the associated methodology and assumptions for the analysis described in this report.

2.2.2 Resource Optimization Model

ROM is a multi-stage production simulation model of PGE's resource portfolio. PGE described ROM and its application to energy storage resource evaluation in Chapter 8 of PGE's 2016 Integrated Resource Plan (IRP).[12] ROM was originally designed to quantify operational challenges and costs associated with renewables integration. Because of this history, ROM already incorporated the key features required for quantifying the operational value of energy storage resources: optimal unit commitment and dispatch of the PGE resource fleet over multiple time horizons, impacts of forecast errors (e.g., day-ahead to real-time), ancillary service requirements, and sub-hourly dispatch.

ROM simulations allow for the estimation of the operational value of energy storage resources that are operated in a coordinated manner within PGE's resource fleet. Operational value streams include: energy arbitrage, load following, regulation, spinning, and non-spinning reserves. ROM does not address capacity value, values for other services at the transmission, distribution, and customer levels, or the interactions between operational and non-operational value streams.

[10] DOE Energy Storage Computational Tool Overview. US Department of Energy. August 2012 https://www.smartgrid.gov/document/doe_energy_storage_computational_tool_overview.html.

[11] AB 2514 Energy Storage System Procurement Targets from Publicly Owned Utilities. California Energy Commission. http://www.energy.ca.gov/assessments/ab2514_energy_storage.html (Azusa Light and Water, City of Banning, City of Pasadena, Riverside Public Utilities, and City of Vernon).

[12] Additional information about the development of ROM can be found in Section 7.2.1.1 in PGE's 2016 IRP.

For the Energy Storage Potential Evaluation, PGE updated energy price assumptions and evaluated three configurations, including: 50-MW 2-hour, 4-hour, and 6-hour ESSs, each with 90% round-trip efficiency. For each of these configurations, a ROM simulation yielded the operational cost of meeting loads and ancillary service requirements across a test year (2021) with and without the ESS. The operational value of the ESS is calculated as the cost difference between these two simulations. This approach optimizes across the energy and ancillary service value streams in order to provide a single number that represents their combined value. Additional information about the ROM modeling approach and the simulations conducted to support the Energy Storage Potential Evaluation can be found in Appendix B.

2.2.3 Integrated Planning Tool

IPT provides a life-cycle analysis of the Outage Mitigation benefits (via extended life of PGE assets) and Power Reliability benefits (via avoided outage costs to individual customers) associated with ESSs located at the substation, feeder, and customer level. The tool was developed by the Strategic Asset Management group (SAM) at PGE and BIS Consulting. The analysis was executed by representatives from T&D Planning, SAM, and BIS Consulting.

IPT and other life-cycle cost tools quantify customer and company risks due to service failures, including the cost of future asset replacements, and the economic costs incurred by customers due to a loss of power. The cost of outages to customers is calculated based on study and survey data of the value of reliable electrical service to customers; these same values are used by SAM in all of its risk analyses. The inputs estimate an expected impact cost to customers for each customer class evaluated due to a loss of power. In other words, all residential customers are assumed to have the same outage impact cost, per kilowatt-hour, as are all commercial customers and all industrial customers. System data was used to determine the average annual load, by customer class, for each grid location analyzed. The system disturbance database and the outage management system were then used to evaluate outage frequency at different grid locations. The benefit of battery installation was calculated as the avoided risk cost to customers and PGE—primarily due to outage avoidance or duration reduction—due to the battery installation.

All substations and feeders were evaluated to assess distribution system benefits. For analysis of individual commercial and industrial (C&I) customers, a sample of customers were selected from grid locations expected to have relatively high value. Thus, the base values provided for C&I customer-sited ESSs are greater than system-wide averages.

The results are expressed in NPV, assuming replenishment/replacement of batteries to maintain constant capacity over time in perpetuity. To evaluate ESSs with a finite life, the 10-year NPV was assumed to be 70% of the infinite-life value based upon the discount rate and other assumptions used in the analysis.

Because PGE uses outage risk to prioritize distribution investments through the IPT, the IPT can be used both to estimate system benefits associated with Outage Mitigation (including avoided distribution investments), as well as to estimate individual customer benefits associated with improved Power Reliability for a customer-sited ESS. These different benefit streams are described below in Section 2.2.3.1 and 2.2.3.2 respectively.

2.2.3.1 System Benefits: Outage Mitigation / Avoided Distribution Investments

To compute the value of upgrading distribution infrastructure, the IPT multiplies the likelihood of a distribution component failing by the cost of the outage to the affected customers. This method works for distribution projects at the feeder and substation level, which affect many customers (sometimes thousands), because the cost of the outage to affected customers uses averages from reliable survey data and analysis. In the face of the need to replace distribution equipment, the method both prioritizes which projects should be done first and provides a quantitative benefit/cost ratio. For applications at the feeder and substation level, these benefits flow to all customers because benefits associated with avoided distribution investments are socialized. In other words, these are system benefits when the ESS is located at the feeder or substation level. This specific benefit stream is hereon referred to as Outage Mitigation/ Avoided Distribution Investments or Outage Mitigation/ Avoided Dx.

2.2.3.2 Individual Customer Benefits: Power Reliability

The same methodology (probability of outage times cost to affected customers) is used in this evaluation to approximate the Power Reliability benefits for customers with customer-sited ESSs.[13] This evaluation uses average customer outage costs – based on survey data – in order to assign a value to Power Reliability benefits at a general level. The actual cost of an outage for a specific customer will vary significantly from aggregate average outage costs derived from survey data. The only way to know the actual cost of an outage to a specific customer is to ask the customer or to offer increased reliability at a given price and to see if that customer is willing to purchase it. The Power Reliability values used in this report should be taken as one approach to estimating a customer benefit that varies widely from one customer to another; these values should not be assumed to equate to the actual value of Power Reliability to any specific customer.

2.3 Use Cases

Navigant's analysis evaluated the value of different applications in PGE's service area across five different use cases (specific combinations of grid location, energy storage power rating, and stacked applications). Within a given use case, different scenarios were considered with different durations (i.e., 2 hours and 4 hours), as well as different business rules for ESS dispatch.

To determine the appropriate set of stacked applications and business rules for each use case, Navigant considered four criteria:

- **Location:** Whether a storage application can be performed at all locations on the grid (transmission, distribution, and customer) or only at certain locations
- **Duration:** The minimum duration required for storage to provide application value (≤2 hours to 4 hours)

[13] While customer-sited ESSs may be located behind or in front of the meter, this analysis assumes that customer-sited systems are located behind the meter in order to simplify the differentiation between system benefits and individual customer benefits. For these specific scenarios, Power Reliability and Outage Mitigation/ Avoided Distribution Investment benefits are mutually exclusive due to the metering configuration. However, real installations may provide opportunities to operate ESSs in a way to blend Power Reliability and Outage Mitigation/ Avoided Distribution Investment benefits. Such opportunities should be evaluated on an installation-specific basis.

- **Utilization:** How frequently the ESS is dispatched to support the application, ranging from low to high
- **Commitment:** How important it is for the ESS to be available at specific times to support the application

Navigant used the last three criteria to assess the stacking compatibility of different applications. Navigant did not evaluate the following applications as part of the stacked use case analysis, as these applications were considered to have low value:

- Voltage Support
- Black Start
- Transmission Congestion
- Distribution Deferral
- Distribution Congestion
- Volt/VAR Control

Furthermore, each application above has moderate-to-high commitment (i.e., Black Start, Transmission Congestion, Distribution Deferral, and Distribution Congestion) and/or utilization (i.e., Voltage Support, Volt/VAR Control), which would detract from capturing greater benefits from other more valuable applications.

Furthermore, multiple related applications were combined together as Energy + Ancillary Services (E+AS), as PGE may perform these in conjunction with one another to maximize value. This aggregated application considers the co-optimized benefits of Energy Arbitrage, Regulation, Load Following, and Spin/Non-spin Reserves, which are all used by PGE to optimize the dispatch of energy storage along with its other generation resources.

Table 2-2 summarizes the compatibility of all applications that were considered for stacking within use cases.

Table 2-2. Application Stacking Compatibility

Application	DCR	TOU	PR	OM/Dx	Tx D	E+AS	Cap
Capacity (**Cap**)	Partially Compatible	Compatible	Highly Compatible	Highly Compatible	Compatible	Compatible	
Energy + Ancillary Services (**E+AS**)	Limited Compatibility	Limited Compatibility	Partially Compatible	Partially Compatible	Compatible		
Transmission Deferral (**Tx D**)	Partially Compatible	Compatible	Highly Compatible	Highly Compatible			
Outage Mitigation/ Avoided Distribution Investments (**OM/Dx**)	Partially Compatible	Partially Compatible	Incompatible				
Power Reliability (**PR**)	Partially Compatible	Partially Compatible					
Time-of-Use Charge Reduction (**TOU**)	Compatible						
Demand Charge Reduction (**DCR**)							

- *Highly Compatible* = The benefits of both applications can be captured at or near their full potential value.
- *Compatible* = The applications can technically be performed with one another, but the full benefits may not be realized, because the target duration for the applications may be different.
- *Partially compatible* = Performing one application directly reduces the benefits of the other.
- *Limited compatibility* = Dispatch decisions would be challenging, because the ESS would be used frequently for both applications, one of which is for customers and the other for PGE.
- *Incompatible* = Applications cannot be performed together, as each application works only at specific grid locations that are mutually exclusive.

Source: Navigant

The following descriptions provide details to explain the compatibility map in Table 2-2:

- **Capacity (Cap)** is generally compatible with most applications. It is highly compatible with OM/Dx and PR since those applications may hold the capacity in reserve and is only infrequently used. For TOU and E+AS, the ESS may be used for other applications at all other times, when not needed for capacity. For Transmission Deferral (Tx D), both applications are infrequently called upon the dispatch and are unlikely to cause conflict, as both are needed during times of peak system demand, and thus the ESS can provide Capacity while also supporting Tx D. However, Cap requires 4 hours of energy storage capacity, while TOU, E+AS, and Tx D may require a shorter duration. For DCR, there can be conflict, as a customer's peak load may not be coincident with system peak load. Thus, one application may need to be prioritized at the expense of the other.

- **Energy + Ancillary Services (E+AS)** has limitations in compatibility, because the ESS is dispatched on a regular basis throughout each day. E+AS is compatible with Cap and Tx D, and the ESS capacity can be held in reserve for these applications during a small number of days of the year, while still extracting most of the E+AS benefits. However, Cap and Tx D may require a longer ESS duration than is required for E+AS. OM/Dx and PR benefits scale with the average state of charge and can therefore be partially derived when performing E+AS. TOU and DCR are customer applications that require the ESS to be frequently dispatched or reserved, thus making it challenging to co-optimize the dispatch of TOU and/or DCR for the customer's benefit in coordination with E+AS for PGE's benefit.
- **Transmission Deferral (Tx D)** has duration, utilization, and commitment constraints similar to those for Cap and therefore has similar compatibility with other applications. It is likely that, similar to Cap, transmission deferral will also require ESSs of about 4 hours in duration, but it may be possible in certain cases for a shorter duration ESS to suffice.
- **Outage Mitigation/ Avoided Distribution Investments (OM/Dx)** is highly compatible with both Cap and Tx D since the energy capacity can be held in reserve for all applications. For DCR, TOU, and E+AS, the OM/Dx benefits scale with the average state of charge of the ESS, as the outages are typically random and do not vary significantly with duration on a $/kWh basis. OM/Dx is incompatible with PR, because OM/Dx represents a system benefit associated with avoided distribution investments, which are socialized across customers, while PR represents an individual customer benefit for customer-sited ESSs that may not be visible to the utility.
- **Power Reliability (PR)** is operationally similar to OM/Dx and therefore has similar compatibility with other applications, and benefits scale with the average state of charge of the ESS. As indicated above, PR is incompatible with OM/Dx, because PR is only applicable for customer-sited ESSs, while OM/Dx is only applicable for distribution-sited ESSs.
- **Time-of-use Charge Reduction (TOU)** is similar to E+AS in that it is dispatched frequently, does not require a long-duration ESS, and can have other applications prioritized above it without significantly reducing benefits. Therefore, its compatibility with other applications is similar. The notable difference is with DCR, where it is easier for a customer to co-optimize TOU and DCR (relative to E+AS and DCR), especially if the customer's peak is during the TOU on-peak period.
- **Demand Charge Reduction (DCR)** is less compatible with stacking in comparison to most applications. For Cap and Tx D, there can be conflict if a customer's peak load is not coincident with system peak load. Thus, one application may need to be prioritized at the expense of the other. For OM/Dx and PR, the benefits scale with the average state of charge, which can be quite high for DCR, as the ESS does not need to be dispatched on most days. Compatibility with E+AS is limited, as it can be challenging to co-optimize the dispatch of DCR for the customer's benefit in coordination with E+AS for PGE's benefit.

Based on the ability to stack these applications, Navigant developed use cases covering the highest-value applications from transmission, distribution, and customer-sited perspectives. Table 2-3 below summarizes the five use cases evaluated in 15 different scenarios (labeled 1a through 5d), while the details and assumptions for each use case are provided in Section 2.3.1 through 2.3.5.

Table 2-3. Use Cases Evaluated

Characteristic	Transmission	Distribution Substation	Distribution Feeder	Medium + Large C&I	Small C&I + Residential
Power	20 MW	10 MW	2 MW	1 MW (aggregated)	1 MW (aggregated)
Duration	2 hr, 4 hr	2 hr, 4 hr	2 hr, 4 hr	2 hr, 4 hr	4 hr
Scenarios	1a. Tx (2h) 1b. Tx (4h)	2a. Dx Sub. (2h) 2b. Dx Sub. (4h)	3a. Dx Feed. (2h) 3b. Dx Feed. (4h) 3c. Dx Feed. (4h, rsvd.)	4a. C&I (2h, PGE) 4b. C&I (4h, PGE) 4c. Med. C&I (4h, DCR) 4d. Lg. C&I (4h, DCR)	5a. Sm. C&I (4h, PGE) 5b. Sm. C&I (4h, TOU) 5c. Resi. (4h, PGE) 5d. Resi. (4h, TOU)
Application			Scenarios		
Cap	1a, 1b	2a, 2b	3a, 3b, 3c	4a, 4b, 4c, 4d	5a, 5b, 5c, 5d
E+AS	1a, 1b	2a, 2b	3a, 3b	4a, 4b	5a, 5c
Tx D	1a, 1b	2a, 2b	3a, 3b, 3c	4a, 4b, 4c, 4d	5a, 5b, 5c, 5d
OM/Dx		2a, 2b	3a, 3b, 3c		
PR				4a, 4b, 4c, 4d	5a, 5b, 5c, 5d
TOU					5b, 5d
DCR				4c, 4d	

Source: Navigant

The subsections below provide further details for each use case.

2.3.1 Transmission

The transmission use case assumes an ESS size of 20 MW with a duration of 2 hours (Scenario 1a) and 4 hours (Scenario 1b). In the scenarios evaluated, Transmission Deferral and Capacity each required the ESS to be reserved for 10 days/year. Energy + Ancillary Services took priority for the remainder of the year. Outage Mitigation / Avoided Distribution Investments, Power Reliability, TOU Charge Reduction, and Demand Charge Reduction applications were not considered, as they require the ESS to be located downstream on the network. Table 2-4 summarizes the assumptions and scenarios for this use case.

Table 2-4. Transmission Use Case Assumptions

Applications	Value	Business Rules
Power	20 MW	(Assumption)
Duration	1a: 2 hr 1b: 4 hr	(Assumption)
Business Rules	-	Energy + Ancillary Services
Transmission Deferral	$125-250/kW *(2-4 hr, 0-2 yr, 5% capacity ratio)*[14]	Reserved 10 days/yr
Capacity	$120/kW-yr *(4 hr basis)*	Reserved 10 days/yr
Energy + Ancillary Services	$60/kW-yr	Run when not reserved (345 days/yr)
Outage Mitigation/ Avoided Distribution Investments	-	-
Power Reliability	-	-
TOU Charge Reduction	-	-
Demand Charge Reduction	-	-

Source: Navigant

2.3.2 Distribution Substation

The distribution substation use case assumed an ESS size of 10 MW with a duration of 2 hours (Scenario 2a) and 4 hours (Scenario 2b). In the scenarios evaluated, Transmission Deferral and Capacity each required the ESS to be reserved for 10 days/year. Energy + Ancillary Services took priority for the remainder of the year. Outage Mitigation/ Avoided Distribution Investments benefits were small, because the ESS is not targeted at specific circuits with low reliability and a high average value of service. The analysis assumed that Outage Mitigation/ Avoided Distribution Investments benefits scale with the average state of charge, as IPT results indicate that the benefits scale approximately linearly with duration. Power Reliability, TOU Charge Reduction, and Demand Charge Reduction applications were not considered, as they require the ESS to be located downstream on the network at a customer site.

For the 4-hour ESS (Scenario 2b), it was assumed that 50% of the energy capacity is used for Energy + Ancillary Services, while 50% of the energy capacity is reserved for Outage Mitigation/ Avoided Distribution Investments, as the ROM analysis indicates that the E+AS benefits do not significantly increase with duration, while the IPT analysis indicates that Outage Mitigation/ Avoided Distribution Investments benefits do scale with duration.

Table 2-5 summarizes the assumptions and scenarios for this use case.

[14] The base case assumes the capital cost of transmission is $125/kW, the ESS capacity (kW) is 5% of the transmission capacity, 4 hours of energy storage capacity is required for deferral, and the expense is deferred by 1 year. The high case assumes a $250/kW capital cost, 2 hours of energy storage required, and 2 years of deferral. The low case assumes no deferral.

Table 2-5. Distribution Substation Use Case Assumptions

Applications	Value	Business Rules
Power	10 MW	(Assumption)
Duration	2a: 2 hr 2b: 4 hr	(Assumption)
Business Rules	-	Energy + Ancillary Services priority
Tx Deferral	$125-250/kW *(2-4 hr, 0-2 yr, 5% capacity ratio)*[15]	Reserved 10 days/yr
Capacity	$120/kW-yr *(4 hr basis)*	Reserved 10 days/yr
Energy + Ancillary Services	$60/kW-yr	Run when not reserved (345 days/yr)
Outage Mitigation/ Avoided Distribution Investments	$2-9-16/kWh	Available capacity used for outages[16]
Power Reliability	-	-
TOU Charge Reduction	-	-
Demand Charge Reduction	-	-

Source: Navigant

2.3.3 Distribution Feeder

The distribution feeder use case assumed an ESS size of 2 MW with a duration of 2 hours (Scenario 3a) and 4 hours (Scenarios 3b and 3c). The ESS was reserved for the benefit of Transmission Deferral and Capacity for 10 days/year for each application. For the 2-hour ESS in Scenario 3a, Energy + Ancillary Services took priority 345 days of the year, and the Outage Mitigation/ Avoided Distribution Investments benefits were assumed to scale with the average state of charge. For the 4-hour system in Scenario 3b, it was assumed that 50% of the energy capacity is used for Energy + Ancillary Services, while 50% of the energy capacity is reserved for Outage Mitigation/ Avoided Distribution Investments. In Scenario 3c, Outage Mitigation/ Avoided Distribution Investments took priority 345 days throughout the year with the ESS at 100% state of charge except for 20 days of the year when needed for Transmission Deferral and Capacity. Power Reliability, TOU Charge Reduction, and Demand Charge Reduction applications were not considered, as they require the ESS to be located downstream on the network at a customer site. Table 2-6 summarizes the assumptions and scenarios for this use case.

[15] The base case assumes the capital cost of transmission is $125/kW, the ESS capacity (kW) is 5% of the transmission capacity, 4 hours of energy storage capacity is required for deferral, and the expense is deferred by 1 year. The high case assumes a $250/kW capital cost, 2 hours of energy storage required, and 2 years of deferral. The low case assumes no deferral.

[16] The average available capacity for a 2-hour ESS when used for Energy + Ancillary Services is 47%, based upon ROM analysis. The average available capacity is assumed to be 83% on days when needed for Transmission Deferral or Capacity. For a 4-hour ESS, half of the energy capacity is set aside, so the average state of charge is approximately 75%.

Table 2-6. Distribution Feeder Use Case Assumptions

Applications	Value	Business Rules
Power	2 MW	(Assumption)
Duration	3a: 2 hr 3b/3c: 4 hr	(Assumption)
Business Rules	-	3a/3b: Energy + AS priority 3c: Outage Mitigation/ Avoided Distribution Investments priority
Tx Deferral	$125-250/kW *(2-4 hr, 0-2 yr, 5% capacity ratio)*[17]	Reserved 10 days/yr
Capacity	$120/kW-yr *(4 hr basis)*	Reserved 10 days/yr
Energy + Ancillary Services	$60/kW-yr	3a/3b: Run when not reserved (345 days/yr) 3c: Not used
Outage Mitigation/ Avoided Distribution Investments	$3-56-230/kWh	Available capacity used for outages[18]
Power Reliability	-	-
TOU Charge Reduction	-	-
Demand Charge Reduction	-	-

Source: Navigant

2.3.4 Customer (Medium–Large C&I)

The medium–large C&I customer use case assumed an ESS size of 1 MW with a duration of 2 hours (Scenario 4a) and 4 hours (Scenarios 4b, 4c, and 4d). In Scenarios 4c and 4d, Demand Charge Reduction is given priority over all other applications. These ESSs are assumed to be 4 hours, as a 4-hour system will offer greater flexibility than a 2-hour system to perform multiple applications, including Demand Charge Reduction, for a greater number of customers. Only a portion of the aggregated capacity is assumed to be committed as a firm resource for Capacity and Transmission Deferral. The Power Reliability benefits were assumed to scale with the average state of charge. For Scenarios 4a and 4b, the ESS is reserved for 10 days per year for each of Transmission Deferral and Capacity, while Energy + Ancillary Services took priority 345 days of the year, and the Power Reliability benefits were assumed to scale with the average state of charge. For 4-hour ESSs, Scenarios 4c and 4d utilized the entire energy capacity for Demand Charge Reduction, while Scenario 4b used half of the energy capacity for Energy + Ancillary Services and reserved the other half for Power Reliability. TOU Charge Reduction was not considered, as the low margin between peak and off-peak rates for medium–large C&I customers does

[17] The base case assumes the capital cost of transmission is $125/kW, the ESS capacity (kW) is 5% of the transmission capacity, 4 hours of energy storage capacity is required for deferral, and the expense is deferred by 1 year. The high case assumes a $250/kW capital cost, 2 hours of energy storage required, and 2 years of deferral. The low case assumes no deferral.

[18] The average available capacity for a 2-hour ESS when used for Energy + Ancillary Services is 47%, based upon ROM analysis. The average available capacity is assumed to be 83% on days when needed for Transmission Deferral or Capacity. In scenario 1, half of the energy capacity is set aside for the 4-hour ESS, so the average state of charge is approximately 75%.

not offer as much value as other applications. Outage Mitigation/ Avoided Distribution Investments was not considered, as the application requires the ESS to be located upstream on the distribution network. Table 2-7 summarizes the assumptions and scenarios for this use case.

Table 2-7. Medium / Large C&I Use Case Assumptions

Applications	Value	Business Rules
Power	1 MW, aggregated	(Assumption)
Duration	4a: 2 hr 4b/4c/4d: 4 hr	(Assumption)
Business Rules	-	4c/4d: Demand Charge Reduction priority 4a/4b: Energy + Ancillary Services priority
Tx Deferral	$125-250/kW *(2-4 hr, 0-2 yr, 5% capacity ratio)*[19]	4c/4d: 20-50-80% firm resource[20] 4a/4b: Reserved 10 days/yr
Capacity	$120/kW-yr *(4 hr basis)*	4c/4d: 20-50-80% firm resource 4a/4b: Reserved 10 days/yr
Energy + Ancillary Services	$60/kW-yr	4c/4d: Not used 4a/4b: Run when not reserved (345 days/yr)
Outage Mitigation/ Avoided Distribution Investments	-	-
Power Reliability	$1-145-500/kWh	Available capacity used for outages[21]
TOU Charge Reduction	-	-
Demand Charge Reduction	Schedules 83, 85 *(60-80-100% reduction)*	4c/4d: Used as needed (~5%) 4a/4b: Not used

Source: Navigant

2.3.5 Customer (Residential & Small C&I)

The residential (Scenarios 5c and 5d) + small C&I (Scenarios 5a and 5b) use case assumed an aggregated group of ESSs with 1 MW total capacity and a duration of 4 hours. These ESSs are assumed to be 4 hours, as a 4-hour system will offer greater flexibility than a 2-hour system to perform multiple applications, including Demand Charge Reduction, for a greater number of customers. The ESS was reserved for the benefit of Transmission Deferral and Capacity for 10 days/year for each application. In Scenarios 5b and 5d, TOU Charge Reduction took priority 345 days of the year, and the Power Reliability

[19] The base case assumes the capital cost of transmission is $125/kW, the ESS capacity (kW) is 5% of the transmission capacity, 4 hours of energy storage capacity is required for deferral, and the expense is deferred by 1 year. The high case assumes a $250/kW capital cost, 2 hours of energy storage required, and 2 years of deferral. The low case assumes no deferral.

[20] On an aggregated basis, it assumed that the aggregated ESSs used for DCR can provide Tx Deferral and Capacity, but that the firm resource that can be committed is only a fraction of the total capacity (low = 20%, base = 50%, high = 80%), as some portion of ESSs may be committed to DCR, particularly during system peak periods.

[21] The average available capacity for a 2-hour ESS when used for Energy + Ancillary Services is 47%, based upon ROM analysis. The average available capacity is assumed to be 83% on days when needed for Transmission Deferral or Capacity. In scenario 1, half of the energy capacity is set aside, so the average state of charge is approximately 75%.

benefits were assumed to scale with the average state of charge. In Scenarios 5a and 5c, the Energy + Ancillary Services took priority 345 days of the year, and the Power Reliability benefits were assumed to scale with the average state of charge. Scenarios 5b and 5d utilized the entire energy capacity for TOU Charge Reduction, while Scenarios 5a and 5c used half of the energy capacity for Energy + Ancillary Services and reserved the other half for Power Reliability. Demand Charge Reduction was not considered, because residential and small C&I customers do not currently have demand charges. Outage Mitigation / Avoided Distribution Investments was not considered, as the application requires the ESS to be located upstream on the distribution network. Table 2-8 summarizes the assumptions and scenarios for this use case.

Table 2-8. Residential / Small C&I Use Case Assumptions

Applications	Value	Business Rules
Power	1 MW, aggregated	(Assumption)
Duration	4 hr	(Assumption)
Scenarios	-	5b/5d: TOU priority 5a/5c: Energy + Ancillary Services priority
Tx Deferral	\$125-250/kW *(4 hr, 0-2 yr, 5% capacity ratio)*[22]	Reserved 10 days/yr
Capacity	\$120/kW-yr *(4 hr basis)*	Reserved 10 days/yr
Energy + Ancillary Services	\$60/kW-yr	5b/5d: Not Used 5a/5c: Run when not reserved (345 days/yr)
Outage Mitigation/ Avoided Distribution Investments	-	-
Power Reliability	Resi = \$1/kwh Sm C&I = \$1-145-500/kWh	Available capacity used for outages[23]
TOU Charge Reduction	Schedules 7, 32 *(40-70-100% of max reduction)*	5b/5d: Run on weekdays when not reserved 5a/5c: Not used
Demand Charge Reduction	-	-

Source: Navigant

2.4 Energy Storage Technologies

The analytical methodology employed in this analysis has been designed to be technology-agnostic. Key

[22] The base case assumes the capital cost of transmission is \$125/kW, the ESS capacity (kW) is 5% of the transmission capacity, 4 hours of energy storage capacity is required for deferral, and the expense is deferred by 1 year. The high case assumes a \$250/kW capital cost, 2 hours of energy storage required, and 2 years of deferral. The low case assumes no deferral.

[23] The average available capacity for a 2-hour ESS when used for Energy + Ancillary Services is 47%, based upon ROM analysis. The average available capacity is assumed to be 83% on days when needed for Transmission Deferral or Capacity. In scenario 1, half of the energy capacity is set aside, so the average state of charge is approximately 75%.

technology parameters that would affect the net cost-benefit analysis of an actual deployment include the following:

- **Cost:** Cost not only varies significantly between technologies (e.g., Li-ion vs. flow), but also within a given technology, including multiple sub-chemistries, each with variations in pricing between vendors. The cost also depends on the size and duration of the ESS. Further, different technologies and vendors will achieve different levels of cost reduction between now and 2021. This analysis focuses on benefits. PGE will consider representative costs in its energy storage proposals, understanding that actual costs will not be available until PGE receives commercial bids for given ESSs.
- **Lifetime:** For financial evaluation purposes, the ESS life is typically considered equivalent to the warranty period. The actual warranty period not only varies between technologies, but also varies within a specific product, as different warranties can be structured with different associated costs. In this analysis, the lifetime is assumed to be 10 years, which is currently a common warranty period used for different energy storage technologies.
- **Degradation Rate:** The degradation rate impacts the level of achievable benefits over time and depends not only upon the technology, but also upon ESS-specific parameters. For example, degradation depends upon both cycle fade (which depends on the ESS-specific duty cycle) and calendar fade (which is relatively independent of cycling, but may depend on factors such as ambient temperature). Not only is there significant uncertainty in the degradation rate, there are a variety of different approaches to handling degradation, including oversizing the ESS initially to have the energy capacity at end of life (which results in greater capital costs) or regularly replenishing/replacing capacity regularly to maintain a constant capacity (which results in greater operating costs). In this analysis, degradation is assumed to be negligible as a result of regular capacity replenishment, an increasingly common practice by ESS providers.
- **Efficiency:** The efficiency of the ESS does have an impact on both costs and benefits. In this analysis, the round-trip efficiency is assumed to be 90%, which is representative of various technologies including Li-ion batteries, advanced lead-acid batteries, and flywheels.

Thus, because of the significant variability and uncertainty associated with these parameters, PGE prefers to take a technology-agnostic approach to the analysis and evaluate all viable technologies at the time of procurement. While representative parameters will be considered in the final potential evaluation report, PGE will consider actual parameters associated with specific bids at the time of procurement, including other factors not described above (e.g., response time, footprint, etc.).

As indicated above, the baseline analysis in Section 3.1-3.2 considers benefits associated with a generic ESS with a 10-year life, constant capacity, and a 90% round-trip efficiency. In Section 3.3, the analysis evaluates the impact of lifetime, degradation, and efficiency. Furthermore, Table 2-9 provides typical parameters associated with common energy storage technologies.

Table 2-9 Parameters of Common Grid Storage Technologies

Technology	Duration	Size	Efficiency	Lifetime[24]	Location
Mechanical					
PHES[25]	>6 hr	100s MW	75-85%	Decades	Tx
CAES[26]	>6 hr	100s MW	60-70%	Decades	Tx
Flywheel	<1 hr	> 100 kW	80-90%	> 20,000 cycles	Dx - Tx
Electrochemical					
Li-ion	15 min-4 hr	> 5 kW	80-95%	2,000 – 20,000 cycles	BTM – Tx
Flow	> 2 hr	> 5 kW	60-75%	2,000 – 20,000 cycles	BTM – Tx
Advanced Lead-Acid	2-6 hr	> 5 kW	80-90%	1,000 – 4,000 cycles	BTM – Tx
Molten Salt[27]	4-8 hr	> 50 kW	75-85%	2,000 – 5,000 cycles	Dx – Tx

Source: Multiple sources[28]

Other potential energy storage technologies also exist, including the following:

- **Chemical:** Technologies such as hydrogen and syngas are not yet cost-competitive, have low efficiency, and are not as responsive as electrochemical technologies.
- **Thermal:** Two types of thermal storage that are commercially available today include ice storage and electric water heaters. Ice storage provides space conditioning typically to commercial buildings by making ice overnight when electricity prices are low and then using this ice to lower the building's HVAC load during the day, reducing energy and demand charges. Given the moderate climate and low demand charges in PGE's service area, this technology is not commercially viable here at present. Electric water heaters are the primary other version of thermal energy storage. PGE is actively pursuing the use of water heaters both for demand response and for broader grid integration activities.[29] Accordingly, water heaters are not being actively explored by PGE within UM 1751.
- **Other Electronic/Electrochemical:** A variety of different technologies are available that may not have been captured above. These are either not suitable for the target duration (e.g., ultracapacitors) or are not mature enough to warrant special consideration at this point. However, they may be considered at the point of procurement.

[24] Cycle lifetimes reflect equivalent full cycles in the case of duty cycles with partial depth-of-discharge (e.g., frequency regulation).

[25] Pumped hydroelectric energy storage

[26] Compressed air energy storage

[27] Includes sodium sulfur and sodium nickel halide

[28] Values are primarily obtained from the *DOE/EPRI Electricity Storage Handbook in Collaboration with NRECA* (2015). The ranges provided reflect typical values, but some exceptions may exist beyond these ranges.

[29] See PGE's 2017 Smart Grid Report, pp. 47-48, 55, 67. http://edocs.puc.state.or.us/efdocs/HAQ/um1657haq16327.pdf.

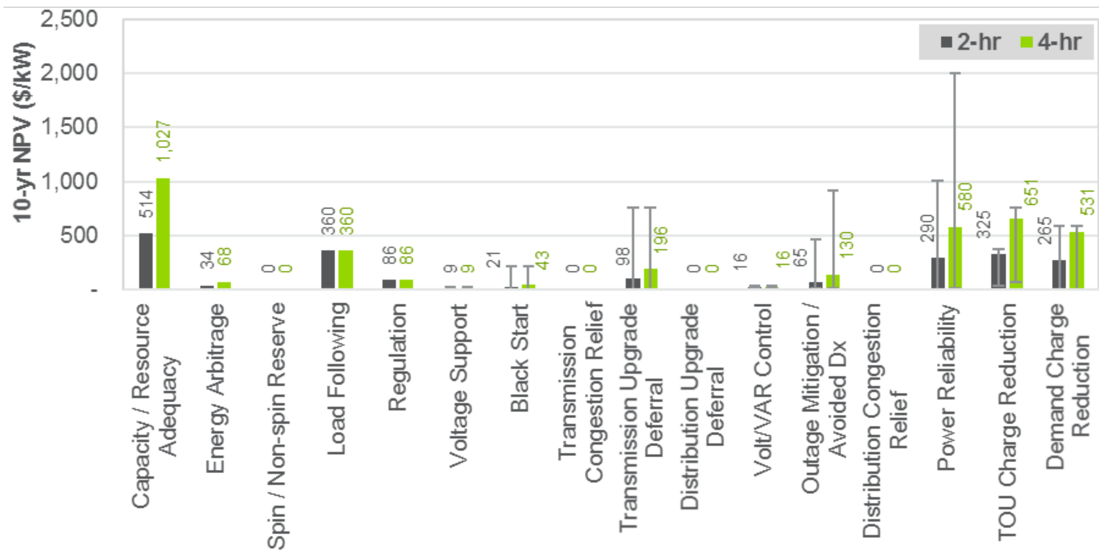
3. RESULTS

This section presents the results of the storage potential evaluation analysis. Section 3.1 evaluates the benefits associated with individual applications. Section 3.2 provides the results associated with the five different use cases, including the results of different scenarios with each use case and low, base, and high conditions associated with each scenario. Within a given use case, Navigant considered different scenarios with different durations (i.e., 2 hours and 4 hours), as well as different business rules for ESS dispatch. Section 3.3 evaluates how these results vary depending upon specific technology parameters.

3.1 Application Benefits

Figure 3-1 illustrates the 10-year NPV of the benefits associated with specific applications. The range and variability of each application is described below in Table 3-1. Note that ranges are provided only for benefits with particularly significant variability and/or uncertainty. Further, it is worth noting that the analysis assumes the benefits only vary over time with inflation. Over time, certain factors (e.g., commodity prices, renewables penetration, changing rate structures, etc.) may have a significant impact on the value of these benefits. Further, the analysis assumes only a modest penetration of energy storage. At larger penetrations, certain benefit streams may be diminished. For example, the value of additional capacity may diminish, or PGE may require longer durations of storage to meet its resource adequacy needs.

Figure 3-1. 10-year Benefits of Each Application[30]



Source: Navigant

[30] Error bars are provided only for applications with significant uncertainty/variability in benefits.

Table 3-1. Benefit Ranges

Application	Base Value[31]	Low Value	High Value	Variation with Duration
Capacity / Resource Adequacy	$120/kW-yr Assume 4-hour ESS required.	(same as base)	(same as base)	4 hours of storage is required, so the benefit is half as much for a 2-hour ESS.
Energy Arbitrage	$4/kWh-yr	(same as base)	(same as base)	Arbitrage benefits roughly scale with energy, so a 4-hour ESS would provide about twice the benefits of a 2-hour ESS. The actual benefits may be slightly less than double, as the margin between discharge and charge decreases with duration.
Spin/ Non-spin Reserve	$0/kW-yr	n/a	n/a	n/a (see Table 2-1)
Load Following	$42/kW-yr	(same as base)	(same as base)	ROM results indicate that the value of an ESS performing Load Following does not vary significantly with duration. Instead, benefits scale with power, so the $/kW value is similar for a 4-hour ESS vs. a 2-hour ESS.
Regulation	$10/kW-yr	(same as base)	(same as base)	Same as Load Following.
Voltage Support	$1/kVAR-yr	$0 PGE does not have a need for the service.	$2/kVAR-yr Assume 2x base value.	Benefits scale with power (kW), so the benefits do not increase with duration.
Black Start	$5/kW-yr Assume 4 hours required.	$0 PGE does not have a need for the service.	$25/kW-yr High end of representative range. Assume 2 hours required.	With 4 hours of storage required, the benefit scales with energy up to 4 hours. For the high case, only 2 hours of storage is required, so the benefit is the same for the 4-hour and 2-hour ESSs.
Transmission Congestion Relief	$0	n/a	n/a	n/a (see Table 2-1)
Transmission Upgrade Deferral	$125/kW Tx capacity Assume 1 year of deferral with 4 hours required.	$0 Assume grid location limits deferral value.	$250/kW Tx capacity Assume 2 years of deferral with 2 hours required.	With 4 hours of storage required, the benefit scales with energy up to 4 hours. For the high case, only 2 hours of storage is required, so the benefit is the same for the 4-hour and 2-hour ESSs.
Distribution Upgrade Deferral	$0	n/a	n/a	n/a (see Table 2-1)

[31] Values reflect 2016 dollar values. Units vary depending upon how each value scales. Values may scale with energy (kWh), real power (kW), or reactive power (kVAR). Further, some values represent annual benefits (e.g., $/kW-year), while others represent 10-year lifetime benefits (e.g., $/kW).

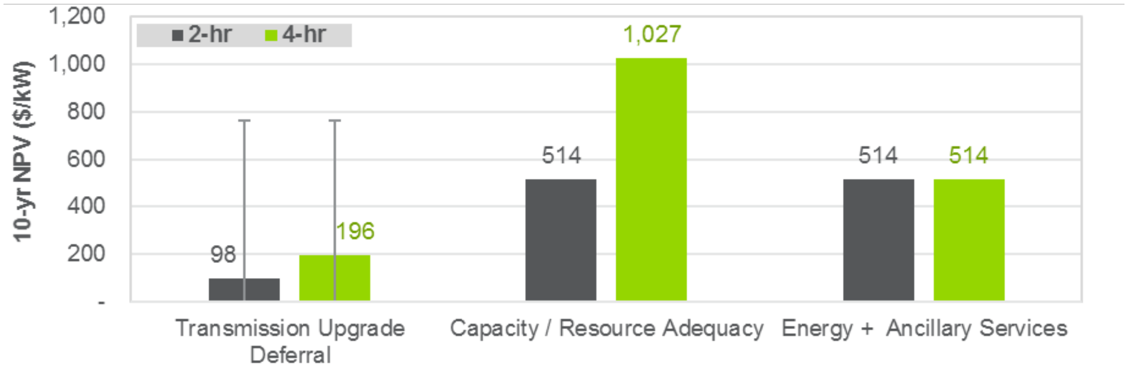
Application	Base Value[31]	Low Value	High Value	Variation with Duration
Volt/VAR Control	$16/kVAR	$8/kVAR Assume cost is half of representative recent investment.	$32/kVAR Assume cost is twice of representative recent investment.	Benefits scale with power (kW), so the benefits do not increase with duration.
Outage Mitigation/ Avoided Distribution Investments	$32/kWh Average of averages at substation and feeder levels	$2/kWh Lowest value at substation level	$225/kWh Highest value at feeder level	The IPT analysis demonstrates that benefits scale approximately linearly with duration, so the value of a 4-hour ESS is about twice the value of a 2-hour ESS.
Distribution Congestion Relief	$0	n/a	n/a	n/a (see Table 2-1)
Power Reliability	$140/kWh Average value at customer level	$1/kWh Lowest value at customer level	$490/kWh Highest value at customer level	The IPT analysis demonstrates that benefits scale approximately linearly with duration, so the value of a 4-hour ESS is about twice the value of a 2-hour ESS.
TOU Charge Reduction	$19/kWh-yr Small C&I	$2/kWh-yr Medium and Large C&I	$22/kWh-yr Residential	Benefits scale linearly with duration up to 5 hours (duration of on-peak period), so the value of a 4-hour ESS is about twice the value of a 2-hour ESS.
Demand Charge Reduction	$62/kW-yr Large C&I. Assume 4 hours required.	$0/kW-yr Residential and Small C&I	$69/kW-yr Medium C&I. Assume 2 hours required.	With 4 hours of storage required, the benefit scales with energy up to 4 hours. For the high case, only 2 hours of storage is required, so the benefit is the same for the 4-hour and 2-hour ESSs.

Source: Navigant

3.1.1 Transmission-Sited Energy Storage Systems

Based on the analysis above, Navigant selected Transmission Upgrade Deferral, Capacity, and Energy + Ancillary Services for inclusion in the use cases with transmission-sited ESSs. Navigant excluded Transmission Congestion Relief, Black Start, and Voltage Support due to their relatively low value and moderate-to-high level of commitment, which impedes the more valuable collection of applications within Energy + Ancillary Services. Figure 3-2 summarizes the benefits of each individual application. Note that these values reflect independent applications and do not consider reductions in total value due to stacking.

Figure 3-2. Benefits of Selected Applications for Transmission-Sited ESSs

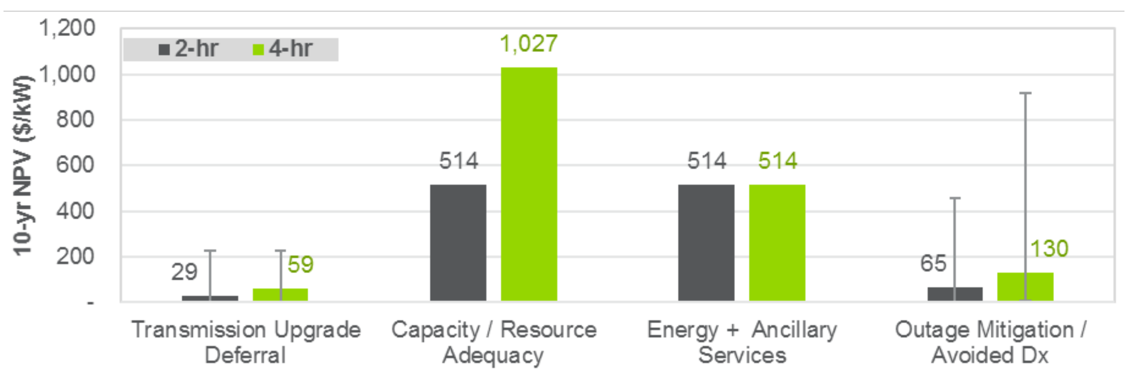


Source: Navigant

3.1.2 Distribution-Sited Energy Storage Systems

The use cases for distribution-level ESSs consider all selected transmission applications, as well as Outage Mitigation/ Avoided Distribution Investments. Distribution Congestion Relief, Distribution Upgrade Deferral, and Volt/VAR were excluded due to their low value and moderate-to-high level of commitment, which impede with the more valuable collection of applications within Energy + Ancillary Services. Figure 3-3 summarizes the benefits of each individual application. Note that these values are for independent applications and do not consider reductions in total value as a result of stacking. These do, however, consider differences in potential benefits at the distribution level. As described in Section 3.2.2, Transmission Upgrade Deferral benefits are lower than at the transmission level, and Outage Mitigation/ Avoided Distribution Investments benefits are lower than the Power Reliability benefits at the customer level.

Figure 3-3. Benefits of Selected Applications for Distribution-Sited ESSs

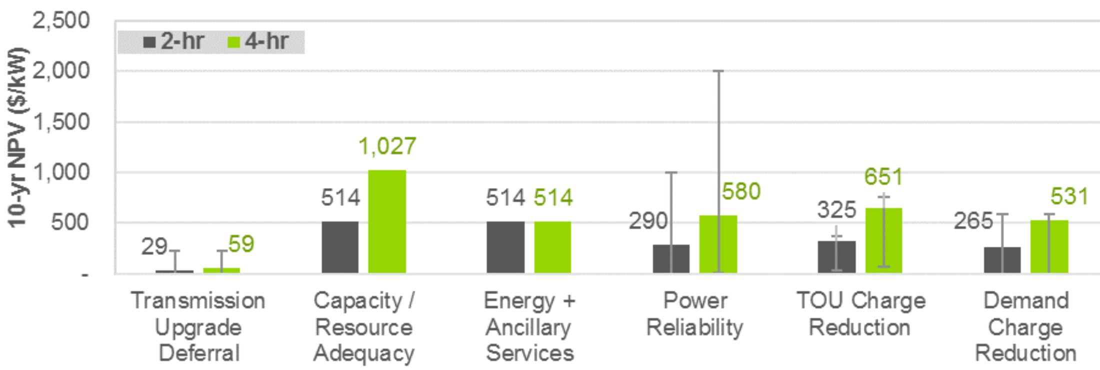


Source: Navigant

3.1.3 Customer-Sited Energy Storage Systems

The use cases for customer-level ESSs consider all selected applications for the transmission- level and distribution-level use cases, as well as TOU Charge Reduction and Demand Charge Reduction (DCR). Figure 3-4 summarizes the benefits of each individual application. Note that these values are for independent applications and do not consider reductions in total value as a result of stacking. These do, however, consider differences in potential benefits at the customer level. As described in Section 2.3, Transmission Upgrade Deferral benefits are lower than at the transmission level, and Power Reliability benefits are higher than the Outage Mitigation/ Avoided Distribution Investments at the distribution level.

Figure 3-4. Benefits of Selected Applications for Customer-Sited ESSs

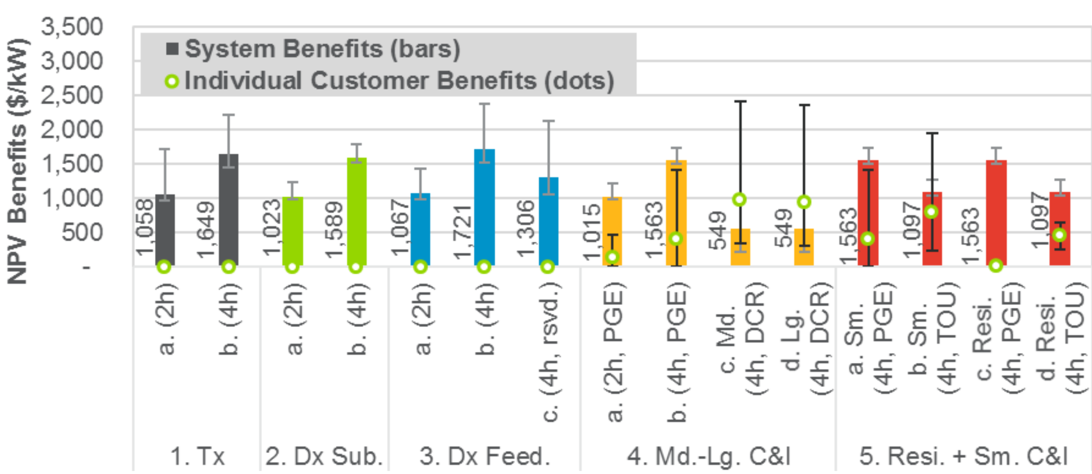


Source: Navigant

3.2 Optimized Use Cases

Figure 3-5 summarizes the range of benefits obtained for each of the use cases.[32] The results delineate between system benefits (all benefits except TOU and DCR) and individual customer benefits (bill savings from TOU and DCR). The details for each use case are discussed in greater detail in Section 3.2.1 through Section 3.2.5. The assumptions and inputs for each use case are described in Section 2.3. The error bars show the range of results between the low and high conditions. The inputs for the base, low, and high conditions are described for each use case in Section 2.3.1 through 2.3.5.

Figure 3-5. Summary of Results for all Use Cases



Source: Navigant

[32] All NPV benefits were calculated in 2020 USD based on the weighted average cost of capital (6.204%), then converted to 2017 USD based upon assumed inflation (2%).

Figure 3-6 compares the system benefits of 4-hour vs. 2-hour ESSs at different grid locations. The ratio between system benefits of 4-hour ESSs and the benefits of 2-hour ESSs generally increases going from the transmission level down to the feeder level. There is then a drop-off in in the benefit ratio at the customer level, in part because the Power Reliability benefits are individual customer benefits, whereas Outage Mitigation/ Avoided Distribution Investments benefits are system benefits. For all examples in Figure 3-6, the 4-hour ESS provides greater benefits than a 2-hour ESS at ratio of approximately 1.3 or higher. The ratio is typically about 1.5 and is nearly 1.7 in certain cases. Whether a 2-hour or 4-hour ESS is preferable depends upon the ratio of costs between them.

Figure 3-6. System Benefits of 4-hour vs. 2-hour ESSs

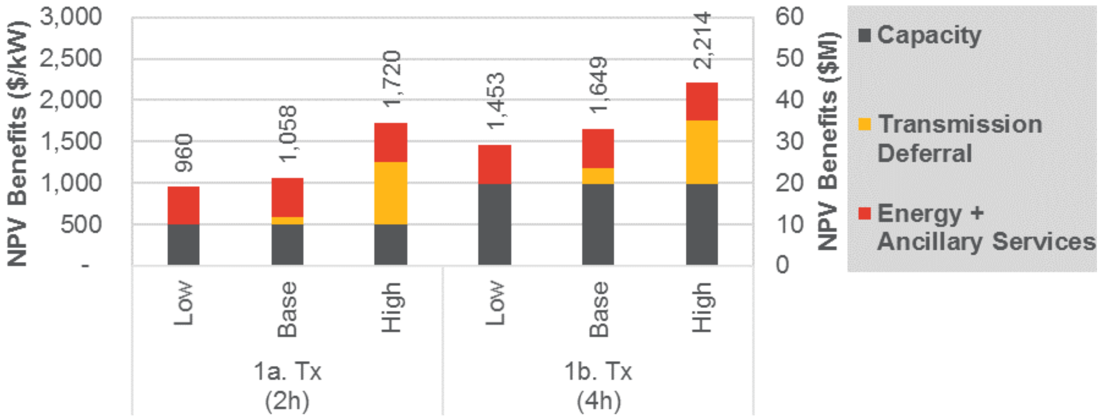
Source: Navigant

3.2.1 Case 1: 20 MW ESS on Transmission Line

Figure 3-7 illustrates the system benefits under each of the transmission-level scenarios analyzed. The left axis provides the normalized benefits ($/kW), while the right axis provides total system benefits. These benefits serve as a benchmark for target ESS costs.

Two scenarios were evaluated, including one for a 2-hour ESS (1a) and one for a 4-hour ESS (1b). In each case, the ESSs support Capacity and Transmission Deferral for 10 days each year, then provide Energy + Ancillary Services for the other 345 days. The inputs and assumptions for transmission-level ESSs are described in Table 2-3 and Section 2.3.1.

Figure 3-7. System Benefits of 20 MW Transmission-sited ESSs



Source: Navigant

The benefits increase going from a 2-hour to a 4-hour ESS primarily due to additional Capacity benefits, as 4 hours of storage are required, so only half of the benefit is realized for a 2-hour ESS. The Transmission Deferral benefits are also higher for the 4-hour ESS in the base case, as it assumed that 4 hours of storage are required. However, it is assumed that only a 2-hour ESS is required in the high case.

The key source of variability between the low, base, and high conditions is the Transmission Deferral benefit. The Capacity and E+AS benefits were assumed to be the same for all, as the confidence in the level of these benefits obtained from the ROM analysis is relatively high. However, for Transmission Deferral, the following factors may vary:

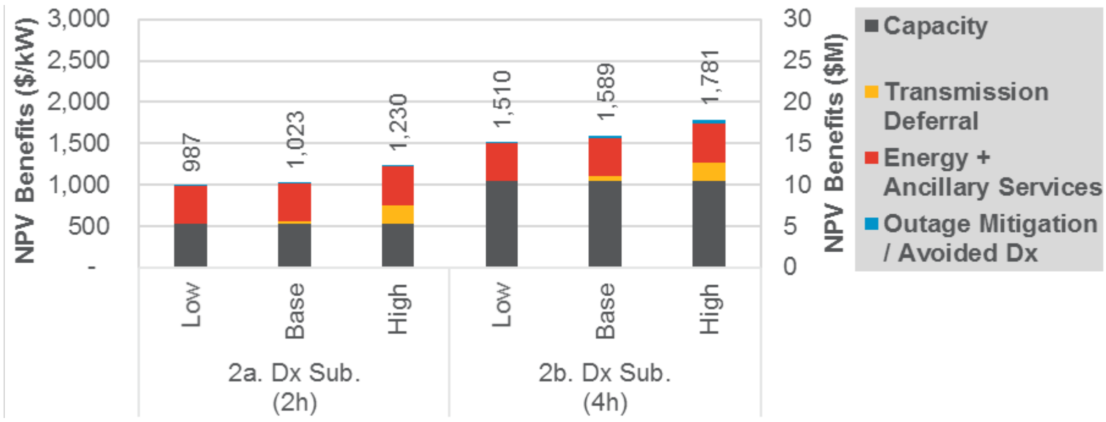
- Required duration (low/base = 4 hours, high = 2 hours)
- Cost of transmission equipment, based on the type of investment (low/base = $125/kW, high = $250/kW)
- Deferral period (low/base = 1 year, high = 2 years)
- Capacity of transmission deferred (low = 0 kW, base/high = 20 kW transmission per kW storage)

3.2.2 Case 2: 10 MW ESS at Distribution Substation

Figure 3-8 illustrates the system benefits under each of the substation-level scenarios analyzed. The left axis provides the normalized benefits ($/kW), while the right axis provides total system benefits. These benefits serve as a benchmark for target ESS costs.

Two scenarios were evaluated, including one for a 2-hour ESS (2a) and one for a 4-hour ESS (2b). In each case, the ESSs support Capacity and Transmission Deferral for 10 days each year, then provide Energy + Ancillary Services for the other 345 days. The inputs and assumptions for substation-level ESSs are described in Table 2-3 and Section 2.3.2.

Figure 3-8. System Benefits of 10 MW Substation-sited ESSs



Source: Navigant

Relative to transmission-level ESSs, the key difference is the amount of Transmission Deferral benefits. PGE analysis indicates that load reductions at the distribution level yield only ~30% impact along any transmission route (i.e., 10 MW distribution load reduction = 3 MW load reduction along a specific transmission route), so the distribution-level benefits are assumed to be 30% of the transmission-level benefits.

The differences in other benefits are relatively small. The Capacity and E+AS benefits are similar, except the Capacity benefits at the distribution level are slightly higher (~5%) due to reduced T&D losses during peak periods. The Outage Mitigation/ Avoided Distribution Investments benefits are minimal, as substation-level storage is only able to mitigate transmission-level outages, while most outages are driven by events at the distribution level.

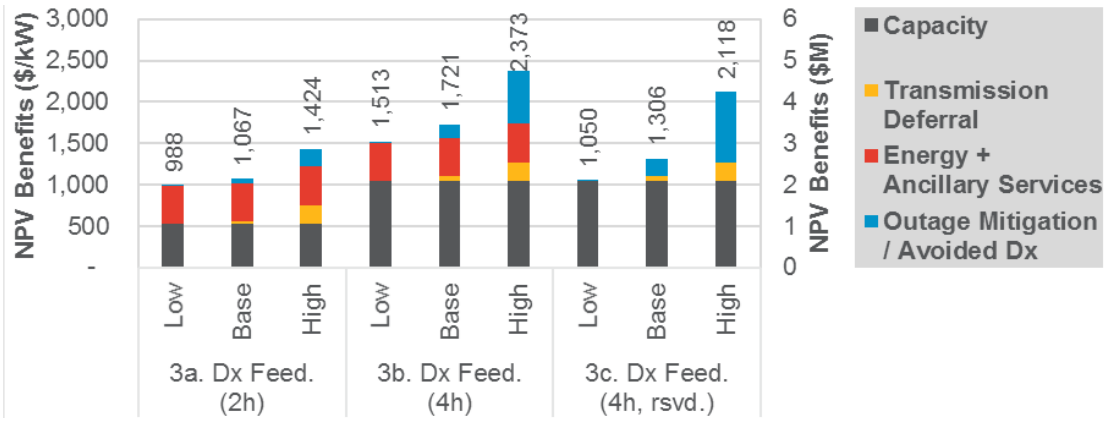
The sources of variability between the low, base, and high conditions are the same as for the transmission-sited ESS for the Capacity, Transmission Deferral, and Energy + Ancillary Services benefits. For the Outage Mitigation/ Avoided Distribution Investments benefits, the benefits vary by substation depending upon the frequency of transmission outages at the substation, and the average value of service for impacted customers.

3.2.3 Case 3: 2 MW ESS on Distribution Feeder

Figure 3-9 illustrates the system benefits under each of the feeder-level scenarios analyzed. The left axis provides the normalized benefits ($/kW), while the right axis provides total system benefits. These benefits serve as a benchmark for target ESS costs.

Three scenarios were evaluated. In the first two scenarios – one with a 2-hour ESS (3a) and one with a 4-hour ESS (3b) – the ESSs support Capacity and Transmission Deferral for 10 days each year, then provide Energy + Ancillary Services for the other 345 days, and the Outage Mitigation/ Avoided Distribution Investments application is available with a varying energy capacity depending upon the state of charge when an outage occurs. In the third scenario (3c), the ESS is reserved for Outage Mitigation/ Avoided Distribution Investments during all times when not needed for Capacity or Transmission Deferral (345 days/year). The inputs and assumptions for feeder-level ESSs are described in Table 2-3 and Section 2.3.3.

Figure 3-9. System Benefits of 2 MW Feeder-sited ESSs



Source: Navigant

Relative to substation-level ESSs, the key difference is the amount of Outage Mitigation/ Avoided Distribution Investments benefits. These benefits are higher than at the substation level, as feeder-level ESSs can help to mitigate distribution-level outages in additional to transmission outages, particularly on long feeders without robust tie lines. There is, however, significant variability in these benefits, as they depend upon the configuration of the feeder, the frequency of outages on the feeder, and the average value of service for impacted customers. Further, the benefits for 4-hour ESSs are greater, because only a 2-hour ESS is needed for E+AS, leaving 50% of the total energy capacity available for Outage Mitigation/ Avoided Distribution Investments except when occasionally needed for Capacity or Transmission Deferral.

For 4-hour ESSs, another scenario (3c) was analyzed that looked at the relative benefits for an ESS that is not used for E+AS and instead holds all of the energy storage capacity in reserve at all times, except when occasionally needed for Capacity or Transmission Deferral. In this case, the average available energy capacity increases from ~75% to nearly 100%. Thus, the Outage Mitigation/ Avoided Distribution Investments benefits increase by about one third in this case. However, the loss in E+AS benefits outweighs this impact, resulting in lower total benefits even in the high condition. Thus, it generally makes sense to utilize the ESS for E+AS rather than holding the full capacity in reserve for Outage Mitigation/ Avoided Distribution Investments. This finding may vary for certain feeders.

The sources of variability between the low, base, and high conditions are similar to the previous use cases for the Capacity, Transmission Deferral, and Energy + Ancillary Services benefits. For the Outage Mitigation/ Avoided Distribution Investments benefits, the benefits vary by feeder depending upon the configuration of the feeder, the frequency of outages on the feeder, and the average value of service for impacted customers.

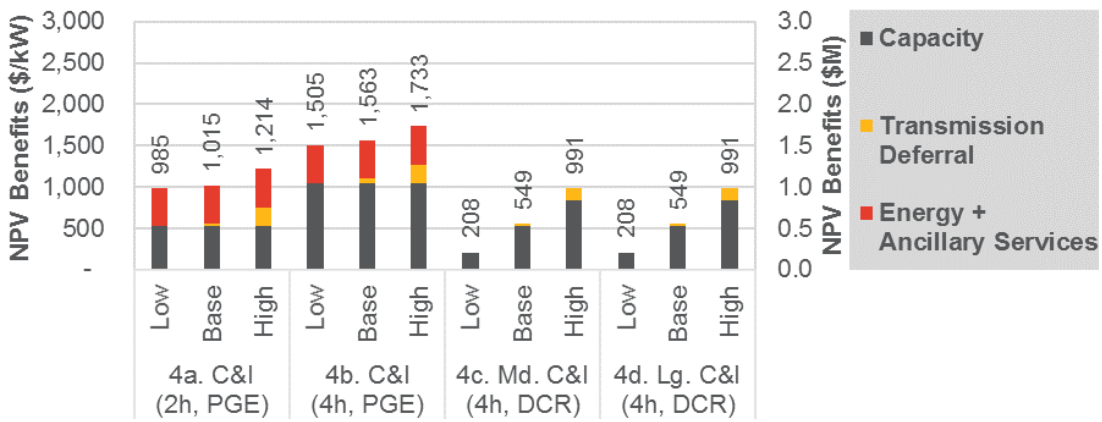
3.2.4 Case 4: 1 MW Aggregated Medium–Large C&I Customers

Figure 3-10 illustrates the system benefits under each of the customer-level scenarios analyzed for medium-to-large C&I customers,[33] while Figure 3-11 illustrates the benefits to the customer where the ESS is sited. The left axis provides the normalized benefits ($/kW), while the right axis provides total system benefits.

[33] Customers on rate schedules 83 (31 – 200 kW) or 85 (201 – 4,000 kW).

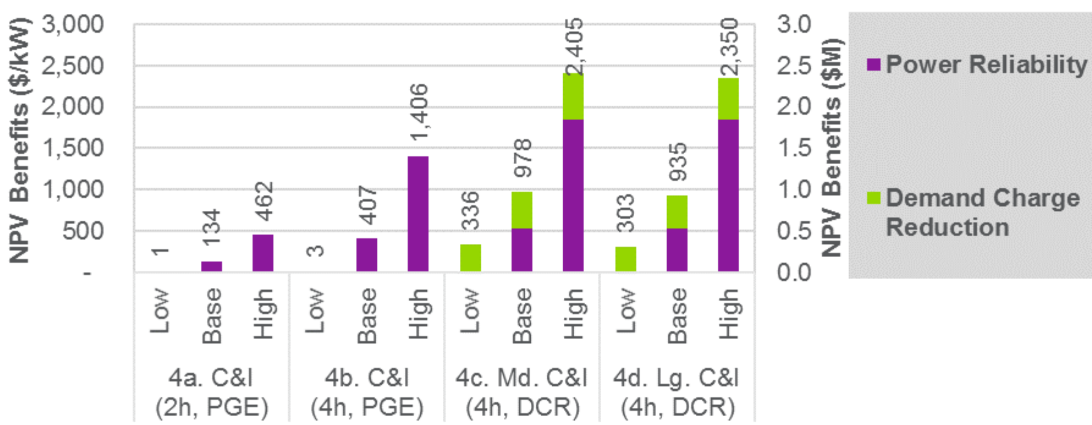
Four scenarios were evaluated. In the first two scenarios – one with a 2-hour ESS (4a) and one with a 4-hour ESS (4b) – the ESSs support Capacity and Transmission Deferral for 10 days each year, then provide Energy + Ancillary Services for the other 345 days, and Power Reliability is available with a varying energy capacity depending upon the state of charge when an outage occurs. In the last two scenarios – one for a medium C&I customer (4c) and one for a large C&I customer (4d) – the ESS is used primarily for Demand Charge Reduction. A portion of the aggregated capacity is available when needed for Capacity and Transmission Deferral, and Power Reliability is available with a varying energy capacity depending upon the state of charge when an outage occurs. The inputs and assumptions for these ESSs are described in Table 2-3 and Section 2.3.4.

Figure 3-10. System Benefits of 1 MW Aggregated Customer-sited ESSs (Medium-Large C&I)



Source: Navigant

Figure 3-11. Individual Customer Benefits of 1 MW Aggregated Customer-sited ESSs (Medium-Large C&I)



Source: Navigant

The first two scenarios (4a, 4b) evaluate 2-hour and 4-hur ESSs are operationally similar to feeder-level ESSs, as they are operated by PGE for E+AS. The key difference relative to feeder-level ESSs is the amount of Power Reliability benefits relative to Outage Mitigation/ Avoid Distribution Investments benefits and the fact that Power Reliability provides individual customer benefits rather than system benefits.

Placing the ESS at specific customer sites can target specific locations with high value of service.[34] As discussed in Section 2.2.3.2, Power Reliability benefits for individual customers are likely to vary significantly from customer to customer. Because the benefit accrues uniquely to one customer, the benefit does not stack on the system benefits and instead is an individual customer benefit.

The last two scenarios (4c, 4d) evaluate 4-hour ESSs at medium and large C&I customer sites used for Demand Charge Reduction (DCR) rather than for E+AS. The key differences are:

- Lower Capacity and Transmission Deferral benefits due to lower guaranteed available capacity (low = 20%, base = 50%, high = 80%)
- No E+AS benefits
- Higher PR benefits (i.e., higher average state of charge for DCR vs. E+AS)
- DCR benefits included

The sources of variability between the low, base, and high conditions are the similar to the previous use cases for the Capacity, Transmission Deferral, and Energy + Ancillary Services benefits. In addition, the Capacity and Transmission Deferral benefits scale depending upon the assumed level of guaranteed capacity. For the Power Reliability benefits, the benefits vary by customer depending upon the configuration of the associated feeder, the frequency of outages for the customer, and the value of service for the customer. For DCR, the average monthly demand reduction may vary depending upon the customer's load profile (assumed reduction relative to ES power rating: low = 60%, base = 80%, high = 100%) and the demand charge (which was the only assumed difference between medium and large C&I customers).

Overall, the system benefits are significantly lower for the DCR ESSs. The magnitude of the individual customer benefits from DCR is similar to the system benefits from E+AS when operated by PGE. However, the DCR benefits also result in lower revenue for PGE, which may increase costs to other customers and is not accounted for in the system benefits. The Power Reliability benefits can be quite high in certain cases, but these benefits accrue to a specific customer.

3.2.5 Case 5: 1 MW Aggregated Small C&I + Residential Customers

Figure 3-12 illustrates the system benefits under each of the customer-level scenarios analyzed for small C&I and residential customers,[35] while Figure 3-13 illustrates the benefits to the customer where the ESS is sited. The left axis provides the normalized benefits ($/kW), while the right axis provides total system benefits.

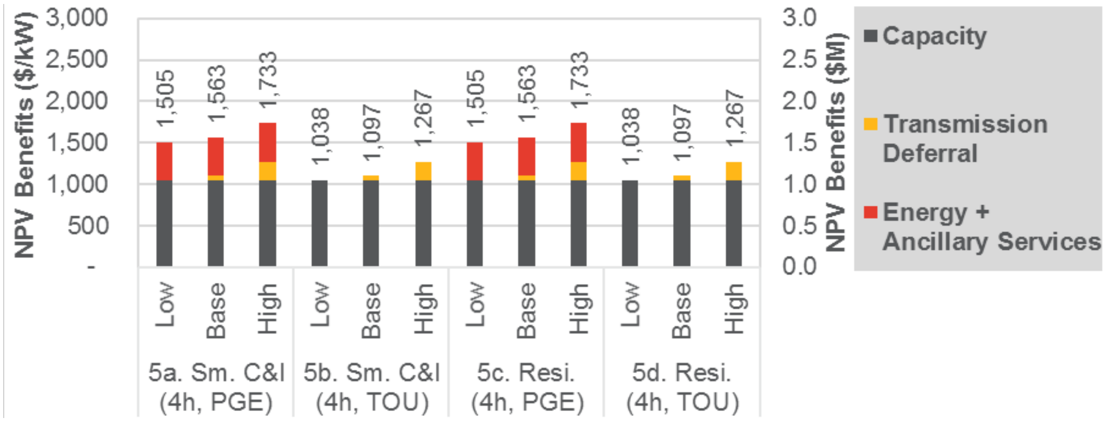
Four scenarios were evaluated. In two scenarios – one for a small C&I customer (5a) and one for a residential customer (5c) – the ESSs support Capacity and Transmission Deferral for 10 days each year, then provide Energy + Ancillary Services for the other 345 days, and Power Reliability is available with a varying energy capacity depending upon the state of charge when an outage occurs. In the last two scenarios – one for a small C&I customer (5b) and one for a residential customer (5d) – the ESS is used for TOU Charge Reduction instead of Energy + Ancillary Services when not needed for Capacity and Transmission Deferral, and Power Reliability is available with a varying energy capacity depending upon

[34] Note that the range of Power Reliability values shown here is from a selected sample of customers that may have a higher average benefit relative to the system-wide average for all PGE customers.

[35] Customers on rate schedules 7 (residential) or 32 (C&I, <30 kW).

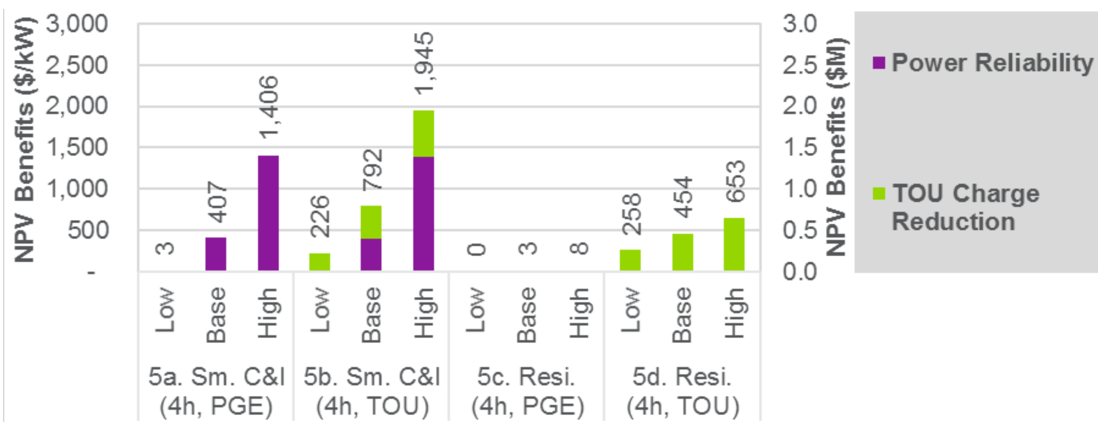
the state of charge when an outage occurs. The inputs and assumptions for these ESSs are described in Table 2-3 and Section 2.3.5.

Figure 3-12. System Benefits of 1 MW Aggregated Customer-sited ESSs (Small C&I + Residential)



Source: Navigant

Figure 3-13. Individual Customer Benefits of 1 MW Aggregated Customer-sited ESSs (Small C&I + Residential)



Source: Navigant

The "PGE" scenarios evaluate 4-hour ESSs that are operationally similar to the ESSs operated by PGE at medium and large C&I customer sites. The results for small C&I customers are identical to those for medium and large C&I customers, as there is no assumed difference in Power Reliability benefits. However, the Power Reliability benefits are assumed to be significantly lower for residential customers due to a lower value of service.

The TOU scenarios in Figure 3-12 evaluate 4-hour ESSs used for TOU Charge Reduction, rather than E+AS. Relative to the ESSs utilized for E+AS, these ESSs have:

- The same Capacity and Transmission Deferral benefits
- No E+AS benefits

- Similar PR benefits (i.e., similar average state of charge for TOU vs. E+AS)[36]
- TOU benefits included

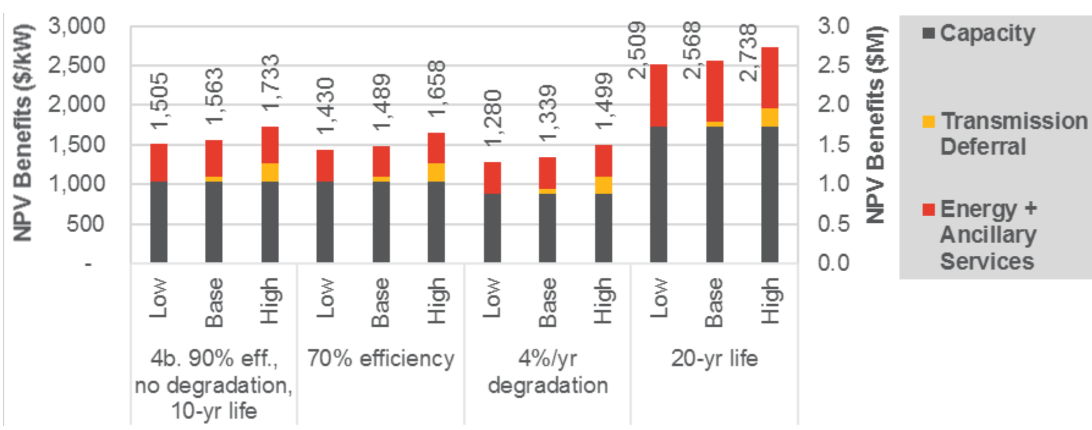
The sources of variability between the low, base, and high conditions are the similar to the prior use case for the Capacity, Transmission Deferral, and Energy + Ancillary Services benefits. As with medium and large C&I customers, the Power Reliability benefits for small C&I customers vary by customer depending upon the configuration of the associated feeder, the frequency of outages for the customer, and the value of service for the customer. For residential customers, the value of service is assumed to be low under all conditions. The average monthly TOU benefits may vary depending upon the customer's load profile, as the ESS capacity may exceed the customer's load during peak hours (assumed TOU reduction relative to max potential reduction: low = 40%, base = 70%, high = 100%) and the TOU rate schedule.

Thus, the system benefits are lower due to the lack of E+AS benefits. The magnitude of the individual customer benefits from TOU is similar to the system benefits from E+AS when operated by PGE. However, the TOU benefits also result in lower revenue for PGE, which may increase costs to other customers and is not accounted for in the system benefits. The PR benefits can be quite high in certain cases, but these benefits accrue to a specific customer.

3.3 Technology Comparison

To evaluate the impact of technology on the NPV of lifetime system benefits, key technology parameters (efficiency, degradation, and lifetime) discussed in Section 2.4 were varied for the 4-hour PGE-controlled ESS located at a C&I customer site (4b). This specific scenario was selected to illustrate the impact of these parameters on a variety of benefit streams. The conclusions from this analysis illustrate how benefits would scale under other use cases and scenarios. Figure 3-14 and Figure 3-15 summarize these results for system benefits and individual customer benefits, respectively.

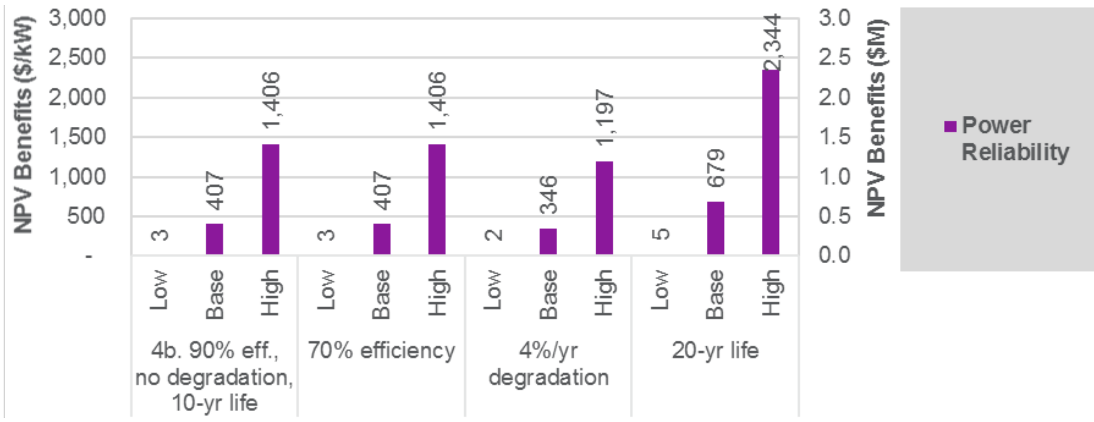
Figure 3-14. Impact of Technology Parameters on System Benefits



Source: Navigant

[36] The average state of charge for TOU is higher, but it uses the entire ESS, while the average state of charge for E+AS is lower, but it only uses half of a 4-hour ESS.

Figure 3-15. Impact of Technology Parameters on Individual Customer Benefits



Source: Navigant

This analysis demonstrates that the impact of efficiency for this use case is relatively small, because most of the benefits (Capacity, Transmission Deferral, and Outage Mitigation/ Avoided Dx) stem from occasional use of the ESS and do not require frequent cycling. The only benefit stream significantly affected by efficiency is E+AS. The E+AS benefits for the 70% efficiency scenario were ~85% of their value for the reference scenario with 90% efficiency. Total system benefits were >95% relative to the reference scenario.

The impact of degradation is more notable, because it has a more significant impact on most benefit streams. The impact on Transmission Deferral benefits is minimal, because those benefits accrue in the first 1-2 years. However, the Capacity, E+AS, and Power Reliability streams are all ~15% lower for the 4%/year degradation scenario relative to the reference scenario with no degradation, as it is assumed the capacity available for each application decreases with the available energy capacity.[37] Because the Transmission Deferral benefits are relatively small, overall systems benefits were also ~15% lower than the reference scenario.

The impact of ESS life is more profound. An ESS with a 20-year life produces nearly 67% more benefit than the reference ESS with a 10-year life. As is the case for degradation, the Capacity, E+AS, and Power Reliability streams are all similarly impacted, while the Transmission Deferral benefits remain about the same. Note that both the 10-year and 20-year cases assume no degradation, which is the result of regular capacity replenishment. If degradation was significant and capacity was not replenished, the impact of extending the life of the ESS to 20 years would be somewhat diminished.[38]

[37] Note that while 4%/year degradation is relatively high, it provides a representative case of significant degradation, and it may be somewhat representative for this use case, in which the ESS is cycled nearly twice per day for Energy + Ancillary Services. Additionally, while the ESS degrades below 70% of initial capacity by the end of the 10-year period (which is below the common 80% threshold), it is not assumed that any replacement or replenishment occurs.

[38] Here, ESS life is assumed to be independent of degradation. Typically, these two parameters are related to one another, often based on the time to degrade to 80% of original energy capacity. However, the ESS life is typically equal to the warranty period for financial purposes, and warranties can have varying periods for the same technology, depending upon how they are structured.

APPENDIX A. OPUC ANALYSIS REQUIREMENTS

As outlined in UM 1751, Table A-1 provides the storage potential evaluation issues that should be addressed, examined and resolved at the staff workshops in the first half of 2017.

Table A-1. Recommended Evaluation Framework

Requirement	Analysis Approach
Establish a consistent list of use cases or applications to be considered in the Evaluation	Evaluate use cases identified in Appendix A of UM 1751 Staff Recommendation document and included in report Table 2-3.
Establish a consistent list of definitions of key terms	As defined in the US Department of Energy Glossary of Energy Storage Terms and *DOE/EPRI Electricity Storage Handbook in Collaboration with NRECA*.
Timeframe for analyses	10 years for initial analysis. For the proposal, due on January 1, 2018, the analysis timeframe should be equal to the lifetime and life-cycle cost of the proposed ESS.
Potential valuation methodology or methodologies the electric companies may use for estimating storage potential in each use case or application	Incorporate the agreed-upon list of factors provided in Appendix A of UM 1751 Staff Recommendation document and included in report Table 2-1.
Criteria for identifying the main opportunities for investment in storage	Cost-effectiveness, diversity, location, and utility learning.
Approach for identifying system locations with the greatest storage potential	Considering five generic locations for draft evaluation: transmission, distribution substation, distribution feeder, residential/small C&I customers, and medium/large C&I customers. PGE will look at specific locations for the final potential evaluation report.
Level of detail required in the evaluation results and required supporting data.	Detailed in Table A-2.

Source: Adapted by Navigant from Public Utility Commission of Oregon Staff Report Public Meeting Date: March 21, 2017

One of the recommended steps in the evaluation framework is to develop a potential valuation methodology to estimate storage potential in each use case or application. Table A-2 provides the key elements as outlined in the staff public meeting on March 21, for consideration in the potential evaluation. These key elements provided guidance for the potential evaluation detailed in this report.

Table A-2. Key Elements for Potential Evaluation

Requirement	Analysis Approach
Electric companies should analyze each use case listed in Appendix A for each evaluated storage site.	The analysis considers use cases consisting of a set of applications performed by an ESS at a grid location (transmission, substation, feeder, or BTM).
Final Storage Potential Evaluations Should include detailed cost estimates for each proposed storage system.	Draft evaluation focuses on benefits, rather than costs.
When storage services can be defined based upon market data, a market valuation should be used for such identified services.	Where available, market pricing was used as a basis. Otherwise, avoided costs were used.

Requirement	Analysis Approach
Final evaluations submitted by January 1, 2018 should provide detailed descriptions of the proposed sites.	Out of scope for the draft evaluation.
“Resiliency” should be defined in the form of a use case or as a unique, quantifiable benefit if it is included in the Final Storage Potential Evaluation.	Value of resiliency/reliability is incorporated within the IPT analysis of Outage Mitigation and Power Reliability benefits.
The components of each model, including the attributes in Staff Recommendation No. 6, should be identified and drafted in both the draft and final evaluations.	These applications are addressed in Table 1-1.
A single base year may be used for modeling purposes.	Simulation of operational value was undertaken for a 2021 test year due to data availability through the 2016 IRP and the timing of PGE’s incremental capacity need.
Staff must be able to validate the assumptions and methods used to evaluate the cost-effectiveness of each proposed ESS in the final proposals.	The methodology, including models, assumptions, and data sources, is described herein.

Source: Adapted by Navigant from Public Utility Commission of Oregon Staff Report Public Meeting Date: March 21, 2017

Navigant used the modeling attributes outlined in the staff public meeting on March 21, to help guide energy storage potential modeling decisions. Energy storage has several unique characteristics, and staff views it as essential that any models used in the evaluations have the attributes listed in Table A-3. Staff believes that the June 1, 2017, draft evaluations do not need to include the first three items but the attributes included need to be documented clearly. Nonetheless, these items are incorporated into the analysis described herein.

Table A-3. Modeling Attributes

Attribute	Analysis Approach
Capacity to evaluate sub-hourly benefits	Sub-hourly analysis is used in ROM (15-min intervals with reserves to manage fluctuations down to one minute).
Ability to evaluate location-specific benefits based on utility-specific values	ESSs sited at general transmission, substation, feeder, and customer locations are considered herein. Locational benefits from the IPT model are based on PGE-specific parameters. Specific sites are to be considered by PGE in the final evaluation.
Enables co-optimization between services	ROM analysis co-optimizes energy and ancillary services. The use cases run in NVEST prioritize different applications and the utilization of the ESS for those applications based upon their value and compatibility.
Capacity to evaluate bulk energy, ancillary service, distribution-level, and transmission-level benefits	Benefits are assessed for each application in Section 3.1.
Ability to build ES conditions (e.g., power/energy capacity, charge/discharge rates, charging/discharging efficiencies, efficiency losses) into the optimization	The analysis in Section 2.3 considers the impact of ESS sizing, while the analysis in Section 2.4 considers the impact of efficiency, degradation, and lifetime. Optimized dispatch in ROM takes into account the listed ES conditions in every time step.

Source: Adapted by Navigant from Public Utility Commission of Oregon Staff Report Public Meeting Date: March 21, 2017

APPENDIX B. MODELING DETAILS

The following sections provide additional detail regarding the modeling tools and approach used, beyond the discussion in Section 2.2.

B.1 Navigant Valuation of Energy Storage Tool (NVEST)

Section 2.2.1 describes the NVEST model at a high level. As mentioned above, a detailed description of the basic methodology is publicly available online.[39] Further, many of the assumptions, inputs, and data sources specifically associated with the analysis in this report are described elsewhere within the document:

- Section 2.1 describes the analytical approach and data sources used for each application;
- Section 2.2 describes the sources for the inputs and assumptions that were used;
- Section 2.3 describes the assumptions associated with each use case; and
- Section 2.4 describes the assumptions associated with the energy storage technology and performance.

The list below describes other important assumptions used to determine the value of each use case.

- The net present value (NPV) of each use case reflects the net operating benefit of the ESS. It includes both the benefits accrued from operating the ESS for specific applications, as well as the variable operating costs associated with operating the ESS (e.g., charging costs). It does not include costs associated with ESS ownership (i.e., installed capital costs, as well as fixed operating and maintenance costs).
- Values associated with the energy capacity (kWh) and power capacity (kW) of the ESS (e.g., annual kW available for Energy + Ancillary Services) are reduced by the assumed degradation rate (e.g., 2%/year). Degradation is assumed to be exponential (i.e., Capacity in year 10 = $(1 – 2\%)^9$ = 83% of original capacity).
- Values associated with system benefits (e.g., $/kW-year for Energy + Ancillary Services) are assumed to escalate at inflation rate of 2% per year. Input values are escalated from their base year (typically 2016) to their value in the initial year (2021), as well escalated during each year of the deployment (typically through 2030).
- The NPV is calculated assuming a discount rate/ weighted average cost of capital of 6.204%. The ESS is assumed to be deployed in 2021, and the NPV is calculated in 2020 USD based upon the assumption that an investment is made in 2020 before the ESS goes live in 2021. This NPV is then converted to 2017 USD by adjusting for inflation (2%).

B.2 Resource Optimization Model (ROM)

PGE engaged in detailed modeling of ESSs within the 2016 IRP using ROM. ROM is a multi-stage production simulation model of PGE’s resource portfolio. ROM was originally designed to quantify operational challenges and costs associated with renewables integration. In addition to energy storage

[39] DOE Energy Storage Computational Tool Overview. US Department of Energy. August 2012. https://www.smartgrid.gov/document/doe_energy_storage_computational_tool_overview.html.

evaluation, ROM is used to calculate PGE's Variable Energy Integration Costs as well as the Day-Ahead Forecast Error costs associated with wind generation in PGE's calculation of Net Variable Power Costs. Recent ROM development work has been discussed in past and ongoing IRP dockets, including LC 56 and LC 66. Key model development decisions and subsequent enhancements were also reviewed by an external Technical Review Committee. Because of this history, ROM already incorporated the key features required for quantifying the operational value of energy storage resources: optimal unit commitment and dispatch of the PGE resource fleet over multiple time horizons, impacts of forecast errors (e.g., day-ahead to real-time), ancillary service requirements, and sub-hourly dispatch. More information about ROM and PGE's preliminary energy storage evaluation can be found in Chapter 8 of the 2016 IRP.[40]

Positive discussions with stakeholders regarding PGE's approach to modeling energy storage in the 2016 IRP encouraged the Company to continue to explore energy storage evaluation through production simulation modeling exercises. PGE also received positive feedback on its methodology from utilities and industry organizations across the country. PGE's methodology was highlighted in the Energy Storage Association's 2016 primer on energy storage modeling in IRPs[41] and PGE was invited to present the analysis at industry and policy forums, including the Western Energy Institute's Integrated Resource Planning Forum and the North Carolina Sustainable Energy Association's Energy Storage Working Group. At these forums, utilities around the country shared similar challenges in quantifying the value of energy storage. Key functionality enabled by PGE's approach includes the ability to: co-optimize value across multiple applications and timescales, capture portfolio effects and declining marginal values; quantify monetizable benefits over short timescales in a region without ancillary service markets, and capture utility-specific opportunities and constraints.

In the Energy Storage Potential Evaluation, PGE sought to leverage and update the analysis presented in the 2016 IRP as part of the broader effort to understand the value of energy storage on the PGE system. This appendix summarizes the new ROM analysis conducted to support the Energy Storage Potential Evaluation. It does not address capacity value, locational value, or the interactions between operational and non-operational value streams. These topics are discussed by Navigant in the main body of the report.

ROM Simulation Configuration

PGE quantified the value associated with operational applications in the Energy Storage Potential Evaluation by conducting multiple ROM simulations, each with a different energy storage configuration, and comparing the results to a base case, in which PGE's resource fleet is modeled without the addition of ESSs. Each ROM simulation yields the operational cost of meeting loads and ancillary service requirements across a test year. PGE assumed that the ESSs were capable of providing all of the modeled ancillary services, including: load following, which encompasses the mitigation of forecast errors and renewables integration challenges down to five minutes; regulation; spinning; and non-spinning reserves. The difference in cost between ROM simulations with and without an ESS yielded the net variable cost impact, or the operational value of the ESS. This cost difference reflects the combined value of the co-optimized operational applications—energy arbitrage and the ancillary services listed above. This value is monetized through energy market transactions and variable cost savings throughout the PGE resource fleet, including avoided fuel burn, variable O&M, and unit starts. The operational value

[40] Additional background about ROM and its use in PGE's Variable Renewable Integration Study can be found in Section 7.2.1.1 in PGE's 2016 IRP.

[41] "Including Advanced Energy Storage in Integrated Resource Planning: Cost Inputs and Modeling Approaches," November 2016, http://energystorage.org/system/files/attachments/irp_primer_002_0.pdf.

identified in this analysis therefore assumes that PGE has the ability to control the ESS in coordination with the dispatch of its resource fleet.

PGE evaluated three ESS configurations, including 50-MW ESSs with 2-hour, 4-hour, and 6-hour durations. While the storage investments made by PGE under HB 2193 are capped at 38.7 MW, PGE chose to model 50-MW ESSs in this analysis due to computational considerations common to production cost models, which are discussed below. The Navigant analysis assumes that the benefits of the ESSs determined by ROM scaled linearly to the specific resource sizes considered in the report. PGE's base resource portfolio in ROM reflected the 2021 fleet modeled in the Variable Energy Integration Study (Run 4) described in Section 7.2.1.1 in the 2016 IRP. Hourly and 15-minute energy prices were based on the Reference Case in the 2016 IRP.

Dispatch Behavior

The dispatch behavior of energy storage resources depends on market conditions as well as system demand and the availability and characteristics of other resources in the portfolio. In particular, the extent to which energy storage resources are dispatched to provide reserves depends strongly on the demand for those reserves and the other resources available to provide them. Depending on the cost of providing various reserves with resources within PGE's portfolio, the optimal energy storage dispatch may also prioritize providing some services over others. For example, in time steps[42] when adequate hydro resources are available to provide reserves, the value of providing these reserves with a storage system is small. However, in time steps in which reserves would otherwise be met with thermal resources, providing these services with an ESS provides the opportunity to avoid fuel burn, O&M costs, and potentially unit starts. These economic considerations vary from time step to time step, so the dispatch and provision of reserves provided by the ESS also varies over time. Such considerations also vary by utility depending on market structures as well as the nature of loads and resources available to meet those loads.

Weekly Dispatch Snapshots

Figure B-1 illustrates the simulated dispatch behavior, state of charge, and reserve provisions for a 50-MW, 2-hour ESS with 90% efficiency over the course of a week in January (left panel) and August (right panel) with 15-minute resolution. On the January week, the charging/discharging pattern does not follow a predictable daily trend and the amount of storage capability being utilized (as indicated by the range in the state of charge) changes dramatically from day to day. The regulation reserve provisions tend to follow a diurnal pattern broadly reflective of the daily net load shape, although some time steps deviate from this pattern. Load following reserve provisions change dramatically both across and within days, with no obvious predictable pattern. Note that while the ESS has a 50 MW capacity, reserve provisions can well exceed 50 MW because the ESS is assumed to be capable of switching between charging and discharging modes over very short timescales.[43] Therefore an ESS that is charging at 50 MW could simultaneously provide up to 100 MW of upward reserves and ESS that is discharging at 50 MW could simultaneously provide up to 100 MW of downward reserves.[44] While this assumption is valid for many

[42] Time steps in the ROM modeling were one hour in the day-ahead stage and 15 minutes for other stages.

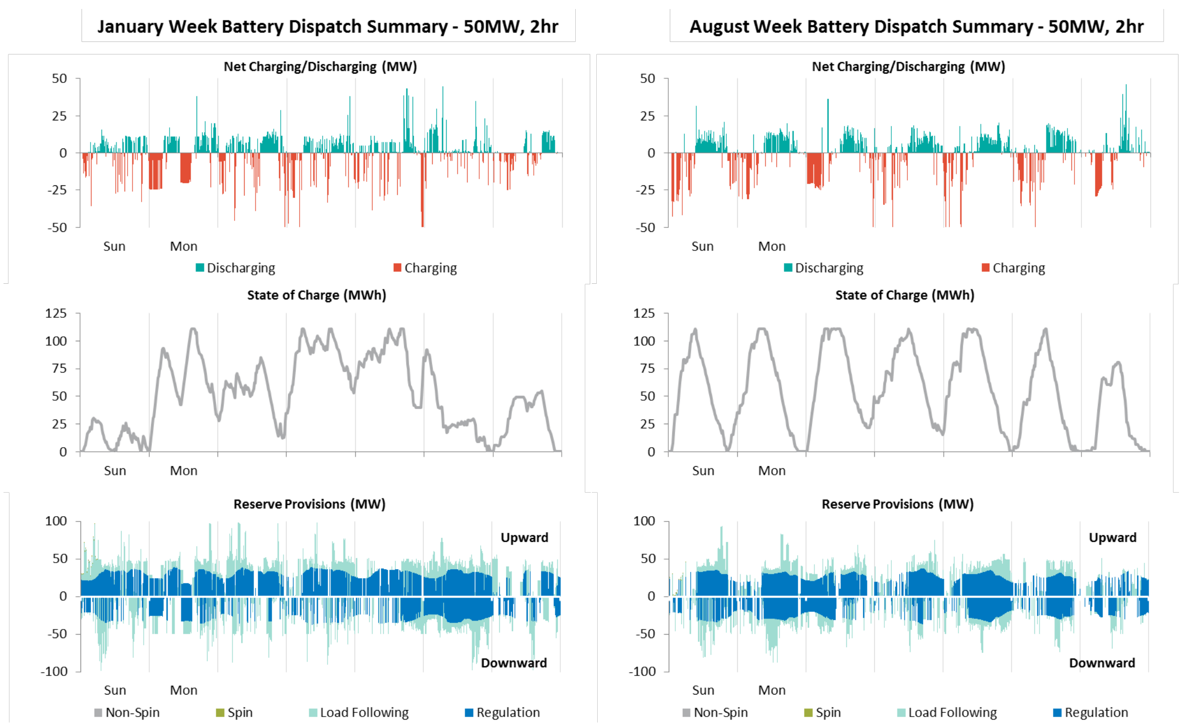
[43] Down to four seconds for regulation.

[44] Load following reserve provisions reflect both load following held in the real-time stage and any differences in ESS dispatch between the day-ahead and real-time stages brought about by forecast errors. This accounting may give rise to periods in which the total reserve provisions appear to exceed the physical capabilities of the ESS even though ESS capability constraints are respected in ROM.

battery technologies, it may not be valid for energy storage technologies with time delays associated with switching between charging and discharging modes—pumped hydro storage, for example.

In contrast, on the August week, the ESS consistently experiences a full or near-full charge and discharge cycle once per day—charging in the early morning hours and discharging in the evening during peak demand conditions. This periodicity is reflected in the state of charge panel. Similar to the January week, the regulation reserve provisions generally follow a predictable daily shape, while the load following provisions are less predictable.

Figure B-1. Energy Storage Dispatch – 50-MW, 2-hour ESS



Source: PGE

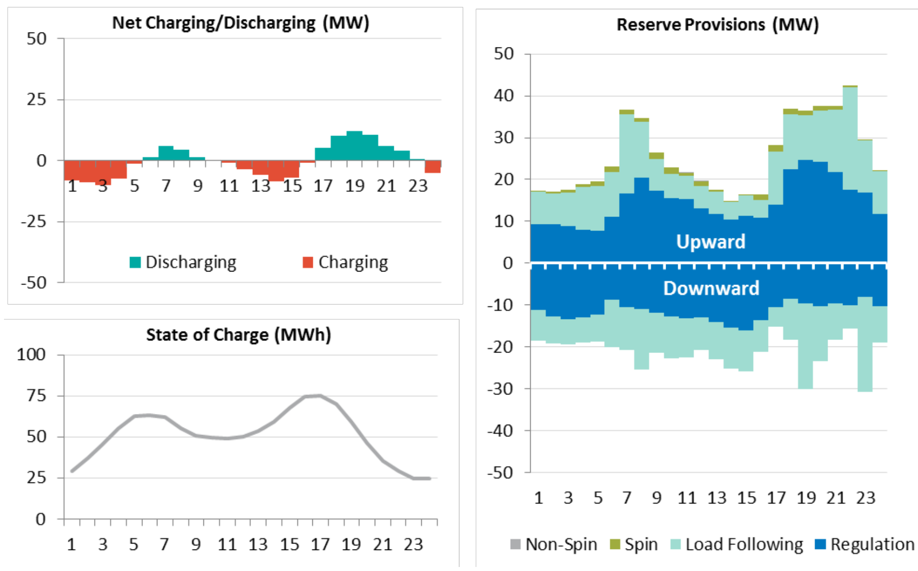
Seasonal Dispatch Patterns

The dispatch behavior can also be summarized on an average basis across seasons to identify general dispatch trends. Average daily dispatch behavior, state of charge, and reserve provisions are shown by quarter in Figure B-2 through Figure B-5.

In the first quarter, the ESS tends to charge in the early morning hours and early afternoon and discharge during the morning and evening peaks, reflecting the load shape. Similarly, average reserve provisions are highest during the morning and evening peaks and during these periods the batteries tend to prioritize providing more upward than downward reserves.

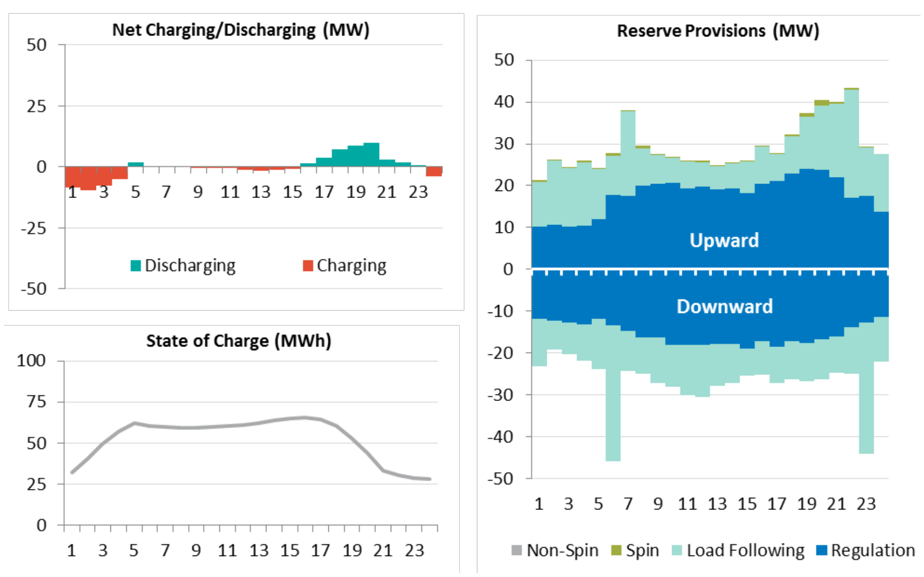
During the second quarter, the average charge/discharge pattern is less reflective of load levels throughout the day and a larger portion of the ESSs' capacity is held to provide both upward and downward reserves. This may be reflective of the constraints on the system imposed by high hydro conditions in the springtime. In addition, the ESS provides significant load following at the on/off-peak boundaries, which helps the system to mitigate the effects of scheduling market purchases in on/off-peak blocks in the day-ahead with imperfect information.

Figure B-2. Q1 Energy Storage Dispatch Summary – 50-MW, 2-hour ESS



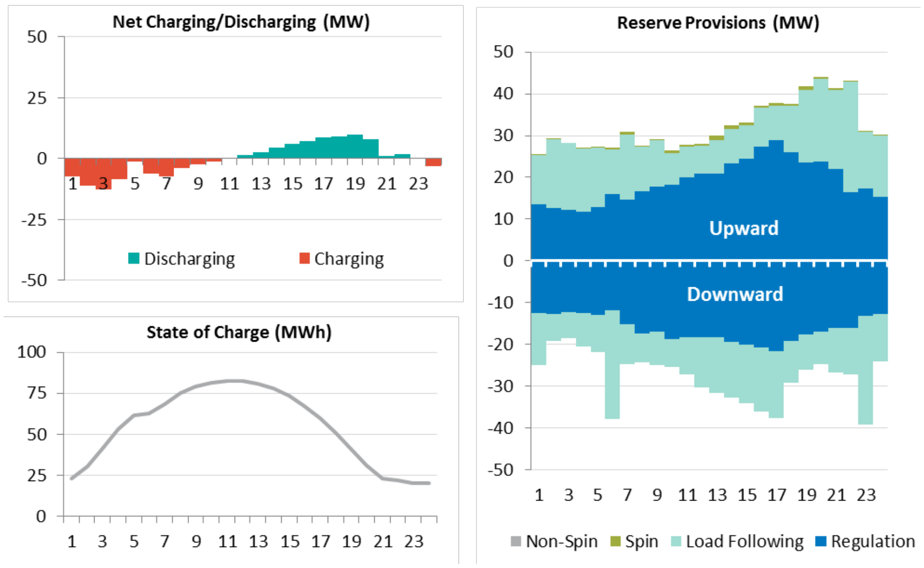
Source: PGE

Figure B-3. Q2 Energy Storage Dispatch Summary – 50-MW, 2-hour ESS



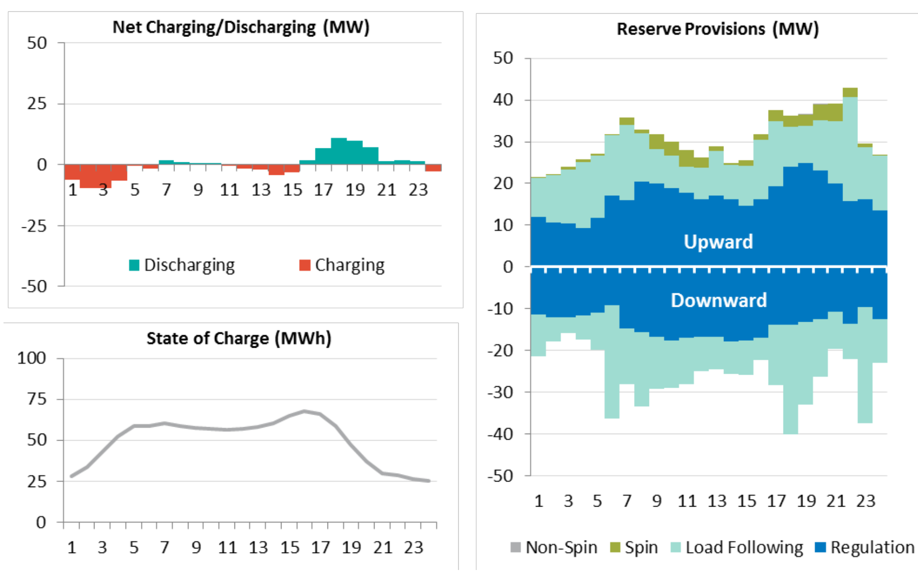
Source: PGE

Figure B-4. Q3 Energy Storage Dispatch Summary – 50-MW, 2-hour ESS



Source: PGE

Figure B-5. Q4 Energy Storage Dispatch Summary – 50-MW, 2-hour ESS



Source: PGE

In the third quarter, the charge/discharge pattern is largely reflective of the late summer load shape—the ESS tends to charge in the first part of the day and discharge to meet the evening peak. On average, reserve provisions from the ESS are greatest in the third quarter, and the peak provisions for different reserve services are somewhat offset in time, suggesting economics tradeoffs in scheduling these services. For example, while regulation on the ESS peaks in the early evening, load following provisions tend to be higher in the late evening and early morning.

Both charging/discharging patterns and the timing of reserve provisions are similar between the fourth quarter and the first quarter, although the fourth quarter sees a slight increase in the magnitude of reserve provisions on the ESS. While spinning reserve provisions are still relatively small, they tend to be greater in the fourth quarter, which may be reflective of the reduced hydro capability in the fall relative to other seasons.

In all seasons, the daily average charge and discharge patterns are fairly flat relative to the -50 MW to +50 MW potential of the ESS, indicating that if significant ramps are experienced on the ESS, they are not consistently experienced at the same time of day throughout the season. This weak diurnal trend suggests that large ramps are largely driven by dynamic flexibility needs on the system, which vary from day to day and across the day, rather than energy arbitrage opportunities, which typically have a more predictable daily shape. The Reserve Provision panels in Figure B-2 through Figure B-5 corroborate this observation. They show that a significant portion of the ESS capacity is being used to provide regulation and load following reserves. Load following in this context includes both the average upward and downward deviations from day-ahead hourly schedules and fifteen-minute real-time dispatch as well as the additional reserves held in the 15-minute real-time stage to accommodate fluctuations down to the five-minute time scale. The ESS was also found to provide limited spinning reserves and negligible non-spinning reserves due to the ability of other resources in the PGE fleet to provide these services at relatively low cost.

Identified Operational Value

The operational value identified through these simulations is summarized in Table B-1 below. These values are lower than the value identified in the 2016 IRP, in part because the electricity price update reflects increased solar and storage buildout in California and the Southwest.[45] This additional solar generation reduced on-peak prices in the Northwest under Reference Case assumptions. However, the on-peak price reductions were not large enough in the 2021 test year to create the inverted arbitrage opportunities described in California—where ESSs may charge during the day with low or negatively-priced solar and discharge during the high-priced evening peak hours. Instead, the on-peak price reductions experienced in the Northwest and the price-flattened effects of energy storage built elsewhere in the West served to reduce daily price volatility and therefore reduced the value of energy storage in the PGE system relative to prior simulations. PGE anticipates that continued development of renewables will affect the value of energy storage over time and anticipates that higher renewable penetrations are generally likely to increase the value of energy storage in the longer term, despite this near term finding.

Table B-1. ROM Results for 50 MW ESSs

System	Operational Value (nominal $, millions)	Operational Value (2016$/kW-yr)
50 MW, 2 hr	3.27	59.2
50 MW, 4 hr	3.66	66.4
50 MW, 6 hr	3.47	62.9

Source: PGE

The ROM simulations also suggest that the operational value of ESSs may increase slightly as the duration is increased from two hours to four hours; however, this value appears to decline in going from

[45] The energy storage evaluation in the 2016 IRP used electricity pricing from the 2013 IRP Update. The differences in electricity pricing described in this study reflect changes in the WECC-wide fleet between the 2013 IRP Update and the 2016 IRP.

a 4-hour to 6-hour duration. This finding highlights the limitations of production simulation models in resolving small differences in operational value. This is discussed further in the following section.

Model Convergence

All production simulation models, including ROM, require the user to specify a convergence tolerance. Typically, the optimization algorithms run until this tolerance is achieved or until a specified time limit is reached. For complex systems with non-linear or non-convex constraints or cost terms, convergence to the specified tolerance can be challenging, resulting in a tradeoff between runtime and precision. To ensure reasonable runtimes, PGE specified a tolerance of 3%. While most weeks[46] achieve converge to a solution well within the 3% target, some weeks in the simulation instead hit the runtime limit, resulting in reduced precision. PGE has also tested ROM using lower tolerance settings (1%) and longer runtime limits (up to 24 hours per simulated week) and found that while these settings affected whether some weeks converged within the runtime limit, it did not significantly affect the findings for most weeks.

These computational and challenges tend to decline for larger ESSs, as they have larger relative impacts on total operational cost. PGE chose to model a 50 MW ESS in this analysis to balance the desire to model small ESSs for compliance with HB 2193 with these computational convergence challenges.

Effects of Forecast Errors

Even with a much tighter tolerance, multi-stage production simulations may result in negative or lower than expected benefits in some weeks due to forecast errors and commitment constraints. While somewhat counterintuitive, these findings reflect real potential outcomes, not spurious modeling artifacts. Consider, for example, a system in which natural gas nominations must be made in the day-ahead stage. Such a system may determine different commitment schedules for natural gas plants in the day-ahead stage if the fleet includes an ESS than if it does not include an ESS. In real-time, the load or renewable output may deviate from the forecasts that were available in the day-ahead and while some of these deviations are accommodated through reserves, there remains a probability that the schedules established for the fleet without the energy storage system are coincidentally more helpful for balancing the realized renewable output than the schedules established for the fleet with the ESS. Because ROM simulates these forecast errors and the associated impact on dispatch, there are some weeks in which the fleet happens to perform better without an ESS or some weeks in which a 4-hour ESS happens to perform better than a six-hour ESS.

To the extent that forecast errors and convergence tolerances affect the identified value of various ESSs, the value of such ESSs is effectively the same to within the precision of the modeling methods. For this reason, PGE recommended that Navigant use the same operational value for all ESSs of duration equal to or greater than 2 hours. This approach does not preclude long duration storage resources from providing additional value through other applications. For example, a 4-hour ESS provides more capacity value and locational value than a 2-hour ESS.

Differentiating Between Operational Applications

The operational value results suggest that increasing the duration of energy storage resources beyond 2 hours up to 6 hours may not increase the operational value of the ESS within the PGE fleet appreciably. This finding suggests that ancillary services and applications that are associated with short timescales

[46] ROM simulations optimize dispatch across whole weeks.

are the primary drivers of operational value in the near term. This observation is largely consistent with the findings in PGE's 2016 IRP energy storage analysis. PGE did not evaluate ESSs with durations longer than 6 hours, but anticipates that longer duration ESSs may provide additional energy arbitrage and other longer timescale benefits not yet quantified.

PGE conducted additional simulations to explicitly identify the portion of the operational value associated with the various operational applications. This exercise is complex and computationally intensive within a production simulation modeling framework. Because ROM optimizes dispatch across all applications and operational value is monetized through avoided fuel and other variable costs across PGE's fleet, there is no straightforward approach to differentiating value associated with one operational application versus another in a single simulation. Instead, multiple simulations are required in which the ESS is modeled with and without the ability to provide specific services in order to isolate the value of providing those services. Such an exercise requires significant time and computational effort.

To broadly characterize the relative value of the operational applications, PGE conducted an additional ROM simulation to isolate the value of providing regulation, conducted an additional simulation in a simplified dispatch model to approximate the value of energy arbitrage, and supplemented this additional data with observations from the dispatch results to infer the value of remaining operational end uses. The results of the ROM run conducted to isolate the value of providing regulation are summarized in Table B-2. These results indicate that regulation comprises approximately 17% of the total operational value.

Table B-2. ROM Results Isolating the Value of Regulation

System	Operational Value (2016$/kW-yr)
50-MW, 2-hr ESS with all capabilities	59.2
50-MW, 2-hr ESS that cannot provide regulation	49.4
Implied value of providing regulation	**9.9**

Source: PGE

The simplified energy arbitrage-only dispatch simulation of the 50-MW, 2-hour ESS yielded $426,587 of nominal market revenue in 2021, or $7.7/kW-year in 2016$. This comprises 13% of the total value identified in ROM. Importantly, this value represents the potential for the ESS to reduce costs through energy arbitrage in the market, not the actual market revenue associated with the dispatch simulated in ROM. Because the ESS is dispatched to provide ancillary services in ROM, a portion of this revenue is foregone in the ROM simulations in order to provide these other, higher value services.

PGE assumed that the load following value could be approximately isolated by subtracting the energy arbitrage and regulation value from the total operational value. This assumption was based on the observation that the ESSs rarely provided spinning or non-spinning reserves in the ROM dispatch simulations due to the ability of other low cost resources within PGE's fleet to provide these reserves. The resulting approximate break out of the value associated with operational end uses is summarized in Table B-3.

As the analysis shows, the majority of the operational benefits of the ESS are associated with providing load following. This finding comports with expectation as load following reserves allow the fleet to mitigate forecast errors of both the load and renewables and to provide sub-hourly balancing down to the five-minute time scale. This finding is also consistent with the observation that increasing the duration to provide longer term services does not appreciably affect the operational value of the ESS.

Table B-3. Decomposition of the Value of Operational Applications

End Use	Operational Value (2016$/kW-yr)	% of Total
Energy Arbitrage	7.7	13%
Load Following	41.6	70%
Regulation	9.9	17%
Spin & Non-spin Reserves	0.0	0%
All operational applications	**59.2**	**100%**

Source: PGE

Conclusions

The analysis described in this report represents the continued evolution of PGE's energy storage modeling efforts and provides a snapshot given the information and modeling capabilities available today. The findings are specific to PGE and the resource portfolios modeled and are therefore likely to differ from other utilities and/or markets.

In the future, the operational value of energy storage resources will be affected by PGE's loads and resource fleet, market conditions and new market structures (e.g., the Western Energy Imbalance Market), as wells as new technologies within PGE's service area (both utility-scale and distributed). In particular, resources that provide flexibility to the system, including demand response, may erode some of the future value of energy storage if they can provide the same services over multiple timescales. Conversely, resources that require more flexibility from the system, such as additional wind and solar, may increase the future value of energy storage. As described in the 2016 IRP, the marginal value of energy storage may also tend to decrease on a given ESS as the need for additional flexibility reduces with the size of the energy storage fleet.

PGE will continue to assess these system-level factors within the Integrated Resource Planning process and the Company seeks to incorporate updates to the energy storage analysis as new information becomes available. PGE will also work to refine its modeling capabilities to improve resource characterization, runtimes, and convergence where possible. Through these efforts, PGE aims to be a leader in energy storage evaluation and to continue to provide novel insights into the potential for energy storage resources to provide value to the system.

B.3 Integrated Planning Tool (IPT)

Additional details for the IPT are provided in the attached report prepared by BIS Consulting for PGE.

Date	April 18, 2017
From	Darin Johnson
To	Brian Spak, PGE
Copy	Jon Robinson, PGE Josh Mullins
Regarding	Report on life-cycle cost analysis of energy storage and locational benefits.

BIS Consulting is pleased to submit this report on cost/benefit assessment of energy storage options and the locational benefits. This report is based on life-cycle cost analysis using the Integrated Planning Tool (IPT), developed by the Strategic Asset Management group (SAM) at PGE. It documents estimated benefits of energy storage in terms of avoided outage cost to customers and extended life of assets.

This work was carried out by a project team comprising representatives from T&D, Planning, SAM, and BIS Consulting. Deliverables include this report, and specialized versions of the IPT developed to support the analysis.

Background

PGE intends to install energy storage systems (i.e., batteries) at one or more locations to satisfy Oregon HB 2193. There are multiple benefits of energy storage, one of which is reduced outage risk to customers. Other benefits are outside the scope of this study.

Reduced outage duration produces benefits in two ways.

- The future cost to customers due to outages is reduced since power can be restored more quickly. This benefit is quantified based on standard outage cost assumptions utilized by SAM for all benefit/cost analyses of this type.
- Reduced consequence of failure, and thereby reduced risk, extends the economic life of aging assets, allowing PGE to delay capital expenditures.

PGE has identified three possible locations for energy storage.

- At substations connected to the bus. This option allows for restoration of power in cases of lost transmission supply.
- At multiple locations along a given feeder trunk, in conjunction with feeder automation. This allows restoration of power for any outage at the substation, and restoration of most customers on the feeder for any feeder-level outage.
- Customer-sited. This option keeps selected customers on-line for any outage on the distribution system.

This analysis is one step in a broader process of benefit/cost/locational assessment for battery options. The intent of this work is to provide input to a more comprehensive discussion of benefits to be performed by others.

Sources of information

This analysis makes use of two major sources of information.

SAM tools, including IPT

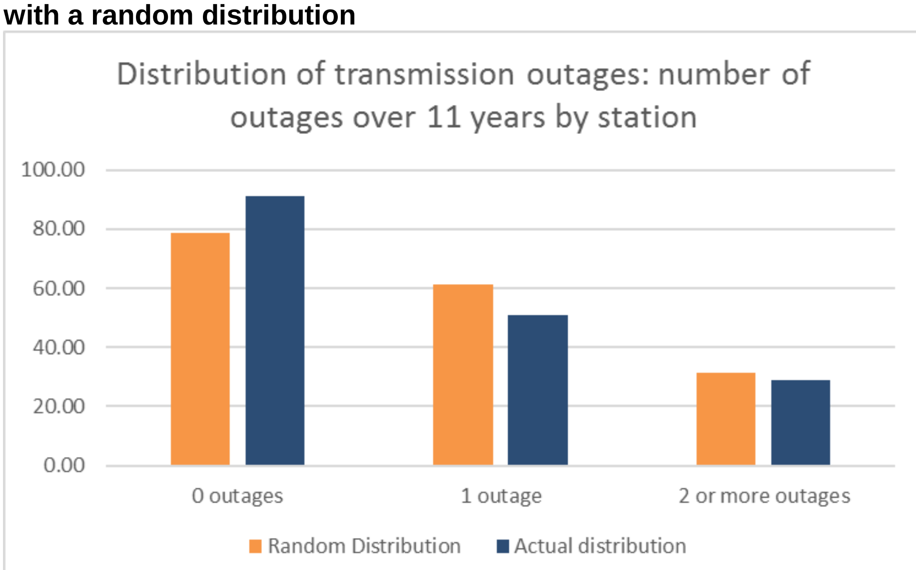
The first is the suite of risk-based life-cycle cost tools, which includes the IPT, developed by SAM. These tools quantify risk due to failures, including the cost to customers due to loss of power. The cost of outages is calculated based on customer survey results, which are incorporated into all of SAM's risk analyses. These tools are used to calculate life-cycle cost, including outage risk and future asset replacements, with or without batteries, per the assumptions described below. The results are expressed in net present values, assuming cyclic replacement of aged or failing batteries (i.e., the benefits extend far into the future).

System Disturbance Database (SDDB) for loss-of-transmission events

The second source of data is the SDDB and the outage management system. These databases include cause codes, which were used to estimate the frequency of loss-of-transmission events over the past 11 years; the outage validation was completed by the T&D Planning team, a review for inappropriately coded events was done by T&D.

The team expected that some substations would be more susceptible to loss-of-transmission events than others, and that this increased exposure will cause those substations to be more attractive locations for battery installation. However, statistical analysis of the data does not support rejecting the null hypothesis – that loss-of-transmission events are randomly distributed. To see this we compared the actual distribution of how many substations experienced zero, one, or two or more outages over the 11-year period with what we would expect the distribution to look like. The result is shown in the graph below.

Comparison of actual distribution of loss-of-transmission outage counts by substation with a random distribution



A Chi-Square test returns a value of 0.14, which is not enough to indicate the distribution is non-random. Therefore, we have assumed that all substations face the average probability of loss of transmission.

The team deemed the duration data for loss-of-transmission outages not reliable enough for use, so the average duration for all such outages was used.

Substation option

A battery installed at the substation bus will allow PGE to restore power to all customers in the event of an outage at the bus due to failure of the transformer or loss of transmission supply. It will not provide reliability benefits in case of an outage at the bus itself (e.g., wildlife in the buswork, or any feeder-level outages, such as cable failure or non-asset failures from weather, trees, or animals). Assumptions include the following.

- Batteries are installed at each bus at the substation.
- The batteries will restore power in case of loss of transmission supply or substation transformer failure; bus- and feeder-level outages are unaffected.
- Three sizes are evaluated: 2-hour, 4-hour, and “infinite.” These define the number of hours customers can be served by the battery. For example, under the two-hour-battery scenario, any outage less than two hours will be reduced to a momentary. Longer outages will be reduced by the duration of the battery.
- Based on historical data, the annual probability of a loss of supply event is 7.1%. Statistical analysis of the historical data suggests that this probability applies approximately evenly to all substations. Based on discussions among the project team, we have assumed that all loss of transmission events will have a duration of 248 minutes, which is the system average.
- Transformer failure probabilities and failure scenarios (i.e., durations) are based on the assumptions by the T&D team during development of the IPT.

Summary of results:

- The analysis gives the total life-cycle cost of ownership for major assets at each substation under each scenario. The difference from the base case (no battery) is the total benefit due to avoided risk and extended service life from a battery sized to carry the load for that length of time (i.e., 2, 4, or “infinite” hours).
- The benefits are shown in “per kWh” terms, to normalize for the load at each substation. Although the total benefit increases with larger batteries, the benefit per kWh drops because the incidence of longer durations outages that could take advantage of the capacity is less likely.
- If the batteries are used for other purposes, such as peak shaving, and are not fully charged, you will have to interpolate to estimate the actual benefit.

Detailed results are contained in the workbooks accompanying this report. The estimated kWh is the average load at the substation multiplied by the assumed battery duration (12 hours used for “infinite” battery).

The results are heavily stratified, with a few substations showing significant benefits. These are generally substations with a high percentage of commercial load, which has a higher assumed cost per lost kWh than residential or industrial load.

Feeder option

Feeder batteries will be installed at multiple locations along the length of the feeder. Smart switches will also be installed, so that power can be restored to all customers except those in the same zone where the outage occurs. For example, if a tree falls into the line halfway down the feeder, the customers between the substation and the switch *upstream* from the fault and customers downstream of the switch *downstream* of the fault will be restored after a momentary outage. Customers in the same zone as the fault will face a sustained loss of supply. In case of a loss of supply at the substation, all customers will be restored.

Assumptions include the following.

- Sufficiently sized batteries are installed at two locations on each feeder (i.e., three zones), including the substation. Feeder load is assumed to be distributed evenly among the zone, and all necessary automation is assumed to be installed.
- The batteries will fully restore power in case of loss of transmission supply or substation transformer failure. Two thirds of customers will be restored after a momentary outage for any feeder-level event. Feeder-level events include trunk-asset failures and non-asset risk due to weather, vegetation, animals, etc. Non-asset risk on the taps is assumed to be unaffected.
- Three sizes are evaluated: 2-hour, 4-hour, and “infinite.” These define the number of hours customers can be served by the battery. For example, under the two-hour-battery scenario, any outage less than two hours will be reduced to a momentary. Longer outages will be reduced by the duration of the battery.
- Probabilities and failure scenarios (i.e., durations) for all asset failures and non-asset events are based on the assumptions developed by T&D during development of the IPT.

Summary of results:

- The analysis gives the total life-cycle cost of ownership for major assets at each substation under each scenario. The difference from the base case (no battery) is the total benefit due to avoided risk and extended service life from a battery sized to carry the load for that length of time (i.e., 2, 4, or “infinite” hours).
- The benefits are shown in “per kWh” terms, to normalize for the load at each feeder. This represents to the total average load on the feeder, so the total required battery capacity for the three-battery system.
- If the batteries are used for other purposes, such as peak shaving, and are not fully charged, you will have to interpolate to estimate the actual benefit.
- The per-kWh benefit is substantially higher for feeder-level batteries than for batteries at the substation. The reason is that the feeder batteries will restore power in the event of a non-asset risk event (e.g., weather, vegetation, animals) on the feeder; these events represent the majority of outage risk in the system.

Detailed results are contained in the workbooks accompanying this report. The estimated kWh is the average load on the feeder multiplied by the assumed battery duration (12 hours used for “infinite” battery).

As with substations, the results are stratified, with a few feeders showing significant benefits. These are generally feeders with a high percentage of commercial load, which has higher assumed cost per lost kWh than residential or industrial load.

Customer option

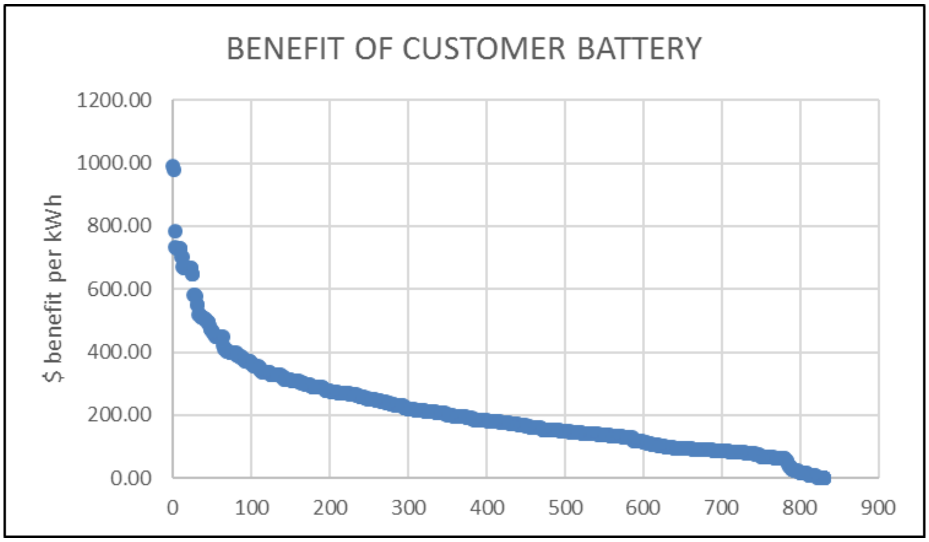
The final option considered is a customer-sited battery that will restore power after any outage in the transmission or distribution system. Assumptions include the following.

- Batteries are installed near the meter for commercial customers identified by PGE.
- Alternate service or backup generation are not available.
- The batteries will fully restore power for any outage to the customer.
- These customers are fed from the trunk, so there are no relevant risks from assets or non-asset events on the tap to consider.
- Only the “infinite” battery size is evaluated. This will generally be a 4-hour battery, although more capacity may be required for customers on rural or remote feeders where outage durations are longer.
- Probabilities and failure scenarios (i.e., durations) for all asset failures and non-asset events are based on the assumptions by T&D during development of the IPT.

Summary of results:

- The analysis gives the total life-cycle cost of ownership for major assets serving key customers. The difference from the base case (no battery) is the total benefit due to avoided risk and extended service life from a battery sized to carry the load for the full duration of any outage.
- The per-kWh benefit for this option is higher than either the substation or feeder option. There are two reasons for this: first, the battery restores power to all the customers it serves (generally one) after any outage. Second, the battery serves only commercial customers, who benefit most in economic terms from reduced outage duration.

Detailed results are contained in the workbooks accompanying this report. The estimated kWh is the average customer load multiplied by the average duration of outages at the feeder: 4 hours for urban, 5 hours for rural, 6 hours for remote. The graph below shows the estimated benefit from avoided risk each customer in per kWh to normalize for load.



Interpretation of results

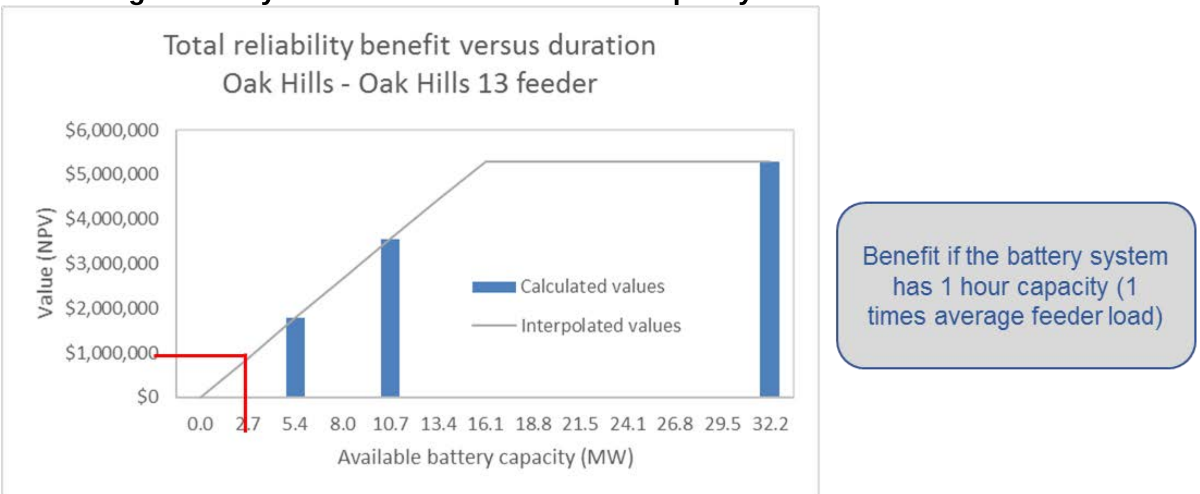
Incorporation into comprehensive model

These results are intended to be integrated into a more comprehensive cost/benefit model developed by PGE. Depending on how the batteries will be used, the available capacity may be less than the full capacity of the battery at any given time. In order to estimate the benefit based on actual expected capacity, we recommend you consider the following procedure.

- Assume a linear fit of the value as a function of capacity from zero (the base case) through the four-hour option.
- Extend this line until it reaches the benefit of the "infinite battery, which is the upper limit.
- Graph this curve against duration multiplied by the average load of the feeder or substation.
- Use this graph to pick off benefits for as many scenarios as necessary to populate the benefit/cost model.

An example is show below for the Oak Hills – Oak Hills 13 feeder, which has an average load of 2.7 MW.

Estimating reliability benefit based on available capacity



If the battery is expected to have eight hours' capacity 75% of the time ($5.3 million benefit) and one hour's capacity 25% of the time ($1 million benefit), then the expected benefit will be approximately 5.3 x 75% + 1.0 x 25% = $4.0 million.

Additional recommendations

Recommended additional steps include the following.

- Continued review and vetting of the results to ensure they conform with expectations.
- Before spending decisions are made, a pre-scoping task to ensure quality results is needed. This should include validation of assumptions, system configuration, and historical outage and other data.
- Additional runs for other scenarios or for sensitivity analysis may be needed. We recommend that you contact us for support. The model used is a specialized version of the IPT, developed specifically for this analysis; training on other SAM tools may not be sufficient for easy use of this one.

We appreciate the opportunity to work with your group on this assessment. Please do not hesitate to contact us with any questions.

Summary of PGE's Energy Storage RFI

PGE issued a Request for Information (RFI) on May 23rd, 2016 to assist in understanding and evaluating the capabilities of companies that can function as the engineering, procurement, and construction (EPC) primary contractor for energy storage projects. The RFI requested company professional background, financials, energy storage program development experience, technology performance, performance guarantees, and references. Responses were collected until June 10th, 2016. PGE received 27 responses from:

1. 1Enregy
2. ABB
3. AES
4. AMS
5. Burns and McDonnel
6. Eaton
7. Edison Energy
8. Enerdel
9. Eos Energy Storage
10. GCN
11. GI Energy
12. Lockheed Martin
13. LSP
14. Mega Point Energy, LLC
15. NEC Energy Storage
16. Renewable Energy Systems Holding Ltd
17. S and C Electric
18. SolarCity
19. Stem
20. Stornetic
21. Sumitomo
22. SunPower
23. Sunverge
24. Tesla
25. TrinaBEST
26. UET
27. Younicos

Responses were evaluated on the strength of the organization and personnel, financial viability, experience and technical competence, preferred storage technology, the ability to provide performance guarantees, and references.

The majority of respondents focused on larger, grid-scale storage solutions. Less than 1/3 of respondents provided information focused on customer-sited storage installations.
Of the 27 responses, 19 proposed lithium-ion battery technology, three proposed flow-battery technology, three were technology agnostic, one proposed zinc battery and one lithium air battery technology. Seven responses were from storage manufacturers. Most respondents were willing to negotiate with PGE to create capacity guarantees. All but seven respondents were willing to share generalized pricing information without a non-disclosure agreement. However, costs were difficult to compare because of the inconsistent inclusion of additional equipment (e.g. power conversion systems).

The RFI provided PGE a relatively short list of companies that could likely engineer, procure, and construct one or many energy storage systems to meet the HB 2913 mandate. From a high-level, PGE was impressed by both the quality and quantity of responses, and has benefited from the responses and follow-up discussions with many of the vendors.