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V. Denise Saunders
Associate General Counsel

March 8, 2018

Via Electronic Filing

Public Utility Commission of Oregon
Filing Center
201 High St SE, Suite 100
Salem OR 97301-3612

Re: LC 66 – PORTLAND GENERAL ELECTRIC COMPANY, 2016 Integrated Resource Plan (IRP) Update

Attention Filing Center:

Enclosed for filing in the above-captioned docket is Portland General Electric Company's (PGE) Motion for Commission Acknowledgement of PGE's 2016 Integrated Resource Plan (IRP) Update. Also, concurrent with this filing is an update to its 2016 IRP. These documents are being filed by electronic mail with the Filing Center.

PGE asks that, consistent with the schedule adopted by the Administrative Law Judge, the Commission acknowledge the IRP Update at its April 24, 2018 Regular Public Meeting so that PGE can include the financial parameters in its May 1 avoided cost update filing.

PGE is also providing fifteen copies of the filing.

Thank you for your assistance.

Sincerely,

V. Denise Saunders
Associate General Counsel

VDS:bop

Enclosures

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

LC 66

In the Matter of PORTLAND GENERAL ELECTRIC COMPANY, 2016 Integrated Resource Plan.	**PORTLAND GENERAL ELECTRIC COMPANY'S MOTION FOR COMMISSION ACKNOWLEDGEMENT OF PGE'S 2016 INTEGRATED RESOURCE PLAN UPDATE**

Portland General Electric Company (PGE) submits the enclosed 2016 Integrated Resource Plan update (IRP Update) to the Public Utility Commission of Oregon (OPUC or Commission) pursuant to Commission Order No. 07-002, Guideline 3(g) and Oregon Administrative Rule (OAR) 860-027-0400(8). The IRP Update includes the following items:

- Status updates on key items from the 2016 IRP Action Plan, including updates on various Commission requirements and studies.
- Need assessment updates, including an updated long-term load forecast and updated energy, capacity, and RPS needs.
- Updated capacity contribution values for incremental wind and solar resources.
- Revised supply-side resource costs and operating parameters indicating a decline in the overnight capital costs for wind and solar resources and an increase in the overnight capital cost for a gas-fired combined-cycle turbine.
- Refreshed financial parameters, which provide new long-term financial assumptions (including corporate tax rate, return on equity, cost of debt, inflation, and the economic lives for the supply-side resources).
- Updated short- and long-term natural gas price and wholesale market price forecasts.

The IRP Update does not propose any changes to the acknowledged 2019 IRP actions.

PGE provided the updated supply-side resource information to the parties on January 25, 2018, and provided the updated capacity contribution values on February 28, 2018. In addition, PGE discussed details regarding the IRP Update at its February 15, 2018 roundtable meeting. PGE is filing the full IRP Update with this Motion.

This motion and the IRP Update are made, in part, to respond to recent recommendations by the Commission and Commission Staff that PGE seek acknowledgment of IRP updates in order to more frequently update inputs to the avoided cost process.[1] Accordingly, PGE asks that the Commission acknowledge the IRP Update consistent with the procedural schedule issued by the ALJ[2] so that it can include the updated financial parameters in its May 1 avoided cost update filing. This will allow for greater accuracy in the calculation of avoided costs and thereby limit the significant financial subsidies that PGE's customers continue to provide to sophisticated multi-national energy developers due to the use of outdated forecasts and financial assumptions.

PGE's IRP Update is filed consistent with applicable Commission orders and rules and should be acknowledged so that PGE can ensure that its resource acquisitions and future planning decisions are based on the best available assumptions and forecasts.

Dated this 8th day of March, 2018.

Respectfully submitted,

V. Denise Saunders

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[1] Docket No. UM 1728, September 12, 2017 Public Meeting of the Commission, video hearing at approximately 37:14 (Commission Staff suggesting that acknowledgement of IRP Updates would help with "cliff phenomenon"); 1:47:24 (Commissioner Decker agreeing with Staff and suggesting that utilities seek acknowledgement of IRP Updates that change capital costs); 153:25 (Commissioner Bloom agreeing with Commissioner Decker and Staff and stating that if utilities were to get acknowledgement of their updates "it would solve a lot of issues.")(archived video available at http://apps.puc.state.or.us/edockets/docket.asp?DocketID=19526)

[2] Commission Prehearing Memorandum (Feb 21, 2018).

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

DOCKET NO. LC 66

In the Matter of PORTLAND GENERAL ELECTRIC COMPANY	PORTLAND GENERAL ELECTRIC COMPANY's 2016 IRP UPDATE – March 2018

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1. Executive Summary

The Oregon Public Utility Commission (OPUC or Commission) acknowledged Portland General Electric Company's (PGE or Company) 2016 Integrated Resource Plan (IRP) in two orders on August 8, 2017 and December 12, 2017, respectively. PGE's 2016 IRP provided a path for the Company to provide service to our customers with additional low cost renewable energy resources, while adhering to the promise to provide safe, reliable, and affordable electricity. The Company is currently working to implement the acknowledged action items from the 2016 IRP.

PGE submits this 2016 IRP Update to inform the Commission of the Company's actions since acknowledgment and to provide an assessment of key changes in resource costs and financial parameters from the 2016 IRP. Specifically, this Update presents a revised resource need assessment and status updates on key action items and requirements from PGE's 2016 IRP acknowledgment Orders.[1] PGE also provides updated supply side resource costs and operating parameters, financial parameters, carbon offset costs, and incremental wind and solar capacity contributions.

In compliance with Oregon Administrative Rule (OAR) 860-027-0400(8) and IRP Guideline 3(g), this Update includes the following items:

- Status updates on key items from the 2016 IRP Action Plan, including updates on various Commission requirements and studies
- Need assessment updates, including an updated long-term load forecast and updated energy, capacity, and RPS needs
- Updated capacity contribution values for incremental wind and solar resources
- Revised supply side resource costs and operating parameters indicating a decline in the overnight capital costs for wind and solar resources and an increase in the overnight capital cost for a gas-fired combined-cycle turbine
- Refreshed financial parameters, which provide new long-term financial assumptions (including corporate tax rate, return on equity, cost of debt, inflation, and the economic lives for the supply side resources)
- Updated short- and long-term natural gas price and wholesale market price forecasts.

As discussed in this update, the 2019 IRP public process, enabling studies, and analytical work are all underway. PGE would like to thank stakeholders for their early engagement in this process. The Company looks forward to continuing to share and discuss information at the upcoming roundtables and technical meetings.

[1] OPUC Order No. 17-386 and No. 18-044.

2. Status Reports on Acknowledged Actions and Requirements of Acknowledgement Orders

2.1. Demand Side Actions

2.1.1. Energy Efficiency

Order No. 17-386 acknowledged PGE's target to acquire 135 MWa of cost effective energy efficiency by 2021 with the condition that PGE will provide an update on the Energy Trust of Oregon's (Energy Trust) activities and progress on the large customer funding issue in the Company's IRP update in 2018.[2] PGE provides the following update:

- In response to concerns raised by the Oregon Citizen Utility Board in PGE's 2018 General Rate Case, OPUC Order No. 17-466 adopted a stipulation in which the parties agreed that the Commission should direct Energy Trust to increase the funding cap from 18.4% to 20%
- Order No. 17-466 also directs OPUC Staff to develop and present a scope for an investigation into the funding of energy efficiency and the allocation of costs and benefits among rate classes.

PGE also notes that in 2017, the OPUC opened Docket No. UM 1893 to increase transparency and create regularity for filing avoided costs used in the evaluation of energy efficiency programs. The docket also describes a stakeholder process for modifications to the existing avoided costs calculations. PGE is currently working with the Energy Trust to enhance the capacity valuation of energy efficiency measures to better align avoided capacity cost with each measure's capacity value.

PGE anticipates meeting or exceeding the energy efficiency (EE) action target. The updated long-term forecast from Energy Trust anticipates increased EE acquisitions. A summary of 2019-2023 is provided in Section 3.2.

2.1.2. Demand Response

In its acknowledgment of the 2016 IRP, the Commission modified PGE's proposed action items with respect to demand response (DR) as follows:

- Through 2020, acquire at least 77 MW (winter) and 69 MW (summer) of new demand response resource as a floor, while working to reach the demand response high case targets of 162 MW (summer) and 191 MW (winter);
- Hire a third party to conduct a study for demand response specific to PGE's service territory with results in time to inform PGE's subsequent IRP;
- Work with Staff to establish, manage, and support a "Demand Response Review Committee" to assist in the development and success of PGE's demand response activities including review of PGE's proposals for demand response programs; and
- Within nine months (of August 8, 2017), present multiple viable demand response test bed sites to the Demand Response Review Committee, and by July 1, 2019, establish a demand response test bed.

The following subsections address how PGE made progress toward these action items.

[2] *See* Order No. 17-386 at 8, Appendix A at 1.

2.1.2.1. Portfolio Targets

PGE is on target with the goals set out in the acknowledged IRP. The Company will achieve these goals through a portfolio of programs, including firm and non-firm resources in both the residential and nonresidential sectors. As noted in the 2017 Smart Grid Report, PGE achieved 18.7 MW of DR in 2016, which is above the targets for that year. Section 3.3 outlines the highlights from the largest programs in PGE's portfolio.

Preliminary results from the Flex residential dynamic rates pilot have been promising. PGE is planning to implement a full-scale deployment of dynamic rates and behavioral demand response in 2019 and included an estimate of costs expected in the 2019 general rate case. Following the release of the preliminary third-party evaluation report, PGE will provide detailed plans and subsequent tariffs.

The smart thermostat program continues to grow. In 2017, PGE expanded the Bring-Your-Own-Thermostat program to include non-Nest thermostats. As of January 2018, approximately 7,000 customers had signed up for the program. PGE plans to propose a direct install channel for the program in 2018 to further expand the potential base of customers and include hard-to-reach markets such as low-income and more rural customers.

In 2017, PGE significantly reworked its Energy Partner program, which provides demand response options to nonresidential customers to better address barriers to implementation and respond to customer feedback. PGE shifted the program from a traditional aggregator model to a more direct implementation model. This change allowed the Company to contract directly with customers with assistance from an implementation contractor and demand response management system provider. It also allowed for greater flexibility in contract options customized to individual customers and the ability to pass on more value to participants for incentives. PGE now provides customers with multiple windows and notification time options, as well as the choice to self-aggregate meters, if desired. The Company also added a smart thermostat option to ensure there is an easy entry option for smaller commercial customers. Given previous research, PGE expects these changes to help grow the programs, by both bringing in previously disqualified customers and increasing the available load from existing participants.

PGE kicked off its multifamily water heater pilot in 2017. This program targets multifamily rental properties for direct load control of electric resistance water heaters, which make up the vast majority of water heaters in the multifamily sector. Initial customer response is positive and the Company expects to see approximately 1,000 units enabled this year. The pilot has a target of 8,000 units by the end of 2019.

2.1.2.2. Enabling Study

PGE is planning a comprehensive enabling study to inform the 2019 IRP. The study will examine resource potential for DR and distributed energy resources (DER), including any interactions between these resources. The study will provide resource potential across the planning period of the 2019 IRP under a variety of scenarios. At the time of this filing, PGE is selecting a vendor for the study and expects to have results by the end of this year.

2.1.2.3. Demand Response Review Committee

PGE identified and reached out to potential members of the Demand Response Review Committee (DRRC), including OPUC Staff. PGE and the proposed members will hold their first meeting by the end of the first quarter of 2018.

2.1.2.4. Demand Response Test Bed

PGE began the internal process of scoping, budgeting, and examining possible sites for the Demand Response Test Beds, using OPUC Order No. 17-386 as a guiding document. The Company will review initial drafts of these working papers first with the DRRC. Upon agreement between the DRRC and PGE, the Company will submit a proposal to the OPUC consistent with the timeline outlined in the order.

2.1.3. Conservation Voltage Reduction

The Commission acknowledged PGE's proposal to deploy 1 MWa of conservation voltage reduction (CVR) through 2020 and directed PGE to report in Docket UM 1657 on the Company's CVR program.

CVR is the strategic reduction of feeder voltage, deployed with substation transformer voltage control technology, to operate distribution feeders within the low range of American National Standards Institute (ANSI) acceptable voltages (114V – 120V). Advanced CVR, known as volt/VAR optimization (VVO) utilizes distributed phase balancing and voltage-regulating devices to achieve higher granularity and control, as well as enable advanced automation and balance of systems for distributed energy resources.

PGE continues to develop CVR as an integrated function of grid modernization and anticipates meeting the 1 MWa 2020 target included in the 2016 IRP Action Plan. All existing and planned substation modernization projects include the provision of CVR capability via transformer load tap changer and line drop compensator installations. Controller settings within CVR devices automate the operation of CVR. As the distribution system becomes more interactive, PGE's Transmission & Distribution Department will investigate advanced operational and programming techniques for optimizing CVR holistically with other emergent grid functions.

PGE will continue to report on its conservation voltage reduction program in Docket UM 1657.

2.2. Supply Side Actions

2.2.1. Bilateral Capacity Procurement

In the Commission's IRP acknowledgement order (Order No. 17-386), the Commission acknowledged capacity needs of 561 MW, 240 MW of which must be dispatchable, in 2021. The Commission also acknowledged PGE's proposal to procure capacity via bilateral negotiations and the filing of a waiver of Competitive Bidding Guidelines and to issue all-source RFP for any capacity needs (including dispatchable capacity) that may remain unfilled after completing bilateral negotiations.

PGE successfully completed this action item consistent with the IRP acknowledgement order. In Order No. 17-494, the Commission granted a waiver of the competitive bidding guidelines for PGE's bilateral negotiations to fill PGE's capacity needs consistent with the IRP acknowledgement order. The Commission's order included two conditions. One, the Commission required PGE to reengage the Commission before advancing offers <u>not</u> identified in the top five ranked indicative offers presented in the waiver application. Second, the Commission required PGE to inform Staff and the Commission on the status of the bilateral negation process through regular updates and also as part of PGE's IRP Update. PGE kept Staff informed throughout PGE's negotiations and includes, as part of this IRP Update, the following report on the results of the bilateral procurement and description of the Company's remaining capacity need following the execution of bilateral agreements.

PGE completed the bilateral procurement process and entered into three power purchase agreements with two counterparties. Specifically, PGE entered into a power purchase agreement with Avangrid Renewables for 100 MW of capacity during the summer and winter seasons. The contract term would begin July 1, 2019 and continue through February 29, 2024. Additionally, the

Company entered into two power purchase agreements with the Bonneville Power Administration (BPA). Both agreements with BPA provide PGE with 100 MW of annual capacity for a five-year term beginning January 1, 2021. Table 1 summarizes these three agreements.

TABLE 1: AGREEMENTS RESULTING FROM PGE'S BILATERAL PROCUREMENT PROCESS

Counterparty	Contract Capacity	Seasonality	Term Beginning	Term Ending
Avangrid Renewables	100 MW	Summer & Winter	July 1, 2019	February 29, 2024
Bonneville Power Administration	100 MW	Annual	January 1, 2021	December 31, 2025
Bonneville Power Administration	100 MW	Annual	January 1, 2021	December 31, 2025

All three resources qualify as dispatchable resources and satisfy PGE's acknowledged need for at least 240 MW of dispatchable capacity. While their combined capacity contribution is below PGE's identified bilateral procurement target of 350-450 MW of capacity, PGE forecasts that these agreements, coupled with updated load forecasts and the potential for additional actions (identified in section five) will satisfy PGE's 2021 capacity deficit.

2.2.2. Acquisition of Renewable Energy Resources

PGE's IRP addendum, filed in November 2017, revised the Company's 2016 IRP original renewables action plan and proposed to acquire approximately 100 MWa of renewable resources by 2021. In Commission Order No. 18-044, the OPUC acknowledged (with conditions) PGE's revised action item to issue a Request for Proposals (RFP) for new renewable energy resources.[3] Three of the conditions require further action within the subsequent RFP process. These conditions require PGE to:

1. Provide updates to the Company's energy, capacity, and RPS needs;
2. Discuss aspects of RFP design and scoring that impact the treatment of Montana wind resources; and
3. Provide a full description of the cost containment mechanism proposed by PGE.[4]

Consistent with Commission Order No. 18-044, PGE will be addressing these requirements within the RFP docket.

In addition, the conditions require PGE to incorporate a "glide path" analysis, which contextualizes potential near-term actions within the Company's longer-term RPS compliance strategy into future IRPs and Renewable Portfolio Implementation Plans (RPIPs). PGE intends to incorporate the concept of a renewable "glide path" into its portfolio design for the next IRP and will be seeking stakeholder feedback regarding both portfolio construction and renewable glide paths within its IRP public process.

[3] OPUC Order No. 18-044 at 1.

[4] *Id.* at 2.

The final condition invites OPUC Staff to open a docket addressing the mechanisms by which PGE may return the value of incremental RECs to customers. This condition addresses PGE's proposal to return to customers the value of RECs generated from resources procured through the RFP in years 2021-2024.

In this Update, PGE addresses condition one above. Section 4 provides a refreshed look at the Company's energy, capacity, and RPS needs. The remainder of this section describes PGE's progress in issuing the 2018 Renewable RFP and briefly summarizes PGE's efforts in fulfilling the Commission's remaining acknowledgment conditions. A more thorough discussion of such efforts will occur in the 2018 Renewables RFP docket (UM 1934).

PGE initiated the design and approval process for the Company to conduct a renewables RFP in 2018. On February 23, 2018, PGE provided a draft RFP to all parties and interested persons in the utility's most recent general rate case, RFP, and IRP dockets.[5] On March 2, 2018, PGE hosted a pre-issuance bidder and stakeholder workshop to answer questions and consider feedback regarding the draft RFP. PGE intends to file the Final Draft RFP with the OPUC in mid-March 2018. Upon Commission acknowledgement, PGE intends to issue a final RFP to the bidding community and require all bids to be submitted by June 15, 2018.

PGE designed its 2018 draft Renewable RFP to include the proposed scoring elements described in the Company's 2016 IRP addendum and the conditions of acknowledgment identified by the Commission in Order No. 18-044.

The 2018 draft Renewable RFP includes a proposed cost containment mechanism that requires all short-listed offers to pass a price score screen. The price score screen requires that the forecast, levelized offer costs be less than the forecast levelized offer value inclusive of energy value, capacity value, and flexibility value. Consistent with Order No. 18-044, the RFP includes a full description of this cost containment mechanism and includes an appendix providing an additional illustrative example of how this cost containment mechanism is applied.

The 2018 draft Renewable RFP also includes scoring requirements applicable to potential Montana wind resources. PGE actively participated in the Montana Renewables Development Action Plan forum hosted by BPA. In parallel, PGE developed transmission requirements that would enable mature Montana wind developments to participate in the Company's competitive solicitation provided they have actively participated in a BPA transmission service request process. Specifically, for resources located outside PGE's Balancing Authority Area (BAA), bidders must provide a reasonable, achievable plan for acquiring long-term firm service to deliver to an acceptable delivery point. At a minimum, those bidders interconnecting into BPA's BAA must have completed phase four of BPA's TSEP [6] process (Record of Decision issued) and are expected to be granted long-term firm service upon completion of near-term, viable system upgrades. Near-term, viable upgrades include upgrades or additions to existing infrastructure, expected to be completed six-months prior to the Project's commercial operation date (COD). Alternatively, PGE will accept bids with executed Precedent Transmission Service Agreements (PTSA) offering conditional firm-bridge service that converts to long-term firm service upon completion of system upgrades. Eligible bids offering a conditional firm bridge must also be forecast to convert to long-term firm within one year after COD.

The Company continues to explore the possibility of submitting a benchmark resource in the competitive solicitation. At the time of this filing, PGE has not acquired development rights to submit a benchmark bid and PGE's identified potential benchmark resource may ultimately not be available. However, if successful in acquiring development rights, PGE intends to bid an

[5] The draft documents are available at the following address: https://www.portlandgeneral.com/our-company/energy-strategy/resource-planning/request-for-proposals

[6] Transmission Service Request Study and Expansion Process

approximately 300 MW wind resource into the 2018 Renewable RFP. The resource would be a greenfield resource constructed in Eastern Oregon. The resource would achieve commercial operation in 2020 and is qualified for the 100% production tax credit (PTC).

2.2.3. Dispatchable Standby Generation

In Order No. 17-386, the Commission acknowledged PGE's proposal to acquire 16 MW of dispatchable standby generation (DSG) to meet its standby capacity needs (non-spin).

PGE designed its DSG program to leverage customer-sited emergency backup generators for grid support. The Company contracts with commercial and industrial customers, who maintain on-site backup generators capable of providing at least 250 kW of power. If needed, PGE can utilize these generators to provide required standby reserves (non-spinning) that can start quickly during periods of critical power need.

PGE developed a method of partial dispatch with the Balancing Authority, which provides customizability in output power levels. This capability enhances customer experience by operating only the DSG units that are required during an event.

Cumulative capacity from enrolled DSG sites was approximately 123 MW as of Q4 2017. Currently, PGE has an additional 11 MW of projects under construction and the Company expects to complete these within the 2018-2020 timeframe. PGE continues to communicate with interested customers and is on track to meet the acknowledged DSG capacity objectives. The Company will include a subsequent DSG study in the 2019 IRP.

2.3.Integration Actions

2.3.1. Energy Storage

PGE submitted a proposal for the development of energy storage systems in Docket No. UM 1856 in compliance with House Bill 2193. In total, PGE's proposed projects combine to approximately 39 MW of energy storage resources. Descriptions of these resources are available in PGE's testimony filed in Docket No. UM 1856 on January 5, 2018. The target date for the Commission's order is August 15, 2018. If approved, PGE anticipates that the resources would start coming online in 2020.

In Section 5.1 of this Update, PGE provides a sensitivity analysis of a maximum view of the capacity impact of the storage projects.

2.4. Enabling Studies for Next IRP

In Order No. 17-386, the Commission acknowledged PGE's proposal to perform a number of enabling studies and other activities to inform the next IRP. As described below, PGE has made substantial progress in performing most of the studies and activities. The Company will continue to share the results of its efforts with stakeholders during the 2019 IRP public workshops.

2.4.1. Market Capacity

Consistent with the 2016 IRP acknowledgement order, PGE has begun the process of scoping a Market Capacity Study, which the Company will use to inform the 2019 IRP. PGE intends to examine the Company's reliance on market capacity based on expectations that the Pacific Northwest will move from a capacity surplus to a deficit over the next few years. The Market Study will explore potential changes in PGE's access to regional resources across various time frames.

The Company plans to engage a third party consultant to perform a literature review and analysis of recent regional market studies from the Northwest Power & Conservation Council (NWPCC), the Pacific Northwest Utilities Conference Committee, and the Bonneville Power Administration. The Study will offer insights into how much capacity may currently be available in the region, how much PGE may be able to access, and expected changes both values over time. The Company will then examine the seasonal quantities from the study in RECAP to help inform the 2019 IRP. The study will not provide insights into the economics of resources.

PGE discussed the scoping of the Market Capacity Study at the IRP Roundtable 18-1 meeting on February 14, 2018.

2.4.2. Flexibility Analysis

In Order No. 17-386, the OPUC directed PGE to conduct a study of flexible capacity and curtailment metrics to inform the next IRP. PGE began scoping this study and shared initial plans with stakeholders at Roundtable 18-1 on February 14, 2018. The Company is examining using PGE's Resource Optimization Model (ROM) for the analysis and forming a technical advisory committee. PGE will share additional information with stakeholders at technical workshops and Roundtables in 2018.

2.4.3. Customer Insights

In 2017, PGE hired Market Strategies International, a consultant, to perform a customer survey to assess customers' resource preferences and cost expectations. PGE presented the results of the study at the Company's Roundtable 18-1 on February 14, 2018.[7] PGE appreciates the high level of customer engagement in the survey and includes the following customer responses among the key findings:

- a desire to see more renewable energy sources in the PGE energy mix (both residential and business customers expressed this desire and were consistently aligned),
- a desire for PGE to score environmental concerns higher than costs concerns,
- a low preference for Demand Response relative to other energy sources. This outcome may be due to incomplete customer knowledge about the programs, highlighting the need for improved communication.

2.4.4. Decarbonization Study

PGE engaged Evolved Energy Research (EER) to conduct a Decarbonization Study for the PGE service area. The primary goal of the study was to develop scenarios in which PGE's customers engage in dramatic decarbonization of the local energy economy and to understand how this transformation might impact the electricity sector and PGE's resource needs. PGE worked with EER to scope three primary deep decarbonization scenarios, each of which meets an 80% reduction in energy-related greenhouse gas emissions relative to 1990 levels by 2050. These scenarios are:

- High Electrification Future – In this future, the study reduces fossil fuel consumption by electrifying end-uses to the extent possible and increasing renewable electricity generation.

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[7] The Customer Insights presentation is available on PGE's IRP website at: https://www.portlandgeneral.com/our-company/energy-strategy/resource-planning/integrated-resource-planning. See the February 14, 2018 Roundtable #18-1 PGE Presentation PDF, pages 129-177.

- Distributed Energy Future – In this future, distributed energy resources proliferate in homes and businesses, which also realize higher levels of electrification.
- Low Electrification Future – In this future, the study uses greater levels of renewable fuels, notably biofuels and synthetic electric fuels, to satisfy energy demand and reduce emissions.

PGE discussed the scoping of the Decarbonization Study at the Company's August 24, 2017 IRP Roundtable 17-3 and invited EER to present the draft results to stakeholders at IRP Roundtable 18-1 on February 14, 2018.[8] PGE plans to engage stakeholders in additional discussions regarding how the insights gained from the Decarbonization Study should inform the 2019 IRP within its IRP public stakeholder process. PGE also plans to include the final Decarbonization Study as an appendix in the 2019 IRP.

2.4.5. Accessing Montana Resources

OPUC Order No. 17-386 adopted Staff's recommendation that PGE "[h]old a workshop to explore the issue of transmission and the potential access to higher capacity wind resources in Montana and Wyoming."[9] PGE will work with stakeholders to schedule a workshop in 2018 and will report back on the discussion to the broader stakeholder group.

Additionally, PGE is actively participating in ongoing regional discussions regarding transmission issues related to accessing resources located in Montana, including the Montana Renewables Development Action Plan forum hosted by BPA.[10]

2.4.6. Load Forecasting Improvements

PGE continues to investigate improvements to its load forecasting model and encourages stakeholders to provide input throughout the 2019 IRP process. On February 15, 2018, PGE discussed the load forecasting action items listed in Order No. 17-386 with stakeholders. The purpose of this discussion was to engage with, and elicit feedback from, stakeholders on PGE's proposed approach to these requirements as follows:

- PGE is assessing its approach to scenario analysis and considering development of probabilistic forecasts. The Company will share the results of this work with stakeholders in mid-2018. PGE plans to conduct technical workshops on load forecasting throughout future IRP cycles to continue discussion of forecasting models and improvements with stakeholders.
- PGE will provide documentation of its out-of-sample testing with its long-term load forecast models for the 2019 IRP.
- A technical appendix on load forecasting formally documenting forecast assumptions and model specifications will be included in the 2019 IRP.

PGE will incorporate feedback from stakeholders as appropriate and will continue to discuss the development and study of load forecasting improvements with stakeholders, including Commission Staff, throughout the 2019 IRP process.

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[8] The materials presented at the Roundtable meeting are available on PGE's IRP website. https://www.portlandgeneral.com/our-company/energy-strategy/resource-planning/integrated-resource-planning

[9] OPUC Order No. 17-386, at 19.

[10] *See* website: https://www.bpa.gov/Projects/Initiatives/Montana-Renewable-Energy/Pages/Montana-Renewable-Energy.aspx.

2.4.7. Direct Access Study

OPUC Order No. 17-386 directs PGE to complete a study of risks associated with Direct Access in the next IRP cycle. PGE plans to scope and launch this study in the March-April 2018 timeframe and will engage stakeholders in the process through the upcoming 2018 IRP Roundtables.

2.5. Additional Recommendations from 2016 IRP

2.5.1. Distribution System Planning

In its 2016 IRP acknowledgment order, the Commission directed PGE to work with Staff and other parties to advance distributed energy resource representation in the IRP process. It also directed PGE to work with Staff to define a proposal for opening a Distribution System Planning (DSP) investigation. In July of 2017, PGE established a series of monthly meetings with OPUC Staff to discuss the foundational elements of Distribution System Planning, and to provide information on existing planning practices. PGE will continue to work with Staff to aid and inform their investigation into DSP.

To implement the Commission's directives, the PGE Distribution Planning Department engaged a third-party consultant, ICF Resources, LLC (ICF), to conduct research into a Distribution Resource Planning roadmap. Preliminary findings identified key planning criteria and interdepartmental touchpoints for program development. Based on these findings, the Distribution Planning Department organized the foundational development process into four priority elements, to include:

- Streamlining the DER Interconnection Process,
- Projecting a Baseline Hosting Capacity,
- Assessing Resource Locational Value, and
- DER Forecasting, with Delimited Load and Generation Profiles.

ICF will conduct a phase 2 study in the first half of 2018 to inform PGE's Distribution System Planning Department of the process steps for building the foundational elements of distribution resource planning, identified above. The Distribution System Planning Department is also collaborating with PGE's Customer Programs Department and IRP team to compose a process for iterative shared development of distributed resource forecasts and system value analysis. This process will be informed by a consultant study that assesses distributed resource and flexible load penetration as portfolio options subject to sensitivities. This is meant to capture interactive effects between resources and to ensure a standard methodology in distributed resource forecasting.

Additionally, the Distribution Planning Department is beginning the process of incorporating the EPRI DRIVE[11] DER simulation platform into the Distribution Planning software model. This new functionality will streamline a Hosting Capacity Assessment for the system and serve as a step toward quantifying locational value.

3. Need Assessment

For this IRP Update, PGE updated the capacity, energy, and RPS need assessments. These assessments are based on the same methodology as the 2016 IRP, but with updated inputs for the

[11] The Electric Power Research Institute's Distribution Resource Integration and Value Estimation (DRIVE) software tool assesses the distribution system impacts from DERs.

December 2017 load forecast (discussed in Section 3.1) and an updated contract snapshot (discussed in Section 3.3).[12]

The Company routinely refreshed the need assessments to reflect current inputs and plans to continue that practice in both the Renewable RFP and the 2019 IRP public process. Based on feedback from the Commission, Staff, and stakeholders, PGE is also expanding the treatment of uncertainty in need assessments and provides a selection of sensitivities in Section 5 of this Update. PGE plans to expand the examination of uncertainties in the 2019 IRP.

PGE does not reassess the need for flexible capacity in this Update. The Company met the need identified in the 2016 IRP through the execution of the Wells Renewal Agreement[13] and the bilateral contracts. As discussed in Section 2.4.2, PGE will be completing a flexible capacity study as part of the 2019 IRP.

3.1. Load Forecast

The 2016 IRP Update uses PGE's long-term load forecast released in December of 2017 to identify its energy and capacity needs. The December 2016 forecast was included in the need assessment update in PGE's Reply Comments to its 2016 IRP (Section 4.2.9, filed March 31, 2017). Table 2 presents the difference between these two forecasts in year 2021.

TABLE 2: NET SYSTEM LOAD FORECAST IN 2016 IRP UPDATE VS 2016 IRP COMMENTS

	Energy		Winter Peak		Summer Peak	
	2021	2022-50	2021	2022-50	2021	2022-50
Load Forecast	MWa	Growth	MW	Growth	MW	Growth
2016 IRP Comments (Dec. 2016 forecast)	2,360	1.2%	3,662	0.9%	3,633	1.2%
2016 IRP Update (Dec. 2017 forecast)	2,313	1.1%	3,607	0.8%	3,618	1.1%
Difference	-47		-44		-26	

The primary difference in these two forecasts is due to an update in the normal weather input assumption; however, PGE made minor refinements to the forecast model as well. The December 2017 forecast reflects the following:

- The normal weather assumption considers the upward trend in regional temperatures. Historically, PGE's forecast has assumed that the average temperature of the last 15 years was representative of the average temperature of the next 30+ years. The assumption in both the December 2016 and December 2017 forecasts is that average temperature will continue to gradually increase over time.
- PGE's short-term models, which project energy deliveries for 25 forecast groups through 2022, reflect refinements to model structure. The periods of data used to establish the regression have been updated to include more recent data and

[12] The assessments do not include assumptions regarding potential resource additions from the Renewable RFP.

[13] The Wells Renewal Agreement was executed in 2017 and allocates a changing portion of the Wells hydro facility to PGE from September 2018 through September 2028.

standardized across forecast groups. The temperature set points used as drivers to weather-sensitive models have been reviewed and refreshed. Trend variables were added into some models' regression equations, and, in some cases, employment drivers were removed.

- All inputs used in PGE's short-term models have been refreshed with the most recent data.
  - Historical energy deliveries data through October of 2017. Recent energy deliveries data reflects strong in-migration, declining residential average usage per customer, recent weakness in commercial energy deliveries and continued strength in PGE's industrial class.
  - Economic forecasts from the Oregon Office of Economic Analysis dated November 29, 2017.
  - An updated energy efficiency forecast from the Energy Trust dated November 2017.
- PGE's long-term models have not been refreshed, except to incorporate the updated normal weather assumption described above and elections consistent with the long-term direct access (LTDA) program effective January 1, 2018.

3.2. Energy Efficiency Forecast

As discussed in Section 3.1, Energy Trust provided an updated long-term energy efficiency forecast in November 2017. In addition to updated load and avoided cost inputs from PGE, Energy Trust also incorporated several model updates, including the following: expanded application of the 10% conservation adder from one element to three (energy, capacity, transmission and distribution), updates to measures and emerging technology, and updated deployment rate assumptions. The incremental annual deployment (energy) and total resource costs for 2019-2023 are shown in Table 3 for both the June 2015 forecast included in the 2016 IRP and the November 2017 forecast.

TABLE 3: ENERGY EFFICIENCY FORECAST SUMMARIES (JUNE 2015 AND NOVEMBER 2017)

Forecast	2019	2020	2021	2022	2023
Incremental EE (MWa, End of Year, Gross, Busbar)					
Jun 2015	33.6	29.5	27.1	24.4	23.5
Nov 2017	36.7	30.4	29.5	28.3	26.0
Total Resource Cost (2017 k$)					
Jun 2015	$62,641	$56,102	$53,358	$50,005	$50,096
Nov 2017	$101,947	$86,892	$85,920	$83,490	$81,701

Energy Trust also introduced partial forecasts (energy only) for two items not included in the June 2015 forecast: residential lighting market transformation and unexpected large projects (mega-project adder). PGE examined these items in the Expanded Energy Efficiency sensitivity provided in Section 5. For simplicity, the sensitivity does not attempt to account for any adjustments for embedded trends in the load forecast or for new customer loads associated with unexpected large EE projects.

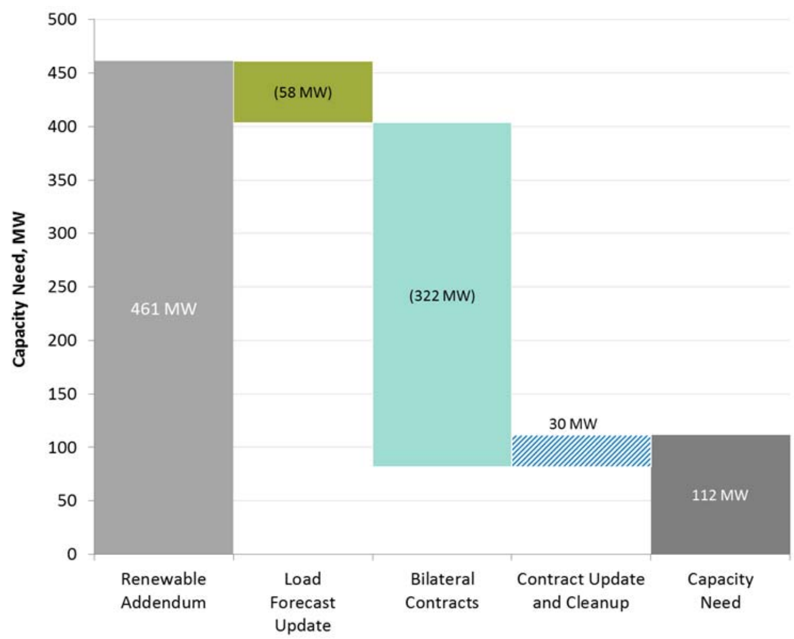
3.3.Contract Update

PGE refreshed the need assessments to include a more recent snapshot of executed contracts, most notably, the 300 MW of recently completed capacity contracts from the bilateral capacity procurement discussed in Section 2.2.1. This Update also includes a January 17, 2018 snapshot of executed Qualifying Facility (QF) contracts and revised expected online dates. This contains approximately 24 MW of additional QF contracts executed after October 19, 2017. Additionally, PGE addressed minor data cleanup items, including t: correction for a contract assigned to two resource groups, correction for the assignment of two shape profiles, and correction of Canadian Entitlement Obligations.

3.4.Capacity Need

In the 2016 IRP, PGE used the RECAP[14] model to estimate capacity need based on an annual standard of 2.4 hours of loss of load per year.[15] For the IRP Update, PGE updated RECAP to the load and contract snapshots discussed previously. These updates reduced the 2021 capacity need to 112 MW from the 461 MW included in the Revised Renewables Action Addendum filed in November 2017. As seen in Figure 1, the bilateral contracts account for a reduction of approximately 322 MW and the load forecast accounts for approximately 58 MW. The remaining change is attributed to the updated snapshot of QF online dates, executed contracts, and contract data cleanup discussed in Section 3.3.

FIGURE 1: CAPACITY NEED IMPACT DUE TO UPDATED LOAD AND CONTRACTS



As seen in Figure 2, the comparison of the heat maps for 2021 from the 2016 IRP and this Update, there has been a substantial reduction to the Loss-of-Load Expectation (LOLE).

[14] Renewable Energy Capacity Planning model, a comprehensive open source loss of load probability (LOLP) model created by Energy and Environmental Economics (E3).

[15] Section 5.1.3 of the 2016 IRP provided a description of RECAP.

FIGURE 2: COMPARISON OF 2021 LOSS OF LOAD EXPECTATION HEAT MAPS

2016 IRP

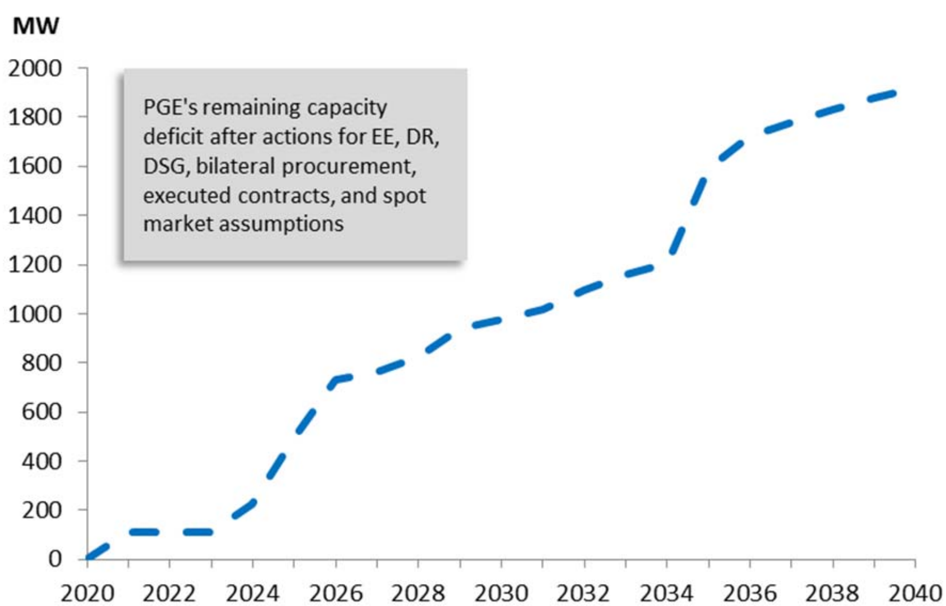
	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
1	0.01	0.01	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.03
2	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.01
3	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.01
4	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.01
5	0.01	0.01	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.02
6	0.13	0.11	0.05	0.02	0.00	0.00	0.00	0.00	0.00	0.01	0.13	0.28
7	0.47	0.37	0.32	0.04	0.00	0.00	0.01	0.02	0.03	0.09	0.54	1.13
8	1.88	1.01	0.68	0.09	0.00	0.00	0.03	0.10	0.10	0.16	1.17	2.48
9	3.20	1.73	0.77	0.05	0.01	0.01	0.13	0.39	0.12	0.13	2.12	3.97
10	2.55	1.16	0.53	0.04	0.01	0.04	0.38	0.83	0.17	0.07	1.72	3.60
11	1.88	0.80	0.34	0.02	0.02	0.09	0.81	1.52	0.23	0.05	1.27	2.89
12	1.58	0.51	0.17	0.01	0.03	0.18	1.35	2.33	0.36	0.04	0.99	2.41
13	1.46	0.31	0.09	0.01	0.06	0.33	2.10	3.36	0.53	0.03	0.86	1.79
14	1.19	0.16	0.05	0.00	0.08	0.50	3.08	4.57	0.82	0.02	0.72	1.34
15	0.91	0.13	0.04	0.00	0.11	0.66	3.91	5.57	1.22	0.03	0.62	1.05
16	0.79	0.14	0.03	0.00	0.12	0.86	4.59	6.36	1.65	0.04	0.76	1.40
17	1.27	0.25	0.06	0.00	0.16	1.00	4.78	6.69	1.99	0.09	1.32	3.22
18	3.14	0.66	0.15	0.01	0.16	0.84	4.51	6.71	2.11	0.26	3.01	5.66
19	5.04	1.47	0.40	0.01	0.15	0.58	3.72	6.26	1.96	0.41	4.62	7.40
20	4.86	1.74	0.58	0.02	0.12	0.36	2.84	5.09	1.75	0.35	4.22	6.62
21	3.55	1.23	0.40	0.02	0.06	0.19	1.75	3.75	1.42	0.14	3.01	4.63
22	2.01	0.65	0.12	0.01	0.02	0.07	0.72	2.01	0.38	0.02	1.62	2.60
23	1.08	0.33	0.02	0.00	0.00	0.01	0.03	0.22	0.01	0.00	0.54	1.27
24	0.16	0.04	0.00	0.00	0.00	0.00	0.00	0.01	0.00	0.00	0.08	0.22

2016 IRP Update

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
1	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
3	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
4	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
5	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
6	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
7	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.01	0.01
8	0.01	0.01	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.02	0.06
9	0.04	0.03	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.03	0.06
10	0.02	0.01	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.02	0.03
11	0.01	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.01	0.02
12	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.01	0.00	0.00	0.01	0.01
13	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.03	0.00	0.00	0.00	0.01
14	0.00	0.00	0.00	0.00	0.00	0.00	0.01	0.10	0.01	0.00	0.00	0.00
15	0.00	0.00	0.00	0.00	0.00	0.00	0.02	0.25	0.01	0.00	0.00	0.00
16	0.00	0.00	0.00	0.00	0.00	0.00	0.05	0.41	0.04	0.00	0.00	0.00
17	0.00	0.00	0.00	0.00	0.00	0.00	0.08	0.52	0.06	0.00	0.02	0.02
18	0.01	0.01	0.00	0.00	0.00	0.00	0.06	0.55	0.08	0.00	0.06	0.13
19	0.05	0.02	0.00	0.00	0.00	0.00	0.03	0.47	0.08	0.00	0.14	0.22
20	0.06	0.02	0.00	0.00	0.00	0.00	0.02	0.32	0.05	0.00	0.14	0.16
21	0.04	0.01	0.00	0.00	0.00	0.00	0.01	0.14	0.02	0.00	0.08	0.07
22	0.01	0.00	0.00	0.00	0.00	0.00	0.00	0.06	0.00	0.00	0.02	0.02
23	0.01	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.01
24	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00

In later years, the capacity deficit continues to increase due to load growth and resource expirations. Figure 3 shows the updated annual capacity deficit for 2020 through 2040.

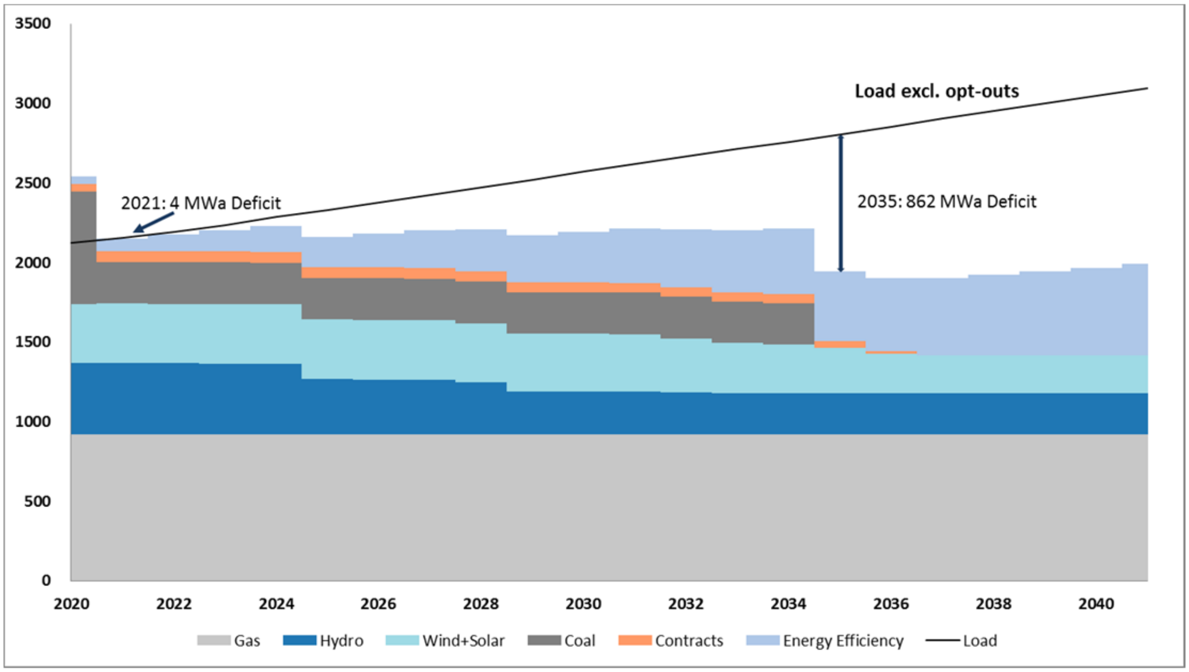
FIGURE 3: ANNUAL CAPACITY DEFICIT



3.5. Energy Load-Resource Balance

The energy load-resource balance (LRB) compares the expected annual average energy availability of PGE's resources (generating plants, contracts, and EE) to the expected annual average load under normal hydro and weather conditions for each year of the IRP analysis. The energy LRB for this Update uses the same methodology as the 2016 IRP, including the exclusion of peaking capacity resources. The energy deficit for 2021 declined to approximately 4 MWa due primarily to the updated load forecast and the execution of additional QF contracts. Figure 4 provides a refreshed LRB from 2020 through 2040. This information is also provided in tabular format in Appendix E.

FIGURE 4: PGE'S PROJECTED ANNUAL AVERAGE ENERGY LOAD-RESOURCE BALANCE



3.6. RPS Need

PGE updated its forecast RPS position based on the Company's December 2017 load forecast, contracts executed through January 17, 2018, and the final 2016 REC inventory included in the 2016 RPS Compliance Report, which was filed in mid-2017. Under these Reference Case assumptions, the PGE renewable resource portfolio is forecast to be 53 MWa short of the Company's RPS compliance obligation in 2025 (excluding banked RECs). Full utilization of the REC bank for RPS compliance in future years would result in a REC deficit and non-compliance beginning in 2033, with an RPS need of 373 MWa in the following year.[16]

PGE's forecast physical RPS position and REC bank composition under Reference Case conditions are illustrated in Figure 5, Figure 6, and Figure 7.

[16] The RPS need is identified for the year following the initial year of RPS deficit because the RPS need in the initial year of deficit is affected by the volume of RECs remaining in the bank in that year.

FIGURE 5: FORECAST PHYSICAL REC POSITION UNDER REFERENCE CASE CONDITIONS

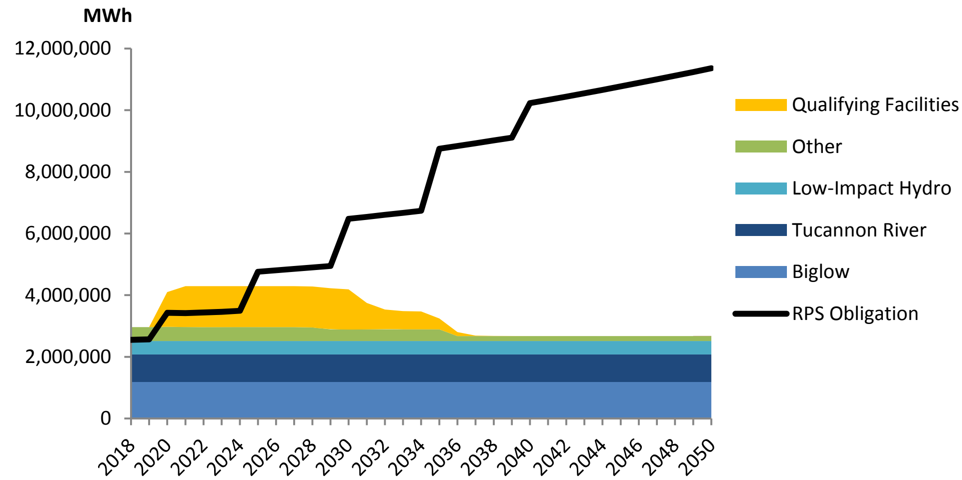


FIGURE 6: FORECASTED REC BANK COMPOSITION UNDER REFERENCE CASE CONDITIONS BY RESOURCE

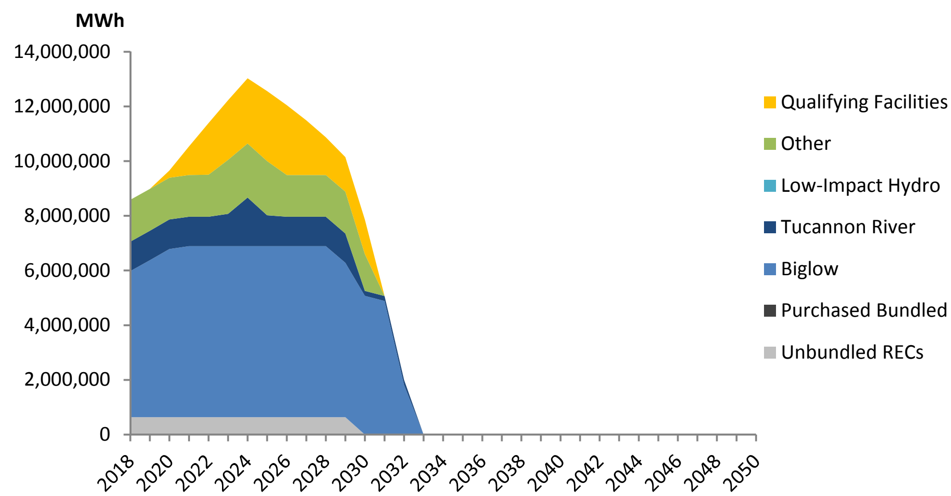
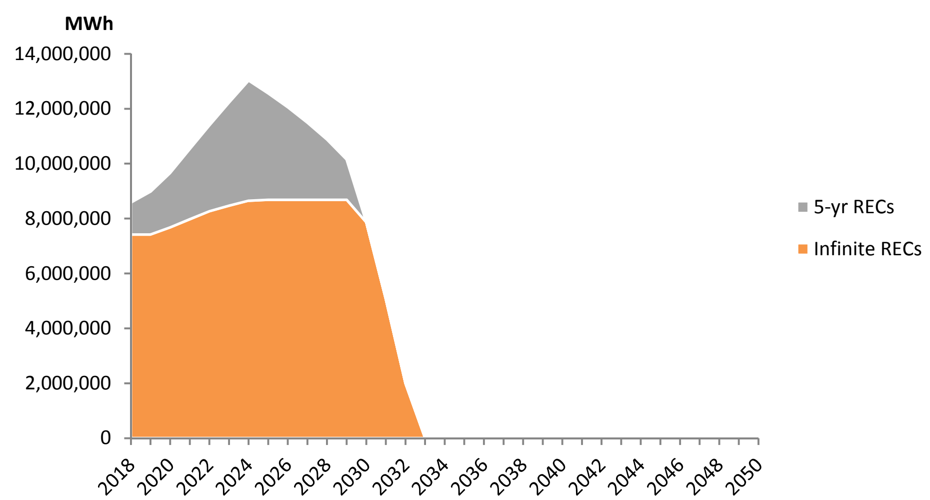


FIGURE 7: FORECAST REC BANK COMPOSITION UNDER REFERENCE CASE CONDITIONS BY REC TYPE

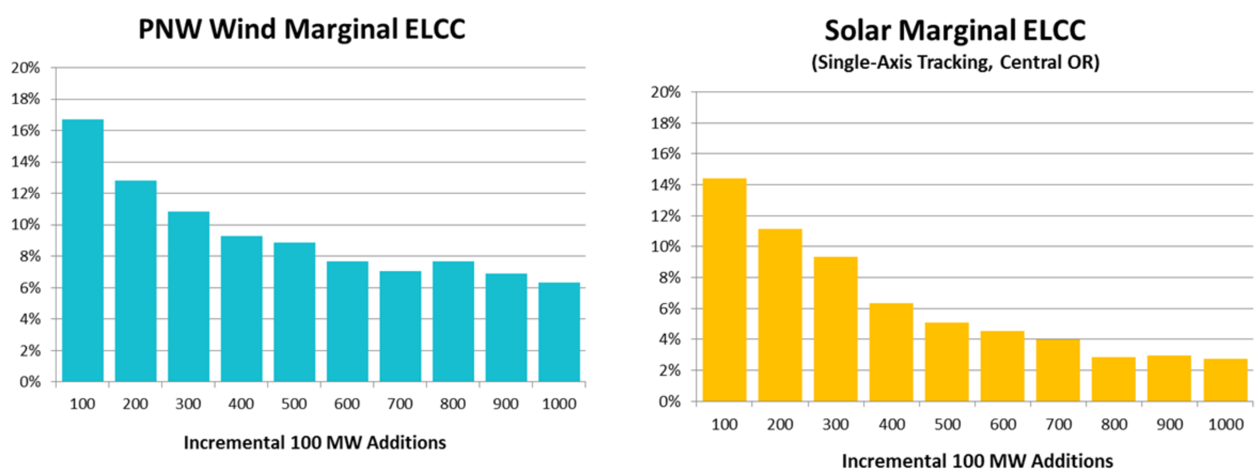


PGE has not updated the glide path analysis presented in its 2016 IRP Revised Renewable Action, as the Company is not proposing incremental renewable actions within this IRP Update. However, PGE continues to investigate glide path analyses in preparation for the 2019 IRP, consistent with Order No. 18-044.

4. Capacity Contribution

In the 2016 IRP, PGE calculated the estimated capacity contribution for incremental additions of 100 MW of wind and solar resources using the RECAP model. These results were shared in the IRP in Figure 5-11. For the IRP Update, PGE updated the capacity contribution calculations to reflect the current snapshot of the system modeled in RECAP for the capacity need assessment described in Section 3.4. Incremental resources were added in 100 MW increments above the executed contracts already included in the model. In addition to the updated load forecast, the RECAP snapshot includes the executed Wells contract, bilateral contracts, and an additional roughly 220 MW of solar executed after the snapshot used in the 2016 IRP. The results of the calculations are shown in Figure 8[17] and provided in tabular format in Appendix D.

FIGURE 8: CAPACITY CONTRIBUTION FOR INCREMENTAL WIND AND SOLAR



The PNW Wind and Solar capacity contribution values are inputs to PGE's Schedule 201 pricing. Consistent with Commission Order No. 14-058, PGE intends to include these updated values in the May 1, 2018 update to Schedule 201 Avoided Costs to better reflect capacity value to customers. The Company notes that as mentioned above, with the refreshed snapshot, the next incremental bin for solar is the first 100 MW (14.4%). Using the same methodology, the Company also estimated the capacity contribution value for 100 MW of a Montana Wind resource as 36.2%.

5. Sensitivities

The Commission and parties have requested that PGE expand the treatment of uncertainties in the IRP process. One area of particular interest was the treatment of uncertainties in conducting need

[17] These figures were also shared in the February 15 Roundtable #18-1.

assessments. In response to this concern, PGE examined sensitivities to capacity, energy, and RPS need in the Renewables Addendum filed in November 2017. PGE also began work to expand the treatment of uncertainties in the 2019 IRP and conducted an initial discussion with stakeholders at the Company's IRP Roundtable 18-1 on February 14.

To further the conversation and begin developing the processes for the 2019 IRP, PGE examined seven sensitivities to its need assessments for this Update. Additionally, PGE examined the impacts to the capacity contribution values for incremental wind and solar resources. Each sensitivity was examined in isolation from one another. The sensitivities tested are summarized in Table 4.

TABLE 4: DESCRIPTION OF SENSITIVITIES

Sensitivities	Description
QF Executed 75%	For QF projects with executed contracts that are not online, assumed 75% completion rate
QF Executed 50%	For QF projects with executed contracts that are not online, assumed 50% completion rate
QF Proposed 50%	For proposed QF projects w/o executed contracts, assumed 50% completion rate
Renewables RFP	100 MWa PNW Wind in 2021, with two REC cases for 2021-2024
Energy Storage	39 MW available all hours, capacity and capacity contribution only
Expanded Energy Efficiency	Lighting transformation, mega-project adder
Zero Load Growth	No load growth after 2019

One area of uncertainty is the completion rate for qualifying facility (QF) projects. PGE plans based on the assumption that QF developers will honor their contractual obligations and therefore all of the projects committed under executed QF contracts will reach COD. To examine the potential impact of reduced completion rates, the Renewables Addendum examined sensitivities of 75% and 50% completion rates for executed contracts. Those were refreshed for this Update along with the addition of a sensitivity examining a completion rate for 50% of the proposed but not yet executed QF projects. In all three sensitivities, PGE applied the completion rate to all technologies.

PGE also examined the potential impact of two ongoing resource actions: the Renewables RFP (discussed in Section 2.2.2) and Energy Storage (discussed in Section 2.3.1). While the impact of these actions on the need assessments depends on the resources selected, the sensitivities provide some insight into the magnitude of the impact. For the Renewables RFP, PGE examined a 100 MWa Pacific Northwest (PNW) wind resource. This sensitivity also examined two cases for the treatment of RECs generated in 2021-2024, one in which PGE retains the RECs and a second case where these RECs are otherwise used. For Energy Storage, an upper limit was examined by modeling a 39 MW resource available in all hours. As a simplification, this was examined only for its impact to capacity need and capacity contribution.

In the Expanded Energy Efficiency sensitivity, PGE estimated the impact of two additional EE items provided by Energy Trust (lighting transformation and mega-project adder). For simplicity in the sensitivity, PGE did not adjust load to account for any embedded transformation in the trending, nor to account for any additional load associated with the mega projects. PGE estimated the capacity impact of the two items based on the energy values provided by Energy Trust and measure shapes from the NWPCC's Regional Technical Forum.

Finally, to examine the impact of load growth, a sensitivity was constructed with no load growth after 2019.

For capacity, energy, and capacity contribution values, the sensitivities were examined for the year 2021, as discussed in Section5.1 For the impact on RPS need, the sensitivities were examined based on the physical shortage in 2025, change to initial deficit year, and the quantity of additional renewables needed in the following year. For this exercise, the initial deficit year is defined as the first year when the RPS obligation cannot be fully met through either physical resources or banked RECs. Section 5.2 provides the RPS impacts are provided in Section 5.2.

PGE provides these sensitivities informationally to give insight into the sensitivity of the reference case estimates to a variety of conditions. These sensitivities are based on simplistic assumptions and do not represent a normal distribution, nor capture all potential uncertainties, such as transportation electrification or increased adoption of distributed solar.

5.1. Capacity and Energy

Table 5 shows the impact of the sensitivities on the capacity need, energy need, and capacity contribution values. Energy need is examined in terms of the energy availability as calculated for the Energy LRB (see Section 3.5). As in Section 4 above, the capacity contribution values (ELCC) are based on independently adding 100 MW of incremental Solar and PNW Wind resources.

The three QF sensitivities show a wide range of potential impacts on the capacity and energy needs. These cases also show significant impacts on the incremental solar capacity contribution (4.2% to 28.1%). The PNW Wind capacity contribution value decreased significantly under the Renewables RFP sensitivity as the test resource added was also PNW Wind. The Expanded Energy Efficiency and Zero Load Growth scenarios produced similar impacts on the remaining capacity need and minor impacts on the energy need.

TABLE 5: SENSITIVITY IMPACTS ON CAPACITY, ENERGY, AND CAPACITY CONTRIBUTION

Sensitivity	2021 Capacity Need MW	2021 Energy Need MWa	Solar ELCC	PNW Wind ELCC
Reference	112	4	14.4%	16.7%
QF Executed 75%	150	44	20.3%	15.3%
QF Executed 50%	197	83	28.1%	14.5%
QF Proposed 50%	32	(131)	4.2%	19.7%
Renewables RFP	73	(96)	16.5%	9.5%
Energy Storage	70	4	15.3%	17.2%
Expanded Energy Efficiency	96	(9)	15.1%	17.2%
Zero Load Growth	96	6	14.2%	17.2%

Notes:

1. Negative Energy Need values indicate an energy-long position from the perspective of the energy availability calculation in the Energy LRB (not based on economic dispatch).

5.2. RPS Need

The impact of the sensitivities on the RPS Need was examined with respect to: 1) the 2025 physical RPS shortage (i.e., the shortage in 2025 if PGE does not rely on its REC bank); 2) the first year in which PGE would run out of RECs and would be unable to comply if it were to rely on its REC bank, or the REC deficit year; and3) the remaining RPS shortage in the following year should no incremental action be taken. Table 6 provides a summary of the results across each of the sensitivities.

The QF completion cases show that PGE's near-term physical RPS shortage is highly sensitive to the assumed QF completion rate, as a large quantity of QFs have contractually committed to come online and to produce RECs in the early 2020s. The analysis also found that PGE's longer term RPS needs are less sensitive to the QF completion rate assumption, due largely to the scale of the increase in RPS obligations over time and the expiration of QF contracts.[18]

PGE also tested the impact of the potential procurement of 100 MWa of RPS-eligible resources in the forthcoming RFP on its forecast RPS position. This analysis considered two scenarios, one in which PGE retains the RECs from the procured resources for RPS compliance in all years, and a second in which PGE utilizes the RECs generated prior to 2025 by any procured RPS resources to return value to customers in those years (See Section 2.2 above). Retention of the near-term RECs for RPS compliance pushes out the REC deficit year by one year relative to the case in which these RECs are otherwise utilized, but does not significantly impact forecast long-term REC needs due to the steep increase in RPS obligations in 2035.

PGE's forecast RPS needs under the Zero Load Growth sensitivity pushes the REC deficit year out by one year compared to the reference case. The RPS shortage in the following year (2035) is substantial (509 MWa) due to the increase in the RPS requirement as a percentage of retail sales in that year. The Expanded Energy Efficiency sensitivity does not change the REC deficit year relative to the reference case, but does reduce the REC deficit in the following year (2034) by 13 MWa. The differences in the 2025 physical RPS shortage between the reference case and the Zero Load Growth and Expanded EE sensitivities are relatively small, 16 MWa and 7 MWa, respectively.

[18] In the 2016 IRP and the IRP Update, PGE does not assume that expired QF contracts are renewed. PGE also assumes that no additional QF contracts are executed (with the exception of the sensitivity examining a 50% completion rate for currently proposed QF projects).

TABLE 6: RPS NEED ACROSS SENSITIVITIES

Case	Physical shortage in 2025 (MWa)	REC deficit year	RPS shortage in following year (MWa)
Reference	53	2033	373
QF Executed 75%	91	2032	381
QF Executed 50%	129	2031	387
QF Proposed 50%	None	2036	660
Renewables RFP (RECs retained in all years)	None	2036	612
Renewables RFP (2021-2024 RECs otherwise used)	None	2035	589
Expanded Energy Efficiency	46	2033	360
Zero Load Growth	37	2034	509

6. Supply Side Resource Costs and Operating Parameters

PGE based the 2016 IRP supply side options (SSO) resource costs and parameters on studies conducted by Black & Veatch and DNV GL in 2015. Results from the studies were used to model new resources during the portfolio construction and analysis process.

In 2017, PGE requested updated studies from the same two consultants for the following six generic resources:

- Gorge Wind
- Montana Wind
- Single-Axis Tracking Photovoltaic Solar
- Combined-cycle combustion turbine (1x1 GE 7HA.01)
- Simple-cycle combustion turbine (1x0 GE 7F.05)
- Reciprocating engines (6x0 Wärtsilä 18V50SG)

PGE updated the fixed cost revenue requirement calculations to incorporate the refreshed resource studies, financial parameters, and carbon offset costs. A comparison of the financial and operational resource parameters utilized in this Update to what was incorporated in the 2016 IRP is provided in Table 7 below. The refreshed parameters incorporate additional data that became available between 2015 and 2017.

Table 7: Updated Supply Side Resource Summary

Updated Resource Assumptions -- COD 2021										
2018$	Update or 2016 IRP	New & Clean Nameplate MW	Degraded Nameplate MW	Degraded Heat Rate Btu / kWh	Expected Availability % [1]	Econ. Life Years [2]	Overnight Capital Cost $ / kW [3]	Fixed O&M $ / kW-yr [4]	Variable O&M $ / MWh [5]	Real Lev. Fixed Cost $ / kW-yr [6]
Renewable Resources										
Central Station Solar Tracking PV	Updated	103	103	N/A	23%	20	$1,471	$8.57	$0.87	$152
	2016 IRP	103	103	N/A	24%	25	$1,911	$10.61	$0.87	$176
Wind Plant PNW	Updated	332	332	N/A	35%	30	$1,475	$44.88	$0.87	$188
	2016 IRP	338	338	N/A	34%	27	$1,664	$47.75	$0.87	$222
Wind Plant Montana	Updated	240	240	N/A	42%	30	$1,493	$44.88	$0.87	$190
	2016 IRP	236	236	N/A	42%	27	$1,713	$47.75	$0.87	$225
Thermal Resources										
Natural Gas CCCT-H	Updated	424	400	6,450	90%	38	$1,370	$8.00	$3.37	$172
	2016 IRP	400	387	6,503	95%	35	$1,125	$9.06	$2.76	$164
Wärtsilä Reciprocating Engine	Updated	110	107	8,470	98%	38	$1,364	$11.53	$7.34	$175
	2016 IRP	110	110	8,437	96%	30	$1,508	$3.57	$9.48	$193
SCCT - Frame 1x0 GE 7F.05	Updated	231	218	10,170	96%	38	$648	$7.24	$7.04	$124
	2016 IRP	230	224	9,981	98%	30	$648	$3.41	$9.86	$126

Notes:

1. Expected Availability is expected capacity factor for Wind and Solar PV. For 2016 IRP Thermal Resources, Expected Availability is capacity adjusted for scheduled maintenance and the forced outage rate. For the updated Thermal Resources, Expected Availability is capacity adjusted for scheduled maintenance and forced outage during periods of demand.
2. Economic life assumptions updated to PGE's depreciation study filed in Docket No. UM 1809.
3. Capital Costs include OEFSC payments to Climate Trust of Oregon. Carbon Offset cost updated to the 2017 schedule.
4. Based on degraded MW.
5. Variable O&M includes integration costs from the Variable Energy Integration Study.
6. Includes fixed capital carrying and operating costs, which include fixed O&M, fixed gas transportation wheeling, ongoing capital additions, and land lease payments as applicable. Updated costs incorporate BPA wheeling rates from the BP-18 rate case, with later years escalated at the inflation rate. The Montana Wind resource includes the cost of one segment of BPA wheeling, but does not include any additional transmission expenses.

The refreshed financial parameters include assumptions on PGE's corporate tax rate (revised to capture the December 2017 changes to federal tax law), return on equity, cost of debt, inflation, and the economic lives for the supply side resources. The carbon offset costs are estimated payments to the Oregon Energy Facility Siting Committee (EFSC) for natural gas resources. PGE updated these costs to capture both the increased offset rate from October 2017 and the new resource parameters. Section 7 provides an in-depth discussion of the financial parameters.

The following sections provide descriptions of the major changes observed between the SSO studies in the 2016 IRP and the ones performed for this Update.

The Fall 2017 supply side resource studies are included in Appendix A and Appendix B. The updated estimated EFSC permitting costs for the carbon offset monetary payments are provided in Appendix C. PGE notified its stakeholders on January 25, 2018 that these documents had been posted on PGE's IRP Website[19] .

6.1. Renewable Resources

In the fall of 2017, DNVGL provided updated financial and operating parameters for three of the renewable resources included in the 2016 IRP:

[19] *See* https://www.portlandgeneral.com/our-company/energy-strategy/resource-planning/integrated-resource-planning.

1. Gorge Wind
2. Montana Wind
3. Single-Axis Tracking Photovoltaic Solar

Overall, the Overnight Cost of Capital and Fixed Operational & Maintenance costs trended lower across these three renewable resources versus the parameters presented in the 2016 IRP. PGE also revised the economic life assumption of the various renewable resources to tie with the Company's depreciation study filed in Docket No. UM 1809. Section 7 provides further discussion of the Financial Parameters.

The net impact of PGE's refreshed Financial Parameters along with the updated financial and operating parameters is lower real-levelized fixed costs on a $/kW-yr basis, which declined 15% for Gorge Wind to $188/kW-yr, 16% for Montana Wind to $190/kW-yr, and 13% Single-Axis Solar to $152/kW-yr. A large component of these declines was due to lower overnight cost of capital estimates, which declined by 11%, 13%, and 23%, respectively, for the three resources. The estimated fixed costs (on a $/kW-yr basis) declined by 6% for the wind resources and by 19% for the solar resource.

6.2. Thermal Resources

In the fall of 2017, Black & Veatch provided an update to three of the thermal resources included in the 2016 IRP:

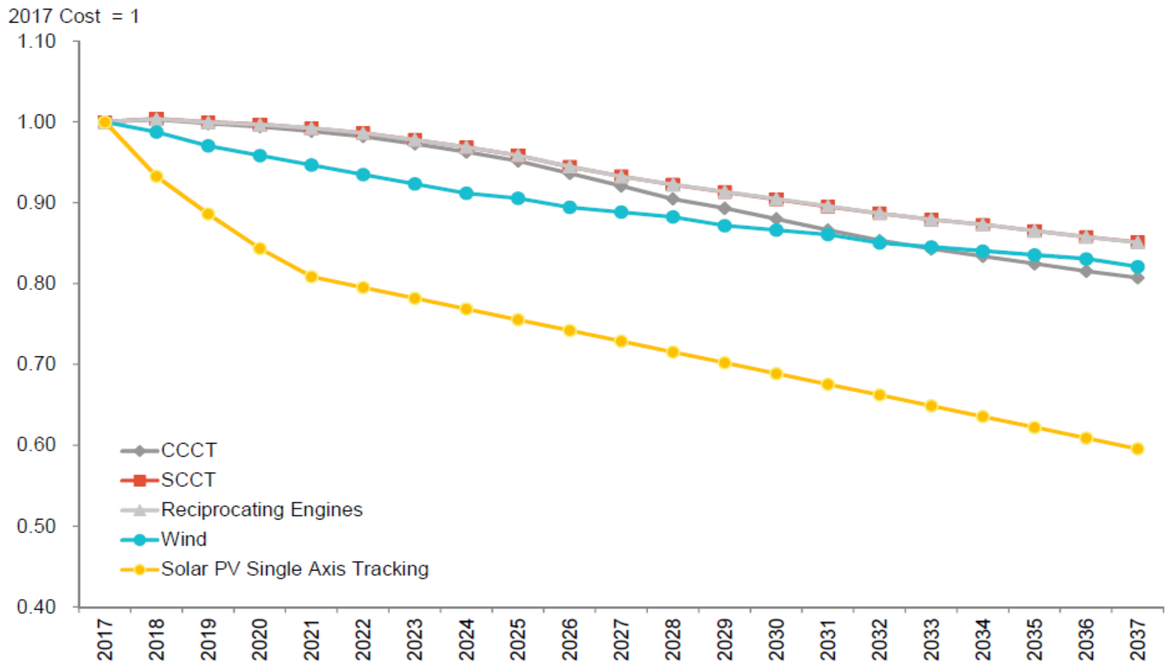
1. Natural Gas-Fired Combined Cycle Combustion Turbine (CCCT) (1x1 GE 7HA.01)
2. 6x0 Wärtsilä 18V50SG (reciprocating engines)
3. Simple Cycle Combustion Turbine (SCCT) (1x0 GE 7F.05)

While operating parameters for the three thermal resources were relatively unchanged from the 2016 IRP, there were some changes to the capital and fixed cost assumptions. The CCCT's Overnight Capital Cost increased approximately 22% to $1,370/kW. The consultant attributed the change to the use of data from more recent projects. This was slightly offset by a 12% decrease in fixed O&M, which was estimated at $8.00/kW-yr for this study. The overall impact on the real-levelized fixed cost was an increase of 5% to $172/kW-yr. This figure includes changes to PGE's Financial Parameters, which are discussed in greater detail in Section 7 of this filing.

6.3. Technology Maturity Outlooks

Black & Veatch and DNV GL also provided refreshed technical maturity outlooks that illustrate estimated changes in the future overnight cost of capital for the various resources. In general, advances in technologies coupled with learning curve effects and economies of scale result in a decline in the real cost per kW. Figure 9 reports the set of capital cost "forecast factors" for the next 20 years, normalized to 2017 and on a constant dollar basis.

FIGURE 9: OVERNIGHT COST OF CAPITAL TECHNICAL MATURITY OUTLOOK



Source: DNV GL Fall 2017 Renewable SSO Report and Black & Veatch Fall 2017 Thermal SSO Report

7. Financial Parameters

Financial parameters including inflation, cost of debt, return on equity, and tax assumptions are used in resource cost calculations. The values in the 2016 IRP were based on inputs from 2016 and earlier. In this Update, PGE is refreshing the parameters to current assumptions as listed below in Table 8.

TABLE 8: PGE'S LONG-TERM FINANCIAL ASSUMPTIONS

Financial Parameters Cost of Capital Component	%
Composite Income Tax Rate[1]	27.08%
Incremental Cost of Long-Term Debt	4.97%
Allowed Return on Equity[2]	9.50%
Long-Term Debt Share of Capital Structure	50.00%
Equity Share of Capital Structure	50.00%
Weighted Cost of Capital	7.24%
Nominal Weighted After-Tax Cost of Capital	6.56%
Long-Term General Inflation	2.00%
Economic Lives[3]	**Years**
Thermal Plants	38
Solar	20
Wind	30

Notes:
1. Reflects December 2017 changes to federal tax law.
2. Allowed ROE from Docket No. UE 319.
3. Depreciation Study filed in Docket No. UM 1809.

The most notable update is the 27.08% composite income tax rate, which was reduced from the 40.00% used in the 2016 IRP. The decline is due to the December 2017 changes to the federal tax law. PGE's estimated incremental cost of long-term debt increased to 4.97% from the 4.68% used in the 2016 IRP, reflecting an estimated increase in risk premium over treasuries and a forecast of higher long-term interest rates. In Docket No. UE 319, the Commission authorized a return on equity of 9.50% which is a decrease from the 9.60% used in the 2016 IRP. The assumed debt / equity mix remained 50% / 50%.

The combination of the updated cost of capital components results in a weighted cost of capital of 7.24%, an increase of 0.10% compared to the 2016 IRP assumption. The after-tax weighted average cost of capital is reduced by the income tax benefit on debt. The decrease in the federal tax rate reduced the debt tax benefit. This resulted in an increased after-tax cost of capital of 6.56%, compared to the 6.20% used in the 2016 IRP. The current forecast of long-term inflation is 2.0%, which was the same as the rate used in the 2016 IRP.

PGE is also updating the economic life assumptions used for the various supply side resources. The resource costs discussed in Section 6 of this filing utilize a 38-year life for thermal plants, a 20-year life for solar facilities, and a 30-year life for wind facilities. These economic lives are based on PGE's Depreciation Study filed in December 2016 in Docket No. UM 1809.

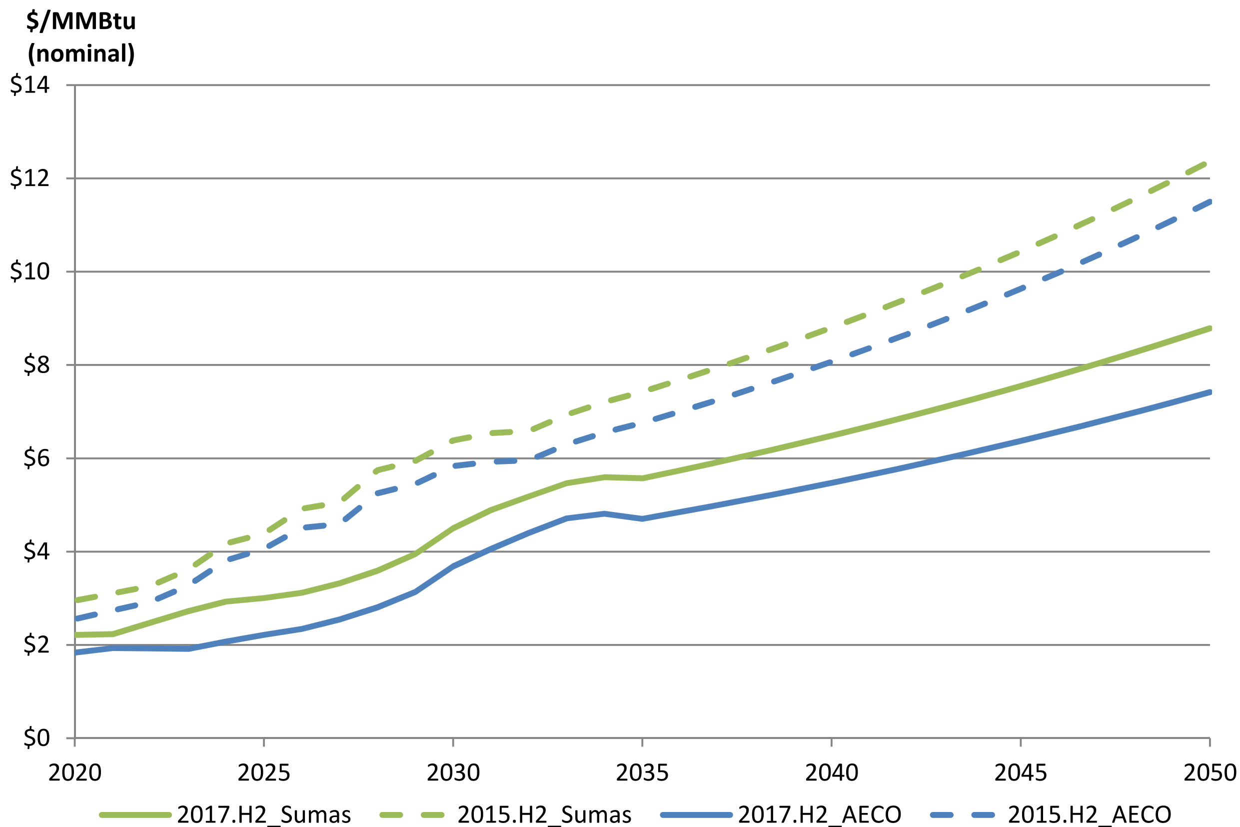
8. Natural Gas Forecast

This IRP Update incorporates an updated PGE gas trading curve and long-term gas price forecasts. PGE continues to use the long-term natural gas price forecast supplied by Wood Mackenzie for the reference forecast. The updated forecast is from year-end 2017 (denoted as 2017.H2). The forecast vintage incorporated in the 2016 IRP was 2015.H2.

The Wood Mackenzie 2017.H2 long-term gas price forecast for Henry Hub fell slightly when compared to the IRP forecast due to an expected continuation of abundant supply. Delivered gas prices specific to the Pacific Northwest fell substantially due to large anticipated fuel price reduction in Alberta, which affects neighboring regions.

For this Update, PGE derived the reference case natural gas forecasts from market forward prices for the near-term (2020-2021) and the Wood Mackenzie long-term fundamental forecast for 2023-2035. Linear interpolation was used to calculate prices in the year 2022 to transition between the two forecasts. The extension of the forecast after 2035 was updated to assume real growth based on an average in the escalation rates from forecast from the Energy Information Administration's (EIA) Annual Energy Outlook 2017 (AEO2017) and IHS Global Insight. Figure 10 compares the annual reference case Sumas and AECO prices from the two forecasts.

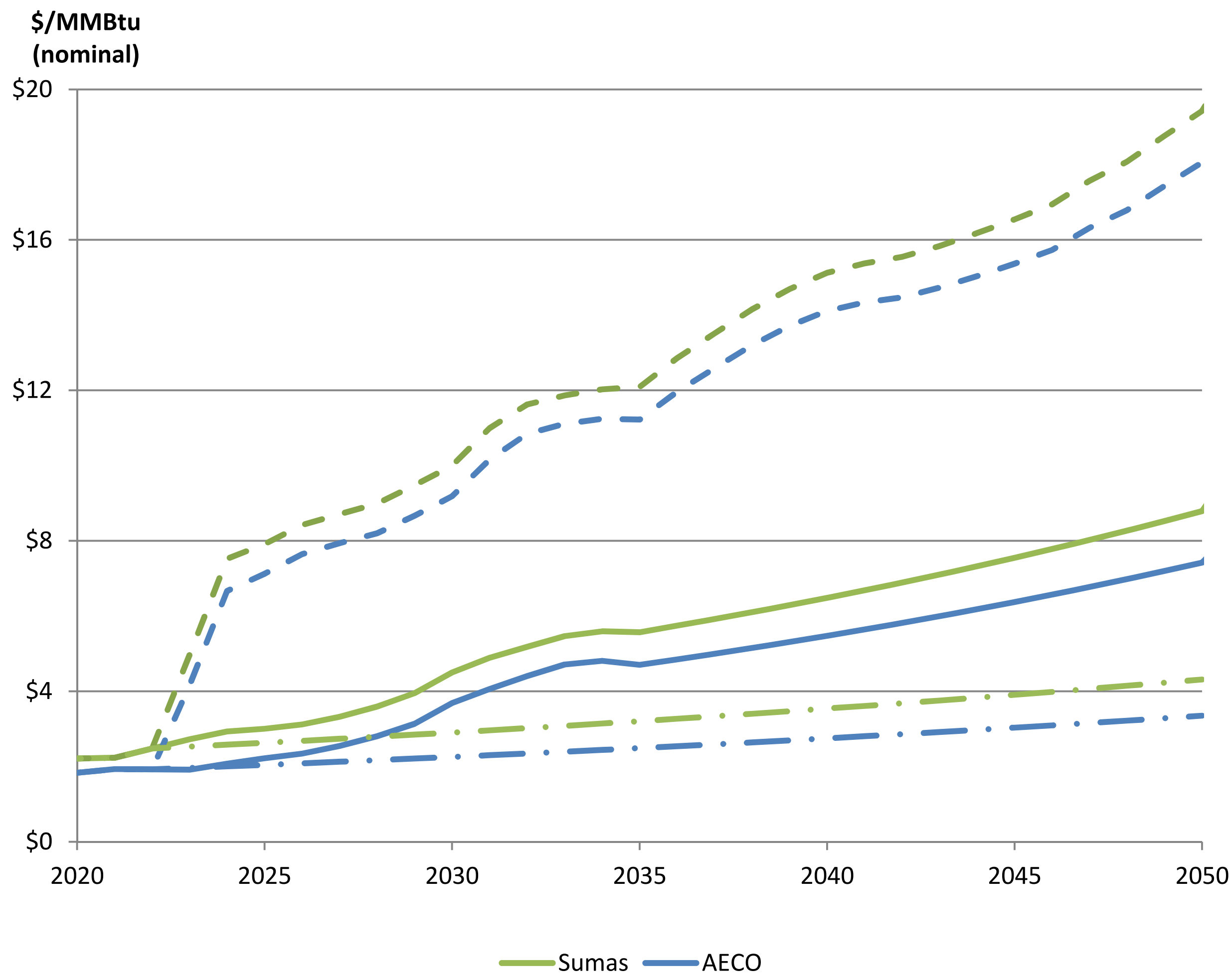
FIGURE 10: REFERENCE CASE NATURAL GAS PRICES FOR SUMAS AND AECO HUBS



In addition to updating the reference case forecast, PGE also updated the low and high cases. The low case assumes no real growth in prices after 2022. The high case is based on Henry Hub prices from the "High Oil" scenario in the AEO2017. Prices across the three futures are the same through 2021. By 2050, there is significant divergence in the forecasts, as seen in Figure 11.

The natural gas price forecasts were used to create updated wholesale market prices as discussed in Section 9.

FIGURE 11: 2017.H2 REFERENCE, HIGH, AND LOW FORECASTS FOR SUMAS AND AECO HUBS

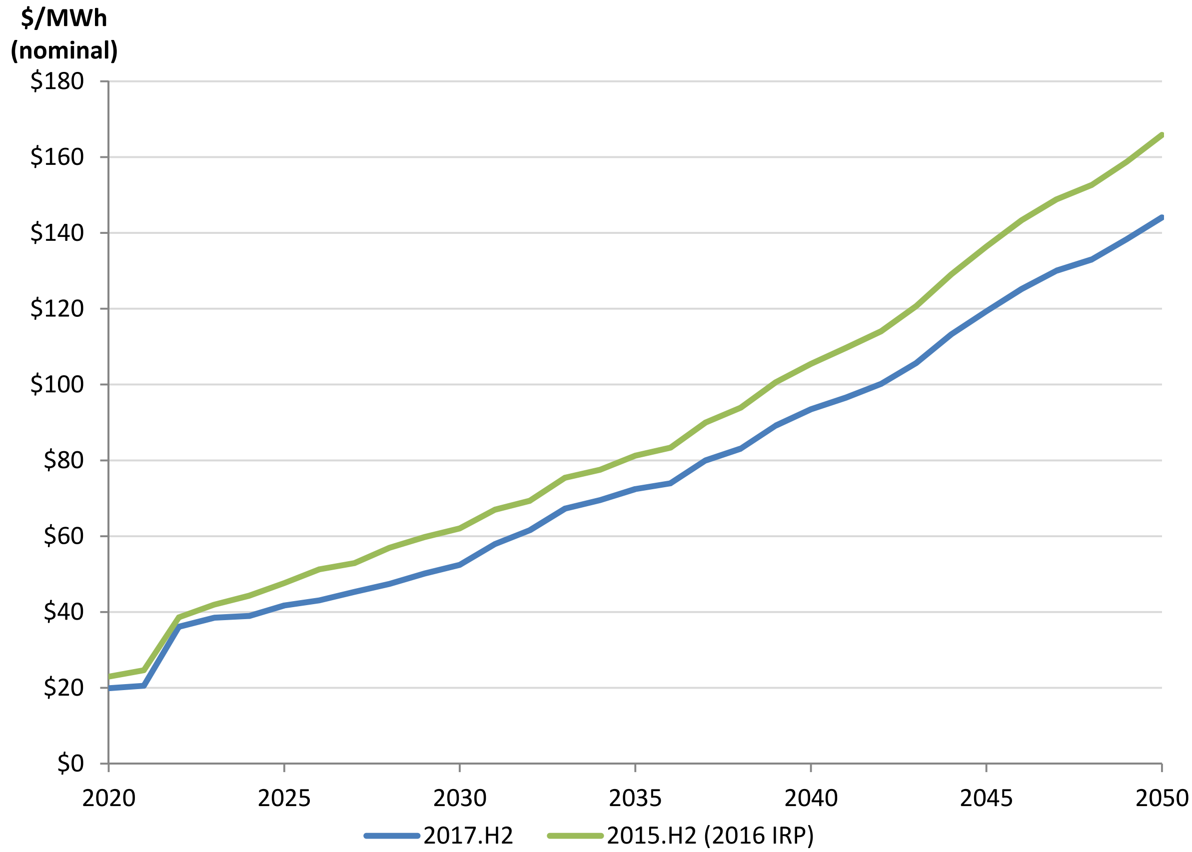


9. Wholesale Market Prices

In the 2016 IRP, PGE modeled wholesale market prices with EPIS's AURORAxmp model and a Wood Mackenzie WECC-wide input database with specific modifications, as described in Chapter 10 of the IRP.[20] In this Update, PGE refreshed the wholesale market pricing based on the same model, but with natural gas prices updated as discussed in Section 8. All other input assumptions remain the same. Figure 12 shows that the resulting reference case electricity prices for the Pacific Northwest are lower than those in the 2016 IRP.

[20] The 2016 IRP and the IRP Update used AURORAxmp model version 12.1.1015 and Wood Mackenzie input database version 2015.H2.

FIGURE 12: WHOLESALE ELECTRICITY PRICE COMPARISON BETWEEN 2017.H2 AND 2015.H2 REFERENCE FORECASTS



Consistent with what done in the 2016 IRP, PGE simulates alternative futures to analyze the impact on prices of materially different macroeconomic conditions for:

- Gas prices: low and high natural gas prices as shown in Section 8;
- Carbon prices: a “no carbon” and a “high carbon” future as described in Chapter 10.3 of the 2016 IRP.

All of these futures are created with reference load conditions because varied load within the PGE service territory has a negligible effect on wholesale energy prices for the region.

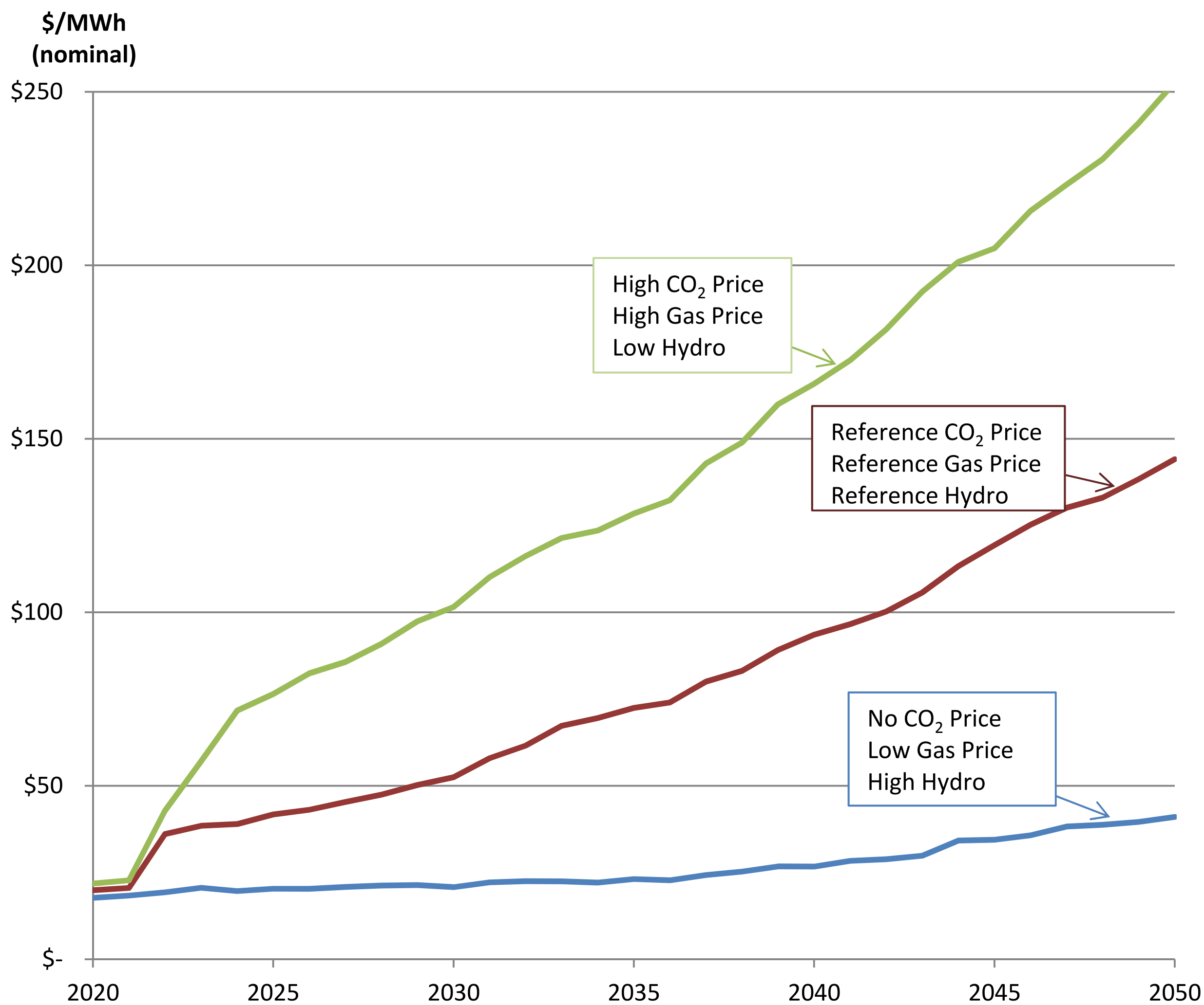
In the 2016 IRP market price futures, PGE considered one hydro condition (reference) across the gas and carbon forecasts and examined critical hydro conditions under reference gas and carbon prices. In this Update, the Company expands the consideration of hydro conditions in the market price futures by combining gas and carbon cases with three different hydro conditions in the Pacific Northwest, specifically:

- Reference hydro, combined with all gas and carbon conditions.
- Low hydro, combined with all gas and carbon conditions.
- High hydro, combined with all gas and carbon conditions.

In this Update, PGE defines low hydro as a 10% reduction in Pacific Northwest hydro energy production compared to reference and high hydro as a 10% increase in energy production compared to reference.

[Figure 13](#) plots the annual reference case prices and the highest and lowest price futures, showing the wide range of prices resulting from the simulations. Appendix F reports the annual wholesale electricity prices for all 27 price futures discussed above.

FIGURE 13: 2017.H2 ANNUAL WHOLESALE ELECTRICITY PRICES (HIGH, REFERENCE, AND LOW)



10. Appendices

Appendix A. Black and Veatch Characterization of Supply-Side Options (2017)

FINAL

CHARACTERIZATION OF SUPPLY-SIDE OPTIONS (2017)

B&V PROJECT NO. 196332
B&V FILE NO. 40.0000

PREPARED FOR

Portland General Electric

4 OCTOBER 2017

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Legal Notice

This report was prepared for Portland General Electric ("Client") by Black & Veatch ("Consultant"). In performing the services, Consultant has made certain assumptions or forecasts of conditions, events, or circumstances that may occur in the future. Consultant has taken reasonable efforts to assure that assumptions and forecasts made are reasonable and the basis upon which they are made follow generally accepted practices for such assumptions or projections under similar circumstances. Client expressly acknowledges that actual results may differ significantly from those projected as influenced by conditions, events, and circumstances that actually occur.

1.0 Introduction

Black & Veatch has prepared this report characterizing supply-side options (SSOs) to be considered in upcoming Integrated Resource Planning (IRP) activities to be conducted by Portland General Electric (PGE). The SSOs requested by PGE include the following:

- 1x0 GE 7F.05 CTG.
- 6x0 Wartsila 18V50SG Reciprocating Engines (RICE).
- 1x1 GE 7HA.01 Combined Cycle (CCCT).
- Biomass Combustion (35 MW Bubbling Fluidized Bed).
- Geothermal (35 MW Binary System).
- Battery Storage (50 MW, 100 MWh Lithium Ion Battery).
- Battery Storage (10 MW, 60 MWh Redox Flow Battery).

Each of these technology options is described in the following sections, including a brief technology overview and characterization of the performance and cost parameters. A full matrix of cost and performance parameters for the 7 requested SSOs is provided as Appendix A. Expenditure patterns for each SSO are provided in Appendix B. A Technology Maturity Outlook for each SSO, described further in Subsection 2.5.4 is included in Appendix C.

2.0 Design Basis and General Assumptions

2.1 DESIGN BASIS FOR SUPPLY-SIDE OPTIONS

To develop technical performance and cost characteristics, Black & Veatch worked with PGE to establish design basis parameters for each of the SSOs under consideration. The design basis parameters are summarized in Table 2-1.

Table 2-1 Design Basis for Supply-Side Options

SUPPLY-SIDE OPTION	MAJOR EQUIPMENT	DUTY	NET CAPACITY (MW)	CAPACITY FACTOR (PERCENT)	PRIMARY FUEL
1x0 GE 7F.05	Combustion Turbine: GE 7F.05 Emissions Control: SCR, CO Catalyst	Peaking	230	11	Natural Gas
6x0 Wartsila 18V50SG	Recip. Engine: Wartsila 18V50SG Heat Rejection: Wet Cooling Tower Emissions Control: SCR, CO Catalyst	Peaking	110	25	Natural Gas
1x1 GE 7HA.01	Combustion Turbine: GE 7HA.01 Duct Firing: None Emissions Control: SCR, CO Catalyst Heat Rejection: Wet Cooling Tower	Intermediate	400	70	Natural Gas
Biomass Combustion	Boiler: Bubbling Fluidized Bed Emissions Control: Selective Non-Catalytic Reduction (SNCR), Fabric Filter Heat Rejection: Wet Cooling Tower	Baseload	35	85	Wood
Geothermal – Binary	System: Binary Geothermal System Heat Rejection: Air-Cooled Condenser	Baseload	35	84	N/A
Battery Storage	Battery: Lithium Ion Discharge Duration: 2 hours	Storage	50	N/A	N/A
Battery Storage	Battery: Redox Flow Discharge Duration: 6 hours	Storage	10	N/A	N/A

2.2 GENERAL SITE ASSUMPTIONS

In addition to the design basis parameters shown in Table 2-1, Black & Veatch worked with PGE to establish the following general site assumptions for the SSOs:

- For 1x0 GE 7F.05 and 6x0 Wartsila 18V50SG options, units are assumed to be installed as additions at existing combined cycle or thermal plant sites. All other options are assumed to be installed at greenfield sites.
- The site has sufficient area available to accommodate construction activities including, but not limited to, office trailers, lay-down, and staging.
- The plant will not be located on environmentally or culturally sensitive lands. The project site will require neither mitigation nor remediation.
- Pilings are assumed under major equipment, and spread footings are assumed for all other equipment foundations.

- All buildings will be preengineered unless otherwise specified.
- Construction power is available at the boundary of the site.
- Potable, service, and fire water will be supplied from the local water utility.
- Wastewater disposal will utilize local sewer systems.
- Cooling water, if required, will be treated sewage effluent or groundwater. Allowances for pipeline costs are included in the Owner's cost.
- Costs for transmission lines and switching stations are included as part of the Owner's cost estimate.

2.3 CAPITAL COST ESTIMATING ASSUMPTIONS

Black & Veatch worked with PGE to establish the following capital cost estimating assumptions for the SSOs:

- Capital cost estimates were developed on an engineering, procurement, and construction (EPC) basis. The EPC capital cost estimates presented in this document include both direct and indirect costs.
- All capital cost estimates are presented in 2017 dollars.
- EPC capital cost estimates are presented as "overnight" costs and do not include any allowances for escalation, financing fees, interest, or other general Owner's cost items.
- Separately from the EPC capital cost estimates, a recommended allowance for Owner's costs has been provided for each technology. Potential Owner's costs are listed in Table 2-2.

Table 2-2 Potential Owner's Costs for Power Generation/Storage Projects

Project Development • Site selection study • Land purchase/rezoning for greenfield sites • Transmission/gas pipeline right-of-way • Road modifications/upgrades • Demolition • Environmental permitting/offsets • Public relations/community development • Legal assistance • Provision of project management	**Owner's Contingency** • Owner's uncertainty and costs pending final negotiation • Unidentified project scope increases • Unidentified project requirements • Costs pending final agreements (i.e., interconnection contract costs) **Owner's Project Management** • Preparation of bid documents and the selection of contractors and suppliers • Performance of engineering due diligence • Provision of personnel for site construction management
Spare Parts and Plant Equipment • Combustion turbine and reciprocating engine materials, gas compressors, supplies, and parts • Steam turbine materials, supplies, and parts • Boiler materials, supplies, and parts • Balance-of-plant equipment/tools • Rolling stock • Plant furnishings and supplies	**Taxes/Advisory Fees/Legal** • Taxes • Market and environmental consultants • Owner's legal expenses • Interconnect agreements • Contracts (procurement and construction) • Property
Plant Startup/Construction Support • Owner's site mobilization • Operations and Maintenance (O&M) staff training • Initial test fluids and lubricants • Initial inventory of chemicals and reagents • Consumables • Cost of fuel not recovered in power sales • Auxiliary power purchases • Acceptance testing • Construction all-risk insurance	**Utility Interconnections** • Natural gas service • Gas system upgrades • Electrical transmission • Water supply • Wastewater/sewer **Financing (included in fixed charge rate)** • Financial advisor, lender's legal, market analyst, and engineer • Loan administration and commitment fees • Debt service reserve fund

2.3.1 Direct Cost Assumptions

Direct costs include the costs associated with the purchase of equipment, erection, and contractors' services. Assumptions regarding direct costs within the capital cost estimates include the following:

- Construction costs are based on a turnkey EPC contracting philosophy.
- Permitting and licensing are excluded from EPC costs. These items should be included in the Owner's cost estimate.

2.3.2 Indirect Cost Assumptions

Indirect costs within the capital cost estimates are assumed to include the following:

- General indirect costs, including all necessary services required for checkout, testing, and commissioning.
- Insurance, including builder's risk, general liability, and liability insurance for equipment and tools.
- Engineering and related services.
- Field construction management services including field management staff with supporting staff personnel, field contract administration, field inspection and quality assurance, and project control.
- Technical direction and management of startup and testing, cleanup expense for the portion not included in the direct cost construction contracts, safety and medical services, guards and other security services, insurance premiums, and performance bonds.
- Contractor's contingency and profit.
- Transportation costs for delivery to the jobsite.
- Startup and commissioning spare parts.

Indirect costs are assumed to exclude the following:

- Initial inventory of spare parts for use during operation. These items are assumed to be included in the Owner's costs.
- Allowance for funds used during construction and financing fees. These costs should be included in the Owner's overall cost estimate.

2.4 OPERATION AND MAINTENANCE COST ESTIMATING ASSUMPTIONS

Assumptions associated with operations and maintenance (O&M) cost estimates developed by Black & Veatch include the following:

- O&M cost estimates were developed as representative estimates based on (1) previous Black & Veatch experience with projects of similar design and scale, and (2) relevant vendor information available to Black & Veatch.

- For gas-fired combustion turbine options, the annual number of starts may affect maintenance patterns. For gas-fired reciprocating engines, the number of starts does not affect maintenance patterns. Annual starts were assumed as follows:
  - 1x0 GE 7F.05: 120 starts/year
  - 6x0 Wartsila 18V50SG: 350 starts/year
  - 1x1 GE 7HA.01: 12 starts per year
- O&M cost estimates were categorized into fixed O&M and nonfuel variable O&M components. Nonfuel variable O&M costs exclude the cost of fuel (e.g., natural gas or woody biomass). Depending upon the SSO, fuel may or may not be required.
  - Fixed O&M costs include labor (operations, maintenance, technical services, and administration), routine maintenance (major equipment and systems, including contracted services) and other expenses (training, office and administrative expenses, bonus and incentives, and miscellaneous). Options assumed to operate as peaking units have minimal staff, assumed to be shared with staffing at an existing, adjacent facility. Costs are presented in $/kW-year.
  - For labor costs, the average burdened wage rate is assumed to be $61/hr.
  - Nonfuel variable O&M costs include outage maintenance, parts and materials, water usage, chemical usage and equipment. Costs are presented in $/MWh.
- Nonfuel variable wear and tear costs and nonfuel startup variable O&M costs are presented as sub-categories of nonfuel variable O&M costs and are defined as follows:
  - Nonfuel variable wear and tear costs include annualized estimated variable maintenance costs on the turbines, generators, HRSG when applicable, and SCR catalysts. Costs are presented in $/MWh.
  - Nonfuel startup variable O&M costs assume an average start and include makeup water and chemicals. This estimate does not include fuel or electricity. Costs are presented in $/start.
- All nonfuel O&M cost estimates are presented in 2017 dollars.
- Additionally, Black & Veatch provided estimates of fuel startup variable O&M Usage presented in million British thermal units (MMBtu)-HHV/start.

2.5 ADDITIONAL PARAMETER ASSUMPTIONS

In addition to capital and O&M cost parameters, PGE requested characterization of the other financial parameters, including overnight total cost standard deviation, capital expenditures and maintenance accruals, decommissioning costs, and a technical maturity outlook. A brief description of the methodology applied for each of these financial parameters is described in the following subsections.

2.5.1 Overnight Total Cost Standard Deviation

One standard deviation accounts for approximately 68.2 percent of the data points for a given data set, assuming a normal distribution. Given the planning level of this IRP study, Black & Veatch assumed a normal distribution and estimated the standard deviation by comparing the technology options on a relative basis. The standard deviation estimates are based on expert judgment and were based on Black & Veatch project experience with units of similar size and type, where possible.

2.5.2 Capital Expenditures/Maintenance Accruals

Operation of certain SSOs requires periodic replacement of specific systems or equipment (either dependent upon number of years in service or hours of operation). For example, the operation of a geothermal facility typically requires the drilling of new supply wells at regular intervals during the lifetime of the power project, and depending on the extent of charge/discharge cycling, battery energy storage systems may require periodic replacement of batteries.

Typically, Black & Veatch does not provide estimates of the costs associated with these activities as capital expenditures or maintenance accruals separately from other O&M costs. In instances where these periodic costs are necessary (for the SSOs under consideration in this report, excluding battery energy storage systems), these costs have been included in the relevant O&M costs associated with specific technology options. For these SSOs, the periodic system/equipment replacement requirements are noted in the technology-specific assumptions.

2.5.3 Decommissioning Costs

The total estimated decommissioning cost is presented in 2017 USD based on a percentage of the total overnight capital cost. Relative percentages are based on recent decommissioning cost estimates for a similar scope of decommissioning for similar assets and Black & Veatch expert judgment. Values are net of salvage.

Typically, a fixed amount of money is accrued each year over the book life of the asset to cover the cost of decommissioning the asset. For all SSOs, it is assumed the site would be returned to a brownfield condition at the end of its book life.

2.5.4 Technology Maturity Outlook

To provide an outlook on technology maturity and the potential for reductions in future capital costs, Black & Veatch employed a methodology for estimating future costs associated with each of the SSOs considered in this study. To provide this technology maturity outlook, Black & Veatch employed data developed by the US Department of Energy (US DOE) Energy Information Administration (EIA) in the Annual Energy Outlook (AEO) 2017 and applied these data to the present-day capital costs for each SSO. For the data developed for the AEO 2017, EIA employs the National Energy Modeling System (NEMS). Black & Veatch has provided estimates of total capital cost from 2017 to 2037. All estimates of future capital costs are presented on a constant dollar basis (i.e., in 2017 dollars).

2.5.4.1 NEMS Attributes

Relative strengths of the NEMS estimates of future capital costs for generation technologies include the following:

- NEMS was first developed in 1993 and has been employed by the EIA since then to provide a basis for the AEO. The model employs an analytical methodology; is well-documented, and has been peer reviewed over the course of time.
- NEMS is one of the more commonly used methods for future capital cost forecasting.
- The forecast data provided by NEMS provide technology-specific forecasts for the majority of technologies of interest, and forecast data is provided on a year-by-year basis from 2017 to 2050, which is consistent with the time horizon considered in this study.
- Within the NEMS model, future cost forecasts are developed and updated annually, rather than on cycles of multiple years (i.e., 2 to 5 years).
- The estimates are developed by the US DOE rather than national laboratories and technology-specific advocacy groups. In many cases, the national laboratories advocacy groups have a specific area of technical focus. The estimates developed by US DOE utilize information provided by the laboratories and other groups but are considered to have less technology bias than estimates developed by others.

Relative weaknesses of these estimates include the following:

- NEMS is a model of the energy market within the United States, and no model is able to fully integrate and consider all factors that affect costs of generation assets. The model may not predict short-term market effects. For example, the NEMS model did not forecast the increase in capital costs of all generation facilities in the 2005 to 2009 time period, which was attributed to (1) short-term shortage in craft labor supply and (2) short-term increases in commodity prices. While virtually all forecast models are limited in their ability to predict these short-term variations, the NEMS model is considered to provide a general indication of price trends over the long term.
- The NEMS model assumes continual development for all technologies, which may not be the case, particularly for technologies that are mature from a technical perspective. For example, coal fired boiler, simple cycle turbine and reciprocating engine technologies are unlikely to see significant reductions in cost.

Given these considerations, the NEMS forecast of future capital cost is useful as a means to quantify general capital cost trends for the disparate set of generation options available to utilities. These trends provide a reasonable base case for future capital costs, and variations for specific technologies may be considered via sensitivity analysis, if necessary. For example, for emerging technologies such as battery energy storage, analysis of variations in forecasts may be beneficial.

2.5.4.2 Estimated Future Capital Costs for PGE IRP 2016

As part of the NEMS data within the AEO 2017, EIA developed forecasts of capital cost (over the 2017 to 2050 time period) for technologies as listed in Table 2-3. Black & Veatch requested data associated with these forecasts, and EIA provided the data via email in June 2017. The data provided by EIA includes the overnight capital costs for these technologies presented in 2016 dollars (on a $/kW basis). Based on notes from EIA, these data represents the "cost of new plants, including contingencies, excluding regional multipliers, excluding tax credits."

Table 2-3 Technologies Included in NEMS Data Provided by EIA

CONVENTIONAL TECHNOLOGIES	RENEWABLE TECHNOLOGIES	DISTRIBUTED GENERATION TECHNOLOGIES
Coal with 30% CCS	Biomass	Distributed Generation Base
Coal with 90% CCS	Landfill Gas	Distributed Generation Peak
Combustion Turbine	Hydroelectric	
Advanced Comb. Turbine	Wind (Onshore)	
Combined Cycle	Offshore Wind	
Advanced Combined Cycle	Solar Thermal	
Adv. CC w/ Sequestration	Solar Photovoltaic (PV)	
Fuel Cell		
Nuclear		
Hydroelectric		

Maintaining a constant dollar basis, Black & Veatch developed a set of "forecast factors," and normalized these factors to 2017 values for each technology presented in the NEMS overnight capital cost data. The resulting forecast factors for conventional technologies, including nuclear, are illustrated in Figure 2-1. The forecast factors for renewable technologies, including fuel cell and distributed generation technologies, are illustrated in Figure 2-2. A table of these NEMS-based forecast factors for conventional and renewable technologies is presented in Appendix C.

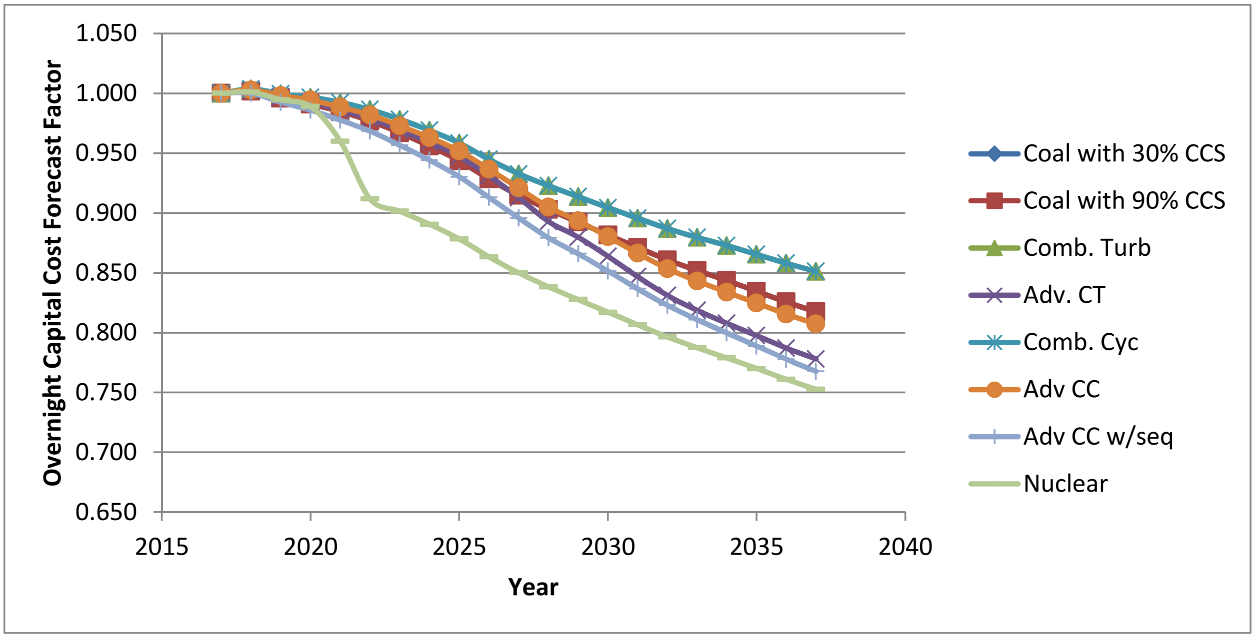


Figure 2-1 **Overnight Capital Cost Forecast Factors for Conventional Technologies**

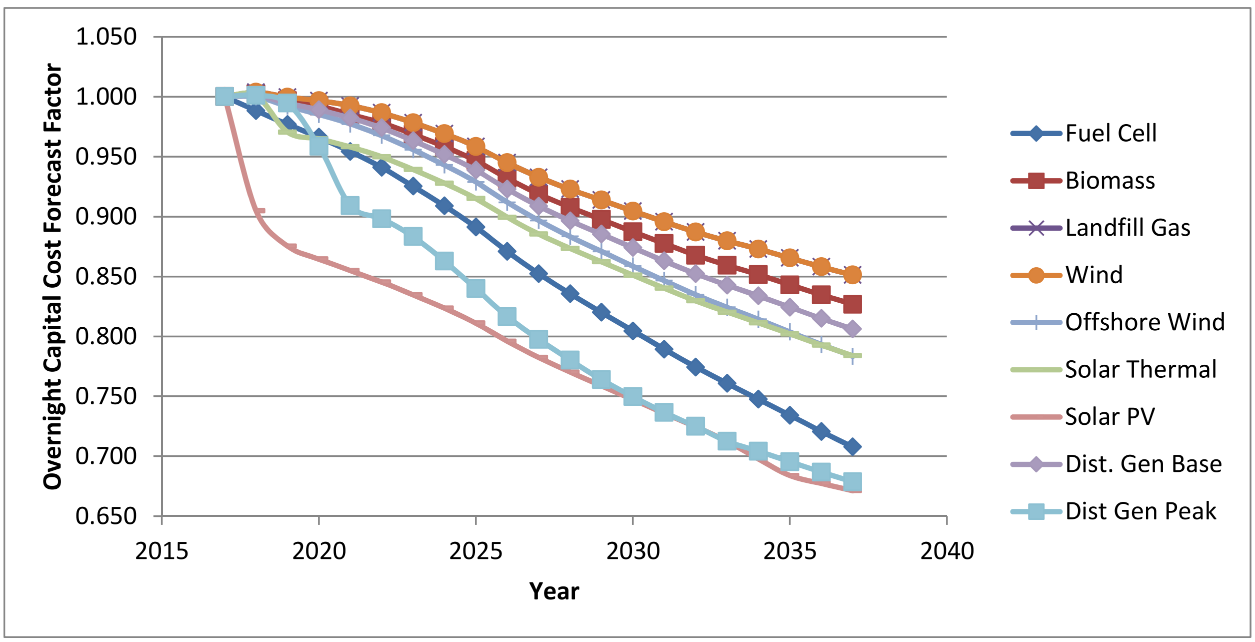


Figure 2-2 **Overnight Capital Cost Forecast Factors for Renewable Technologies**

For the SSOs considered in this IRP study, the estimates of future capital costs were based on the corresponding technology forecast factors (based on NEMS data). The future capital cost for each SSO was estimated by multiplying the present-day total overnight capital cost by the appropriate technology forecast factor. For example, the future capital costs of the simple cycle GE 7F.05 SSO were based on the set of forecast factors associated with the NEMS data for combustion turbine technologies. To estimate the total capital cost in a specific year (in 2017 dollars), the present-day capital cost (in 2017 dollars) was multiplied by the combustion turbine forecast factor associated with the specified year. The NEMS technology forecast factors applied for each SSO are identified in Table 2-4.

Table 2-4 Technology-Specific Forecast Data Employed for Supply-Side Options

SUPPLY-SIDE OPTION	EIA NEMS TECHNOLOGY FORECAST EMPLOYED
1x0 GE 7F.05	Combustion Turbine
6x0 Wartsila 18V50SG	Combustion Turbine
1x1 GE 7HA.01	Advanced Combined Cycle
Biomass Combustion	Biomass
Geothermal – Binary	Biomass[1]
Battery Storage – Li-Ion	Not Applicable[2]
Battery Storage – Redox Flow	Not Applicable[2]

Notes:
1. For Geothermal SSOs, Black & Veatch considered these to be technologically mature renewable options, similar in terms of future capital cost outlook to Biomass SSOs.
2. Expected trends for battery energy storage options are not consistent with any of the technology forecasts provided within the EIA data. Therefore, for battery storage applications, Black & Veatch developed a separate estimate of future capital costs.

2.5.4.3 Other NEMS Characteristics

Regarding the NEMS technology data applied to each SSO, Black & Veatch notes the following:

- While the NEMS data included geothermal and hydroelectric cost data, Black & Veatch notes that this data was not presented in the same fashion as other technologies within the data provided by EIA. The costs for geothermal and hydroelectric provided by EIA had significant fluctuations from year to year. According to EIA staff, capital costs for geothermal and hydroelectric technologies were determined by selecting projects from within a database of existing sites with site-specific costs.[1]

- Because the NEMS capital cost data for geothermal and hydroelectric technologies did follow a consistent trend, Black & Veatch did not apply these forecasts to geothermal and hydroelectric options considered in this study.
- Because both geothermal and pumped storage hydroelectric are considered technologically mature renewable/storage options, Black & Veatch applied forecast factors associated with Biomass technologies, which are also considered to be a technologically mature renewable technologies.

- For utility-scale battery energy storage technologies, none of the technologies included in the NEMS data were considered consistent with anticipated capital costs over the next 25 years. Therefore, Black & Veatch reviewed past and present battery price data to develop capital cost forecast factors for battery energy storage technologies, as shown in Figure 2-3. Projections are based on industry-wide learning curve data for battery cells, packs, and stacks published in July 2017.[2]
  - Black & Veatch anticipates that capital costs associated with battery energy storage facilities may decrease to 0.72 of the 2017 basis cost by 2020 (on a constant dollar basis).
  - By 2025 capital costs may further decrease to 0.50 of the 2017 basis cost (on a constant dollar basis).
  - By 2030 capital costs may further decrease to 0.45 of the 2017 basis cost, leveling off thereafter (on a constant dollar basis)
  - The estimates of future costs for utility-scale battery are consistent with industry learning curve price reductions that have been tracked since 2010.

[1] In an email to Black & Veatch, Laura Martin of the Electricity Analysis Team at EIA stated: "Reflected in the [geothermal and hydroelectric technology] costs I provided you are just the least-cost plants available each year, based on the model results in that scenario. Within the model we develop a supply curve of capacity and costs for the technology, and pass the electricity model information about the most economic sites (looking at total operating costs, not just capital costs) and the model makes decisions about whether or not to build. As sites are chosen, the supply curves are readjusted each year, and the overnight costs associated with the cheapest 'total cost' site may jump around."

[2] Schmidt, E. et al, "The future cost of electrical energy storage based on experience rates," *Nature Energy* (2) 17110, 2017.

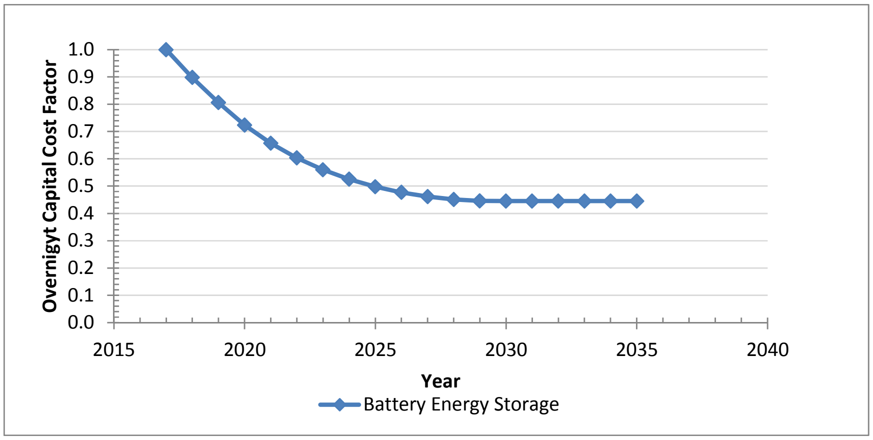


Figure 2-3 **Overnight Capital Cost Forecast Factors for Battery Energy Storage Supply-Side Options**

3.0 Conventional Generation Options

Three conventional generation SSOs were considered:

- 1x0 GE 7F.05 CTG.
- 6x0 Wartsila 18V50SG RICE.
- 1x1 GE 7HA.01 CCCT.

These conventional SSOs and their performance and cost characteristics are defined in the following subsections.

3.1 1X0 GE 7F.05

3.1.1 Technology Overview

The 7F.05 is an air cooled heavy frame CTG with a single shaft, 14-stage axial compressor, 3-stage axial turbine, and 14-can-annular dry low NO_x (DLN) combustors. The 7F.05 is GE's fifth-generation 7F machine with the latest advancements including a redesigned compressor and three variable stator stages and a variable inlet guide vane for improved turndown capabilities. GE's 7F fleet of over 800 units has over 33 million operating hours.

Key attributes of the GE 7F.05 include the following:

- High availability.
- 40 MW/min ramp rate.
- Start to 200 MW in 10 minutes, full load in 11 minutes.
- Natural gas interface pressure requirement of only 435 psig.
- Dual fuel capable.
- DLN combustion with CTG NOx emissions of 9 ppm on natural gas.
- Water injected combustion with CTG NOx emissions of 42 ppm on diesel fuel.
- High exhaust temperature makes it difficult to implement post-combustion NOx emissions controls.

3.1.2 Technology-Specific Assumptions

Cost and performance characteristics have been developed for a simple cycle natural gas-fired GE 7F.05 combustion turbine facility. Relevant assumptions employed in the development of performance and cost parameters for the 7F.05 facility include the following:

- The power plant would consist of a single GE 7F.05 CTG, located outdoors in a weather-proof enclosure.
- To reduce NOx and CO emissions, a SCR system with oxidation catalyst would be utilized. The SCR system would include purge/tempering air for startup and to reduce CTG exhaust temperature to within the operational limits of the SCR catalyst.
- A generation building would house electrical equipment, engine controls, mechanical equipment, warehouse space, offices, break area, and locker rooms.
- No natural gas compression has been assumed for this option.

3.2 6X0 WARTSILA 18V50SG

3.2.1 Technology Overview

The 18V50SG is a turbocharged, four-stroke spark-ignited natural gas engine. Unlike dual fuel reciprocating engines, the SG does not require liquid pilot fuel during startup and to maintain combustion. The 18V50SG utilizes 18 cylinders in a "V" configuration. Each cylinder has a bore diameter of 500 millimeters (19-11/16 inches) and a stroke of 580 millimeters (22-13/16 inches). Each engine operates at a shaft speed of 514 revolutions per minute. Individual cylinder computer controls and knock sensors provide precise control of the combustion process, enabling the engine to operate more efficiently while minimizing emissions. There have been at least 62 18V50SG engines sold to date with initial commercial operations starting in 2013.

For this characterization, it is assumed that engine heat is rejected to the atmosphere by way of a mechanical draft cooling tower. In locations with limited water resources, an air-cooled heat exchanger may be employed as an alternative to a mechanical draft cooling tower. An 18V50SG power plant utilizing air cooled heat exchangers would require very little makeup water as the engines do not typically utilize inlet cooling for power augmentation or water injection for NO_x reduction.

Key attributes of the Wartsila 18V50SG include the following:

- High full- and part-load efficiency.
- Minimal performance impact at hot-day conditions.
- 10 minutes to full power.
- Minimal power plant footprint.
- Low starting electrical load demand.
- Ability to cycle on and off without impact of maintenance costs or schedule.
- Natural gas interface pressure requirement of 75 psig.
- Not dual fuel capable.

While the 18V50SG does not provide dual fuel capability, the diesel variation of the engine, the 18V50DF model, does provide dual fuel capability. In diesel mode, the main diesel injection valve injects the total amount of light fuel oil as necessary for proper operation. In gas mode, the combustion air and the fuel gas are mixed in the inlet port of the combustion chamber, and ignition is provided by injecting a small amount of light fuel oil (less than one percent by heat input). The injected light fuel oil ignites instantly, which then ignites the air/fuel gas mixture in the combustion chamber. During startup, the 18V50DF must operate in diesel mode until the engine is up to speed; once up to speed, the unit may operate in gas mode.

Wartsila offers a standard, pre-engineered six-engine configuration for the 18V50SG and the 18V50DF, sometimes referred to as a "6-Pack". The 6-Pack configuration has a net generation output of approximately 110 MW and ties the six engines to a single bus and step-up transformer. This configuration provides economies of scale associated with the balance of plant systems (e.g., step-up transformer and associated switchgear) and reduced engineering costs.

3.2.2 Technology-Specific Assumptions

Cost and performance characteristics have been developed for a simple cycle (6x0) natural gas-fired Wartsila 18V50SG reciprocating engine facility. Relevant assumptions employed in the development of performance and cost parameters for the 18V50SG facility include the following:

- The facility would consist of six Wartsila 18V50SG reciprocating engines, arranged as slide along units and co-located in a common engine hall.
- The engine hall would be one of a number of rooms within a generation building. The generation building would also include space for water treatment, electrical equipment, engine controls, mechanical equipment, warehouse space, offices, break area, and locker rooms.
- An SCR system with oxidation catalyst would be utilized to minimize NOx and CO emissions.
- Engine heat is rejected to atmosphere by way of a common wet mechanical draft cooling tower.

3.3 1X1 GE 7HA.01

3.3.1 Technology Overview

The GE 7HA.01 is an air cooled heavy frame CTG with a single shaft, 14-stage axial compressor, 4-stage axial turbine, and 12-can-annular DLN combustors. The 7HA.01 has a single inlet guide vane stage and three variable stator vain stages to vary compressor geometry for part load operation. The 7HA.01, along with the scaled-up 7HA.02 and 50 Hertz versions, the 9HA.01 and 9HA.02, represent the largest and most advanced heavy frame CTG technologies from GE. The compressor design is scaled from GE's 7F.05 and 6F.01 (formally 6C) designs. The 7HA.01 will use a DLN 2.6+ AFS (Axial Fuel Staged) fuel staging combustion system which allows for high firing temperatures and improved gas turbine turndown while maintaining emissions guarantees, stable operations, and allows for increased fuel variability. 7HA.01 first shipments are expected to begin in 2016. GE has 16 orders of its HA CTG technology to date.

This option would also employ a triple-pressure HRSG, reheat condensing STG, wet surface condenser, and wet mechanical draft counterflow cooling tower. The STG would likely employ a single axial flow exhaust.

Key attributes of the GE 7HA.01 include the following:

- High availability.
- CTG 50 MW/min ramp rate.
- Combined cycle start times dependent on bottoming cycle, HRSG, and STG design. A nominal hot start time of 60 minutes is typical.
- Natural gas interface pressure requirement of about 500 psig.
- Dual fuel capable.
- DLN combustion with CTG NOx emissions of 25 ppm on natural gas.

3.3.2 Technology-Specific Assumptions

Cost and performance characteristics have been developed for a combined cycle natural gas-fired GE HA.01 CTG-based facility. Relevant assumptions employed in the development of performance and cost parameters include the following:

- The power plant would consist of a single GE 7HA.01 CTG, located outdoors in a weather-proof enclosure with close-coupled three-pressure HRSG.
- An axial flow reheat condensing steam turbine would accept steam from the HRSG at three pressure levels. The steam turbine would be located within a building.
- A wet surface condenser and mechanical draft counterflow cooling tower would reject STG exhaust heat to atmosphere.
- To reduce NOx and CO emissions, a SCR system with oxidation catalyst would be utilized. The SCR system would be located within the HRSG in a temperature region conducive to the SCR catalyst.
- A generation building would house electrical equipment, engine controls, water treatment equipment, mechanical equipment, warehouse space, offices, break area, and locker rooms.
- Natural gas compression has been assumed for this option.

3.4 TECHNICAL AND FINANCIAL PARAMETERS

Technical parameters for conventional energy options considered for PGE are summarized in Table 3-1, while cost and financial parameters for conventional energy options considered for PGE are summarized in Table 3-1 and Table 3-2.

Table 3-1 Technical Parameters for Conventional Generation Options

SUPPLY-SIDE OPTION	NET CAPACITY (MW)[1]	AVERAGE DESIGN LIFE NET CAPACITY, INCLUDING DEGRADATION (MW)	CAPACITY FACTOR (PERCENT)	LAND REQUIRED (ACRES/ MW)[2]	NET PLANT HEAT RATE (BTU/ kWh-HHV)	AVERAGE DESIGN LIFE NET PLANT HEAT RATE, INCLUDING DEGRADATION (BTU/kWh-HHV)	FUEL CONSUMPTION VERSUS OUTPUT (MMBtu/h-[HHV] VERSUS KW-NET, NEW AND CLEAN)[3]	MINIMUM TURNDOWN CAPACITY (PERCENT)[4]	RAMP RATE (MW/MIN)	MINIMUM RUN/ DOWN TIMES (HOURS)	START TIME TO FULL LOAD (MINS)[5]	WATER CONSUMPTION (MGD)	SCHEDULED MAINTENANCE (WEEKS/YR)[6]	EQUIVALENT FORCED OUTAGE RATE – DEMAND (PERCENT)	EPC PERIOD (MONTHS)[7]
1x0 GE 7F.05	231	218	11	0.04	9,830	10,170	$y = 1.657E\text{-}08x^2 + 1.883E\text{-}03x + 9.521E+02$	43	40	0.5 / 0.5	11	0.0	1.8	4.0	24
6x0 Wartsila 18V50SG	110	107	25	0.06	8,300	8,470	$y = -3.336E\text{-}09x^2 + 7.875E\text{-}03x + 8.800E+01$	25	84	0.5 / 0.5	5	0.36	0.9	2.2	24
1x1 GE 7HA.01	424	400	70	0.04	6,290	6,450	$y = 1.638E\text{-}09x^2 + 4.583E\text{-}03x + 4.283E+02$	33	55	2.0 / 1.0	Hot:60 Warm:100 Cold:210	1.9	3.9	2.9	30

Notes:

1. Performance parameters assume International Organization for Standardization (ISO) conditions (59° F, 60% relative humidity, and sea level elevation). Net capacity is defined as the nameplate (or gross) unit capacity minus any auxiliary losses.
2. Typical value; actual value is specific to project, location, and owner's requirements.
3. For combustion turbines and reciprocating engines, heat rate is a function of output as well as fuel consumption. In Black & Veatch's experience, providing a curve showing fuel consumption as a function of output provides a more accurate result. The curve provided is fuel consumption versus output (MMBtu-HHV versus kW-net, new and clean). Heat rate can be further determined by dividing fuel consumption by output.
4. While maintaining emissions compliance for combustion turbine and reciprocating engine based option.
5. Start times exclude purge time. Combined cycle start time definitions: Hot start is defined as a start after an 8 hour shutdown (generally considered 8 hours or less). Warm start is defined as a start after a 48 hour shutdown (generally considered 8 to 48 hours). Cold start is defined as a start when the steam turbine rotor temperature is at or near atmospheric temperature (generally considered greater than 48 hours).
6. Maintenance values are annual averages based on prime mover (combustion turbine or reciprocating engine) manufacturer recommended maintenance.
7. The project duration period starts with EPC contractor notice to proceed (NTP) and ends at the commercial operation date (COD). Some excluded activities are permitting and EPC specification development.

Table 3-2 Financial Parameters for Conventional Generation Options

SUPPLY-SIDE OPTION	BOOK LIFE (YEARS)	EXPENDITURE PATTERN (BY MONTH)	OVERNIGHT EPC CAPITAL COST ($000, 2017$)	OWNER'S COST ALLOWANCE (PERCENT)[8]	OVERNIGHT TOTAL CAPITAL COST ($000, 2017$)	OVERNIGHT TOTAL CAPITAL COST STANDARD DEVIATION, 1σ ($000, 2017$)	FIXED O&M COSTS ($/kW-YEAR)[9]	NONFUEL VARIABLE O&M COST (2017$/MWh)[9]	NONFUEL VARIABLE WEAR AND TEAR COSTS (2017$/MWh)[10]	CAPITAL ADDITIONS/ MAINTENANCE ACCRUAL (2017$/YEAR)	NONFUEL STARTUP VARIABLE O&M COSTS (2017$/ START)[11]	STARTUP FUEL CONSUMPTION (MMBTU-HHV/ START)[12]	DECOMMISSIONING COST ($000, 2017$)[13]
1x0 GE 7F.05	30	Refer to Appendix B	115,000	25	143,750	10,800	6.7	6.9	6.7	Refer to Note 14	4	295	1,380
6x0 Wartsila 18V50SG	30	Refer to Appendix B	116,000	25	145,000	10,900	11.0	7.2	6.3	Refer to Note 14	11	72	1,260
1x1 GE 7HA.01	30	Refer to Appendix B	449,000	25	561,250	56,200	7.4	3.3	2.7	Refer to Note 14	370	950	9,770

Notes (continued from Table 3-1):

8. Owner's cost allowance includes costs associated with project development, operating spare parts and plant equipment, owner's contingencies and project management, utility interconnections, taxes, and legal fees. The owner's cost allowance can vary widely.
9. Estimates expressed in terms of new and clean condition.
10. Estimated wear and tear costs include annualized estimated variable maintenance costs on the turbines, generators, HRSG, and SCR catalysts, as applicable.
11. Assumes average start. Includes makeup water and chemicals. Does not include fuel or electricity.
12. Startup fuel consumption for achieving CTG/RICE full load operation.
13. Decommissioning costs are typically accrued annually over the design life of the asset to decommission the facility. Total project decommissioning costs, net of salvage, are provided in 2017 USD. Assumes the site would be returned to a brownfield condition at the end of its design life.
14. Operation of certain SSOs requires periodic replacement of specific systems or equipment (either dependent upon number of years in service or hours of operation). In instances where these periodic costs are necessary, these costs have been included in the relevant O&M costs associated with specific technology options.

4.0 Renewable Generation Options

Renewable SSOs considered include the following:

- Biomass Combustion (35 MW Bubbling Fluidized Bed).
- Geothermal (35 MW Binary System).

These renewable SSOs and their performance and cost characteristics are defined in the following sections.

4.1 BIOMASS COMBUSTION

4.1.1 Technology Overview

Direct biomass combustion power plants in operation today use the same steam Rankine cycle that was introduced commercially over 100 years ago. In many respects, biomass power plants are similar to coal plants. When burning biomass, pressurized steam is generated in a boiler and then expanded through a turbine to produce electricity. Prior to its combustion in the boiler, the biomass fuel may require processing to improve the physical and chemical properties of the feedstock. Boiler systems used in biomass combustion include stoker fired, suspension fired, fluidized bed, cyclone, and pile burners. Newly constructed biomass-fired generation facilities likely employ either a stoker boiler or a fluidized bed boiler. Advanced technologies, such as integrated biomass gasification combined cycle and biomass pyrolysis, are under development but have not achieved widespread commercial operation at utility scales.

Although wood is the most common biomass fuel, other biomass fuels include agricultural residues such as bagasse (sugar cane residues), dried manure and sewage sludge, black liquor from pulp mills, and dedicated fuel crops such as fast growing grasses and eucalyptus.

Biomass plants usually have a capacity of less than 50 MW because of the dispersed nature of the feedstock and the large quantities of fuel required. As a result of the smaller scale of the plants and lower heating values of the fuels, biomass plants are less efficient than modern fossil fuel plants. These factors usually limit the use of direct-fired biomass technology to inexpensive or waste biomass sources.

Biomass power projects must maintain a careful balance to ensure long-term sustainability with minimal environmental impact. Most biomass projects target the use of biomass waste material for energy production, saving valuable landfill space. Biomass projects that burn forestry or agricultural products must ensure that both fuel harvesting and collection practices are sustainable and do not adversely affect the environment. Biomass projects that collect thinning from forests to reduce the risk of forest fires are increasingly seen as a way to restore a positive balance to forest ecosystems while avoiding catastrophic and polluting uncontrolled forest fires.

Unlike coal or natural gas, biomass may be viewed as a carbon-neutral power generation fuel. While carbon dioxide (CO_2) is emitted during biomass combustion, a nearly equal amount of CO_2 is absorbed from the atmosphere during the biomass growth phase. Furthermore, biomass fuels contain little sulfur compared to coal and, therefore, produce less sulfur dioxide (SO_2). Finally, unlike coal, biomass fuels typically contain only trace amounts of toxic metals, such as mercury (Hg), cadmium, and lead.

While biomass fuels offer certain emissions benefits relative to coal and natural gas, biomass combustion facilities typically require technologies to control emissions of NO_x, particulate matter (PM), and CO to meet state and or federal regulatory requirements.

4.1.2 Technology-Specific Assumptions

For this PGE IRP effort, Black & Veatch developed performance and cost parameters for a biomass facility employing a Bubbling Fluidized Bed (BFB) boiler, with a net generation output of 35 MW-net. Relevant assumptions employed in the development of performance and cost parameters for the 35 MW-net biomass energy facility include the following:

- The primary fuel for the biomass facility will be woody biomass, with an average moisture content of 40 percent and an as-received heating value of 5,100 Btu/lb (HHV).
- The facility will have an average annual capacity factor of 85 percent. It is estimated that the facility would produce approximately 260,600 MWh per year of electricity.
- The facility will have a wood fuel yard sufficiently sized to store 30 days of woody biomass fuel.
- Air quality control equipment includes SCR systems for NOx control, sorbent injection for acid gas control, and a fabric filter for PM control.

4.2 GEOTHERMAL

4.2.1 Technology Overview

Geothermal power is produced by using steam or a secondary working fluid in a Rankine Cycle to produce electricity. Geothermal energy was first used to make electricity at the beginning of the 20th century. In 1904, Prince Piero Conti, owner of the Larderello fields in Italy, attached a generator to a natural-steam-driven engine which lit four light bulbs. This experiment led to the installation of the world's first geothermal power plant in 1911, with a capacity of 250 kilowatts. The government of New Zealand was the first significant producer of geothermal electricity, with the ~150-MW Wairakei power plant, which began operating in 1958. Shortly thereafter, the first power plants were installed at The Geysers in California, USA. By 1975, the Larderello fields were capable of producing about 400 MW of power. By the mid-1980s, The Geysers' output had peaked at about 1,600 MW, after which it declined to its present output at about 850 MW.[3] Today, roughly 70 geothermal power facilities are in operation in over 20 countries around the world, generating approximately 13.3 GW as of January 2016.[4]. There is a natural concentration of geothermal

[3] Sanyal, S. K. (2011) Fifty Years of Power Generation at The Geysers - The Lessons Learned. Proceedings, Thirty-sixth Workshop on Geothermal Reservoir Engineering, Stanford University, January 31 - February 2, 2011, SGP-TR-191.

[4] B. Matek, (2016). 2016 Annual US and Global Geothermal Power Production Report. Geothermal Energy Association. Washington, DC, USA.

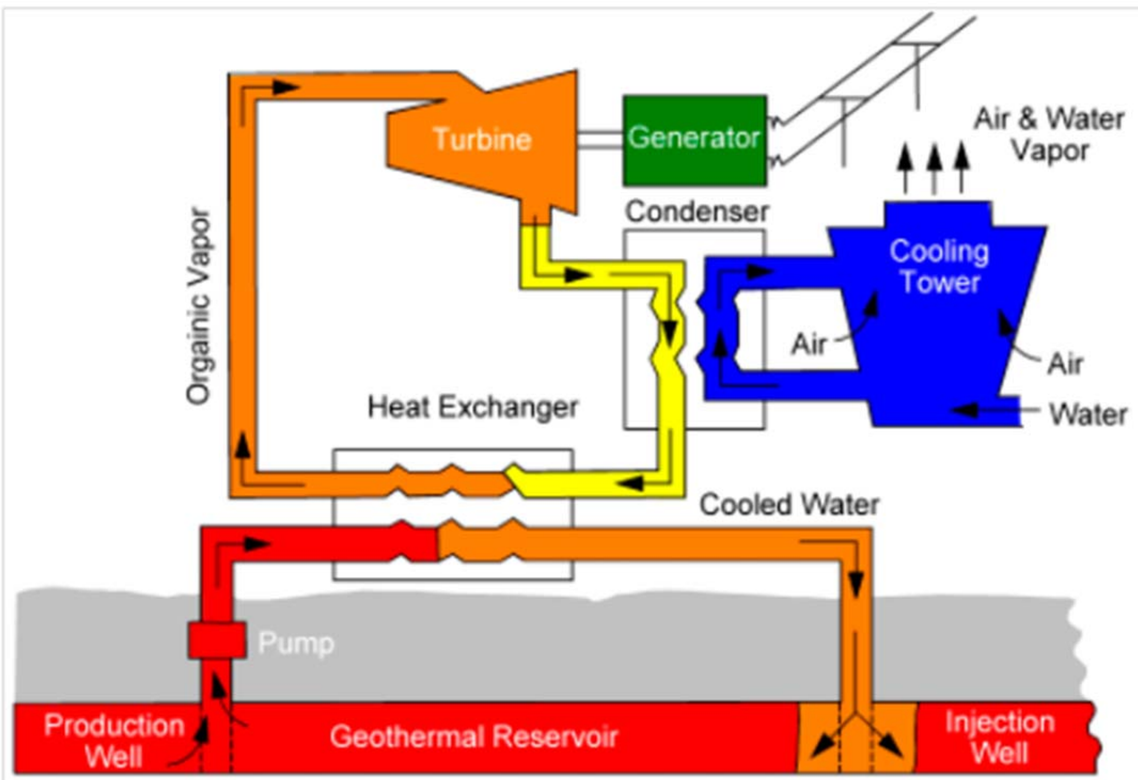
resources in regions characterized by volcanism, active tectonism, or both. For example, Indonesia and The Philippines have many large, high-temperature geothermal resources.

The most commonly used power generation technologies are direct steam (or dry steam), single-flash, dual-flash, and binary systems. In addition, efforts are underway to develop “enhanced geothermal” projects. The choice of technology is driven primarily by the temperature and quality of the steam/liquid extracted from the geothermal resource area. These geothermal technologies are classified as follows:

- Direct steam: For geothermal resources that provide slightly superheated steam, direct-steam technologies may be employed. Superheated steam (with temperatures exceeding 350° F [177° C]) is gathered from the geothermal reservoir (via production wells) to drive a condensing steam turbine-generator. Following expansion in the steam turbine, the brine is scrubbed as necessary to remove acid gases and other contaminants, and re-injection wells are employed to return the geothermal brine to the geothermal reservoir.
- Single-Flash or Double-Flash: Flash systems are used in high temperature (i.e., greater than 350° F [177° C]) liquid-dominated geothermal reservoirs. Upon extraction from the geothermal reservoir, the geothermal fluid is a pressurized two-phase mixture of liquid brine and steam. This two-phase mixture is routed to a separator, where the pressure of the mixture is reduced, causing the fluid to flash into steam. This steam is then expanded in steam turbine generator. Double-flash systems flash the separated brine a second time. In double-flash systems, the lower temperature steam may be expanded through a separate steam turbine, or the steam may be introduced into the high-pressure turbine through a second admission port. As in direct steam systems, the spent brine is scrubbed and re-injected into the geothermal reservoir.
- Binary: Binary cycle systems are employed for development of liquid-dominated geothermal reservoirs that do not have temperatures sufficiently high enough to flash steam (i.e., less than 350° F [177° C]). In a binary system, a secondary fluid is employed to capture thermal energy of the brine and operate within a Rankine Cycle. Additional details regarding binary geothermal systems are discussed below.
- Enhanced geothermal (or “hot dry rock”): For geologic formations with high temperatures but without the necessary subsurface fluids or permeability, fluid may be injected to develop geothermal resources. Typically, the geologic structure must be hydraulically fractured to achieve a functional geothermal resource. While enhanced geothermal projects are currently being demonstrated around the world (including the Newberry Volcano EGS demonstration near Bend, Oregon), this technology is not yet considered commercial.

Considering the temperatures associated with geothermal resource areas located in Oregon, it is anticipated that geothermal developments would utilize either binary geothermal systems or enhanced geothermal systems. Because of the technical and cost uncertainty associated with enhanced geothermal systems, Black & Veatch has selected binary geothermal options for this characterization and has developed performance and cost parameters for a 35 MW-net binary geothermal facility.

In a binary plant, the thermal energy in the geothermal brine is transferred in a heat exchanger to a secondary working fluid for use in a fairly conventional Rankine cycle, as shown in Figure 4-1. The brine itself does not contact moving parts of the power plant, thus minimizing the potential of equipment fouling (e.g., scaling, corrosion or erosion). Binary plants may be especially advantageous for low brine temperatures (i.e., less than about 350°F [177°C])) or for brines with high dissolved gases or high corrosion or scaling potential.



Source: Colorado Department of Natural Resources

Figure 4-1 Binary Geothermal System

Most binary plants operate on pumped wells and geothermal fluid remains in the liquid phase throughout the plant, from production wells through the heat exchangers to the injection wells. Dry cooling is typically used with a binary plant to avoid the necessity for make-up water required for a wet cooling system. Dry cooling systems generally add 5 to 10 percent to the cost of the power plant compared to wet cooling systems. Because of chemical impurities, the waste geothermal fluid is not generally suitable for cooling tower make-up. There is a wide range of candidate working fluids for the closed power cycle. The working fluid of the binary system is generally selected to achieve good thermodynamic match to the particular geothermal temperature. The optimal fluid would provide high utilization efficiency with safe and economical operation.

4.2.2 Technology-Specific Assumptions

Relevant assumptions employed in the development of performance and cost parameters for the 35 MW-net geothermal energy facility include the following:

- The geothermal energy facility would employ a binary geothermal system with dry cooling methods (rather than a wet cooling tower) to minimize water requirements.
- The facility will have an average annual capacity factor of 85 percent.
- To extract and re-inject geothermal brine, the facility would utilize 5 supply wells and 5 return wells.
  - Capital costs estimated by Black & Veatch include the cost of well development.
  - Variable O&M costs estimated by Black & Veatch include costs associated with development of 1 new supply well every 5 years. When drilling replacement wells, it is assumed that 1 out of every 5 supply wells is dry (i.e., does not provide sufficient flow and is unusable), and well replacement costs include costs associated with drilling of dry wells.
- The geothermal project would require 35 acres of land, and this land would be leased for the lifetime of the project. Land lease costs for the geothermal facility are included in the Variable O&M costs estimated by Black & Veatch.

4.3 TECHNICAL AND FINANCIAL PARAMETERS

Technical parameters for renewable energy options considered for PGE are summarized in Table 4-1, while cost and financial parameters for renewable energy options considered for PGE are summarized in Table 4-2.

Table 4-1 Technical Parameters for Renewable Generation Options

SUPPLY-SIDE OPTION	NET CAPACITY (MW)[1]	AVERAGE DESIGN LIFE NET CAPACITY, INCLUDING DEGRADATION (MW)	CAPACITY FACTOR (PERCENT)	LAND REQUIRED (ACRES/ MW)[2]	NET PLANT HEAT RATE (BTU/ kWh-HHV)	AVERAGE DESIGN LIFE NET PLANT HEAT RATE, INCLUDING DEGRADATION (BTU/kWh-HHV)	FUEL CONSUMPTION VERSUS OUTPUT (MMBtu-HHV VERSUS KW-NET, NEW AND CLEAN)[3]	MINIMUM TURNDOWN CAPACITY (PERCENT)[4]	RAMP RATE (MW/MIN)	MINIMUM RUN/ DOWN TIMES (HOURS)	START TIME TO FULL LOAD (MINS)[5]	WATER CONSUMPTION (MGD)	SCHEDULED MAINTENANCE (WEEKS/YR)[6]	EQUIVALENT FORCED OUTAGE RATE – DEMAND (PERCENT)	EPC PERIOD (MONTHS)[7]
Biomass Combustion	35	35	85	1.0	13,000	13,350	N/A	25	1.75	8.0 / 8.0	180	1.0	3.83	7.5	36
Geothermal -- Binary	35	N/A	85	1.0	N/A	See Note (8)	N/A	50	4.5	0.5 / 0.5	10	0.2	3.83	6.0	24[9]

Notes:

1. Performance parameters assume International Organization for Standardization (ISO) conditions (59° F, 60% relative humidity, and sea level elevation). Net capacity is defined as the nameplate (or gross) unit capacity minus any auxiliary losses.
2. Typical value; actual value is specific to project, location, and owner's requirements.
3. For combustion turbines and reciprocating engines, heat rate is a function of output as well as fuel consumption. In Black & Veatch's experience, providing a curve showing fuel consumption as a function of output provides a more accurate result. The curve provided is fuel consumption versus output (MMBtu-HHV versus kW-net, new and clean). Heat rate can be further determined by dividing fuel consumption by output.
4. While maintaining emissions compliance for combustion turbine and reciprocating engine based option.
5. Start times exclude purge time. Combined cycle start time definitions: Hot start is defined as a start after an 8 hour shutdown (generally considered 8 hours or less). Warm start is defined as a start after a 48 hour shutdown (generally considered 8 to 48 hours). Cold start is defined as a start when the steam turbine rotor temperature is at or near atmospheric temperature (generally considered greater than 48 hours).
6. Maintenance values are annual averages based on prime mover (combustion turbine or reciprocating engine) manufacturer recommended maintenance.
7. The project duration period starts with EPC contractor notice to proceed (NTP) and ends at the commercial operation date (COD). Some excluded activities are permitting and EPC specification development.
8. Geothermal resources typically degrade at about 1.5°F per year. This is typically accounted for via decrease in net power output, which may be mitigated somewhat by additional well that is drilled once per five years.
9. EPC period for geothermal projects is considered 24 months for construction of generation systems. Project development, including drilling of test wells and associated well development activities, is assumed to require 24 months, but development is assumed to be conducted prior to the EPC period.

Table 4-2 Financial Parameters for Renewable Generation Options

SUPPLY-SIDE OPTION	BOOK LIFE (YEARS)	EXPENDITURE PATTERN (BY MONTH)	OVERNIGHT EPC CAPITAL COST ($000, 2017$)	OWNER'S COST ALLOWANCE (PERCENT)[10]	OVERNIGHT TOTAL CAPITAL COST ($000, 2017$)	OVERNIGHT TOTAL CAPITAL COST STANDARD DEVIATION, 1σ ($000, 2017$)	FIXED O&M COSTS ($/kW-YEAR)[11]	NONFUEL VARIABLE O&M COST (2017$/MWh)[11]	NONFUEL VARIABLE WEAR AND TEAR COSTS (2017$/MWh)[12]	CAPITAL ADDITIONS/ MAINTENANCE ACCRUAL (2017$/YEAR)	NONFUEL STARTUP VARIABLE O&M COSTS (2017$/ START)[13]	STARTUP FUEL CONSUMPTION (MMBTU-HHV/ START)[14]	DECOMMISSIONING COST ($000, 2017$)[15]
Biomass Combustion	40	Refer to Appendix B	170,800	25	213,500	32,000	145	9.6	N/A	See Note (16)	N/A	N/A	2,080
Geothermal -- Binary	30	Refer to Appendix B	235,700	25	282,800	70,700	110	16.8	N/A	See Note (16)	N/A	N/A	3,940

Notes (continued from Table 4-1):

10. Owner's cost allowance includes costs associated with project development, operating spare parts and plant equipment, owner's contingencies and project management, utility interconnections, taxes, and legal fees. The owner's cost allowance can vary widely.
11. Estimates expressed in terms of new and clean condition.
12. Estimated wear and tear costs include annualized estimated variable maintenance costs on the turbines, generators, HRSG, and SCR catalysts, as applicable.
13. Assumes average start. Includes makeup water and chemicals. Does not include fuel or electricity.
14. Startup fuel consumption for achieving CTG/RICE full load operation.
15. Decommissioning costs are typically accrued annually over the design life of the asset to decommission the facility. Total project decommissioning costs, net of salvage, are provided in 2017 USD. Assumes the site would be returned to a brownfield condition at the end of its design life.
16. Operation of certain SSOs requires periodic replacement of specific systems or equipment (either dependent upon number of years in service or hours of operation). In instances where these periodic costs are necessary (for the SSOs under consideration in this report), these costs have been included in the relevant O&M costs associated with specific technology options.

5.0 Energy Storage Options

Energy Storage SSOs considered include the following:

- Battery Storage (50 MW, 100 MWh Lithium Ion Battery).
- Battery Storage (10 MW, 60 MWh Redox Flow Battery).

These energy storage options and their performance and cost characteristics are defined in the following subsections.

5.1 BATTERY ENERGY STORAGE

5.1.1 Technology Overview

Batteries are electrochemical cells that convert chemical energy into electrical energy. This conversion is achieved via electrochemical oxidation-reduction (redox) reactions occurring at the electrodes of the batteries. The batteries of interest for this report are secondary batteries that can be recharged (i.e., the redox reaction can be reversed). The main components of a battery are the positive electrode (cathode), the negative electrode (anode) and the electrolyte. The resulting potential, or voltage, of the battery is based on the composition of the electrodes and the redox reactions that occur at the electrodes.[5]

Battery energy storage systems employ multiple (up to several thousand) batteries and are charged via an external source of electrical energy. The battery energy storage system discharges this stored energy to provide a specific electrical function. Examples of these functions, as defined by the Energy Storage Association (ESA), are as follows:

- Spinning Reserve: the use of energy storage to supply generation capacity that is online and dispatchable within 10 minutes.
- Non-Spinning Reserve: a resource that follows spinning reserve dispatch during loss of generation or transmission events and usually required to respond within 10 to 15 minutes.
- Capacity Firming: the use of energy storage to fill in capacity (power) when variable energy resources, such as solar and wind, fall below their rated output.
- Voltage Support: the use of energy storage to manage and supply reactive power on the grid at or near a power factor of 1.
- Frequency Regulation: the use energy storage to maintain grid system frequency with a resource that is capable of responding within seconds.
- Ramping Service: using energy storage ramping to offset excessive ramping of other generating facilities, often variable energy resources such as solar or wind.

[5] Linden's Handbook of Batteries. Edited by Thomas B. Reddy.

The size of a battery energy storage system is based on two parameters: power, usually in kW or MW, and energy, usually in kWh or MWh. The energy storage capacity of a battery designates how long a given energy storage system can discharge at a given power. Other parameters relevant for energy storage systems are:

- Ramp-rate: how quickly an energy storage system can change its power output, typically in MW/ min.
- Response time: how quickly an energy storage system can reach its rated power (constrained by power conversion system [PCS]).
- Round-trip efficiency: the amount of energy discharged from an energy storage system relative to the amount required for charging.
- Discharge duration: how long a battery can be discharged at a given power.
- Charge/Discharge rate (C-rate): how quickly the battery can charge or discharge relative to a one-hour charge or discharge (for example, a 2C rate charges or discharges in 30 minutes).

Operational parameters associated with battery energy storage technologies include:

- State-of-charge (SOC): how much energy is stored in an energy storage system relative to the maximum energy storage capacity. In general, maximum lifetime of battery systems occurs when the SOC is maintained between 10 and 90 percent.
- Depth of discharge (DoD): how discharged an energy storage system is relative to the maximum energy storage capacity.
- Cycles-to-failure (CtF): the number of cycles at 100 percent DoD until the battery's energy storage capacity is degraded to 80 percent of its original capacity.

Battery types employed within battery energy storage systems include lithium-ion (Li-ion), lead-acid and flow batteries. This section will focus on two commonly deployed utility scale battery technologies, namely, Li-ion battery and Redox Flow battery technologies.

5.1.1.1 Lithium Ion Batteries

Lithium ion batteries are a form of energy storage where all the energy is stored electrochemically within each cell. During charging or discharging, lithium ions are created and are the mechanism for charge transfer through the electrolyte of the battery. In general, these systems vary from vendor to vendor by the composition of the cathode or the anode. Some examples of cathode and anode combinations are shown in Figure 5-1.

The battery cells are integrated to form modules. These modules are then strung together in series/ parallel to achieve the appropriate power and energy rating to be coupled to the PCS.

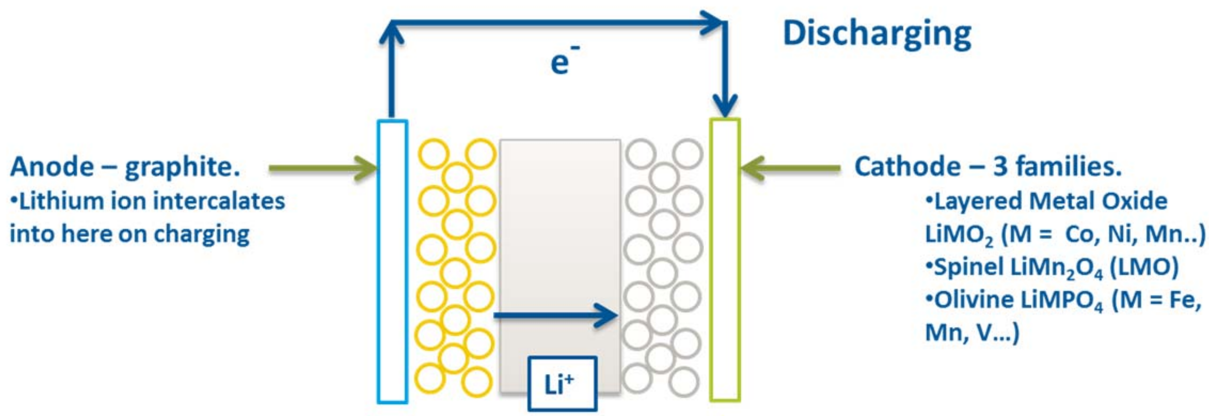


Figure 5-1 Lithium Ion Battery Showing Different Electrode Configurations

Lithium ion battery storage systems are typically used for both power and energy applications. One strength of lithium ion batteries is their strong cycle life. For shallow, frequent cycles, which are quite common for power applications, lithium ion systems demonstrate good cycle life characteristics. Additionally, lithium ion systems demonstrate good cycle life characteristics for deeper discharges common for energy applications. Overall, this technology offers the following benefits:

- Excellent Cycle Life: Lithium ion technologies have superior cycling ability to other battery technologies such as lead acid.
- Fast Response Time: Lithium ion technologies have a fast response time which is typically less than 100 milliseconds.
- High Round Trip Efficiency: Lithium ion energy conversion is efficient and has a 90 percent round trip efficiency (DC-DC).
- Versatility: Lithium ion solutions can provide many relevant operating functions.
- Commercial Availability: Dozens of strong lithium ion vendors.
- Energy Density: Lithium ion solutions have a high energy density to meet space constraints.

An image of a sample lithium ion BESS can be found in Figure 5-2.

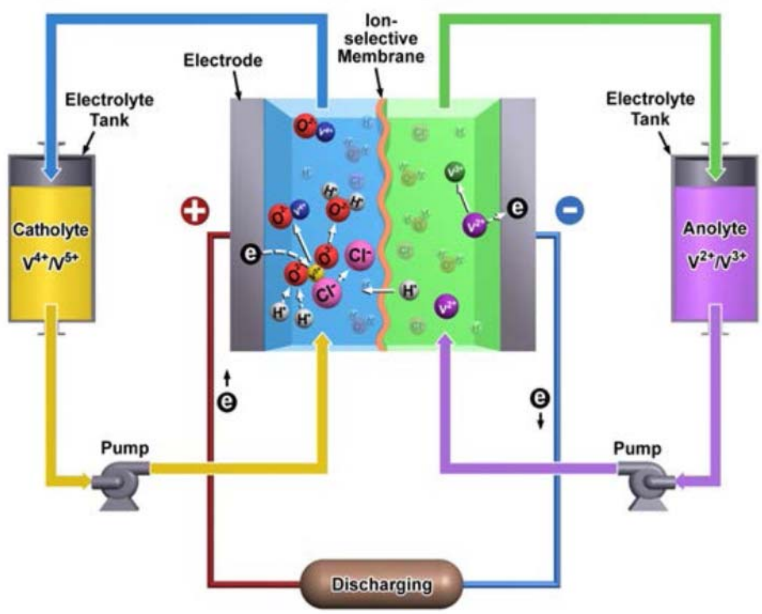
Figure 5-2 Lithium Ion Battery Energy Storage System located at the Black & Veatch Headquarters

Various Li-ion battery systems are installed around the world, including projects in the United States. The 30 MW/ 120 MWh Escondido Li-ion energy storage project owned by SDG&E is currently the largest installed. PGE also employs a 5 MW Li-Ion system at the Salem Smart Power Center (SSPC) as part of the Pacific Northwest Smart Grid Demonstration. According to the DOE Energy Storage Database, the United States installed (or under construction) capacity of Li-ion is about 334 MW.[6]

5.1.1.2 Redox Flow Batteries

Redox flow batteries are another form of electrochemical storage. Redox flow batteries are the most commercially developed technology of the various flow battery technologies. In this technology, the energy for these systems is stored within a liquid electrolyte stored in tanks. The volume of electrolyte can be scaled to produce the desired energy storage capacity; the power cells (where the reactions happen) can be scaled to produce the desired power output. A diagram of a redox flow battery can be found on Figure 5-3.

[6] DOE Energy Storage Database (beta). Sadia National Laboratories. http://www.energystorageexchange.org/, does not include unverified projects



Source: DOE/Electric Power Research Institute [EPRI] 2013 Electricity Storage Handbook.

Figure 5-3 Diagram of Vanadium Redox Flow Battery

This technology is also integrated with a PCS to form the overall BESS. Redox batteries are more typically used for energy applications, as they can more effectively be scaled to longer discharge periods than lithium ion batteries. However, one drawback with flow batteries is the space requirements for these systems relative to other battery technologies. The Redox flow batteries require more space for the installation than lithium ion batteries. Redox BESS can be modular, as shown on Figure 5-4, and containerized systems, as shown on Figure 5-5.

Source: Prudent Energy

Figure 5-4 Redox Flow Battery

Source: UniEnergy.

Figure 5-5 Containerized Flow Battery

Various Flow battery systems are installed around the world, including projects in the United States. The 600 kW Gills Onions Project in California, the 1 MW Avista Project in Washington, and other projects in Japan and China employ Flow batteries. According to the DOE Energy Storage Database, the United States installed (or under construction) capacity of Flow battery is about 4 MW.[7]

A summary of representative performance parameters for battery energy storage systems employing Li-ion and Flow batteries is provided in Table 5-1.

5.1.2 Technology-Specific Assumptions

Black & Veatch developed performance and cost parameters for 50-MW and 10-MW battery energy storage systems, capable of discharging at their rated power for 2 and 6 hours, respectively. Relevant assumptions employed in the development of these performance and cost parameters include the following:

- The battery storage system is assumed to have a 20 year service lifetime. Assuming one (complete) discharge of the battery energy per day, it is anticipated that the battery energy storage modules employed within the system will provide 20 years of operation. No capacity additions (i.e., periodic battery replacement) were included in estimates of either capital costs or O&M costs.
- Service contracts for long-term battery maintenance (provided by the OEM) are included in the fixed O&M costs.

[7] DOE Energy Storage Database (beta). Sandia National Laboratories. http://www.energystorageexchange.org/

Table 5-1 Representative Performance Parameters for Lithium Ion and Redox Flow Energy Storage Systems

PARAMETER	LI-ION	REDOX FLOW
Commercial Availability	Commercial	Commercial
Facility Power Rating, MW	0.005 to 32	0.05 to 5
Module Power Rating, MW	0.005 to 4	0.005 to 0.25
Facility Energy Capacity, MWh	0.005 to 120	0.2 to 10
Module Energy Capacity, MWh	0.1 to 2	0.03 to 0.5
Ramp Rate, MW/min	Note[1]	Note[1]
Response Time[2]	< 100 ms	< 100 ms
Round-Trip Efficiency, percent	75 to 90	65 to 75
Discharge Duration, hours	0.25 to 4	3 to 8
Charge/Discharge Rate, C[3]	C/4 to 4C	C/8 to C/3

Notes:

1. Li-ion and Redox Flow systems are able to ramp up from an idle status to full rated capacity in less than 1 second.
2. Amount of time system takes to reach rated power.
3. Charge/discharge rate is conventionally expressed in terms of "C-rate". Under this convention, a system with a charge/discharge rate of 2C could be fully charged or discharged in 30 minutes (1/2 hour), while a system with a charge/discharge rate of 6C could be fully charged or discharged in 10 minutes (1/6 hour).

5.2 TECHNICAL AND FINANCIAL PARAMETERS

Technical parameters for energy storage options considered for PGE are summarized in Table 5-2, while cost and financial parameters for energy storage options considered for PGE are summarized in Table 5-3. Additional parameters specific to energy storage options are shown in Table 5-4.

Table 5-2 Technical Parameters for Energy Storage Options

SUPPLY-SIDE OPTION	NET CAPACITY (MW)¹	AVERAGE DESIGN LIFE NET CAPACITY, INCLUDING DEGRADATION (MW)	CAPACITY FACTOR (PERCENT)	LAND REQUIRED (ACRES/MW)²	NET PLANT HEAT RATE (BTU/ kWh-HHV)	AVERAGE DESIGN LIFE NET PLANT HEAT RATE, INCLUDING DEGRADATION (BTU/kWh-HHV)	HEAT RATE VERSUS OUTPUT (BTU/KWh-HHV VERSUS KW-NET, NEW AND CLEAN)	MINIMUM TURNDOWN CAPACITY (PERCENT)	RAMP RATE (MW/MIN)	MINIMUM RUN/ DOWN TIME (HOURS)	START TIME TO FULL LOAD (MINS)	WATER CONSUMPTION (MGD)	SCHEDULED MAINTENANCE (WEEKS/YR)	EQUIVALENT FORCED OUTAGE RATE – DEMAND (PERCENT)	EPC PERIOD (MONTHS)³
Battery Storage – Lithium Ion	50	N/A	N/A	0.04(4)	N/A	N/A	N/A	0	Refer to Note 5	N/A	N/A	N/A	2	N/A	12 to 15
Battery Storage – Redox Flow	10	N/A	N/A	0.16(4)	N/A	N/A	N/A	0	Refer to Note 5	N/A	N/A	N/A	2	N/A	12 to 15

Notes:

1. Performance parameters assume ISO conditions (59° F, 60% relative humidity, and sea level elevation). Net capacity is defined as the nameplate (or gross) unit capacity minus any auxiliary losses.
2. Typical value; actual value is specific to project, location, and owner's requirements.
3. The project duration period starts with EPC contractor NTP and ends at the COD. Some excluded activities are permitting and EPC specification development.
4. For battery energy storage systems (BESS), 1 acre can accommodate approximately 40 to 60 MWh of energy storage capacity. Therefore, a 50 MW|100 MWh system would require approximately 2 acres and a 10 MW|40 MWh system would require approximately 1 acre.
5. BESS are able to ramp up from an idle status to full rated capacity in less than 1 second.

Table 5-3 Financial Parameters for Energy Storage Options

SUPPLY-SIDE OPTION	BOOK LIFE (YEARS)	EXPENDITURE PATTERN (BY QUARTER)	OVERNIGHT EPC CAPITAL COST ($000, 2017$)	OWNER'S COST ALLOWANCE (PERCENT)⁶	OVERNIGHT TOTAL CAPITAL COST ($000, 2017$)	OVERNIGHT TOTAL CAPITAL COST STANDARD DEVIATION, 1σ ($000, 2017$)	FIXED O&M COSTS ($/kW-YEAR)⁷	NONFUEL VARIABLE O&M COST (2017$/MWh)⁷	NONFUEL VARIABLE WEAR AND TEAR COSTS (2017$/MWh)⁸	CAPITAL ADDITIONS/ MAINTENANCE ACCRUAL (2017$/YEAR)	NONFUEL STARTUP VARIABLE O&M COSTS (2015$/ START)	FUEL STARTUP VARIABLE O&M COSTS (MMBTU-HHV/ START)	DECOMMISSIONING COST ($000, 2017$)⁹
Battery Storage	20	Refer to Appendix B	71,000	12	79,500	9,900	12	N/A	N/A	200,000(10)	N/A	N/A	1,240
Battery Storage	20	Refer to Appendix B	36,700	12	41,100	5,100	30	N/A	N/A	45,000(10)	N/A	N/A	640

Notes (continued from Table 5-2):

6. Owner's cost allowance includes costs associated with project development, operating spare parts and plant equipment, owner's contingencies and project management, utility interconnections, taxes, and legal fees. The owner's cost allowance can vary widely.
7. Estimates expressed in terms of new and clean condition.
8. Estimated wear and tear costs include annualized estimated variable maintenance costs on the turbines, generators, and batteries.
9. Decommissioning costs are typically accrued annually over the design life of the asset to decommission the facility. Total project decommissioning costs, net of salvage, are provided in 2015 USD. For all SSOs except Pumped Storage Hydro, the site would be returned to a brownfield condition at the end of its design life. For Pumped Storage Hydro, it is assumed that powerhouse equipment would be decommissioned and salvaged, and the facility/reservoirs would be retired in place, with the site secured as appropriate (e.g., reservoirs drained, additional security fencing installed, and signs posted).
10. The cost per year presented here assumes 365 cycles per year at 80% depth of discharge (DoD) for both technologies. For lithium ion, the degradation per year is approximately 1.8%. For vanadium redox, the degradation is less than 1% per year.

Table 5-4 Additional Parameters for Energy Storage Options

SUPPLY-SIDE OPTION	NET CAPACITY (MW)	ENERGY CAPACITY (MWh)	ROUND TRIP EFFICIENCY (PERCENT)
Battery Storage – Lithium Ion	50	100	85
Battery Storage – Redox Flow	10	60	75

Appendix A. Supply-Side Option Parameters (Full Table)

		Design Basis Parameters						Technical/Performance Parameters											
No.	Supply-Side Option	Option Design Basis	Duty	Net Capacity (MW)(1)	Average Design Life Net Capacity, Including Degradation (MW)	Capacity Factor (%)	Primary Fuel	Land Required (acres/MW)(2)	Net Plant Heat Rate (Btu/kWh-HHV)	Average Design Life Net Plant Heat Rate, Including Degradation (Btu/kWh-HHV)	Heat Rate vs Output (Btu/kWh versus kW-net, New and Clean)	Fuel Consumption versus Output (MMBtu/hr-HHV versus kW-net, New and Clean)(3)	Minimum Turndown Capacity (%)(4)	Ramp Rate (MW/min)	Minimum Run/Down Times (hours)	Start Time to Full Load (mins) (5)	Water Consumption (MGD)	Scheduled Maintenance (weeks/yr) (6)	Equivalent Forced Outage Rate - Demand (%)	EPC Period(7) (months)
1	1x0 GE 7F.05	Combustion Turbine: GE 7F.05 Emissions Control: SCR, CO catalyst	Peaking	231	218	11%	Natural Gas	0.04	9,830	10,170	See Next Column	$y = 1.657E-08x^2 + 1.883E-03x + 9.521E+02$	43%	40	0.5 / 0.5	11	0	1.80	4.0%	24
2	6x0 Wartsila 18V50SG	Recip. Engine: Wartsila 18V50SG Heat Rejection: Wet Cooling Tower Emissions Control: SCR, CO catalyst	Peaking	110	107	25%	Natural Gas	0.06	8,300	8,470	See Next Column	$y = -3.336E-09x^2 + 7.875E-03x + 8.800E+01$	25%	84	0.5 / 0.5	10	0.36	0.90	2.2%	24
3	1x1 GE 7HA.01	Combustion Turbine: GE 7HA.01 Duct Firing: None Emissions Control: SCR, CO catalyst Heat Rejection: Wet Cooling Tower	Intermediate	424	400	70%	Natural Gas	0.04	6,290	6,450	See Next Column	$y = 1.638E-09x^2 + 4.583E-03x + 4.283E+02$	33%	55	1.5 / 1.5	Hot: 60 Warm: 100 Cold: 210	1.90	3.90	2.9%	30
4	Biomass Combustion	Boiler: Bubbling Fluidized Bed Emissions Control: SNCR, Fabric Filter Heat Rejection: Wet Cooling Tower	Baseload	35	35	85%	Wood	1.0	13,000	13,350	$y = 3.918E-06x^2 - 0.3086x + 19,000$	n/a	25%	1.75	8.0 / 8.0	180	1.0	3.83	7.5%	36
5	Geothermal -- Binary	System: Binary Geothermal System Heat Rejection: Air-Cooled Condenser	Baseload	35	n/a	85%	n/a	1.0	n/a	n/a	Refer to Note 21	n/a	50%	4.5	0.5 / 0.5	10	0.20	3.83	6.0%	24(16)
6	Battery Storage -- Lithium Ion	Battery: Lithium Ion Discharge Duration: 2 hrs	Storage	50	n/a	n/a	n/a	0.04(14)	n/a	n/a	n/a	n/a	0%	Refer to Note 15	n/a	n/a	n/a	2	n/a	12 to 15
7	Battery Storage -- Redox Flow	Battery: Redox Flow Discharge Duration: 6 hrs	Storage	10	n/a	n/a	n/a	0.16(14)	n/a	n/a	n/a	n/a	0%	Refer to Note 15	n/a	n/a	n/a	2	n/a	12 to 15

NOTES:

(1) Performance parameters assume ISO conditions (59° F, 60% relative humidity, and sea level elevation). Net capacity is defined as the nameplate (or gross) unit capacity, minus any auxiliary losses.

(2) Typical value; actual value is specific to project, location, and owner's requirements.

(3) For combustion turbines and reciprocating engines, heat rate is a function of output as well as fuel consumption. In Black & Veatch's experience, providing a curve showing fuel consumption as a function of output provides a more accurate result. The curve provided is Fuel Consumption versus Output (MMBtu-HHV versus kW-net, New and Clean). Heat rate can be further determined by dividing fuel consumption by output.

(4) While maintaining emissions compliance for Options 1 through 7.

(5) Start times exclude purge time. Combined cycle start time definitions: Hot start is defined as a start after an 8 hour shutdown (generally considered 8 hours or less). Warm start is defined as a start after a 48 hour shutdown (generally considered 8 to 48 hours). Cold start is defined as a start when the steam turbine rotor temperature is at or near atmospheric temperature (generally considered greater than 48 hours).

(6) Natural gas fueled option maintenance values are annual averages based on prime mover (combustion turbine or reciprocating engine) manufacturer recommended maintenance, excluding annual outages. Renewable option maintenance based on industry norms

(7) The project duration period starts with EPC contractor notice to proceed (NTP) and ends at the commercial operation date (COD). Some excluded activities are permitting and EPC specification development

(8) Owner's cost allowance includes costs associated with project development, operating spare parts and plant equipment, owner's contingencies and project management, utility interconnections, taxes, and legal fees. The owner's cost allowance can vary widely

(9) Estimates expressed in terms of new and clean condition.

(10) Estimated wear and tear costs include annualized estimated variable maintenance costs on the turbines, generators,steam generator, batteries, and SCR catalysts, as applicable

(11) Assumes average start. Includes makeup water and chemicals. Does not include fuel or electricity

(12) Startup fuel consumption for achieving CTG/RICE full load operation.

(13) Decommissioning costs are typically accrued annually over the design life of the asset to decommission the facility. Total project decommissioning costs are provided in 2017 USD. For all SSOs, the site would be returned to a brownfield condition at the end of its design life.

(14) For battery energy storage systems (BESS), 1 acre can accommodate approximately 40 to 60 MWh of energy storage capacity. Therefore, a 50 MW|100 MWh system would require approximately 2 acres and a 10 MW|40 MWh system would require approximately 1 acre

(15) BESS are able to ramp up from an idle status to full rated capacity in less than 1 second

(16) EPC period for geothermal projects is considered 24 months for construction of generation systems. Project development, including drilling of test wells and associated well development activities, is assumed to require 24 months, but development is assumed to be conducted prior to the EPC period

(17) Design life for battery energy storage options is consistent with the warranties/guarantees provided by battery OEMs and is consistent with the capacity maintenance costs listed in the Table

(18) Operation of certain SSOs requires periodic replacement of specific systems or equipment (either dependent upon number of years in service or hours of operation). In instances where these periodic costs are necessary (for the SSOs under consideration in this report), these costs have been included in the relevant O&M costs associated with specific technology options

(19) The cost per year presented here assumes 365 cycles per year at 80% depth of discharge (DoD) for both technologies. For lithium ion, the degradation per year is approximately 1.8%. For vanadium redox, the degradation is less than 1% per year.

(20) Daily storage based on the 8 hours of discharge per day.

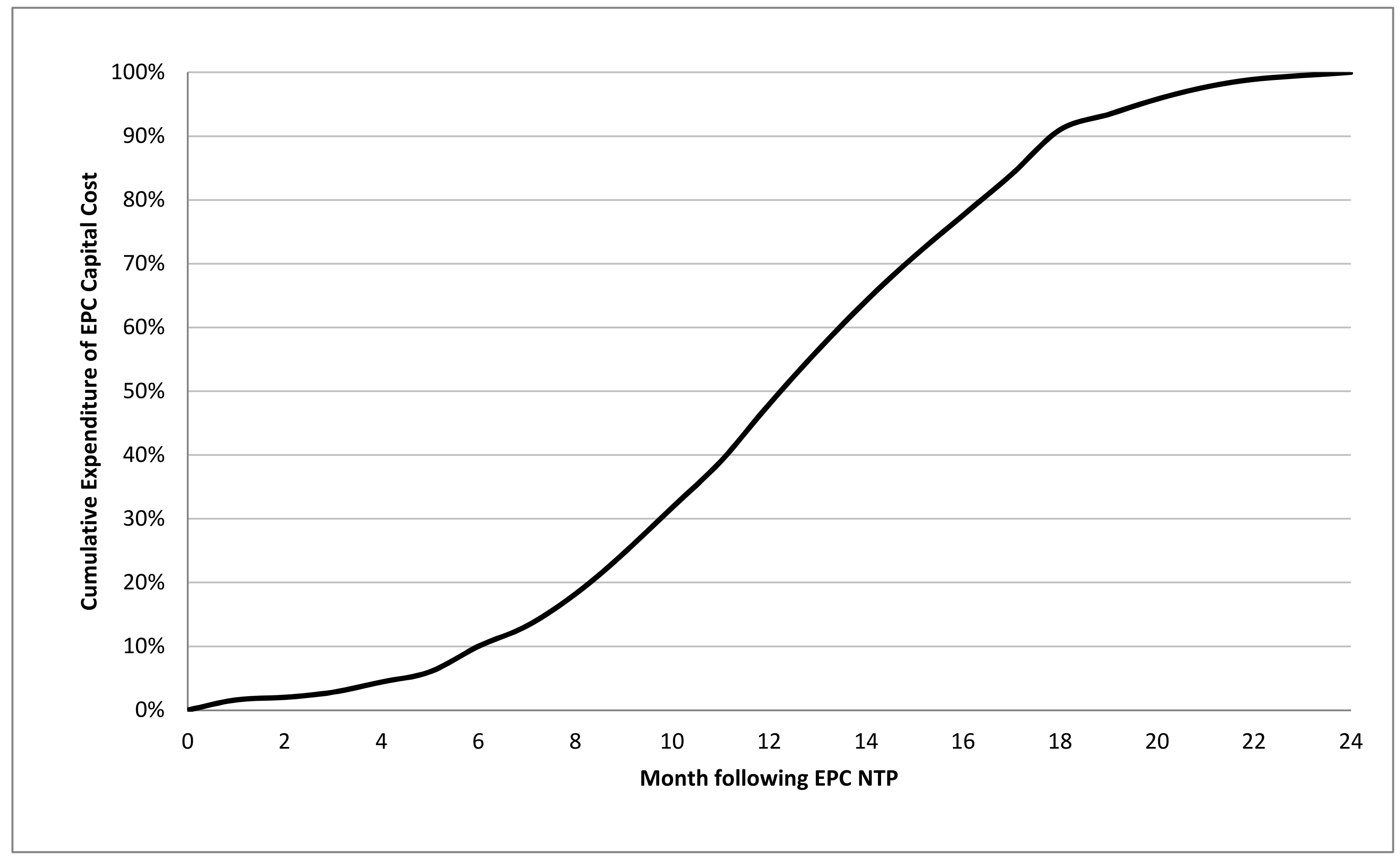
(21) Geothermal resources typically degrade at about -1.5degF per year. This is typically accounted for via decrease in net power output, which may be mitigated somewhat by additional well that is drilled once per five years

		Financial Parameters													Energy Storage Parameters	
No.	Supply-Side Option	Book Life (years)	Expenditure Pattern (by month/qtr)	Overnight EPC Capital Cost ($000, 2017$)	Owner's Cost Allowance [8] (%)	Overnight Total Capital Cost ($000, 2017$)	Overnight Total Capital Cost Standard Deviation, 1σ ($,000, 2017$)	Fixed O&M Cost (2017$/kW-year)[9]	Nonfuel Variable O&M Cost (2017$/MWh) [9]	Nonfuel Variable Wear and Tear Costs (2017$/MWh)[10]	Capital Additions/ Maintenance Accrual (2017$/yr)	Nonfuel Startup Variable O&M Costs (2017$/start)[11]	Fuel Startup Variable O&M Usage (MMBtu-HHV/start)[12]	Decommissioning Cost ($000, 2017$)[13]	Energy Capacity (MWh)	Round Trip Efficiency (%)
2	1x0 GE 7F.05	30	Refer to Appendix B	115,000	25%	143,750	10,800	6.7	6.9	6.7	Refer to Note 18	4	295	1,380	n/a	n/a
3	6x0 Wartsila 18V50SG	30	Refer to Appendix B	116,000	25%	145,000	10,900	11.0	7.2	6.3	Refer to Note 18	11	72	1,260	n/a	n/a
5	1x1 GE 7HA.01	30	Refer to Appendix B	449,000	25%	561,250	56,200	7.4	3.3	2.7	Refer to Note 18	370	950	9,770	n/a	n/a
7	Biomass Combustion	40	Refer to Appendix B	170,800	25%	213,500	32,000	145	9.60	n/a	Refer to Note 18	n/a	n/a	2,080	n/a	n/a
8	Geothermal -- Binary	30	Refer to Appendix B	235,700	20%	282,800	70,700	110	16.8	n/a	Refer to Note 18	n/a	n/a	3,940	n/a	n/a
10	Battery Storage -- Lithium Ion	20[17]	Refer to Appendix B	71,000	12%	79,500	9,900	12	n/a	n/a	200,000[19]	n/a	n/a	1,240	100	85
11	Battery Storage -- Redox Flow	20[17]	Refer to Appendix B	36,700	12%	41,100	5,100	30	n/a	n/a	45,000[19]	n/a	n/a	640	60	75

Appendix B. SSO Expenditure Patterns

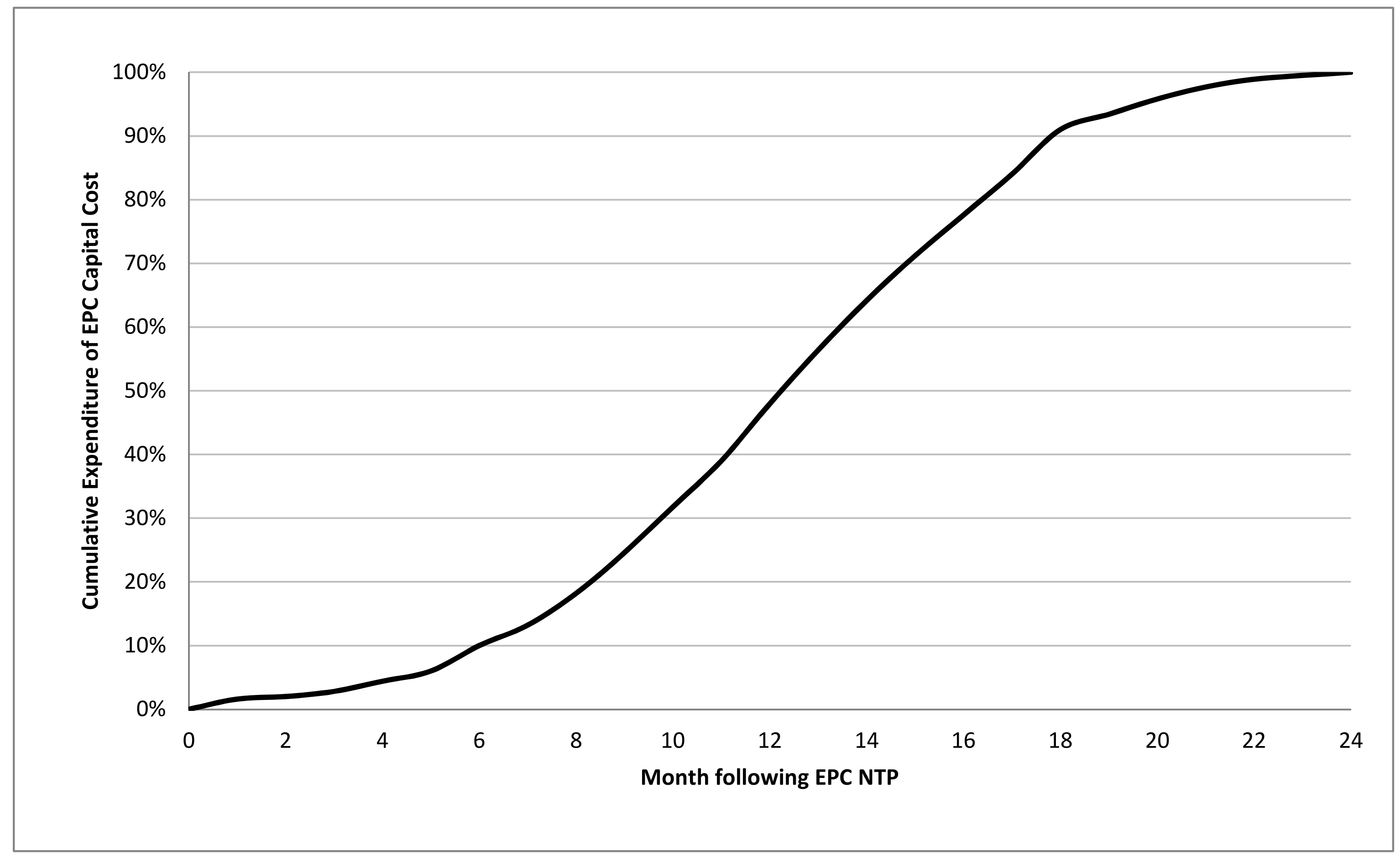
Expenditure Pattern for EPC Capital Cost
Supply Side Option: 1x0 MW GE 7F.05

Year	Month	Cumulative Month	Monthly Expenditure (%)	Cumulative Expenditure (%)
		0	0.0%	0.0%
1	1	1	1.6%	1.6%
1	2	2	0.4%	2.0%
1	3	3	0.8%	2.8%
1	4	4	1.6%	4.4%
1	5	5	1.6%	6.0%
1	6	6	4.0%	10.0%
1	7	7	3.2%	13.2%
1	8	8	5.0%	18.2%
1	9	9	6.4%	24.6%
1	10	10	7.2%	31.8%
1	11	11	7.2%	39.0%
1	12	12	9.0%	48.0%
2	1	13	8.4%	56.4%
2	2	14	7.8%	64.2%
2	3	15	7.0%	71.2%
2	4	16	6.4%	77.6%
2	5	17	6.4%	84.0%
2	6	18	7.0%	91.0%
2	7	19	2.4%	93.4%
2	8	20	2.4%	95.8%
2	9	21	1.9%	97.7%
2	10	22	1.2%	98.9%
2	11	23	0.6%	99.5%
2	12	24	0.5%	100.0%



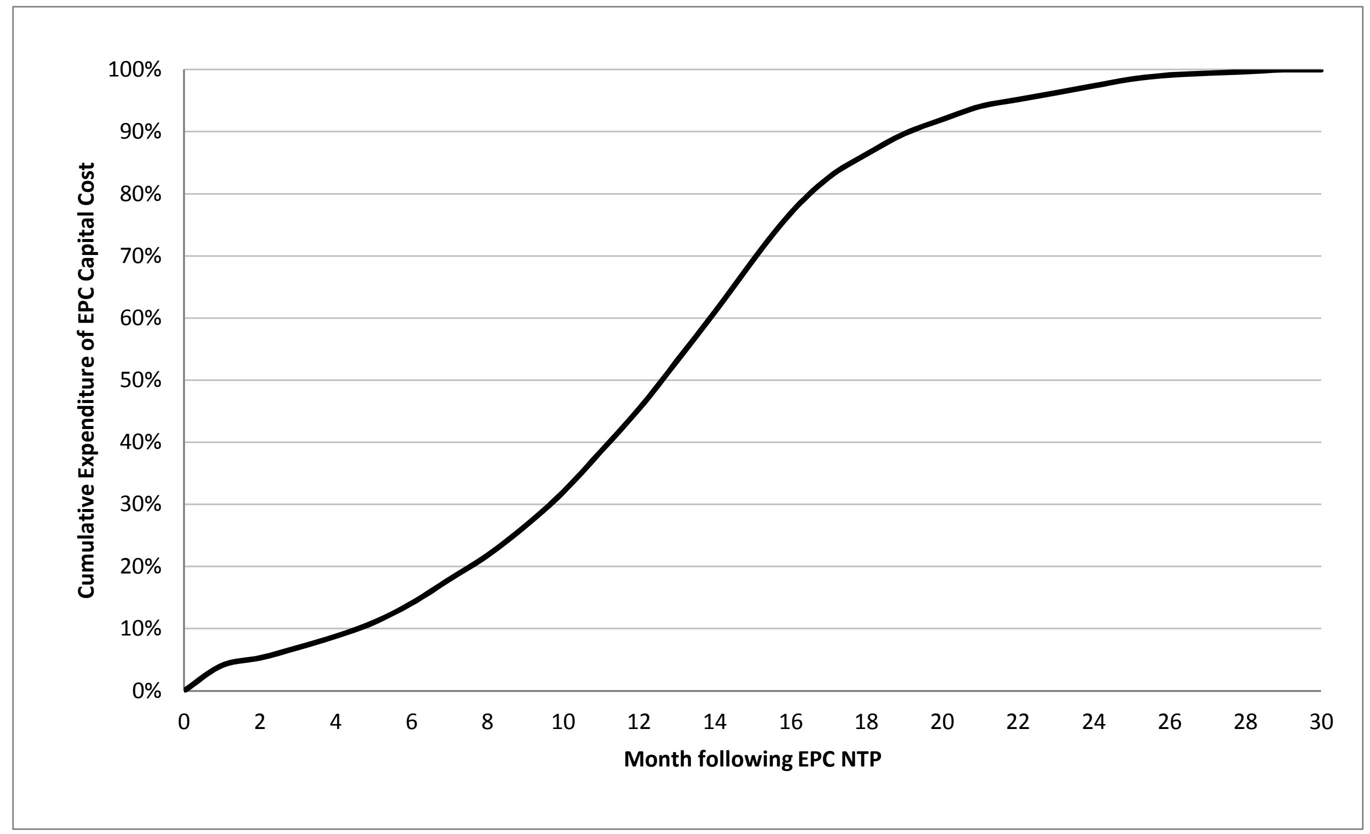
Expenditure Pattern for EPC Capital Cost
Supply Side Option: 6x0 Wartsila 18V50SG

Year	Month	Cumulative Month	Monthly Expenditure (%)	Cumulative Expenditure (%)
		0	0.0%	0.0%
1	1	1	1.6%	1.6%
1	2	2	0.4%	2.0%
1	3	3	0.8%	2.8%
1	4	4	1.6%	4.4%
1	5	5	1.6%	6.0%
1	6	6	4.0%	10.0%
1	7	7	3.2%	13.2%
1	8	8	5.0%	18.2%
1	9	9	6.4%	24.6%
1	10	10	7.2%	31.8%
1	11	11	7.2%	39.0%
1	12	12	9.0%	48.0%
2	1	13	8.4%	56.4%
2	2	14	7.8%	64.2%
2	3	15	7.0%	71.2%
2	4	16	6.4%	77.6%
2	5	17	6.4%	84.0%
2	6	18	7.0%	91.0%
2	7	19	2.4%	93.4%
2	8	20	2.4%	95.8%
2	9	21	1.9%	97.7%
2	10	22	1.2%	98.9%
2	11	23	0.6%	99.5%
2	12	24	0.5%	100.0%



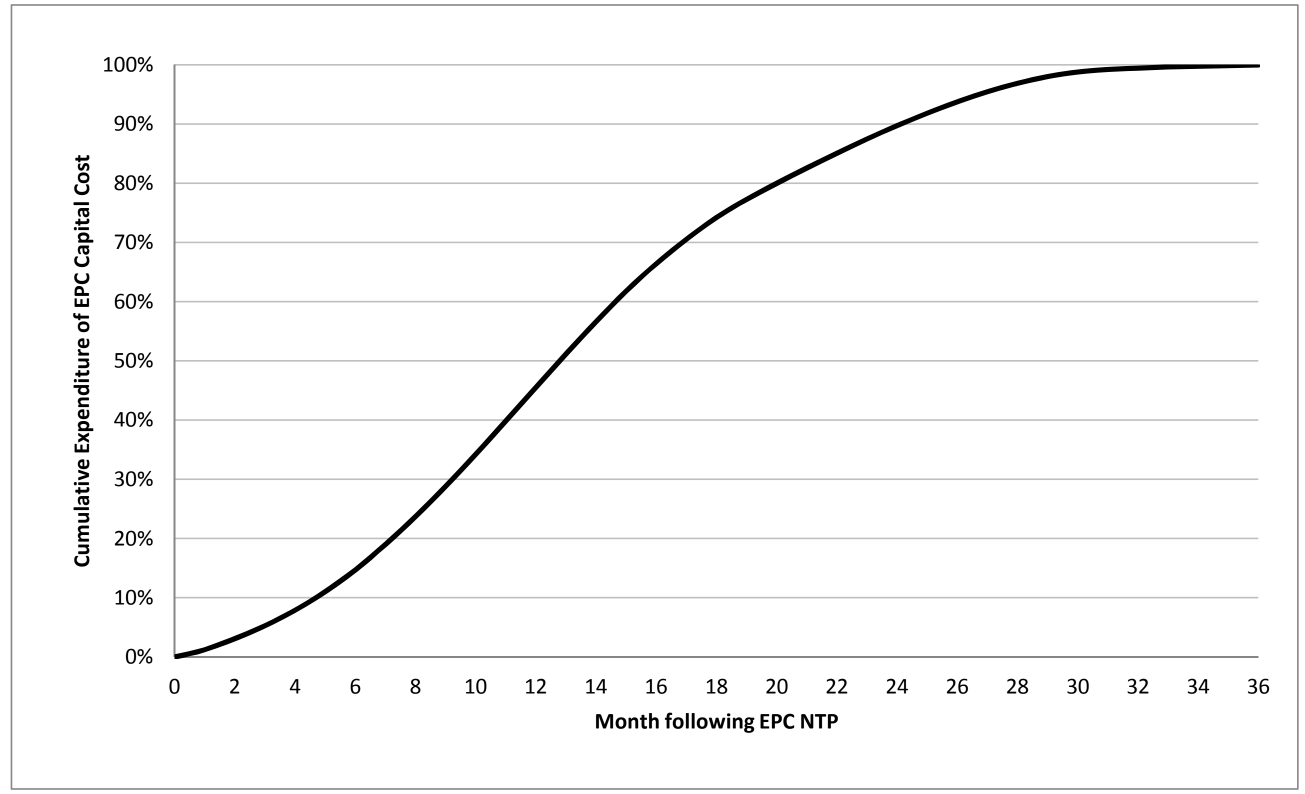
Expenditure Pattern for EPC Capital Cost
Supply Side Option: 1x1 GE 7HA.01

Year	Month	Cumulative Month	Monthly Expenditure (%)	Cumulative Expenditure (%)
		0	0.0%	0.0%
1	1	1	4.1%	4.1%
1	2	2	1.2%	5.3%
1	3	3	1.7%	7.0%
1	4	4	1.9%	8.8%
1	5	5	2.2%	11.0%
1	6	6	3.1%	14.1%
1	7	7	3.9%	18.0%
1	8	8	3.9%	21.8%
1	9	9	4.8%	26.6%
1	10	10	5.5%	32.0%
1	11	11	6.6%	38.6%
1	12	12	6.8%	45.4%
2	1	13	7.7%	53.1%
2	2	14	7.9%	61.0%
2	3	15	8.3%	69.3%
2	4	16	7.7%	76.9%
2	5	17	5.8%	82.7%
2	6	18	3.8%	86.4%
2	7	19	3.3%	89.7%
2	8	20	2.3%	92.0%
2	9	21	2.1%	94.1%
2	10	22	1.1%	95.2%
2	11	23	1.1%	96.3%
2	12	24	1.1%	97.4%
3	1	25	1.1%	98.5%
3	2	26	0.7%	99.2%
3	3	27	0.3%	99.4%
3	4	28	0.3%	99.7%
3	5	29	0.3%	100.0%
3	6	30	0.0%	100.0%



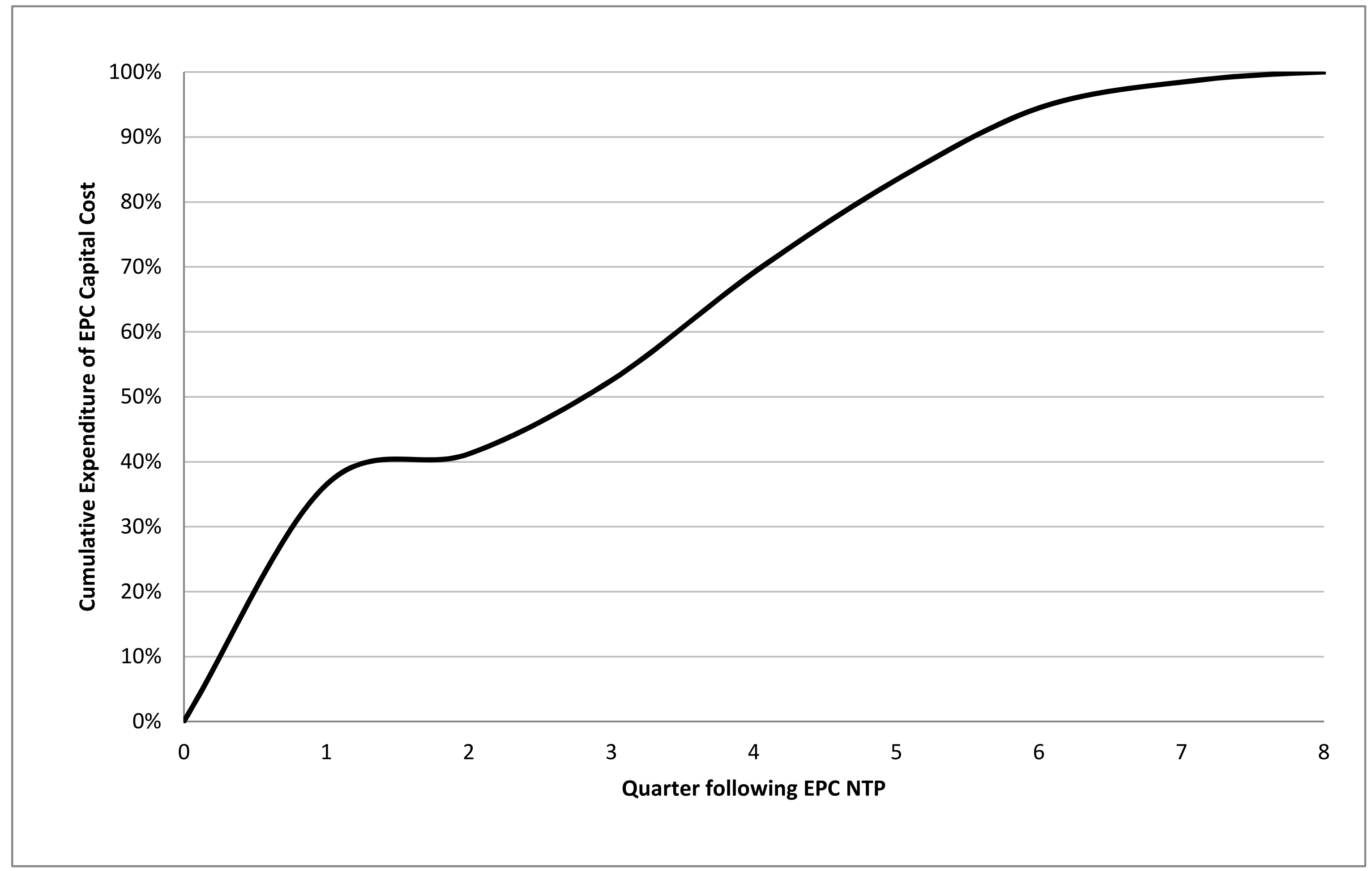
Expenditure Pattern for EPC Capital Cost
Supply Side Option: 35 MW Biomass Combustion (BFB)

Year	Quarter	Cumulative Month	Monthly Expenditure (%)	Cumulative Expenditure (%)
		0	0.0%	0.0%
1	1	1	1.2%	1.2%
1	2	2	1.9%	3.1%
1	3	3	2.2%	5.3%
1	4	4	2.6%	7.9%
1	5	5	3.2%	11.0%
1	6	6	3.7%	14.7%
1	7	7	4.3%	19.0%
1	8	8	4.7%	23.7%
1	9	9	5.1%	28.8%
1	10	10	5.4%	34.2%
1	11	11	5.6%	39.8%
1	12	12	5.7%	45.5%
2	1	13	5.6%	51.2%
2	2	14	5.5%	56.6%
2	3	15	5.2%	61.8%
2	4	16	4.6%	66.4%
2	5	17	4.1%	70.5%
2	6	18	3.7%	74.2%
2	7	19	3.0%	77.3%
2	8	20	2.7%	80.0%
2	9	21	2.6%	82.6%
2	10	22	2.5%	85.1%
2	11	23	2.4%	87.5%
2	12	24	2.2%	89.7%
3	1	25	2.1%	91.8%
3	2	26	1.9%	93.8%
3	3	27	1.7%	95.5%
3	4	28	1.4%	96.9%
3	5	29	1.1%	98.0%
3	6	30	0.8%	98.8%
3	7	31	0.4%	99.2%
3	8	32	0.2%	99.5%
3	9	33	0.2%	99.6%
3	10	34	0.1%	99.8%
3	11	35	0.1%	99.9%
3	12	36	0.1%	100.0%



Expenditure Pattern for EPC Capital Cost
Supply Side Option: 35 MW Geothermal

Year	Quarter	Cumulative Quarter	Quarterly Expenditure (%)	Cumulative Expenditure (%)
		0	0.0%	0.0%
1	1	1	36.5%	36.5%
1	2	2	4.7%	41.2%
1	3	3	11.3%	52.5%
1	4	4	16.6%	69.1%
2	1	5	14.3%	83.4%
2	2	6	11.1%	94.5%
2	3	7	4.0%	98.5%
2	4	8	1.5%	100.0%
3	1	9	0.0%	100.0%
3	2	10	0.0%	100.0%
3	3	11	0.0%	100.0%
3	4	12	0.0%	100.0%
4	1	13	0.0%	100.0%
4	2	14	0.0%	100.0%
4	3	15	0.0%	100.0%
4	4	16	0.0%	100.0%
5	1	17	0.0%	100.0%
5	2	18	0.0%	100.0%
5	3	19	0.0%	100.0%
5	4	20	0.0%	0.0%



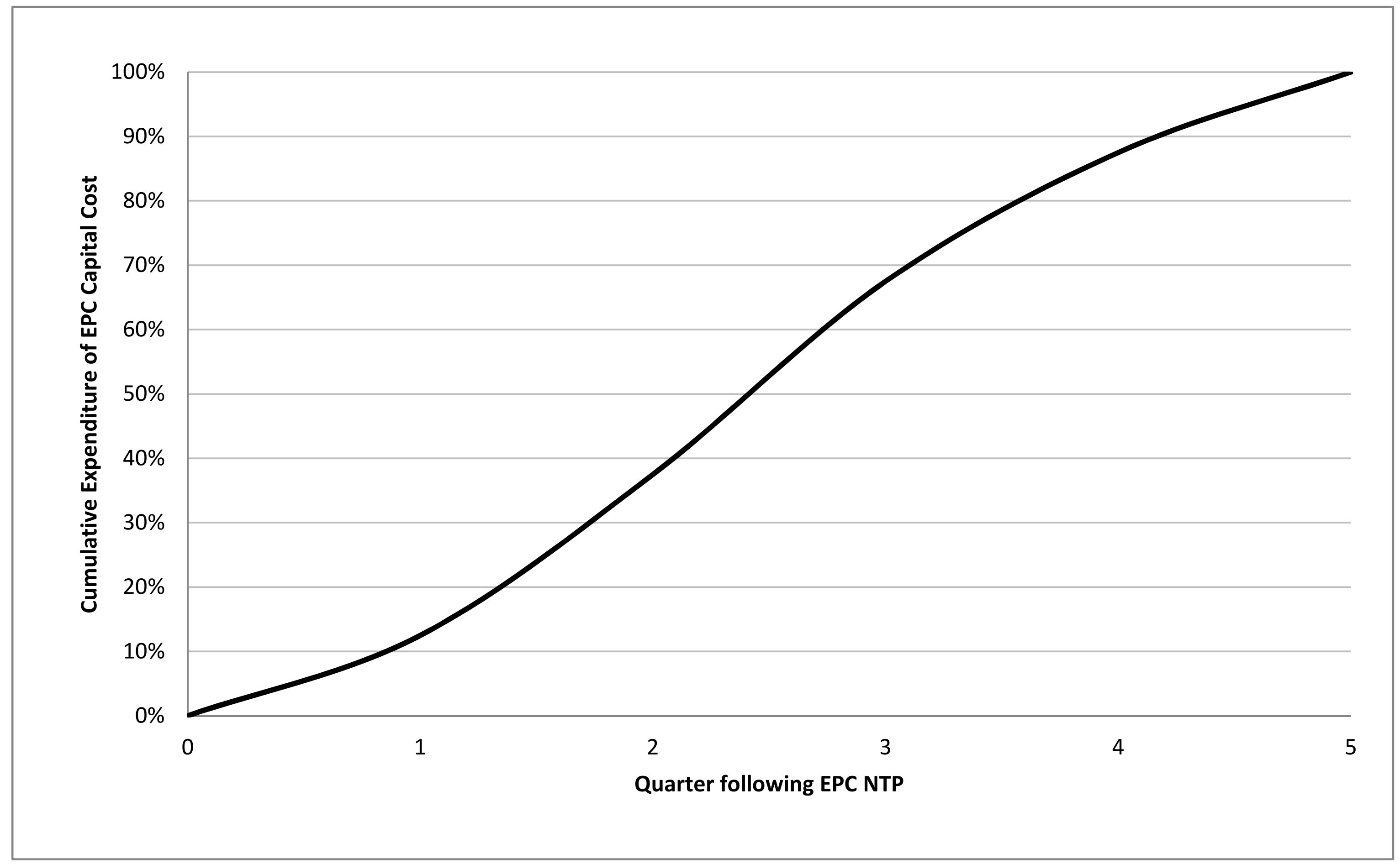
Note:

(1) Geothermal expenditure pattern assumes project development (including well field development) represents roughly one-third of project cost. It is assumed that PGE would buy the project at the beginning of the EPC contract, and all development costs would be re-imbursed to the project developer during Month 1 of the EPC period.

Expenditure Pattern for EPC Capital Cost

Supply Side Option: 50 MW Li-Ion Battery Energy Storage

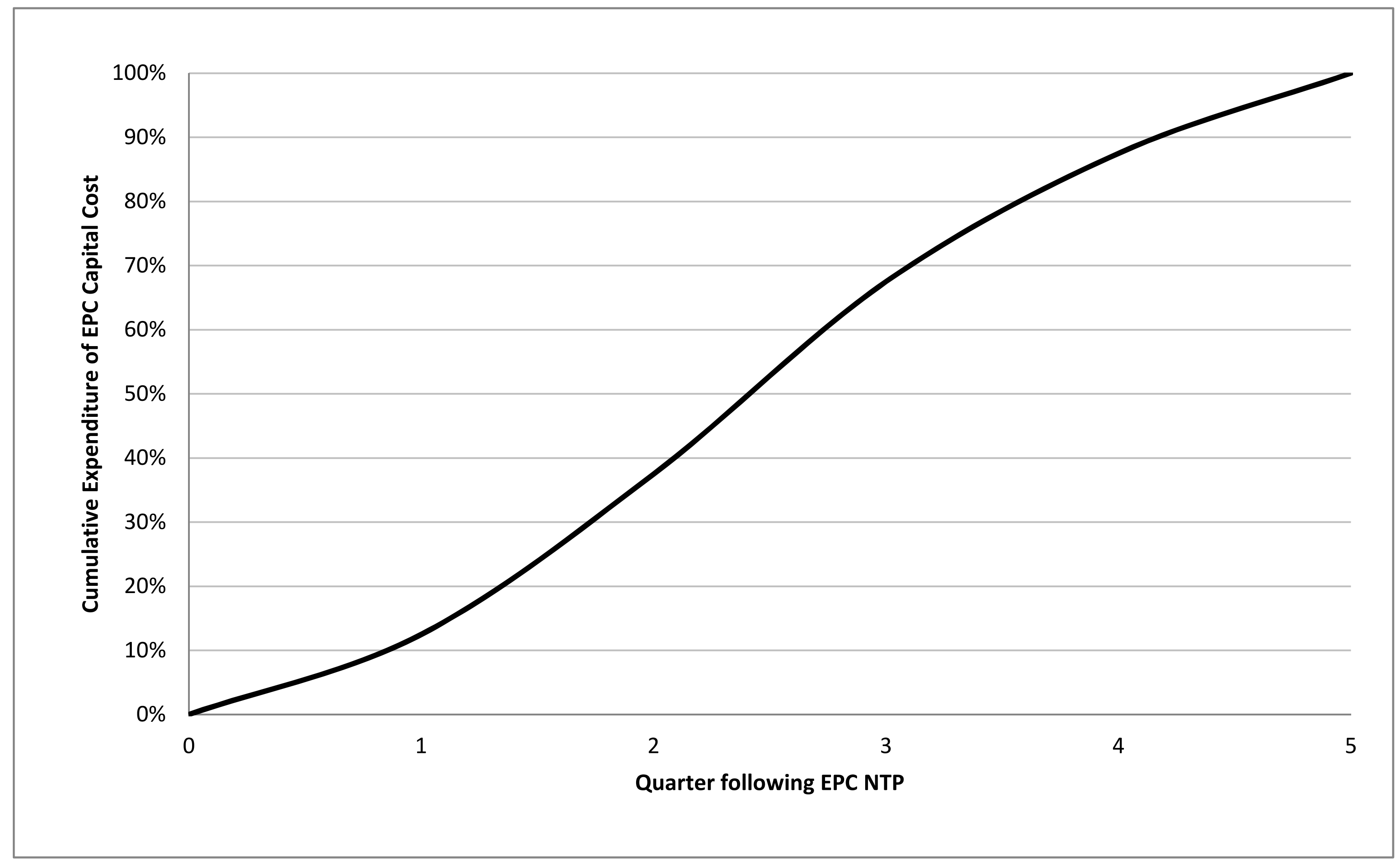
Year	Quarter	Cumulative Quarter	Quarterly Expenditure (%)	Cumulative Expenditure (%)
		0	0.0%	0.0%
1	1	1	12.5%	12.5%
1	2	2	25.0%	37.5%
1	3	3	30.0%	67.5%
1	4	4	20.0%	87.5%
2	1	5	12.5%	100.0%
2	2	6	0.0%	100.0%
2	3	7	0.0%	100.0%
2	4	8	0.0%	100.0%
3	1	9	0.0%	100.0%
3	2	10	0.0%	100.0%
3	3	11	0.0%	100.0%
3	4	12	0.0%	100.0%
4	1	13	0.0%	100.0%
4	2	14	0.0%	100.0%
4	3	15	0.0%	100.0%
4	4	16	0.0%	100.0%
5	1	17	0.0%	100.0%
5	2	18	0.0%	100.0%
5	3	19	0.0%	100.0%
5	4	20	0.0%	100.0%



Expenditure Pattern for EPC Capital Cost

Supply Side Option: 10 MW Redox Flow Battery Energy Storage

Year	Quarter	Cumulative Quarter	Quarterly Expenditure (%)	Cumulative Expenditure (%)
		0	0.0%	0.0%
1	1	1	12.5%	12.5%
1	2	2	25.0%	37.5%
1	3	3	30.0%	67.5%
1	4	4	20.0%	87.5%
2	1	5	12.5%	100.0%
2	2	6	0.0%	100.0%
2	3	7	0.0%	100.0%
2	4	8	0.0%	100.0%
3	1	9	0.0%	100.0%
3	2	10	0.0%	100.0%
3	3	11	0.0%	100.0%
3	4	12	0.0%	100.0%
4	1	13	0.0%	100.0%
4	2	14	0.0%	100.0%
4	3	15	0.0%	100.0%
4	4	16	0.0%	100.0%
5	1	17	0.0%	100.0%
5	2	18	0.0%	100.0%
5	3	19	0.0%	100.0%
5	4	20	0.0%	100.0%



Appendix C. Technology Maturity Outlook

Table C-1 Total Capital Cost Forecast Factors by Technology (Constant Dollar Basis)

TECHNOLOGY	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037
Coal with 30% CCS	1.000	1.002	0.996	0.991	0.985	0.977	0.967	0.956	0.944	0.928	0.915	0.903	0.892	0.882	0.871	0.861	0.852	0.844	0.835	0.826	0.817
Coal with 90% CCS	1.000	1.002	0.996	0.991	0.985	0.977	0.967	0.956	0.944	0.928	0.915	0.903	0.892	0.882	0.871	0.861	0.852	0.844	0.835	0.826	0.817
Combustion Turbine	1.000	1.004	1.000	0.997	0.992	0.987	0.978	0.969	0.958	0.945	0.933	0.923	0.914	0.905	0.896	0.887	0.880	0.873	0.865	0.858	0.851
Advanced Comb. Turbine	1.000	1.002	0.997	0.993	0.986	0.979	0.969	0.959	0.947	0.931	0.913	0.893	0.880	0.864	0.847	0.831	0.819	0.808	0.798	0.787	0.778
Combined Cycle	1.000	1.004	1.000	0.997	0.992	0.987	0.978	0.969	0.958	0.945	0.933	0.923	0.914	0.905	0.896	0.887	0.880	0.873	0.865	0.858	0.851
Advanced Combined Cycle	1.000	1.003	0.998	0.994	0.988	0.982	0.973	0.963	0.952	0.937	0.921	0.905	0.893	0.880	0.866	0.853	0.843	0.834	0.825	0.815	0.807
Adv. CC w/ Sequestration	1.000	1.000	0.993	0.986	0.978	0.968	0.957	0.944	0.930	0.913	0.896	0.879	0.866	0.851	0.837	0.823	0.811	0.800	0.789	0.778	0.768
Fuel Cell	1.000	0.988	0.977	0.966	0.954	0.941	0.925	0.909	0.891	0.871	0.852	0.836	0.820	0.804	0.789	0.774	0.761	0.748	0.734	0.721	0.708
Nuclear	1.000	1.001	0.995	0.989	0.960	0.912	0.901	0.891	0.878	0.863	0.850	0.838	0.828	0.817	0.807	0.796	0.787	0.779	0.770	0.761	0.753
Biomass	1.000	1.002	0.997	0.992	0.985	0.978	0.969	0.958	0.947	0.932	0.919	0.908	0.898	0.887	0.877	0.868	0.859	0.851	0.843	0.835	0.827
Landfill Gas	1.000	1.004	1.000	0.997	0.992	0.987	0.978	0.969	0.958	0.945	0.933	0.923	0.914	0.905	0.896	0.887	0.880	0.873	0.865	0.858	0.851
Wind (Onshore)	1.000	1.004	1.000	0.997	0.992	0.987	0.978	0.969	0.958	0.945	0.933	0.923	0.914	0.905	0.896	0.887	0.880	0.873	0.865	0.858	0.851
Offshore Wind	1.000	1.000	0.992	0.985	0.977	0.968	0.956	0.943	0.929	0.912	0.897	0.883	0.871	0.859	0.846	0.835	0.824	0.814	0.804	0.793	0.783
Solar Thermal	1.000	1.001	0.970	0.965	0.958	0.950	0.939	0.928	0.915	0.899	0.885	0.873	0.862	0.851	0.840	0.830	0.820	0.811	0.802	0.793	0.784
Solar PV	1.000	0.905	0.875	0.864	0.855	0.845	0.835	0.823	0.811	0.796	0.782	0.770	0.759	0.747	0.736	0.725	0.712	0.698	0.684	0.677	0.671
Distributed Gen Base	1.000	1.001	0.995	0.989	0.982	0.974	0.963	0.952	0.939	0.923	0.909	0.896	0.885	0.874	0.863	0.852	0.843	0.834	0.824	0.815	0.806
Distributed Gen Peak	1.000	1.001	0.995	0.959	0.909	0.898	0.883	0.863	0.840	0.816	0.798	0.780	0.764	0.750	0.736	0.725	0.712	0.704	0.695	0.687	0.679

Source: U.S. Department of Energy, Energy Information Administration, National Energy Modeling System (NEMS). Data developed as part of Annual Energy Outlook 2017 (AEO2017).

Appendix B. DNV GL Evaluation of Three Renewable Supply Options

INTEGRATED RESOURCE PLANNING

Evaluation of Three Renewable Supply Options

Portland General Electric Company

Document No.: 10054020-HOU-T-01-C
Date: 7 December 2017

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D. Pardo Project Manager, Project Engineering	C. Gessert Project Manager, Project Engineering	D. Schoborg Senior Engineer, Project Engineering

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C	7 December 2017	Updated confidentiality	D. Pardo	C. Gessert	D. Schoborg

1 INTRODUCTION

Portland General Electric Company ("PGE" or the "Customer") has requested Garrad Hassan America, Inc., (hereinafter DNV GL), to provide updates to technical and financial information provided in the previous report "Integrated Resource Planning: Evaluation of Five Renewable Energy Supply Options," dated 25 November 2015 ("the 2015 analysis") [1]. PGE has requested that DNV GL provide updates related to three potential renewable electricity generation projects in support of the Customer's Integrated Resource Planning ("IRP" or "Project"). The updated projects are as follows:

- Onshore wind project in Ione, Oregon
- Onshore wind project in Central Montana
- Solar photovoltaic (PV) single-axis tracker project in Christmas Valley, Oregon

Additionally, PGE requested that only specific technical and financial parameters be updated from the 2015 analysis, as reflected in the scope of work executed between DNV GL and PGE.

Where possible and appropriate, DNV GL has kept the assumptions and methodologies similar to the 2015 analysis, such that meaningful conclusions can be drawn from a comparison between the results in the 2015 analysis and this updated report. The information provided in this Technical Note summarizes the updated results of DNV GL's analyses of these three projects along with the methodologies employed and assumptions made. Unless otherwise noted, all previous assumptions made during the 2015 analysis remain.

2 ABBREVIATIONS AND TERMINOLOGY

The following abbreviations are used in this document:

Abbreviation	Meaning
AC	Alternating Current
aMW	Average Megawatts – the total annual production divided by the number of hours per year
BoP	Balance of Plant
DC	Direct Current
EPC	Engineering, Procurement, Construction
GTM	Greentech Media
IEA	International Energy Agency
IRP	Integrated Resource Planning
O&M	Operations and Maintenance
OSEIA	Oregon Solar Energy Industries Association
PGE	Portland General Electric
PTC	Production Tax Credit
PV	Photovoltaic
Wp	Watts Peak – the measure of DC output under full solar radiation

The average capacity of the energy projects discussed herein is given in average megawatts (aMW). This is different than the project's nameplate capacity, which is discussed below in units of megawatts (MW).

The solar industry tends to base its calculations on DC electricity, whereas utilities tend to prefer to work in AC electricity. In order to convert the requested solar parameters into AC units, a DC-to-AC conversion factor of 1.2 was used. This value is commonly seen in the industry; however, for a more accurate value for a given project, a site-specific and technology-specific evaluation is required.

Within this report, solar cost results referenced to watts peak (e.g., $/Wp) are based on DC power, whereas cost results referenced to watts (e.g., $/MW) have been converted to AC power.

3 SUMMARY OF THE WORK

PGE requested that DNV GL update numerical values for the specific technical and financial parameters described in Sections 3.1 and 3.2 below, for three of the renewable energy projects under consideration in its IRP. This section describes the methodology and assumptions DNV GL used to determine these numerical values.

The three renewable energy projects under consideration are as follows:

Project name	Location	Average capacity	Generation technology
Ione Wind	Ione, Oregon	116 aMW	Wind
Central MT Wind	Montana East of Rockies Along Colstrip Line	100 aMW	Wind
Christmas Valley Solar 2	Christmas Valley, Oregon	25 aMW	Solar (single axis tracking)

As noted by PGE, these three projects are not currently under development.

3.1 Technical parameters

3.1.1 Nameplate capacity

3.1.1.1 Results

- Ione Wind: 332 MW
- Central MT Wind: 240 MW
- Christmas Valley Solar 2: 103 MWac

3.1.1.2 Methodology

For all projects, the Nameplate Capacity is calculated by dividing the Average Capacity by the Capacity Factor.

3.1.1.3 Assumptions

Assumes Average Capacities provided by the Customer (see table above).

3.1.2 Capacity factor

3.1.2.1 Results

- Ione Wind: 35%
- Central MT Wind: 42%
- Christmas Valley Solar 2: 23.3%

3.1.2.2 Methodology

- Wind projects: Gross energy is based on the power curve noted below and assumed mean wind speed (see assumptions below). Net energy includes typical energy loss factors and model-specific availability assumptions.
- Solar projects: DNV GL notes that there is a slight decrease in capacity factor from the 2015 analysis. This was due to using a different source of meteorological data from the 2015 analysis. DNV GL analyzed 5-8 publicly available and SolarAnywhere Clean Power Research sources of meteorological data, with a special focus on global horizontal irradiance (GHI). Using our latest approach, we eliminate any sources that show anomalous trends in GHI, diffuse horizontal irradiance (DHI), temperature, or wind speed and selected the source closest to median. This is the approach that DNV GL believes results in the lowest uncertainty data being used in the energy assessment. The PVsyst software was used to calculate net energy, assuming spacing and loss factors considered reasonable for the region and type of technology. The DC net capacity factor was calculated as the ratio of the net energy to the product of the Average Capacity and 8760 hour per year. The reported AC net Capacity Factor was calculated by applying a DC/AC ratio of 1.2, which is considered reasonable for this region.

3.1.2.3 Other assumptions

- Ione Wind: Mean wind speed of approximately 6.6 m/s, which is based on extensive wind resource analysis and experience in the region
- Central MT Wind: Mean wind speed of approximately 8.2 m/s, which is based on extensive wind resource analysis and experience in the region
- Christmas Valley Solar 2: Result given in AC based on DC capacity factor of 19.4% with DC/AC ratio of 1.2. Assumed horizontal single axis tracking oriented due south, normalized by DC capacity, assumed Performance Ratio of 80.0%, solar resource based on regional irradiation data, includes loss factor for inverter clipping.

3.1.3 Power curve

3.1.3.1 Results

The Vestas V110 – 2.0 MW turbine was identified as representative of the type of technology utilized in projects with this wind regime.

3.1.3.2 Methodology

Identified example of turbine currently available in the market and representative of a potentially appropriate turbine to be utilized in these regions and wind conditions.

3.1.4 8760s

3.1.4.1 Wind

The predicted 8760 of energy production at both the Ione Wind and Central MT Wind sites has been derived from hourly wind speeds from DNV GL Virtual Met Data (VMD) and hourly temperature and pressure data from MERRA-2. The long-term average seasonal and diurnal variation in air density was developed from temperature and pressure records from the MERRA-2 data and scaled to the site-predicted long-term annual site air density. The VMD simulated wind speeds at a hub height of 80 m were adjusted to reflect the predicted long-term mean wind speed and monthly profile at each site, as described in Section 3.1.2.

A simulated time series of production data was calculated using the time series of air density, wind direction, and VMD wind speeds. Energy loss factors were applied appropriately to the resulting production time series.

The resulting expected energy production at 80 m at the Ione Wind and Central MT Wind sites are presented in the accompanying Excel numerical results in the form of an 8760 time series. It is noted that the uncertainty associated with the prediction of any given month or hour of day is significantly greater than that associated with the prediction of the annual energy production. It is also noted that the results presented are inclusive of all losses.

3.1.4.2 Solar PV

DNV GL simulated the solar PV project using internal tools and the PVsyst simulation software, the most commonly used simulation tool in the industry. DNV GL currently uses version 6.52 and independently quality-checks new releases prior to adopting them. DNV GL included assumed losses for the energy simulation and assumed two annual module washes. Losses occurring after the inverter (i.e., AC ohmic, transformer, station loads, and unavailability) are calculated in a post-processing tool. DNV GL presents the expected energy production in the accompanying excel numerical results in the form of an 8760 time series.

3.2 Financial parameters

The financial parameters below were requested by the Customer. All cost figures presented herein are in 2016 dollars.

3.2.1 Total overnight capital cost, including EPC and owner's costs

3.2.1.1 Results

- Ione Wind: $M ($1,491/kW)
- Central MT Wind: $M ($1,508/kW)
- Christmas Valley Solar 2: $176M ($1,710/kWac)

3.2.1.2 Methodology

The total overnight capital cost is the cost to instantaneously develop and construct a project. Financing costs are excluded.

For the wind projects, DNV GL reviewed capital cost information for over 50 U.S. wind power projects constructed in 2015, 2016, and 2017. These projects were constructed with a variety of wind turbine technology (that is, the capital cost estimates are original equipment manufacturer (OEM)-agnostic). DNV GL has observed that BoP EPC costs vary from region to region; however, the number of Northwest U.S. wind projects constructed from 2013 to the present is limited. To better understand how Northwest U.S.

wind project BoP EPC costs compare to nation-wide costs, DNV GL analyzed BoP EPC costs in the Northwest from 2008 through 2012 (when significant wind construction was undertaken in the Northwest) and scaled those findings against nation-wide costs to develop a Northwest-specific projection. The values presented are median values.

Additional background on capital costs can be found in the U.S. Department of Energy's 2016 Capital Cost Estimates for Utility Scale Electricity Generating Plants Report [1] and for solar projects, in GTM Research's Executive Briefing Solar Data – Q3 2016 [4].

3.2.1.3 Other assumptions

- Ione Wind: Based on the following breakdown:
    - $897/kW turbine
    - $367/kW EPC
    - $227/kW development/contingency/etc.
- Central MT Wind: Based on the following breakdown:
    - $897/kW turbine
    - $384/kW EPC
    - $227/kW development/contingency/etc.
- Christmas Valley Solar 2: Cost includes turnkey construction costs and reflects single-axis tracking technologies and regional larger utility-scale PV projects that often require financing.
- These estimates do not include the cost of capital, taxes, or other financing costs.
- These estimates do not include financial impacts associated with any tax credits (e.g., the Production Tax Credit, Investment Tax Credit, etc.), or potential impacts from other revenue sources.
- The "development/contingency/etc." cost estimates provided above cover a nominal level of development spending and typical contingency above the price of the construction contract and are included here to reflect more complete project costs. These values are inherently project specific.

3.2.2 Range of costs from average total overnight capital cost

3.2.2.1 Results

- Wind projects: expected range $+2.6 to $-1.3M/MW
- Christmas Valley Solar 2: Expected range: $+1.5M to $-2.0M/MWac

3.2.2.2 Methodology

- Onshore wind project: These expected values and a range of costs were determined based on a review of over 50 U.S. wind power projects constructed in 2015, 2016, and 2017.

- Solar projects: range of ±15% based on recent project costs using similar technologies in Idaho and Colorado [6].

3.2.3 Escalation rate for capital costs over next 20 years, if different from inflation

3.2.3.1 Results

The following table and plot show DNV GL's projection for the percentage decrease in overnight capital cost for onshore wind and solar PV tracker projects. These results were informed from the 2015 analysis [1] and updated by using GTM Research's Executive Briefing Solar Data – Q3 2016 [4], and DNV GL's Wind and Solar Due Diligence Project Databases [6]. DNV GL compiled historical overnight values and correlated these to key historical market indicators, commodity prices, demographic information, and other metrics. Statistical multivariable regressions were performed until significant outcomes were obtained and a model was developed and applied to generate the projected values.

No ongoing capital costs are assumed for a given project after it achieves commercial operation.

Table 3-1 Percentage of 2017 Overnight Cost (based on $2017)

Year	Onshore Wind	PV
2017	100%	100%
2018	99%	93%
2019	97%	89%
2020	96%	84%
2021	95%	81%
2022	93%	80%
2023	92%	78%
2024	91%	77%
2025	91%	76%
2026	89%	74%
2027	89%	73%
2028	88%	72%
2029	87%	70%
2030	87%	69%
2031	86%	68%
2032	85%	66%
2033	85%	65%
2034	84%	64%
2035	84%	62%
2036	83%	61%
2037	82%	60%

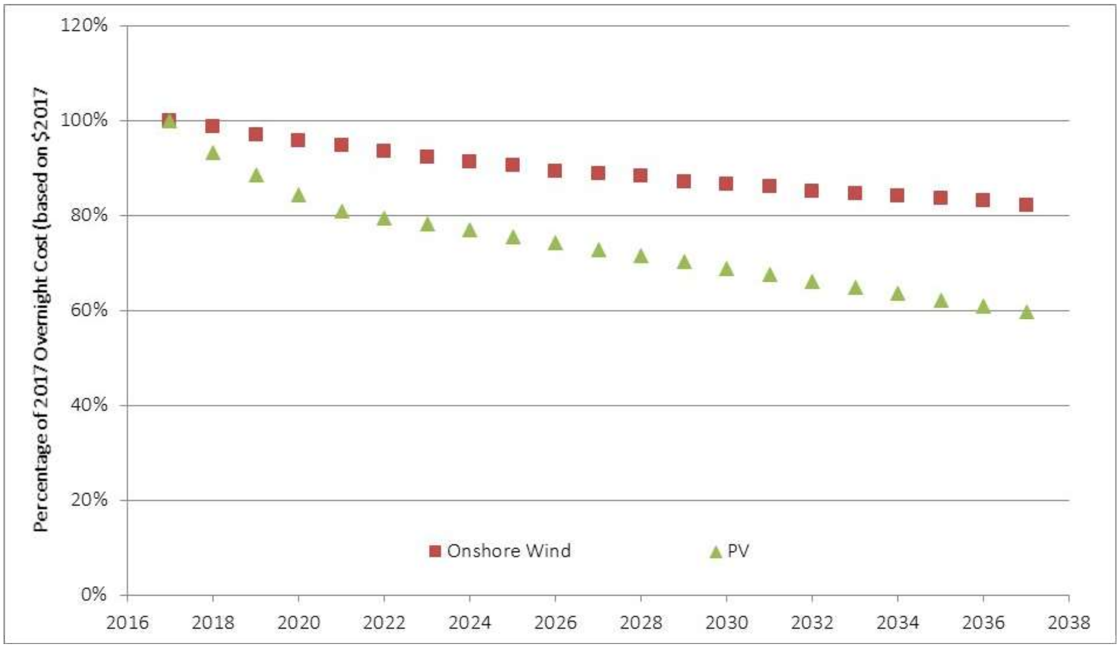


Figure 3-1 Percentage of 2017 Overnight Cost (based on $2017)

has presented values for year one; a 1% to 3% yearly escalator is common and typically negotiated as part of the O&M agreement for years thereafter.

Nominal environmental costs (such as bat and bird monitoring) have been included. Note that these costs may be present only in the first few years of a project's operation, and are inherently project specific. DNV GL has assumed no significant environmental monitoring requirements.

3.2.4 Breakdown of fixed O&M costs including, but not limited to, service contracts and warranty costs, royalty payments, and labor

3.2.4.1 Results

- Ione Wind:
    - Scheduled Turbine O&M: $17,000/MW
    - BoP O&M: $2,000-4,000/MW
    - Utilities/Consumption: $1,500/MW
    - Project Management Administration: $3,000/MW
    - Generation Charges: $1,000/MW
    - Land Lease: $5,500/MW
    - Insurance: $3,000/MW

- Property Taxes: $5,500/MW
  - Professional Advisory: $3,000/MW
  - Other G&A: $1,500/MW
- Central MT Wind:
  - Scheduled Turbine O&M: $17,000/MW
  - BoP O&M: $2,000-4,000/MW
  - Utilities: $1,500/MW
  - Project Management Administration: $3,000/MW
  - Generation Charges: $1,000/MW
  - Land Lease: $5,500/MW
  - Insurance: $3,000/MW
  - Property Taxes: $5,500/MW
  - Professional Advisory: $3,000/MW
  - Other G&A: $1,500/MW
- Christmas Valley Solar 2:
  - Module Cleaning: $2,400/MWac
  - Other: $6,000/MWac

3.2.4.2 Methodology

- Wind Projects: The above wind estimates are based on typical costs from projects using similar technologies at similar locations in the U.S. [6] and industry publications [7].

  Additional information on some of these charges is provided below:
  - Scheduled Turbine O&M: annual or semi-annual service
  - BoP O&M: maintenance of the physical plant
  - Utilities: electricity, water, sewer, etc. needed to operate the project facilities
  - Project Management Administration: on-site and off-site project and asset management
  - Generation Charges: interconnection charges
  - Professional Advisory: outside services such as engineering, tax, and legal services
  - Other G&A: general and administrative costs not captured above, including nominal environmental costs
- Solar Projects:
  - DNV GL's estimate is based on two module washings per year.

- The above solar estimate is based on a scope that commonly includes periodic inspection of major equipment, 24/7 monitoring, inventory management, occasional medium voltage and inverter work, preventive maintenance and monthly reporting. For sites in Oregon periodic vegetation control is common. DNV GL would expect a +25 MWac installation to have either on-site staff, or guaranteed response times. [6]

3.2.4.3 Other assumptions

- Wind projects: Based on DNV GL database and publicized industry data [7].
- Solar projects: Based on DNV GL database. Cost does not include insurance, taxes, utility fees, land lease, and other similar costs. These values are typically excluded from the technical documents reviewed by DNV GL. As such, DNV GL has too few data points to provide a meaningful estimate of non-technical costs.

3.2.5 Non-fuel variable O&M

3.2.5.1 Results

- Ione Wind: Not applicable
- Central MT Wind: Not applicable
- Christmas Valley Solar 2: Not applicable

3.2.5.2 Methodology

Consistent with the 2015 analysis and based on discussion with PGE, project O&M costs are considered to be covered under either "Fixed O&M" or "Ongoing expected Capital Additions or maintenance accrual". As such, no costs are expected in this category.

3.2.5.3 Other assumptions

None.

3.2.6 Ongoing expected Capital Additions or maintenance accrual

DNV GL notes that in this Report and at the request of the Customer, the term "ongoing capital additions" is synonymous with the term "unscheduled maintenance," which is more commonly used in the solar and wind industries.

3.2.6.1 Results

- Ione Wind: $12,500/MW/year
- Central MT Wind: $13,500/MW/year
- Christmas Valley Solar 2: $4,800/MWac/year

3.2.6.2 Methodology

Costs in this section are associated with the replacement or repair of major components. These are typically considered to be unscheduled costs [3].

3.2.6.3 Other assumptions

The values in this section are based on typical values seen within the wind and solar industries. The values presented here are averages over the economic life of the project.

- Ione Wind: Based on DNV GL database, 20-year average value, does not include unscheduled BOP maintenance.
- Central MT Wind: Based on DNV GL database, 20-year average value, does not include unscheduled BoP maintenance.
- Christmas Valley Solar 2:
    - 20-year average value
    - Depending on how the fixed-cost O&M contract is structured and whom it's with, a typical range is $3,600 – 6,000/MWac/year; and includes an inverter reserve and other on-site O&M costs, plus monitoring. On-site costs exclude insurance, taxes, utility fees, and similar, which are typically considered as separate line items in project budgets.
    - DNV GL notes that the cost of non-fixed O&M has increased from the 2015 analysis due to scope shifting from fixed O&M costs to non-fixed O&M costs. This shift has been driven by the competitive solar landscape. As a result of this price pressure, a less rigorous fixed O&M scope has become more common (e.g. less preventative maintenance) – which results in more issues being resolved via the non-fixed O&M budget.

3.2.7 Decommissioning accrual

3.2.7.1 Results

- Ione Wind: $0.00
- Central MT Wind: $0.00
- Christmas Valley Solar 2: $0.00

3.2.7.2 Methodology

For wind projects, decommissioning cost may be fully offset by salvage value or resale of used components in certain conditions. The five items listed below will have the largest impact on the net cost. Projects for which the below items are true are those most likely to have a net decommissioning cost of $0 or a small gain.

- Access roads do not need to be removed
- Transmission lines do not need to be removed

- Collection system does not need to be removed. Note that overhead collection system removal is significantly more expensive than underground collection system removal
- Major components aged 5 years or less can typically be re-sold for a percentage of their purchase price. This typically helps reduce net costs more than simply scrapping the metal found in the components
- Current scrap metal prices (primarily steel, iron and copper) at the time of decommissioning are at current prices or higher

Final cost may vary depending on the specific configuration of the site, as well as local, county, state, or other ordinances. A bond may be required to accumulate funds, although this is uncommon for onshore wind projects.

For the Christmas Valley 2 solar projects, decommissioning cost is assumed to be offset by salvage value of used components. A bond may be required to accumulate funds. DNV GL notes that the future cost to dispose of any waste that may in the future be deemed hazardous was not considered (e.g. lead solder).

3.2.7.3 Other assumptions

None.

4 REFERENCES

[1] DNV GL, 703337-USPO-T-01-C PGE renewables IRP support, dated 25 November 2015.

[2] U.S. Department of Energy, Capital Cost Estimates for Utility Scale Electricity Generating Plants Report, dated November 2016.

[3] DNV GL, Turbine O&M costs, 10054020, *Confidential*, dated 05 July 2017.

[4] GTM Research, Executive Briefing Solar Data – Q3 2016, dated October 2016.

[5] OSEIA & Green Energy Institute, Oregon Solar Business Plan Project Update, Dated 21 December 2016.

[6] DNV GL, Wind and Solar Due Diligence Project Databases, dated 31 May 2017.

[7] MAKE Global Wind Turbine, O&M Costs, dated 22 November 2016.

Appendix C. EFSC CO2 OFFSET PAYMENT CALCULATION

Includes updates from rules amended on October 23, 2017.

Aligns with Fall 2017 Supply Side Study.

Calculated Monetary Payments 7HA.01 CCCT 7F05 SCCT Wärtsilä

Calculated Monetary Payments	7HA.01 CCCT	7F.05 SCCT	Wärtsilä
Monetary Path Requirement ($ million)	$6.75	$3.17	$2.15
Monetary Path Requirement ($ / kW)	$15.93	$13.73	$19.53

Plant Characteristics Source:

Black & Veatch Thermal Supply Side Option Study, Fall 2017

Appendix D. CAPACITY CONTRIBUTION FOR INCREMENTAL WIND AND SOLAR

Table 9 the tabular format of Figure 8, presents capacity contribution for incremental additions of 100 MW of wind and solar resources using the RECAP model.

TABLE 9: CAPACITY CONTRIBUTION FOR INCREMENTAL WIND AND SOLAR

Incremental 100 MW Additions	Marginal ELCC	
	PNW Wind	Solar
100	16.7%	14.4%
200	12.8%	11.2%
300	10.8%	9.4%
400	9.3%	6.3%
500	8.9%	5.1%
600	7.7%	4.5%
700	7.1%	4.0%
800	7.7%	2.8%
900	6.9%	2.9%
1000	6.3%	2.7%

Appendix E. Projected Annual Average Energy Load-Resource Balance, MWa

Table 10, the tabular format of Figure 4 for 2020-2040, describes PGE's energy load-resource balance (LRB) given no incremental resource additions (with the exception of EE actions).

Notes for Table 10:

- Additional discussion is provided in Section 3.5, Energy Load-Resource Balance.
- The energy LRB is based on annual average available energy, not economic dispatch.
- Thermal resources are adjusted for maintenance and forced outage rates. Duct firing and peaking units are excluded.
- EE actions are included as a resource.
- Load is the 1-in-2 annual average load excluding opt-outs and before incremental EE actions.

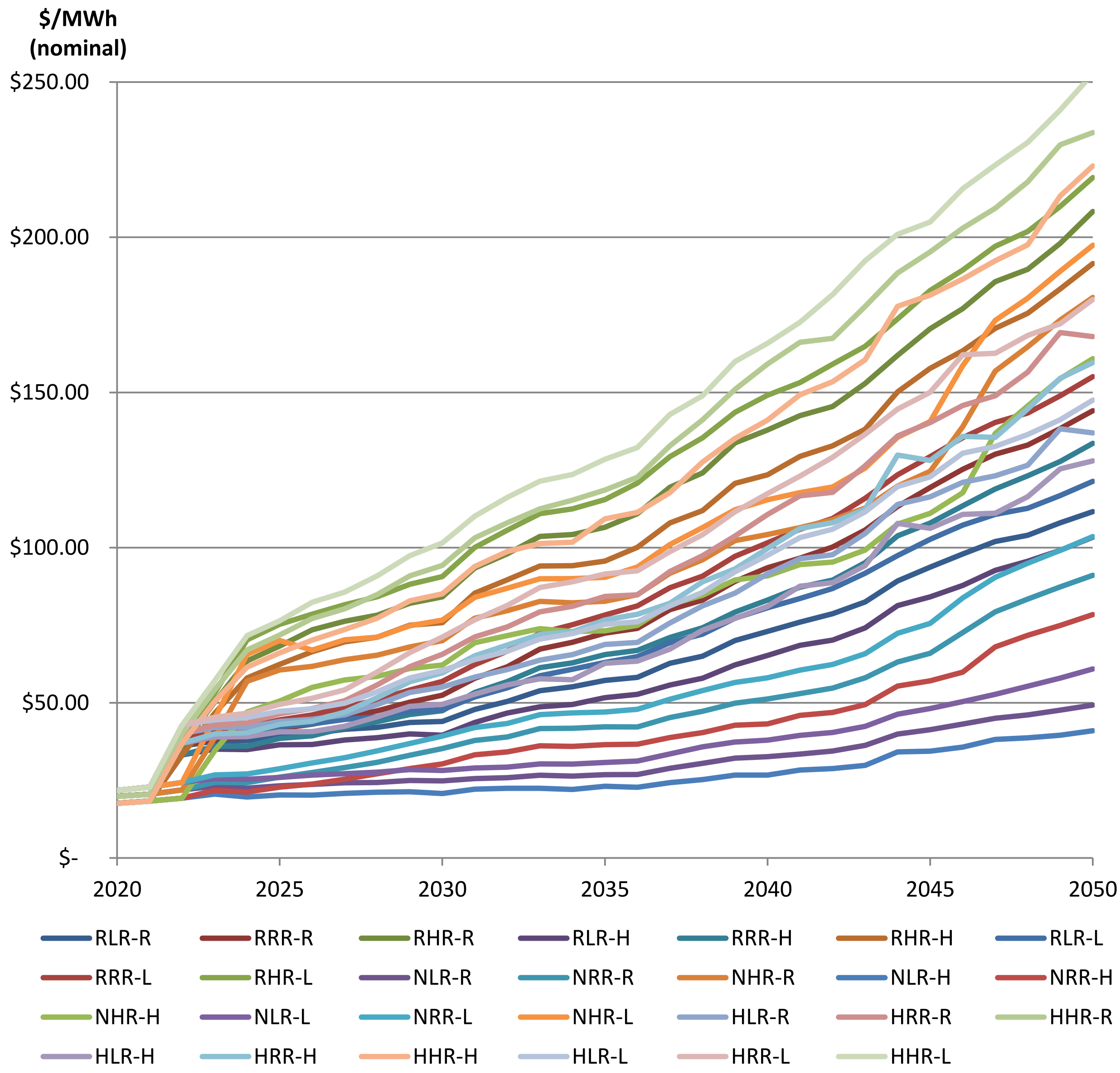
Table 10: PGE's Projected Annual Average Energy Load-Resource Balance, MWa

	2020	2021	2022	2023	2024	2025	2030	2035	2040
Gas	920	920	920	920	920	920	920	920	920
Hydro	450	448	446	444	442	348	267	257	257
Wind+Solar	370	374	374	374	374	374	365	287	237
Coal	705	262	262	262	262	262	262	0	0
Contracts	49	69	69	69	69	69	62	43	1
Energy Efficiency	48	78	107	134	160	187	317	436	552
Total Resources	**2542**	**2150**	**2177**	**2203**	**2227**	**2159**	**2193**	**1943**	**1967**
Load	**2123**	**2154**	**2194**	**2236**	**2284**	**2331**	**2569**	**2805**	**3047**
Energy Deficit	**(419)**	**4**	**17**	**33**	**57**	**172**	**376**	**862**	**1080**

Appendix F. WHOLESALE MARKET CURVES

Figure 14 shows the full spectrum of pricing per variation of carbon, gas, and hydro conditions.

FIGURE 14: 2017.H2 WHOLESALE ELECTRICITY PRICE COMPARISON WITH VARIED CARBON, FUEL PRICE, AND HYDRO CONDITIONS.



Appendix G. Wholesale Energy Futures under Different Hydro Conditions

The tables shown in this appendix contain references to futures, according to the following naming convention: Carbon Case, Gas Case, Load Case (Dash) Hydro Case. For example, RHR-L would refer to Reference carbon pricing, High gas pricing, Reference load, and Low hydro conditions.

Table 11: Annual Wholesale Pacific Northwest Energy Prices, Reference Carbon Prices and Varied Hydro Conditions ($/MWh nominal)

	Reference Hydro			High Hydro			Low Hydro		
Year	**RLR-R**	**RRR-R**	**RHR-R**	**RLR-H**	**RRR-H**	**RHR-H**	**RLR-L**	**RRR-L**	**RHR-L**
2020	$19.88	$19.88	$19.88	$17.66	$17.66	$17.66	$21.82	$21.82	$21.82
2021	$20.55	$20.55	$20.55	$18.37	$18.37	$18.37	$22.82	$22.82	$22.82
2022	$36.11	$36.11	$36.11	$33.23	$33.23	$33.23	$38.33	$38.33	$38.33
2023	$37.66	$38.48	$50.23	$35.07	$35.97	$46.64	$39.86	$40.73	$53.10
2024	$37.79	$38.96	$63.55	$34.92	$36.01	$58.00	$40.72	$42.03	$70.28
2025	$39.53	$41.72	$68.29	$36.49	$38.55	$62.40	$42.34	$44.50	$75.31
2026	$40.08	$43.10	$73.51	$36.55	$39.38	$66.49	$43.22	$46.10	$78.58
2027	$41.47	$45.31	$76.28	$38.02	$41.95	$69.66	$44.65	$48.61	$81.59
2028	$42.09	$47.43	$78.24	$38.78	$43.92	$71.13	$45.50	$50.96	$84.20
2029	$43.67	$50.20	$82.06	$39.99	$46.25	$75.01	$47.33	$54.13	$88.17
2030	$44.01	$52.47	$84.13	$39.56	$47.47	$75.83	$47.81	$56.92	$90.66
2031	$47.88	$57.94	$93.45	$43.70	$53.34	$85.36	$51.91	$62.32	$100.05
2032	$50.43	$61.60	$98.02	$46.72	$56.86	$89.62	$54.85	$66.64	$105.60
2033	$53.90	$67.29	$103.63	$48.71	$61.31	$94.10	$58.72	$72.47	$110.93
2034	$55.15	$69.51	$104.24	$49.46	$62.87	$94.15	$60.82	$75.16	$112.47
2035	$57.24	$72.44	$106.53	$51.67	$65.54	$95.68	$63.02	$78.30	$115.45
2036	$58.22	$74.01	$110.97	$52.73	$66.87	$100.13	$64.90	$81.23	$120.79
2037	$62.72	$80.01	$119.45	$55.71	$71.03	$107.97	$69.39	$87.10	$129.29
2038	$65.02	$83.12	$124.06	$57.90	$74.19	$111.91	$72.11	$90.81	$135.39
2039	$70.05	$89.15	$133.73	$62.20	$79.24	$120.73	$77.26	$97.21	$143.62
2040	$73.03	$93.54	$137.90	$65.26	$83.12	$123.46	$80.62	$101.54	$149.12
2041	$76.02	$96.60	$142.54	$68.53	$87.27	$129.38	$83.62	$105.90	$153.18
2042	$78.70	$100.22	$145.49	$70.19	$89.54	$132.80	$86.86	$109.40	$159.09
2043	$82.52	$105.68	$152.88	$74.15	$95.14	$138.13	$91.74	$115.88	$164.87
2044	$89.29	$113.29	$161.98	$81.33	$103.81	$150.17	$97.45	$123.45	$173.69
2045	$93.71	$119.36	$170.52	$84.14	$107.93	$157.74	$102.68	$129.32	$182.85
2046	$97.95	$125.23	$177.03	$87.80	$113.46	$163.39	$107.25	$135.45	$189.42
2047	$101.96	$130.10	$185.70	$92.70	$118.89	$170.65	$110.70	$140.35	$197.07
2048	$103.98	$133.04	$189.68	$95.64	$123.12	$175.49	$112.68	$143.39	$201.83
2049	$107.99	$138.36	$198.05	$99.12	$127.76	$183.34	$116.78	$148.95	$209.94
2050	$111.62	$144.10	$208.31	$103.37	$133.59	$191.53	$121.38	$155.07	$219.23

TABLE 12: ANNUAL WHOLESALE PACIFIC NORTHWEST ENERGY PRICES, NO CARBON PRICES AND VARIED HYDRO CONDITIONS ($/MWH NOMINAL)

	Reference Hydro			High Hydro			Low Hydro		
Year	**NLR-R**	**NRR-R**	**NHR-R**	**NLR-H**	**NRR-H**	**NHR-H**	**NLR-L**	**NRR-L**	**NHR-L**
2020	$19.88	$19.88	$19.88	$17.66	$17.66	$17.66	$21.82	$21.82	$21.82
2021	$20.55	$20.55	$20.55	$18.37	$18.37	$18.37	$22.82	$22.82	$22.82
2022	$21.97	$21.97	$21.97	$19.31	$19.31	$19.31	$24.34	$24.34	$24.34
2023	$23.14	$24.38	$38.69	$20.60	$21.80	$34.53	$25.56	$26.79	$44.88
2024	$22.52	$24.30	$56.92	$19.68	$21.27	$47.02	$25.34	$27.08	$65.62
2025	$23.25	$26.04	$60.61	$20.31	$22.84	$50.60	$25.97	$28.78	$70.07
2026	$23.72	$27.57	$61.77	$20.29	$23.82	$54.99	$26.72	$30.63	$67.01
2027	$24.22	$29.13	$63.88	$20.85	$25.42	$57.35	$27.18	$32.32	$70.30
2028	$24.32	$30.82	$65.36	$21.22	$27.13	$58.52	$27.67	$34.52	$71.15
2029	$25.00	$33.12	$68.00	$21.35	$28.81	$61.04	$28.47	$36.88	$74.84
2030	$24.83	$35.27	$70.01	$20.79	$30.32	$62.18	$28.20	$39.29	$76.67
2031	$25.58	$37.91	$77.25	$22.19	$33.28	$69.38	$29.03	$42.02	$83.99
2032	$25.88	$39.01	$79.69	$22.47	$34.19	$71.64	$29.30	$43.34	$86.96
2033	$26.69	$41.73	$82.67	$22.45	$36.14	$73.89	$30.29	$46.21	$89.96
2034	$26.39	$41.79	$82.24	$22.08	$35.95	$72.98	$30.28	$46.75	$90.01
2035	$26.87	$42.27	$82.73	$23.13	$36.53	$73.20	$30.77	$47.02	$90.45
2036	$26.89	$42.21	$84.85	$22.77	$36.69	$74.97	$31.26	$47.93	$93.75
2037	$28.91	$45.28	$91.73	$24.29	$38.83	$81.67	$33.53	$51.16	$100.99
2038	$30.49	$47.26	$96.09	$25.25	$40.41	$84.63	$35.82	$53.97	$106.48
2039	$32.16	$49.91	$102.25	$26.74	$42.78	$89.59	$37.38	$56.56	$112.20
2040	$32.66	$51.24	$104.20	$26.72	$43.22	$90.90	$38.00	$58.05	$115.41
2041	$33.49	$52.98	$106.46	$28.35	$45.97	$94.56	$39.52	$60.55	$117.73
2042	$34.45	$54.75	$109.00	$28.82	$46.88	$95.35	$40.47	$62.38	$119.54
2043	$36.29	$58.05	$112.79	$29.83	$49.44	$99.20	$42.40	$65.81	$125.62
2044	$39.92	$63.13	$119.82	$34.20	$55.38	$107.57	$46.32	$72.40	$135.55
2045	$41.34	$65.97	$124.61	$34.42	$57.08	$111.05	$48.16	$75.59	$140.60
2046	$43.18	$72.66	$138.98	$35.75	$59.90	$117.68	$50.42	$83.79	$158.64
2047	$45.01	$79.33	$156.85	$38.23	$68.00	$136.76	$52.72	$90.44	$173.22
2048	$46.13	$83.42	$164.71	$38.73	$71.74	$145.67	$55.37	$94.96	$180.39
2049	$47.65	$87.35	$173.32	$39.57	$74.95	$154.43	$57.95	$99.14	$189.03
2050	$49.28	$91.08	$180.59	$41.02	$78.45	$160.89	$60.90	$103.57	$197.40

Table 13: Annual Wholesale Pacific Northwest Energy Prices, High Carbon Prices and Varied Hydro Conditions ($/MWh nominal).

	Reference Hydro			High Hydro			Low Hydro		
Year	**HLR-R**	**HRR-R**	**HHR-R**	**HLR-H**	**HRR-H**	**HHR-H**	**HLR-L**	**HRR-L**	**HHR-L**
2020	$19.86	$19.86	$19.86	$17.62	$17.62	$17.62	$21.80	$21.80	$21.80
2021	$20.52	$20.52	$20.52	$18.29	$18.29	$18.29	$22.78	$22.78	$22.78
2022	$40.07	$40.07	$40.07	$36.98	$36.98	$36.98	$42.81	$42.81	$42.81
2023	$42.03	$42.87	$54.17	$39.01	$40.00	$50.39	$44.51	$45.34	$57.07
2024	$42.15	$43.47	$67.01	$39.09	$40.36	$61.51	$45.27	$46.65	$71.67
2025	$44.02	$46.48	$71.84	$40.64	$43.06	$66.11	$47.26	$49.51	$76.44
2026	$44.72	$48.18	$77.15	$40.75	$44.03	$70.21	$48.08	$51.47	$82.42
2027	$46.14	$50.69	$80.28	$42.46	$46.98	$73.64	$49.87	$54.20	$85.68
2028	$49.42	$55.78	$84.89	$45.48	$51.66	$77.26	$53.56	$59.92	$90.88
2029	$53.35	$61.66	$90.91	$48.84	$56.83	$82.86	$58.00	$66.21	$97.39
2030	$55.09	$65.64	$94.25	$49.53	$59.66	$85.11	$60.38	$71.19	$101.50
2031	$58.27	$71.22	$103.13	$52.78	$65.17	$93.94	$63.96	$76.75	$110.16
2032	$60.71	$74.48	$108.02	$55.78	$68.62	$98.76	$66.62	$81.36	$116.18
2033	$63.77	$79.31	$112.49	$57.74	$72.02	$101.31	$70.55	$87.18	$121.42
2034	$65.56	$81.08	$115.28	$57.47	$72.87	$101.75	$72.31	$88.97	$123.56
2035	$68.80	$84.28	$118.58	$62.75	$76.72	$109.29	$75.32	$91.49	$128.47
2036	$69.47	$84.80	$122.67	$63.41	$78.51	$111.37	$76.12	$92.55	$132.27
2037	$75.71	$92.30	$132.79	$67.33	$82.05	$117.73	$81.22	$98.71	$142.91
2038	$81.24	$97.42	$141.18	$73.40	$88.99	$127.60	$85.59	$104.19	$148.94
2039	$85.33	$103.74	$150.96	$77.20	$93.14	$135.18	$92.21	$111.57	$159.97
2040	$91.56	$110.68	$159.15	$81.03	$99.72	$141.10	$97.53	$117.40	$165.85
2041	$96.44	$116.68	$166.16	$87.59	$106.16	$149.26	$103.22	$123.05	$172.61
2042	$97.72	$117.83	$167.42	$88.72	$108.04	$153.47	$105.92	$129.13	$181.55
2043	$104.56	$126.36	$177.71	$94.23	$112.42	$160.52	$111.50	$136.48	$192.40
2044	$113.93	$136.00	$188.48	$107.83	$129.83	$177.77	$119.67	$144.62	$200.98
2045	$116.36	$140.29	$195.25	$106.22	$128.10	$181.33	$122.81	$150.05	$204.90
2046	$121.05	$145.80	$202.91	$110.73	$135.85	$186.53	$130.41	$162.14	$215.63
2047	$123.16	$148.93	$209.32	$111.08	$135.53	$192.40	$132.61	$162.60	$223.24
2048	$126.55	$156.54	$217.81	$116.39	$144.66	$197.57	$136.46	$168.37	$230.56
2049	$138.29	$169.29	$229.78	$125.39	$154.58	$213.31	$141.20	$172.15	$241.02
2050	$136.98	$167.98	$233.73	$127.93	$159.61	$222.97	$147.55	$179.97	$252.75