Integrated Resource Plan

JULY 2019

PGE

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Acronyms

Acronym	Agency/Entity/Term
AAGR	annual average growth rate
AC	alternating current
ACE	Affordable Clean Energy (ACE) rule
ACP	Alternative Compliance Payment
ADF	Augmented Dickey Fuller
AECO	AECO Hub(TM)
AEO	Annual Energy Outlook (EIA)
AGC	automated generation control
AMI	advanced metering infrastructure
aMW	average megawatts
ANSI	American National Standards Institute
APS	Arizona Public Service
ARIMA	autoregressive integrated moving average
ATC	available transfer capacity
BAA	Balancing Authority Area
BA	Balancing Authority
BDR	Behavioral Demand Response
BESS	battery energy storage system
BEV	battery-electric vehicle
BLM	Bureau of Land Management
BNEF	Bloomberg New Energy Finance
BPA	Bonneville Power Administration
BYOT	bring your own thermostat
C&I	commercial & industrial
CA	California
CAA	Clean Air Act
CAES	compressed air energy storage
CAFE	Corporate Average Fuel Economy
CAIR	Clean Air Interstate Rule
CAISO	California Independent System Operator
CCA	community choice aggregation
CCCT	combined-cycle combustion turbine
CDD	cooling degree days
CEAE	Canadian Entitlement Allocation Extension
CEC	California Energy Commission
CHP	combined heat and power
CO_2	carbon dioxide
COD	commercial operation date
COLA	combined construction and operating license application
COS	cost of service
COP21	21st Conference of the Parties (COP21)
CPP	Clean Power Plan
CT	combustion turbine
CVR	conservation voltage reduction
DA	day-ahead
DC	direct current
DEQ	Department of Environmental Quality (Oregon)
DER	distributed energy resources
DF	distributed flexibility
DG	distributed generation
DLC_{EV}	EV direct load control
DLC	direct load control
DOE	Department of Energy
DOJ	Department of Justice
DR	demand response
DRP	distribution resource planning
DRRC	Demand Response Review

Acronym	Agency/Entity/Term
	Committee
DSG	dispatchable standby generation
DSM	demand-side management
DSP	distribution system planning process
DTC	dynamic transfer capability
E3	Energy + Environmental Economics, Inc.
EE	energy efficiency
EER	Evolved Energy Research
EFSC	Energy Facility Siting Council (Oregon)
EIA	U.S. Energy Information Agency
EIM	Energy Imbalance Market
ELCC	effective load carrying capability
Energy Trust	Energy Trust of Oregon
EPA	Environmental Protection Agency (U.S.)
EPC	engineer, procure and construct
EPRI	Electric Power Research Institute
EQC	Environmental Quality Commission
ESS	electricity service suppliers
EUE	expected unserved energy
EV	electric vehicle
FERC	Federal Energy Regulatory Commission
GAMS	General Algebraic Modeling System
GDP	gross domestic product
GEAR	Green Energy Affinity Rider
GHG	greenhouse gas
GW	gigawatt
GWa	gigawatt average
HA	hour-ahead
HB	House Bill

Acronym	Agency/Entity/Term
HDD	heating degree days
HDR	HDR Engineering, Inc.
IE	independent evaluator
IOU	investor owned utility
IRP	Integrated Resource Plan
IRS	Internal Revenue Service
ITC	investment tax credit
KPSS	Kwiatkowski, Phillips, and Shin
kW-yr	kilowatt year
kW	kilowatt
kWh	kilowatt hour
LCOE	levelized cost of energy
LDV	light-duty vehicle
Li-ion	lithium-ion
LOLE	loss-of-load expectation
LOLH	loss-of-load hour
LT	long term
LTDA	long-term direct access
LTF	long-term firm transmission
LRB	load resource balance
Mid-C	Mid-Columbia River
misc.	miscellaneous
MMBtu	million British Thermal Units
MRDAP	Montana Renewables Development Action Plan
MSI	Market Strategies International
MT	Montana
MW	megawatt
MWa	megawatt average
MW_{AC}	MW on the AC side of the inverter
MWh	megawatt hour
MY	model year
NCAT	National Coalition for Advanced Transportation

Acronym	Agency/Entity/Term
NERC	North American Electric Reliability Corporation
NHTSA	National Highway Traffic Safety Administration
NLDA	New Load Direct Access program
NOPR	notice of proposed rulemaking
NPVRR	net present value of revenue requirement
NREL	National Renewable Energy Laboratory
NW	Northwest
NWA	Non-wires Alternative
NWPCC	Northwest Power and Conservation Council
O&M	operation and maintenance
OAR	Oregon Administrative Rule
OASIS	Open Access Same-Time Information System
OATT	Open Access Transmission Tariff
OCEP	Oregon Clean Electricity and Coal Transition Plan
ODOE	Oregon Department of Energy
ODOT	Oregon Department of Transportation
OEA	Oregon Office of Economic Analysis
OPUC	Public Utility Commission of Oregon
OR	Oregon
ORS	Oregon Revised Statutes
OSB	Oregon State Bar
PEV	plug-in electric vehicle
PG&E	Pacific Gas & Electric
PGE (or the Company)	Portland General Electric Company
PGEM	PGE's Marketing Function
PHEV	plug-in hybrid electric vehicle

Acronym	Agency/Entity/Term
PM	particulate matter
PNUCC	Pacific Northwest Utilities Conference Committee
PNW	Pacific Northwest
POLR	Provider of Last Resort
PPA	power purchase agreement
PTC	production tax credit
PTR	peak time rebate
PUC	Public Utility Commission
PUD	People’s / Public Utility District
PURPA	Public Utility Regulatory Policies Act
PV	photovoltaic
PW1, PW2	Port Westward1, Port Westward2
QF	qualifying facility
RAS	remedial action schemes
RDF	Renewable Development Fund
REC	Renewable Energy Credit
RECAP	Renewable Energy Capacity Planning model
RFP	request for proposals
ROM	Resource Optimization Model
RPS	Renewable Portfolio Standards
RT	real-time
SAFE	Safer Affordable Fuel-Efficient rule
SB	Senate Bill
SCCT	simple-cycle combustion turbine
SD	standard deviation
SMR	small modular reactor
SSO	supply side option
SSPC	Salem Smart Power Center
ST	short term
T&D	transmission and distribution
TOU	time-of-use

Acronym	Agency/Entity/Term
TTC	total transfer capability
UAMPS	Utah Associated Municipal Power Systems
VAR	Volt-Ampere Reactive
VAST (TM)	Vehicle Adoption Simulation Tool
VER	variable energy resource
WA	Washington
WECC	Western Electricity Coordinating Council
WCI	Western Climate Initiative
WM	Wood Mackenzie

Portland General Electric's 2019 Integrated Resource Plan embraces the positive change that is shaping our industry, while prioritizing universal access to clean, affordable and reliable electricity.

This is the first plan developed since we made our commitment to cut PGE's greenhouse gas emissions by more than 80% by 2050. It proposes measured steps we can take today to address the climate crisis, while allowing flexibility for adjustments as technology and policies continue to evolve.

This document underscores our commitment to transparency and collaboration. We engaged customers and stakeholders throughout its development, and their insights and feedback were instrumental in shaping our resource strategies.

This IRP also embodies the spirit outlined in our "**Vision for a Clean Energy Future**." Since we introduced our vision in 2018, we have been accelerating the transformation of our company:

- We announced the Wheatridge Renewable Energy Facility, the first of its scale to combine wind and solar energy with battery storage.
- The Boardman plant will cease coal-fired operations at the end of 2020.
- We are working to advance electrification in other areas of the economy, especially the transportation system, which accounts for 40% of Oregon's GHG emissions.
- We are enhancing reliability by modernizing our systems to create a smarter, more resilient grid.

Our 2019 IRP is the culmination of a multi-year research and engagement process — our most exhaustive analysis ever. After constructing and testing 43 different portfolios, we identified actions needed between now and 2025 to move us forward on our path to our 2050 goal. The plan calls for:

- 150 MWa of renewable resources by 2023.

- A similar amount (157 MWa) of cost-effective energy efficiency.
- Increased reliance on demand response to help balance sources and uses of electricity during peak months. This includes 141 MW during winter months, 211 MW during summer months and 4 MW of customer battery storage.
- Additional actions to help meet capacity needs as a result of expiring contracts and the retirement of baseload coal plants like Boardman.

The energy industry is undergoing a period of profound change and uncertainty driven by climate change, new technologies and changing customer expectations. By incorporating maximum flexibility into the plan, we will be able to accommodate shifts in needs, in consultation with the Oregon Public Utility Commission and our stakeholders.

We believe our 2019 IRP represents the very best path forward and welcome feedback from our customers and stakeholders during the coming review process. Combatting the climate crisis while ensuring universal access to reliable, affordable electricity demands leadership, vision and commitment.

It's a call for all of us to work together for a clean energy future for Oregon.

Sincerely,

Maria Pope | President and CEO

Executive Summary

Portland General Electric (PGE, or the Company) is proud to submit our 2019 Integrated Resource Plan (IRP) for consideration by our customers, stakeholders, and the Public Utility Commission of Oregon (OPUC, or the Commission). In 2018, we made a simple but daunting commitment to lead the transformation to a clean energy future for our customers and our corner of the Pacific Northwest. We made that commitment to lead because we believe combatting climate change while ensuring universal access to reliable and affordable electricity is a societal imperative, and that it will not happen without leadership, vision, and commitment. We also have an obligation to ensure that the electric system transformation does not leave anyone behind, with all customers sharing in the benefits and opportunities of a clean energy future. Our 2019 Integrated Resource Plan is our first long-term plan since making that commitment, and it incorporates this vision for our clean energy future. It shows a pathway to reach our long-term goals given what we know today, and acknowledges the vast uncertainty that faces our industry in the coming decades. We propose measured near-term actions to set us in the right direction while ensuring that we can continue to deliver affordable and reliable electricity. Our plan focuses on three major steps to meet commitments to customers in service of our shared clean energy future.

1. Engage our customers around new technologies and programs.

Our plan asks that everyone play their part in creating a clean energy future. To help us, we will ask our customers to engage with us in new ways.

Energy efficiency. PGE has long used energy efficiency (EE) to deliver low-cost and low-carbon results for our customers. We estimate that, with the help of our customers, we currently avoid about one million metric tons of greenhouse gas emissions ($MMtCO_2e$) per year with energy efficiency investments made since 2010. That's equivalent to taking about 150,000 cars off the road or about 17 percent of our annual greenhouse gas (GHG) emissions. Our plan calls for continued investments in cost-effective energy efficiency, which we estimate could avoid an additional 0.7 $MMtCO_2e$ per year by 2025.

Distributed flexibility. With distributed flexibility, we can use the technologies and energy behaviors of our customers (in their home or business) to provide the same services and value that power plants and grid investments provide. This includes demand response programs, such as installing smart thermostats and smart electric vehicle (EV) chargers, as well as programs that allow customers to help support the grid with their backup power and battery storage systems. Under our plan we estimate that by 2025 our distributed flexibility programs will avoid the need for approximately 200 MW of conventional generation, about half the size of the Carty Generating Station. And we expect these programs to continue to grow as more of our customers adopt new clean technologies, like EVs, over time.

These distributed energy resource (DER) programs are critical to our ability both to drive carbon out of our economy and to maintain reliability in the electricity system at a low cost.

2. Decarbonize our energy supply as cost effectively as possible.

To reach our long-term decarbonization goal, we will need additional renewable resources, like wind and solar, to drive greenhouse gases out of our generation portfolio. Specifically, we estimate that we will need to add at least 50-60 MWa[1] of new renewables every year for the next thirty years. To make meaningful progress while taking advantage of continued cost declines and the limited remaining availability of federal tax credits, our plan calls for additional renewables in the near term. These renewables will expand our renewable portfolio and complement the voluntary options, like our Green Tariff, that allow customers who so choose to decarbonize even faster.

Renewable procurement. Our plan calls for an additional 150 MWa of new renewable resources by 2023, with conditions that will ensure low-cost outcomes for our customers. We estimate these renewables will save about 0.6 MMtCO_2per year through 2050. Our near-term plan will help us make real progress toward our goal while maintaining flexibility to respond as conditions change in the future.

3. Maintain reliability by leveraging what we have today and embracing new clean technologies.

Our plan identifies the potential need for significant amounts of additional resources to maintain reliability in the mid-2020s, due in part to the loss of about 350 MW of capacity as contracts that we've signed for resources in the region expire. During this same time, we expect the Pacific Northwest region to require additional resources due to retiring coal plants. Forecasts also show that the costs of new clean technologies, like energy storage, will continue to decline. We propose a staged process to allow us to take measured actions that support reliability in the face of continued uncertainty.

Pursue cost-competitive existing resources. To continue to drive down both carbon and costs, it is essential that we make the best use of resources that are already available in the region. Our first step to ensuring reliability is to seek agreements for capacity on existing resources in the region to the extent that they are available and cost-competitive.

Clean technology procurement. If, despite our other actions, we still forecast a potential reliability shortage in the mid-2020s, we plan to conduct a competitive solicitation for new non-emitting resources that support reliability. This could include battery storage, pumped hydro, renewable resources, or combinations of renewables and storage. The solicitation would exclude new fossil fuel-based generation.

When taken together, we believe these actions will allow us to meet our customers' needs while maintaining affordability in a way that is consistent with our values and the values expressed within the public process that supported the development of this plan.

The following sections briefly summarize the observations, assumptions, and analysis that underpin our plan.

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[1] An average MW (or MWa) is shorthand for the amount of energy that a resource produces on average over the course of a typical year. Because renewables and many power plants do not produce energy all of the time, they typically produce fewer MWa than their total generating capacity.

ES.1 A Changing Energy Landscape

The 2019 IRP was developed against a landscape of rapid growth in clean energy. Our customers, and electricity customers across the country, want clean energy and expect us to act to help avert the climate crisis. Policymakers in Oregon and around the West have responded with new state policy proposals that support decarbonization through both economic signals and clean energy mandates. Many states in the West have adopted aggressive new clean energy policies that further the expansion of renewable resource development and the retirement of emitting thermal resources, including California, Washington, New Mexico, Nevada, and Colorado. In Oregon, the legislature contemplated House Bill (HB) 2020, which would have authorized a cap and trade program—called the "Oregon Climate Action Program"—starting January 1, 2021. HB 2020 would have helped facilitate decarbonization of our energy supply and accelerated transportation electrification, and would have protected our customers from unnecessary price impacts while doing so. PGE joined environmental and consumer advocates, organized labor, businesses, family forestland owners, rural economic development organizations, and other utilities in supporting passage of HB 2020. Although this bill did not pass during the 2019 legislative session, PGE is committed to reducing our greenhouse gas emissions by more than 80 percent by 2050, consistent with our proportionate share of the state's economy-wide GHG reduction goal, and will continue to engage in and advocate for policies that are consistent with our strategy while protecting affordability and reliability.

Amidst broad consumer- and policy-driven change, clean energy technology companies are rising to the challenge. As a result, cost declines for wind, solar, and battery technologies continue, and clean technologies are increasingly competitive with conventional fossil fuel-based generators. The make-up of the grid has shifted quickly and wholesale electricity markets in the West are increasingly experiencing the availability of zero or negative marginal-cost renewable power. Simultaneously, the retirement of thermal generators has accelerated the potential for capacity shortages in the West and reinforced the need for both sound utility planning and regional solutions.

ES.2 Our Planning Process

Integrated resource planning provides a thoughtful way for PGE and the region to pursue and embrace the positive change that our industry is undergoing, while ensuring that our customers have access to affordable and reliable energy. The process allows us to align the way we do business with our customers' values, as well as local and state energy policies. To engage the public in the development of our plan, we host a public process in which we provide information and request feedback to help guide our decision-making.

Before we began work on the 2019 IRP, we engaged stakeholders in a conversation around guiding values. We heard that affordability, sustainability, and transparency were paramount to many of our stakeholders as they engaged in the IRP process. We kept these values in mind throughout our planning and took tangible steps to be responsive to what we heard. Specifically, we shared draft analyses more frequently, requested feedback on specific design questions, invited stakeholders to submit informal comments throughout the process, and modeled specific portfolios requested by stakeholders.

Over the 17-month public process for the development of the 2019 IRP, we held 12 public meetings, which were attended by 221 people online and in person. We received 58 written comments, five portfolio requests, and hosted our first community listening session to seek feedback from traditionally underrepresented groups that work within the communities we serve. We are grateful to everyone who chose to participate in our public process and hope those who participated will see their vital feedback reflected in our plan. While we received generally positive feedback about our efforts to engage stakeholders that traditionally participate in our process, we were much less successful in bringing new perspectives into our process. This will be an area of continued focus for PGE as we work to engage the communities we serve in our planning and decision-making processes.

To address both the evolving energy landscape and the feedback that we heard throughout our process, we designed and implemented the 2019 IRP with a focus on four key themes: decarbonization; customer decisions; uncertainty and optionality; and technology integration and flexibility. These themes encompass some of the most pressing questions facing our industry today and in the coming decades.

- **Decarbonization.** We are committed to enabling local transformation to a clean energy economy. By 2050, we will reduce our greenhouse gas (GHG) emissions by more than 80 percent and help decarbonize other sectors in the economy by enabling the adoption of new clean electric technologies, like EVs. To support these goals, we considered decarbonization and the clean energy transition through several new innovative analyses within the IRP, including our Decarbonization Study[2] and related Decarbonization Scenario,[3] carbon pricing reflective of a potential cap and trade program in Oregon,[4] a scoring metric reflecting portfolio performance in a carbon-constrained future,[5] and incorporation of market-based EV forecasts throughout our analysis.[6] These components of our plan help to ensure that PGE will continue to drive GHGs out of our energy economy and that we will be well positioned to serve our customers in a clean energy future.
- **Customer decisions.** Increasingly, customer decisions around their energy use and the source of their energy are impacting the electricity sector, including long-term planning. In the 2019 IRP, we address customer decisions through a comprehensive study (the Navigant "DER Study") of customer adoption of DERs and customer participation in distributed flexibility programs (including demand response and dispatchable customer storage).[7] We also tested sensitivities related to customer participation in voluntary renewable programs.[8] Our goal in these exercises is to ensure that our plans are robust across a range of potential customer

[2] The Decarbonization Study can be found in External Study A. Deep Decarbonization Study.

[3] See Section 7.4.1 Decarbonization Scenario.

[4] See Section 3.2.2 Carbon Prices.

[5] See Section 7.2.1 Scoring Metrics.

[6] See Section 4.1.3.1 Electric Vehicles.

[7] Information from the DER Study is referenced in Chapter 4. Resource Needs and Chapter 5. Resource Options. The study can be found in External Study C. Distributed Energy Resource Study.

[8] See Section 4.7.2 Voluntary Renewable Program Sensitivities.

decisions in the future and to ensure that utility actions and customer actions remain compatible and coordinated.

- **Uncertainty & optionality.** We anticipate the current rapid change in technology, policy, and wholesale markets is likely to continue in the foreseeable future. As such, our 2019 IRP provides a robust treatment of uncertainty in terms of both the range of potential futures considered and the incorporation of these futures into portfolio analysis. We consider 810 potential futures that depend on economic conditions, technological progress, natural gas prices, carbon prices, hydro conditions, and the future deployment of renewables across the West. In response to our stakeholders, we have also evolved our portfolio construction and scoring process to better reflect the value of optionality amidst these uncertainties and to better capture the risks associated with commitments to new large and long-lived energy infrastructure.
- **Technology integration and flexibility.** With the continued proliferation of renewable and distributed resources, it is increasingly important that our planning consider the challenges and opportunities associated with integrating these technologies. Building on PGE's leadership in renewable integration and energy storage analysis, the 2019 IRP incorporates a holistic evaluation of flexibility challenges and potential solutions through three related exercises: an integration cost study for renewables,[9] a flexibility value analysis for dispatchable resources,[10] and a flexibility adequacy study for our portfolio.[11] In anticipation of future distribution resource planning (DRP) efforts, we also provide an example of how locational value may factor into resource economic evaluation in future IRPs.[12]

ES.3 Growing Resource Needs

Our analysis to support the 2019 IRP begins with a detailed evaluation of our need for resources. PGE meets customer needs with a diverse portfolio of resources, including energy efficiency, renewables, hydropower, and thermal generation. Over time, our resource needs shift due to changes in demand, changes in our resource mix (due to retirements or expiring contracts), and policy drivers, like the Renewable Portfolio Standard (RPS).

Our analysis shows that PGE faces growing resource needs and uncertainty throughout the 2020s. As approximately 350 MW of capacity contracts expire in the mid-2020s, we face increasing needs for resources that support reliability (i.e., capacity needs), even after considering the potential impacts of distributed energy resources like energy efficiency, customer-sited solar and storage, and demand response. Under Reference Case assumptions, these capacity needs grow to 685 MW by 2025. However, uncertainties in economic conditions, DER adoption, EV adoption, and market availability suggest that our needs in 2025 could range between approximately 350 MW and approximately 1,000 MW. These estimates exclude the potential impacts to regional reliability of loads that elect to take energy service from an energy service supplier (ESS) through long-term direct access (LTDA) or

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[9] See Section 6.1.3 Integration Costs.

[10] See Section 6.2.2 Flexibility Value.

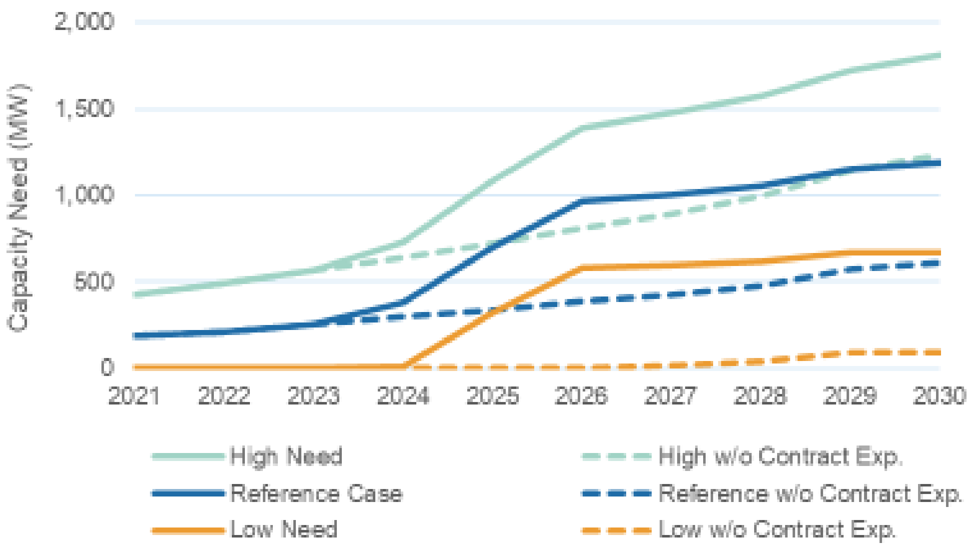
[11] See Section 4.6 Flexibility Adequacy.

[12] See Section 6.4 Locational Value.

New Load Direct Access (NLDA). In Docket No. UE 358, PGE urges the OPUC to allow PGE to plan for the capacity needs associated with these loads so that we can effectuate our role as their reliability provider as the region becomes more capacity-constrained.

Our need for new dispatchable capacity resources in the mid-2020s will depend strongly on our ability to replace expiring contracts with similar quantities of capacity. As shown in Figure ES-1 below, if we replace all expiring contracts with new contracts, on a 1-for-1 capacity basis, and our needs grow relatively slowly (as indicated by the Low Need Future), we may be capacity-adequate without new resource additions. However, if cost-competitive capacity options are not available in the market and we face more quickly growing needs (as indicated by the High Need Future), over 1,000 MW of new capacity resources may be required by 2025. The possibility of these two widely divergent scenarios requires our Action Plan to be both flexible enough for us to respond to evolving conditions and robust enough to provide for significant procurement of new resources should the identified needs persist.

FIGURE ES-1: Future capacity needs under various scenarios



Our analysis also suggests that without incremental action, our generation portfolio is expected to be short to the market on an average annual basis beginning in 2021, with the forecast market shortage generally growing into the future. By 2025, the market shortage exceeds 344 MWa in 90 percent of futures and is forecast to be 515 MWa in the Reference Case. Consistent with this finding and the potential for voluntary programs to provide incremental energy to the portfolio, we considered only those portfolios that add less than 250 MWa in incremental resources through 2025 in selecting our preferred portfolio.

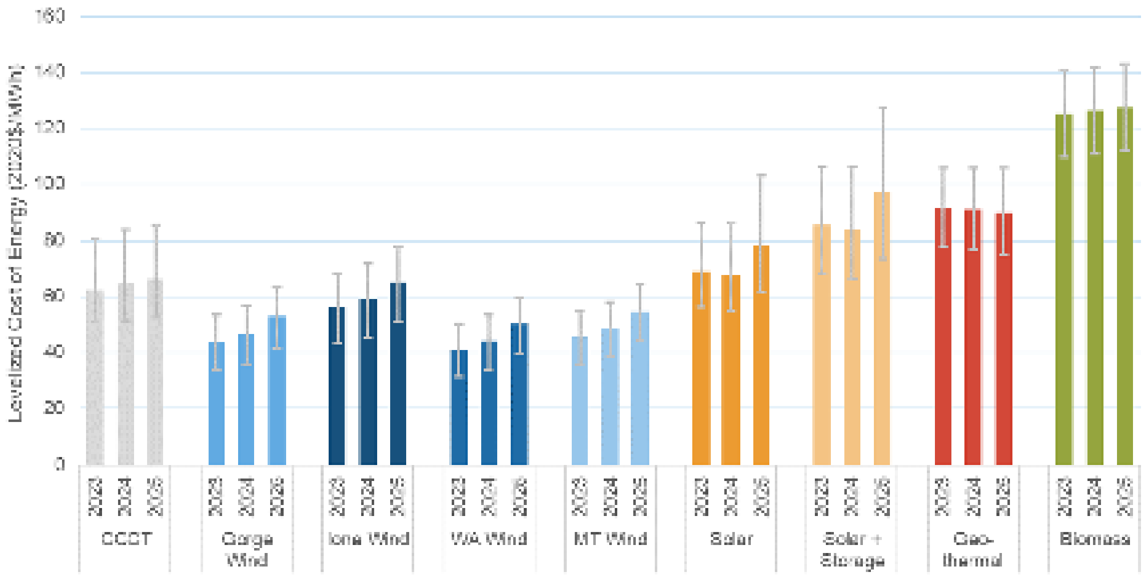
Our analysis did not identify near-term needs for additional Renewable Energy Credits (RECs) to meet Renewable Portfolio Standard (RPS) obligations. Our forecasts indicate that we expect to be physically compliant with the RPS through 2029 and that banked RECs could be used to defer the need for incremental RECs until 2036. However, deferring action would preclude the opportunity to secure low-cost resources to meet near-term capacity and energy needs with clean technologies. It would also create an impractical requirement that we successfully procure 627 MWa of additional renewables over two years to comply with the RPS in 2037. We do not believe that our near-term renewable strategy should rely on such an unrealistic assumption about future procurement.

The energy and capacity needs we identified in the mid-2020s can be met in a variety of ways. For example, we can meet energy needs through a combination of purchases from wholesale energy markets and new energy resources, like wind and solar. Similarly, we can meet capacity needs through a combination of renewable resources, dispatchable capacity resources (such as thermal generators and energy storage), or contracts with other entities in the region. More information about the resource options considered in the 2019 IRP can be found in Chapter 5. The remainder of the IRP focuses on the tradeoffs between these resource options and the identification of the best combination of resource options for PGE to pursue to meet our customers' needs.

ES.4 Shifting Resource Economics

One of the primary changes influencing the electricity sector and resource planning is the continued cost decline of clean technologies like wind, solar, and battery energy storage. The combination of cost declines and the continued availability of federal tax credits in the near-term create a time-limited opportunity to secure cost-competitive clean resources to meet our customers' needs. Figure ES-2 shows the real-levelized cost of each of the generic energy resource options considered in our 2019 IRP.

FIGURE ES-2: Levelized costs of energy resource options by type and online date

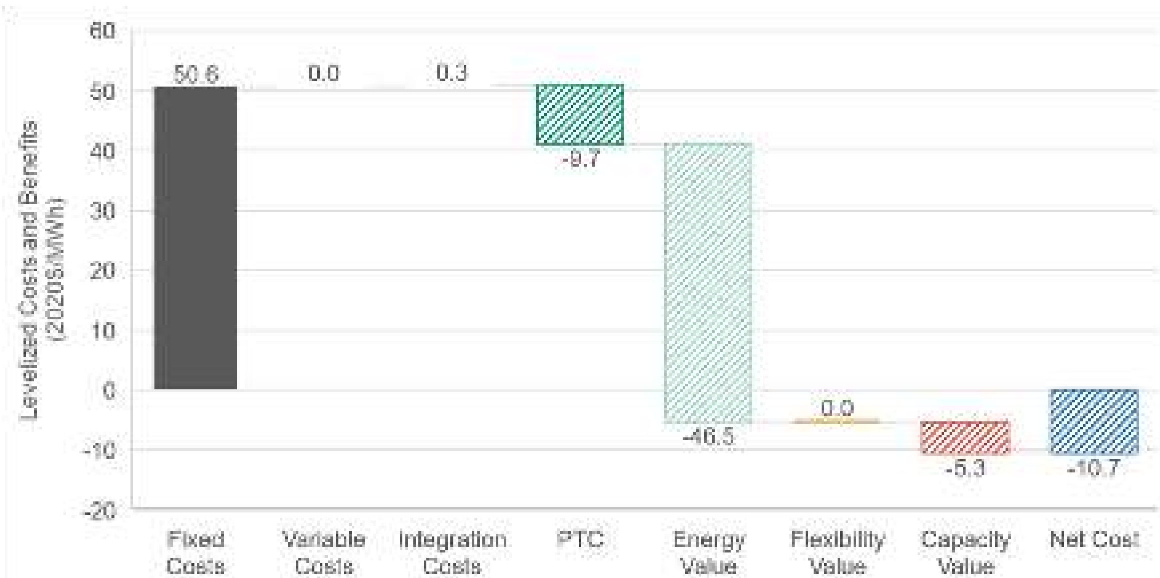


Our analysis suggests that wind resources may provide the lowest-cost energy compared to other energy resources, including combined-cycle combustion turbines (CCCTs). It also indicates that cost uncertainty is relatively large compared to the cost differences between energy resource options. This highlights the importance of taking incremental actions to procure renewable resources, while preserving optionality with respect to technology, resource type, and location in competitive solicitations.

The levelized costs also highlight the benefits of near-term renewable action to qualify for federal tax credits. Wind projects that come online by December 31, 2022[13] may qualify for the federal production tax credit (PTC) at the 60 percent level. The PTC steps down to the 40 percent level for projects that come online the following year and then goes away. At the 60 percent level, we find that the PTC lowers the cost of wind by approximately 20 percent, providing an incentive of about $170 million to pursue 150 MWa of wind in the near-term, rather than waiting until 2025 or later. The federal investment tax credit (ITC) provides a similar incentive for solar. The ITC scales down from 30 percent to 10 percent for projects that come online after December 31, 2023.[14] We estimate that the availability of the 30 percent ITC reduces the cost of solar and solar plus storage by approximately 16 percent relative to the 10 percent ITC, providing an additional incentive to acquire renewable resources prior to 2025.

In addition to cost, we analyzed the various benefits that renewable resources bring to the system and compared them to alternative ways of meeting customer needs. We found that by helping to meet both our energy and capacity needs, wind resources are expected to bring more benefits than costs over their lifetime (see Figure ES-3). In the Reference Case, a 150 MWa Washington Wind resource that qualifies for the 60 percent PTC saves about $180 million over its lifetime relative to a strategy of relying on the market for energy and a simple-cycle combustion turbine for an equivalent amount of capacity.

FIGURE ES-3: Costs and benefits of Washington Wind resource that comes online by December 31, 2022



While the long-term benefits of pursuing near-term renewables are compelling, our stakeholders have raised questions about whether today's customers should be paying for resources that will benefit customers in future years. To address this question of intergenerational equity, we estimated

13 Our analysis considers such a project to have a 2023 online date.

14 These projects come online in 2025 in our analysis because we assume that projects that would come online in 2024 would be accelerated to December 31, 2023 to qualify for the higher level of tax incentive.

the potential average impact to retail power prices of pursuing renewables within the 2019 IRP Action Plan between 2021 and 2035. Our analysis found that pursuing near-term wind is expected to cause a small net increase in power prices between 2023 and 2026 (approximately 0.04 cents per kWh[15]) but is expected to result in lower power prices beginning in 2027 or 2028, relative to a strategy of meeting customer energy and capacity needs without the renewable addition. Waiting until 2026 for the same wind addition would result in larger estimated power price impacts due to the unavailability of federal tax credits (approximately 0.05 cents per kWh between 2026 and 2030) and would not result in net reductions to power prices until 2031. While we found that near-term renewable action does bring forward some costs and the associated potential for small increases in power prices, the benefits of securing federal tax credits also reduce the expected magnitude of near-term power price increases and brings forward the potential for power price reductions associated with renewables from the early 2030s to the late 2020s. The exact impacts to rates and timing of these impacts will depend on the cost and performance of acquired resources and future market conditions.

Technological innovation has also led to dramatically reduced costs for battery storage in recent years, challenging the notion that meeting capacity needs will necessarily require new fossil fuel-based resources. Our analysis suggests that by 2025, battery resources may be cost-competitive with a simple-cycle combustion turbine (SCCT). The 2019 IRP made significant progress toward better understanding the potential role of battery storage within our portfolio, particularly with the analysis of storage capacity contribution and flexibility value. However, we have identified energy storage as a critical area for additional learning. Future efforts will focus on quantification of locational value of battery storage through PGE's distribution resource planning (DRP) process, and continued refinements in energy storage methodologies in the IRP.

ES.5 Portfolio Analysis – Bringing it All Together

We constructed 43 portfolios of resource options that tested a wide range of potential strategies for meeting our near-term needs. Some portfolios tested specific resource options in isolation or tested variations in the size and timing of resource actions, while others utilized optimization algorithms to design portfolios to meet objectives of interest to PGE and/or our stakeholders. Figure ES-4 summarizes the resulting resource additions through 2025.

To compare the portfolios, we evaluated each across a set of non-traditional scoring metrics as well as traditional cost and economic risk metrics. We selected the non-traditional scoring metrics based on feedback received in our public process and to account for risks not captured with the traditional economic risk metrics. We excluded portfolios that performed among the worst with respect to any non-traditional metric from further evaluation. We then identified the best performing portfolios based on their performance with respect to the traditional cost and economic risk metrics. The near-term resource additions in these portfolios are shown in Figure ES-5.

[15] For reference, total revenues per kWh as reported in the FERC Form 1 for 2018 were approximately 10.2 cents/kWh.

FIGURE ES-4: Resource additions through 2025 across the portfolios investigated

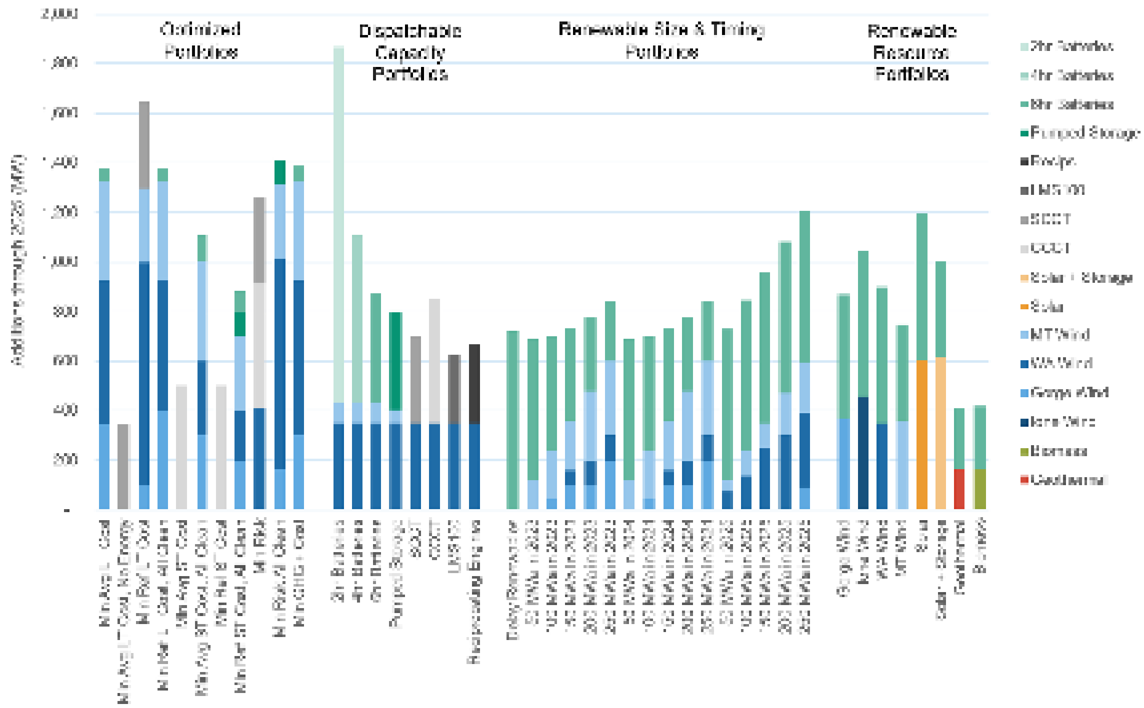


FIGURE ES-5: Resource additions in best performing portfolios

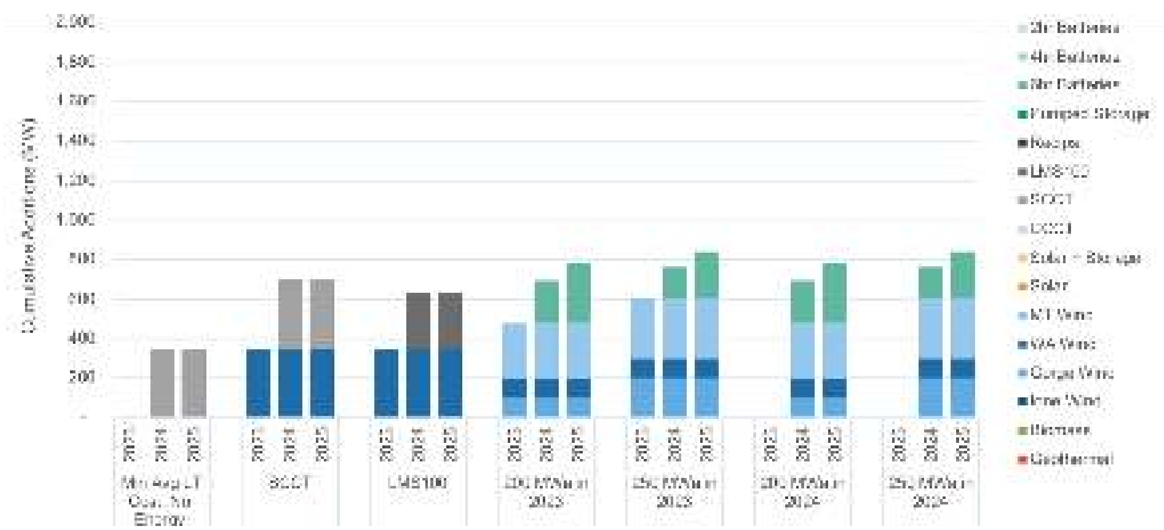


Table ES-1 and Table ES-2 list the traditional and non-traditional scores for each of the best performing portfolios.

TABLE ES-1: Portfolio scores for best performing portfolios, traditional scoring metrics

Portfolio	Category	Cost	Variability	Severity
Min Avg LT Cost, No Energy	Optimized	25,436	3,808	30,987
SCCT	Dispatchable Capacity	25,351	3,675	30,699
LMS100	Dispatchable Capacity	25,515	3,652	30,863
200 MWa in 2023	Renewable Size & Timing	25,744	3,653	30,987
250 MWa in 2023	Renewable Size & Timing	25,620	3,605	30,807
200 MWa in 2024	Renewable Size & Timing	25,804	3,648	31,043
250 MWa in 2024	Renewable Size & Timing	25,693	3,611	30,879

TABLE ES-2: Portfolio scores for best performing portfolios, non-traditional scoring metrics

Portfolio	GHG-Constrainted Cost	Near Term Cost	High Tech Future Cost	GHG Emissions	Incremental Criteria Pollutants	2025 Energy Additions
Min Avg LT Cost, No Energy	25,351	6,025	15,313	108	61	10
SCCT	25,266	6,051	15,256	102	61	160
LMS100	25,430	6,067	15,418	102	265	189
200 MWa in 2023	25,713	6,099	14,919	100	0	183
250 MWa in 2023	25,577	6,097	15,009	97	0	236
200 MWa in 2024	25,773	6,093	14,977	101	0	183
250 MWa in 2024	25,650	6,089	15,080	98	0	236

The best performing portfolios share the following commonalities:

- **Customer resources:** All portfolios include all cost-effective energy efficiency and DER adoption and participation assumptions based on the Navigant DER Study.
- **Renewable resource additions:** Six of the seven best performing portfolios incorporate renewable actions prior to 2025 (four add renewables in 2023 and two add renewables in 2024). Renewable addition sizes across these six portfolios range from 150 MWa to 250 MWa.
- **Capacity resource additions:** All seven of the best performing portfolios incorporate capacity additions prior to 2025. Capacity is provided by battery storage in four portfolios, a simple-cycle combustion turbine (SCCT) in two portfolios, and three LMS100 units in one portfolio. The portfolios that incorporate battery storage add incremental capacity in both 2024 and 2025, while the portfolios that add thermal resources for capacity make a single larger capacity addition in 2024 due to thermal unit sizes. Capacity additions through 2025 range

between 238 and 299 MW in the portfolios that include storage and between 279 MW and 347 MW in the portfolios that add thermal units. Remaining capacity needs are met with the Capacity Fill resource described in Section 7.1.1.1 Resource Adequacy.

We designed an additional portfolio, the Mixed Full Clean portfolio, to capture the most common elements across the best performing portfolios. The Mixed Full Clean portfolio met all of the screening criteria and performed among the best performing portfolios on the basis of the traditional cost and risk metrics—making it our preferred portfolio. In this portfolio, we meet our resource needs (after accounting for DERs and potential capacity contracts) with a combination of renewable resources and energy storage. Specifically, we add 150 MWa of additional wind in 2023 that qualifies for the 60 percent PTC and approximately 250 MW of energy storage by 2025 that has a duration of at least six hours. Table ES-3, Table ES-4, and Table ES-5 summarize the cumulative components of the preferred portfolio in more detail.

TABLE ES-3: Cumulative customer resource additions in the preferred portfolio

	Reference Case			Low Need			High Need		
	2023	2024	2025	2023	2024	2025	2023	2024	2025
Energy Efficiency (MWa)*	108	133	157	111	140	167	108	133	157
Demand Response[†]									
Summer DR (MW)	190	202	211	329	359	383	104	106	108
Winter DR (MW)	129	136	141	263	282	297	72	73	73
Dispatchable Standby Generation (MW)	136	137	137	136	137	137	136	137	137
Dispatchable Customer Storage (MW)	2.2	3.0	4.0	7.3	9.1	11.2	1.1	1.6	2.2

*Energy efficiency savings reflect the forecast of deployment by the end of the year and are at the meter.
[†]Distributed Flexibility values are at the meter.

TABLE ES-4: Cumulative renewable resource additions in the preferred portfolio

	Reference Case			Low Need			High Need		
	2023	2024	2025	2023	2024	2025	2023	2024	2025
Wind Resources									
Gorge Wind (MWa)	41	41	41	41	41	41	41	41	41
WA Wind (MWa)	0	0	77	0	0	77	0	0	77
MT Wind (MWa)	109	109	109	109	109	109	109	109	109
Total Renewables (MWa)	150	150	227	150	150	227	150	150	227

TABLE ES-5: Cumulative dispatchable capacity additions in the preferred portfolio

	Reference Case			Low Need			High Need		
	2023	2024	2025	2023	2024	2025	2023	2024	2025
Storage Resources									
6hr Batteries (MW)	0	37	37	0	37	37	0	37	37
Pumped Storage (MW)	0	200	200	0	200	200	0	200	200
Total Storage (MW)	0	237	237	0	237	237	0	237	237
Capacity Fill (MW)	123	79	358	0	0	0	425	423	739
Total Dispatchable Capacity (MW)	123	316	595	0	237	237	425	660	976

ES.6 PGE's Action Plan

The analysis presented in this IRP confirms that amid the rapid technological and market changes being experienced in the West, utilities, including PGE, face large uncertainties in future needs and resource economics. This IRP also demonstrates that PGE can take low-risk, near-term actions to meet near-term needs and set the company on a course to achieve critical long-term goals. In support of our goals and in alignment with our preferred portfolio, we are seeking acknowledgment of the 2019 IRP Action Plan briefly summarized below.

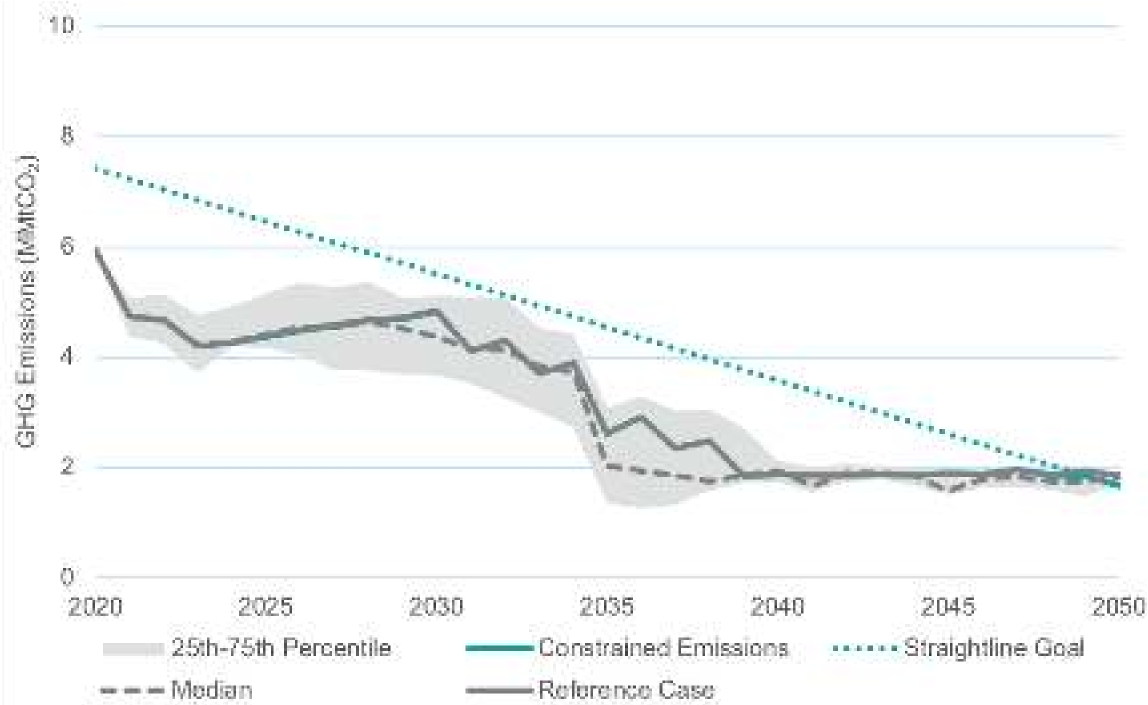
- **Customer resource actions.** Customer participation will be critical to achieving long-term decarbonization at the lowest cost to customers. Based on the findings of the Navigant DER Study, PGE proposes the following actions to support customer participation in demand side management programs.
    - Action 1A. Seek to acquire all cost-effective energy efficiency, which is currently forecasted by the Energy Trust of Oregon to be 157 MWa on a cumulative basis by 2025.
    - Action 1B. Seek to acquire all cost-effective and reasonable distributed flexibility, which is currently forecasted to include, on a cumulative basis:
        - 141 MW of winter demand response (Low: 73 MW, High: 297 MW).
        - 211 MW of summer demand response (Low: 108 MW, High: 383 MW).
        - 137 MW of dispatchable standby generation.
        - 4.0 MW of utility-controlled customer storage (Low: 2.2 MW, High: 11.2 MW).
- **Renewable actions.** Through portfolio analysis, PGE determined the best balance of cost and risk includes a near-term renewable action that contributes to meeting near-term energy and capacity needs as well as long-term renewable obligations and that qualifies for federal tax credits. PGE proposes to pursue the following action to acquire renewable resources:

  - Action 2. Conduct a Renewables Request for Proposals (RFP) in 2020, seeking up to approximately 150 MWa of RPS-eligible resources to enter PGE's portfolio by the end of 2023. PGE proposes the following conditions as part of this action:
    - The Renewables RFP would be open to all RPS-eligible resources.
    - The Renewables RFP would incorporate a cost-containment screen similar to PGE's 2018 Renewables RFP.
    - PGE would return the value of RECs generated from acquired resources prior to 2030 to customers, similar to the proposal in PGE's 2016 IRP Revised Renewable Action Plan.
    - PGE plans to provide a proposal for transmission requirements for this RFP within the 2019 IRP docket.
- **Capacity actions.** To ensure that PGE can meet our future capacity needs, while taking into consideration the potential impact of uncertainties, PGE plans to conduct the following staged process to secure capacity in the 2024 to 2025 timeframe.
  - Action 3A. Pursue cost-competitive agreements for existing capacity in the region.
  - Action 3B. Update the Commission and stakeholders on the status of PGE's bilateral negotiations and any resulting impacts on capacity needs.
  - Action 3C. Conduct an RFP for non-emitting resources to meet remaining capacity needs.

In addition to meeting our near-term needs, this Action Plan will help us continue on the course to meeting our goal of reducing GHGs by more than 80 percent by 2050. We estimate that the proposed renewable action would avoid approximately 16 million metric tons of GHGs between 2023 and 2050 and would represent 5 to 12 percent of the total additional clean and renewable resources that we need between now and 2050 to hit our goal. The GHG emissions forecast associated with our plan is shown, with uncertainties, in Figure ES-6 below. The trajectory reflects the effects of both near-term and outer year renewable additions, the effects of ceasing coal-fired operations at Boardman by the end of 2020, the exit of Colstrip Units 3 and 4 from our portfolio no later than the end of 2034,[16] and the impacts of a potential future cap and trade program in Oregon. Our analysis suggests that with continued effort to deploy energy efficiency, implement Senate Bill 1547, and respond to potential climate and clean energy policies, we would be on course to stay close to or below our target emissions trajectory between now and 2050.

[16] In Chapter 7, we explore additional sensitivities related to Colstrip's inclusion in our portfolio over time.

FIGURE ES-6: Greenhouse gas emissions forecast



ES.7 Conclusion

Throughout the 2019 IRP, we aimed to design an Action Plan that reflects our values, responds to customer and stakeholder feedback, and embraces the positive change that continues to shape the electric utility industry. Oregon's traditional, yet robust, IRP framework has aided us in these efforts. In some cases, we have proposed evolutions in how this framework may adapt to the shifting demands of customers and the opportunities afforded by new technologies. Our proposed Action Plan allows us to continue pursuing low-cost and clean technologies to benefit customers, while mitigating future risks. Our plan also gives us the flexibility to adapt and learn as conditions change and new opportunities arise. More importantly, the Action Plan provides clarity on our priorities and invites further conversation with customers, stakeholders, and the Commission. We look forward to working together in this IRP and in future planning efforts to chart the course toward a clean, affordable, and reliable energy future.

CHAPTER 1. 2016 IRP in Review

Portland General Electric Company's (PGE, or the Company) 2016 Integrated Resource Plan (IRP) was a collaborative plan developed in consultation with the Oregon Public Utility Commission (OPUC or Commission) Staff and public stakeholders. Through two orders, entered on August 8, 2017[17] and December 12, 2017[18] respectively, the Commission acknowledged the 2016 IRP, which focused on four categories of actions: demand-side actions, supply-side actions, integration actions, and enabling studies.

Below is a high-level overview of our substantial progress in implementing the actions in our 2016 IRP Action Plan and the directives from OPUC acknowledgment Orders No. 17-386 and 18-044, summarized in the green boxes in the text. Each action also provides a reference to additional information in the 2019 IRP.

Chapter Highlights

- ★ PGE is on track to meet 2021 demand side procurement targets.
- ★ PGE successfully procured 300 MW of regional capacity through bilateral contracts.
- ★ PGE successfully completed its 2018 Renewables RFP and selected the Wheatridge Renewable Energy Facility.
- ★ PGE expects to bring up to 39 MW of energy storage online by the end of 2020.
- ★ PGE implemented and completed numerous modeling enhancements and enabling studies and discussed the results with stakeholders at multiple public meetings.

[17] *In the Matter of Portland General Electric Company, 2016 Integrated Resource Plan*, Docket No. LC 66, Order No. 17-386 (entered Aug. 8, 2017 and filed Oct. 9, 2017).

[18] *In the Matter of Portland General Electric Company, 2016 Integrated Resource Plan*, Docket No. LC 66, Order No. 18-044 (Feb. 2, 2018).

1.1 Demand Side

PGE made significant demand-side resource acquisitions following the 2016 IRP acknowledgement and is on course to fulfill the actions included in our 2016 Action Plan.

1.1.1 Energy Efficiency

Action Item: Acquire 135 MWa of cost-effective energy efficiency.

Modifications Required by the Commission:

1. PGE will use the Energy Trust's most recent forecast data for changes to the 2021 capacity need;
2. PGE will provide an update on the Energy Trust's activities and progress on the large customer funding issue in its IRP update in 2018; and
3. PGE will make available the Energy Trust's energy efficiency forecast data and provide an explanation of their model in the company's next IRP.

Order No. 17-386 at 8.

We are on target to procure 135 MWa of cost-effective energy efficiency (EE) by 2021. As noted in our 2016 IRP Update, filed March 3, 2018, OPUC Order No. 17-466 directs the Energy Trust of Oregon (Energy Trust) to increase the large customer funding cap from 18.4 percent to 20 percent. In this IRP, we use the Energy Trust's most recent forecast data for changes to the 2021 capacity need and provide the Energy Trust's EE forecast data and explanation of the agency's model in External Study B. Additional discussion of the Energy Trust's forecast and its use in the 2019 IRP portfolios is provided in Section 4.1.2 Energy Efficiency.

1.1.2 Demand Response

Action Item: Acquire 77 MW (winter) and 69 MW (summer) demand response.

Modifications Required by the Commission:

1. Through 2020, acquire at least 77 MW (winter) and 69 MW (summer) of new demand response resource, while working to reach the demand response high case targets of 162 MW (summer) and 191 MW (winter);
2. 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;
3. 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
4. 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.

Order No. 17-386 at 9.

1.1.2.1 Demand Response Acquisition

We are making good progress on the demand response (DR) requirements ordered by the Commission in the 2016 IRP. Currently, we have four DR products in operation:

- **Smart Thermostats.** Residential product that leverages electric ducted heating/cooling systems to shift energy consumption during winter and summer events.
- **Energy Partner.** Business and government product that curtails energy from heating/cooling and/or process equipment during peak periods using nominations agreed upon between PGE and participating customers.
- **Multi-family Water Heater.** Product designed for multi-family residences that shifts tenant water heater electricity usage.
- **Flex Pilot.** Program to encourage residential customers to shift their peak period consumption during winter and summer events. The pilot ended on April 30, 2019, but we have relaunched the program as Flex 2.0 (approved April 9, 2019 by the OPUC),[19] and introduced a standardized approach to peak time events. We are in the process of refining the Time of Day rate.

To date, we have achieved 21 MW of the 77 MW of winter DR and 32 MW of the 69 MW of summer DR. We are on target to achieve our 2020 DR goals. We anticipate scaling up the Flex 2.0 offering to bring in an additional 17 MW of DR capacity through the remainder of 2019.

1.1.2.2 Demand Response Study

We continue to work with consultants to better understand the potential for DR in the Northwest (NW), to inform our design of DR programs, and to establish inputs to the integrated resource planning process.[20] For the 2016 IRP, we worked with The Brattle Group to examine load reduction capabilities we could gain through the deployment of specific DR programs, along with the expected cost-effectiveness of these programs.[21] Building on the Brattle DR-potential study we engaged Navigant Research to include DR in a propensity-to-adopt study for distributed resources and flexible load. The Navigant study sought to help us better understand the likelihood of customer participation in several existing and potential DR programs. Scenarios from this study informed analysis for the 2019 IRP, as described in Section 5.1 Distributed Flexibility.

1.1.2.3 Demand Response Testbed

Since the 2016 IRP, PGE has implemented a Demand Response Testbed pilot program. In late 2017, we began working with Commission Staff to establish a Demand Response Review Committee (DRRC). On February 23, 2018, the DRRC began meeting to discuss the development and review of future PGE DR program proposals. A subset of the DRRC met for intensive workshops from May 1–4, 2018 at the Rocky Mountain Institute's E-Lab. In September of 2018, we shared a draft Demand

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[19] OPUC Docket ADV 920.

[20] The Brattle Group and Global Energy Partners, *Assessment of Demand Response Potential for PGE*, prepared for PGE, March 16, 2009. Also, Ahmad Faruqui and Ryan Hledik, *An Assessment of Portland General Electric's Demand Response Potential*, prepared by The Brattle Group for Portland General Electric, November 28, 2012.

[21] The Brattle Group, *Demand Response Market Research: Portland General Electric, 2016 to 2035*, prepared for PGE, January 2016.

Response Testbed program proposal with the DRRC. After review by the DRRC, we filed the proposal with the OPUC on October 25, 2018.[22]

We proposed Schedule 13, Opt-Out Residential Demand Response Testbed Pilot in Advice No. 18-14. Schedule 13 seeks to establish high program participation in DR by eligible residential customers through a peak time rebate (PTR), in which customers may receive a rebate when they respond to our notification of peak time events. Customers living in specific geographical areas are automatically enrolled in the program and can opt out if desired. Schedule 13 became effective April 10, 2019 and we will offer the testbed pilot through June 30, 2022.

1.1.3 Conservation Voltage Reduction

Action Item: Deploy 1 MWa of conservation voltage reduction through 2020

Order No. 17-386 at 9.

We are making progress on conservation voltage reduction (CVR)[23] work and we provided an update in our annual Smart Grid Report filed on May 31, 2017.[24] In 2017, we worked to develop the analytics needed to increase observability and customer-level alarms for instances of voltage levels outside of ANSI voltage limits. We will use this communications network and analytics to capture CVR benefits for customers through 2020 and beyond and align CVR work with other distribution resource planning efforts. We will continue providing future updates on CVR in our Smart Grid Report (OPUC Docket UM 1657), which PGE files with the Commission every two years. The 2019 Smart Grid Report was filed May 31, 2019.

1.1.4 Dispatchable Standby Generation

Action Item: Acquire 16 MW of dispatchable standby generation

Order No. 17-386 at 18.

We are on track to reach the 2021 goal of 135 MW of dispatchable standby generation (DSG), with approximately 127.8 MW enrolled as of December 2018. We also have several sites in construction and a queue of other customers planning to deploy DSG. Appendix E provides more about our DSG program and Appendix F provides our recommended DSG actions.

1.2 Supply Side Actions

Action Item: Pursue actions to meet PGE's capacity needs in 2021, which were estimated at 561 MW, 240 MW of which must be dispatchable. Procure capacity via bilateral negotiations and filing of waiver of Competitive Bidding Guidelines. Issue all-source RFP for any capacity needs

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[22] OPUC New Schedule 13, *Opt-Out Residential Demand Response Testbed Pilot and Application*, Docket No. ADV 859, Advice No. 18-14 (filed Oct. 25, 2018).

[23] CVR is the strategic reduction of feeder voltage, deployed with phase balancing and distributed voltage regulating devices to ensure end-customer voltage is within the low range of ANSI (American National Standards Institute) acceptable voltages (114V – 120V).

[24] *In the Matter of Portland General Electric Company, Annual Smart Grid Report*, Docket No. UM 1657 (filed May 31, 2017).

(including dispatchable capacity) that may remain unfilled after completing bilateral negotiations.

Modifications Required by the Commission:

1. Complete bilateral negotiations, with periodic updates to Staff as to status of negotiations and progress toward completing negotiations of key terms and conditions;
2. Concurrently, work with Staff and stakeholders to scope and launch a regional market study of potentially available resources to be run in parallel with the company's efforts to complete the bilateral negotiations; and
3. Report to the Commission, within four months (of August 8, 2017), the results of the bilateral negotiations and the need for: (a) completing the market study; (b) re-running models and developing a new preferred portfolio using data from the bilateral contracts, the market study, and any other new analyses; and (c) issuing an initial RFP for specific short- to medium-term resources before proceeding with an all-source RFP.

Order No. 17-386 at 17-18.

1.2.1 Bilateral Negotiations

Our 2016 IRP Update, filed March 8, 2018, updated the Commission on our use of bilateral negotiations to procure needed capacity. Pursuant to OPUC Order No. 17-494, we kept the Commission and Staff informed on negotiations, and ultimately executed contracts totaling 300 MW of capacity using the bilateral procurement process:[25]

- 200 MW of annual capacity with five-year term.
- 100 MW of seasonal peak capacity during summer and winter periods with a five-year term beginning in 2019.

Because we did not seek a major capacity resource acquisition after completing the bilateral negotiations, we did not complete a study of "potentially available resources" in the region. However, we conducted a market capacity study to support the 2019 IRP as discussed in Section 1.4.5 and Section 2.4.2.1, and the final report is available in External Study E.

1.2.2 Renewable Actions

In November 2017, we filed an addendum to the 2016 IRP proposing to acquire approximately 100 MWa of renewable resources by 2021. In Order No. 18-044, the OPUC conditionally acknowledged our revised renewable action item, allowing us to proceed with issuing a Request for Proposals (RFP) for new renewable energy resources.[26] The Commission's conditions required us to:

- Provide updates to the Company's energy, capacity, and Renewable Portfolio Standards (RPS) needs.
- Discuss aspects of RFP design and scoring that impact the treatment of Montana wind resources.

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[25] *In the Matter of Portland General Electric Company, Application for Waiver of Competitive Bidding Guidelines*, Docket No. UM 1892, Order No. 17-494 (Dec. 11, 2017).

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

- Provide a full description of the cost containment mechanism proposed by PGE.
- Develop a glide path analysis for use in future IRPs.
- Staff may request that the Commission open a docket[27] to "determine a specific mechanism for delivering value from incremental [renewable energy certificates] (RECs) to customers."[28]

1.2.2.1 2018 Renewables RFP

PGE fulfilled the first three conditions in Docket UM 1943, the 2018 Renewables RFP docket.[29] In collaboration with Staff, stakeholders, and interested parties, we designed and conducted our 2018 RFP in compliance with the Competitive Bidding Guidelines, in accordance with Commission Order No. 18-171, and with oversight by the Commission-selected independent evaluator (IE), Bates White. The Commission acknowledged our final shortlist on December 19, 2018.[30]

On February 12, 2019, we announced the results of the 2018 RFP and that PGE and NextEra were jointly developing the Wheatridge Renewable Energy Facility (Wheatridge), North America's first major energy facility to co-locate wind (300 MW), solar (50 MW), and battery storage (30 MW). PGE will own 100 MW of Wheatridge's wind project and will purchase the output of the balance of the project under power purchase agreements (PPAs). The wind portion of Wheatridge will be operational by December 2020, allowing it to qualify for 100 percent of the federal production tax credit (PTC). We expect the solar and battery resources to be operational in 2021 and to qualify for the federal investment tax credit (ITC).

1.2.2.2 Glide Path Analysis

Condition four of OPUC Order No. 18-044 instructs PGE to develop a glide path analysis in future IRPs. We designed the glide path analysis as a means for assisting us, the Commission, and stakeholders to understand our long-term renewables strategy and the incremental procurement steps needed to accomplish this strategy. For the 2019 IRP, we sought stakeholder feedback regarding both portfolio construction and the renewable glide paths embedded in the 2019 IRP portfolios. See Section 7.3.3 for more information on renewable glide paths in the 2019 IRP.

1.3 Energy Storage

> **Action Item:** Submit storage proposal in accordance with House Bill 2193, by January 1, 2018.
>
> Order No. 17-386 at 18.

Pursuant to House Bill 2193 and OPUC Docket No. UM 1751, we submitted a proposal for the development of energy storage systems in Docket No. UM 1856. In total, our proposed projects combine to approximately 39 MW of energy storage resources. Descriptions of these resources are

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[27] At the time of filing of this IRP, the Commission had not opened a docket to establish the mechanism for valuing RECs.

[28] *Id.*

[29] *In the Matter of Portland General Electric Company, 2018 Request for Proposals for Renewable Resources*, Docket UM 1934 Order No. 18-171 (May 21, 2018).

[30] Order No. 18-483.

available in our testimony filed in Docket No. UM 1856 on January 5, 2018. Pending completion of all regulatory requirements, we anticipate that these resources will come online in 2020.[31]

1.4 Enabling Studies to Inform 2019 IRP

Action Item: Perform enabling studies to inform next IRP.

1. Flexible Capacity and Curtailment Metrics
2. Customer Insights
3. Decarbonization
4. Risks Associated with Direct Access

Modifications Required by the Commission:

Perform the following additional studies.

5. Treatment of Market Capacity
6. Accessing Resources from Montana
7. Load Forecasting Improvements

Order No. 17-386 at 19.

We conducted six key enabling studies to help inform the 2019 IRP. The studies performed represent our continuous effort to enhance our long-term planning process and improve modeling assumptions. This section provides synopses of each study and references to additional information in this IRP. We discuss load forecasting improvements in Section 1.5.1.

1.4.1 Flexible Capacity and Curtailment Metrics

We considered resource flexibility, flexibility adequacy, and renewable curtailment in the 2019 IRP through three parallel studies, summarized below.

- **Variable renewable integration cost study.** As in past IRPs, we estimated the cost associated with balancing renewable resources integrated into our system by simulating system dispatch and costs in the Resource Optimization Model (ROM). The resulting integration costs and curtailment statistics for Pacific Northwest (PNW) wind, Montana wind, and central Oregon solar are available in Section 6.1.3 Integration Costs.
- **Flexibility value study.** We incorporated the value of flexibility for flexible capacity resources directly into the 2019 IRP portfolio analysis. We also calculated the flexibility value using ROM to simulate the operational cost impacts of introducing flexible capacity resources. Section 6.2.2 Flexibility Value discusses this analysis.
- **Flexibility adequacy study.** Building upon previous flexibility adequacy work in our 2016 IRP, we engaged Blue Marble Analytics to research existing literature on flexibility adequacy, to develop methodologies and metrics to assess system flexibility adequacy for the PGE system, and to conduct an analysis of flexibility adequacy and the potential contribution of flexible

[31] *In the Matter of Portland General Electric Company, Draft Storage Potential Evaluation*, Docket UM 1856, Order No. 18-290 (Aug. 13, 2018).

capacity for PGE. Section 4.6 Flexibility Adequacy presents the results of the study and describes how we used the results in the 2019 IRP.

1.4.2 Customer Insights

To assess and better understand our customers' resource preferences and cost expectations, we engaged Market Strategies International (MSI) to conduct our 2017 Customer Insights Survey.[32] We discussed the study with stakeholders at an IRP Roundtable Meeting on February 14, 2018, and we used the results to inform our 2019 IRP long-term resource planning. Section 2.1.2 Customer Preferences summarizes the survey results.

1.4.3 Decarbonization

We 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 our customers engage in dramatic decarbonization of the local energy economy and to understand how this transformation might impact the electricity sector and our resource needs. We worked with EER to scope three deep decarbonization scenarios each of which meets an 80 percent reduction in energy-related greenhouse gas emissions (GHG) relative to 1990 levels by 2050. We discussed the study with stakeholders at IRP Roundtable 18-1 on February 14, 2018, and we incorporated the findings into a sensitivity analysis, described in Section 7.4.1. The full study report can be found in External Study A.

1.4.4 Risks Associated with Direct Access

For the 2019 IRP, we conducted a sensitivity analysis to examine the potential scale of the capacity adequacy impacts associated with long-term direct access load. Section 4.7.3 provides detailed information on this analysis.

1.4.5 Treatment of Market Capacity

To inform the 2019 IRP's treatment of market capacity, we engaged Energy + Environmental Economics, Inc. (E3) to investigate PNW resource adequacy, regional market capacity availability, and future load and resource changes. We worked with Staff and stakeholders to scope this study and ultimately shared the results at PGE's Roundtable 18-5 on October 31, 2018.[33] This study broadly examines the PNW capacity load resource balance under reference, low, and high need scenarios. Section 2.4.2.1 Market Capacity Study provides the results from the study and discusses how we incorporated the results into the 2019 IRP. E3's report is available in External Study E.

1.4.6 Accessing Resources from Montana

Previous analyses, including analysis within our 2016 IRP, have suggested that wind resources in Montana may provide improved capacity factors and resource diversity benefits over additional wind development in the Columbia River Gorge. To better understand our ability to make use of these

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32 PGE, 2017 Integrated Resource Plan Survey. Retrieved Jul. 9, 2019, from https://www.portlandgeneral.com/-/media/public/our-company/energy-strategy/documents/msi-customer-insights-study-rt-18-1-2018-02-14.pdf?la=en.

33 PGE Roundtable 18-5 (2018, October 18). IRP Public Meetings. Retrieved from https://www.portlandgeneral.com/our-company/energy-strategy/resource-planning/integrated-resource-planning/irp-public-meetings. See also Appendix C. 2019 IRP Public Meeting Agendas for a list of public meetings where PGE discusses the Market Capacity study.

resources, the Commission and stakeholders requested that we assess the potential for accessing renewable resources from Montana in the 2019 IRP. In developing the 2019 IRP, we held stakeholder workshops to discuss the potential for accessing resources, particularly wind, from Montana.[34] These discussions provided critical input on transmission pricing and availability, diversity benefits, regional planning efforts, and other issues related to accessing Montana resources.

In 2017 and 2018, we actively participated in the development of the Montana Renewables Development Action Plan (MRDAP), a process led by the state of Montana and the Bonneville Power Administration (BPA). BPA released the MRDAP[35] in June of 2018, and a subsequent update[36] in October of 2018. The MRDAP sets forth the opportunities and barriers related to renewable resource development in Montana and provides recommendations for next steps. Section 5.2.1 Wind Power and Section 5.5.4 Transmission Modeling in the IRP describe how we used or considered information from the MRDAP in the 2019 IRP.

1.5 Additional Items

1.5.1 Load Forecasting Improvements

Action Item: Conduct ongoing workshops, including consideration of probabilistic forecasts with interested stakeholders to improve PGE's forecasts.

1. Conduct out-of-sample testing and select models based on these results.
2. Include a technical appendix that describes forecast methodology and contains a list of the forecast modeling assumptions (and explanations) and the model specifications (equations).

Order No. 17-386 at 19.

New technologies, changing consumer preferences and end uses, and energy efficiency gains are just a few of the factors that impact our load forecasting. For the 2016 IRP, we contracted Itron, an independent industry expert, to conduct a review of our load forecast methodology. Itron found our methodology to be effectively consistent with industry standards, and provided recommendations to further align our methodology and models, which we implemented. For the 2019 IRP, we added probabilistic forecasting, conducted out-of-sample testing, reassessed long-term models, and included a technical appendix that discusses our load forecast methodology. Chapter 4. Resource Needs offers additional information on our load forecast, and Appendix D describes our load forecast methodology, modeling assumptions, and model specifications.

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34 PGE Roundtable 18-3 (2018, August 22) and Roundtable 18-7 (2017, December 19). IRP Public Meetings. Retrieved from https://www.portlandgeneral.com/our-company/energy-strategy/resource-planning/integrated-resource-planning/irp-public-meetings .

35 *Montana Renewables Development Action Plan*. Retrieved Nov. 5, 2018, from https://www.bpa.gov/Projects/Initiatives/Montana-Renewable-Energy/Documents Montana/Montana-Renewables-Development-Action-Plan-June-2018.pdf.

36 *Montana Renewables Development Action Plan* (Update – October 2018). Retrieved Nov. 5, 2018, from https://www.bpa.gov/Projects/Initiatives/Montana-Renewable-Energy/Documents Montana/Action Items - MRDAP - October Update_Final.pdf.

1.5.2 Portfolio Ranking and Scoring Metrics

Action Item: Hold workshops with interested parties to develop a simple and clear set of portfolio scoring metrics, with a focus on using only metrics that have a clear interpretation and robust discussions on the appropriate way to incorporate short- and medium-term options and the relative importance of high-cost versus low-cost outcomes.

Order No. 17-386 at 19.

We held multiple workshops with interested stakeholders to discuss and develop portfolio scoring metrics for the 2019 IRP. At Roundtable 17-3, we had an open conversation with stakeholders about the stakeholder values that attendees wanted to see reflected through scoring in the 2019 IRP. We provided a summary of our takeaways from that conversation at IRP Roundtable 18-1 on February 14, 2018. Five common themes emerged from the conversation :

- Cost and risk
- Sustainability
- Fairness and transparency
- Reliability and resiliency
- Incrementalism and optionality

We incorporated these themes into both scoring metric design and other aspects of the IRP analysis. At the request of stakeholders, we provided multiple iterations of draft portfolio analysis and scoring throughout the Fall of 2018. This gave stakeholders the opportunity to provide feedback on scoring metric design with a more tangible understanding of how scoring metric design decisions might influence portfolio analysis findings. Chapter 7. Portfolio Analysis describes the resulting scoring methodology.

1.5.3 Distribution Resource Planning

Action Item:

1. Work with Staff and other parties to advance distributed energy resource forecasting and distributed energy resource representation in the IRP process.
2. Work with Staff to define a proposal for opening a distribution system planning investigation

Order No. 17-386 at 19.

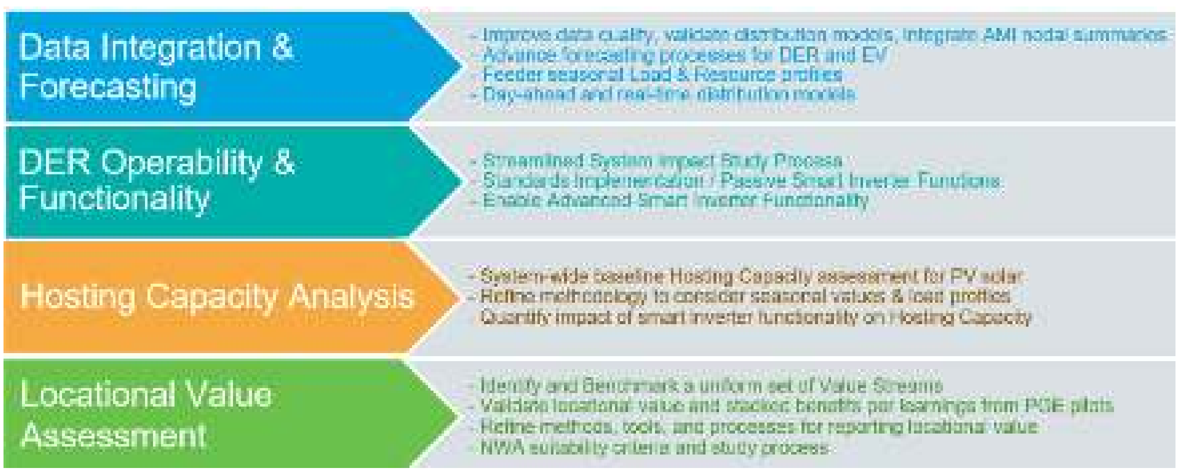
To advance the forecasting and representation of distributed energy resources in the 2019 IRP, we engaged Navigant Consulting to holistically evaluate the potential for PGE customers to adopt distributed resources and to participate in distributed resource programs (the DER Study). Navigant presented draft results to stakeholders at IRP Roundtable 18-3 on August 22, 2018 and incorporated feedback from stakeholders into the final analysis, which Navigant presented at IRP Roundtable 18-4 on September 26, 2018. The results of the DER Study became major inputs for our needs assessment and portfolio analysis. A summary of the DER Study is available in External Study C. The study results and implications on long-term planning are discussed throughout the 2019 IRP, particularly in Chapter 4. Resource Needs (adoption of electric vehicles, customer solar, and non-dispatchable customer storage) and Chapter 5. Resource Options (demand response and dispatchable customer storage).

In 2017, we began exploring options for implementing distribution resource planning (DRP) into our current transmission and distribution (T&D) planning processes. We focused on processes that would allow us to more effectively and reliably integrate distributed energy resources (DERs) into the Company's T&D system, while continuing to meet core operational imperatives. We believe that DRP will form the foundation for our efforts to modernize the electricity grid, making it more flexible, efficient, and cost-effective. DRP will also accelerate our decarbonization goals by enabling the integration of low carbon resources into the grid.

In 2018, we began conversations with Commission Staff in preparation for a DRP investigatory docket. In February 2019, Staff issued its white paper, *A Proposal for Electric Distribution System Planning*, which set forth a proposal for launching an investigation into distribution system planning. PGE, along with other stakeholders, provided feedback on Staff's proposal and Staff held a pre-docket workshop on March 1, 2019 to further discuss and refine the proposal. Following the workshop, Staff modified its proposal and formally requested that the Commission open an investigatory docket into distribution system planning.[37]

The Commission officially opened Docket No. UM 2005 on March 22, 2019. We are actively participating in this docket and continue to work on advancing our capabilities in the four areas detailed in Figure 1-1: data integration and forecasting, DER operability and functionality, hosting capacity analysis, and locational value assessment.

FIGURE 1-1: PGE focus areas for advancing the use of DERs to support the grid



37 *In the Matter of Public Utility Commission of Oregon, Investigation into Distribution System Planning*, Docket No. UM 2005, Staff Report (Mar. 14, 2019).

1.5.4 Boardman Biomass

Since the 2016 IRP, we continued to explore the possibility of reconfiguring the Boardman Generating Station to use torrefied biomass for fuel after coal-fired operations cease by December 31, 2020. We extensively researched this option because of the significant potential benefits a conversion might offer by diversifying our energy mix with a large-scale, dispatchable, carbon-neutral renewable generating resource. We explored all aspects of a potential conversion and conducted test burns in 2016 and 2017. Our analysis found that while running Boardman on torrefied biomass is technically feasible, a conversion is not expected to be economically competitive with other resources at this time. This is due to a combination of factors, notably the cost of securing a reliable fuel supply and the costs associated with retrofitting the plant with new controls to meet required emissions standards. We are preparing a decommissioning plan for the plant given that a biomass conversion will not proceed at this time. The decommissioning plan will address the steps needed to prepare and manage the facility in a manner that would preserve any potential value for customers, in the event we determine at a future date the plant’s non-coal-related equipment or facilities could beneficially be repurposed for other energy-related functions that are consistent with our resource plan and clean energy commitments.

CHAPTER 2. Planning Environment

With each IRP, PGE reviews the diversity of external factors that impact our long-term resource planning. Factors such as changes in law and policy, general economic conditions, technological advances, and environmental concerns can influence our overall resource strategy. The 2019 IRP examines the following external influences:

- Evolving customer expectations
- Federal and state policy changes
- Wholesale market landscape
- Technological innovation

This chapter examines the potential implications of these external influences and describes how we consider the effect of these outside factors in the 2019 IRP.

Chapter Highlights

- ★ PGE's 2019 IRP addresses the impact of the rapid change on the electricity industry by focusing on four key themes: decarbonization, customer decisions, uncertainty and optionality, and technology integration and flexibility.
- ★ Energy-, environmental-, and technology-conscious customers are enabling PGE to enhance and develop energy products and services that provide customers with options.
- ★ Performance improvements and cost reductions continue to drive growth in clean energy resources.
- ★ Thermal resource retirements in the West may create resource adequacy challenges in the near future.

2.1 Customer Landscape

Every day, PGE's customers are discovering and embracing new ways of living with and using electricity. Sparked by evolving technology and an increasing desire for more environmentally conscious energy options, customers are expressing ever-changing energy preferences and needs, presenting us with the opportunity to engage differently with them. Traditionally, our relationship with customers focused on providing safe, reliable, and affordable energy, with all electricity and information flowing unidirectionally from PGE to the customer. Today, more customers want flexibility, the bidirectional flow of energy and information, and the ability to manage their energy use to meet their savings and sustainability goals. As Oregon's largest electric utility, we are actively assessing these changing customer preferences and aligning our products, processes, and systems to quickly meet our customers' needs.

We are constructing a more customer-centric business model through enhanced customer analytics, varying media channels, touchpoint surveys, and market research. These tools are helping us understand and appreciate the varying customer preferences that exist for high tech customers versus office complexes, schools, or retail stores. Similarly, we are learning what products and services meet the needs of residential customers living in multi-family dwellings as opposed to single family dwellings, and for renters versus owners.

This new model will also help us promote beneficial programs such as energy efficiency and our growing list of voluntary renewable energy programs. As we strive to be our customers' most-trusted energy partner, PGE is moving beyond providing basic electricity service to create a diversified portfolio of resources and rates products based on changing customer preferences and increasing customer energy savviness. To align planning and operations, our 2019 IRP applies a customer-focused lens to the analysis and Action Plan.

2.1.1 Economic and Migration Trends

Oregon's economic outlook is a key input to PGE's macroeconomic projections of customer and load growth, as discussed in Chapter 4. Resource Needs. Oregon's economic expansion has continued since the last IRP cycle, although at a gradually slowing rate. Employment growth has slowed from peak expansion levels of approximately 3.5 percent in mid-2015 to 2.3 percent in 2017 and 1.8 percent in 2018. These employment growth levels remain in step with growth in the labor force, keeping the unemployment rate in Oregon at historic lows which in turn encourages migration into Oregon and increases incomes. Per capita personal income grew at an average annual rate of 3.3 percent for 2016 and 2017. As Oregon growth has outpaced the U.S., our service area has grown even more rapidly, as urban areas continue to outpace growth in rural communities across Oregon. Population growth in the Portland metro area averaged 1.7 percent compared to 1.5 percent for Oregon from 2015 to 2018.

While the current expansion is past its peak, Oregon's growth advantage is anticipated to continue. In its 10-year forecast, Oregon's Office of Economic Analysis (OEA) expects employment growth in Oregon to outpace the national trend. OEA forecasts annual growth rates for Oregon averaging 0.9 percent versus 0.6 percent for the U.S. Alongside a strong employment forecast, migration is expected to continue to drive Oregon's population growth, which averages 1.1 percent, outpacing the average annual growth rate for the U.S. of 0.7 percent.

As described in Chapter 4. Resource Needs, these combined economic factors result in continued growth in our customer base and the demand for electricity in the Reference Case. However, uncertainties in future economic conditions create a large range of future potential loads and resource needs. The 2019 IRP incorporates new methodologies and frameworks to account for these uncertainties in the long-term planning process.

2.1.2 Customer Preferences

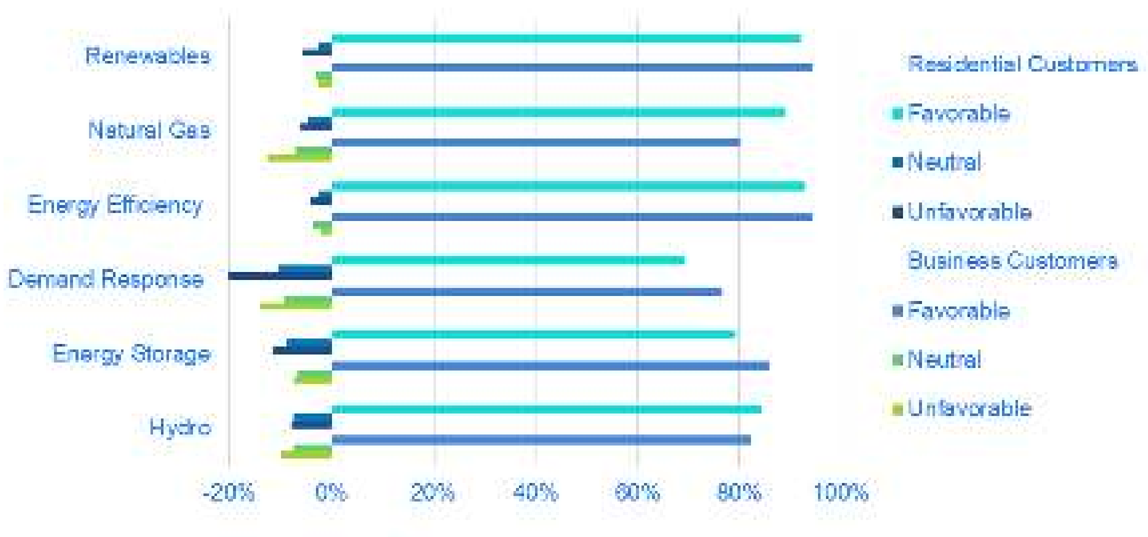
PGE engaged Market Strategies Incorporated (MSI) to conduct an updated Customer Insights Survey in 2017 to assess customers' resource preferences and cost expectations.[38] We used the survey results to help inform our 2019 IRP portfolio construction, scoring metrics, and Action Plan. The survey involved a random sample of 502 residential PGE customers and 168 general business customers. MSI recruited and screened customers to complete a web survey focused on our future energy supply. PGE and MSI designed the survey with the following four objectives in mind:

- Provide information on customer preferences to support the public process of integrated resource planning.
- Understand customer concerns and preferences as they relate to integrated resource planning.
- Quantify customers' perceptions and receptivity to a variety of energy resource options, allowing us to assess individual resource and resource mix options on a ratio scale of customer support.
- Determine which resource options customers would be most likely to support, and the degree to which certain options would be supported over others.

The findings from our 2017 customer survey reinforce those from the 2016 IRP public and regulatory process: that some stakeholders and many customers express a strong preference for and interest in seeing PGE transition its generation from fossil fuel to clean and renewable resources. As shown in Figure 2-1 below, clean resources such as energy efficiency and renewables have high favorability and very low unfavorability with both residential and general business customers. Preferences for other resources, including energy storage, hydropower, natural gas, and demand response, varied more between residential and general business customers, with a significant portion of customers indicating a neutral or unfavorable response to demand response.

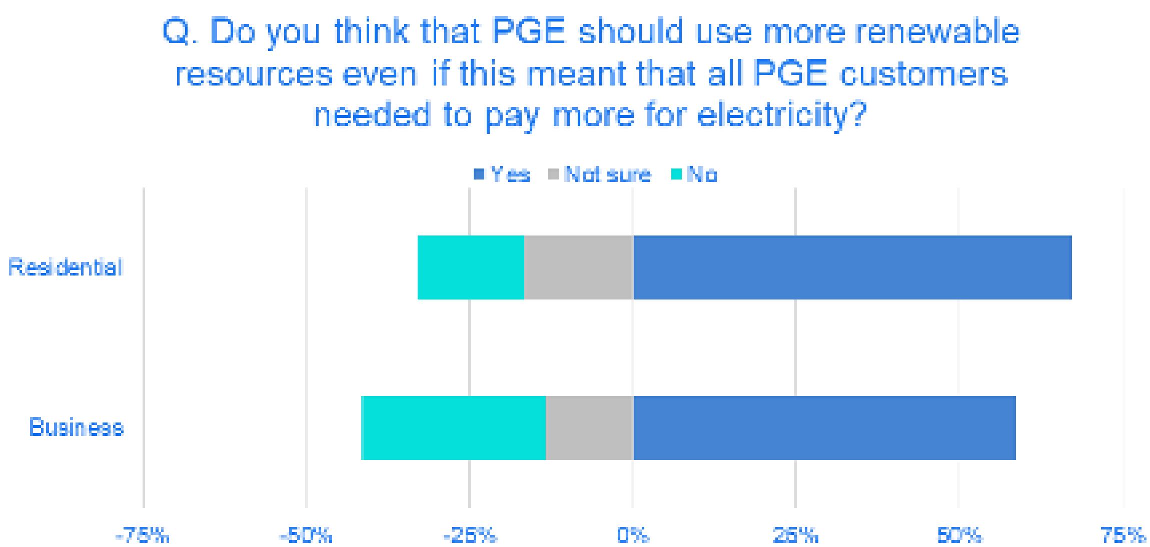
[38] PGE, 2017 Integrated Resource Plan Survey. Retrieved Jul. 9, 2019, from https://www.portlandgeneral.com/-/media/public/our-company/energy-strategy/documents/msi-customer-insights-study-rt-18-1-2018-02-14.pdf?la=en.

FIGURE 2-1: Customer resource preferences across key resource options



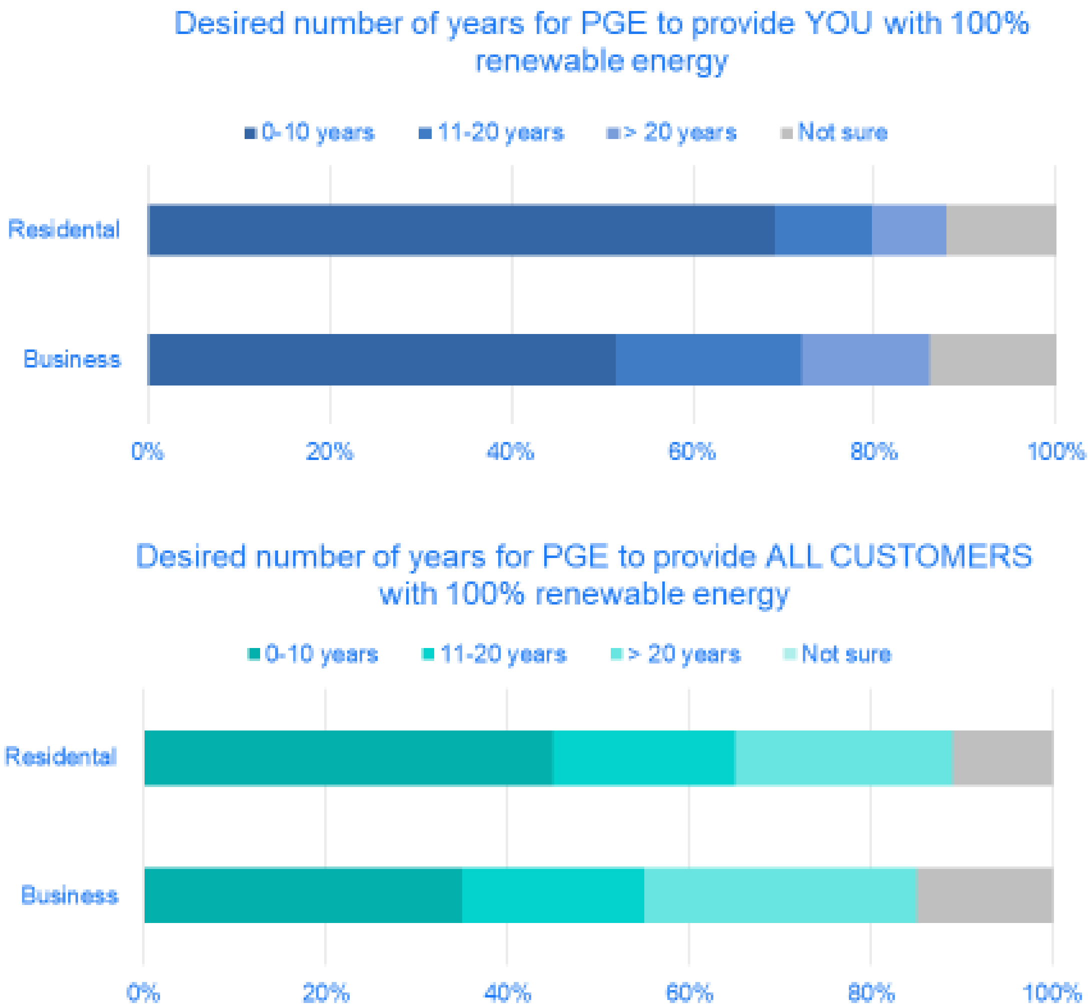
Reinforcing the preference for renewable resources, customers also indicated a strong willingness to pay more for electricity to bring about this transformation of the system. As shown in Figure 2-2 below, 54 percent of residential customers stated a willingness to pay 10 percent or more for incremental renewables. The figure also shows that 34 percent of general business customers are willing to pay 10 percent or more for additional renewables, while 64 percent of business customers are willing to pay 5 percent or more.

FIGURE 2-2: Customer support for use of more renewable resources



The survey also showed that customers expect PGE to provide 100 percent renewable power to their home or business within 20 years or less (see Figure 2-3). Additionally, a large majority of residential (65 percent) and general business (55 percent) customers believe that PGE should achieve 100 percent renewable energy across its entire service territory within 20 years.

FIGURE 2-3: Customer expectations for 100 percent clean and renewable energy



As PGE considers these stated customer preferences for faster access to more renewable energy, we must balance these preferences with other considerations, such as equity and affordability. Many of PGE's customers are low-income and impacted by the current costs of energy despite many discount and energy assistance programs offered by PGE. To address this reality, we design our voluntary renewable energy programs to respond to preferences of participating customers without harming non-participants. Additionally, our 2019 IRP's proposed renewable actions leverage federal tax credits and employ cost containment screens in resource evaluation to limit the financial impact of the incremental resources on all customers. Going forward, we will continue to seek ways to bring more clean and renewable energy to our customers as affordably as possible.

2.1.3 Voluntary Green Energy Programs, Products and Services

As indicated in the Customer Insights Survey conducted by MSI, many of PGE's customers are environmentally conscious and want reliable and renewable energy, even if they must pay more for it. Customers want the ability to choose among options. As with other utilities, we must construct programs and adjust planning processes to address the breadth and diversity of customer choices, preferences, and needs. An example of this is our current Green Future℠ renewable energy options, designed to meet our customers' preference for renewables. Green Future renewable energy products include:

- **Green Source℠.** Allows residential customers the option to obtain all their paid energy from 100-percent renewable energy sources.
- **Clean Wind℠.** Offers commercial and industrial customers the option to purchase up to 100 percent of their energy from various wind projects in 200-kWh blocks.
- **Green Future℠ Solar.** Allows residential and business customers to purchase one-kW blocks of solar energy from a solar project in Willamina, Oregon.

These products allow our customers to be 100 percent renewable through the purchase of renewable energy credits (RECs) that match the customers' load. We created the Green Future program 20 years ago, and thanks to a strong partnership with Green Mountain Energy Company (Green Mountain),[39] it is the first renewables program in the country to reach 200,000 participants. For the past nine years, Green Future has been ranked number one in the country for the largest customer participation in a voluntary renewables program, according to the U.S. Department of Energy's National Renewable Energy Laboratory (NREL).[40]

In April 2018, we sought to expand our voluntary renewable portfolio to offer large nonresidential customers the opportunity to receive bundled renewable energy through a green tariff. We filed a proposal for a subscription-based, green tariff program that allows large non-residential customers to be directly assigned the costs and output of a new, utility-scale renewable resource via long-term agreements with the utility. Under this green tariff, customers receive the energy and the RECs from a new renewable resource. The Commission opened Docket UM 1953 to address our proposal. After multiple rounds of testimony, workshops, a hearing, and briefs, the Commission issued Order No. 19-075 on March 5, 2019, authorizing PGE to develop and offer its customers a green tariff, with the initial program limited to 300 MW nameplate capacity of new renewable resources acquired via power purchase agreements (PPA).[41] PGE's Green Energy Affinity Rider (GEAR), Schedule 55, became effective on March 8, 2019.[42]

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[39] Green Mountain promotes and sells the Green Future renewable options to PGE customers via door-to-door efforts (Courtesy Knock Program) and staffing tables at storefronts and events.

[40] National Renewable Energy Lab. *Top Ten Utility Green Pricing Programs*. Retrieved July 9, 2019, from https://www.nrel.gov/analysis/assets/pdfs/utility-green-power-ranking.pdf.

[41] *In the Matter of Portland General Electric Company, Investigation into Proposed Green Tariff*, Docket No. UM 1953, Order No. 19-075 (Mar. 5, 2019). (The 300 MW includes 100 MW for the Company Procured Option or subscription-based program and 200 MW for a Customer Supply Option (bring-your-own PPA). A second phase of the docket will consider additional issues such as: utility ownership, credit calculations, green tariff interaction with Oregon's direct access program, and reassessment of the Commission's previously adopted nine conditions for green tariffs.)

[42] Advice No. 19-06, New Schedule 55, Green Energy Affinity Rider (GEAR).

Customer participation in voluntary green energy programs that provide both energy and RECs to customers have the potential to impact our resource needs (including energy and capacity) and greenhouse gas (GHG) emissions. Some programs, such as Community Solar, may also impact our REC position by reducing the retail sales that affect the determination of RPS requirements. Because these programs have not yet started or are relatively new, the 2019 IRP does not explicitly incorporate forecasts of customer participation in these programs within its core portfolio analysis. However, Section 4.7.2 Voluntary Renewable Program Sensitivities explores the potential impacts of customer participation in these programs and we have designed the Action Plan to be robust to potential customer enrollment in these programs. As we roll out these programs, we will monitor customer participation and incorporate its impacts in future IRPs and IRP Updates.

2.2 Policy Landscape

Local, state, and federal policy, including legislative actions, can impact our integrated resource planning process and assumptions. The following sections provide a summary of the key current, changing, and new policy options that impacted our 2019 IRP. We continue to engage in energy and environmental policy conversations at the local, state, and federal level to pursue prudent and sustainable policies that will achieve real GHG reductions on our system while maintaining safe, reliable, and affordable power for all our customers.

2.2.1 Federal Policies

The current federal administration has significantly modified several energy and environmental policies enacted by the prior administration. This has included the replacement of the Clean Power Plan (CPP), pausing the U.S. Environmental Protection Agency (EPA) GHG tailpipe standards for light-duty vehicles, and withdrawing from the U.S. commitment under the Paris Agreement.

2.2.1.1 Clean Power Plan

Under the Obama Administration, the EPA established the Clean Power Plan (CPP) by rulemaking that was finalized in October 2015. The rule established emission guidelines for states to develop plans to address GHG emissions from existing power plants. The rule was intended to result in a reduction of carbon emissions from existing power plants across all states to approximately 32 percent below 2005 levels by 2030. Implementation of the CPP was stayed by the Supreme Court on February 6, 2016, and there has been ongoing litigation on the CPP, brought by both supporters and opponents. Meanwhile, on October 10, 2017, the Trump Administration's EPA proposed to withdraw the CPP and in August 2018, the EPA proposed the Affordable Clean Energy (ACE)[43] rule to replace the CPP. This rulemaking was finalized on June 19, 2019 and included the repeal of the CPP. Given the uncertainty around the CPP, we did not include CPP assumptions in the 2019 IRP. We will continue to monitor the developments around the new ACE rule, including likely litigation, and any other federal climate policy. We are supportive of a federal system to address GHG emissions and we hope the federal government will address this global pollutant at a federal level.

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[43] The EPA proposed the ACE rule on August 21, 2018, with the goal of establishing emission guidelines to address the GHG emissions from existing coal-fired power plants. See Affordable Clean Energy rule proposal.

2.2.1.2 EPA Greenhouse Gas Tailpipe Standards

On August 24, 2018, the EPA and the U.S. Department of Transportation's National Highway Traffic Safety Administration (NHTSA) published in the Federal Register a proposal to freeze the Corporate Average Fuel Economy (CAFE) and GHG emissions standards for cars and light-duty trucks for Model Years (MY) 2021 through 2026 at the MY 2020 levels. The proposed rule, *The Safer Affordable Fuel-Efficient (SAFE) Vehicles Rule for Model Years 2021–2026 Passenger Cars and Light Trucks*, would revoke California's preemption waiver, which allows California to adopt standards for vehicle emissions that are more stringent than the federal Clean Air Act standards. The comment period for this rulemaking ended on October 26, 2018.

PGE is part of the National Coalition for Advanced Transportation (NCAT) which is currently challenging the underlying determination of the proposed SAFE Rule. NCAT is a coalition of leading companies that support electric vehicle (EV) and other advanced transportation technologies and related infrastructure. NCAT's primary objectives are to defend against potential threats to federal, California, and other state motor vehicle emissions and fuel economy standards that incentivize electric vehicles and infrastructure. NCAT also participates in negotiations and rulemakings regarding such standards and promotes appropriate electric vehicle and infrastructure incentive programs.

PGE strongly opposes any action that would undermine state regulatory authority, which is critical to protecting public health and the environment. Additionally, strong federal and state vehicle standards are necessary for providing the regulatory and financial support for electric vehicles, as well as related infrastructure. Although this rulemaking is not directly relevant to the IRP, transportation electrification will be key to meeting societal GHG reduction goals as the transportation sector accounts for the largest source of GHG emission nationwide. This is also true in Oregon, where transportation accounts for nearly 40 percent of the GHG emissions in the state. Transportation electrification also has the added benefit of improving local air quality and public health and may additionally help with the system integration of renewable energy resources.

2.2.1.3 U.S. Commitment under the Paris Agreement

On June 1, 2017, President Trump announced that the United States would withdraw from the Paris Agreement on climate change, which seeks to limit the increase in the global average temperature and increase the ability to adapt to climate change and foster climate resilience. A summary of the Paris Agreement and the U.S. commitment made by the prior administration under the agreement is included in the 2016 IRP.[44] In the absence of federal leadership regarding GHG emissions, PGE joined more than 2,500 businesses, local governments, and organizations from across the U.S. in declaring their intent to continue to ensure the U.S. remains a global leader in reducing carbon emissions by signing the #WeAreStillIn pledge.[45] PGE also set its own goal of reducing GHG emissions on its system by more than 80 percent by 2050, consistent with the goals of the Paris Agreement.

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[44] PGE's 2016 IRP, Section 3.1.4.1. November 2016. https://www.portlandgeneral.com/our-company/energy-strategy/resource-planning/integrated-resource-planning/2016-irp.

[45] The full list of #WeAreStillIn signatories can be found at https://www.wearestillin.com/signatories.

2.2.1.4 Federal Tax Credits

Federal tax credits continue to play a significant role in renewable energy investment decisions. Congress's extension of the production tax credit (PTC)[46] and investment tax credit (ITC)[47] in December 2015 (through the 2016 Consolidated Appropriations Act), created an opportunity for PGE to reduce lifetime costs for customers through the Company's recently completed 2018 Renewables RFP. Our 2019 IRP incorporates these continuing tax benefits into resource evaluation for qualifying projects. More information is available in Section 5.2.1 Wind Power and Section 5.2.2 Solar PV.

2.2.2 State Policies

2.2.2.1 Legislative

Without federal government action, much of the conversation regarding GHG emissions has been at the state and local level. Below are various state policies that have the potential to impact 2019 IRP assumptions.

Oregon Clean Electricity and Coal Transition Plan

In 2016, we worked with a wide range of stakeholders to craft and pass the Oregon Clean Electricity and Coal Transition Plan (Senate Bill 1547), which doubles the Oregon RPS to 50 percent by 2040 and puts an end date of 2035 on PGE serving its customers with coal-fired electricity. With passage of the Oregon Clean Electricity and Coal Transition Plan, Oregon's electricity sector is on a path to meet its proportionate share of the state's 2050 greenhouse reduction goal. A detailed summary of the Oregon Clean Electricity & Coal Transition Plan and its IRP considerations were included in the 2016 IRP.

Cap and Trade

Passage of a cap and trade bill was a priority for Oregon's legislative leadership and Governor in the 2019 legislative session. A Carbon Policy Office was established (HB 5201 – 2018) to convene workgroups and commission studies ahead of the 2019 legislative session. The goal of the Carbon Policy Office is to provide policy recommendations to the Legislature to help craft cap and trade legislation that can achieve the state's climate goals while continuing to grow the state's economy.

The 2019 Oregon Legislature contemplated House Bill (HB) 2020, which would have authorized a cap and trade program—called the "Oregon Climate Action Program"—in Oregon starting January 1, 2021. The basic structure of the program had the following elements.

- **Economy-wide cap on GHG emissions.** Covered electricity, natural gas, transportation fuels, and manufacturing; would regulate about 100 entities that comprise more than 80 percent of the state's emissions.
- **Regional.** Design intended to facilitate linkage with the Western Climate Initiative (WCI), which currently includes California and Quebec cap and trade programs.

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46 The PTC is a tax-credit awarded for each megawatt-hour (MWh) of generation from a qualifying energy resource for the first ten years of the resource's operation. Currently, the tax credit is only available to wind energy resources.

47 The ITC allows for receipt of a tax credit equal to a fixed percentage of eligible equipment costs.

- **Mandatory GHG reduction goals.** Mandatory statewide GHG reduction goal set to at least 45 percent below 1990 emission levels by 2035 and at least 80 percent below 1990 levels by 2050.
- **Compliance.** Allowances required for each ton of carbon dioxide equivalent (CO_2e) emitted.

Although HB 2020 did not pass during the 2019 legislative session, we are committed to helping Oregon achieve a clean energy future and to reducing GHG emissions on our system by more than 80 percent by 2050. As the largest electricity service provider in the state serving almost 50 percent of Oregon's population and about 75 percent of the state's economic activity, it is critical that the transition to a clean electricity system is done in a cost-effective way that keeps the system affordable and reliable. An economy-wide mandatory cap on GHG emissions could help Oregon realize its reduction goals in the most efficient manner if the compliance program is designed to protect Oregonians from unnecessary costs.

Consistent with past IRPs, the 2019 IRP accounts for the potential effects of future carbon regulation. While it did not pass in the 2019 legislative session, cap and trade remains the most relevant carbon policy proposal in Oregon at this time. It therefore provides the basis for estimating the impacts of future carbon regulations within the IRP. Specifically, we apply a carbon price for electric generation within the state of Oregon and for imports into the state of Oregon beginning in 2021. Additional information on our cap and trade modeling is found in Section 3.2.2 Carbon Prices and Appendix I.

Senate Bill 1044

Senate Bill 1044, passed by the legislature and awaiting signature by the Governor, sets a state policy linking Oregon's greenhouse gas reduction goals to the adoption of zero-emission vehicles (ZEVs) in the state. The bill requires the Oregon Department of Energy to monitor ZEV adoption and, if the state is off track, to recommend strategies to the Legislature to spur ZEV adoption. These could include policies to develop more infrastructure (such as electric vehicle charging and hydrogen fueling stations) and increase public awareness about ZEVs and their benefits. Also promoted by the bill, ZEV purchasing by state government and the creation of the ability for school districts to utilize public purpose charge moneys on the purchase of electric buses and fleet vehicles.

2.2.2.2 Regulatory

During the 2019 IRP planning process, several regulatory dockets raised critical issues impacting customers, reliability, the environment, or future utility planning. Below are a few of the dockets influencing the 2019 IRP analysis and Action Plan.

Transportation Electrification

Technological advancements in transportation electrification along with increasing customer choice for clean energy require legislative and regulatory changes that keep pace. To that end, we created a comprehensive transportation electrification plan that supports our and Oregon's clean energy goals, aids grid integration, and supports customer adoption of electric vehicles. We continue to keep the OPUC abreast of transportation electrification work through our biennial Smart Grid Report and separate Transportation Electrification Plans.

- **UM 1811 (Transportation Electrification Plan).** In UM 1811, PGE filed a set of Transportation Electrification program proposals on December 27, 2016 and an update to the proposed plans on February 15, 2019. In these filings, we proposed to:
  - Partner with TriMet to conduct an electric mass transit pilot.
  - Expand our Electric Avenue network up to an additional six charging stations (station defined as up to four DC fast chargers with Level 2 charging on-site).
  - Conduct an outreach and education pilot.
  - Implement a residential EV charging pilot program that encourages customers to deploy connected Level 2 EV charging infrastructure at their homes.
  - Implement a business EV charging pilot that mitigates the cost of installing charging infrastructure at 90 different nonresidential customer sites.
- **UM 1826 (Clean Fuels Program).** PGE filed a plan on March 29, 2019 with the following components:
  - An EV grant fund: We will launch a competitive grant fund to support non-residential customers in a variety of project types to advance transportation electrification to the benefit of residential customers.
  - A school bus electrification project: We will work with up to 5 school districts to help them acquire an electric school bus and install charging infrastructure.
  - Subsidized Electric Avenue access: We will offer free two-year subscriptions to the Electric Avenue network of charging stations to any Oregonian who receives the state's income-qualified rebate for the purchase or lease of a new or used electric vehicle.
  - Public outreach activities for transportation electrification: We will educate residential customers and raise awareness about the benefits of electric vehicles. These activities include a total cost of ownership tool on our website, engagement with dealers and at public events, and a ride-and-drive event with a national vendor.

As established in AR 609, PGE will file a Transportation Electrification Plan later this year that will analyze PGE's portfolio of near-term and long-term transportation electrification actions. In addition to the activities described above, the 2019 IRP includes explicit forecasts for EV adoption and the associated impacts to loads and resources needs. Additional information can be found in Section 4.1.3.1 Electric Vehicles.

Energy Storage

Pursuant to OPUC acknowledgment of the 2016 IRP and as directed by HB 2193, we filed an energy storage proposal in November 2017 with the OPUC (Docket UM 1856). The proposal called for 39 MW of storage to be developed at various locations across the grid. In August 2018, the OPUC issued an order that outlined an agreed approach to the development of five energy storage projects by PGE. The 2019 IRP includes battery storage resources that represent our proposed storage projects within our existing and contracted resources in all portfolios (see Section 4.2 Existing and Contracted Resources).

Senate Bill (SB) (978)

In 2017, the Oregon legislature passed SB 978, directing the OPUC to investigate and report to the legislature on how developing industry trends, technology, and policy drivers in the electricity sector might impact the existing regulatory system and incentives. We actively worked on this initiative with both external stakeholders and the OPUC to provide guidance and support for the report. The OPUC issued the final report to the legislature on September 14, 2018 in which the OPUC committed to four focus areas:

- **Utility Incentive Alignment.** Explore performance-based ratemaking and other regulatory tools to align utility incentives with customer goals, industry trends, and statewide goals.
- **Regional market development.** Cooperate with other states to support and explore development of an organized regional market.
- **Participation.** Develop a strategy for low income and environmental justice groups' engagement and inclusion in OPUC processes that will carry forward beyond the SB 978 proceeding.
- **Retail choice.** Improve the Commission's regulatory tools to value system costs and benefits, which enables customer choice and a strong utility system.

Community Solar

As directed by SB 1547, the OPUC initiated a rulemaking in July 2016 to develop a community solar program in Oregon. Through a collaborative process, parties agreed on rules to govern the program, which were subsequently adopted by the Commission in November 2017. In Docket UM 1930, the OPUC and stakeholders are currently working to develop a program implementation manual to govern certification, consumer protection, credit price, and program launch. The program administrator, Energy Solutions, is working with staff and stakeholders to develop a program implementation manual with an anticipated program launch in 2019. We do not forecast participation in Community Solar in this IRP, but we discuss potential future impacts relative to our needs in Section 4.7.2 Voluntary Renewable Program Sensitivities.

New Load Direct Access

In 2018, the OPUC created a New Load Direct Access program, capped at approximately 120 MWa, for unplanned, large, new loads and large load growth at existing sites. As a result, PGE filed its first New Load Direct Access tariff (Advice 19-04, Schedule 689) on February 5, 2019 for OPUC approval. The PUC suspended the tariff filing for further investigation to be completed in early 2020. See Docket No. UE 358.

PGE's proposed program offers the ability for customers with new, separately metered load of 10 MWa or more to choose alternate energy supply. Because these loads are not included in our load forecast, they are not included in the resource needs assessment in the 2019 IRP. Despite our role as the reliability provider, we currently have no ability to ensure that these loads are planned for from a reliability perspective and that they do not pose reliability risks to our other customers. In addition to the standard program requirements set forth by the OPUC through rulemaking Docket No. AR 614 and resulting OPUC Order 18-341, we proposed two resource-adequacy mechanisms to ensure that system reliability is protected and that cost-of-service customers are protected from cost and risk shifts as we serve the role of reliability provider. We provide analysis and discussion of the potential risks associated with Direct Access in Section 4.7.3 Direct Access and Resource Adequacy.

2.2.3 Local Policies

In addition to substantive efforts at the state level to advance clean energy goals through cap and trade and regulatory dockets, local municipalities within our service territory are taking a leadership role by setting aggressive clean energy goals. On June 1, 2017, the City of Portland and Multnomah County[48][49] passed resolutions focused on 100-percent clean energy with two key milestones: all of the city and county's electricity will come from clean and renewable sources by 2035; and all energy in the city and county (including transportation, residential, and commercial building sectors) will come from clean and renewable sources by 2050. Both milestones are based on the entire city and county, not just for public operations. Other key elements of the resolutions included:

- Accelerating the shift to electric cars, buses, and freight.
- Supporting frequent and affordable transit service.
- Prioritizing community-based renewable development and local electricity generation.
- Opposing any new fossil fuel development.
- An ongoing commitment to meet the city and county's proportionate GHG reductions under the Paris Climate Agreement.

Other cities and jurisdictions within our service territory are also looking to develop renewable energy goals and/or climate action plans, including the cities of Beaverton, Hillsboro, Milwaukie, Salem, and Silverton. We support increasing renewables as part of our commitment to clean energy and overall efforts to reduce GHG emissions and look forward to partnering with local cities and counties that want to go 100-percent clean and renewable.

2.3 Technology Trends

Clean technologies, notably wind, solar, and energy storage, have benefited from significant technology improvements in recent years that have increased performance and decreased costs of these resources. This section describes the major recent trends for each of the technologies. The guidance from each of the technology trends inform the Technology Futures used in the 2019 IRP portfolio analysis (see Section 3.3 Technology Cost Uncertainties).

2.3.1 Wind Power

According to the Department of Energy, wind power additions continued at a rapid pace in 2017, with 7,017 MW of new capacity added in the United States and $11 billion invested. Supported by favorable tax policy, state renewable policies, and other factors, cumulative wind power capacity

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[48] C. of Portland. Resolution No. 32789. Retrieved April 9, 2019, from https://www.portlandoregon.gov/auditor/article/642811.

[49] Mult. Co. Board of Commissioners. (2017, June 1). 100% Renewable Resolution Final.doc. Retrieved June 15, 2019, from https://multco.us/file/100-renewable-resolution-finaldoc.

grew to 88,973 MW.[50] Wind power also represented the third-largest source of U.S. electric-generating capacity additions in 2017, behind solar and natural gas.[51]

Following a long-term trend, average turbine capacity, rotor diameter, and hub height have been increasing. The Department of Energy's (DOE) 2017 Wind Technology Market Report shows the average nameplate capacity of installed wind turbines in the U.S. in 2017 was 2.32 MW, up 8 percent over 2016 and average hub height up 4 percent.[52] Turbine design changes are driving capacity factors significantly higher over time.[53] The DOE report also states that the average 2017 capacity factor among projects built from 2014 to 2016 was 42 percent, compared to an average of 31.5 percent among projects built from 2004 to 2011, due largely to increases in hub height and rotor diameter.[54] These capacity factor improvements have coincided with continued reductions in installed costs, driving the levelized cost of wind down significantly in recent years.[55] See Section 5.2.1 Wind Power for information about how wind resources are characterized in the 2019 IRP.

2.3.2 Solar Power

Solar photovoltaic (solar PV) system costs have also declined in recent years, primarily due to reductions in soft costs.[56],[57] The declining cost of solar as well as policies that support the development of solar have driven investment in solar across the United States, but especially in areas with a strong solar resource, such as California and the Southwest.[58] Utility-scale solar represented more than 25 percent of all generating capacity additions nationwide in each of the past five years.[59] Most of the projects are single-axis tracking crystalline silicon modules.[60] In 2017, solar made up 31 percent of all U.S. capacity additions although these capacity additions declined in comparison to 2016's record year, which was driven by the investment tax credit's (ITC) then-planned phaseout.[61] In 2018, cumulative U.S. solar installations totaled 10.6 GW_{dc}—6.2 GW_{dc} of which was utility solar, accounting for 58 percent of total U.S. annual capacity additions.[62] See Section 5.2.2 Solar PV for information about how solar resources are characterized in the 2019 IRP.

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50 Department of Energy 2017 *Wind Technologies Market Report*. Retrieved Mar. 16, 2019, from https://www.energy.gov/sites/prod/files/2018/08/f54/2017_wind_technologies_market_report_8.15.18.v2.pdf.

51 *Id.*

52 *Id.*

53 *Id.*

54 *Id.*

55 *Id.* ("The average installed cost of wind has dropped from $2405/kW in 2010 to $1610/kW in 2017, a decrease of 33%.")

56 "Soft costs are the non-hardware costs associated with going solar. These costs include permitting, financing, and installing solar, as well as the expenses solar companies incur to acquire new customers, pay suppliers, and cover their bottom line. These "soft costs" are tacked-on to the overall price a customer pays for a solar energy system." Retrieved Mar. 16, 2019, from https://www.energy.gov/eere/articles/soft-costs-101-key-achieving-cheaper-solar-energy.

57 *Utility-Scale Solar, Empirical Trends in Project Technology, Cost, Performance and PPA Pricing in the United States*, 2018 edition. Retrieved May 15, 2019, from https://emp.lbl.gov/sites/default/files/lbnl_utility_scale_solar_2018_edition_slides.pdf.

58 *Id.*

59 *Id.*

60 *Id.*

61 *Id.*

62 Wood Mackenzie/SEIA *U.S. Solar Market Insight®, Executive Summary, 2018 Year in Review*, p. 5 (Mar. 2019).

2.3.3 Battery Storage

Battery energy storage costs have declined significantly in recent years. A confluence of three factors has driven these cost declines. These include market transformation efforts such as California's energy storage mandate, and incentives for fast response via market design such as those undertaken by PJM Interconnection. Another factor is the effect of increased adoption of lithium ion batteries outside of the electricity industry for both personal devices and increasingly, electric vehicles.

In the U.S., 708 MW of power capacity, representing 867 MWh of energy capacity of utility-scale battery storage was in operation at the end of 2017.[63] Over 80 percent of these batteries are based on lithium-ion chemistry.[64] While battery systems can provide multiple "stacked" benefits over various timescales, systems in operation to date have primarily been designed to provide a small set of services, depending on the needs of the system for which they were built. These services include local reliability, as in the California Independent System Operator (CAISO) territory, and frequency regulation, as shown by PJM.[65]

Recent battery proposals and development in the West are increasingly focused on providing capacity and mitigating the impacts of the evening ramp that has resulted from rapid adoption of solar in California and the Southwest. In November 2018, California utility regulators approved Pacific Gas & Electric's (PG&E) proposal to build a 567.5 MW battery project at Moss Landing, California to displace gas-fired peaking resources.[66] Then in February 2019, Arizona Public Service (APS) announced its plan to add 850 MW of battery storage to its fleet.[67] The plan includes coupling batteries with solar resources at the solar sites.[68] The battery storage will integrate APS solar resources to provide capacity to the system when demand peaks during sunset.[69] Despite the significant growth in the battery storage market over the last five years, considerable uncertainty remains regarding future cost and performance trajectories. See Section 4.1.3.2 Distributed Solar and Non-dispatchable Battery Storage, Section 5.3.1 Battery Energy Storage, and Section 5.2.3 Solar Plus Storage for information about how battery resources and solar plus storage are characterized in the 2019 IRP.

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63 *EIA U.S. Battery Storage Market Trends, May 2018*. Retrieved May 10, 2019, from https://www.eia.gov/analysis/studies/electricity/batterystorage/pdf/battery_storage.pdf.

64 *Id.*

65 *Id.*

66 Retrieved May 10, 2019, from https://www.naturalgasintel.com/articles/116525-california-oks-pge-plan-to-replace-gas-fired-power-plants-with-battery-storage.

67 Retrieved May 10, 2019, from https://www.publicpower.org/periodical/article/ariz-utility-plans-add-850-mw-storage-100-mw-solar.

68 *Id.*

69 *Id.*

2.4 Regional Wholesale Electricity Landscape

2.4.1 Recent Trends

The Western wholesale electricity system is currently undergoing transformations in energy supply, available capacity, and consumption patterns. The combination of expanded solar and wind deployment with ongoing thermal plant retirements creates the potential for price volatility and uncertainty in the West, with low or negative pricing during hours with high renewable output and very high pricing during hours with high load and supply constraints.

Recently, these factors have been compounded by aging gas infrastructure and supply disruptions. Gas-related constraints tend to vary by time of year but have posed challenges in both winter and summer seasons. Pipelines and natural gas storage have experienced strain in the winter due to high demand from heating loads, while limited hydro resources, the timing of solar ramping, and high peak loads have exacerbated summer demands for gas generation and flexibility from the gas fleet. Gas withdrawal constraints imposed on Aliso Canyon by the California Public Utility Commission (CPUC) have further complicated constraints on the Western power grid, highlighting the interdependence of the electricity and gas systems in the West.

Markets in the West are experiencing further uncertainty about future supply due to the evolving policy and regulatory landscape in the West. Key drivers of this uncertainty include: plans to retire thermal resources in the West, which are summarized in the following section; long-term planning uncertainty in California due to the rapid expansion of Community Choice Aggregation (CCA); uncertainty regarding the implications of the PG&E bankruptcy; and new 100-percent clean energy standards, including California's Senate Bill 100[70] and New Mexico's Senate Bill 489.[71] Amid this uncertainty, the market has yielded increasing forward trading curves, challenging the notion that the availability of low-priced gas and electricity can be expected to continue well into the future in the West.

2.4.2 Regional Capacity Changes

The Pacific Northwest electricity generating resource fleet will change significantly in the next few years as several thermal generating units retire. Additional resources are scheduled to retire across the West. The tightening of capacity regionally and in the West has created interest in regional adequacy, but little by way of new capacity resource commitments. Table 2-1 provides a list of announced retirements in the Pacific Northwest for a total of over 2,600 MW by the end of 2025. According to the U.S. Energy Information Administration, nearly 19,000 MW of generating capacity in the West is scheduled to retire between 2019 and 2030.[72]

Many IRPs and regional adequacy studies assume some availability of unsecured capacity from other regions or unspecified market entities. Historically, these assumptions of available unsecured capacity have not led to regional reliability failures in the Northwest due largely to the flexibility

[70] Retrieved May 15, 2019, from https://leginfo.legislature.ca.gov/faces/billNavClient.xhtml?bill_id=201720180SB100.

[71] Retrieved May 15, 2019, from https://www.nmlegis.gov/Sessions/19%20Regular/final/SB0489.pdf.

[72] *Electric Power Monthly*, Table 6.6 Planned U.S. Electric Generating Unit Retirements, U.S. Energy Information Administration. Retrieved May 9, 2019, from https://www.eia.gov/electricity/monthly/epm_table_grapher.php?t=epmt_6_06.

afforded by hydro reservoirs and gas storage. However, as the capacity length of the region is reduced (and the fueling risk profile changes), events such as cold snaps, fuel disruptions, low hydro, or major plant outages have the potential to cause regional instability. In these situations, the assumed availability of unsecured capacity becomes important.

TABLE 2-1: Announced retirement plants in the Pacific Northwest

State	Plant Name	Operator	Capacity (MW)	Retirement Year	Fuel
OR	John C Boyle 1_2	PacifiCorp	83.6	2019	Hydro
OR	Boardman (OR)	PGE	585	2020	Coal
WA	Centralia Generation 1	TransAlta Corp	670	2020	Coal
MT	Colstrip 1	Talen Energy	307	2019	Coal
MT	Colstrip 2	Talen Energy	307	2019	Coal
WA	Centralia Generation 2	TransAlta Corp	670	2025	Coal

Regional resource adequacy may be further challenged by programs that exclude loads from long-term planning exercises and resource adequacy requirements. For example, utilities in Oregon have traditionally excluded Direct Access loads from load resource balance in the IRP process. With the expansion of Direct Access to new loads and the tightening of supply in the West, it is increasingly important to consider resource adequacy for these loads in the regulatory process in order to maintain reliability in the region. Additional discussion about Direct Access is provided in Section 4.7.3 Direct Access and Resource Adequacy.

2.4.2.1 Market Capacity Study

In Order No. 17-386, the OPUC directed PGE to conduct a market capacity study to inform the next IRP cycle.[73] We contracted with Energy + Environmental Economics (E3) to conduct the study of market capacity. The two-part study contains a review of the recent regional adequacy assessments and a heuristic model of regional capacity with recommendations for market capacity assumptions for our long-term planning. E3 shared the results of their study with stakeholders at the PGE Roundtable on October 31, 2018. Their presentation slides are available on the IRP website.[74] In addition, External Study E provides a report prepared by E3 and the capacity model is available on the IRP website.[75]

E3's review of regional adequacy assessments included the Northwest Power and Conservation Council's (NWPCC or the Council) 2023 Regional Adequacy Assessment, the Bonneville Power Administration's (BPA) 2017 Pacific Northwest Loads and Resources Study (the White Book), and the Pacific Northwest Utilities Conference Committee's (PNUCC) 2018 Northwest Regional Forecast of Power Loads and Resources. While the regional adequacy studies use different methodologies and

[73] OPUC Order No. 17-386 at 19.

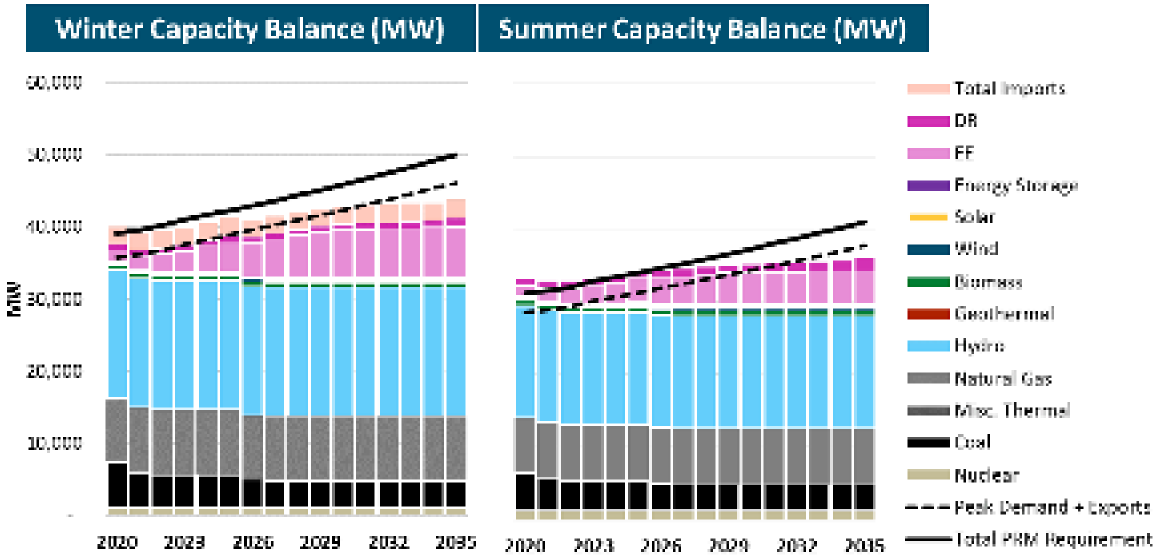
[74] Retrieved May 15, 2019, from https://www.portlandgeneral.com/-/media/public/our-company/energy-strategy/documents/2018-10-31-irp-roundtable-18-5.pdf?la=en.

[75] Retrieved May 15, 2019, from https://www.portlandgeneral.com/-/media/public/our-company/energy-strategy/documents/e3-market-capacity-study-rt-18-5-2018-10-28.pdf?la=en.

assumptions, each concluded that the regional capacity supply in winter was short by the year 2021. E3 determined that key uncertainties in forecasting regional adequacy include "loads, new build expected to come online before 2021, level of DSM (demand side management) that is realized, contribution of unknown status IPP (independent power producer) generation, and external market purchases."[76]

For the second part of the study, E3 prepared a fifteen-year heuristic model of the winter and summer regional capacity supplies and demand calibrated to the Council's 2023 Regional Adequacy Assessment with inputs from the Council's 7th Power Plan. In addition to a base case, E3 prepared low and high scenarios that examine the impacts of uncertainties in load, energy efficiency, demand response, and import assumptions. Figure 2-4[77] summarizes the model's base case results for the regional capacity supply for winter and summer, revealing a regional winter capacity deficit beginning in 2021 and a summer capacity deficit beginning in 2026. The low and high scenarios are shown in E3's report in External Study E.

FIGURE 2-4: Base Case Northwest capacity balance by season



The model also provides E3's recommended market capacity assumptions for each scenario for PGE's long-term adequacy planning, as shown in Figure 2-5.[78] These recommendations were incorporated into our capacity adequacy assessments and represent the amount of capacity that we assume can be secured on an hour-ahead basis in constrained conditions with no prior agreements. We consider the opportunity to meet capacity needs with agreements for existing resources separately in Section 7.1.1 Portfolio Design Principles and Chapter 8.

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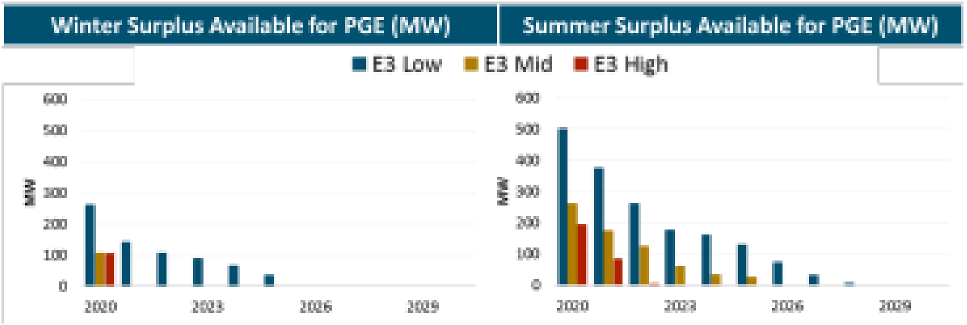
[76] Roundtable 18-5 (2018, October 2018). IRP Public Meetings. Retrieved from https://www.portlandgeneral.com/our-company/energy-strategy/resource-planning/integrated-resource-planning/irp-public-meetings.

[77] E3, *Northwest Loads and Resources Assessment*, Figure 11.

[78] E3, *Northwest Loads and Resources Assessment*, Figure 14.

FIGURE 2-5: Recommended market capacity assumption for PGE's long-term planning



2.5 Integrated Resource Planning Themes and Innovations

Across all the key considerations comprising today's planning environment, the electricity industry continues to see significant change, often at an accelerating pace. In such an environment, it could be tempting to defer plans and decisions until conditions or a path forward become more certain. At PGE, we recognize that thoughtful planning in the context of rapid change can be challenging, but we believe that long-term planning is even more critical in times of great change and uncertainty.

The electricity industry must continue to evolve at a rapid pace to meet the needs of its customers, its communities, and the environment. Integrated resource planning helps PGE and the region to thoughtfully pursue these changes. To accomplish this, we focused on four key themes in the design and implementation of the 2019 IRP. These themes, which encompass some of the most pressing questions regarding the future of the electricity industry, include decarbonization, customer decisions, uncertainty and optionality, and technology integration and flexibility.

2.5.1 Decarbonization

To meet the expectations of our customers and to be a leader in the community, we are committed to enabling local transformation to a clean energy economy. Our goal is to reduce GHG emissions in our service area by more than 80 percent by 2050 and to help decarbonize other sectors in the economy by enabling the adoption of new clean electric technologies such as electric vehicles. To support these goals, we considered decarbonization and the clean energy transition through several new innovative analyses in the IRP, including:

- **PGE's Decarbonization Study.** We commissioned an independent study to identify technology pathways toward reducing economy-wide GHGs in our service area by 80 percent by 2050. This study identified three pillars to successful decarbonization: energy efficiency, decarbonizing electricity, and electrification. We used the findings of this study to inform our goals around a clean energy future[79] and to design a Decarbonization Scenario, which is described in Section 7.4.1 Decarbonization Scenario. See External Study A for the full study.
- **Electric Vehicle forecasting.** As identified in our Decarbonization Study, transportation electrification is a critical strategy to reducing economy-wide GHGs and has the potential to significantly impact the electricity sector over time. For the first time, the 2019 IRP explicitly

[79] PGE, *The Path to a Decarbonized Energy Economy*, 2018. Retrieved May 8, 2019, from https://www.portlandgeneral.com/-/media/public/our-company/energy-strategy/documents/pge-decarbonization-white-paper.pdf?la=en.

incorporates the potential effects of future market adoption of electric vehicles on our resource needs. More information on the EV forecasts and their incorporation into the needs assessment can be found in Section 4.1.3.1 Electric Vehicles.

- **Carbon Pricing.** Similar to prior IRPs, we incorporate carbon pricing impacts into market price forecasting and the economic evaluation of new resource options. See Section 3.2.2 Carbon Prices for more information.
- **Carbon-constrained portfolios.** We believe that our 2050 goal to reduce GHG emissions by more than 80 percent is in the interest of our customers, the communities we serve, and the state of Oregon. The 2019 IRP incorporates this goal into both the design and evaluation of portfolios, ensuring that the Action Plan allows us to pursue resource actions that best balance cost and risk to customers. This is achieved by ensuring that all near-term actions under consideration do not preclude achievement of the 2050 GHG goal and by incorporating a risk metric that considers the potential economic performance of each portfolio in a carbon-constrained future. More information on our approach to incorporating our 2050 GHG goal into IRP analyses can be found in Section 7.2.1 Scoring Metrics.

These aspects of the 2019 IRP allow for a traditional evaluation of cost and risk while ensuring that proposed near-term actions do not preclude deep decarbonization in the long run. Our resulting GHG forecast through 2050 can be found in Section 7.3.4 Greenhouse Gas Emissions.

2.5.2 Customer Decisions

Consistent with the IRP Guidelines and the original intent of utility integrated resource planning, the 2019 IRP remains focused on identifying actions that we may take to best serve our customers. While not determined within the IRP, customer decisions ultimately affect the context in which PGE takes resource actions and, in some cases, may directly affect our decision-making process. For example, as customers grapple with whether to purchase an electric vehicle or to install rooftop solar, we must account for the potential impacts of these decisions on future resource needs, especially if these customer resources are to be utilized to benefit the entire system. Customer decisions also have the potential to create additional burden for cost-of-service customers if costs and benefits are not appropriately evaluated and allocated. The integrated resource planning process provides an opportunity to quantify these costs and benefits in a way that is consistent with the treatment across other resource actions.

The 2019 IRP addresses customer decisions in the following ways:

- **DER adoption.** The 2019 IRP incorporates the results of a detailed study (DER Study), conducted by Navigant Consulting, of the potential for customers to adopt new technologies, including electric vehicles, rooftop solar, and storage. The study, which can be found in External Study C, developed low, reference, and high forecasts for customer adoption based on technology prices and policy and market drivers, as well as customer propensity-to-adopt models. More information on how these forecasts are incorporated into IRP analysis can be found in Section 4.1.3 Passive Customer DER Forecasting. The DER Study also includes forecasts for customer participation in demand response or flexible load programs as well as dispatchable customer storage programs. Over time, these programs may contribute to meeting material portions of our capacity and flexibility needs, especially as adoption of electric vehicles enables a growing direct load control resource through flexible EV charging. More information on the impacts of distributed flexibility in the 2019 IRP can be found in Section 5.1 Distributed Flexibility.

- **Voluntary renewable programs.** Voluntary renewable program growth and development present both challenges and opportunities for our long-term resource planning process. Participation in voluntary programs may help us to decarbonize our generation portfolio much faster than Oregon's RPS would otherwise dictate, without placing additional costs on customers who cannot afford to decarbonize as quickly. However, the design and implementation of these programs require care to fairly attribute costs and benefits and to maintain reliability. The IRP process provides valuable insight and information to inform these design and implementation questions. The potential impacts of customer participation in voluntary renewable programs on resource planning are discussed in Section 4.7.2 Voluntary Renewable Program Sensitivities.
- **Direct Access.** Direct access programs allow a subset of commercial and industrial customers to enter into agreements with energy service suppliers for their energy. Agreements with energy service suppliers for unsecured resources shift costs and risks associated with reliability to cost-of-service customers. While we are required to exclude long-term direct access loads from integrated resource planning, the Commission acknowledged our request to study the risks associated with Direct Access in OPUC Order No. 17-386. This analysis is provided in Section 4.7.3 Direct Access and Resource Adequacy.

In addressing customer decisions in the 2019 IRP, our goals are to ensure that our plans are robust across a range of potential outcomes and that utility actions and customer actions remain compatible and coordinated.

2.5.3 Uncertainty and Optionality

We anticipate that the rapid change in technology, policy, and wholesale markets observed in recent years will likely continue in the future. Long-term planning will continue to require evaluation of risk across a wide range of potential future conditions. The 2019 IRP more thoroughly treats the uncertain range of potential futures and more robustly incorporates these futures into portfolio analysis. In total, the 2019 IRP considers 810 potential futures that depend on economic conditions, technological progress, natural gas prices, carbon prices, hydro conditions, and the future deployment of renewables across the West. Chapter 3. Futures and Uncertainties describes these futures, which we use to develop portfolios and to evaluate the cost and risks of portfolio economic performance.

The futures examined in the 2019 IRP also provide a means for addressing optionality in portfolio construction and scoring. In the past, we have constructed portfolios with specified resource additions through the entire analysis period (through 2050), while noting that the IRP Action Plan focuses only on near-term actions. In this way, portfolios lacked the flexibility to adjust as potential futures are ultimately realized over time; portfolio scoring therefore neglected the benefits of optionality. In Section 7.1 Portfolio Construction, we introduce a means to account for the benefits of optionality through a new approach to portfolio construction that specifies near-term resource additions, while allowing outer-year resource additions the flexibility to evolve differently in different futures. The economic performance in these futures factors directly into the risk metrics used for portfolio scoring, ensuring that portfolio performance considers the impact of optionality.

Through robust uncertainty analysis and new methodologies for capturing the value of optionality, we ensure that near-term resource actions put us on the path to accomplishing our long-term goals, while considering the technology, policy, and market uncertainties facing the electricity industry.

2.5.4 Technology Integration and Flexibility

As described in Chapter 2. Planning Environment, the availability and cost competitiveness of new clean technologies are rapidly changing how electricity is produced, consumed, and managed. The rapid expansion of renewable resources in the West requires that utilities better understand the operational implications of high penetrations of renewables within the planning process. In the past, resource planning has predominantly focused on the potential for renewable resource integration to result in additional costs associated with operating the system—variable renewable integration costs.

Today, flexible and distributed technologies, such as energy storage and flexible load, offer new solutions with potential value to the grid on shorter timescales and with more granular geographic resolution than traditional dispatchable resources provide. In this environment, the planning challenge must address the potential costs of integrating variable clean technologies, but also the value provided by flexible resources, including those that may be deployed on the distribution system or at a customer site.

Building on our leadership in modeling renewable integration costs and energy storage value, the 2019 IRP incorporates a holistic evaluation of flexibility challenges and potential solutions through three related exercises:

- An update to the traditional determination of renewable integration costs (see Section 6.1.3 Integration Costs).
- The calculation of a flexibility value for each dispatchable resource option (see Section 6.2.2 Flexibility Value).
- An evaluation of PGE’s flexibility adequacy needs (see Section 4.6 Flexibility Adequacy).

Our flexibility analysis requires rigorous analytics to characterize the behavior of renewables and flexible resources over very short time scales. Distributed technologies pose an additional layer of complexity because their behavior and value may vary geographically and on very short time scales. While the 2019 IRP provides new and consequential insights regarding the adoption of distributed technologies and their performance at the bulk system level, the 2019 IRP does not include locational resource evaluation as might be considered within a distribution resource planning process. In parallel with, but outside of the IRP process, we have initiated a distribution resource planning process. Future IRPs will integrate the results from this process into their analysis. See Section 6.4 Locational Value for high level insights on the potential contribution of locational value to resource evaluation in future IRP cycles.

Coordinated planning for the efficient integration of renewable resources and the full utilization of distributed resources remains an industry-wide challenge. We continue to make progress in refining our analytics, applying those analytics to new technologies, and testing frameworks for bringing together the insights from integrated and distribution resource planning.

CHAPTER 3. Futures and Uncertainties

As described in Chapter 2. Planning Environment, the electricity sector is undergoing rapid change due to a combination of customer, technological, market, and policy drivers. These changes will continue to impact PGE's needs, the resource options available to meet these needs, and the wholesale markets in which we operate. In this changing environment, thoughtful long-term planning requires a robust treatment of the various uncertainties that will impact our portfolio performance over time.

In the 2016 IRP, we addressed uncertainty and risk through the evaluation of portfolio performance across 23 futures that explored uncertainties in gas prices, carbon prices, hydro conditions, load, and technology cost and performance. Stakeholders expressed concern that PGE's uncertainty analysis in the 2016 IRP did not adequately address the potential risks associated with large and long-lived resource commitments given the high degree of uncertainty facing the industry. In response, uncertainty was a key topic of discussion in the 2019 public IRP Roundtable process and a central focus of the analytical innovations in this current IRP. In our analysis of uncertainty, we focused on:

- Incorporating explicit treatment of uncertainties in future customer adoption of clean technologies and participation in customer programs.
- Testing a broader set of futures that consider combined uncertainties across key drivers, rather than testing key drivers in isolation.
- Incorporating uncertainties in resource needs and resource economics into portfolio construction to better capture the benefits associated with preserving optionality and the potential risks associated with making long-term commitments.

The sections below discuss how uncertainty affects resource needs, wholesale market pricing, technology costs, and hydro conditions. In each area, we sought to create an analytical framework that addressed questions and concerns from stakeholders and provided useful insights into portfolio evaluation and recommended resource actions. We believe each area alone represents a major enhancement to the IRP process; collectively they provide a more robust view of the values, risks, and tradeoffs impacting energy resource planning and decision-making under uncertainty.

Chapter Highlights

★ The key drivers of uncertainty in the 2019 IRP include economic trends, technological innovation, the policy environment, and customer decisions.

★ PGE's evaluation accounts for uncertainties in resource needs, wholesale market conditions, technology costs, and hydro conditions.

★ In the 2019 IRP, PGE designed and evaluated portfolios considering 270 futures under 810 future conditions (each of the 270 futures considered across three potential hydro conditions).

3.1 Need Uncertainties

> **The Reference Case**
>
> Many analyses and studies conducted in preparation for the 2019 IRP deal with reference assumptions that are made across all the applicable variables. The collection of all these assumptions is referred to as the Reference Case.

The assessment of resource needs is a key purpose of the IRP process and a factor in determining the need for resource actions. The examination of resource needs is greatly enhanced in the 2019 IRP to provide deeper insight into the key drivers of need uncertainty across the planning horizon, bounds to the potential need conditions, and insight into the persistence of need across years and conditions. In addition, we developed a new approach to constructing portfolios that allows for the consideration of need uncertainty in the development and evaluation of portfolios, marking a significant advancement from our previous capabilities. We also updated scoring metrics to include a screening metric associated with need. Combined, these improvements and updates help to provide greater confidence in assessing the short- and long-term uncertainty of need and the potential risks of different options for the size and timing of resource actions, providing a more robust analysis to inform the recommended actions described in the Action Plan.

As part of the expanded treatment of need uncertainty, we examined Low and High Need Futures in addition to the Reference Case. These futures capture several potential uncertainties that may impact the amount of energy and capacity needed by PGE across the planning horizon, as well as the impacts on Renewable Portfolio Standards (RPS) obligations.

PGE designed the Need Futures to create wide sensitivities to the Reference Case by varying drivers in the same direction of impact on need. For example, the Low Need Future examines a world with lower than expected loads due in part to economic slowing and slow adoption of electric vehicles (EVs), high adoption of energy efficiency and behind-the-meter solar, and high participation levels in demand response programs.

The list below describes the variables that drive PGE's resource needs across the Need Futures, while Table 3-1 summarizes the corresponding assumptions in each Need Future.

- **Top-down Load Forecast.** The 2019 IRP considers three scenarios related to macroeconomic trends and impacts to future loads. In addition to the Reference Case, the low and high growth scenarios capture uncertainty in economic drivers and forecast model uncertainty. The top-down load forecast is discussed in Section 4.1.1 Top-down Econometric Forecasting and in Appendix D. Load Forecast Methodology.
- **Energy Efficiency.** The 2019 IRP considers two scenarios related to energy efficiency adoption. In addition to the Reference Case, the Low Need Future assumes the acquisition of energy efficiency that is incremental to the Energy Trust's cost-effective forecast. Energy efficiency is discussed in Section 4.1.2 Energy Efficiency.
- **Distributed Photovoltaics (PV).** The 2019 IRP considers three potential trajectories for customer adoption of distributed PV based on the adoption forecasts from the Navigant Distributed Resource and Flexible Load Study (the DER Study, which can be found in External Study C. Distributed Energy Resource Study). See Section 4.1.3.2 Distributed Solar and Non-

dispatchable Battery Storage for additional information.

- **Electric Vehicle + Direct Load Control of EV (EV + DLC_{EV}).** The 2019 IRP considers three potential trajectories for customer adoption of EVs based on the adoption forecasts from the DER Study (see Section 4.1.3.1 Electric Vehicles). Each EV adoption scenario also has a corresponding forecast for participation in an EV direct load control (DLC_{EV}) demand response program that allows the utility to shift EV charging load in time. (See Section 5.1.1 Demand Response for further discussion of this topic). For consistency in the Need Futures, PGE paired the low EV forecast with the low DLC_{EV} forecast and similarly, the high EV forecast with the high DLC_{EV} forecast.
- **Demand Response.** The 2019 IRP considers three scenarios for customer participation in demand response programs based on the DER Study (see Section 5.1.1 Demand Response).
- **Customer Battery Storage.** The 2019 IRP considers three scenarios for customer adoption of battery storage based on the forecasts in the DER Study. See Section 4.1.3.2 Distributed Solar and Non-dispatchable Battery Storage and Section 5.1.2 Dispatchable Customer Battery Storage for additional information.
- **Market Capacity.** The 2019 IRP considers three scenarios for the availability of capacity from the market during constrained conditions, which are based on the findings and recommendations in the Market Capacity Study, discussed in Section 2.4.2.1 Market Capacity Study.

TABLE 3-1: Need Future variables

	Low Need Future	Reference Need	High Need Future
Top-down Load Forecast	Low Growth	Reference	High Growth
Energy Efficiency	High EE	Reference	Reference
Distributed PV	High Adoption	Reference	Low Adoption
EV + DLC_{EV}	Low Adoption	Reference	High Adoption
Demand Response	High Participation	Reference	Low Participation
Customer Battery Storage	High Adoption	Reference	Low Adoption
Market Capacity	High Availability	Reference	Low Availability

Unlike past IRPs, the 2019 IRP considers the three Need Futures in both the construction and evaluation of portfolios. This allows the portfolio analysis to better capture costs and risks associated with large and long-lived resource actions given the uncertainty in future resource needs. More information on PGE's methodology can be found in Section 7.1 Portfolio Construction. The Need Futures also provide for a more robust discussion of PGE's renewable procurement strategy, as described in Section 7.3.3 Renewable Glide Path.

In addition to the three Need Futures, PGE examined sensitivities to provide insight into other uncertainties that may impact need. In Section 4.7 Need Sensitivities, PGE examines sensitivities in resource needs related to PURPA qualifying facilities (QFs), customer participation in voluntary renewable programs, and long-term direct access programs.

3.2 Wholesale Market Price Uncertainty

Forecasts of future wholesale market prices for electricity are a major driver of resource performance within PGE's portfolio. The forecasts have a growing uncertainty across the planning horizon due to numerous factors, including the potential impacts of renewable and greenhouse gas (GHG) policies, natural gas markets, and resource availability. To investigate the impacts of market price uncertainty on resource performance, PGE simulated hourly prices through 2050 by varying four key market price drivers within the Western Electricity Coordinating Council (WECC) Aurora market price forecasting model: natural gas prices, carbon prices, the quantity of installed renewable capacity across the WECC, and hydro generation conditions in the Pacific Northwest. The following sections discuss these market price drivers. More information about PGE's market price forecasting methodology is available in Appendix I. 2019 IRP Modeling Details.

3.2.1 Natural Gas Prices

Natural gas commodity prices have historically been significant drivers of wholesale electricity prices, with natural gas generating units setting the market clearing price in many hours. Natural gas prices have also shown significant volatility in the past few decades. While gas prices in recent years have generally been low, uncertainty remains in long-term gas prices.

For the 2019 IRP, gas prices for 2020 through 2023 rely on PGE's forward gas trading curve from the second quarter of 2018 (2018 Q2). PGE incorporates uncertainty in natural gas prices after 2023 by considering low, reference, and high forecast trajectories. Appendix I provides a description of the structure of each forecast.

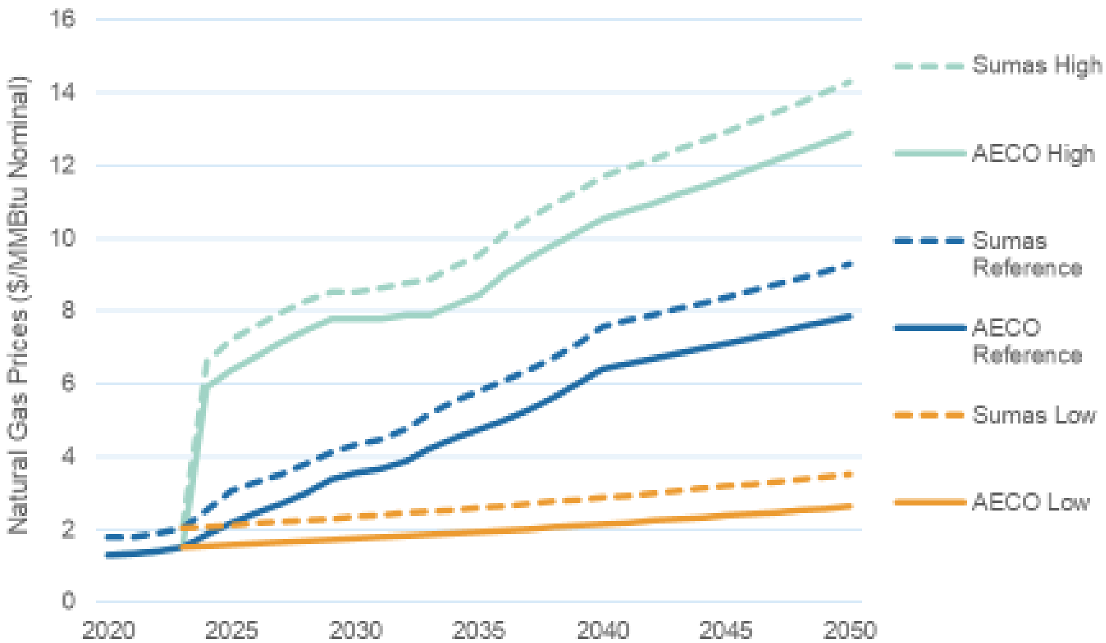
The Reference Case uses the 2018 H1 vintage Wood Mackenzie gas forecast for the years 2025-2040, with linear interpolation applied in 2024 to transition from the PGE forward gas trading curve. The Reference Case anticipates relatively modest price increases prior to 2030 due to high levels of domestic production, limited export opportunities, and increased oil-associated gas production. Steeper price increases are forecast in the 2030-2040 timeframe, following expected development of export channels along with depletion of the lowest-cost production wells. Between 2020 and 2040, the Reference Case has changed little since the 2016 IRP Update, with an average annual decrease of approximately 0.2 percent for the AECO prices. Refer to Appendix I for a comparison of the 2016 IRP update and 2019 IRP natural gas price forecasts.

After 2040, the last year of the Wood Mackenzie forecast, PGE simplifies the model by assuming prices will grow at the rate of inflation through 2050. This differs from the methodology used in the 2016 IRP and IRP Update, which estimated real escalation rates based on outer-year trends. PGE adopted a more conservative methodology for the 2019 IRP to reduce the potential impacts of long-term market price escalation on the performance of near-term resource actions.

To capture a reasonable bound of uncertainty on the low side of the forecast, PGE examined a Low Gas Price Future that assumes natural gas prices grow at the rate of inflation beginning in 2024. This is an approximation of a scenario where near-term market conditions persist due to circumstances such as technology enhancements, continued limited export capability, and high levels of oil-associated gas production.

The High Gas Price Future applies the 2018 Annual Energy Outlook (AEO) Low Oil and Gas Resource Technology case forecast beginning in 2024. Among scenarios published for the 2018 AEO, the Low Oil and Gas Resource Technology case results in the highest long-term projection of gas prices. This is an approximation based on an assessment by the U.S. Energy Information Agency (EIA) of reduced ultimate recovery per well, limited stock of undiscovered resources, and a sluggish rate of cost-saving technological advancement. As in the Reference Case, prices in the High Gas Price Future grow with inflation after 2040.

FIGURE 3-1: AECO and Sumas hub prices across Gas Price Futures



3.2.2 Carbon Prices

Future GHG policies have the potential to dramatically impact resource economics for both GHG-emitting and GHG-free resources. PGE has included carbon pricing in IRP analysis since 2008, consistent with Order No. 08-339. The 2016 IRP incorporated carbon prices reflecting the potential for the federal Clean Power Plan (CPP) to result in trading of CPP compliance instruments.

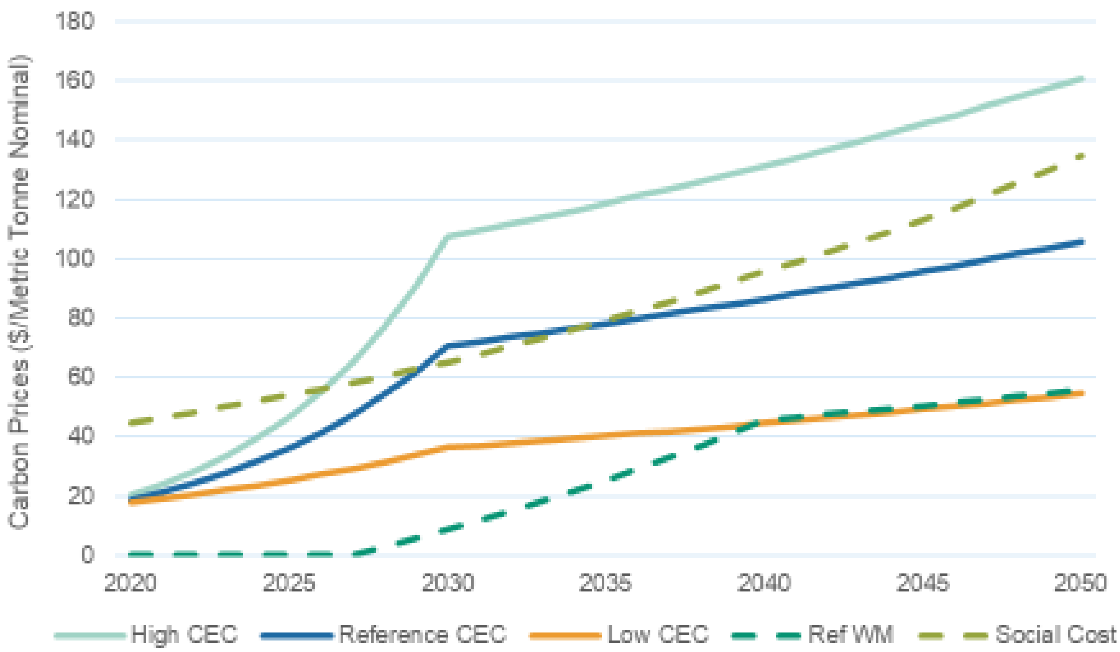
As PGE prepared the 2019 IRP, the Oregon Legislature was actively considering the introduction of a cap and trade program in Oregon. Section 2.2.2 State Policies describes this legislative proposal (HB 2020) in more detail. Although HB 2020 did not pass during the 2019 legislative session, the 2019 IRP continues the past practice of incorporating the most relevant greenhouse gas policy proposals to date into long-term planning. To capture the potential impacts of future climate policies, PGE simulated a linked greenhouse gas allowance market between California, Oregon, and Washington. The analysis assumed that carbon pricing in Oregon and Washington begins in 2021 and that activities in California continue to set the allowance price. The carbon price forecast is therefore based on the carbon allowance price forecasts provided by the California Energy Commission (CEC). Appendix I. 2019 IRP Modeling Details provides additional information about how PGE implemented carbon pricing in the 2019 IRP.

Table 3-2 summarizes the carbon price assumptions for each region and Carbon Price Future. Assumptions based on carbon prices from the Wood Mackenzie database are represented by "Reference WM". Figure 3-2 shows the low, reference, and high CEC allowance price forecasts along with the Wood Mackenzie carbon prices. In response to stakeholder request, Figure 3-2 also includes the social cost of carbon.[80]

TABLE 3-2: Carbon Price Future assumptions

Region	Low Carbon Price Future	Reference Case	High Carbon Price Future
CA+OR+WA	Low CEC	Reference CEC	High CEC
Rest of WECC	None	Reference WM	Reference WM

FIGURE 3-2: Carbon price trajectories utilized in the Carbon Price Futures



3.2.3 High Renewable WECC Buildout

PGE relies on the Wood Mackenzie Base Case WECC resource database to simulate future hourly electricity prices. During the public process, stakeholders requested an additional view of the WECC database with a higher renewable resource buildout. PGE agreed on this concept as an important driver of uncertainty.

Western markets have demonstrated that the deployment of renewable resources, particularly solar, can have material impacts on wholesale market price trends. California's passage of SB 100 and the active conversations taking place in multiple Western states around increasingly ambitious clean and renewable energy policies make it increasingly likely that future renewable deployment across the West may far exceed current market forecasts. Considering these developments, PGE believes that

80 EPA. Retrieved Jun. 27, 2019, from https://19january2017snapshot.epa.gov/climatechange/social-cost-carbon_.html.

it is important to investigate how a more rapid expansion of renewable deployment in the West might impact PGE's portfolio and new resource options. Toward this end, PGE developed a High Renewable WECC Future.

The High Renewable WECC Future approximates a world with high penetration of renewables across the WECC at levels exceeding current RPS planning standards. Such an outcome could be caused by drivers such as resource economics, legislation, or customer choice. The purpose of this analysis is to consider the potential effect on wholesale electricity prices and their subsequent impacts on resource portfolio performance. This is a key development in the analysis of wholesale market price uncertainty compared to the 2016 IRP and an important area of continued investigation for future cycles.

In the High Renewable WECC Future, renewable resources were added within sub-regions until the available carbon-free generation was equal to 100 percent of load by 2040 (neglecting curtailment). PGE defined the sub-regions as: Canada, Pacific Northwest, Rockies, Basin, California, and the Desert Southwest. In each sub-region, PGE layered in renewable additions linearly between 2020 and 2040 using the regional wind-to-solar ratios from the new resource additions in the Wood Mackenzie database. The High Renewable WECC Future also incorporated a linear decline of coal-fired power to zero in the WECC between 2030 and 2040. Appendix I presents additional information about the High Renewable WECC Future.

Figure 3-3 compares the total WECC capacity installed by technology type in the Reference Case and High Renewable WECC Future. By 2040, the High Renewable WECC Future has no coal plants and approximately 150 GW of additional wind and solar capacity. For modeling purposes, PGE does not add new resources after 2040 and freezes WECC load at its 2040 level.

As shown in Figure 3-4, gas resources dispatch at a declining rate in the High Renewable WECC Future as compared to the Reference Case, due to higher levels of renewable generation that shift the economic use of many natural gas resources from baseload to peaking. Thermal generation persists in the High Renewable WECC Future due to renewable curtailment and balancing needs. Wind shows slight curtailment in the outer years. Solar experiences curtailment earlier and more dramatically than wind, beginning in the late 2020s and ramping to nearly 25 percent curtailment by 2040.

FIGURE 3-3: WECC-wide nameplate capacity resource stacks for the Reference Case and High Renewable WECC Future

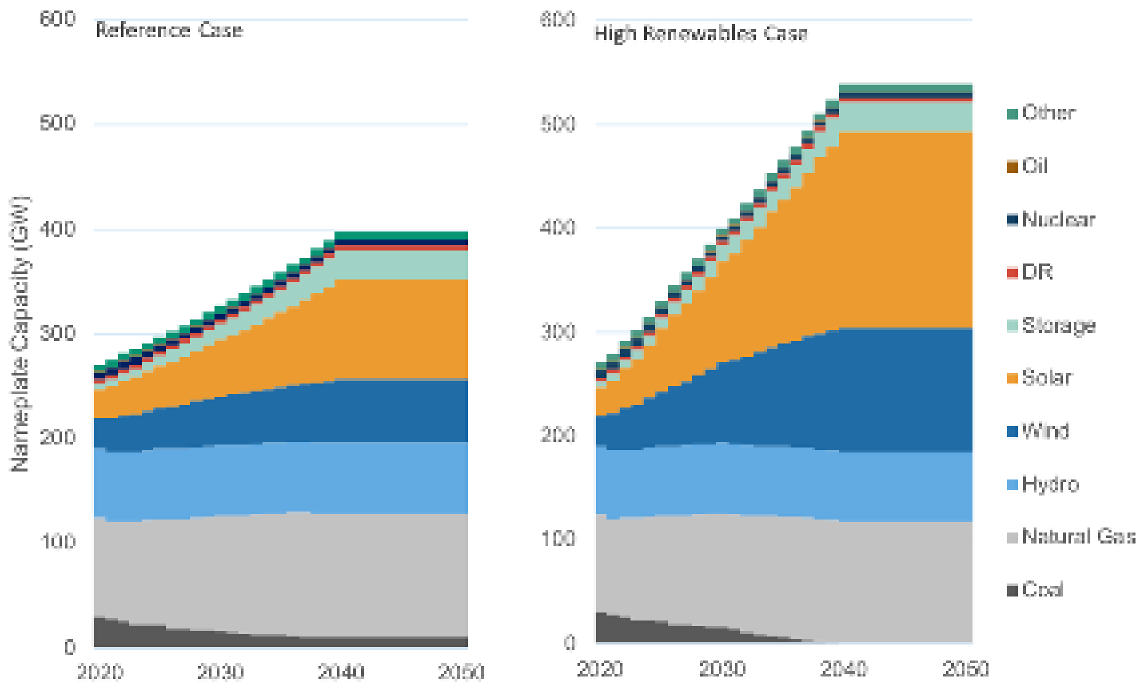


FIGURE 3-4: WECC-wide generation for the Reference Case and High Renewable WECC Future

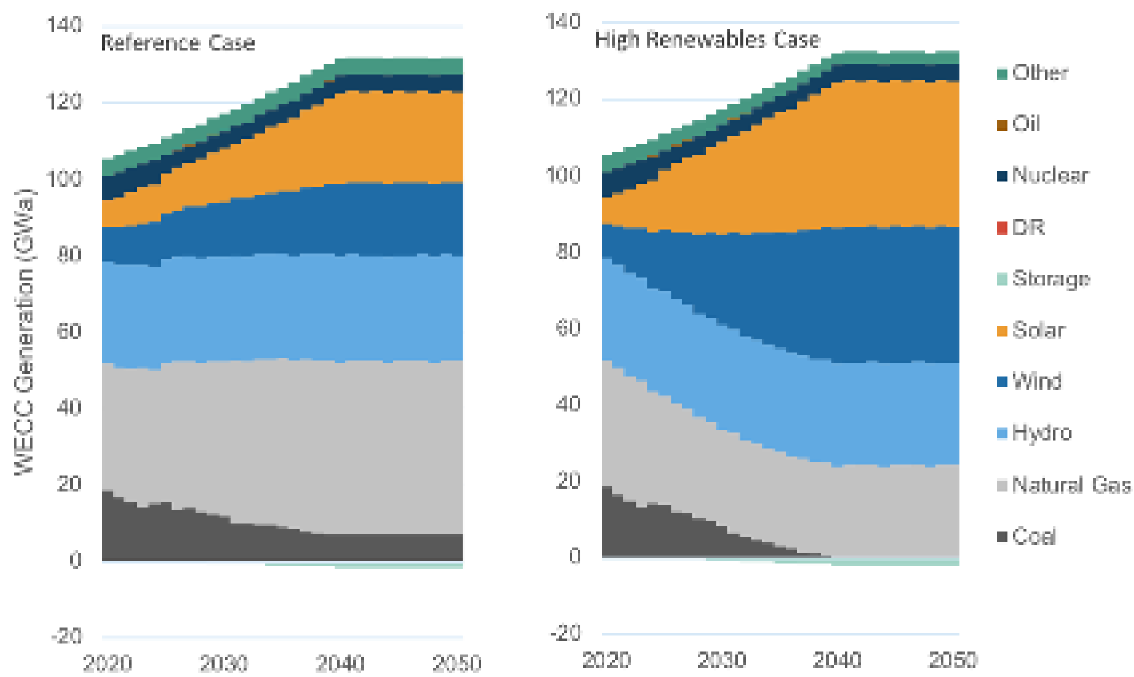


Figure 3-5 shows the annual average wholesale electricity price and volatility[81] for the OregonWest[82] pricing zone in the Reference Case and the High Renewable WECC Future (assuming reference conditions for gas prices, carbon prices, and hydro). As expected, the expanded renewable buildout depresses prices on an annual average level (left) due to the high volume of low variable cost renewables, but creates significantly higher volatility (right) as the marginal resource fluctuates between renewables and the thermal resources that provide balancing when renewable production is low.

FIGURE 3-5: OregonWest average annual wholesale energy prices and price volatility for the Reference Case and High Renewable WECC Future

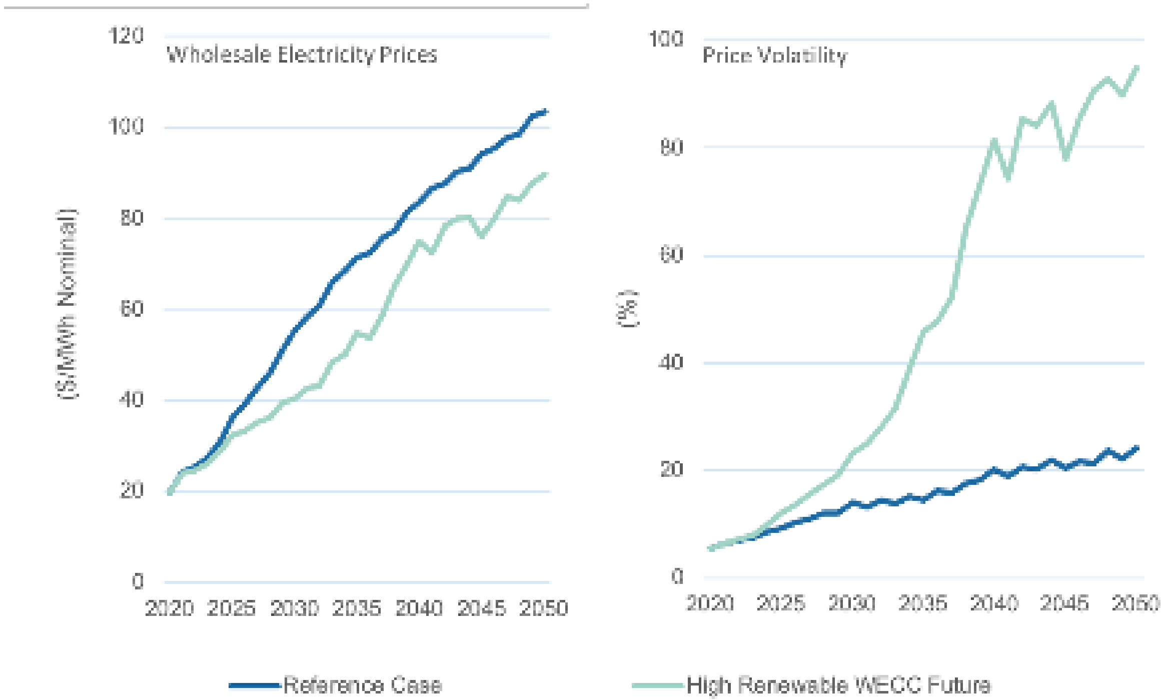
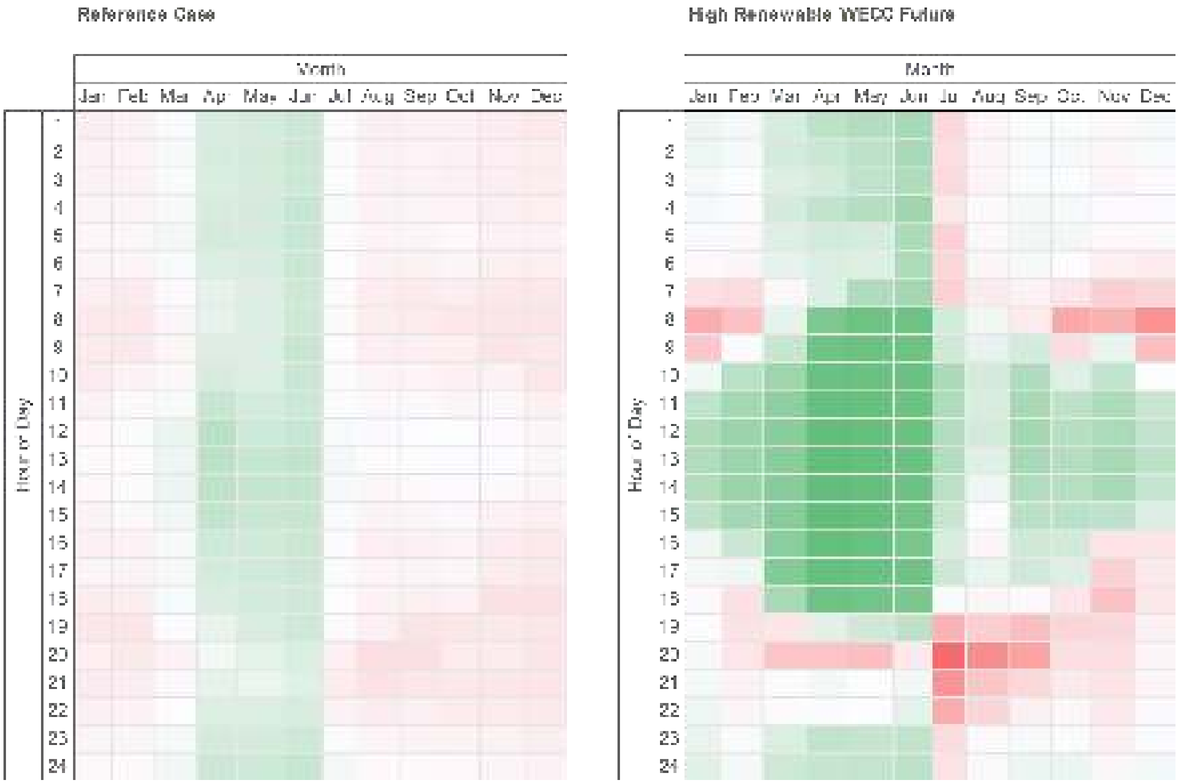


Figure 3-6 shows OregonWest average wholesale electricity price month-hour heatmaps of 2040 prices in the Reference Case and High Renewable WECC Future cases (also assuming reference conditions for gas prices, carbon prices, and hydro). The heatmaps illustrate that expanded renewable energy generation also creates deviations from the Reference Case in seasonal and diurnal patterns. In the Reference Case, the spring and early summer months exhibit price depression in a uniform manner across all hours of the day. In contrast, the High Renewable WECC Future displays price depression in all seasons during midday hours, caused mainly by heightened solar production across the WECC. Both cases show the most pronounced price depression in the spring due to low loads and high hydro availability during the season.

[81] The volatility calculation represents the standard deviation of hourly prices expressed as a percentage of the annual average price.

[82] Defined by Wood Mackenzie as the WECC_PNW_OregonWest zone in Aurora.

FIGURE 3-6: Average month-hour wholesale electricity price heatmaps for the Reference Case and High Renewable WECC Future in the year 2040



In the development of the market price futures that ultimately inform PGE's risk metrics, PGE considered the High Renewable WECC Future in combination with the Gas and Carbon Price Futures and hydro conditions. In addition, the High Renewable WECC Future also flows into the High Tech Future scoring metric described in Section 7.2.1 Scoring Metrics.

3.2.4 Pacific Northwest Hydro Conditions

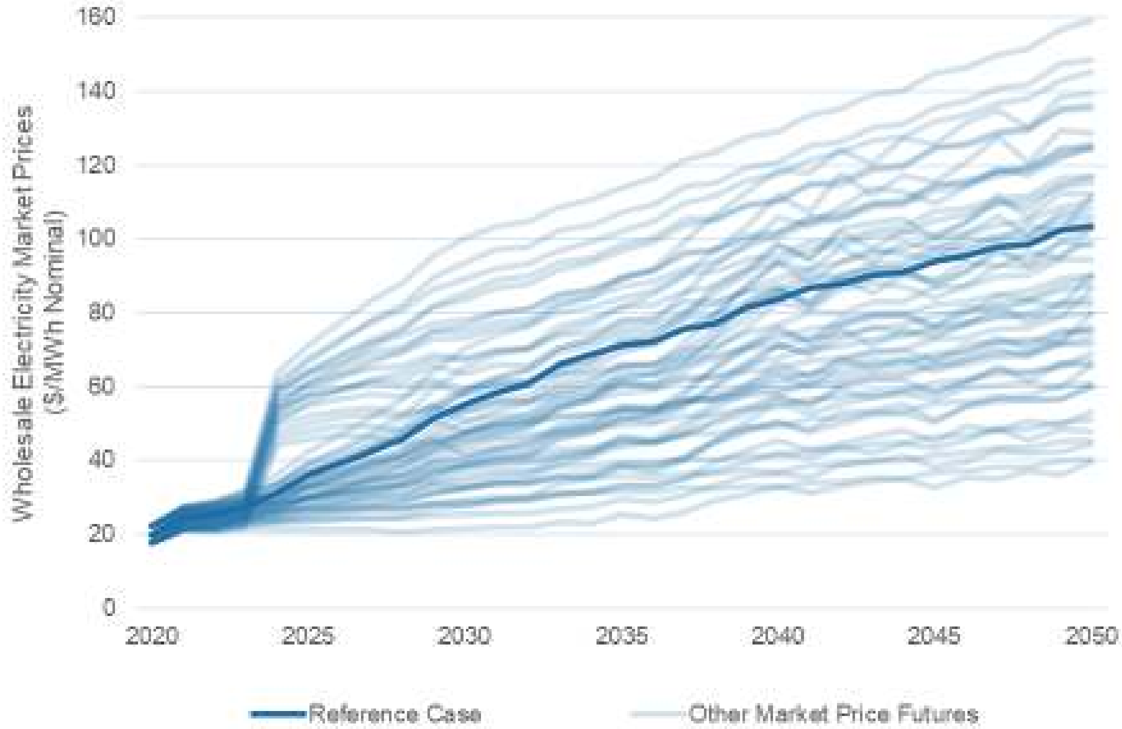
Hydro generation in the Pacific Northwest strongly influences electricity prices. In the 2016 IRP, PGE considered one hydro condition (reference) across the gas and carbon forecasts and examined critical hydro conditions under reference gas and carbon prices. PGE expanded the treatment of hydro conditions in the 2016 IRP Update by considering three hydro conditions across the gas and carbon cases, and retained this methodology for the 2019 IRP. The low and high hydro conditions were modeled as +/- 10 percent (approximately one standard deviation) of annual Pacific Northwest energy production compared to reference.

Low and High Hydro Conditions were included in the analysis of portfolio performance across risk metrics. They were not considered in portfolio construction.

3.2.5 Electricity Market Price Futures

Consideration of the electricity market price drivers described in the previous sections resulted in 54 distinct hourly price streams for each year through 2050. Figure 3-7 shows the average annual prices across the 54 Market Price Futures.

FIGURE 3-7: OregonWest annual prices across all 54 Market Price Futures



A wide range of uncertainty is present in wholesale electricity prices beginning in the mid-2020s and persisting through 2050 due to a confluence of uncertainty in renewable development, GHG policy, natural gas prices, and hydro generation. In the mid-2020s, the High Gas Price Future is a primary driver of a step-change in the highest prices in the range of forecasts. The transition from PGE's near-term forward trading curve to the EIA high price forecast is discussed in Section 3.2.1 Natural Gas Prices and Appendix I. 2019 IRP Modeling Details. The lowest prices in the forecast range result mainly from the High Renewable WECC Future and Low Carbon Price Future. Variation in natural gas prices and renewable buildout levels displayed the highest impact on wholesale electricity prices, while GHG prices and hydro conditions served to either mitigate or exacerbate pricing trajectories. See Appendix I. 2019 IRP Modeling Details for more information on market price sensitivities.

3.3 Technology Cost Uncertainties

In Chapter 2. Planning Environment, PGE describes some of the factors that have contributed to rapid cost reductions for clean technologies in recent years. PGE recognizes that capital costs are uncertain in the near term and that these uncertainties are likely to increase across the planning horizon, particularly for less mature technologies. Evaluating capital cost uncertainty in this environment of rapid technological change is critical to long-term planning. In addition to the reference costs developed by HDR Engineering, Inc. (HDR) in their study of resource parameters and costs (see External Study D. Characterizations of Supply Side Options), PGE prepared low and high capital cost trajectories for renewable and thermal resources.

In the Supply Side Options Study (see External Study D. Characterizations of Supply Side Options), HDR reported the standard deviation of the overnight capital costs for each technology assuming a 2018 notice to proceed. In addition to this uncertainty, some technologies, particularly clean technologies that are benefitting from expanding global deployment in recent years, have considerable uncertainty in future cost reductions. To address this, PGE used experience-curve[83] analysis to develop low and high capital cost trajectories for wind, solar, battery storage, and geothermal technologies, in which technology costs are assumed to decrease over time as the industry gains more maturity. PGE sourced applicable learning rates and installed capacity forecasts for this exercise from Bloomberg New Energy Finance (BNEF) and the EIA. Appendix I. 2019 IRP Modeling Details provides a description of the analysis.

Figure 3-8 and Figure 3-9 show the resulting capital cost curves for renewable and thermal technologies, which consider both the first commercial operation date (COD) year cost uncertainty and the long-term learning curve uncertainty. The capital cost ratios in these curves reflect the capital cost in each year and scenario compared to the reference initial cost for each technology to illustrate the relative uncertainty over time on a consistent basis across resources. Chapter 5. Resource Options and Chapter 6. Resource Economics provide additional resource cost information. For simplification, Figure 3-8 shows only one wind location, but the same trends apply to all wind resources investigated in the 2019 IRP. Similarly, Figure 3-9 shows only one battery duration, but PGE applies the same percentage declines across all battery technologies. These curves indicate a large amount of capital cost uncertainty both in the near term and across the planning horizon for all three technologies, with solar and batteries showing a greater potential for future cost declines than wind. Additional details about the cost trajectories are available in Appendix I. 2019 IRP Modeling Details.

[83] As described in *Perspectives on Experience* (The Boston Consulting Group, 1972), the cost decline per cumulative production ("the Experience Curve") was developed by Bruce D. Henderson and the Boston Consulting Group and is widely used in industry.

FIGURE 3-8: Capital cost uncertainty for renewable resources

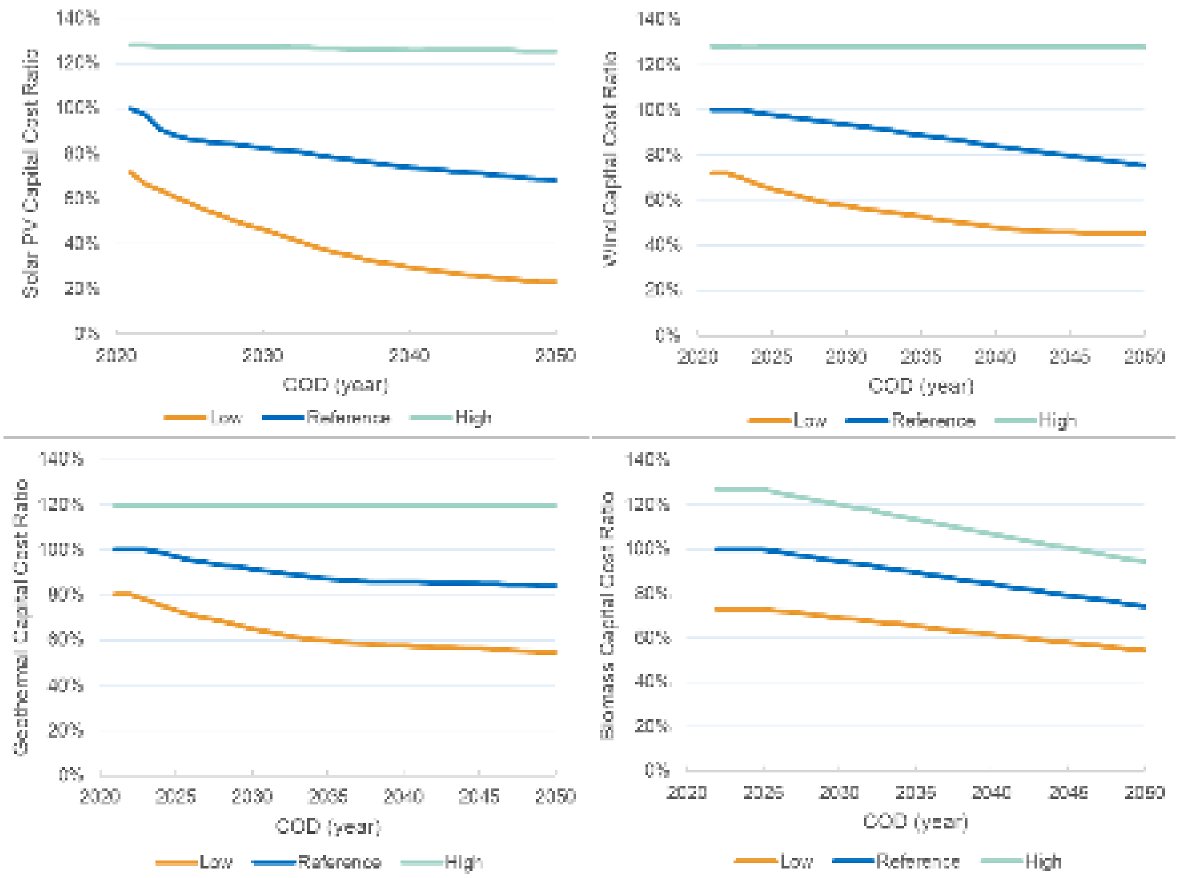
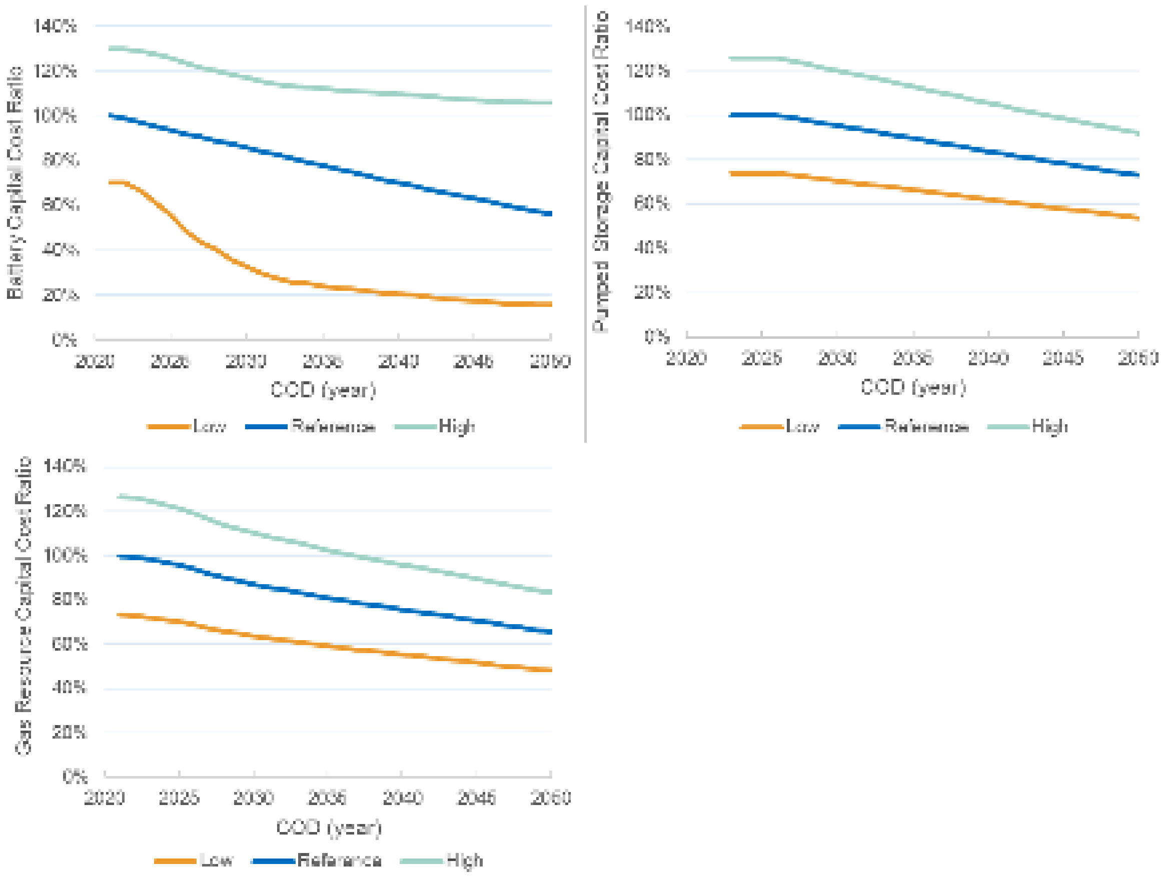


FIGURE 3-9: Capital cost uncertainty for dispatchable capacity resources



PGE used the capital cost trajectories to create five Technology Cost Futures (shown in Table 3-3) to examine the impact of the cost uncertainty in portfolio performance. These futures capture possibilities such as low solar and battery costs with reference wind costs, allowing for a more nuanced examination of the impact of cost assumptions than in the 2016 IRP, which moved all resources together between low, reference, and high cost projections.

TABLE 3-3: Technology Cost Futures

Technology Cost Future	Wind Costs	Solar Costs	Biomass & Geothermal Costs	Battery Costs	Pumped Storage Costs	Gas Resource Costs
Reference	Reference	Reference	Reference	Reference	Reference	Reference
Low Cost Wind	Low	Reference	Reference	Reference	Reference	Reference
High Cost Wind	High	Reference	Reference	Reference	Reference	Reference
Low Cost Solar & Storage	Reference	Low	Reference	Low	Reference	Reference
High Cost Solar & Storage	Reference	High	Reference	High	Reference	Reference

The five Technology Cost Futures factor into both portfolio construction and scoring. In addition, PGE included the Low Solar & Storage Cost Future in the High Tech Future scoring metric described in Section 7.2.1 Scoring Metrics. Although the low and high cost scenarios for geothermal, biomass, pumped storage, and gas fired resources are not included in the Technology Cost Futures, and therefore, do not directly impact portfolio analysis and scoring, they are discussed in Chapter 6. Resource Economics.

3.4 Combined Futures

When considered together, the Need, Market Price, and Technology Futures described above explore a wide range of uncertainties that influence both the performance of new resource options and the size and timing of recommendations in the Action Plan.

The 2019 IRP considers the Need, Market Price, and Technology Futures as independent drivers of potential resource and portfolio performance and incorporates them into portfolio analysis by investigating all possible combinations of the futures. As shown in Table 3-4, this approach results in 810 combined futures, a substantial increase relative to the 23 futures investigated in the 2016 IRP. These futures are explored further in Chapter 7. Portfolio Analysis.

TABLE 3-4: Number of futures investigated in 2019 IRP

	Need Futures		Market Price Futures		Technology Futures		Combined Futures
# of Futures	3	×	54	×	5	=	810

One innovation in the 2019 IRP is that many of these futures flow directly into portfolio construction, allowing the evaluation to account for the flexibility that near-term actions might afford or the constraints they might impose on future procurement as conditions evolve. As described in Section 7.1 Portfolio Construction, the resource additions made after 2025 associated with each portfolio can vary across the Need (3), Market Price (18[84]), and Technology Futures (5), resulting in 270 potential trajectories of outer-year resource additions for each portfolio. All 810 futures are considered in the analysis of portfolio performance described in Section 7.2.1 Scoring Metrics. This approach ensures that PGE's scoring metrics account for the value of optionality and the potential risks across the planning horizon.

[84] The scenarios for gas prices, carbon prices, and the high renewable WECC buildout.

CHAPTER 4. Resource Needs

PGE's first step in evaluating portfolios for long-term planning is to characterize resource needs over time. This chapter describes how PGE evaluates its resource needs to ensure that each portfolio meets capacity adequacy requirements, meets energy needs, and allows PGE to comply with the Oregon Renewable Portfolio Standard (RPS). Throughout this chapter, PGE shows resource needs under Reference Case conditions as well as High and Low Need Futures that allow us to consider the uncertainties described in Chapter 3. Futures and Uncertainties.

Chapter Highlights

- ★ PGE's load forecast layers the impact of customer-sited photovoltaics, electric vehicles, and energy efficiency on its top-down econometric forecast.
- ★ PGE examines the uncertainty associated with its load forecast model and uses scenario analysis to assess the impact of changes in economic trends and customer resource adoption rates.
- ★ PGE faces growing capacity needs across all Need Futures with a wide range of potential need by 2025.
- ★ PGE is forecast to be a net purchaser of market energy beginning in 2021.
- ★ Without incremental renewable resource actions, Renewable Portfolio Standards (RPS) obligations will exceed RPS generation for the Reference Case beginning in 2030.
- ★ PGE's Flexibility Adequacy study builds upon previous IRP analysis and a systematic review of existing flexibility literature.
- ★ Excluding long-term direct access customers from PGE's capacity planning shifts reliability risks from participants to cost-of-service supply customers.

4.1 Load Forecast

PGE's assessment of resource needs begins with the forecasting of electric loads. The Company undertook major enhancements to the load forecast in this IRP to better characterize uncertainty and customer adoption of distributed technologies. The load forecast considered for long-term planning within the IRP is comprised of the items listed below and described in the following sections:

- Section 4.1.1 Top-down Econometric Forecasting. The top-down load forecast describes large-scale patterns in consumption, particularly as related to weather and the economy, and has been the basis of load forecasting in PGE's prior IRPs. In this section we discuss uncertainty, key assumptions, and trends. Probabilistic forecasts and model development are discussed in Appendix D.
- Section 4.1.2 Energy Efficiency. This section describes the Energy Trust of Oregon's (Energy Trust) energy efficiency savings projections, which are embedded in PGE's top-down load forecast, and incremental energy efficiency savings, which are included in the Low Need Future.
- Section 4.1.3 Passive Customer DER Forecasting. This section describes the forecasts for customer adoption of electric vehicles, distributed photovoltaics, and non-dispatchable customer storage with low, reference, and high scenarios. (Other distributed energy resources are discussed in Section 5.1 Distributed Flexibility.)

These elements are combined to create the load forecasts described in Section 4.1.4 Load Scenarios. By examining both the uncertainty and the potential impact of rapidly accelerating customer trends, we are better able to examine the robustness of resource actions across a wide range of potential outcomes.

4.1.1 Top-down Econometric Forecasting

PGE's top-down forecasting models take an econometric approach by estimating the relationships between PGE service area load growth and exogenous drivers. These exogenous drivers include seasonal and weather variables and macroeconomic indicators that are used to describe regional economic trends.

Weather, specifically ambient temperature, is the largest factor affecting customer electricity demand. This is particularly true for PGE's residential and commercial sectors, as industrial loads tend to be less weather sensitive. PGE uses several weather variables in its energy and peak models including heating and cooling degree days and wind speed. Energy use is also correlated with economic activity.[85] Over time, the relationship of energy use to economic growth has changed.[86] PGE recognizes this environment in the development of its top-down forecasting models.

[85] Arora, V; Lieskovsky, J. (November 2014), *Electricity Use as an Indicator of U.S. Economic Activity*. Retrieved Apr. 19, 2019, from https://www.eia.gov/workingpapers/pdf/electricity_indicator.pdf.

[86] Retrieved Apr. 19, 2019, from https://www.eia.gov/todayinenergy/detail.php?id=10491.

PGE's economic models forecast monthly energy deliveries by customer class and peak demand for the total PGE system. The primary model inputs are weather, population, employment, gross domestic product (GDP), customer counts, and historical loads. Appendix D[87] provides additional details on the models that constitute the 2019 IRP top-down forecast and how those models were tested and selected.[88]

All forecasts have inherent uncertainty. For example, there is uncertainty associated with the model input data, the selection of the model itself and the relationships established within it, and factors external to the model. To reflect uncertainty in the model input data[89] and the relationships estimated in the load forecast and in response to Commission input,[90] PGE used regression outputs to empirically develop high- and low-load growth scenarios. These scenarios also incorporate stochastic load risk analysis to support the 2019 IRP. Figure 4-10 in Section 4.1.4 shows the low, reference, and high top-down load forecasts.

As shown in Table 4-1, the low and high scenarios are defined by low and high growth of the model's economic drivers as well as by adding or subtracting one standard deviation in model uncertainty. Model uncertainty was explored by conducting stochastic simulations of the sector-level forecasts that bootstrapped model residual errors and coefficient errors over 10,000 runs.

TABLE 4-1: Top-down load forecast scenarios

	Low Load	Reference Case	High Load
Economic Driver	Average annual growth rates (2020-2050)		
Population	0.4%	0.9%	1.4%
Employment*	0.0%	0.5%	1.2%
US GDP	1.6%	1.9%	2.5%
Model Uncertainty†	-1 SD	None	+1 SD

*Oregon total non-farm employment.

†Standard deviation (SD) including regression error and coefficient uncertainty.

4.1.1.1 Key Assumptions

In addition to the relationships with macroeconomic drivers, PGE's load forecast also makes the following key assumptions.

- **Inherent assumptions.** PGE's top-down econometric models estimate how loads may evolve in the future assuming the consumption patterns observed in recent history persist. These models assume no structural or rapid changes in customer behavior, equipment efficiencies, or appliance saturation. PGE relies on top-down forecasting both in setting rates and in long-term planning to capture large-scale trends.

87 Requested in the Commissions General Recommendation 1 in Order No. 17-386.

88 Including the results of out-of-sample testing, as required by Order No. 17-386.

89 A large component of load forecast uncertainty, weather variability, is quantified separately as part of the capacity adequacy model discussed in Section I.3 RECAP Model.

90 IRP Guideline 4b in Order No. 07-002, and the Commission's General Recommendation 1 in Order No. 17-386.

- **Weather assumptions.** PGE's load forecasts reflect normal or expected weather conditions over the course of each year. For the 2019 IRP, the expected weather conditions are represented by a trended model for heating and cooling degree days to reflect the gradually warming regional climate.[91] The forecasts do not attempt to predict, for example, an El Niño winter, or a particularly hot summer, or any particular weather event.

  The impacts of weather variability on capacity adequacy requirements are important because electric loads are highly sensitive to weather within a given year.[92,93] The impacts of interannual weather variability are assessed in PGE's capacity adequacy evaluation, which is described in Section 4.3.

- **Long-term direct access assumptions.** Customers with approximately 240 MWa of combined commercial and industrial load in PGE's service area are currently on long-term direct access (LTDA) schedules. These customers have opted out of PGE's cost-of-service (COS) supply rates and receive energy from electricity service suppliers (ESS).

  Traditionally, IRP Guideline 9 in Order No. 07-002 has been interpreted as prohibiting the inclusion of long-term (five-year) direct access customer loads in long-term planning for both energy and capacity needs.[94] The 2019 IRP portfolio analysis applies this interpretation. However, as discussed in Section 4.7.3 Direct Access and Resource Adequacy, this interpretation presents reliability and cost risks to cost-of-service supply customers. Consistent with prior IRPs, PGE includes one-year direct access customers in its IRP planning because these customers may return to PGE's COS rates with little notice.

  Commission Order No. 18-341 created the option for customers with new loads to receive their energy from an ESS under a separate New Load Direct Access (NLDA) program.[95] The 2019 IRP does not directly address NLDA customers, as these are by definition customer loads that have not been planned for by the utility.

4.1.1.2 Load Trends

Residential sector trends. A customer growth forecast of 0.7 percent, offset by declining use per customer of 0.6 percent, is driving the residential sector energy deliveries. PGE expects customer growth to continue in response to population growth in the Company's service area. Declining use per customer reflects Oregon's history of energy efficiency, changing codes and standards, fuel switching, and end-use trends. Residential use-per-customer has fallen more than 20 percent since 1990, or an average of 0.9 percent per year. The decrease is particularly strong across seasons with milder temperatures, reflecting the impact of appliance and lighting efficiencies on usage that is not related to temperature. In summer months, increasing use of air conditioners has stabilized use per

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[91] See discussion in Appendix D. Load Forecast Methodology.

[92] NERC (August 2012), *Reliability Assessment Guidebook*. Retrieved Apr. 19, 2019, from https://www.nerc.com/files/Reliability%20Assessment%20Guidebook%203%201%20Final.pdf.

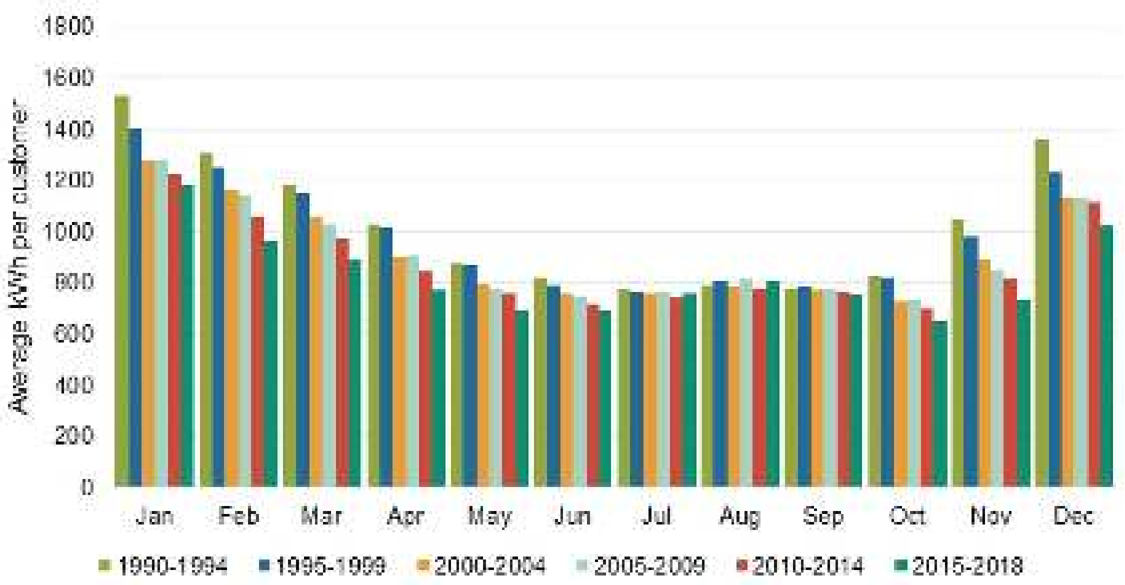
[93] Bartos, M., Chester, M., Johnson, N., Gorman, B., Eisenberg, D., Linkov, I., & Bates, M. (2016, November 2). *Impacts of rising air temperatures on electric transmission ampacity and peak electricity load in the United States*. Retrieved Apr. 16, 2019, fromhttps://iopscience.iop.org/article/10.1088/1748-9326/11/11/114008.

[94] Order No. 07-002 at 19, https://apps.puc.state.or.us/orders/2007ords/07-002.pdf.

[95] Docket AR 614, *In the Matter of Rulemaking Related to a New Large Load Direct Access Program*, Order No. 18-341 at 5.

customer. PGE forecasts residential energy deliveries to grow 0.1 percent in the Reference Case, excluding potential impacts of accelerating adoption of distributed photovoltaics and electric vehicles, which are discussed in the following sections.

FIGURE 4-1: Monthly residential use per customer since 1990

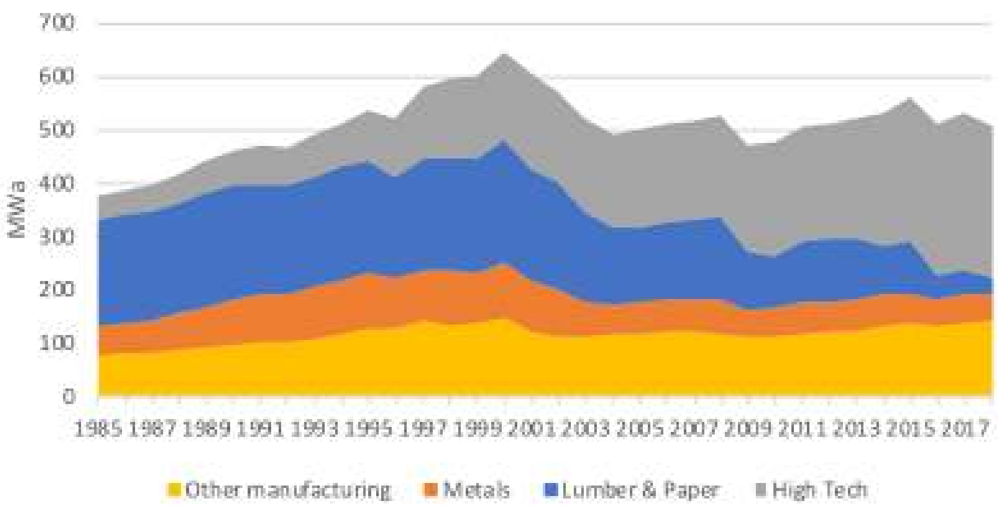


Commercial sector trends. Commercial sector load growth is linked to residential customer growth as demand for services such as healthcare, education, retail, food stores, and restaurants expands with population growth. However, as with the residential sector, changing codes, standards, and end-use trends have caused declining use-per-customer trends in the commercial sector that offset customer growth. PGE forecasts net system[96] commercial energy deliveries to grow 0.5 percent.

Industrial sector trends. Several decades ago, lumber and paper manufacturing represented the largest industrial segment in PGE's service area. This sector has declined, with significant plant closures in recent years, and now the key driver of future industrial loads is growth in the high-technology sector, notably semiconductor manufacturing and data centers. PGE forecasts net system industrial energy deliveries to grow 1.9 percent in the Reference Case.

[96] The net system forecast includes deliveries to both cost-of-service supply and long-term direct access customers.

FIGURE 4-2: Changing mix of industries in PGE's service area since 1985



Peak trends. The Pacific Northwest has historically experienced annual peaking events in the winter based on characteristics of the regional climate including a long heating season, generally mild temperatures, and appliance stock, including penetrations of electric heat and air conditioning systems.

In alignment with the region, PGE has historically been a winter-peaking utility. However, in 2002 the Company's annual system peak occurred in the summer for the first time. Since 2002, PGE has experienced its annual peak in the summer in 9 out of the 17 years (53 percent). Drivers of this change are long-term trends in appliance stock, including increasing air conditioning system penetration, and load composition as PGE's industrial loads have grown more quickly than the system on average and also tend to be more sensitive to cooling than heating needs.

Reflecting these trends, PGE's forecast shows its expected annual peak occurring in the summer and its seasonal peak, before the inclusion of increased penetration of behind-the-meter solar, growing more rapidly in the summer than in the winter. While forecasts for the Pacific Northwest at a regional level maintain a winter peak, they also reflect the trend of seasonal peaks growing more rapidly in the summer, with the Pacific Northwest Utilities Conference Committee (PNUCC) regional forecast reflecting a 0.3-percent differential in average annual growth rate for the summer peak versus winter peak.[97]

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[97] PNUCC 2018 *Northwest Regional Forecast, annual average growth rate reflected for years 2019-2027 net of energy efficiency.* Retrieved Apr. 19, 2019, from http://www.pnucc.org/sites/default/files/Xdak24C14w3677n7KsL43OEL4J25MW0b3d5cmx3FGD4d9OQ3B189OF/2018%20Northwest%20Regional%20Forecast%20v2.pdf

4.1.2 Energy Efficiency

The State of Oregon has a strong history of supporting energy efficiency (EE) through adoption and implementation of legislation and programs. Investment in EE has helped to reduce customer loads, the need for infrastructure and resource investments, exposure to market price risks, and the state's emission footprint. A continued prioritization of cost-effective EE savings is a key foundation to achieving PGE's and the region's decarbonization goals.[98]

The Energy Trust of Oregon (Energy Trust) is the independent, non-profit organization in charge of identifying the state's EE potential and allocating funds to EE projects.[99] Through the Energy Trust's work, the state has acquired more than 600 MWa of EE electricity savings.[100] The shared goal of Energy Trust and PGE is to provide sufficient funding to acquire all available cost-effective EE within PGE's service area. The requirement for the acquisition of EE to be cost-effective enables consideration of all measures that are equal to or less than the avoided cost of electric generation resources, with appropriate adjustments to reflect the additional value associated with the capacity, transmission and distribution, and risk mitigation benefits, as well as the 10-percent conservation benefit.

In PGE's 2016 IRP docket and other OPUC dockets, stakeholders have expressed a desire for more transparency into the avoided cost inputs from utilities and the Energy Trust's cost-effective modeling. Some stakeholders also expressed concern that the forecasting methodology may underestimate the potential EE savings across the planning horizon. The Energy Trust, PGE, OPUC Staff, and stakeholders have subsequently worked together in several workshops and meetings and, as discussed below, have made progress on a number of these issues.

Energy Trust held discussions with stakeholders in 2017 about the cost-effectiveness calculation methodology. Following those discussions, Energy Trust incorporated several updates into their model, including expanded application of the 10-percent conservation adder from one element to three (energy, capacity, transmission and distribution), updates to measures and emerging technology, and updated deployment rate assumptions.

The 2019 IRP incorporates the Energy Trust's most recent long-term EE savings forecasts from November 2017. Energy Trust provided forecasts for the cost-effective deployable potential and the achievable deployable potential.[101] Additionally, Energy Trust provided a report on their methodology which is included as External Study B. Figure 4-3 shows the cost-effective deployable EE acquisitions for 2020 through 2037 by customer segment.[102]

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[98] See the Decarbonization Study in External Study A.

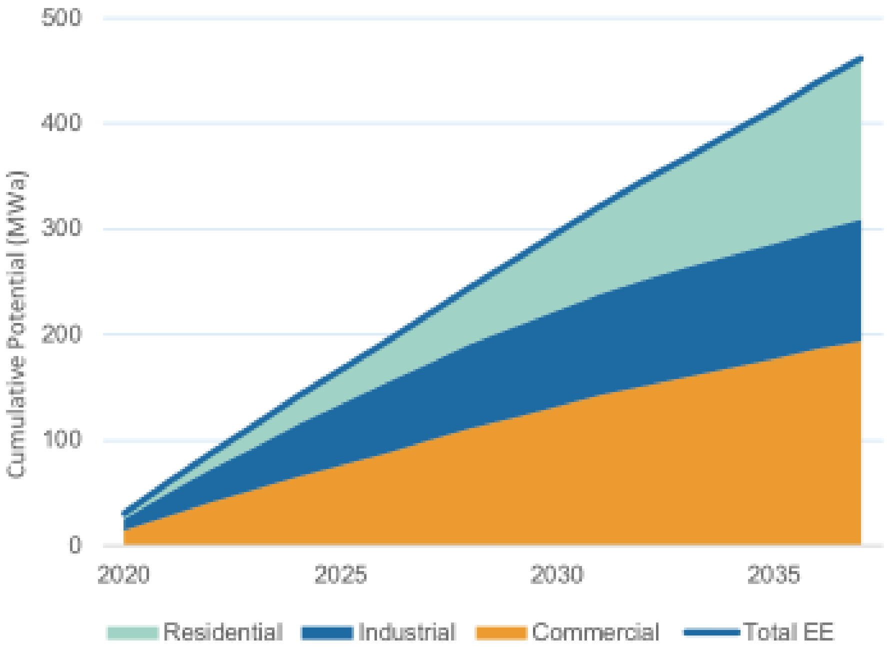
[99] Energy Trust of Oregon, "Who We Are." Retrieved Apr. 18, 2019, from https://www.energytrust.org/about/explore-energy-trust/mission-approach/.

[100] External Study B. Energy Trust of Oregon Methodology, p. 1.

[101] The Energy Trust's methodology report in External Study B. Energy Trust of Oregon Methodology also refers to the cost-effective deployable potential as the final savings projection. The report discusses the achievable potential before the deployable adjustment.

[102] In the following sections and in Figure 4-3, unless specified, references to the cost-effective deployable energy efficiency forecasts do not include partial forecasts.

FIGURE 4-3: Cost-effective deployable savings forecast by customer segment



Gross year-end EE savings adjusted for line losses. Excludes partial forecasts.

In the November 2017 EE projections, Energy Trust also introduced partial forecasts (energy only) for two items not included in the previous forecast: residential lighting market transformation and unexpected large projects (mega-project adder). The partial forecasts are not included in the Reference Case EE assumptions, which may require adjustments to account for embedded trends in the econometric load forecast or for new customer loads associated with unexpected large EE projects. PGE recognizes the uncertainty in the EE projections and examined a high EE scenario (described below).

As discussed in Section 3.1, PGE constructed three Need Futures to examine uncertainty in the capacity, energy, and RPS needs, and the implications for portfolio construction and risk. For both the Reference Case and High Need Future, the EE savings projections align with the cost-effective deployable forecast. The EE savings are incorporated in the top-down econometric load forecast discussed in Section 4.1.1. The year-end savings and costs are summarized in Table 4-2.

To address the uncertainty in future EE projections and in response to stakeholder concerns, PGE examined the impact of additional EE acquisitions beyond the cost-effective deployable projections in the Low Need Future. This future could result from several conditions including customer choice, technology advancement, increased avoided costs, new codes and standards, and new legislation. While PGE does not attempt to define the specific drivers, the Company determined that for this scenario, it is reasonable to assume a quantity of EE acquisitions based on the incremental savings in the achievable deployable forecast above the cost-effective deployable forecast. This assumption is included in the Low Need Future with a simplified cost estimate of 125 percent of the $/MWh cost of the cost-effective deployable forecast. Table 4-2 includes the incremental EE savings and costs modeled in the Low Need Future.

TABLE 4-2: Projections of incremental energy efficiency savings and cost

Year	Reference EE		Incremental High EE	
	MWa	Cost (2020$k)*	MWa	Cost (2020$k)*
2020	30.4	$81,763	0	0
2021	29.5	$80,849	0	0
2022	28.3	$78,562	0	0
2023	26.0	$76,878	3.6	$13,461
2024	26.8	$82,328	3.7	$14,326
2025	25.6	$87,024	3.7	$15,631
2026	26.1	$91,499	3.2	$13,952
2027	26.0	$96,092	3.2	$14,624
2028	27.1	$100,737	3.0	$14,142
2029	25.2	$101,441	3.1	$15,822
2030	25.6	$108,394	3.4	$18,230
2031	25.4	$111,120	4.2	$22,748
2032	24.4	$114,230	5.8	$33,824
2033	22.4	$113,900	5.1	$32,739
2034	22.8	$120,163	5.4	$35,769
2035	23.3	$124,587	5.4	$36,334
2036	24.6	$132,290	5.4	$36,473
2037	22.7	$130,861	5.9	$42,223
Total 2020-2037	**462.0**	**$1,832,719**	**64.2**	**$360,295**

*Gross year-end savings adjusted for line losses. Excludes partial forecasts.

OPUC Staff, the Energy Trust, utilities, and stakeholders have been working in Docket Nos. UM 1893 and AR 621 to continue to improve the process for developing avoided cost inputs and cost-effective measure calculations. This work is ongoing and has already resulted in process changes that improve transparency and better capture the value of energy efficiency measures for Energy Trust's 2020 budget cycle. PGE looks forward to continued collaboration with parties in these dockets.

4.1.3 Passive Customer DER Forecasting

In acknowledgment of the 2016 IRP, the OPUC ordered PGE to "[w]ork with Staff and other parties to advance distributed energy resource forecasting and distributed energy resource representation in the IRP process."[103] To accomplish this, PGE engaged Navigant to perform a Distributed Energy and Flexible Load study (DER Study) for the 2019 IRP, which forecasts customer adoption for all

103 OPUC Order No. 17-386 at page 19.

distribution-connected resources at an aggregate system level from 2020-2050, capturing interactive effects among resources and accounting for uncertainty through scenario analysis.

In this section, we describe three components of the DER Study, which we refer to as passive DER: electric vehicles, distributed solar, and non-dispatchable customer battery storage.[104] They are incorporated in the load forecast for long-term planning. These technologies may see accelerating adoption in the future—trends which are not characterized well by the top-down load forecast discussed in Section 4.1.1.

4.1.3.1 Electric Vehicles

Transportation electrification represents a significant tool to aid Oregon in achieving its economy-wide decarbonization goals. Given the potential for development and societal momentum behind this industry transformation, PGE recognizes the need to analyze the impacts of the resulting requirements on the bulk electric system.

To evaluate the potential load impacts from electric vehicle adoption, PGE engaged Navigant Consulting to develop electric vehicle forecasts as part of its holistic evaluation of future DER adoption. Navigant conducted bottom-up plug-in electric vehicle (PEV) forecasting in PGE's service area using its Vehicle Adoption Simulation Tool (VAST™), a statistically-driven propensity-to-adopt model. This provided PGE with a system-level annual forecast for combined residential and fleet battery-electric vehicles (BEV) and plug-in hybrid electric vehicles (PHEVs).[105] To account for the uncertainty in estimates of future PEV sales, Navigant created high and low scenarios based on the drivers shown in Table 4-3.

TABLE 4-3: Electric vehicle adoption scenarios

	Low EVs	Reference Case	High EVs
Technology Costs	Navigant high lithium-ion costs	Navigant reference lithium-ion costs	Navigant low lithium-ion costs
Policies	Decreased vehicle availability, production, and marketing	Navigant reference vehicle availability, production, and marketing	Increased vehicle availability, production, and marketing
Carbon Prices	PGE Low Carbon Price Future	PGE Reference Carbon Price Future	PGE High Carbon Price Future
Time-of-use (TOU) participation	0% residential TOU	10% residential TOU	Opt-out residential TOU

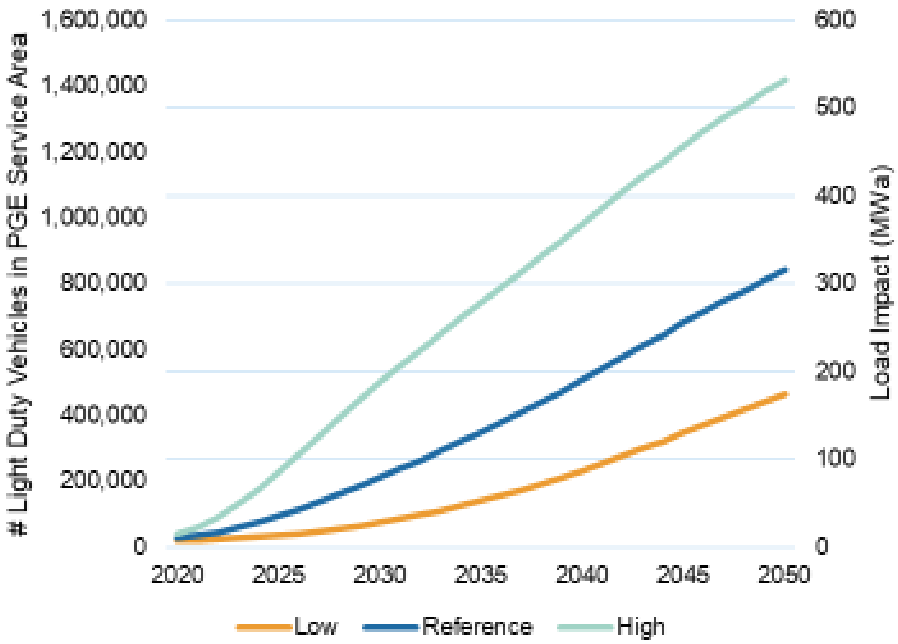
The resulting EV penetration and associated load impact forecasts are shown in Figure 4-4 below, with the total number of light-duty vehicles (LDVs) displayed on the left axis and the corresponding

104 The other elements of the DER Study are discussed in Chapter 5. Resource Options.

105 This forecast is for light-duty vehicles only. PGE anticipates that forecasts for medium and heavy-duty vehicle forecast will be incorporated in future IRP planning cycles.

average annual load impact on the right axis. The Reference Case forecast predicts that approximately 35 percent of the LDVs in PGE's service territory will be electric by 2050.

FIGURE 4-4: Electric vehicle forecasts



In the 2019 IRP, EV loads are represented explicitly with hourly shapes in both resource adequacy modeling and in portfolio dispatch simulations in the PGE-Zone Model. More information about EV forecasting in the 2019 IRP can be found in External Study C. Refer to Section 5.1 Distributed Flexibility for details on EV direct load control (DLC), EV as a demand response resource, and how charging load control is incorporated into long-term planning.

4.1.3.2 Distributed Solar and Non-dispatchable Battery Storage

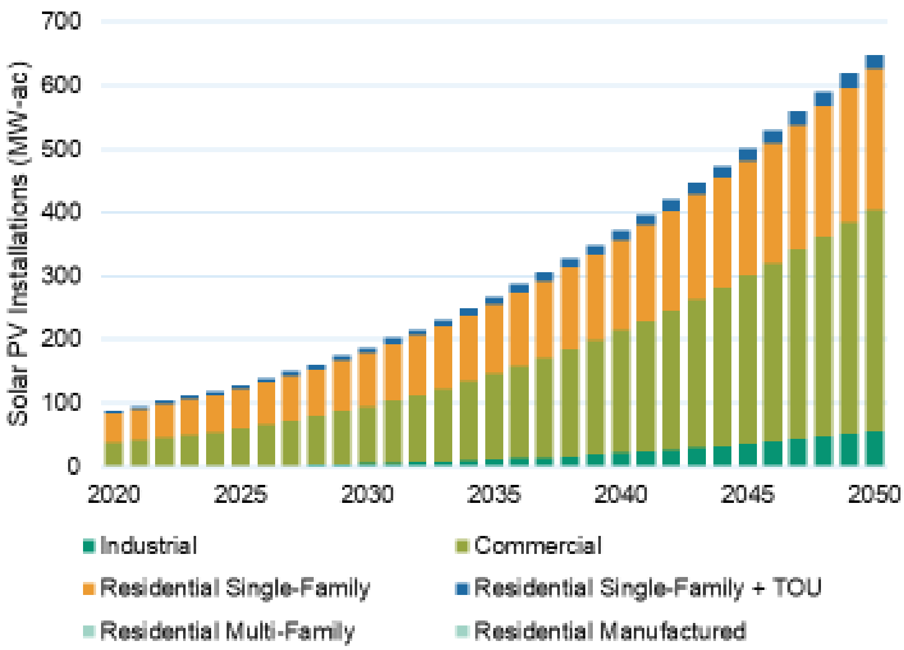
Navigant's DER forecast includes deployments of distributed (or behind-the-meter) solar photovoltaic systems and non-dispatchable customer battery storage systems (both stand-alone and systems paired with solar). The non-dispatchable customer storage systems described in this section are assumed to be operated for bill management, such as for TOU bill optimization or demand charge reduction, and to provide backup power. Dispatchable customer storage systems, which can be optimized to provide maximum value to the grid, are discussed in Chapter 5. Resource Options. To account for the uncertainty in estimates of future solar and storage adoption, Navigant created high and low scenarios based on the drivers shown in Table 4-4 below.

The resulting Reference Case behind-the-meter solar adoption forecast is shown in Figure 4-5, broken out by customer segment. The forecast shows continued growth in rooftop solar adoption across the planning horizon, particularly among residential single-family and commercial customers.

TABLE 4-4: Solar and storage adoption scenarios

	Low Solar & Storage	Reference Case	High Solar & Storage
Technology Costs	Navigant high PV and lithium-ion costs	Navigant reference PV and lithium-ion costs	Navigant low PV and lithium-ion costs
Policies	Decreased marketing	Navigant reference marketing	Investment tax credit (ITC) continues through 2050 and increased marketing
Carbon Prices	PGE Low Carbon Price Future	PGE Reference Carbon Price Future	PGE High Carbon Price Future
TOU participation	0% residential TOU	10% residential TOU	Opt-out residential TOU

FIGURE 4-5: Behind-the-meter solar adoption by customer segment in Reference Case



Solar adoption is shown for each scenario in Figure 4-6. The high scenario reflects the significant impact of the federal investment tax credit (ITC) on rooftop solar economics for customers.

The adoption forecast of non-dispatchable customer battery storage (Figure 4-7) indicates that most customers adopting a battery storage system for their own individual use are expected to pair it with an on-site solar PV system. By co-locating solar and storage at the customer site, the battery systems are able to qualify for the ITC.

FIGURE 4-6: Behind-the-meter solar adoption scenarios

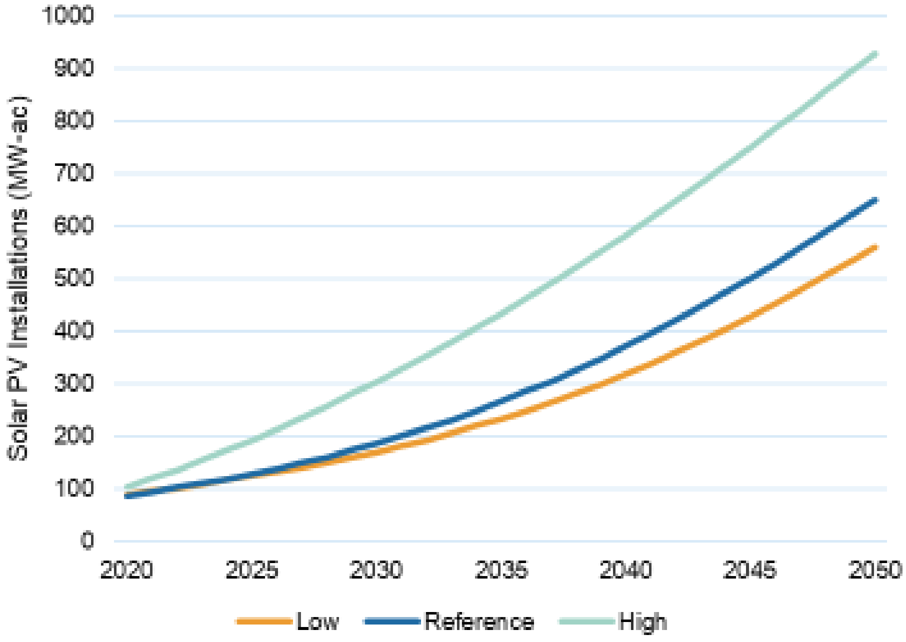
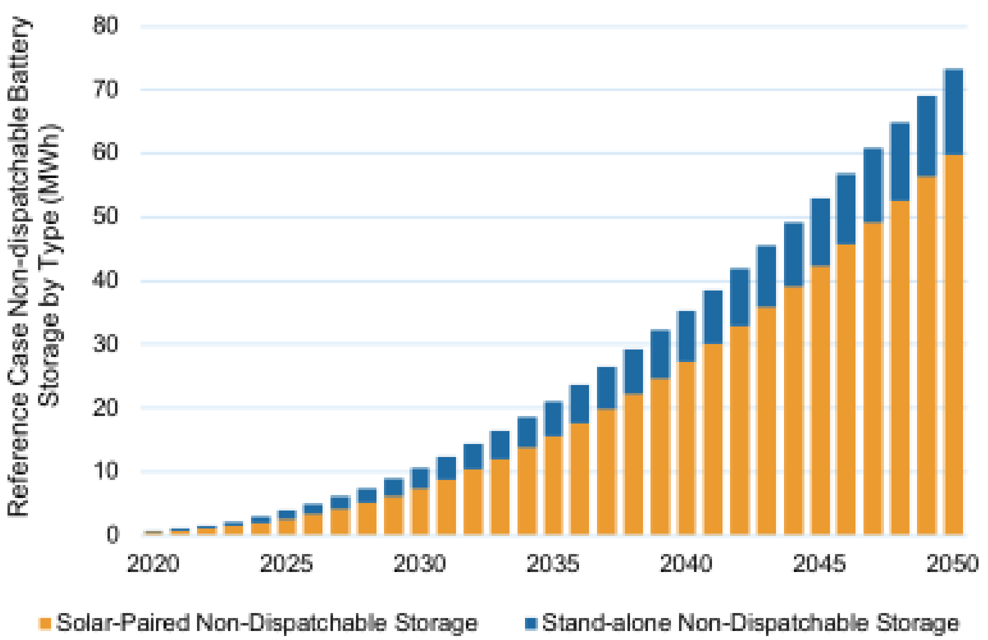
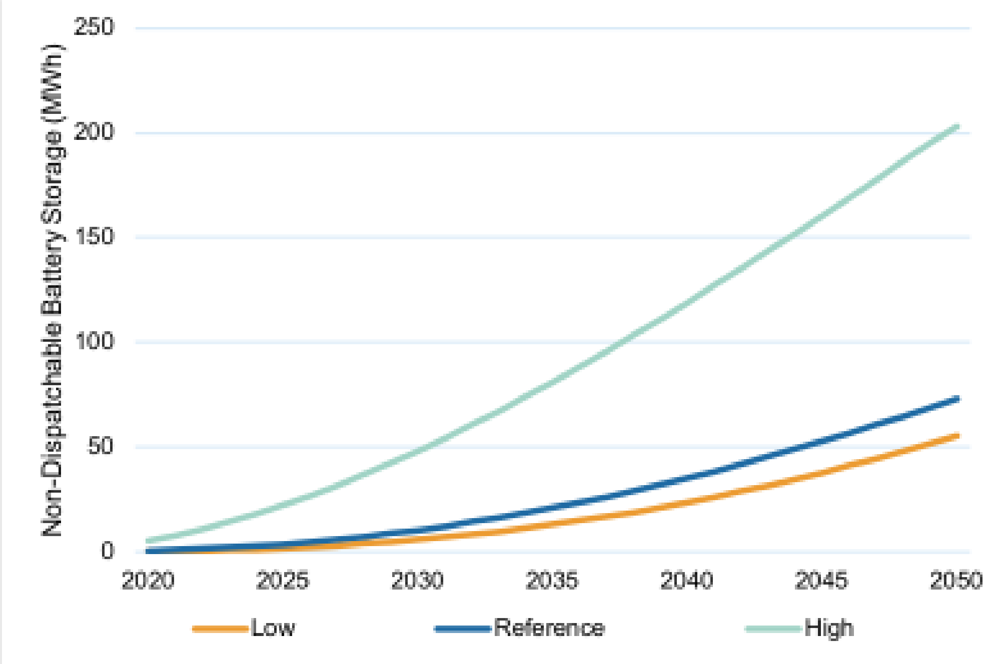


FIGURE 4-7: Non-dispatchable customer battery storage adoption in Reference Case



Non-dispatchable battery storage adoption is shown across each future in Figure 4-8. Consistent with the distributed solar forecast, the high scenario reflects the impact of the ITC on economics for customers.

FIGURE 4-8: Non-dispatchable customer battery storage adoption scenarios



More information about solar and battery storage forecasting in the Navigant DER Study can be found in External Study C. Distributed Energy Resource Study. In the 2019 IRP, behind-the-meter solar and non-dispatchable customer battery storage are represented explicitly with hourly shapes in both the resource adequacy modeling and in portfolio dispatch simulations in Aurora.

4.1.4 Load Scenarios

In the 2019 IRP, PGE combines the load components discussed above to create forecasts for long-term planning that account for both customer adoption of distributed technologies and uncertainties in forecasts. In this section, we provide information to show the combined energy and peak loads and the changing impact of components over time. Note that as the models are very complex, these tables and figures have been simplified for presentation. Note also that as discussed in Section 4.1.1.1 Key Assumptions, the top-down load forecast does not include LTDA loads,[106] and as discussed in Section 4.1.2 Energy Efficiency, the top-down forecast includes cost-effective deployable EE savings.

Figure 4-9 shows energy impact of EE savings, distributed PV generation, and EE load in the Reference Case in 2020 and 2050. These waterfall charts begin with the base load, which refers to the top-down load forecast adjusted to remove the EE savings and the assumed embedded quantities of distributed PV generation and EV load. These show that while the impacts are forecast to be small in 2020, we anticipate a significant increase in EE savings and a large growth in EV load over time. The impact of distributed PV, while growing, is less substantial.

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106 Annual net system load forecasts, which include long-term direct access loads, are provided in Section D.5 Net System Load.

FIGURE 4-9: Reference Case load impacts of passive customer resource actions

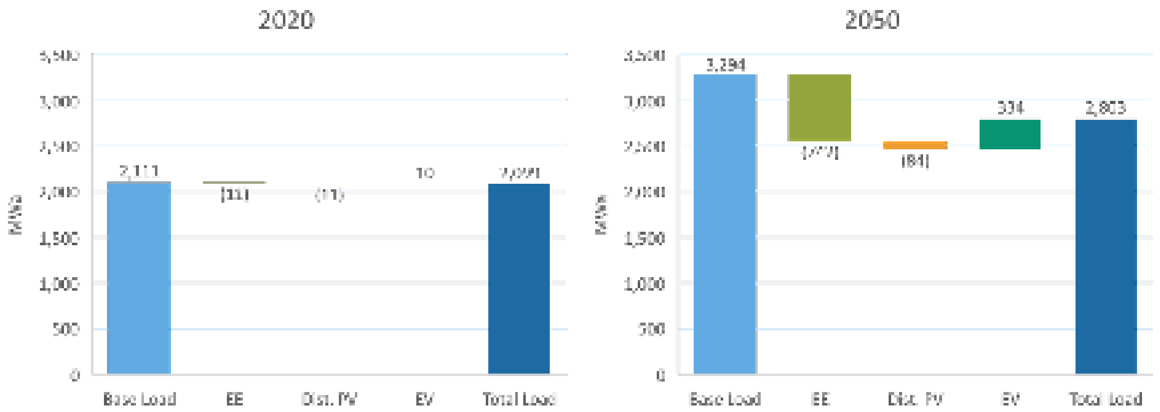


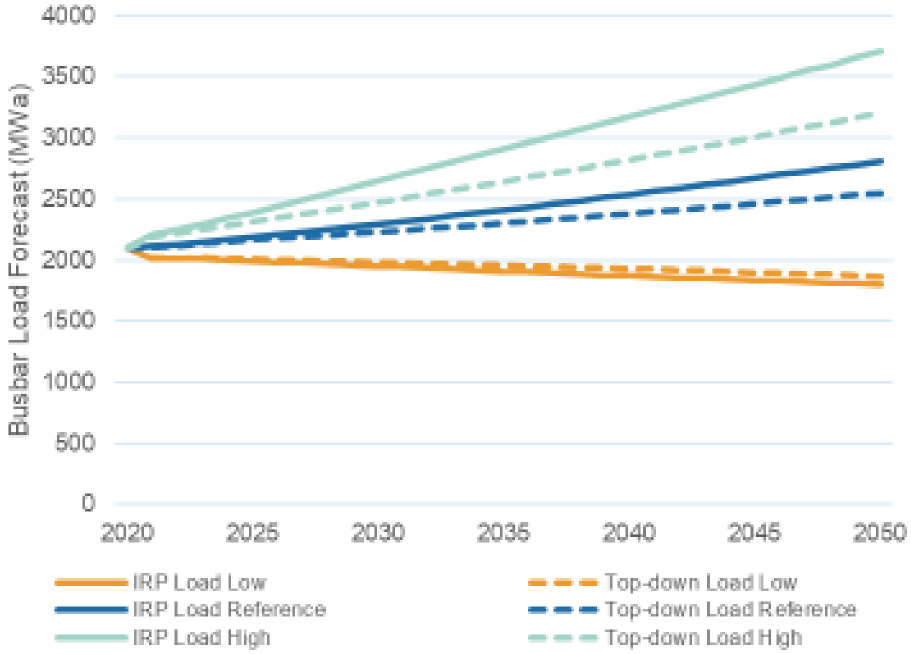
Table 4-5 summarizes the combination of components for the low, reference, and high load scenarios. These scenarios are part of the Need Futures described in Section 3.1. Per Section 3.1, the Low Need Future assumes low EV adoption and high adoption of distributed solar and distributed battery storage, while the High Need Future assumes high adoption of EVs and low adoption of distributed solar and distributed battery storage.

TABLE 4-5: Load components for each load scenario

	Low Load	Reference Case	High Load
Top-down Load Forecast	Low Growth	Reference Case	High Growth
Energy Efficiency	High EE	Cost-effective EE	Cost-effective EE
Electric Vehicles	Low Adoption	Reference Case	High Adoption
Dist. Solar and Non-dispatchable Battery Storage	High Adoption	Reference Case	Low Adoption

The resulting load forecasts capture a wide range of uncertainty as shown in Figure 4-10. The dashed lines show the low, reference, and high top-down load forecasts and the solid lines show the total IRP forecast adjusted for the passive DER components. The net passive DER forecasts have an increasing impact on load over time and by load scenario.

FIGURE 4-10: Load forecast scenarios in MWa



The largest component of uncertainty both in the near-term and across the planning horizon is in the top-down load forecast. However, the relative impact of the DER forecasts grows over time, in particular for the EV forecast, as seen in Table 4-6 below. Table 4-6 provides the energy deliveries by component for 2020 and 2050 for each scenario and the average annual growth rate.

TABLE 4-6: Load forecast scenarios, energy deliveries in MWa

	Low Need			Reference Case			High Need		
	2020	2050	AAGR	2020	2050	AAGR	2020	2050	AAGR
Top-down Load Forecast	2,096	1,869	-0.4%	2,096	2,549	0.7%	2,096	3,208	1.4%
Base Load Forecast*	2,111	2,614	0.7%	2,111	3,294	1.5%	2,111	3,954	2.1%
Energy Efficiency†	(11)	(879)	-	(11)	(742)	-	(11)	(742)	-
Passive DERs‡	(13)	(119)	7.6%	(11)	(84)	6.9%	(11)	(72)	6.3%
Electric Vehicles**	7	185	11.3%	10	334	12.3%	16	565	12.6%
Total Load Forecast	**2,094**	**1,801**	**-0.5%**	**2,099**	**2,803**	**1.0%**	**2,105**	**3,704**	**1.9%**

*The base load forecast is the top-down load forecast adjusted to exclude the impacts of the cost-effective deployable EE savings and the assumptions for the embedded distributed PV generation and electric vehicle load.

†The EE savings are cumulative values adjusted for line losses and intra-year deployment, beginning in the year 2020. The AAGR is not calculated because savings prior to 2020 are not reported in these values.

‡For simplification, the passive DER values reflect distributed PV generation only.

**As discussed in Section 4.1.3.1 Electric Vehicles, this EV forecast is for light-duty vehicles.

In Table 4-7, PGE presents a 1-in-2 peak using expected (normal) weather conditions. This means there is a 1-in-2, or 50 percent, probability that the actual peak load will exceed the forecast peak load during the specified year.

TABLE 4-7: Load forecast scenarios, peak demand in MW*

	Low Need			Reference Case			High Need		
	2020	2050	AAGR	2020	2050	AAGR	2020	2050	AAGR
Summer	3,426	3,502	0.1%	3,436	4,919	1.2%	3,450	6,282	2.0%
Winter	3,349	3,108	-0.2%	3,358	4,754	1.2%	3,373	6,351	2.1%
Annual	**3,426**	**3,502**	**0.1%**	**3,436**	**4,919**	**1.2%**	**3,450**	**6,351**	**2.1%**

*The values in Table 4-7 estimate the impacts of DERs on peak load. The IRP analysis captures these impacts explicitly through hourly shapes.

4.2 Existing and Contracted Resources

PGE is a regional leader in providing clean, reliable, and affordable energy to electricity customers. The Company's diversified resource portfolio is a mix of 28 percent natural gas, 15 percent hydro, 15 percent coal, 9 percent wind, and 33 percent purchased power (a mix of renewables, hydro, and thermal resources).[107]

Since PGE's historic commitment to cease coal operations in Oregon,[108] the Company has been working with the Energy Trust to maximize the EE available in its territory and has accelerated the procurement of renewables and dispatchable capacity. Since PGE's last IRP, the Company has secured long-term contracts with regional entities for more than 300 MW of capacity and additional contacts for qualifying facilities (QF). PGE also completed the 2018 Renewables RFP, resulting in the addition of the Wheatridge Renewable Energy Facility to PGE's resource portfolio. The Company's current portfolio of power plants and contracts after these latest additions is described in Appendix E.

As with prior IRPs, PGE accounts for all existing resources and all contracts executed as of a specified date (in this case, December 18, 2018), within the needs assessment and portfolio analysis. Wheatridge Renewable Energy Facility is included in the assessment and analysis even though the contract was executed after December 18 (details are provided in the following section).

4.2.1 Wheatridge Renewable Energy Facility

The most recent major addition to PGE's resource portfolio is the Wheatridge Renewable Energy Facility (Wheatridge) in Morrow County, Oregon. In 2019, PGE entered into agreements with NextEra for the project, which will consist of 300 MW of wind, 50 MW of solar, and 30 MW of battery storage. The wind portion of the facility will enter service at the end of 2020 and the solar and storage

[107] As a percentage of total system load. Last updated December 2017. See https://www.portlandgeneral.com/our-company/energy-strategy/how-we-generate-electricity.

[108] Boardman 2020 Plan: https://www.portlandgeneral.com/corporate-responsibility/environmental-stewardship/air-quality-emissions/boardman-plant-air-emissions.

components will be in service by the end of 2021. PGE will own 100 MW of the wind resources and entered into a long-term purchase agreement with NextEra for the remainder of the project.

4.2.2 HB 2193 Storage

In compliance with HB 2193, PGE filed a proposal to develop five energy-storage projects totaling 39 MW. After testimony and comments, parties to UM 1856 filed a stipulation with the Commission, which the Commission accepted in Order No. 18-290.[109] The stipulation required PGE to provide additional site analyses, an updated storage modeling plan, a revised residential pilot project proposal, and a valuation methodology which co-optimizes all potential benefits from storage. Pending OPUC Staff review of these updated materials, PGE anticipates that these resources will be online sometime in 2020.

For this IRP, modeling assumes that the resources enter service by 2021 and bases the quantities on the minimum sizes described in the filing.

4.3 Capacity Adequacy

PGE conducted a capacity adequacy assessment from 2021 through 2050 using the Renewable Energy Capacity Adequacy Planning model (RECAP), a probabilistic loss-of-load model developed by Energy + Environmental Economics, Inc. (E3). As in the 2016 IRP, the capacity adequacy assessment examines capacity need based on the hourly availability of loads and resources and includes the estimated requirements for contingency reserves. The model does not calculate need based on a prescribed planning reserve margin, but rather calculates the amount of incremental capacity needed to achieve a targeted reliability metric. As in the 2016 IRP, the metric for the study is a loss-of-load expectation (LOLE) of no more than 2.4 hours per year, or 1 day in 10 years, a common industry standard. The capacity assessment includes the need to supply contingency reserves,[110] but does not examine the need for flexible capacity for forecast error, load following, or regulation. These are considered within the flexibility adequacy assessment, which is discussed in Section 4.6 Flexibility Adequacy.

4.3.1 Analysis Updates for the 2019 IRP

The capacity need analysis in this IRP contains two key updates: robust treatment of distributed energy resources, and results of a market capacity study. These updates are summarized below.

4.3.1.1 Distributed Energy Resources

In the 2016 IRP, PGE modeled all demand response resources in RECAP with two simplified seasonal profiles. The analysis did not contain explicit forecasts of adoption of distributed PV or electric vehicles. In this IRP, the Navigant Distributed Resource and Flexible Study (DER Study), discussed in Section 5.1 Distributed Flexibility and Section 4.1.3 Passive Customer DER Forecasting, provided forecasts for demand response programs, customer-sited photovoltaics (distributed PV), customer-sited storage, and light-duty EVs. PGE incorporated these forecasts in the capacity adequacy analysis.

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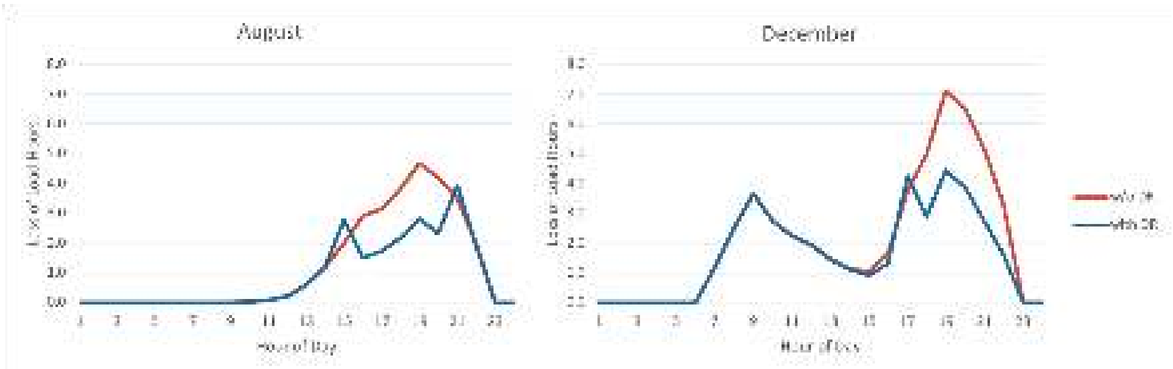
[109] *In the Matter of Portland General Electric Company, Draft Storage Potential Evaluation*, Docket UM 1856, Order No. 18-290 (Aug. 13, 2018).

[110] The contingency reserves are the required spinning and supplemental reserves and are discussed in Appendix I. 2019 IRP Modeling Details.

The demand response programs included in the need assessments have a wide range of characteristics including the number of calls per season, call hours, and whether they reduce load or shift load to other times. The modeling in this IRP captures many of these characteristics, but in some cases, simplifications were necessary due to limited information or constraints of the RECAP model. PGE anticipates that continued development of the modeling of these resources will be a focus of the next IRP cycle.

Figure 4-11 provides examples of the loss-of-load hour (LOLH) profiles for August and December of the year 2025 with and without the demand response programs before any additional resource actions other than customer resource actions such as EE and distributed standby generators (DSG). This figure shows that for December, PGE anticipates a significant reduction in the evening peak of the LOLH profile due to demand response programs. Although smaller, a significant impact is also expected for August.

FIGURE 4-11: Loss-of-load hour profiles for 2025 with and without demand response



In combination, the distributed flexibility programs (demand response and dispatchable customer storage) and the DSG program are expected to avoid the need for approximately 200 MW of capacity in 2025.

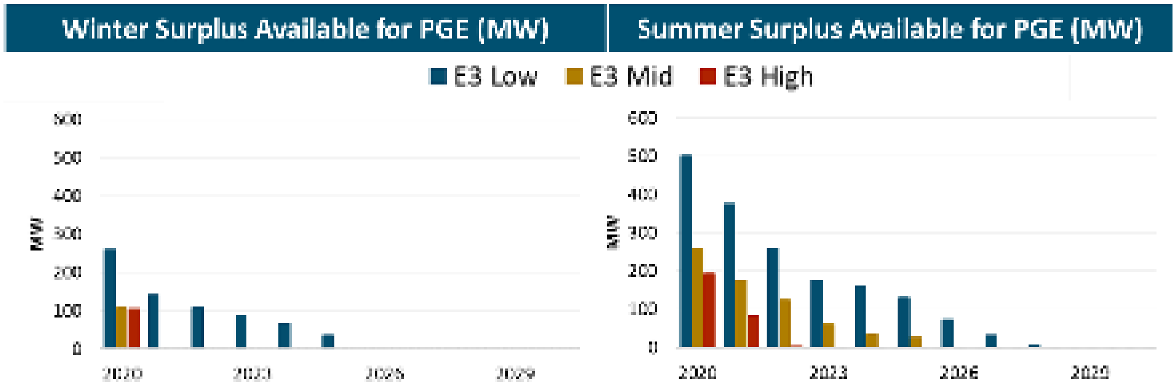
4.3.1.2 Market Capacity

Market capacity in the RECAP analysis represents the amount of capacity assumed to be available from the market under constrained conditions without any prior contractual agreements. In the capacity assessment, market capacity is treated as a resource in the existing resource stack, reducing the amount of capacity needed to achieve the annual reliability target.

In response to stakeholder feedback and Order No. 17-386,[111] PGE contracted with E3 to conduct a study of regional capacity to inform the assumption of market capacity for the capacity assessment. An overview of the study is provided in Section 2.4.2.1 Market Capacity Study and E3's report is provided in External Study E. In addition to a base case, E3 examined low and high capacity need scenarios for the region. E3's recommendation for market capacity assumptions for PGE's long-term planning for winter and summer on-peak hours were included in the RECAP model and are summarized in Figure 4-12.

[111] OPUC Order No. 17-386 at 19.

FIGURE 4-12: Recommended market capacity assumption for PGE's long-term planning*



* Source: E3, *Northwest Loads and Resource Assessment*, Figure 14. See External Study E. Market Capacity Study.

During the shoulder seasons, market capacity in the on-peak hours is modeled as the larger of the 2016 IRP assumption (200 MW) or the E3 estimate of summer availability for the year. For the off-peak hours, market capacity is assumed to be unconstrained.

RECAP inputs were also refreshed to incorporate items such as the top-down load forecast, Wheatridge, and QF contracts executed as of December 18, 2018. More information on RECAP and the modeling updates that were completed to support the 2019 IRP can be found in Appendix I, Section I.3 RECAP Model.

4.3.2 Capacity Need

In the 2016 IRP, PGE's capacity need assessment considered a single scenario, the Reference Case. PGE's 2016 IRP Update included additional capacity sensitivities to provide insight into the uncertainty of need. As part of the expanded treatment of uncertainty in this IRP, PGE prepared low and high capacity need assessments in addition to the Reference Case. These assessments are incorporated into the three Need Futures discussed in Section 3.1 and are used in portfolio design. The drivers of uncertainty examined include the top-down load forecast, EV forecast, and the market capacity assumption. Table 3-1 lists the drivers and their settings in each Need Future.

The capacity adequacy assessment shows a wide range of potential need in the near term (from 309 MW to 1066 MW in 2025) with growing uncertainty over time, as seen in Figure 4-13, which shows the capacity need in the three Need Futures. In the Reference Case, the capacity shortage increases from 190 MW in 2021 to 685 MW in 2025 and grows to 2,639 MW in 2050. A summary in tabular format is provided in Appendix G.

Examining the year 2025 in the Reference Case, the assessment found a LOLE of 125 hours before adding any additional resources (other than targeted additions for energy efficiency, distributed flexibility, and DSG). Figure 4-14 shows a heatmap showing the seasonal and diurnal nature of the need, which is concentrated in both the summer (afternoon to evening) and the winter (both morning and evening).

FIGURE 4-13: Capacity need across need futures

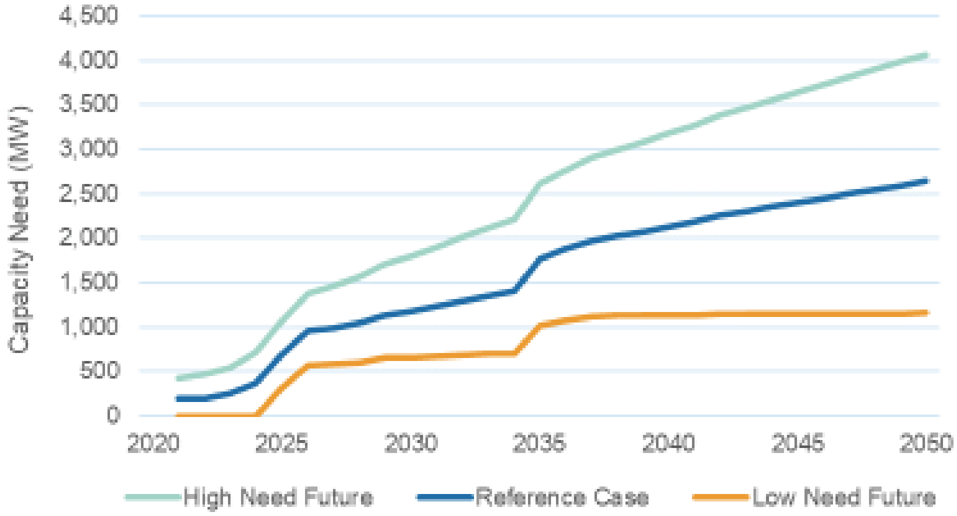
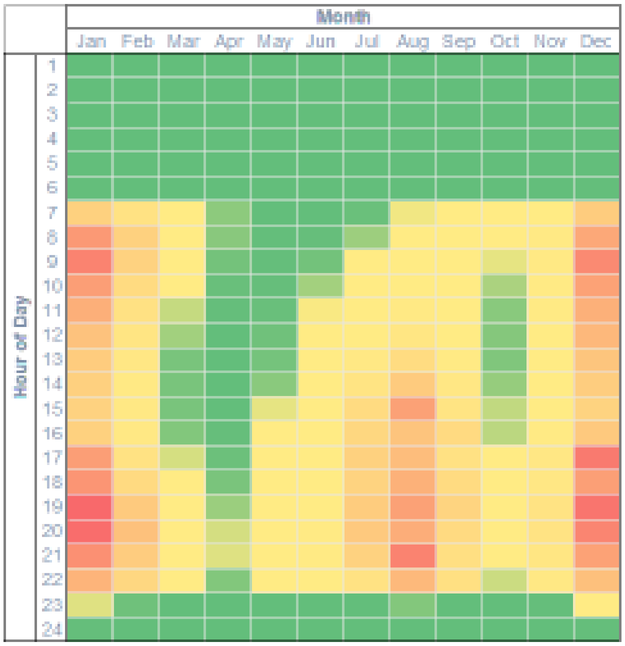
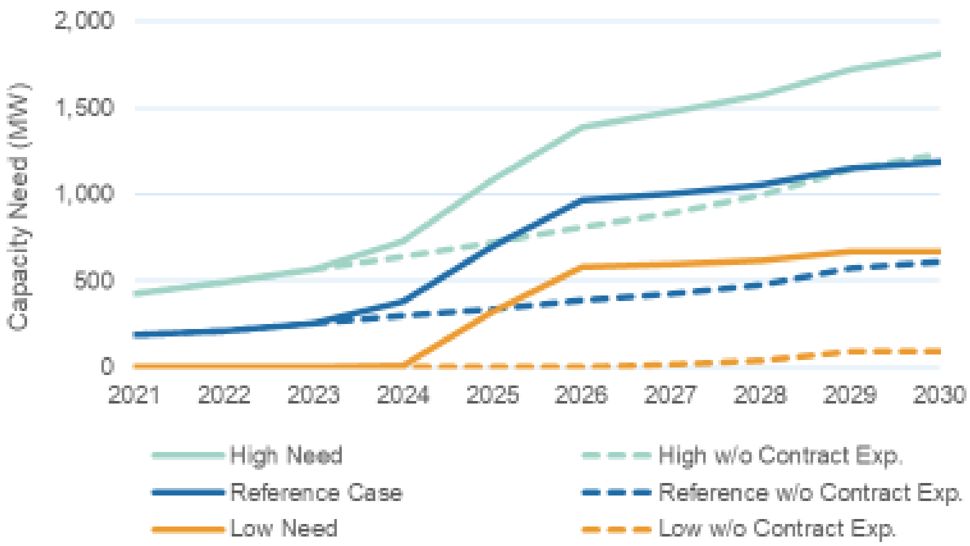


FIGURE 4-14: Reference Case loss-of-load expectation in 2025



Much of PGE's forecast capacity need in the mid-2020s is driven by the expiration of contracts. Figure 4-15 shows how capacity need grows in the Reference, Low, and High Need Futures both with and without upcoming contract expirations between 2021 and 2025. In the Reference Case, approximately half of the capacity need in 2025 is due to contract expiration, whereas in the Low Need Future, all capacity need in 2025 is driven by contract expiration. In other words, the range of uncertainties considered within PGE's need analysis encompasses a future in which all capacity need is met in 2025 if PGE were to successfully negotiate for capacity to replace the contracts that expire between now and then. The uncertainty analysis also encompasses a future in which PGE would require an additional 707 MW of capacity in 2025 in addition to capacity that would replace expiring contracts. This wide range of potential future conditions necessitates a near-term procurement plan for capacity that is both flexible enough to respond to changing conditions and robust enough to provide an avenue for significant capacity procurement if it is needed.

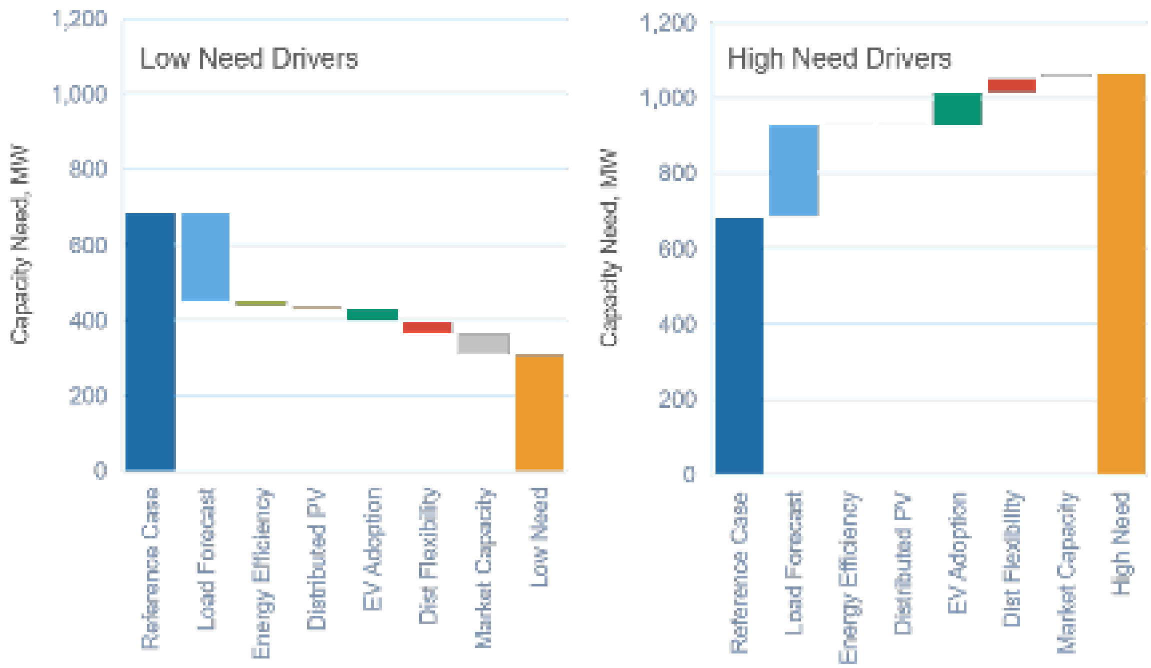
FIGURE 4-15: Impact of contract expirations on capacity need



In addition to examining aggregated uncertainties across the planning horizon in the Low and High Need Futures, PGE conducted multiple sensitivities to examine the relative impacts of key capacity need drivers in 2025. The waterfall charts in Figure 4-16 show that the driver with the largest impact in both the Low and High Need Futures is the top-down load forecast. The low and high top-down load forecasts estimate uncertainty in customer loads due to economic and migration assumptions, as well as due to uncertainty in the forecasting model. The load forecast is discussed in Section 4.1 Load Forecast. Moderate impacts are seen from the uncertainty captured in the forecasts for electric vehicles, market capacity, and distributed flexibility (demand response and customer-sited storage).

In addition to the Low, Reference, and High Need Futures, PGE also examined the capacity need impact of sensitivities regarding QFs, voluntary programs, LTDA load, and a decarbonization scenario. The first three sensitivities are discussed in Section 4.7 and the decarbonization scenario is discussed in Section 7.4.1.

FIGURE 4-16: Drivers of capacity need uncertainty in 2025



The capacity contributions of new resource options were also estimated using the RECAP model. The results of the analysis are discussed in Section 6.2.3 Capacity Value and the modeling details are discussed in Appendix I. 2019 IRP Modeling Details.

4.4 Energy Need

Integrated resource planning has long relied on analysis of both capacity and energy needs. While capacity adequacy remains a crucial aspect of characterizing critical customer needs, specifically reliability of supply, the usefulness of the traditional energy needs analysis has evolved over time. As Western energy markets continue to shift in response to new renewable and GHG policies as well as rapidly changing renewable resource economics, PGE must evolve both the calculation and the application of its energy needs analysis.

Traditionally, PGE accounted for future energy needs by comparing the annual energy available from existing and contracted resources with forecast loads. The definition of energy availability depended on the nature of the resource, with renewables and hydro providing their expected generation based on average conditions, traditionally baseload thermal resources providing energy based on their capacities with reductions for forced outages and maintenance outages, and peaking resources providing no energy. This exercise was largely based on the premise that low heat rate generators may be expected to operate as baseload generation throughout the year, an operational paradigm that may be less relevant in a market with increasing levels of renewables and carbon pricing. For consistency with prior IRPs, PGE presents this traditional Energy Load Resource Balance accounting framework in Appendix G.

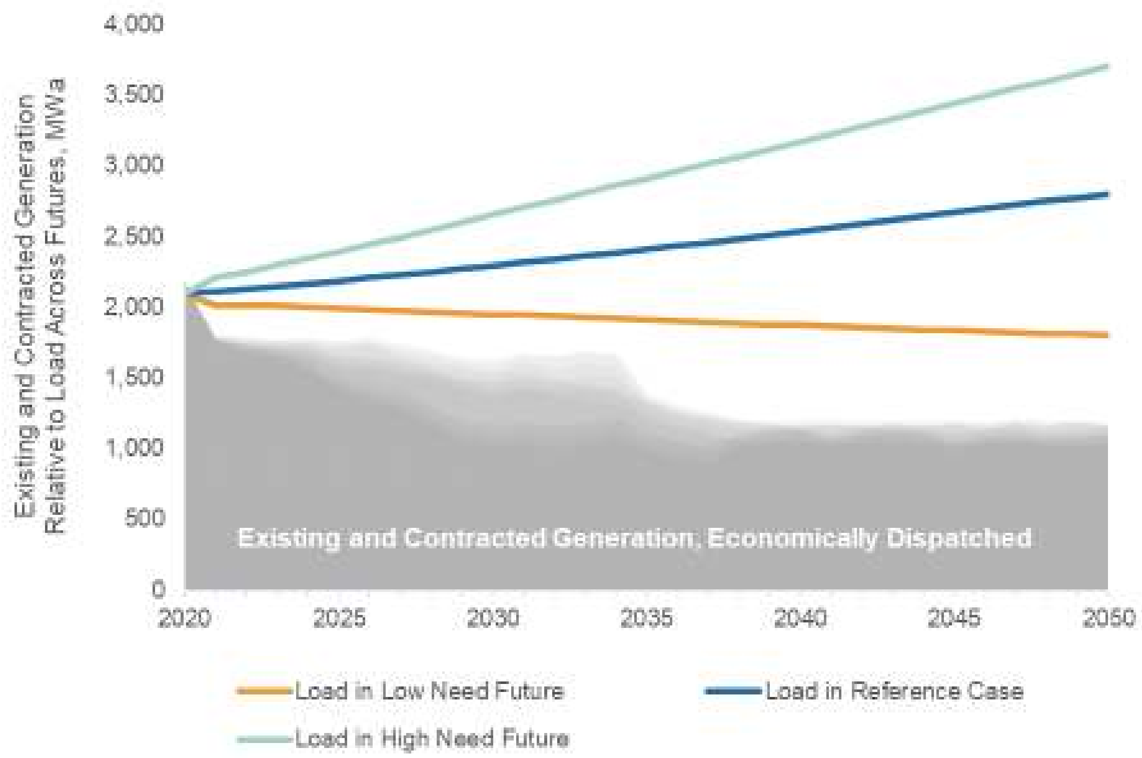
4.4.1 Market Energy Position

To inform this resource plan, PGE proposes an alternative approach to characterizing our energy position, which more specifically captures evolving market dynamics and the associated uncertainties. PGE's energy position compares forecast loads to forecast generation from existing and contracted resources and is described across 54 futures that encompass uncertainties in both PGE needs and market conditions (including carbon prices, gas prices, and WECC-wide renewable buildout).

The purpose of investigating PGE's market energy position is to identify the portion of our customers' energy needs that we anticipate to be met with resources in our portfolio versus purchases from the market and to ensure that our proposed resource actions do not result in a portfolio that is persistently long to the market into the future. Unlike the capacity adequacy assessment, which determines the minimum levels of procurement that we must undertake to meet customer need, this analysis helps to develop a balanced portfolio that would not result in making PGE overly reliant as a purchaser or as a seller on the market in the future.

Figure 4-17 compares PGE's loads and existing and contracted resources between 2020 and 2050 with no incremental resource actions beyond energy efficiency and DERs. The gray shaded area represents the total simulated generation from existing and contracted resources across all futures with the layers of lighter shading indicating variation in dispatch due to the market conditions in each future.[112]

FIGURE 4-17: Load and existing and contracted generation



[112] See Section I.4.2 PGE-Zone Model for a description of how PGE simulates generation from existing resources and new resource options.

PGE's energy market position is calculated by subtracting the existing and contracted generation from the load in each future. A positive number indicates that PGE expects to be short to the market on an average annual energy basis (that is, will be a net purchaser from the market), while a negative number would indicate that PGE expects to be long to the market on an average annual energy basis (that is, will be a net seller into the market). The resulting energy market position is shown across all combinations of Need Futures and Market Price Futures in Figure 4-18.

FIGURE 4-18: Energy shortage to market across futures

In the near term, PGE's energy position is forecast to shift from a long position in 2020 to a short market position in 2021 due to the closure of Boardman and the potential impacts of carbon pricing which, for IRP analysis, is assumed to begin in 2021. As shown in Figure 4-18, PGE is generally expected to be shorter to market (increasing net market purchases) over time as loads grow and resources exit the portfolio. Therefore, resource additions that do not cause PGE to be energy long in the near-term are not expected to cause PGE to be persistently energy long into the future.

Table 4-8 summarizes PGE's near-term energy market position in the Reference Case and across the futures in 2025. Without resource actions beyond energy efficiency and DERs, PGE is expected to meet approximately 515 MWa of energy demand with purchases from the market by 2025 in the Reference Case. This energy shortage is sensitive across the Need and Market Price Futures, but still exceeds 344 MWa in 90 percent of futures.

TABLE 4-8: Energy position in 2025

	2025 Energy Position (Shortage to Market, MWa)
Reference Case	515
10th Percentile	344
90th Percentile	907

The potential market purchases described above would not mean that PGE would rely on the market for resource adequacy, rather that the energy available from the market is anticipated to be lower cost than energy from a portion of PGE's existing and contracted resource portfolio during some parts of the year. While this exposure to the market does not create a reliability risk, it does potentially introduce economic risks to customers related to the potential for high market prices. These risks are captured through the economic risk metrics described in Section 7.2.1 Scoring Metrics.

In addition to the economic risk metrics, PGE takes into consideration its forecasted energy shortages within portfolio construction and scoring. The ultimate goal of considering potential energy shortages within each of these components of the IRP is to develop a balanced portfolio that is neither overly reliant on the market nor puts PGE in a persistently long market position into the future. While the analysis described above identifies a near-term Reference Case energy shortage of 515 MWa and increasing energy shortages in later years, PGE conservatively identified 250 MWa as a reasonable maximum energy addition size for consideration of near-term actions. This assumption accounts for additional uncertainties not contemplated in this analysis and for the potential impacts of additional customer decisions that may affect PGE's energy position (see Section 4.7.2 Voluntary Renewable Program Sensitivities). This energy addition constraint was considered in the following aspects of portfolio construction and scoring:

- Portfolios that examine renewable addition size and timing test portfolios with up to 250 MWa of renewable additions (see Section 7.1.3 Renewable Size and Timing Portfolios)
- A non-traditional scoring metric (Energy Additions through 2025) screens out portfolios that add more than 250 MWa of new resources in the near term from consideration for the preferred portfolio (see Section 7.2.1 Scoring Metrics).

4.5 RPS Need

Since its inception in SB 838, the Oregon Renewable Portfolio Standard (RPS) has played a major role in driving the development of renewable resources to serve PGE customers. In 2016, SB 1547 established new escalating RPS requirements that reach 50 percent of retail sales by 2040 (see Table 4-9).

TABLE 4-9: RPS obligations per SB 1547

Years	RPS Requirement (% of retail sales)
2020-2024	20%
2025-2029	27%
2030-2034	35%
2035-2039	45%
2040+	50%

SB 838 also established REC banking as a mechanism for providing compliance flexibility, allowing the utility to bank RECs that are not needed for RPS compliance in a given year for use in a future year. SB 1547 revised REC banking rules to limit the lifespan of most RECs generated after SB 1547 went into effect in mid-2016 to five years.[113] This change was designed to preserve the flexibility afforded by the REC banking mechanism while reducing the ability of the utility to rely on banked RECs for RPS compliance indefinitely into the future, a strategy that might otherwise stall meaningful progress toward meeting the 2040 RPS requirement and the policy objectives of SB 1547.

To understand PGE's RPS needs, it is helpful to consider PGE's physical RPS position, as well as its Renewable Energy Credit (REC) position over time. PGE uses the term physical RPS compliance to refer to a year in which the volume of RECs generated by RPS-eligible resources in PGE's resource portfolio meets or exceeds the RPS obligation in that year. PGE's physical RPS position, which compares forecast-generated RECs to the forecast RPS obligation over time, is shown for the Reference Case in Figure 4-19 and Figure 4-20 and a summary in tabular format is provided in Appendix G.[114] PGE projects that without incremental renewable resource actions, RPS obligations will exceed generation from RPS-eligible resources in the Reference Case beginning in 2030, when RPS requirements increase from 27 percent to 35 percent of retail load. PGE's forecasted physical RPS shortage in 2030 is summarized in Table 4-10.

PGE's REC position is impacted both by contemporaneous generation from RPS-eligible facilities as well as banked RECs from prior compliance years. In contrast to the physical RPS position described above, PGE's REC position is expected to be long well into the 2030s without incremental action. PGE forecasts that in the Reference Case a strategy of compliance through REC bank depletion could meet RPS obligations through 2035. However, such a strategy would require PGE to procure an additional 627 MWa by 2037 to ensure compliance in the Reference Case and would significantly delay the benefits of bringing new renewable resources onto the system. Given the intent of SB 1547, the preferences expressed by many of our customers, and our own long-term decarbonization goals, PGE does not consider such a strategy to be in the interest of our customers, the state of Oregon, or our company. PGE believes that it is appropriate to apply a minimum standard of physical RPS compliance in its long-term planning process and to use the REC bank to mitigate compliance risks

113 Except for new resources that are online by 2022, which are allowed to generate "infinite-life" RECs for the first five years of operations.

114 The value of RECs generated by the Wheatridge Energy Facility prior to 2025 will be returned to customers and as such, the RECs are not also included in the forecast of REC production for meeting RPS obligations.

and achieve cost reductions on a year-to-year basis depending on loads, renewable generation, and market conditions.

FIGURE 4-19: RPS obligations and forecast REC generation without incremental action

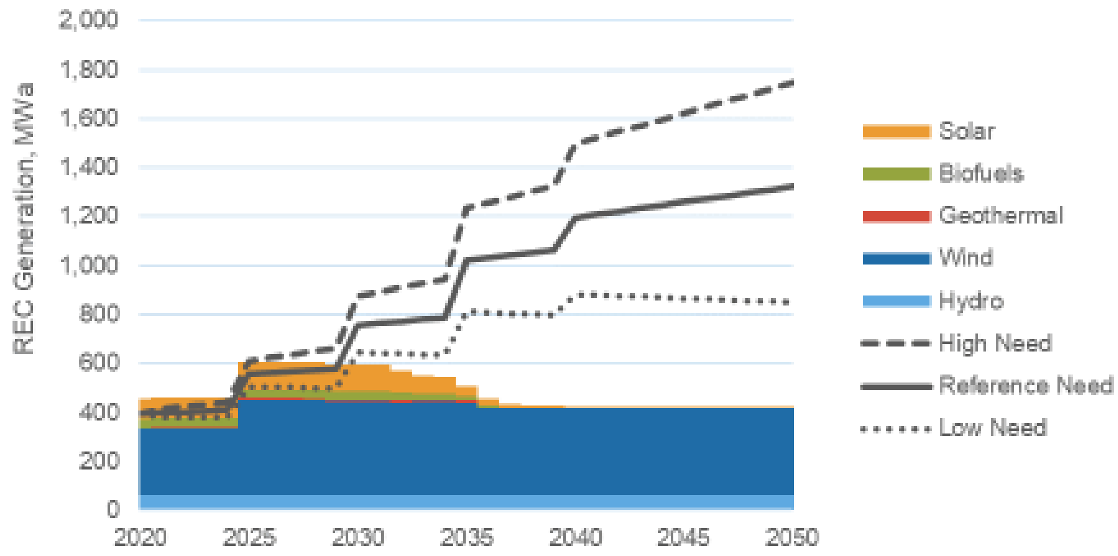


FIGURE 4-20: Physical RPS shortage across Need Futures

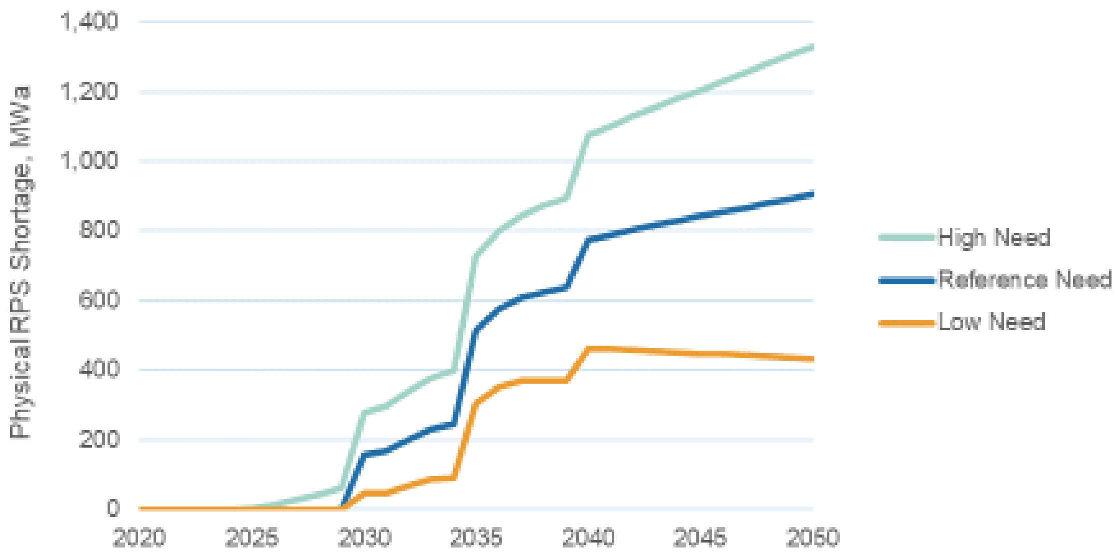


TABLE 4-10: Physical RPS shortage in 2030

Need Future	2030 Physical RPS Shortage (MWa)
Reference Case	161
Low Need Future	47
High Need Future	282

While uncertainty in future loads and DER adoption results in a wide range in the need for incremental RPS resources over time, meeting long-term RPS obligations will require substantial procurement of renewable resources between 2020 and 2040 regardless of the Need Future. Table 4-11 summarizes PGE's forecast RPS obligation and RPS shortage in 2040 for each Need Future if no incremental actions are taken. Based on this analysis, PGE estimates that future renewable procurement will need to average between 25 and 58 MWa per year beginning in 2022 to ensure RPS compliance by 2040.

TABLE 4-11: Forecasted 2040 RPS needs in 2040 in each Need Future

	Reference Case	Low Need Future	High Need Future
2040 RPS Obligation (MWa)	1192	877	1,494
2040 REC Generation w/o Action (MWa)	401	401	401
2040 RPS Shortage w/o Action (MWa)	791	475	1,093
Average Annual RPS Addition for Physical Compliance in 2040 (MWa)	42	25	58

4.5.1 Other Renewable Procurement Drivers

In addition to long-term RPS needs, there are other factors that may influence PGE's decision to pursue incremental renewable resources in the near term. These factors are considered in portfolio analysis and are briefly discussed below.

- **Near-term capacity needs.** As investigated in Docket UM 1719 and implemented in the 2016 IRP with continued development in this IRP, probabilistic analysis indicates that renewable resources may materially contribute to resource adequacy requirements, especially as developers explore new structures that pair variable renewables with storage. PGE has implemented methodologies in the IRP and in its procurement activities to ensure that renewable resources are appropriately evaluated in the context of their contributions to resource adequacy.
- **Resource economics.** PGE's most recent experience in procuring renewable resources through a Request for Proposals confirmed that renewables can represent an increasingly cost-competitive option for providing energy and capacity to customers if acquired through a competitive process. Several factors influence the economics of potential near-term renewable resource actions, including capital cost reductions, changes in federal tax credits, and carbon pricing. These factors, which are described in more detail in Chapter 6. Resource Economics, ultimately impact the cost and risk metrics evaluated in portfolio scoring and the competitiveness of near-term renewable actions relative to other options for meeting customer needs.
- **Decarbonization goals.** The state of Oregon has an established goal of reducing statewide GHG emissions by 75 percent relative to 1990 levels by 2050.[115] To help meet this goal and

[115] (2018) Oregon Greenhouse Gas Emissions. Retrieved Apr. 18, 2019, from https://www.oregon.gov/deq/aq/programs/Pages/GHG-Oregon-Emissions.aspx.

the GHG goals of the communities PGE serves, the Company committed to reduce GHG emissions on its system by more than 80 percent by 2050. Continued development of cost-competitive renewable resources in the Northwest will be necessary to achieve this goal.

As indicated by these compounding factors, the complexity of renewable resource planning extends beyond the fulfillment of an RPS obligation. In Order No. 18-044, the Commission acknowledged this complexity and ordered PGE to conduct a glide path analysis in its IRP to take these factors into account and to contextualize proposed near-term RPS actions within PGE's long-term needs.[116] This glide path analysis, which discusses future renewable resource actions with respect to both PGE's RPS needs and forecast energy position, is presented in Section 7.3.3 Renewable Glide Path.

4.6 Flexibility Adequacy

As the PGE system and Western grid continue to experience a higher penetration of variable energy resources (VERs), it is ever more important to develop methodologies to assess flexible capacity adequacy and incorporate flexibility into long-term planning. In Order No. 17-386, the Commission ordered PGE to conduct a study investigating flexible capacity.[117] The Flexibility Adequacy Study described below and the analysis described in Section 6.2.2 Flexibility Value comprise PGE's response to that specific requirement. PGE worked with Blue Marble Analytics, an independent consultant, to conduct a study assessing baseline system flexibility adequacy and the effects of additional flexible capacity resources on system flexibility adequacy. Analysis in this IRP builds upon the 2016 IRP's flexible capacity analysis and a systematic review of existing literature on flexibility. The findings of the Flexibility Adequacy Study are summarized below; the full Blue Marble Analytics' study is included in External Study F.

4.6.1 Literature Review

Blue Marble Analytics began its investigation into flexibility adequacy for PGE by reviewing a range of planning, thought leadership, and academic literature detailing flexibility challenges. The goal of this review was to identify common definitions of flexibility and flexibility adequacy as well as methods and metrics for assessing flexibility adequacy. The literature review identified an increasing interest on the part of researchers and utilities in incorporating flexibility challenges into planning and operations. Despite this interest, the literature review identified no widely adopted flexibility adequacy metric or standard.

In existing literature, production cost simulation modeling is most commonly used for flexibility analysis. Production cost simulations use optimal unit commitment and economic dispatch to yield least cost dispatch of the system to meet load and reserves. Production cost simulations can model multi-stage commitment, scheduling, and dispatch. Each stage includes inputs such as load, forecast errors, reserves, VER generation, and resource availability.

Insufficient flexibility is often identified via shortages within a production cost simulation—for example, unserved energy or reserve shortfalls. Studies use loss-of-load expectation attributed to flexibility events (LOLE-Flex) to distinguish loss-of-load events driven by flexibility shortages from

[116] OPUC Order No. 18-044 at 5.

[117] OPUC Order No. 17-386 at 19.

those driven by capacity shortfalls.[118],[119] Even when shortages are not observed in production cost simulations, there could be flexibility-related strain on a system. Some flexibility metrics are used to indicate when a system may be approaching the limits of available flexibility. These metrics can add insight on magnitude and seasonal distribution of times of higher flexibility stress. Additional studies measured the available upward or downward flexibility present in the system.[120]

4.6.2 Methodology

Based on the findings of the literature review, Blue Marble Analytics used a PGE-specific production cost model, the Resource Optimization Model (ROM), to investigate flexibility constraints on PGE's system. ROM is a multi-stage optimal commitment and dispatch model that accounts for the operational impacts of forecast errors, operating constraints based on commitment decisions with imperfect information, gas constraints, and operating reserves (load following, regulation, spinning, and non-spinning reserves) to ensure that the system can respond to short time-scale variability of load and renewables as well as contingency events. ROM optimizes plant dispatch and system operation given average-year conditions for inputs such as variable energy resource output and hydro conditions. Simulations are run in three stages that correspond to the day-ahead (DA), hour-ahead (HA) and real-time (RT). The DA stage describes system commitment and scheduling based on forecasts the day before the operating day. Next, the HA stage adjusts system generation and market transactions based on hour-ahead forecasts. In the RT stage, the system ultimately re-dispatches based on operating day conditions. Decisions made in previous stages, including commitment or market transactions, constrain the RT stage. In this study, the year of interest is 2025. The simulation uses the reference top-down econometric load forecast; due to the ROM modeling schedule, the forecast is an earlier vintage than the econometric load forecast used in other sections of the IRP. For 2025, there was no large change between the two load forecasts. For more details on ROM, please refer to Section I.5 Resource Optimization Model (ROM).

Key assumptions in ROM used for this study that differ from the setup used to estimate integration costs in Section 6.1.3 and flexibility value in Section 6.2.2 are highlighted below.

- **Market Availability.** ROM includes access to a market at specified electricity prices consistent with the Reference Case detailed in Section 3.2.5 Electricity Market Price Futures. In the Flexibility Adequacy Study, market purchases are constrained to align with results of the Market Capacity Study in on-peak winter and summer and constrained to transmission limits at other times. Market sales are constrained to transmission limits. ROM's market access is constrained to these limits during the DA and HA stages. In the RT stage, there is no market access. In investigating flexibility adequacy, market purchases or sales do not provide additional flexibility to the system in real-time.
- **Day-Ahead (DA) on-peak capacity product.** In 2025, the PGE system is forecast to be short on capacity, as discussed in Section 4.3.2. For modeling purposes, an inflexible and relatively expensive DA on-peak capacity product is added to address capacity adequacy. If selected

[118] *PNM 2017-2036 Integrated Resource Plan*, Public Service Company of New Mexico, July 2017.

[119] *Flexibility Metrics and Standards Project – a California Energy Systems for the 21st Century (CES-21) Project*, Astrape Consulting, EPRI, LLNL, PG&E, and SDG&E, January 2016.

[120] *Seventh Northwest Conservation and Electric Power Plan*, Northwest Power and Conservation Council, Feb. 2016.

in the DA, the DA on-peak capacity product is also present in the HA and RT stages and it cannot be re-scheduled within the day. The product is available in 100-MW increments for the 16-hour on-peak block. Adding the DA capacity product allows PGE to focus on flexibility-driven challenges in this analysis, rather than capacity adequacy. When unserved energy is observed while capacity is available to the system but not dispatched or committed, the unserved energy can be attributed to flexibility inadequacy.

To quantify flexibility adequacy needs, Blue Marble Analytics conducted Base Case simulations of the PGE system in 2025 under average-year conditions, with existing and contracted resources.[121] Blue Marble Analytics additionally conducted Battery Cases, where portions of the inflexible DA on-peak capacity product were replaced with increasing increments of a flexible 4-hour battery resource to investigate the effects of flexible resource additions on reducing flexibility challenges.

Blue Marble Analytics used two types of metrics to track flexibility challenges, consistent with the metrics identified in the literature review: annual unserved energy associated with flexibility constraints and upward available flexibility, or headroom. These metrics were also used to investigate seasonal or time-related trends in flexibility challenges. The findings of the Flexibility Adequacy Study are summarized in the following sections.

4.6.3 Study Findings

A selection of key findings from this work are summarized below.

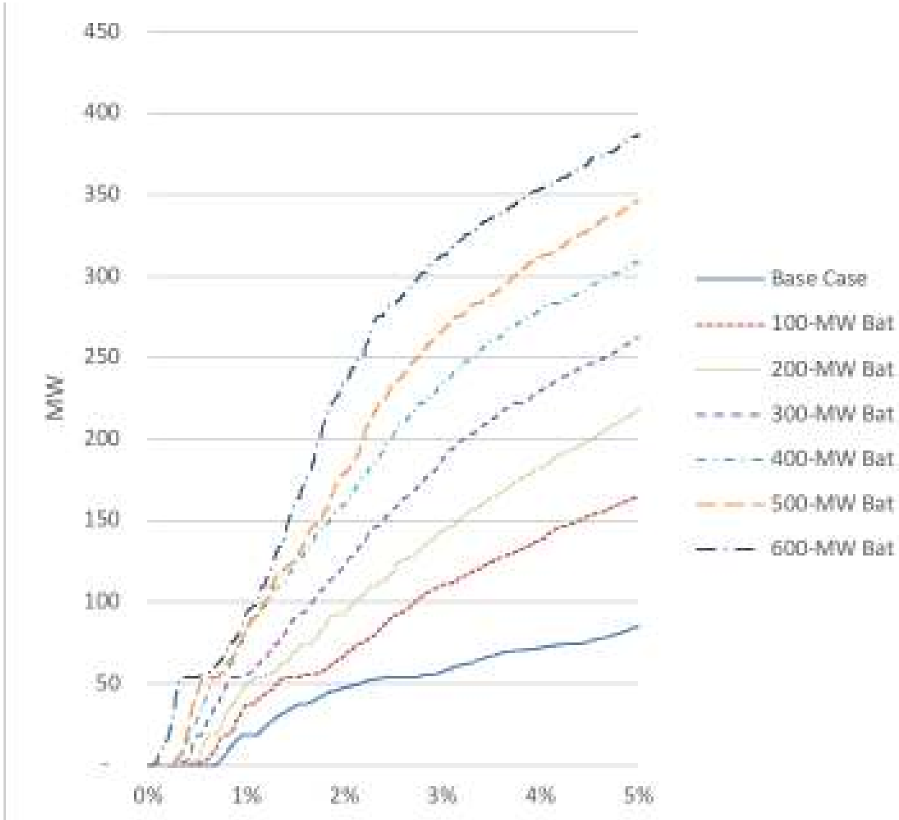
- **If no further flexibility actions are taken, the PGE system may encounter upward flexibility challenges in the mid-term.** In the Base Case, if capacity needs are met through inflexible, relatively expensive DA capacity products in 2025, production cost modeling suggests that there may be challenges in providing enough upward flexibility to the PGE system. Five percent of the time, system headroom, an indicator of upward flexibility stress, is at or below 84 MW (see the Base Case in Figure 4-21)[122] and there are 14 hours per year in which flexibility violations occur for a total of 800 MWh of unserved energy. Violations are concentrated in winter morning peak hours and metrics of flexibility stress similarly indicate the system is most constrained in the winter.
- **Observed flexibility issues are driven primarily by forecast error.** During observed instances of upward flexibility violations, ramping constraints are not binding. Upward flexibility shortages observed in this analysis are primarily driven by forecast error in combination with an insufficient ability to re-commit resources after the DA stage. The inflexible capacity product cannot be re-scheduled within the day, and existing resources' DA commitment decisions flow through to the HA and RT. However, though ramping constraints were not concurrently observed with the flexibility violations, the significant number of timepoints with very little remaining upward headroom suggest that an area for future examination is the exploration of ramp limitations under different scenarios.
- **Adding flexible resources such as batteries reduces system flexibility challenges.** Flexible resources, such as energy storage, can dispatch to respond as conditions change and can

[121] The exception is Wheatridge Renewable Energy Facility, which is modeled as a placeholder wind resource.

[122] Blue Marble Analytics, *Flexibility Adequacy Study*, Figure 14.

also shape energy intra-day. However, the study notes examples in which replacement of inflexible DA capacity with flexible battery capacity can unintuitively result in more observed flexibility violations; some examples are due to energy limitations and others due to the interaction of scheduling and forecast error. As large-scale deployment of energy storage occurs, we will continue to investigate their operation within our portfolio and effects on flexibility.

FIGURE 4-21: Duration curve of system headroom in the Base Case and Battery Cases

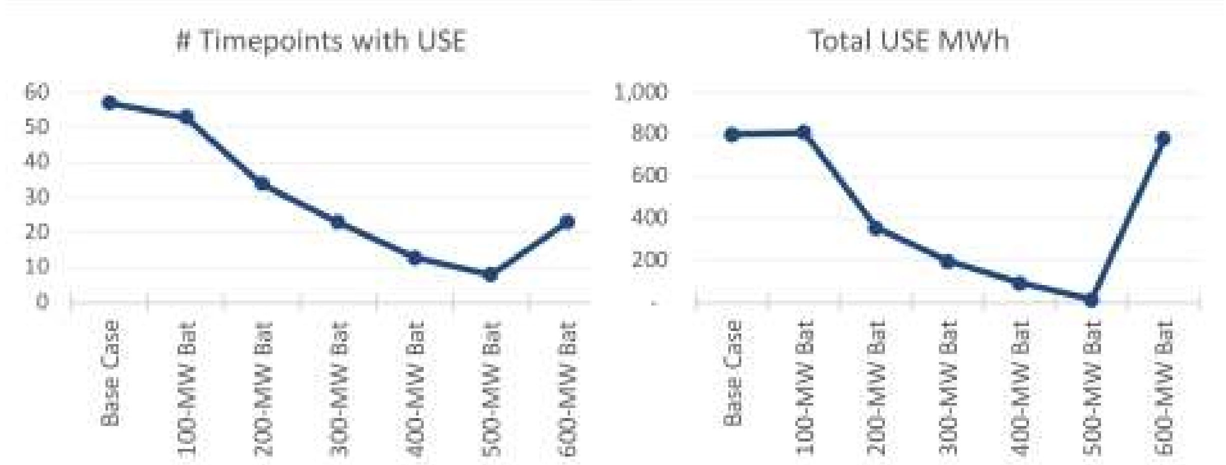


4.6.4 Considerations within the Action Plan

As discussed in the previous section, the PGE system faces potential flexibility challenges if our capacity needs are met only with inflexible, expensive resources such as those that cannot be committed within the day and have a high dispatch cost. Though this analysis focused on 2025, as contract expirations continue beyond 2025, flexibility challenges may continue to increase. Furthermore, though we did not observe ramping constraints with the instances of flexibility violations in this study, the significant number of timepoints with little remaining headroom suggests caution in assessing whether ramp limitations may be observed in the future. In the Base Case, 190 hours per year had less than 50 MW of headroom remaining.

In examining the results of the study, PGE found that by replacing a portion of the inflexible capacity with 400 MW of flexible resources, flexibility violations were reduced to 94 MWh and the frequency to three hours per year, or approximately in alignment with the RT imbalance levels recommended in the Flexible Capacity analysis from the 2016 IRP.[123] The reduction in flexibility violations is shown in Figure 4-22.[124] In addition, the amount of available upward headroom increases and 56 hours remain with headroom below 50 MW.

FIGURE 4-22: Comparison of unserved energy in the Base Case and Battery Cases



In the near- to mid-term, the activity focused on meeting capacity adequacy needs should be structured so that flexibility needs are also met in the process and that 400 MW of flexible resources can be acquired by 2025. Though this study models flexible capacity additions as batteries, we can meet these needs through other flexible resources such as hydro power with storage reservoirs or pumped hydro facilities. As in prior IRPs, PGE will update our recommendation if there are material changes to the portfolio or loads that affect need.

4.7 Need Sensitivities

In this section, PGE presents findings from sensitivities that examine the potential impacts on the need assessments from qualifying facilities, voluntary renewable programs, and LTDA loads.

4.7.1 QF Sensitivities

PGE's need assessments include the forecast of generation from all executed QF contracts.[125] This includes the output from projects that have not been constructed and for which there is uncertainty about whether or not the projects will be constructed. There is also uncertainty in the quantity of additional QF contracts that will be executed in the near-term.

To provide insight into the potential magnitude of the uncertainties, PGE conducted a sensitivity analysis to examine the impact of QF uncertainty on the capacity, energy, and RPS need assessments compared to the base assumption of including all executed QF contracts. The low QF sensitivity excludes 50 percent of the generation from the executed QF contracts that were not online as of the contract snapshot date (December 18, 2018). In addition to all executed QF contracts, the high QF

123 OPUC Docket No. LC 66. See PGE's 2016 IRP, Section 5.3.2.5. https://www.portlandgeneral.com/our-company/energy-strategy/resource-planning/integrated-resource-planning/2016-irp.

124 Blue Marble Analytics, *Flexibility Adequacy Study*, Figure 6.

125 The 2019 IRP includes QFs executed as of December 18, 2018.

sensitivity includes all of the generation from potential QF projects that were active in progressing toward contract execution in the 90 days prior to the contract snapshot date. All other assumptions in this analysis reflect the Reference Case.

Table 4-12 provides a summary of the sensitivity results. The additional generation in the high QF sensitivity (an increase of 47 MWa in 2025) reduces the capacity need by 14 MW. The impact on the RPS physical shortage in 2030[126] (a reduction of 46 MWa) is very similar to the energy impact in 2025. The high QF sensitivity shifts the REC deficiency year[127] out one year from the Reference Case. In the opposite direction, the reduced generation in the low QF sensitivity (a reduction of 73 MWa in 2025) increases the capacity need by 52 MW, increases the 2030 RPS physical shortage by 72 MWa, and shifts the REC deficiency year in by three years.

TABLE 4-12: Resource needs across QF sensivitites

	High QF	Base QF	Low QF
2025 Capacity Need (MW)	671	685	738
2025 Energy Shortage to Market (MWa)	469	515	588
2030 RPS Physical Shortage (MWa)	115	161	233
REC Deficiency Year	2037	2036	2033

The analysis provides informative bookends of the potential impact to resource needs; however, we note the underlying factors that can result in delayed or terminated projects and the factors that can lead to newly executed contracts are not mutually exclusive. PGE will likely experience delays, terminations, and executions of QF contracts in the near-term.

We will continue to monitor the status of QF projects and, as noted in Section 4.2, we will provide updates within the docket if there are changes that materially impact the recommended actions.

4.7.2 Voluntary Renewable Program Sensitivities

The IRP has traditionally focused on resource actions that PGE intends to take to meet the needs of all cost-of-service customers. However, as described in Section 2.1.3, customers have increasing options for participating in programs that will impact PGE's portfolio. Specifically, Community Solar and PGE's Green Tariff will allow customers to specify the source of a portion or all of their energy needs and allow for resources that are not planned for within the IRP to bring both energy and capacity to the system. The portion of PGE's needs that must be filled through the IRP process may therefore diminish as a result of participation in these programs.

Customer participation PGE's Green Tariff is not included in the base needs assessment or portfolio analysis, as it only recently has been offered. However, it is instructive to consider how participation in both Green Tariff and Community Solar might affect PGE's resource needs and might interact with potential near-term actions.

126 The year 2030 is the year of RPS physical shortage in the Reference Case. See Section 4.5.

127 The REC deficiency year is the year when the REC bank balance is forecast to be zero without additional RPS actions. See Section 4.5.

To investigate questions relating to voluntary program participation, PGE designed three sensitivities. In all three sensitivities, it is assumed that PGE customers fill the full first capacity tier of Community Solar (93.15 MW for PGE). Participation in PGE's Green Tariff varies across the three sensitivities up to the total cap approved by the OPUC in Order No. 19-075 (0 MW, 100 MW, and 300 MW). The resource assumptions for the three sensitivities are summarized in Table 4-13. The modeled Green Tariff resource is based on the Washington Wind resource described in Section 5.2.1 Wind Power. The modeled Community Solar resource has a capacity factor of 13 percent, based roughly on the solar resource quality in PGE's service area, and capacity contribution values based on the solar resource described in Section 6.2.3 Capacity Value.

TABLE 4-13: Resource implications of voluntary program sensitivities

	Sensitivity A			
Program	Installed Capacity (MW)	Generation (MWa)	Capacity Contribution (MW)	Avoided RPS (MWa)
Community Solar	93	12	15	4
Green Tariff	0	0	0	0
Total	**93**	**12**	**15**	**4**

	Sensitivity B			
Program	Installed Capacity (MW)	Generation (MWa)	Capacity Contribution (MW)	Avoided RPS (MWa)
Community Solar	93	12	15	4
Green Tariff	100	43	24	0
Total	**193**	**55**	**38**	**4**

	Sensitivity C			
Program	Installed Capacity (MW)	Generation (MWa)	Capacity Contribution (MW)	Avoided RPS (MWa)
Community Solar	93	12	15	4
Green Tariff	300	129	54	0
Total	**393**	**141**	**68**	**4**

Table 4-14 summarizes PGE's resource needs in the Base Case (no participation) and under each of the sensitivities described above.

TABLE 4-14: Needs assessment under voluntary program sensitivities

2025 Capacity Need (MW)	Base Case	Sensitivity A	Sensitivity B	Sensitivity C
Reference Case	685	670	647	617
Low Need Future	309	294	271	241
High Need Future	1,065	1,050	1,027	997

2025 Energy Shortage (MWa)	Base Case	Sensitivity A	Sensitivity B	Sensitivity C
Reference Case	515	503	460	374
10th Percentile across futures	344	332	289	203
90th Percentile across futures	907	895	852	767

2030 Physical RPS Shortage (MWa)	Base Case	Sensitivity A	Sensitivity B	Sensitivity C
Reference Case	161	157	157	157
Low Need Future	47	43	43	43
High Need Future	282	277	277	277

Across all the sensitivities, there remains significant capacity need in 2025 regardless of the level of participation in voluntary programs. PGE's energy position is more sensitive to customer participation in voluntary programs, but even under Sensitivity C, PGE maintains an open energy position in 2025 of at least 203 MWa on an annual basis in 90 percent of futures. Impacts to PGE's RPS position are limited due to the design of both programs: Community Solar does not produce RECs for RPS compliance, but instead reduces the RPS obligation through a reduction in retail sales; and the Green Tariff flows any generated RECs to participating customers. As a result, the RPS Physical Shortage in 2030 is largely unchanged across the sensitivities.

PGE will continue to monitor customer participation in voluntary programs and will update our needs assessment as additional information becomes available. The exercise described above suggests that it is unlikely that these updates would materially impact PGE's near-term capacity and RPS needs. Potential impacts to PGE's energy position are considered within the design of the preferred portfolio and the Action Plan.

4.7.3 Direct Access and Resource Adequacy

IRP Guideline 9 states that "An electric utility's load-resource balance should exclude customer loads that are effectively committed to service by an alternative electricity supplier."[128,129] In past IRPs, PGE interpreted this Guideline to require the exclusion of all long-term direct access (LTDA) customers

[128] OPUC Order No. 07-047 at 6.

[129] In OPUC Order No. 07-002, the Commission adopted IRP Guideline 9 in Docket UM 1056, a docket that commenced in 2002. The Commission cited stakeholder comments, noting that "11.3% of PGE's eligible load elected to take service from electricity service suppliers (ESSs) in 2005." (citing Order No. 07-002 at 19) As of 2018, roughly 41% of eligible load has opted out of PGE's cost-of-service supply.

from our need assessments, portfolio analysis, and action plan. While the 2019 IRP has employed the same assumption for consistency with past practice, PGE believes that the interpretation of this guideline requires further consideration. Excluding long-term opt-out direct access customers from PGE's capacity planning, while retaining the Provider of Last Resort (POLR) responsibility, shifts reliability risks from direct-access participants to cost-of-service supply customers. These risks are heightened under tightening resource adequacy conditions, continued plant retirements across the West (see Section 2.4.2 Regional Capacity Changes), and growth in LTDA load that now tallies approximately 240 MWa (and even more in terms of system coincident peak MWs). The reliability risks associated with unplanned resource adequacy are heightened when accounting for the expansion of very large single loads (10 MWa minimums and potential for some as large as 100-200 MWa) participating in direct access through the NLDA program.[130] Without reconsidering Guideline 9, a larger portion of regional capacity needs will fall outside regulated long-term planning processes while regional needs for new capacity grow and short-term capacity availability declines. In this section we describe the potential risks associated with the traditional interpretation of IRP Guideline 9 and explore the magnitude of potential capacity needs that remain unaccounted for because of this interpretation.[131]

PGE has excluded LTDA customer loads and NLDA customer loads from all aspects of the need assessments described in Chapter 4. Resource Needs, including energy, capacity, RPS, and flexibility needs. Accordingly, PGE has not planned for any resource adequacy or flexibility needs associated with LTDA customer loads. This practice has introduced risk to PGE cost-of-service supply customers because of the asymmetry in obligations between regulated and unregulated energy providers. More specifically:

- Electricity service suppliers, to which customers have committed for their energy supply, are not required to plan for or procure resources in advance necessary to meet resource adequacy needs associated with their committed loads; and
- Today, PGE cannot preferentially provide reliability and flexibility to cost-of-service supply customers over direct access customers.

Consequently, all customers (cost-of-service supply and direct-access) are put at risk of a reliability event and the electricity service supplier has no regulatory obligation to plan to avoid such an adverse scenario.

Numerous studies have highlighted that the capacity position in the Pacific Northwest and across the Western Interconnect is expected to shift dramatically in the 2020s as thermal resources continue to be retired. PGE's Market Capacity Study predicts that the Pacific Northwest may become capacity deficient in the early to mid-2020s. Since the finalization of that study, there have been additional announcements of plans for early coal retirements.

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130 The NLDA program rules are set forth in OPUC Order No. 18-341. PGE proposed its NLDA program in Schedule 689 which is pending further investigation at the OPUC. See Docket UE 358. While PGE's program is capped at 119 MWa, the OPUC has offered to entertain waivers to the program cap.

131 Considering these concerns, and as part of its proposed NLDA program, PGE has asked the Commission to authorize the electric utility to plan for loads served by long-term direct access, thereby reversing IRP Guideline 9. See PGE Advice No. 19-02, p. 3.

In this environment of rapid change, it becomes increasingly important that PGE identify and mitigate new potential risks to our customers. Under the current interpretation of IRP Guideline 9, PGE has no ability to ensure that all the loads in our Balancing Authority (BA) have associated plans for resource adequacy and that our cost-of-service supply customers are protected from the unregulated decisions made by electricity service suppliers (ESSs) serving customers in our Balancing Authority. While this risk has existed since the introduction of direct access, regional resource adequacy constraints and the expansion of direct access increase the risk of reliability impacts to cost-of-service supply customers. In the section below, we examine the potential scale of the capacity adequacy impacts to the PGE Balancing Authority of two sensitivities of direct access load.

4.7.3.1 Direct Access Capacity Adequacy Sensitivities

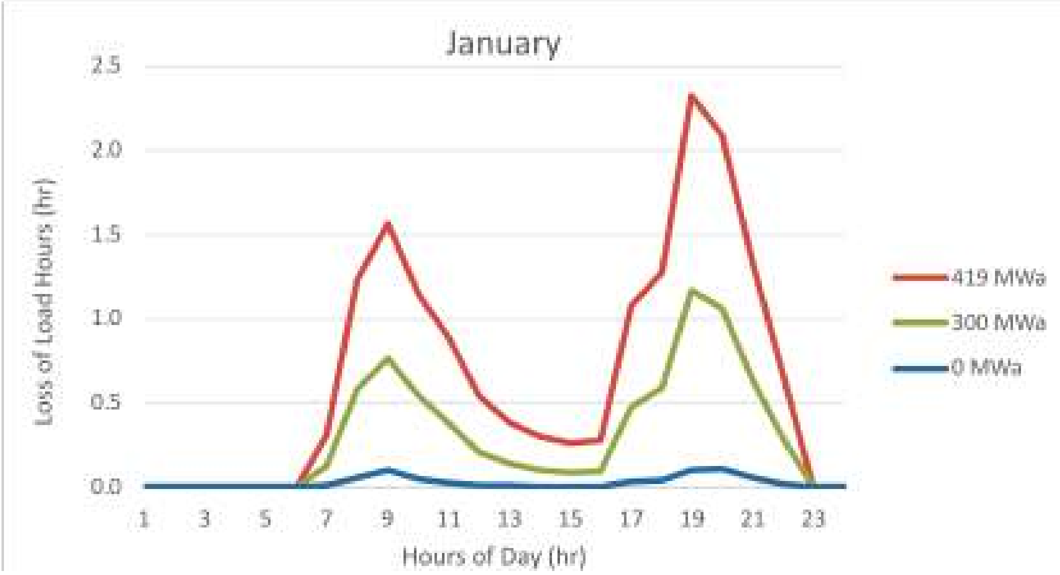
To estimate the capacity need associated with long-term opt-out direct access customers, PGE prepared two sensitivities for the year 2025, with the first examining the impact of including 300 MWa of LTDA load and the second examining the impact of 419 MWa of LTDA load. The 300-MWa sensitivity represents the impact of the enrollment limit of the LTDA program for existing load and the 419 MWa represents the combined enrollment limits of the programs for existing load and new load (300 + 119 MWa). The load shapes associated with the LTDA load in the sensitivities are based on hourly historical direct access metered loads. As shown in Table 4-15, if the both programs are fully subscribed in 2025, the exclusion of the LTDA and NDLA loads from PGE's resource adequacy assessment could result in over 500 MW of capacity needs within PGE's BA for which ESSs are not obligated to plan and PGE is not currently permitted to plan.

TABLE 4-15: Capacity need associated with LTDA sensitivities

	Incremental Capacity Need
300 MWa Long-term Direct Access (existing load program)	373 MW
419 MWa Long-term Direct Access (existing + new load programs)	526 MW

Additionally, PGE examined the impact to the annual loss-of-load expectation (LOLE) and the January loss-of-load hour (LOLH) profile of the system. Higher values indicate greater probabilities of load exceeding resources. As discussed in Section 4.3 Capacity Adequacy, the reliability target is LOLE of no more than 2.4 hours per year (equivalent to the industry standard 1-day-in-10-years reliability metric). Including 419 MWa of LTDA load to an adequate system increased PGE’s LOLE to 53.7 hours per year (or approximately 22-days-in-10-years). The impact on the January LOLH profile is examined in Figure 4-23, which shows the profile for the system without any LTDA load and with adequate capacity to achieve the annual reliability target in the blue line (0 MWa). The green and red lines (300 MWa and 419 MWa) show how this profile changes when the LTDA load sensitivities are included. There is a steep increase to the LOLH due to the added load, with the annual reliability target more than exceeded in a single month for both sensitivities.

FIGURE 4-23: Loss-of-load-hour profiles in direct access sensitivities



This analysis demonstrates that the consequences of continuing to exclude LTDA loads from resource adequacy planning could be very large. This issue becomes both apparent and urgent in a time when the region is quickly facing substantial resource shortages. To protect our customers from the potential consequences of resource shortages, PGE has and will continue to advocate for regulatory solutions that share the responsibility for resource adequacy and reliability across all customers.

CHAPTER 5. Resource Options

In the 2019 IRP, we consider all known resources to meet the needs identified in Chapter 4. Resource Needs while focusing the analysis on commercially available technologies, including distributed energy resources (DER) and supply-side options. To aid in this effort, PGE engaged third-party consultants to provide resource characteristics and forecasts across the broad range of technologies and programs.[132] This chapter begins with an exploration of the distributed flexibility programs and technologies (including demand response and dispatchable customer storage) that we expect will contribute to meeting PGE's resource needs. We then describe the candidate supply side options that are tested in portfolio analysis, including energy storage, renewables, and thermal resources. We conclude with discussions of transmission, emerging technologies, and the advantages and disadvantages of utility and third-party ownership of resources.

Chapter Highlights

★ PGE describes results from a study performed to identify new distributed flexibility targets.

★ PGE considers wind, solar, biomass, geothermal, battery storage, pumped hydro storage, and natural gas resources and provides summary characteristics for each.

★ PGE uses its transmission system to safely and reliably deliver energy to its customers.

★ Given the geographic diversity of its generation resources, PGE is heavily reliant on Bonneville Power Administration (BPA) transmission.

[132] Information on DER was provided by Navigant through the DER Study (External Study C. Distributed Energy Resource Study), and supply-side options were provided by HDR in the Supply Side Options Study (External Study D. Characterizations of Supply Side Options).

5.1 Distributed Flexibility

As discussed in Section 1.1.2, PGE engaged Navigant to conduct a comprehensive DER study (External Study D) to improve the IRP forecast of customer adoption of technology and participation in demand response programs.

This section discusses the demand response and dispatchable customer storage portions of the study, which we refer to as distributed flexibility (DF). For discussion of passive DERs (including distributed solar and non-dispatchable customer battery storage) please see Section 4.1.3.

5.1.1 Demand Response

In the 2016 IRP, PGE engaged the Brattle Group to conduct a Demand Response Potential Evaluation to understand the potential for customer participation in demand response (DR) programs in the future. These programs would allow PGE to meet a portion of its future system needs through the participation of customer loads, including both load curtailment and load shifting. PGE utilized the Demand Response Potential Evaluation to develop a DR target of 77 MW in winter and 69 MW in summer by 2021, which the OPUC acknowledged as a demand response procurement floor in PGE's 2016 IRP Acknowledgment Order No. 17-386.[133] The OPUC also ordered PGE to "hire a third party to conduct a study for demand response specific to PGE's service area with results in time to inform PGE's subsequent IRP".[134] In response to the Order and to advance the consideration of DR in our resource planning processes, PGE engaged Navigant Consulting to identify new targets for the 2019 IRP.

PGE leveraged the robust analysis in the Demand Response Potential Evaluation and worked with Navigant to improve the consideration of customer adoption drivers, interactive effects between programs, the adoption of new technologies such as electric vehicles, and forecast uncertainty. Navigant and PGE developed the DR targets described in this section (and included in the 2019 IRP) in conjunction with the customer adoption forecasts of other distributed energy resources, including customer-sited photovoltaics and customer-dispatched battery storage, discussed in Section 4.1.3. The Navigant DER Study is available in External Study C.

Table 5-1 provides a list of the programs investigated by Navigant and included in the DR evaluation. Importantly, these programs interact with one another. For example, participation in one may preclude participation in others. The various programs may also affect a customer's decision to pursue other DER technologies. These interactive effects required that Navigant evaluate all programs in coordination with each other.

PGE pursued several incremental improvements to its treatment of DR within the Navigant DER Study. These incremental improvements are described below.

133 OPUC Order No. 17-386 at 9.

134 *Id.*

TABLE 5-1: Demand response programs considered

Program Type	Program
Residential Pricing	TOU[1]
	PTR[2]
	PTR with Technology Pairing
	BDR[3]
Residential DLC	BYOT[4] – AC[5] & Space Heating
	BYOT – AC
	BYOT – Space Heating
	AC/Space Heating DLC[6]
	AC DLC
	Space Heating DLC
	Smart Water Heater DLC
	Water Heating DLC
	EV[7] DLC
Non-Residential Pricing	PTR
	PTR with Technology Pairing
Non-Residential DLC	AC & Space Heating DLC
	AC DLC
	Space Heating DLC
	Water Heating DLC
	Third-Party DLC
Non-Residential Curtailment	C&I[8] Curtailable Tariff

[1] Time-of-Use
[2] Peak Time Rebate
[3] Behavioral Demand Response
[4] Bring Your Own Thermostat
[5] Air Conditioning
[6] Direct Load Control
[7] Electric Vehicle
[8] Commerical & Industrial

5.1.1.1 Customer Participation Forecasting

The Demand Response Potential Evaluation in the 2016 IRP estimated the maximum system peak demand reduction capability that PGE could realistically achieve through the deployment of specific DR programs in its service territory under reasonable expectations about future market conditions. As PGE transitions its DR activities from pilot to program deployment, we seek an improved understanding of customer adoption potential to appropriately incorporate DR into long-term resource planning. Toward this end, PGE prioritized learnings around customer adoption and adoption drivers of DER technologies in the Navigant study.

Navigant provided updated long-term potential forecasts based on updated market conditions as well as explicit modeling of customer adoption based on such drivers as technology development, available incentives, policy, and the composition of customer types within PGE's service area. This resulted in improved internal consistency relating to customer adoption trajectories across programs.

5.1.1.2 Interactive Effects

The Demand Response Potential Evaluation in the 2016 IRP focused on each program in isolation to gauge the maximum achievable development for every category of DR. PGE then applied heuristics to adjust the resource size and account for potential interactions between programs when specific combinations of programs were present in a portfolio. The Navigant DER study advanced this work through explicit treatment of potential interactions between programs in both customer participation decisions and in program performance. Navigant accounted for interactions between similar DR programs and the effect of combining DR with other distributed resources, such as energy efficiency, solar, storage, and electric vehicles. For example, the forecast growth in participation in the electric vehicle direct load control (EV DLC) program is internally consistent with the electric vehicle adoption forecast used throughout the IRP.

5.1.1.3 Inputs and Uncertainties

Navigant's study updated market data to account for changes in wholesale electricity price forecasts, PGE customers by segment, seasonal peak demand, carbon pricing scenarios, and other key assumptions that drive estimates of DR potential and cost-effectiveness. Navigant also used PGE's five-year program-deployment targets[135] to initialize its customer adoption simulations. PGE developed these targets based on the acknowledged demand response actions in the 2016 IRP.

In response to stakeholder feedback to the 2016 IRP, this IRP was developed with a focus on analyzing uncertainty (see Chapter 3 for more discussion). To provide more insight regarding the uncertainties related to the DER adoption forecast, Navigant produced high and low scenarios by varying key input adoption drivers to simulate environments that may be more or less favorable for customer participation in programs. Table 5-2 shows the drivers and the variations investigated in the Navigant study.

TABLE 5-2: Demand response adoption scenarios

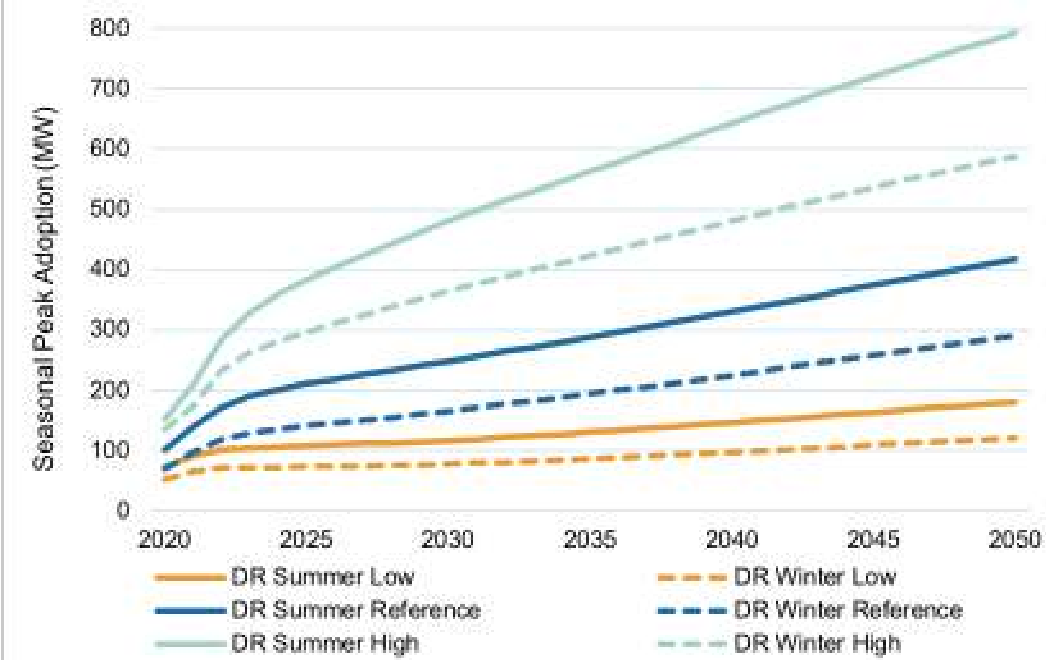
	Low DR	Reference Case	High DR
Technology Costs	+50% cost by 2030	Navigant reference DR cost model	-50% cost by 2030
Policies	Less favorable policy	Navigant reference policy model	More favorable policy
Carbon Prices	No change	PGE Reference Carbon Price Future	No change
TOU participation	0% residential TOU	10% residential TOU	Opt-out residential TOU

Figure 5-1 shows the low, reference, and high forecasts of the total DR portfolio for the summer and winter. Customer participation is anticipated to expand rapidly through 2023 and maintain steady

135 Five-year DR program target approximations are based on 2016 IRP acknowledged deployment goals combined with estimated achievable growth from planned program development.

growth through 2050. In the 2024-2050 timeframe, expanding EV DLC programs are anticipated to drive growth (Section 4.1.3.1 Electric Vehicles discusses the link to EV load forecasts).

FIGURE 5-1: Summer and winter demand response resources across futures



5.1.2 Dispatchable Customer Battery Storage

As part of the DER Study, Navigant provided forecasts for customer adoption of both dispatchable and non-dispatchable customer battery storage resources. Non-dispatchable customer storage resources impact PGE's resource needs but are not options that PGE may use to actively manage its resource portfolio. Adoption of non-dispatchable customer storage is discussed in Section 4.1.3.2 Distributed Solar and Non-dispatchable Battery Storage.

Dispatchable customer storage, however, can be actively managed by the utility, creating the potential for these resources to provide bulk system and local grid services. Because customers can also use these systems for backup power in the event of outages, dispatchable customer storage represents a promising new distributed technology for providing both participant and utility benefits.

To forecast dispatchable customer storage, Navigant leveraged the value streams identified for customer-sited storage in PGE's Energy Storage Potential Evaluation. Navigant based the customer decision to adopt on the cost of the battery system, the value of backup power, and the value of the battery system to the utility, assuming a mechanism for compensating the customer for utility value. In Navigant's model, the adoption drivers in the low and high scenarios for storage were linked to solar assumptions, as shown in Table 5-3.

TABLE 5-3: Solar and storage adoption scenarios

	Low Solar & Storage	Reference Case	High Solar & Storage
Technology Costs	Navigant high PV and lithium-ion costs	Navigant reference PV and lithium-ion costs	Navigant low PV and lithium-ion costs
Policies	Decreased marketing	Navigant reference marketing	Investment tax credit (ITC) continues through 2050 and increased marketing
Carbon Prices	PGE Low Carbon Price Future	PGE Reference Carbon Price Future	PGE High Carbon Price Future
TOU participation	0% residential TOU	10% residential TOU	Opt-out residential TOU

Figure 5-2 demonstrates the resulting forecast adoption of dispatchable storage and indicates that most customers who participate in a dispatchable storage program are also likely to adopt rooftop solar. Figure 5-3 shows aggregate adoption trajectories for the low, reference, and high adoption scenarios. The high adoption scenario reflects the significant impact of the federal investment tax credit on the economics of pairing rooftop solar with storage.

FIGURE 5-2: Reference case dispatchable customer storage adoption trajectory by type

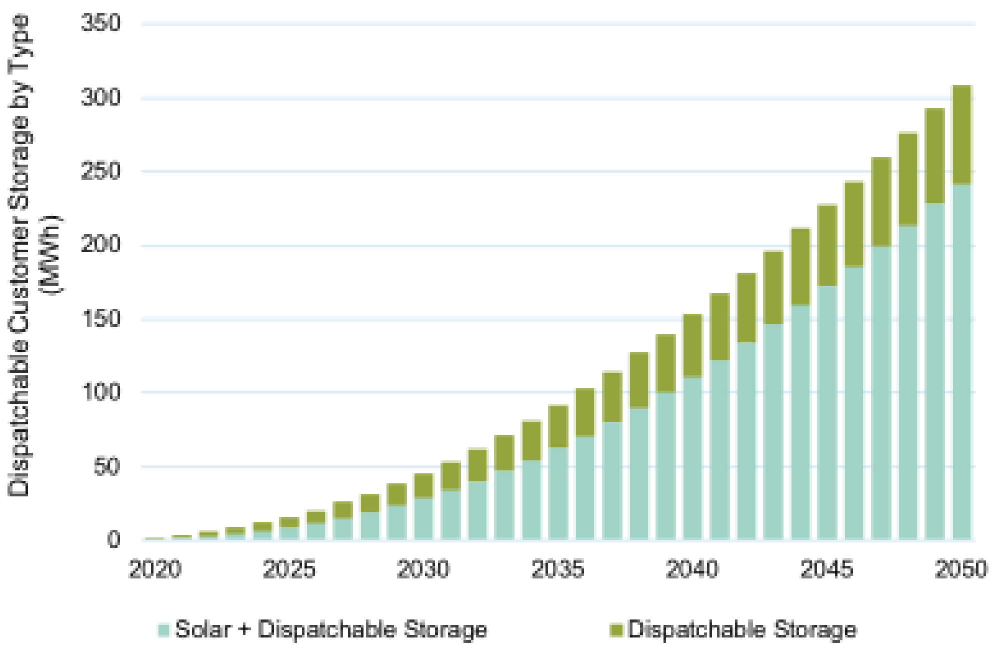
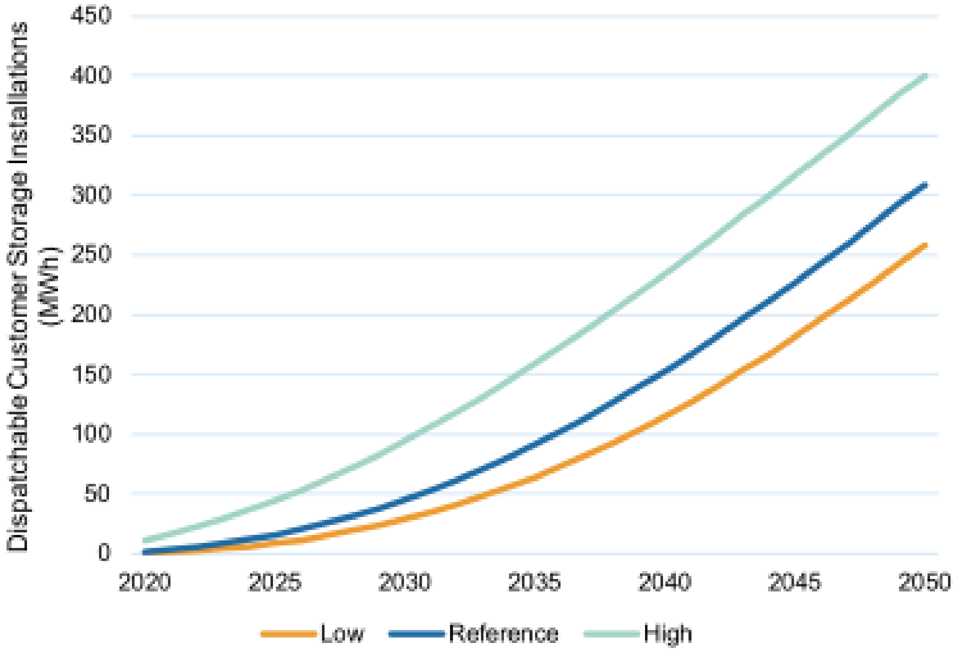


FIGURE 5-3: Dispatchable customer storage adoption forecast scenarios



5.1.3 Incorporation into the IRP

As discussed in Section 3.1, PGE incorporated the distributed flexibility forecasts in to the Need Futures to investigate their impact on the capacity adequacy assessment. Table 5-4 provides an assumption of adoption by Need Future. For the Low Need Future, PGE assumes low adoption of electric vehicles, which is paired with low participation in the EV DLC program. The other DR programs and the dispatchable customer storage program are assumed to have high adoption rates in the Low Need Future.

TABLE 5-4: Distributed flexibility scenarios in each Need Future

	Low Need Future	Reference Case	High Need Future
Demand Response & Flexible Load	High Adoption	Reference	Low Adoption
Dispatchable Customer Storage	High Adoption	Reference	Low Adoption
EV DLC	Low Adoption	Reference	High Adoption

The distributed flexibility resources were also included in the PGE-Zone Model to estimate their wholesale market revenue across the Market Price Futures. The forecasts and simplified cost estimates[136] were incorporated in the base portfolio assumptions for portfolio analysis. PGE's recommended distributed flexibility actions are detailed in Chapter 8. Action Plan.

136 The cost estimates were based on simplified assumptions from the NWPCC's 7th Power Plan. See https://www.nwcouncil.org/reports/seventh-power-plan, Chapter 14 and Appendix J.

5.2 Renewables

To inform the characterization of utility-scale renewable resources for this IRP, PGE engaged HDR, Inc. to provide a Supply Side Resource Study. This section highlights key information from the resulting HDR report, along with additional cost considerations associated with these resources.

5.2.1 Wind Power

PGE analyzed new wind resources in four locations: Columbia Gorge, Southeastern Washington; and Central Montana (near Loco Mountain), and Ione, Oregon. HDR selected the same type of turbine for all four locations to illustrate the impact of location independent of technology.

Table 5-5 provides summary information on a 100-MWa wind resource project for each location from the HDR study (External Study D). As expected, the overnight capital costs display little variation on a dollar-per-kW basis due to uniform turbine technology and similar land and labor costs.

TABLE 5-5: Wind resource characteristics

	Ione, OR	Columbia Gorge	Southeast Washington	Loco Mountain, MT
Plant capacity (MW)	306.0	244.8	234.0	234.0
Capacity factor	32.7%	40.8%	42.9%	42.9%
Capital cost (2018$/kW)*	$1,508	$1,539	$1,531	$1,520
Turbine count†	85	68	65	65

*Project capital cost is estimated based on an overnight, turnkey EPC delivery, based on a 2018 notice to proceed.

†For this IRP, HDR characterized the performance and costs associated with the Vestas V136-3.6, 3.6 MW turbine. These turbines have a hub height of 105 meters and a rotor diameter of 136 meters.

For the purpose of the analysis in the 2019 IRP, each of these locations is assumed to have one wheel of BPA transmission cost. In addition, the Montana resource includes additional losses and wheeling costs based on information in the Montana Renewable Development Action Plan (MRDAP) and feedback from stakeholders in the IRP Public Roundtable process (see Section 5.5.4).

Technology cost uncertainties increase across the planning horizon and are discussed in Section 3.3. Resource economics, including the levelized cost of energy and a capacity factor sensitivity, are described in Chapter 6.

5.2.1.1 Production Tax Credits

The federal production tax credit (PTC) is a tax-credit awarded for each megawatt hour (MWh) of generation from a qualifying energy resource for the first ten years of the resource's operation. Historically, the tax credit was available to wind, biomass, hydroelectric, and geothermal energy resources. Since 2017, the tax credit has been only available to wind energy resources. The tax credit is inflation-adjusted, and, in 2019, is worth $25 per MWh.

PGE assumes PTC eligibility consistent with Internal Revenue Service (IRS) guidance.[137] Facilities qualify for the PTC by starting construction in a qualifying year and being placed in service no later than four calendar years after construction begins.

TABLE 5-6: PTC schedule

Begin Construction (Year)	Placed in Service Date	Percent of PTC
2016	On or before December 31, 2020	100%
2017	On or before December 31, 2021	80%
2018	On or before December 31, 2022	60%
2019	On or before December 31, 2023	40%
2020 – 2050	Not applicable	0%

5.2.1.2 Energy Generation

The HDR reports contain wind energy profiles specific to each location.[138] For each location, PGE received a long-term annual capacity factor and seven years of hourly generation profiles based on historical wind data. These data were created by Vaisala, a wind energy consultant. As seen in Table 5-5, the long-term annual net capacity factors vary by location, ranging from 32.7 to 42.9 percent. The wind resources vary in seasonal and diurnal timing of their generation, as well as their probability of generation under high load conditions. The IRP captures the impact of these characteristics on the levelized cost of energy, the expected value of energy, and capacity provided by each resource, as detailed in Chapter 6.[139] For example, the levelized cost of energy at Ione is higher than that of Montana because Ione has a lower capacity factor and requires more turbines to produce the same output.

Figure 5-4 shows average monthly wind shapes for the four wind sites used in the HDR study. These shapes illustrate the seasonal difference in expected output between locations. For instance, the Montana wind resource generally maintains high output levels during the fall and winter months, while the strongest production in the Columbia Gorge happens in the spring and summer months.

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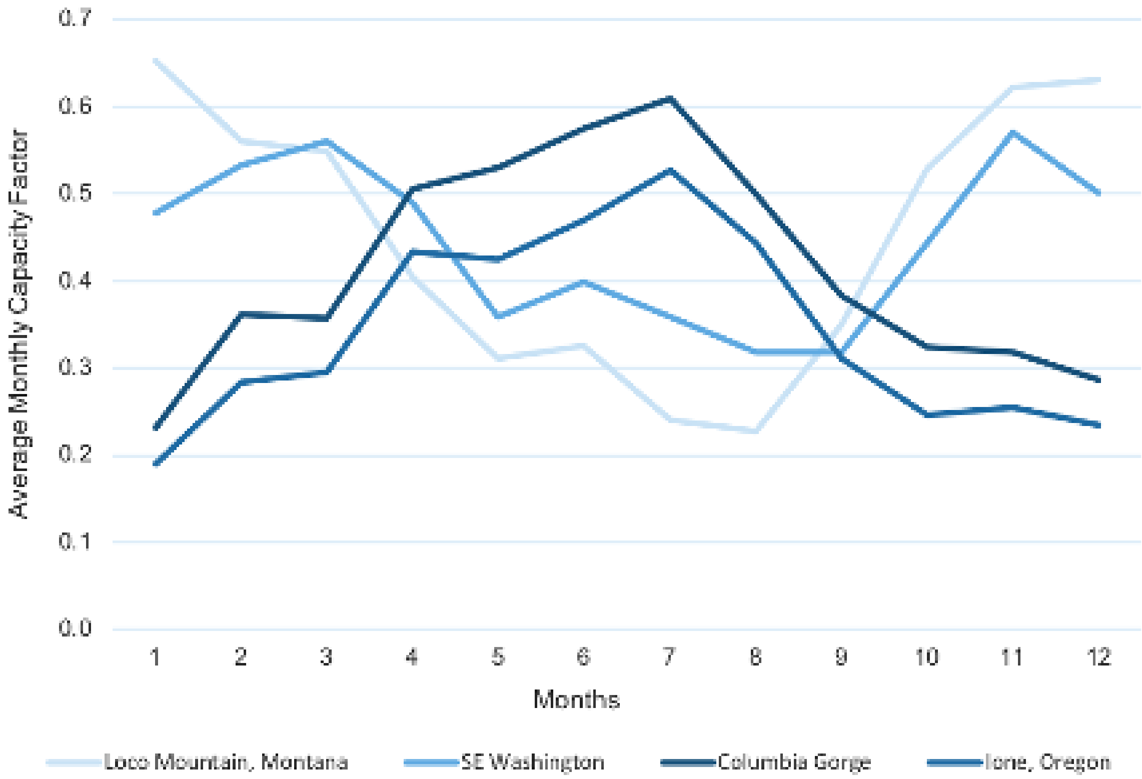
[137] Facilities qualify for the PTC by taking advantage of the Internal Revenue Service's Five Percent Safe Harbor provision. Under this provision, project owners can establish the beginning of construction by incurring at least five percent of the total cost of the facility in the qualifying year. PGE considers the Continuity Safe Harbor set forth in section 3 of IRS Notice 2016-31 and Notice 2017-04. Under the Continuity Safe Harbor in section 3 of Notice 2017-04, if a facility was placed in service before a calendar year that is no more than four calendar years after construction began, the facility will be considered to make continuous progress towards completion. As an example, a wind facility entering the portfolio in January 1, 2024 is assumed to be eligible for 40 percent of the PTC because it is assumed to be online by December 31, 2023 and to have safe harbored turbines in 2019.

[138] For each location PGE received a long-term annual capacity factor and seven years of hourly generation profiles based on historic wind data.

[139] PGE prepared a sensitivity analysis to examine the impact of the capacity factor assumption on resource economics. This is described in Section 6.5.

FIGURE 5-4: Average monthly wind capacity factors by location



5.2.2 Solar PV

PGE engaged HDR to provide plant performance and financial characteristics of a 25-MWa single-axis tracking solar facility in Christmas Valley, Oregon. This region benefits from a higher level of solar irradiance than the PGE service area. Table 5-7 lists solar resource features and financial parameters from HDR's report (External Study D).

TABLE 5-7: Solar PV characteristics

	Solar PV
Plant capacity (MW_{AC})	95
DC/AC ratio	1.30
Annual capacity factor*	24.8%
Capital cost (2018$/kW)†	$1,510

*The DC/AC ratio is a power conversion factor that accounts for the relationship between rated power of the DC solar array and the rated power of the DC-AC inverter.

†Based on a notice to proceed in 2018.

In addition to an annual capacity factor, HDR also provided a seven-year hourly generation profile based on historical solar irradiance data. This was used in PGE's capacity contribution analysis and informed the daily and monthly shaping of the annual generation for the PGE-Zone Model. IRP analysis assumed that utility-scale solar PV was located off-system with one wheel of BPA transmission. Technology cost uncertainties are discussed in Section 3.3. Resource economics, including the levelized cost of energy, are considered in Chapter 6. Portfolio analysis is included in Chapter 7, and utility-scale solar paired with storage is discussed in Section 5.2.3.

5.2.2.1 Investment Tax Credit

PGE's IRP analysis considers the ITC for qualifying solar resources as set forth in Chapter 48 of the Internal Revenue Code. Consistent with the Internal Revenue Code, PGE includes the phase-down of the ITC for qualifying solar resources from 30 percent in 2019 to 10 percent in 2022 and beyond. The Continuity Safe Harbor benefit allows solar resources to begin construction to maintain ITC eligibility in the applicable ITC phase-down year. The Safe Harbor benefit applies so long as a qualifying solar resource is placed in service no more than four calendar years after construction of the resource began. However, section 6 of Notice 2018-59 clarifies that the Continuity Safe Harbor does not extend for any solar energy property placed in service after January 1, 2024. Table 5-8 summarizes the ITC amount and deadlines for placing a project in service based on Notice 2018-59.

TABLE 5-8: ITC schedule

Begin Construction (Year)	Placed in Service Date	Percent of ITC
Before January 1, 2020	Before January 1, 2024	30%
Before January 1, 2021	Before January 1, 2024	26%
Before January 1, 2022	Before January 1, 2024	22%
Before January 1, 2022	On or after January 1, 2024	10%
On or after January 1, 2022	On or after January 1, 2022	10%

5.2.3 Solar Plus Storage

In PGE's public roundtable process, stakeholders requested that PGE examine a co-located solar plus storage resource. PGE utilized information from HDR on standalone solar and battery storage to model a 100-MW solar plus 25-MW 4-hour battery co-located system. This exercise made the following assumptions:

- 100 percent of energy stored in the battery storage system was derived from the co-located solar PV system.
- Overnight capital costs of the battery storage system were reduced by 10 percent compared to the overnight costs of a standalone 4-hour battery.[140]
- Fixed operation and maintenance (O&M) costs of the battery storage were reduced by 10 percent compared to the fixed O&M costs of a standalone 4-hour battery.[141]
- Land lease costs for the battery storage system were removed due to the co-location.

[140] This a reasonable simplification for an AC-coupled system. For example, Bloomberg NEF (BNEF) approximates 13 percent for a DC-coupled solar plus storage system, which is likely to have greater equipment savings. See BNEF report, *Solar-Storage Design Synergies Support Dispatchable PV.*

[141] The same percentage reduction was applied to O&M, considering shared labor costs.

In a 2013 letter ruling, the IRS stipulated that a commercial, behind-the-meter battery included in the installation of a solar system qualifies for the ITC.[142] However, eligibility is dependent on the charging relationship between the storage device and solar system.[143] Based on the charging assumption described above, PGE assumed that the modeled solar plus storage resource would qualify for the ITC.

IRP analysis assumed that the solar plus storage resource would be located off-system with one wheel of BPA transmission. Chapter 6. Resource Economics provides additional information on solar plus storage performance and economics.

5.2.4 Geothermal

Geothermal power is a technologically mature and commercially available renewable resource. PGE examined a 30-MW geothermal flash steam plant sited in a viable location in the Pacific Northwest. Table 5-9 provides a summary of key characteristics from HDR's resource report (External Study D).

TABLE 5-9: General characteristics of geothermal

	Geothermal
New and clean capacity (MW)	30
Average degraded capacity (MW)	23
Capital cost (2018$/kW)*	$6,216

*Based on a notice to proceed in 2018.

For simplicity, analysis for the 2019 IRP assumed that geothermal was located off-system with one wheel of BPA transmission. Technology cost uncertainties are discussed in Section 3.3. Geothermal economics are discussed in Chapter 6, followed by portfolio analysis in Chapter 7.

5.2.5 Biomass

Biomass generation is a non-intermittent renewable resource. PGE examined a 30 MW plant with a circulating fluidized bed steam generator fueled by woody biomass. Characteristics of this plant from the HDR report (External Study D) are shown in Table 5-10.

TABLE 5-10: General characteristics of biomass

	Biomass
Fuel	Woody biomass delivered to site by truck
New and clean capacity (MW)	30
Capital cost (2018$/kW)*	$5,935

*Based on a notice to proceed in 2018.

[142] IRS, Private Letter Ruling 201308005.

[143] ITC eligibility for the combined resource is contingent on the use of the co-located solar at a minimum 75 percent on an annual basis to charge the battery. The ITC for the solar and battery storage may be reduced on a pro-rata basis if less than 100 percent of the energy stored in the device during an annual period derives from the solar technology.

Analysis for the IRP assumed that biomass resources were located off-system, with one wheel of BPA transmission. Biomass is assumed to be net neutral from a GHG perspective, but does result in other types of emissions. Technology cost uncertainty is discussed in Section 3.3. Biomass economics are discussed in Chapter 6.

5.3 Utility Energy Storage

PGE selected two commercially available storage technologies for evaluation in the 2019 IRP: lithium-ion (Li-ion) batteries and pumped hydro storage.[144] Generic technical and cost assumptions were provided by HDR Engineering Inc. (HDR) for:

- 2-hour, 4-hour, and 6-hour duration Li-ion battery energy storage systems (BESS).
- Variable speed closed-loop pumped hydro energy storage system.

The HDR reports are available in External Study D.

5.3.1 Battery Energy Storage

Li-ion BESS are not yet widely deployed at utility scale. However, costs are declining due to economies of scale and technological maturity, largely driven by expanding demand from both the energy and transportation sectors. BESS are advantageous in their modularity and relatively short construction lead times when compared to other resources. Further, they are capable of very fast responses in switching between charge and discharge, can be sited on the distribution system, can contribute to microgrids, and can provide various ancillary services. Table 5-11 lists Li-ion BESS operating and financial parameters from HDR's report (External Study D).

TABLE 5-11: Battery energy storage characteristics

	Li-ion battery 2-hour duration	Li-ion battery 4-hour duration	Li-ion battery 6-hour duration
Plant capacity (MW)	100	100	100
Energy (MWh)	200	400	600
Discharge duration (hours)	2	4	6
Round trip efficiency (%)	82%	87%	89%
Capital cost (2018$/kW)*	$916	$1554	$1902
Capital cost (2018$/kW-storage duration hour)	$458	$388	$317

*Project capital cost is estimated based on an overnight, turnkey engineer, procure and construct (EPC) delivery, based on a 2018 notice to proceed.

In the 2019 IRP analysis, battery installations are considered to be located within PGE's system and are not modeled based on a unit size constraint. Projections of battery costs through time are very uncertain, as discussed in Section 3.3. Battery storage economics are discussed in Chapter 6. Discussion of solar plus storage systems can be found in Section 5.2.3.

144 The modeling techniques used to analyze these two technologies can also be applied to other storage technologies, including flow batteries and compressed air energy storage systems.

5.3.2 Pumped Hydro Storage

Pumped hydro storage is a mature technology which typically provides slightly longer discharge durations than batteries. However, pumped hydro projects use natural or man-made reservoirs that are usually located off-system, require large amounts of land, and involve lengthy construction periods due to complex siting and permitting processes. Table 5-12 lists the features of the pumped hydro storage resource described by HDR. Additional information is provided in HDR's report in External Study D.

TABLE 5-12: Pumped hydro storage characteristics

	Pumped Hydro Storage
Plant capacity (MW)	1,200
Storage duration (hours)	8
Average turnaround efficiency	80%
Ramp rate (MW/min)	255
Capital cost (2018$/kW)*	$2,252

*Project capital cost is estimated based on an overnight, turnkey EPC delivery, based on a 2018 notice to proceed.

IRP analysis assumed that pumped hydro resources were located off-system, requiring one wheel of BPA transmission to PGE's system, with a unit size of 100 MW. Equipment costs for pumped hydro are less uncertain than for batteries; however, each project is unique in size and location, impacting construction costs and performance characteristics. Pumped hydro storage economics are discussed in Chapter 6.

5.4 Natural Gas Generators

PGE analyzed four natural gas technologies, covering a range of operating characteristics:

- Simple Cycle Aero Derivative Combustion Turbine Generator: 1x0 GE LMS 100PA+ (LMS 100)
- Simple Cycle Frame Combustion Turbine Generator: 1x0 GE 7HA.02 (Frame SCCT)
- Simple Cycle Reciprocating Engines: 6x0 Wartsila 18V50SG (Recips)
- Combined-Cycle Combustion Turbine Generator: 1x1 GE 7HA.02 (CCCT)

Table 5-13 summarizes the major characteristics of each resource from the HDR report (External Study D).

Analysis for the IRP assumed that natural gas resources were located off-system with one wheel of BPA transmission, and were fueled with AECO gas. Technology cost uncertainty is discussed in Section 3.3. Resource economics are discussed in Chapter 6.

TABLE 5-13: General characteristics of natural cast generators

	LMS 100	Frame SCCT	Recips	CCCT
New and clean capacity (MW)*	96	356	108	517
Average degraded heat rate (Btu/kWh)	8,930	9,135	8,453	6,232
Capital cost (2018$/kW)†	$1,154	$531	$1265	$906
CO_2 emissions (lb/MMBtu)	118	118	118	118

* The capacity value is the net new and clean value at 55 F. For recips, the value represents six units at 18 MW each.

† Based on a notice to proceed in 2018 and the new and clean net capacity at 55 F.

5.4.1 Combined Heat and Power

Combined heat and power (CHP) is a well-developed technology often associated with natural gas generators. Costs and operational characteristics for CHP are both site-specific and driven by customer economics and requirements. As such, PGE did not include CHP in portfolio analysis. According to a 2014 study by ICF International for the Oregon Department of Energy, by 2030, PGE and PacifiCorp service areas will have a cumulative CHP potential of 90.4 MW. Further detail on CHP was published in Appendix J of PGE's 2016 IRP.[145]

5.5 Pacific Northwest Transmission System

5.5.1 Pacific Northwest Transmission Background

The Pacific Northwest transmission system moves electricity from generation facilities located throughout the region to various load centers. Electric power systems require constant balancing of power supply, demand, and transmission capability. The Pacific Northwest transmission system is organized into Balancing Authority Areas (BAAs), including the PGE BAA, where system operators continuously balance electricity demands with generation while keeping power flows within specific limits to ensure reliable load service.

BPA owns and operates approximately 75 percent of the high-voltage transmission grid in the region, which consists of 15,000 miles of wires and 260 substations in eight states.[146] Figure 5-5[147] provides a graphical representation of the Pacific Northwest transmission system. The BPA system is segmented into the main BPA network, which is largely used to move power within the region, and large interregional transmission lines, referred to as interties, which provide users of the regional transmission system access to areas outside the Pacific Northwest region.

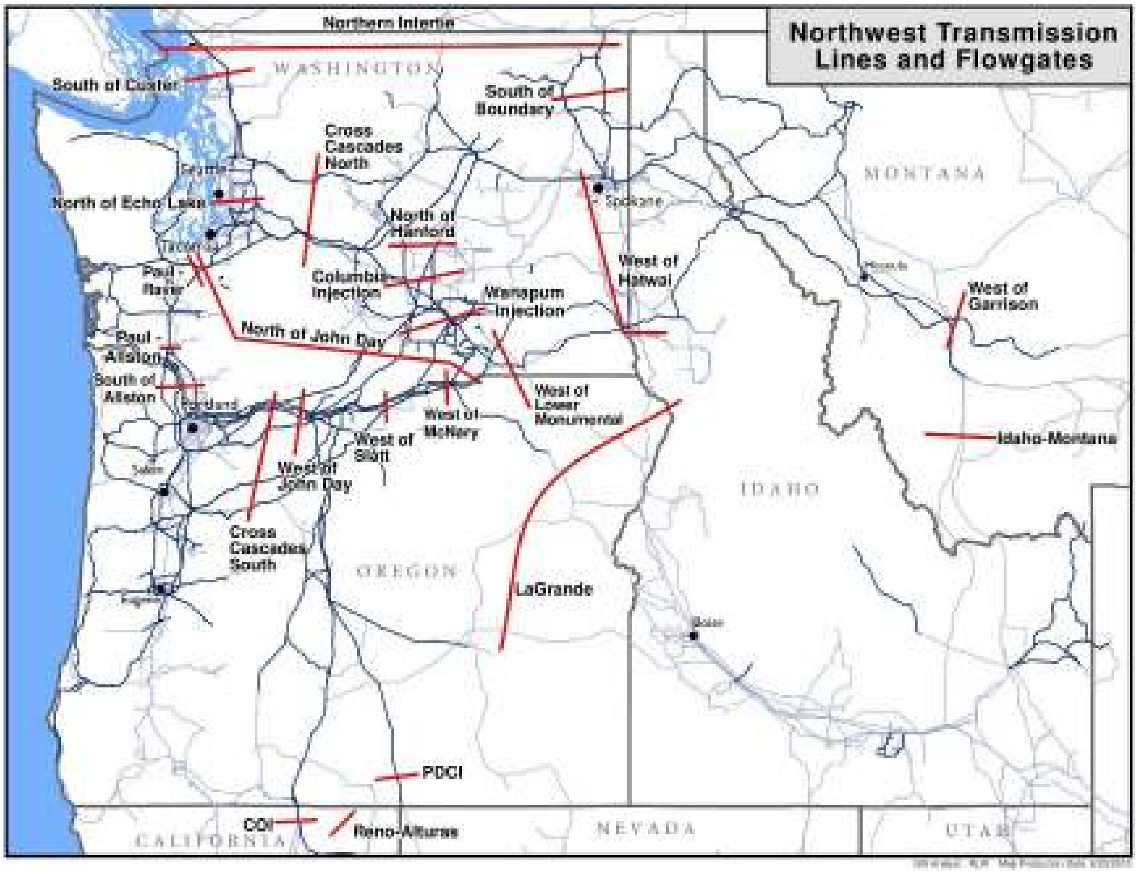
145 PGE's 2016 IRP, Appendix J. November 2016. https://www.portlandgeneral.com/our-company/energy-strategy/resource-planning/integrated-resource-planning/2016-irp.

146 BPA Facts, updated May 2018. Retrieved Apr. 19, 2019, from https://www.bpa.gov/news/pubs/GeneralPublications/gi-BPA-Facts.pdf.

147 BPA. (2015, June 23.) Flowgate Map. Retrieved Apr. 19, 2019, from https://transmission.bpa.gov/Business/Operations/Paths/Flowgate Map_2015-06-23.pdf

BPA has further divided its transmission system into flowgates.[148] The red lines shown above in Figure 5-5 represent the flowgates that BPA manages within its transmission system. Each flowgate has a capacity limit set using industry reliability standards and is actively monitored by BPA to ensure reliable and safe operation of the grid. BPA sets the total transfer capability (TTC) for the flowgate based on this capacity. As BPA transmission customers (including PGE) contract for scheduling rights impacting these flowgates, BPA performs a series of calculations to determine the remaining capacity on the path. That remaining capacity is referred to as available transfer capability (ATC). Many paths in the Pacific Northwest are constrained in the sense that there is little to no ATC to sell and the paths need to be monitored under certain operating conditions to ensure system operating limits are not exceeded.

FIGURE 5-5: Pacific Northwest transmission system with BPA flowgates



When offering transmission on its network, BPA evaluates how the proposed use of the transmission system will physically affect the flowgates using power flow studies. An individual transmission request can impact multiple flowgates due to the inherent electrical behavior of the transmission system. These requests can be limited or denied because of a single constrained flowgate.

[148] Flowgates are also referred to as cutplanes. BPA defines flowgates/cutplanes as follows: "Transmission lines and facilities owned by BPA on a constrained portion of BPA's internal network transmission grid or transmission lines and facilities owned by BPA and one or more neighboring transmission providers that are interconnected and the separately owned facilities are operated in parallel in a coordinated manner, and each of the owners has an agreed upon allocated share of the transfer capability." Retrieved Apr. 19, 2019, from https://www.bpa.gov/transmission/Doing Business/bp/tbp/Glossary-BPA-Transmission-BPs-V01.pdf, p.10.

Due to load growth and/or additional generation, use of the transmission system is likely to increase over time, increasing power flows through existing flowgates. These constraints present a growing challenge for PGE, as most of the current and potential future resources are located off PGE's system and are likely to require BPA transmission to reach PGE's system.

5.5.2 PGE Transmission Assets and Contracted Rights

The PGE service territory is a compact area located primarily in Oregon's Willamette Valley. PGE owns and operates its own transmission system and BAA to deliver energy to PGE's retail customers while also providing transmission service to other wholesale transmission customers as required by the Federal Energy Regulatory Commission and PGE's Open Access Transmission Tariff (OATT). Most of PGE's existing owned transmission assets are within the Utility's service territory. Within this service territory, as a transmission owner and transmission service provider, PGE has the obligation to plan, build, and operate the transmission system to ensure the reliable delivery of power needed to serve customer load as well as the needs of PGE's OATT transmission customers.

The PGE transmission and distribution system has 1,663 miles of lines (213 miles of 500 kV, 408 miles of 230 kV, 566 miles of 115 kV, and 476 miles of 57 kV) and includes 176 substations and switching stations. PGE's transmission system is interconnected with BPA's transmission system and PacifiCorp's West transmission system (PacifiCorp West). PGE is one of three co-owners of the AC Intertie, the primary transmission path between the Pacific Northwest and Northern California and is an owner of a portion of the Colstrip Transmission System, providing transmission service from the Colstrip plant in Montana westward into the main BPA system.

PGE's Marketing Function (PGEM) is responsible for obtaining the transmission service needed to serve PGE load and for scheduling the use of that transmission in the most efficient and economical manner to meet demand. The goals in managing PGEM's transmission portfolio are to:

- Ensure access to PGE's off-system resources.
- Ensure access to regional markets to allow PGE to meet load service obligations in a cost-effective manner while ensuring reliability and deliverability.
- Ensure power delivery during a 1-in-10 peak load event.

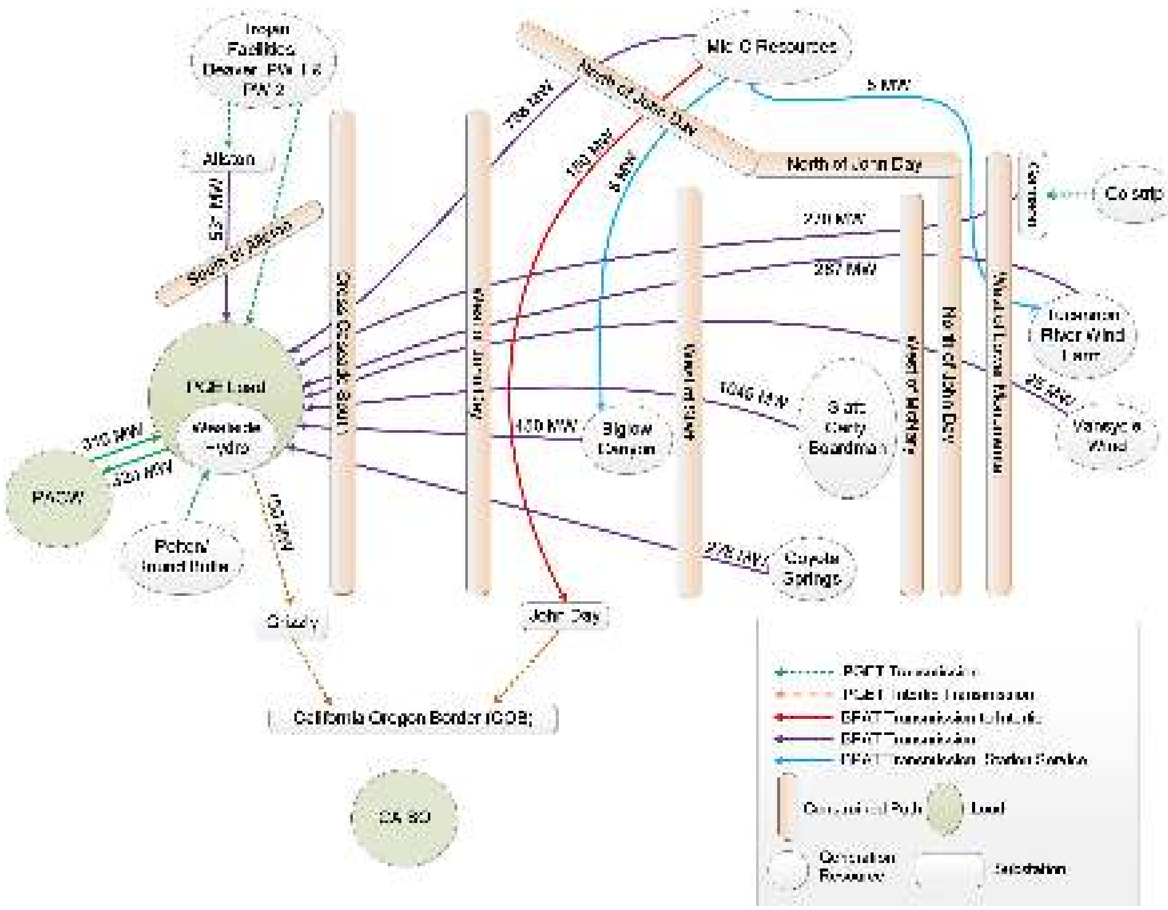
PGEM's transmission portfolio consists of capacity rights on the PGE system, the BPA system, and the AC Intertie and the Montana Intertie, enabling energy pathways into the Pacific Northwest. Due to the geographic location of PGE's service territory, most of PGE's generation resources are off-system. PGEM relies on BPA transmission rights to import power from these remote generation resources and to deliver power purchases to serve PGE's load. These off-system resources consist of thermal, hydro, wind resources, and various contracted generation. PGEM also holds additional transmission rights to access the Pacific Northwest Mid-Columbia (Mid-C) wholesale power hub, which PGE relies on for economic transactions, balancing load, and meeting peak demand. See Figure 5-6 for an overview of PGEM's transmission portfolio.[149]

[149] PGEM contracted transmission rights as of April 17, 2019. An additional 300 MW will be added to the portfolio associated with the Wheatridge Renewable Energy Facility upon commercial operation of the facility.

Figure 5-6 provides a snapshot of PGEM-contracted transmission scheduling rights to support the delivery of PGE-owned generation, power purchase agreements (PPAs), and market purchases. The tan bars in Figure 5-6 represent BPA-managed flowgates (as also referenced in Figure 5-5). Due to the flow-based nature of the interconnected grid, constraints on these flowgates create limits on flows to PGE's load centers, irrespective of where the source generation is located in BPA's system.

PGEM also uses its contracted transmission rights to access the Western Energy Imbalance Market (EIM) through PGE's interface with the PacifiCorp West BAA, and to access the California Independent System Operator markets (CAISO) BAA through the AC Intertie. Access to the EIM enhances PGE's ability to efficiently integrate variable resources on an intra-hour energy basis and to deliver least-cost energy supply to our customers.

FIGURE 5-6: Snapshot of PGE's market function transmission portfolio with generation resources and transmission



5.5.3 Transmission Uncertainties

The areas of uncertainty discussed in this chapter will be important considerations in PGE transmission system planning and PGEM's transmission portfolio management going forward. As the regional transmission and generation landscapes evolve, so too will PGE's approach to transmission planning and transmission portfolio management.

5.5.3.1 Transmission Constraints and Availability

Resource portfolios in the region have grown and shifted in response to increasing loads, the introduction of new large loads, and the rapid growth of variable energy resources. However, the delivery capabilities of the Northwest's transmission system in general have not kept pace with these changing demands. As a result, the region is experiencing congestion and uncertainties related to the availability of firm transmission during certain times of the year.[150] This situation is of growing concern to PGE, as many of the future resource alternatives being explored will be off-system and will generally require BPA transmission. The flowgates that currently have the largest impact on PGE's transmission portfolio are the South of Allston, West of John Day, and Cross Cascades South flowgates, which are seasonally constrained. Looking into the future, the specific location of a resource could result in other flowgates being impacted when delivering energy to PGE.

In 2018, BPA revisited its long-term ATC methodology as well as certain assumptions and practices that fed that analysis. This reassessment ultimately resulted in changes to ATC on certain flowgates.[151] BPA provides detailed information on its current ATC methodology on its website, as well as information on its efforts to improve the ATC methodology going forward. In addition, BPA provides extensive details on its resulting transmission availability and queue assessments.[152]

Figure 5-7[153] displays a snapshot view of the current TTC for several key BPA flowgates relative to the remaining long-term firm transmission (LTF) ATC, after accounting for existing contracted rights and all transmission requests in BPA's transmission queue. A negative quantity indicates that more transmission has been requested than is available for purchase.

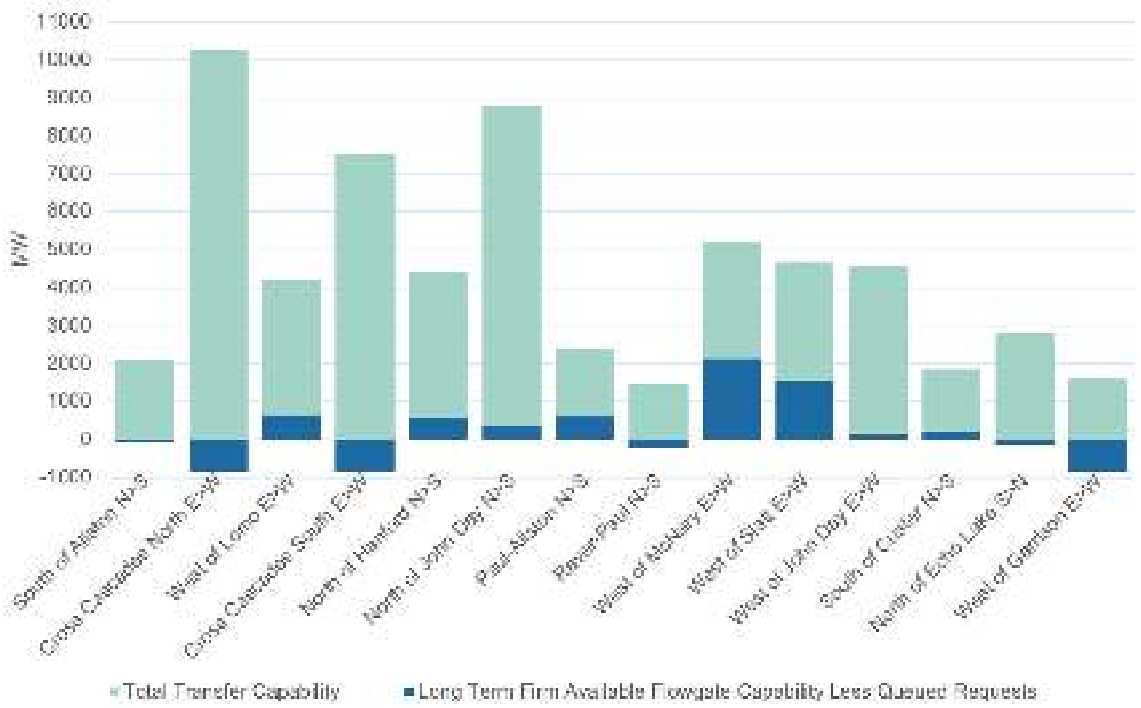
[150] See BPA efforts on the South of Allston Redispatch Pilot and North of Echo Lake Congestion management efforts. Retrieved May 15, 2019, from https://www.bpa.gov/transmission/CustomerInvolvement/Non-Wire-SOA/Pages/default.aspx and https://www.bpa.gov/PublicInvolvement/Cal/Pages/IndividualEvent.aspx?item=1064.

[151] BPA. (2018, May 31.) Commercial Assessment Update. Retrieved May 15, 2019, from https://www.bpa.gov/transmission/Doing%20Business/ATCMethodology/Documents/01.31.18-Commercial-Update-Final.pdf.

[152] BPA. (n.d.) Transmission Availability. Retrieved Apr. 19, 2019, from https://www.bpa.gov/transmission/Reports/TransmissionAvailability/Pages/default.aspx

[153] Retrieved Apr. 19, 2019, from https://www.bpa.gov/transmission/Reports/TransmissionAvailability/Documents/atc_less_pending.xls.

FIGURE 5-7: BPA's long-term firm transmission inventory by flowgate



This data as presented by BPA show that some key flowgates are commercially limited.[154] While some of these flowgates have direct impact on PGE's capability to serve load today, depending on the geographic location of future resources each of these flowgates could have important impacts on PGE's future operations. These constraints on BPA's system present a challenge to managing a portfolio of transmission rights to serve customers.

BPA system operators routinely take preventive actions to ensure that the capacity of its transmission system is not exceeded. These actions include (but are not limited to):

- The issuance of transmission loading relief resulting in the limiting or suspending of hourly non-firm and/or firm sales (including redirects).
- Re-dispatching generation facilities.
- Imposing restrictive reliability limits.
- When the above is insufficient, curtailing non-firm and firm transmission usages.

BPA has initiated and completed a variety of transmission system improvements over the last several years; however, the region is still experiencing transmission constraints during various times of the year. Additionally, BPA has signaled to the region they are shifting their approach away from utilizing new construction to meet changing transmission needs, and thus it is unlikely to see increases in the amount of ATC available for purchase.[155] PGE continues to engage in regional conversations regarding planning, expansion, and evolution of product offerings to enable active management of

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154 Data available at https://www.bpa.gov/transmission/Reports/TransmissionAvailability/Documents/LTF_Pending_Queue.xls and https://www.bpa.gov/transmission/Reports/TransmissionAvailability/Documents/atc_less_pending.xls (retrieved Apr. 19, 2019).

155 Retrieved Apr. 19, 2019, from https://www.bpa.gov/Projects/Projects/I-5/Documents/letter_I-5_decision_final_web.pdf.

the transmission portfolio to meet our reliability obligations while providing safe and cost-effective service for our customers.

5.5.3.2 Montana Transmission

Montana presents a potentially appealing location for siting wind generating facilities. Its high average wind speeds suggest generating facilities could have attractive capacity factors. Further, its geographic diversity relative to the current PGE wind portfolio and the seasonal timing of the generation could provide increased capacity contribution benefits compared to other locations. As directed by OPUC Order No. 18-044, PGE designed the structure of the 2018 Renewables RFP to allow for the potential participation of Montana wind resources.[156] Additionally, PGE actively participated in the Montana Renewable Development Action Plan (MRDAP) process[157] and shared findings at the Commission's IRP Transmission Workshop on December 18, 2018.

However, the future availability and cost of transmission from Montana to PGE's load remains uncertain, as does the future use of the existing transmission facilities needed to deliver power from Montana. PGE will continue to actively monitor the development of renewables in Montana and the resulting impacts on transmission.

5.5.3.3 Future Transmission Considerations

As PGE considers various resource options to meet future load service obligations, PGEM must evaluate its current portfolio and the transmission service needed to deliver power from resources to customers. A key element in evaluating resources is understanding the general location of generation resources in the region relative to the location of regional load centers, and the impact on the regional transmission system during peak loading events.

Long-term firm transmission plays an important role in PGEM's provision of service as it has the highest curtailment priority (and thus is the least likely to be curtailed), is available for procurement sufficiently in advance of delivery, provides certainty as an annual product, and gives PGEM the right to renew service for contract periods of five years or longer. Most other transmission products are unavailable for purchase more than 365 days prior to delivery with no certainty of availability, and no other BPA transmission products provide the assurance that transmission will be available for current or future use to support an underlying resource. PGEM will continue to rely on long-term transmission for reliably serving load. In addition, as BPA continues to evolve its long-term product offerings, PGEM will evaluate the costs and benefits of these products in its management of its transmission portfolio.

Operating a transmission system requires that PGE must serve peak loads reliably, minimize the operational cost and risks related to transmission constraints, and assure deliverability of resources for which PGE's customers have made a sizable investment. As detailed throughout the transmission section, the transmission landscape of the Pacific Northwest is in a dynamic state at a time when resource portfolios are shifting heavily toward renewable resources. Demand is also highly variable and can quickly change as new large loads materialize. Accordingly, PGE has begun to explore other

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[156] Retrieved Apr. 19, 2019, from https://apps.puc.state.or.us/orders/2018ords/18-044.pdf.

[157] Retrieved Apr. 19, 2019, from https://www.bpa.gov/Projects/Initiatives/Montana-Renewable-Energy/Pages/Montana-Renewable-Energy.aspx.

potential alternatives to address resiliency in congested areas, especially along key corridors and paths like the South of Allston flowgate. In doing so, PGE will continue to prioritize reliability, cost, risk, and decarbonization goals.

5.5.4 Transmission Modeling in the IRP

In this IRP, each portfolio incorporates the costs of transmission to deliver each generating resource to PGE's service territory. For modeling purposes, PGE assigns BPA tariff rates to future generation projects in the Utility's portfolio that require BPA transmission.[158] This assumes that off-system generation resources with the characteristics detailed in this chapter will have access to transmission at BPA rates. For Montana wind resources, PGE calculated transmission costs and losses by using information from the MRDAP as well as recent tariff filings from Puget Sound Energy and BPA. These costs are incremental to those associated with wheeling from BPA to PGE.

Assumptions about transmission cost and availability have been critical to both the operation and planning of PGE and other regional utilities. Accordingly, PGE is continuing to investigate holistic approaches that incorporate transmissions related assumptions into its long-term planning process and further identify how those assumptions could connect to future procurement or development of resources. PGE will continue to actively participate in regional stakeholder collaborations to best determine the intersection of transmission and long-term planning.

5.6 Emerging Technologies

Though PGE's analysis focused on resources considered to be commercially available within the timeframe of the action plan, a broad range of existing and emerging generation technologies were considered during the IRP roundtable process.[159] We continue to monitor the status of emerging technologies, particularly those that can contribute maintaining reliability and furthering our climate goals.

For this IRP we highlight three potential emerging technologies: a hydrogen energy economy, small-scale next generation nuclear, and hydrokinetic generators.

5.6.1 Hydrogen

Hydrogen is a highly volatile gas that is not found in pure form on Earth. It can, however, be produced from a variety of primary energy sources. The only combustion byproduct of hydrogen fuel is water, making it an attractive option for transportation, electricity generation, or as an intermediate storage medium. Currently, hydrogen is typically produced from natural gas, but it could also be made by electrolysis from water, in which case there may be little or no carbon emissions associated with the production and use of hydrogen.

The use of hydrogen to store renewable energy is of interest to the electric power industry. Electrolyzers could be used to convert water to hydrogen using surplus renewable electricity, providing both flexible demand and electricity storage. The resulting hydrogen could then be stored

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[158] In the IRP, battery storage systems are assumed to be operating in PGE's BAA and incur no transmission costs.

[159] PGE Roundtable 17-2 (2017, May 10). IRP Public Meetings. Retrieved from https://www.portlandgeneral.com/our-company/energy-strategy/resource-planning/integrated-resource-planning/irp-public-meetings.

and used as fuel in either transportation applications or electricity generation, making a significant contribution to economy-wide decarbonization.

While there are both cost and technological challenges to overcome for hydrogen production, transportation, and storage, countries such as Japan, Australia, and the Netherlands are initiating large-scale projects which will inform the feasibility of a hydrogen energy economy in the next 20 years. The HyStock[160] project located in the Netherlands is of particular interest as a pilot for power-to-gas hydrogen supply chain development. This implementation uses wind and solar electricity to produce hydrogen, which is then stored and transported through gas pipelines.

In the portfolio analysis for this IRP, PGE did not model either a flexible load for power-to-hydrogen or a hydrogen-fueled resource, but hydrogen was included in the Decarbonization Study in External Study A.

5.6.2 Small Scale Next Generation Nuclear

Nuclear energy is emissions-free and non-intermittent, but faces challenges with cost and waste disposal. Recent conversations related to nuclear in the West have primarily focused on research and development of small modular reactors (SMR). NuScale, a company focused on SMR technology that is based in Oregon, has recently partnered with Utah Associated Municipal Power Systems (UAMPS) and the Department of Energy (DOE) to pursue an SMR facility to be located at Idaho National Laboratory.[161] The project is expected to become operational in 2026.

Oregon state law prohibits the siting or construction of new nuclear plants until the U.S. Nuclear Regulatory Commission (NRC) approves an adequate repository for the disposal of high-level radioactive waste.[162] PGE's 2019 IRP does not, therefore, include nuclear as a resource option in portfolio analysis.

5.6.3 Hydrokinetic Energy

Hydrokinetic energy generators are devices that produce electricity from the movement of water, including ocean waves, currents, and in-stream energy production. While this technology is in the research-and-development phase and faces potential locational challenges (including permitting, operations, and transmission), it may provide the opportunity for carbon-free electricity with less intermittency than on-shore wind.

Oregon is a leader in research and testing of wave energy in the United States. Efforts to further develop and deploy hydrokinetic energy generators along the Oregon Coast increased after the Oregon Land Conservation and Development Commission adopted amendments to the Oregon Territorial Sea Plan on January 24, 2013. A critical amendment was the addition of a map designating potential areas for development of marine renewable energy. Oregon State University has partnered with the DOE and other stakeholders to build a wave energy test facility called PacWave located off

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160 Gasunie, *HyStock*. Retrieved Jul. 11, 2019, from https://www.gasunie.nl/en/expertise/hydrogen-theme/hystock.

161 DOE Site Use Permit DE-NE700065.

162 ORS 469.595

the Oregon Coast, between Newport and Waldport.[163] PGE will continue to monitor the developments in hydrokinetic energy in Oregon and throughout the country.

5.7 Utility and Third-Party Ownership

IRP Guideline 13 of OPUC Order No. 07-002 concerns resource acquisition considerations. It specifically requires an electric utility to "assess the advantages and disadvantages of owning a resource instead of purchasing power from another party."[164] The guideline does not suggest that differing ownership structures be distinguished within the IRP's portfolio modeling or Action Plan recommendations.

In this IRP, PGE proposes the acquisition of new resources to meet the Utility's energy and capacity needs. The IRP does not include recommendations regarding ownership structures, but does provide generic descriptions of the ownership options available, along with potential generic pros and cons of each option. The selection of a specific resource and specific ownership structure depends on numerous factors unique to the proposed resource, including, but not limited to, the project development maturity, resource performance, resource pricing, and counterparty capability. Those specific resource considerations are generally only defined through responses to requests for proposals and not made available for study within the IRP. Accordingly, PGE uses a comprehensive approach within the RFP process to assess the risks and benefits of specific utility-owned and contracted resource offers as required by the Competitive Bidding Rules.

Consistent with Guideline 13, in the following sections PGE discusses the risks and benefits associated with resource ownership, as well as third-party delivered PPAs, capacity purchases and tolling agreements. This section also provides a summary of relevant modifications to the Competitive Bidding Rules in recent years.

5.7.1 Benefits of Utility Resource Ownership

Utility-owned resources offer a number of benefits to PGE's customers. Utility-owned resources can be fully controlled and utilized to the benefit of PGE's customers, operations are aligned with the customer's long-term interest, their costs can be shared with existing resources, their financing costs are reduced through access to capital markets, and their ownership allows for long-term access to valuable resources.

Utilization

Utility-owned resources can be fully controlled and utilized for PGE's customers. The limitations on a utility-owned plant's performance and operation are generally defined by the operating limits of the facility as opposed to any contractual structures imposed by a third-party owner. The ability to fully utilize a resource provides the opportunity to secure the maximum asset value on behalf of PGE's customers.

The ability to fully and freely operate a facility is of importance when market conditions and operation strategy change. For example, when PGE entered into the Energy Imbalance Market, PGE

[163] PacWave. (n.d.) Retrieved May 15, 2019, from http://pacwaveenergy.org/.

[164] *In the Matter of an Investigation Into Integrated Resource Planning*, Docket No. UM 1056, Order No. 07-002 (Jan. 8, 2007).

was able to bid its owned resources into the marketplace without accounting for contractual constraints associated with legacy contracts. When procuring a resource, PGE will make a number of assumptions regarding market structure, economic scenarios and resource operation. However, should the future differ significantly from those assumptions, a utility-owned resource may continue to be operated in the best interest of customers, whereas a third-party owned resource may continue to be operated as was originally agreed in the structured contract. This difference is of particular importance for new technologies, such as battery energy storage, as the optimal use case may not be fully appreciated at the time a long-term contract is executed.

Operational Alignment

Utilities generally control the operation of utility-owned resources. As such, there exists natural alignment between the facility's operation and PGE customers' interests. Changes in operation, maintenance practice, or maintenance investment can be made if determined to be in the customer's best interest. The alignment of a utility-owned resource's operation with customer interest provides valuable protections to PGE's customers.

Synergies with Existing Resources

A utility-owned resource may benefit from co-location to utilize existing infrastructure. Co-location can reduce costs and minimize the footprint of a new generating project. For example, PGE built the Port Westward Unit 2 project at the existing Port Westward site, and the project did not require new roads or other infrastructure other than the new plant and minimal facilities. Furthermore, the resources associated with operations and maintenance can be shared across multiple utility-owned resources, providing another beneficial opportunity to reduce costs while improving overall service.

Financing

Utilities, including PGE, generally maintain relatively low debt-to-total-capital ratios and strong credit ratings. As a result, utilities are well positioned to raise capital to develop and construct a project as needed. The ability to raise capital at a reasonable cost provides increased certainty that, if an offer for a utility-owned resource is selected, the development will go forward to completion.

Long-Term Access to Resources

Utility ownership provides long-term access to generation resources, which can provide important value to utility customers. For example, substantial renewable energy generation value is associated with the specific project location. In the case of wind or solar resources, prime sites undergo development first, and resource owners often select these sites based upon site-specific factors critical to the value of the resource, such as wind speed. Utility ownership generally creates the opportunity to continue to generate at the specific project location, even after reaching the end of original equipment design life. In contrast, if a utility purchased power from a third-party, long-term access to the specific project location is limited by third-party willingness to continue marketing a resource to PGE. Utility ownership mitigates this risk by allowing the utility to maintain long-term access to valuable resource sites and generally allows for the utility to make life extension improvements, modify plant performance, and use the site for future resources, all for the benefit of PGE's customers.

5.7.2 Risks Associated with Utility Ownership

The risks associated with utility ownership relate to unexpected costs and the absence of a third-party owner to absorb some risk. Costs associated with a utility-owned project may differ from original forecasts. Should project costs be greater than forecast then PGE and its customers will experience an elevated cost. This can differ from a contracted resource, as a third party generally charges PGE's customers a cost-plus price to earn a profit while covering the risk of project underperformance. A utility-owned resource generally does not incur any margin above actual plant expenses and a fair and reasonable return on capital expenditures. As such, there is a risk that costs exceed original forecasts. However, this risk is balanced by the likelihood that cost outcomes outperform original project forecasts and customer costs are lowered. The benefits of lower-than-forecast costs are not experienced with a third-party owned project.

Project performance risk can often be effectively mitigated. Attention toward equipment selection, project siting, and a well-developed EPC plan address the bulk of risk prior to commercial operation. Utilizing plant operator experience, employing preventative maintenance plans, and managing relationships with local distribution and transmission system operators further manages risk following commercial operation. A utility can also minimize energy output risks to it and its customers by negotiating effective performance guarantees and warranty and maintenance provisions in equipment supply, maintenance, and EPC agreements.

5.7.3 Third-Party Ownership and Contracting

Resources can also be owned by third parties and made available to PGE through contract. Common contracts include power purchase agreements, capacity purchases, and tolling agreements. The contracts have a variety of terms and conditions, including the product delivered, delivery contingencies (e.g., firm or unit-contingent), pricing (fixed and/or index), and delivery location.

5.7.4 Benefits of Third-Party Ownership

Contracts like PPAs require one party to provide physical power to another party, in this case PGE. Third-party ownership provides benefits to PGE's customers through the sharing of project risk. The primary risks borne by a third-party are construction risks and operating risks. Subject to the terms of the agreement, the third-party power producer bears some of the risk associated with construction of the project. This assumption of risk reduces a risk that may be assumed by a utility and its customers. Third-party power suppliers also generally bear the operating risks associated with the power project, particularly if the resource does not meet specific availability or performance targets.

5.7.5 Risks Associated with Third-Party Owned Resources

A major risk associated with a third-party owned resource is the commitment to a specific contractual arrangement through the duration of the contract term. Signing a contract locks PGE into a specific arrangement for the term of the contract. If policy, regulation, market, or any other changes occur, PGE cannot modify the contract without mutual agreement. For instance, future carbon legislation or market organization changes could significantly change how PGE would want to operate its resources. However, contracts for third-party owned resources may not allow for such changes.

Third-party owned resources also introduce counterparty risk and balance sheet risks. In response to the energy crisis of the early 2000s and reinforced by the recent turmoil in the financial markets, most long-term PPAs incur imputed debt and margin requirement costs. Additionally, recent changes to accounting standards require that the future cash flow commitment of some PPAs be reflected as direct debt. The risk of direct or imputed debt is important because credit rating agencies can compare the risk of default for different companies normalized for their choices to build or enter a PPA. As a result, PPAs typically reduce PGE's financial flexibility and increase the utility's borrowing costs.

Margin requirements are a standard feature within most fixed price PPAs. This feature serves to protect both PGE and the seller from the likelihood of default when market prices move materially from the negotiated fixed price of the PPA. When market prices depart from the negotiated contract price, the contracting counterparties are exposed to counterparty default. Margin requirement clauses could require the seller or buyer to post cash collateral or a letter of credit that would incur costs for PGE and its customers. Both direct and imputed debt and margin requirements reduce the total benefit of PPAs. PPAs add to the liability side of PGE's balance sheet without any of the benefits of ownership, thus generally raising PGE's cost of debt.

5.8 Competitive Procurement Process

Over several years, the OPUC opened multiple dockets to address the competitive procurement process in Oregon, and specifically considered the diversity of resource ownership opportunities.[165] Through Docket AR 600, the OPUC, Staff, and interested parties worked to create rules that would "[p]rovid[e] for the evaluation of competitive bidding processes that allow for diverse ownership of renewable energy sources that generate qualifying electricity."[166] In Order No. 18-324, the OPUC adopted new competitive bidding rules designed to "complement the integrated resource planning (IRP) process."[167]

Through the IRP process, we make no recommendation as to ownership structures for our identified resource needs because we believe that an RFP docket is the appropriate place to address the issue. Further, PGE believes that a robustly designed RFP, conducted pursuant to Division 89, will provide the best opportunity to access the varied resource technology and offer structures available in a competitive market, allowing us to seek out the options that will bring the best value for customers. As we consider future resource acquisitions, we will objectively weigh the benefits and risks of the various ownership structures, considering the bids received during the RFP process, and ensure compliance with the Commission's competitive bidding rules for electric companies.

In compliance with OAR 860-089-0250, Appendix J provides details on the RFP design and modeling methodology PGE intends to use for a future Renewable RFP.

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165 *In the Matter of an Investigation Regarding Competitive Bidding*, Docket No. UM 1182, Order No. 14-149 (Apr. 30, 2014); see also *In the Matter of Rulemaking Regarding Allowances for Diverse Ownership of Renewable Energy Resources*, Docket No. AR 600, opened May 20, 2016; and *In the Matter of an Investigation of Competitive Bidding Guidelines Related to Senate Bill 1547*, Docket No. UM 1776, opened May 20, 2016.

166 Senate Bill 1547 (2016) at ORS 469A.075(A)(d).

167 Codified at Chapter 860, Division 89 (Resource Procurement for Electric Companies) of the Oregon Administrative Rules. See OAR 860-089-0010.

CHAPTER 6. Resource Economics

As described in Chapter 2. Planning Environment, many of the key factors influencing resource economics are rapidly evolving. This chapter shows how technological advancements and changing market dynamics are expected to impact both the costs and the benefits of our candidate resource options in the future. Specifically, we show why we expect renewable resources to be the most cost-competitive energy resource options available and how the relative costs and benefits of new technologies such as battery storage are highly uncertain over the 2019 IRP Action Plan period. This chapter describes the relevant costs associated with each resource, summarizes resource benefits or value, and compares net cost impacts across the resource options by considering costs and benefits together.

Chapter Highlights

- ★ Resource economics are compared across clean and renewable technologies as well as conventional resources. The relative economic performance of resources varies widely depending on future technology costs and market conditions.
- ★ The levelized cost of energy (LCOE) from new wind resources is expected to be below the LCOE of a combined-cycle combustion turbine (CCCT) in the Reference Case and in most futures, due in part to the cost savings associated with federal tax credits.
- ★ The net cost of wind resources (levelized costs net of capacity and energy value) is negative in the Reference Case and most of the futures, indicating that renewable resources are likely the lowest cost option for securing long-term energy.
- ★ The relative economics across capacity resources (including thermal and storage) are uncertain due to rapidly dropping battery costs and uncertainty in future wholesale market conditions. In some futures, batteries are expected to be cost-competitive with traditional thermal resources in the near future.

6.1 Resource Costs

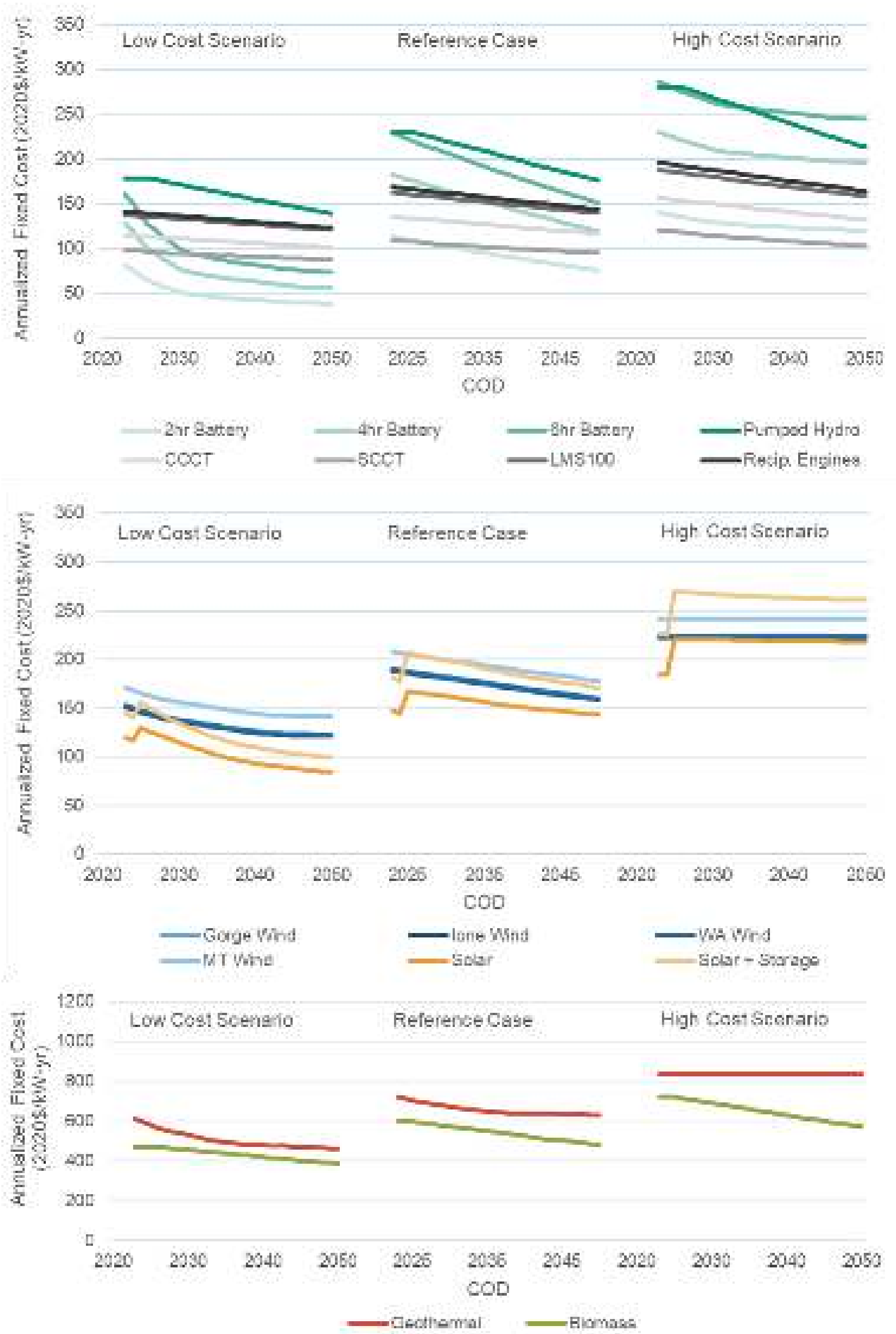
In evaluating the cost of resources, the IRP considers fixed costs, which are driven by the installed capacity of a given resource and are not affected by how the resource is operated, and variable costs, which depend on resource operations in each year. Both categories of costs are described below.

6.1.1 Fixed Costs

Fixed costs for new resource options in the 2019 IRP consist of fixed capital carrying costs and fixed operating costs. Fixed capital carrying costs include book and tax depreciation, required return, property tax, and federal and state income tax. Fixed operating costs comprise fixed operation and maintenance costs, fixed wheeling costs, and fixed fuel transportation cost. Fixed cost calculations are based on resource-specific data provided by HDR Engineering, Inc. in External Study D. Characterizations of Supply Side Options, and PGE-specific assumptions, including cost of capital, long-term inflation, and taxes.

Fixed costs for new resources are incorporated into portfolio costs by applying the annualized fixed cost (in 2020$/kW-yr) for each year in which the resource is included in the portfolio. Annualization of fixed costs occur over the full economic life of each resource. Annualized fixed costs are specified by resource vintage (commercial operation date [COD]) to capture the effects of capital cost declines and other time-varying parameters. For each technology, the 2019 IRP analysis examines three different capital cost scenarios (low, reference, and high), which capture uncertainties in both present-day costs and future cost declines. The five technology cost futures, as described in Section 3.3 Technology Cost Uncertainties, are generated from combinations of the three capital cost scenarios shown in Figure 6-1.

FIGURE 6-1: Fixed cost scenarios for new resource options



6.1.2 Variable Costs

PGE estimates annual dispatch and variable costs for new resource options through 2050 using an Aurora hourly simulation of loads and resource dispatch within a single zone that represents the PGE portfolio. This PGE-Zone simulation employs optimal commitment and dispatch algorithms in Aurora to identify the hourly dispatch of each resource against market prices determined by the WECC-wide pricing Aurora simulation for the Oregon West pricing zone (see Appendix I. 2019 IRP Modeling Details for more information), while meeting all resource-specific constraints.[168] Variable renewables are treated as "must-run" and subject to hourly availability constraints. For storage resources, key operational parameters include power capacity (in MW), storage capacity (in MWh), and roundtrip losses. The new resource total variable cost includes variable O&M, fuel costs, emissions costs, and start-up costs.

Table 6-1 summarizes both the levelized capacity factor and corresponding levelized variable costs for each resource option (excluding storage) under the Reference Case over the economic life of each resource option (with COD 2023). Variable cost impacts of the production tax credit are excluded from the table but included in total resource costs. Costs associated with charging energy storage resources are excluded from the levelized variable costs and are instead accounted for as a reduction in the energy value described in Section 6.2.1 Energy Value. Annual simulated variable costs are incorporated into portfolio costs for each year in which a resource is included in the portfolio.

The table also lists the range across Market Price Futures based on the upward and downward semi-deviations relative to the Reference Case. Capacity factors and variable costs vary over time and scenario for dispatchable resources and are in some cases highly sensitive to future market price conditions. For example, the capacity factor of the combined-cycle combustion turbine (CCCT) is significantly lower in several futures than it is in the Reference Case, indicated by the asymmetrical uncertainty bounds. The performance of the CCCT is negatively impacted (resulting in lower capacity factors) in the High Renewable WECC Future, where renewable deployment drives more extreme price depression and volatility over time. In contrast, the simple-cycle combustion turbine (SCCT) capacity factor is significantly higher than it is in the Reference Case in these futures because the unit dispatches during the more frequent, though short duration, high-priced periods. Variable cost uncertainty for the dispatchable thermal resources is primarily driven by fuel and carbon price uncertainty across the futures.

[168] For thermal resources, these constraints include minimum up and down times, minimum capacity, ramp rate, maintenance schedules, and forced outages.

TABLE 6-1: Levelized capacity factors and variable costs for new resource options (2023 COD)

	Capacity Factor		Levelized Variable Cost (2020$/MWh)	
	Reference Case	Range*	Reference Case	Range*
Gorge Wind	40.8%	-	$0.00	-
Ione Wind	32.7%	-	$0.00	-
WA Wind	42.9%	-	$0.00	-
MT Wind	42.9%	-	$0.00	-
Central OR Solar	24.8%	-	$0.00	-
Solar + Storage	24.2%	-	$0.00	-
Geothermal	92.2%	-	$2.49	-
Biomass	91.1%	-	$50.22	-
CCCT	74.7%	51.7% - 75.4%	$41.68	$30.37 - $59.92
SCCT	1.3%	0.8% - 9.2%	$61.77	$45.69 - $90.33
LMS 100	6.5%	3.9% - 12.7%	$56.21	$41.73 - $83.00
Reciprocating Engines	12.1%	8.1% - 15.7%	$54.69	$39.95 - $78.91

*Ranges reflect upward and downward semi-deviations around the Reference Case across the Market Price Futures. Renewable resources are treated as "must-run" in all scenarios, and thus have no range of capacity factors.

6.1.3 Integration Costs

PGE's IRPs have included estimates of the costs associated with the self-integration of wind generation since 2009. A history of the process for the development of integration cost estimates is detailed in Section 7.2.1 Wind of PGE's 2016 IRP. Consistent with previous IRPs, the 2019 IRP estimates integration costs using PGE's Resource Optimization Model (ROM), a multi-stage commitment and dispatch model that uses mixed integer programming implemented with General Algebraic Modeling System (GAMS) programming and utilizing the Gurobi Optimizer. ROM simulates the variable costs associated with meeting load over the course of a single year, including fuel costs, variable operations and maintenance costs, startup costs, and costs and revenues associated with market interactions. More detail about ROM can be found in Section I.5 Resource Optimization Model (ROM). The integration cost is calculated by dividing the system cost difference between the cases in which additional renewables are included and the base case by the additional renewable output. In the 2019 IRP, PGE estimates renewable integration costs for 100 MWa of wind and solar resources based on a 2025 test year (see Table 6-2).

In addition to calculating integration costs, the analysis yields curtailment statistics for candidate renewable resources. High production from renewable resources can result in periods of time where the system has an oversupply of renewable energy, which may be curtailed. Curtailment may occur for economic or operational reasons, and the cost and amount of curtailment depends on a variety of factors including market prices, system conditions, and resource constraints. Within ROM's simulation of the PGE system, curtailment of renewable resources is allowed at no additional cost so that the integration costs described above incorporate any cost savings associated with dynamic renewable curtailment to provide flexibility to the system (or, flexibility value). If renewable resources were not allowed to curtail in the simulations, we would expect the renewable integration costs to be higher than those listed in Table 6-2. The assumption of zero cost curtailment in these simulations may also slightly overestimate the benefits of renewable curtailment, particularly for wind resources that must forego the production tax credit to curtail. The simulated curtailment over the course of model year 2025 is listed for of the variable renewable resources in Table 6-3.

TABLE 6-2: Renewable integration costs for new renewable resource options

	Renewable Integration Cost (2020$/MWh)
Gorge Wind	0.33
Ione Wind	0.33
MT Wind	0.07
WA Wind	0.31
Central OR Solar	1.36
Solar + Storage	0.00
Geothermal	0.00
Biomass	0.00

TABLE 6-3: Renewable curtailment statistics

	Renewable Curtailment in 2025 (MWh/%)
Gorge Wind	1,851/0.04%
Ione Wind	1,851/0.04%
MT Wind	790/0.02%
WA Wind	1,842/0.04%
Central OR Solar	645/0.01%

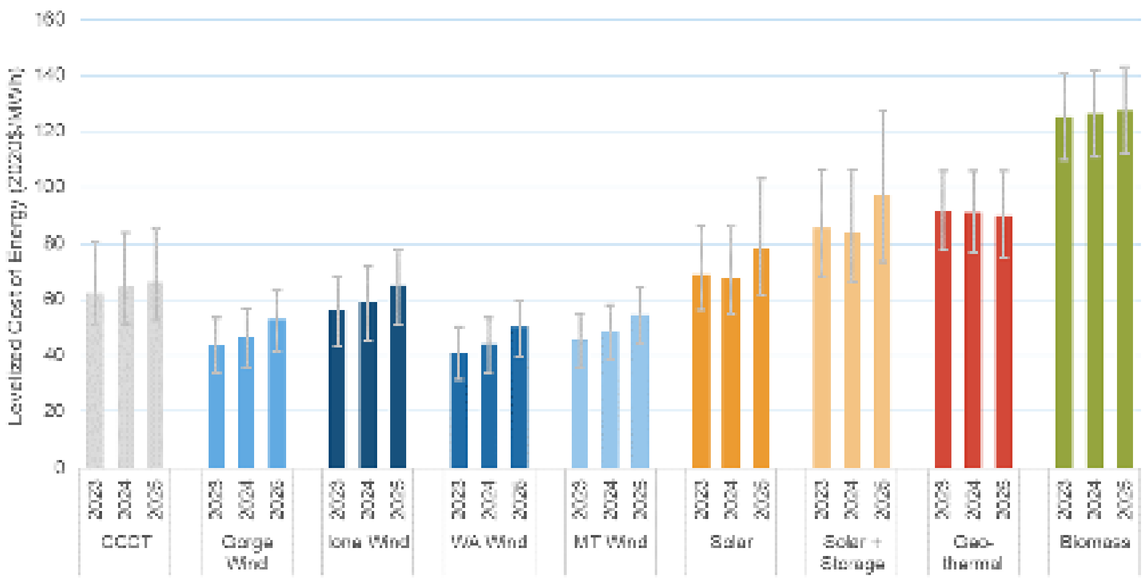
Actual renewable curtailment may vary in a given year depending on several factors, including load levels, renewable output, hydro conditions, and transmission constraints. The observed level of flexibility-driven curtailment in this analysis does not materially impact the near-term economics of renewable resources. However, continued renewable additions in future years could increase the likelihood of renewable curtailment. PGE will continue to evaluate the potential for renewable curtailment in future IRP cycles.

6.1.4 Levelized Cost of Energy

The levelized cost of energy (LCOE) is a $/MWh metric often used to compare cost across energy resources. It represents the sum of fixed, variable, and integration costs, net of federal tax credits, levelized across the economic life of the resource, then divided by the levelized annual energy generation over the same period. The LCOE is an imperfect metric, failing to account for the value provided by energy resources and providing little useful insight into resources that are primarily used to provide capacity, such as peaking plants and energy storage resources—the capacity resource options. Nevertheless, the LCOE can be useful for comparing costs of energy resources on a consistent basis, particularly renewables. The LCOEs of the resource options that predominantly provide energy to a portfolio—the energy resource options—are shown in Figure 6-2 based on COD. This analysis suggests that, strictly based on LCOE, wind resources may provide the lowest cost energy compared against other energy resources including CCCTs. It also indicates that cost uncertainty is relatively large compared to the cost differences between energy resource options, highlighting the importance of preserving flexibility in technology, resource type, and location in competitive solicitations seeking renewable resources.

The LCOE also highlights the benefits of near-term renewable action to qualify for federal tax credits. The LCOE of wind increases between 16 and 22 percent from 2023 to 2025 due to the expiration of the federal production tax credit (PTC) and the LCOE of solar and solar + storage increases 16 percent from 2024 to 2025 due to the step down of the federal investment tax credit (ITC). For both wind and solar, resources are assumed to come online on December 31st of the year prior to the listed COD to qualify for tax credits.

FIGURE 6-2: Levelized cost of energy (LCOE) of energy resource options



6.2 Resource Value

In addition to resource costs, the value that resources bring to the system factors heavily into portfolio performance. Resource values that are explicitly incorporated into portfolio analysis include energy value and flexibility value. Other sources of value are implicitly included in portfolio evaluation through portfolio construction. For example, renewable resources that offset the need for additional capacity resources to meet resource adequacy needs implicitly bring capacity value to a portfolio. Unlike energy and flexibility value, this capacity value is not subtracted from portfolio costs as a line item but is instead reflected through the reduced cost of procuring capacity resources for the portfolio. In this section, we describe the value streams associated with each resource regardless of whether they are included explicitly or implicitly in portfolio costs.

6.2.1 Energy Value

The energy value for each resource option represents the market revenues or the value of avoided market purchases when the resource dispatches. This value is calculated by Aurora in the PGE-zone simulation described above in Section 6.1.2 Variable Costs. The energy value varies widely across Market Price Futures and varies over time as market prices, fuel prices, and carbon prices change. The levelized energy value over the economic life of each resource option (with COD 2023) is listed in Table 6-4 below. Upward uncertainty in energy values are very large for the peaking resources and energy storage due to the high market price volatility in the High Renewable WECC Future. The high energy values in this future reflect the value of avoided market purchases during frequent high-priced periods.

TABLE 6-4: Energy values for new resource options (2023 COD)

	Levelized Energy Value (2020$/MWh)	
	Reference Case	Range*
Gorge Wind	$44.87	$31.03 - $59.03
Ione Wind	$44.79	$30.85 - $58.83
WA Wind	$46.51	$32.35 - $61.02
MT Wind	$47.39	$32.83 - $61.98
Central OR Solar	$39.97	$24.63 - $56.69
Solar + Storage	$40.61	$26.62 - $57.72
Geothermal	$47.83	$32.97 - $62.29
Biomass	$47.98	$33.13 - $62.51
CCCT	$51.54	$38.42 - $75.43
SCCT	$66.71	$51.53 - $124.12
LMS 100	$60.55	$46.44 - $112.26
Reciprocating Engines	$59.56	$45.11 - $106.43

	Annualized Energy Value (2020$/kW-yr)	
	Reference Case	Range*
2-hour Batteries	$5.32	$4.15 - $35.03
4-hour Batteries	$9.77	$7.67 - $54.03
6-hour Batteries	$12.35	$9.68 - $64.78
Pumped Storage	$7.15	$5.58 - $78.39

*Ranges reflect upward and downward semi-deviations around the Reference Case across the Market Price Futures.

6.2.2 Flexibility Value

The 2019 IRP introduces flexibility value, a new component of PGE's economic analysis that captures the value of providing flexibility to the system by responding to forecast errors, enabling fast ramping, and meeting reserve requirements. The potential value associated with these capabilities was explored in the 2016 IRP evaluation of energy storage resources and is expanded in the 2019 IRP to more holistically account for the flexibility provided by all dispatchable resource options within portfolio analysis.

Flexibility values of new resources are estimated using ROM simulations of the PGE system. When additional resources are added to the system, the new resource can be used to serve load and avoid higher-cost market purchases as well as enable the re-dispatch of existing resources to meet flexibility requirements on the system (ramps and reserve requirements) at lower cost. Because the dispatch of each resource in the Aurora PGE-zone simulation does not account for these flexibility-related requirements, the incremental value identified in the ROM simulation that is not attributable to a resource's energy value is collectively referred to as its flexibility value. Flexibility value therefore encompasses multiple operational value streams, including load following, regulation, spin, non-spin, and renewable integration (including both ramping and forecast error mitigation).

For each new resource option, flexibility value is calculated by subtracting the market revenues associated with dispatching the resource from the total system cost savings achieved by including the resource in the portfolio and dividing by the resource addition size. PGE's estimates of flexibility values for new resources based on a 2025 test year are summarized in Table 6-5. Flexibility value is largest for energy storage resources, which can ramp rapidly from full discharge to full charge.[169] The difference in flexibility value between storage resources does not appear to be significantly impacted by duration, suggesting that most flexibility value is associated with flexibility constraints on short time scales (that is, less than two hours). This finding is largely consistent with PGE's prior efforts to characterize the operational value of energy storage.

TABLE 6-5: Flexibility values of new dispatchable resource options

	Flexibility Value (2020$/kW-yr)
Solar + Storage	-
2-hour Battery	$23.73
4-hour Battery	$28.10
6-hour Battery	$29.43
Pumped Storage	$25.95
CCCT	$8.40
LMS 100	$8.87
Reciprocating Engines	$9.19
SCCT	$4.82

169 In this analysis, minimum generation and minimum pumping levels for pumped storage are neglected. PGE aims to incorporate these constraints into future analyses of pumped storage resources, as applicable.

6.2.3 Capacity Value

Resource capacity value is incorporated into portfolios by requiring each portfolio to meet capacity needs with resource additions, based on the capacity contributions of each technology. For example, when a wind resource is included in a portfolio, the amount of capacity that needs to be provided by adding other resources is reduced by the capacity contribution of the wind resource.

The capacity contribution values for individual resources were calculated for the Reference Case using the Renewable Energy Capacity Planning (RECAP) model, maintaining consistency with the methodology used to calculate capacity need.[170] The capacity contribution is expressed as the MW reduction to the amount of conventional capacity needed to achieve the annual reliability target.[171] This is divided by the size of the resource addition to calculate the ELCC value (effective load carrying capability). For example, if 100 MW of wind reduced the need for conventional capacity by 27 MW, the ELCC of the wind addition is 27 percent.

Figure 6-3 shows the ELCC values for four wind resources based on incremental additions of 100 MW. The locations with generation profiles that better align with the capacity need profile have higher contributions. All locations exhibit a declining contribution as the addition size grows because the remaining capacity need is less aligned with the generation profile.

FIGURE 6-3: Marginal ELCC for wind resources

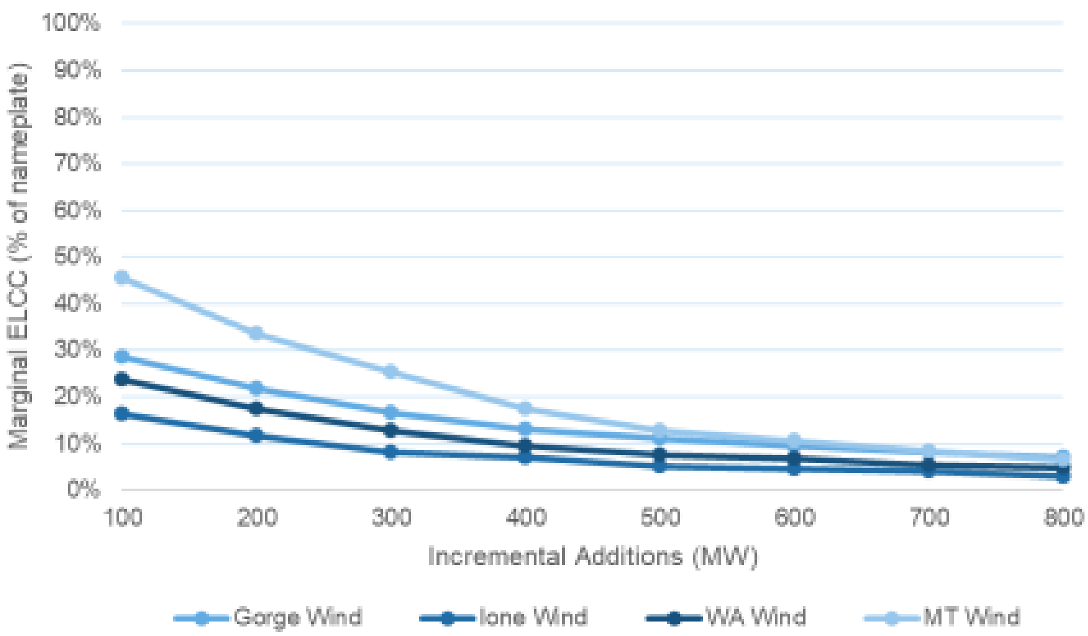


Figure 6-4 shows the ELCC values for solar and for solar + storage. These also show a declining marginal value, though the storage reduces the rate of decline for solar + storage.

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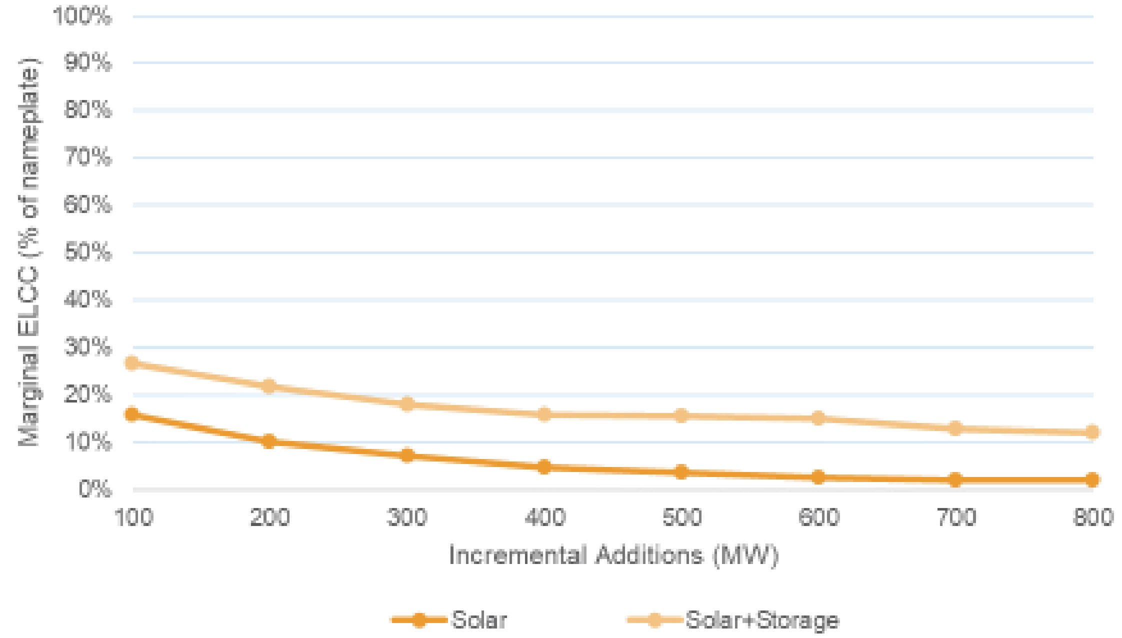
170 The RECAP model is discussed in Appendix I. 2019 IRP Modeling Details and the capacity need assessment is discussed in Section 4.3 Capacity Adequacy. In some cases, where numerical noise has been observed, ELCC curves have been smoothed to ensure non-increasing marginal capacity contributions.

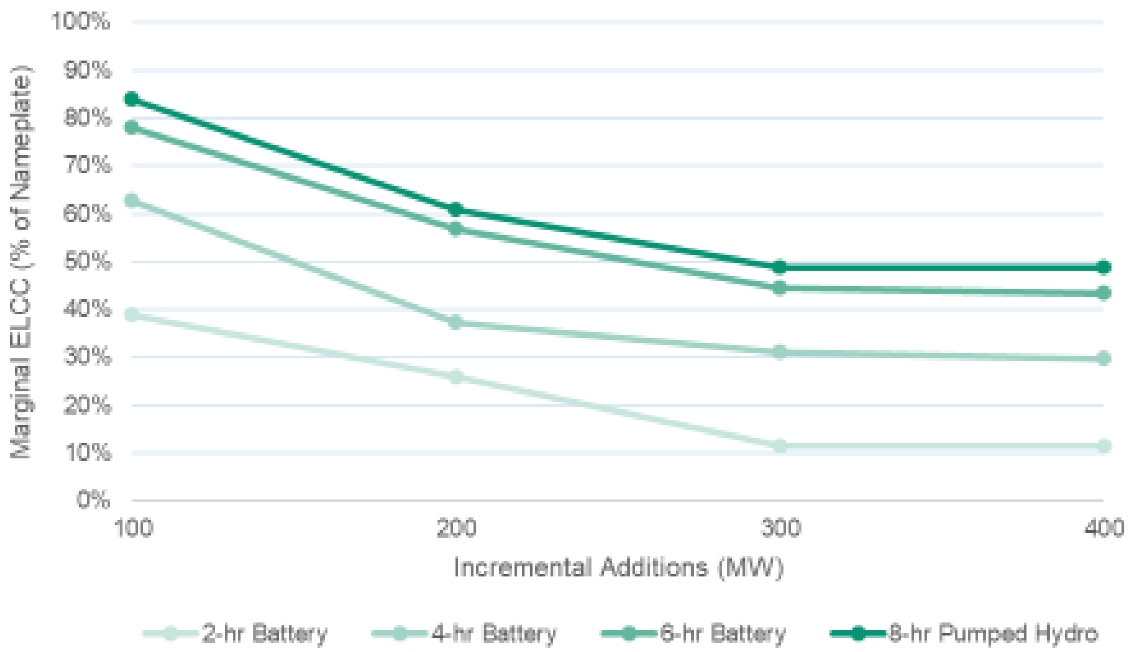
171 As discussed in Section 4.3 Capacity Adequacy, the conventional capacity in RECAP is a 100 MW unit that has a 5 percent forced outage rate.

FIGURE 6-4: Marginal ELCC for solar resources



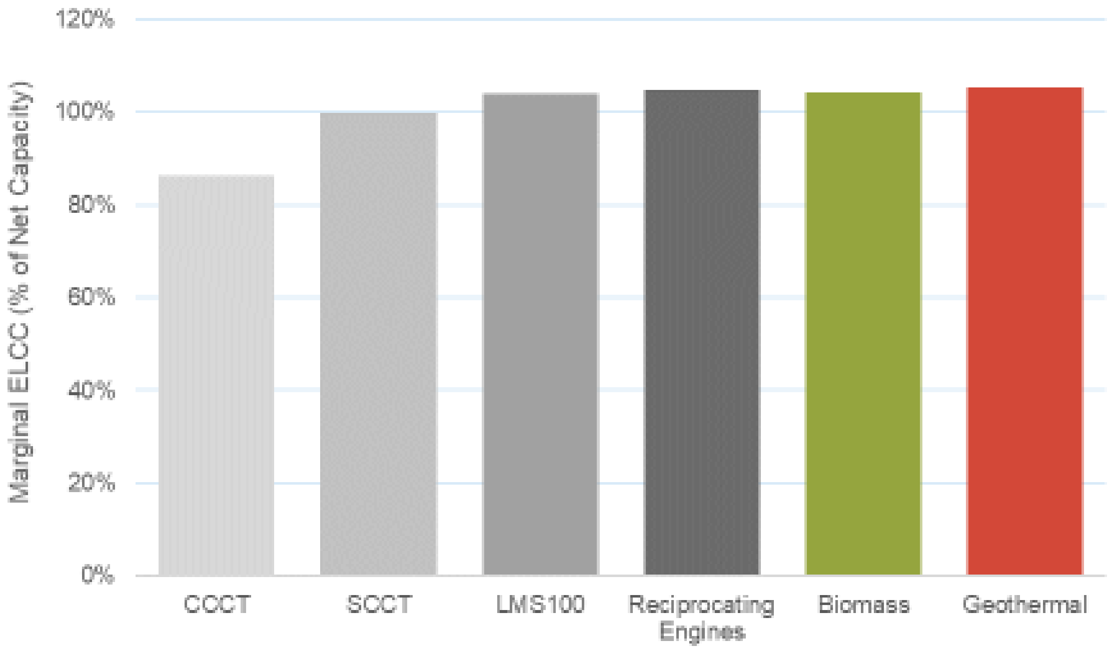
ELCC values were calculated for the four types of storage examined in this IRP. Figure 6-5 shows a higher contribution for resources with longer durations. As with wind and solar, storage resources have a declining marginal value. With each addition, the remaining need becomes less “peaky,” reducing the capacity contribution for the next increment. Additional discussion of storage capacity contribution is provided in Appendix I. 2019 IRP Modeling Details.

FIGURE 6-5: Marginal ELCC for storage resources



For thermal resources, the capacity contribution is impacted by the unit size, seasonal profile, and forced outage rate. A resource may have a capacity contribution that is greater than 100 percent if, for example, it has a lower forced outage rate than the RECAP model's conventional capacity resource.[172] Figure 6-6 provides the ELCC values for the new thermal resources. Unlike variable energy resources and short-duration storage, these resources are available across all hours and have little to no decline in their capacity contribution values for incremental additions until the reliability target is met.

FIGURE 6-6: Marginal ELCC for unit size additions of thermal resources



For the purpose of comparing resources outside of portfolio analysis, a capacity value is typically attributed to a resource based on its capacity contribution multiplied by the net cost of securing capacity from the lowest cost capacity option. As shown in Figure 6-1, there remains considerable uncertainty in the relative cost of new capacity resources, particularly energy storage resources. However, in the Reference Case, the simple-cycle combustion turbine (SCCT) remains the lowest cost capacity resource in the near term. Figure 6-7 shows how capacity value can be derived by isolating the portion of the cost of the SCCT that is not attributable to providing other types of value to the system and is therefore attributed to the SCCT's ability to contribute to meeting capacity needs.

In the figure, the net cost of capacity is equal to the capacity value of the SCCT divided by its capacity contribution, 99.7 percent, resulting in $103/kW-yr. Note that this value estimates the cost of new capacity resources based on the technology cost and performance forecasts in this IRP and does not predict actual procurement outcomes. Actual procurement activities may yield capacity resources at lower costs than this indicative value through competitive bidding and/or procurement of existing resources in the region.

[172] A discussion of the impact of the thermal resource characteristics on the ELCC value is provided in Appendix I. 2019 IRP Modeling Details.

FIGURE 6-7: Derivation of capacity value from SCCT costs and benefits

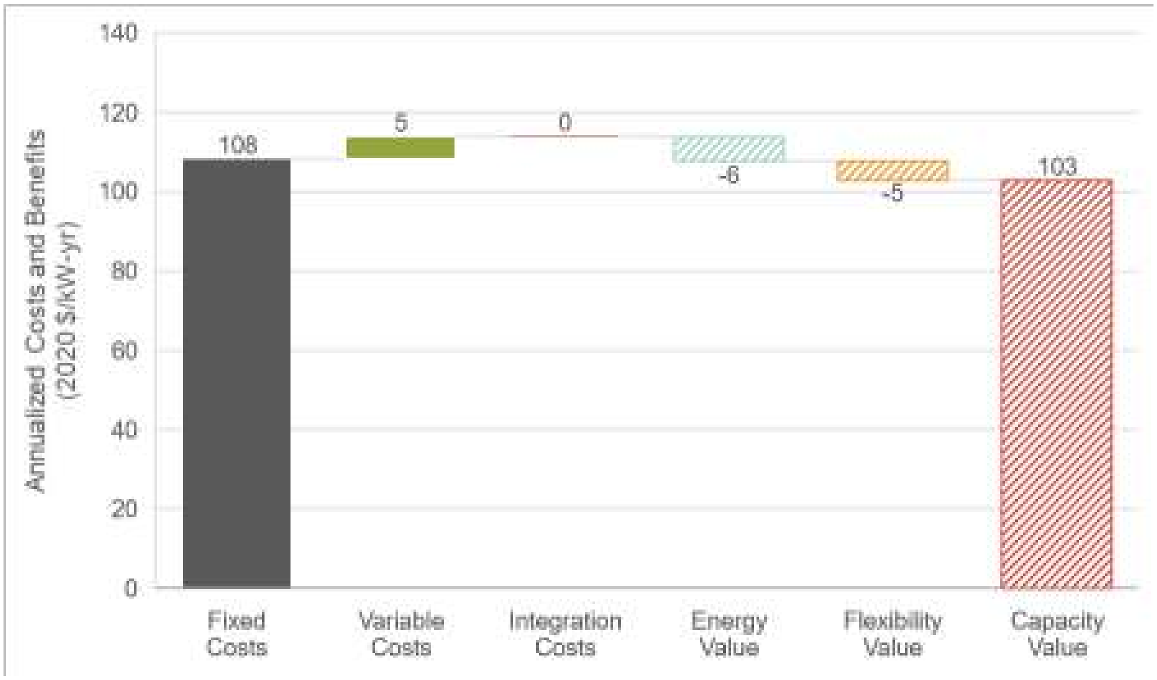


Table 6-6 shows how a capacity value for each resource can be derived from the net cost of capacity. For energy resources, the ELCC and corresponding capacity value (in $/MWh) is shown corresponding to 100 MWa addition sizes. For capacity resources, the ELCC and corresponding capacity value (in $/kW-yr) are shown for the amount of capacity required of each resource to provide 100 MW of capacity contribution. For example, if 500 MW of a capacity resource is required to achieve a 100-MW capacity contribution, the corresponding ELCC at 100-MW capacity contribution is equal to 20 percent. These values reflect the effects of the declining marginal ELCC curves shown above and are helpful in comparing capacity resources that might be used to fill substantial portions of PGE's capacity needs on a consistent basis.

TABLE 6-6: ELCC and capacity values of resource options

	ELCC of 100 MWa Energy Addition	Capacity value of 100 MWa Energy Addition (2020$/MWh)
Gorge Wind	24%	$6.81
Ione Wind	12%	$4.29
MT Wind	37%	$10.30
WA Wind	19%	$5.34
Central OR Solar	9%	$4.49
Solar + Storage	20%	$9.96
Geothermal	105%	$13.49
Biomass	104%	$13.51
CCCT	86%	$13.63

	ELCC at 100 MW of Capacity Contribution	Capacity value at 100 MW of Capacity Contribution (2020$/kW-yr)
2-hour Battery	20%	$20.28
4-hour Battery	50%	$51.46
6-hour Battery	72%	$74.52
Pumped Storage	79%	$81.68
SCCT	100%	$102.99
LMS 100	104%	$107.48
Reciprocating Engines	105%	$108.34

6.3 Resource Net Cost

The net cost of a resource provides a more complete picture of relative economics between resources than the LCOE. Net cost can be calculated in different ways, but in this discussion, we define it as the sum of all fixed, variable, and integration costs, net of any tax incentives and any value provided to the portfolio, including energy, flexibility, and capacity values.

A positive net cost according to this definition means that we would expect it to be more expensive to provide an equivalent amount of energy, capacity, and flexibility with the resource than it would be to rely on the wholesale market for energy, the proxy capacity resource for capacity (in this case a SCCT), and our existing resource portfolio for flexibility. A negative net cost means that the resource option is expected to be lower cost than relying on the wholesale market for energy, the proxy capacity resource for capacity, and our existing resource portfolio for flexibility.

Figure 6-8 shows the derivation of the net cost for a Washington Wind resource with 2023 COD under Reference Case conditions. In the figure, the wind resource has a negative net cost (-$11/MWh) because the sum of resource costs net of federal tax credits is less than the levelized benefits that it provides to the system (energy value and capacity value). Note that while the 2023 COD Washington Wind resource is RPS-eligible, the net cost analysis indicates that it costs less than the equivalent amount of non-RPS-eligible energy and capacity, so there is no additional premium associated with RPS-eligibility. In this circumstance, the theoretical value of the Renewable Energy Credits (RECs) produced by the resource is therefore zero.

The levelized net costs of the energy resource options are shown in Figure 6-9. The error bars indicate uncertainties in fixed and variable costs as well as energy value.

The net cost analysis indicates that several energy resources may potentially achieve negative net costs, including the CCCT, Gorge Wind, Ione Wind, WA Wind, MT Wind, and Solar. The CCCT, Gorge Wind, WA Wind, and MT Wind resources achieve negative net costs in the Reference Case. This analysis indicates that renewable resources are expected to be the lowest cost option for providing energy on a long-term basis from new resources. This has significant implications for the design and performance of portfolios, as described in Chapter 7.

FIGURE 6-8: Derivation of net cost of 100 MWa of Washington Wind (2023 COD)

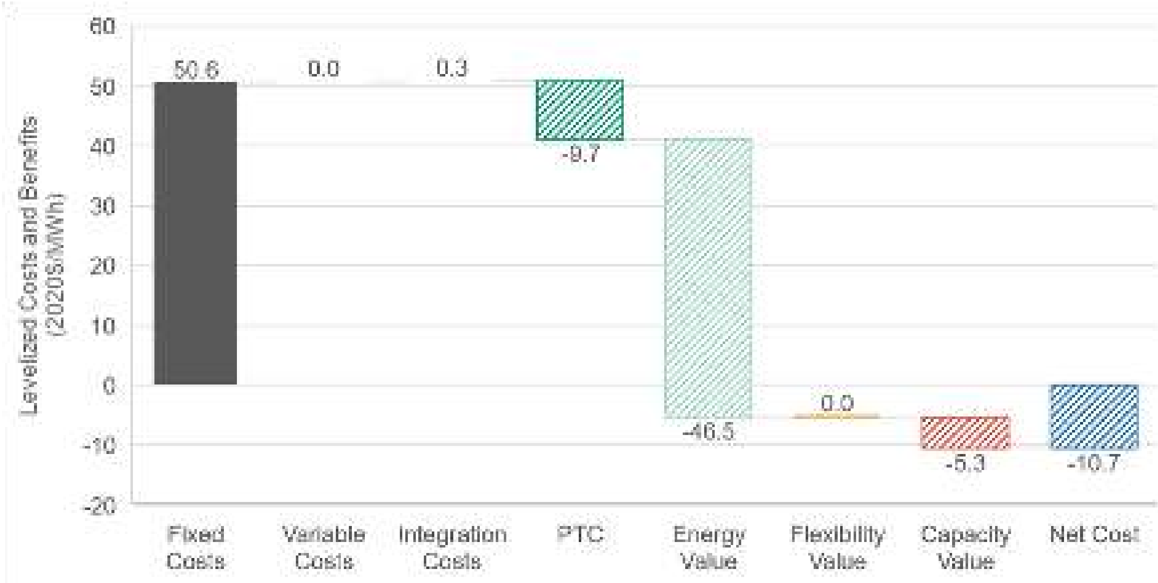
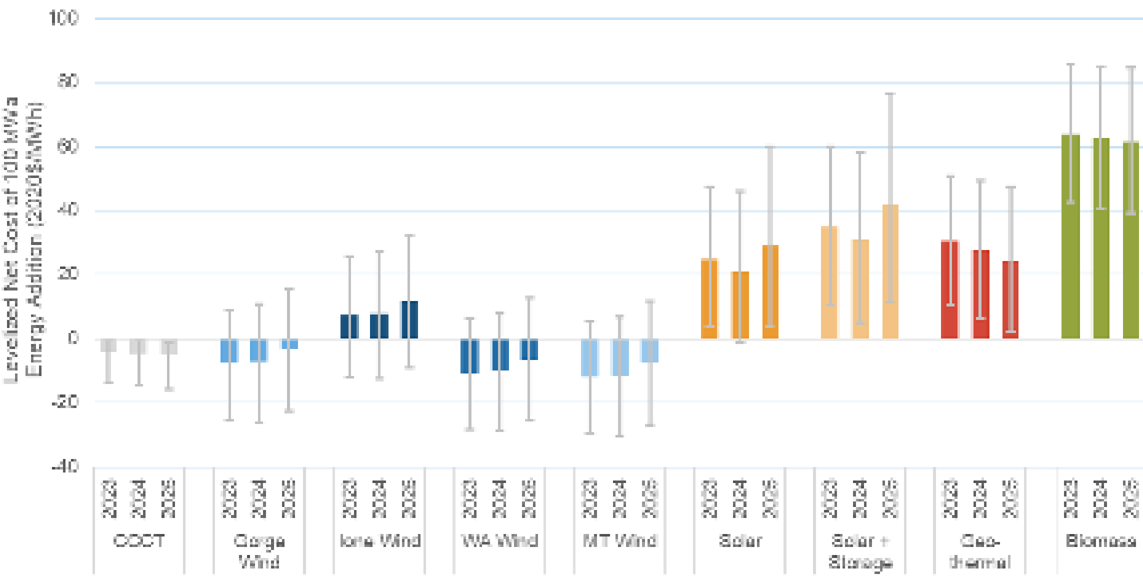
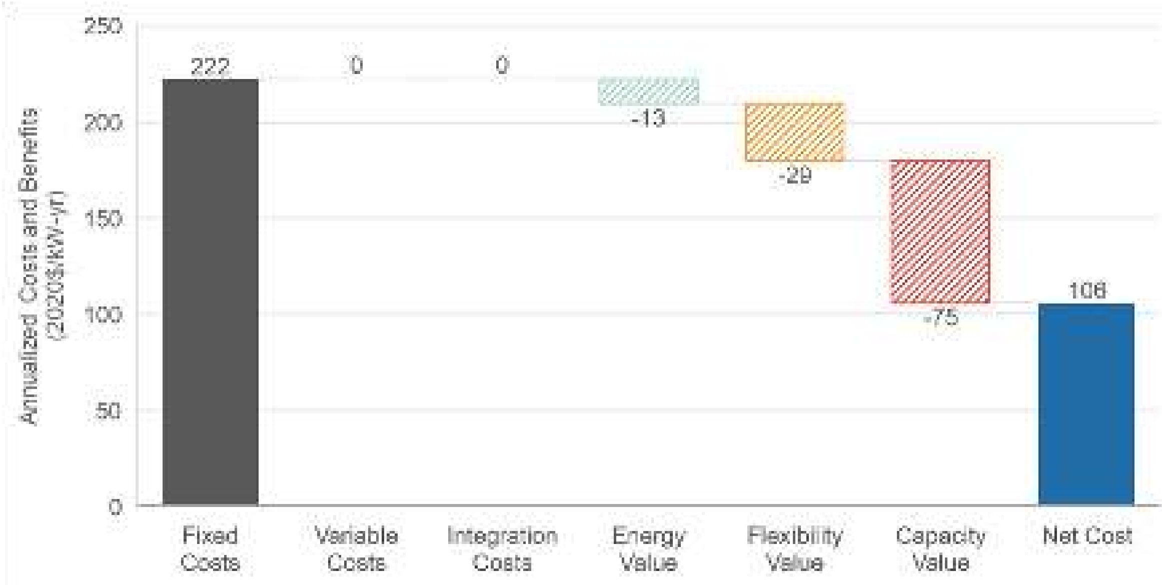


FIGURE 6-9: Net costs of energy resource options by COD



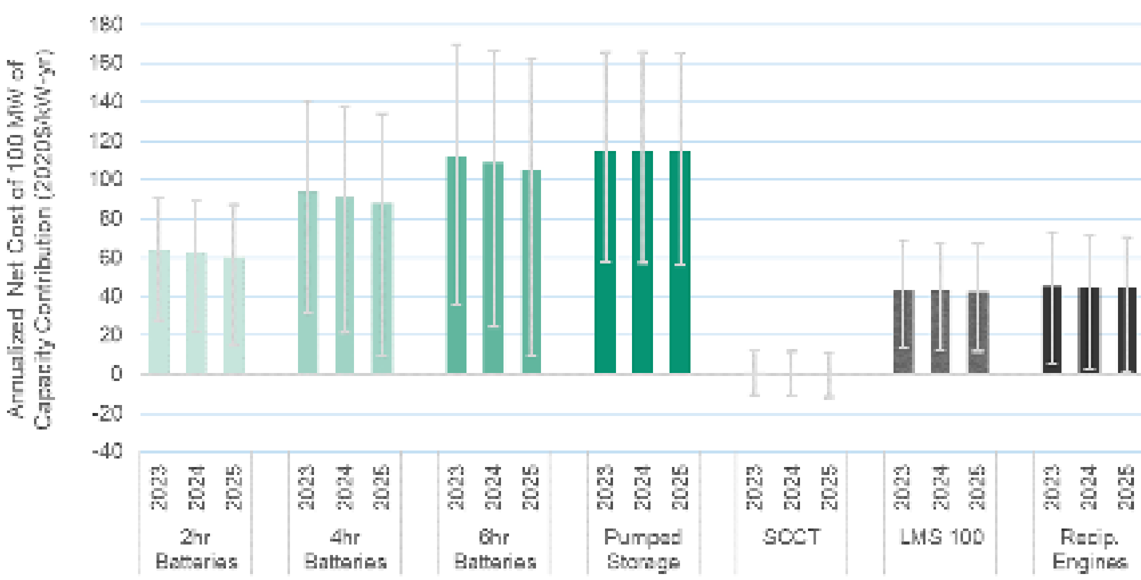
The derivation of net costs is also shown for a capacity resource (a 6-hour battery) under Reference Case conditions in Figure 6-10. The 6-hour battery has a positive net cost ($106/kW-yr) because the sum of its anticipated annualized energy value, flexibility value, and capacity value does not outweigh its annualized fixed costs. In other words, the net cost analysis identifies a $106/kW-yr premium for securing 100 MW of capacity from 6-hour batteries rather than the proxy capacity resource (an SCCT) under Reference Case conditions.

FIGURE 6-10: Derivation of net cost of 4-hour batteries at 100 MW of capacity contribution (2025 COD)



The annualized net costs across the capacity resource options are shown in Figure 6-11. The net costs reflect the value of each resource if enough of the resource is added to the portfolio to provide 100 MW of capacity contribution. The error bars indicate uncertainties in fixed and variable costs as well as energy value.

FIGURE 6-11: Net costs of capacity resource options by COD



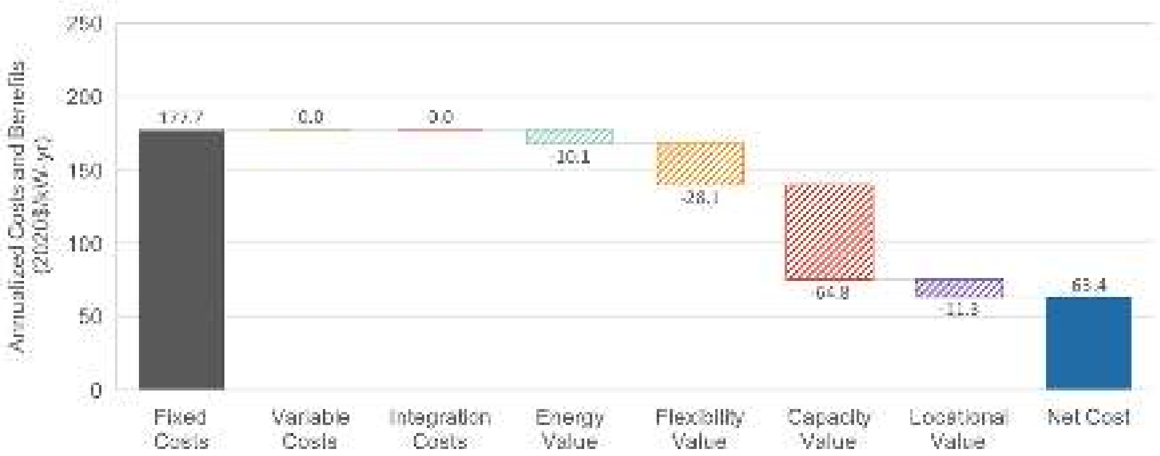
The net cost analysis highlights the high degree of uncertainty in resource economics for capacity resources. While the net cost of batteries is considerably higher than the SCCT in the Reference Case, the bounds of uncertainty encompass a scenario in which 4-hour batteries and 6-hour batteries are cost-competitive relative to an SCCT by 2025. The futures in which batteries are more cost-competitive relative to the SCCT factor into PGE's portfolio analysis through the risk metrics described in Section 7.2.1 Scoring Metrics.

The net costs of new resources described above provide helpful insights for understanding the economic tradeoffs between specific resource actions. However, this simplistic view of resource economics neglects risks associated with future uncertainties and potential interactions between resources. These are investigated through portfolio construction and evaluation, which are described in the following chapter.

6.4 Locational Value

Battery systems located on the distribution system may have additional benefits not yet incorporated into portfolio analysis or the net cost analysis shown above. In future IRP cycles, PGE hopes to incorporate insights from its distribution system planning (DSP) process, including locational value, more holistically into IRP resource and portfolio evaluation. Figure 6-12 shows how locational value might factor into resource net cost analysis for distributed storage in the future. The example shown incorporates the base transmission and distribution benefits for a substation-located 4-hour battery system from PGE's Energy Storage Potential Evaluation.[173]

FIGURE 6-12: Impact of locational value on net cost of a distributed 4-hour battery with 2025 COD

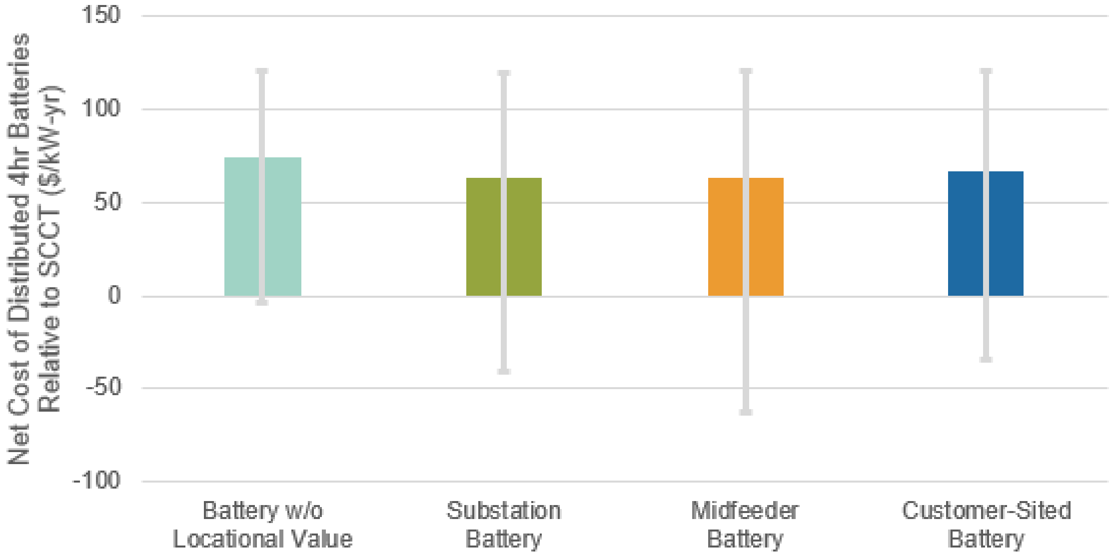


PGE's Energy Storage Potential Evaluation found that locational value could vary significantly by location. Figure 6-13 shows how the ranges of locational value identified in the Energy Storage Potential Evaluation might impact net costs for a 4-hour battery system at different types of locations on the distribution system. In this example, the error bars incorporate uncertainties in fixed and variable costs, energy value, and the locational value ranges identified in the Energy Storage Potential Evaluation. The base locational value does not have a significant impact on the net cost of 4-hour batteries in the Reference Case. However, the error bars encompass situations in which net costs are negative, indicating that the use of battery systems to support the transmission and distribution system in specific locations while also providing bulk system benefits could be cost effective relative to an SCCT. PGE is continuing to refine our analysis of locational benefits and

173 OPUC Docket UM 1856, *PGE's Energy Storage Proposals and Revised Energy Storage Potential Evaluation*. Filed November 1, 2017.

hopes to update this analysis with the results of future DSP exercises in future IRP planning cycles, with the goal of holistically incorporating locational value into future IRP portfolio analysis.

FIGURE 6-13: Net cost of 4-hour batteries at various locations on the distribution system



6.5 Capacity Factor Sensitivities

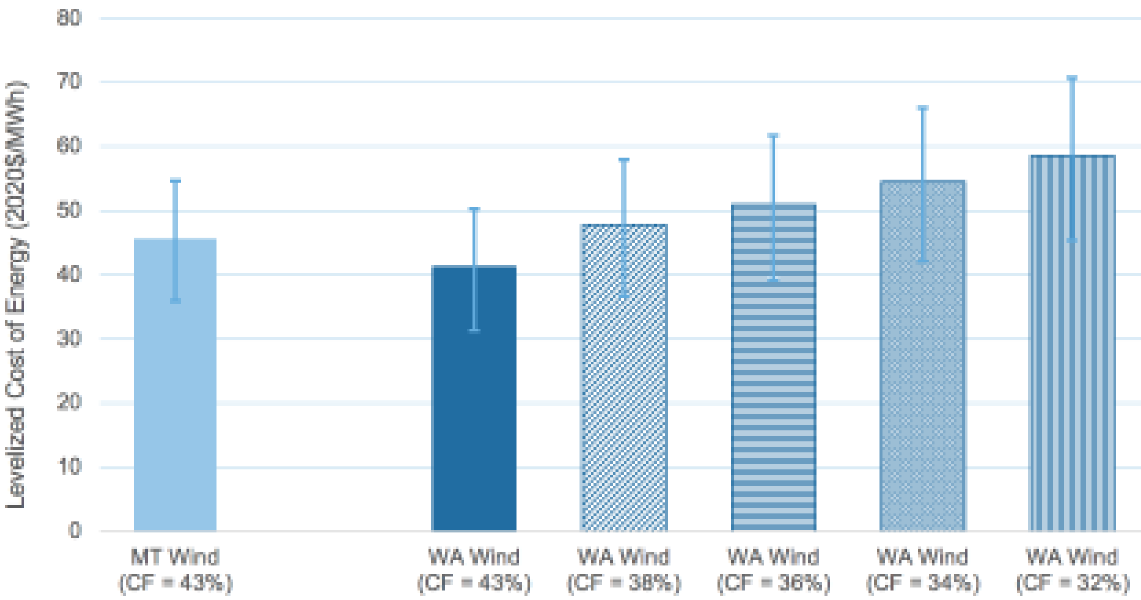
PGE recognizes that in addition to uncertainties regarding technology costs and price futures, there is uncertainty in resource performance characteristics, particularly for projections of wind capacity factors. Actual wind generation is sensitive to the turbine technology and site layout, in addition to the specific weather patterns.

In the public process supporting the development of the 2019 IRP, some stakeholders expressed concern about the capacity factors for the generic wind resource in the supply-side study. In particular, there was concern that the values for the Columbia Gorge and Southeast Washington were higher than expected based on existing facilities. PGE notes that the analysis conducted by HDR and Vaisala reflected progress in turbine technology, larger rotor diameters, and higher hub heights, advances which may not impact performance uniformly across wind regimes.[174] However, in order to provide information about the magnitude of the impact of wind capacity factor assumptions on resource economics and respond to stakeholder requests, PGE conducted five sensitivities with reduced assumptions for capacity factors for Washington Wind and compared these to the economic performance of Montana Wind. In these sensitivities, the capacity factor of the Washington Wind resource is adjusted downward to examine the impacts to the LCOE and net cost of energy. To estimate these impacts, the Washington Wind resource output shape was scaled down uniformly to achieve each alternative capacity factor. This resulted in reduced generation, energy value, and capacity value per MW of installed wind.

[174] As described in External Study D. Characterizations of Supply Side Options, the 2019 IRP analysis utilizes performance information for a Vestas V136-3.6 turbine, which generates up to 3.6 MW with a 136-meter rotor diameter at a 105-meter hub height. In contrast, the 2016 IRP generic wind resource assumptions were developed based on a GE 2.0-116 turbine, which generates up to 2 MW with a 116-meter rotor diameter at an 80-meter hub height.

Figure 6-14 shows the results of this analysis. Under the base assumptions, the two generic wind resources in Washington and Montana both have a 43 percent capacity factor. Due to additional transmission costs, the Montana Wind resource has a higher LCOE than the Washington Wind resource ($46/MWh versus $41/MWh, for 2023 COD). The error bars in Figure 6-14 reflect capital cost uncertainties. The sensitivity analysis suggests that a generic Washington Wind resource with a capacity factor of less than 40 percent is expected to cost more on a real-levelized basis than the generic Montana Wind resource investigated in this IRP under Reference Case conditions. It also suggests that the magnitude of LCOE uncertainty that is captured by examining capital cost uncertainty is comparable to the potential impacts of capacity factor variation. On an LCOE basis, the magnitude of the capital cost uncertainty considered in the analysis is roughly equivalent to varying the capacity factor up or down 7 percent.

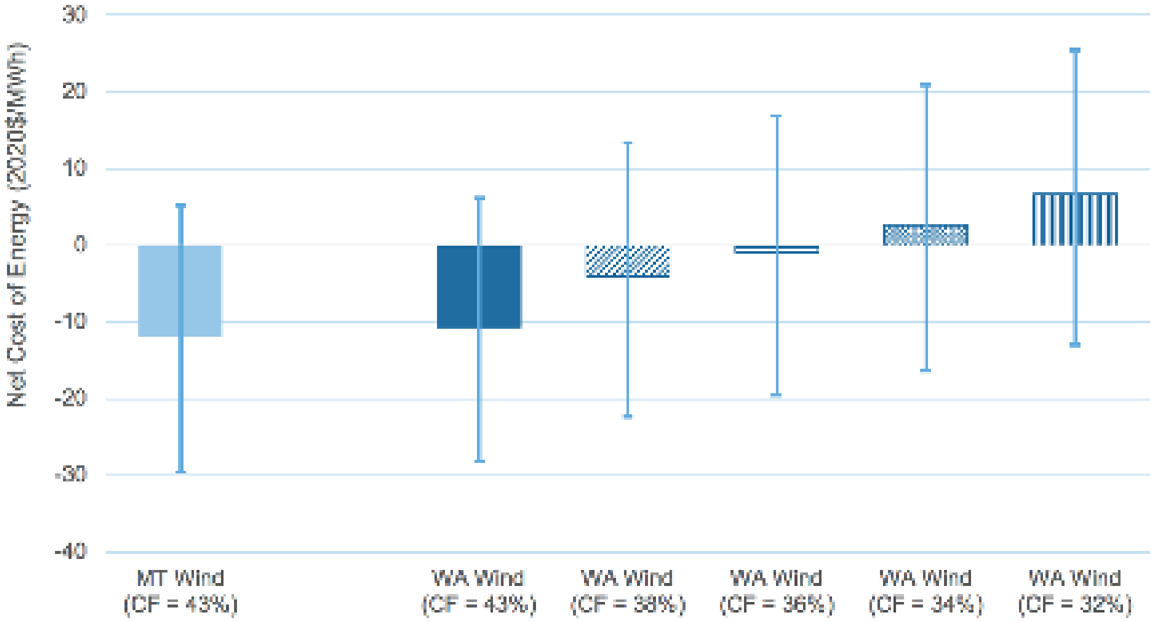
FIGURE 6-14: Levelized cost sensitivities for wind (2023 COD)



The analysis also investigated the impact of capacity factor on the net cost of energy from each resource, assuming a 100 MWa addition size. Recall that the net cost of energy accounts for both the cost of the resource and the expected benefits, specifically the energy and capacity value of wind resources. As shown in Figure 6-15, the Montana Wind resource outperforms the Washington Wind resource across all sensitivities because it provides more value to the portfolio. The error bars in Figure 6-15 reflect uncertainties in both capital costs and market prices, which impact energy value.

In actual procurement, site-specific information about both resource quality and resource cost will be available for a more precise determination of both levelized costs and benefits. In the planning stage, the goal is to examine a range of potential resource options because such precise information is not available. The 2019 IRP makes generic, but robust conclusions on the economics of potential wind resource additions by examining multiple generic wind resources with different resource qualities and by testing a range of potential capital costs.

FIGURE 6-15: Net cost sensitivities for wind



CHAPTER 7. Portfolio Analysis

PGE undertook a rigorous portfolio analysis to determine the set of actions that will provide the best balance of cost and risk. This analysis considers the resource needs described in Chapter 4. Resource Needs, the cost and performance of resource options summarized in Chapter 5. Resource Options, and a scoring process based on traditional and non-traditional scoring metrics.

This chapter describes our portfolio construction process and our use of a new portfolio optimization tool, summarizes our portfolio scoring process and scoring results, describes our preferred portfolio selection process, and describes the preferred portfolio, including the associated renewable glide path and GHG emissions forecast.

Chapter Highlights

- ★ PGE leveraged a portfolio optimization tool to supplement our traditional hand-designed portfolios with optimized portfolios.
- ★ Portfolios are designed to consider flexibility and optionality in later years based on need, market price, and technology futures.
- ★ PGE used traditional scoring metrics to identify the portfolios that best balance cost and risk while excluding portfolios that performed poorly with respect to non-traditional scoring metrics that reflect shared values between PGE and our stakeholders.
- ★ The Mixed Full Clean portfolio is the preferred portfolio and includes customer resources, renewable resource additions, and capacity additions between now and 2025, while allowing for flexibility in meeting longer-term needs.

7.1 Portfolio Construction

PGE has traditionally hand-designed portfolios to investigate a range of questions regarding the relative economics and performance of new resource options. In the 2016 IRP, PGE was urged to change our approach to portfolio construction in three ways:

1. To use a portfolio optimization model to determine if there are lower-cost alternatives to hand-designed portfolios.
2. To dynamically account for uncertainty in future resource needs within portfolio construction rather than prescribing resource additions into the future based only on the Reference Case.
3. To address the value of optionality.

To address these concerns and to bring more sophistication to our portfolio construction process, we developed a portfolio optimization tool, ROSE-E, to complement the traditional approach of designing portfolios by hand. ROSE-E develops portfolios that minimize a specified objective subject to various user-designed constraints, allowing it to both produce optimized portfolios and automate the construction of hand-designed portfolios. More information about ROSE-E can be found in Appendix I. 2019 IRP Modeling Details.

We also fundamentally changed our approach to designing portfolios so that portfolio analysis better captures the costs and risks associated with large and long-lived resource actions given uncertainties in future resource needs and resource economics. Each portfolio in the 2019 IRP consists of a fixed set of near-term actions and a range of potential future actions that are dynamically optimized in each of the 270 Need, Price, and Technology Futures.[175] This was accomplished with a two-stage portfolio construction process undertaken for each individual portfolio. This process is summarized in Figure 7-1 and described below.

In the first stage of the portfolio construction process, PGE established a set of portfolio design constraints and selected an objective function (more information on the types of available constraints and objective functions is available in Appendix I. 2019 IRP Modeling Details). ROSE-E then solved for resource additions across all years and all futures that minimized the specified objective while satisfying the specified constraints. In the Portfolio Optimization run, the near-term resource additions (that is, additions made through 2025) were solved for by the optimization algorithm while being constrained to be the same across every future so that the portfolio would reflect a single set of near-term actions. These common near-term additions were then taken to the next stage.

In the second stage of the portfolio construction process, the Scoring Optimization run solved for the set of resource additions after 2026 in each future that minimized the net present value revenue requirement (NPVRR), calculated between 2021 and 2050 in that future. This step ensured that portfolio scores reflected the lowest possible cost outcomes in each future even if an alternative objective function was used in the Portfolio Optimization step to develop the near-term additions.

175 Portfolio construction considers only Reference Case hydro conditions. However, portfolio scores also incorporate portfolio performance across Low and High Hydro conditions.

FIGURE 7-1: Portfolio construction methodology

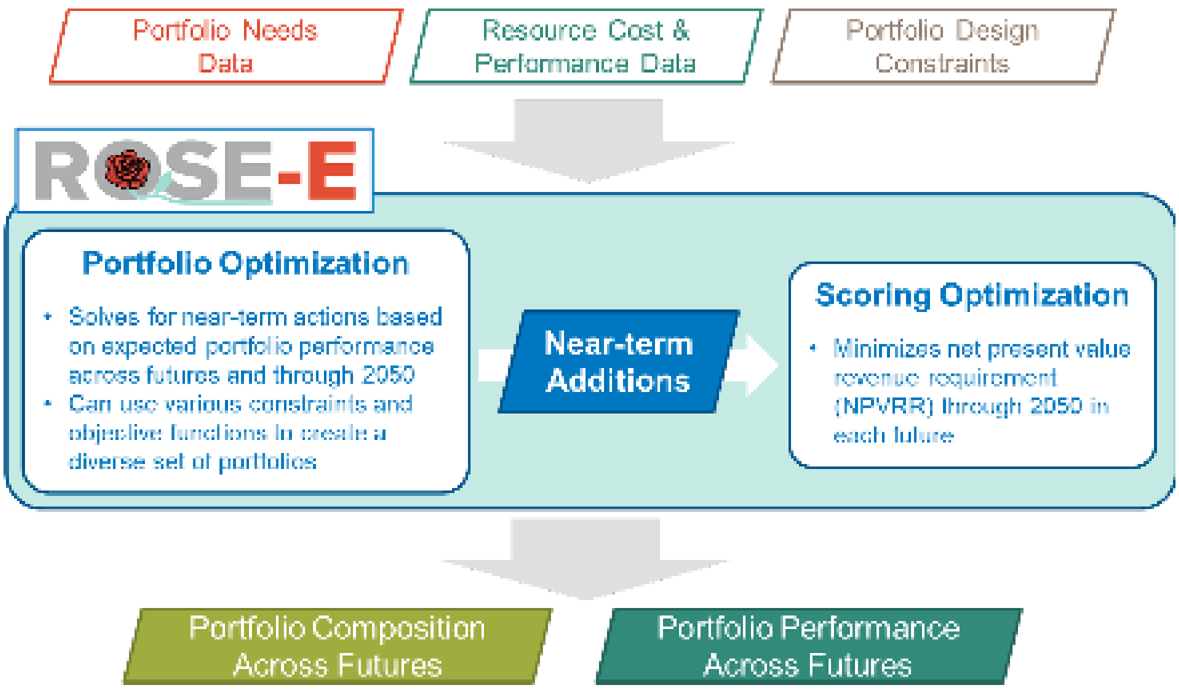
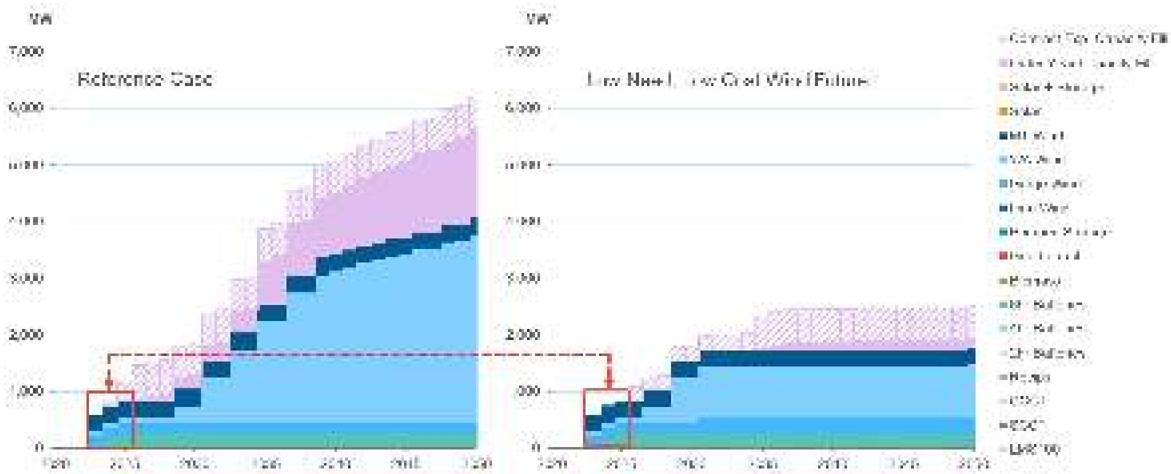


Figure 7-2 illustrates how PGE's portfolio construction process can result in different resource additions between 2026 and 2050 across futures while reflecting the same near-term additions. In this example, 250 MWa of wind is added in 2023 and remaining capacity needs through 2025 are met with 6-hour batteries. This results in a consistent set of resource additions through 2025 across all futures (shown in the red boxes in Figure 7-2).[176] In the long term, however, resource additions vary considerably across futures. In the Reference Case (shown in the left panel of Figure 7-2), additional wind resources are layered into the portfolio from the late 2020s through 2050, eventually reaching nearly 4,000 MW of wind. In an alternative future (Low Need and Low Cost Wind, shown in the right panel of Figure 7-2), incremental wind additions are made throughout the 2020s, but end in the early 2030s due to low resource needs. By considering potential resource trajectories across all 270 futures within the design and scoring of each portfolio, this methodology embeds the value of flexibility and optionality, as well as the risk associated with large and long-lived resource actions within the traditional economic risk metrics.

176 Capacity Fill additions, which may correspond to shorter duration actions, vary across portfolios in the near-term. The Capacity Fill resource is discussed in Section 7.1.1.1 Resource Adequacy and Section 6.2.3 Capacity Value.

FIGURE 7-2: Example of flexible portfolio construction



In the next section, we describe some of the common design principles applied across all the portfolios examined in the 2019 IRP.

7.1.1 Portfolio Design Principles

All portfolios were designed according to the principles and constraints discussed in this section. This consistent application of constraints allows for a fair comparison across portfolios. A portfolio that does not conform with the principles described here cannot be directly compared to conforming portfolios.

7.1.1.1 Resource Adequacy

All portfolios must meet PGE's capacity needs in all years in the Reference Case. In the Low Need and High Need Futures, portfolios are required to meet resource adequacy needs beginning in 2026. The capacity needs driving this constraint are described in Section 4.3 Capacity Adequacy and the contributions of each resource option to meeting capacity needs (the capacity contribution) are described in Section 6.2.3 Capacity Value.

The portfolio optimization allows use of a generic Capacity Fill resource to meet a portion of its capacity needs. The Capacity Fill resource is priced at just above the net cost of capacity of a simple-cycle combustion turbine (SCCT) derived in Section 6.2.3 Capacity Value ($103/kW-yr). In the near term (through 2025), Capacity Fill can be used for up to the portion of PGE's capacity needs associated with the expiration of contracts. In other words, the Capacity Fill resource simulates the potential for PGE to replace the capacity that is rolling off due to contract expirations on a 1-to-1 basis. PGE's ability to replace this capacity with cost-competitive contract options will depend on the products and pricing available from counterparties in the region.

After 2025, portfolios are allowed unconstrained access to the Capacity Fill resource. If none of the resource options provide capacity at a cost lower than the net cost of a SCCT, the portfolio will meet its remaining capacity needs beginning in 2026 with the Capacity Fill resource. At a high level, the Capacity Fill resource could reflect capacity options that may be available through bilateral negotiations with counterparties in the region, from participation in demand response programs, or from new technologies such as energy storage, should their costs become competitive with the cost of an SCCT. While the cost of the Capacity Fill resource is estimated in this analysis based on the net cost of a new SCCT, actual costs of competitive capacity options may be less expensive.

7.1.1.2 RPS Requirements

All portfolios must comply with Oregon's RPS requirements through the entire planning horizon. PGE's RPS obligations and RPS needs are described in Section 4.5 RPS Need. ROSE-E simulates the generation, banking, and retirement of Renewable Energy Credits (RECs) from RPS-eligible resources and enforces the five-year lifetime limit on banked RECs consistent with SB 1547. For each portfolio to meet RPS requirements in each future, the retired RECs in each year must meet or exceed the RPS obligation in that year. To ensure steady progress toward meeting PGE's 2040 RPS requirements and Oregon's 2050 GHG goal, PGE requires all portfolios between 2027 and 2050 across all futures to meet physical RPS compliance, such that the RECs generated in each year must meet or exceed the RPS obligation in that year.

7.1.1.3 Energy Position

PGE's energy position is described in Section 4.4.1 Market Energy Position. To ensure that resource additions do not put PGE in a persistently long energy position, we impose two energy constraints on all portfolios. First, in the Reference Case, generation from new resources may not exceed PGE's forecasted net market shortage as described in Section 4.4.1 Market Energy Position beginning in 2026. Second, in all futures, generation from new resources may not exceed PGE's forecasted net market shortage between 2041 and 2050. A small relaxation of this constraint is allowed only in the futures in which the physical RPS compliance constraint would require a portfolio to be energy long.

7.1.1.4 Procurement Constraints

For resource additions made through 2025, PGE enforces unit-size constraints for all thermal resources and pumped storage. For thermal units, resources must be added in single-unit increments, except for reciprocating engines, which must be added in 6-unit blocks. Pumped storage must be added in 100-MW increments, and renewable resources and batteries can be added in any MW size. Unit constraints are relaxed after 2025 to improve computational efficiency and because additions in that period are not being considered for inclusion in the Action Plan in this IRP. PGE excludes thermal resource additions from all portfolios after 2025 but does allow access to the Capacity Fill resource during this time.

PGE also imposes constraints on resource additions between 2026 and 2050 to approximate practical and logistical considerations around resource procurement activities. Beginning in 2026, renewable procurement is assumed to occur on a two-year cycle, so that renewable resource additions enter the portfolio in odd years. Capacity resource additions are assumed to occur on a two-year cycle that is staggered with the renewable procurement activities, resulting in capacity additions in even years. In each year beginning in 2026, resource additions are limited to 500 MW to ensure that the evaluation of near-term actions does not hinge on a presumption of heroic resource development efforts sometime in the future. This limit does not apply to Capacity Fill additions, as they do not represent new long-lived infrastructure.

7.1.2 Optimized Portfolios

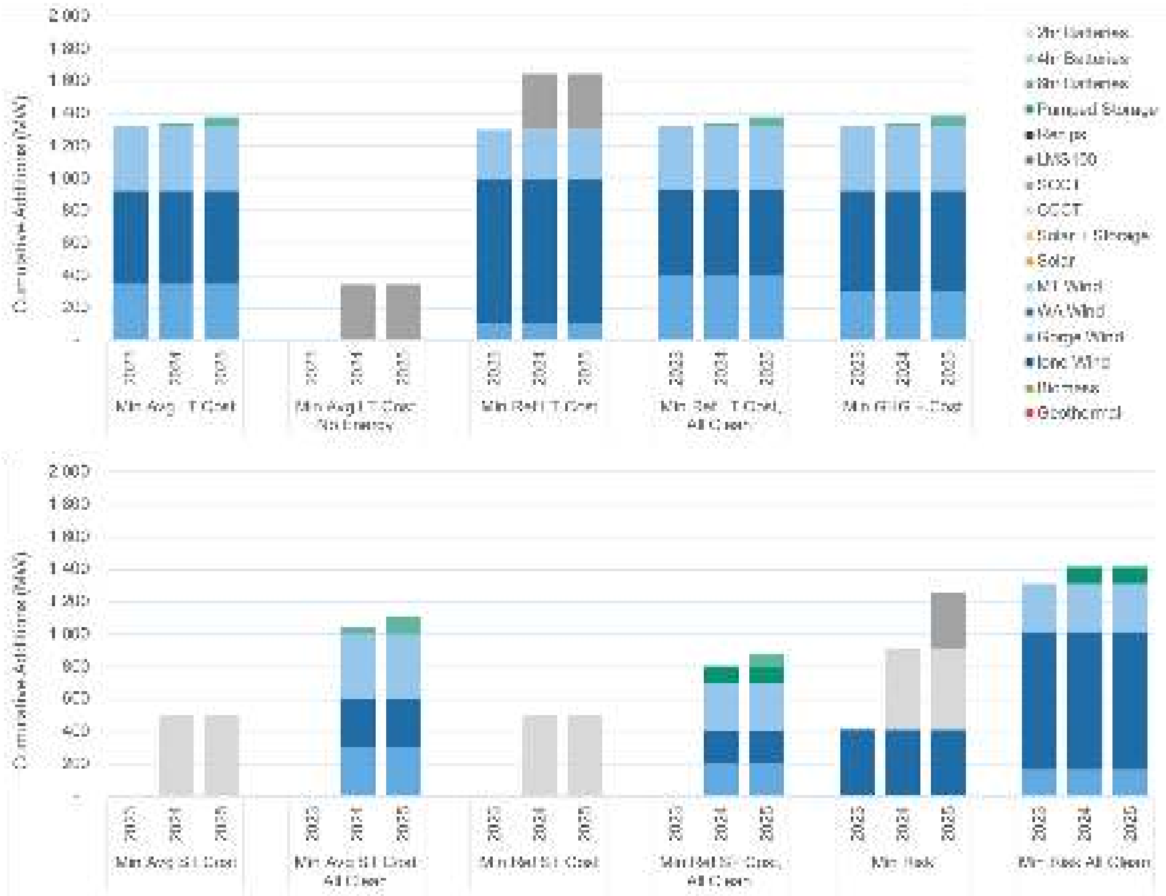
In response to stakeholder requests and to provide a more complete investigation of potential portfolios, PGE evaluated eleven *Optimized Portfolios* with various portfolio design considerations. These portfolios were designed to explore optimization across cost, risk, and emissions. Table 7-1 lists the objective function and portfolio design constraints for each of the Optimized Portfolios.

TABLE 7-1: Optimized Portfolio specifications

Portfolio	Objective Function	Portfolio Design Constraints
Min Avg LT Cost	Minimizes average long-term (LT) NPVRR through 2050 across futures	None
Min Avg LT Cost, No Energy	Minimizes average NPVRR through 2050 across futures	Excludes energy resources (i.e., allows only energy storage and peaking plants)
Min Ref LT Cost	Minimizes Reference Case NPVRR through 2050	None
Min Ref LT Cost, All Clean	Minimizes Reference Case NPVRR through 2050	Excludes GHG-emitting resources
Min Avg ST Cost	Minimizes average short-term (ST) NPVRR through 2025 across futures	None
Min Avg ST Cost, All Clean	Minimizes average NPVRR through 2025 across futures	Excludes GHG-emitting resources
Min Ref ST Cost	Minimizes Reference Case NPVRR through 2025	None
Min Ref ST Cost, All Clean	Minimizes Reference Case NPVRR through 2025	Excludes GHG-emitting resources
Min Risk	Minimizes semi-deviation of NPVRR through 2050 across futures	Reference Case NPVRR cannot exceed $25,500 million
Min Risk, All Clean	Minimizes semi-deviation of NPVRR through 2050 across futures	Excludes GHG-emitting resources; Reference Case NPVRR cannot exceed $25,500 million
Min GHG + Cost	Minimizes the sum of the average NPVRR through 2050 across futures and the cumulative emissions across futures	Excludes GHG-emitting resources

Resource additions through 2025 resulting from these optimized portfolios are shown in Figure 7-3. The resource additions across the optimized portfolios help to identify some of the key tradeoffs between the resource options. Three of the four portfolios that minimize long-term costs introduce approximately 1,300 MW of wind in 2023 due to the cost savings associated with the federal production tax credit (PTC). These resources are assumed to come online on December 31, 2022 to qualify for 60 percent of the PTC. In two of these portfolios, a small amount of 6-hour battery storage is selected in addition to the limited quantity of the Capacity Fill resource to meet the remaining capacity needs through 2025 due to the capacity contribution of the wind resources.

FIGURE 7-3: Near-term resource additions in Optimized Portfolios



The portfolios that minimize short-term costs (NPVRR through 2025) yield two different types of strategies. When thermal resource additions are allowed, a combined-cycle combustion turbine (CCCT) is added in 2024 and no renewables are added through 2025. However, when thermal resources are excluded, renewable additions are made in 2024 to capture 40 percent of the PTC and to meet a portion of near-term capacity needs. Remaining capacity needs in these portfolios are met with pumped storage and 6-hour batteries in addition to a limited quantity of the Capacity Fill resource.

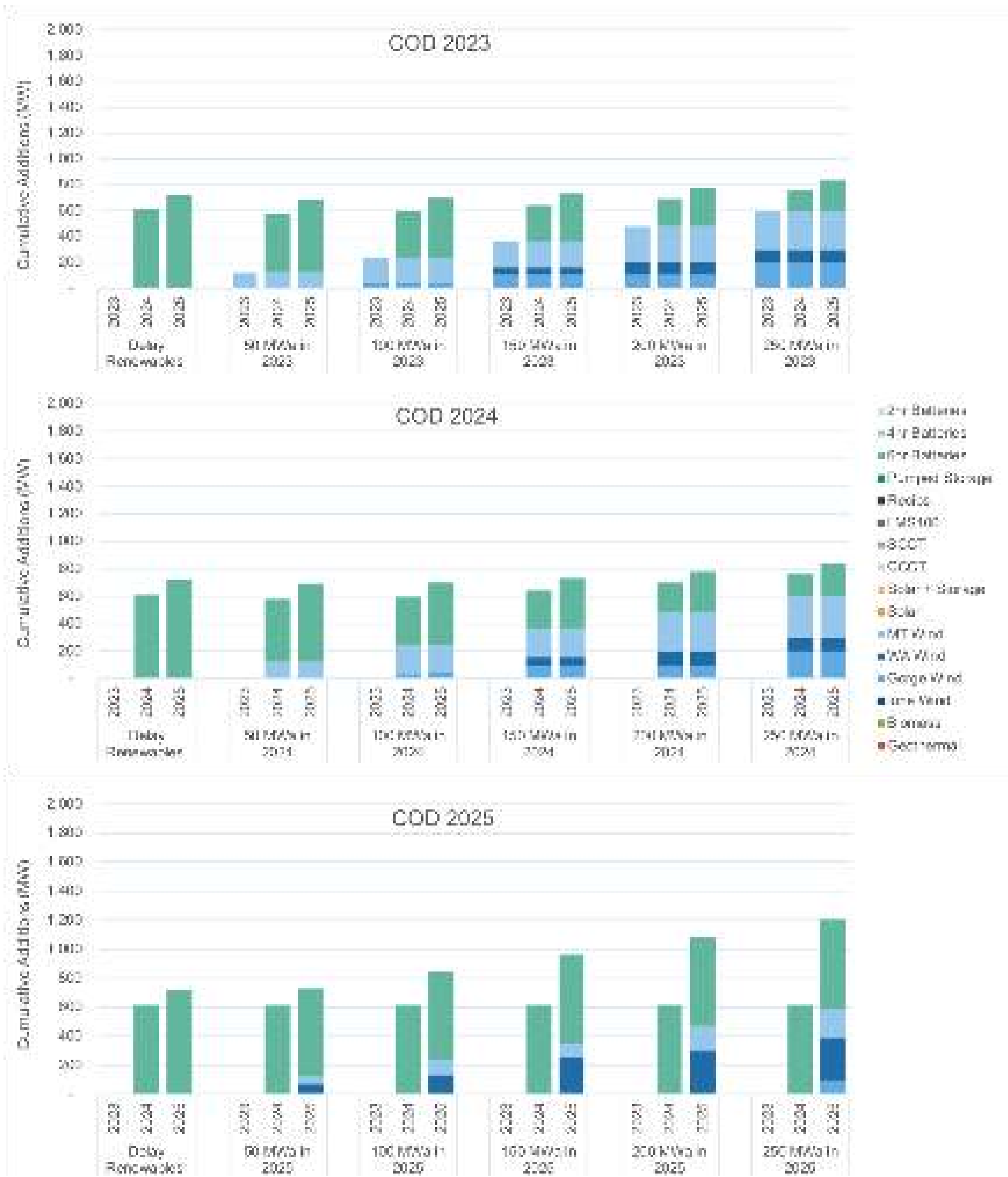
The portfolios that minimize risk and emissions plus cost provide a wide range of renewable addition sizes from approximately 400 MW to approximately 1,300 MW, all with 2023 COD. These portfolios also meet capacity needs by selecting various dispatchable resources including a CCCT, SCCT, and pumped storage.

7.1.3 Renewable Size and Timing Portfolios

To further understand the economics of near-term renewable actions, PGE developed a set of portfolios that test various renewable addition sizes and CODs. These *Renewable Size & Timing Portfolios* were designed to test resource addition sizes between 0 and 250 MWa at 50-MWa increments and CODs between 2023 and 2025. Within these parameters, the renewable resources are selected to minimize the average NPVRR across futures. For comparability across these portfolios, dispatchable capacity additions through 2025 are limited to 6-hour batteries and a limited quantity of the Capacity Fill resource. The resulting resource additions for each portfolio are summarized in Figure 7-4.

Nearly all the Renewable Size & Timing Portfolios incorporate multiple wind resources to take advantage of diversity benefits across wind locations. Across most of these portfolios, as renewable addition size increases, the size of the 6-hour battery additions decrease, reflecting the capacity contribution of the renewable resources. The only exception is the 2025 COD portfolios, where approximately 600 MW of 6-hour batteries are added in 2024 to meet capacity needs in that year. In these portfolios, the renewable resources do not have the ability to avoid a portion of the 2024 capacity additions because they are not available until 2025. This results in significantly more capacity being added to the portfolio through 2025 and highlights the importance of staging the next renewable procurement effort in advance of developing new potentially large capacity resources to meet capacity needs in the mid-2020s. It also suggests that there may be value in pursuing capacity from existing resources in the region to ensure resource adequacy in the near-term while providing additional time to better understand the size of PGE's capacity needs should new long-lived capacity resources be needed in the mid-2020s.

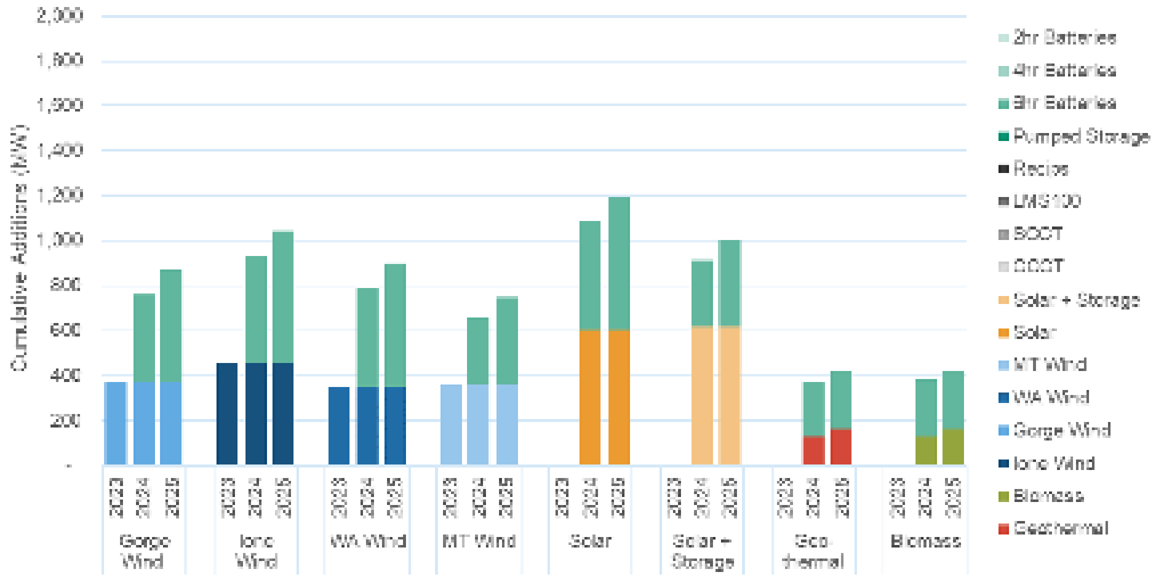
FIGURE 7-4: Near-term resource additions in Renewable Size & Timing Portfolios



7.1.4 Renewable Resource Portfolios

PGE designed a set of portfolios, the *Renewable Resource Portfolios*, to examine the relative performance across the different types of renewable resource options. For comparability, these portfolios each add 150 MWa of renewables between 2023 and 2025 and meet remaining capacity needs with 6-hour batteries and a limited quantity of the Capacity Fill resource. The resulting portfolio additions through 2025 are shown in Figure 7-5.

FIGURE 7-5: Near-term resource additions in Renewable Resource Portfolios



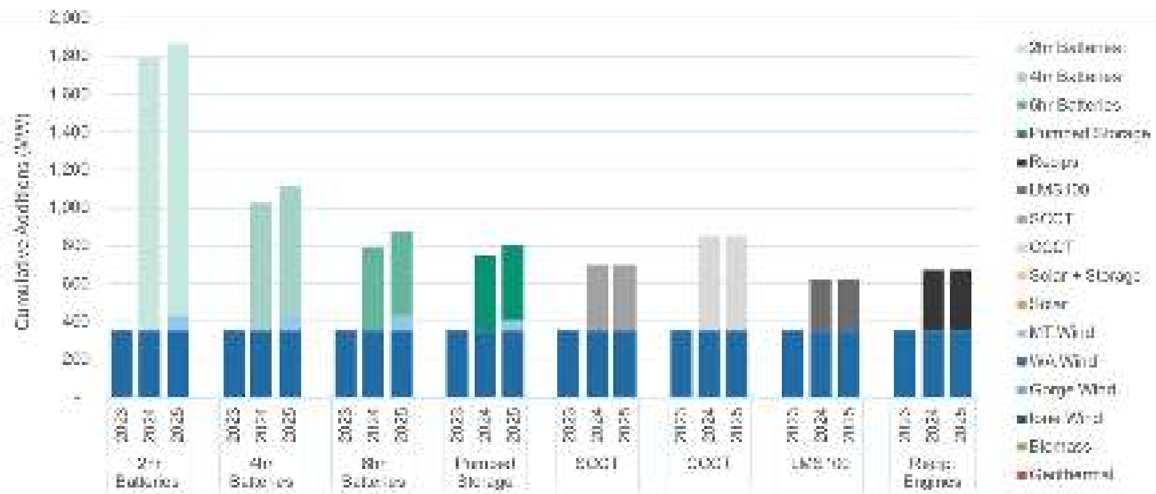
The Renewable Resource Portfolios yield a wide range of resource addition sizes due to the range of capacity factors across the renewable resources. The timing of the resource additions also varies by resource based on economic factors, especially the effects of federal tax credits (PTC for wind and ITC for solar and solar plus storage) and the capacity value of the resources. Wind resources are consistently added in 2023 to capture 60 percent of the PTC while solar resources are added in 2024 (assumed online date of December 31, 2023) to capture the 30-percent ITC. Geothermal and biomass resources are staged in over 2024-2025, corresponding to the increasing capacity needs during that time. The size of the 6-hour battery additions also varies across the portfolios depending on the capacity contribution of each renewable resource. The fewest 6-hour batteries are needed for the portfolios with geothermal, biomass, solar plus storage, and Montana wind.

7.1.5 Dispatchable Capacity Portfolios

PGE designed a set of *Dispatchable Capacity Portfolios* to compare the relative performance across the dispatchable capacity resources. For comparability, these portfolios each incorporate 150 MWa of Washington wind in 2023 and allow an additional renewable addition in 2025 if economically feasible. In each portfolio, dispatchable capacity additions through 2025 are constrained to the resource of interest and a limited quantity of the Capacity Fill resource. The resulting portfolio additions through 2025 are shown in Figure 7-6.

The most striking finding across the Dispatchable Capacity Portfolios is the large quantity of shorter-duration batteries that would be required to meet PGE's near-term capacity needs if other resources are not available. If only 4-hour batteries and the limited quantity of Capacity Fill are available to meet PGE's capacity needs, it would require nearly 700 MW of these batteries to meet PGE's near-term resource needs or about 20 percent of PGE's 1-in-2 peak demand. While PGE has made significant progress in quantifying the capabilities of battery systems in the 2019 IRP, this level of reliance on batteries in practice would require a much more robust evaluation of the impact of battery systems at scale within our portfolio. Furthering our understanding of battery systems, their capabilities, and potential contributions to our portfolio at scale will be an area of focus in future IRP cycles.

FIGURE 7-6: Near-term resource additions in Dispatchable Capacity Portfolios

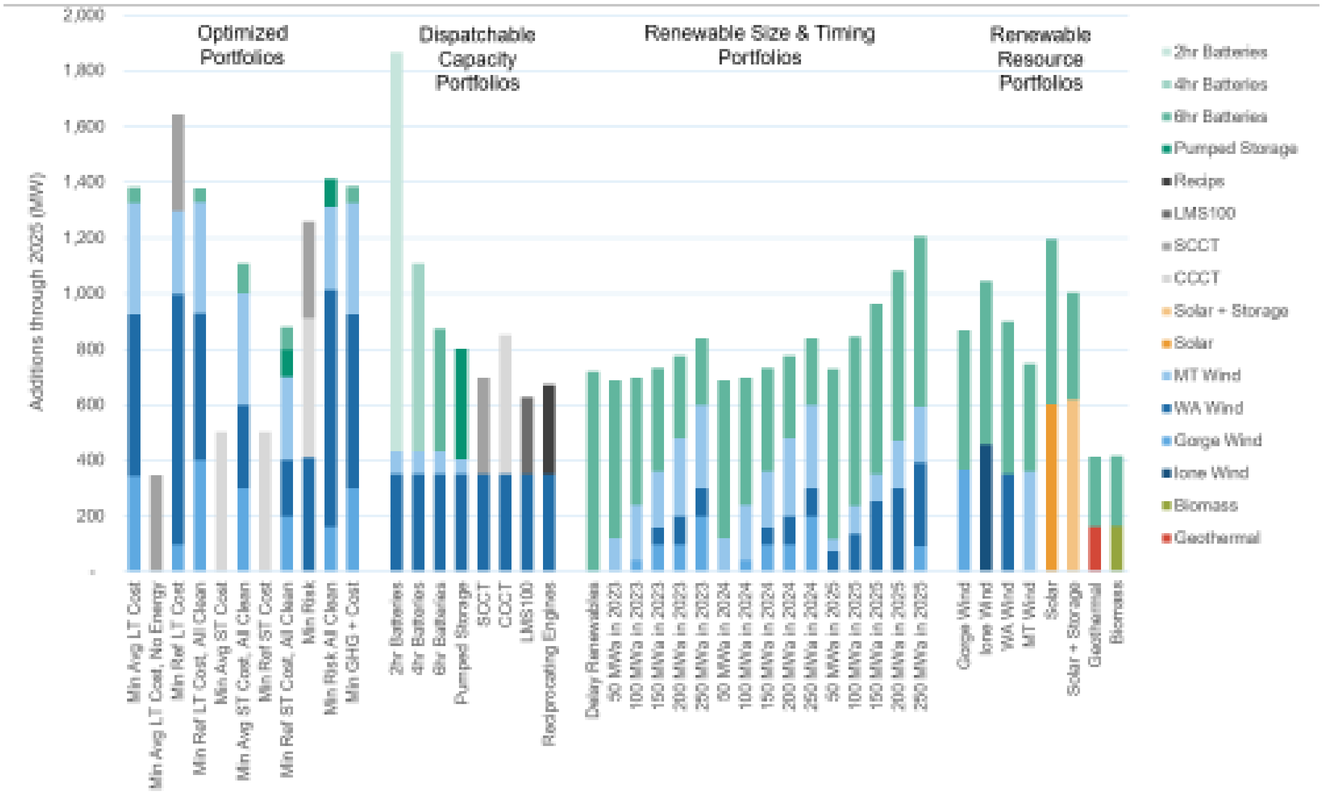


7.2 Portfolio Performance

The portfolio construction process described above resulted in 43 portfolios for consideration in selecting the preferred portfolio. These portfolios are summarized in terms of their associated resource additions through 2025 in Figure 7-7.

To select a preferred portfolio, PGE evaluated each of these 43 portfolios against nine traditional and non-traditional scoring metrics using a multi-stage scoring process, which is described in the following section.

FIGURE 7-7: Resource additions through 2025 across all portfolios



7.2.1 Scoring Metrics

During the IRP public roundtable process, PGE collaborated with stakeholders to develop a list of scoring metrics to evaluate candidate portfolios. These metrics encompass both traditional cost and risk metrics as well as non-traditional metrics, which reflect feedback received in our public process and account for risks not captured with the traditional economic risk metrics.

TABLE 7-2: Traditional scoring metrics

Metric	Description	Units
Cost	Net present value of the revenue requirement (NPVRR) in the Reference Case through 2050. Consistent with the OPUC IRP Guidelines, this is the primary cost metric that is used to evaluate candidate portfolios.	Million 2020$
Variability	Semi-deviation of the NPVRR through 2050 across futures, relative to the Reference Case. This metric captures the potential variation in cost outcomes across futures, considering only futures in which customer cost impacts exceed the Reference Case. Portfolios with low variability scores tend to provide more cost certainty and tend to lessen the impacts to customers of higher than expected cost conditions.	Million 2020$

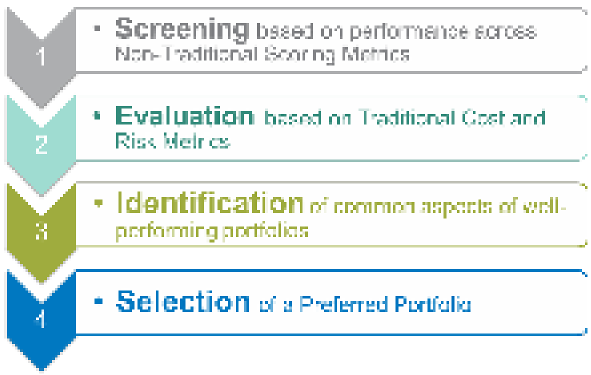
Metric	Description	Units
Severity	The tail value at risk (TailVAR) at the 90th percentile of the NPVRR through 2050 across futures. This metric measures the potential magnitude of very high cost outcomes across the futures. Portfolios with low severity scores tend to have less costly worst-case scenarios.	Million 2020$

TABLE 7-3: Non-traditional scoring metrics

Metric	Description	Units
Near-Term Cost	The NPVRR between 2021 and 2025 under the Reference Case. This metric provides information to help balance tradeoffs between long-term and near-term cost impacts of potential resource actions.	Million 2020$
GHG-Constrained Cost	Estimates NPVRR through 2050 in the Reference Case, allowing GHG-constrained operations and procurement between 2040 and 2050. This metrics examines the risk of regret in a GHG-constrained future.	Million 2020$
Cost in High Tech Future	NPVRR through 2050 in a future with High Renewable WECC-wide Buildout, Low Solar and Battery Costs, and Reference Case Needs. This metric examines the risk of regret in a future with rapid advancement and deployment of clean technologies.	Million 2020$
Cumulative GHG Emissions	Cumulative GHG emissions to meet load between 2021 and 2050 in the Reference Case, including emissions from PGE resources and net market purchases. This metric captures risk associated with potential future regulations related to GHG emissions.	$MMtCO_2$
New Resource Criteria Pollutants	The sum of the cumulative NO_2, SO_2, and particulate matter (PM) emissions from new resource additions between 2021 and 2050 in the Reference Case. This metric captures risks associated with current and potential future regulations related to criteria pollutants.	Short tons
Energy Additions through 2025	Total generation from new resources added through 2025. This metric is used to identify portfolios that may put PGE at risk of being persistently long to the market on an average annual basis.	MWa

7.2.2 Portfolio Scoring

PGE undertook a multi-stage scoring process to evaluate portfolios and to arrive at a preferred portfolio. This process combines evaluation across the traditional cost and risk metrics with the consideration of non-traditional metrics and a less prescriptive selection process for the preferred portfolio than PGE has employed in the past. This process allows PGE to meet the IRP Guidelines while reflecting our own values and the values expressed by our stakeholders within our public process. The four-stage process is described below.



1. Screening based on performance across the Non-Traditional Scoring Metrics.

While non-traditional scoring metrics are not used for the direct determination of the best balance of cost and risk, they do provide valuable information to ensure that the Action Plan aligns with PGE's values and the priorities expressed by stakeholders. The first step in the scoring process screens out those portfolios that perform the worst with respect to any of the non-traditional scoring metrics. For most non-traditional metrics, portfolios that have scores that exceed one standard deviation above the mean do not go on to the next step in portfolio evaluation. The only exception to this screening rule is the *Energy Additions Through 2025* metric. As described in Section 4.4.1 Market Energy Position, PGE identified 250 MWa as a conservative constraint on near-term energy additions for consideration in identifying the preferred portfolio. Portfolios that add more than 250 MWa of energy to the portfolio are screened out at this stage. Portfolio screening outcomes are summarized in Figure 7-8. Table 7-4 the portfolio scoring results across both traditional and non-traditional scoring metrics, with those portfolios that were screened out in the first step shaded gray.

FIGURE 7-8: Non-traditional scoring metric screens

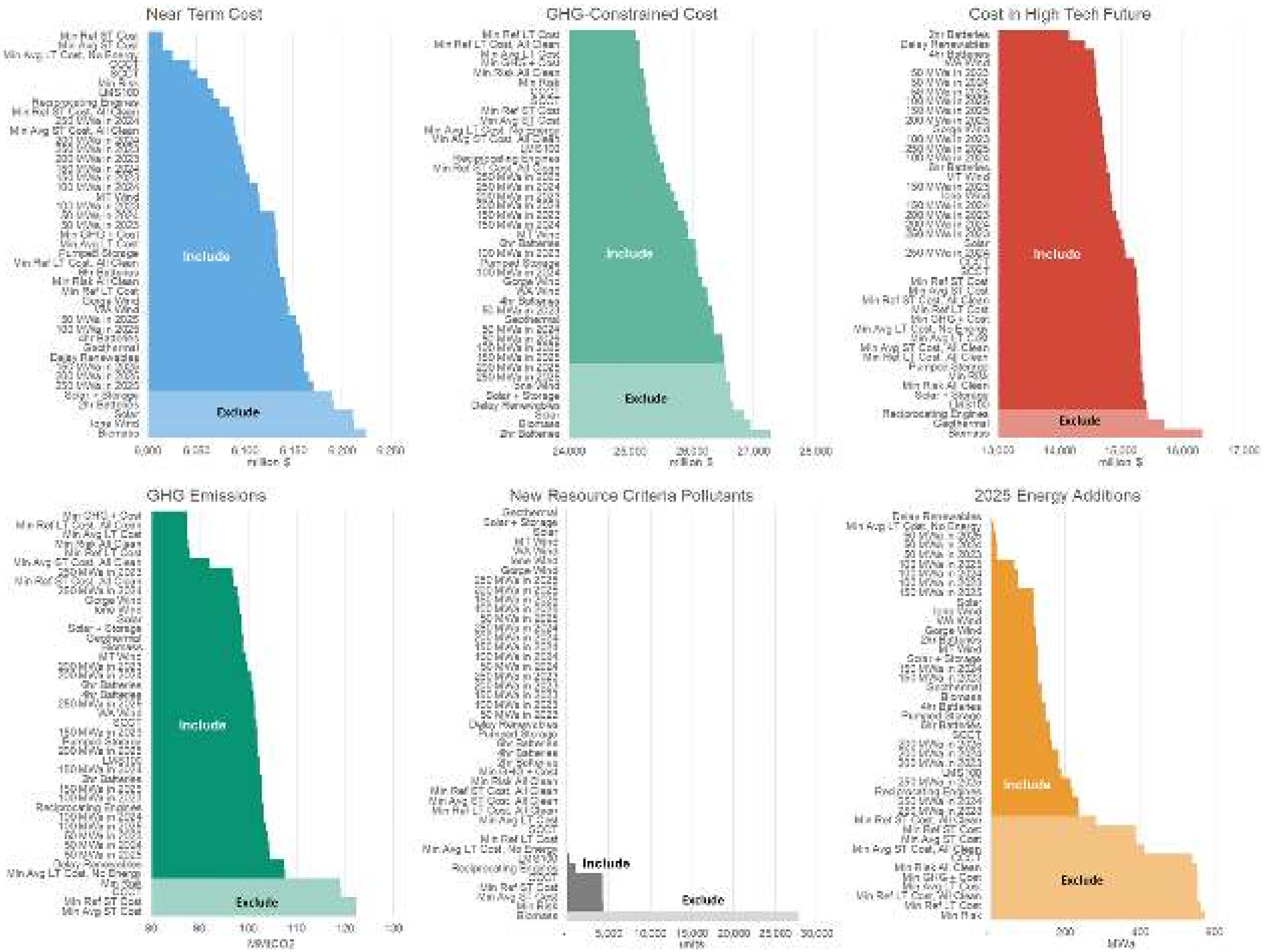


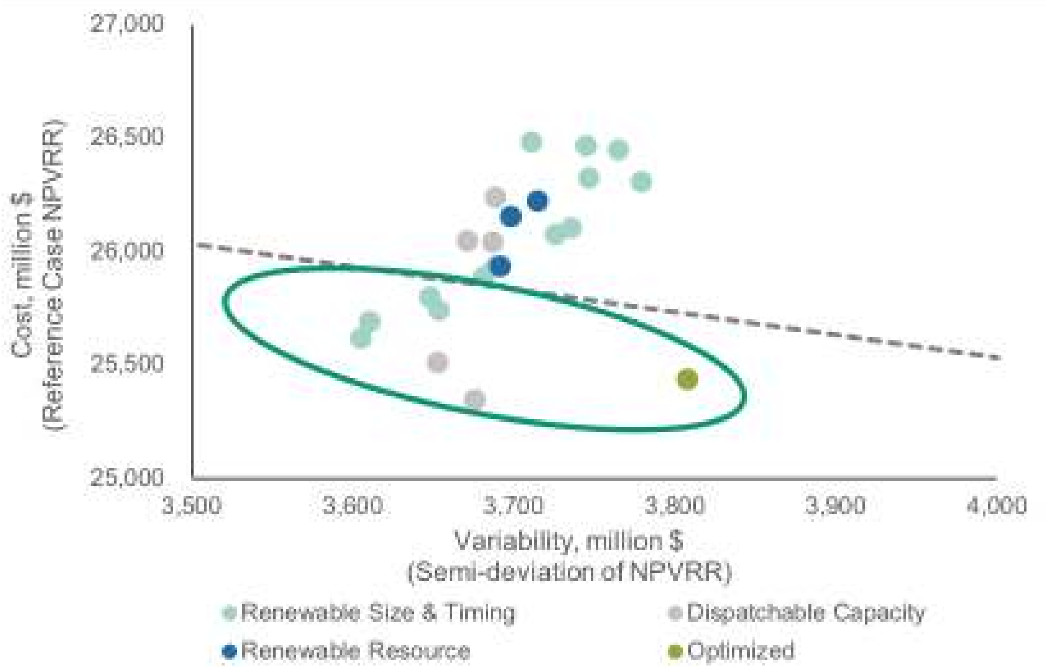
TABLE 7-4: Portfolio scores

		Traditional Metrics			Non-Traditional Metrics					
Portfolio Category	Description	Cost	Variability	Severity	GHG Constrained Cost	Near Term Cost	High Tech Future Cost	GHG Emissions	Incremental Criteria Pollutants	2025 Energy Additions
Optimized	Min Avg LT Cost	25,220	3,299	30,087	25,144	6,133	15,320	88	0	354
Optimized	Min Avg LT Cost, No Energy	25,436	3,808	30,587	25,350	6,025	15,313	100	61	10
Optimized	Min Ref LT Cost	25,170	3,323	30,032	25,091	6,142	15,295	88	61	361
Optimized	Min Ref LT Cost, All Clean	25,215	3,314	30,087	25,142	6,134	15,335	88	0	354
Optimized	Min Avg ST Cost	25,418	3,702	30,758	25,317	6,015	15,274	122	4,781	388
Optimized	Min Avg ST Cost, All Clean	25,464	3,448	30,473	25,397	6,091	15,329	92	0	412
Optimized	Min Ref ST Cost	25,418	3,702	30,758	25,317	6,015	15,274	122	4,781	388
Optimized	Min Ref ST Cost, All Clean	25,608	3,560	30,765	25,540	6,085	15,292	97	0	282
Optimized	Min Risk	25,332	3,511	30,420	25,230	6,087	15,346	119	4,172	571
Optimized	Min Risk All Clean	25,289	3,300	30,169	25,212	6,141	15,370	88	0	351
Optimized	Min GHG + Cost	25,224	3,307	30,091	25,146	6,133	15,307	88	0	358
Dispatchable Capacity	2hr Batteries	26,533	3,700	31,834	27,242	6,192	14,357	103	0	123
Dispatchable Capacity	4hr Batteries	26,244	3,688	31,531	26,203	6,158	14,505	101	0	147
Dispatchable Capacity	6hr Batteries	26,052	3,671	31,295	26,048	6,136	14,777	101	0	159
Dispatchable Capacity	Pumped Storage	26,046	3,687	31,282	26,070	6,153	15,336	102	0	149
Dispatchable Capacity	SCCT	25,351	3,675	30,699	25,266	6,051	15,256	102	61	160
Dispatchable Capacity	CCCT	25,332	3,583	30,420	25,238	6,013	15,219	119	4,781	538
Dispatchable Capacity	LMS100	25,515	3,652	30,863	25,480	6,067	15,418	102	265	189
Dispatchable Capacity	Reciprocating Engines	25,539	3,663	30,894	25,473	6,073	15,435	103	1,003	219
Renewable Size & Timing	Delay Renewables	26,675	3,835	32,085	26,671	6,150	14,421	107	0	-42
Renewable Size & Timing	50 MWa in 2023	26,310	3,779	31,700	26,329	6,192	14,395	104	0	17
Renewable Size & Timing	100 MWa in 2023	26,076	3,726	31,419	26,076	6,115	14,726	103	0	74
Renewable Size & Timing	150 MWa in 2023	25,895	3,681	31,188	25,877	6,105	14,827	102	0	129
Renewable Size & Timing	200 MWa in 2023	25,744	3,653	30,987	25,713	6,099	14,919	100	0	183
Renewable Size & Timing	250 MWa in 2023	25,620	3,635	30,807	25,577	6,097	15,009	97	0	236
Renewable Size & Timing	50 MWa in 2024	26,326	3,746	31,719	26,345	6,151	14,611	104	0	17
Renewable Size & Timing	100 MWa in 2024	26,109	3,735	31,451	26,106	6,113	14,758	103	0	74
Renewable Size & Timing	150 MWa in 2024	25,941	3,688	31,231	25,923	6,101	14,871	102	0	129
Renewable Size & Timing	200 MWa in 2024	25,804	3,678	31,043	25,771	6,073	14,977	101	0	181
Renewable Size & Timing	250 MWa in 2024	25,698	3,611	30,879	25,650	6,089	15,080	98	0	230
Renewable Size & Timing	50 MWa in 2025	26,455	3,766	31,849	26,467	6,151	14,612	106	0	15
Renewable Size & Timing	100 MWa in 2025	26,470	3,743	31,802	26,498	6,157	14,634	104	0	65
Renewable Size & Timing	150 MWa in 2025	26,480	3,710	31,760	26,516	6,162	14,660	103	0	115
Renewable Size & Timing	200 MWa in 2025	26,507	3,687	31,728	26,530	6,166	14,692	102	0	165
Renewable Size & Timing	250 MWa in 2025	26,526	3,641	31,680	26,554	6,171	14,734	101	0	215
Renewable Resource	Gorge Wind	26,161	3,698	31,431	26,167	6,143	14,696	98	0	121
Renewable Resource	[illegible] Wind	26,598	3,718	31,868	26,618	6,217	14,851	98	0	118
Renewable Resource	WA Wind	26,225	3,715	31,491	26,241	6,146	14,589	101	0	118
Renewable Resource	MT Wind	25,940	3,691	31,224	25,926	6,114	14,802	100	0	128
Renewable Resource	Solar	26,880	3,723	32,125	26,858	6,211	15,058	99	0	116
Renewable Resource	Solar + Storage	26,606	3,705	31,861	26,624	6,191	15,172	99	0	128
Renewable Resource	Geothermal	26,385	3,698	31,671	26,344	6,158	15,717	99	0	135
Renewable Resource	Biomass	26,992	3,690	32,278	26,958	6,225	16,328	99	27,708	135
Hand Designed Portfolios	Mixed Full Clean	25,740	3,614	31,004	25,694	6,098	15,341	100	0	213

2. Evaluation based on Traditional Cost and Risk Metrics.

The second step in portfolio scoring compares the remaining portfolios on the basis of the traditional cost and risk metrics. To identify the best balance of cost and risk, PGE examined the primary cost metric with each risk metric. Figure 7-9 shows a scatter plot of the cost versus variability for the remaining 22 portfolios. The slope of the dashed line represents a 50/50 weighting between cost and variability. Those portfolios that fall below the dashed line performed best in cost and variability. This exercise was repeated for cost and severity in Figure 7-10.

FIGURE 7-9: Portfolio performance on the basis of cost and variability



As illustrated in Figure 7-10, the cost and severity metrics tend to be correlated across the portfolios: portfolios that have low cost scores also tend to have low severity scores. As a result, the same portfolios performed the best in both of the cost/risk evaluations. These portfolios are listed in Table 7-5 and Table 7-6 and the corresponding near-term resource additions are shown in Figure 7-11. Among these best performing portfolios, those that include thermal resources tend to have lower cost scores, while those that include larger renewable actions tend to have lower variability scores. The *SCCT* portfolio has the lowest cost and severity scores, while the *250 MWa in 2023* portfolio has the lowest variability score.

FIGURE 7-10: Portfolio performance on the basis of cost and severity

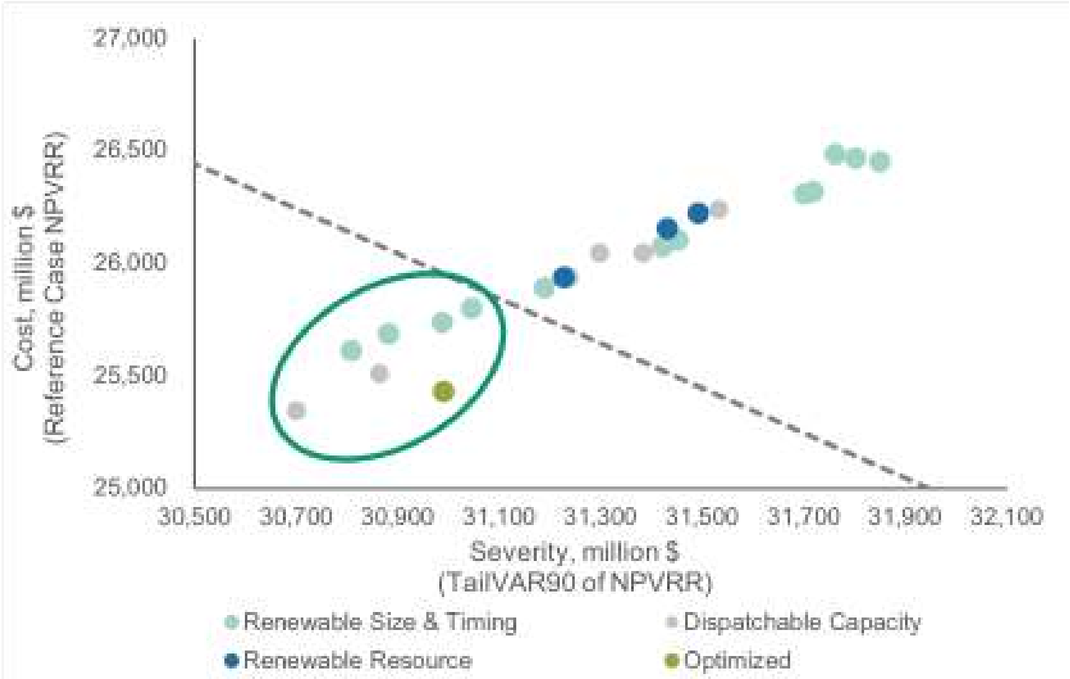


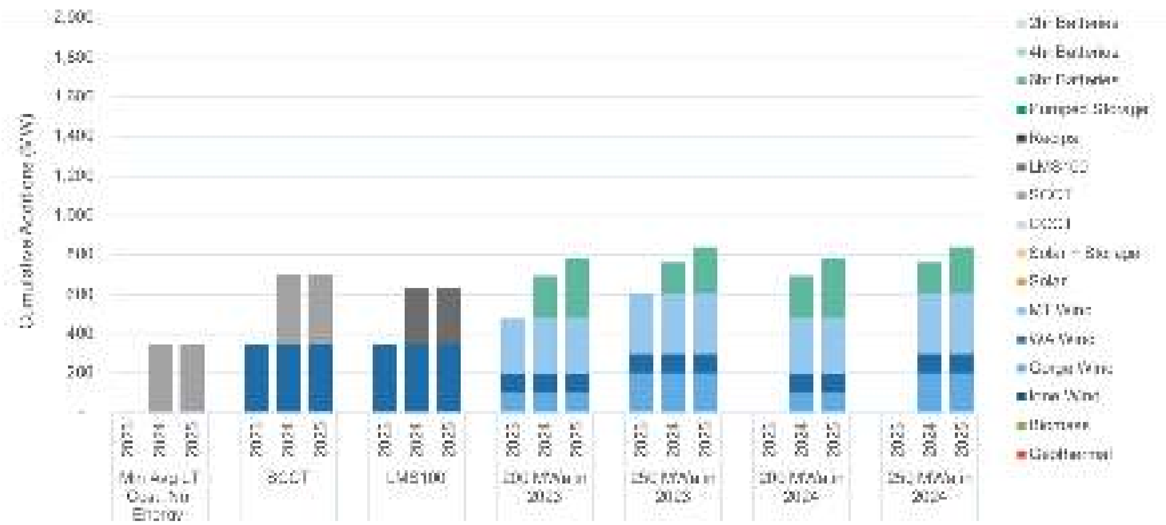
TABLE 7-5: Best performing portfolios, traditional scoring metrics

Portfolio	Category	Cost	Variability	Severity
Min Avg LT Cost, No Energy	Optimized	25,436	3,808	30,987
SCCT	Dispatchable Capacity	25,351	3,675	30,699
LMS100	Dispatchable Capacity	25,515	3,652	30,863
200 MWa in 2023	Renewable Size & Timing	25,744	3,653	30,987
250 MWa in 2023	Renewable Size & Timing	25,620	3,605	30,807
200 MWa in 2024	Renewable Size & Timing	25,804	3,648	31,043
250 MWa in 2024	Renewable Size & Timing	25,693	3,611	30,879

TABLE 7-6: Best performing portfolios, non-traditional scoring metrics

Portfolio	GHG-Constrainted Cost	Near Term Cost	High Tech Future Cost	GHG Emissions	Incremental Criteria Pollutants	2025 Energy Additions
Min Avg LT Cost, No Energy	25,351	6,025	15,313	108	61	10
SCCT	25,266	6,051	15,256	102	61	160
LMS100	25,430	6,067	15,418	102	265	189
200 MWa in 2023	25,713	6,099	14,919	100	0	183
250 MWa in 2023	25,577	6,097	15,009	97	0	236
200 MWa in 2024	25,773	6,093	14,977	101	0	183
250 MWa in 2024	25,650	6,089	15,080	98	0	236

FIGURE 7-11: Resource additions in best performing portfolios



3. Identification of common aspects of well-performing portfolios.

PGE examined the commonalities in resource additions across each of the best performing portfolios. The similarities and differences among these portfolios are summarized below.

- **Customer Resources:** All portfolios include all cost-effective energy efficiency as well as DER adoption and participation assumptions consistent with the DER Study described in External Study C. Distributed Energy Resource Study.
- **Renewable Resource Additions:** Six of the seven best performing portfolios incorporate renewable actions prior to 2025 (four add renewables in 2023 and two add renewables in 2024). Renewable addition sizes across these six portfolios range from 150 to 250 MWa. This finding reflects multiple factors, including the value associated with meeting a portion of near-

term capacity needs with renewable resources, the value of avoiding market purchases, and the continued benefits of renewable resources prior to the expiration of federal tax credits. Additional information about renewable resource economics can be found in Chapter 6. Resource Economics.

- **Capacity Resource Additions:** All seven of the best performing portfolios incorporate capacity additions prior to 2025. Capacity is provided by battery storage in four portfolios, an SCCT in two portfolios, and three LMS100 units in one portfolio. The portfolios that incorporate battery storage add incremental capacity in both 2024 and 2025, while the portfolios that add thermal resources for capacity make a single larger-capacity addition in 2024 due to thermal unit sizes. Capacity additions through 2025 range between 238 and 299 MW in the portfolios that include storage and between 279 and 347 MW in the portfolios that add thermal units. Remaining capacity needs are met with the Capacity Fill resource described in Section 7.1.1.1 Resource Adequacy.

4. Selection of a preferred portfolio.

For past IRPs, PGE designated one of the evaluated portfolios as the preferred portfolio based strictly on the calculated cost and risk metrics. While such an approach is straightforward, it may result in a preferred portfolio that is overly precise and prescriptive. As described in Chapter 6. Resource Economics, the relative economics of specific resources is uncertain, suggesting that preserving the flexibility to pursue various technologies and resource locations may yield cost savings for customers. The preferred portfolio in the 2019 IRP is therefore designed not to identify a specific set of resources, but to reflect a set of reasonable actions that would allow PGE to capture the cost and risk benefits of the best performing portfolios. To this end, PGE designed a preferred portfolio according to the following principles:

- **Customer Resources:** Include all cost-effective energy efficiency as well as the DER adoption and participation assumptions consistent with the DER Study described in External Study C. Distributed Energy Resource Study.
- **Renewable Resource Additions:** Allow up to 150 MWa of additional renewable resources in 2023 or 2024. While the portfolio analysis suggests that allowing a larger renewable resource addition in 2023 or 2024 may further reduce costs, limiting the size of the incremental renewable action to 150 MWa provides for additional flexibility should any of the capacity actions have associated energy generation (such as hydro products). Additional renewable resource additions are also allowed in 2025 if selected by the portfolio optimization.
- **Capacity Resource Additions:** Allow new capacity resource additions through 2025 from technologies that do not emit greenhouse gases. The scoring analysis summarized above suggests that energy storage performs well relative to thermal resources on the basis of cost and risk. Furthermore, pursuing energy storage resources in combination with DERs and bilateral agreements for existing resources in the region may allow for improved right-sizing of capacity additions to PGE's needs over time.

PGE implemented the constraints described above within ROSE-E to construct the Mixed Full Clean portfolio and identified it as the preferred portfolio for the 2019 IRP. The new resource options selected in the Mixed Full Clean portfolio and the resulting portfolio performance are summarized in the following section.

7.3 Preferred Portfolio

The near-term additions in the Mixed Full Clean portfolio are shown in Figure 7-12. Table 7-7 through Table 7-9 provide the complete list of resources encompassed within the Mixed Full Clean portfolio in each of the Need Futures, including customer resources.

FIGURE 7-12: Near-term additions in the preferred portfolio

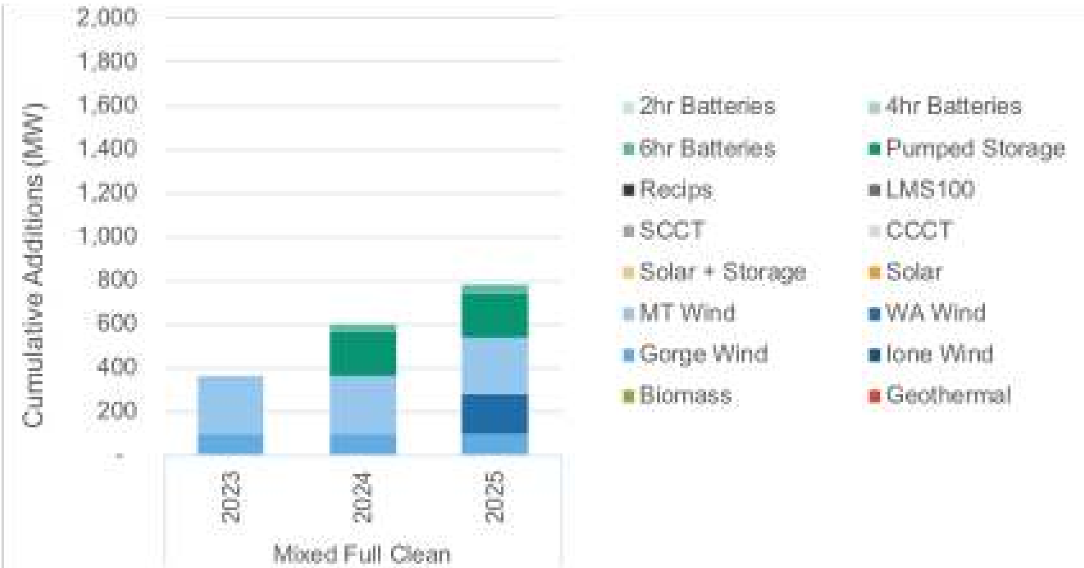


TABLE 7-7: Cumulative customer resource additions in the preferred portfolio

	Reference Case			Low Need			High Need		
	2023	2024	2025	2023	2024	2025	2023	2024	2025
Energy Efficiency (MWa)*	108	133	157	111	140	167	108	133	157
Demand Response†									
Summer DR (MW)	190	202	211	329	359	383	104	106	108
Winter DR (MW)	129	136	141	263	282	297	72	73	73
Dispatchable Standby Generation (MW)	136	137	137	136	137	137	136	137	137
Dispatchable Customer Storage (MW)	2.2	3.0	4.0	7.3	9.1	11.2	1.1	1.6	2.2

*Energy efficiency savings reflect the forecast of deployment by the end of the year and are at the meter.

†Distributed Flexibility values are at the meter.

TABLE 7-8: Cumulative renewable resource additions in the preferred portfolio

	Reference Case			Low Need			High Need		
	2023	2024	2025	2023	2024	2025	2023	2024	2025
Wind Resources									
Gorge Wind (MWa)	41	41	41	41	41	41	41	41	41
WA Wind (MWa)	0	0	77	0	0	77	0	0	77
MT Wind (MWa)	109	109	109	109	109	109	109	109	109
Total Renewables (MWa)	150	150	227	150	150	227	150	150	227

TABLE 7-9: Cumulative dispatchable capacity additions in the preferred portfolio

	Reference Case			Low Need			High Need		
	2023	2024	2025	2023	2024	2025	2023	2024	2025
Storage Resources									
6hr Batteries (MW)	0	37	37	0	37	37	0	37	37
Pumped Storage (MW)	0	200	200	0	200	200	0	200	200
Total Storage (MW)	0	237	237	0	237	237	0	237	237
Capacity Fill (MW)	123	79	358	0	0	0	425	423	739
Total Dispatchable Capacity (MW)	123	316	595	0	237	237	425	660	976

7.3.1 Preferred Portfolio Performance

The Mixed Full Clean portfolio passes all of the non-traditional scoring metric screens and is one of the best performing portfolios based on traditional cost and risk metrics. As indicated in Figure 7-13, the Mixed Full Clean portfolio costs more, but performs better on the variability risk metric than those portfolios that include thermal resources. The cost, variability, and severity of the Mixed Full Clean portfolio is comparable to the portfolios that test larger renewable addition sizes (see Figure 7-14).

The strong economic performance of the Mixed Full Clean portfolio is largely driven by the incorporation of wind additions prior to December 31, 2022, which qualify for the 60-percent federal production tax credit (PTC). At this level, the PTC lowers the cost of a 150-MWa Washington Wind addition by approximately $170 million, or 20 percent of the resource cost. Wind additions also provide cost and risk benefits to the portfolio by reducing the amount of market purchases required to meet customer energy needs and reducing the need for additional capacity. In the Reference Case, the addition of 150 MWa of Washington wind to the portfolio is estimated to save about $180 million over its lifetime relative to a strategy of relying on the market for energy and an SCCT for an equivalent amount of capacity.

FIGURE 7-13: Cost versus variability for the preferred portfolio

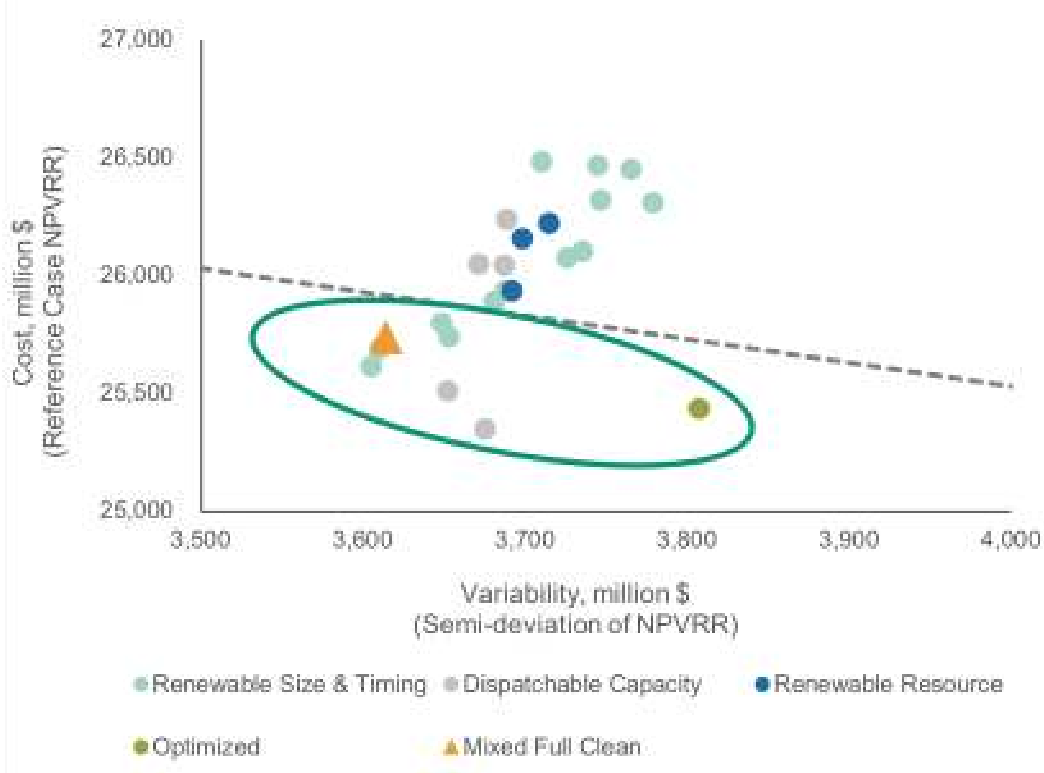
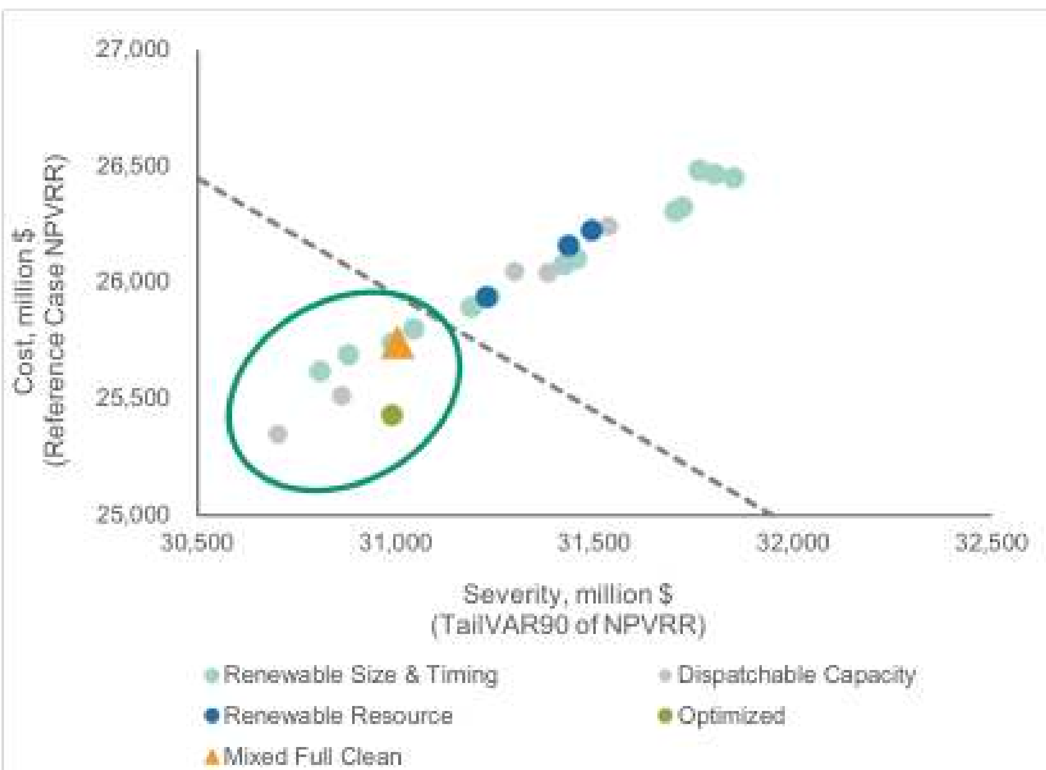
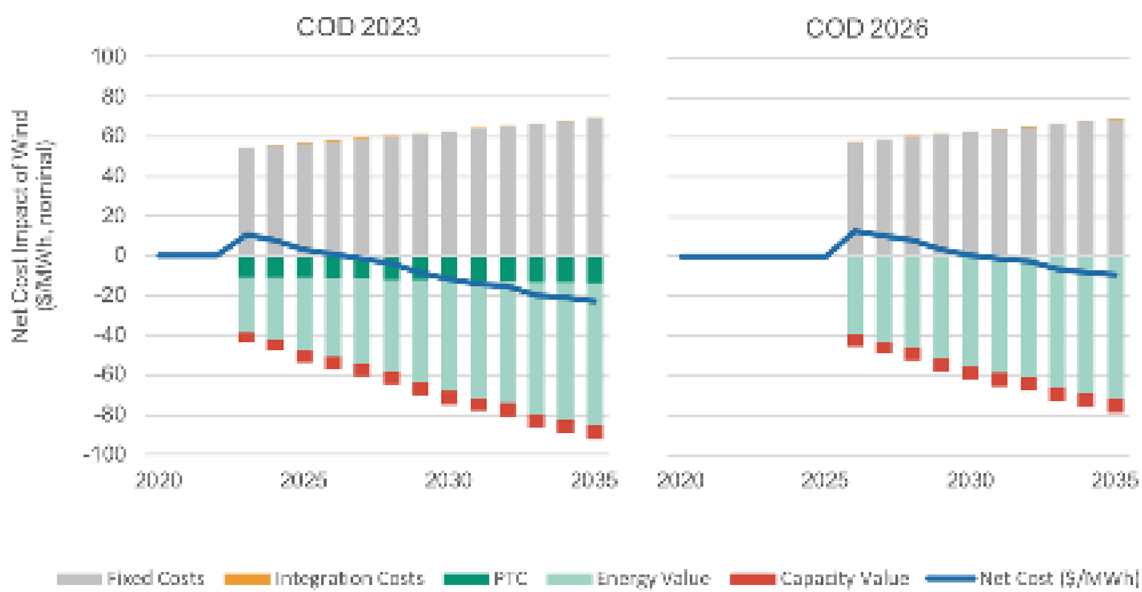


FIGURE 7-14: Cost versus severity for the preferred portfolio



While the long-term benefits of pursuing near-term renewables are compelling, some stakeholders have raised questions about whether today's customers should be paying for resources that will benefit customers in future years. To address this question of intergenerational equity, we estimated the potential average impact to power prices between 2021 and 2035 of pursuing renewables in the near term. This analysis explored the expected annual costs and benefits over time of a renewable addition size consistent with the preferred portfolio (150 MWa of Washington Wind with COD 2023 to qualify for the 60-percent PTC) and the same sized renewable addition in 2026. Both additions were effectively modeled as PPAs with prices that escalate with inflation. In other words, fixed costs and PTC impacts were levelized over the life of the project. The resulting annual net cost impacts for the additions (in $/MWh generated) are summarized in Figure 7-15.

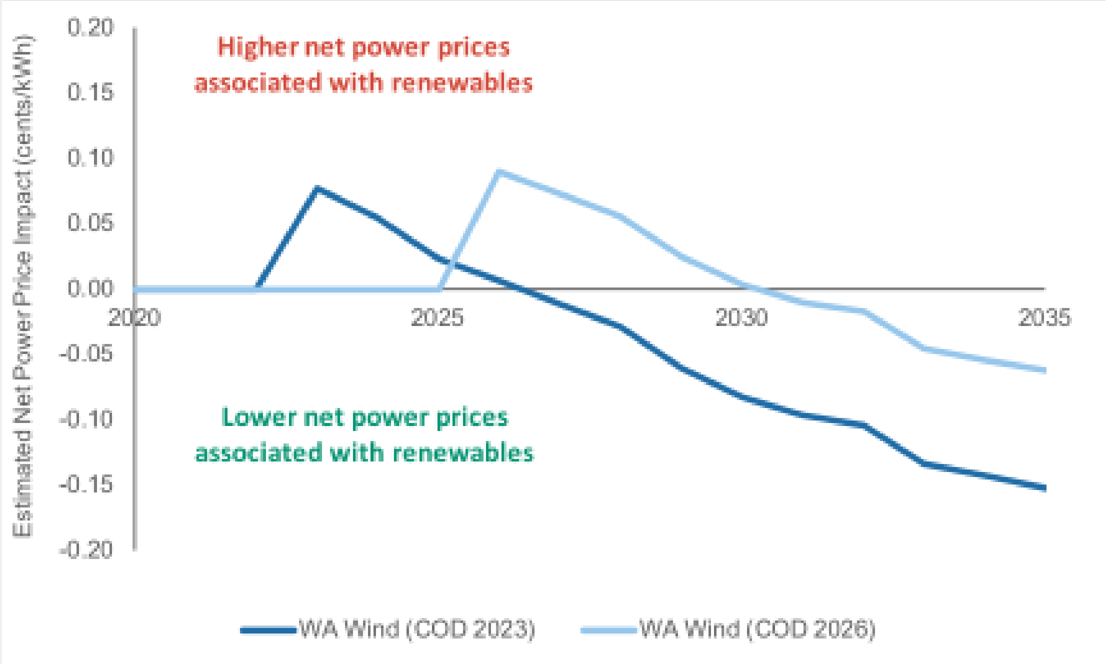
FIGURE 7-15: Annual net cost impact of Washington Wind additions



To estimate the annual net impacts to retail power prices associated with the renewable additions (in cents per kWh of sales), the resulting net costs were scaled up to the resource addition size of 150 MWa and divided by the retail sales forecast in each year. This analysis, which is shown for each year and each renewable addition in Figure 7-16, demonstrates that renewable action is expected to cause a small net increase in power prices in the first years of a project, but that the availability of the PTC decreases the magnitude of these increases, shortens the period over which the increases are expected, and results in larger net reductions to power prices sooner, relative to deferring renewable action.

More specifically, the analysis indicates that pursuing near-term wind is expected to cause a small net increase in average power prices between 2023 and 2026 (approximately 0.04 cents/kWh) but is expected to lower rates beginning in 2027, relative to a strategy of meeting customer energy and capacity needs without the renewable addition. Waiting until 2026 for the same wind addition would result in slightly larger estimated power price impacts due to the unavailability of federal tax credits (averaging approximately 0.05 cents/kWh between 2026 and 2030) and would not result in net reductions to power prices until 2031. The exact impacts to rates and timing of these impacts will depend on the cost, performance, and ownership structure of acquired resources, as well as future market conditions.

FIGURE 7-16: Estimated net impacts to retail power prices of Washington Wind additions

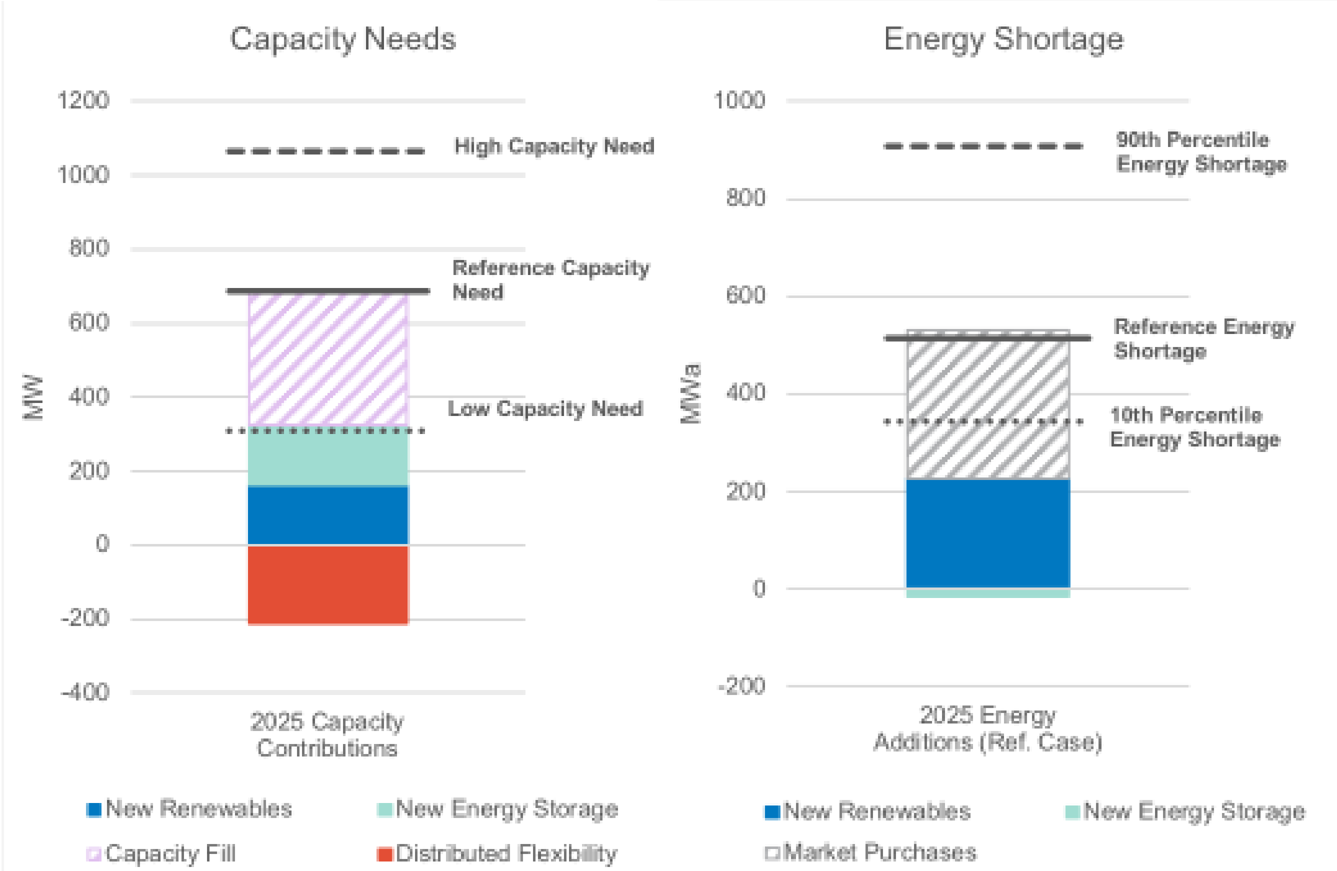


7.3.2 Contribution to Meeting Needs

The Mixed Full Clean portfolio will allow PGE to address near-term needs while providing adequate flexibility to respond as conditions evolve in the future. Figure 7-17 shows how the Mixed Full Clean portfolio meets PGE's energy and capacity needs in 2025. The Mixed Full Clean portfolio adds new long-term resources to meet just under 50 percent of PGE's total capacity needs in 2025 in the Reference Case, with the remainder of needs assumed to be met through other means, including, but not limited to contracts for capacity from existing resources in the region. Of the capacity added from new resource additions, approximately half is provided by new renewables and the rest is provided by energy storage. The new renewable and storage resource additions in the preferred portfolio meet approximately 40 percent of the Reference Case energy shortage in 2025, leaving 60 percent of the energy shortage to be served by other means. In the IRP, this portion of our energy needs are met by market purchases, but other resources could contribute to meeting these needs, including, but not limited to energy associated with additional contracts or customer participation in voluntary renewable programs. The preferred portfolio provides adequate flexibility in energy and capacity needs to accommodate resource needs that are lower than expected, as demonstrated by the Low Capacity Need and 10th Percentile Energy Shortage lines in Figure 7-17.[177] However, additional resources could be required to meet needs that are higher than expected, as shown by the High Capacity Need and 90th Percentile Energy Shortage lines in Figure 7-17.

177 Distributed Flexibility encompasses all existing and incremental demand response, dispatchable customer storage, and dispatchable standby generation in the Reference Case. It appears below the axis because these resources are already accounted for in the determination of the identified capacity needs.

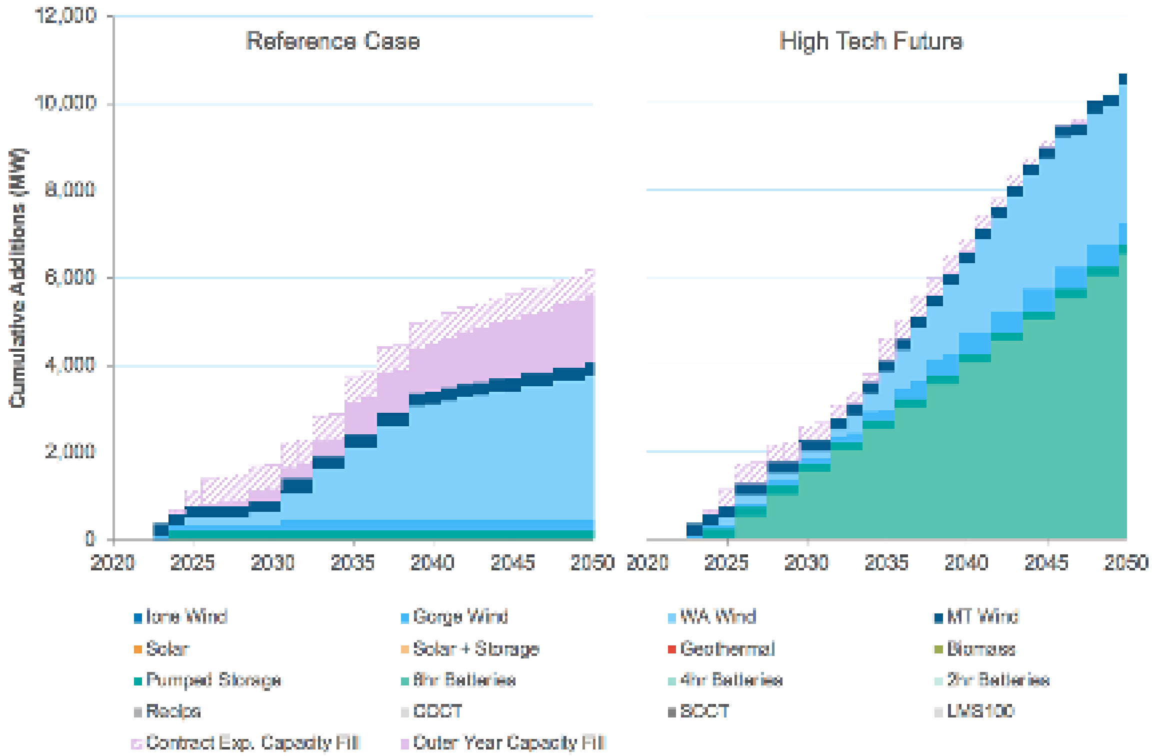
FIGURE 7-17: Mixed Full Clean portfolio contribution to 2025 resource needs



In the long term, the composition of the Mixed Full Clean portfolio develops differently over time as future market and technology conditions evolve. In total there are 270 potential resource addition trajectories considered for the Mixed Full Clean portfolio across the Need, Market Price, and Technology Cost Futures. To illustrate the potential variation into the future, we explore resource additions in two specific futures: the Reference Case, and the High Tech Future that contemplates high deployment of renewables across the West as well as low solar and battery technology costs.

Figure 7-18 shows the installed capacity of new resources in the Mixed Full Clean portfolio in the Reference Case and the High Tech Future. While resource additions through 2025 are identical in the two futures, technology and market evolution drive substantially different strategies from 2026 through 2050. The differences are most pronounced in their capacity additions. In the Reference Case, battery storage costs remain more costly than traditional capacity and capacity needs that remain after accounting for renewables and DERs are met with the Capacity Fill resource described in Section 7.1.1.1 Resource Adequacy. In contrast, the High Tech Future reflects both lower battery costs and higher battery value due to market price volatility driven by accelerated renewable deployment in the West. As a result, 6-hour batteries are steadily added to the portfolio to fill almost all of PGE's remaining capacity needs through 2050 in this future.

FIGURE 7-18: Installed capacity of new resources in the Mixed Full Clean portfolio



The preferred portfolio also demonstrates different long-term renewable strategies across the various futures. Figure 7-19 shows how renewable additions are staged in the Reference Case well above physical RPS requirements, closing PGE's market energy shortage by the late-2030s. In the High Tech Future, however, renewable additions after 2025 are delayed until the mid-2030s and do not close PGE's market position until the mid-2040s. In this future, the renewable procurement strategy is affected by the accelerated deployment of renewables in the West, which depresses market prices during times of high renewable output and decreases the value of renewables in PGE's portfolio. In other words, in the High Tech Future, it becomes more cost effective to leverage the benefits of other entities developing renewables by purchasing low cost energy from the market. In both futures, renewable additions are driven by economic rather than RPS-compliance considerations, as evidenced by the fact that renewable additions exceed physical RPS obligations in most years, further growing PGE's renewable energy credit (REC) bank (see Figure 7-20).

The significant variation in resource additions between these futures demonstrates that the Mixed Full Clean portfolio maintains adequate optionality to pursue dramatically different procurement strategies in the future depending on how markets and technologies evolve. The scale of the additions that arise through 2025 relative to those made in the following decades (see Figure 7-18) also provides assurance that the near-term actions in the preferred portfolio are incremental relative to the long-term need.

FIGURE 7-19: Energy generation in the Mixed Full Clean portfolio

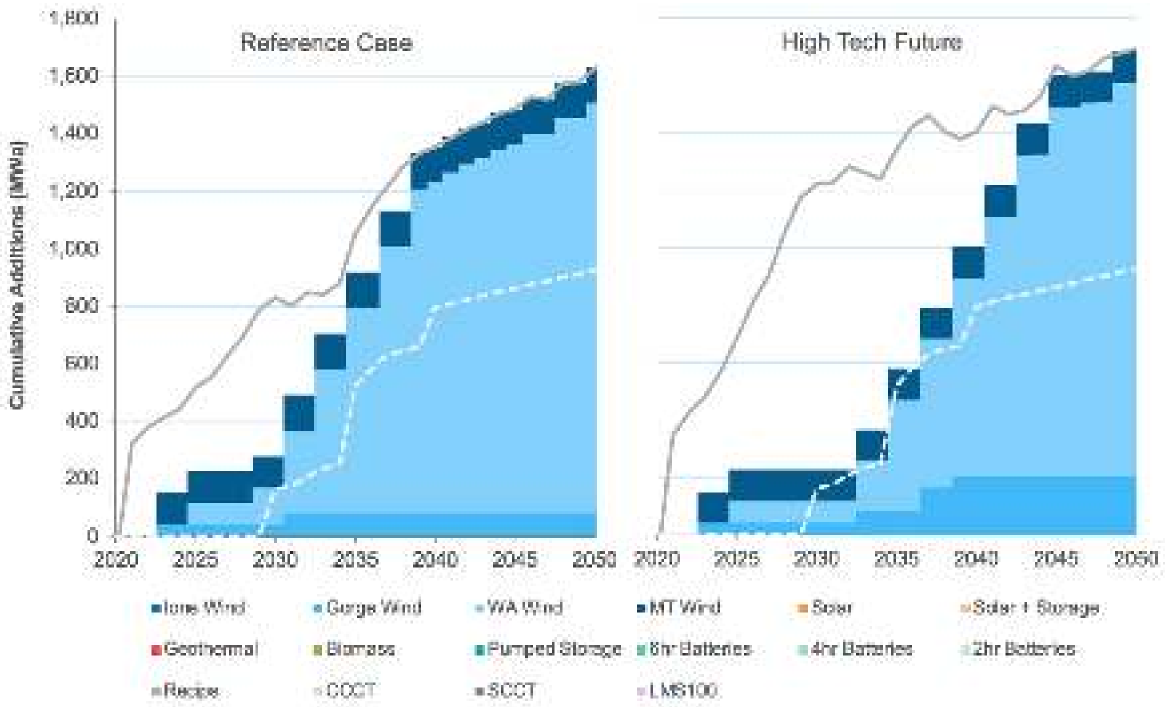
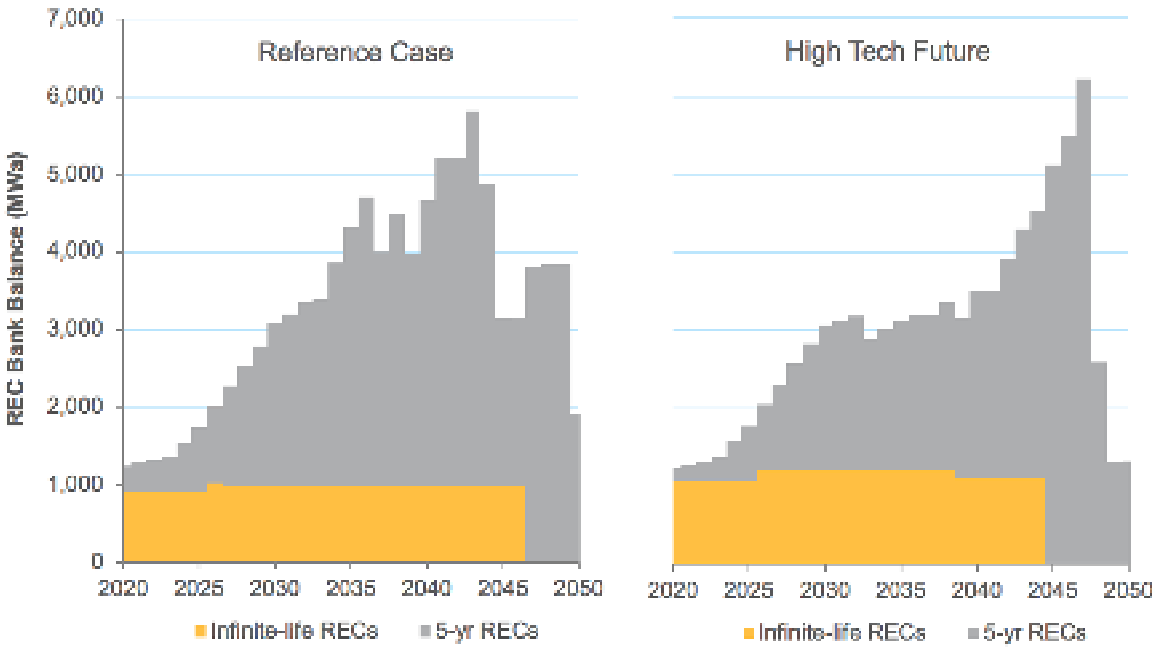


FIGURE 7-20: REC bank balance in the Mixed Full Clean portfolio

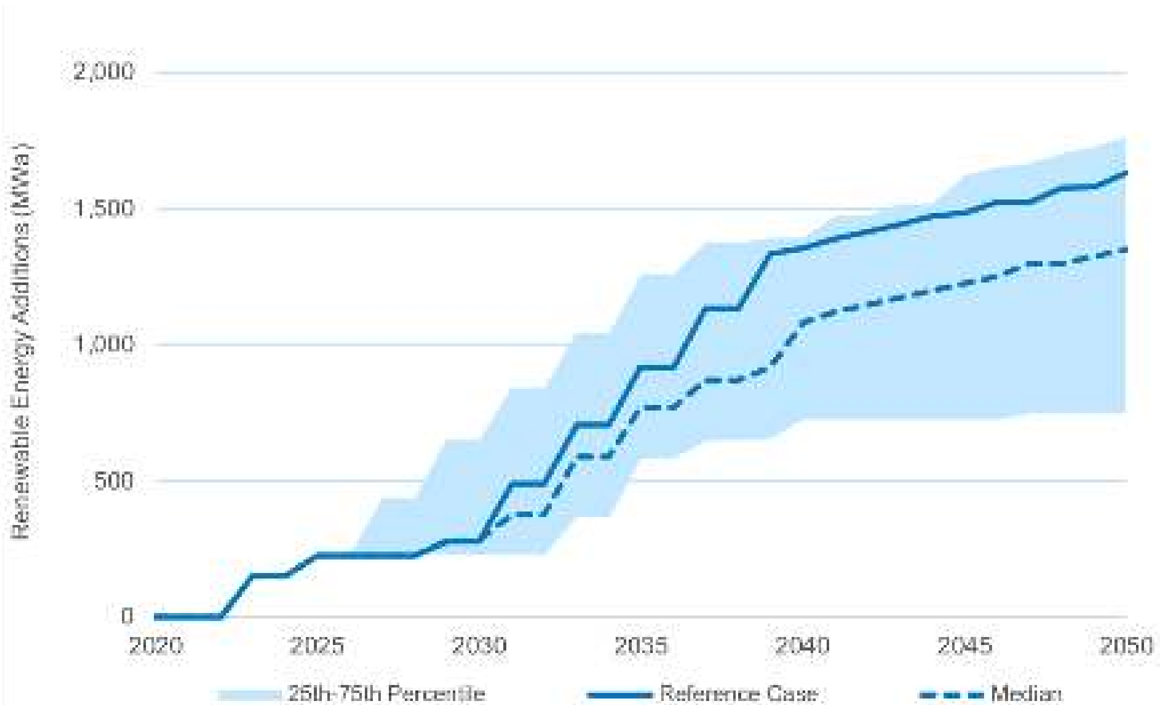


7.3.3 Renewable Glide Path

In OPUC Order 18-044, the Commission directed PGE to conduct a renewable glide path analysis to support the design of future renewable resource actions. In response, PGE has embedded the concept of a renewable glide path into its portfolio construction framework. All portfolios investigated in the 2019 IRP have an associated renewable glide path that contextualizes near-term renewable actions within a longer-term renewable strategy. Importantly, the renewable glide path is not a single trajectory, but a set of potential trajectories that will evolve over time as PGE gains additional information about our future needs and the market landscape.

The renewable glide path for the Mixed Full Clean portfolio is shown in Figure 7-21. The solid line represents the renewable resource additions over time under Reference Case conditions, while the dashed line represents the median of renewable resource additions across all futures and the shaded area reflects the 25th-75th percentile of renewable resource additions across futures. Resource additions are observed in two-year steps due to the procurement constraints described in Section 7.1.1.4 Procurement Constraints. While the Mixed Full Clean portfolio includes resource additions in 2023 and 2025 across all futures, consistent with the principles of portfolio construction, there remains uncertainty in the next economically optimal renewable resource addition beyond 2025. The next economically optimal renewable resource addition occurs in 2027 in 25 percent of futures, in or before 2029 in 50 percent of futures, and in or before 2033 in 75 percent of futures.

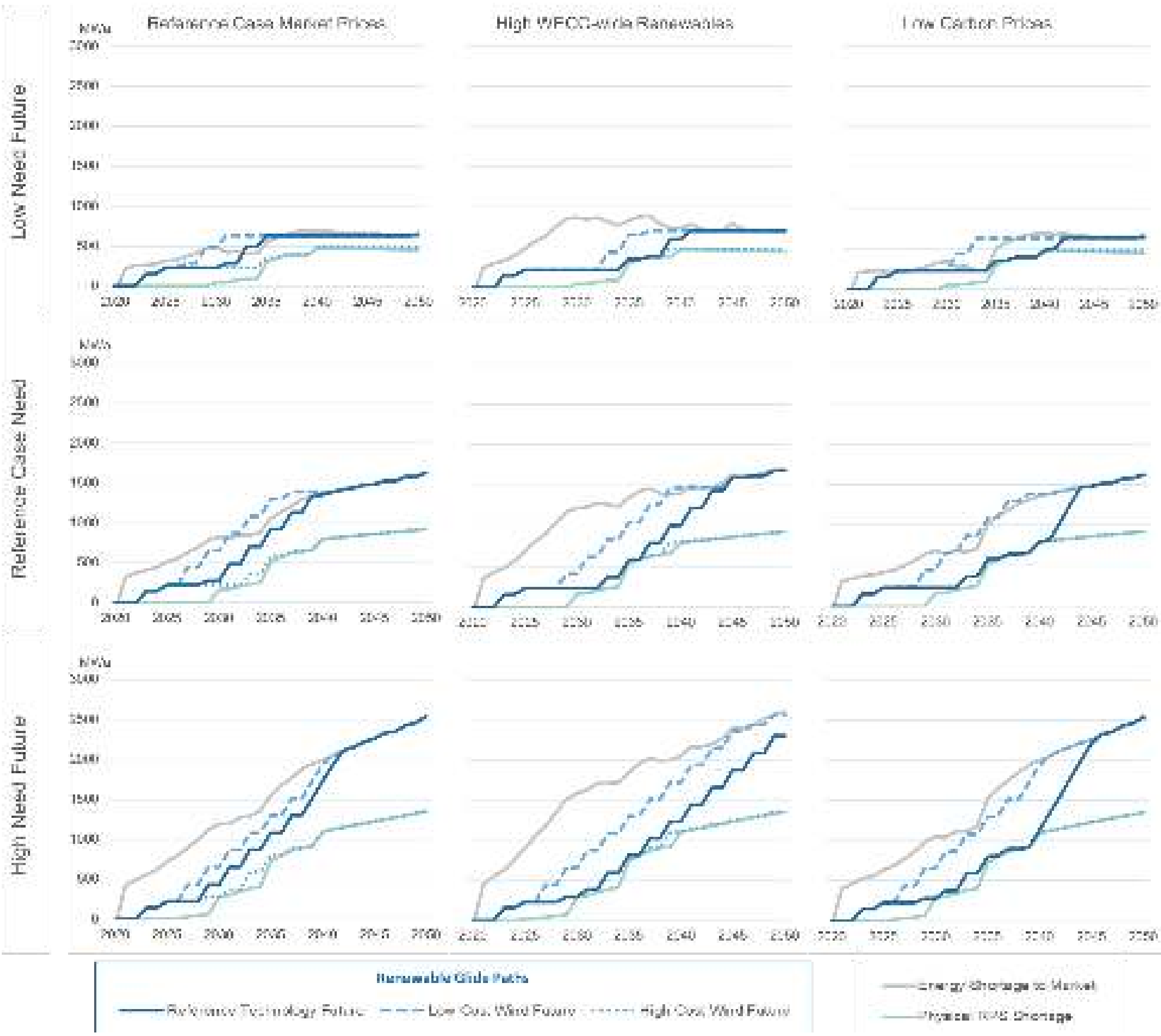
FIGURE 7-21: Renewable glide path in the preferred portfolio



To examine the drivers of renewable procurement in each of these futures, it is helpful to compare the renewable glide paths in specific futures to the energy and RPS positions described in Section 4.4 Energy Need and Section 4.5 RPS Need. Figure 7-22 shows the incremental renewable additions by year in twenty-seven specific futures: all three Need Futures (Low, Reference, and High), three of the 18 Market Price Futures (Reference Case, High WECC-wide Renewables with Reference Gas Prices and Carbon Prices, and Low Carbon Prices with Reference WECC-wide Buildout and Reference Gas Prices), and three Technology Price Futures (Reference Case, Low Cost Wind, and High Cost Wind). In each graph, realizations of the renewable glide path are shown in blue, while

PGE's energy-shortage-to-market is shown in gray and PGE's physical RPS needs are shown in light green. Consistent with the constraints described in Section 7.1.1 Portfolio Design Principles, the renewable glide path generally falls between the RPS need and the energy shortage so that portfolios meet physical RPS compliance without going persistently long to the market on an average annual basis.

FIGURE 7-22: Renewable Glide Path in specific futures



While the renewable additions between 2023 and 2025 are the same across all futures, the cost-optimized renewable additions vary widely after 2025 depending on the need, market conditions, and technological evolution. In the Reference Market Price Future (left panels) and Reference Technology Future (solid blue lines), cumulative renewable resource additions exceed the physical RPS shortage in all years and renewable additions are layered in over time to close PGE's short market position by approximately 2040. This indicates that renewable resources in these futures represent a lower cost option for meeting customer energy and capacity needs than turning to the market for energy and the generic capacity fill resource for capacity. In the Low Cost Wind Future (dashed light blue line), the economics favor renewable procurement even more than in the Reference Case and renewable additions close PGE's open market position by around 2030 (with the exception of the High Need Future). In the High WECC-wide Renewables Market Price Future (middle panels), renewable resource economics are generally less favorable than the Reference Case because renewable deployment across the West suppresses market prices during hours of high renewable output. This effect can be seen as a delay in the ramp-up of renewable resources to close PGE's open energy market position. For example, in the Reference Technology Future and with Reference Case Need (solid blue line in middle panel), the renewable ramp-up does not begin until the early 2030s and PGE's open energy position is not closed until approximately 2045. When high renewable technology costs are combined with High WECC-wide buildout of renewables (dotted lines in middle panels), renewable additions are largely limited to the amounts required for physical RPS compliance. This future, however, may be an unlikely outcome because it contemplates a rapid expansion of renewable deployment across the West without continued renewable technology cost declines.

Similar phenomena are observed in the Low Carbon Price Future (right panels), where renewable technology costs determine whether future renewable additions are driven by RPS obligations or by economics. In the Low Carbon Price Future, PGE's energy open position is also much smaller in the near term due to dispatch economics for existing thermal resources in the portfolio. When combined with the Low Need Future (upper right panel), this results in the persistence of a relatively small open position through 2035. In this extreme case, the renewable glide path responds by delaying the next renewable resource action to 2035, except in the Low Wind Cost Future.

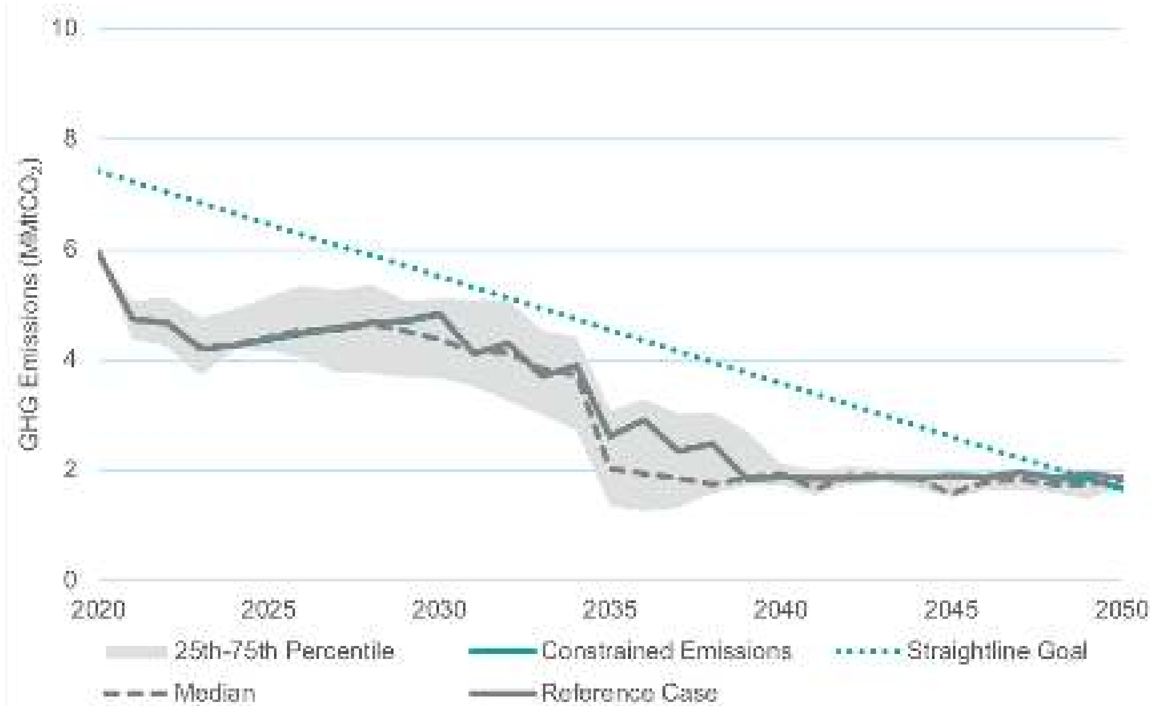
In summary, in each Need Future, there are Price and Technology Futures in which renewable resources become the most cost-effective options for meeting energy needs. In these futures, renewable additions ramp up quickly to fill PGE's remaining budget for energy until annual net market purchases are zero. In other futures in which renewable resources are not the most economic option for providing energy to customers, future renewable resource additions are instead driven by RPS constraints, resulting in much less renewable deployment. The near-term additions in the Mixed Full Clean portfolio allow PGE to take advantage of the near-term opportunity to pursue cost-competitive renewables, while allowing the long-term flexibility to ensure strong outcomes for PGE and PGE customers in either of these potential future states.

7.3.4 Greenhouse Gas Emissions

The Mixed Full Clean portfolio enables PGE to continue to drive down portfolio GHG emissions. Figure 7-23 illustrates the Reference Case and range of potential GHG emission trajectories corresponding to the Mixed Full Clean portfolio and considering uncertainties across the Need, Technology Cost, and Market Price Futures (under Reference Hydro Conditions). The trajectory reflects the effects of both near-term and outer year renewable additions, the effects of ceasing coal-fired operations at Boardman by the end of 2020, the exit of Colstrip Units 3 and 4 from our portfolio no later than the end of 2034, and the potential impacts of a cap and trade program in Oregon. Our analysis suggests that with continued effort to deploy energy efficiency, implement

Senate Bill 1547, and respond to potential climate and clean energy policies, we would be on course to stay close to or below our target emissions trajectory between now and 2050.

FIGURE 7-23: GHG emissions in the preferred portfolio



7.4 Additional Insights

7.4.1 Decarbonization Scenario

PGE's Decarbonization Study, which can be found in External Study A, explores technology pathways to reducing GHG emissions in PGE's service area by 80 percent below 1990 levels by 2050 across the entire energy economy. PGE undertook the study with Evolved Energy Research to better understand how energy services might be met in a deeply decarbonized future and what such a future might entail for an electric utility. The study identified three common strategies that are necessary across all technology pathways and that must be pursued simultaneously and aggressively to reach the goal. First, all the pathways required dramatic increases in energy efficiency to reduce total energy consumption across the economy including transportation, electricity, natural gas, and industrial energy demand. Second, meeting the goal required decarbonization of electricity supply through continued development of clean and renewable resources. And finally, the scenarios all relied on electrification to avoid the direct combustion of fossil fuels through the adoption of new clean technologies like electric vehicles and heat pumps.

While the pathways investigated in the Decarbonization Study are not prescriptive and do not represent market forecasts of consumer behavior, they do provide illustrative scenarios to better understand how the electricity system may evolve within a deeply decarbonized world. As a first step to gaining this understanding, a Decarbonization Scenario was developed and tested as part of PGE's portfolio analysis. In this scenario, loads were adjusted to estimate the impacts of the electric vehicle adoption, energy efficiency, and electrification in the High Electrification pathway described in the Decarbonization Study. Distributed flexibility assumptions in this scenario reflect the Reference Case, with the exception of electric vehicle direct load control (EV DLC) programs, which were scaled up with the EV load. Market prices and resource dispatch reflected the High Renewable WECC Future. PGE conducted a separate needs assessment, dispatch simulation, and portfolio optimization in this specific scenario, given the near-term resource additions in the preferred portfolio and applying a carbon constraint over time.[178]

The renewable resource additions in the Decarbonization Scenario relative to the energy market shortage over time are shown in Figure 7-24. For context, the same information is also shown for the Carbon-Constrained Future, which assumes Reference Case resource needs and economics. The greater energy market shortage in the Decarbonization Scenario reflects the growth in electricity demand associated with electrification, the offsetting effect of additional energy efficiency, and the effects of the High Renewable WECC Future market prices. Renewable resource additions in the Decarbonization Scenario ramp up at approximately the same pace as in the Carbon-Constrained Future through 2040 and continue to ramp up quickly in the 2040s to meet the growing load, while renewable additions slow in the 2040s in the Carbon-Constrained Future.

FIGURE 7-24: Decarbonization Scenario renewable additions

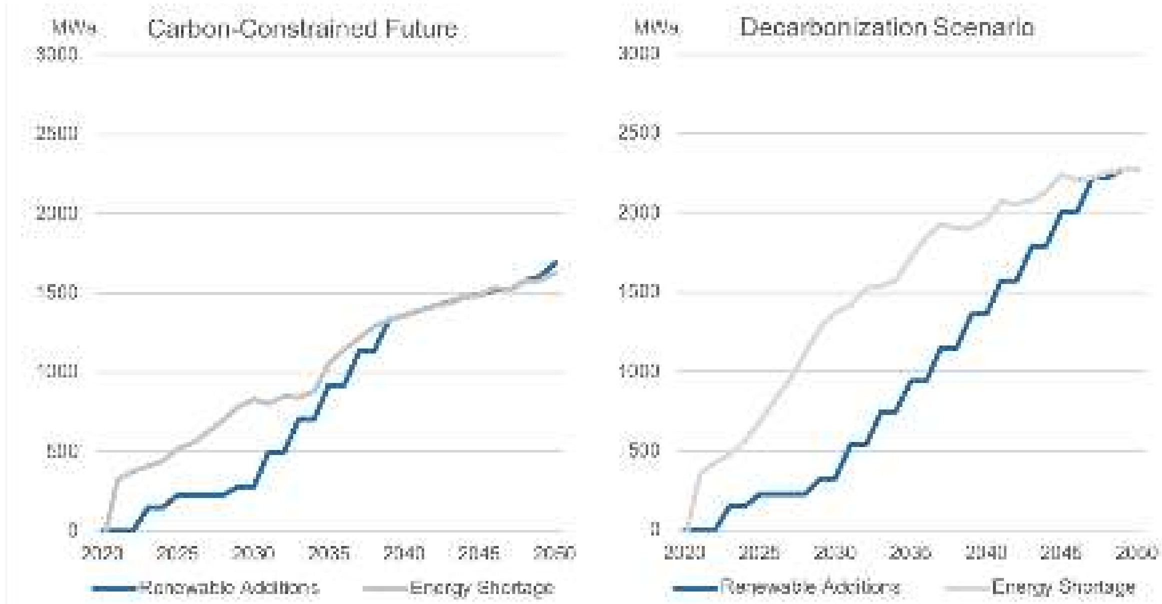
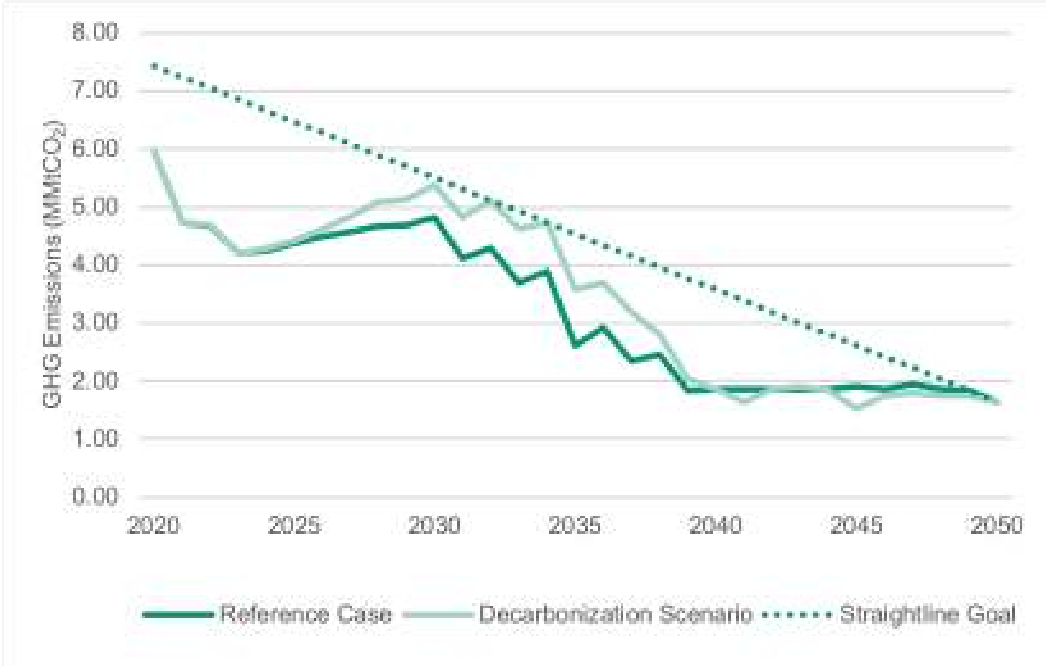


Figure 7-25 shows the corresponding implications for GHG emissions within the electricity sector. While growing electrification loads without corresponding renewable additions appear to lead to an increase in GHG emissions in the 2030s, this analysis excludes the emissions that are avoided through electrification of end uses that would otherwise rely on direct combustion of fossil fuels. The Decarbonization Study demonstrated that electrification results in emissions reductions across the economy as a whole, even if the electricity sector experiences higher loads as a result. This Decarbonization Scenario analysis also demonstrates that electrification does not preclude PGE

[178] The application of the carbon constraint in the portfolio optimization means that portfolio costs in this future are not directly comparable to portfolio costs in other futures because the carbon constraint relies on heuristic estimates of thermal resource production costs.

from meeting our long-term decarbonization goals, as the emissions drop to Reference Case levels by 2040 and meet PGE's goal in 2050.

FIGURE 7-25: Decarbonization Scenario GHG emissions



7.4.2 Colstrip Sensitivities

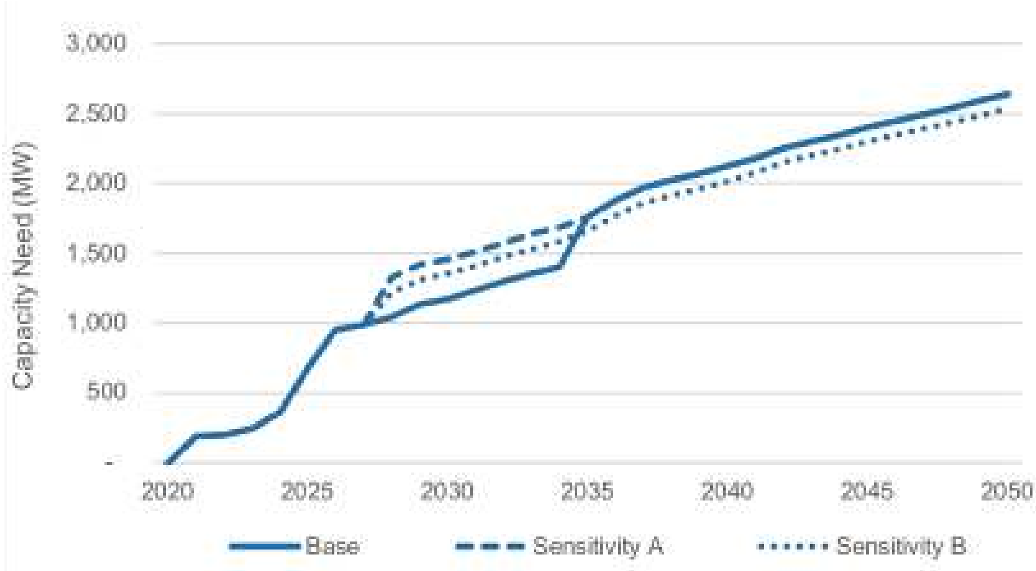
Consistent with the requirements of SB 1547, the portfolios and portfolio costs described in this chapter reflect the depreciation of Colstrip units 3 and 4 by the end of 2030 and the removal of Colstrip units 3 and 4 from PGE's portfolio by the end of 2034. In the 2016 IRP, PGE investigated alternative scenarios for the removal of Colstrip from PGE's portfolio. Stakeholders in PGE's 2019 IRP public process requested that PGE incorporate Colstrip scenarios that contemplate the removal of Colstrip from PGE's portfolio by the end of 2027 and the replacement of Colstrip at that time with Montana Wind. In response, PGE investigated the preferred portfolio under two alternative scenarios relating to Colstrip:

- **Sensitivity A.** Colstrip is fully depreciated and exits PGE's portfolio by the end of 2027. All replacement energy and capacity required as a result of Colstrip's exit is solved for by the portfolio optimization.
- **Sensitivity B.** Colstrip is fully depreciated and exits PGE's portfolio by the end of 2027. Beginning in 2028, the portfolio incorporates a 296-MW Montana Wind resource to replace a portion of the capacity and energy associated with Colstrip's exit. Any replacement energy and capacity that is required beyond the Montana Wind replacement resource is solved for by the portfolio optimization.

The impact to PGE's capacity need in each sensitivity is shown in Figure 7-26.

As shown, acceleration of Colstrip's exit from PGE's portfolio to 2027 brings forward approximately 280 MW of capacity need into the mid-2020s when PGE also faces increased capacity needs due to expiring contracts. If expiring contracts are not replaced with similar amounts of capacity and if Colstrip were to exit PGE's portfolio at the end of 2027, PGE's capacity need would increase to approximately 1,300 MW in 2028 under Reference Case conditions. The Montana Wind replacement resource included in Sensitivity B as described above would fill approximately 103 MW of this capacity need.

FIGURE 7-26: Capacity need in Colstrip sensitivities



PGE investigated the traditional cost and risk metrics of the preferred portfolio across both Colstrip sensitivities. The results of this analysis are shown in Table 7-10.

TABLE 7-10: Portfolio scoring metrics for Colstrip sensitivities

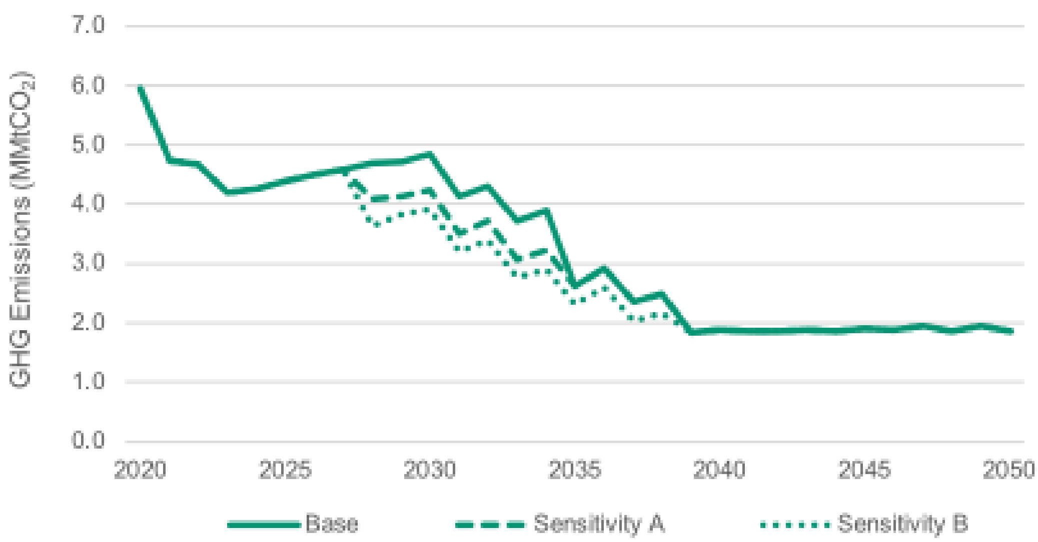
	Scoring Metric (million 2020$)		
	Cost	**Variability**	**Severity**
Base Case	25,740	3,614	31,004
Colstrip Sensitivity A 2027 Exit	25,507	3,652	30,834
Colstrip Sensitivity B 2027 Exit w/ MT Wind	25,542	3,585	30,761

The Colstrip sensitivities indicate that the preferred portfolio Reference Case cost may be lowered if Colstrip were to exit PGE's portfolio at the end of 2027 instead of the end of 2034. However, this strategy also increases risk as expressed by the variability metric. The addition of Montana Wind to the portfolio in 2028 to replace a portion of the energy and capacity associated with Colstrip results in higher Reference Case costs, but lower variability, relative to the strategy of replacing energy and capacity in a cost optimal manner.

The inclusion of Colstrip also impacts PGE's portfolio GHG emissions. Figure 7-27 shows how PGE's GHG emissions trajectory varies across the Colstrip sensitivities under Reference Case conditions.

Under Reference Case conditions, an early exit of Colstrip from PGE's portfolio results in a reduction in GHG emissions of approximately 0.6 million metric tons per year.

FIGURE 7-27: GHG emissions in Colstrip sensitivities



While these findings suggest that there may be economic benefits to removing Colstrip from PGE's portfolio earlier than the end of 2034, PGE has not evaluated the costs and risks of actions related to Colstrip in the two- to four-year 2019 IRP Action Plan time frame for the following reasons:

- First, at the time of this report, there remains considerable uncertainty in the future cost of operating Colstrip because the co-owners of Colstrip units 3 and 4 have not yet executed a coal supply contract for operations after 2019. The IRP analysis incorporates coal pricing assumptions based on past coal prices, which may not be indicative of the future.
- Second, the near-term economics of Colstrip units 3 and 4 would be materially impacted by the adoption of carbon regulation in Oregon. The 2019 IRP analysis incorporates carbon pricing based on an assumption of Oregon adopting a cap and trade program linked to California and in effect at the beginning of 2021. While this assumption is largely consistent with the most relevant policy proposal under consideration, at the time of this report, the specific form and timing of carbon regulation in Oregon remains uncertain.
- Third, the early exit sensitivities described above incorporate a change to the depreciation schedule for Colstrip units 3 and 4 that has not been proposed by PGE or considered by the Commission. The full evaluation of potential actions related to Colstrip units 3 and 4 will require consideration of cost recovery and rate impacts that are not incorporated into traditional IRP portfolio analysis.
- And finally, due to the structure of the agreements between the co-owners of Colstrip units 3 and 4, PGE has limited ability to pursue actions related to Colstrip in a unilateral manner. In addition, the co-owners have diversity in ownership, business practice, emissions goals, and regulatory processes, which introduces uncertainty and complexity into any joint decision-making process.

PGE will continue to examine options related to Colstrip units 3 and 4 as additional information becomes available. In considering options related to Colstrip, PGE will continue to prioritize cost impacts and risks to customers, reliability, and GHG emissions implications.

CHAPTER 8. Action Plan

Amid the rapid technological and market change being experienced in the electric sector in the West, utilities face large uncertainties in future needs and resource economics. This IRP demonstrates that, despite these uncertainties, PGE can take low-risk, near-term actions to meet near-term needs and set the Company on a course to achieve critical long-term goals.

Chapter Highlights

★ PGE's action plan proposes a set of resource actions that we intend to undertake over the next four years to acquire the resources identified in the preferred portfolio.

★ The preferred portfolio, Mixed Full Clean, represents the set of resources that provide the best combination of expected cost and risk for PGE and our customers under the assumptions used in the IRP process.

★ Customer resource actions include all cost-effective energy efficiency and all cost effective and reasonable distributed flexibility, including demand response, dispatchable customer storage, and dispatchable standby generation.

★ Renewable resource actions include a Renewables RFP to be conducted in 2020, seeking 150 MWa of renewable resources to come online by 2023.

★ Capacity resource actions include a multi-stage procurement process that will allow PGE to pursue agreements for cost-competitive capacity within the region and to conduct a non-emitting Capacity RFP in 2021 to fill any remaining capacity needs.

8.1 Key Elements of the Preferred Portfolio

The Mixed Full Clean portfolio, PGE's preferred portfolio, meets customer needs through three types of actions described below:

- **Customer Actions.** The Mixed Full Clean portfolio incorporates all cost-effective energy efficiency and forecasts for customer participation in a broad suite of demand response and dispatchable customer resource programs. Table 8-1 summarizes the impact of these actions.

TABLE 8-1: Cumulative customer resource additions in the preferred portfolio

	Reference Case			Low Need			High Need		
	2023	2024	2025	2023	2024	2025	2023	2024	2025
Energy Efficiency (MWa)*	108	133	157	111	140	167	108	133	157
Demand Response†									
Summer DR (MW)	190	202	211	329	359	383	104	106	108
Winter DR (MW)	129	136	141	263	282	297	72	73	73
Dispatchable Standby Generation (MW)	136	137	137	136	137	137	136	137	137
Dispatchable Customer Storage (MW)	2.2	3.0	4.0	7.3	9.1	11.2	1.1	1.6	2.2

*Energy efficiency savings reflect the forecast of deployment by the end of the year and are at the meter.
†Distributed Flexibility values are at the meter.

- **Renewable Actions.** The Mixed Full Clean portfolio incorporates a 150 MWa renewable addition in 2023. This addition allows us to leverage federal tax credits to secure low-cost renewables to meet our near-term energy and capacity needs while making steady progress toward meeting long-term RPS needs and GHG goals. Table 8-2 summarizes renewable additions in the preferred portfolio.

TABLE 8-2: Cumulative renewable resource additions in the preferred portfolio

	Reference Case			Low Need			High Need		
	2023	2024	2025	2023	2024	2025	2023	2024	2025
Wind Resources									
Gorge Wind (MWa)	41	41	41	41	41	41	41	41	41
WA Wind (MWa)	0	0	77	0	0	77	0	0	77
MT Wind (MWa)	109	109	109	109	109	109	109	109	109
Total Renewables (MWa)	150	150	227	150	150	227	150	150	227

- **Capacity Actions.** The Mixed Full Clean portfolio incorporates the addition of medium- to long-duration energy storage resources to meet our capacity needs in 2024 and 2025. The portfolio also accounts for the potential of bilateral agreements with existing resources in the region to meet a portion of our capacity needs as contracts begin to expire. Table 8-3 provides a summary of the dispatchable capacity resources in the preferred portfolio.

TABLE 8-3: Cumulative dispatchable capacity additions in the preferred portfolio

	Reference Case			Low Need			High Need		
	2023	2024	2025	2023	2024	2025	2023	2024	2025
Storage Resources									
6hr Batteries (MW)	0	37	37	0	37	37	0	37	37
Pumped Storage (MW)	0	200	200	0	200	200	0	200	200
Total Storage (MW)	0	237	237	0	237	237	0	237	237
Capacity Fill (MW)	123	79	358	0	0	0	425	423	739
Total Dispatchable Capacity (MW)	123	316	595	0	237	237	425	660	976

Near-term action is critical to securing reliable and affordable supply for our customers and achieving our decarbonization goals. PGE's Action Plan focuses on the proliferation of high value customer resources, the continued pursuit of expanded renewables in the region, and the staged pursuit of capacity to ensure reliability amidst changing conditions and future uncertainties.

8.2 Customer Resource Actions

We believe that customer participation will be critical to achieving long-term decarbonization at the lowest cost to customers. We engaged Navigant Consulting to develop forecasts and uncertainty bands for customer adoption of distributed technologies and electric vehicles as well as participation in demand side management programs (the DER Study). Based on the findings in this study, PGE proposes the following actions to support customer participation in demand side management programs:

- **Action 1A. Seek to acquire all cost-effective energy efficiency.**

  We plan to acquire all cost-effective energy efficiency, which is currently forecast by the Energy Trust to be 157 MWa on a cumulative basis by 2025.

- **Action 1B. Seek to acquire all cost-effective and reasonable distributed flexibility.**

  We plan to acquire all cost-effective and reasonable distributed flexibility resources that customers choose to provide. By 2025, this is currently forecast to include, on a cumulative basis:

  - 141 MW of winter demand response (Low: 73 MW, High: 297 MW).
  - 211 MW of summer demand response (Low: 108 MW, High: 383 MW).

  - 137 MW of dispatchable standby generation and 4.0 MW of dispatchable customer storage (Low: 2.2 MW, High: 11.2 MW).

8.3 Renewable Actions

Through portfolio analysis, we identified that a near-term renewable action that contributes to meeting near-term energy and capacity needs as well as long-term renewable obligations provides the best balance of cost and risk. In addition, we found that renewable resources that qualify for federal tax credits are expected to be the lowest cost energy resource options on a real-levelized basis. More specifically, a wind addition of 150 MWa that comes online by December 31, 2022 to qualify for 60% of the federal production tax credit (PTC) saves approximately $180 million relative to a strategy of relying on wholesale markets for energy and a simple-cycle combustion turbine (SCCT) for an equivalent amount of capacity in the Reference Case. Additional discussion about the near-term cost impacts of renewables and our renewable glide path analysis can be found in Section 7.3 Preferred Portfolio.

Consistent with our preferred portfolio and the findings described above, we propose to pursue the following action to acquire renewable resources:

Action 2. Conduct a Renewables Request for Proposals (RFP) in 2020, seeking up to approximately 150 MWa of RPS-eligible resources to enter PGE's portfolio by the end of 2023.

We propose the following conditions for this Renewables RFP:

- **Open to all RPS-eligible resources.** While the wind resources examined in this IRP performed the best among the generic renewable resources, actual renewable resources may vary in their costs, production, and value to the system relative to the generic resources investigated in the IRP. Providing for flexibility across renewable technologies and locations while leveraging the analytical methodologies in the IRP to fairly evaluate benefits to the system will allow us to identify those resources that provide the best value for customers.
- **Cost-containment screen.** As described in Chapter 6. Resource Economics, one of the primary findings of the 2019 IRP is that near-term renewables are forecast to cost less than the equivalent amount of energy and capacity from non-renewable resources on a real-levelized basis. However, there could be factors in actual procurement that lead some bids to have higher resource costs or lower forecast value than reflected in the generic IRP resources. Similar to the 2018 Renewables RFP, we propose to apply a cost-containment screen within the RFP to exclude any resources that do not have expected levelized benefits (energy, capacity, and flexibility) that exceed their levelized costs. Meeting this cost-containment screen would be a necessary, but not sufficient, requirement for any successful bid.
- **REC Value Mechanism.** As described above and in Section 4.5 RPS Need, we do not require RECs from new resources to meet near-term RPS obligations. To help lower the costs of renewables procured as part of this action, PGE proposes to return the value of RECs generated from those resources prior to 2030 (our physical RPS deficiency year) back to customers. We included a similar condition in the 2016 IRP Revised Renewable Action, which was acknowledged by the Commission. We look forward to addressing the REC value

mechanism for our most recent renewable resource acquisition and the action proposed here in a separate Commission docket.

- **Transmission Considerations.** The continued development of renewable resources in the Northwest will likely require changes to the transmission system, in terms of both transmission development and utilization. The growth of renewables in the region will also require that we reassess how we consider transmission within resource planning and procurement processes. These changes are likely to impact both cost and risk to customers and to utilities in the region, but they will be necessary to achieve our clean energy goals.

  In the long term, we seek to promote a holistic solution that enables continued renewable development to benefit customers while appropriately addressing potential risks to both customers and the utility. Any comprehensive solution will require working collaboratively with BPA and regional entities on solutions that address the concerns of both renewable developers and entities charged with maintaining reliability. Such a solution will require the flexibility to adapt to a changing landscape, from both a resource and transmission development perspective. We recognize that reaching such a solution will require significant effort and time on our part as well as from the OPUC, stakeholders, developers, and potentially other entities in the region. Moreover, it will not be possible to identify and vet a complete solution in the timeline required to capture the benefits of near-term renewable procurement identified in this IRP.

  In lieu of a more holistic solution, we are assessing current requirements and developing an interim approach specific to the proposed renewable procurement action in this IRP. While the interim approach will be refined and reviewed in the RFP process, we are providing preliminary information on this issue to help inform the review of the renewable action in this IRP. Specifically, we are considering the current framework of the Pacific Northwest transmission system, the options available through various transmission products, and the potential role of contractual obligations related to delivery of supply. We are applying the following design principles to this exercise:

  - Enable a fair, transparent, and competitive renewable resource procurement process.
  - Provide reasonable assurances of delivery, project success, and value to customers.
  - Adequately identify and mitigate potential shifts in cost and risk to customers and PGE.
  - Appreciate differences between dispatchable and variable resources.

  PGE continues to work internally on developing this interim approach to ensure that we can present a comprehensive and clear proposal to stakeholders while addressing the above design principles and feedback received from stakeholders. We will provide this proposal to the Commission and stakeholders within the 2019 IRP docket. Ultimately, we expect the Commission to determine whether to acknowledge PGE's proposal within the context of a Renewables RFP docket.

PGE is considering, but has not at this time determined, whether the Company plans to submit a benchmark resource to this Renewables RFP. PGE will provide an update on the Company's decision regarding a potential benchmark resource prior to an RFP.

For more information about RFP design and scoring to support this action, see Appendix J. Renewable RFP Design and Modeling Methodology.

8.4 Capacity Actions

As described in Section 4.3 Capacity Adequacy, we identified a capacity need of 368 MW in 2024, growing to 685 MW by 2025 in the Reference Case.[179] Potential capacity needs in 2025 range from 309 MW to 1,065 MW when considering uncertainty in economic conditions, changes in the load forecast, and customer adoption of distributed energy resources and electric vehicles. Approximately 350 MW of this growing capacity need relates to the expiration of contracts, suggesting that the need to develop new capacity resources in 2025 currently is highly uncertain.

Under a scenario in which we can replace expiring contracts with similarly sized products and the conditions comprising the Low Need Future come to fruition, we may be capacity adequate in 2025. However, if cost-competitive options for existing resource capacity are not available and conditions evolve as they do in the High Need Future, we may require over 1,000 MW of new capacity from an RFP. Therefore, capacity actions must be flexible enough for us to respond to evolving conditions and robust enough to provide for significant procurement of new resources should the identified needs persist.

Our analysis also identified that energy storage represents an increasingly competitive capacity option relative to traditional resources, despite the considerable uncertainty that remains around battery economics in the mid-2020s. Most of the portfolios that performed the best, based on cost and risk, used renewables and energy storage to meet capacity needs in 2024 and 2025. As a result, our preferred portfolio meets capacity needs in 2024 and 2025 with renewable resources and energy storage.

To ensure that we can meet our future capacity needs while taking into consideration the potential impact of uncertainties, we plan to conduct the following staged process to secure capacity in the 2024 to 2025 timeframe:

- **Action 3A. Pursue cost-competitive agreements for existing capacity in the region.**

  We plan to pursue cost-competitive agreements for existing capacity in the region to meet a portion of our capacity needs in 2024 and 2025. For cost-competitive resources that are larger than 80 MW and have a duration longer than 5 years, we will submit requests for waivers of the Division 089 Resource Procurement[180] rules.

- **Action 3B. Update the Commission and stakeholders on the status of PGE's bilateral negotiations and any resulting impacts on capacity needs.**

  We plan to provide an update of our capacity and energy needs based on any updates to forecast loads, as well as existing and contracted resources, prior to initiating an RFP for new capacity resources.

[179] This capacity need is calculated after accounting for the contributions of the energy efficiency and distributed flexibility resources described as part of the Customer Resource Actions, and before accounting for potential capacity contributions from the Renewable Action.

[180] OAR 860-089-0010(2).

- **Action 3C. Conduct an RFP for non-emitting resources to meet remaining capacity needs.**

  We plan to conduct an RFP in 2021 if capacity needs remain after considering the actions described above. The RFP would exclude resources that directly emit GHG emissions as a consequence of generating electricity. Eligible resources could include, but are not limited to, battery storage, pumped storage, renewables plus storage, and geothermal. We plan to engage with stakeholders regarding whether new non-emitting resources paired with low carbon energy from existing resources, for example BPA system power, should be eligible to participate. We plan to provide an update on this action item, including the action target size and RFP design information, in a future IRP Update.

  PGE is considering, but has not at this time determined, whether the Company plans to submit a benchmark resource to this RFP. PGE will provide an update on the Company's decision regarding a potential benchmark resource prior to an RFP.

This staged process would allow us to flexibly meet our customers' needs by meeting the following objectives:

- Make the best use of existing resources in the region before requiring new resource development.
- Provide additional time to develop certainty about the magnitude and nature of capacity needs in 2024-2025.
- Provide additional time to better understand the potential impacts of large-scale energy storage systems within our portfolio.
- Allow PGE and our customers to benefit from the additional technological progress and deployment experience that is currently underway in the energy storage sector.

Through the above capacity actions, we will also ensure that the portfolio of capacity resources meets our flexibility adequacy needs as described in Section 4.6 Flexibility Adequacy.

8.5 Conclusion

Throughout the 2019 IRP, we aimed to design an Action Plan that reflects our values, responds to customer and stakeholder feedback, and embraces the positive change that continues to shape the electric utility industry. Oregon's traditional, yet robust, IRP framework has aided us in these efforts. In some cases, we have proposed evolutions in how this framework may adapt to the shifting demands of customers and the opportunities afforded by new technologies. Our proposed Action Plan allows us to continue pursuing low-cost and clean technologies to benefit customers, while mitigating future risks. Our plan also gives us the flexibility to adapt and learn as conditions change and new opportunities arise. More importantly, the Action Plan provides clarity on our priorities and invites further conversation with customers, stakeholders, and the Commission. We look forward to working together in this IRP and in future planning efforts to chart the course toward a clean, affordable, and reliable energy future.

Appendix A. IRP Guidelines Compliance Checklist

TABLE A-1: Guideline 1 – Substantive Requirements

	Requirement	PGE Compliance	Chapter
Guideline 1a	All resources must be evaluated on a consistent and comparable basis.		
	All known resources for meeting the utility's load should be considered, including supply-side options which focus on the generation, purchase and transmission of power – or gas purchases, transportation and storage – and demand-side options which focus on conservation and demand response.	Consistent with Order No. 07-002, PGE considers known supply-side and demand-side resources that the Company expects to become available. These resources include energy efficiency (EE), demand response (DR), dispatchable standby generation (DSG), central-station solar, solar-plus-storage combination, wind, geothermal, biomass, pumped hydro and battery storage and natural gas facilities. Supply-side resource options are tested with estimates of associated transmission wheeling costs.	Chapter 5. Resource Options
	Utilities should compare different resource fuel types, technologies, lead times, in-service dates, durations and locations in portfolio risk modeling.	PGE tested resource options that vary across each of the listed criteria within the portfolio analysis.	Chapter 5. Resource Options Chapter 6. Resource Economics Chapter 7. Portfolio Analysis
	Consistent assumptions and methods should be used for evaluation of all resources.	PGE evaluated all resources using a common set of assumptions and modeling methods.	Chapter 7. Portfolio Analysis
	The after-tax marginal weighted-average cost of capital (WACC) should be used to discount all future resource costs.	PGE applied its after-tax marginal weighted-average cost of capital of 6.54 percent as a proxy for the long-term cost of capital.	Appendix I. 2019 IRP Modeling Details
Guideline 1b	Risk and uncertainty must be considered. At a minimum, utilities should address the following sources of risk and uncertainty:		
	1. Electric utilities: load requirements, hydroelectric generation, plant forced outages, fuel prices,	PGE accounts for various uncertainties in the 2019 IRP analysis. These uncertainties include resource needs	Chapter 3. Futures and Uncertainties

	Requirement	PGE Compliance	Chapter
	electricity prices and costs to comply with any regulation of greenhouse gas emissions.	(load forecast, energy efficiency forecast, distributed resources and market capacity availability), wholesale market conditions (gas and carbon prices and electricity prices) technology costs (wind, solar and battery storage) and hydro conditions. The portfolios are designed considering 270 futures and evaluated under 810 future conditions. PGE considers additional reliability risks associated with forced outages, hydro availability, and loads in the resource adequacy evaluation in RECAP.	Chapter 4. Resource Needs
	2. Natural gas utilities: demand (peak, swing and baseload), commodity supply and price, transportation availability and price, and costs to comply with any regulation of greenhouse gas emissions.	N/A to PGE	N/A
	Utilities should identify in their plans any additional sources of risk and uncertainty.	Refer to 1b.1. for a list of uncertainties considered in the 2019 IRP.	Chapter 3. Futures and Uncertainties
Guideline 1c	The primary goal must be the selection of a portfolio of resources with the best combination of expected costs and associated risks and uncertainties for the utility and its customers.	PGE undertook a multi-stage scoring process which combines traditional cost and risk metrics (cost, variability and severity) while considering non-traditional metrics that capture additional risks. This process resulted in a preferred portfolio, the Mixed Full Clean portfolio, which combines the components of the portfolios that perform the best on the basis of expected costs and associated risks. The IRP Action Plan is designed to allow PGE to pursue the resources in the preferred portfolio.	Chapter 7. Portfolio Analysis
	The planning horizon for analyzing resource choices should be at least 20 years and account for end effects. Utilities should consider all costs with a	PGE calculated the fixed and variable costs of portfolios from 2021 through 2050. PGE accounted for end effects by levelizing the costs (recovery of life-	Chapter 6. Resource Economics

Requirement	PGE Compliance	Chapter
reasonable likelihood of being included in rates over the long term, which extends beyond the planning horizon and the life of the resource.	cycle resource investment and fixed costs, including estimated decommissioning) of resources procured within the planning horizon and anticipated to serve PGE customers after 2050.	
Utilities should use present value of revenue requirement (PVRR) as the key cost metric. The plan should include analysis of current and estimated future costs for all long-lived resources such as power plants, gas storage facilities and pipelines, as well as all short-lived resources such as gas supply and short-term power purchases.	PGE uses expected NPVRR between 2021 and 2050 as the primary cost metric in portfolio evaluation. The Company includes all other costs over time for gas transport, transmission, fuel, fixed cost recovery, etc. within the revenue requirement modeling for all long-lived and short-lived resources. That is, PGE includes all costs the Company would expect to incur to have access to and operate the resource. Input assumptions for these costs were primarily sourced from HDR, Wood Mackenzie, the Energy Information Administration, and PGE data for existing and contracted resources.	Chapter 7. Portfolio Analysis
To address risk, the plan should include, at a minimum:		
1. Two measures of PVRR risk: one that measures the variability of costs and one that measures the severity of bad outcomes.	PGE evaluates its portfolio using traditional risk metrics of variability and severity. The variability is the semi-deviation of the NPVRR through 2050 across futures, relative to the Reference Case. The severity considers the tail value at risk (TailVAR) at the 90th percentile of the NPVRR through 2050 across all futures.	Chapter 7. Portfolio Analysis, Section 7.2.1 Scoring Metrics
2. Discussion of the proposed use and impact on costs and risks of physical and financial hedging.	PGE did not propose any long-term financial or physical hedging activities beyond the resource additions contemplated within this IRP. Costs and risks associated with the resource additions that could	Chapter 7. Portfolio Analysis

	Requirement	PGE Compliance	Chapter
		provide a physical hedge against future wholesale market price volatility are considered as part of PGE's portfolio analysis.	
	The utility should explain in its plan how its resource choices appropriately balance cost and risk.	Candidate portfolios are evaluated based on the cost and risk metrics described in Guideline 1.C.1. above. Prior to this evaluation, portfolios that perform poorly with respect to a set of non-traditional scoring metrics that capture other risks are screened out. The resource actions in the preferred portfolio are designed to reflect the commonalities between the portfolios that perform the best on the basis of cost and risk. The Action Plan is not designed to identify a specific set of resources but to specify a set of reasonable actions that would allow PGE to capture the cost and risk benefits of the best performing portfolios.	Chapter 7. Portfolio Analysis Chapter 8. Action Plan
Guideline 1d	The plan must be consistent with the long-run public interest as expressed in Oregon and federal energy policies.	The analysis and actions laid out in the 2019 IRP reflect all known federal and state energy policies in Oregon, including the Oregon Clean Electricity and Coal Transition Plan (SB 1547).	Chapter 2. Planning Environment

TABLE A-2: Guideline 2 – Procedural Requirements

	Requirement	PGE Compliance	Chapter
Guideline 2a	The public, which includes other utilities, should be allowed significant involvement in the preparation of the IRP. Involvement includes opportunities to contribute information and ideas, as well as to receive information. Parties must have an opportunity to make relevant inquiries of the utility formulating the	PGE sought and received feedback from the public through a series of public roundtable meetings throughout 2018 and 2019. At these meetings, the Company shared the results of its research, analysis, and findings with external stakeholders and asked for feedback on values, assumptions, methodologies, and	Appendix C. 2019 IRP Public Meeting Agendas

	Requirement	PGE Compliance	Chapter
	plan. Disputes about whether information requests are relevant or unreasonably burdensome, or whether a utility is being properly responsive, may be submitted to the Commission for resolution.	findings.	
Guideline 2b	While confidential information must be protected, the utility should make public in its plan any non-confidential information that is relevant to its resource evaluation and action plan. Confidential information may be protected through use of a protective order, through aggregation or shielding of data, or through any other mechanism approved by the Commission.	PGE's IRP provides non-confidential information used for portfolio evaluation and development of the action plan.	N/A
Guideline 2c	The utility must provide a draft IRP for public review and comment prior to filing a final plan with the Commission.	PGE distributed a draft IRP for public review on May 17, 2019 and received comments from stakeholders on June 17, 2019.	N/A

TABLE A-3: Guideline 3 – Plan Filing, Review and Updates

	Requirement	PGE Compliance	Chapter
Guideline 3a	A utility must file an IRP within two years of its previous IRP acknowledgment order. If the utility does not intend to take any significant resource action for at least two years after its next IRP is due, the utility may request an extension of its filing date from the Commission.	PGE filed its last IRP on November 15, 2016. The Commission issued a partial acknowledgment Order No. 17-386 on October 9, 2017, which memorialized the decision made at the Public Meeting on August 8, 2017. The Commission issued Order 18-044 On February 2, 2018 acknowledging PGE's 2016 IRP Revised Renewable Action Plan. The 2019 IRP was filed within two years of the effective date of the partial acknowledgment order, August 8, 2017.	
Guideline 3b	The utility must present the results of its filed plan to the Commission at a public meeting prior to the deadline for written public comment.	PGE will comply with this Guideline.	N/A

	Requirement	PGE Compliance	Chapter
Guideline 3c	Commission staff and parties should complete their comments and recommendations within six months of IRP filing.	N/A	N/A
Guideline 3d	The Commission will consider comments and recommendations on a utility's plan at a public meeting before issuing an order on acknowledgment. The Commission may provide the utility an opportunity to revise the plan before issuing an acknowledgment order.	N/A	N/A
Guideline 3e	The Commission may provide direction to a utility regarding any additional analyses or actions that the utility should undertake in its next IRP.	N/A	N/A
Guideline 3f	Each utility must submit an annual update on its most recently acknowledged plan. The update is due on or before the acknowledgment order anniversary date. Once a utility anticipates a significant deviation from its acknowledged IRP, it must file an update with the Commission, unless the utility is within six months of filing its next IRP. The utility must summarize the update at a Commission public meeting. The utility may request acknowledgment of changes in proposed actions identified in an update.	On March 8, 2018, PGE filed an update to the 2016 IRP.	N/A
Guideline 3g	Unless the utility requests acknowledgement of changes in proposed actions, the annual update is an informational filing that:		
	Describes what actions the utility has taken to implement the plan;	PGE complied with this guideline.	N/A
	Provides an assessment of what has changed since the acknowledgment order that affects the action plan, including changes in such factors as load, expiration of resource contracts, supply-side and demand-side resource acquisitions, resource costs, and transmission availability; and	PGE complied with this guideline.	N/A
	Justifies any deviations from the acknowledged action plan.	PGE complied with this guideline.	N/A

TABLE A-4: Guideline 4 – Plan Components

	Requirement	PGE Compliance	Chapter
	At a minimum, the plan must include the following elements:		
Guideline 4a	a. An explanation of how the utility met each of the substantive and procedural requirements;	The purpose of this table is to show compliance with this Guideline. PGE includes more detailed descriptions and explanations of compliance with Commission requirements in the body of the 2019 IRP.	Appendix A
Guideline 4b	b. Analysis of high and low load growth scenarios in addition to stochastic load risk analysis with an explanation of major assumptions;	PGE includes analysis of its high- and low-load growth scenarios. PGE also uses stochastic load risk in evaluating capacity needs in the RECAP model.	Appendix D. Load Forecast Methodology Chapter 4. Resource Needs Chapter 3. Futures and Uncertainties
Guideline 4c	For electric utilities, a determination of the levels of peaking capacity and energy capability expected for each year of the plan, given existing resources; identification of capacity and energy needed to bridge the gap between expected loads and resources; modeling of all existing transmission rights, as well as future transmission additions associated with the resource portfolios tested;	PGE performs four related analyses: 1) a capacity-adequacy assessment based on a reliability model that captures peaking capabilities of resources; 2) a flexibility-adequacy study; 3) a market energy position investigation; and 4) an energy load-resource balance calculation. All portfolios incorporate transmission costs, including those unique to each portfolio.	Chapter 4. Resource Needs Appendix G. Load Resource Balance External Study F. Flexible Adequacy Report
Guideline 4d	For natural gas utilities, a determination of the peaking, swing and base-load gas supply and associated transportation and storage expected for each year of the plan, given existing resources; and identification of gas supplies (peak, swing and base-load), transportation and storage needed to bridge the gap between expected loads and resources;	N/A to PGE	N/A

	Requirement	PGE Compliance	Chapter
Guideline 4e	Identification and estimated costs of all supply-side and demand-side resource options, taking into account anticipated advances in technology;	PGE develops resource-specific revenue requirements and engaged the expertise of external consultants, HDR Inc., to estimate costs and advances in technology. The estimates from HDR include outlooks on technology maturity and the potential for reductions in future capital costs. PGE also conducted learning-curve analysis to estimate upper and lower bounds on future technology cost trajectories.	Chapter 5. Resource Options External Study D. Characterizations of Supply Side Options
Guideline 4f	Analysis of measures the utility intends to take to provide reliable service, including cost-risk tradeoffs;	Portfolio construction in the 2019 IRP is required to meet a reliability target by filling a MW shortage determined in RECAP Loss-of-Load Probability study. The cost-risk tradeoffs are examined in ROSE-E portfolio analysis through different resource additions used to fill that shortage.	Appendix I. 2019 IRP Modeling Details Chapter 7. Portfolio Analysis
Guideline 4g	Identification of key assumptions about the future (e.g., fuel prices and environmental compliance costs) and alternative scenarios considered;	PGE identified natural gas prices, carbon prices, WECC-wide renewable deployment, clean technology costs, economic conditions, customer technology adoption, and customer program participation as key assumptions about the future. Chapter 3 describes how scenarios were designed to capture uncertainties in each of these assumptions.	Chapter 3. Futures and Uncertainties
Guideline 4h	Construction of a representative set of resource portfolios to test various operating characteristics, resource types, fuels and sources, technologies, lead times, in-service dates, durations and general locations – system-wide or delivered to a specific portion of the system;	PGE complies with this guideline in its portfolio analysis. Portfolios are designed to consider flexibility and optionality in later years based on need, market price, and technology futures. A diverse set of resource types, locations, and combinations is used in the portfolio construction.	Chapter 7. Portfolio Analysis Appendix I. 2019 IRP Modeling Details Chapter 5. Resource Options
Guideline 4i	Evaluation of the performance of the candidate portfolios over the range of identified risks and uncertainties;	PGE estimated cost and performance of candidate portfolios across 810 potential future conditions to capture a range of risks and uncertainties.	Chapter 7. Portfolio Analysis

	Requirement	PGE Compliance	Chapter
Guideline 4j	Results of testing and rank ordering of the portfolios by cost and risk metric, and interpretation of those results;	PGE undertook a multi-stage scoring process to evaluate portfolio consisting of a screening phase based on non-traditional scoring metrics, an evaluation phase based on traditional cost and risk metrics, and a phase where common aspects of well-performing portfolios are identified to finally arrive at a preferred portfolio. This process allows PGE to meet this guideline while reflecting our values and the values expressed by the stakeholders during the public process.	Chapter 7. Portfolio Analysis
Guideline 4k	Analysis of the uncertainties associated with each portfolio evaluated;	Uncertainties associated with each portfolio are reflected through portfolio construction and the risk metrics that consider portfolio performance across multiple futures.	Chapter 3. Futures and Uncertainties Chapter 7. Portfolio Analysis
Guideline 4l	Selection of a portfolio that represents the best combination of cost and risk for the utility and its customers;	The preferred portfolio, which informs the action plan, results from a rigorous screening and scoring process and represents the best combination of cost and risk to PGE and its customers in addition to reflecting the company's and stakeholders' values.	Chapter 7. Portfolio Analysis
Guideline 4m	Identification and explanation of any inconsistencies of the selected portfolio with any state and federal energy policies that may affect a utility's plan and any barriers to implementation;	To the best of PGE's knowledge, the preferred portfolio is consistent with all state and federal energy policies.	Chapter 7. Portfolio Analysis
Guideline 4n	An action plan with resource activities the utility intends to undertake over the next two to four years to acquire the identified resources, regardless of whether the activity was acknowledged in a previous IRP, with the key attributes of each resource specified as in portfolio testing.	PGE's Action Plan includes activities that the Company intends to undertake or commit to in the next two to four years. PGE describes three categories of action: Customer Resources Actions, Renewable Actions, and Capacity Actions.	Chapter 8. Action Plan

TABLE A-5: Guideline 5 – Transmission

Requirement	PGE Compliance	Chapter
Portfolio analysis should include costs to the utility for the fuel transportation and electric transmission required for each resource being considered. In addition, utilities should consider fuel transportation and electric transmission facilities as resource options, taking into account their value for making additional purchases and sales, accessing less costly resources in remote locations, acquiring alternative fuel supplies, and improving reliability.	Portfolio analysis includes costs for the fuel transportation and electric transmission required for each resource PGE considers in its analysis. PGE bases Pacific Northwest (PNW) natural gas transport costs on current rates, with escalation at inflation going forward. PGE also uses BPA's published transmission tariff rates as (with escalation) for all new generating resources within the PNW.	Chapter 5. Resource Options

TABLE A-6: Guideline 6 – Conservation

	Requirement	PGE Compliance	Chapter
Guideline 6a	Each utility should ensure that a conservation potential study is conducted periodically for its entire service territory.	PGE received the most recent long-term conservation potential study for our service territory from the Energy Trust of Oregon (Energy Trust) in November 2017. PGE coordinated with the Energy Trust to support the development of the EE forecast. Specifically, PGE provided information to the Energy Trust, which included load growth assumptions, cost of capital, and avoided cost inputs.	Chapter 4. Resource Needs External Study B. Energy Trust of Oregon Methodology
Guideline 6b	To the extent that a utility controls the level of funding for conservation programs in its service territory, the utility should include in its action plan all best cost/risk portfolio conservation resources for meeting projected resource needs, specifying annual savings targets.	Since 2002, the Energy Trust has been the independent, non-profit organization in charge of identifying the State's EE potential. PGE and other utilities fund such programs and work with the Energy Trust to implement EE measures. PGE maintains a long-term, productive relationship with the Energy Trust to ensure that EE remains a top priority resource for the Company and the State.	Chapter 4. Resource Needs External Study B. Energy Trust of Oregon Methodology
Guideline 6c	To the extent that an outside party administers		

Requirement	PGE Compliance	Chapter
conservation programs in a utility's service territory at a level of funding that is beyond the utility's control, the utility should:		
Determine the amount of conservation resources in the best cost/risk portfolio without regard to any limits on funding of conservation programs; and	The portfolios incorporate the results of the energy efficiency studies conducted by the Energy Trust which determine the amount of potential energy efficiency without regard to any funding limits, with the exception of the SB 838 funding constraints.	Chapter 4. Resource Needs External Study B. Energy Trust of Oregon Methodology
Identify the preferred portfolio and action plan consistent with the outside party's projection of conservation acquisition.	PGE's preferred portfolio and Action Plan are consistent with the Energy Trust's EE savings projection. PGE continues to work collaboratively with the Energy Trust to assure sufficient funding for acquisition of all cost-effective EE, subject to consumer adoption constraints.	Chapter 7. Portfolio Analysis Chapter 8. Action Plan

TABLE A-7: Guideline 7 – Demand Response

Requirement	PGE Compliance	Chapter
Plans should evaluate demand response resources, including voluntary rate programs, on par with other options for meeting energy, capacity and transmission needs (for electric utilities) or gas supply and transportation needs (for natural gas utilities).	OPUC Order No. 17-386 acknowledged the 2016 IRP and directed PGE to conduct a study by a third party for demand response in PGE's service territory. In response to this order, PGE engaged Navigant Consulting to include forecasts of demand response program participation as part of the Distributed Resources and Flexible Load Study. The programs considered in the study include residential and non-residential pricing, direct load control, and non-residential curtailment.	Chapter 5. Resource Options External Study C. Distributed Energy Resource Study

TABLE A-8: Guideline 8 – Environmental Costs (Order 08-339)

	Requirement	PGE Compliance	Chapter
Guideline 8a	BASE CASE AND OTHER COMPLIANCE SCENARIOS: The utility should construct a base-case scenario to reflect what it considers to be the most likely regulatory compliance future for carbon dioxide (CO_2), nitrogen oxides, sulfur oxides, and mercury emissions. The utility also should develop several compliance scenarios ranging from the present CO_2 regulatory level to the upper reaches of credible proposals by governing entities. Each compliance scenario should include a time profile of CO_2 compliance requirements. The utility should identify whether the basis of those requirements, or "costs," would be CO_2 taxes, a ban on certain types of resources, or CO_2 caps (with or without flexibility mechanisms such as allowance, credit trading, or a safety valve). The analysis should recognize significant and important upstream emissions that would likely have a significant impact on its resource decisions. Each compliance scenario should maintain logical consistency, to the extent practicable, between the CO_2 regulatory requirements and other key inputs.	PGE constructed the CO_2 price Reference Case based on the proposed Cap and Trade program in Oregon. PGE incorporated GHG pricing provided by the California Energy Commission into its market pricing and dispatch models to simulate the Carbon pricing scenarios. Portfolio analysis in the 2019 IRP also incorporates the requirements of the Oregon Clean Electricity and Coal Transition Plan. The Reference Case assumes full regulatory compliance for particulates, SO_X, NO_X, and mercury emissions for all resources.	Chapter 3. Futures and Uncertainties
Guideline 8b	TESTING ALTERNATIVE PORTFOLIOS AGAINST THE COMPLIANCE SCENARIOS: The utility should estimate, under each of the compliance scenarios, the present value of revenue requirement (PVRR) costs and risk measures, over at least 20 years, for a set of reasonable alternative portfolios from which the preferred portfolio is selected. The utility should	PGE tests its portfolios against futures and uncertainties that incorporate a range of future CO_2 prices. The set of futures is broad and diverse, reasonably reflecting the types of changing circumstances that could be encountered and the resulting impact on the cost and risk of various portfolio choices.	Chapter 3. Futures and Uncertainties

	Requirement	PGE Compliance	Chapter
	incorporate end-effect considerations in the analyses to allow for comparisons of portfolios containing resources with economic or physical lives that extend beyond the planning period. The utility should also modify projected lifetimes as necessary to be consistent with the compliance scenario under analysis. In addition, the utility should include, if material, sensitivity analyses on a range of reasonably possible regulatory futures for nitrogen oxides, sulfur oxides, and mercury to further inform the preferred portfolio selection.		
Guideline 8c	TRIGGER POINT ANALYSIS. The utility should identify at least one CO_2 compliance "turning point" scenario which, if anticipated now, would lead to, or "trigger" the selection of a portfolio of resources that is substantially different from the preferred portfolio. The utility should develop a substitute portfolio appropriate for this trigger-point scenario and compare the substitute portfolio's expected cost and risk performance to that of the preferred portfolio – under the base case and each of the above CO_2 compliance scenarios. The utility should provide its assessment of whether a CO_2 regulatory future that is equally or more stringent than the identified trigger point will be mandated.	The preferred portfolio contains no new resources that would emit GHG emissions. We therefore do not expect that more stringent CO_2 compliance obligations would affect the preferred portfolio. We do test all portfolios against a carbon-constrained future and incorporate those findings into the non-traditional scoring process. We also test the preferred portfolio under a decarbonization scenario that contemplates economy-wide efforts to reduce GHG by 80% by 2050. These tests result in differences to resource additions after 2025, but no changes to the preferred portfolio through 2025.	Chapter 7. Portfolio Analysis
Guideline 8d	OREGON COMPLIANCE PORTFOLIO: If none of the above portfolios is consistent with Oregon energy policies (including the state goals for reducing greenhouse gas emissions) as those policies are applied to the utility, the utility should construct the	The portfolio analysis in the 2019 IRP is consistent with current and potential Oregon energy policies including SB 1547 and Cap and Trade. The analysis also shows how PGE can contribute to meeting the state goal for GHG reductions by investigating each portfolio	Chapter 2. Planning Environment

	Requirement	PGE Compliance	Chapter
	best cost/risk portfolio that achieves that consistency, present its cost and risk parameters, and compare it to those of the preferred and alternative portfolios.	under a carbon-constrained future.	

TABLE A-9: Guideline 9 – Direct Access Loads

Requirement	PGE Compliance	Chapter
An electric utility's load-resource balance should exclude customer loads that are effectively committed to service by an alternative electricity supplier.	Currently, PGE excludes estimated Direct Access load based on current customer elections. The Company does not plan long-term resources to meet the potential demand from long-term opt-out customers. Nonetheless, PGE acts as the reliability provider for these customer loads.	Chapter 4. Resource Needs

TABLE A-10: Guideline 1 – Multi-state Utilities

Requirement	PGE Compliance	Chapter
Multi-state utilities should plan their generation and transmission systems, or gas supply and delivery, on an integrated-system basis that achieves a best cost/risk portfolio for all their retail customers.	N/A	N/A

TABLE A-11: Guideline 11 – Reliability

Requirement	PGE Compliance	Chapter
Electric utilities should analyze reliability within the risk modeling of the actual portfolios being considered. Loss of load probability, expected planning reserve margin, and expected and worst-case unserved energy should be determined by year for top-performing portfolios. Natural gas utilities should analyze, on an integrated basis, gas supply, transportation and storage, along with demand side resources, to reliably meet peak, swing, and base-load system	PGE analyzed reliability by introducing a reliability constraint in the development of portfolios. The Company used a loss-of-load assessment to determine the capacity needed to maintain resource adequacy. PGE uses a single comprehensive loss-of-load model for assessing capacity need, renewable capacity contribution, and evaluating portfolio reliability, creating a consistent methodology through the IRP process. PGE models this using the RECAP model (see	Chapter 4. Resource Needs Appendix H. Summary of Portfolios

Requirement	PGE Compliance	Chapter
requirements. Electric and natural gas utility plans should demonstrate that the utility's chosen portfolio achieves its stated reliability, cost, and risk objectives.	Appendix I. 2019 IRP Modeling Details for a description of RECAP); with the goal of achieving a loss-of-load expectation below 2.4 hours a year.	

TABLE A-12: Guideline 12 – Distributed Generation

Requirement	PGE Compliance	Chapter
Electric utilities should evaluate distributed generation technologies on par with other supply-side resources and should consider, and quantify where possible, the additional benefits of distributed generation.	PGE evaluates distributed generation (including DSG, DR, EE, distributed solar, and storage) on par with other supply-side resources. These technologies do not include line losses and transmission costs that are included for central station supply-side resources in the evaluation when such facilities are located outside the service territory.	Chapter 5. Resource Options

TABLE A-13: Guideline 13 – Resource Acquisition

	Requirement	PGE Compliance	Chapter
Guideline 13a	An electric utility should, in its IRP:		
	Identify its proposed acquisition strategy for each resource in its action plan.	PGE describes its proposed Action Plan, including strategies to acquire customer resources (energy efficiency, demand response, DSG, and dispatchable customer storage), renewable resources, and capacity resources.	Chapter 8. Action Plan
	Assess the advantages and disadvantages of owning a resource instead of purchasing power from another party.	PGE plans to pursue cost-competitive contract opportunities to fill its capacity needs and to conduct a non-emitting capacity RFP in 2021 to fill any remaining need. PGE also provides a discussion on the benefits and risks of power purchase agreements in Chapter 5. Resource Options.	Chapter 8. Action Plan

	Requirement	PGE Compliance	Chapter
	Identify any Benchmark Resources it plans to consider in competitive bidding.	PGE is considering whether to submit a benchmark for inclusion in the renewable and/or capacity resource RFPs proposed in the Action Plan. PGE will provide updated information about benchmark resources prior to issuing each RFP.	
Guideline 13b	Natural gas utilities should either describe in the IRP their bidding practices for gas supply and transportation, or provide a description of those practices following IRP acknowledgment.	N/A to PGE	N/A

TABLE A-14: Flexible Capacity Resources (Order No. 12-013)

	Requirement	PGE Compliance	Chapter
1	Forecast the Demand for Flexible Capacity: The electric utilities shall forecast the balancing reserves needed at different time intervals (e.g., ramping needed within 5 minutes) to respond to variation in load and intermittent renewable generation over the 20-year planning period;	As a response to Order No. 17-386 in which the Commission ordered PGE to conduct a study investigating Flexible Capacity, the company engaged Blue Marble Analytics to undertake this study. Blue Marble used the ROM model specific to PGE to stimulate flexibility constraints such as balancing reserves among others, to assess the system responsiveness to short time-scale variability of load and renewables as well as forecast errors.	External Study F. Flexible Adequacy Report
2	Forecast the Supply of Flexible Capacity: The electric utilities shall forecast the balancing reserves available at different time intervals (e.g., ramping available within 5 minutes) from existing generating resources over the 20-year planning period; and	The Blue Marble study described above included the balancing reserve capability of existing generating resources.	External Study F. Flexible Adequacy Report
3	Evaluate Flexible Resources on a Consistent and Comparable Basis: In planning to fill any gap between the demand and supply of flexible capacity, the	PGE performed a Flexibility Value Analysis to evaluate how dispatchable resource options may lower the cost of providing system flexibility. The potential	Chapter 6. Resource Economics

	Requirement	PGE Compliance	Chapter
	electric utilities shall evaluate all resource options, including the use of EVs, on a consistent and comparable basis.	flexibility associated with electric vehicle charging direct load control is included in the resource adequacy assessment.	

TABLE A-15: Energy Storage (Order No. 18-290)

	Requirement	PGE Compliance	Chapter
1	Stipulation language: PGE will explain how the locational value of energy storage resources are considered in the IRP planning process.	PGE discusses the consideration of locational value for energy storage resources in Chapter 6.	Chapter 6. Resource Economics

Appendix B. 2016 IRP Action Plan Checklist

TABLE B-1: Commission Requirements from PGE's 2016 IRP Orders No. 17-386, Appendix A and Order No. 18-044

SUPPLY-SIDE REQUIREMENTS	PGE Compliance	Chapter
CAPACITY		
■ Complete bilateral negotiations, with periodic updates to Staff as to status of negotiations and progress toward completing negotiations of key terms and conditions ■ Work with Staff and stakeholders to scope and launch a regional market study of potentially available resources to be run in parallel with the company's efforts to complete the bilateral negotiations ■ Report to the Commission, within four months (of August 8, 2017), the results of the bilateral negotiations and the need for: (a) completing the market study; (b) re-running models and developing a new preferred portfolio using data from the bilateral contracts, the market study, and any other new analyses; and (c) issuing an initial RFP for specific short- to medium-term resources before proceeding with an all-source RFP.	PGE completed the bilateral negotiations process in 2017 and updated the Commission and Staff on the bilateral process, including the 300 MW of capacity contracts the Company ultimately executed. PGE also updated the Commission via the Company's 2016 IRP Update, filed March 8, 2018. Because PGE did not pursue a major capacity resource after the bilateral procurement process, the Company did not complete the envisioned market study to evaluate "potentially available resources" in the region. However, PGE engaged Energy + Environmental Economics (E3) to perform a market capacity study to inform the 2019 IRP as discussed in Section 2.4.2.1, and the final report is available in External Study E.	Chapter 2. Planning Environment External Study E. Market Capacity Study
DISPATCHABLE STANDBY GENERATION (DSG)		
■ Acquire 16 MW expansion of dispatchable standby generation	As of December 2018, PGE had enrolled 127.8 MW of DSG, with several projects in construction or in the queue.	
ENERGY STORAGE		
■ Submit storage proposal in accordance with House Bill 2193, by January 1, 2018	PGE submitted a proposal for the development of energy storage systems in Docket No. UM 1856.	
RENEWABLES		
■ Issue RFP for 100 MWa new renewable resources	PGE conducted the renewable RFP in 2018 and announced the results on February 12, 2019	
■ Providing updated information: PGE will provide	PGE provided updated information on the Company's energy,	

SUPPLY-SIDE REQUIREMENTS	PGE Compliance	Chapter
updates to its energy, capacity, and Renewable Portfolio Standard (RPS) needs within the RFP docket. PGE will update assumptions for qualifying facilities (QF) completion rates and unbundled Renewable Energy Credits (RECs) and incorporate those assumptions in the RFP analysis as sensitivities	capacity and RPS needs in UM 1943, PGE's renewables RFP docket.	
▪ Use of glide path analysis in future IRPs and Renewable Portfolio Standard Implementation Plans (RPIPs): PGE will develop a glide path analysis for use in future IRPs and RPIPs.	In the 2019 IRP, PGE incorporated a renewable glide path analysis within portfolio construction that focuses on uncertainties in future RPS and energy needs. The Renewable Glide Path associated with the preferred portfolio is summarized in Chapter 7.	Chapter 7. Portfolio Analysis
▪ Montana wind and Columbia Gorge wind questions: PGE will address RFP design and scoring elements relevant to Montana wind resources in the bidder and stakeholder workshops it conducts as part of the RFP public process.	PGE designed the structure of the 2018 renewables RFP to allow for potential participation of Montana wind resources.	
▪ Cost containment mechanism: The RFP will include a full description of the cost containment mechanism.	PEG required all bids to pass a cost containment screen in order to be considered for the final short list. This cost containment mechanism was described in UM 1943.	
▪ Delivering value from incremental RECs to customers: Staff may request that we open a docket on mechanisms for delivering value from incremental RECs to customers in a public meeting at a later date.	PGE agreed to return the value of RECs from procured resources generated prior to 2025 to customers. The OPUC has not yet opened a docket on this subject.	

TABLE B-2: Commission Requirements from PGE's 2016 IRP Order No. 17-386, Appendix A – demand-side actions

Demand-Side Requirements	PGE Compliance	Chapter
ENERGY EFFICIENCY		
▪ Changes to 2021 capacity need must use the Energy Trust's most recent forecast data.	The 2019 IRP uses the Energy Trust's most recent forecast data to evaluate changes to the 2021 capacity need.	Chapter 4. Resource Needs External Study B. Energy Trust of Oregon Methodology
▪ PGE will provide an update on the Energy Trust's activities and progress on the large customer funding issue in its IRP update in 2018.	PGE reported on the large customer funding issue in its 2016 IRP Update.	LC 66, see PGE's filing of March 8, 2018.
▪ PGE will make available the Energy Trust's energy efficiency forecast data and provide an explanation of their model in the company's next IRP.	PGE incorporates the Energy Trust's most recent long-term EE forecast in the 2019 IRP. External Study B provides the Energy Trust's EE data and an explanation of the agency's model.	Chapter 4. Resource Needs External Study B. Energy Trust of Oregon Methodology
DEMAND RESPONSE		
▪ 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).	PGE has achieved 32 MW of the 77 MW of winter DR and 21 MW of the 69 MW of summer DR, and is on target to achieve the 2020 DR goals	Chapter 1. 2016 IRP in Review
▪ 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.	PGE engaged Navigant Research to include DR in a propensity to adopt study for distributed resources and flexible load.	Chapter 5. Resource Options External Study C. Distributed Energy Resource Study
▪ 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.	PGE worked with Commission Staff to form a Demand Response Review Committee, which began meeting in early 2018.	
▪ Within nine months (of August 8, 2017), present multiple viable demand response test bed sites to the	With the help of the DRRC, PGE created and submitted a Residential DR Testbed Pilot, which became effective April 1,	Chapter 1. 2016 IRP in Review

Demand-Side Requirements	PGE Compliance	Chapter
Demand Response Review Committee, and by July 1, 2019, establish a demand response test bed.	2019 and will be available through June 30, 2022.	
CONSERVATION VOLTAGE REDUCTION (CVR)		
■ Deploy 1 MWa of conservation voltage reduction through 2020.	PGE is making progress on its deployment and provided the Commission with an update on CVR in its May 2017 Smart Grid Report.	Chapter 1. 2016 IRP in Review UM 1657, PGE's Smart Grid Report

TABLE B-3: Commission Requirements from PGE's 2016 IRP Order No. 17-386, pp. 10-11 – enabling studies

Enabling Study Requirements	PGE Compliance	Chapter
ENABLING STUDIES TO INFORM NEXT IRP		
■ Flexible Capacity and Curtailment Metrics	PGE conducted a Flexibility Adequacy study to assess the amount of flexible capacity needed to maintain resource adequacy. The study was performed by Blue Marble Analytics and can be found in External Study F. In addition to this study, PGE performed analysis to determine the flexibility value of resources, and the Curtailment Metrics were examined as part of the Renewable Integration Cost study in Chapter 6.	External Study F. Flexible Adequacy Report Chapter 6. Resource Economics Appendix I. 2019 IRP Modeling Details
■ Customer Insights	To inform the 2019 IRP, PGE engaged Market Strategies International to conduct 2017 Customer Insights survey to assess customers' resource preferences and cost expectations. The study results are available on the PGE IRP website.	Chapter 2. Planning Environment
■ Decarbonization Study	PGE commissioned Evolved Energy Research to conduct a study exploring economy-wide pathways to decarbonization in our area. The study results can be found on the PGE IRP website in addition to External Study A of the 2019 IRP.	External Study A. Deep Decarbonization Study
■ Risks Associated with Direct Access	PGE conducted a sensitivity analysis to examine the potential	Chapter 4. Resource Needs

Enabling Study Requirements	PGE Compliance	Chapter
	scale of the capacity-adequacy impacts associated with long-term direct access load. The analysis is described in Section 4.7.3.	
▪ Treatment of Market Capacity	PGE engaged E3 to perform an assessment of changes in the region's future load and resources balance and their impact on market capacity availability and their implications on PGE's long-term planning.	External Study E. Market Capacity Study
▪ Accessing Resources from Montana	PGE actively participated in the Montana Renewable Development Action Plan (MRDAP) process and incorporated the recommendations and information resulting from this process into the 2019 IRP portfolio analysis. The Company shared MRDAP information with stakeholders during its December 19, 2018 Roundtable.	Chapter 5. Resource Options Chapter 7. Portfolio Analysis Appendix C. 2019 IRP Public Meeting Agendas
▪ Load Forecasting Improvements	PGE discussed the load forecast methodology with Staff and stakeholders at workshops and Roundtables (see Appendix C). PGE added probabilistic forecasting, conducted out-of-sample testing, and reassessed long-term models. Information about the load forecast is provided in Section 4.1 and a technical appendix discussing the load forecast methodology is provided in Appendix D.	Appendix D. Load Forecast Methodology

TABLE B-4: Commission Requirements from PGE's 2016 IRP Order No. 14-415, pp. 13-14 – other requirements

Additional Requirements	PGE Compliance	Chapter
LOAD FORECASTING		
▪ Conduct ongoing workshops, including consideration of probabilistic forecasts, with interested Stakeholders to improve PGE's forecasts.	PGE held a series of workshops and public meetings in 2018 to work with IRP stakeholders concerning the Company's load forecast methodology.	Appendix C. 2019 IRP Public Meeting Agendas
▪ Conduct out-of-sample testing and select models based	PGE performed out-of-sample testing.	

Additional Requirements	PGE Compliance	Chapter
on these results.		
■ Include a technical appendix that describes forecast methodology and contains a list of the forecast modeling assumptions (and explanations) and the model specifications (equations).	Appendix D describes PGE's load forecast methodology, as well as provides a list of modeling assumptions and model specifications.	Appendix D. Load Forecast Methodology
PORTFOLIO RANKING & SCORING METRICS		
■ Hold workshops with interested parties to develop a simple and clear set of portfolio scoring metrics, with a focus on using only metrics that have a clear interpretation and robust discussions on the appropriate way to incorporate short- and medium term options and the relative importance of high-cost versus low-cost outcomes.	PGE and IRP stakeholders engaged in multiple public input meetings to discuss scoring metrics and scoring methodology for the 2019 IRP.	Chapter 7. Portfolio Analysis Appendix C. 2019 IRP Public Meeting Agendas
DISTRIBUTION SYSTEM PLANNING		
■ Work with Staff and other parties to advance distributed energy resource forecasting and distributed energy resource representation in the IRP process.	PGE engaged Navigant Consulting to conduct a holistic evaluation of the potential for PGE customers to adopt distributed resources. Navigant presented draft results to stakeholders at a public meeting and revised assumptions based on stakeholder feedback. The final results of the study were incorporated into PGE's needs assessment and portfolio analysis.	External Study C. Distributed Energy Resource Study Appendix C. 2019 IRP Public Meeting Agendas
■ Work with Staff to define a proposal for opening a distribution system planning investigation.	PGE is actively participating in Docket No. UM 2005 to investigate distribution resource planning implementation in the Company's transmission and distribution planning process.	
TRANSMISSION		
■ Hold a workshop to explore the issue of transmission and the potential access to higher capacity wind resources in Montana and Wyoming.	On December 19, 2018, PGE held a Roundtable on transmission planning and the Company's participation in the Montana Renewable Development Action Plan (MRDAP) process. PGE incorporated information and recommendations	Appendix C. 2019 IRP Public Meeting Agendas Chapter 5. Resource Options

Additional Requirements	PGE Compliance	Chapter
	from the MRDAP into the 2019 IRP analysis of Montana Wind resources and portfolios.	

APPENDIX C. 2019 IRP Public Meeting Agendas

PGE manages IRP development through a collaborative, interactive process with an active customer and public stakeholder group. All IRP meetings are open to the public and are hosted at least once per quarter. Before we began work on the 2019 IRP, we engaged stakeholders in a conversation around values. We heard that affordability, sustainability, and transparency are paramount to many of our stakeholders as they engage in the IRP process. We kept those values in mind throughout our process and took tangible steps to improve our process to be responsive to what we heard. Specifically, we shared draft information more frequently as the analysis unfolded; we requested feedback on specific design questions; we invited stakeholders to submit informal comments throughout the process; and we modeled specific portfolios requested by stakeholders. In the process of creating the 2019 IRP PGE hosted thirteen roundtable and technical meetings. In total 221 attendees have participated either over the phone or in-person and provided 58 written comments. Public stakeholders had opportunity to submit comments anytime during IRP development via email, over the phone, or at meetings. As we moved through analysis for the 2019 IRP, PGE specifically requested stakeholders submit portfolios to be included in the 2019 modeling considerations; five unique portfolio requests were received. This feedback helped inform our resource plan.

PGE makes all meeting materials available on the IRP webpage and advertises public meeting dates there as well. The interests and values shared with us are incorporated into our final IRP and a summary of the comments we received are posted to our 2019 IRP webpage.

This summary of our meeting dates and topics hosted in support of the 2019 IRP are a simplified snapshot of the dedication of a group of individuals from the community who have put in time to advocate for their communities and to educate us. We have attempted to incorporate what we have heard and plan to continue to engage and evolve through this 2019 IRP and into future IRP development.

August 24, 2017, Roundtable 17-3

- Resource Cost Studies Update
- Resource Cost & Levelization
- Scoring Metrics Discussion
- Decarbonization Study
- IRP Scheduling/Planning

February 14, 2018, Roundtable 18-1 (Day 1 – 2019 IRP Kickoff)

- 2019 IRP
- Portfolio Construction
- Futures and Uncertainties
- Flexibility Assessment Methodology
- Decarbonization Study

- Market Study
- Customer Insights

February 15, 2018, Roundtable 18-1 (Day 2 – Technical Meeting)

- 2016 IRP Update Introduction
- Need Assessments and Sensitivities
- Capacity Contribution
- Supply Side Resources
- Energy Trust EE Forecast
- Distributed Resource & Flexible Load Study
- Load Forecast
- Load Forecast Workshop

April 26, 2018, Technical Meeting

- ROSE-E Model Discussion
- Market Capacity Scoping Discussion

May 16, 2018, Roundtable 18-2

- 2019 IRP Overview & Updates
- Load Forecast Workshop
- Futures
- Wholesale Electricity Market
- Portfolio Construction
- Scoring Metrics Workshop
- Decarbonization Study – Role in 2019 IRP

July 11, 2018, IRP Technical Meeting

- Market Capacity Study Update
- Distributed Energy & Flexible Load Study
- Flexibility Analysis Scope
- WECC Wide High Renewables Buildout

August 22, 2018, IRP Roundtable 18-3

- Draft Navigant Study Results
- ROSE-E Carbon Constraints
- Montana Wind Workshop – Part 1

- Draft Market Prices
- Supply Side Options Studies

September 26, 2018, IRP Roundtable 18-4

- Final Navigant Results
- Draft Portfolios
- Draft Scoring Metrics
- Draft Renewable Supply Side Study

October 31, 2018, IRP Roundtable 18-5

- Market Capacity Study Update
- Load Forecast Update
- Resource Need Update
- Portfolio & Scoring Update

November 28, 2018, IRP Roundtable 18-6

- Flexibility Analysis
- Final Navigant Distributed Energy Resources Scenarios
- Resource Need Update
- Portfolio & Scoring Update

December 19, 2018, IRP Roundtable 18-7

- Montana Transmission
- Distribution System Planning

February 27, 2019, IRP Roundtable 19-1

- Updated Need Assessment
- Updated Flexibility Analysis
- Updated Portfolio Analysis
- Draft Action Plan
- Draft Renewables Glide Path

May 22, 2019, IRP Roundtable 19-2

- Updated Portfolio Analysis
- Updated Preferred Portfolio
- Near-Term Resource Additions
- Renewable Glide Path

- Greenhouse Gas Forecast
- 2019 IRP Next Steps

June 12, 2019, IRP Community Listening Session

- IRP Planning and the Community

APPENDIX D. Load Forecast Methodology

This appendix provides additional detail about PGE's load forecast. As discussed in Section 4.1, the load forecast is a combination of the top-down econometric forecast and the passive distributed energy resources (DER) forecast.

As in previous sections, unless specified, the load values in this appendix reflect cost-of-service supply load and do not include long-term direct access loads.

Note that while the term "passive DER" is used in the IRP chapters to refer to electric vehicle loads, customer-located distributed solar photovoltaics, and customer-dispatched battery storage, in this appendix, electric vehicle load is examined separately to provide additional information.

D.1 Econometric Forecast

This section was prepared to describe the methodology and assumptions of PGE's long-term econometric load forecast models, as directed in Order No. 17-386.[181] These models forecast energy deliveries (in MWh) and peak demand (in MW) through 2050. This appendix also presents tabular detail of the forecast results.

Development of PGE's econometric load forecast reported in this IRP began in early 2018, and after public workshops and discussions with OPUC Staff,[182] the forecast was finalized in September 2018.[183] The first workshop in February 2018 included an open discussion of stakeholder requests. At the next load forecast workshop in May 2018, PGE presented refined models and draft forecast results and encouraged stakeholders to provide feedback to be incorporated into the final forecast. In the summer of 2018, PGE provided data and forecast models to OPUC Staff for more detailed review and discussion of methodology. Staff provided feedback including some suggestions,[184] which PGE addressed. PGE completed its models in September and presented final econometric load forecast results at a public roundtable in October 2018.

PGE worked with stakeholders to develop a methodology for creating probabilistic forecasts that ultimately reflects the uncertainty in the forecast model structure and in the model coefficients. That probability distribution was used in conjunction with high and low growth alternate economic driver variables to develop high and low forecasts around the base case forecast. The forecast methodology is described in Section D.1.3 Process.

D.1.1 Refinements Since Last IRP

Several refinements have been made to the long-term models since the 2016 IRP and IRP Update. The structures of the long-term models were reassessed and in doing so, the residential class model

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[181] Order No. 17-386 at 19.

[182] Presentations are available at https://www.portlandgeneral.com/our-company/energy-strategy/resource-planning/integrated-resource-planning/irp-public-meetings.

[183] Because the load forecast is an early input to the IRP modeling process, the load forecast is finalized several months ahead of the IRP document release.

[184] For example, Staff identified that the magnitude of driver uncertainty was assigned an unrealistically low value in the evaluation of probabilistic loads. PGE agreed and changed approach.

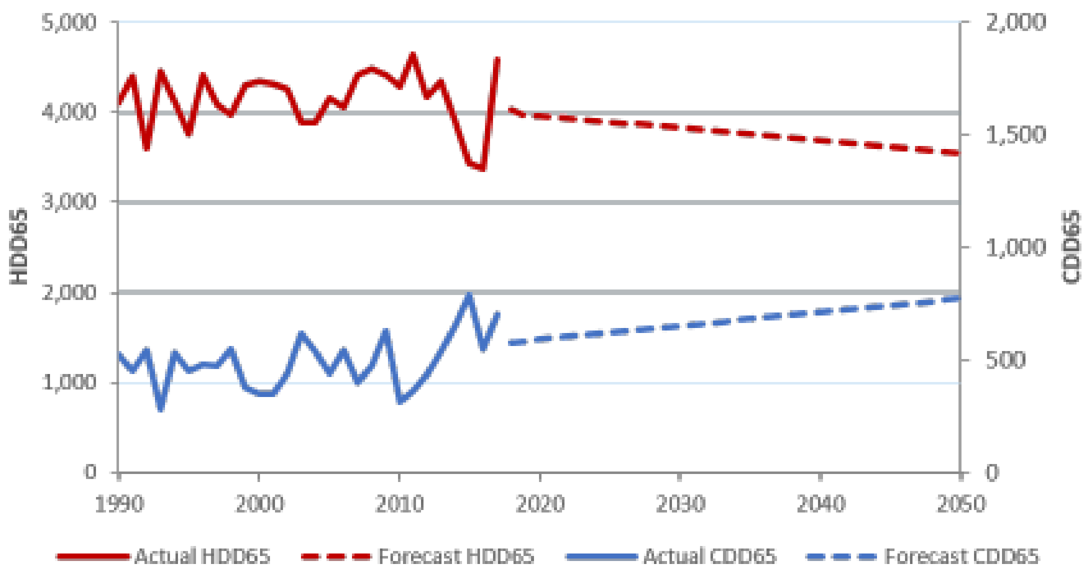
moved to a use-per-customer structure, which disentangles the increasing customer count and decreasing use-per-customer trends. For all models, the model structure includes improved handling of stationarity and more documentation and standardization of model testing and model selection (see Section D.1.3). There is also more transparency in the categories of uncertainty reflected in the high and low growth scenarios.

D.1.2 Inputs

D.1.2.1 Normal Weather Assumption

PGE assumes normal weather as an input to the load forecast. As a result, the load forecast reflects a typical weather year rather than a weather forecast. Weather variability above and below the normal weather assumption is expected. The intention is to use an unbiased weather assumption such that the actual weather is warmer than normal 50 percent of the time and cooler than normal 50 percent of the time. PGE uses a trend to create the forward-looking normal weather assumption that reflects the gradually warming climate. The methodological approach continues the trend observed since 1975, using data since 1941 to "hinge" the initial point of that trend.[185] Figure D-1 shows historical actual and forward-looking normals for heating and cooling degree days (HDD and CDD)[186] using this methodology.

FIGURE D-1: Normal weather expectation in terms of heating degree days and cooling degree days



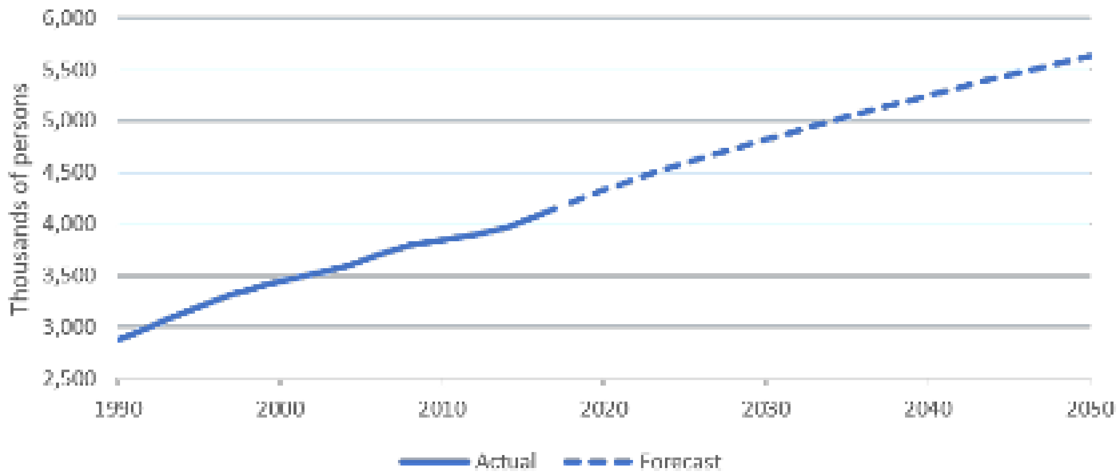
185 Livezey, Robert E., et al. "Estimation and extrapolation of climate normals and climatic trends." *Journal of Applied Meteorology and Climatology* 46.11 (2007): 1759-1776. https://journals.ametsoc.org/doi/pdf/10.1175/2007JAMC1666.1

186 Heating and cooling degree days (HDD and CDD) are the number of degrees that a day's temperature deviates from the temperature setpoint. For heating degree days, the measurement represents the extent to which a building would need heated to reach the temperature setpoint, and for cooling degree days, the measurement represents the extent to which a building would need cooled to reach the temperature setpoint. For these regressions with monthly data, HDD and CDD are summed for all days in the month. As an example, on a day with average temperature of 75° F, HDD60 = 0 and CDD65 = 75 - 65 = 10.

D.1.2.2 Oregon Population

Oregon's population is closely related to the number of households in PGE's service area, and it is used as a driver of residential customer count in PGE's residential energy deliveries model. PGE uses the Oregon Office of Economic Analysis's forecast of Oregon population, extrapolated from 2030 to 2050. The projected average annual growth rate from 2020 to 2050 is 0.9 percent. Figure D-2 shows the historical actual and projected population levels.

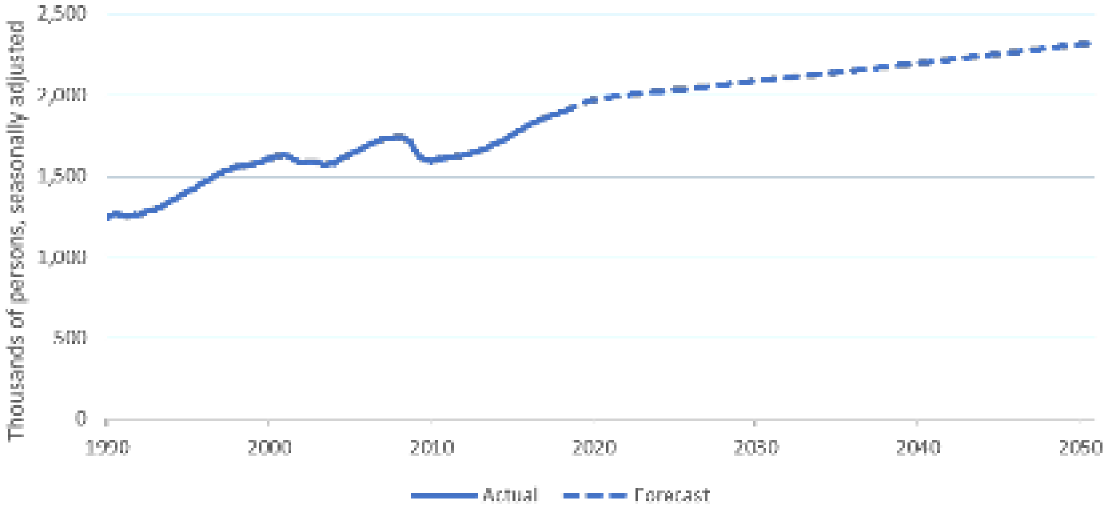
FIGURE D-2: Oregon population



D.1.2.3 Oregon Total Non-farm Employment

The level of employment in Oregon is the economic driver of PGE's commercial energy deliveries forecast. PGE uses the Oregon Office of Economic Analysis's forecast of employment, extended to 2050. The projected average annual growth rate from 2020 to 2050 is 0.5 percent. Figure D-3 shows the historical actual and forecast levels of total non-farm employment.

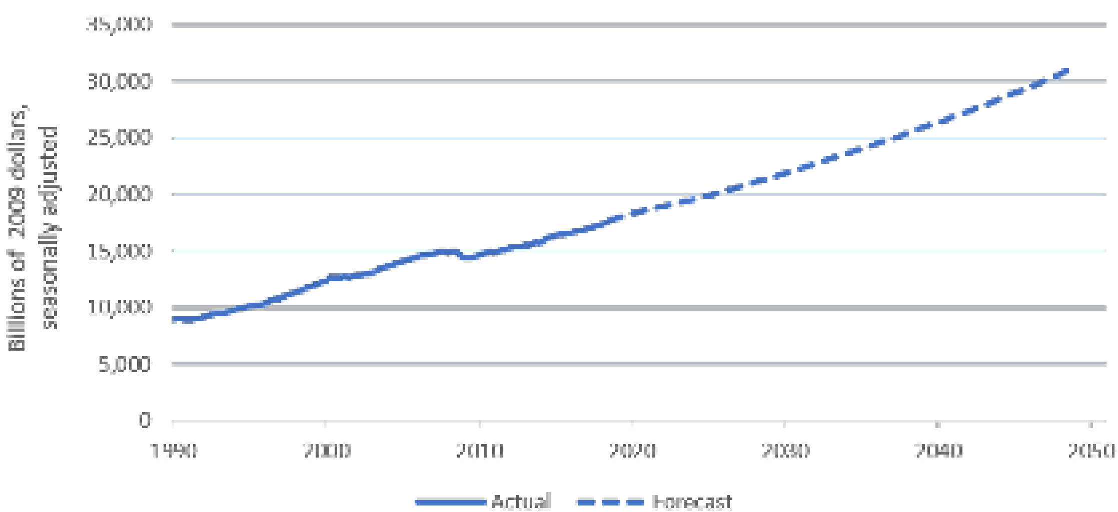
FIGURE D-3: Oregon total non-farm employment



D.1.2.4 U.S. Gross Domestic Product

Gross domestic product (GDP) is the economic driver of PGE's industrial energy deliveries forecast. PGE uses the IHS Markit's forecast of U.S. GDP, extended to 2050, as its input assumption. The projected average annual growth rate from 2020 to 2050 is 1.9 percent. Figure D-4 shows the historical actual and forecast real GDP.

FIGURE D-4: U.S. real gross domestic product, seasonally adjusted



D.1.3 Process

The long-term load forecast is built on a set of near-term models with a five-year time horizon and a set of long-term models extending to 2050. On a quarterly basis, PGE determines whether to update its short-term forecast models, which typically results in two or three updates per year. PGE also undertakes a focused reevaluation of its long-term models in advance of each IRP.

PGE considers energy deliveries in twenty-five forecast groups for the near-term models. These consist of monthly models based on historical billing cycle energy deliveries data for different residential housing types (i.e., single family, multi-family, mobile home, other) with electric and non-electric heating types as well as commercial and manufacturing models based on industry type. Near-term energy deliveries are individually forecast for PGE's approximately thirty largest industrial customers.

The near-term energy deliveries forecast model adjusts the results of the regression-based model to account for incremental programmatic energy efficiency (EE) savings. The top-down load forecast for the 2019 IRP uses Energy Trust of Oregon's EE savings forecast from November 2017.

For its long-term models, PGE has three forecast groups based on revenue class: residential, commercial, and industrial. The long-term models use data from 1990 to mid-2018 (the most recent data available at the time of the forecast) to build the regressions, and the resulting forecasts are used to determine long-run equilibrium growth rates that are applied to extend the near-term models. These growth rates include EE trends since 1990, capturing a long history of efficiency savings in Oregon.

D.1.3.1 Residential Model

The long-term residential energy deliveries model, shown in Equation 1, comprises forecasts for both customer count, which is an annual model based on Oregon population (Equation 2), and use-per-customer, which is a monthly model based on relationships with heating and cooling degree days (Equation 3). The resulting monthly use-per-customer forecast is aggregated to an annual level before being combined with the annual customer count forecast, for an annual forecast of residential energy deliveries.

EQUATION 1: Residential energy deliveries

$$kWh_{res} = \mathrm{UPC}_{res} \times CC_{res}$$

Where:

- UPC = Use-per-customer forecast
- CC = Customer count forecast

EQUATION 2: Residential use-per-customer

$$UPC_{res,t} = \sum_{k=0}^{11} (\beta_k Month_k + \alpha_k Trend_k) + \beta_{12} HDD60 + \beta_{13} CDD65 + \beta_{14} UPC_{res,t-1} + \varepsilon_t$$

Where:

- HDD60 = Heating degree day with 60° F setpoint
- CDD65 = Cooling degree day with 65° F setpoint
- ε_t = error term

EQUATION 3: Residential customer count

$$\Delta^2 CC_{res,t} = \beta_0 + \beta_1 \times \Delta^2 POP_{OR} + \epsilon_t$$

Where:

- $\Delta^2 y = (y_t - y_{t-1}) - (y_{t-1} - y_{t-2})$, representing a second-order difference
- POP_{OR} = Oregon population
- ε_t = error term

D.1.3.2 Commercial Model

The commercial energy deliveries model, shown in Equation 4, is a monthly model that establishes a relationship of commercial energy deliveries to Oregon total non-farm employment and heating and cooling degree days.

EQUATION 4: Commercial energy deliveries

$$\Delta kWh_{com,t} = \sum_{k=0}^{11}(\beta_k Month_k) + \beta_{12}\Delta OENTNA + \beta_{13}\Delta HDD55 + \beta_{14}\Delta CDD60 + \beta_{15}\varepsilon_{t-1} + \sum_{i=1}^{12}(\beta_{15}\omega_{12}\Delta kWh_{com,t-i}) + \varepsilon_t$$

Where:

- $\Delta y = (y_t - y_{t-1})$, representing a first-order difference
- OENTNA = Oregon total non-farm employment
- HDD55 = Heating degree day with 55° F setpoint
- CDD60 = Cooling degree day with 60° F setpoint
- ε_t = error term

D.1.3.3 Industrial Model

The industrial model is a monthly model that includes gross domestic product as a driver of energy deliveries (Equation 5).

EQUATION 5: Industrial energy deliveries

$$\Delta kWh_{ind,t} = \sum_{k=0}^{11}(\beta_k Month_k) + \beta_{12}\Delta GDPR + \beta_{13}\Delta kWh_{ind,t-1} + \beta_{14}\varepsilon_{t-1} + \varepsilon_t$$

Where:

- $\Delta y = (y_t - y_{t-1})$, representing a first-order difference
- GDPR = Real U.S. Gross Domestic Product
- ε_t = error term

D.1.3.4 Peak Model

The peak model, shown in Equation 6, is a monthly model that relates the single-hour, peak demand of PGE's net system (in MW) to average monthly demand (in MWa) and weather variables. The model considers the impact of heating and cooling degree days (HDD and CDD) as well as the growing use of air conditioning in Oregon. It includes the prior day's cooling degree days to represent the impact of heat gain in the summer, as two consecutive hot days are more impactful on summer peak than a single day event and wind speed on days where heating is needed, as a windy cold day requires more heating load than a non-windy cold day.

EQUATION 6: Peak demand

$$\Delta MW_t = \sum_{k=0}^{11} (\beta_k \Delta MWa_k Month_k) + \beta_{12} \Delta PKDAY_{CDD} * ACSAT + \beta_{13} \Delta PD_{CDD} * COOLING + \beta_{14} \Delta PKDAY_{HDD} + \beta_{15} \Delta PKDAY_{WIND} * HEATING + \beta_{16} \Delta MW_{t-1} + \beta_{17} \Delta MW_{t-2} + \beta_{17} \varepsilon_{t-12} + \varepsilon_t$$

Where:

- $\Delta y = (y_t - y_{t-12})$, representing a seasonal first-order difference
- MWa = average monthly demand
- $PKDAY_{CDD}$ = CDD with 65° F setpoint on the day the peak occurred
- ACSAT = Percentage of households with air conditioning
- PD_{CDD} = CDD with 65° F setpoint on the day prior to the day the peak occurred
- COOLING = Binary 1 or 0, 1 for observations where $PKDAY_{CDD}>0$
- $PKDAY_{HDD}$ = HDD with 65° F setpoint on the day the peak occurred
- HEATING = Binary 1 or 0, 1 for observations where $PKDAY_{HDD}>0$
- $PKDAY_{WIND}$ = Average daily wind speed on the day the peak occurred
- ε_t = error term

D.1.4 Model Development and Evaluation

In response to OPUC Staff feedback in LC 66, and as part of continual refinements to methodology, PGE worked to standardize and more formally document its model development process and evaluation criteria.

A series of testing steps are used to develop the long-term forecast models. This testing includes univariate review of the underlying structure of the energy deliveries time series; examination of the relationship between energy deliveries to drivers including weather variables; and testing of alternative model structures including naïve, differenced, and "automatic" ARIMA.[187] To compare and select between alternate models, the model fit statistics, coefficients, and model residuals are reviewed and out-of-sample testing is performed.

- **Univariate analysis.** Univariate analysis of historical sector-level time series is conducted to identify trends, seasonality, cycles, breaks, and outliers. The first step is to visually inspect the data series. Then the autocorrelation of the series is reviewed and statistical tests such as the Augmented Dickey Fuller (ADF) and Kwiatkowski, Phillips, Schmidt, and Shin (KPSS) tests are used to assess the underlying structure of the data. When tests imply non-stationarity in a variable, PGE explores data transformations, use of trend variables, and naïve forecasts.
- **Weather responsiveness.** Scatter plots and testing in the regression models are used to determine the appropriate HDD and CDD variables for inclusion in each model. Figure D-5 shows the weather responsiveness of the three long-term models with monthly energy deliveries plotted against average monthly temperature using data since 2000.

  In Figure D-5 (a), the scatter follows a relatively tight "U" shape, indicating that residential energy usage increases as the average temperature falls below 60˚F and as the average temperature is above 65˚F. This implies use of an HDD variable calculated from a 60˚F base and a CDD variable with a 65˚F base. In (b), commercial energy usage increases as the average temperature falls below 55˚F and when the average temperature is above 60˚F. In (c), the broad scatter implies that energy deliveries to the industrial class have no meaningful weather dependence.
- **Alternate forecasts and out-of-sample testing.** PGE reviews a variety of alternate model specifications for each of the forecast groups and compares the forecasts from each model in out-of-sample tests, which use a training period to estimate the model and a testing period to evaluate model performance. By using a historical sample for model evaluation, the model error is isolated because the values of input variables are known (i.e., weather and economic drivers). Testing includes: 1) models using a variety of economic drivers, as well as those with no economic driver; 2) models with and without monthly indicator variables; and 3) models using a variety of data transformations. As part of the standardization of the model evaluation and to benchmark against the most simplistic models, PGE also tests naïve and seasonally naïve forecasts.
- **Residual review.** PGE reviews the autocorrelation and normality of residuals in the models for

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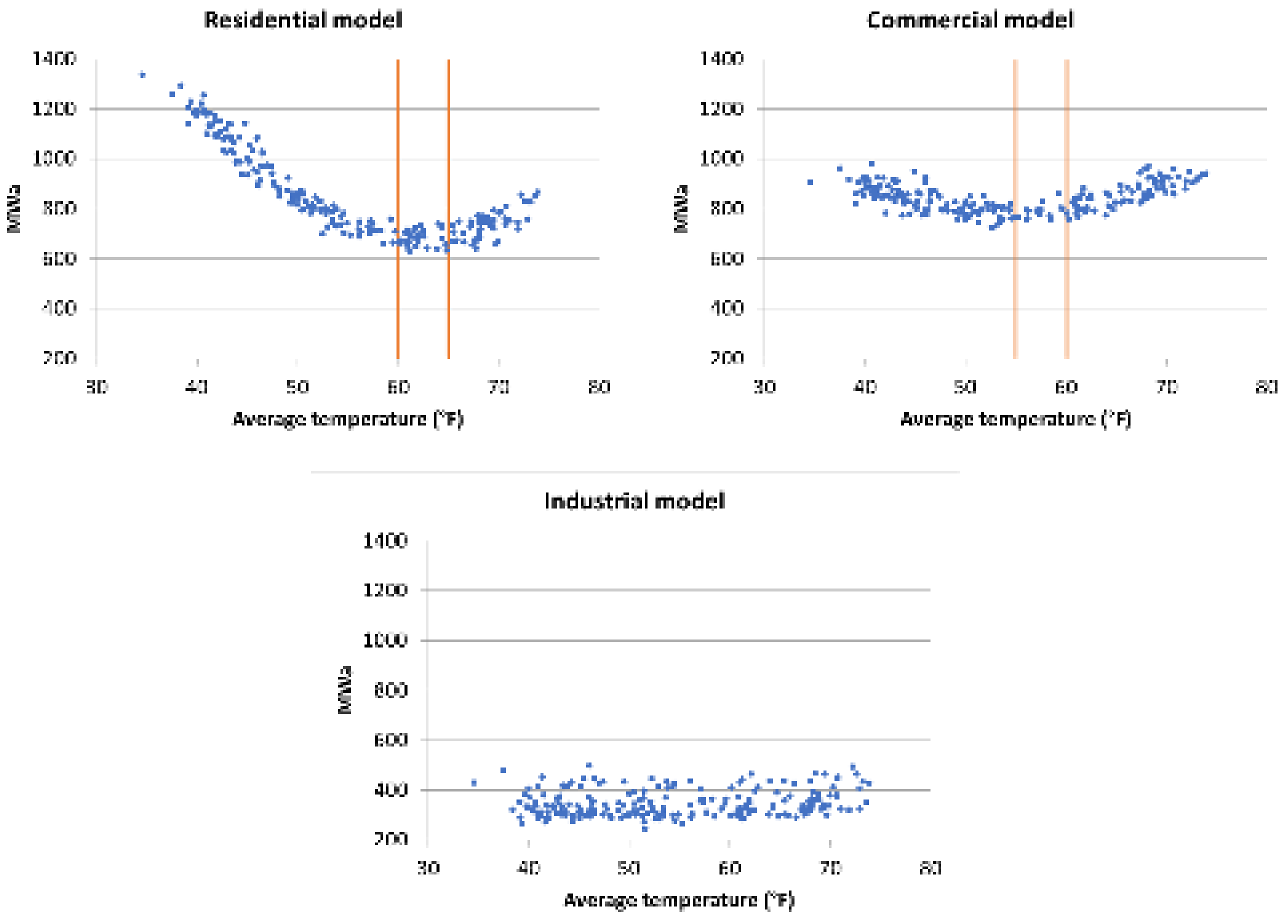
187 ARIMA stands for autoregressive integrated moving average, and it is a class of time-series forecast models. PGE's forecasting software, EViews, has an automatic ARIMA forecasting option that "optimizes" ARIMA model structure based on a selected statistical measure.

any considered alternative model structures. Ideally, residuals are white noise, which means that they are uncorrelated, have a mean of 0, have constant variance, and are normally distributed. The extent to which residuals of a regression statistically differ from white noise indicates the potential to improve model specification. Residuals that are meaningfully correlated might lead to the addition of autoregressive or moving average terms to the model, or otherwise re-visiting the regression model specification.

FIGURE D-5: Weather sensitivity of energy deliveries to (a) the residential class, (b) the commercial class, and (c) the industrial class



D.1.5 Probabilistic Loads

All forecasts are subject to uncertainty, including uncertainties associated with forecasts of input variables themselves and the complexity of the estimated relationships with those variables. Some of these uncertainties can be characterized in a quantitative way using model parameters. In the 2019 IRP cycle, PGE has striven to further clarify uncertainties and quantify them to the extent possible.

The single most important driver of load variability is weather. Residential and small commercial loads are particularly sensitive to weather due to heating and cooling loads, and weather is known to be highly variable from one year to the next. PGE addresses the stochastic risk in the load forecast associated with weather, analyzing over 30 years of weather variability, in its Resource Adequacy model, described in Section 4.3 Capacity Adequacy and Section I.3 RECAP Model.

Two sources of uncertainty that are characterized using the output statistics of the regression models described above are model uncertainty and coefficient uncertainty. Model uncertainty is the standard error of the regression, or a reflection of how the model performs over the period of data used to inform the model. Coefficient uncertainty is the standard error associated with the estimated coefficient which defines the relationship between the dependent and driver variables.

The EViews forecast software was used to run stochastic simulations that combine the model uncertainty and coefficient uncertainty to create confidence bands around the base case forecast. During simulation runs, coefficients are randomly varied along with residuals and the errors are quantified and used to obtain confidence intervals. Ten thousand simulations were run for each of the long-term regression models.

Figure D-6 shows the resulting 75 percent and 95 percent confidence bounds on the three energy deliveries models. Figure D-7 shows the bounds on the peak model.

Another category of uncertainty is those related to the driver variables used in the regression models. Uncertainties in the forecast of the economic driver variables are considered by scenario analysis, described further in Section D.3 below.

Other uncertainties not quantified yet worth mentioning relate to variables excluded from the models and the estimation periods of the models. A model is by design a simplification of reality. The interdependencies of energy deliveries are complex and wide spread across the macroeconomy. The benefits and uncertainties of different variable selection and estimation periods are weighed during the model development and evaluation process.

FIGURE D-6: Confidence interval on the net system residential (left), commercial (middle), and industrial (right) energy deliveries models

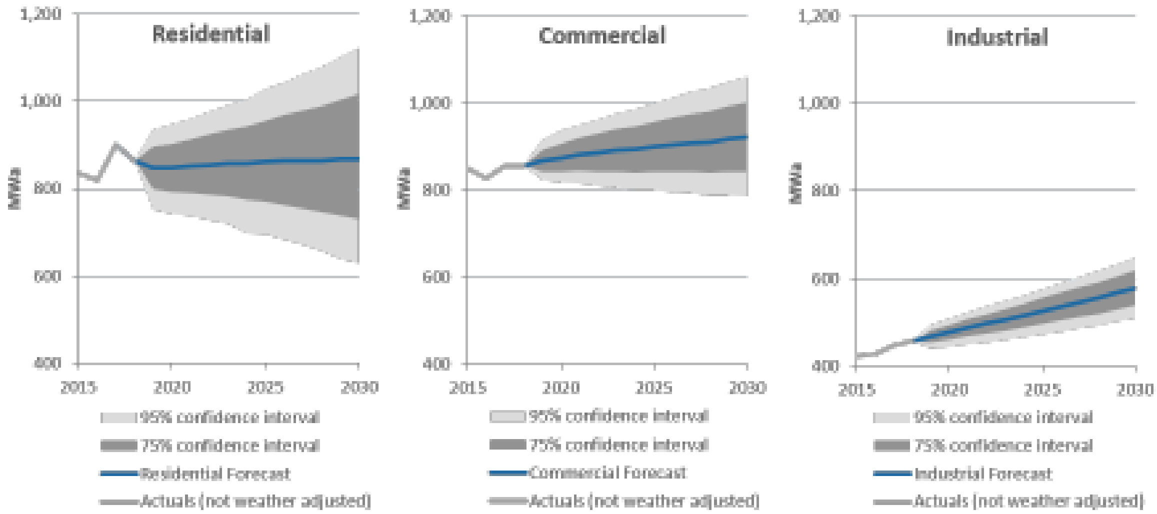
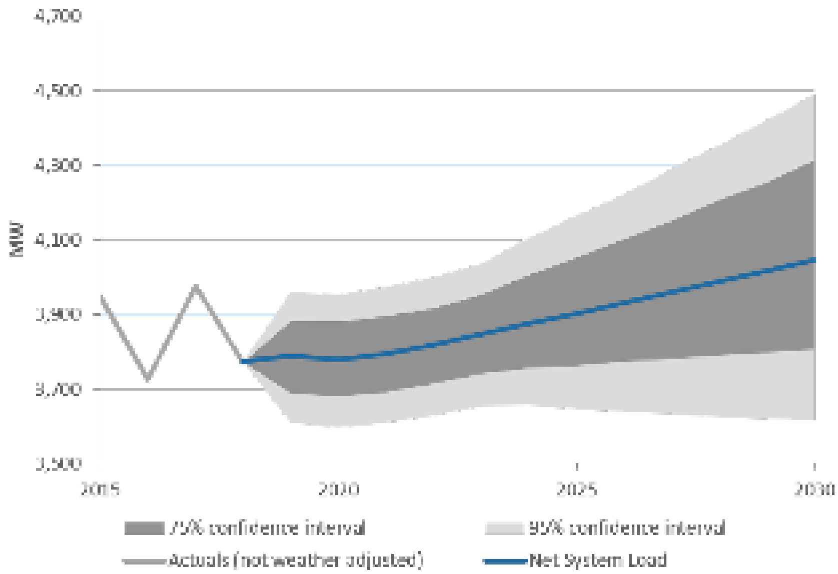


FIGURE D-7: Resulting 75 percent and 95 percent confidence bounds on the net system peak demand model



D.2 EV and Passive DER Forecasting

For the first time, PGE has integrated its econometric forecast models with explicit individual forecasts of electric vehicle (EV) adoptions, behind-the-meter solar, and customer-dispatched distributed battery storage. The forecasts are discussed in Section 4.1.3. Each takes a more granular, bottom-up, approach than PGE's top-down econometric forecast.

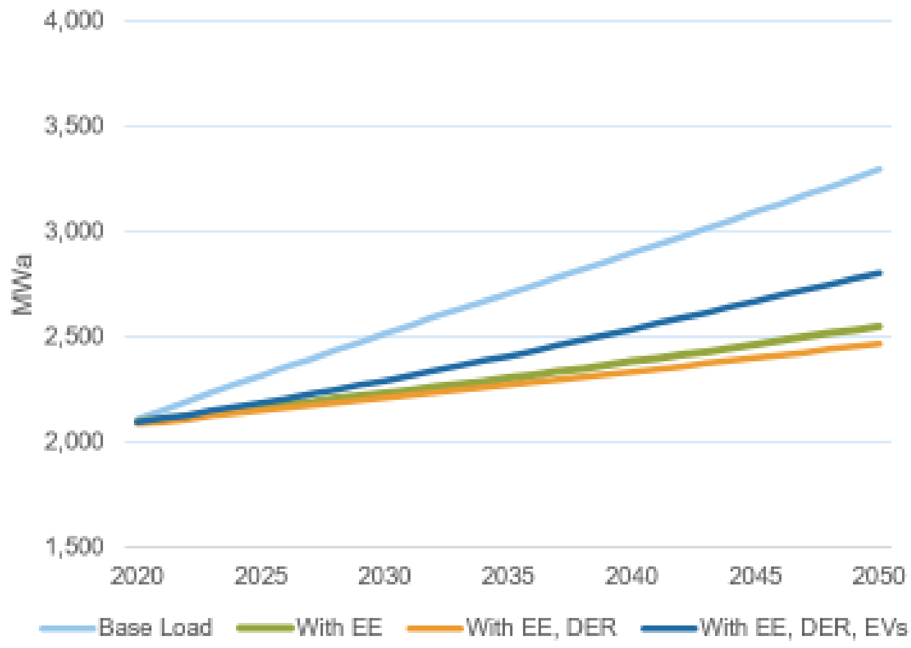
To combine the top-down forecasts with the explicit forecasts for EVs and passive DER, PGE began with the top-down forecasts, considered the estimated impact of EVs and passive DER embedded in the top-down forecasts, and added the incremental impacts from the bottom-up forecasts. PGE assumed the amount embedded in the top-down forecast as equal to the 2018 values from the forecasts. Further reconciliation of top-down and bottom-up forecasting methodologies will be an area of focus for PGE in future IRP cycles.

Figure D-8[188] shows the effect of the layering of energy forecasts in the Reference Case as described below.

1. The "Base Load" forecast is the top-down load forecast excluding impacts of EE acquisitions beginning in 2020 and excluding the embedded passive DER quantities forecast for 2018.
2. The "With EE" layer adds the impact of Energy Trust's projected EE savings on the "Base Load".
3. The "With EE, DER" layer adds the passive DER forecast.
4. The final layer "With EE, DER, and EV" includes the EV load forecast and represents PGE's Reference Case forecast.

188 In this figure, DER refers to distributed PV.

FIGURE D-8: Layering of forecast for Reference Case load, MWa



D.3 High and Low Growth Scenarios

High and low growth scenarios were constructed that incorporate high and low growth alternates of the economic driver variables in the top-down load forecast as well as +/- 1 standard deviation of uncertainty from the regression model parameters as described in Section D.1.5. Table D-1 summarizes the components of the low, reference, and high load scenarios.

TABLE D-1: Load components for each load scenario

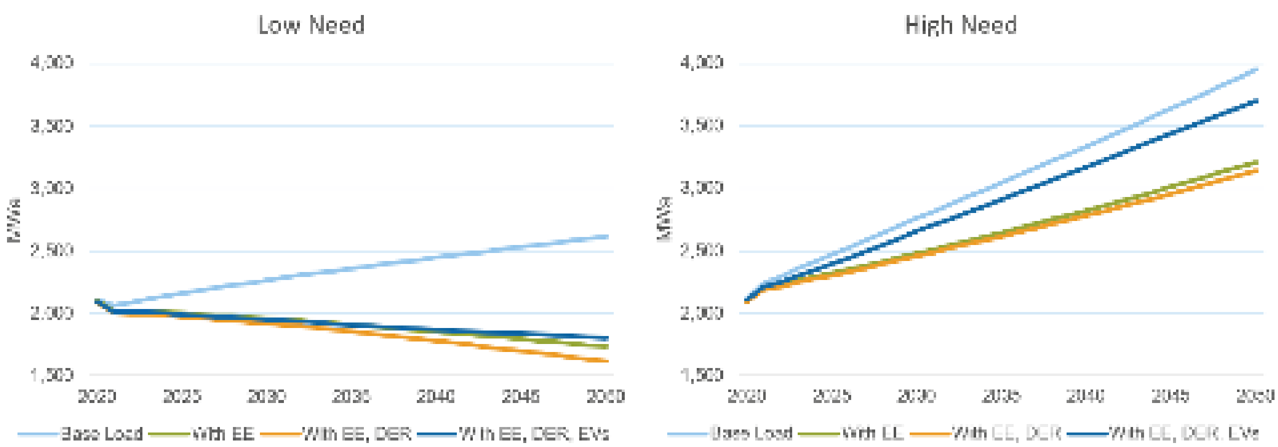
	Low Load	Reference Case	High Load
Economic Driver		Average annual growth rates (2020-2050)	
Population	0.4%	0.9%	1.4%
Employment*	0.1%	0.5%	1.1%
US GDP	1.6%	1.9%	2.5%
Model Uncertainty†	Less 1 standard deviation	None	Plus 1 standard deviation
Energy Efficiency	High EE	Cost Effective EE	Cost Effective EE
Electric Vehicles	Low Adoption	Reference Case	High Adoption
Passive DER (Solar and non-dispatchable storage)	High Adoption	Reference Case	Low Adoption

* Oregon total non-farm employment.

†Standard deviation includes regression error and coefficient uncertainty. The error distributions are not perfectly normal, so one standard deviation only roughly equates to a 68% confidence interval.

Figure D-9[189] presents the impacts of each of the load components in the high and low load forecast scenarios.

FIGURE D-9: Layering of low and high load forecasts, MWa



D.4 Results

Results of the top-down econometric models described above are combined with explicit forecasts for EE, EV, and behind-the-meter solar and storage to arrive at the total load scenarios shown in the tables below. As discussed in Section 4.1.1.1, these load forecasts do not include long-term direct access loads. For reference, Section D.5 provides low, reference, and high forecasts for Net System Load by residential, commercial, and industrial customers. Net System Load includes both cost-of-service supply customers and long-term direct access customers.

D.4.1 Energy Load Forecasts

Table D-2 provides a summary of the load forecast scenarios for energy deliveries (in MWa) at the busbar.[190] Table D-3, Table D-4, and Table D-5 provide the annual forecasts for the reference, low, and high scenarios. For these tables, note that passive DER captures the forecasts for generation from distributed PVs only.

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189 In this figure, DER refers to distributed PVs.

190 As mentioned above, the load forecasts in this section do not include long-term direct access loads.

TABLE D-2: Load forecast scenarios in MWa

	Low Need			Reference Case			High Need		
	2020	2050	AAGR	2020	2050	AAGR	2020	2050	AAGR
Top-down Load Forecast	2,096	1,869	-0.4%	2,096	2,549	0.7%	2,096	3,208	1.4%
Base Load Forecast*	2,111	2,614	0.7%	2,111	3,294	1.5%	2,111	3,954	2.1%
Energy Efficiency†	(11)	(879)	-	(11)	(742)	-	(11)	(742)	-
Passive DERs‡	(13)	(119)	7.6%	(11)	(84)	6.9%	(11)	(72)	6.3%
Electric Vehicles**	7	185	11.3%	10	334	12.3%	16	565	12.6%
Total Load Forecast	**2,094**	**1,801**	**-0.5%**	**2,099**	**2,803**	**1.0%**	**2,105**	**3,704**	**1.9%**

*The base load forecast is the top-down load forecast adjusted to exclude the impacts of the cost-effective deployable EE savings and the assumptions for the embedded distributed PV generation and electric vehicle load.

†The EE savings are cumulative values adjusted for line losses and intra-year deployment, beginning in the year 2020. The AAGR is not calculated because savings prior to 2020 are not reported in these values.

‡For simplification, the passive DER values reflect distributed PV generation only.

**As discussed in Section 4.1.3.1 Electric Vehicles, this EV forecast is for light-duty vehicles.

TABLE D-3: Reference Case load scenario with layers, MWa

Year	(a) Base Load	(b) Energy Efficiency	(c) Electric Vehicles	(d) Passive DER	(e) = (a) + (b) + (c) + (d) Total Load
2020	2,111	-11	10	-11	2,099
2021	2,152	-41	14	-12	2,112
2022	2,193	-70	18	-13	2,128
2023	2,239	-97	23	-14	2,151
2024	2,278	-124	29	-15	2,169
2025	2,317	-150	37	-17	2,187
2026	2,356	-176	45	-18	2,207
2027	2,395	-202	54	-19	2,228
2028	2,436	-228	63	-21	2,250
2029	2,475	-255	73	-22	2,271
2030	2,514	-280	83	-24	2,294
2031	2,554	-306	94	-26	2,316
2032	2,593	-331	104	-28	2,339
2033	2,631	-354	116	-30	2,363
2034	2,668	-377	127	-32	2,386

Year	(a) Base Load	(b) Energy Efficiency	(c) Electric Vehicles	(d) Passive DER	(e) = (a) + (b) + (c) + (d) Total Load
2035	2,706	-400	138	-34	2,410
2036	2,745	-423	150	-37	2,435
2037	2,783	-447	162	-39	2,459
2038	2,821	-470	175	-42	2,484
2039	2,860	-493	188	-45	2,510
2040	2,899	-515	201	-48	2,536
2041	2,937	-538	215	-51	2,563
2042	2,976	-561	229	-54	2,590
2043	3,015	-583	243	-57	2,617
2044	3,054	-606	256	-61	2,644
2045	3,093	-629	271	-64	2,671
2046	3,133	-652	284	-68	2,698
2047	3,173	-674	297	-72	2,724
2048	3,214	-697	309	-76	2,750
2049	3,254	-720	322	-80	2,777
2050	3,294	-742	334	-84	2,803
Average annual growth rate	**1.5%**	**-**	**12.3%**	**6.9%**	**1.0%**

The AAGR is not calculated for energy efficiency because savings prior to 2020 are not reported in these values.

TABLE D-4: Low load scenario with layers, MWa

Year	(a) Base Load	(b) Energy Efficiency	(c) Electric Vehicles	(d) Passive DER	(e) = (a) + (b) + (c) + (d) Total Load
2020	2,111	-11	7	-13	2,094
2021	2,061	-41	9	-16	2,013
2022	2,087	-70	10	-18	2,009
2023	2,117	-99	11	-20	2,010
2024	2,140	-129	12	-22	2,001
2025	2,161	-159	14	-25	1,991
2026	2,181	-188	16	-28	1,981

Year	(a) Base Load	(b) Energy Efficiency	(c) Electric Vehicles	(d) Passive DER	(e) = (a) + (b) + (c) + (d) Total Load
2027	2,203	-217	18	-30	1,974
2028	2,226	-247	21	-33	1,968
2029	2,246	-276	25	-36	1,959
2030	2,266	-305	29	-39	1,952
2031	2,287	-334	34	-42	1,944
2032	2,307	-364	38	-46	1,936
2033	2,325	-393	44	-49	1,927
2034	2,343	-421	49	-52	1,919
2035	2,360	-449	55	-56	1,910
2036	2,379	-478	61	-60	1,902
2037	2,397	-508	68	-63	1,894
2038	2,414	-536	76	-67	1,887
2039	2,431	-565	83	-71	1,879
2040	2,449	-593	92	-75	1,871
2041	2,465	-622	101	-79	1,865
2042	2,482	-651	110	-84	1,858
2043	2,499	-679	119	-88	1,851
2044	2,516	-708	128	-92	1,844
2045	2,532	-736	138	-97	1,837
2046	2,549	-765	147	-101	1,830
2047	2,566	-793	157	-106	1,823
2048	2,582	-822	166	-110	1,815
2049	2,598	-850	175	-115	1,808
2050	2,614	-879	185	-119	1,801
Average annual growth rate	**0.7%**	**-**	**11.3%**	**7.6%**	**-0.5%**

The AAGR is not calculated for energy efficiency because savings prior to 2020 are not reported in these values.

TABLE D-5: High load scenario with layers, MWa

Year	(a) Base Load	(b) Energy Efficiency	(c) Electric Vehicles	(d) Passive DER	(e) = (a) + (b) + (c) + (d) Total Load
2020	2,111	-11	16	-11	2,105
2021	2,237	-41	24	-13	2,208
2022	2,295	-70	36	-13	2,247
2023	2,358	-97	51	-14	2,297
2024	2,413	-124	68	-15	2,343
2025	2,469	-150	90	-16	2,392
2026	2,525	-176	111	-17	2,443
2027	2,582	-202	134	-18	2,495
2028	2,640	-228	155	-19	2,547
2029	2,699	-255	177	-21	2,601
2030	2,758	-280	198	-22	2,654
2031	2,816	-306	218	-23	2,705
2032	2,875	-331	237	-25	2,757
2033	2,931	-354	257	-27	2,808
2034	2,988	-377	276	-28	2,859
2035	3,045	-400	295	-30	2,910
2036	3,104	-423	313	-32	2,961
2037	3,162	-447	332	-34	3,013
2038	3,221	-470	351	-36	3,066
2039	3,279	-493	370	-38	3,118
2040	3,339	-515	389	-41	3,171
2041	3,398	-538	409	-44	3,226
2042	3,458	-561	429	-46	3,279
2043	3,518	-583	448	-49	3,333
2044	3,579	-606	465	-52	3,386
2045	3,640	-629	484	-55	3,441
2046	3,702	-652	502	-58	3,494
2047	3,764	-674	518	-62	3,547
2048	3,828	-697	533	-65	3,599
2049	3,890	-720	550	-69	3,652

Year	(a) Base Load	(b) Energy Efficiency	(c) Electric Vehicles	(d) Passive DER	(e) = (a) + (b) + (c) + (d) Total Load
2050	3,954	-742	565	-72	3,704
Average annual growth rate	**2.1%**	**-**	**12.6%**	**6.3%**	**1.9%**

The AAGR is not calculated for energy efficiency because savings prior to 2020 are not reported in these values.

D.4.2 Peak Load Forecasts

Table D-6 provides a summary of the peak load forecasts (MW) at the busbar for each load scenario.[191] Table D-7 provides the seasonal peak loads for each year and scenario. These tables reflect total load values (the top-down econometric forecast combined with the forecasts for EVs and passive DERs, and in the case of the low scenario, the forecast for additional EE savings).

TABLE D-6: Load forecast scenarios, peak demand in MW

	Low Need			Reference Case			High Need		
	2020	2050	AAGR	2020	2050	AAGR	2020	2050	AAGR
Summer	3,426	3,502	0.1%	3,436	4,919	1.2%	3,450	6,282	2.0%
Winter	3,349	3,108	-0.2%	3,358	4,754	1.2%	3,373	6,351	2.1%
Annual	**3,426**	**3,502**	**0.1%**	**3,436**	**4,919**	**1.2%**	**3,450**	**6,351**	**2.1%**

TABLE D-7: Peak load forecast by scenario and season, MW

	Low Need		Reference Case		High Need	
Year	Summer	Winter	Summer	Winter	Summer	Winter
2020	3,426	3,349	3,436	3,358	3,450	3,373
2021	3,299	3,201	3,456	3,383	3,633	3,589
2022	3,302	3,205	3,485	3,418	3,697	3,669
2023	3,311	3,209	3,524	3,455	3,777	3,758
2024	3,312	3,192	3,560	3,482	3,859	3,837
2025	3,311	3,177	3,600	3,516	3,952	3,934
2026	3,312	3,167	3,641	3,552	4,047	4,032
2027	3,314	3,158	3,685	3,592	4,144	4,133

191 As mentioned above, the load forecasts in the section do not include long-term direct access loads.

	Low Need		Reference Case		High Need	
Year	**Summer**	**Winter**	**Summer**	**Winter**	**Summer**	**Winter**
2028	3,315	3,149	3,730	3,632	4,241	4,233
2029	3,319	3,141	3,776	3,674	4,340	4,334
2030	3,324	3,135	3,824	3,717	4,436	4,436
2031	3,329	3,129	3,872	3,761	4,530	4,533
2032	3,334	3,121	3,920	3,805	4,621	4,627
2033	3,338	3,114	3,970	3,851	4,714	4,723
2034	3,343	3,108	4,021	3,897	4,806	4,818
2035	3,349	3,103	4,072	3,944	4,898	4,912
2036	3,355	3,098	4,123	3,991	4,987	5,005
2037	3,363	3,095	4,177	4,042	5,081	5,102
2038	3,371	3,092	4,231	4,093	5,174	5,198
2039	3,379	3,090	4,286	4,145	5,267	5,295
2040	3,389	3,089	4,342	4,198	5,360	5,391
2041	3,400	3,090	4,408	4,262	5,457	5,492
2042	3,411	3,092	4,466	4,318	5,553	5,591
2043	3,423	3,093	4,525	4,374	5,647	5,690
2044	3,434	3,095	4,581	4,427	5,738	5,785
2045	3,446	3,098	4,640	4,485	5,834	5,885
2046	3,458	3,100	4,697	4,540	5,926	5,981
2047	3,469	3,102	4,753	4,595	6,017	6,075
2048	3,480	3,103	4,806	4,646	6,103	6,165
2049	3,492	3,106	4,863	4,702	6,194	6,261
2050	3,502	3,108	4,919	4,754	6,282	6,351
Average annual growth rate	**0.1%**	**-0.2%**	**1.2%**	**1.2%**	**2.0%**	**2.1%**

D.5 Net System Load

Net System Load includes both cost-of-service supply customers and direct access customers. While Net System Load is not used in the IRP need assessments or portfolio analysis, the information in this section is provided for reference.

The following tables provide the reference, low, and high econometric load forecasts for Net System Load in MWa at the busbar, by class. The commercial class here also includes street and highway lighting, and the industrial class includes both transmission and primary level customers. The high and low scenarios capture high and low growth conditions and +/- 1 standard deviation of uncertainty from the regression model parameters. These forecasts do not include the impacts of the explicit forecasts for EVs, DERs, or additional EE savings above Energy Trust's projections.

TABLE D-8: Econometric Net System Load with reference growth conditions, MWa

Year	Residential	Commercial	Industrial	Total
2020	920	891	536	2,347
2021	920	889	551	2,361
2022	921	889	566	2,376
2023	922	895	582	2,398
2024	923	899	592	2,414
2025	924	904	603	2,430
2026	925	908	614	2,447
2027	926	913	625	2,464
2028	928	917	636	2,482
2029	929	922	648	2,499
2030	930	926	660	2,516
2031	932	931	672	2,534
2032	933	935	684	2,553
2033	934	940	697	2,571
2034	936	945	709	2,590
2035	937	949	723	2,609
2036	939	954	736	2,629
2037	940	959	749	2,648
2038	942	963	763	2,668
2039	943	968	777	2,688
2040	945	973	792	2,710
2041	946	977	806	2,730
2042	947	982	821	2,751
2043	949	987	836	2,773
2044	951	992	852	2,795
2045	952	997	867	2,817
2046	954	1,002	884	2,839
2047	955	1,007	900	2,862
2048	957	1,012	917	2,886
2049	959	1,017	934	2,909

Year	Residential	Commercial	Industrial	Total
2050	960	1,022	951	2,933
Average annual growth rate	**0.1%**	**0.5%**	**1.9%**	**0.7%**

Table D-9: Econometric Net System Load with low growth conditions, MWa

Year	Residential	Commercial	Industrial	Total
2020	879	873	520	2,273
2021	871	865	533	2,269
2022	863	858	547	2,268
2023	856	857	561	2,273
2024	848	855	570	2,273
2025	839	853	578	2,271
2026	830	851	587	2,269
2027	821	849	597	2,267
2028	812	848	607	2,267
2029	800	847	617	2,264
2030	790	845	627	2,263
2031	781	843	637	2,261
2032	772	841	647	2,260
2033	762	839	657	2,258
2034	753	836	667	2,257
2035	744	834	677	2,255
2036	735	831	688	2,254
2037	726	829	698	2,252
2038	717	826	708	2,251
2039	707	823	719	2,249
2040	698	820	729	2,248
2041	689	817	740	2,246
2042	680	814	750	2,245
2043	672	811	761	2,243
2044	663	808	772	2,242
2045	654	804	782	2,241
2046	645	801	793	2,239
2047	636	797	804	2,238

Year	Residential	Commercial	Industrial	Total
2048	628	794	815	2,236
2049	619	790	826	2,235
2050	610	786	837	2,234
Average annual growth rate	**-1.3%**	**-0.5%**	**1.5%**	**-0.1%**

TABLE D-10: Econometric Net System Load with high growth conditions, MWa

Year	Residential	Commercial	Industrial	Total
2020	962	908	549	2,418
2021	969	914	566	2,449
2022	977	920	584	2,482
2023	986	933	603	2,522
2024	996	944	615	2,555
2025	1,007	955	626	2,589
2026	1,018	966	639	2,623
2027	1,030	977	651	2,659
2028	1,042	989	664	2,695
2029	1,056	1,000	677	2,733
2030	1,068	1,011	692	2,771
2031	1,081	1,022	705	2,808
2032	1,093	1,034	719	2,847
2033	1,106	1,046	734	2,885
2034	1,118	1,058	748	2,924
2035	1,131	1,070	763	2,964
2036	1,144	1,082	778	3,004
2037	1,157	1,094	793	3,045
2038	1,170	1,107	809	3,086
2039	1,183	1,119	825	3,128
2040	1,197	1,132	842	3,171
2041	1,211	1,145	858	3,213
2042	1,224	1,157	875	3,257
2043	1,238	1,170	893	3,301
2044	1,253	1,184	910	3,347
2045	1,267	1,197	928	3,392

Year	Residential	Commercial	Industrial	Total
2046	1,281	1,210	947	3,438
2047	1,296	1,224	965	3,484
2048	1,311	1,237	984	3,532
2049	1,325	1,251	1,004	3,580
2050	1,340	1,265	1,024	3,629
Average annual growth rate	**1.3%**	**1.3%**	**2.3%**	**1.4%**

APPENDIX E. Existing and Contracted Resources

A diverse portfolio of existing resources helps PGE meet its energy and capacity needs of PGE's system. These resources are described below in Section E.1 PGE Power Plants, Section E.2 Contracts, and Section E.3 Customer Side.

As used in this context, "existing" encompasses executed agreements for resources which may or may not currently be in service (such as the Wheatridge Renewable Energy Facility and some PURPA qualifying facilities).

E.1 PGE Power Plants

E.1.1 Thermal Resources

The technology and size characteristics for each plant is provided below. It is important to note that in these descriptions, capacity (in MW) represents the annual average net capacity of the power plant, inclusive of any duct-firing capabilities and excluding any de-rates for maintenance or forced outage rates. Most combined-cycle combustion turbines (CCCTs) provide less capacity in the summer when high temperatures affect operations, while other steam technologies are less sensitive to temperature. In contrast, energy (in MWa) represents the annual average availability after projected forced outages and maintenance.[192]

Carty

Carty is a CCCT resource providing 437 MW of annual average capacity, inclusive of 47 MW of duct firing, and built adjacent to PGE's Boardman coal plant in Boardman, Oregon. The plant includes a highly efficient Mitsubishi Heavy Industries (MHI) G-class combustion turbine. The plant became operational on July 29, 2016. The average annual energy is 362 MWa.

Coyote Springs

Coyote Springs is a gas-fired CCCT facility in Boardman, Oregon that became operational in 1995. Coyote Springs has an annual average capacity of 252 MW (including 2 MW of additional capacity when operating an auxiliary boiler to supply steam-to-steam customers) and an average annual energy availability of 234 MWa.

Port Westward 1

Port Westward 1 (PW1) reached commercial operation in June 2007. This CCCT plant located in Clatskanie, Oregon is among the most efficient natural-gas-fired generators of its type in the Northwest. The plant supplies approximately 411 MW of annual average capacity (including approximately 19 MW of duct firing) and has an average annual energy of 351 MWa.

Beaver

Beaver is a CCCT facility in Clatskanie, Oregon. PGE placed the plant into service in 1976. Beaver has an annual average capacity of 485 MW. The six combustion turbines (CTs) operate primarily on

[192] PGE excludes peaking units and duct firing from average energy.

natural gas, but can also be fueled with No. 2 diesel fuel oil via on-site tank storage. The CTs each have heat recovery steam generators that connect to a single steam turbine, allowing PGE to operate the plant either in simple-cycle mode or in combined–cycle mode. A separate simple cycle unit, Beaver 8 was added to the site in 2001 and has an annual average capacity of 23 MW. As PGE generally uses Beaver for peaking and wind-following purposes, the plant is not included in the energy load resource balance (LRB) for this IRP.

Port Westward 2

Port Westward 2 (PW2) is located in Clatskanie, OR, adjacent to PGE's PW1 plant. PW2 began commercial operations in December 2014. It is composed of 12 natural gas-fired reciprocating engines with a total annual average capacity of approximately 225 MW. In addition to providing peak capacity, the modular configuration provides a wide range of dispatch flexibility for wind, load following, and additional ancillary services.

Boardman

Boardman is a pulverized coal plant in Boardman, Oregon with an annual average capacity of approximately 575 MW. It came into service in 1980 and will cease coal-fired operations by year-end 2020. The plant burns coal transported by rail from the Powder River Basin. PGE is the operator of the plant, and has a 90-percent ownership interest, equal to a 518-MW share of the plant. The average annual energy availability for PGE is approximately 444 MWa. Idaho Power owns the remaining 10 percent of Boardman.

Colstrip

Colstrip Units 3 and 4 are coal-fired units in Colstrip, Montana. They are mine-mouth plants, with coal transported by conveyor belt directly from the on-site mine to the boiler. The plants went into service in 1984 and 1986, respectively. Talen Generation LLC operates and manages the Colstrip plant. PGE owns 20 percent of Units 3 and 4, representing approximately 296 MW of annual average capacity. The annual average energy availability for PGE's share of Colstrip Units 3 and 4 is 262 MWa. Per SB 1547, this IRP includes the removal of Colstrip Units 3 and 4 from the Company's resource stack by January 1, 2035. PGE prepared two sensitivities of removing the Colstrip from the resource stack at the end of 2027. These are discussed in Section 7.4.2.

E.1.2 Hydro Plants

PGE owns and operates eight hydroelectric plants on the Deschutes, Clackamas, and Willamette River systems. Two plants, Pelton and Round Butte, have reservoir storage flexibility, while the remaining plants have a limited ability to store water and shape energy. PGE generally operates these plants as run-of-river projects.

In addition to energy production, these resources (mainly Pelton and Round Butte) provide peaking and load-following capabilities.[193] A portion of PGE's hydro capacity also contributes to meeting

[193] As noted in Appendix I, PGE hydro projects were modeled with the same monthly sustained maximum capacity values used in the 2016 IRP. Due to limited time, the Company did not reexamine the values in this IRP. In a future IRP cycle, PGE plans to evaluate the plant capabilities under current licensing and habitat requirements.

required spinning and supplemental (non-spin) operating reserve requirements, which are necessary for responding to system contingencies.

Pelton-Round Butte Hydro Project

PGE operates the Pelton and Round Butte plants on the Deschutes River near Madras, Oregon. The Federal Energy Regulatory Commission (FERC) issued a new 50-year license for this project on June 21, 2005. The plants have a combined annual average dependable capacity[194] of approximately 448 MW and an expected annual energy production of 165 MWa under average hydro conditions. PGE owns 66.67 percent of each plant (approximately 299 MW, 110 MWa), with the remaining shares owned by the Confederated Tribes of the Warm Springs Reservation (Tribes). The Tribes have the right to increase their ownership shares to 49.99 percent on December 31, 2021, and in this IRP, PGE assumes that the Tribes will exercise this right, reducing PGE's shares of Pelton and Round Butte.[195] The Tribes agreed to sell all of their output to PGE through 2024. See Section E.2.2 below for more details on the agreement.

Clackamas River Hydro Projects

PGE owns and operates six plants on the Clackamas River system. FERC issued a new 45-year license for the projects on December 21, 2010.[196] The plants, with their average annual dependable capacities, are:

- Timothy Powerhouse, 0.9 MW
- Harriet Powerhouse, 0.5 MW
- Oak Grove, 31 MW
- North Fork, 29 MW
- Faraday, 29 MW
- River Mill, 16 MW

The total expected annual energy production is 78 MWa under average hydro conditions. The Timothy Powerhouse became operational in December 2018. It is an RPS-compliant microturbine located at the base of Timothy Lake Dam.

Willamette Falls Hydro Project

PGE owns and operates the Sullivan plant on the Willamette River at Willamette Falls. FERC issued a new 30-year license on December 8, 2005.[197] The plant's average annual dependable capacity is 16 MW and the expected annual energy production is 15 MWa under average hydro conditions.

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194 The annual average of each month's estimated maximum generation maintainable for four hours under average hydro conditions.

195 In this IRP, the Tribes' initial option to update the ownership shares to 49.99% at the end of 2021 is modeled as a simplified 50%. The Tribes have a second option to update their ownership shares to 50.01% on December 31, 2036.

196 The FERC license was amended on August 15, 2014 to include the Harriet Powerhouse.

197 For this IRP, PGE assumes the Willamette Falls Hydro Project FERC license is renewed.

E.1.3 Wind and Solar Plants

Biglow Canyon

Completed in three phases in 2007, 2009, and 2010, the Biglow Canyon Wind Farm (Biglow) in the lower Columbia River Gorge near Wasco, Oregon has a total nameplate generating capacity of 450 MW. Based on an expected capacity factor of approximately 27 percent, PGE estimates Biglow's annual average energy production at 122 MWa. Biglow's generation is RPS compliant.

Tucannon River Wind Farm

Located near Dayton, Washington, PGE's Tucannon River Wind Farm (Tucannon) consists of 116 2.3-MW Siemens wind turbine generators and has a total nameplate capacity of 267 MW. The plant's 35 percent expected capacity factor results in an output of 94 MWa. The project was completed and operational in December 2014. Generation from Tucannon is RPS compliant.

Wheatridge Renewable Energy Facility

In 2019, PGE entered into agreements with NextEra for the Wheatridge Renewable Energy Facility in Morrow County, Oregon. The facility will consist of 300 MW of wind, 50 MW of solar, and 30 MW of battery storage. The wind portion of the facility will enter service at the end of 2020 and the solar and storage components will be in service by the end of 2021. PGE will own 100 MW of the wind resources and entered into a long-term purchase agreement with NextEra for the remainder of the project (see Section E.2.3).

Solar

PGE owns three solar photovoltaic (PV) projects: Sunway 1 (ODOT I5 & I205), Sunway 2 (Prologis), and Sunway 3 (Prologis 2). These projects entered service between 2008 and 2010 and are located on multiple properties in PGE's service territory. The original leases have all transferred to PGE ownership. The combined AC rating is approximately 3.2 MW and the forecasted average energy is 0.5 MWa. The Clean Wind Fund receives a portion of the RECs associated with these projects. PGE's leased and contracted PV projects are included in Section E.2.

E.1.4 Energy Storage

HB 2193 Energy Storage

In compliance with HB 2193, PGE filed a proposal to develop five energy storage projects totaling 39 MW. After testimony and comments, parties to UM 1856 filed a stipulation with the Commission, which the Commission accepted in Order No. 18-290.[198] The stipulation required PGE to provide additional site analyses, an updated storage modeling plan, a revised residential pilot project proposal, and a valuation methodology which co-optimizes all potential benefits from storage. Pending OPUC Staff review of these updated materials, PGE anticipates that these resources will be online sometime in 2020.

For this IRP, modeling assumes that the resources enter service by 2021 and bases the quantities on the minimum sizes described in the filing.

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[198] *In the Matter of Portland General Electric Company, Draft Storage Potential Evaluation*, Docket UM 1856, Order No. 18-290 (Aug. 13, 2018).

Salem Smart Power Center (SSPC)

PGE deployed a 5-MW (1.25 MWh) Li-ion battery inverter system at the SSPC as part of the Pacific Northwest Smart Grid Demonstration. This advanced Li-ion battery system provides uninterrupted power, reactive power (VAR support), and ancillary services. It can also be configured for use as energy storage for small-scale ancillary services in firming and shaping variable resources, such as solar and wind generation. The SSPC was part of a regional and visionary transactive control demonstration project co-funded by the US DOE under the American Recovery and Reinvestment Act. The primary contractor was Battelle, with PGE serving as a subcontractor on the project. PGE has created substantial leverage through its approximately $6 million investment, which has been matched three-to-one by the US DOE and other partners.

PGE formally launched the project in 2010 and went live in May 2013. When the demonstration concluded in January 2015, PGE confirmed that project assets are responsive to transactive control. The resulting assets, especially the battery inverter system, continue to operate as part of PGE's transmission and distribution system. Its current use is to provide routine automatic under-frequency response in compliance with NERC BAL-003-1.

E.2 Contracts

PGE's resources include a variety of contracts for both energy and capacity. This section summarizes the long and mid-term contracts included in this IRP. The hydro capacity values in this section represent annual average dependable values, not plant capacities.

E.2.1 Mid-Columbia and Canadian Entitlement Allocation

PGE has contracts for project shares for some of the hydro facilities on the mid-section of the Columbia River (Mid-C). The shares include proportional rights to the project reservoirs, allowing for shaping of energy across hours and days. PGE also has the ability to utilize these resources to provide ancillary services, including regulation and spinning reserves.[199]

Wells

The Wells Dam is located downstream of Chief Joseph and was completed in 1967. The 10-turbine facility is operated by the Douglas County PUD No. 1 (Douglas PUD). The agreement for PGE's original share of Wells expired on August 31, 2018. Per OPUC Order No. 14-415, PGE sought to renew all or a portion of the Wells contract if a cost-effective agreement could be reached.[200] In 2017, PGE entered into an agreement with Douglas PUD for a varying portion of the project through September 30, 2028.

Priest Rapids Project

The Priest Rapids Project is located downstream of Rock Island and consists of the Wanapum Dam (10 units, completed in 1964) and the Priest Rapids Dam (10 units, completed in 1961). Both facilities are operated by the Grant County PUD No. 2 (Grant PUD). PGE has contractual rights to approximately

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199 The ability of the Mid-C project to provide shaping and ancillary services varies across seasons and between years due to operating constraints and streamflow conditions.

200 OPUC Order No. 14-415, III.A.2.b.

8.62 percent of each facility through the spring of 2052. The combined annual average dependable capacity of PGE's share is approximately 125 MW and the expected annual average energy under average hydro conditions is 89 MWa. Both values are prior to PGE's associated Canadian Entitlement obligations discussed below.

Canadian Entitlement Allocation

This agreement relates to the Columbia River hydro projects. Columbia River storage reservoirs located in Canada are operated to increase the overall value of the Columbia River hydro system. A portion of the generation benefits received by the projects in the US are shared with Canada. The original agreement for the entitlement benefits ended in 2003, but an extension agreement is effective until 2024. PGE's share of Mid-C projects (Wells, Wanapum, and Priest Rapids) is subject to obligations for the Canadian Entitlement Allocation Extension (CEAE). PGE models this as a delivery of on-peak power to Canada. For the purposes of this IRP, PGE assumes that the CEAE renews after 2024 (or that the net effect of any operating changes after the expiration is approximately the same as if the agreement is renewed).

E.2.2 Pelton, Round Butte, and the Re-regulating Dam

As discussed in Section E.1.2, the Confederated Tribes of the Warm Springs Reservation (Tribes) have a 33.33-percent ownership share of the Pelton and Round Butte plants with contractual rights to increase their ownership to 49.99 percent at the end of 2021. The Tribes also own 100 percent of the associated Re-regulating Dam (Re-reg Dam, 10 MW, 10 MWa), which is operated by PGE. PGE and the Tribes entered into an agreement for PGE to purchase the Tribes' shares of Pelton, Round Butte, and the Re-reg Dam from 2015 through 2024.

E.2.3 Wheatridge Energy Facility

As discussed in Section E.1.3, PGE entered into agreements with Next Era for the Wheatridge Energy Facility, including long-term purchase agreements for 200 MW of wind, 50 MW of solar, and 30 MW of battery storage. The wind portion of the facility will enter service at the end of 2020 and the solar and storage components will be in service by the end of 2021.

E.2.4 2018 Bilateral Capacity Agreements

The bilateral negotiations for capacity resulted in the execution of three agreements in early 2018.

Bonneville Power Administration (BPA)

PGE executed two agreements with BPA, each having 100 MW of annual capacity, with a five-year term beginning in 2021.

Avangrid Renewables

PGE executed an agreement with Avangrid Renewables for 100 MW of seasonal peak capacity during summer and winter periods with a five-year term beginning in July 2019.

E.2.5 Additional Contracts

Table E-1 and Table E-2 summarize additional contract resources in PGE's existing portfolio, excluding qualifying facility (QF) agreements, which are summarized in Section E.2.6.

TABLE E-1: Additional contracts by technology, MWa

	2021	2022	2023	2024	2025	2030	2035	2040	2045	2050
Solar	2	19	19	19	19	19	19	0	0	0
Hydro	11	11	11	11	11	11	0	0	0	0
Wind	31	31	31	31	31	24	24	0	0	0
Total	**45**	**62**	**62**	**62**	**62**	**54**	**43**	**0**	**0**	**0**

TABLE E-2: Additional contracts by technology, MW (year-end)

	2021	2022	2023	2024	2025	2030	2035	2040	2045	2050
Solar	10	70	70	70	70	70	70	0	0	0
Hydro	36	36	36	36	36	36	0	0	0	0
Wind	99	99	99	99	99	75	75	0	0	0
Total	**145**	**205**	**205**	**205**	**205**	**181**	**145**	**0**	**0**	**0**

E.2.6 Qualifying Facility Contracts

PGE has contracted to purchase the output of numerous QF projects as required by PURPA[201] and state regulations. The 2019 IRP includes 132 QF contracts executed as of December 18, 2018, totaling approximately 601 MW. Table E-3 provides a summary of the approximate annual MWa of QF contracts by technology and Table E-4 provides a summary of the capacity (year-end).

TABLE E-3: Qualifying facility by technology, MWa

	2021	2022	2023	2024	2025	2030	2035	2040	2045	2050
Solar	109	112	112	112	112	112	37	5	0	0
BioGas	8	8	8	8	8	3	0	0	0	0
Biomass	33	33	33	33	33	33	17	0	0	0
Geothermal	8	8	8	8	8	8	8	0	0	0
Hydro	0	0	0	0	0	0	0	0	0	0
Wind	3	3	3	3	3	3	0	0	0	0
Total	**162**	**165**	**165**	**165**	**165**	**159**	**62**	**5**	**0**	**0**

201 The US Public Utility Regulatory Policies Act of 1978.

TABLE E-4: Qualifying facility by technology, MW (year-end)

	2021	2022	2023	2024	2025	2030	2035	2040	2045	2050
Solar	528	528	528	528	528	528	169	21	0	0
BioGas	10	10	10	10	10	2	0	0	0	0
Biomass	43	43	43	43	43	43	20	0	0	0
Geothermal	10	10	10	10	10	10	10	0	0	0
Hydro	1	1	1	1	1	0	0	0	0	0
Wind	9	9	9	9	9	9	0	0	0	0
Total	**601**	**601**	**601**	**601**	**601**	**592**	**199**	**21**	**0**	**0**

E.3 Customer Side

E.3.1 Energy Efficiency

PGE is committed to helping customers reduce their energy use. The Company has a long history of working with the Energy Trust of Oregon (Energy Trust) to identify and acquire cost-effective energy efficiency measures. Through the combined efforts of the Energy Trust, customers, and utilities, Oregon is a national leader in capturing energy efficiency. In 2018, Energy Trust programs added over 34 MWa of additional energy efficiency savings.[202] Section 4.1.2 discusses the long-term energy efficiency savings forecast for the 2019 IRP and External Study B contains a report from Energy Trust describing their forecasting methodology.

E.3.2 Demand Response

Through four programs, PGE has partnered with customers to achieve approximately 21 MW of winter demand response and 32 MW of summer demand response. Section 1.1.2 describes PGE's current demand response programs and the Smart Grid Testbed Pilot.

E.3.3 Dispatchable Standby Generation

PGE's innovative dispatchable standby generation (DSG) program works with customers to utilize customer-sited backup generators to provide non-spinning reserves. A detailed description of the DSG program was provided in PGE's 2016 IRP.[203] As of December 2018, PGE had agreements for approximately 127.8 MW of DSG capacity. As a low-cost resource (approximately $41/kW-yr, including capital and fixed O&M, 2020$), PGE recommends continued expansion of the DSG program to serve non-spinning reserves. The 2019 IRP analysis of the targeted DSG fleet capacity is discussed in Appendix F and the Action Plan recommendations are discussed in Chapter 8.

[202] Energy Trust, *2018 Annual Report to the Oregon Public Utility Commission & Energy Trust Board of Directors*, April 15, 201, p. 5, PGE net savings.

[203] PGE's 2016 Integrated Resource Plan, Volume 1, Section 7.1.4 (filed Nov. 15, 2016).

E.3.4 Distributed Generation

In 2018, there were approximately 73 MW_{AC} of customer-sited PV resources (distributed PV) connected to PGE's distribution system that are not owned or contracted for[204] by PGE. Most customers with distributed PV are enrolled in either the Net Metering program (approximately 58 MW_{AC}) or the Feed-In-Tariff (approximately 15 MW_{AC}). Owned resources are included in Section E.1.3 and contracted resources are included in Section E.2.

The other distributed generators include low-impact hydro, small-scale wind, fuel cells, biogas generators, and combined heat and power (CHP). Most of these are contracted for by PGE and are included in Section E.2.

[204] Contracted for through a lease agreement, Schedule 201 QF agreement, or other power purchase agreement.

APPENDIX F. Dispatchable Standby Generation Study

PGE's Dispatchable Standby Generation (DSG) program offers access to a fleet of customer-located diesel generators that provide non-spinning reserves to PGE's system. A summary of the existing program is provided in Appendix E. Existing and Contracted Resources and a detailed discussion of the program was provided in Section 7.14 of PGE's 2016 IRP.[205]

In the 2019 IRP Action Plan (Chapter 8), PGE recommends continued expansion of the DSG fleet as a cost-effect action to meet the system's non-spin needs. In order to assess future megawatts of DSG needed, PGE performed a DSG study using the same methodology as used by Energy + Environmental Economics, Inc. (E3) in the 2016 IRP.

As discussed in Section 4.3 Capacity Adequacy, PGE's capacity adequacy assessment is based on an adequacy measure of the ability to serve the hourly load plus required operating reserves (spinning and non-spin). For the DSG study, PGE used a two-step Renewable Energy Capacity Plannig (RECAP) process to separate the "standby" capacity need (non-spin) from the "active" capacity need (load and spin) for the Reference Need Future:

1. RECAP was run through 2050 with the current DSG resources excluded and non-spin requirements removed. RECAP determined the capacity needed to achieve the annual reliability metric for each year (2.4 hours per year). This determined the need for active capacity, expressed as conventional units (defined as 100-MW units with a five percent forced outage rate).
2. RECAP was run through 2050 with the current DSG resources included, non-spin requirements included, and additional active capacity resource included based on Step 1. RECAP determined the remaining standby capacity needed (expressed as conventional units) to achieve the 2.4 hr/yr reliability metric.

PGE converted the conventional units to the equivalent DSG capacity to calculate the targeted fleet capacity for 2021-2050. Table F-1 illustrates the current DSG fleet capacity,[206] the targeted total fleet capacity, and the fleet deficit. The Action Plan (discussed in Chapter 8) includes DSG actions to meet the targeted DSG fleet capacity.

TABLE F-1: DSG fleet capacity, MW (meter)

	2021	2022	2023	2024	2025	2030	2035	2040	2045	2050
Current Fleet Capacity	128	128	128	128	128	128	128	128	128	128
Targeted Fleet Capacity	**134**	**134**	**136**	**137**	**137**	**142**	**149**	**156**	**161**	**166**
Deficit (Target - Current)	6	6	9	9	9	14	22	28	33	38

205 See PGE's 2016 Integrated Resource Plan, Volume 1, Section 7.1.4 (filed Nov. 15, 2016).

206 As of December 2018.

APPENDIX G. Load Resource Balance

G.1 Estimated Annual Capacity Need, MW

Table G-1 describes PGE's resources from a capacity perspective and identifies the remaining capacity need in the Reference Case given no incremental additions (with the exception of energy efficiency, distributed flexibility, and DSG actions). PGE provides this table for summary purposes and notes that the table does not reflect the complexity of the load and resource modeling in PGE's capacity assessment, as discussed in Section 4.3 Capacity Adequacy.

PGE also notes that the total reserve margin percentage (TRM%) is not an output of the capacity adequacy assessment, rather, it is an artifact of the summary views of resources selected for the table. For example, if hydro resources were summarized based on the view of low hydro conditions for the Mid-Columbia resources, the TRM% would be lower, however, the Capacity Shortage (expressed in MW) would remain the same. Similarly, if high hydro conditions were selected, the TRM% would be higher while the Capacity Shortage would remain the same.

Notes for Table G-1:

- Resources are summarized primarily by either average annual capacities or effective load carrying capability (ELCC) values and are at the busbar.
- Other Contracts includes capacity contracts and QF contracts for biomass, biogas, and geothermal.
- Load is the 1-in-2 peak load in the Reference Case and includes the impacts of energy efficiency actions and passive DER (electric vehicle loads, distributed PV generation, and customer-dispatched battery storage). It does not include long-term direct access load. See Section 4.1.4 Load Scenarios.
- Capacity Shortage is the need for additional capacity calculated by the E3 Renewable Energy Capacity Planning model (RECAP) in order to achieve the annual adequacy target. It is expressed in terms of MW of conventional units (100 MW, 5 percent forced outage rate). Positive values indicate need.
- Total Reserve Margin (TRM) is calculated as Total Resources plus Capacity Shortage minus load.
- TRM% is the ratio of TRM to load.

TABLE G-1: PGE's estimated annual capacity need, MW

	2021	2022	2023	2024	2025	2030	2035	2040	2045	2050
Gas	1833	1833	1833	1833	1833	1833	1833	1833	1833	1833
Coal	296	296	296	296	296	296	0	0	0	0
Hydro	786	784	784	780	547	472	472	472	472	472
Wind+Solar	293	342	347	368	350	360	294	191	160	160
Other Contracts	344	344	344	278	244	44	25	0	0	0
Storage	15	15	13	12	12	12	0	0	0	0
DER	70	77	84	96	96	133	180	227	296	362
DSG	107	106	108	109	109	113	119	124	128	132
Market Capacity	91	58	37	26	19	10	8	6	8	9
Total Resources	**3835**	**3856**	**3846**	**3798**	**3507**	**3273**	**2931**	**2854**	**2897**	**2968**
Load	**3456**	**3485**	**3524**	**3560**	**3600**	**3824**	**4072**	**4342**	**4640**	**4919**
Total Reserve Margin	569	568	568	606	593	625	623	636	658	689
TRM%	16%	16%	16%	17%	16%	16%	15%	15%	14%	14%
Load+Reserves	4024	4053	4092	4166	4192	4448	4694	4978	5298	5608
Capacity Shortage	**190**	**197**	**246**	**368**	**685**	**1176**	**1763**	**2124**	**2401**	**2639**

G.2 Annual Capacity Need by Need Future

Table G-2 shows the range of PGE's projected capacity need from 2021 to 2050 by Need Future. The Need Futures are described in Section 3.1 and the capacity need is discussed in Section 4.3.2.

TABLE G-2: Annual capacity need by Need Future, MW

Need Future	2021	2022	2023	2024	2025	2030	2035	2040	2045	2050
Low	0	0	0	0	309	655	1016	1134	1148	1156
Reference	190	197	246	368	685	1176	1763	2124	2401	2639
High	423	474	548	712	1065	1796	2611	3176	3646	4065

G.3 Projected Annual Average Energy Load-Resource Balance, MWa

Table G-3 presents PGE's energy load-resource balance (LRB) given no incremental resource actions (except for energy efficiency). The methodology for constructing the energy LRB remains the same as what was used in the 2016 IRP LRB. The following list provides a summary of the methodology and components of the energy LRB:

- The energy LRB is based on annual average available energy from resources, not economic dispatch.
- Thermal resources are adjusted for maintenance and forced outage rates. Duct firing and peaking units are excluded.
- Other Contracts includes biomass, biogas, and geothermal contracts.
- Energy efficiency actions are included as a resource and reflect cumulative savings beginning in 2020 with adjustments for intra-year deployment and line losses.
- The load is the annual average load before incremental EE actions. The load includes the impacts of the distributed PV and EV forecasts. It does not include the long-term direct access load.

TABLE G-3: PGE's projected annual average energy load-resource balance, MWa

	2021	2022	2023	2024	2025	2030	2035	2040	2045	2050
Gas	945	945	945	945	945	945	945	945	945	945
Coal	262	262	262	262	262	262	0	0	0	0
Hydro	417	416	416	413	321	271	259	259	259	259
Wind+Solar	465	500	500	500	500	492	413	338	334	333
Other Contracts	50	50	50	50	50	44	25	0	0	0
Energy Efficiency	41	70	97	124	150	280	400	515	629	742
Total Resources	**2179**	**2244**	**2271**	**2294**	**2228**	**2294**	**2043**	**2059**	**2167**	**2280**
Load	**2153**	**2198**	**2248**	**2292**	**2337**	**2574**	**2810**	**3051**	**3300**	**3545**
Energy Deficit / (Surplus)	**(26)**	**(45)**	**(23)**	**(2)**	**109**	**279**	**767**	**993**	**1133**	**1265**

G.4 REC Production and Obligation by Need Future

Table G-4 provides a summary of the forecast of annual REC production from existing and contracted resources and a summary of projected annual REC obligations for RPS compliance by Need Future. The Need Futures are described in Section 3.1 and the RPS need is discussed in Section 4.5.

REC Production in Table G-4 shows the portion of RECs generated from executed PURPA qualifying facility (QF) contracts and those generated from other resources (PGE owned, leased, or contracted).

TABLE G-4: REC production and obligation, MWa

Need Future	2021	2022	2023	2024	2025	2030	2035	2040	2045	2050
REC Production										
PGE Resources and Non-QF Contracts	314	332	332	332	450	441	440	396	396	396
QF Contracts	125	125	125	125	152	152	62	5	0	0
Total	**439**	**457**	**457**	**457**	**602**	**594**	**502**	**401**	**396**	**396**
REC Obligation										
Low Need Future	379	377	377	376	504	640	805	877	860	843
Reference Case	398	401	405	408	555	755	1020	1192	1256	1319
High Need Future	416	423	433	441	609	875	1234	1494	1621	1746

APPENDIX H. Summary of Portfolios

Appendix H. Summary of Portfolios

Section 1. Best Performing Portfolio Reliability Metrics

Portfolios were designed to meet the annual capacity need identified for each year in the capacity adequacy assessment. These calculations were performed within ROSE-E based on parameterizations of the resource capacity contributions determined by RECAP. As a result, capacity additions in each portfolio meet capacity needs approximately, but not exactly. To investigate the accuracy of this approximation and to satisfy IRP Guideline 11, PGE used RECAP to examine the reliability metrics for the year 2025 in the Reference Case for the best performing portfolios, including the preferred portfolio.

The results of the RECAP analysis are provided in Table H-1 and show that best performing portfolios were approximately equal in reliability and none had residual capacity needs due to the capacity approximation greater than 2 MW. The reliability metrics reported in Table H-1 are:

- Residual capacity shortage, which is expressed in megawatts of conventional units (100 MW, 5 percent forced outage rate) and captures any additional capacity required beyond what is included in each portfolio to meet a loss of load expectation (LOLE) requirement of 2.4 hours per year.
- LOLE, which is the expected number of hours per year in which loads plus contingency reserves is expected to exceed available generation. PGE's reliability metric is and LOLE if 2.4 hours per year.
- Expected Unserved Energy (EUE), which is the expected amount of load in MWh per year that would not be met during loss of load events.
- TailVar90 of unmet demand, which is the expected magnitude of shortage experienced in the top 10th percentile of loss of load events.

Table H-1: Top portfolio reliability metrics for 2025 in the Reference Case

Portfolio	Residual Capacity Shortage (MW)	LOLE (hour)	EUE (MWh)	TailVar90 (MWh)
SCCT	0	2.4	299	388
LMS100	1.7	2.4	292	373
200 MWa in 2023	0	2.3	262	361
250 MWa in 2023	0	2.2	263	366
200 MWa in 2024	0	2.3	262	361
250 MWa in 2024	0	2.2	263	366
Min Avg LT Cost, No Energy	0.1	2.4	292	380
Mixed Full Clean	0	2.2	262	364

Section 2: Portfolio Summaries

The following is a brief synopsis of each individual portfolio evaluated in the 2019 IRP. In each portfolio, new resource additions through 2025 are the same across futures. In later years, portfolios can optimize for each individual future, and thus can create tangibly different resource expansion paths. In this appendix, portfolio capacity and energy information are presented for the Reference Case.

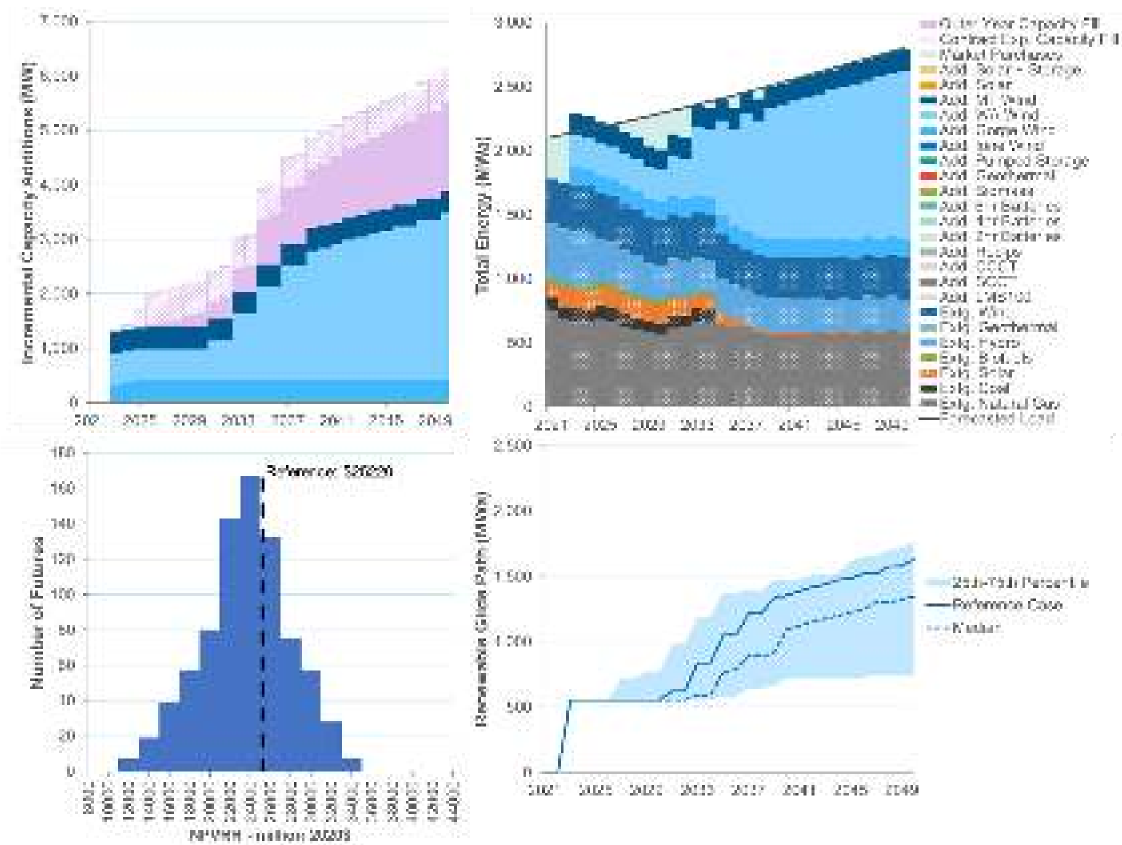
Portfolio 1: Minimize Average Long-Term Cost

This portfolio minimizes the average long-term cost over all equally-weighted futures. With no portfolio-specific restrictions, it adds more than 1300 MW of Gorge, Washington, and Montana wind in 2023, as well as 14 MW and 42 MW of 6-hour batteries in 2024 and 2025.

Table H-2: Portfolio summary

Portfolio Name	Min Avg LT Cost
Portfolio Category	Optimized Portfolios
Portfolio Run Objective Function	Min NPVRR
Portfolio NPVRR Year	2050
Unit Sizes Enforced	Yes
Required Resource Additions	-
Resource Limitations	-
Future Weighting	Equal
Maximum NPVRR	-

Figure H-1: Portfolio summary charts[1]



[1] Existing resources contributing to the total energy values here and in each subsequent figure represent both owned and contracted resources.

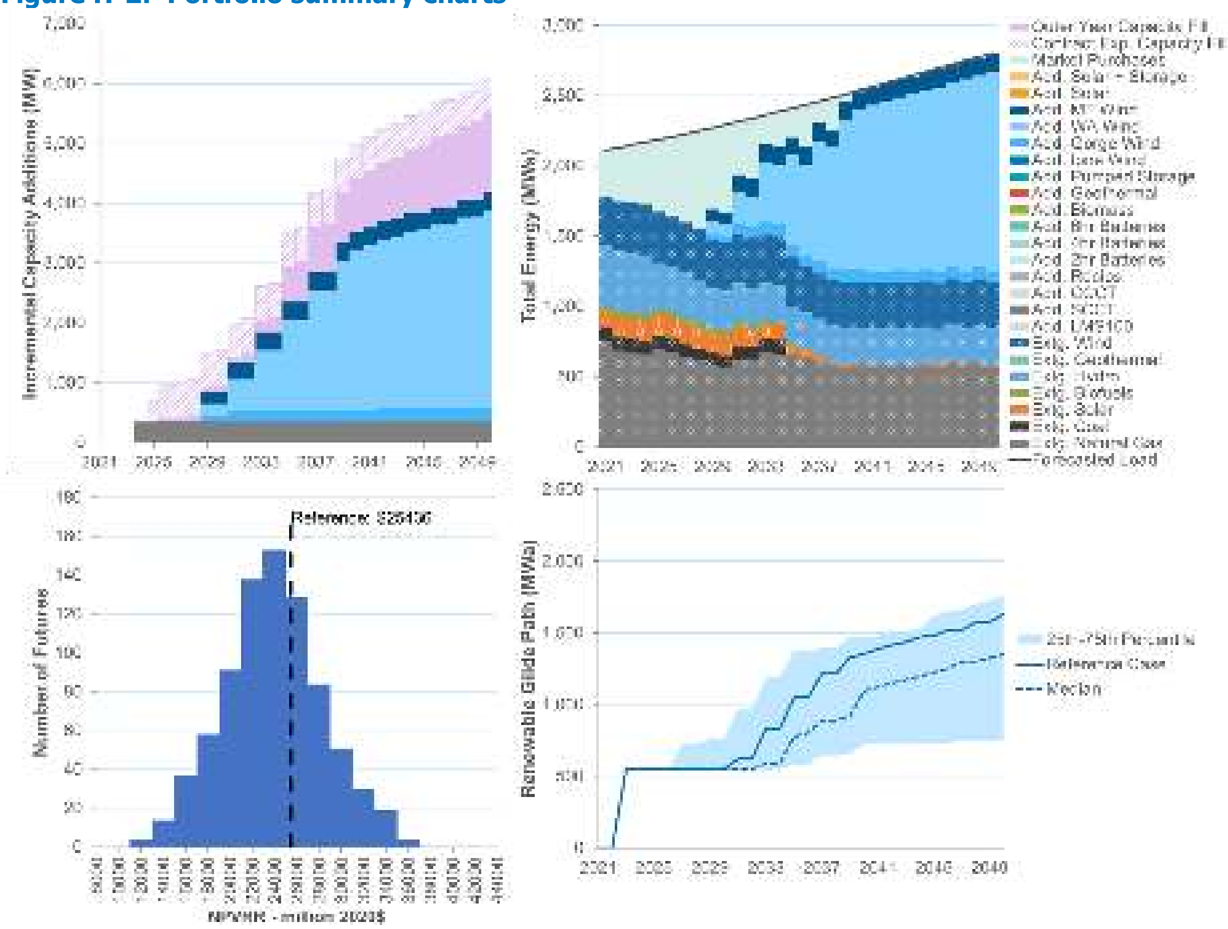
Portfolio 2: Minimize Average Long-Term Cost, No Energy

This portfolio minimizes the average long-term cost over all equally-weighted futures but prohibits additional energy additions in the action plan window. A simple-cycle natural gas plant is added in 2024, and no other resources are built in through 2025.

Table H-3: Portfolio summary

Portfolio Name	Minimize Average Long-Term Cost, No Energy
Portfolio Category	Optimized Portfolios
Portfolio Run Objective Function	Min NPVRR
Portfolio NPVRR Year	2050
Unit Sizes Enforced	Yes
Required Resource Additions	-
Resource Limitations	No CCCT, no renewables until 2026
Future Weighting	Equal
Maximum NPVRR	-

Figure H-2: Portfolio summary charts



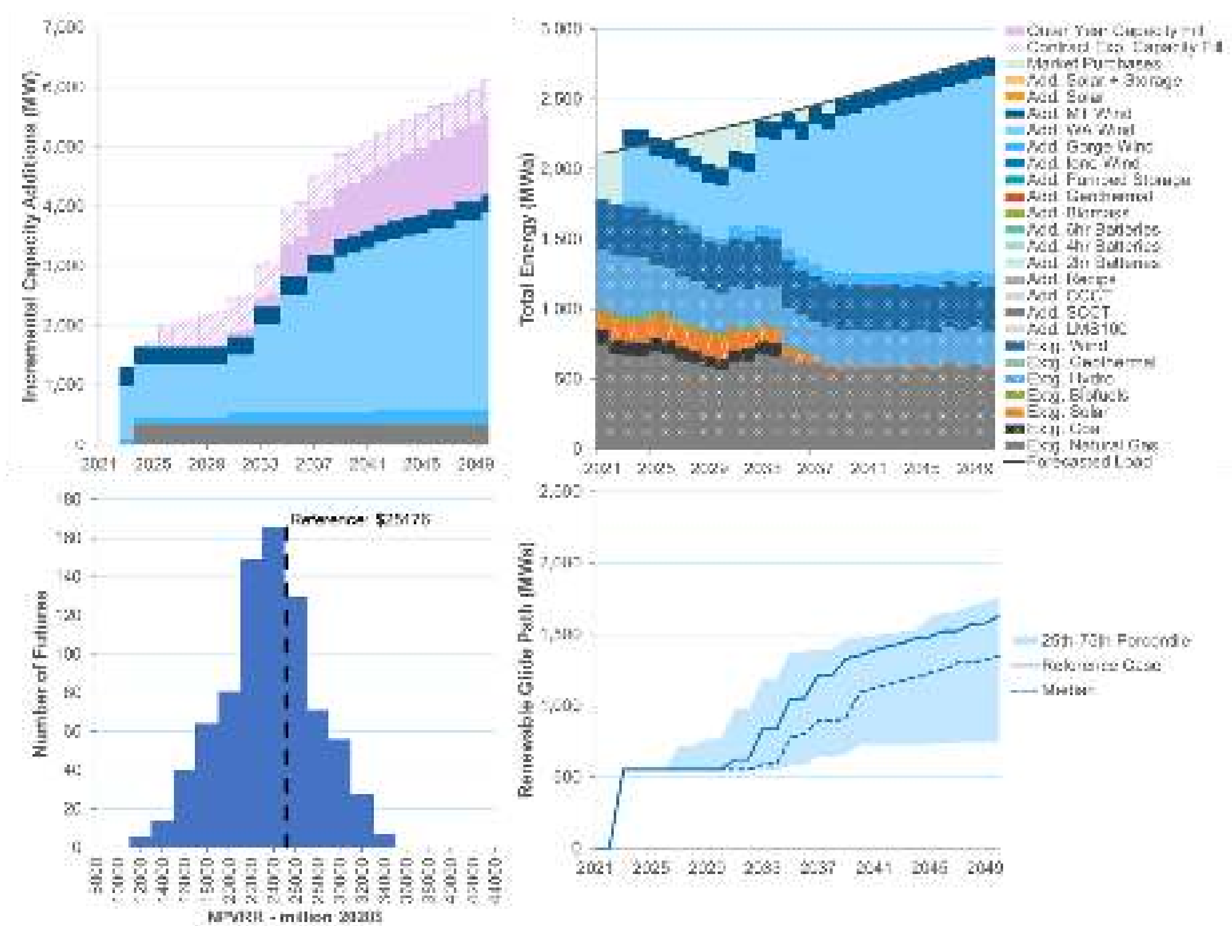
Portfolio 3: Minimize Reference Long-Term Cost

This portfolio minimizes the long-term cost over the Reference Case. With no other portfolio-specific restrictions, it adds nearly 1300 MW of wind in 2023, primarily from Washington. In 2024, a simple-cycle natural gas plant is added.

Table H-4: Portfolio summary

Portfolio Name	Min Ref LT Cost
Portfolio Category	Optimized Portfolios
Portfolio Run Objective Function	Min NPVRR
Portfolio NPVRR Year	2050
Unit Sizes Enforced	Yes
Required Resource Additions	-
Resource Limitations	-
Future Weighting	Reference Case Only
Maximum NPVRR	-

Figure H-3: Portfolio summary charts



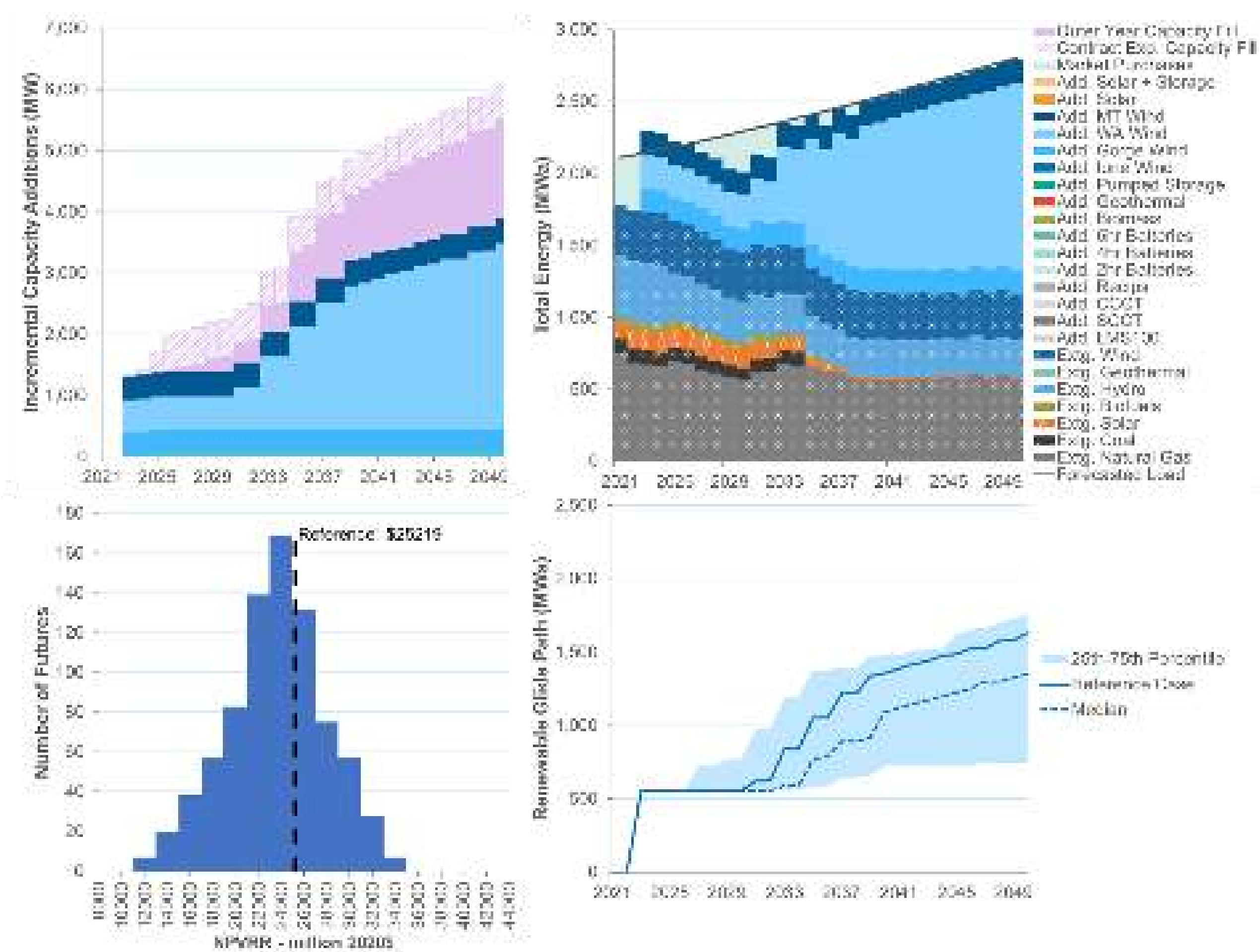
Portfolio 4: Minimize Reference Long-Term Cost, All Clean

This portfolio minimizes the long-term cost over the Reference Case, while being constrained to only consider non-thermal resources. This portfolio adds 1329 MW of Washington, Gorge, and Montana wind in 2023 and 12MW and 39MW of 6-hour batteries in 2024 and 2025.

Table H-5: Portfolio summary

Portfolio Name	Min Ref LT Cost, All Clean
Portfolio Category	Optimized Portfolios
Portfolio Run Objective Function	Min NPVRR
Portfolio NPVRR Year	2050
Unit Sizes Enforced	Yes
Required Resource Additions	-
Resource Limitations	No thermal
Future Weighting	Reference Case Only
Maximum NPVRR	-

Figure H-4: Portfolio summary charts



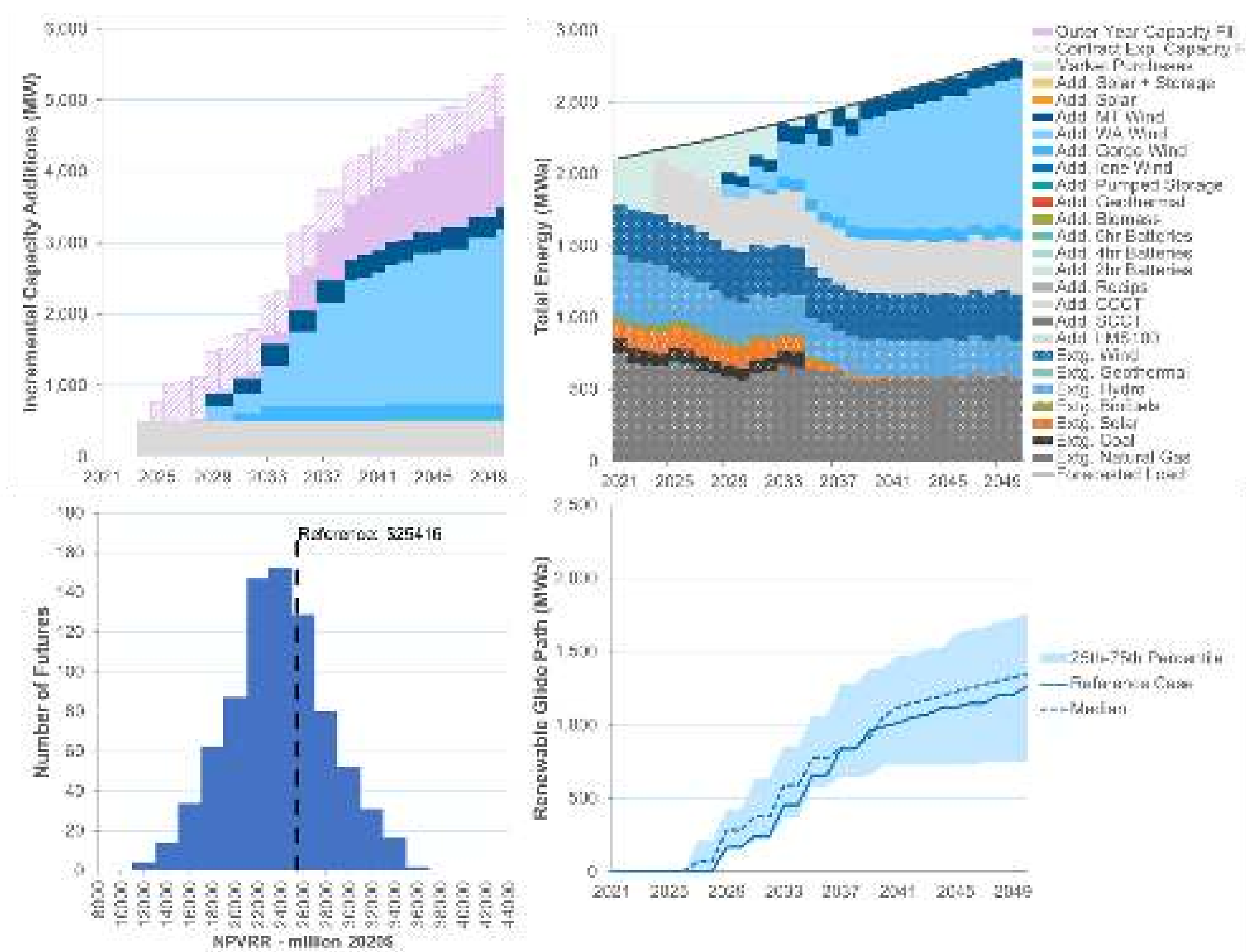
Portfolio 5: Minimize Average Short-Term Cost

This portfolio minimizes the average short-term cost over all equally-weighted futures. In the action plan window, this portfolio builds a combined-cycle natural gas plant in 2024 and no other resources.

Table H-6: Portfolio summary

Portfolio Name	Min Avg ST Cost
Portfolio Category	Optimized Portfolios
Portfolio Run Objective Function	Min NPVRR
Portfolio NPVRR Year	2025
Unit Sizes Enforced	Yes
Required Resource Additions	-
Resource Limitations	-
Future Weighting	Equal
Maximum NPVRR	-

Figure H-5: Portfolio summary charts



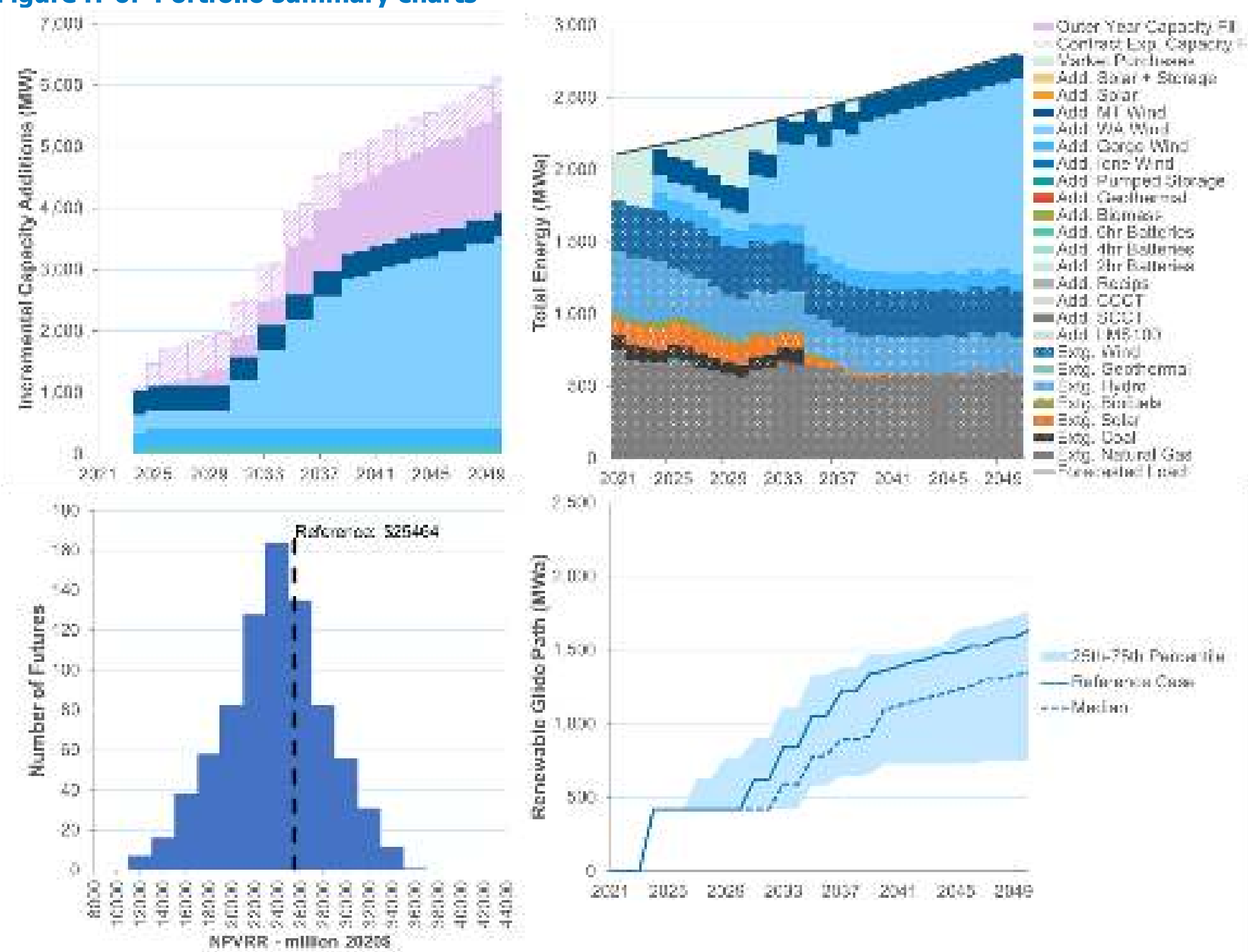
Portfolio 6: Minimize Average Short-Term Cost, All Clean

This portfolio minimizes the average short-term cost over all equally-weighted futures, while prohibiting thermal resources. 1000 MW of Washington, Montana, and Gorge wind are built in 2024, and 43 MW and 66MW of 6-hour batteries are added in 2024 and 2025.

Table H-7: Portfolio summary

Portfolio Name	Min Avg ST Cost: All Clean
Portfolio Category	Optimized Portfolios
Portfolio Run Objective Function	Min NPVRR
Portfolio NPVRR Year	2025
Unit Sizes Enforced	Yes
Required Resource Additions	-
Resource Limitations	No thermal
Future Weighting	Equal
Maximum NPVRR	-

Figure H-6: Portfolio summary charts



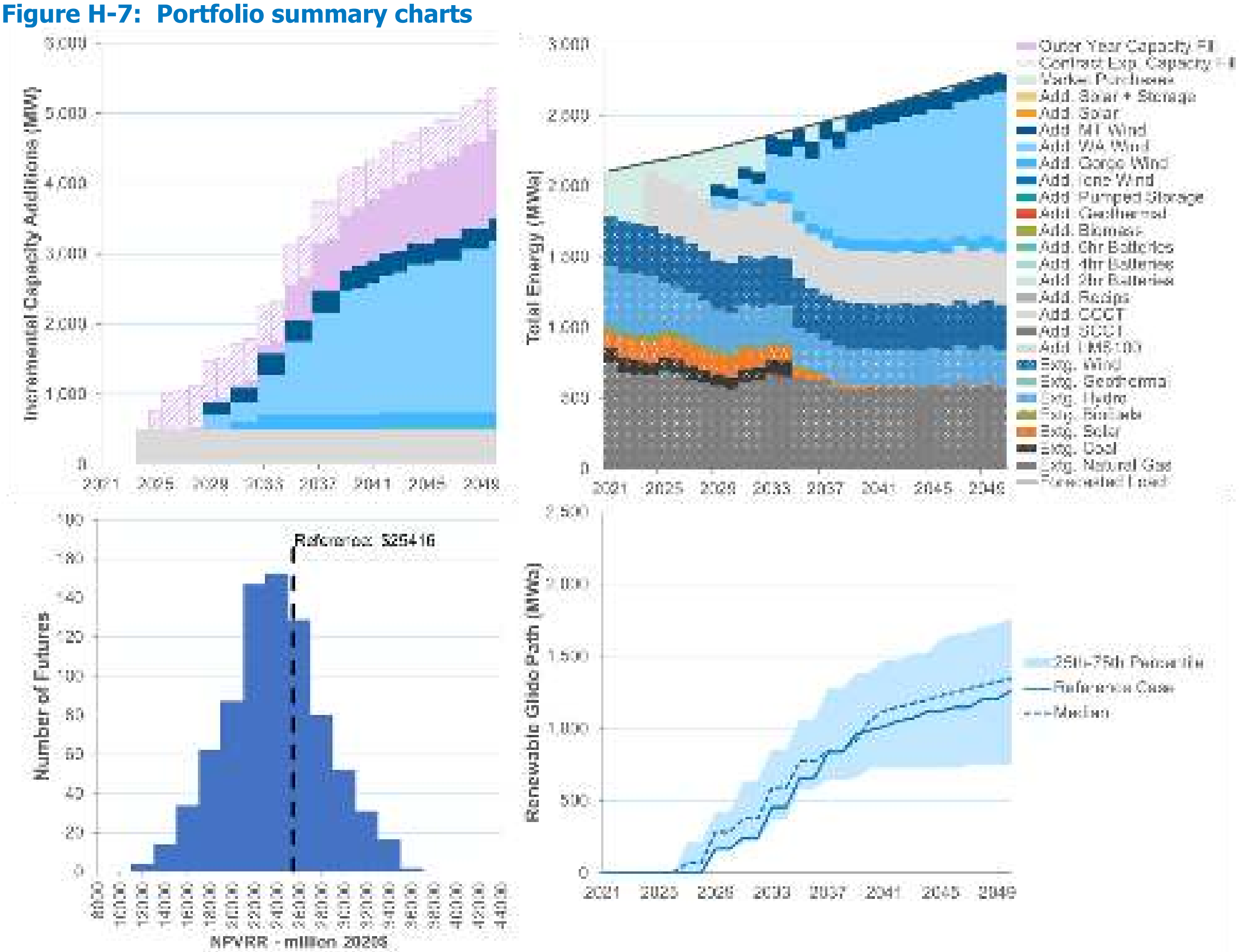
Portfolio 7: Minimize Reference Short-Term Cost

This portfolio minimizes the average short-term cost over only the Reference Case. A combined-cycle natural gas plant is selected in 2024, and no other resources are added in the action plan window.

Table H-8: Portfolio summary

Portfolio Name	Min Ref ST Cost
Portfolio Category	Optimized Portfolios
Portfolio Run Objective Function	Min NPVRR
Portfolio NPVRR Year	2025
Unit Sizes Enforced	Yes
Required Resource Additions	-
Resource Limitations	-
Future Weighting	Reference Case Only
Maximum NPVRR	-

Figure H-7: Portfolio summary charts



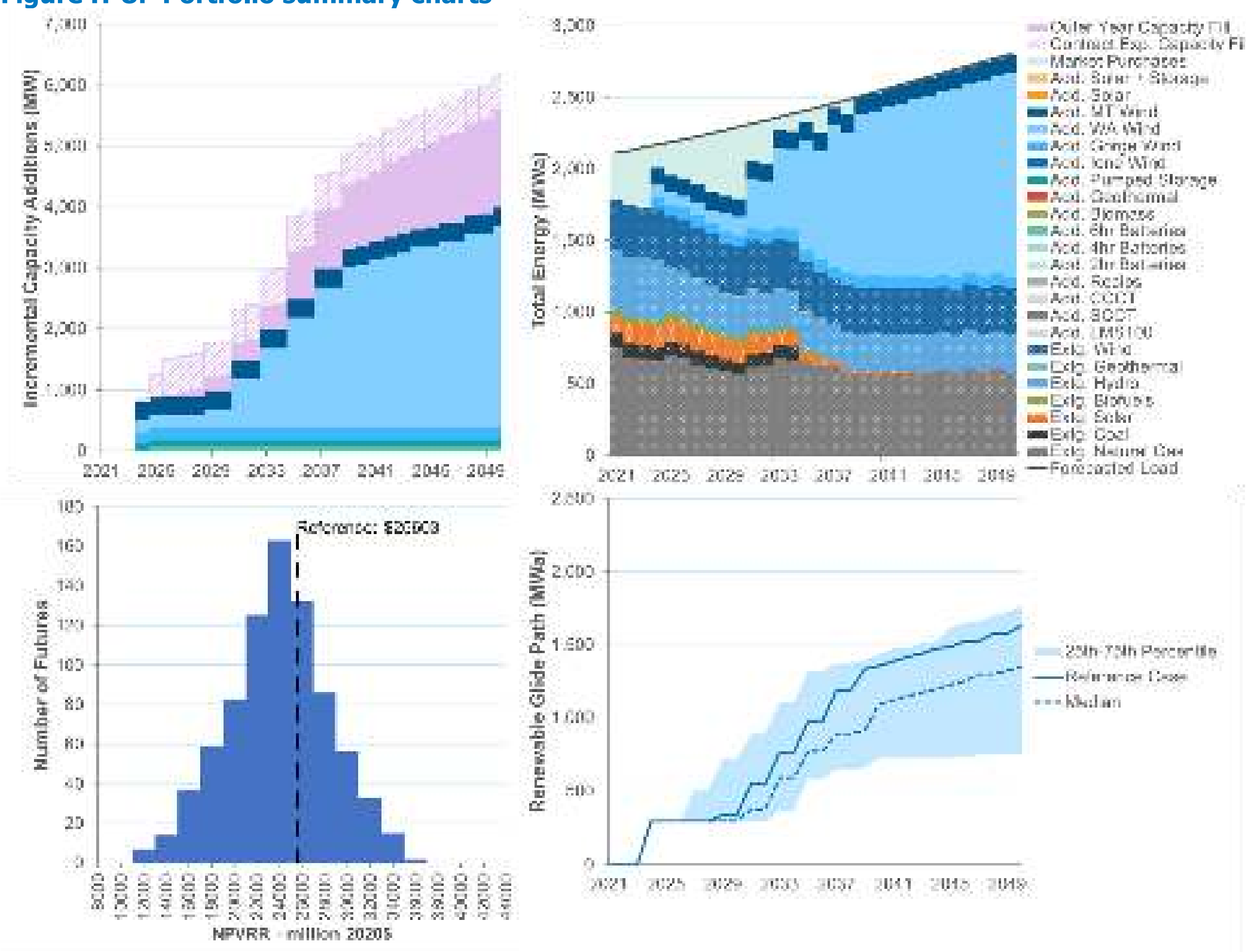
Portfolio 8: Minimize Reference Short-Term Cost, All Clean

This portfolio minimizes the average short-term cost over only the Reference Case while prohibiting thermal resources. 700 MW of Montana, Washington, and Gorge wind is built in 2024, and 6 MW and 75 MW of 6-hour batteries are built in 2024 and 2025. In addition, this portfolio selects 100 MW of pumped storage hydro to be added in 2024.

Table H-9: Portfolio summary

Portfolio Name	Min Ref ST Cost: All Clean
Portfolio Category	Optimized Portfolios
Portfolio Run Objective Function	Min NPVRR
Portfolio NPVRR Year	2025
Unit Sizes Enforced	Yes
Required Resource Additions	-
Resource Limitations	No thermal
Future Weighting	Reference Case Only
Maximum NPVRR	-

Figure H-8: Portfolio summary charts



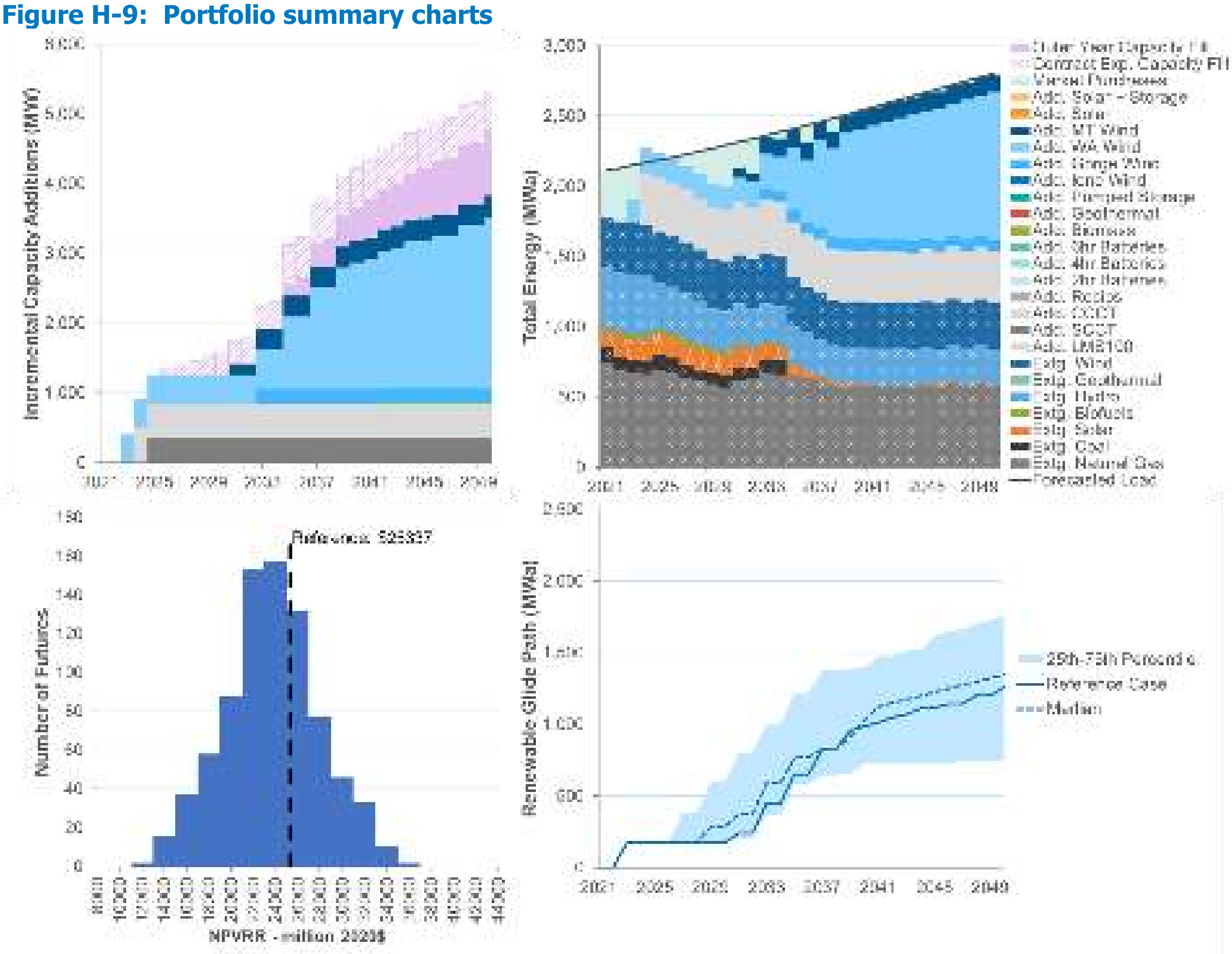
Portfolio 9: Minimize Risk

This portfolio minimizes the semi-variance of the long-term NPVRR across futures, relative to the Reference Case. It is created in two steps. First, the model is run with the specified objective (a QP) without unit size constraints. Next, unit size constraints are manually imposed by rounding the addition sizes in the solution before performing the scoring run. This portfolio builds 400 MW of Washington wind in 2023 followed by a combined-cycle plant in 2024 and a simple-cycle plant in 2025.

Table H-10: Portfolio summary

Portfolio Name	Min Risk
Portfolio Category	Optimized Portfolios
Portfolio Run Objective Function	Min Semi-Variance
Portfolio NPVRR Year	2050
Unit Sizes Enforced	No
Required Resource Additions	-
Resource Limitations	-
Future Weighting	Equal
Maximum NPVRR	25500

Figure H-9: Portfolio summary charts



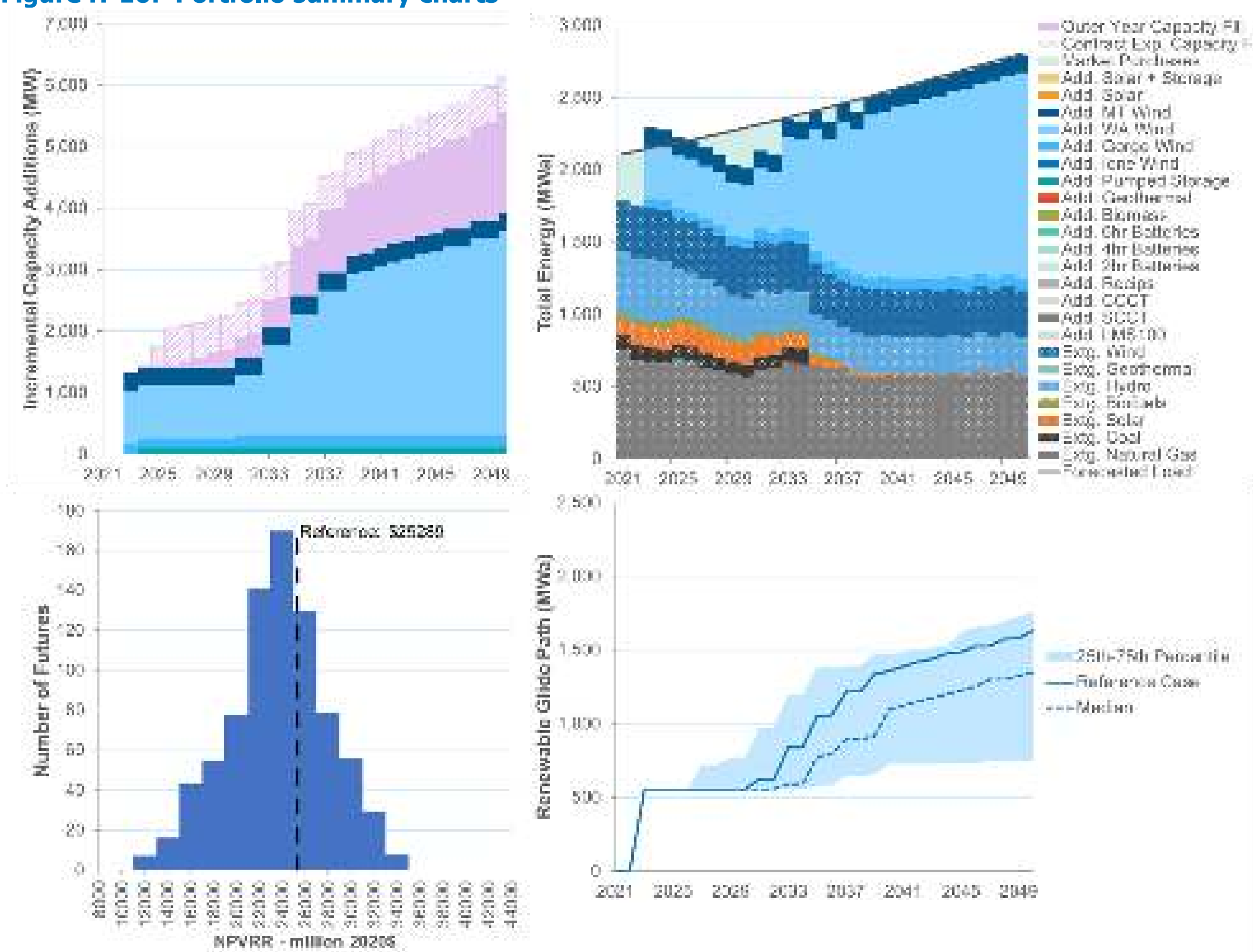
Portfolio 10: Minimize Risk, All Clean

This portfolio also follows the same two-step process as in *Portfolio 9 – Minimize Risk* but without allowing thermal resources. This portfolio builds over 1300 MW of Gorge, Washington, and Montana wind in 2023 and 100 MW of pumped storage hydro in 2024.

Table H-11: Portfolio summary

Portfolio Name	Min Risk: All Clean
Portfolio Category	Optimized Portfolios
Portfolio Run Objective Function	Min Semi-Variance
Portfolio NPVRR Year	2050
Unit Sizes Enforced	No
Required Resource Additions	-
Resource Limitations	No thermal
Future Weighting	Equal
Maximum NPVRR	25500

Figure H-10: Portfolio summary charts



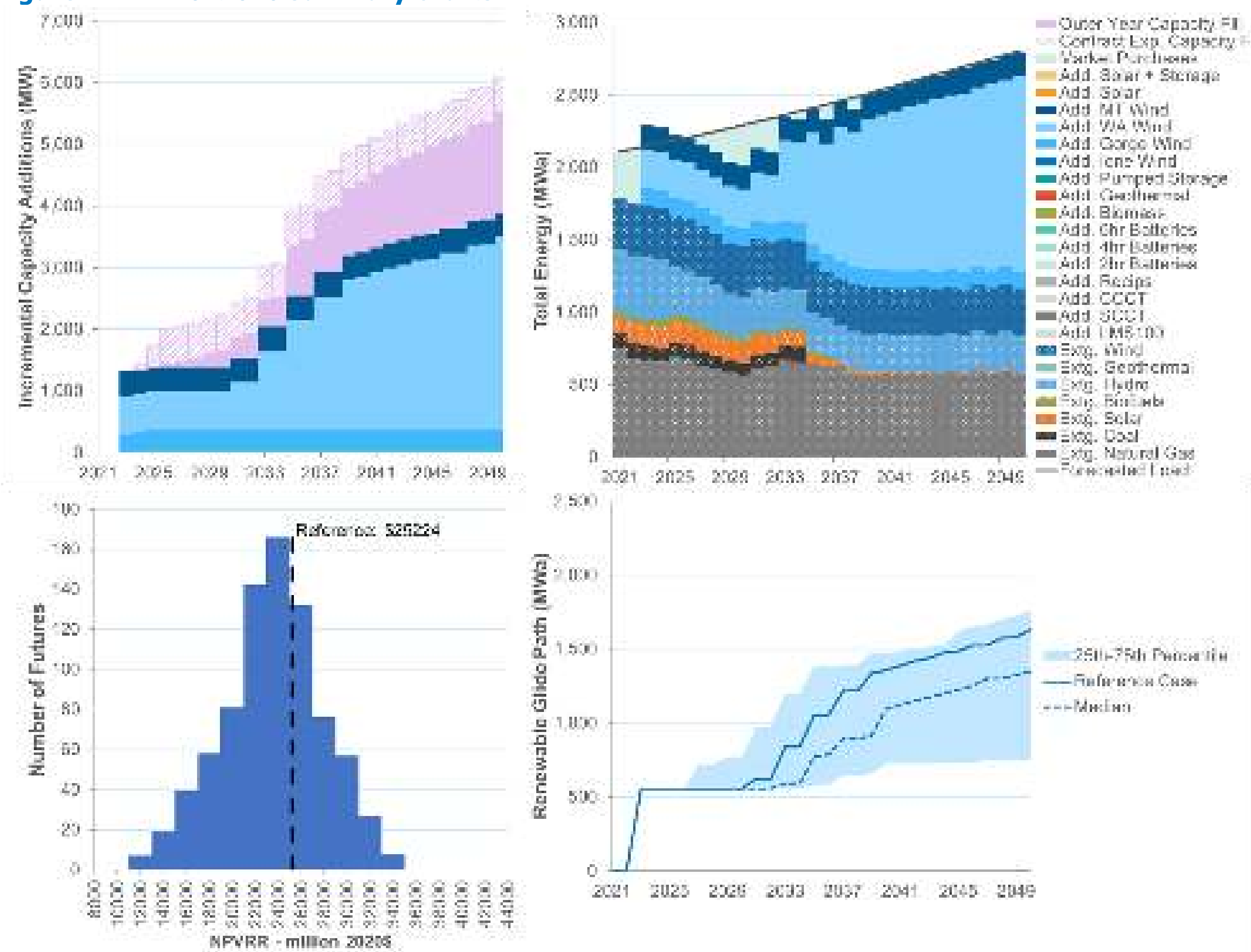
Portfolio 11: Minimize GHG + Cost

This portfolio minimizes the sum of the average cumulative GHG emissions across futures and the average long-term NPVRR across futures. This portfolio adds over 1300 MW of wind in 2023, and adds 17 and 45MW in 2024 and 2025, respectively.

Table H-12: Portfolio summary

Portfolio Name	Min GHG+Cost
Portfolio Category	Optimized Portfolios
Portfolio Run Objective Function	Min GHG + Cost
Portfolio NPVRR Year	2050
Unit Sizes Enforced	Yes
Required Resource Additions	-
Resource Limitations	-
Future Weighting	Equal
Maximum NPVRR	-

Figure H-11: Portfolio summary charts



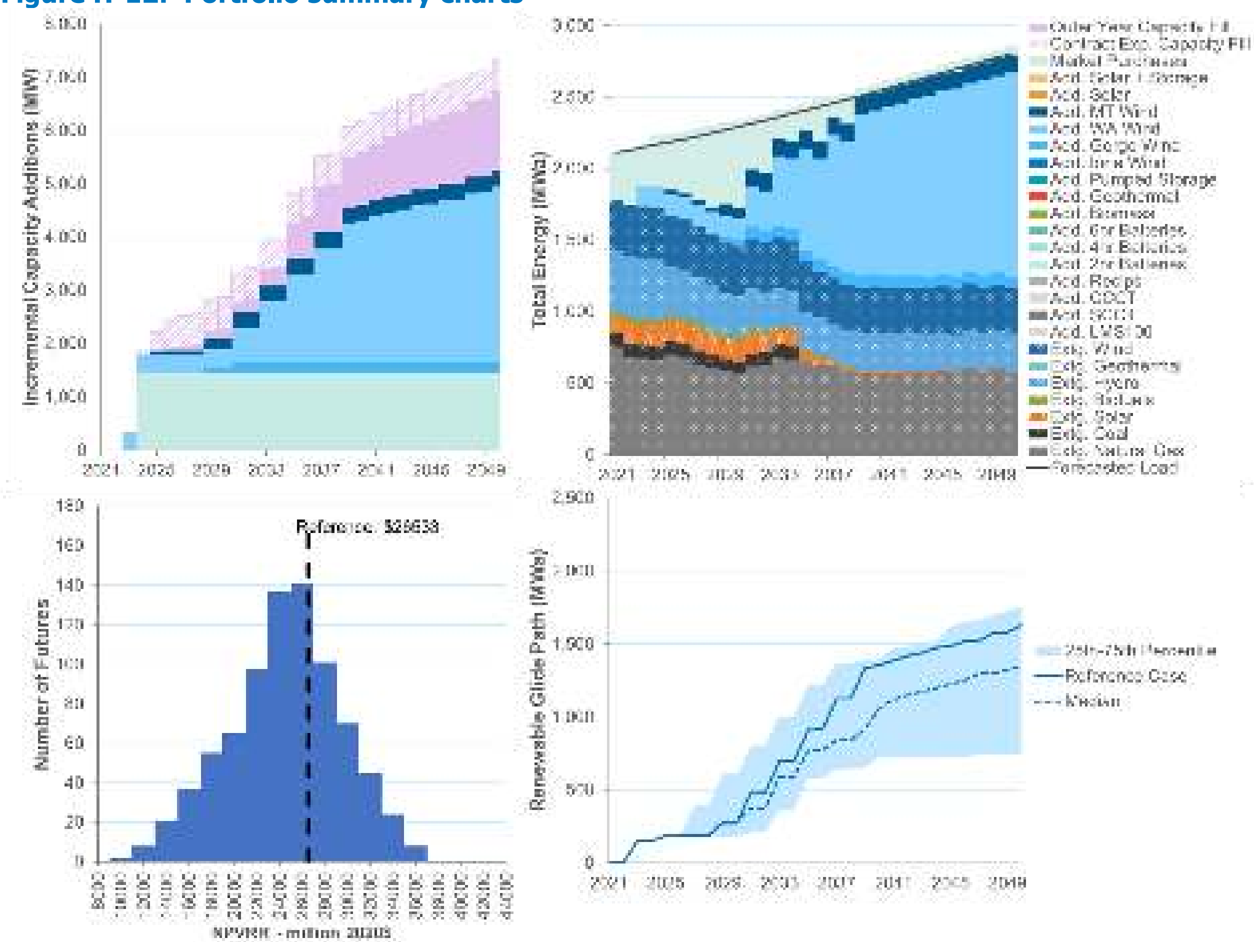
Portfolio 12: 2-Hour Batteries

This portfolio is constrained to add 150 MWa of Washington wind in 2023 and to meet all other capacity needs through 2024 from 2-hour batteries. 1435 MW of 2-hour batteries are selected to be built in 2024, and in 2025 an additional 83 MW of Montana wind is added.

Table H-13: Portfolio summary

Portfolio Name	2hr Batteries
Portfolio Category	Dispatchable Capacity
Portfolio Run Objective Function	Min NPVRR
Portfolio NPVRR Year	2050
Unit Sizes Enforced	No
Required Resource Additions	150 MWa WA wind in 2023
Resource Limitations	No resources other than WA wind and 2-hour batteries available until 2025
Future Weighting	Equal
Maximum NPVRR	-

Figure H-12: Portfolio summary charts



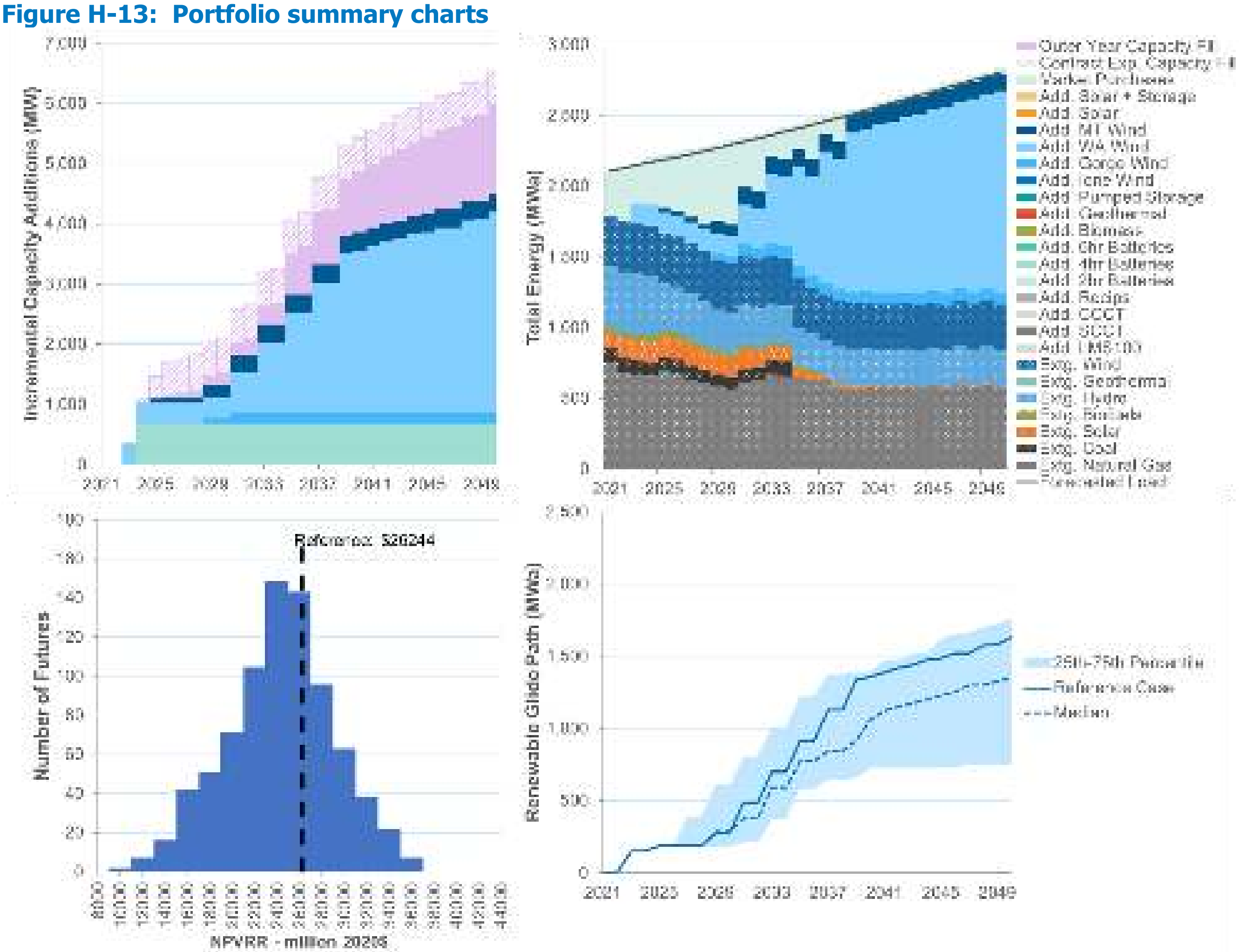
Portfolio 13: 4-Hour Batteries

This portfolio is constrained to add 150 MWa of Washington wind in 2023 and to meet all other capacity needs through 2024 from 4-hour batteries. 676 MW of 4-hour batteries are selected to be built in 2024, and in 2025 an additional 83 MW of Montana wind is added.

Table H-14: Portfolio summary

Portfolio Name	4hr Batteries
Portfolio Category	Dispatchable Capacity
Portfolio Run Objective Function	Min NPVRR
Portfolio NPVRR Year	2050
Unit Sizes Enforced	No
Required Resource Additions	150 MWa WA wind in 2023
Resource Limitations	No resources other than WA wind and 4-hour batteries available until 2025
Future Weighting	Equal
Maximum NPVRR	-

Figure H-13: Portfolio summary charts



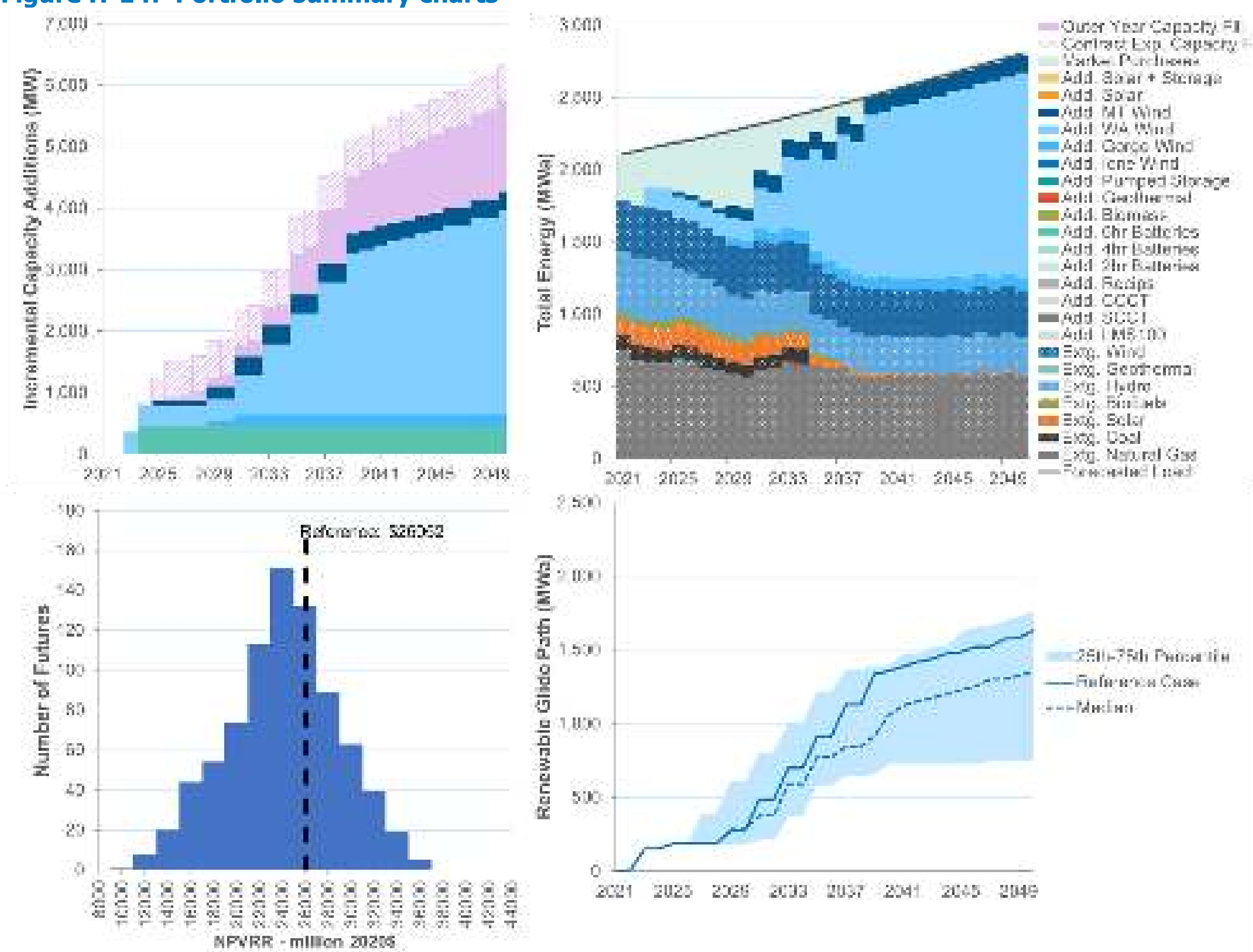
Portfolio 14: 6-Hour Batteries

This portfolio is constrained to add 150 MWa of Washington wind in 2023 and to meet all other capacity needs through 2024 from 6-hour batteries. 441 MW of 6-hour batteries are selected to be built in 2024, and in 2025 an additional 83 MW of Montana wind is added.

Table H-15: Portfolio summary

Portfolio Name	6hr Batteries
Portfolio Category	Dispatchable Capacity
Portfolio Run Objective Function	Min NPVRR
Portfolio NPVRR Year	2050
Unit Sizes Enforced	No
Required Resource Additions	150 MWa WA wind in 2023
Resource Limitations	No resources other than WA wind and 6-hour batteries available until 2025
Future Weighting	Equal
Maximum NPVRR	-

Figure H-14: Portfolio summary charts



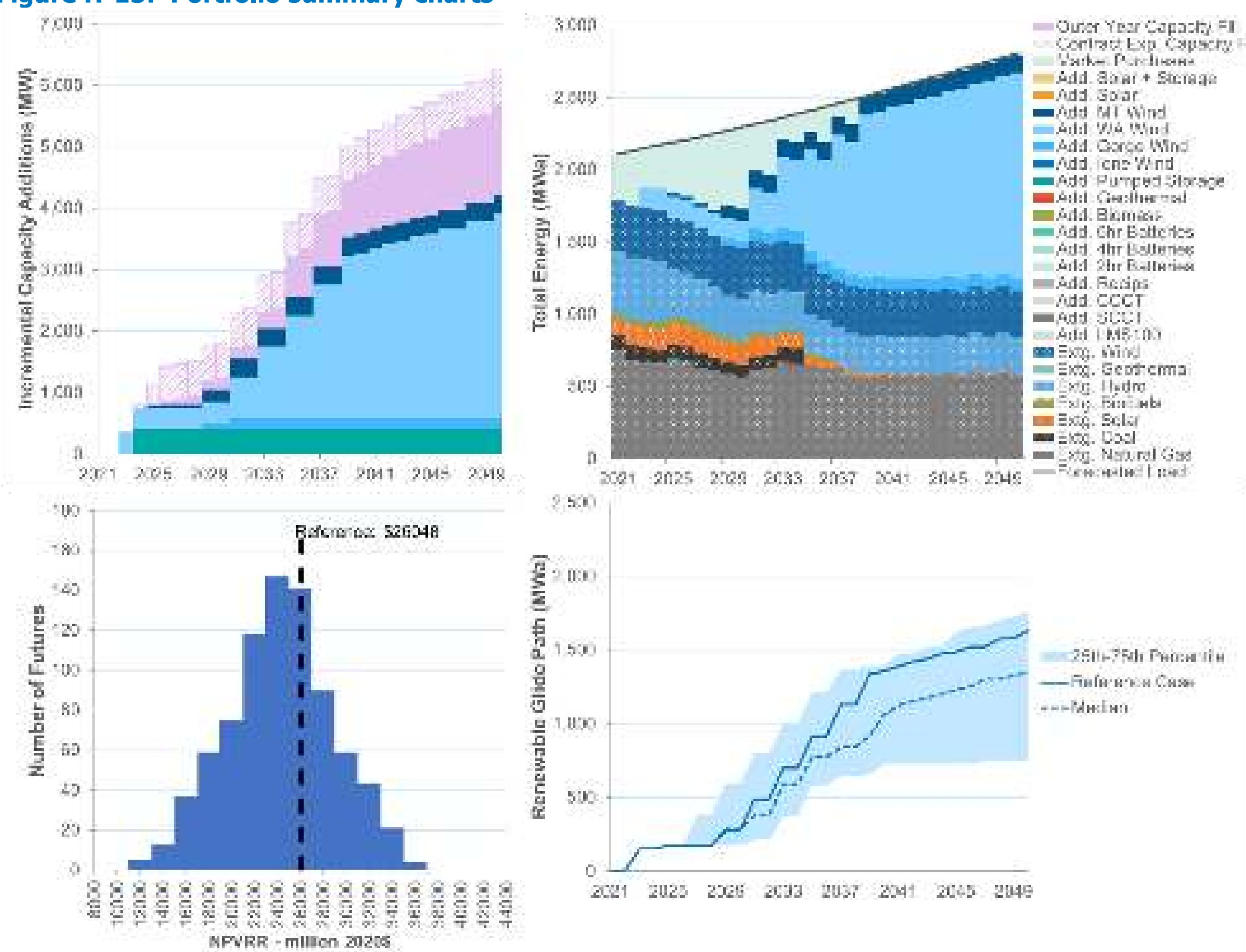
Portfolio 15: Pumped Storage Hydro

This portfolio is constrained to add 150 MWa of Washington wind in 2023 and to meet all other capacity needs through 2024 from the addition of 100 MW increments of pumped storage. 400 MW of pumped storage is selected to be added in 2024, and a 53 MW of Montana wind is added in 2025.

Table H-16: Portfolio summary

Portfolio Name	Pumped Storage Hydro
Portfolio Category	Dispatchable Capacity
Portfolio Run Objective Function	Min NPVRR
Portfolio NPVRR Year	2050
Unit Sizes Enforced	Yes
Required Resource Additions	150 MWa WA wind in 2023
Resource Limitations	No other resources than WA wind and pumped storage available until 2025
Future Weighting	Equal
Maximum NPVRR	-

Figure H-15: Portfolio summary charts



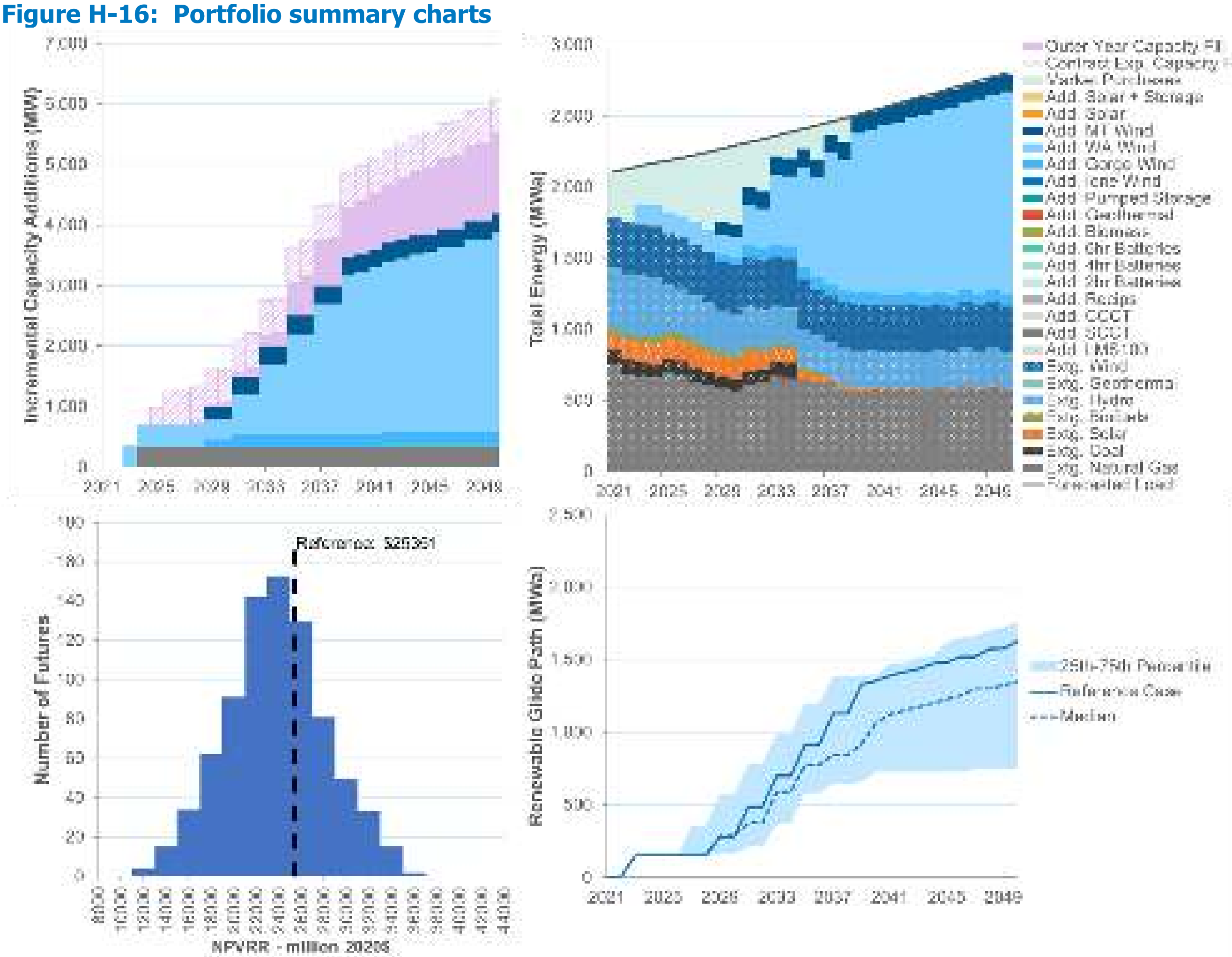
Portfolio 16: SCCT

This portfolio is constrained to add 150 MWa of Washington wind in 2023 and to meet all other capacity needs through 2024 from a SCCT, which is selected to be built in 2024.

Table H-17: Portfolio summary

Portfolio Name	SCCT
Portfolio Category	Dispatchable Capacity
Portfolio Run Objective Function	Min NPVRR
Portfolio NPVRR Year	2050
Unit Sizes Enforced	Yes
Required Resource Additions	150 MWa WA wind in 2023
Resource Limitations	No other resources than WA wind and SCCT available until 2025
Future Weighting	Equal
Maximum NPVRR	-

Figure H-16: Portfolio summary charts



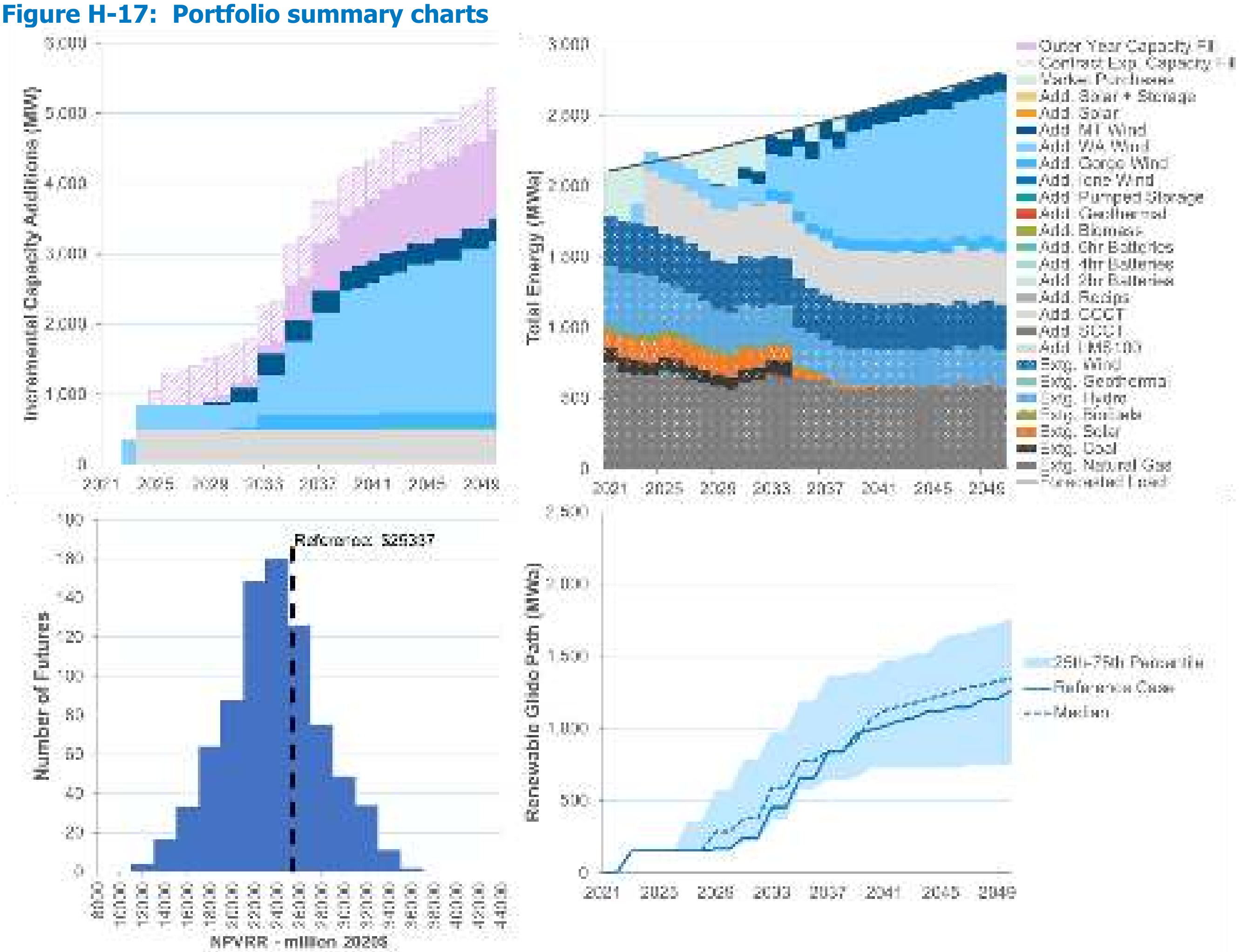
Portfolio 17: CCCT

This portfolio is constrained to add 150 MWa of Washington wind in 2023 and to meet all other capacity needs through 2024 from a CCCT, which is selected to be built in 2024.

Table H-18: Portfolio summary

Portfolio Name	CCCT
Portfolio Category	Dispatchable Capacity
Portfolio Run Objective Function	Min NPVRR
Portfolio NPVRR Year	2050
Unit Sizes Enforced	Yes
Required Resource Additions	150 MWa WA wind in 2023
Resource Limitations	No other resources than WA wind and CCCT available until 2025
Future Weighting	Equal
Maximum NPVRR	-

Figure H-17: Portfolio summary charts



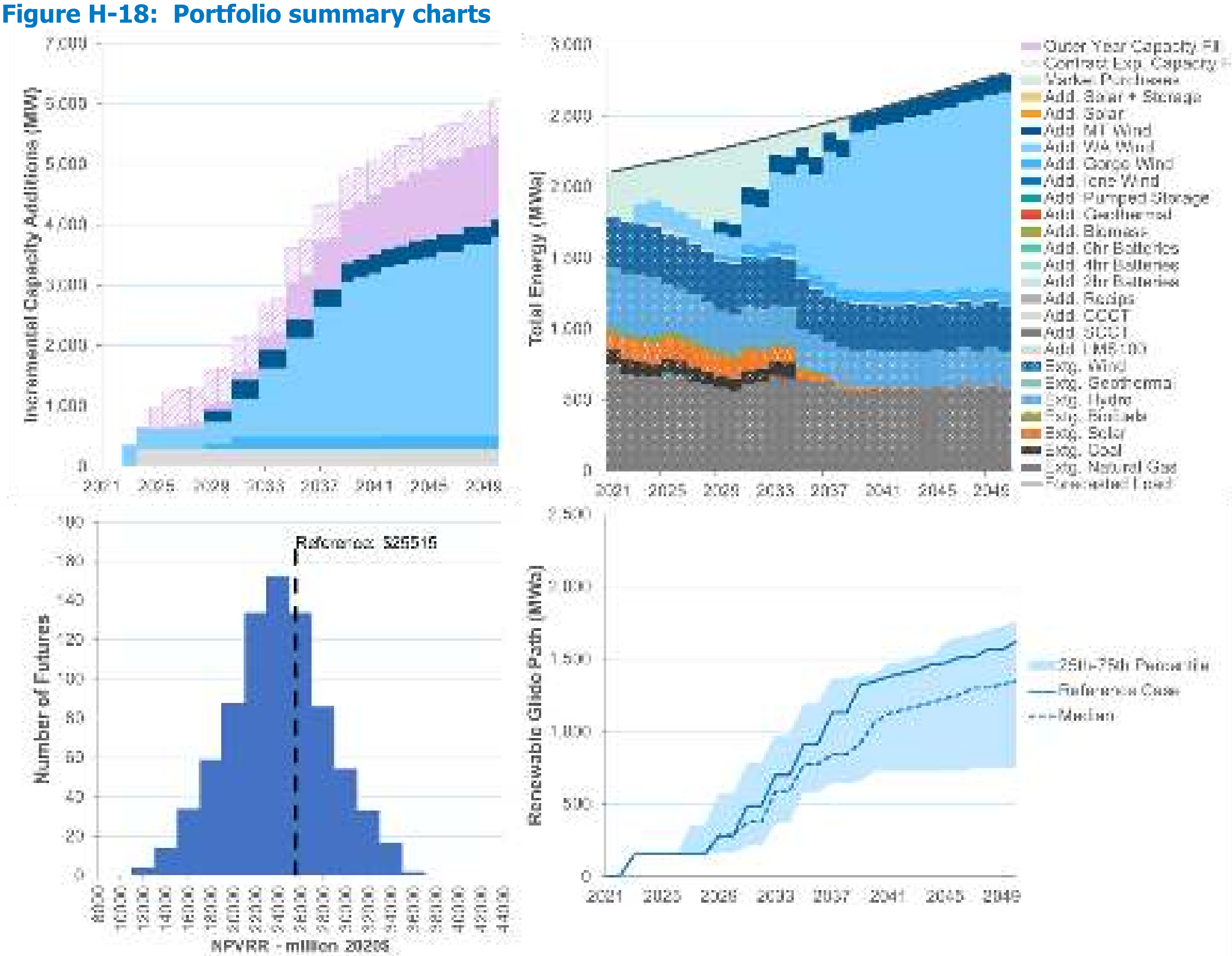
Portfolio 18: LMS100

This portfolio is constrained to add 150 MWa of Washington wind in 2023 and to meet all other capacity needs through 2024 from a LMS100. The LMS100 is selected to be built in 2024.

Table H-19: Portfolio summary

Portfolio Name	LMS100
Portfolio Category	Dispatchable Capacity
Portfolio Run Objective Function	Min NPVRR
Portfolio NPVRR Year	2050
Unit Sizes Enforced	Yes
Required Resource Additions	150 MWa WA wind in 2023
Resource Limitations	No other resources than WA wind and LMS100 available until 2025
Future Weighting	Equal
Maximum NPVRR	-

Figure H-18: Portfolio summary charts



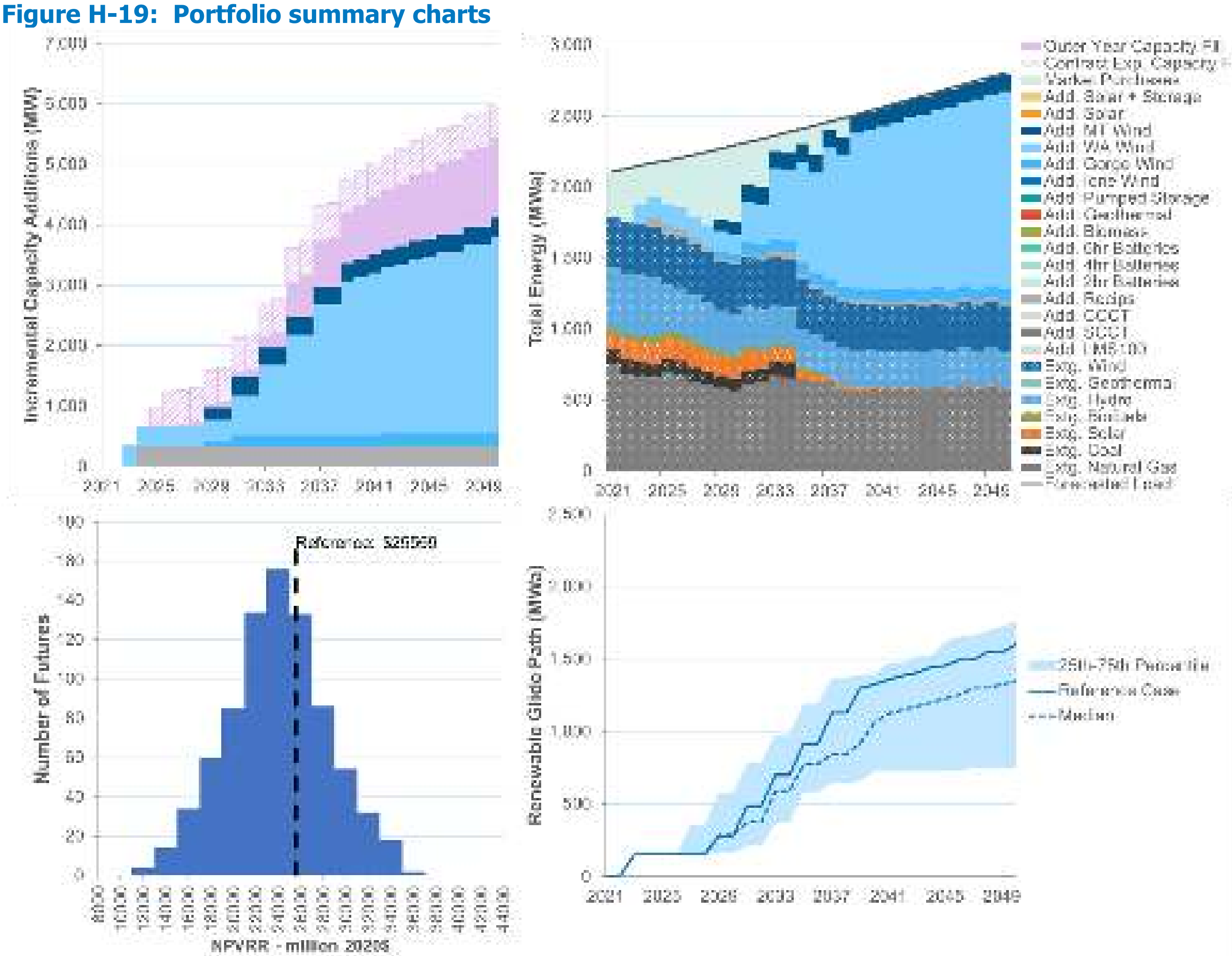
Portfolio 19: Reciprocating Engines

This portfolio is constrained to add 150 MWa of Washington wind in 2023 and to meet all other capacity needs through 2024 from reciprocating engines. Three units of reciprocating engines are selected to be built in 2024.

Table H-20: Portfolio summary

Portfolio Name	Reciprocating Engines
Portfolio Category	Dispatchable Capacity
Portfolio Run Objective Function	Min NPVRR
Portfolio NPVRR Year	2050
Unit Sizes Enforced	Yes
Required Resource Additions	150 MWa WA wind in 2023
Resource Limitations	No other resources than WA wind and reciprocating engines available until 2025
Future Weighting	Equal
Maximum NPVRR	-

Figure H-19: Portfolio summary charts



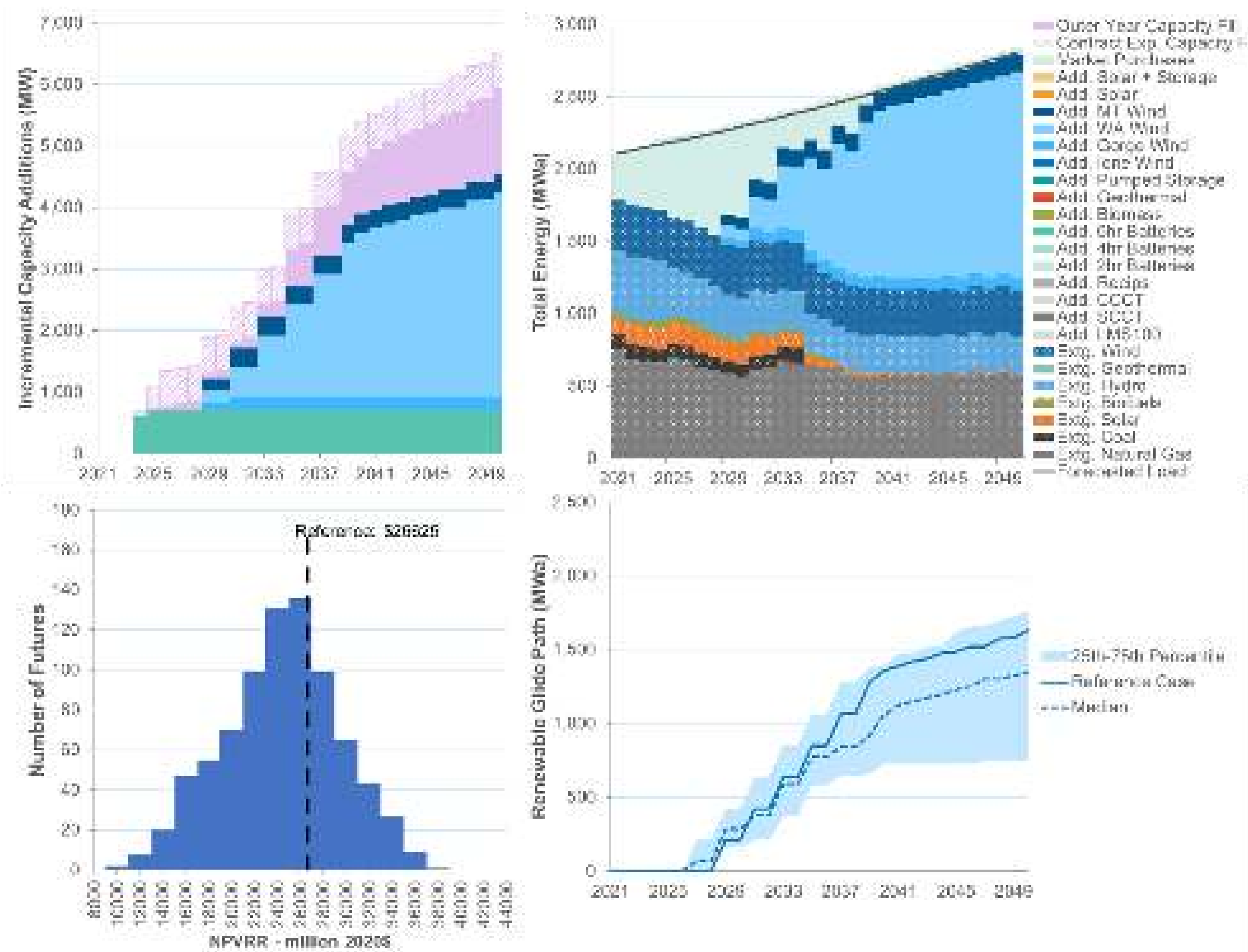
Portfolio 20: Delay Renewables

This portfolio evaluates a future where all renewable procurement is delayed until after 2025 and all capacity needs must be met with 6-hour batteries. This portfolio adds 611 MW of 6-hour batteries in 2024, and an additional 109 MW of 6-hour batteries in 2025.

Table H-21: Portfolio summary

Portfolio Name	No Build
Portfolio Category	Renewable Size and Timing
Portfolio Run Objective Function	Min NPVRR
Portfolio NPVRR Year	2050
Unit Sizes Enforced	No
Required Resource Additions	-
Resource Limitations	No thermal, capacity resources limited to 6-hour batteries through 2025
Future Weighting	Equal
Maximum NPVRR	-

Figure H-20: Portfolio summary charts



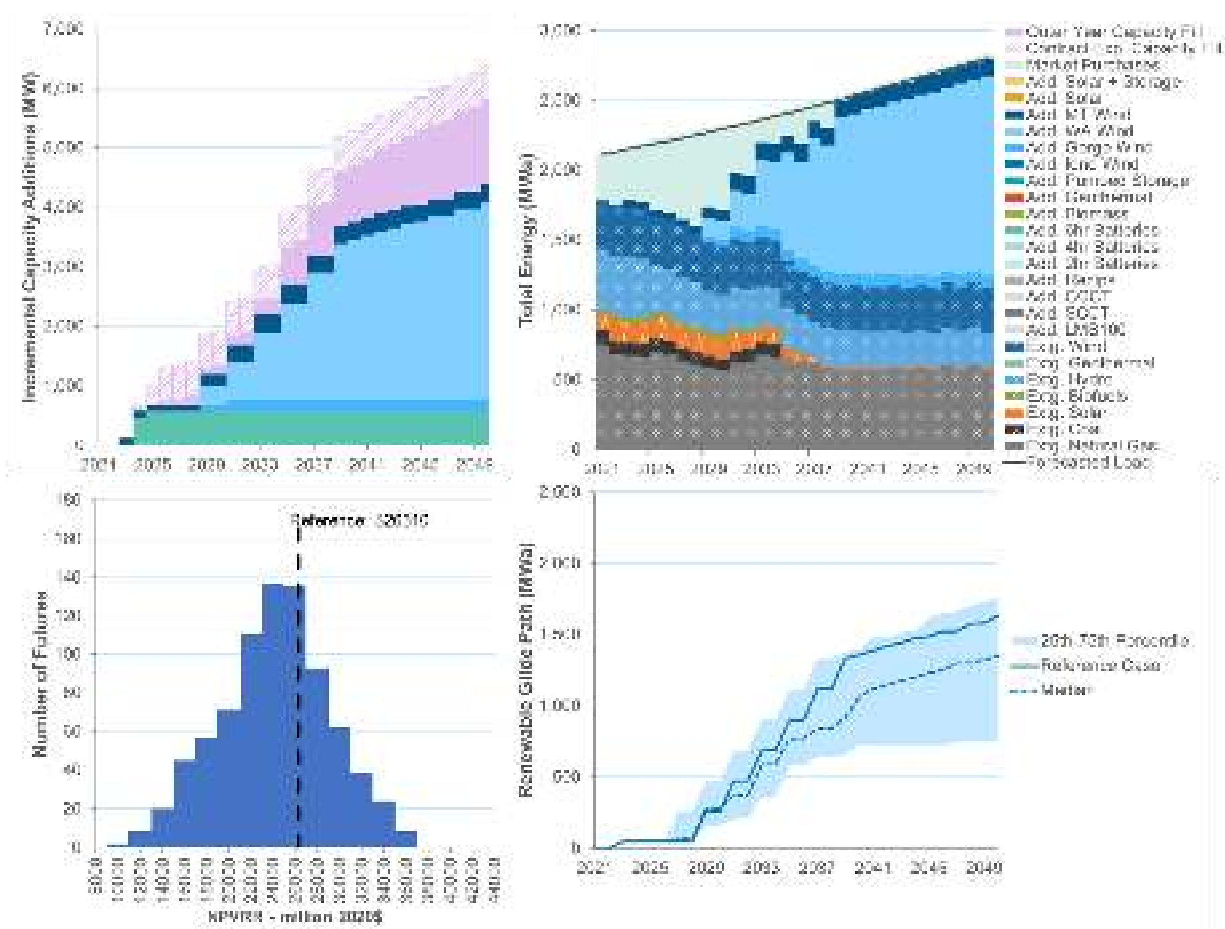
Portfolio 21: 50 MWa in 2023

This portfolio is constrained to add 50 MWa of renewables in 2023 and to meet all remaining capacity needs through 2025 with 6-hour batteries. ROSE-E selected Montana wind to fill the renewable requirement, and 459 MW and 110 MW of 6-hour batteries in 2024 and 2025.

Table H-22: Portfolio summary

Portfolio Name	50 MWa in 2023
Portfolio Category	Renewable Size and Timing
Portfolio Run Objective Function	Min NPVRR
Portfolio NPVRR Year	2050
Unit Sizes Enforced	No
Required Resource Additions	50 MWa RPS Procurement in 2023
Resource Limitations	No thermal, capacity resources limited to 6-hour batteries through 2025
Future Weighting	Equal
Maximum NPVRR	-

Figure H-21: Portfolio summary charts



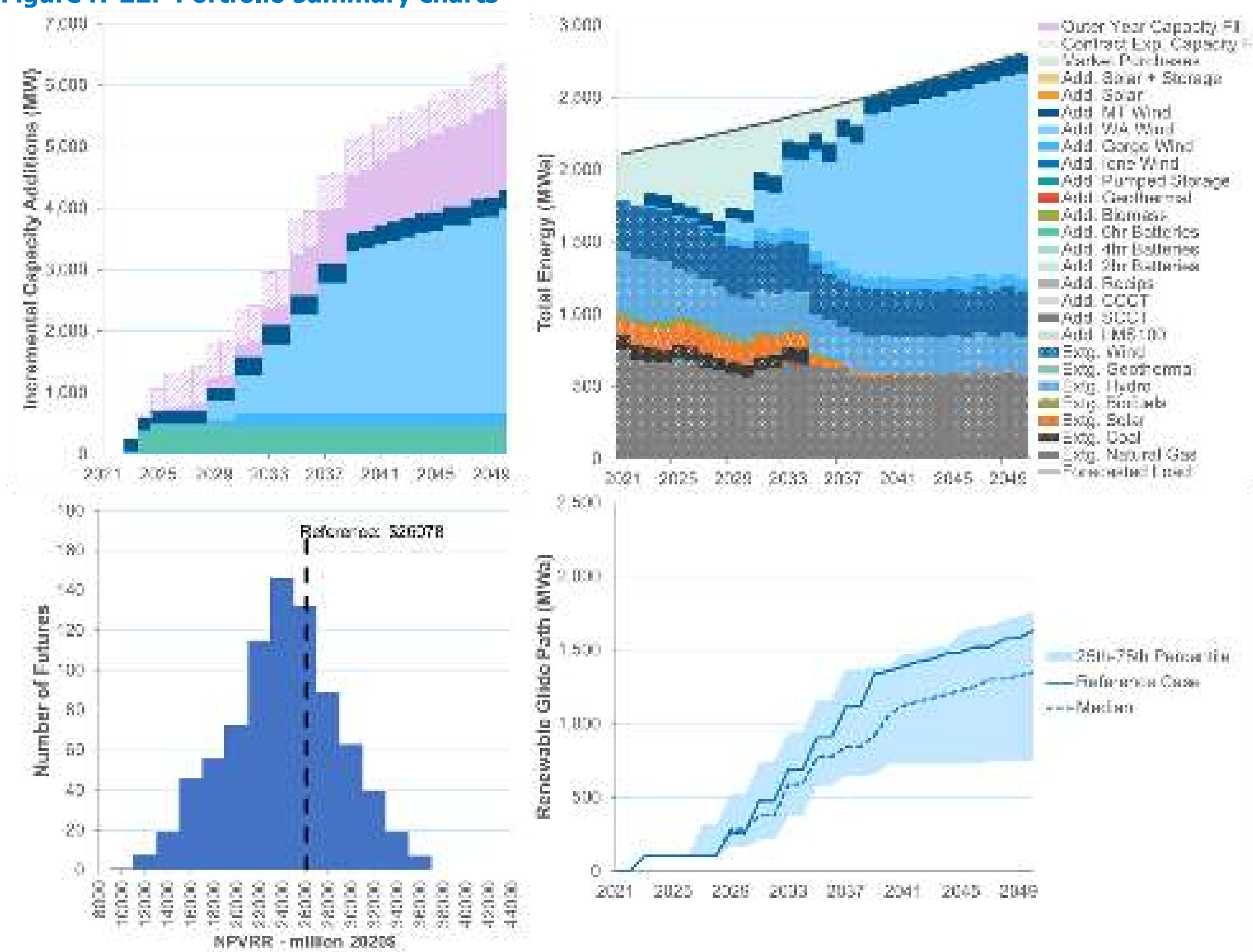
Portfolio 22: 100 MWa in 2023

This portfolio is constrained to add 100 MWa of renewables in 2023 and to meet all remaining capacity needs through 2025 with 6-hour batteries. ROSE-E selected Montana and Gorge wind to fill the renewable requirement, and 355 MW and 102 MW of 6-hour batteries in 2024 and 2025.

Table H-23: Portfolio summary

Portfolio Name	100 MWa in 2023
Portfolio Category	Renewable Size and Timing
Portfolio Run Objective Function	Min NPVRR
Portfolio NPVRR Year	2050
Unit Sizes Enforced	No
Required Resource Additions	100 MWa RPS Procurement in 2023
Resource Limitations	No thermal, capacity resources limited to 6-hour batteries through 2025
Future Weighting	Equal
Maximum NPVRR	-

Figure H-22: Portfolio summary charts



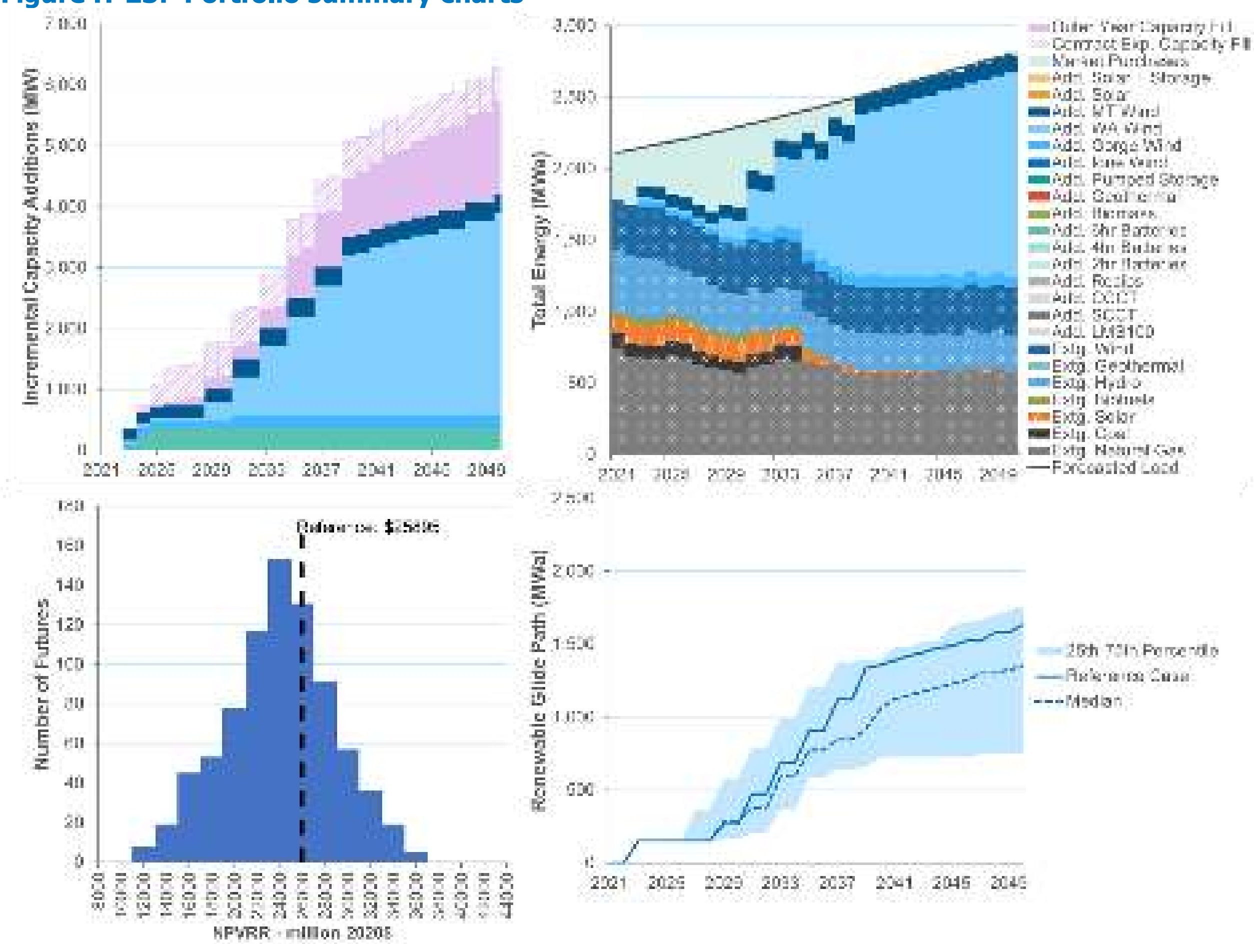
Portfolio 23: 150 MWa in 2023

This portfolio is constrained to add 150 MWa of renewables in 2023 and to meet all remaining capacity needs through 2025 with 6-hour batteries. ROSE-E selected Montana, Gorge, and Washington wind to fill the renewable requirement, and 280 MW and 91 MW of 6-hour batteries in 2024 and 2025.

Table H-24: Portfolio summary

Portfolio Name	150 MWa in 2023
Portfolio Category	Renewable Size and Timing
Portfolio Run Objective Function	Min NPVRR
Portfolio NPVRR Year	2050
Unit Sizes Enforced	No
Required Resource Additions	150 MWa RPS Procurement in 2023
Resource Limitations	No thermal, capacity resources limited to 6-hour batteries through 2025
Future Weighting	Equal
Maximum NPVRR	-

Figure H-23: Portfolio summary charts



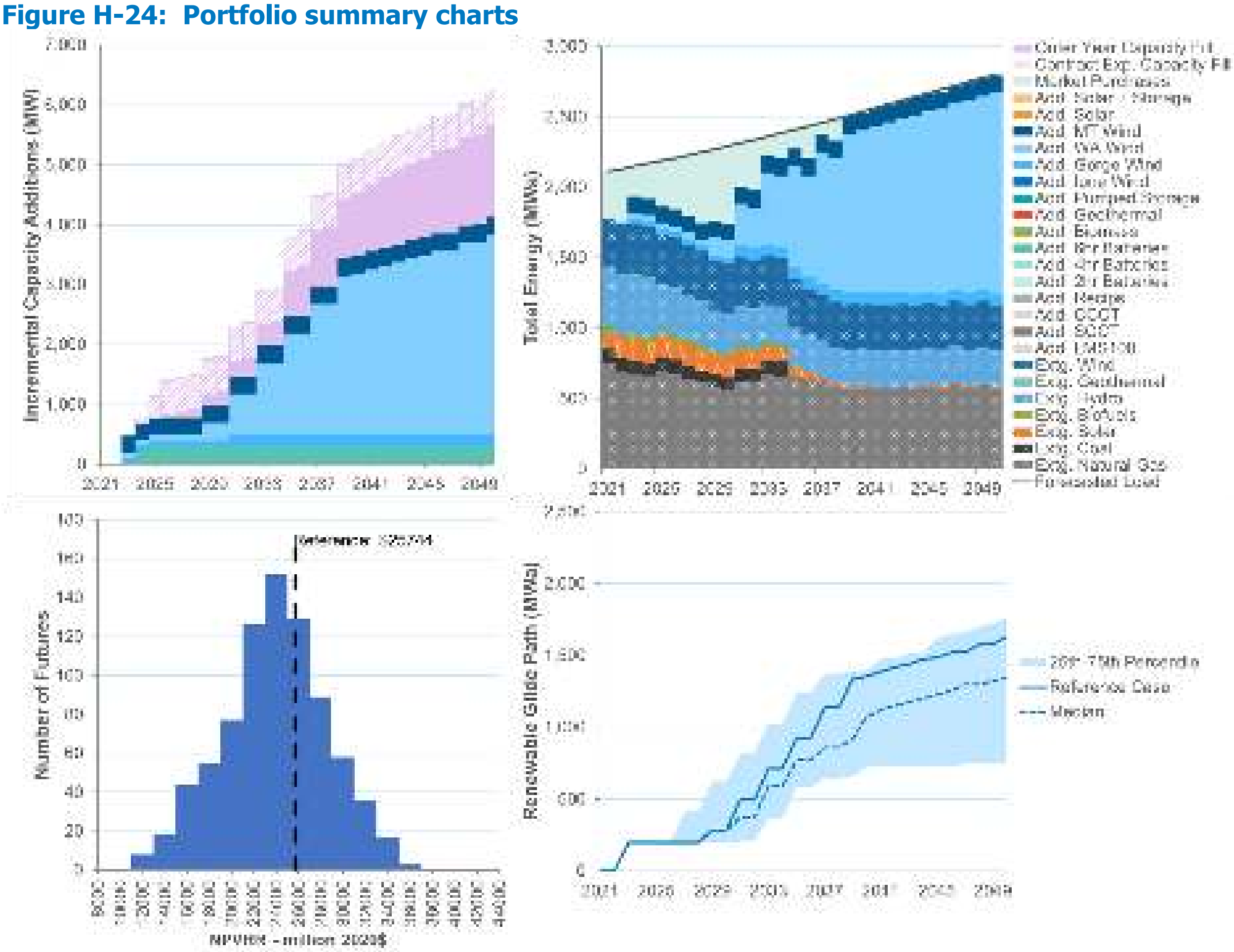
Portfolio 24: 200 MWa in 2023

This portfolio is constrained to add 200 MWa of renewables in 2023 and to meet all remaining capacity needs through 2025 with 6-hour batteries. ROSE-E selected Montana, Gorge, and Washington wind to fill the renewable requirement, and 215 MW and 84 MW of 6-hour batteries in 2024 and 2025.

Table H-25: Portfolio summary

Portfolio Name	200 MWa in 2023
Portfolio Category	Renewable Size and Timing
Portfolio Run Objective Function	Min NPVRR
Portfolio NPVRR Year	2050
Unit Sizes Enforced	No
Required Resource Additions	200 MWa RPS Procurement in 2023
Resource Limitations	No thermal, capacity resources limited to 6-hour batteries through 2025
Future Weighting	Equal
Maximum NPVRR	-

Figure H-24: Portfolio summary charts



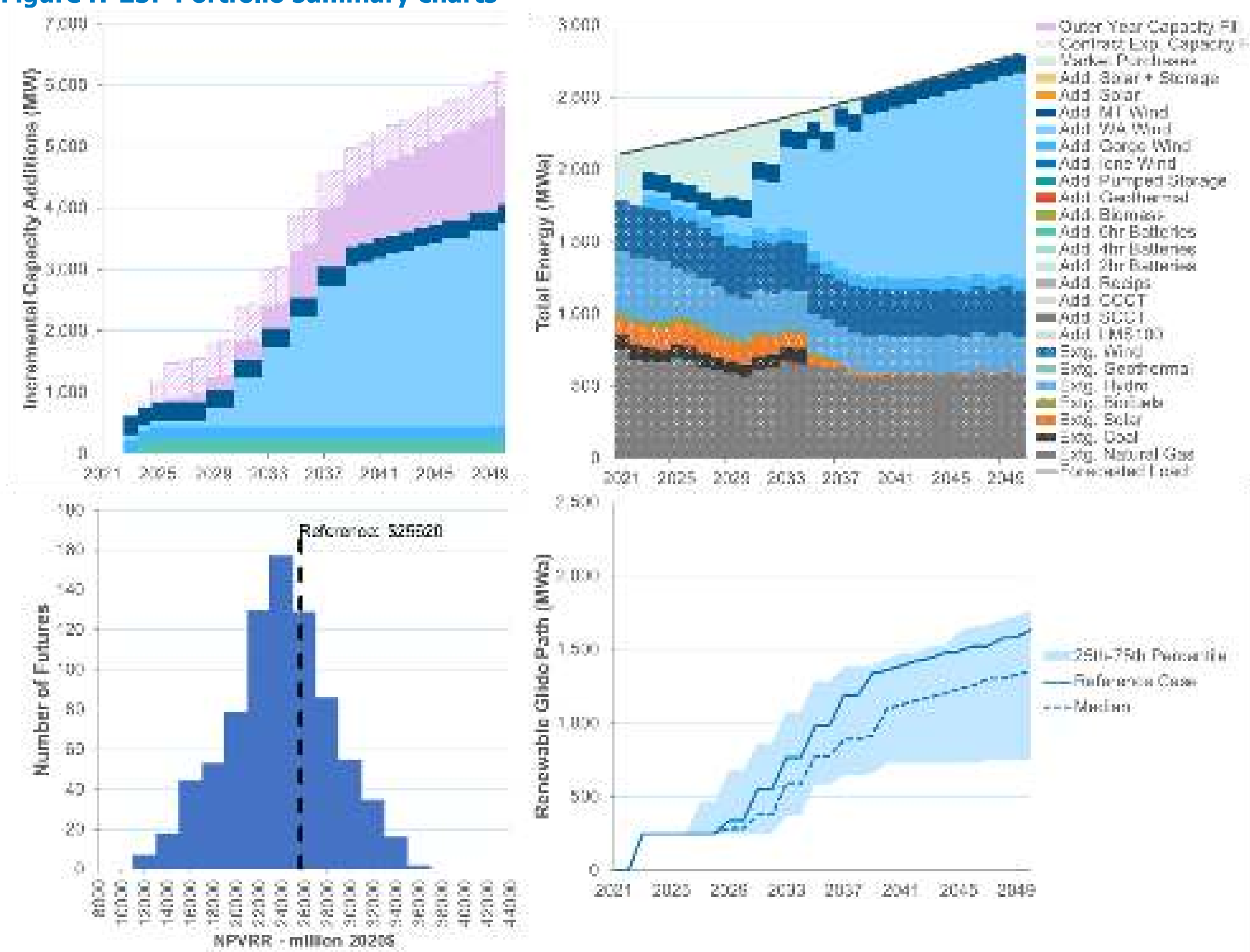
Portfolio 25: 250 MWa in 2023

This portfolio is constrained to add 250 MWa of renewables in 2023 and to meet all remaining capacity needs through 2025 with 6-hour batteries. ROSE-E selected Montana, Gorge, and Washington wind to fill the renewable requirement, and 160 MW and 78 MW of 6-hour batteries in 2024 and 2025.

Table H-26: Portfolio summary

Portfolio Name	250 MWa in 2023
Portfolio Category	Renewable Size and Timing
Portfolio Run Objective Function	Min NPVRR
Portfolio NPVRR Year	2050
Unit Sizes Enforced	No
Required Resource Additions	250 MWa RPS Procurement in 2023
Resource Limitations	No thermal, capacity resources limited to 6-hour batteries through 2025
Future Weighting	Equal
Maximum NPVRR	-

Figure H-25: Portfolio summary charts



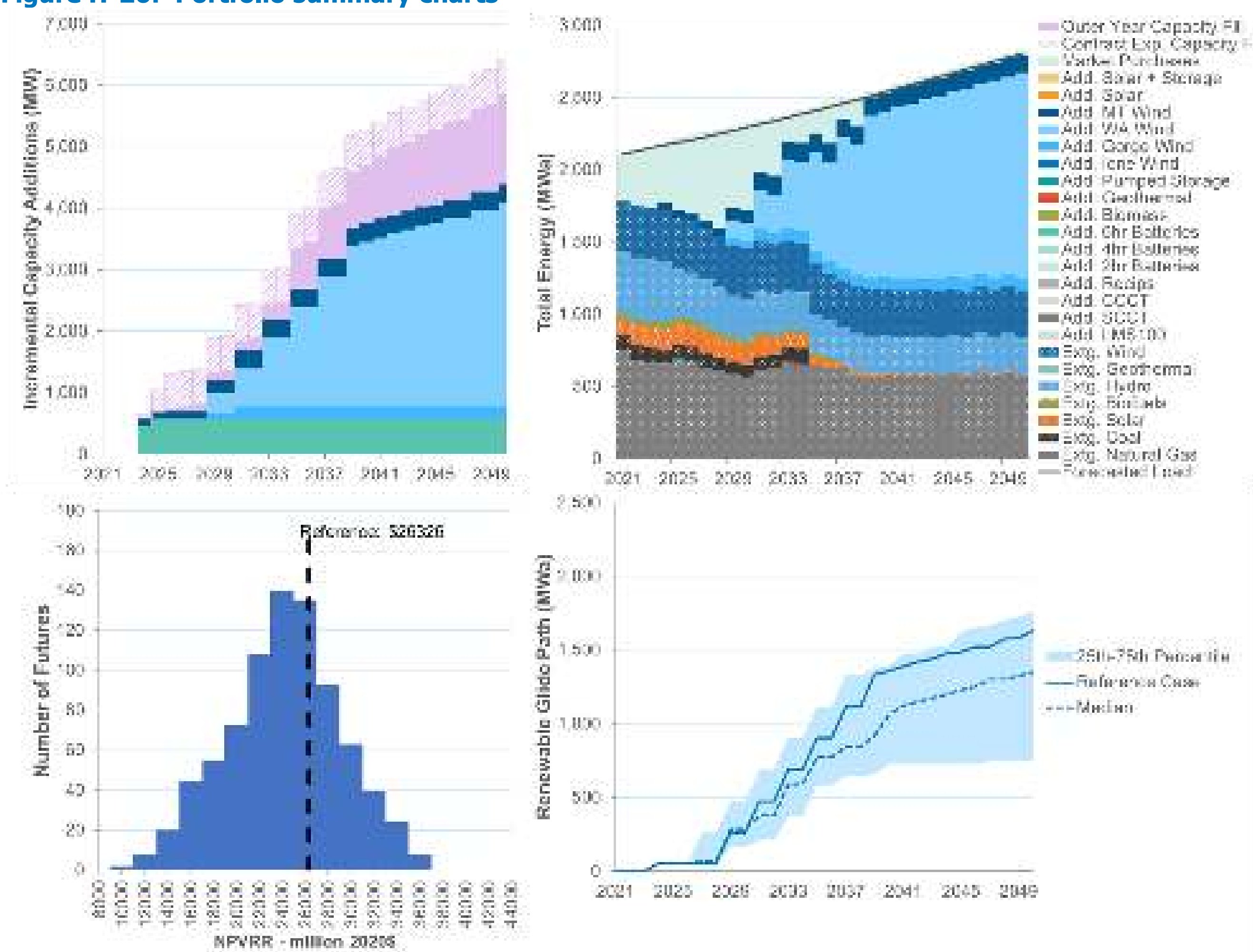
Portfolio 26: 50 MWa in 2024

This portfolio is constrained to add 50 MWa of renewables in 2024 and to meet all remaining capacity needs through 2025 with 6-hour batteries. ROSE-E selected Montana wind to fill the renewable requirement, and 459 MW and 110 MW of 6-hour batteries in 2024 and 2025.

Table H-27: Portfolio summary

Portfolio Name	50 MWa in 2024
Portfolio Category	Renewable Size and Timing
Portfolio Run Objective Function	Min NPVRR
Portfolio NPVRR Year	2050
Unit Sizes Enforced	No
Required Resource Additions	50 MWa RPS Procurement in 2024
Resource Limitations	No thermal
Future Weighting	Equal
Maximum NPVRR	-

Figure H-26: Portfolio summary charts



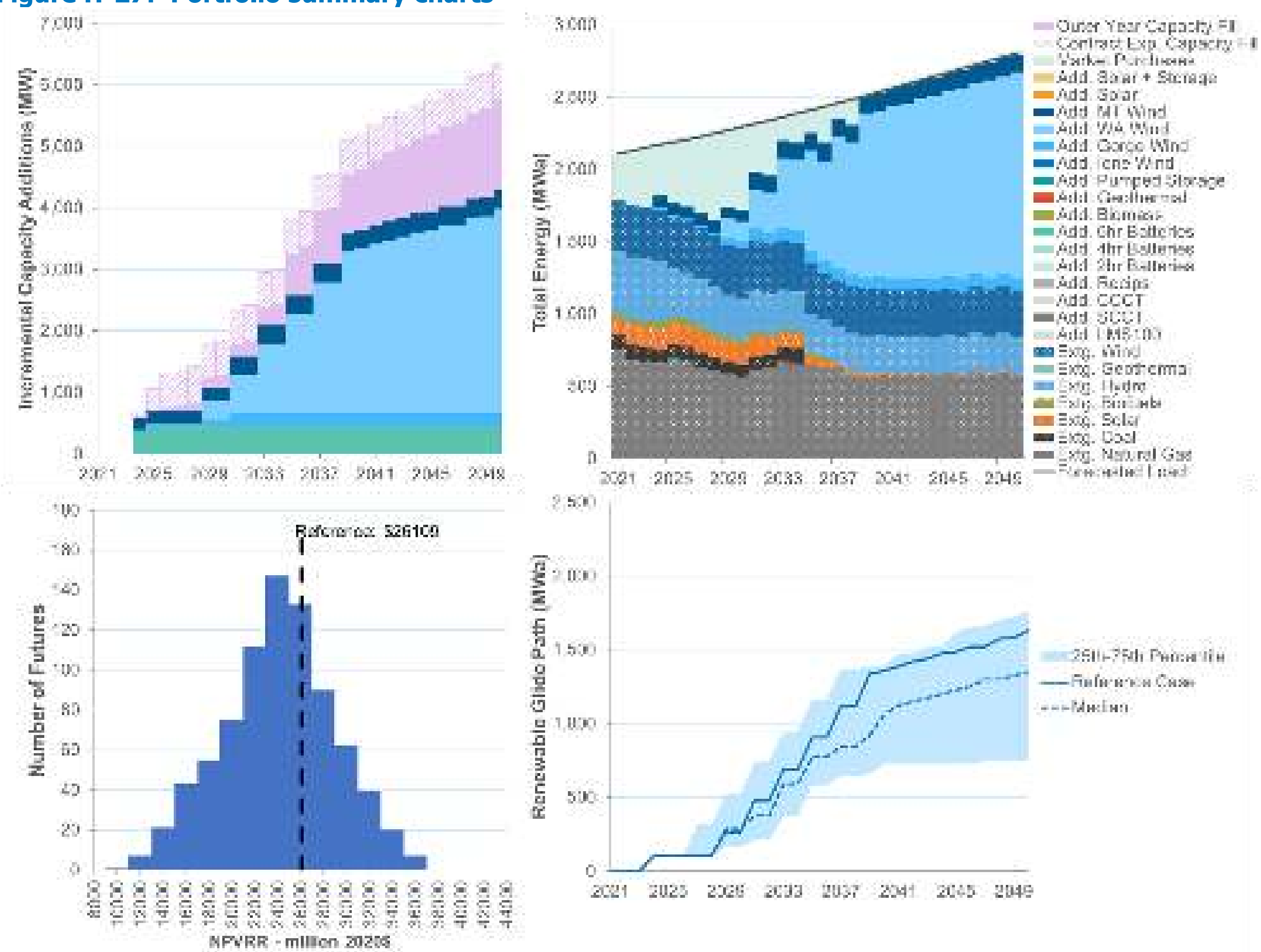
Portfolio 27: 100 MWa in 2024

This portfolio is constrained to add 100 MWa of renewables in 2024 and to meet all remaining capacity needs through 2025 with 6-hour batteries. ROSE-E selected Montana and Gorge wind to fill the renewable requirement, and 355 MW and 102 MW of 6-hour batteries in 2024 and 2025.

Table H-28: Portfolio summary

Portfolio Name	100 MWa in 2024
Portfolio Category	Renewable Size and Timing
Portfolio Run Objective Function	Min NPVRR
Portfolio NPVRR Year	2050
Unit Sizes Enforced	No
Required Resource Additions	100 MWa RPS Procurement in 2024
Resource Limitations	No thermal, capacity resources limited to 6-hour batteries through 2025
Future Weighting	Equal
Maximum NPVRR	-

Figure H-27: Portfolio summary charts



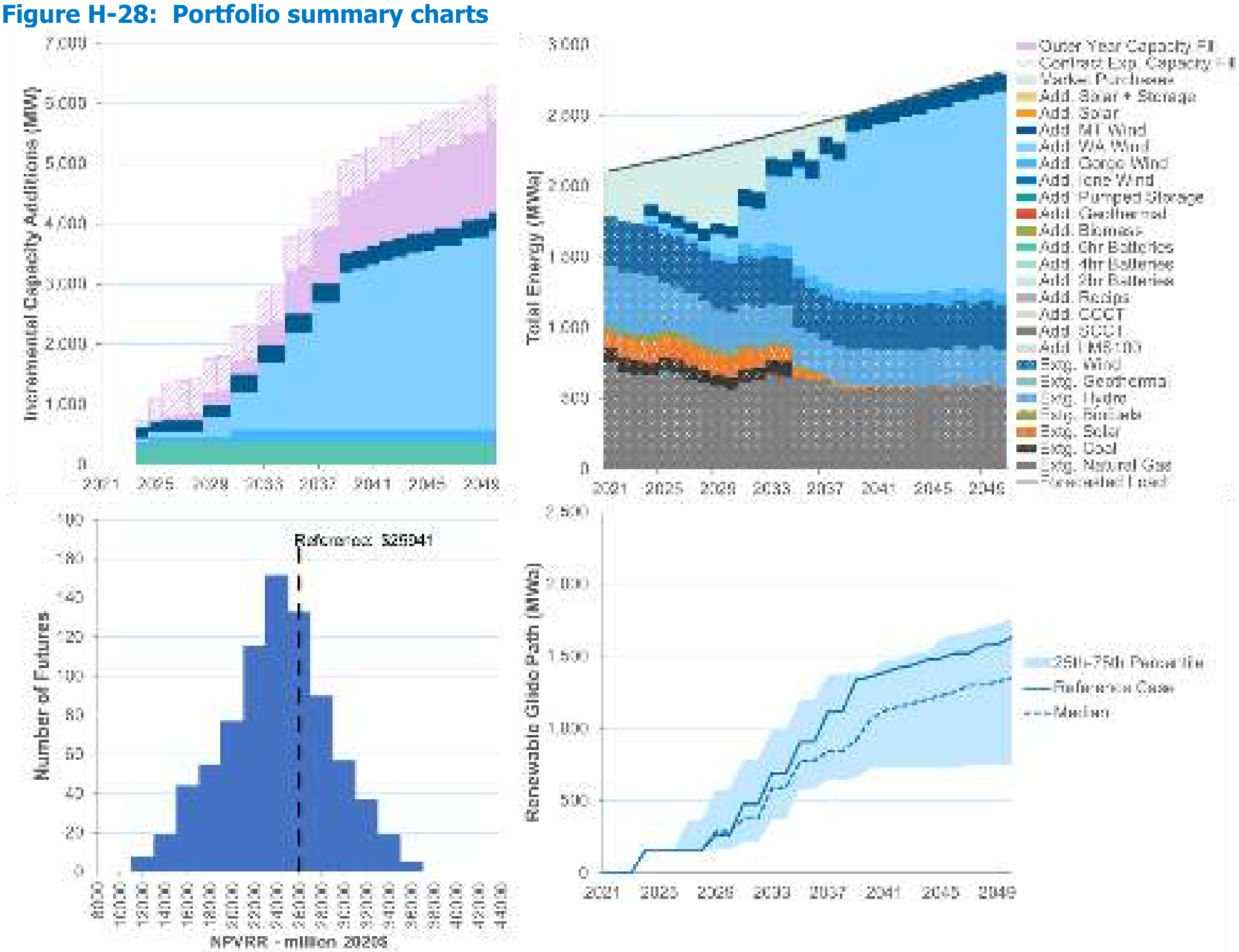
Portfolio 28: 150 MWa in 2024

This portfolio is constrained to add 150 MWa of renewables in 2024 and to meet all remaining capacity needs through 2025 with 6-hour batteries. ROSE-E selected Montana, Washington, and Gorge wind to fill the renewable requirement, and 280 MW and 91 MW of 6-hour batteries in 2024 and 2025.

Table H-29: Portfolio summary

Portfolio Name	150 MWa in 2024
Portfolio Category	Renewable Size and Timing
Portfolio Run Objective Function	Min NPVRR
Portfolio NPVRR Year	2050
Unit Sizes Enforced	No
Required Resource Additions	150 MWa RPS Procurement in 2024
Resource Limitations	No thermal, capacity resources limited to 6-hour batteries through 2025
Future Weighting	Equal
Maximum NPVRR	-

Figure H-28: Portfolio summary charts



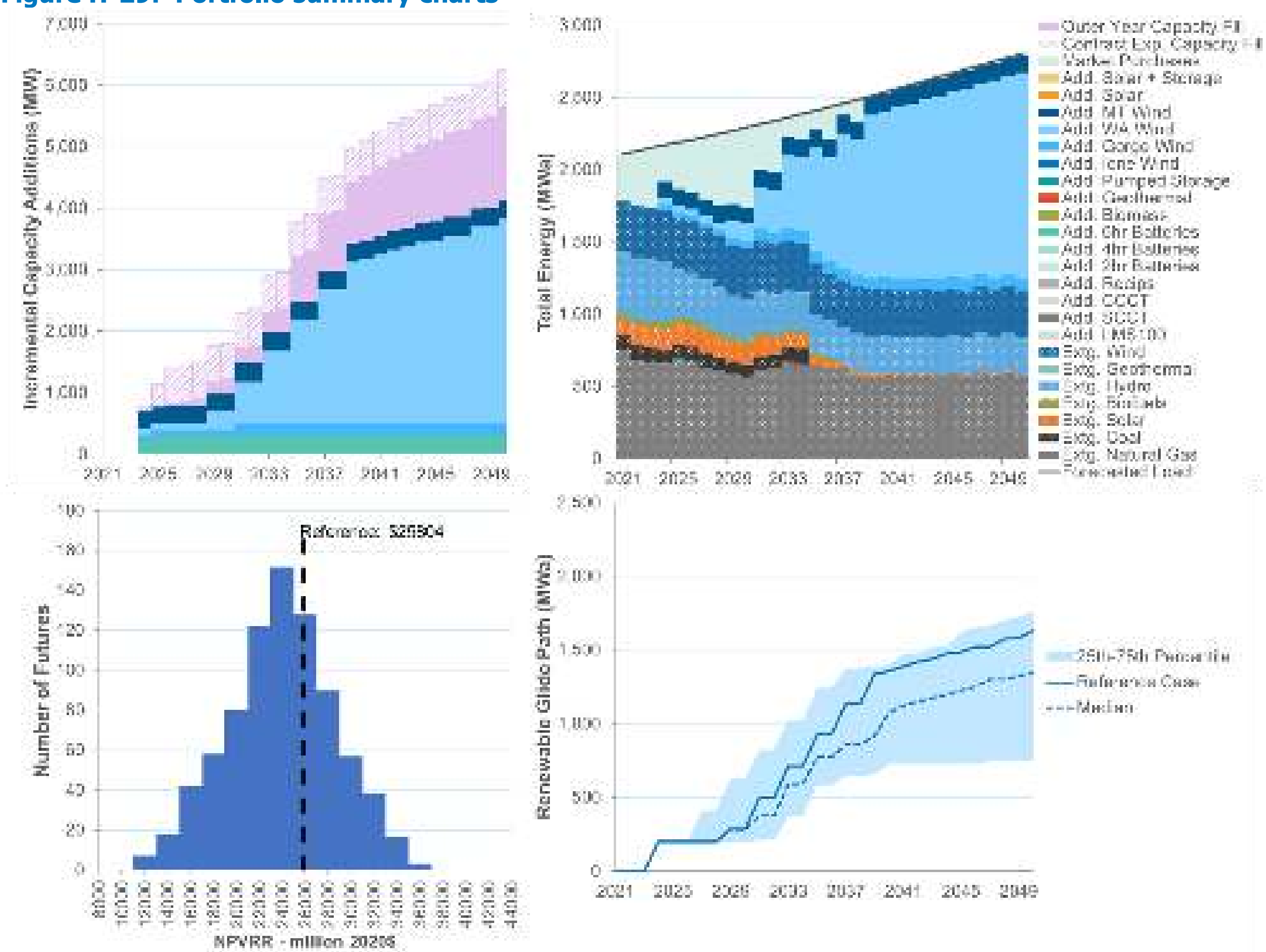
Portfolio 29: 200 MWa in 2024

This portfolio is constrained to add 200 MWa of renewables in 2024 and to meet all remaining capacity needs through 2025 with 6-hour batteries. ROSE-E selected Montana, Washington, and Gorge wind to fill the renewable requirement, and 215 MW and 84 MW of 6-hour batteries in 2024 and 2025.

Table H-30: Portfolio summary

Portfolio Name	200 MWa in 2024
Portfolio Category	Renewable Size and Timing
Portfolio Run Objective Function	Min NPVRR
Portfolio NPVRR Year	2050
Unit Sizes Enforced	No
Required Resource Additions	200 MWa RPS Procurement in 2024
Resource Limitations	No thermal, capacity resources limited to 6-hour batteries through 2025
Future Weighting	Equal
Maximum NPVRR	-

Figure H-29: Portfolio summary charts



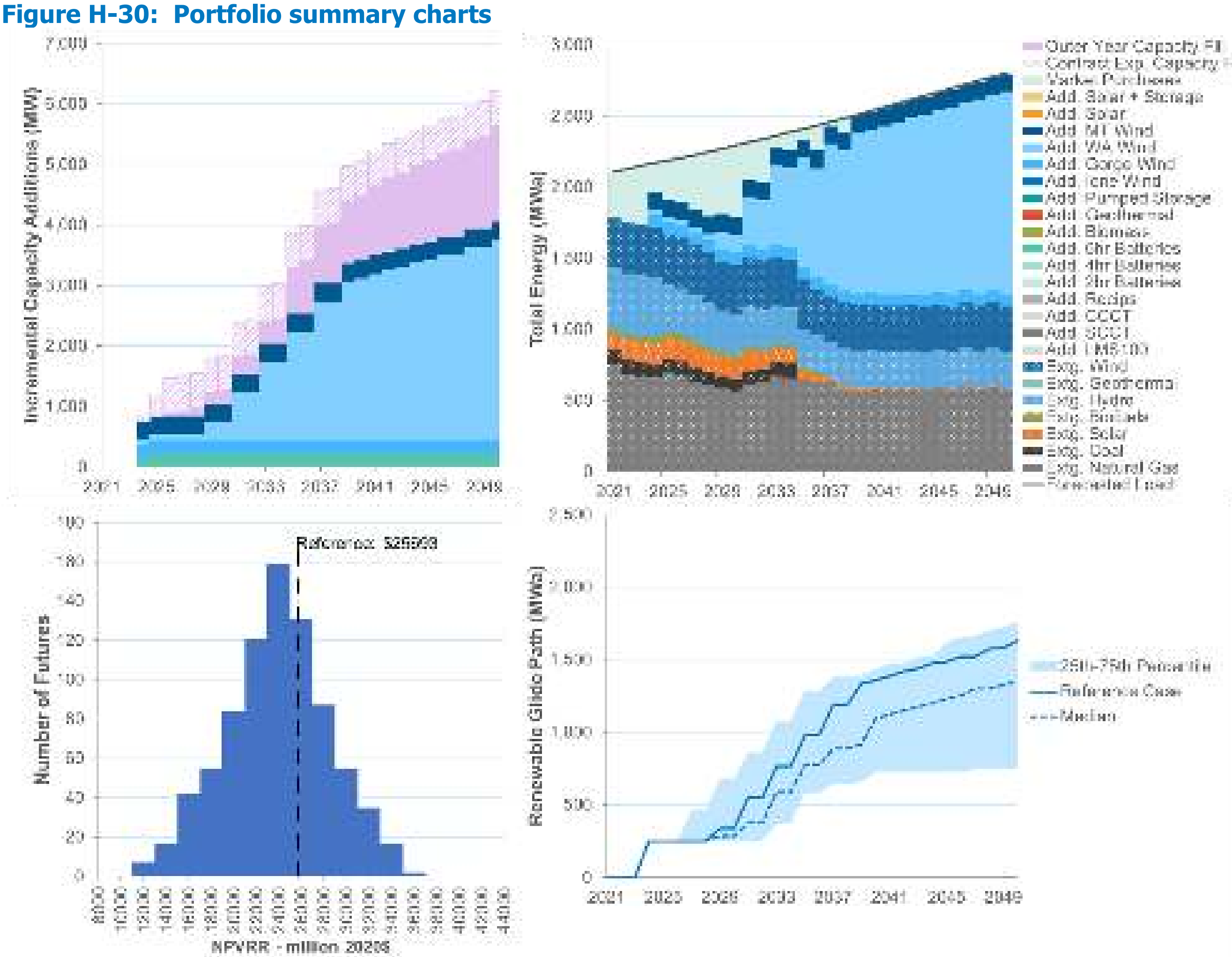
Portfolio 30: 250 MWa in 2024

This portfolio is constrained to add 250 MWa of renewables in 2024 and to meet all remaining capacity needs through 2025 with 6-hour batteries. ROSE-E selected Montana, Washington, and Gorge wind to fill the renewable requirement, and 160 MW and 78 MW of 6-hour batteries in 2024 and 2025.

Table H-31: Portfolio summary

Portfolio Name	250 MWa in 2024
Portfolio Category	Renewable Size and Timing
Portfolio Run Objective Function	Min NPVRR
Portfolio NPVRR Year	2050
Unit Sizes Enforced	No
Required Resource Additions	250 MWa RPS Procurement in 2024
Resource Limitations	No thermal, capacity resources limited to 6-hour batteries through 2025
Future Weighting	Equal
Maximum NPVRR	-

Figure H-30: Portfolio summary charts



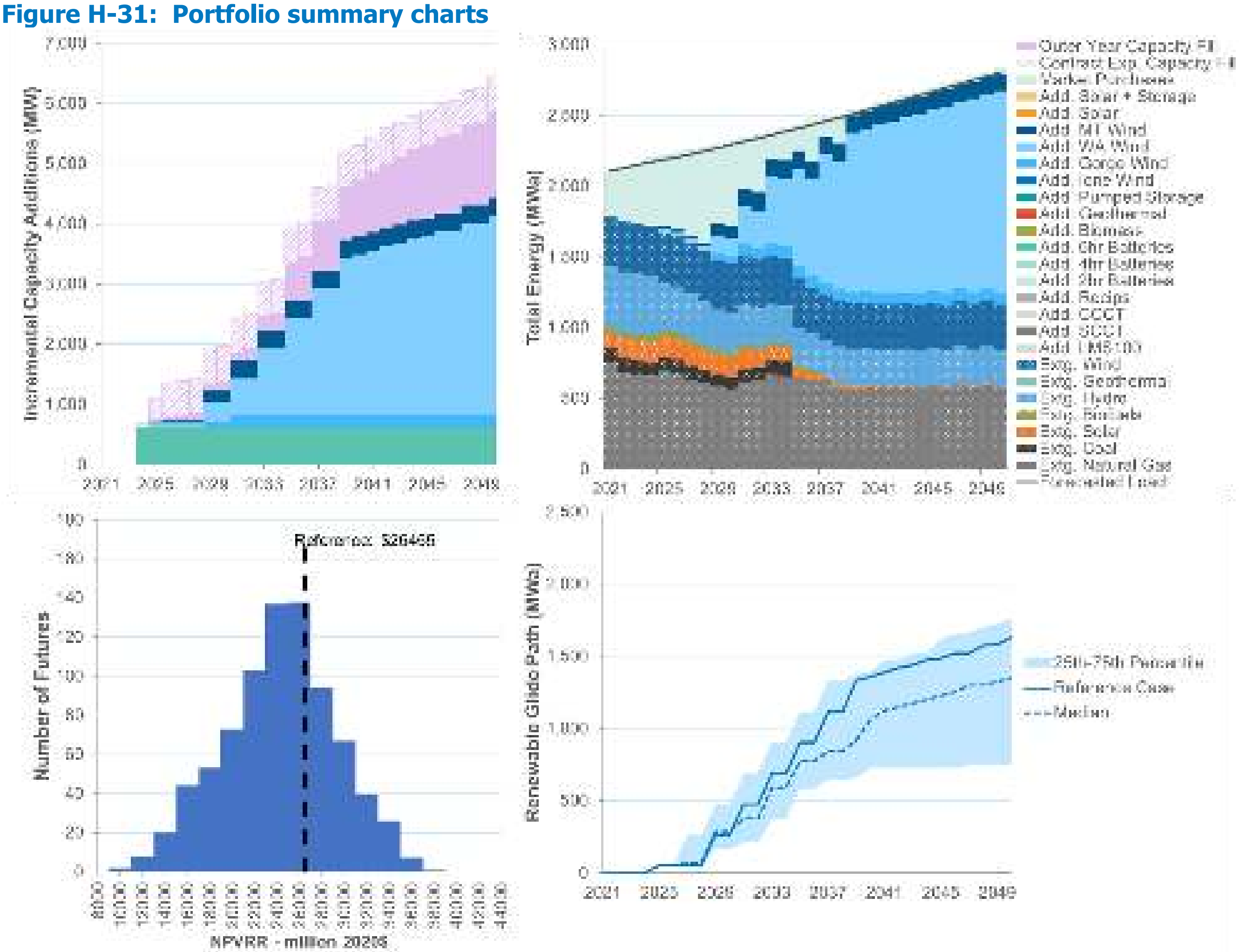
Portfolio 31: 50 MWa in 2025

This portfolio is constrained to add 50 MWa of renewables in 2025 and to meet all remaining capacity needs through 2025 with 6-hour batteries. ROSE-E selected Montana and Washington wind to fill the renewable requirement, and 611 MW of 6-hour batteries in 2024.

Table H-32: Portfolio summary

Portfolio Name	50 MWa in 2025
Portfolio Category	Renewable Size and Timing
Portfolio Run Objective Function	Min NPVRR
Portfolio NPVRR Year	2050
Unit Sizes Enforced	No
Required Resource Additions	50 MWa RPS Procurement in 2025
Resource Limitations	No thermal, capacity resources limited to 6-hour batteries through 2025
Future Weighting	Equal
Maximum NPVRR	-

Figure H-31: Portfolio summary charts



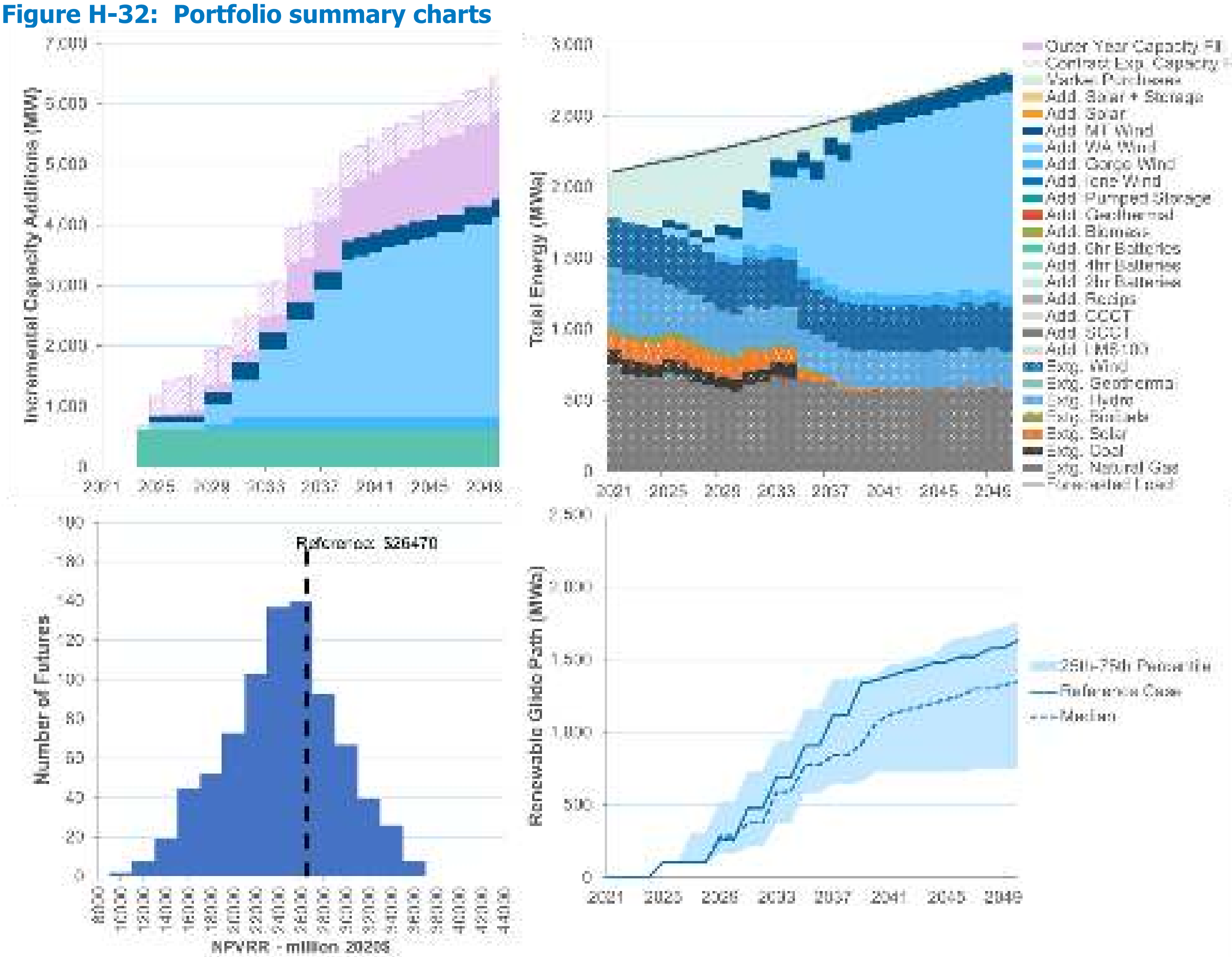
Portfolio 32: 100 MWa in 2025

This portfolio is constrained to add 100 MWa of renewables in 2025 and to meet all remaining capacity needs through 2025 with 6-hour batteries. ROSE-E selected Montana and Washington wind to fill the renewable requirement, and 611 MW of 6-hour batteries in 2024.

Table H-33: Portfolio summary

Portfolio Name	100 MWa in 2025
Portfolio Category	Renewable Size and Timing
Portfolio Run Objective Function	Min NPVRR
Portfolio NPVRR Year	2050
Unit Sizes Enforced	No
Required Resource Additions	100 MWa RPS Procurement in 2025
Resource Limitations	No thermal, capacity resources limited to 6-hour batteries through 2025
Future Weighting	Equal
Maximum NPVRR	-

Figure H-32: Portfolio summary charts



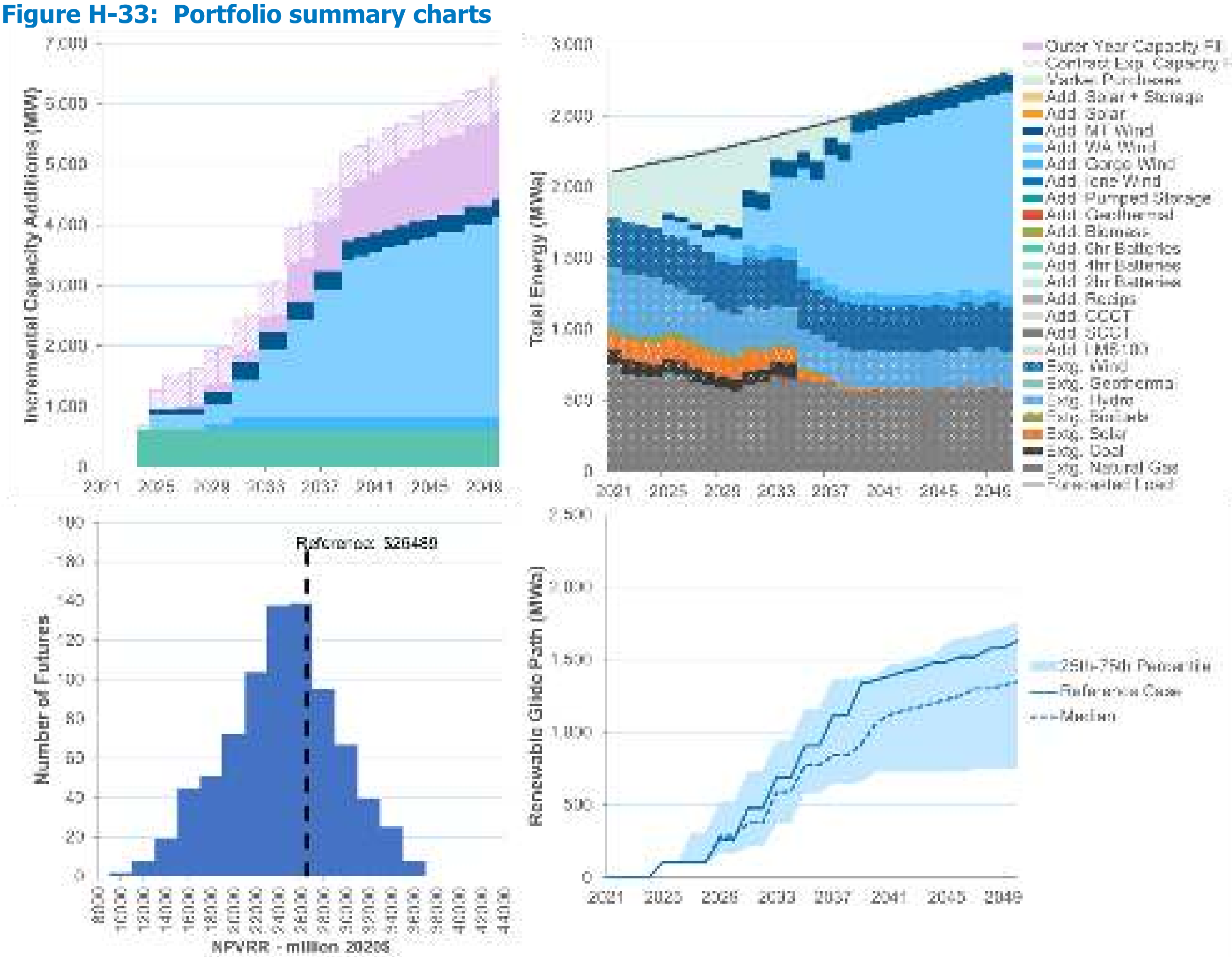
Portfolio 33: 150 MWa in 2025

This portfolio is constrained to add 150 MWa of renewables in 2025 and to meet all remaining capacity needs through 2025 with 6-hour batteries. ROSE-E selected Montana and Washington wind to fill the renewable requirement, and 611 MW of 6-hour batteries in 2024.

Table H-34: Portfolio summary

Portfolio Name	150 MWa in 2025
Portfolio Category	Renewable Size and Timing
Portfolio Run Objective Function	Min NPVRR
Portfolio NPVRR Year	2050
Unit Sizes Enforced	No
Required Resource Additions	150 MWa RPS Procurement in 2025
Resource Limitations	No thermal, capacity resources limited to 6-hour batteries through 2025
Future Weighting	Equal
Maximum NPVRR	-

Figure H-33: Portfolio summary charts



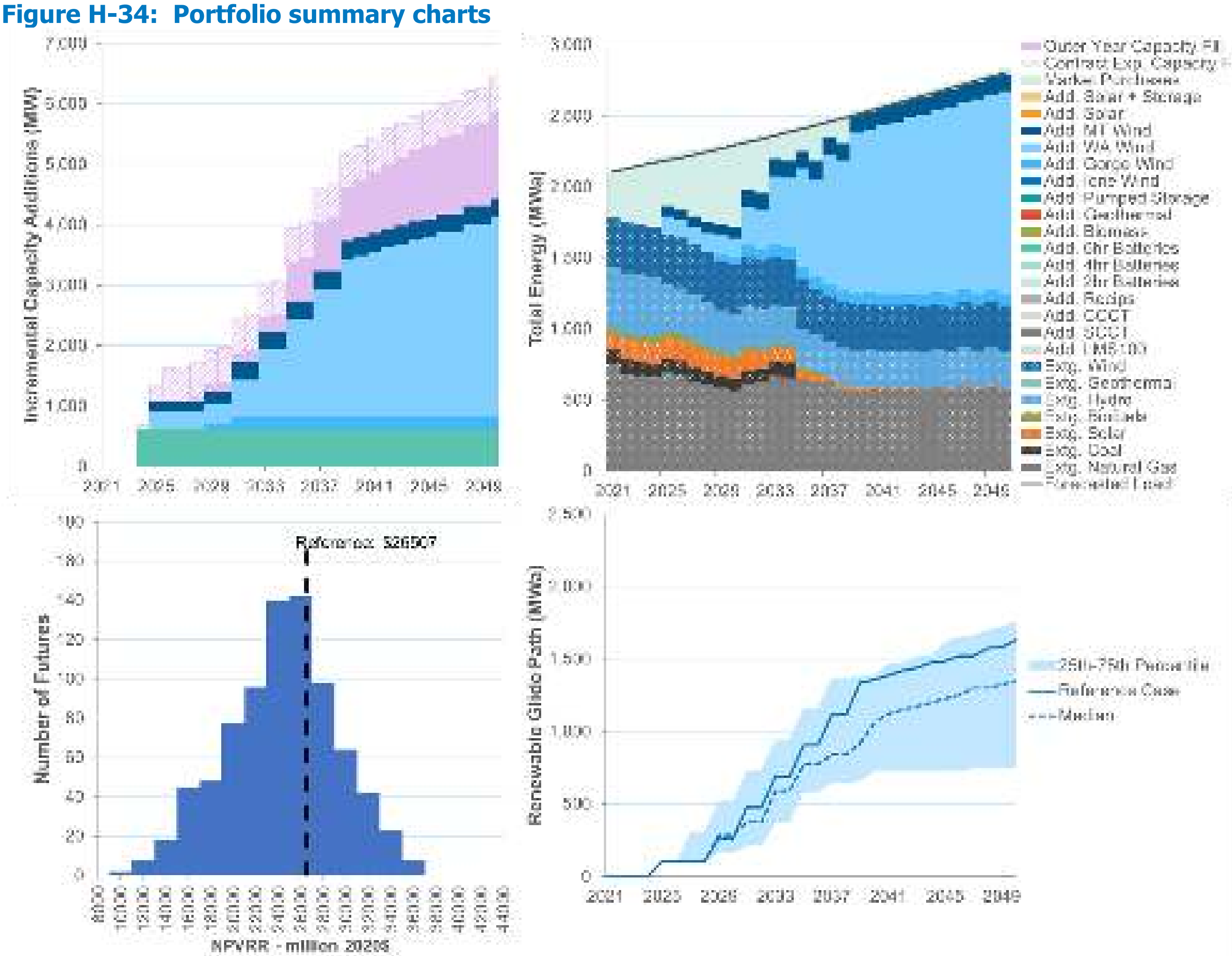
Portfolio 34: 200 MWa in 2025

This portfolio is constrained to add 200 MWa of renewables in 2025 and to meet all remaining capacity needs through 2025 with 6-hour batteries. ROSE-E selected Montana and Washington wind to fill the renewable requirement, and 611 MW of 6-hour batteries in 2024.

Table H-35: Portfolio summary

Portfolio Name	200 MWa in 2025
Portfolio Category	Renewable Size and Timing
Portfolio Run Objective Function	Min NPVRR
Portfolio NPVRR Year	2050
Unit Sizes Enforced	No
Required Resource Additions	200 MWa RPS Procurement in 2025
Resource Limitations	No thermal, capacity resources limited to 6-hour batteries through 2025
Future Weighting	Equal
Maximum NPVRR	-

Figure H-34: Portfolio summary charts



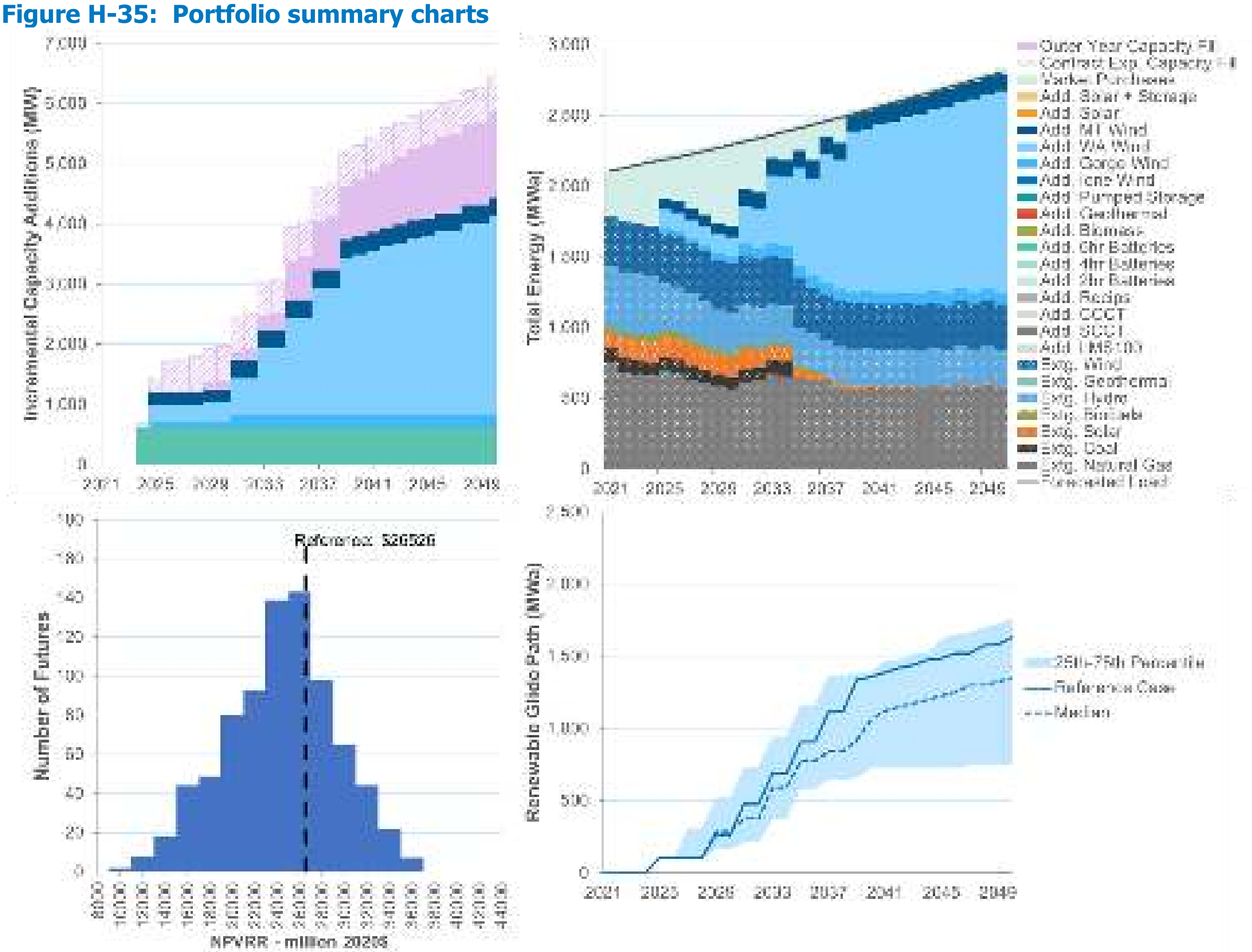
Portfolio 35: 250 MWa in 2025

This portfolio is constrained to add 250 MWa of renewables in 2025 and to meet all remaining capacity needs through 2025 with 6-hour batteries. ROSE-E selected Montana and Washington wind to fill the renewable requirement, and 611 MW of 6-hour batteries in 2024.

Table H-36: Portfolio summary

Portfolio Name	250 MWa in 2025
Portfolio Category	Renewable Size and Timing
Portfolio Run Objective Function	Min NPVRR
Portfolio NPVRR Year	2050
Unit Sizes Enforced	No
Required Resource Additions	250 MWa RPS Procurement in 2025
Resource Limitations	No thermal, capacity resources limited to 6-hour batteries through 2025
Future Weighting	Equal
Maximum NPVRR	-

Figure H-35: Portfolio summary charts



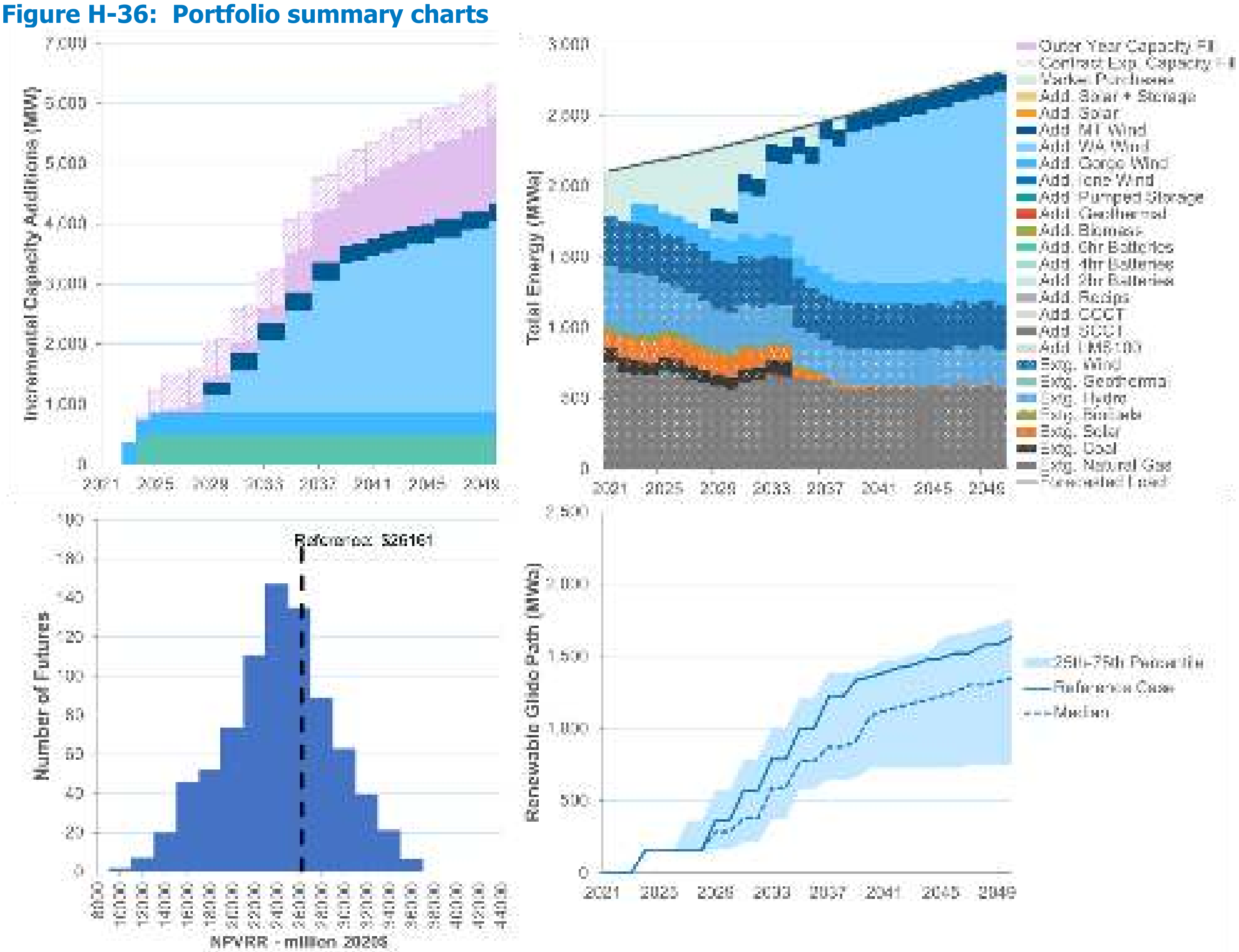
Portfolio 36: Gorge Wind

This portfolio is constrained to add 150 MWa of Gorge wind by 2025 and to meet all remaining capacity needs through 2025 with 6-hour batteries. ROSE-E selected 393 MW and 107 MW of 6-hour batteries in 2024 and 2025.

Table H-37: Portfolio summary

Portfolio Name	Gorge Wind
Portfolio Category	Renewable Resource
Portfolio Run Objective Function	Min NPVRR
Portfolio NPVRR Year	2050
Unit Sizes Enforced	No
Required Resource Additions	150 MWa Gorge wind by 2025
Resource Limitations	No thermal, only 6-hour batteries allowed until 2026
Future Weighting	Equal
Maximum NPVRR	-

Figure H-36: Portfolio summary charts



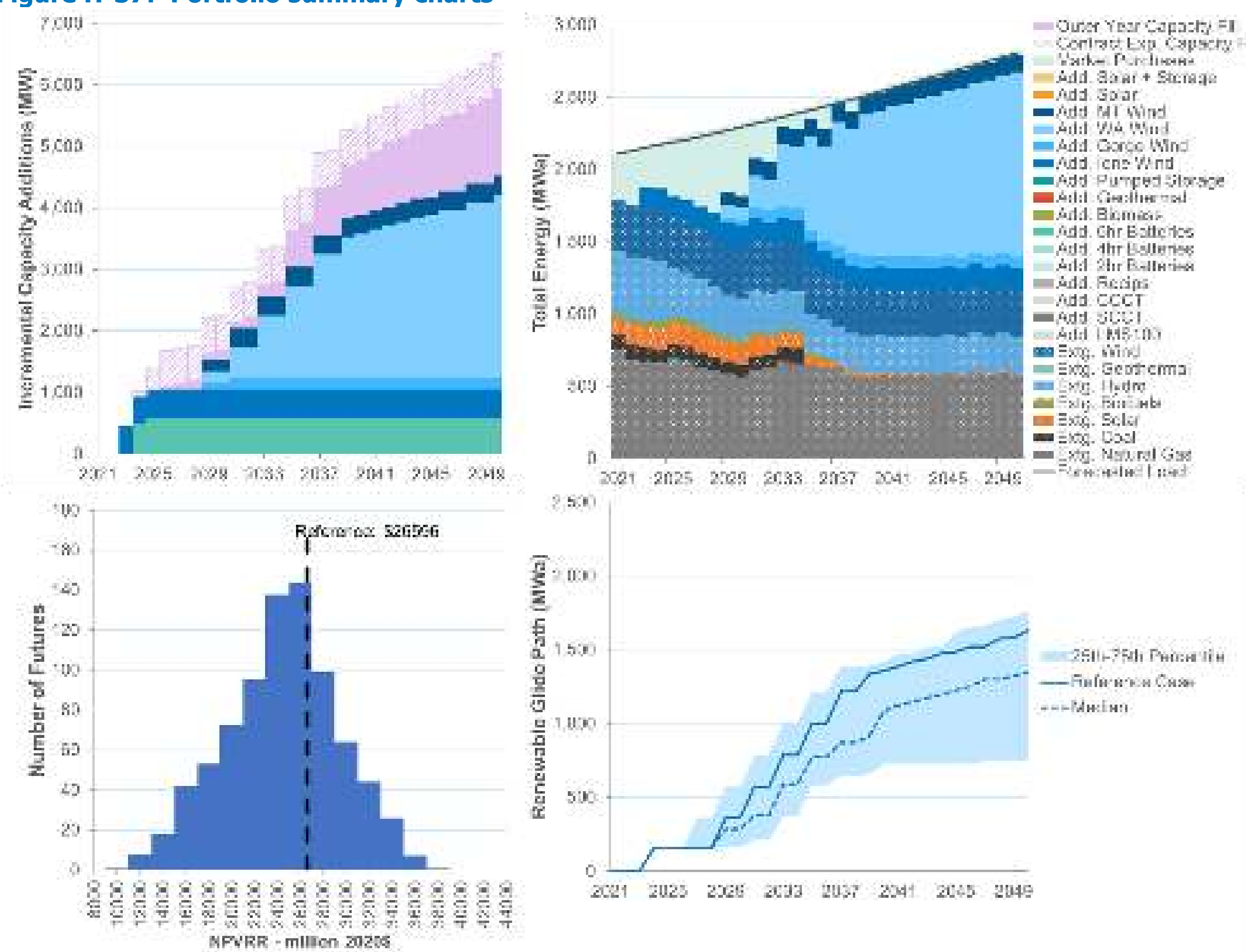
Portfolio 37: Ione Wind

This portfolio is constrained to add 150 MWa of Ione wind by 2025 and to meet all remaining capacity needs through 2025 with 6-hour batteries. ROSE-E selected 478 MW and 109 MW of 6-hour batteries in 2024 and 2025.

Table H-38: Portfolio summary

Portfolio Name	Ione Wind
Portfolio Category	Renewable Resource
Portfolio Run Objective Function	Min NPVRR
Portfolio NPVRR Year	2050
Unit Sizes Enforced	No
Required Resource Additions	150 MWa Ione wind by 2025
Resource Limitations	No thermal, only 6-hour batteries allowed until 2026
Future Weighting	Equal
Maximum NPVRR	-

Figure H-37: Portfolio summary charts



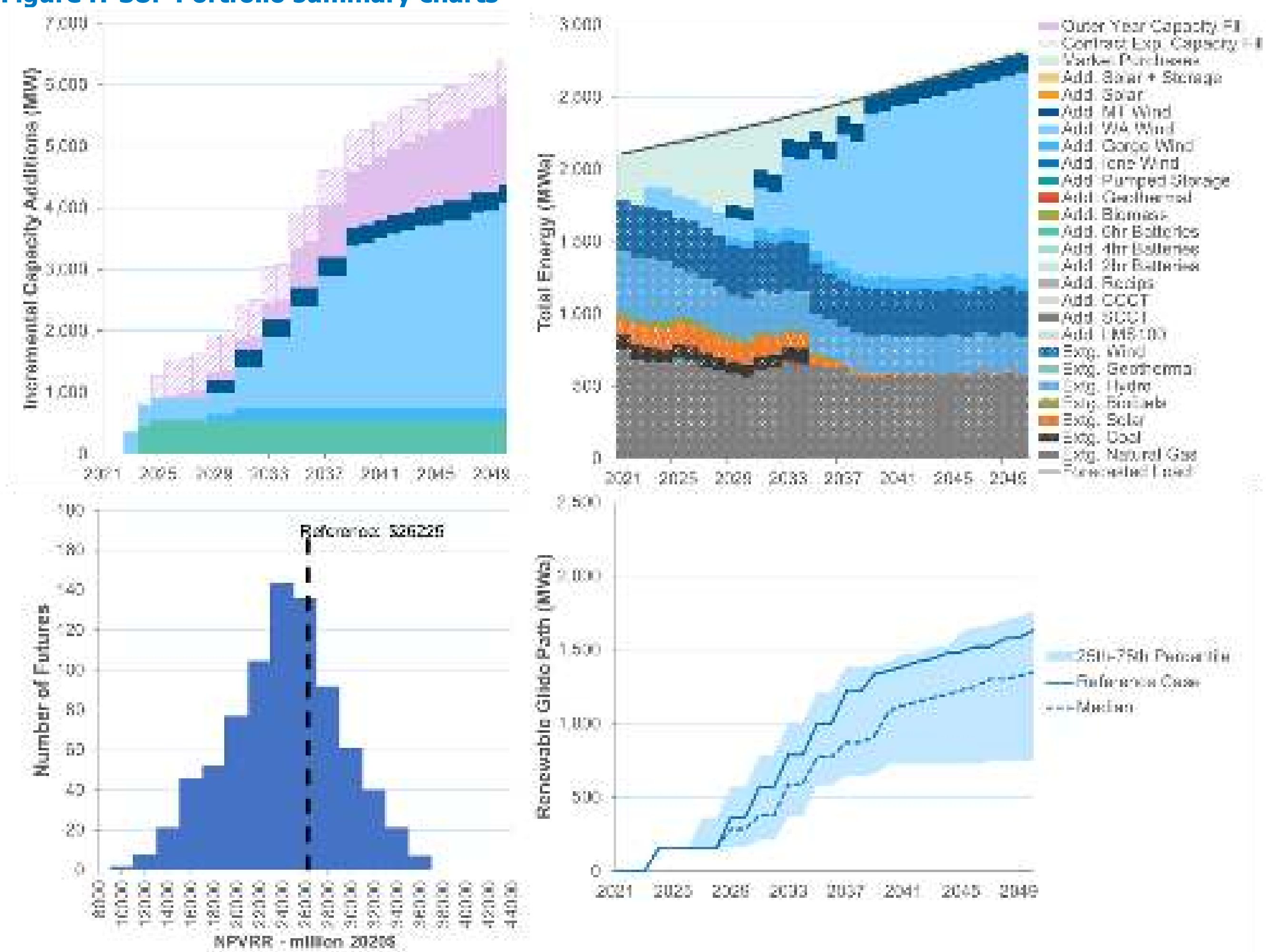
Portfolio 38: Washington Wind

This portfolio is constrained to add 150 MWa of Washington wind by 2025 and to meet all remaining capacity needs through 2025 with 6-hour batteries. ROSE-E selected 441 MW and 109 MW of 6-hour batteries in 2024 and 2025.

Table H-39: Portfolio summary

Portfolio Name	WA Wind
Portfolio Category	Renewable Resource
Portfolio Run Objective Function	Min NPVRR
Portfolio NPVRR Year	2050
Unit Sizes Enforced	No
Required Resource Additions	150 MWa WA wind by 2025
Resource Limitations	No thermal, only 6-hour batteries allowed until 2026
Future Weighting	Equal
Maximum NPVRR	-

Figure H-38: Portfolio summary charts



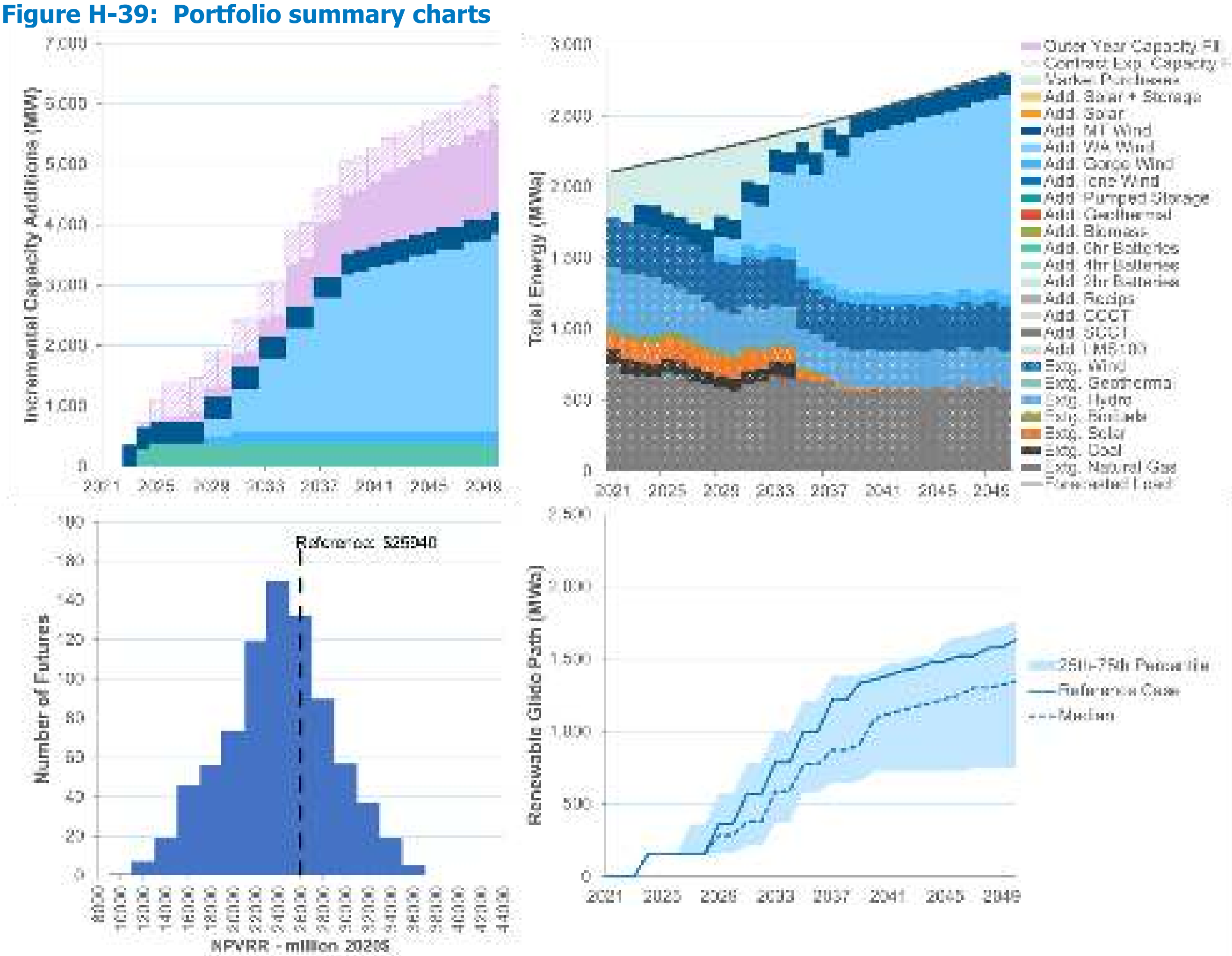
Portfolio 39: Montana Wind

This portfolio is constrained to add 150 MWa of Montana wind by 2025 and to meet all remaining capacity needs through 2025 with 6-hour batteries. ROSE-E selected 296 MW and 94 MW of 6-hour batteries in 2024 and 2025.

Table H-40: Portfolio summary

Portfolio Name	MT Wind
Portfolio Category	Renewable Resource
Portfolio Run Objective Function	Min NPVRR
Portfolio NPVRR Year	2050
Unit Sizes Enforced	No
Required Resource Additions	150 MWa MT wind by 2025
Resource Limitations	No thermal, only 6-hour batteries allowed until 2026
Future Weighting	Equal
Maximum NPVRR	-

Figure H-39: Portfolio summary charts



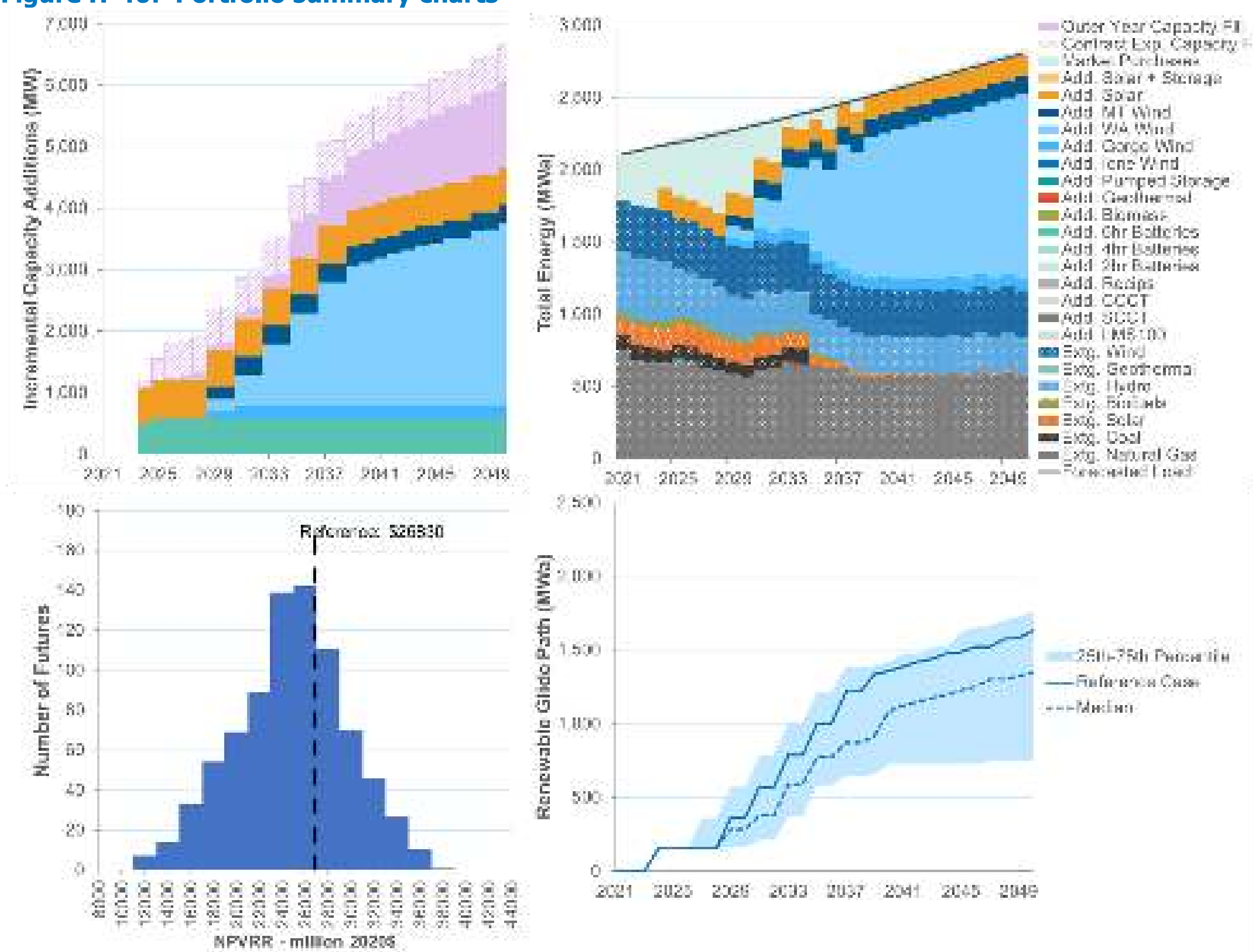
Portfolio 40: Solar

This portfolio is constrained to add 150 MWa of solar generation by 2025 and to meet all remaining capacity needs through 2025 with 6-hour batteries. ROSE-E selected 482 MW and 110 MW of 6-hour batteries in 2024 and 2025.

Table H-41: Portfolio summary

Portfolio Name	Solar
Portfolio Category	Renewable Resource
Portfolio Run Objective Function	Min NPVRR
Portfolio NPVRR Year	2050
Unit Sizes Enforced	No
Required Resource Additions	150 MWa Solar by 2025
Resource Limitations	No thermal, only 6-hour batteries allowed until 2026
Future Weighting	Equal
Maximum NPVRR	-

Figure H-40: Portfolio summary charts



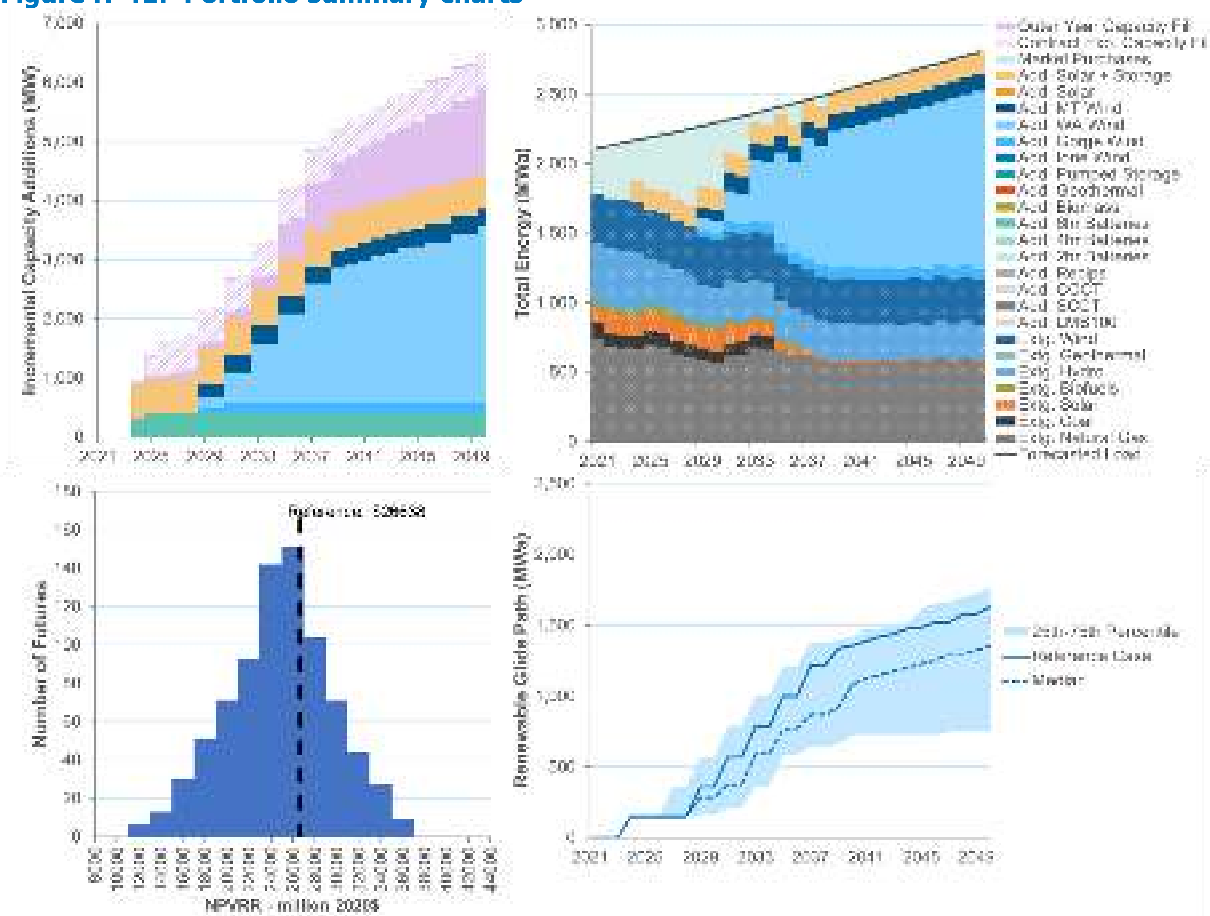
Portfolio 41: Solar Plus Storage

This portfolio is constrained to add 150 MWa of solar plus storage by 2025 and to meet all remaining capacity needs through 2025 with 6-hour batteries. Solar plus storage is modeled as a 100 MW resource paired with a 25MW 4-hour battery. The portfolio addition of solar plus storage isn't sufficient to meet capacity needs, and thus this portfolio also adds 294 and 93 MW of 6-hour batteries in 2024 and 2025.

Table H-42: Portfolio summary

Portfolio Name	Solar Plus Storage
Portfolio Category	Renewable Resource
Portfolio Run Objective Function	Min NPVRR
Portfolio NPVRR Year	2050
Unit Sizes Enforced	No
Required Resource Additions	150 MWa Solar Plus Storage by 2025
Resource Limitations	No thermal, only 6-hour batteries allowed until 2026
Future Weighting	Equal
Maximum NPVRR	-

Figure H-41: Portfolio summary charts



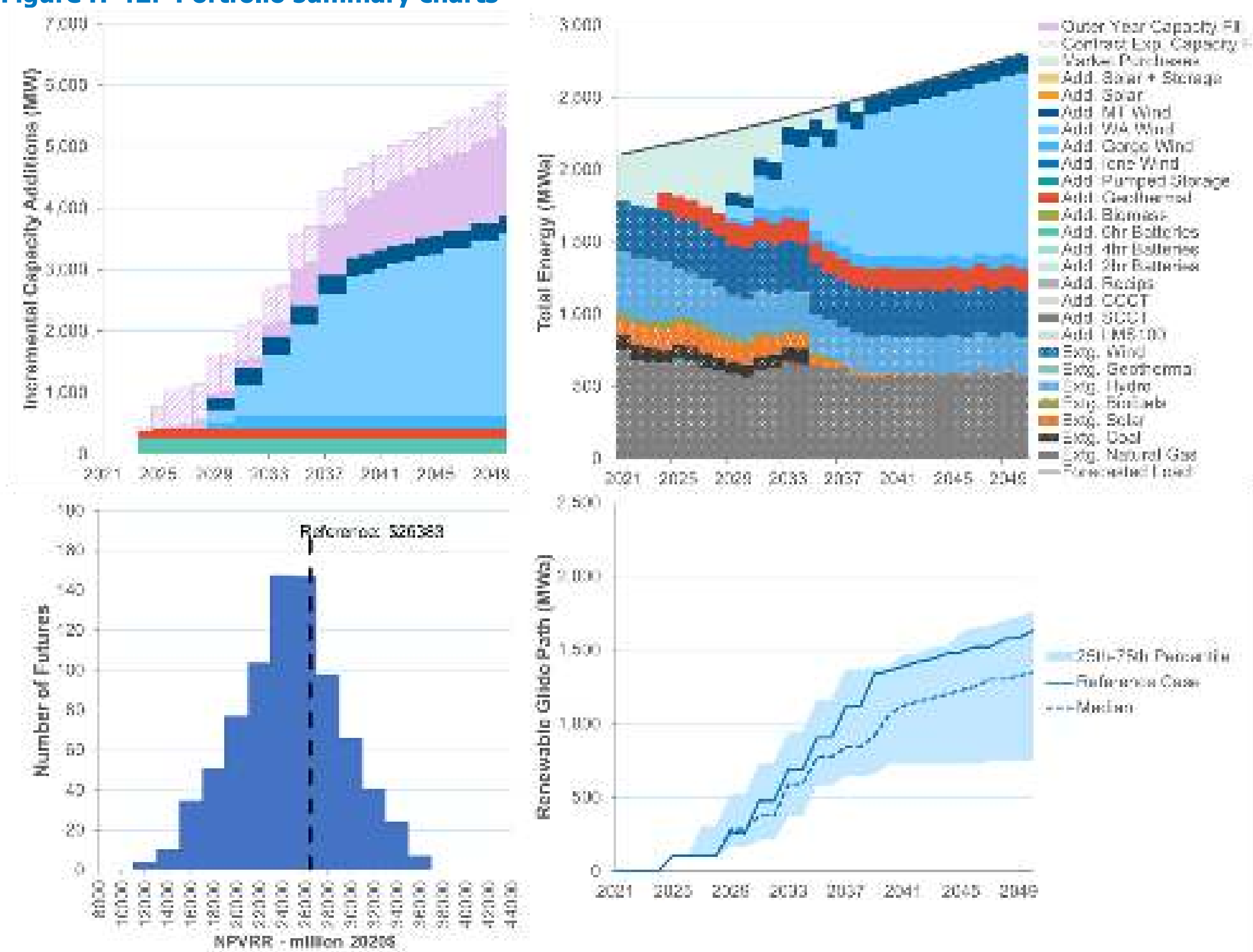
Portfolio 42: Geothermal

This portfolio is constrained to add 150 MWa of geothermal generation by 2025 and to meet all remaining capacity needs through 2025 with 6-hour batteries. ROSE-E selected 243 MW and 9 MW of 6-hour batteries in 2024 and 2025.

Table H-43: Portfolio summary

Portfolio Name	Geothermal
Portfolio Category	Renewable Resource
Portfolio Run Objective Function	Min NPVRR
Portfolio NPVRR Year	2050
Unit Sizes Enforced	Yes
Required Resource Additions	150 MWa Geothermal by 2025
Resource Limitations	No thermal, only 6-hour batteries allowed until 2026
Future Weighting	Equal
Maximum NPVRR	-

Figure H-42: Portfolio summary charts



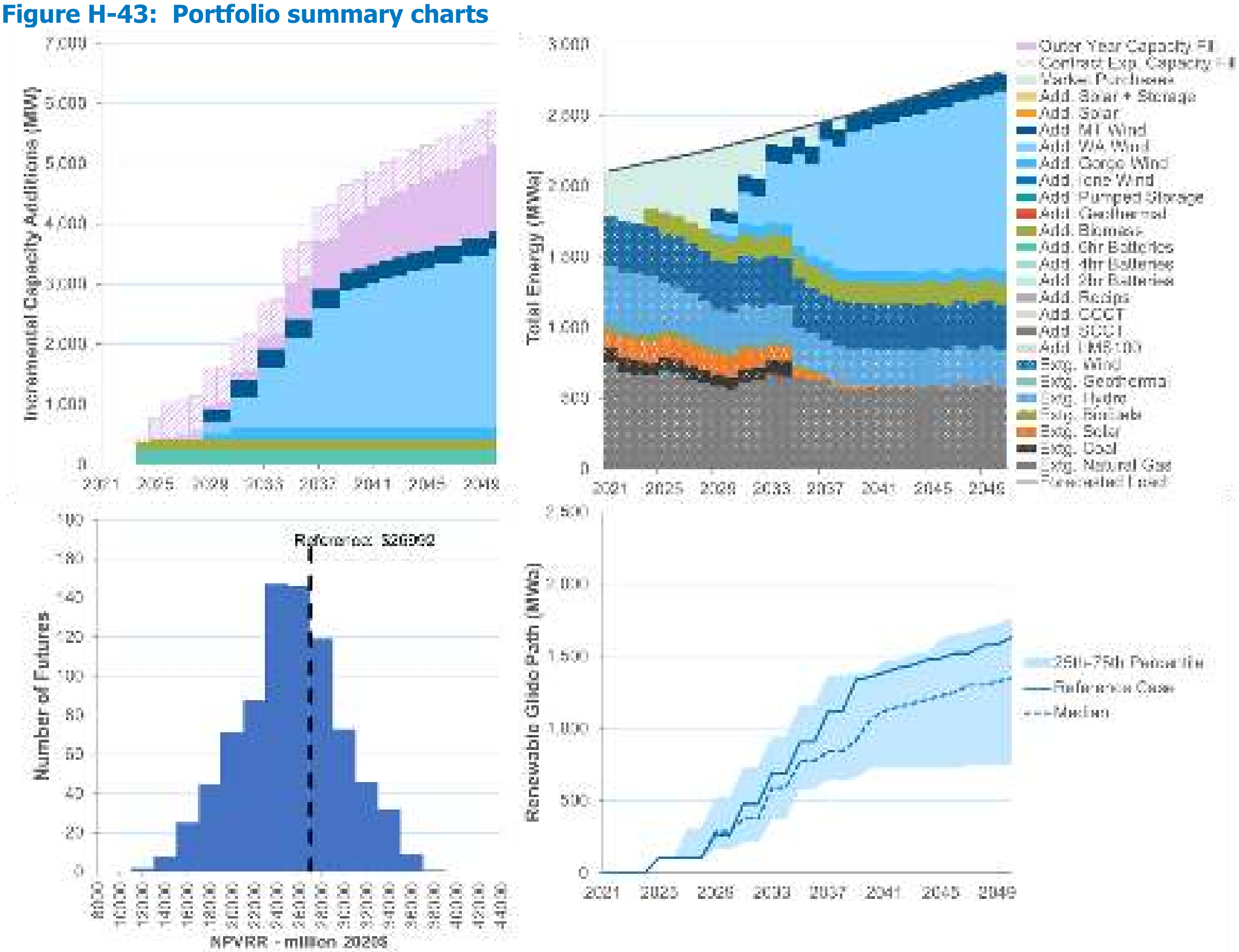
Portfolio 43: Biomass

This portfolio is constrained to add 150 MWa of biomass generation by 2025 and to meet all remaining capacity needs through 2025 with 6-hour batteries. ROSE-E selected 252 MW of 6-hour batteries in 2024.

Table H-44: Portfolio summary

Portfolio Name	Biomass
Portfolio Category	Renewable Resource
Portfolio Run Objective Function	Min NPVRR
Portfolio NPVRR Year	2050
Unit Sizes Enforced	Yes
Required Resource Additions	150 MWa Biomass by 2025
Resource Limitations	No thermal, only 6-hour batteries allowed until 2026
Future Weighting	Equal
Maximum NPVRR	-

Figure H-43: Portfolio summary charts



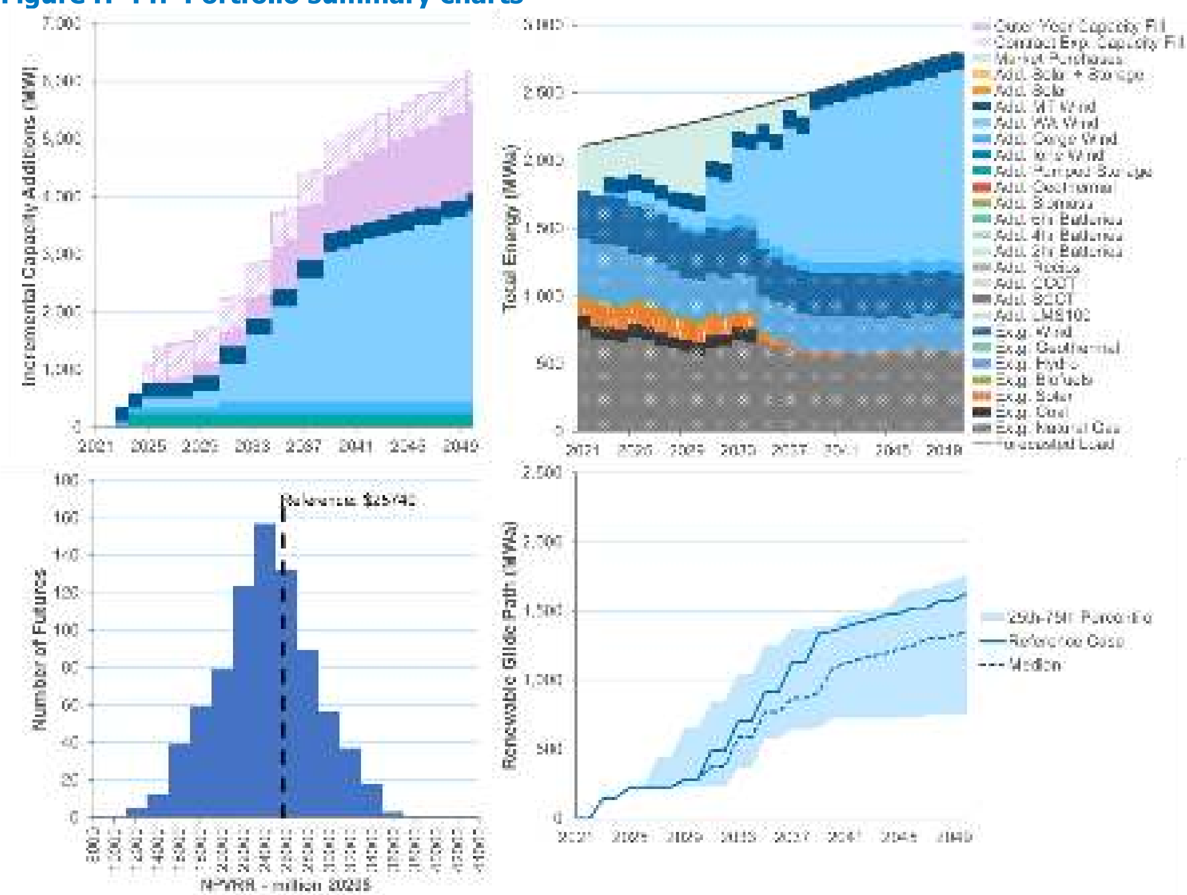
Portfolio 44: Mixed Full Clean

This portfolio allows up to 150 MWa of additional renewable resources in 2023 and/or 2024, and additional renewable resource additions are also allowed in 2025 if selected by the optimization. Further, new capacity resource additions are allowed through 2025 from technologies that do not emit greenhouse gases. With these constraints, the portfolio builds approximately 150 MWa of Gorge and Montana wind in 2023, followed by 200 MW of pumped storage and 37 MW of 6-hour batteries by 2024. In 2025, a 180 MW Washington wind addition is built.

Table H-45: Portfolio summary

Portfolio Name	Mixed Full Clean
Portfolio Category	Hand Designed
Portfolio Run Objective Function	Min NPVRR
Portfolio NPVRR Year	2050
Unit Sizes Enforced	Yes
Required Resource Additions	-
Resource Limitations	No thermal
Future Weighting	Equal
Maximum NPVRR	-

Figure H-44: Portfolio summary charts



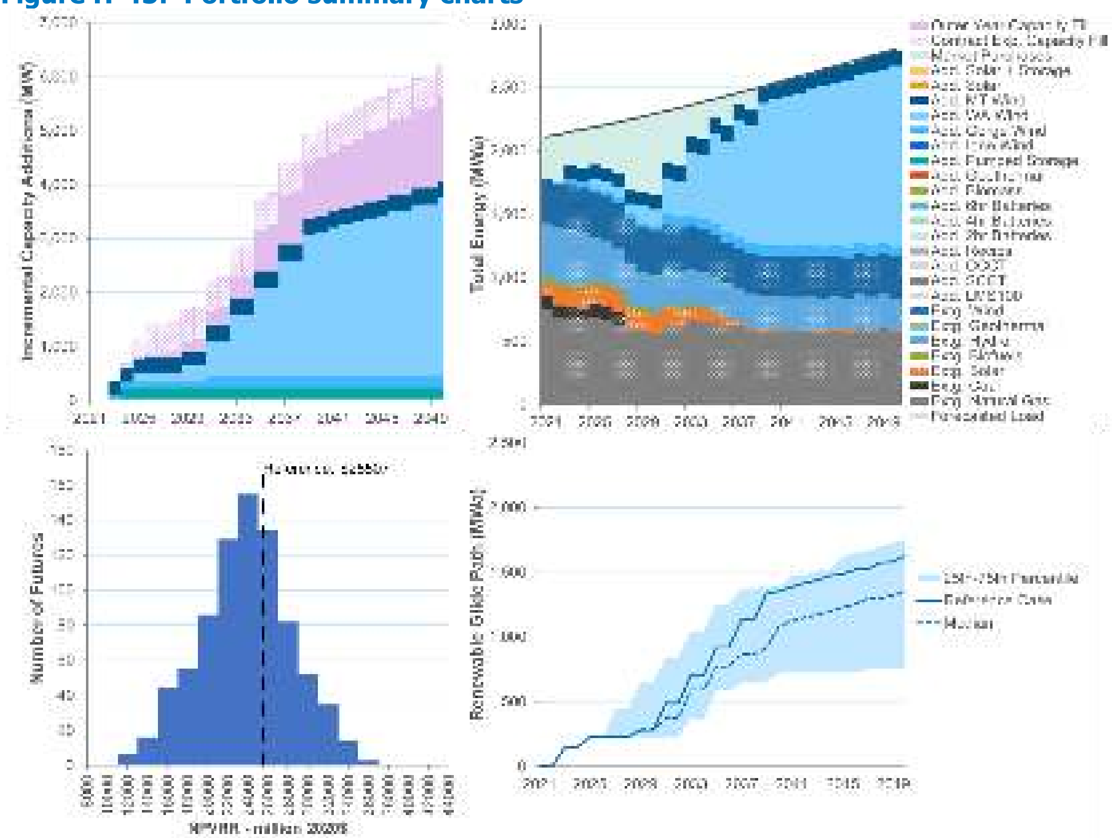
Portfolio 45: Colstrip 2027

This portfolio tests the removal of Colstrip from PGE's resource mix in 2027. The resource additions from *Portfolio 44 – Mixed Full Clean* of wind, pumped storage hydro, and 6-hour batteries are added as inputs and are the only resource additions in the action plan window in the results. In the Reference Case, significant additions of Washington wind are added in later years, though the specific values change across each possible future.

Table H-46: Portfolio summary

Portfolio Name	Colstrip 2027
Portfolio Category	Hand Designed
Portfolio Run Objective Function	Minimize NPVRR
Portfolio NPVRR Year	2050
Unit Sizes Enforced	No
Required Resource Additions	Portfolio 44 Action Plan Additions
Resource Limitations	No Thermal
Future Weighting	Equal
Maximum NPVRR	-

Figure H-45: Portfolio summary charts



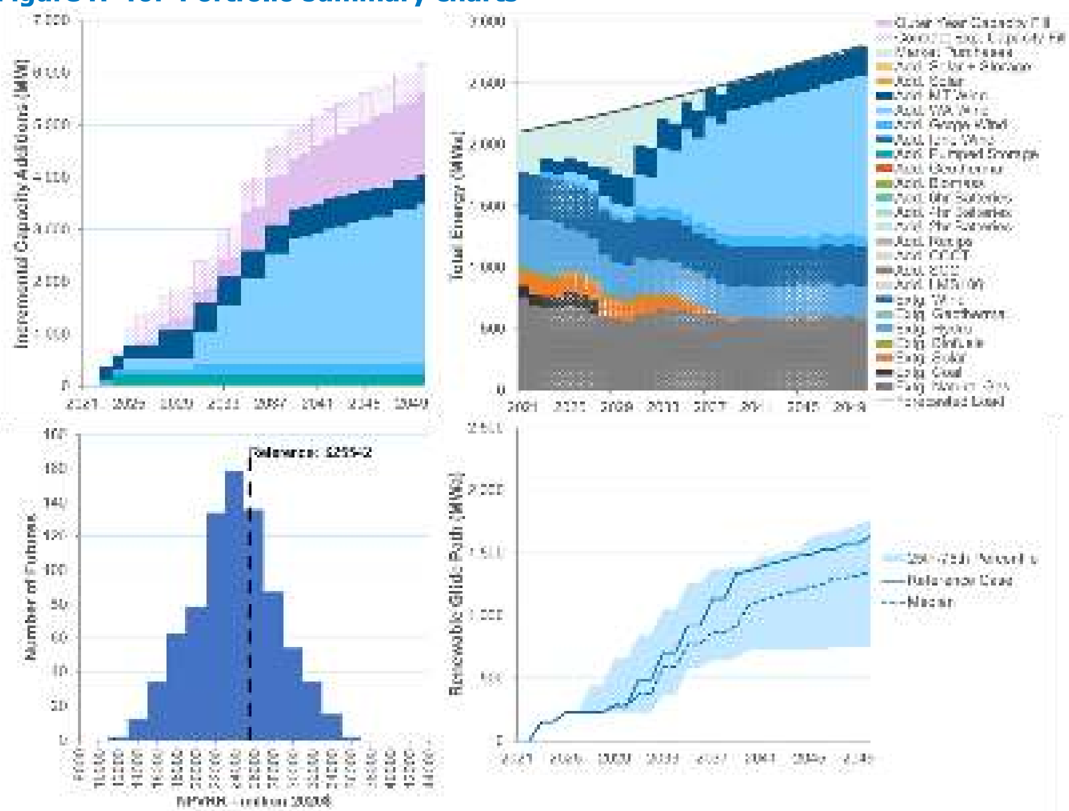
Portfolio 46: Colstrip 2027 MT Wind

This portfolio is equal to *Portfolio 45 – Colstrip 2027* in all ways except that it forces in an additional 126MWa of Montana wind in 2028. Like *Portfolio 45 – Colstrip 2027*, resource additions in the action plan window remains the same as the preferred portfolio, and most of the Reference Case energy needs are met in later years from Washington wind.

Table H-47: Portfolio summary

Portfolio Name	Colstrip 2027 Montana Wind
Portfolio Category	Hand Designed
Portfolio Run Objective Function	Minimize NPVRR
Portfolio NPVRR Year	2050
Unit Sizes Enforced	No
Required Resource Additions	Portfolio 44 action plan additions, plus 296MW Addition of MT Wind in 2028
Resource Limitations	No Thermal
Future Weighting	Equal
Maximum NPVRR	-

Figure H-46: Portfolio summary charts

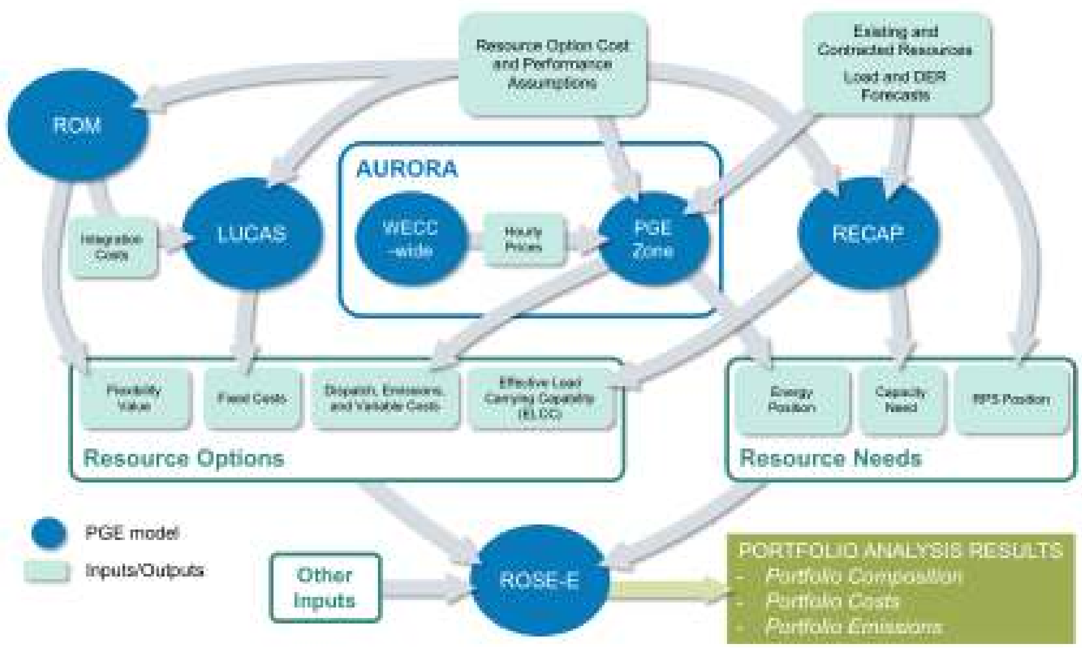


APPENDIX I. 2019 IRP Modeling Details

I.1 Introduction

In the 2019 IRP, PGE expanded upon the work of recent years to incorporate increasingly complex analysis of intermittent resources, customer-side technologies, and the treatment of uncertainty in order to provide a more robust analysis of the potential costs and risks associated with long-term resource procurement. As discussed throughout the IRP, PGE used a suite of models to prepare the analysis. This appendix provides additional details about the models and the analytical work. A comprehensive model flow diagram is shown in Figure I-1 below for reference.

FIGURE I-1: Flow diagram of 2019 IRP models



The purpose and function of each model utilized for the 2019 IRP is briefly described below, with more detailed descriptions provided in the following sections. For a discussion of the load forecast methodology, please see Appendix D.

LUCAS

LUCAS is a revenue requirement model that is used to estimate the levelized fixed costs associated with existing and new resource options. LUCAS outputs are used in ROSE-E to determine the fixed component of portfolio costs.

RECAP

RECAP is a loss-of-load-probability (LOLP)-based capacity adequacy model. Given information about future loads and resources, RECAP calculates PGE's capacity shortage in a given year. The model also produces key reliability metrics, including loss-of-load expectation (LOLE), LOLP, expected unserved energy (EUE), and the TailVar90 of lost load. RECAP also provides LOLE month-hour heatmaps and allows for the determination of the effective load carrying capability (ELCC) of resources. Capacity need and capacity contribution values from RECAP are used in ROSE-E's portfolio construction. A more detailed description of RECAP and its use in the IRP is provided in Section I.3.

Aurora

Aurora is a production cost model developed by Energy Exemplar®. It dispatches resources to meet load and produces corresponding electricity prices. PGE utilizes Aurora[207] for two processes: simulation of market prices based on the dispatch of resources across the entire WECC (WECC-wide run), and simulation of the dispatch of PGE's resources operating within the market (PGE Zone run). Outputs from Aurora are used in ROSE-E for portfolio construction and form the variable cost component of total portfolio costs. A description of how PGE utilized this software for the 2019 IRP is provided in Section I.4.

ROM

ROM is a production cost model that simulates the dispatch of PGE resources to meet PGE loads and to interact with wholesale energy markets. Unlike Aurora, ROM incorporates a more granular treatment of PGE resource performance, and captures phenomena related to renewable integration and resource flexibility through multi-stage optimal unit commitment and dispatch with imperfect forecast information, sub-hourly timesteps, and operating reserves. In past IRPs, ROM has been used to calculate variable energy resource (VER) integration costs and energy storage value. In the 2019 IRP, ROM is also used to investigate flexibility adequacy and resource flexibility value. Section I.5 describes the technical details of all three studies.

ROSE-E

ROSE-E is an optimal capacity expansion model that generates resource portfolios to meet a specified objective, such as minimizing expected costs or emissions. ROSE-E can be used to create optimized portfolios or to automate the process of generating portfolios with specific resource additions (i.e., "hand-designed" portfolios). For each portfolio, ROSE-E also calculates the total portfolio costs and other scoring metrics. See Section I.6 for a detailed description.

I.2 LUCAS – Levelized Fixed Cost Revenue Requirement Tool

The Levelized Utility Cost Aggregator System (LUCAS) is a tool used to calculate revenue requirements for the fixed costs of new supply-side resources and PGE-owned resources. LUCAS is an Excel-based model that uses VBA (Visual Basic for Applications).

Major inputs to LUCAS include:

- **Financial assumptions.** PGE's cost of capital, required return, long-term inflation, tax rates (federal, state, and property), federal investment tax credit, and the Modified Accelerated Cost Recovery System (MACRS) schedule.

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[207] Energy Exemplar® posts a description of its software here: https://energyexemplar.com/products/aurora-electric-modeling-forecasting-software/. In this IRP, PGE adopted Aurora version 13.0.1062.0.

- **PGE-owned resources.** PGE's book and tax depreciation, economic life, deferred tax, fixed O&M, scheduled capital additions, and fixed gas transportation costs.
- **Supply-side resources.** The HDR supply-side resource reports (External Study D) provide overnight capital costs, fixed O&M, project life, decommissioning costs, and plant operating parameters. As applicable, LUCAS captures fixed costs for gas transportation and wheeling. Capital cost trajectories are also included based on information from HDR and PGE's experience curve analysis.

Additionally, for the 2019 IRP, the following items associated with intermittent resources are accounted for in the fixed cost calculations in LUCAS, not in the variable costs from Aurora: integration costs, royalty payments, and federal production tax credits. This treatment is appropriate because these resources have a fixed annual capacity factor, and, as a result, these costs can be treated as if they were fixed for modeling purposes.

For a given resource, LUCAS calculates the total fixed costs for each year, the net present value of those costs across the life of the project, and the real-levelized cost. Through the VBA code, LUCAS creates output tables of real-levelized fixed costs by commercial operation date (COD) and capital cost trajectory, which are used by ROSE-E to determine the fixed component of portfolio costs and to evaluate resource economics.

I.2.1 Long-term Financial Assumptions

As required by Guideline 1a of Order No. 07-002, PGE's estimated after-tax marginal weighted average cost of capital of 6.54 percent serves as a proxy for the long-term cost of capital to discount future resource costs. PGE bases this estimate on information available as of Q2 2018. Table I-1 contains other relevant financial assumptions.

TABLE I-1: 2019 IRP long-term financial assumptions

Component	Percent
Composite Income Tax Rate	27.35%
Incremental Cost of Long-term Debt*	4.94%
Long-term Debt Share of Capital Structure	50.00%
Common Equity Return	9.50%
Common Equity Share of Capital Structure	50.00%
Weighted Cost of Capital	7.22%
Weighted After-Tax Cost of Capital	6.54%
Long-Term General Inflation	2.05%

*The incremental cost of long-term debt is based on an average of three-year forward 30-year borrowing costs (i.e., the cost of 30-year debt in 2018, 2019, and 2020).

I.2.2 Technology Cost Trajectories

The low and high capital cost trajectories for wind, solar, geothermal, and battery storage resources were calculated from the low and high capital costs for the respective resources with a 2018 notice to proceed date provided in HDR's reports and PGE's experience curve analysis. Important factors in the experience curve analysis are the cumulative capacity forecasts and the learning rates (the fractional cost reduction per doubling of cumulative capacity). While the cumulative capacity is estimated through forecasting techniques, researchers estimate the learning rate using historical installed power generation capacity or energy generated as the independent variable and capital cost as the dependent variable.[208]

Note that the reference cost trajectories for solar, wind, and battery storage technologies are from the HDR study. HDR's capital cost trends were developed using data from the EIA's 2017 Annual Energy Outlook National Energy Modeling System (NEMS). For geothermal technology, the reference cost trajectory is based on the reference overnight capital cost from the HDR study for a 2018 notice to proceed and PGE's experience curve analysis for the rest of the IRP planning horizon.

Table I-2 and Table I-3 provide a summary of the inputs to the experience curve analysis for solar, wind, battery, and geothermal technologies.

For pumped storage, biomass, and gas resources, the technology cost trajectories were calculated based on the HDR 2018 notice to proceed values with the high and low trajectories declining at the same rate as the reference values provided by HDR.[209] As discussed in Section 3.3, the low- and high-cost trajectories for these resources and geothermal were considered in the resource economics analysis in Chapter 6, but were not considered in the Technology Cost Futures evaluated in portfolio analysis.

TABLE I-2: Experience curve analysis inputs for solar and wind

	Solar		Wind	
Scenario	**Low**	**High**	**Low**	**High**
Learning Rate	28%	1%	20%	1%
Learning Rate Source	BloombergNEF*	Assumptions to the EIA Annual Energy Outlook 2018 (LR3)	Assumptions to the EIA Annual Energy Outlook 2018 (LR1)	Assumptions to the EIA Annual Energy Outlook 2018 (LR3)
Cumulative Capacity Forecast Source	BloombergNEF New Energy Outlook 2018 (Global)	EIA Annual Energy Outlook 2018 (Reference)	BloombergNEF New Energy Outlook 2018 (Global)	EIA Annual Energy Outlook 2018 (Reference)

*BloombergNEF, *Solar's 28% Experience Curve Is Steeper Than Expected*, 2017.

[208] Bloomberg New Energy Finance and "Improved Experience Curve Indicates Large Future Cost Reductions for Wind Power," Williams & Hittinger, Rochester Institute of Technology, 2015.

[209] For simplicity, the trajectories for all gas resources were modeled based on the SCCT.

TABLE I-3: Experience curve analysis inputs for batteries and geothermal

	Battery Storage		Geothermal		
Scenario	**Low**	**High**	**Low**	**Reference**	**High**
Learning Rate	28%	3%	20%	10%	1%
Learning Rate Source	Assumptions to the EIA Annual Energy Outlook 2018 (LR1)	Assumptions to the EIA Annual Energy Outlook 2018 (LR3) + 2%	Assumptions to the EIA Annual Energy Outlook 2018 (Minimum) + 10%	Assumptions to the EIA Annual Energy Outlook 2018 (Minimum)	Assumptions to the EIA Annual Energy Outlook 2018 (LR3)
Cumulative Capacity Forecast Source	BloombergNEF New Energy Outlook 2018 (Global)	BloombergNEF New Energy Outlook 2018 (Global)	EIA Annual Energy Outlook 2018 (Reference)	EIA Annual Energy Outlook 2018 (Reference)	BloombergNEF New Energy Outlook 2018 (Global)

I.3 RECAP Model

The Renewable Energy Capacity Planning model (RECAP) is a comprehensive loss-of-load probability (LOLP) model developed by Energy + Environmental Economics (E3). The model utilizes Python code with an Excel interface, and is available for download from E3's website.[210] The model calculates the LOLP for each month, day-type,[211] and hour of a test year. Additionally, RECAP calculates the capacity needed to achieve a desired reliability target and the marginal capacity contributions for incremental resources.

PGE first adopted RECAP in the 2016 IRP to provide an internally consistent methodology for assessing both capacity adequacy and capacity contribution.

I.3.1 Inputs

Reliability Target

RECAP requires an annual reliability target and a definition of adequacy. PGE defines capacity adequacy as sufficient resources to meet the hourly load plus required operating reserves (spinning and non-spinning). The reliability target selected is a loss-of-load expectation (LOLE) of no more than 2.4 hours per year, or one day in ten years (a common industry standard). The model expresses capacity need as the quantity of conventional units needed to achieve the annual reliability target. In this study, the conventional units are defined as 100-MW units with five percent forced outage rates (FOR).

210 https://www.ethree.com/tools/recap-renewable-energy-capacity-planning-model/

211 Weekday vs. weekend.

Load

PGE worked with E3 using extensive load and weather data to capture hourly load behavior under a wide variety of weather conditions for the 2016 IRP (from 1980 through 2014). For the 2019 IRP, the dataset was extended to include information from 2015-2017 and the load shapes were scaled to the top-down load forecast. RECAP creates load "bins" for each month, day-type, and hour of the test year. The bins ensure that RECAP accounts for differences in wind and solar distributions across distinct load regimes. For example, wind and solar availability may follow a different distribution under high load conditions than under low load conditions. In the 2019 IRP, RECAP was updated to also capture the low and high top-down load forecasts.

As discussed in Section 4.1.2, the Energy Trust's cost-effective deployable energy efficiency savings forecast is incorporated in the top-down load forecast. For the Low Need Future, RECAP captures the incremental EE savings based on month-hour shape factors calculated from the 12x24 EE Peak Gross tables provided by Energy Trust with the November 2017 long-term energy efficiency forecasts.

Distributed Energy Resources

RECAP inputs were updated to capture the low, reference, and high forecasts from the Navigant DER Study (incremental to the embedded values in the top-down load forecast). The annual and seasonal forecasts were combined with shape factor profiles in RECAP, as summarized below. In some cases, simplifications were needed due to limited information, RECAP limitations, or time constraints.

- **Distributed PV.** The profile for distributed PV generation is based on a 12x24 profile provided by Navigant.
- **Electric Vehicles.** The light-duty electric vehicle load profile is based on a 12x24 profile provided by Navigant.
- **Distributed Battery Storage.** Four separate profiles were created for distributed battery storage to account for whether or not the storage was paired with solar and whether or not the storage was dispatchable by the utility.
- **Demand Response Programs.** Navigant provided winter and summer forecasts for 23 demand response programs. For simplification, some of these programs were combined for modeling in RECAP (e.g., residential and commercial PTR). Seasonal profiles were created to reflect characteristics such as call hours, call durations, and call number limitations. In addition, for some programs, profiles captured additional energy savings or pre- and post-event heating or cooling. Two profiles were created for time-of-use to reflect an expected difference in energy savings between opt-in and opt-out programs.

Wind and Solar

The variability of wind and solar is captured by using either hourly generation profiles from historical actuals or synthetic generation calculated from historical wind and irradiance data. In order to capture correlations with load, the generation profiles need to be time-synchronous with load data. Profiles for wind and solar resources considered in portfolio analysis are based on seven years of hourly generation data provided by Viasala (for wind) and HDR (for solar).

Hydro

The Clackamas, Pelton, and Round Butte projects were modeled with the same monthly sustained maximum capacity values used in the 2016 IRP. For the Company's Mid-C resources, E3 built monthly probability distributions using PGE's monthly dependable capacities, historic hydro conditions, and Northwest Power and Conservation Council (NWPCC or the Council) data relating hydro conditions to peaking capability. Small, run-of river projects and contracts were included with either their monthly average energy, historic generating profile, or no capacity value on a case-by-case basis.

Market Capacity

The market capacity assumptions in RECAP represent the long-term planning assumption for the quantity of capacity available under constrained conditions. For the 2019 IRP, there are low, reference, and high values by season and by on-peak and off-peak hours. The values for winter and summer on-peak hours are based on the regional capacity study prepared for PGE by E3, as discussed in Section 2.4.2.1. E3's study is provided in External Study E. For the spring and fall on-peak hours, the values are based the 2016 IRP assumption of 200 MW (or, if larger, the E3 assumption for summer on-peak). For all seasons, the off-peak assumption is 999 MW.

Utility Storage

Utility-scale battery and pumped hydro storage resources were evaluated in RECAP based on profiles created from an optimization of charge and discharge based on PGE's loss-of-load profile. The optimization was calculated with a program outboard of RECAP.

Additional Items

The following summarizes additional inputs or requirements:

- Thermal resources are represented in RECAP by their capacities associated with monthly average temperatures and forced outage rates.
- Dispatchable standby generation (DSG) resources are represented based on their conventional unit equivalence for the total targeted fleet capacity (existing plus recommended acquisitions). See External Study C for the DSG study.
- QF contracts reflect those executed as of December 18, 2018.
- Additional executed contracts are modeled based on their resource type and contract terms.
- Operating reserve requirements are based on WECC BAL-002 spinning and supplemental (non-spin) reserves (approximated as six percent of load).

I.3.2 Loss-of-Load Expectation and Capacity Need

From the resource input data described above, RECAP creates a resource probability distribution curve for each month, day-type, and hour. For variable resources, distinct distributions are also generated by load level within each month, day-type, and hour. The model then combines the load and resource distributions via the convolution method to create a distribution representing the probability that the load plus reserves exceeds the available resources (variable, customer side, hydro, thermal, contracts, and market capacity) in each month, day-type, or hour.

The 2019 IRP capacity adequacy assessment examined the Low and High Need Futures in addition to the Reference Case. The results of the analysis are described in Section 4.3.2 and additional sensitivities are discussed in Section 4.7.

I.3.3 Capacity Contribution

The capacity contribution or effective load carrying capacity (ELCC) of an incremental resource is the reduction in capacity need to a specific system given both the characteristics of the resource and the system (load profile and the composition of existing resources). This section describes some of the key characteristics captured in RECAP that impact ELCC values.

Technology and Location

The generation profile of a variable energy resource (VER) depends on the technology and location. The technology (such as the wind turbine type or solar photovoltaic panel type) impacts the resource’s ability to convert available fuel (wind, irradiance) to electricity. The resource location changes the profile of the availability of the fuel and the variability across multiple time frames (hourly, seasonally, annually). For highly variable resources, such as wind, multiple years of data improve the characterization of the resource.

Load Correlation

VER generation profiles included in RECAP are from historical data (either actual generation or synthetic generation based on historic wind and irradiance data) that is time-synchronous with load data. Using this information, RECAP captures positive or negative correlations with load. Load correlation provides a simplified method of capturing relationships with weather that can impact both load and generation. The correlation between wind and load can vary substantially by region and by season with some areas experiencing periods of negative correlation.

Portfolio Effects

The ELCC values of two or more complementary resources can be larger than the sum of the separate contribution values. RECAP captures this “portfolio effect” between complementary resources of all types, whether they are seasonal capacity products or variable renewables.

Declining Marginal Value

As RECAP adds more of the same type of VER, seasonal resource, or energy limited resource, each additional unit added has incrementally less capacity value. The rate of decline varies depending on the resource and system profile.

Forced Outage Rates and Unit Sizes

RECAP captures the impact of forced outage rates and unit size on ELCC values for resources such as thermal units. For example, a 200-MW combustion turbine with a three percent forced outage rate has a lower ELCC value than a similarly sized unit with a two percent forced outage rate. Similarly, a 400-MW unit with a five percent forced outage rate will have a lower ELCC value than four 100-MW units with the same forced outage rate due to the higher probability of a 400-MW outage for the single large unit than simultaneous outages across all four 100-MW units.

The results of PGE's analysis of marginal ELCC values for supply-side resources is provided in Section 6.2.3.

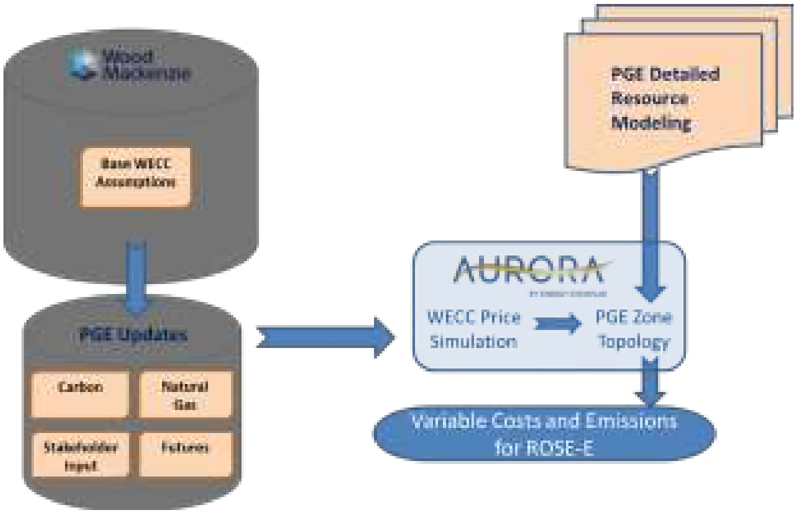
I.4 Aurora – Wholesale Electricity Price and Economic Dispatch Simulation

Aurora is a production cost model that simulates resources in an electricity system using transmission-constrained zonal optimization to produce economic dispatch. PGE used Aurora to simulate:

- Hourly long-term wholesale electricity prices under a variety of conditions based on WECC-wide simulations.
- Hourly long-term economic dispatch, variable costs, fuel costs, emissions, and market revenues of resources in PGE-Zone simulations.

As discussed in Section 3.2, PGE examined the impact on wholesale electricity prices resulting from variation in gas prices, carbon prices, the WECC-wide resource buildout, and hydro conditions. These conditions were simulated through multiple WECC-wide dispatch runs of Aurora, as discussed in Section I.4.1 below. The simulated market price forecasts for the Oregon West zone were used as inputs in the PGE-Zone simulation (assuming PGE is a price-taker[212]). Additionally, the PGE-Zone simulation contains more detailed characterization of existing PGE resources, potential new resources, and forecasted demand-side resources (consistent with the DER Study in External Study C). The PGE-Zone Model is discussed in Section I.4.2 below. Resulting outputs were used for portfolio analysis in the ROSE-E model, and in the resource economics analysis provided in Chapter 6.

FIGURE I-2: Aurora model in the 2019 IRP



212 A price-taker model assumes that PGE actions (resource additions, retirements, and dispatch) do not materially affect regional prices. This is a common simplifying assumption in financial and economic analysis and it is typically applied to compare the value of alternative resources that are small relative to the size of a system (i.e., the WECC) on an equal economic basis.

I.4.1 WECC-wide Price Forecast

To perform the WECC-wide price forecasting for the 2019 IRP, PGE relied on a database of loads, resources, fuel prices, and constraints provided by Wood Mackenzie, a research and consultancy firm. Significant demand hubs in the WECC are represented in Aurora as zones, each with its own power plants and transmission links for import and export of electricity to other zones. This representation is also called the Aurora WECC topology. Aurora simulates markets on an hourly basis through least-cost commitment and dispatch of all resources in the WECC to meet loads with zonal transmission constraints. The 2019 IRP WECC-wide simulations in Aurora used the standard zonal dispatch setting with traditional dynamic price economic commitment. Within these simulations, the shadow price on the load balance constraint in a dispatch optimization establishes the marginal price for each zone.

The WECC topology modeled by Wood Mackenzie and adopted by PGE for this IRP is shown in Figure I-3. The Oregon West zone, which is used for detailed simulation of PGE resources in the Zone model, is highlighted in the red circle.

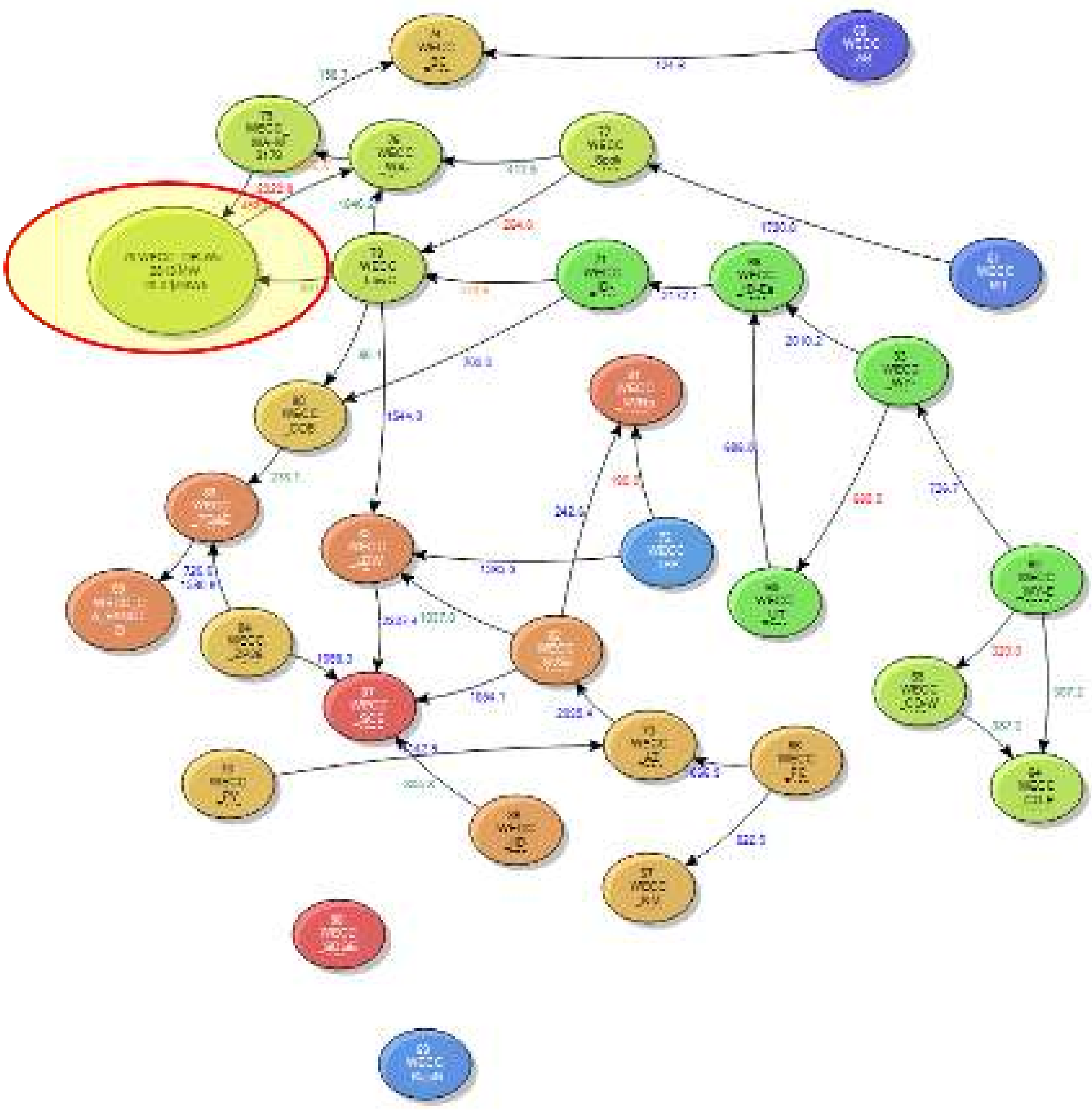
Inputs to Aurora include:

- Regional loads
- Resource parameters
- Transmission capability and wheeling rates
- Fuel prices
- Hydro capacity and generation
- Emissions rates for each resource in the WECC across the analysis horizon

The input database developed by Wood Mackenzie contains assumptions through 2040. After 2040, PGE froze the resource stack and held all economic inputs flat in real 2040 dollars. This approach differs from the 2016 IRP, which extrapolated fuel prices based on real growth rates and determined resource additions through 2050 with Aurora's resource expansion model.

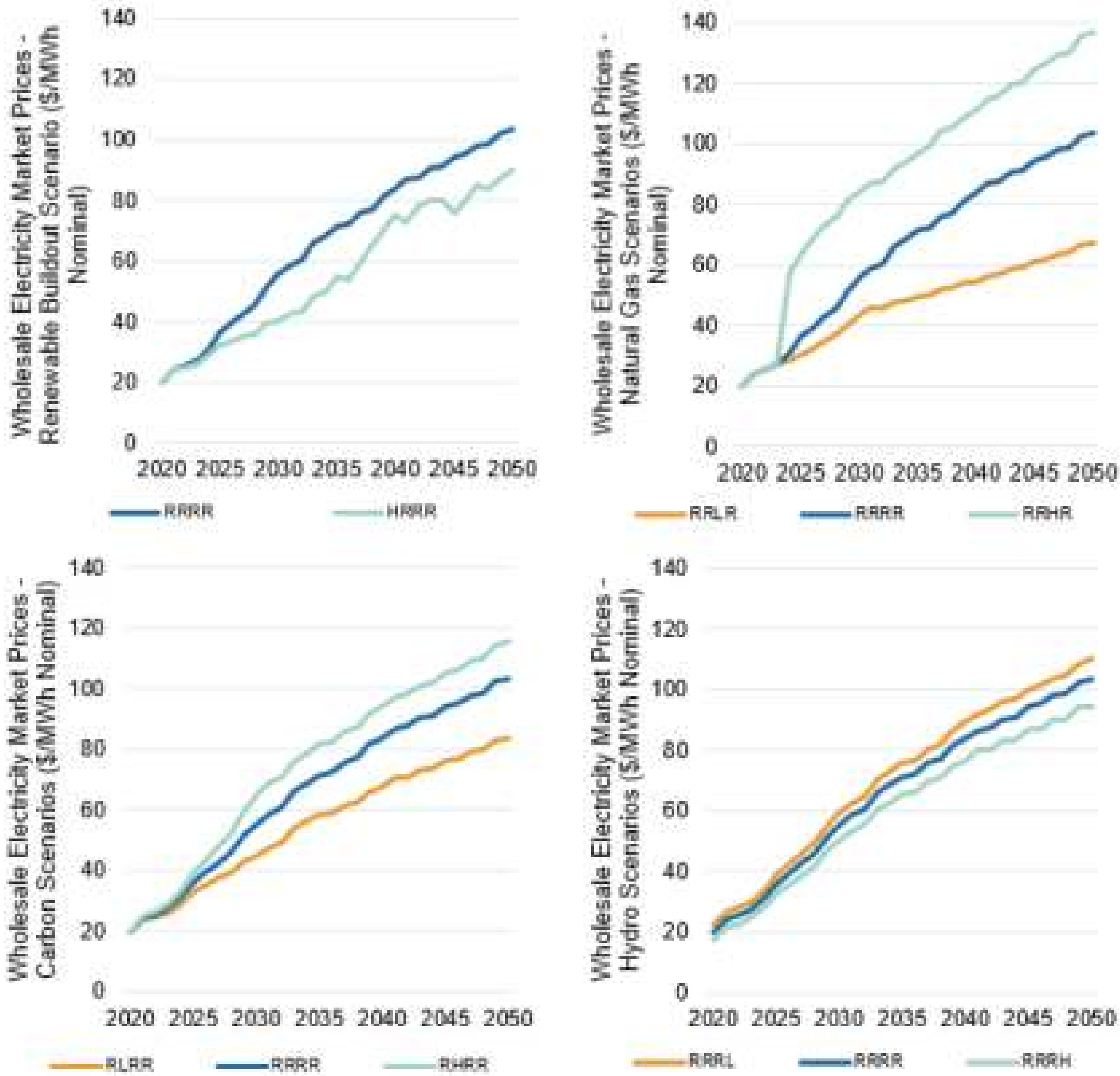
The WECC-wide Aurora model was used to create 54 pricing futures with varied inputs. Resulting hourly simulated prices for the Oregon West zone were then input to the PGE-Zone Aurora model. These prices were used to dispatch PGE portfolio resources. As discussed in Chapter 3. Futures and Uncertainties, deviations from the Reference Case attributable to the driving variables of carbon prices, natural gas prices, and hydro conditions were explored through low and high alternate-scenario forecasts. Variation in the WECC-wide resource mix was investigated through an alternate-scenario forecast that greatly expanded the buildout of renewable resources. Each market price future is labeled by the combined input forecast cases: renewable buildout, carbon price, natural gas price, and hydro condition (in that order). For example, the market price future "**RHLR**" is characterized by **R**eference renewable buildout, **H**igh carbon prices, **L**ow natural gas prices, and **R**eference hydro generation. Figure I-4 provides market price comparisons between Reference and individual variables.

FIGURE I-3: WECC topology – example of hourly price and interchange



As shown in Figure I-4, the most pronounced impact on wholesale electricity market prices is caused by the high gas trajectory, which contains a step-change increase in the early 2020s. Low prices in the wholesale electricity forecasts are mainly driven by the low carbon pricing scenario and the low gas scenario. The methodology used to develop market pricing scenario inputs is detailed for each condition in the following subsections.

FIGURE I-4: Wholesale electricity market price comparison between Reference and individual variables

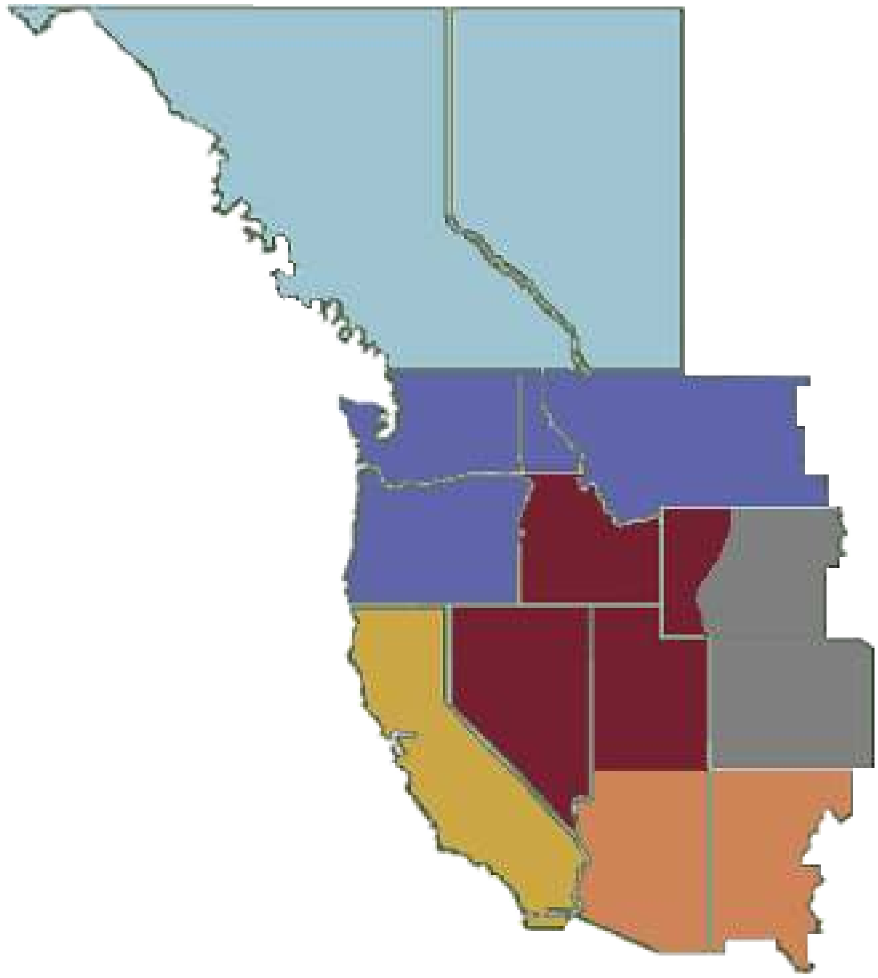


I.4.1.1 WECC-wide Renewable Buildout

As discussed in Chapter 3. Futures and Uncertainties, PGE analyzed a High Renewable WECC Future in addition to the Reference Case buildout that was specified by Wood Mackenzie. The High Renewable WECC Future approximates a scenario where renewable energy is widely deployed by adding renewable resources in each aggregate WECC region until available carbon-free generation is equal to 100 percent of load (neglecting curtailment). Figure I-5 shows the Aurora zone mapping of WECC aggregate regions, which were used to specify locational annual renewable energy additions by amount and type.

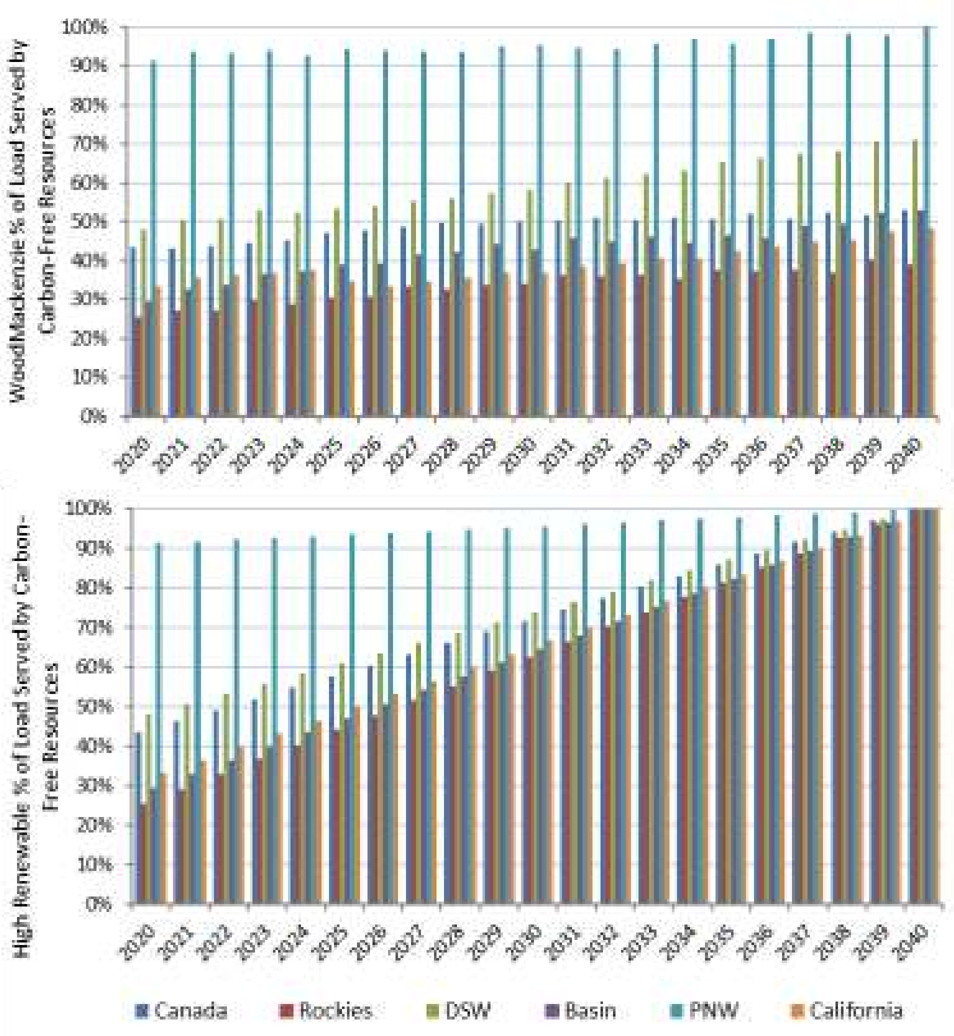
FIGURE I-5: Aurora zone assignments per aggregate WECC region and corresponding color-coded geographical mapping

WoodMac Zone	Region
WECC_Alberta	Canada
WECC_BritishColumbia	Canada
WECC_Montana	PNW
WECC_PNW_IdahoSouthwest	PNW
WECC_PNW_LowerColumbia	PNW
WECC_PNW_OregonWest	PNW
WECC_PNW_Spokane	PNW
WECC_PNW_WashingtonCentral	PNW
WECC_PNW_WashingtonWest	PNW
WECC_Colorado East	Rockies
WECC_Colorado West	Rockies
WECC_Wyoming-RMPA	Rockies
WECC_NevadaNorth	Basin
WECC_NevadaSouth	Basin
WECC_PNW_IdahoEast	Basin
WECC_Utah	Basin
WECC_Wyoming-NWPP	Basin
WECC_BajaNorth	California
WECC_CA_BANCTID	California
WECC_CA_IID	California
WECC_CA_LADWP	California
WECC_CA_PGandE_North	California
WECC_CA_PGandE_ZP26	California
WECC_CA_SCE	California
WECC_CA_SDGE	California
WECC_COB	California
WECC_IPP	California
WECC_Arizona	DSW
WECC_FourCorners	DSW
WECC_NewMexico	DSW
WECC_PaloVerde	DSW



For each aggregate region, the Wood Mackenzie wind and solar additions per year for all represented zones were summed to create regional resource ratios. These ratios were utilized to assign the mix of wind and solar per region in a linear growth trajectory from 2020-2040. For example, the renewable expansion in the region of California had a higher percentage of solar than wind, whereas the PNW region renewable expansion contained a higher percentage of wind than solar. I.4.1.1 the annual available carbon-free generation as a percentage of load by region in the Reference Case and the High Renewable WECC Future.

FIGURE I-6: Annual available carbon-free generation as a percent of load per aggregate region through 2040 in the Reference Case and High Renewable WECC Future



I.4.1.2 Carbon Pricing

Carbon pricing scenarios were designed to simulate carbon programs in Oregon and Washington beginning in 2021 that, while independent, were modeled as having the same carbon prices as California. As such, carbon pricing reflects the GHG allowance price forecasts provided by the California Energy Commission (CEC) for existing policy. PGE applied the 2017 CEC prices, which were published in January of 2018.[213] The CEC forecasts have been updated since the IRP input data was locked-in. For reference, Figure I-7 below compares the 2017 CEC pricing to the preliminary 2019 prices.[214]

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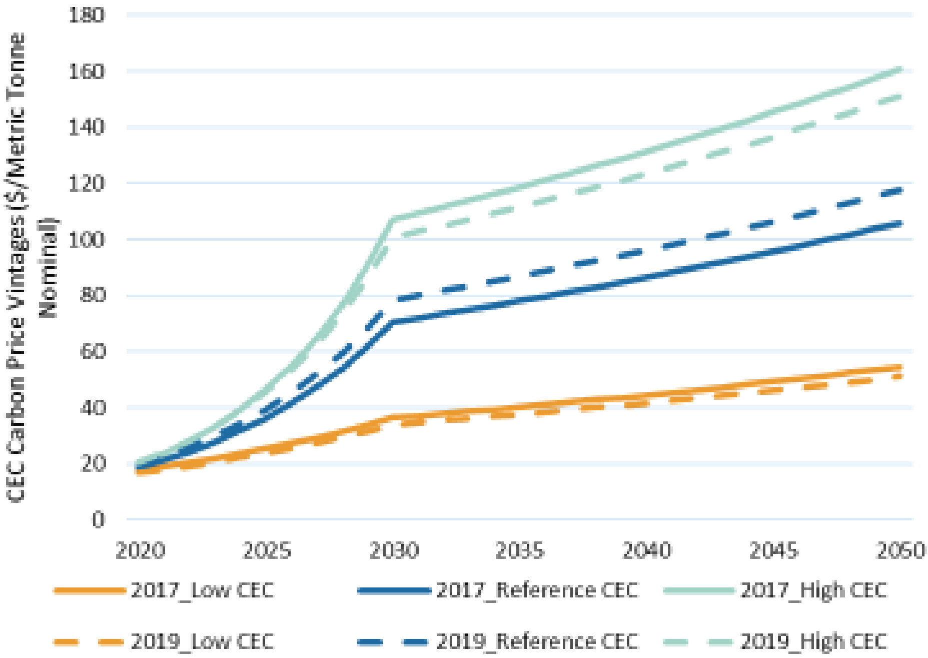
213 Revised 2017 IEPR GHG Price Projections, published 1/16/2018. http://www.arb.ca.gov/cc/capandtrade/auction/auction.htm. 2017 IEPR Deflator Series, using Moody's Analytics, June 2017 GDP Deflator and CPI Forecast.

214 Preliminary 2019 IEPR GHG Price Projections, published 2/5/2019. Staff Report: Initial Statement of Reasons, September 4, 2018, https://www.arb.ca.gov/regact/2018/capandtrade18/ct18isor.pdf.

FIGURE I-7: CEC low, reference, and high carbon prices by forecast vintage



The updated CEC carbon prices are very similar to the 2017 vintage that was used for 2019 IRP analysis. In the updated vintage, the high scenario is slightly reduced, the reference scenario is slightly increased, and the low scenario remains nearly identical.

The Aurora configuration captures carbon constraints to electricity imports and exports between states with different carbon policies by applying a carbon hurdle rate. For modeling purposes, the carbon hurdle rate is represented as a cost adder to transmission wheeling rates between West Coast states and the rest of the WECC. PGE updated hurdle rates in zones with links to Oregon, Washington, and California to conform to the CEC projections above. This was done by extracting the existing carbon price components of wheeling charges from the Wood Mackenzie database, recalculating the carbon price wheeling rate based on CEC price forecasts, and adding the adjusted prices back into the full wheeling charges in the Wood Mackenzie database. The purpose of this adjustment was to simulate the fees that would apply to purchasing out-of-state carbon emitting power.

Carbon pricing scenarios impacted the wholesale electricity prices slightly asymmetrically, with the lower carbon price scenario exhibiting a more pronounced influence than the high carbon price scenario due to the impact of increased economic dispatch from high emitting resources in the low carbon price scenario.

I.4.1.3 Natural Gas Pricing

In order to examine the risks associated with the long-term uncertainty of natural gas prices on wholesale market prices and resource economics, PGE included three natural gas price scenarios in the 2019 IRP using a similar methodology as the 2016 IRP Update through 2040. The low, reference, and high scenarios have the same prices through 2023 based on PGE's short-term forward gas trading curves. The forecasts diverge after 2023, as described below.

For the Reference Case, the gas prices for 2025-2040 are based on the long-term Wood Mackenzie 2018 H1 gas price forecast, which was the most recently released vintage at the time of Aurora modeling for the 2019 IRP. As in prior IRPs, an interpolation year (in this case 2024) is used to blend between the short-term forward curve and the long-term forecast.

PGE applied an altered methodology from the 2016 IRP and IRP Update for the gas prices beyond 2040, which is the end year of the 2018 H1 Wood Mackenzie forecast. In the 2016 IRP and IRP Update, PGE extended the last year of the forecast (2035) by assuming real growth based on outer-year trends. In this IRP, PGE froze prices at the 2040 real value to provide a more conservative estimate of fuel prices in the outer years.

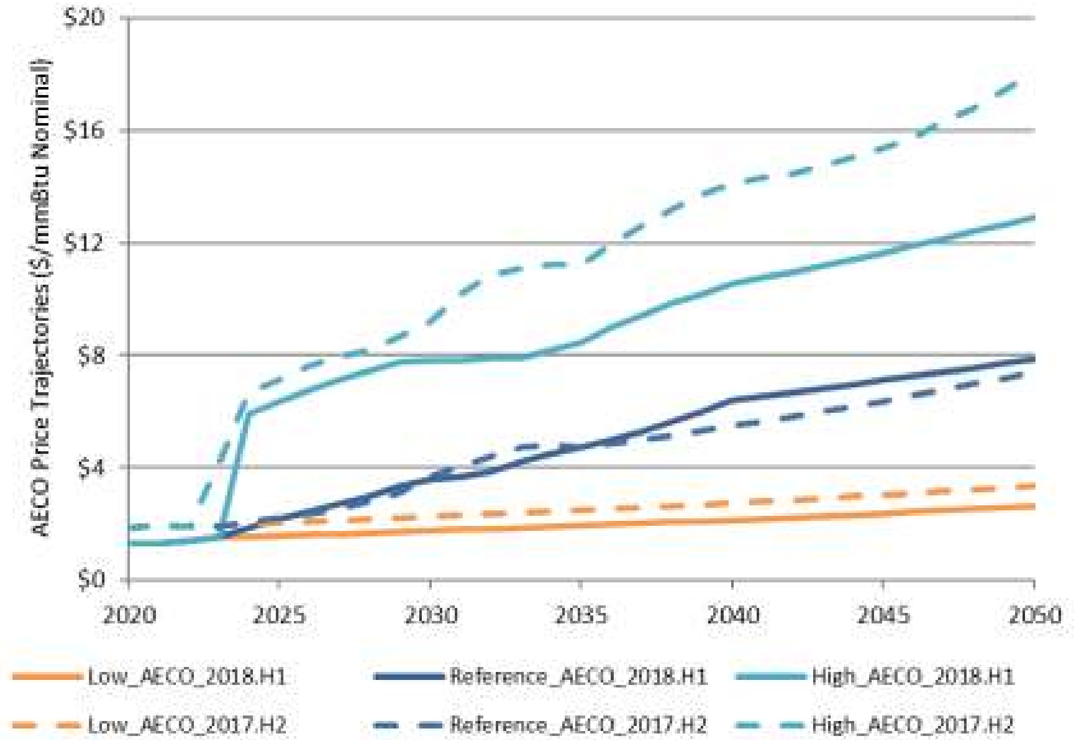
To estimate a low gas price forecast, PGE froze the price of the last year of the gas forward curve (2023) for all hubs and extended this value in real dollars to 2050. The low gas price future assumes prolonged price depression which could occur due to circumstances such as technology enhancements, continued limited export capability, or high levels of oil-associated gas production.

The high gas price forecast was compiled using the EIA Low Oil and Gas Resource Technology forecast from the 2018 Annual Energy Outlook (AEO).[215] The AEO input scenario is applied to the forecast in the year 2024 and represents the most extreme set of unfavorable natural gas price circumstances estimated by the Agency. Because the high gas transition is made without any interpolation between the PGE forward curve and the EIA gas price trajectory, a step-change in output prices is created by the transition between sources, as shown in Figure I-8. As with the Reference and low scenarios, there is no real growth in the high scenario after 2040.

Figure I-8 shows a comparison of low, reference, and high AECO gas prices from the 2016 IRP Update (2017.H2, the dashed lines) and the 2019 IRP (2018.H1, the solid lines).

[215] See Annual Energy Outlook 2018 Tables on https://www.eia.gov/outlooks/aeo/data/browser/.

FIGURE I-8: Natural gas price scenarios from the 2016 IRP Update (2017.H2) and the 2019 IRP (2018.H1)



I.4.1.4 Hydro Conditions

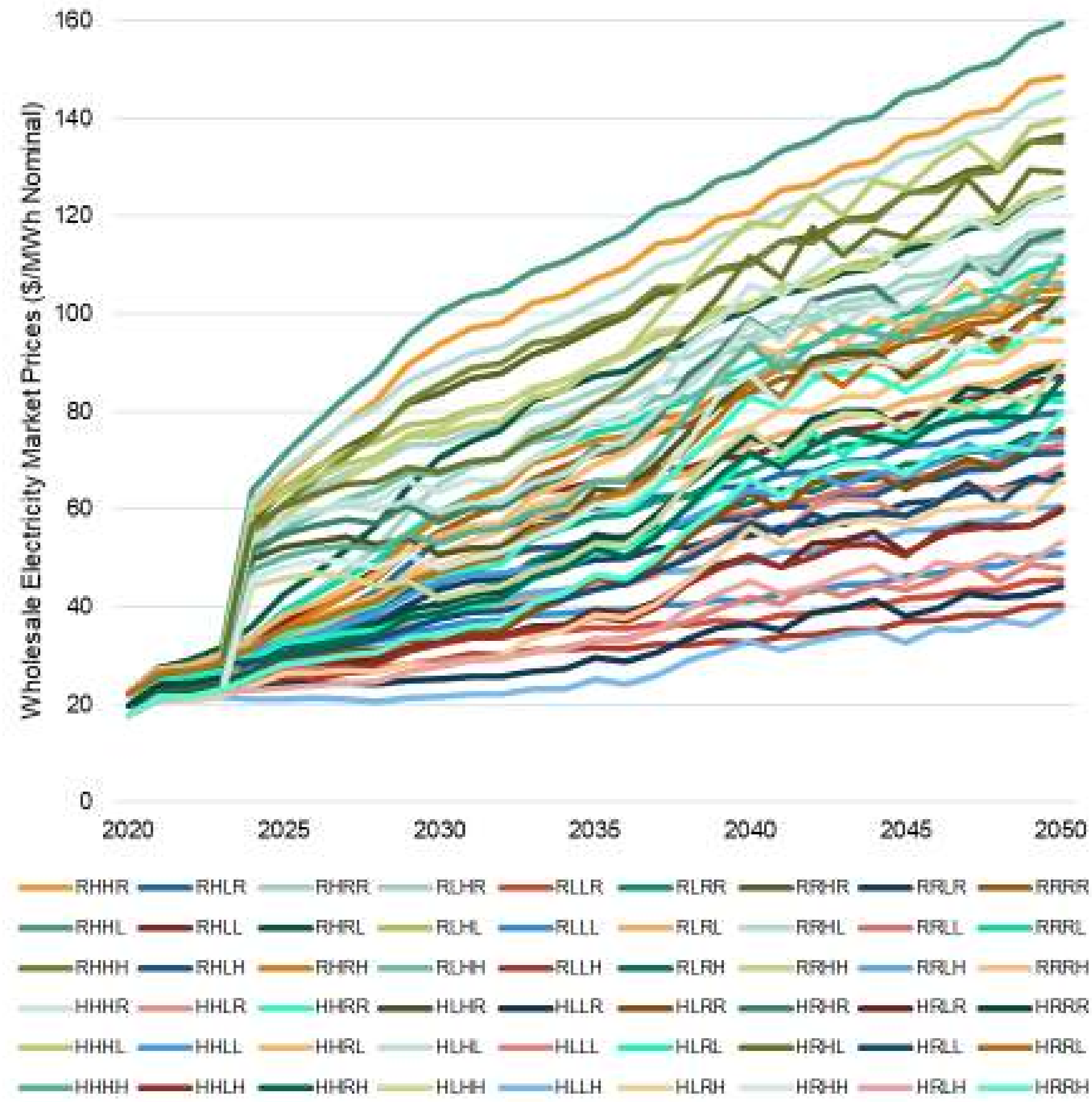
In addition to Reference Case hydro conditions, PGE examined the wholesale price risk from low and high hydro conditions in the Pacific Northwest based on the same methodology as the acknowledged 2016 IRP Update. Reference Case hydro conditions in the Wood Mackenzie database consist of 10-year average hydro generation from the 2001-2012 EIA-923[216] historical monthly data for all WECC areas. For the low and high hydro conditions, the annual hydro generation in the Pacific Northwest was decreased and increased by 10 percent from the Reference Case, or approximately one standard deviation below and above the Reference Case. As in the 2016 IRP Update, seasonal shaping was unchanged.

I.4.1.5 Combined WECC Price Futures for Oregon West

The output of the WECC-wide Aurora model with driving variable analysis was hourly wholesale market prices from 2020 through 2050 across the 54 futures. Figure I-9 shows the annual average prices corresponding to all futures for the Oregon West zone within the WECC-wide Aurora model. These hourly price forecasts were input into the PGE-Zone Model to provide a market reference for dispatching PGE resources, as detailed in Section I.4.2 PGE-Zone Model.

[216] The U.S. Energy Information Administration (EIA) form EIA-923 is published here: https://www.eia.gov/electricity/data/eia923/.

FIGURE I-9: Annual average wholesale electricity price futures for the Oregon West zone



I.4.2 PGE-Zone Model

In contrast to the WECC-wide Aurora pricing simulation described in the prior section, the PGE-Zone Model (PZM) focuses on the PGE-Zone and loads and resources within it. The PZM simulates the economic dispatch of existing PGE resources and determines the net market purchases associated with the Baseline Portfolio[217] under each Market Price Future described in Section 3.2.5 and the three Low, Reference, and High Need Futures introduced in Section 3.1. At an hourly timescale, Aurora economically dispatches PGE generation resources, contracts, and candidate new resources using input electricity prices consistent with each Price Future. When economically dispatched, resources will generate when resource dispatch cost is lower than the electricity market price and will not generate when market purchases are more economical. Existing resource variable costs and

[217] The Baseline Portfolio includes all existing and contracted resources as well as DERs. It does not include the supply-side resource options considered in portfolio construction.

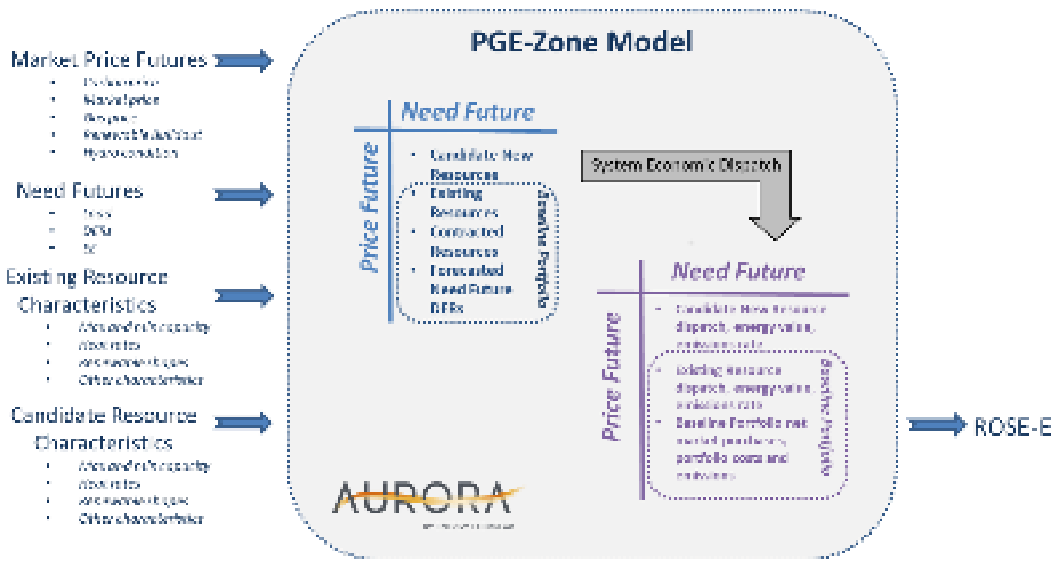
operating characteristics are primarily aligned with the 2019 General Rate Case MONET model. Candidate new resource variable cost and operating characteristics are consistent with the HDR Supply Side Options Study found in External Study D. All resources, including storage resources, have perfect foresight of future electricity prices.

Pricing inputs to the PZM are consistent with outputs from the WECC-wide Aurora pricing simulation. These include forecasted trajectories for carbon prices, gas commodity prices, hydro conditions, and corresponding electricity prices. Consistent with the WECC-wide Aurora pricing simulation, the PZM models through the year 2050.

Outputs from the PZM are provided as inputs to ROSE-E under all Market Price Futures and across all years. Baseline Portfolio outputs include total annual variable costs and annual net market purchases. For candidate resources, the PZM provides resource dispatch, energy value, variable costs, and emission rates. The PZM also provides dispatch, variable cost, energy value, and emissions rates for existing thermal resources, which are utilized to estimate thermal curtailments in the carbon-constrained future.

A diagram summarizing the flow of inputs to and outputs from the PZM is provided in Figure I-10.

FIGURE I-10: PGE-Zone Model in Aurora for the 2019 IRP



I.5 Resource Optimization Model (ROM)

PGE first developed the Resource Optimization Model (ROM) in 2007 to provide a rigorous assessment of the integration cost of variable energy resources. Subsequently, ROM has been utilized in multiple IRPs and analyses. With the contributions of multiple stakeholders and experts in Technical Review Committees (TRC), each subsequent version of ROM has built on previous model versions. ROM, with the inclusion of improvements and additions, was most recently reviewed through an external TRC and public stakeholder meetings in the 2016 IRP.

Consistent with earlier versions, ROM is a multi-stage dispatch optimization model that employs mixed integer programming implemented using the General Algebraic Modeling System (GAMS)[218] programming and a Gurobi Optimizer.[219] It is a constrained optimization model with an objective function of minimizing total system operating costs given operational constraints. Operational constraints include generation plant dispatch requirements (minimum plant up-times, minimum plant generation requirements, etc.), fuel constraints that limit natural gas plant fuel usage to Day-Ahead nomination levels plus or minus drafting and packing pipeline limits, market availability, and system requirements (spinning and non-spinning reserves, regulation, load following, etc.). ROM allocates the system requirements to individual generators to minimize total system cost.

ROM optimizes plant dispatch and system operation for a single year; in this IRP, the year of interest is 2025. One year of analysis consists of 52 one-week modeling runs. For each one-week time period, the model is run in three stages: Day-Ahead (DA) with an hourly timestep, Hour-Ahead (HA) with 15-minute timestep, and Real-Time (RT) with 15-minute timestep. The system takes in inputs in each stage and optimizes system dispatch subject to the operational constraints relevant at that stage. Commitments made in prior stages (e.g., generator commitments) are carried forward to the next stage as constraints.

A summary of relevant input data updated for the 2019 IRP ROM case is described in Table I-4. ROM optimizes plant dispatch and system operation under average-year conditions for inputs such as load, variable energy resource output, and hydro conditions. In this IRP, PGE used ROM for the analysis of flexibility adequacy in Section 4.6, the estimation of integration costs of new variable energy resources in Section 6.1.3, and the assessment of candidate new resources' flexibility value in Section 6.2.2. All three pieces of analysis are built from the 2019 IRP ROM case. Input gas prices, market electricity prices, and carbon prices are consistent with the 2019 IRP Reference Case. Other data, including load, existing contracts, variable energy resource output, and hydro conditions are updated to forecasted average-year levels for 2025. The PGE system is modeled with access to a market in ROM; in estimating integration costs and flexibility value, the market availability is constrained to transmission limits while in the flexibility adequacy study, market availability is consistent with results from External Study E. Market Capacity Study.

[218] GAMS is a high-level modeling system for mathematical programming and optimization that PGE used to program and compile the objective function and operating constraint equations.

[219] The Gurobi Optimizer is a state-of-the-art solver used to solve the resulting constrained optimization problem.

TABLE I-4: ROM input summary

Input	Description
Load	Updated for DA/HA/RT for 2025; average year conditions
Variable energy resources	Updated for DA/HA/RT for 2025 to existing resources, RFP placeholder, and executed contracts; all with average year conditions
Reserve requirements	Updated for DA/HA/RT for 2025
Maintenance schedules	Updated for 2025
Gas prices	Updated for 2025 to Reference Case
Market electricity prices	Updated for 2025 to Reference Case
Carbon prices	Updated for 2025 to Reference Case
Existing contracts	Updated for 2025
Hydro characteristics	Updated for 2025; average year conditions
Market availability	Transmission limit for integration cost and flexibility value analysis; limited to Market Capacity Study results for flexibility adequacy assumption

I.6 ROSE-E – PGE's Portfolio Optimization Tool

ROSE-E is a capacity expansion model that identifies resource additions across potential futures and years. Constrained optimization allows the model to select the best resource expansion path that meets a specific set of goals. For example, there are many ways that PGE could meet energy, capacity, and RPS needs over time. When told to minimize long-term costs, ROSE-E will determine the least-cost manner to meet those needs. Below we describe the key input data, variables, objective functions, constraints, and output data from ROSE-E.

I.6.1 Input Data

To design portfolios that meet PGE's resource needs while evaluating tradeoffs between various resource options, ROSE-E requires the following inputs, which leverage PGE's existing models. These data are consistent across all portfolios; their consistency allows for meaningful comparisons between portfolios.

Existing Resources

To forecast PGE's future energy position, ROSE-E utilizes the economic dispatch from both existing and contracted resources from each Price Future. This information comes from the hourly dispatch simulations, which are performed in Aurora in the PZM (see Section I.4.2). Additionally, ROSE-E uses data on infinite-life and five-year REC generation from existing and contracted resources from each Need Future, which come from PGE's load and resource database.

Resource Needs

To ensure that portfolios are sufficiently reliable, ROSE-E pulls in data on the capacity required to meet a LOLE of 2.4 hours per year for each Need Future. These data come from RECAP (see Section I.3). Further, ROSE-E incorporates data related to maintaining compliance with SB 1547 RPS obligations in each Need Future.

Baseline Portfolio

ROSE-E uses information about how the portfolio would operate without any incremental resource additions beyond recommended actions for energy efficiency, distributed flexibility, and dispatchable standby generation; this is referred to as the Baseline Portfolio. Total variable costs and annual net market purchases for the Baseline Portfolio are generated by the Aurora PGE Zone simulation and factor into portfolio costs and energy-related constraints in ROSE-E.

Financial Assumptions

ROSE-E uses inflation and discount rates consistent with the rest of IRP modeling analysis. A summary of long-term financial assumptions is provided in Section I.2.1.

New Resource Options

ROSE-E evaluates potential new resources across each future, which requires detailed information about both the costs and benefits associated with each resource. The real-levelized fixed costs (capital, fixed O&M, etc.) for new resource options in each Technology Future come from PGE's revenue requirements model (LUCAS, see Section I.2). The variable costs (fuel, variable O&M, etc.) and the economic dispatch for new resource options in each Price Future come from the hourly dispatch simulations performed in the PGE Zone model within Aurora. The capacity contribution as a function of installed capacity for each new resource option is from RECAP. The flexibility values described in Section 6.2.2 are generated in ROM (see Section I.6) and applied in ROSE-E as well. Losses associated with each resource represent the losses to deliver the generation to busbar. Most resources, with the exception of Montana wind and battery storage, are directly modeled at busbar and therefore have no additional losses. The transmission losses associated with Montana resources are described in Section 5.5.4. Battery resources are modeled with a small amount of negative losses to reflect the assumption that batteries may be located closer to load.

Evaluating storage in ROSE-E requires an additional analytical step. The capacity contributions of storage resources are particularly sensitive to the total amount of storage added, whether from pumped hydro or batteries of 2-, 4-, or 6-hour duration. For example, if 100 MW of 6-hour batteries are added to a portfolio, the capacity contribution for adding an additional 100 MW of 4-hour batteries would be lower than if the initial 100 MW of 6-hour batteries were not included in the portfolio. Estimating capacity contribution by individual storage type in isolation could allow ROSE-E to select between storage options seeking higher ELCC values without accounting for the portfolio effect. Instead, ROSE-E estimates the capacity contribution of the storage fleet as a whole in each year as a function of the total storable energy of the fleet (the sum of the storage capacity in MWh times the roundtrip efficiency across all storage resources). This step ensures that portfolio optimization considers a more accurate capacity contribution for storage resources.

I.6.2 Objective Functions

ROSE-E can utilize various objective functions when solving for optimal portfolios. Users have a choice of four objective functions, depending on the portfolio:

- **Minimize NPVRR.** This objective function identifies the resource additions that minimize the expected value of the NPVRR over the full analysis period across the range of potential futures. It requires that the user specify a likelihood for each future. This objective function results in ROSE-E solving with Linear Programming (LP) or Mixed Integer Programming (MIP), depending on whether unit size constraints are imposed.[220]
- **Minimize Variability.** This objective function identifies the resource additions that minimize the semi-variance of the NPVRR, calculated across all futures. Portfolios generated with this objective function will tend to prioritize risk reduction. This objective function assumes that all futures have an equal likelihood, and it results in ROSE-E solving a Quadratic Programming (QP) problem. This objective also requires that the user specify a maximum Reference Case NPVRR. This objective function should not be selected if unit size constraints are imposed.
- **Minimize Near-term Costs.** This objective function identifies the resource additions that minimize the expected value of the NPVRR over a smaller analysis period (typically through 2025) across the range of potential futures. It requires that the user specify a likelihood for each future and the period over which the NPVRR is calculated. Just as with minimizing NPVRR, this objective function results in ROSE-E solving a LP or MIP problem depending on whether unit size constraints are imposed.
- **Minimize Carbon Emissions Plus Cost.** This objective function identifies the resource additions that minimize the expected value of the sum of cumulative carbon emissions between 2021 and 2050 and NPVRR through 2050 across the range of potential futures. It requires that the user specify a likelihood for each future and the period over which the cumulative carbon emissions are calculated. Because ROSE-E does not solve for hourly dispatch, selection of this objective does not impact the thermal dispatch for existing resources or new resource options; rather, it only affects the procurement decision. ROSE-E solves this objective function using a MIP problem.

I.6.3 Constraints

ROSE-E uses constraints to drive the chosen objective function to a result that both ensures PGE meets its core portfolio requirements and addresses the specific portfolio design question that is being considered. Functionally, this creates one set of constraints that apply across each portfolio, and another that vary to create specific portfolios.

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220 Accounting for unit sizes turns the optimization problem solved by ROSE-E into a Mixed Integer Linear Programming problem (rather than a simpler Linear Programming problem). As doing so significantly increases runtimes, enforcing unit constraints is used only for large resources when necessary.

I.6.3.1 Portfolio Constraints

Resource Adequacy

This constraint ensures that the sum of the capacity contribution of all new resources meet or exceed the capacity shortage in each year and each future. The portfolios enforce this constraint in the Reference Case in 2024 and 2025 and in all futures from 2026 through 2050.

In addition to the resources considered, in the 2019 IRP, ROSE-E has the option to select a generic *Capacity Fill* resource.[221] In 2024 and 2025, the Capacity Fill resource is limited by the cumulative size of expiring contracts, and after the action-plan window this resource is unconstrained. ROSE-E will meet its resource adequacy constraints with the generic Capacity Fill resource when no other resource provides capacity at a price lower than an SCCT.

RPS

These constraints ensure that PGE complies with Oregon's RPS requirements throughout the entire time horizon. ROSE-E simulates energy production, from which it generates data on REC generation, banking, and retirement. These constraints enforce rules about both five-year and infinite-life RECs. An addition constraint also ensures physical RPS compliance in specified years by requiring REC generation to meet or exceed RPS obligations in those years.

Energy

In the Reference Case, ROSE-E constrains the amount of energy produced from new resources to be at or below the forecasted net market shortage. Further, in all cases, the energy value must be below the forecasted net market shortage between 2041 and 2050. Without these constraints, ROSE-E could select pathways which position PGE to be persistently long to market. With these constraints imposed, even in futures with cost-effective renewable options available, ROSE-E will limit additions based on portfolio energy needs.

Optionality

After a specified Action Plan window, ROSE-E allows resource additions to vary by future within a given portfolio as conditions evolve. Within the Action Plan window, resource actions are required to be the same across all futures. In this IRP, resource additions are allowed to vary by future after 2025. For example, if a 100-MW battery is added to the portfolio in the Reference Case in 2024, then it must also be added to the portfolio in 2024 in all the other futures. After 2025, the 100-MW battery remains in the portfolio across all futures, but subsequent resource actions can vary depending on the conditions in each future. This framework ensures that ROSE-E portfolios maintain optionality in the context of uncertainty in future resource needs, market conditions, and technology costs.

I.6.3.2 Portfolio Specific Constraints

Resource Procurement

ROSE-E allows for constraints that set both the minimum and maximum incremental additions of each resource type in every year. Generally, most resources are given a range from 0 to 9,999 MW,

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221 See Section 7.1.1.1 for more details.

allowing the optimization to choose the appropriate addition. However, these constraints are used in portfolios with specific resource additions or constraints to meet those specific objectives. In 2023-2025,[222] unit sizes are enforced for dispatchable resources and in the optimized portfolios, however this constraint is removed after 2025 as an approximation for computational efficiency because resource additions in those years are not being considered for inclusion in the 2019 IRP Action Plan.

After the Action Plan window, two types of constraints are enforced to increase the practicality of the resource expansion path. First, renewable and capacity additions are constrained to occur every other year, with capacity procurements in even years and renewable additions in odd years. This approximates the regulatory process within which PGE operates, following the traditional IRP-RFP process for resource procurement. And second, a cap of 500 MW is enforced for resource additions after the Action Plan window. While it is certainly possible that future resource additions could exceed 500 MW in a given year, this constraint is imposed to limit the reliance of a portfolio on the presumption of large and prescriptive resource procurement in a single future year.

RPS Procurement

ROSE-E can require and/or limit the total quantity of renewable procurement each year. This is used to create portfolios which require the procurement of renewable generation while not requiring a specific type of renewable resource. For example, the renewable size and timing portfolios use this constraint to require the individual portfolios to add the specified renewable generation in the desired years.

Total Cost

This constraint limits the total Reference Case cost of any future from exceeding a chosen limit. This is only selected for the optimized portfolio which minimizes risk.

I.6.4 Implementation

As there are large number of possible combinations of objective functions, constraints, and future likelihoods, ROSE-E can create a wide range of portfolios considered "optimal". ROSE-E is written in GAMS, a mathematical modeling platform that allows the user to specify optimization problems and to run optimization solvers on those problems. ROSE-E uses the Gurobi solver. For ease of use, the user specifies each portfolio construction run in an Excel user interface. VBA scripts write the input data from Excel to the text files read by GAMS. A VBA script also calls GAMS to build and solve the optimization problem to design each portfolio. Once GAMS has identified a solution with the solver, it outputs the optimal values for each variable to a series of text files. A VBA script pulls the data from these text files back into Excel for the user to view.

To generate an individual portfolio, the user must specify:

- Resource specifications (their potential additions, unit size, and associated losses)
- The desired objective function (choosing one from the list above)

[222] This period is sometimes referred to as the "Action Plan window," as actions taken as part of the 2019 IRP Action Plan could lead to research additions in these years.

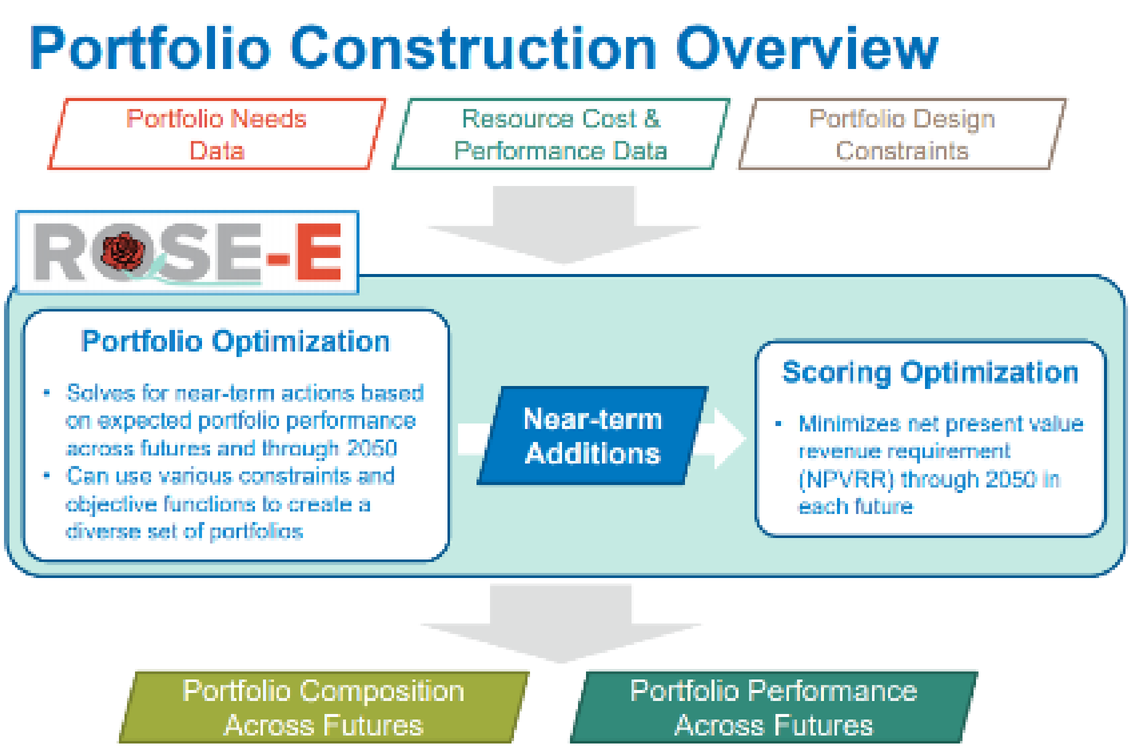
- Each desired constraint (from the group described above)
- The likelihoods for each Technology Future, Need Future, and Price Future

Once the above choices are made, the user will start ROSE-E's optimization. ROSE-E first writes the selected inputs, then uses the chosen method (LP, MIP, or QP) to determine the best possible resource expansion path given the applicable objective, constraints, and futures. The first step of this process occurs in the Portfolio Optimization run, where ROSE-E evaluates all possible resource options over the Action Plan window (between 2023-2025), while also simulating additions and costs through 2050. The Gurobi solver solves the constrained optimization problem and selects the one set of optimal choices for resource procurement which performs best over all applicable futures through 2050 under Reference hydro conditions. The resulting resource additions in the Action Plan window are then used as inputs in the second part of the portfolio construction process.

The second phase, called the Scoring Optimization run, also uses constrained optimization to find the best solution given the same resource specifications, objective function, constraints, and applicable futures used in the Portfolio Optimization run. However, there are three key differences between these two phases. First, the Scoring Optimization run minimizes NPVRR, regardless of the choice of objective function from the first phase. This is an important step to be certain that future expansion paths are least-cost regardless of the objective function chosen to design the portfolio. Second, the Action Plan window additions calculated in the Portfolio Optimization run are now used as fixed inputs in the Scoring Optimization run. Third, the second phase calculates the performance metrics of portfolios across the low and high hydro futures.

The ROSE-E data flow is depicted in Figure I-11.

FIGURE I-11: ROSE-E data flow chart



I.6.5 Results

In running both the Portfolio and Scoring Optimization runs, ROSE-E selects the optimal resource expansion path given the data inputs, objective function, and constraints that have been specified. Contained in this analysis is a large set of information which details how the portfolio performs over all examined futures. For every year between 2021-2050, ROSE-E stores the MW additions of each new resource, their capacity contribution, total GHG emissions, and REC accounting (generation, banking, and retirement). Further, ROSE-E calculates the annual costs and revenues for each year in every future and the NPVRR through 2050 for every future.

With these data, ROSE-E enables the user to consider the impacts of near-term additions while maintaining long-term flexibility in the face of a rapidly changing energy landscape. This consideration of optionality is unique in long-term capacity expansion modeling. By comprehensively comparing portfolios and empirically evaluating tradeoffs between cost and risk, while considering future flexibility, ROSE-E allows for a more complete evaluation of potential near-term actions.

APPENDIX J. Renewable RFP Design and Modeling Methodology

Oregon Public Utility Commission (OPUC) Order No. 18-324 requires that future competitive solicitations use methods and models that adhere to a framework established and reviewed in the acknowledged IRP. Specifically, Oregon Administrative Rule (OAR) 860-089-0250 (2) requires that future requests for proposals (RFPs) reflect the elements, scoring methodology, and associated modeling described in the Commission-acknowledged IRP. This appendix identifies the RFP characteristics that PGE intends to incorporate into a future Renewable RFP to satisfy the Company's proposed Renewable Resource Action Item (Action Item) identified in Section 8.3.

J.1 Elements of Requested Power Products

PGE intends to request proposals for renewable energy products to satisfy the proposed Action Item. Consistent with the proposed Action Item, PGE will target approximately 150 MWa of renewable energy resources in a future solicitation. Bids for renewable resources will be required to meet the requirements of Oregon's Renewable Portfolio Standard, as defined in Oregon Revised Statues (ORS) 469A and include all environmental attributes, including Renewable Energy Certificates (RECs).

PGE will consider proposals for the long-term purchase of renewable energy from an existing or to-be-constructed renewable facility, with energy to be delivered to PGE. The planned minimum bid capacity is 10 MW, with a minimum term duration of twenty years. PGE will also consider acquiring ownership positions in renewable energy resources. Ownership proposals may include (but are not limited to) the sale of existing plants, acquisition of project development rights, joint ownership, and build-own-transfer agreements. Additionally, PGE will consider hybrid structures that include both an ownership component and a power purchase agreement (PPA) (for example, the sale of a phase or portion of a project with an off-take agreement for the balance or a PPA with a purchase option or obligation).

PGE will conduct the RFP in accordance with the Commission's competitive bidding rules and consistent with those rules, will engage in an independent evaluator (IE) to oversee the process.

J.2 Scoring Methodology

J.2.1 Bid Evaluation Criteria

Eligible bids will be assessed by PGE and the IE based on the project's economic competitiveness, project-specific commercial and performance risks, and portfolio economic risk. All bids will be evaluated within an individual offer analysis to assign a bid price and non-price score. Consistent with prior Commission-acknowledged RFPs, PGE's price score will comprise 60 percent of our evaluation criteria, reflecting PGE's desire and commitment to obtain the best possible value for our customers. Non-price factors will comprise the other 40 percent and reflect commercial and performance risks in addition to operational attributes of the bid proposals. PGE will perform additional sensitivity analysis to determine the sensitivity of scoring results on price and non-price weighting.

J.2.2 Criteria Used for Scoring Qualified Bids

The price score will be a function of the bid's forecast levelized cost (or value). Specifically, PGE will calculate the difference between the bid's projected total levelized cost and forecast levelized value. Price scoring will incorporate benefits related to the expected energy value, capacity value, and flexibility value associated with the offers.

PGE cannot capture or quantify many project-specific risks and benefits by evaluating resource price or resource portfolio cost benefit. For those projects, PGE evaluates and assigns a non-price score for specific development criteria, physical characteristics, performance certainty, and credit factors.

J.2.3 Determination of the Offer Cost

An offer's cost reflects the total cost, fixed and variable, associated with the project's delivery of energy and forecast economic dispatch.

An offer's fixed costs include all revenue requirement components including, for resources to be owned by PGE: total depreciation, salvage, return, income taxes, deferred income taxes, property taxes, fixed operating and maintenance costs (O&M), wheeling charges, and ancillary services. For resources contracted for by PGE, an offer's fixed cost includes (if applicable) all forecast fixed payments, capacity charges, ancillary services, and PGE system upgrade costs.

An offer's variable costs include, for resources to be owned by PGE: all fuel costs, variable O&M, emissions costs, start-up costs. For resources contracted for by PGE, an offer's variable cost includes all energy payments, additional variable O&M costs, emission costs passed onto the buyer, and start-up charges, if applicable. PGE will determine the magnitude of an offer's variable costs by the offer's simulated dispatch against forecast market prices developed using the Aurora modeling, forecasting, and analysis software.

To evaluate bids containing different product characteristics on a comparable basis, prices submitted by the bidder may be subject to adjustment.

An offer's total cost for the duration of the offer's term is expressed on a present-value basis and levelized using annuity methods.

J.2.4 Determination of the Energy Value

An offer's energy value reflects the value of energy generated throughout the offer's economic life or term. Energy value for the duration of the offer's term is expressed on a present-value basis, levelized using annuity methods, and included in the offer's total levelized value. The energy value will be based on the simulated dispatch of the offer and the projected revenue associated with PGE's hourly market price forecast. The market price forecast is developed using a fundamental market simulation in Aurora, the principles of which are described in Appendix I. 2019 IRP Modeling Details.

J.2.5 Determination of Capacity Benefits

An offer's capacity benefit reflects the offer's estimated system capacity value. PGE is facing an upcoming capacity deficit and requires capacity products to otherwise displace the need to contract with or construct new generating facilities. PGE will estimate the bid's capacity contribution toward PGE's near-term capacity deficit but will not increase future capacity contributions toward PGE's expanding capacity deficit.

An offer's capacity benefit will be calculated as the product of the offer's capacity value and the avoided capacity cost. The product's capacity value will be calculated using the Renewable Energy Capacity Planning (RECAP) model. RECAP is described in Appendix I. 2019 IRP Modeling Details. The offer's capacity value will be expressed as the quantity of avoided simple-cycle combustion turbine (SCCT) needed to meet PGE's long-term capacity targets. The avoided capacity cost will be based on a per-kilowatt, real-levelized cost (net of wholesale revenues and flexibility value) of an SCCT. The assumed costs and performance of the SCCT are consistent with 2019 IRP capital costs and performance metrics operated under the same wholesale market prices and gas prices used for the energy value described in Section J.2.4. The product of the offer's annual capacity value and levelized avoided capacity cost constitute the offer's annual capacity benefit. Capacity benefit for the duration of the offer's term is expressed on a present-value basis, levelized using annuity methods, and included in the offer's total levelized value.

J.2.6 Determination of Flexibility Benefits

The flexibility value associated with an offer reflects any additional value that the offer may bring to PGE's generation portfolio due to its ability to ramp, respond to forecast errors, or provide ancillary services that is not captured by its energy value. PGE estimates flexibility benefits using approximations of outputs from the Resource Optimization Model (ROM), which the Company uses in the 2019 IRP to quantify the flexibility value of dispatchable resources, as described in Section 6.2.2. The flexibility benefit for the duration of the offer's term is expressed on a present-value basis, levelized using annuity methods, and included in the offer's total levelized value.

J.2.7 Adjustments to Prices Submitted by Bidders

Price represents a significant portion of the overall score. To evaluate offers containing different product characteristics on a comparable basis, prices submitted by bidders will be subject to adjustment for the following considerations:

- **Delivery Point.** If a bidder meets the minimum transmission requirements but does not provide a delivered price, applicable transmission service costs will be applied in order to capture the incremental cost of delivering energy to PGE. These costs include wheeling, losses, and required ancillary services as prescribed in applicable tariffs, as well as any incremental costs for transmission or distribution system improvements necessary to deliver the energy to PGE.

  However, for bids where the bidder has secured and is paying for transmission and ancillary services for delivery from the generation facility to an acceptable delivery point and the offer is inclusive of all applicable service costs identified above, no other transmission costs for those point-to-point services will be applied.
- **Interconnection.** Applicable interconnection costs will be applied in order to capture the identified interconnection upgrade costs identified in an Interconnection Facility Study. However, for bids where the bidder has included the appropriate interconnection costs into the bid price, no other interconnection costs will be applied.

- **Ancillary Services.** If ancillary services are not included in product pricing, bids will be adjusted to account for ancillary services, where applicable, to meet control area operations and transmission provider requirements.

  Bidders will be required to provide a comprehensive list of all ancillary services they plan to provide or purchase in delivering the power product to the delivery point. To the extent that any of these required ancillary services are not supplied by the bidder, PGE will, for scoring purposes, adjust the price provided by the bidder to reflect the cost of acquiring additional ancillary services required.
- **Owner's Costs.** During PGE's Individual Offer Analysis, PGE will assign generic owner's costs to all utility-ownership resources.
- **Performance Assurances.** PGE retains the right to adjust the bid price to include performance-assurance costs should the bidder take exception to the required performance assurances before and after the commercial operation date.
- **Tax Credit Carrying Cost Net Benefits.** For those resources eligible for federal tax credits and offered under a utility-ownership proposal, the Company will evaluate its customer costs associated with utilization of the incremental tax credits.

J.3 Detailed Offer Price Scoring

Following the quantification of offer costs and benefits, including any necessary offer price adjustments described above, PGE will calculate each offer's levelized net cost (or benefit). The offer's price ratio will be based on real-levelized net costs (incorporating energy, capacity, and flexibility benefits). The 600 points associated with the price scoring section will be allocated on a scaled basis, with the lowest net cost offer receiving 600 points.

J.3.1 Offer Price Screen

PGE will require all Renewable RFP bids to pass a cost-containment screen in order to be considered for the initial short list. The cost-containment screen requires bids to be cost-effective under Reference Case conditions considering only the resource's forecasted energy, capacity, and flexibility values. Offers will be considered to have passed the offer price screen if they are determined to have a negative net levelized cost equivalent to a forecasted benefit.

The cost-containment screen will be unique for each resource evaluated by PGE and will elevate resources that provide more value to PGE customers due to the resource's generation profile. For this reason, it is possible that a lower-priced resource will not pass the economic screen while a higher-priced resource will pass the economic screen due to increased resource value, such as by providing higher capacity contribution or more valuable energy production.

J.3.2 Non-Price Factors

Non-price scoring is designed to reflect the commercial and performance risk associated with the project that is not captured in the offer's price score. Non-price scoring will be assigned 400 points. Non-price scores are identified by evaluating each offer's proposal against a rubric of non-price criteria which are categorized below.

J.3.2.1 Project Development Criteria

This category scores the likelihood that a project supporting a bid will be placed in commercial service. The evaluation criteria for this category generally address construction and development risks associated with the completion of projects that are not yet in commercial operation, and which are necessary to support bids. Plants that are already operating may be deemed to earn the maximum possible score in this category.

For projects not already operating, some of the characteristics PGE will consider in non-price scoring are:

- Status of required permits, licenses and environmental studies
- Project team experience
- Method and status of project financing
- Site control
- Cost certainty
  - Status of equipment quotes
  - Sale or PPA price structure
- Project life and extension options. Bids that allow PGE to extend the life of a resource beyond the initial term, or bids allowing for PGE to continue facility operation, provide opportunities for PGE to lower long-term energy supply costs and risks.

J.3.2.2 Project Physical Characteristics

This category captures the physical characteristic risks of the bid products. The evaluation criteria for this category generally address physical and operational risks associated with the production and delivery of power to PGE. Some of the characteristics that PGE will consider in non-price scoring are:

- Interconnection status, transmission status and characteristics, and curtailment obligations.
- Remedial action schemes (RAS). Projects that PGE is able to use as a credit for its obligation to support existing RAS will receive additional points.
- Engineering reliability characteristics.
- Resource fuel availability confidence.

J.3.2.3 Project Performance Certainty

This category scores how well the bid product matches PGE's system operating needs. The evaluation criteria for this category generally address price risk, performance, and supply portfolio concentration risks along with the benefits of operational flexibility. Some of the characteristics that PGE will consider in non-price scoring are:

- Firmness of Energy
- Scheduling period commitment
- Contract/resource start date

- Guarantees and compensation for failure to meet them
- Deviations from form product term sheet

J.3.2.4 Credit Evaluation

This category scores the creditworthiness of the bidder. PGE will take into account the following credit considerations in non-price scoring:

- Debt and equity ratings
- Financial ratio analysis
- Bond risk
- Tangible net worth
- Corporate structure

J.4 Final Short List Determination

J.4.1 Scoring Sensitivity Analysis

PGE will incorporate a price/non-price sensitivity analysis into its short list evaluation to demonstrate the reasonableness of the proposed scoring weighting ratios 60 percent price and 40 percent non-price. PGE will also study how the ranking of its short list would be affected by 70/30 and 50/50 price/non-price weighting sensitivities.

J.4.2 Portfolio Modeling

PGE will also take overall system costs and risks into account in its selection of bids for the final short list. Portfolio modeling will provide PGE with additional information regarding the cost and risk profile of all offers considered. PGE will analyze portfolios using methods consistent with the 2019 IRP and will demonstrate how resources perform together, on a cost and risk basis, due to their specific size, term, portfolio capacity value, and portfolio flexibility value.

PGE will use a portfolio analysis that begins with the assembly of portfolios into many different unique combinations of resources. PGE will develop the candidate portfolios through multiple techniques including 1) portfolio size optimization, 2) portfolio net-cost optimization, 3) cost-screened resource permutations, and, if necessary, 4) additional analyst selected portfolios.

PGE will include sufficient resources in each portfolio to approximately meet the targeted renewable volume in each year. We will calculate the unique capacity value for each portfolio will be calculated using the IRP's RECAP methodology. Any portfolio whose forecasted energy volume does not meet the targeted renewable volume will also include a specified fill resource ("fill"). Including a fill resource ensures the portfolio incorporates the total cost necessary to meet the long-term renewable target. PGE will size the specified fill resource to fulfill the energy target in each year of the analysis.

The portfolio analysis will test combinations of resources across multiple futures. The futures will evaluate portfolio exposure to multiple scenarios of need, market prices, hydro scenarios, and technology costs, as described in Chapter 3. For each portfolio, PGE will calculate the relevant resources' variable costs and energy benefits in Aurora under multiple economic and hydro futures. We will then report the variable net income for each resource annually for all futures.

PGE will calculate a unique portfolio-flexibility value using the portfolio-flexibility tool described in Section 4.6 Flexibility Adequacy. The portfolio flexibility-calculation will recognize the flexibility diversity included in each portfolio.

For each portfolio, PGE will subtract the portfolio-flexibility value and the relevant resources' net incomes from the relevant resources' fixed costs to calculate the portfolio's total net cost for each future.

For each portfolio, PGE will calculate the total present-value net cost under each future to estimate the cost impact of the additions on the PGE system. We will measure this expected cost impact as the total portfolio net present value of revenue requirement (NPVRR) under Reference Case conditions. PGE will evaluate portfolio risk using the traditional scoring metrics described in Chapter 7, then we will calculate portfolio price scores based on Reference Case expected cost and the severity and variability of portfolio costs.

PGE will stress-test portfolio results under multiple energy targets, planning horizons, and fill resource assumptions, then calculate the average portfolio score under all study assumptions. PGE will award 600 points to the portfolio with the best average portfolio score, with all remaining portfolios assigned a price score on a proportionally scaled basis.

PGE will calculate non-price scores for each portfolio, with a maximum of 400 points. The portfolio non-price score will be the weighted average of the component offer's Individual Offer Analysis non-price score weighted by the offer's resource volume. We will calculate total scores for each portfolio, including portfolio price and non-price scores, and include those resources with the highest portfolio total scores in PGE's final shortlist to be presented to the Commission for acknowledgment.

External Study A. Deep Decarbonization Study

Exploring Pathways to Deep Decarbonization for the Portland General Electric Service Territory

April 24, 2018

PREPARED FOR

Portland General Electric

PREPARED BY

Gabe Kwok
Ben Haley

EVOLVED ENERGY RESEARCH

Contents

Executive Summary

Background

Portland General Electric (PGE) retained Evolved Energy Research to undertake an independent study exploring pathways to deep decarbonization for its service territory. This study comes amidst a broad interest in decarbonization from customers and stakeholders, as well as policies and goals to promote clean energy and emissions reductions.

Since 2007, Oregon has had a goal of reducing statewide greenhouse gas (GHG) emissions by 75 percent below 1990 levels by 2050. Recently proposed legislation seeking to establish a cap-and-trade program in Oregon also proposes to tighten the statewide GHG reduction goal to 80 percent below 1990 levels by 2050. At the local level, the City of Portland and Multnomah County passed resolutions in June 2017 committing to 100 percent renewable electricity by 2035 and a complete transition to carbon-free energy by 2050.

These drivers to deeply decarbonize the economy would require a transformation of the energy system, and major choices will need to be made about which technologies play a role and how aggressively to pursue carbon reductions across different sectors. A substantial body of existing technical work shows that the electricity sector plays a pivotal role in a low-carbon transition, but the extent and type of role depends on choices made in other sectors.[1] For example, the level of electrification pursued in buildings and the decision to produce fuels from electricity, such as hydrogen from electrolysis, will have implications for electricity demand and the quantity of renewable electricity generation that will need to be developed.

Due to the potential impact on long-term planning, PGE sponsored this study to inform its Integrated Resource Planning (IRP) efforts. This study is intended to provide an understanding of: (1) the opportunities and challenges of achieving economy-wide deep decarbonization; and (2) the resulting implications for electricity system operations and planning.

Approach

The overarching emissions target for this study is an 80 percent reduction below 1990 levels by 2050 in energy-related CO_2 emissions. CO_2 emissions from fossil fuel combustion have been the predominant source of Oregon's historical GHG emissions, and, since 1990, they have accounted for approximately four-fifths of total GHG emissions in the state. This target would allow for fossil fuel combustion emissions of no more than 9.2 $MMTCO_2$ in 2050 for the state of Oregon. We allocate the statewide carbon budget to PGE's service territory using its projected share of Oregon's population, which is estimated to be 47 percent in 2050.[2] This results in a carbon budget of 4.3 $MMTCO_2$ in 2050 for the PGE service territory.

We designed three future energy scenarios that reduce emissions to comply with the 4.3 $MMTCO_2$ target. These scenarios are referred to as "deep decarbonization pathways" or "pathways", and they provide alternative blueprints for achieving deep decarbonization of the energy system.

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[1] For example, see Williams, et al. (2014) and Haley, et al. (2016).

[2] Population growth rate projections from OEA (2013).

For each sector of the energy economy, we developed a range of measures to replace today's energy infrastructure with efficient and low-carbon technologies over the next three decades. For example, passenger travel currently provided by a gasoline vehicle is replaced by an electric vehicle, and a compact fluorescent (CFL) light bulb is replaced by a light emitting diode (LED) light bulb. Each pathway combines measures across sectors at the scale and rate necessary to meet the study's emissions target.

We use EnergyPATHWAYS, a bottom-up energy systems model, to estimate energy demand, emissions and costs for each pathway. Our analysis starts with the same model and approach we have previously used to evaluate deep decarbonization for the United States, the State of Washington and other jurisdictions. We developed a detailed representation of the PGE service territory energy system, including infrastructure stocks and energy demands for buildings, industry, and transportation. Our analysis incorporates an hourly dispatch of PGE's electricity system, which allows us to better understand fundamental changes to electricity supply and demand, such as how to balance very high levels of intermittent renewables and the impact of electrification on hourly electricity demand.

Pathways

Our study aims to provide an understanding of the broad choices available to achieve deep decarbonization across the economy and the potential implications on the electricity sector. To inform this understanding, we develop three plausible energy futures for PGE's service territory that achieve steep reductions in energy-related CO_2 emissions between now and 2050. These future energy scenarios outline: (1) potential sources and demands for energy types over time; and (2) the scale and timing of change over the next three decades.

Table 1 provides a high-level summary of the three pathways included in this study, where each scenario incorporates alternative emissions reduction strategies and technologies. One of the primary objectives of our scenario design was to reflect a broad range of outcomes for the electricity sector. The High Electrification pathway relies on electrifying space and water heating in buildings and deploying bulk energy storage to balance high levels of renewable generation. Passenger transportation is characterized by high levels of battery electric vehicles (BEV), while freight transportation includes both battery electric and hybrid diesel trucks. The Low Electrification pathway decarbonizes energy supply with a variety of renewable fuels, and electrolysis and power-to-gas facilities provide both electricity balancing services and decarbonized pipeline gas. Passenger transportation is primarily BEV, while compressed and liquefied natural gas trucks are incorporated in the freight transportation sector. The High DER pathway is highly electrified and distributed, with increased rooftop solar PV and distributed energy storage in buildings and industry. The Reference Case projects business-as-usual conditions, including the Oregon Clean Electricity and Coal Transition (OCEP) and Clean Fuels Program (CFP).

Table 1 Scenario Summary

Scenario	Description
High Electrification	Fossil fuel consumption is reduced by electrifying end-uses to the extent possible and increasing renewable electricity generation
Low Electrification	Greater use of renewable fuels, notably biofuels and synthetic electric fuels, to satisfy energy demand and reduce emissions
High DER	Distributed energy resources proliferate in homes and businesses, which also realize higher levels of electrification
Reference	A continuation of current and planned policy, and provides a benchmark against the deep decarbonization pathways

We are not choosing or recommending a pathway to 2050, and the scenarios presented above are not exhaustive. However, the pathways we have included in this study illustrate possible routes to a deeply decarbonized energy system and provide an understanding of trade-offs between complex decisions made by consumers and producers across the energy economy.

Key Findings

The three pathways evaluated in this study demonstrate that achieving deep decarbonization is both possible and there are multiple ways of doing so. Through this analytical exercise, we have identified a number of key findings, which we describe in detail below.

Common Elements to Achieve Deep Decarbonization

Although our pathways demonstrate that a variety of technologies and approaches are possible to realize a low-carbon economy, they also share common strategies, including: energy efficiency, decarbonization of electricity generation and electrification. These *three pillars* are common themes in all pathways, and the energy transformation from today to 2050 reflects: (1) a decline in per capita final energy consumption by approximately 40 percent; (2) a decrease in the carbon intensity of electricity generation to near zero; and (3) an increase in the share of energy coming from electricity or fuels produced from electricity from approximately one-quarter today to at least half by 2050. All three strategies are required and pursuing only one is insufficient.

Planning for a 2050 Energy System

In order to facilitate a pathway to 2050, new energy infrastructure will be required that is low-carbon and efficient. Transformation is required across all sectors with consumers and energy suppliers both playing a key role. The analysis identifies the scale and rate of change for each pathway, and highlights trade-offs between choices made to achieve deep decarbonization. One example is the choice of decarbonizing heat in buildings. Electrification of heat with heat pumps may require electricity distribution network upgrades to allow for growth in electricity demand, but they also provide a source of flexibility and efficient cooling services during the summer. The alternative is decarbonized pipeline gas that requires new central-station fuel production facilities, additional renewable generation and transmission network upgrades. *Both* choices require new infrastructure and highlight how long-term planning will need to address several uncertainties.

Energy Demand and Electricity Demand

Energy efficiency plays a crucial role in all pathways, and *total energy demand* in 2050 is approximately 10 to 20 percent below today's level, while the population grows by more than 40 percent. Despite overall energy demand decreasing, *electricity consumption* increases in all pathways. By 2050, retail electricity sales are projected to increase by 60 to 75 percent relative to today's level. As a result, electricity's share of overall energy demand is projected to increase in a deeply decarbonized future.

Transportation Electrification

Electrification of passenger transportation is a critical component of decarbonizing the energy system, and passenger vehicles are at least 90 percent BEV by 2050 across all pathways. To ensure these vehicles are on the road by 2050 requires consumer adoption to be near 100 percent of vehicle sales during the mid-2030s. Delays in adoption increase the likelihood of missing the 2050 target.

Widespread adoption of electric vehicles (EVs) is projected to be the largest source of increased electricity consumption, and, left unmanaged, would increase peak demand. However, the fleet of EVs across PGE's service territory can employ smart charging by shifting their demand to more efficient times of day. Charging off peak, such as when renewable generation is high or during the middle of the night can mitigate peak load impacts while ensuring that passengers complete all of their intended trips.

Scale of Renewable Resources

Oregon's existing renewable portfolio standard (RPS) requires half of the energy PGE delivers to its customers to come from qualifying renewable resources by 2040. Deep decarbonization extends that ambition in two ways. First, the overall electricity generation mix is more than 90 percent carbon-free by 2050, including onshore wind, solar PV, hydro and geothermal resources. Second, the total quantity that must be generated (in average megawatts) increases due to: (a) electrification of end-use demand, such as heating and transportation; and (b) producing fuels from electricity, such as hydrogen and synthetic natural gas. As a result, the installed capacity of renewables is substantially higher than what's anticipated in any current planning proceedings and is more than double the quantity we would expect under current RPS policy.

Rooftop solar PV can play a key role in electricity supply, but its share of the overall electricity generation mix in a deeply decarbonized energy system is limited by the resource quality in Northwest Oregon (i.e., low capacity factors) and growth in electricity consumption. Distributed solar reduces the need for, but does not completely replace, transmission-connected renewables. Although the Low Electrification pathway has the lowest retail energy deliveries by 2050, the pathway requires the highest level of transmission-connected renewable generation due to electric loads from producing hydrogen and synthetic natural gas.

The scale of renewable resource development present in all scenarios highlights the need for proactive planning to ensure that these resources are available to come online in a timely fashion. This includes identifying promising areas for resource development, possible transmission network upgrades to ensure renewable generation is delivered to load, and operational considerations to balance a highly renewable electricity grid.

Balancing the Electricity System

Electricity systems must be continually balanced across several timescales, from seconds to daily, weekly and seasonal changes. Today, generation from thermal and hydro resources is varied to meet changes in demand. However, balancing electricity supply and demand becomes more challenging when inflexible, variable renewable generation is the principal source of electricity supply. For example, renewable generation exceeds load in approximately half of all hours in 2050 in our pathways.

This operational paradigm necessitates a transition to new forms of balancing resources to integrate renewables and avoid curtailment. New sources of flexibility, including energy storage and flexible demand, can complement traditional sources of flexibility. Flexible demand includes both: (a) flexible end-use loads, such as smart EV charging and water heating; and (b) flexible transmission-connected loads, such as electrolysis and power-to-gas facilities that produce low-carbon fuels. The portfolio of available balancing options depends on choices made across the energy economy.

I. Background

Portland General Electric (PGE) retained Evolved Energy Research to undertake an independent study exploring pathways to deep decarbonization for its service territory. This study comes amidst a broad interest in decarbonization from customers and stakeholders, as well as policies and goals to promote clean energy and emissions reductions at the state and local level. Transitioning towards a low-carbon energy economy will have significant implications for electricity supply and demand, and the various technologies and strategies deployed during this transformation can result in broad outcomes for the electricity sector. Due to the potential impact on long-term planning, PGE sponsored this study to inform its Integrated Resource Planning (IRP) efforts and provide an understanding of: (1) the opportunities and challenges of achieving economy-wide deep decarbonization across its service territory; and (2) the resulting implications for electricity system operations and planning.

A. Motivation and Context

Oregon has long been at the forefront of recognizing the risks imposed by climate change. In 2007, the Oregon legislature passed House Bill 3543 (HB 3543), which established GHG reduction goals, including: (a) 10 percent reduction below 1990 levels by 2020; and (b) 75 percent reduction below 1990 levels by 2050. The Oregon Global Warming Commission (OGWC) was established through the same bill, and later recommended an interim goal of a 40 percent reduction below 1990 levels by 2035.

Recently proposed legislation seeking to establish a cap-and-trade program in Oregon also proposes to tighten the statewide GHG reduction goal. The proposed legislation would require a reduction in statewide GHG emissions to: (a) a goal of 20 percent below 1990 levels by 2025; (b) a limit of 45 percent below 1990 levels by 2035; and (c) a limit of 80 percent below 1990 levels by 2050.

Oregon has existing climate policies targeting specific sectors. The Clean Fuels Program requires the average carbon intensity of transportation fuels to be reduced by 10 percent between 2015 and 2025. The state adopted a Renewable Portfolio Standard (RPS) in 2007, which requires a percentage of retail electricity sales to be met by qualifying renewable electricity generation. This policy originally required 25 percent of load to be met by renewables by 2025. Senate Bill 1547 (SB 1547), also known as the Oregon Clean Electricity and Coal Transition (OCEP), was passed in March 2016 and requires: (1) an increase in the RPS to 50 percent renewables by 2040; and (2) removing coal-fired electricity generation from the state's electricity supply by 2035.

PGE's 2016 IRP reflected the increase in renewable energy requirements and transition from coal generation called for in the OCEP. Throughout the IRP process, stakeholders and customers have expressed interest in low-carbon portfolios and exploring deep emissions reductions. In addition, the City of Portland and Multnomah County passed resolutions committing to ambitious clean energy goals shortly after, including: (a) 100 percent renewable electricity by 2035; and (b) a complete transition to carbon-free energy by 2050.

These drivers to deeply decarbonize the economy would require ambitious energy system transformation. Prior studies examining similar levels of GHG reductions for the states of Washington and California, the United States and countries representing more than 75 percent of global GHG emissions have all identified the following required changes to their future energy systems: (1) highly efficient use of energy; (2) generating electricity with low- and zero-carbon resources; and (3) substituting fossil fuels with electricity and electricity-derived fuel.[3] Pursuing only one change, such as decarbonizing electricity generation, is insufficient to meet economy-wide goals and all three strategies are needed.

In addition to these common themes, there are a range of alternative strategies that make it possible to achieve the same GHG goal. Different technologies and fuels can be deployed to decarbonize energy supply and demand, and the extent of decarbonization by end-use sector may vary. Key differences between pathways identified in prior studies include the level of end-use electrification and the allocation of limited bioenergy resources to decarbonize gaseous and liquid fuels.

As a result, long-term planning for the electricity sector will need to account for decarbonization efforts in other sectors and the complex mix of choices that may be pursued. Examples of actions that would affect long-term electricity planning include: (a) adoption of high levels of electric vehicles in the transportation sector, which affects overall electricity demand and its shape; (2) production of synthetic electric fuels, such as hydrogen from electrolysis, which will increase the demand for clean electricity generation; and (3) deployment of distributed energy resources across homes and businesses. However, the likelihood and timing of these developments and other potential decarbonization efforts is uncertain.

Our study aims to provide an understanding of the broad choices available to achieve deep decarbonization across the economy and the potential implications on the electricity sector. To inform this understanding, we develop a range of plausible energy futures for PGE's service territory that achieve steep reductions in energy-related CO_2 emissions between now and 2050. These future energy scenarios outline: (1) potential sources and demands for energy types over time; and (2) the scale and timing of change over the next three decades.

B. Study Scope

Our study scope includes designing and evaluating three future energy scenarios that deeply decarbonize the PGE service territory's energy system. We refer to these scenarios throughout the report as "deep decarbonization pathways" or simply "pathways". We also developed a Reference Case reflecting current policy to provide a benchmark against the pathways scenarios.

The primary results of our study include projections from today to 2050 of: (1) energy demand by sector and type; (2) energy supply; (3) energy-related CO_2 emissions; and (4) energy system-related costs. This is supplemented by detailed results for the electricity sector, including electricity demand, installed capacity, generation, and hourly dispatch results for PGE's bulk power system.

Given our focus on exploring energy system transformation, we account for all forms of energy (e.g., gasoline, pipeline gas, hydrogen) and our analysis is not limited to electricity. We include CO_2 emissions from energy use, but we do not track non-energy CO_2 and non-CO_2 GHGs. The geography for our analysis is confined to PGE's service territory and excludes the rest of Oregon. Since one of the primary objectives of the study is to explore economy-wide compliance with a GHG target, we include load from customers that are currently under direct access to account for all energy use.

[3] These strategies are commonly referred to as the "three pillars".

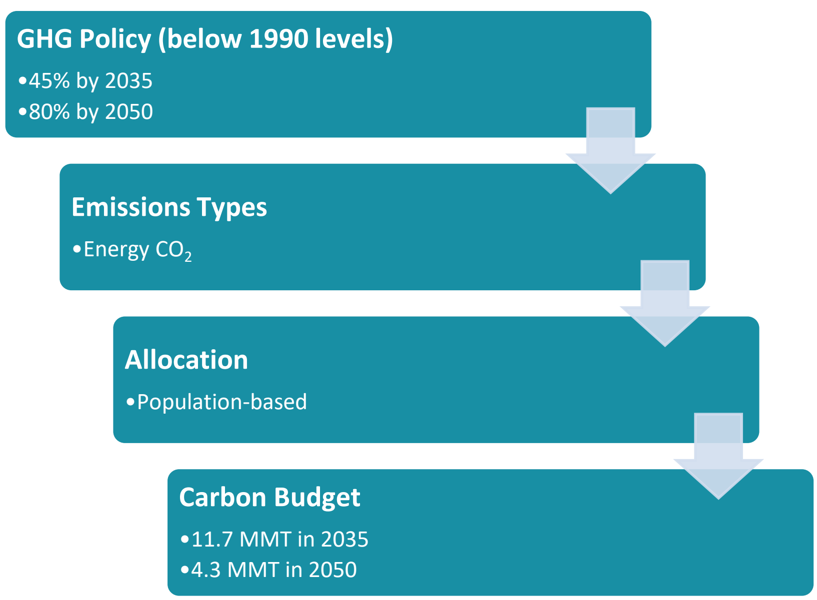
Given the exploratory nature of this study, it is important to emphasize what this study *is not*:

- Our scenarios are not a forecast of the future;
- We are not predicting future outcomes or assigning probabilities to scenarios;
- We are not choosing or recommending a pathway to 2050;
- Scenarios assessed here are not exhaustive and thousands of plausible alternatives exist;
- Scenarios do not reflect PGE's business plan or future resource acquisitions; and
- This study's modeling approach and results do not replace existing tools or processes used in IRP, such as defining "need" for resource adequacy or identifying optimal portfolios, nor do they replace cost-effectiveness evaluation, etc.

C. Study Emissions Target

For the purposes of this study, the energy-related CO_2 emissions budget for PGE's service territory is 11.7 million metric tons ($MMTCO_2$) in 2035 and 4.3 $MMTCO_2$ in 2050. Developing an appropriate emissions budget to evaluate deep decarbonization requires numerous assumptions to account for: (a) the fact that currently there is no binding, economy-wide GHG policy covering PGE's service territory; (b) any state-wide emissions limit must be translated into a budget for PGE's service territory; and (c) the scope of our work includes energy-related CO_2 emissions and excludes non-energy CO_2 and non-CO_2 GHGs. Our approach for deriving the study's emissions budget is summarized in Figure 1 and further described below:

Figure 1 Approach to Develop Study's CO_2 Target



- **GHG Policy**. The context for emission reductions, discussed in the proposed cap-and-trade legislation, requires a reduction in statewide GHG emissions to: (a) 45 percent below 1990 levels by 2035; and (b) 80 percent below 1990 levels by 2050.

- **Emissions Types**. CO_2 emissions from fossil fuel combustion have been the predominant source of Oregon's historical GHG emissions, and, since 1990, energy-related CO_2 emissions have accounted for four-fifths of total gross GHG emissions in the state. For simplicity, we apply the emissions reductions from the above GHG policy to Oregon's 1990 energy-related CO_2 emissions, which were approximately 46 $MMTCO_2$.[4] This results in a state-wide budget for CO_2 emissions from fossil fuel combustion of approximately 25.2 $MMTCO_2$ in 2035 and 9.2 $MMTCO_2$ in 2050. Based on a state population forecast of 5.59 million in 2050, this results in a per capita emissions budget of 1.6 tCO_2 per person, which is consistent with prior decarbonization studies.
- **Budget Allocation**. We allocate the state-wide emissions budget to PGE's service territory using its projected share of Oregon's population. In 2015, the PGE service territory included approximately 1.8 million people or 45 percent of Oregon's population. Projections of long-term population growth show counties within PGE's service territory growing at a slightly faster rate than the state as a whole. PGE's share of the state's population is projected to increase to 46.3 percent in 2035 and 47 percent by 2050. This translates into a carbon budget of 11.7 $MMTCO_2$ in 2035 and 4.3 $MMTCO_2$ in 2050.

The carbon budget we have developed for PGE's service territory is specific to this study. Any future policy mechanisms used to achieve emissions reductions, such as a price on carbon or complementary measures, may result in alternative emissions outcomes than those modeled here. In other words, the *total* statewide GHG emissions target may be compliant in the future, but *where* mitigation occurs is not definite. For example, more or less mitigation may occur between: (a) PGE's service territory and the rest of Oregon; (b) buildings and the industrial sector; and (c) sources of energy CO_2 and other GHGs.

[4] We note that our approach implicitly assumes that non-energy CO_2 and non-CO_2 GHGs will be reduced on an equivalent percentage basis in order to achieve the overall GHG targets. Historical emissions data from DEQ (2016).

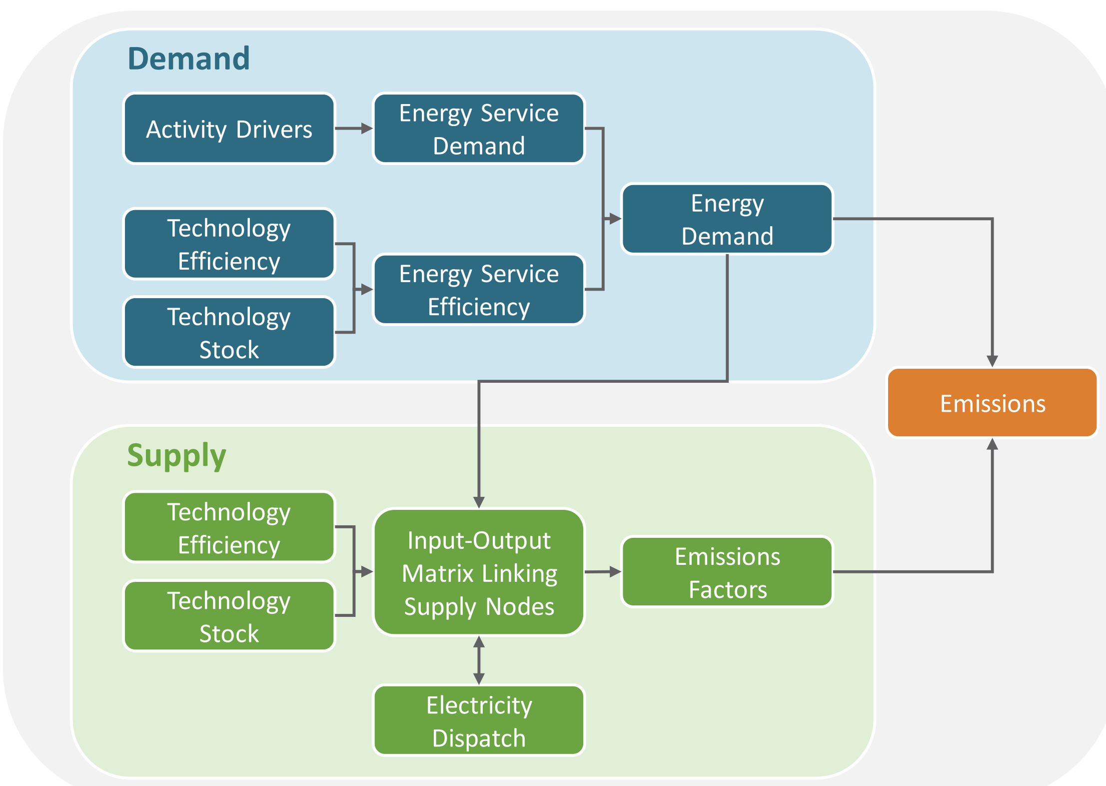
II. Study Assumptions and Approach

A. EnergyPATHWAYS Modeling Framework

We use EnergyPATHWAYS, a bottom-up energy systems model, to estimate energy demand, emissions and costs for each future energy scenario. Our analysis starts with the same model and approach we have previously used to evaluate deep decarbonization for the United States, the State of Washington and other jurisdictions. We developed a detailed representation of the PGE service territory's energy system, including infrastructure stocks and energy demands for buildings, industry, and transportation. Our analysis incorporates an hourly dispatch of PGE's electricity system, which allows us to better understand fundamental changes to electricity supply and demand, such as how to balance very high levels of intermittent renewables and the impact of electrification on hourly load.

Figure 2 depicts the general structure of EnergyPATHWAYS with the demand- and supply-side of the energy system shown separately. The demand-side calculates the quantity of energy demanded by different services at the technology level, such as the kWh of electricity and therms of pipeline gas demanded by water heaters in the residential sector. The supply-side determines how energy demand is met, such as the share of electricity provided by gas-fired combined cycle power plants, onshore wind power plants and rooftop solar PV. The energy system is simulated in sequence with the demand-side run prior to the supply-side.

Figure 2 General Structure of EnergyPATHWAYS



The demand-side starts with exogenous projections of activity drivers, such as population, households, commercial floorspace and industrial value of output. These drivers serve as the basis for projecting demand for energy services. For example, as the number of total residential households and square footage increases, then the demand for lighting will similarly increase. The technology composition of the stock along with the efficiency of each technology creates a service efficiency. In the lighting example, a transition from incandescent to CFL and LED light bulbs would improve service efficiency. Energy service demand and service efficiency are then combined to calculate the demand for energy, while the fuel type depends on the stock of technologies used to satisfy the demand for energy services.[5]

The supply-side is characterized by an input-output (IO) matrix that specifies the flow of energy between "supply nodes" that produce or deliver energy. Examples of supply nodes include power plants and transmission and distribution infrastructure. The coefficients in the matrix specify the amount of input energy required to produce one unit of output energy. For example, a gas-fired combined cycle power plant with a heat rate of 6,824 Btu/kWh (50% efficiency) would require 2.0 units of natural gas to generate 1.0 unit of electricity. These coefficients are dynamic and reflect: (1) changes in the composition and efficiency of supply-side technologies; and (2) outputs from an hourly electricity dispatch (i.e., the generation mix). From this process, emission factors are developed for each fuel. Finally, the emission factors from the supply-side are combined with final energy demand from the demand-side to estimate system-wide emissions.

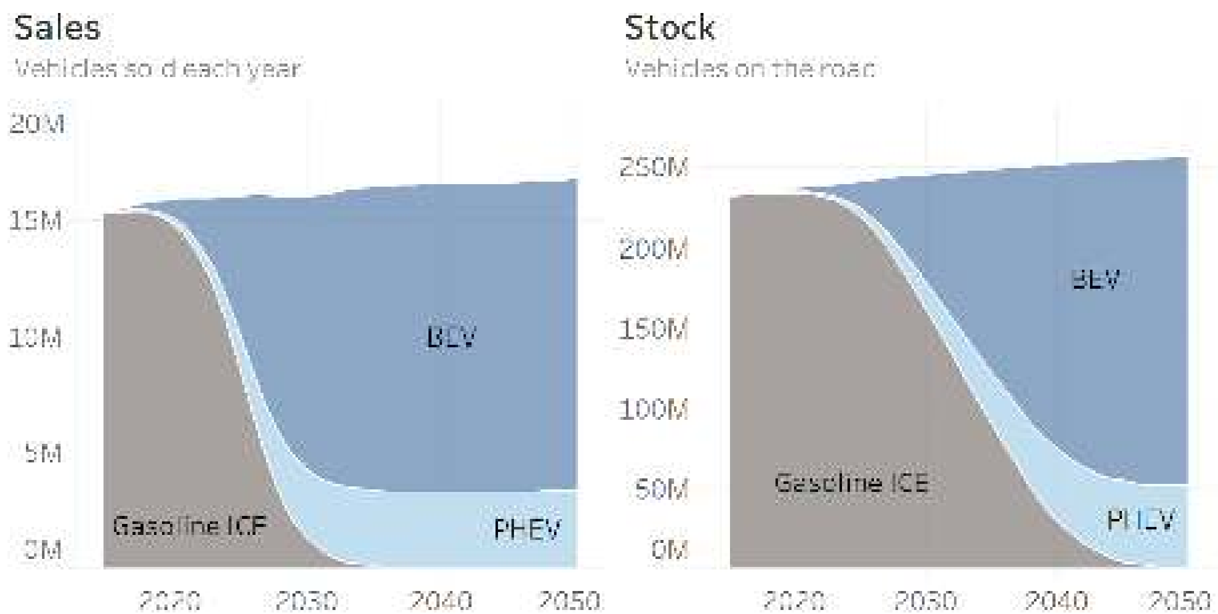
To reduce emissions, we develop measures to replace existing demand- and supply-side equipment and infrastructure with efficient and low-carbon technologies. For example, passenger travel currently provided by a gasoline vehicle is replaced by an EV, and a CFL light bulb is replaced by an LED light bulb. Future energy scenarios are designed by combining measures across sectors at the scale and rate necessary to meet the study's emissions target.

We implement measures through a stock rollover process, where a portion of energy infrastructure retires in each year and must be replaced by new energy infrastructure. In a baseline scenario, retiring infrastructure is generally replaced with the same category of technology, but the cost and performance characteristics reflect the more recent installation year (e.g., a retiring reference dishwasher is replaced by a new reference dishwasher). Alternatively, measures specify the composition of new energy infrastructure (e.g., half of vehicle sales are plug-in hybrid electric vehicles by 2025).

The stock rollover process is illustrated for light-duty vehicles in Figure 3, where the measure shown on the left-hand side of the chart specifies that sales of new light-duty vehicles are 80 percent BEV and 20 percent PHEV by 2035. Changes to the vehicle stock, shown on the right-hand side, are moderated by this process and BEV/ZEV vehicles do not make up all vehicles on the road until 2050. All scenarios in this study assume that infrastructure is retired naturally (i.e., at the end of its lifetime), and there are no early retirements.

[5] A portion of electric energy can be dispatched (i.e., flexible load), and this process is modeled on the supply-side.

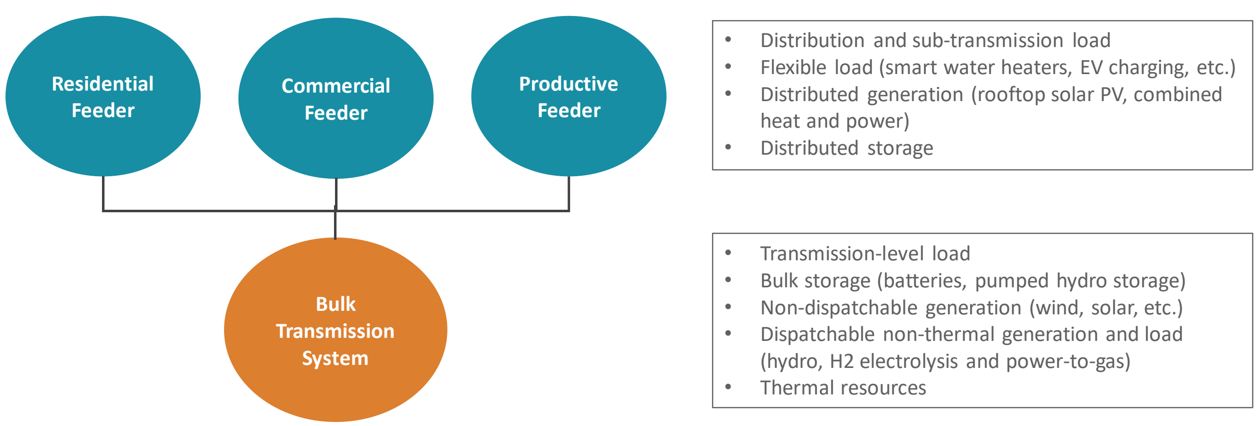
Figure 3 Illustrative Example of Stock Rollover in EnergyPATHWAYS



B. Electricity Sector Modeling

Electricity system operations in EnergyPATHWAYS are modeled on an hourly basis for each year through 2050. This includes a detailed representation of loads and resources at the feeder-level and the bulk transmission system. The structure of the electric system is shown in Figure 4 below, with the boxes illustrating the type of resources included within each node. Electricity dispatch and the development of load shapes are further described below, and we illustrate our approach for a three-day period (February 6-8, 2050).

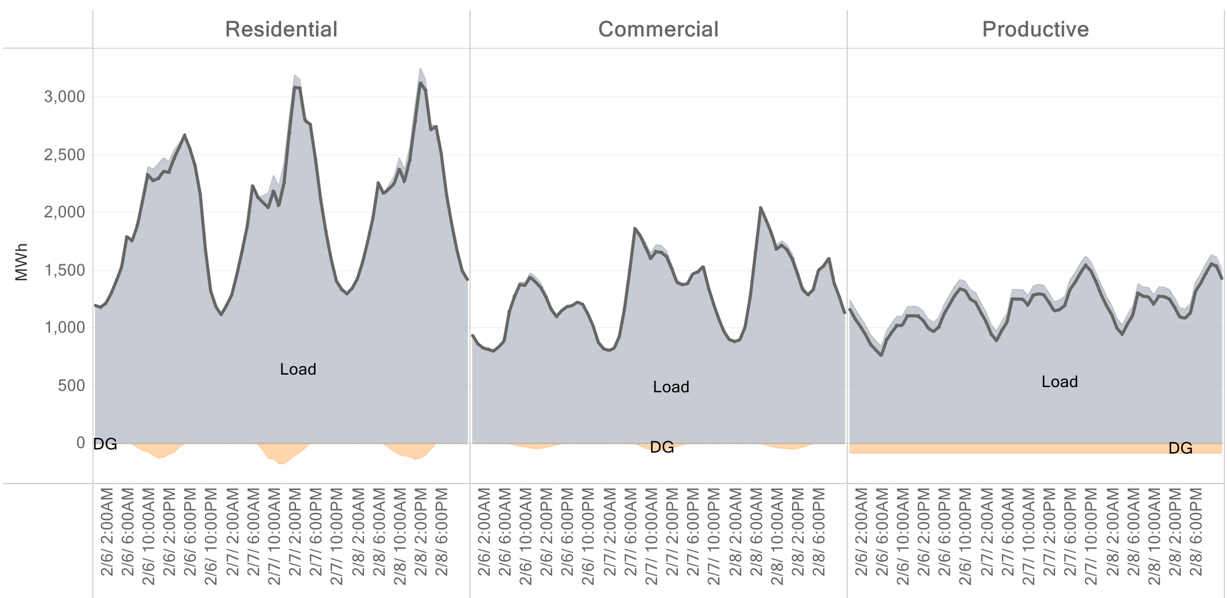
Figure 4 EnergyPATHWAYS Electricity System Structure



System load shapes are developed from the "bottom-up" by multiplying hourly sector, sub-sector, and technology-specific load shapes by the associated annual electricity consumption.[6] The bottom-up shape is then calibrated against a historical, top-down system load shape. Going forward, the system load shape changes in each year as the contribution from end-uses evolves. For example, as LED lighting penetration increases, then night-time demand will decrease due to their higher efficiency relative to incandescent and CFL light bulbs. In addition, the electrification of space heating will increase electric load during winter hours to account for the contribution of heating during winter months.

Sub-sector loads are aggregated to sectors and mapped to a "stylized" residential, commercial and/or productive (industrial) feeder, which models customer type at the distribution level. This is primarily to allocate electric vehicle charging, which could take place at home or at the workplace, onto the electricity distribution system. Distributed generation, such as combined heat and power (CHP) and rooftop solar PV resources are modeled across feeders. Figure 5 shows load and distributed generation for three feeders with the net load shown as the black line.

Figure 5 Distribution System: Net Load



Note: figure is illustrative.

The bulk transmission system receives the distribution-level net load and combines them with transmission-level loads, such as electrolysis and power-to-gas facilities. Output from non-dispatchable resources on the transmission system, such as wind, solar, geothermal and run-of-river hydro, is then accounted for to produce an initial system net load signal, as shown in Figure 6 below. During this three-day snapshot, the minimum net load in a single hour is -4,734 MW due to the coincidence of high wind and solar generation.

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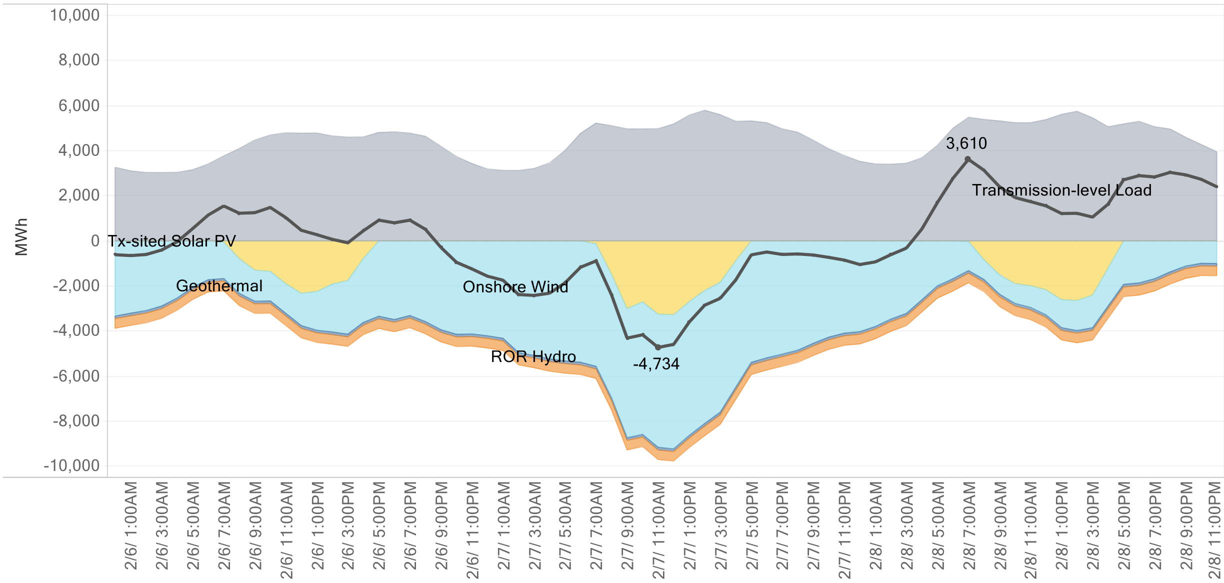
[6] Load and resource shapes reflect 2011 weather conditions.

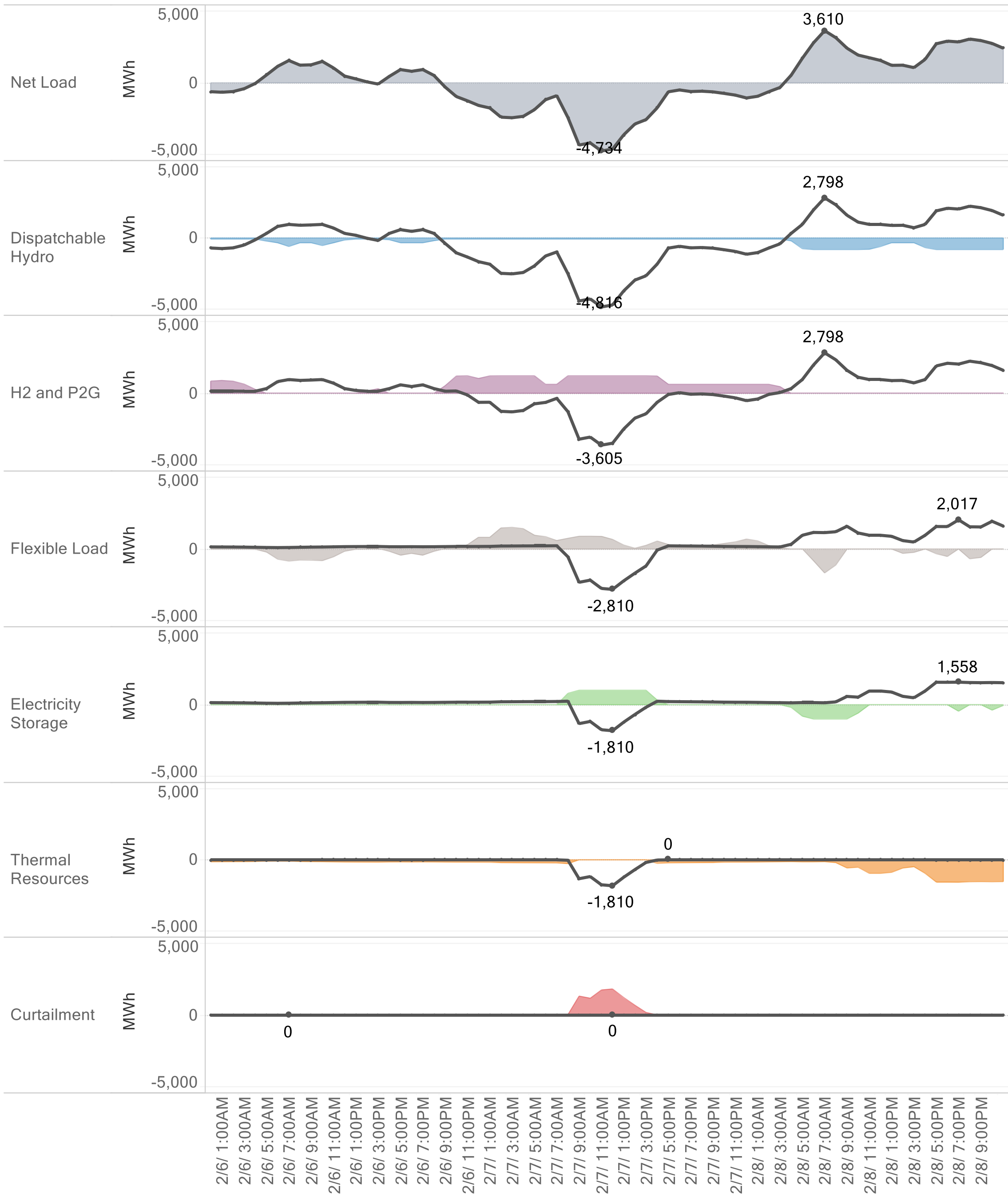
Figure 6 Transmission System: Net Load



Note: figure is illustrative.

Figure 7 illustrates the dispatch of flexible resources in sequence, with each resource dispatching to minimize the net load peaks and valleys. During the three-day period, net load starts with a maximum of 3,610 MW and and a minimum of -4,734 MW. Flexible, carbon-free resources, including dispatchable hydro plants, electric fuel production facilities, flexible loads and energy storage, flatten the net load to a maximum of 1,558 MW and a minimum of -1,810 MW. Thermal generators are dispatched in order of marginal cost to serve the remaining positive net load, while the remaining negative net load is curtailed.

Figure 7 Flexible Resource Dispatch



Note: figure is illustrative.

We model all generation resources in PGE's system, including existing power plants and contracts. The capacity of these resources was provided by PGE, and we developed plant heat rates (efficiencies) for thermal resources based on historical generation and fuel input data from Form EIA-923. Hydro resources are differentiated between dispatchable (e.g., Pelton-Round Butte) and run-of-river, and both resources types are constrained by a monthly energy budget. For imports, we use projected electricity market prices (in $/MWh) and natural gas prices (in $/MMBtu) provided by PGE to develop market heat rates (in MMBtu/MWh) to both cost and assign an emissions intensity.

We use the following heuristic to ensure the quantity of installed generating capacity meets system load in every hour of the year. First, “annual capacity need” is estimated as the maximum hourly net load plus operating reserves. Next, the installed capacity of dispatchable resources is de-rated by their forced outage rate to estimate their contribution. Finally, generic capacity resources are added to fill any gap between “annual capacity need” and the contribution of dispatchable resources. We assume generic capacity resources have the cost and performance characteristics of a frame type combustion turbine, which is consistent with PGE’s IRP.

We note that our modeling results may differ from PGE’s IRP due to the use of alternative models and the inclusion of direct access loads in our scope. We describe the electricity resources for each scenario in Section III.B.1 below.

C. Energy Demand and Supply

EnergyPATHWAYS was originally developed to assess deep decarbonization for the United States, and most of the energy demand and supply inputs are drawn from the EIA’s National Energy Modeling System (NEMS) that produces the *Annual Energy Outlook*.[7] NEMS input data is comprehensive of the U.S. energy system and internally consistent. The primary geography for energy demand in NEMS is the census division, which each include a collection of states. For example, the Pacific census division includes Washington, Oregon and California, while the Mountain census division aggregates the remaining states in the West.

Given the common input data and energy system representation, EnergyPATHWAYS also uses census division as the primary geography. However, the model is geographically flexible by accepting energy demand and supply input data at a variety of geographical resolutions (e.g., state-level) and mapping these together onto one consistent geography. We used this geographic mapping feature to develop the underlying energy system representation for PGE’s service territory. Figure 8 illustrates this process, where energy system data for a variety of geographies is mapped to PGE’s service territory. This “downscaled” energy data is combined with direct inputs of PGE’s service territory to characterize the entire energy system. To allocate input data at various geographical resolutions to PGE’s service territory, we used: (1) households by county in PGE’s service territory; (2) land area (in square miles) by county in PGE’s service territory; and (3) value of shipments of products by industrial sector by state of origin, which allows us to estimate the quantity of industrial activity within a given subsector and state.[8]

[7] For example, see Risky Business Project (2016).

[8] PGE provided county-level households and land area. Value of shipments data is from the Bureau of Transportation Statistics and Federal Highway Administration’s 2015 Freight Analysis Framework.

Figure 8 Geographic Downscaling

Table 2 summarizes the primary input data sources for energy demand by subsector. We use the 2013 PGE Residential Appliance Saturation Survey (RASS) to characterize the existing stock of the residential space heating, air conditioning and water heating subsectors. This includes the composition of technologies and fuels used in single-family, multi-family and manufactured homes. Energy use intensity (energy consumption per stock) is derived from the EIA's Residential Energy Consumption Survey (RECS) and the Northwest Energy Efficiency Alliance's (NEEA) Residential Building Stock Assessment. Energy demand for the remaining residential subsectors (e.g., refrigerators, dishwashers, etc.) is from the EIA AEO 2017. Vehicle miles traveled (VMT) for light-, medium- and heavy-duty vehicles are from Oregon's 2017 Highway Cost Allocation Study (HCAS), while the remaining energy demand is primarily from the EIA's AEO 2017.

Table 2 Summary of Energy Demand Input Data

Demand Subsector	Input Data Sources	Input Data Geography
Residential Space Conditioning and Water Heating	PGE 2013 RASS Study: existing stocks	Service Territory
	EIA RECS and NEEA: energy use intensity	State
Other Residential Subsectors	EIA AEO 2017: energy demand	Census Division
Commercial Subsectors	NWPCC 7th Power Plan: square footage	State
	EIA AEO 2017: energy demand	Census Division
Industrial Subsectors	EIA AEO 2017: energy demand	Census Region
Passenger and Freight Transportation	2017 Oregon HCAS: vehicle miles traveled	State

We compared the initial bottom-up energy demand projections against top-down energy demand data from the EIA's State Energy Data System (SEDS), which includes historical energy demand by fuel and sector. We calibrated EnergyPATHWAYS to reconcile any differences between our near-term modeling outputs and historical data by scaling energy service demand or energy demand. We further calibrated electricity consumption by sector to ensure consistency with PGE's load forecast through 2050.

Energy demand projections are developed separately for a variety of final energy types, which can broadly be categorized as: (1) electricity; (2) pipeline gas; and (3) liquid fuels.[9] Table 3 summarizes the types of resources that can supply each final energy type, and the supply mix determines the emissions intensity of fuels. For example, electricity can be supplied by a variety of fossil and carbon-free

[9] Additional final energy types are modeled, but these represent the vast majority of final energy demand.

resources, and Section III.B.1 details electricity supply assumptions for PGE's service territory. Pipeline gas can be supplied with a mix of natural gas, renewable natural gas (RNG) produced from bioenergy, hydrogen (H2) produced through electrolysis, and synthetic natural gas (SNG) produced though power-to-gas (P2G). Liquid fuels are supplied by refined fossil sources, as well as fuels developed using bioenergy (i.e., renewable diesel and jet fuel).

Table 3 Final Energy Types and Supply Sources

Category	Final Energy Type	Supply Sources
Electricity	Electricity	Coal and natural gas (fossil); hydro; wind; solar PV; geothermal
Pipeline Gas	Pipeline Gas	Natural gas (fossil); RNG (biomethane); H2; SNG
	Compressed Pipeline Gas (CNG)	
	Liquefied Pipeline Gas (LNG)	
Liquid Fuels	Gasoline	Fossil gasoline; ethanol
	Diesel	Fossil diesel; renewable diesel
	Jet Fuel	Fossil jet fuel; renewable jet fuel

D. Biomass

Biomass is key resource for decarbonizing energy systems due to its versality, which allows for biofuels to directly replace both liquid and gaseous fossil fuels. Examples of conversion routes include renewable natural gas (RNG) that replaces natural gas and renewable diesel that replaces diesel. However, the supply of sustainable or net-zero carbon bioenergy resources is limited, and, in prior analyses, scarce bioenergy resources are allocated to fuels and sectors that are challenging to electrify, such as jet fuel for aviation.

In this study, we use the U.S. Department of Energy's *2016 Billion-Ton Report* as the primary source for the availability and cost of bioenergy resources. Given that the supply curve is for the U.S., we make the following assumptions. First, the PGE service territory's allocation of the national supply is its population-weighted share, which is equal to 7.3 million dry tons (MDT), as shown below:

$$PGE's\ share = \frac{PGE\ population}{U.S. population} \times U.S. supply\ of\ sustainable\ biomass\ feedstocks$$

$$7.3\ MDT = \frac{1.8\ million}{320.9\ million} \times 1{,}300\ MDT$$

Second, we assume that other jurisdictions pursue similar bioenergy-related actions, which means that the cost of producing and consuming biofuels reflects movement up the national supply curve. This assumption addresses two considerations: (1) for sub-national (e.g., state or utility service territory) deep decarbonization analyses, it would be unrealistic to assume individual jurisdictions all consume the same (low-cost) portion of the bioenergy supply curve; and (2) given the high cost of transporting biomass across long distances, it's likely that biofuels would be developed close to their source and transported across the country via the same networks that currently transport fossil fuels. Finally, we assume that the biomass feedstock is net-zero carbon, which results in biofuels with very low emissions rates due to some emissions from non-bioenergy use in conversion and refining processes.

E. Key Data Sources

Table 4 summarizes the key data sources used in our energy system modeling. We use data from PGE's 2016 IRP to characterize the cost and performance of electricity supply technologies and rely on the 2013 PGE RASS study to characterize the existing stock of residential appliances, as described above. This is supplemented by state and regional data sources, such as Oregon's Office of Economic Analysis (OEA) and the Northwest Energy Efficiency Alliance (NEEA). Most of the remaining sources are publicly-available reports produced by national laboratories, such as the U.S. Department of Energy (DOE).

Table 4 Overview of Key Data Sources

Category	Sources
Energy Supply Technology Cost and Performance	• PGE 2016 Integrated Resource Plan • NREL Annual Technology Baseline 2017 • EIA Form 923 • DOE Hydrogen Analysis (H2A) Project • ENEA Consulting (2016)
End-Use Technology Cost and Performance	• Input data for EIA's National Energy Modeling System (NEMS) used to produce the Annual Energy Outlook • NREL Electrification Futures Study: End-Use Electric Technology Cost and Performance Projections
Building Stock Characteristics	• PGE 2013 Residential Appliance Saturation Study • NEEA Building Stock Assessment reports
Fossil Fuel Prices	• EIA Annual Energy Outlook 2017
Miscellaneous	• DOE 2017 Billion-Ton Report • FERC Form 714 • 2017 Oregon Highway Cost Allocation Study • OEA Forecasts of Oregon's County Populations and Components of Change, 2010 – 2050

Note: DOE is the U.S. Department of Energy; EIA is the U.S. Energy Information Administration; FERC is the Federal Energy Regulatory Commission; NEEA is the Northwest Energy Efficiency Alliance; NREL is National Renewable Energy Laboratory; and OEA is Oregon's Office of Economic Analysis.

III. Scenarios

A. Overview

Table 5 provides an overview of the three pathways included in this study, which each incorporate alternative emissions reduction strategies and technologies. One of the primary objectives of our scenario design was to reflect a broad range of outcomes for the electricity sector.

The **High Electrification** pathway relies on electrifying space and water heating in buildings and deploying bulk energy storage to balance high levels of renewable generation. Passenger transportation is characterized by high levels of battery electric vehicles (BEV), while freight transportation includes both battery electric and hybrid diesel trucks. The **Low Electrification** pathway decarbonizes energy supply with a variety of renewable fuels, and electrolysis and power-to-gas facilities provide both electricity balancing services and decarbonized pipeline gas. Passenger transportation is primarily BEV, while compressed and liquefied natural gas trucks are incorporated in the freight transportation sector. The **High DER** pathway is highly electrified and distributed, with increased rooftop solar PV and distributed energy storage in buildings and industry.

To provide a benchmark to compare the pathways against, we developed a **Reference Case** that projects business-as-usual conditions. This includes compliance with state-level policy such as the OCEP and CFP, as well as major federal policy such as improvements in corporate average fuel economy standards. The scenario is not designed to achieve an emissions target.

Table 5 Overview of Scenarios

Scenario	Description
High Electrification	Fossil fuel consumption is reduced by electrifying end-uses to the extent possible and increasing renewable electricity generation
Low Electrification	Greater use of renewable fuels, notably biofuels and synthetic electric fuels, to satisfy energy demand and reduce emissions
High DER	Distributed energy resources proliferate in homes and businesses, which also realize higher levels of electrification
Reference	A continuation of current and planned policy, and provides a benchmark against the deep decarbonization pathways

Although the future energy scenarios are characterized by alternative mitigation strategies, they are all constrained by a set of common scenario design principles. This conservative approach allays a broad range of concerns surrounding the technical feasibility and economic affordability of realizing a deeply decarbonized energy system, such as the need for revolutionary technological improvements or disruptive lifestyle changes. The scenario design principles in this analysis include: (a) applying the same demand for energy services; (b) replacing energy infrastructure at the end of its natural life (i.e., there are no early retirements); (c) using commercial or near-commercial technologies; (d) limiting the supply of sustainable bioenergy use; and (e) ensuring there are sufficient electricity resources to serve load in all hours. The sections below describe the energy supply and demand assumptions for each pathway.

B. Energy Supply

1. Electricity Resources

Table 6 summarizes our electricity supply assumptions for each pathway. Coal-fired resource assumptions are consistent with PGE's 2016 IRP and OCEP, where Boardman ceases operations by the end of 2020 and Colstrip units 3 and 4 are out of the resource mix by 2035. We assume the capacity of PGE's existing gas-fired resource fleet is online through 2050, while the amount of energy generated from these resources is a function of our electricity dispatch.

Hydroelectric resources include Pelton-Round Butte, run-of-river (ROR) hydro, Mid-C hydro and other contracts. We assume projected hydro resources and contracts are extended through 2050 (a total of 933 MW), and an additional 23 MW of small hydro is placed on-line in 2035. We assume new geothermal resources of 100 MW in 2035 and growing to 500 MW by 2050. Prior studies have identified 832 MW of conventional geothermal potential in Oregon with a further undiscovered enhanced geothermal system potential of 1,800 MW.[10]

The High DER pathway includes approximately 2,500 MW of behind-the-meter (BTM) solar PV resources across buildings and industry by 2050. We developed this target based on the technical potential of distributed solar PV across PGE's service territory identified in the 2016 IRP.[11] The High and Low Electrification pathways assume approximately 400 MW of BTM solar PV, which is two times the highest level of adoption from the same study.

Pathways rely on high levels of transmission-connected wind and solar PV to decarbonize electricity generation, including: (a) onshore wind located in the Pacific Northwest (PNW); (b) onshore wind located in central Montana; and (c) solar PV located in central Oregon. Approximately 75 percent of electricity generation comes from these resources in the High and Low Electrification pathways, and this level is lower in the High DER pathway due to the quantity of BTM solar PV resources. The installed capacity of these resources depends on the level of transmission-connected load.

Our Reference Case reflects current RPS policy (i.e., 50% in 2040) and any gap between the RPS obligation and generation from existing/projected qualifying resources is met with an equal amount of energy from PNW onshore wind and central Oregon utility-scale solar PV resources. Our analysis did not consider low-carbon generation from new carbon capture and storage (CCS) or nuclear resources.

[10] See Pletka and Finn (2009).

[11] See Table 1-3 of Black and Veatch (2015). Technical potential of 2,810 MW_{dc} translated to 2,555 MW_{ac} assuming an inverter loading ratio of 1.1.

Table 6 Electricity Supply

	High Electrification	Low Electrification	High DER
Coal	Boardman ceases operations by the end of 2020 Colstrip 3 and 4 out of the resource mix by 2035		
Gas	Maintain current fleet		
Hydro	Extend projected hydro contracts through 2050 (933 MW) Additional 23 MW of small hydro		
Geothermal	500 MW additional		
Behind-the-meter Solar PV	405 MW_{ac}		2,555 MW_{ac}
Utility-scale Wind and Solar PV	75% of electricity generation		67% of electricity generation

Note: values for 2050 unless specified otherwise.

The high levels of variable renewable generation included in the pathways necessitate balancing resources to ensure renewables are sufficiently integrated. Table 7 summarizes the flexible resource assumptions for each pathway, all of which include 36 MW/160 MWh of energy storage that comes online in 2021 to approximate PGE's proposed energy storage projects. Balancing in the High Electrification pathway is accomplished through 1,000 MW of bulk 8-hour energy storage, whereas the High DER pathway relies on 2,555 MW of distributed 6-hour storage, which is sized to the same capacity of distributed solar PV. No additional energy storage is developed in the Low Electrification pathway, which alternatively relies on flexible electrolysis and P2G loads. The size of these facilities depends on demand for hydrogen and synthetic natural gas, respectively.

All pathways incorporate flexible demand from select end-use sectors where: (a) load automatically shifts with changing electricity grid conditions; and (b) total electricity consumption does not change.[12] For example, the owner of an EV may wish to charge his or her vehicle when they arrive home, but they're willing to delay charging to later in the evening without affecting the ability to take future trips. Two promising electric loads to operate flexibility include: (1) loads that have a thermal storage medium (i.e., hot water heater) that can operate within a range and allow for flexible operation without service degradation; and (2) transportation loads that require battery storage, which can allow for flexible charging and state-of-charge management without degrading service.

We assume 75 percent of load from light-duty vehicles and water heaters in buildings is flexible by 2050, and 50 percent is flexible in residential space conditioning, residential clothes washing and drying, and commercial space heating subsectors. The amount of flexible load in each pathway depends on the level of electrification, and the higher quantity of electric appliances (e.g., heat pump water heaters) in the High Electrification and High DER pathways provides higher end-use demand flexibility relative to the Low Electrification pathway.

[12] Flexible load is further constrained by the number of hours load can be delayed and advanced in time.

Table 7 Balancing Resources

	High Electrification	Low Electrification	High DER
Energy storage	Proposed energy storage resources (36 MW / 160 MWh)		
	1,000 MW bulk 8-hour storage	No additional	2,555 MW distributed 6-hour storage
Flexible Electric Fuel Loads	Excluded	H2 electrolysis and P2G facilities	Excluded
Flexible End-Use Loads	Percent of electric load that is flexible by 2050: • Light duty vehicles = 75% • Residential and commercial water heating = 75% • Residential space conditioning = 50% • Residential clothes washing and drying = 50% • Commercial space heating = 50%		

2. Liquid and Pipeline Gas Fuel Blends

Table 8 summarizes our assumptions about the composition of pipeline gas, diesel and jet fuel in 2050. The Low Electrification pathway is characterized by several renewable fuels to decarbonize energy supply. Pipeline gas for buildings and industry is assumed to contain 15 percent renewable natural gas (RNG) and 15 percent synthetic electric fuels (H2 and SNG). The share of RNG is 85 percent in pipeline gas that is further liquefied or compressed for transportation vehicles, while the share of H2 and SNG is the same. Biomass is further used to produce liquid transportation fuels (e.g., renewable diesel). The High Electrification and High DER pathways assume no change to the supply of pipeline gas, with all biomass resources allocated to liquid transportation fuels.

Table 8 Liquid and Pipeline Gas Fuel Blend Assumptions in 2050

Type	Blend	High Electrification and High DER	Low Electrification	
		All Sectors	Res/Com/Ind	Transportation
Pipeline Gas	Natural Gas	100%	70%	0%
	RNG	0%	15%	85%
	SNG	0%	8%	8%
	H2	0%	7%	7%
Diesel	Fossil Diesel	0%	0%	0%
	Renewable Diesel	100%	100%	100%
Jet Fuel	Fossil Jet Fuel	0%	0%	0%
	Renewable Jet Fuel	100%	100%	100%

C. Energy Demand

1. Buildings and Industry

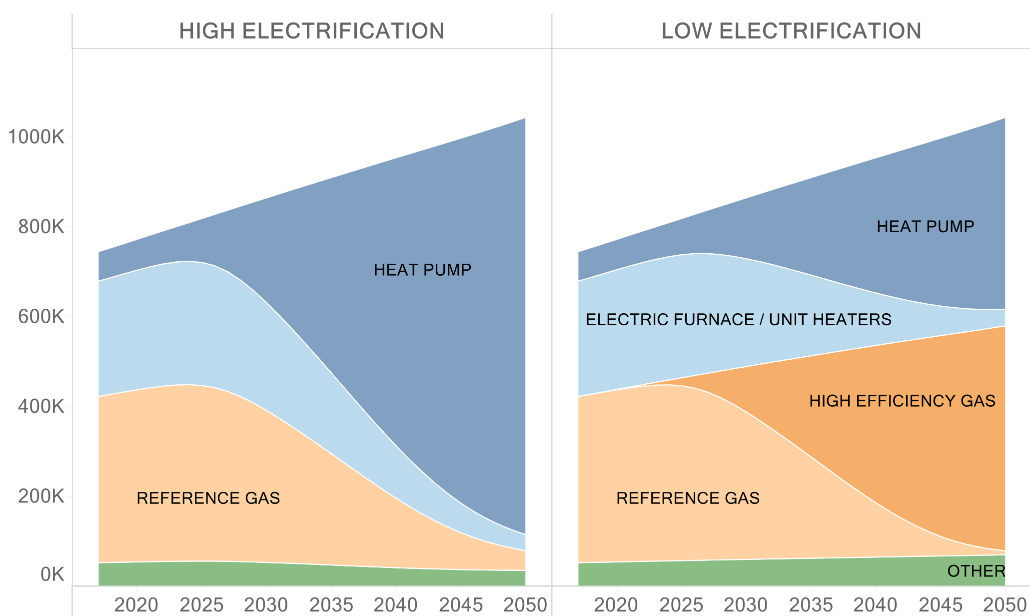
Table 9 summarizes the major low-carbon and efficient technologies in residential and commercial buildings. The High Electrification and High DER pathways are characterized by high levels of air source heat pump (ASHP) adoption for space heating and cooling needs, as well as efficient heat pump water heaters. The Low Electrification pathway relies on high efficiency gas-fired equipment to service space and water heating loads. In both pathways, lighting is provided by LEDs and the best available technology is adopted for other appliances, such as clothes washers, clothes dryers, refrigerators, etc.

Table 9 Predominant End-use Technologies in Buildings

	High Electrification and High DER	Low Electrification
Space Conditioning	Air source heat pump	High efficiency gas furnace High efficiency air conditioner
Water Heating	Heat pump water heater	High efficiency gas water heater
Lighting	LED	
Other Appliances	Best available technology	

We illustrate the change in today's building equipment by showing the evolution of the residential space heating stock through 2050 in Figure 9. Heat in the High Electrification and High DER pathways is largely provided by heat pumps, which includes both standard systems and ductless, mini-split heat pumps. In contrast, heat in the Low Electrification pathway is met by adopting high-efficiency natural gas furnaces, as well as pursuing electric energy efficiency by replacing electric furnaces and heaters with heat pumps.

Figure 9 Residential Space Heating Stock



We incorporated electrification measures in the High Electrification and High DER pathways for a limited number of industrial end-uses, including process heat and boilers. This was informed by NREL's Electrification Futures Study and includes adoption of electrotechnologies such as industrial heat pumps, resistance heating, induction furnaces and electric boilers.[13] These measures translate into electricity representing slightly less than 10 percent of final energy demand for industrial boilers and process heat by 2050.

2. Transportation

Table 10 summarizes our assumptions for vehicle sales shares in 2035 for passenger transportation and freight trucks. In all pathways, battery electric vehicles (BEV) are 90 percent of light-duty vehicle sales, while the remaining 10 percent is: (a) plug-in hybrid electric vehicles (PHEV) in the High Electrification and Higher DER pathways; and (b) hydrogen fuel cell vehicles (HFCV) in the Low Electrification pathway. We assume battery electric trucks account for half of freight truck sales, while the remaining 50 percent is: (a) hybrid diesel trucks consuming renewable diesel fuel in the High Electrification and High DER pathways; and (b) CNG and LNG trucks consuming decarbonized gas in the Low Electrification pathway.

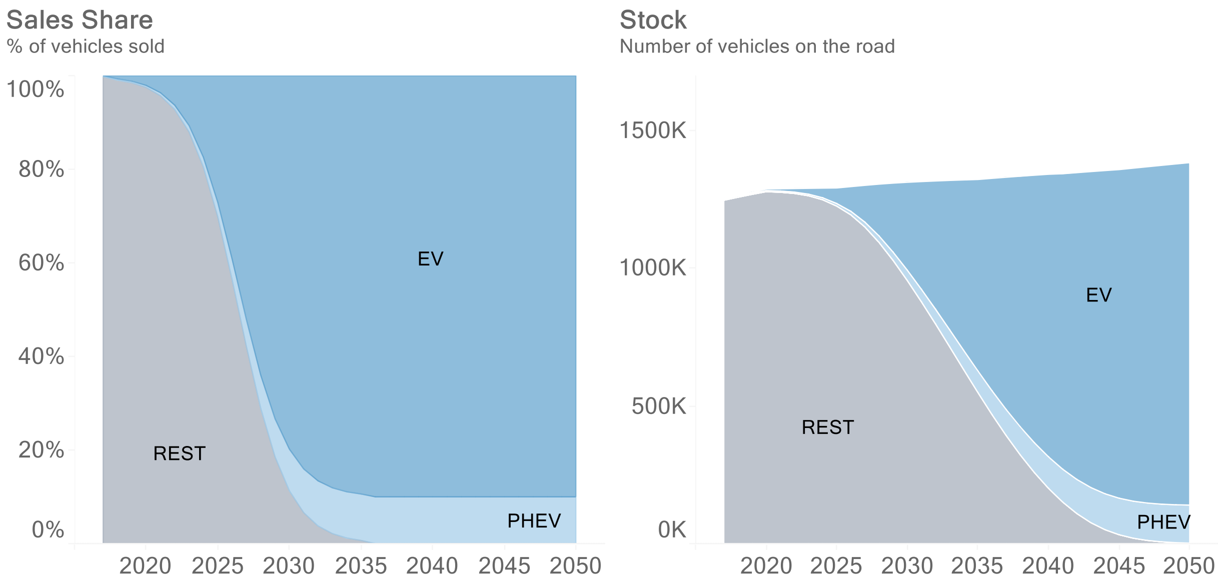
Table 10 On-Road Transportation Vehicle Sales Shares in 2035

Subsector	Technology Type	High Electrification and High DER	Low Electrification
Light-Duty Vehicles	Battery Electric	90%	90%
	Plug-in Hybrid Electric	10%	0%
	Hydrogen Fuel Cell	0%	10%
Medium-Duty Vehicles	Battery Electric	50%	50%
	Hybrid Diesel	50%	0%
	Hybrid CNG	0%	50%
Heavy-Duty Vehicles	Battery Electric	50%	50%
	Hybrid Diesel	50%	0%
	Hybrid LNG	0%	50%

Figure 10 shows how the assumptions in Table 10 change the stock of infrastructure over time, with light-duty vehicle sales shown on the left-hand side and the light-duty stock shown on the right-hand side. In the near-term, EV and PHEV light-duty autos and trucks make up a small portion of sales, but then increase to all vehicle sales in 2035. By the early 2030s, there are more than half a million EVs and PHEVs on the road, but the stock of vehicles does not completely turn-over to ZEVs until the mid-century.

[13] See Section 4 of P. Jadun, et al. (2017).

Figure 10 Light-Duty Vehicle Stock-Rollover: High Electrification Pathway



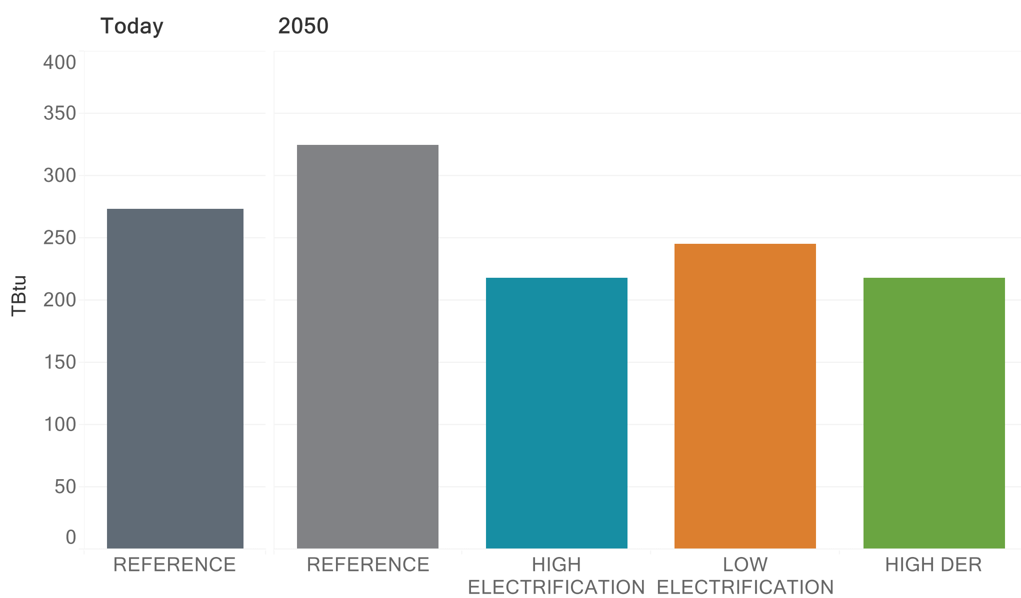
IV. Results: Energy System

In this section, we summarize the changes in the energy system for our future energy scenarios. We report several metrics for the energy system, including final energy demand, energy supply, energy related CO_2 emissions, and incremental energy system costs.

A. High-Level Summary

Reference Case final energy demand is projected to increase from 272 TBtu today to 325 TBtu, approximately a 20 percent increase, as shown in Figure 11 below. End-use demand is projected to increase as the drivers of energy use, such as population and economic activity, all grow through 2050. Final energy is used more efficiently in the pathways scenarios with a range of 218 to 245 TBtu by 2050, which represents a decrease of 25 to 33 percent below the Reference Case in 2050, and 11 to 19 percent below today's level.

Figure 11 Final Energy Demand



Energy-related CO_2 emissions are projected to slightly decrease (-4%) in the Reference Case between 2017 and 2050, as shown in Figure 12. This is largely due to existing policies decarbonizing electricity generation and transportation fuels being offset by growth in overall electricity consumption and vehicle miles traveled. Emissions for all three pathways are below the study's 2050 GHG target of 4.3 $MMTCO_2$. Emissions per capita decrease from 10.9 tCO_2 per person in 2017 to 1.6 tCO_2 per person in 2050, an 85 percent decrease.

Figure 12 Energy-related CO_2 Emissions

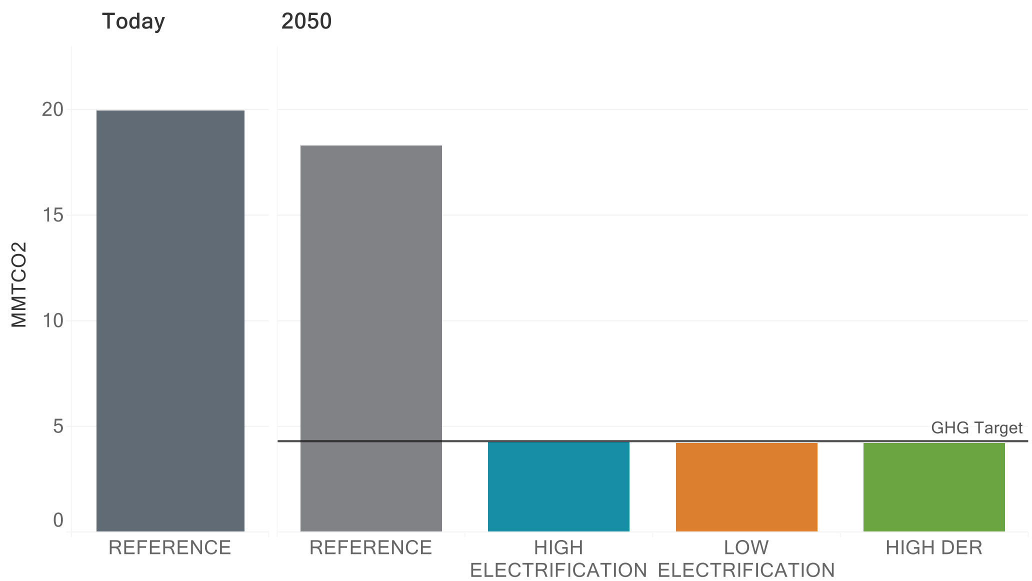
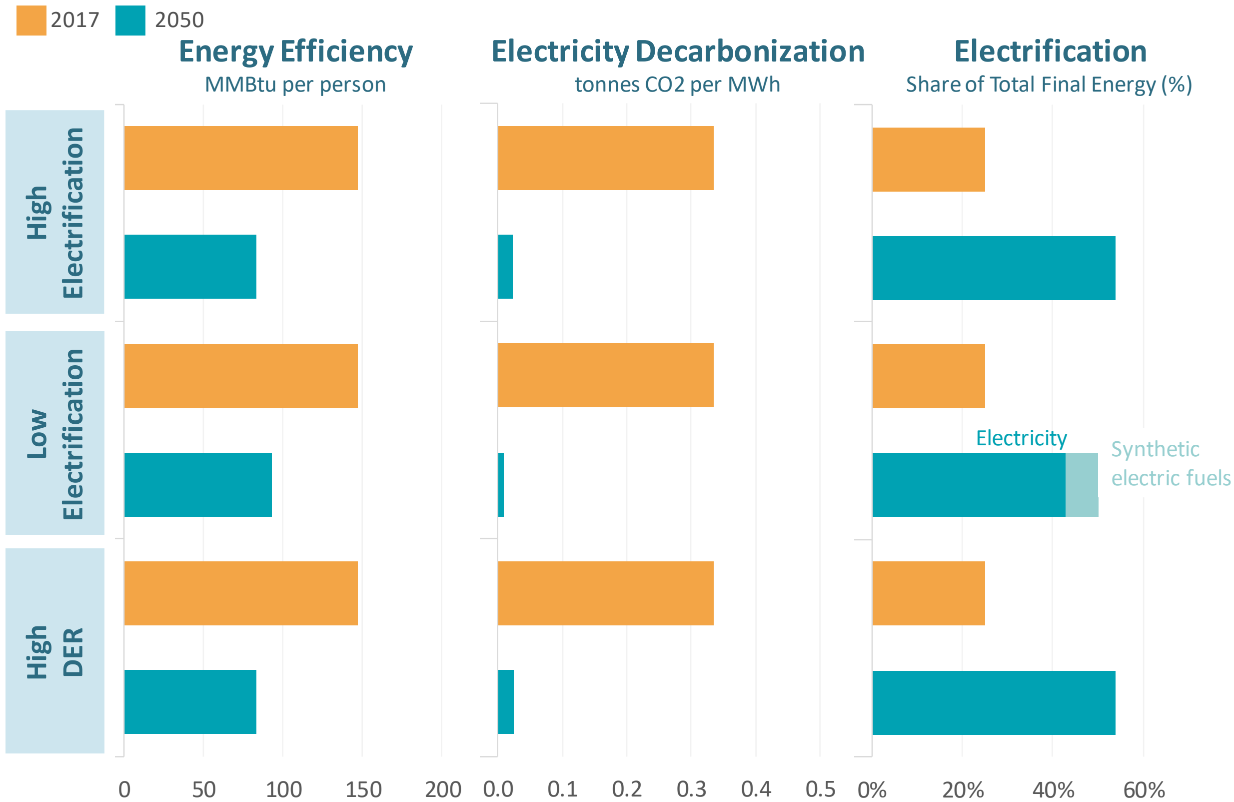


Figure 13 shows three metrics for decarbonization strategies ("three pillars"): (1) energy efficiency, which is estimated as final energy consumed per person; (2) electricity decarbonization, which is measured in tCO_2 emitted per MWh of generation; and (3) electrification, which is expressed as the share of total final energy that is electricity and electric fuels. Per capita energy consumption decreases from approximately 150 MMBtu per person today to between 83 and 93 MMBtu per person, a 37 to 44 percent decrease. This is accomplished without explicit reductions from baseline (Reference Case) energy service demand (e.g., vehicle miles traveled). The carbon intensity of electricity generation decreases by more than 90 percent and is below 0.03 tCO_2/MWh (300 kg CO_2/MWh) in all pathways. The percentage of electricity and electric fuels in total final energy increases from one-quarter today to at least half by 2050. In the Low Electrification pathway, the share of electricity is 43 percent (11 percentage points below the High Electrification pathway), but electric fuels make up 7 percent of total final energy, resulting in a total of 50 percent.

Figure 13 Three Pillars of Decarbonization



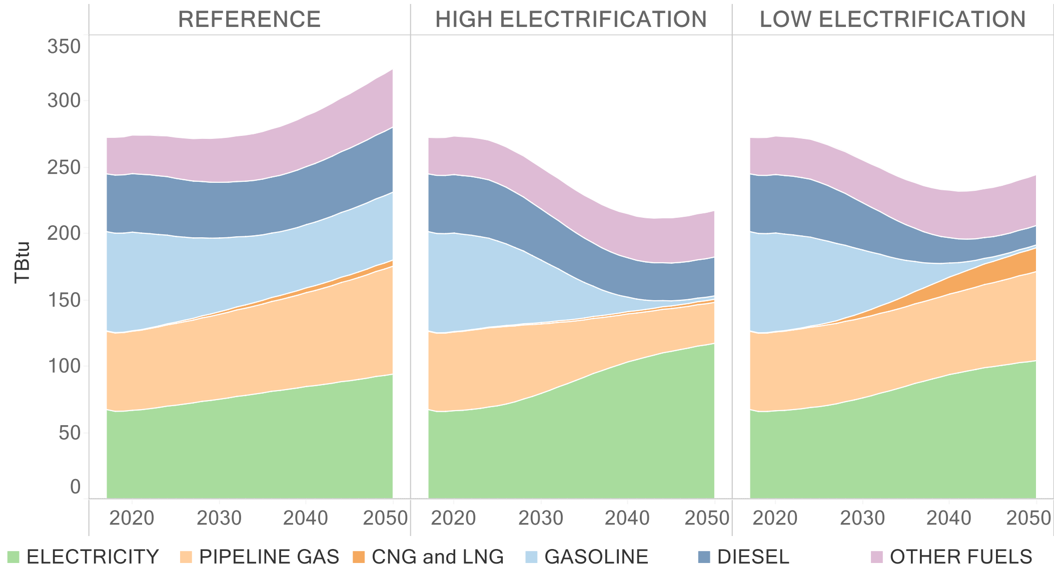
B. Energy Demand

Figure 14 shows end-use demand disaggregated by final energy type for each energy future.[14] The role of electricity expands across all pathways and increases from 25 percent of total end-use demand to 43 to 54 percent in 2050.[15] For comparison, the share of electricity only increases to 29 percent by 2050 in the Reference Case. Demand for liquid transportation fuels, such as gasoline and diesel, sharply decrease in all pathways. This decrease is compensated by higher demand for electricity, as well as CNG and LNG demand in freight transportation in the Low Electrification pathway.

[14] In this section, results for the High DER scenario are not shown, because final energy demand is equivalent to the High Electrification scenario. The impact of increased rooftop solar PV is accounted for when we show retail energy deliveries, which is discussed in Section V.A.

[15] This excludes synthetic electric fuels, which are categorized as "intermediate energy carriers".

Figure 14 Final Energy Demand by Type



Note: "Other Fuels" includes final energy types such as jet fuel, liquefied petroleum gas, biomass, and steam.

Figure 15 summarizes final energy demand for the residential, commercial, productive and transportation sectors. The figure shows Reference Case final energy demand growing over time, with decreases in the transportation sector (primarily due to fuel economy standards) offset by increases in buildings and industry. Total end-use demand decreases by 2050 for all pathways largely due to the efficiency improvements in passenger transportation related to adopting battery electric vehicles. As a result, the transportation sector's share of end-use demand decreases from approximately 46 percent today to 30 percent in 2050. Energy is used more efficiently in residential and commercial buildings, but the level of change varies across pathways based on technology adoption, which we discuss in more detail below.

Figure 15 Final Energy Demand by Sector

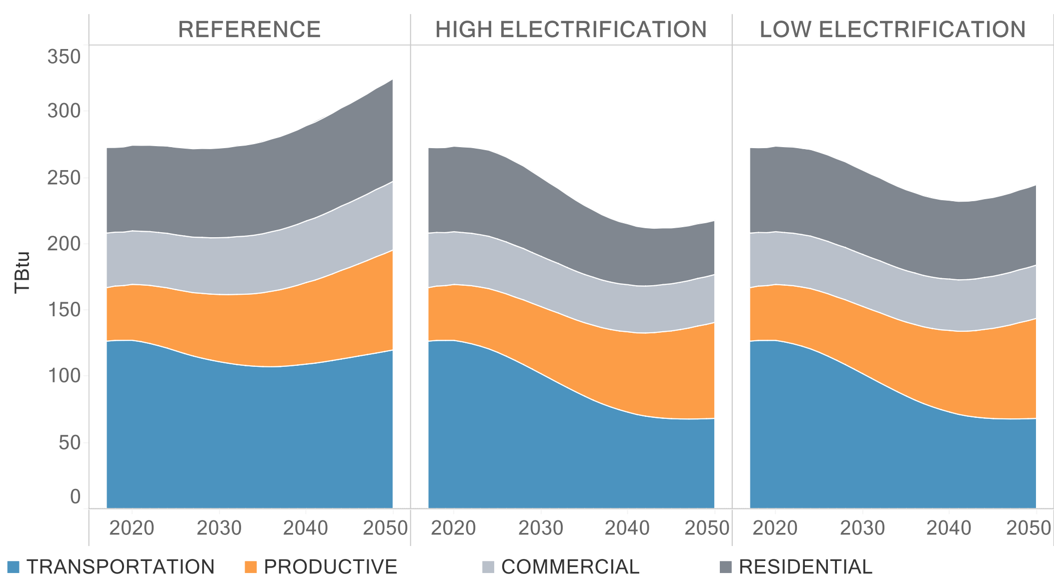
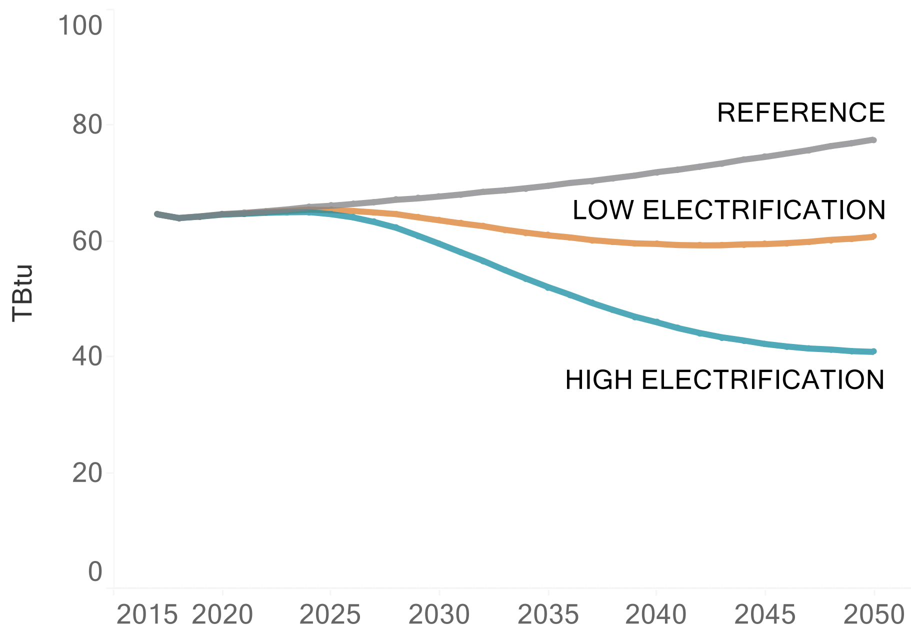


Figure 16 compares projections of residential energy demand and illustrates the improved use of energy in homes in the pathways scenarios relative to the Reference Case. All pathways include several electric energy efficiency measures, such as more efficient clothes washers and dryers, refrigerators, dishwashers and LED lighting. However, the large difference in final energy demand by 2050 between the High and Low Electrification scenarios is due to choices in space and water heating. The High Electrification pathway represents a world where households replace combustion-based furnaces and water heaters with air source heat pumps and heat pump water heaters, respectively. In the Low Electrification pathway, households adopt the most efficient gas furnaces and gas water heaters. However, the efficiency of heat pump technology relative to the best-in-class combustion equipment translates into deeper energy demand reductions.[16]

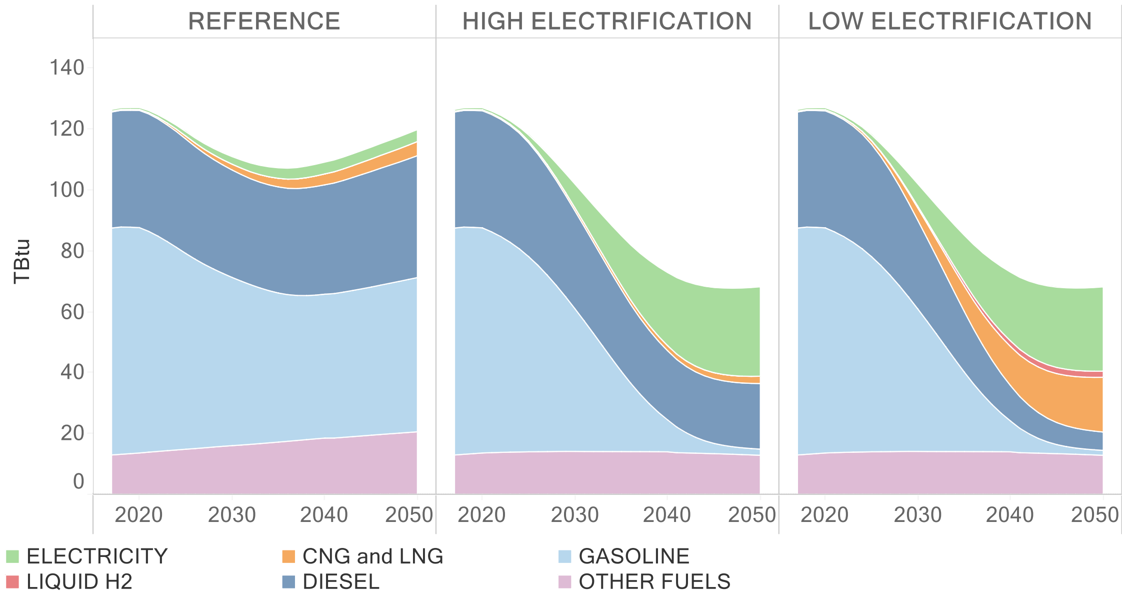
Figure 16 Residential Sector Energy Demand



The projections of energy demand for the transportation sector shown in Figure 17 reflect the changing composition of vehicles on the road. By 2050, the light-duty vehicle fleet is almost entirely electric vehicles, which results in significant decreases in gasoline fuel consumption and only modest increases in electricity consumption, because battery electric powertrains are more efficient than internal combustion engines. In all pathways, half of all freight trucks are electric by 2050, resulting in electricity becoming the largest transportation fuel type. The High Electrification pathway continues to use diesel fuel for the remainder of its freight trucks, but the supply is increasingly renewable diesel (100 percent by 2050). The Low Electrification pathway alternatively relies on hybrid CNG medium-duty trucks and LNG hybrid heavy-duty trucks. By 2050, demand from the CNG and LNG trucks in the Low Electrification pathway accounts for over 20 percent of total pipeline gas demand.

[16] For example, a high efficiency gas furnace has an annual fuel utilization efficiency (AFUE) of 0.98, whereas a standard air source heat pump installed in 2015 in the U.S. has a seasonal coefficient of performance (COP) of 2.45 and this is projected to increase to 3.75 by 2030. See Navigant Consulting (2014) and Jadun, et al. (2017).

Figure 17 Transportation Sector Energy Demand by Final Energy Type



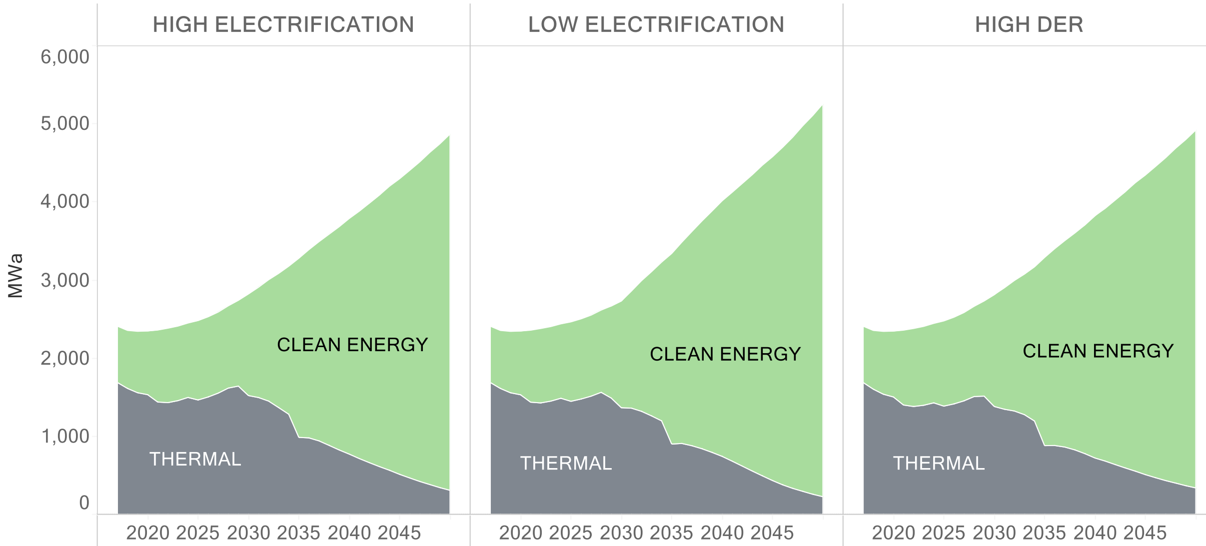
C. Energy Supply

1. Electricity

Figure 18 summarizes electricity supply through 2050, with generation from various resource types categorized as: (a) thermal, which includes generation from coal- and gas-fired resources, generic capacity and market purchases; and (b) clean energy, which includes generation from wind, solar, hydro and geothermal resources.[17] The figure shows that total electricity generation across all pathways grows rapidly, and total generation requirements in 2050 are more than double today's level. In all pathways, generation from non-emitting resources is more than 90 percent of the total and increases by 165 to 190 MWa per year between 2030 and 2050. Generation from thermal resources decreases significantly after 2035, and annual generation falls between 300 and 400 MWa by 2050.

[17] Our generation projections are not directly comparable to PGE's most recent IRP dispatch modeling due to the vintage of the load forecast provided for this study and the inclusion of direct access loads.

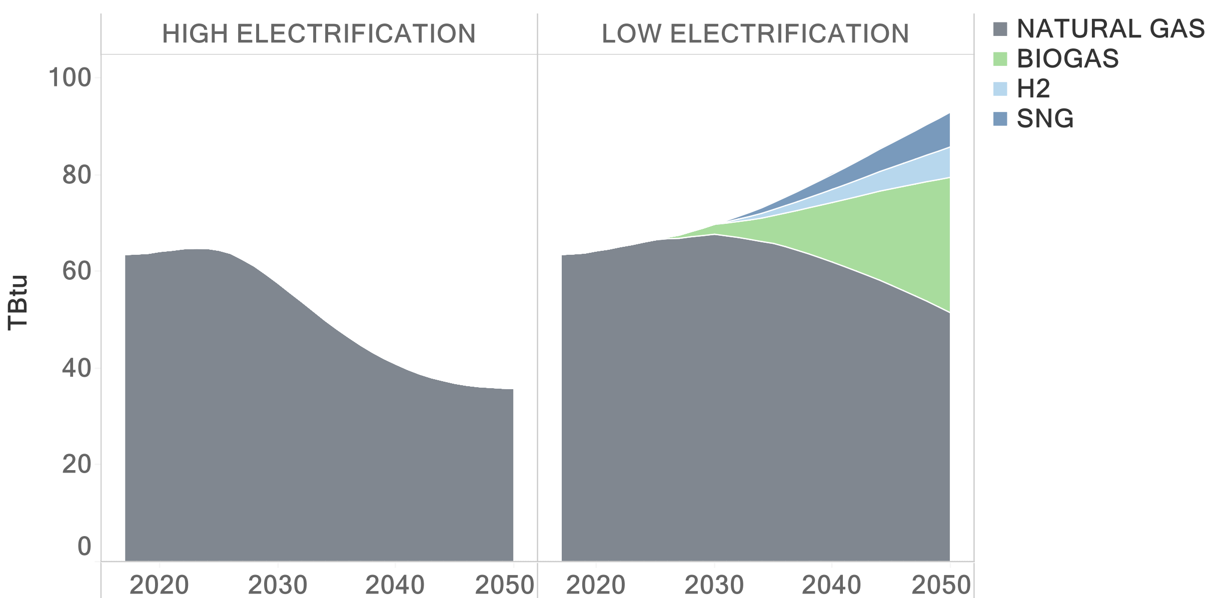
Figure 18 Electricity Supply



2. Pipeline Gas

Figure 19 compares pipeline gas supply for the High Electrification and Low Electrification pathways. In the High Electrification pathway, the pipeline gas supply remains entirely natural gas and total supply decreases by more than 40 percent relative to today due to electrification in buildings. Pipeline gas is decarbonized in the Low Electrification pathway with a combination of biogas and synthetic electric fuels, which reduces the share of natural gas to approximately 55 percent by 2050. Total gas supply increases by approximately 40 percent relative to today largely due to incremental gas demand from freight trucks with only a portion offset by more efficient use of pipeline gas in buildings.

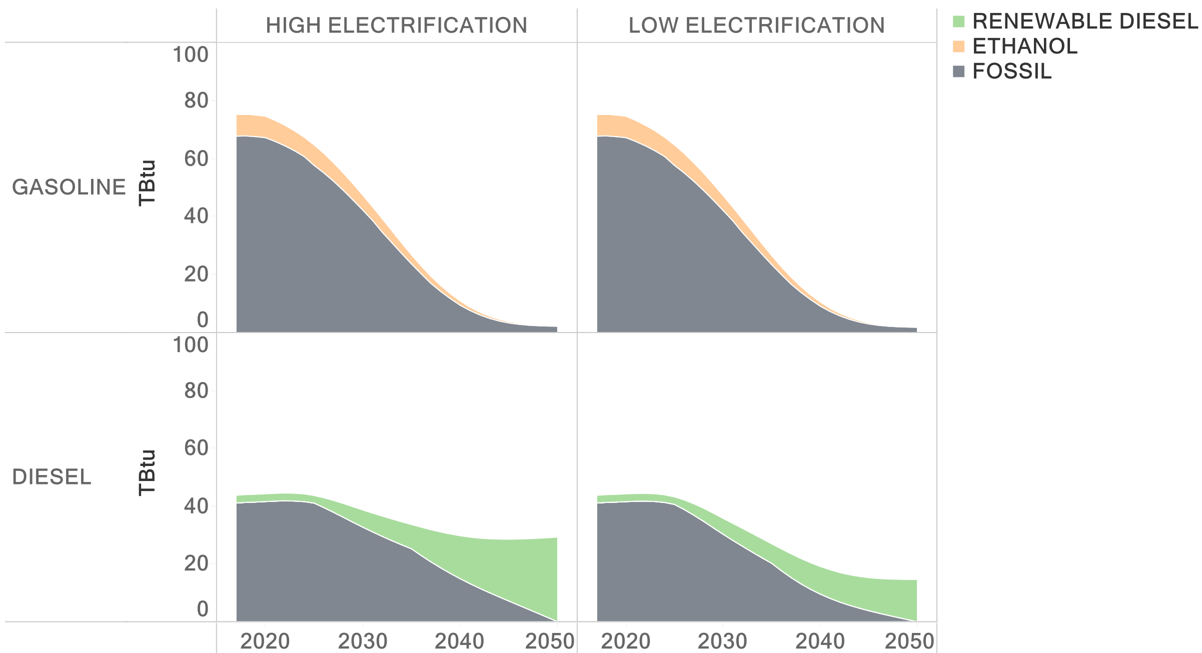
Figure 19 Pipeline Gas Supply



3. Liquid Fuels

Figure 20 summarizes the supply of today's two largest liquid fuels: gasoline and diesel. The supply of gasoline decreases by more than 95 percent by 2050 due to adoption of BEV, PHEV and HFCV vehicles in passenger transportation. Diesel remains a major fuel type in the High Electrification pathway, where half of freight trucks are hybrid diesel trucks. However, diesel supply transitions to 100 percent renewable diesel by 2050. The same supply transition occurs in the Low Electrification pathway, but total demand decreases by two-thirds by 2050 relative to today due to a shift from diesel trucks towards LNG and CNG freight trucks.

Figure 20 Liquid Fuels Supply



D. Energy-related CO_2 Emissions

Figure 21 and Figure 22 summarize energy-related CO_2 emissions by sector and energy type, respectively. The transportation sector's emissions, which is the largest source of emissions today, decrease by more than 90 percent across all pathways. This is the largest reduction by sector and total transportation emissions are less than the combined emissions from residential and commercial buildings by 2050. The transportation sector is primarily decarbonized through the following strategies: (1) electrification of passenger vehicles and freight trucks paired with very low-carbon electricity generation; and (2) decarbonization of liquid and gaseous fuels supplying the remaining fleet of freight trucks with bioenergy. The productive sector contains the largest remaining CO_2 emissions by 2050, and these are primarily from the direction combustion of fossil fuels, as opposed to emissions associated with electricity consumption. Most of the residual emissions in buildings are from combusting pipeline gas, and these are 50 percent higher in the Low Electrification pathway relative to the other pathways.

Figure 21 CO_2 Emissions by Sector

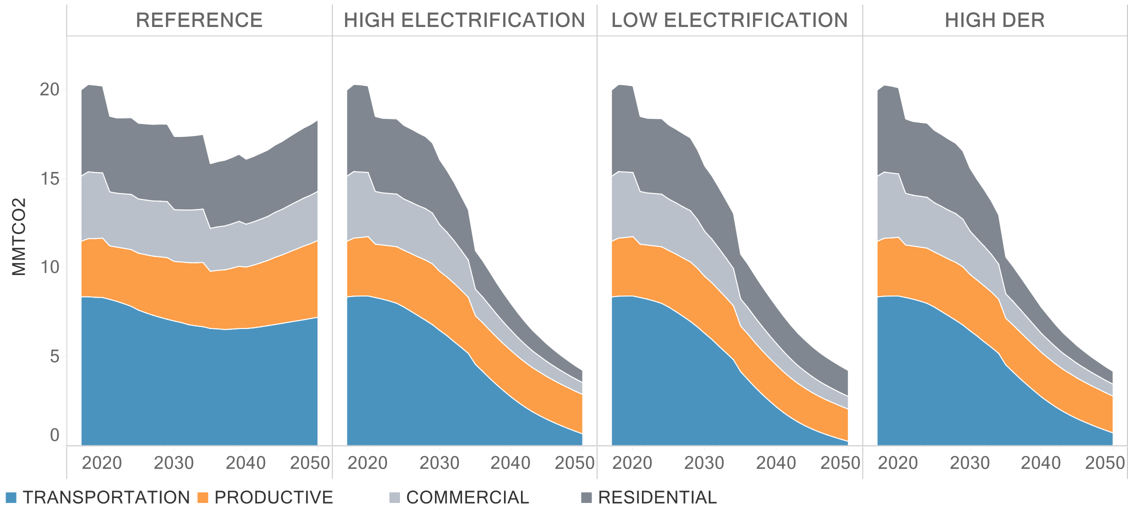


Figure 22 CO_2 Emissions by Energy Type

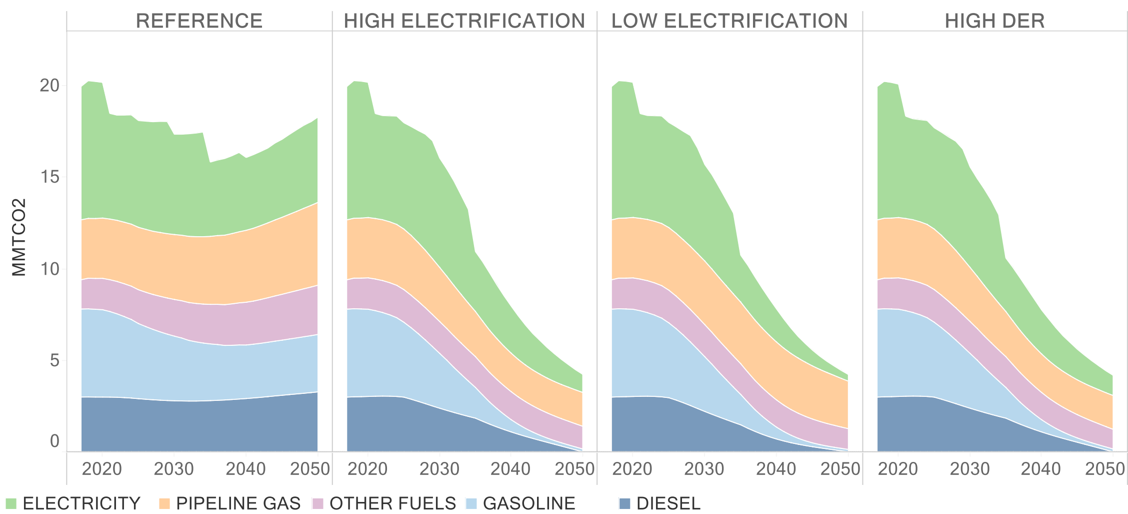
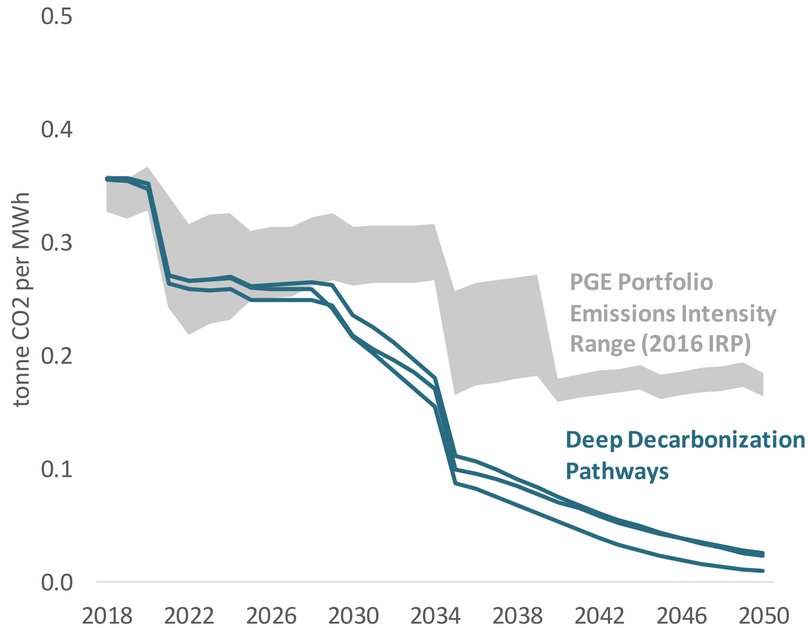


Figure 23 compares the emissions intensity of electricity generation from the three pathways against the range of PGE's portfolio from the 2016 IRP. Both projections decrease over time, with noticeable drops in 2020 and 2035 due to the assumed phase out of coal-fired electricity supply. The emissions intensity in the pathways scenarios begins to aggressively decrease beginning in the mid-2020s, and, relative to the minimum of the range, is at least 33 percent lower in 2035 and more than 85 percent lower by 2050. In 2050, the emissions intensity is below 0.03 tCO_2/MWh for all pathways, while the 2016 IRP ranges from 0.16 to 0.19 tCO_2/MWh.

Figure 23 Emissions Intensity of Electricity Generation



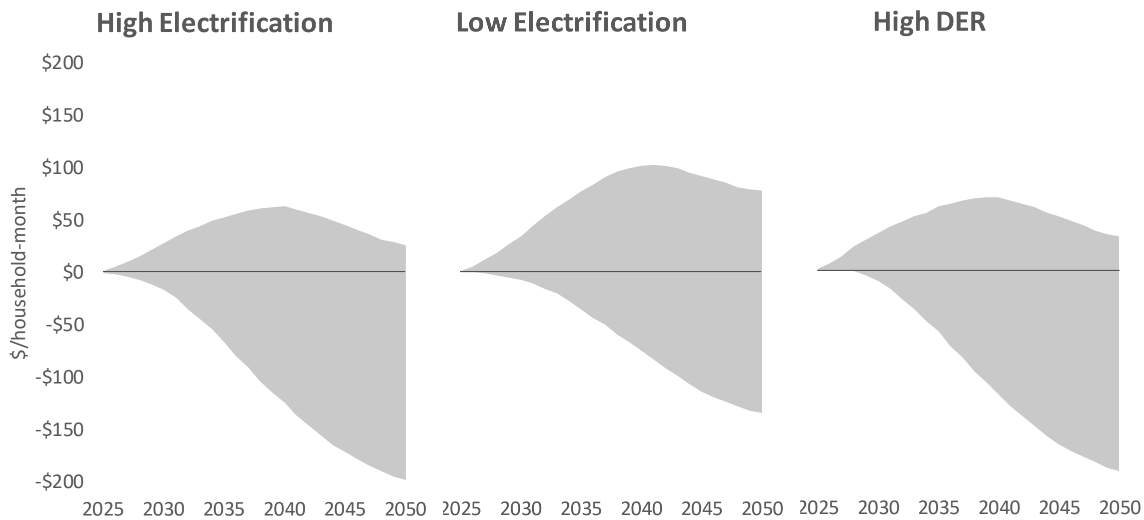
E. Energy System Costs

We measure the cost of transitioninig towards a low-carbon energy economy by comparing the incremental cost of investment in low-carbon and efficient equipment and infrastructure against the savings from avoiding fossil fuel purchases. This is calculated by taking the difference in energy system-related costs between a pathway scenario and the Reference Case. We exclude costs outside of the energy system, as well as benefits from avoiding climate change and air polution.

The annual, incremental cost for households is shown in Figure 24, which includes: (a) the annualized cost of appliances (e.g., high efficiency dishwasher); (b) the annualized cost associated with passenger transportation (e.g., electric vehicle); and (c) energy costs associated with using the equipment (e.g., gasoline for a vehicle and electricity for lighting). Given the challenge of projecting relative costs through a long study horizon (i.e., 2050), we show the results across a range of alternative fossil fuel price and end-use electric technology cost projections.[18] Year-to-year variations are due to: (a) the timing of investment needs; and (b) the assumed projections of technology costs and fuel prices. The range of uncertainties encompass both net cost increases and net cost decreases (savings) by 2050.

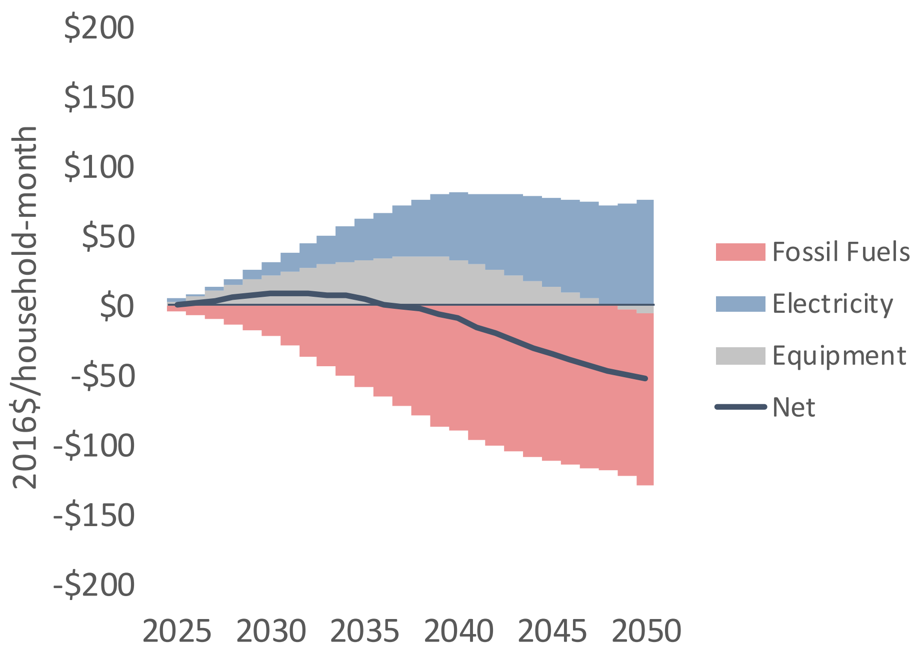
[18] Range of fossil fuel price projections are from the EIA's *Annual Energy Outlook 2017* and end-use electric technology cost projections are from NREL's *Electrification Futures Study*.

Figure 24 Range of Incremental Household Costs



Incremental household costs reflect the underlying changes in the energy system, such as: (a) increased spending on efficient end-use equipment (fixed costs); (b) increased spending on clean electricity infrastructure (fixed costs); and (c) decreased spending on fossil fuel costs (variable costs). Figure 25 illustrates how the structure of incremental household costs evolve over time for the High Electrification pathway under base fossil fuel price and end-use electric technology cost assumptions. Between 2025 and 2050, the average household spends additional money on equipment, such as an electric vehicle, air source heat pump and heat pump hot water heater, as well as additional money to power their equipment with clean electricity, including renewable power plants and transmission/distribution network upgrades. Meanwhile, households spend less money on fossil fuels, such as: (1) gasoline and diesel for their cars and trucks; and (2) natural gas for space and water heating.

Figure 25 Incremental Household Costs by Component: High Electrification Pathway

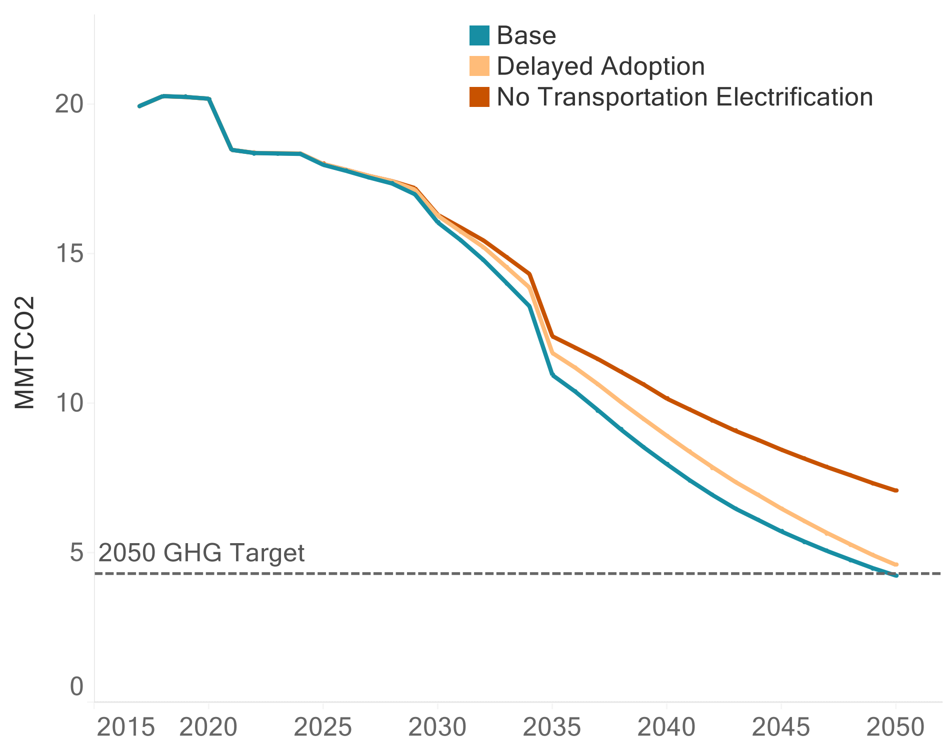


F. Transportation Electrification Sensitivity Analysis

Decarbonizing the transportation sector is essential to realizing economy-wide GHG reduction goals, and the pathways outlined above rely on passenger and freight transportation electrification. This requires aggressive consumer adoption by the mid-2030s for the fleet of vehicles on the road in 2050 to have the necessary low-carbon attributes. In the High Electrification pathway, 100 percent of light-duty vehicle sales are BEV or PHEV by 2035 and 50 percent of medium- and heavy-duty vehicle sales are BEV by 2035. To assess the importance of these aggressive transportation electrification strategies, we tested two sensitivities: (1) delay the assumed year of 100 percent BEV/PHEV adoption for light-duty vehicles from 2035 to 2050 ("Delayed Adoption"); and (2) remove all passenger and freight transportation electrification measures ("No Transportation Electrification").

Figure 26 shows the difference in CO_2 emissions between the High Electrification pathway ("Base") and the two sensitivities. The figure shows that delaying adoption of EVs in passenger transportation increases emissions in 2050 by 8 percent or 0.36 $MMTCO_2$, which results in the pathway no longer complying with the study's 2050 GHG target. This is because more than 10 percent of cars and trucks on the road in 2050 still consume petroleum rather than clean electricity as their fuel. CO_2 emissions increase by two-thirds without any transportation electrification (above 7 $MMTCO_2$) and the sensitivity does not achieve the emissions reductions necessary to meet the 2050 GHG target. We also note that the increase in emissions is partially mitigated through increased renewable diesel consumption by freight trucks (i.e., diesel freight trucks that transition to electric freight trucks in the base case now consume renewable diesel). However, the amount of bioenergy in this sensitivity exceeds the limit described in Section II.D, and, if strictly enforced, then emissions would be higher than shown here.

Figure 26 Energy-related CO_2 Emissions: Transportation Electrification Sensitivities



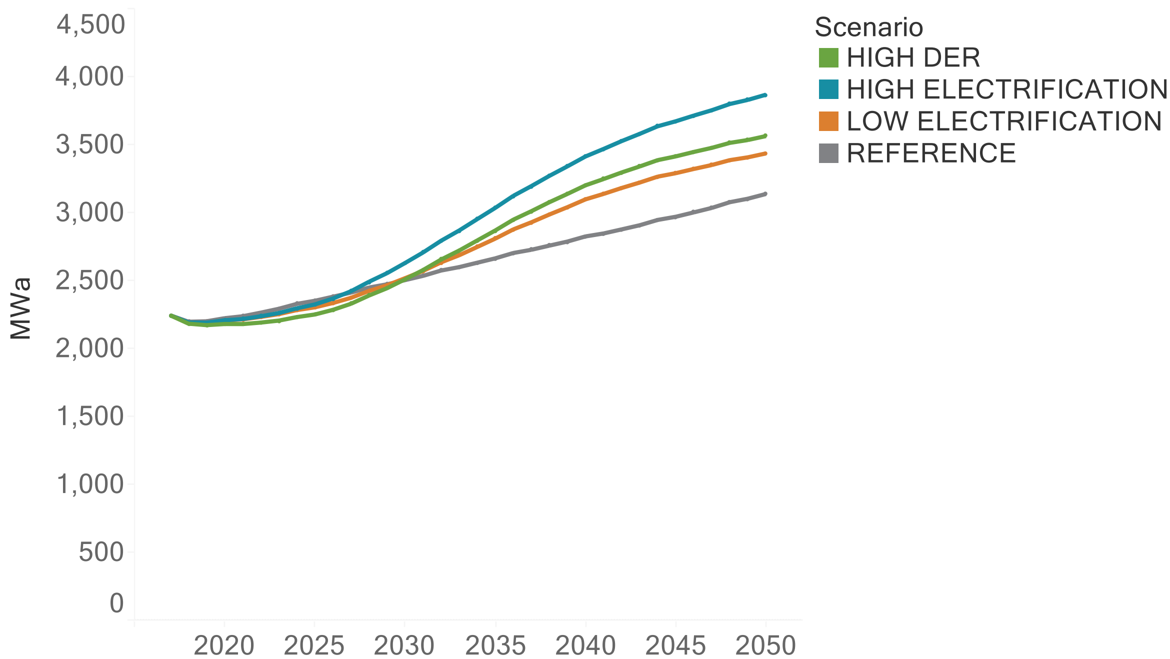
V. Results: Electricity System

This section summarizes results for the electricity system, including load, resources and hourly system operations. We also report the sensitivity of the results to variations in flexible end-use load, flexible electric fuel production, battery energy storage and pumped hydro storage assumptions.

A. Load

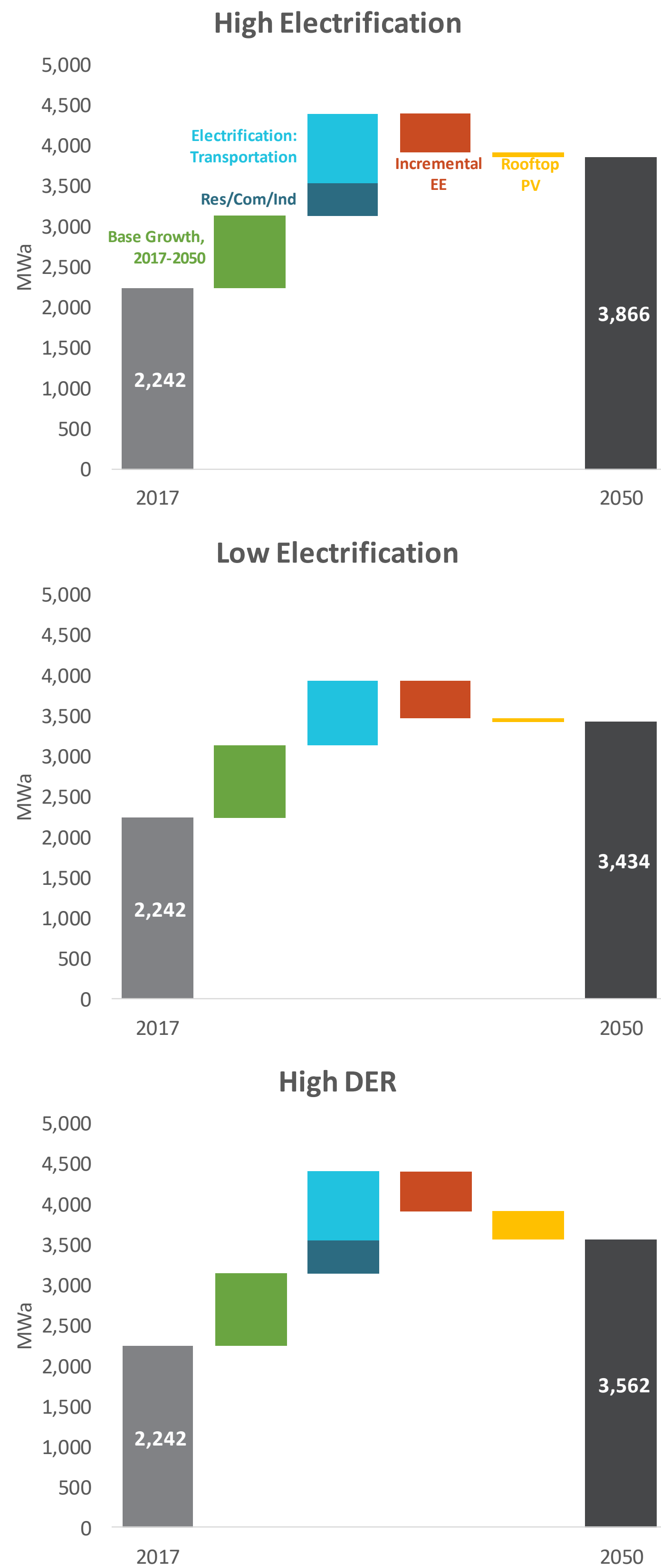
Figure 27 shows the trajectory of retail electricity sales for each scenario through 2050. In the long-run, retail sales in all pathways are higher than the Reference Case, and, as expected, the High Electrification pathway is the highest. Deployment of rooftop solar PV resources in the High DER pathway partially offsets end-use electrification measures, resulting in retail sales that are slightly above the Low Electrification pathway in 2050. Relative to today, retail sales increase by 50 to 70 percent by 2050.

Figure 27 Retail Electricity Sales



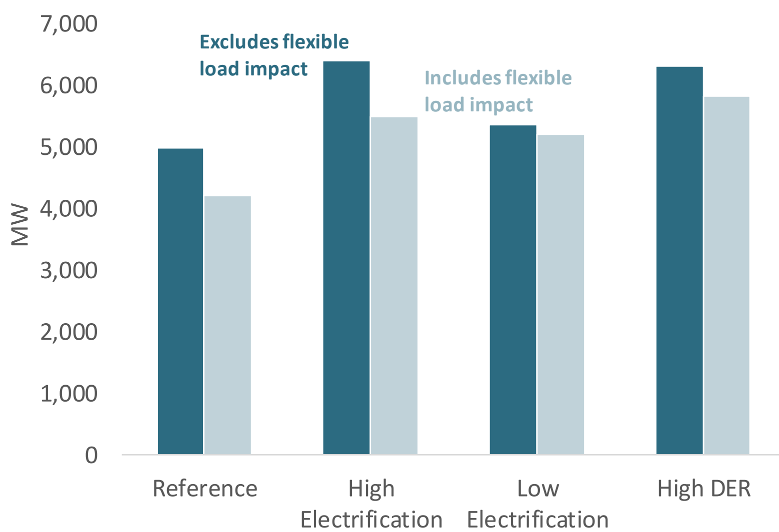
The components of the change in retail sales between 2017 and 2050 are shown in Figure 28, which separates: (a) baseline growth (i.e., growth that is embedded in the Reference Case); (b) electrification of buildings and industry; (c) transportation electrification; (d) incremental energy efficiency (EE measures beyond what's embedded in the Reference Case); and (e) rooftop solar PV generation. This figure highlights two key insights. First, transportation electrification is responsible for 50 to 65 percent of the net increase, as liquid fuels are replaced by electricity. Second, generation from rooftop solar PV has a smaller than expected *net* impact on retail sales. This is most apparent in the High DER scenario, where rooftop solar PV exceeds 2,500 MW (larger than today's average load). In this pathway, incremental electricity demand from end-use electrification still outweighs the directionally opposite impact from rooftop solar. This is a result of the lower-quality solar resource (i.e., low capacity factor) in PGE's service territory, and we would not expect similar conclusions to be drawn in geographies such as California or Arizona.

Figure 28 Evolution of Retail Electricity Sales, 2017-2050



We estimate the system peak load as the highest hourly load value from our simulations. As discussed in Section II.B, our hourly load (and resource) shapes reflect 2011 weather conditions, which means that the results we report here will not exactly match a 1-in-2 (weather-normalized) peak demand. Figure 29 plots the system peak load in 2050 in two ways. The first metric (in dark blue) represents “fixed demand” and excludes any impacts from load shifting, storage charge/discharge and flexible electric fuel production. The chart illustrates how widespread end-use electrification in the High Electrification and Higher DER pathways results in a system peak load of approximately 6,400 MW, which is about 1,400 MW higher than the Reference Case. Despite the proliferation of rooftop solar PV in the High DER pathway, the system peak load is nearly equivalent to the High Electrification pathway since it occurs during a winter morning before meaningful insolation. The second system peak load metric (in light blue) accounts for impacts from flexible end-use loads during the same hour, which moderates the impacts of electrification on peak loads.

Figure 29 2050 System Peak Load



B. Resources

1. Installed Capacity

Figure 30 shows the projection of installed capacity for thermal, generic capacity and renewable resources. Decarbonization of electricity generation and electrification requires renewable resource additions that far exceeds additions included in the Reference Case. The installed capacity of wind, solar, geothermal and hydro resources in the pathways is more than 2x the Reference Case quantity by 2050 and includes: (a) 5,100 to 5,900 MW of onshore wind in the Pacific Northwest; (b) 1,700 to 1,900 MW of onshore wind in Montana; and (c) 3,600 to 5,200 MW of utility-scale solar PV in central Oregon.[19] Rooftop solar PV in the High DER scenario reduces the amount of transmission-connected renewable generation, but its generation portfolio still requires utility-scale additions to reduce the carbon

[19] For context, NREL estimates technical potential of onshore wind resources in Oregon and Washington of approximately 45,480 MW and Black & Veatch estimates approximately 56,150 MW of utility-scale solar PV in Oregon alone. See Lopez et al. (2012) and Black & Veatch (2015).

intensity of electricity generation to levels consistent with the study's carbon budget. The Low Electrification pathway contains the highest installed capacity due to the amount of electricity required to serve synthetic electric fuel production loads.

Figure 30 Installed Generating Capacity

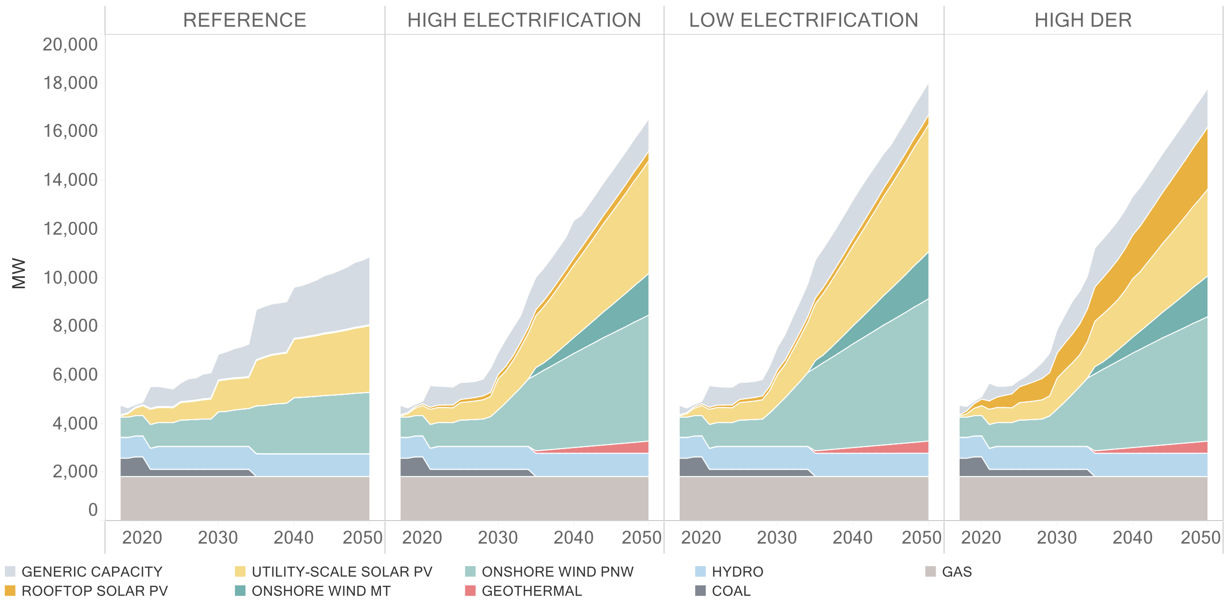
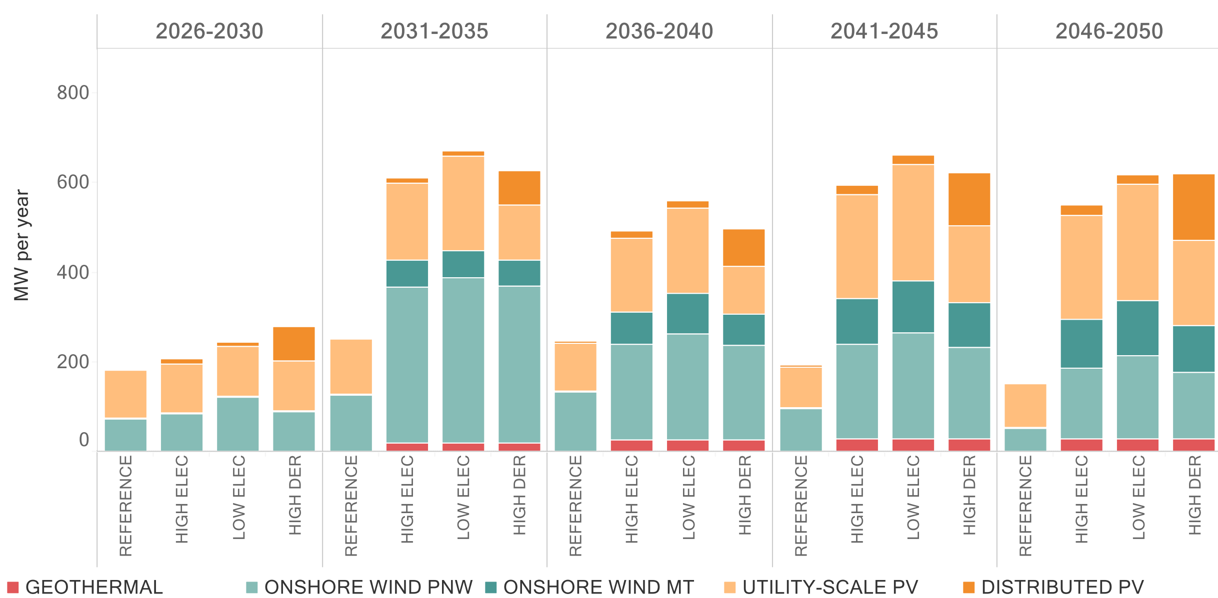


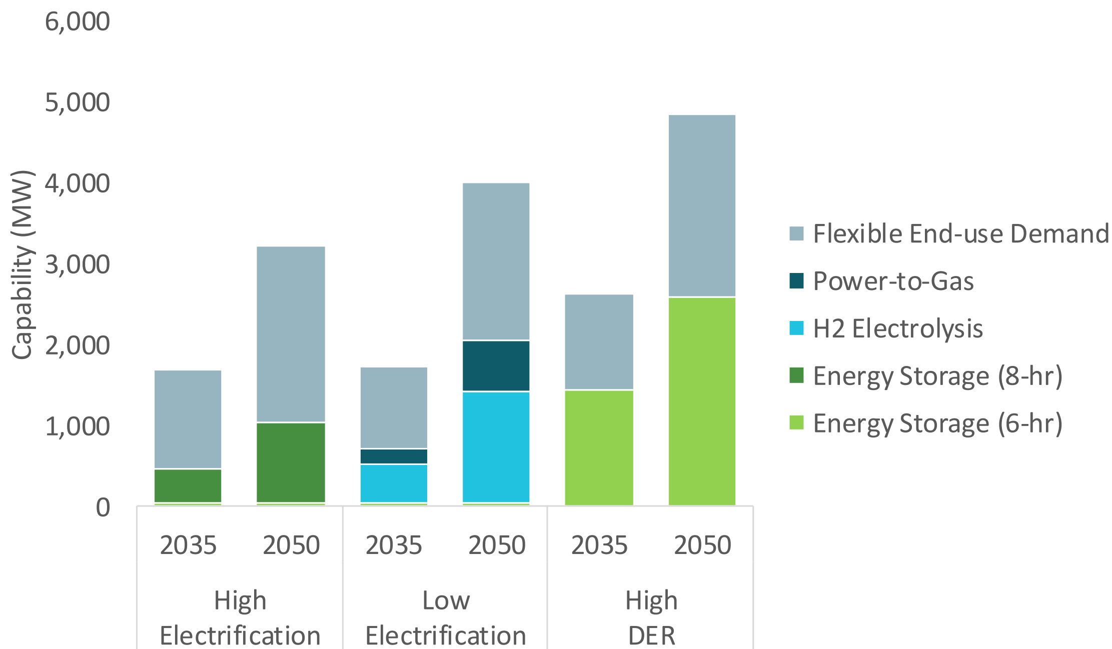
Figure 31 shows the annual average capacity additions of renewable resources, which are approximately 600 MW per year between 2030 and 2050 for the pathways scenarios. Annual renewable additions for the pathways scenarios are more than 2.0x Reference Case levels during the 2030s and more than 3.0x during the 2040s. For context, the amount of new onshore wind capacity beginning in 2030 is the equivalent to one to two Tucannon River (267 MW) wind power plants installed each year.

Figure 31 Average Annual Renewable Installations



The high penetrations of must-run renewable resources added across the pathways necessitate resources to balance electricity supply and demand. In addition to traditional sources of flexibility, such as hydro and thermal, the pathways incorporate a variety of new balancing resources to mitigate curtailment of renewable generation. Figure 32 shows the type and quantity of balancing resources incorporated in each pathway, including: (a) energy storage, which is differentiated between 6- and 8-hr duration; (b) hydrogen electrolysis facilities; (c) power-to-gas facilities; and (d) flexible end-use demand, which is estimated as the maximum hourly load shift in each year. The High Electrification and High DER pathways rely on a combination of flexible end-use demand and energy storage, while the Low Electrification pathway incorporates more than 2,000 MW of hydrogen electrolysis and P2G facilities by 2050 to consume excess renewable electricity generation and produce decarbonized pipeline gas. The High Electrification pathways contains the lowest quantity of physical / central-station balancing resources (i.e., 1000 MW of 8-hr energy storage) and relies on end-use loads to shift energy. The ability of these balancing fleets to minimize curtailment is further discussed in Section C.4 below.

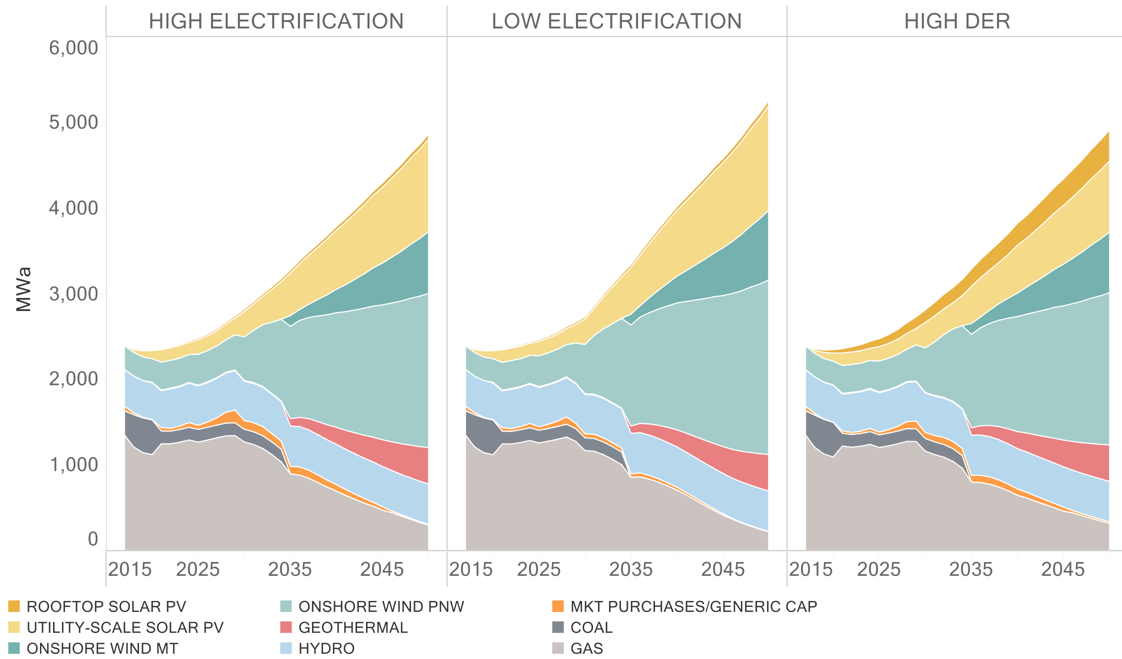
Figure 32 Balancing Resources



2. Generation

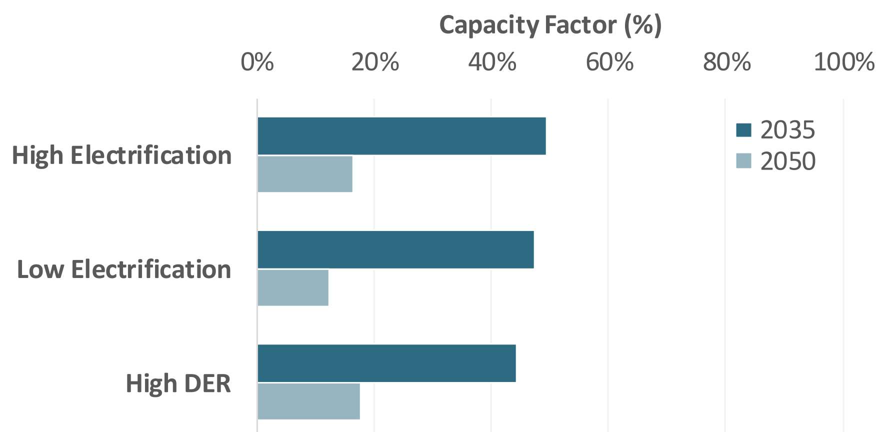
The overall generation mix by resource type for each pathway is shown in Figure 33. Annual generation more than doubles from approximately 2,400 MWa today to between 4,900 and 5,300 MWa by 2050. Carbon-free generation is more than 90 percent of the total by 2050, including an approximate mix of: (a) 50 percent onshore wind in the Pacific Northwest and Montana; (b) 25 percent solar PV, including both utility-scale in central Oregon and rooftop PV resources located within PGE's service territory; (c) 9 percent hydro; and (d) 8 percent geothermal. Due to the increased penetrations of renewable resources, thermal generation decreases significantly over time and is between 4 to 7 percent of total generation by 2050.

Figure 33 Generation by Resource Type



The capacity factor of PGE's existing gas-fired resource fleet is shown in Figure 34. The figure highlights how the growth in intermittent renewable generation between 2035 and 2050 decreases the utilization of these dispatchable resources from approximately 50 percent in 2035 to below 20 percent in 2050, a decrease of approximately 30 percentage points. The highly renewable power systems modeled in this study still require dispatchable resources to maintain reliability, and the gas-fired resource fleet, along with a variety of other balancing resources, have the characteristics to avoid unserved energy. The results here do indicate a shift in the role of these resources, particularly for combined cycle plants, from an energy to a capacity resource.

Figure 34 Gas-fired Resource Fleet Capacity Factor



C. System Operations

1. Load and Net Load

We compare the distribution of hourly load and net load in 2050 for each scenario as histograms in Figure 35, and report summary statistics in Table 11. These two metrics are estimated as follows: (a) load includes inflexible, transmission-level load less behind-the-meter generation (e.g., rooftop solar PV); and (b) net load is load minus non-dispatchable generation, including onshore wind, utility-scale solar PV, geothermal and run-of-river hydro resources. Both exclude the impact of flexible loads and resources.

The load distributions show the expected impacts of electrification, with the High Electrification and High DER distributions shifting towards the right. The net load distributions provide a more meaningful benchmark in terms of assessing the amount of dispatchable capacity needed to reliably meet demand and the flexibility required to avoid curtailment. The net load distribution for the Reference Case, which includes a 50% RPS in 2050, shows net load below zero for 5 percent of hours in the year. The pathways scenarios, which include at least twice as many non-dispatchable renewables, have net load distributions that are much flatter than the Reference Case and frequently below zero.

The High Electrification net load distribution is below zero in approximately 50 percent of hours per year, and the minimum net load experienced is approximately -8,000 MW. During these hours, flexible resources are needed to consume additional load (e.g., energy storage charge) to avoid curtailment. The maximum net load is approximately 5,000 MW, which is about 4 percent higher than the Reference Case's maximum net load. The High DER pathway shows similar net load distribution results due to comparable levels of electrification and renewables.

Relative to the other pathways, the Low Electrification pathway's net load is distributed further left (i.e., more hours with negative net load). Net load is below zero for 64 percent of hours in the year and nearly reaches -10,000 MW in a single hour. This shape is due to different load and resource characteristics, including: (a) lower levels of end-use electrification; and (b) higher levels of inflexible renewable generation. Flexible hydrogen electrolysis and power-to-gas facilities consume load during these negative net load hours to produce low-carbon electric fuels and avoid curtailment.

Figure 35 Distribution of Hourly Load and Net Load in 2050

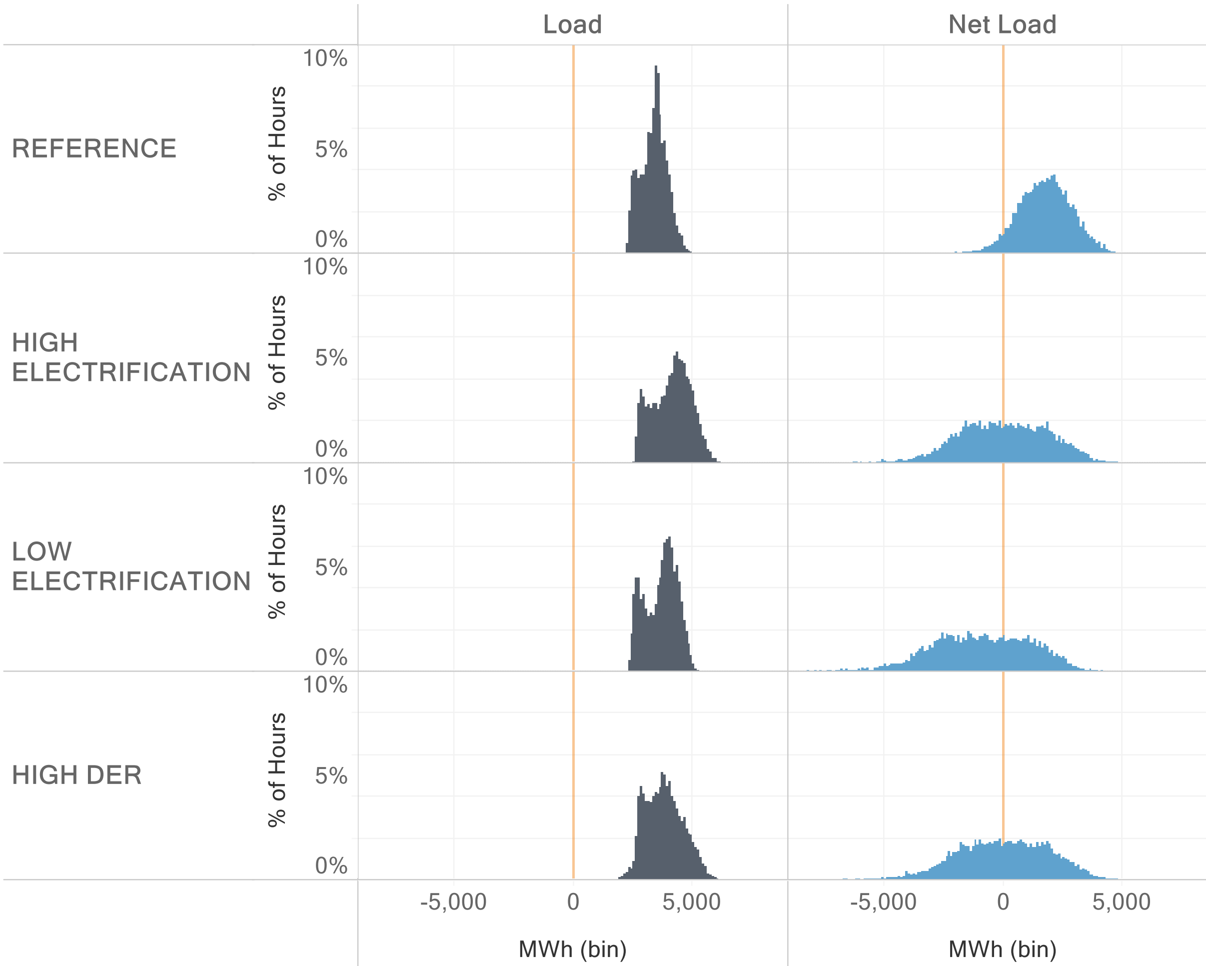


Table 11 Statistics for Hourly Load and Net Load in 2050

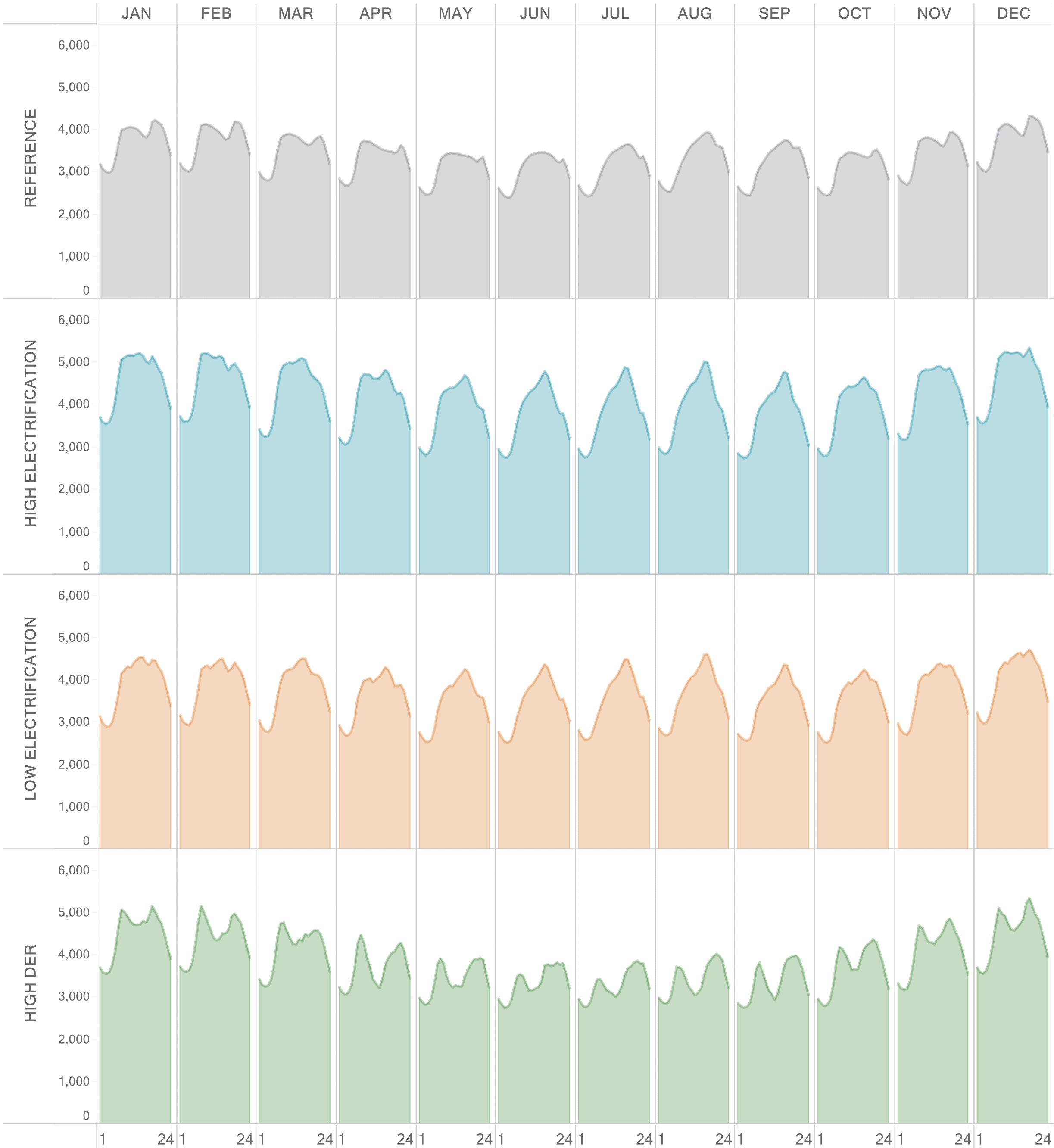
Scenario	Load		Net Load			
	Max	Min	Max	Min	Frequency below 0 MW	
	MW	MW	MW	MW	hrs	% of hrs
Reference	4,972	2,191	4,758	-2,392	457	5%
High Electrification	6,391	2,555	4,957	-7,942	4,346	50%
Low Electrification	5,351	2,273	4,261	-9,996	5,600	64%
High DER	6,310	1,920	4,961	-8,574	4,337	50%

2. Hourly System Load Shape

The average load by month and hour in 2050 for each scenario is summarized in Figure 36. The figure shows the system load shape prior to accounting for flexible loads and illustrates how the nature of electricity demand is affected by rooftop solar PV and varying levels of electrification.[20] The High Electrification pathway shows higher winter loads relative to the Reference Case primarily due to the electrification of space heating, but large new loads are also present in non-winter months largely due to transportation electrification. These non-heating related load increases are also present in the Low Electrification pathway and are most apparent in the early evening hours when most EV charging is assumed to take place. Although the High DER pathway contains the same electrification measures as the High Electrification pathway, the proliferation of rooftop solar PV changes both the daily and seasonal characteristics of electricity demand, including: (a) steep upward and downward ramps during the daylight hours across all months; and (b) large differences in daily energy requirements between winter and spring/summer months.

[20] The load shapes for the pathways also reflect high levels of electric energy efficiency.

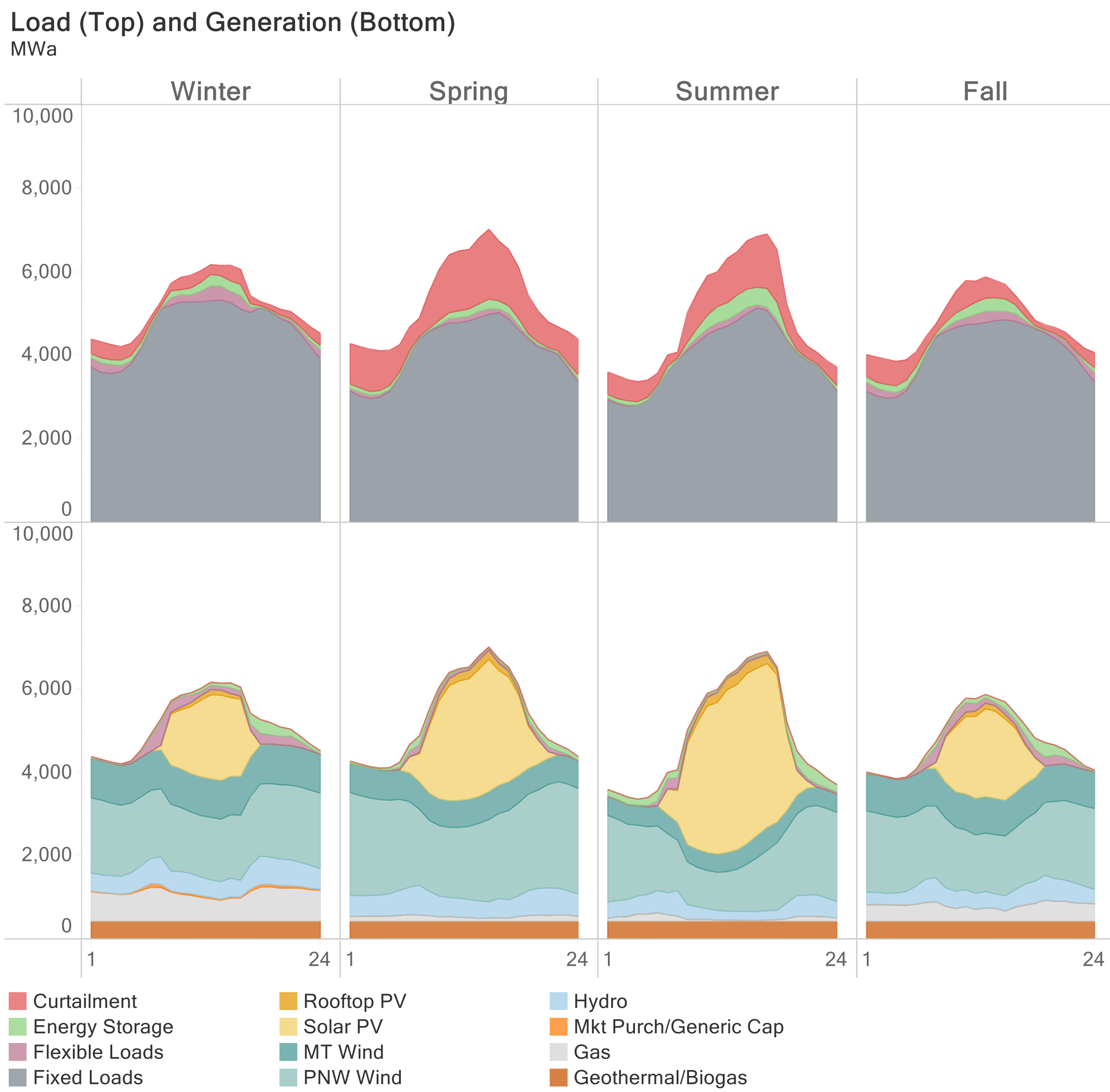
Figure 36 System Load Shape: Month-Hour Average in 2050



3. Month-Hour Electricity Dispatch

Figure 37 through Figure 39 show hourly average dispatch profiles by season for each pathway, where the top panel contains all sources of load and the bottom panel contains all sources of generation.[21] The figures illustrate how electricity supply and demand technologies combine across hours and seasons, and the operating profiles of flexible balancing resources.

Figure 37 Electricity Dispatch: High Electrification Pathway, 2050



[21] Seasons defined as: (a) winter includes December through February; (b) spring includes March through June; (c) summer includes July through September; and (d) fall includes October through November.

Figure 38 Electricity Dispatch: Low Electrification Pathway, 2050

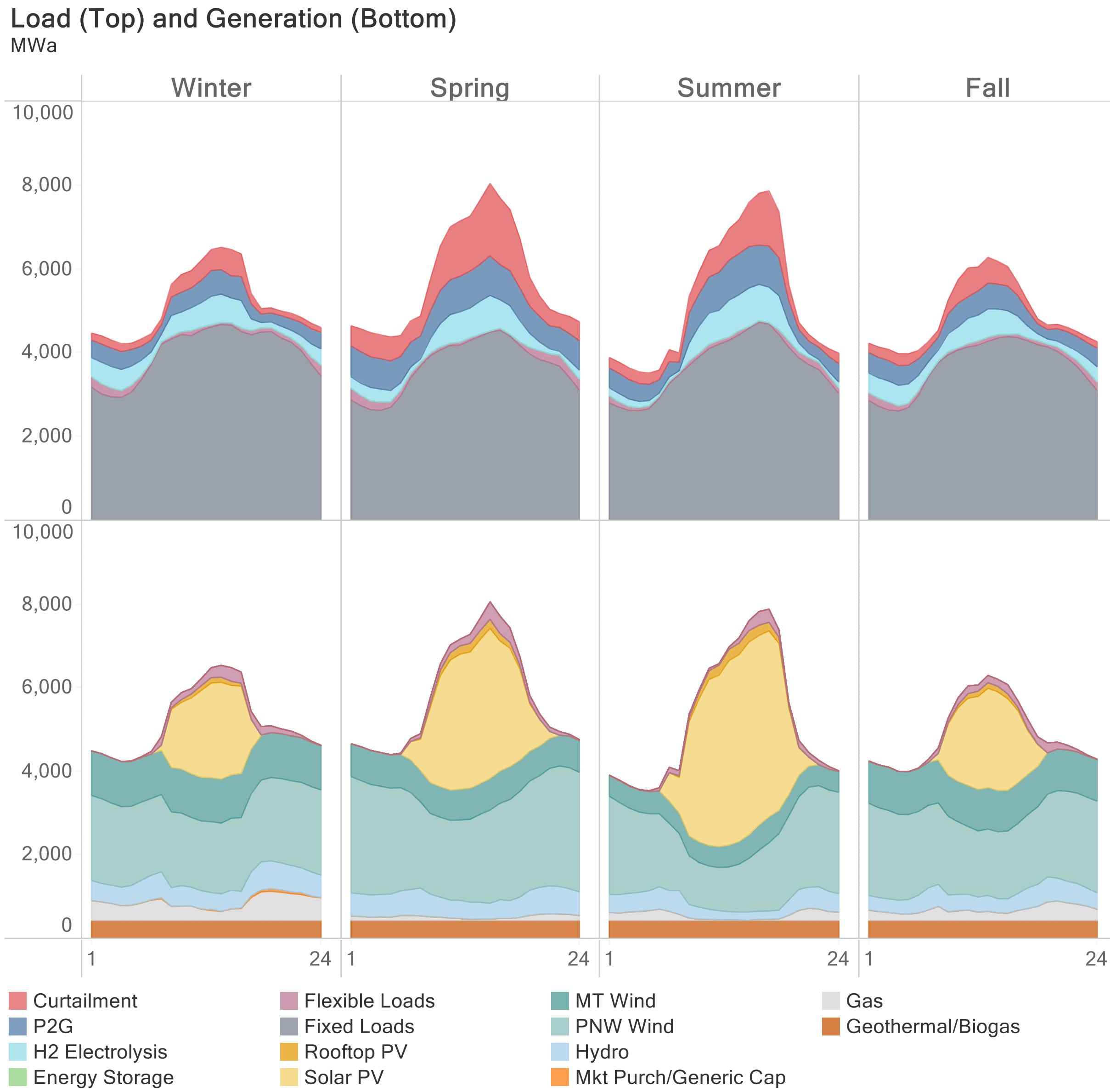
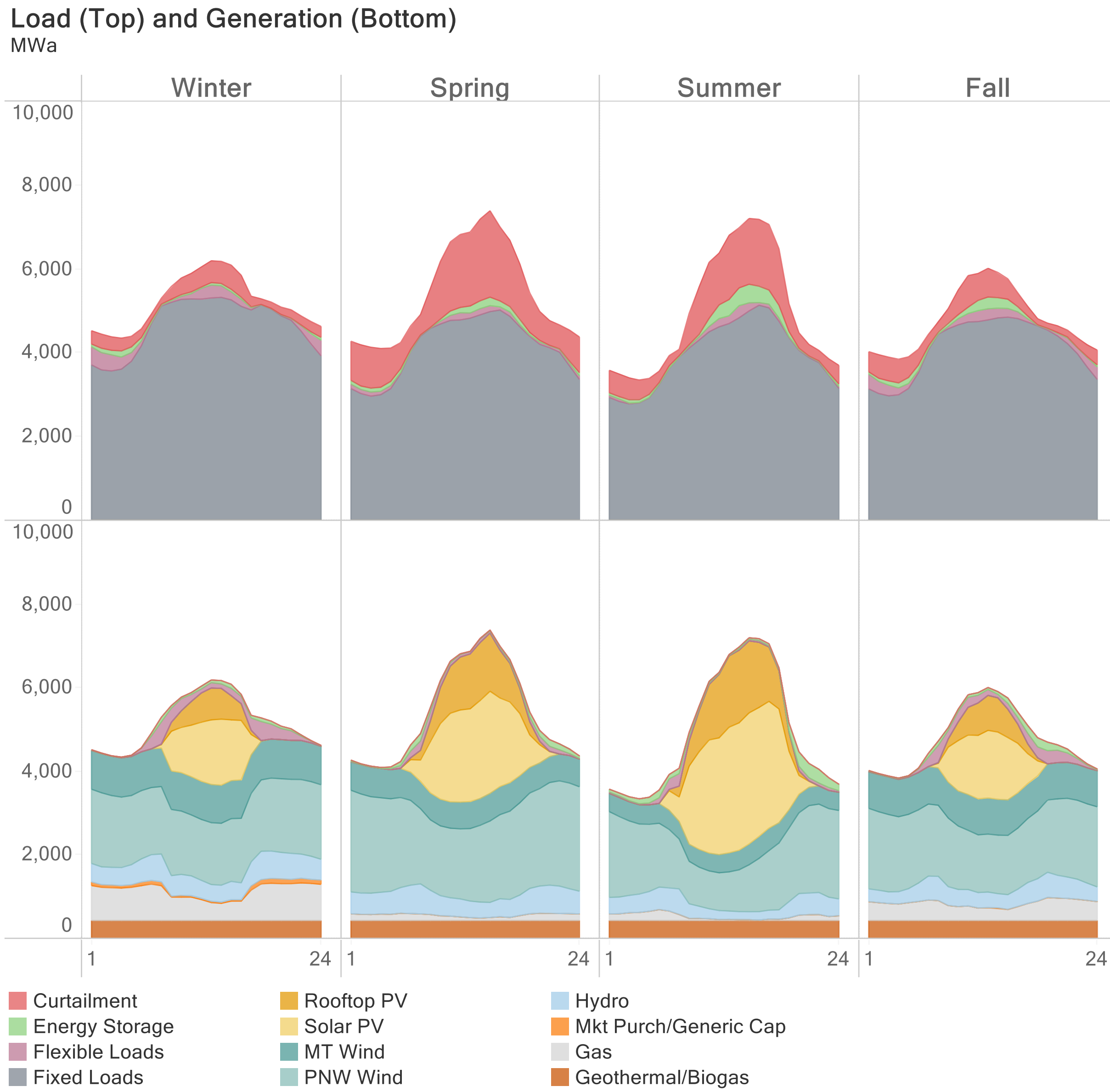


Figure 39 Electricity Dispatch: High Distributed Energy Resources Pathway, 2050



4. Curtailment

Curtailment of renewable generation occurs during periods where: (1) must-run generation exceeds load, resulting in an initial negative net load signal; and (2) balancing resources are unable to shift surplus energy to hours with energy deficits (i.e., positive net load signal). Figure 40 plots annual curtailment for each scenario and shows that curtailment does not become prevalent until the 2035 timeframe. As the share of inflexible, renewable generation increases above 85 percent by 2050, curtailment increases exponentially even after the impacts of balancing resource are accounted for.

Figure 40 Annual Curtailment

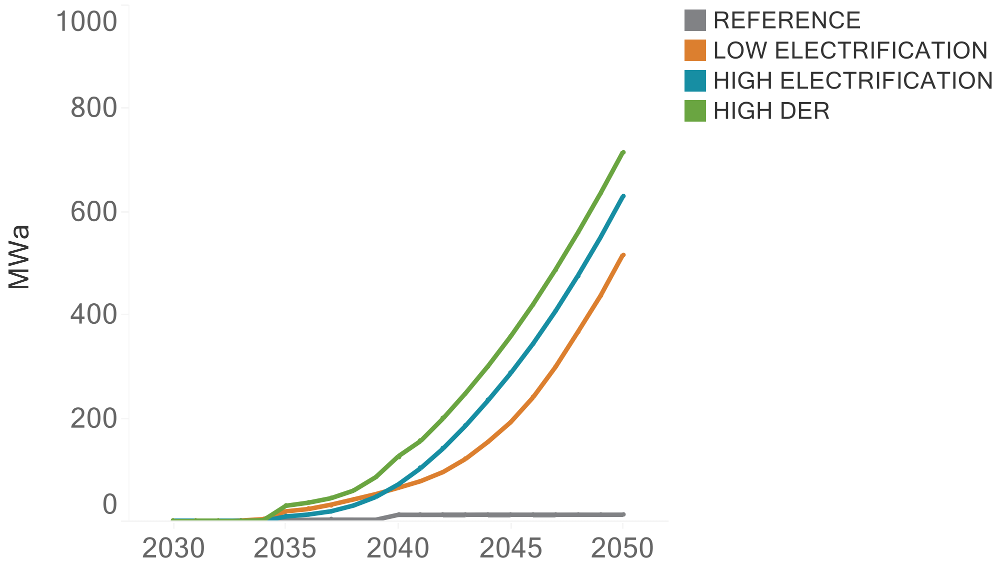


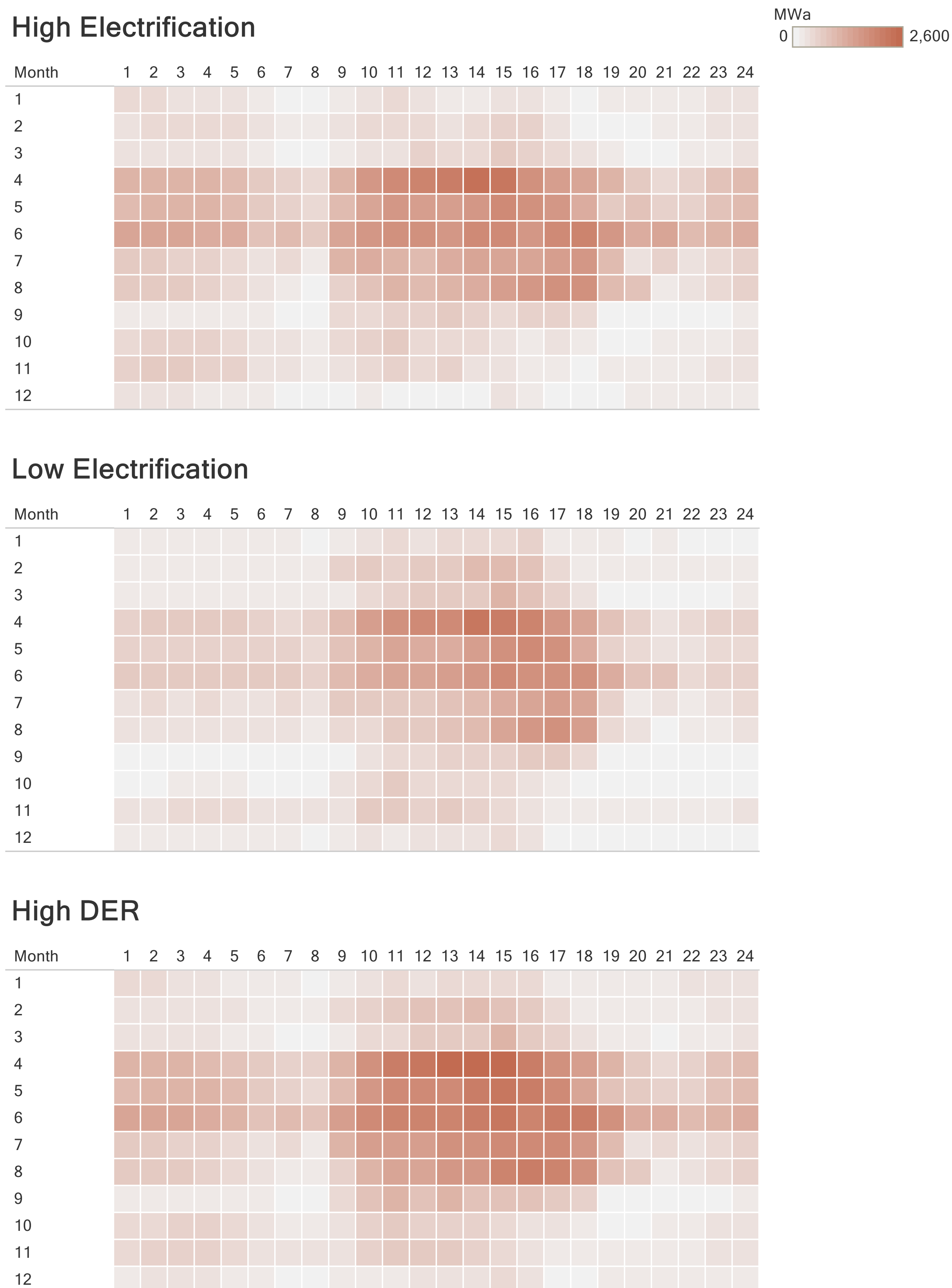
Table 12 summarizes several curtailment metrics for 2035 and 2050, including: (a) the amount of energy curtailed in average megawatts; (b) curtailment normalized as a percentage of available renewable energy; (c) maximum hourly observation; and (d) frequency, expressed in percentage of hours in a year. Curtailed generation is less than 2 percent of available renewable energy in 2035 across all pathways and increases to between 11 and 17 percent by 2050. Curtailment is experienced between 40 and 55 percent of hours in 2050, which is a decrease from the number of hours with negative net load (see Table 11) and reaches a maximum depth between 7,600 and 8,700 MW in a single hour. We explore the impact of alternative demand- and supply-side balancing resource assumptions on curtailment in the following section.

Table 12 Curtailment Metrics for 2035 and 2050

Scenario	Energy		Percent of Available RE		Hourly Maximum		Frequency	
	2035 MWa	2050 MWa	2035 %	2050 %	2035 MW	2050 MW	2035 % hours	2050 % hours
Reference	2	13	0.2%	0.8%	966	2,048	1%	3%
High Electrification	9	630	0.5%	15.0%	2,146	8,032	2%	39%
Low Electrification	19	517	0.9%	11.1%	2,378	7,597	4%	53%
High DER	30	716	1.5%	16.9%	3,121	8,663	5%	46%

The average amount of curtailment for each month and hour in 2050 is depicted as a heat map in Figure 41, with a darker red highlighting more extreme curtailment. The heat maps show that curtailment is concentrated during spring months when loads are low and renewable generation is high. Curtailment experienced during April through June makes up approximately half of annual curtailment, while only 11 to 13 percent occurs between December through February. Although most curtailment is concentrated during day-light hours, it is still experienced during the night-time and is up to 30 percent of the total in the High Electrification pathway.

Figure 41 Curtailment Heat Map for 2050



D. Sensitivity Analyses

In this section, we evaluate the sensitivity of our modeling results to alternative assumptions about the availability of demand- and supply-side resource flexibility. These sensitivities explore the impacts of alternative assumptions from the High Electrification pathway, including: (a) varying the availability of flexible end-use load; (b) including flexible electric fuel production (i.e., electrolysis); and (c) varying the quantity and type of energy storage. These sensitivities are summarized below.

Flexible End-use Load. In the High Electrification pathway, we assume a percentage of electric load is flexible in key end-uses: (a) 75 percent of light-duty vehicle electric load is flexible by 2050; (b) 75 percent of residential and commercial water heating electric load is flexible by 2050; and (c) 50 percent of electric load is flexible for residential space conditioning, residential clothes washing and drying and commercial space heating. We tested three cases designed to assess the importance of end-use flexibility: (a) no flexible end-use load; (b) only flexibility from electric vehicles; and (c) only flexibility from water heaters.

Flexible Electric Fuel Production. The results presented in the prior section highlight the seasonal imbalance between electricity supply and demand in a highly renewable power system. The base assumption in the High Electrification pathway is that energy storage and flexible end-use loads are the principal balancing resources. To assess the impact of long-term or seasonal storage, we conducted a sensitivity analysis where hydrogen produced from electrolysis facilities provides 3.5 percent of pipeline gas supply, which translates into more than 300 MW of electrolysis facilities.

Variation in Energy Storage. Varying the quantity of energy storage affects the ability of a power system to successful integrate inflexible renewable electricity generation. In the High Electrification pathway, the base assumption is that 1,000 MW of 8-hour energy storage is in-service by 2050. In this sensitivity, we assess the implications of: (a) increasing the quantity of 8-hour energy storage from 1,000 MW to 1,500 MW; and (b) assuming 500 MW of 24-hour pumped hydro storage (PHS) by 2050.

Table 13 summaries the results of our sensitivity analyses for 2050, which are shown as differences relative to the High Electrification pathway. We report changes in: (a) curtailment, in terms of average megawatts and percent difference; and (b) energy system CO_2 emissions, in million metric tonnes and percent difference. Removing flexibility from end-use loads increases curtailment by nearly 10 percent and emissions increase by 5 percent due to higher thermal generation, which results in the sensitivity exceeding the study's 2050 carbon budget. Including flexibility from electric vehicles and hot water heaters dampens the effect of losing other end-use flexibility, with curtailment and emissions rising modestly. The sheer volume of electric load from electric vehicles (more than 15 percent of total load in 2050) relative to water heaters allows for better curtailment and emissions outcomes. Electrolysis facilities and pumped hydro, both long-duration storage, show similar outcomes with curtailment decreasing by more than 10 percent. In contrast, increasing the quantity of 8-hour storage produces less than half the reductions in curtailment. The results of these sensitivity analyses highlight the importance of flexible end-use loads for integrating renewable generation, as well as the effectiveness of long-duration energy storage to reduce curtailment and address seasonal energy imbalances that occur in highly renewable electricity systems.

Table 13 Flexibility Sensitivity Analysis Results (Relative to Base Assumptions)

Sensitivity	Curtailment (MWa)	Curtailment (%)	Emissions ($MMTCO_2$)	Emissions (%)
Flexible End-Use Load				
None	+54	+9%	+0.21	+5%
Flexible EV Load Only	+14	+2%	+0.05	+1%
Flexible WH Load Only	+36	+6%	+0.14	+3%
Flexible Electric Fuel Production				
Add Electrolysis Facilities	-78	-12%	-0.08	-2%
Energy Storage				
Increase 8-hr energy storage	-31	-5%	-0.07	-2%
Add 24-hr PHS	-68	-11%	-0.15	-4%

Notes: values for 2050 and relative to High Electrification pathway base assumptions.

VI. Summary

We find that deep decarbonization of the PGE service territory's energy economy is possible and can be achieved using a variety of energy technologies and mitigation strategies. Our analysis of multiple pathways shows that they depend on a set of three pillars that are consistent with many studies examining deep decarbonization in the U.S. and abroad, including: (1) energy efficiency; (2) decarbonizing electricity generation; and (3) increasing the share of electricity and electric fuels. All three pillars are required and pursuing only one is insufficient.

The level of change to the energy system identified in this study is transformational and cannot be achieved with incremental improvements to energy supply and demand. In order to facilitate a pathway to 2050, both consumers and producers will need to participate to ensure that energy infrastructure is low-carbon and efficient. Although 2050 is more than three decades away, a successful transition to a low-carbon economy requires timely planning to account for: (a) the pace of consumer adoption; and (b) the fact that energy infrastructure is long-lasting and takes years to plan for. Despite the ambitious transformation of the energy system, the changes would not entail major lifestyle changes, but the structure of a household's energy bill will shift from fossil fuel expenditures to investments in technology.

Economy-wide decarbonization will profoundly change the way electricity systems are operated and planned for. In terms of power system operations, balancing electricity supply and demand becomes more challenging as inflexible, variable renewable generation becomes the principal source of supply. For example, the three pathways show renewable generation exceeding load in approximately half of all hours by 2050. This operational paradigm necessitates a transition to new forms of balancing resources to integrate renewables and avoid curtailment. New sources of flexibility, including energy storage and flexible demand, can complement traditional sources of flexibility, such as hydro and thermal resources. This also provides an opportunity for PGE's customers to facilitate renewable integration by playing a more active role through smart EV charging and water heating (among others), which expands upon traditional demand response programs.

Electricity system planning in the context of deep decarbonization will need to account for broad changes across the energy economy to ensure that infrastructure with the right attributes is available to come online in a timely fashion. For example, future resource adequacy analyses will need to address changes in: (a) overall load requirements; (b) the shape of hourly load; (c) the level of inflexible renewable resources; and (d) penetration of flexible demand. In addition, the scale of resource additions identified in this study exceeds historical levels due to: (1) reducing the carbon intensity of electricity generation to nearly zero; and (2) increased generation requirements from electrification and/or producing fuels from electricity (i.e., H2 and SNG). As a result, the installed capacity of renewables is substantially higher than what's anticipated in any current planning proceedings and is more than double the quantity we would expect under current RPS policy. If regulators pursue policies commensurate with the emissions reductions evaluated here, then the results of this study highlight a number of considerations that could be investigated in PGE's integrated resource planning efforts to ensure that near-term actions are consistent with a long-term decarbonized future.

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External Study B. Energy Trust of Oregon Methodology

Energy Trust of Oregon
PGE Energy Efficiency Resource Assessment Model

Energy Trust Planning Department
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Energy Trust of Oregon Background

Energy Trust of Oregon, Inc. (Energy Trust) is an independent nonprofit organization dedicated to helping utility customers in Oregon and southwest Washington benefit from saving energy and generating renewable power. Energy Trust funding comes exclusively from utility customers and is invested on their behalf in lowest-cost energy efficiency and clean, renewable energy. In 1999, Oregon energy restructuring legislation (SB 1149) required Oregon's two largest electric utilities—PGE and Pacific Power—to collect a public purpose charge from their customers to support energy conservation in K-12 schools, low-income housing energy assistance, and energy efficiency and renewable energy programs for residential and business customers.[1]

In 2001, Energy Trust entered into a grant agreement with the Oregon Public Utility Commission (OPUC) to invest the majority of revenue from the 3 percent public purpose charge in energy efficiency and renewable energy programs. Every dollar invested in energy efficiency by Energy Trust will save residential, commercial and industrial customers nearly $3 in deferred utility investment in generation, transmission, fuel purchase and other costs.

Energy Trust's model of delivering energy efficiency programs unilaterally across the service territories of the five gas and electric utilities they serve has experienced a great deal of success. Since the inception of the organization in 2002, Energy Trust has achieved total annual savings of 670 aMW of electricity, which includes 23 aMW of savings from self-direct customers. Additionally, Energy Trust has saved 57.9 million therms since gas efficiency programs began in 2003. Combined, this equates to more than 25 million tons of CO_2 emissions avoided and Energy Trust has played a significant factor in achieving relatively flat energy loads observed by both gas and electric utilities from 2007 to 2016, as shown in OPUC utility statistic books.[2]

Energy Trust, with support from PGE, serves residential, commercial and industrial customers in Oregon. In 2017, Energy Trust's service to PGE customers through energy efficiency programs achieved 40.4 aMW of electric savings exceeding goals for the year by 16%. Energy Trust achieved electric savings at a levelized cost of 0.024$/kWh, meeting OPUC performance measures to achieve electric savings at a levelized cost below 0.034 $/kWh.

PGE actively promotes Energy Trust offerings to its customers and supports their participation in Energy Trust efficiency programs. Also, when shared technologies and programs are mutually beneficial, PGE coordinates its demand response program activities with the Energy Trust's energy efficiency programs. For example, smart thermostats are used by PGE for demand response, but also provide energy efficiency savings, which the Energy Trust counts towards its energy saving goals.

In addition to administering energy efficiency programs with support from PGE, Energy Trust also provides a 20-year demand-side management (DSM) resource forecast to identify cost-effective energy efficiency savings potential. This forecast examines how much of that potential is estimated to be achieved by Energy Trust over the 20-year period. The results are used by PGE and other utilities in Integrated Resource Plans (IRP) to inform the energy efficiency resource potential Energy Trust expects

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[1] In 2007, Oregon's Renewable Energy Act (SB 838) allowed the electric utilities to capture additional, cost-effective electric efficiency above what could be obtained through the 3 percent charge, thereby avoiding the need to purchase more expensive electricity. This new supplemental funding, combined with revenues from natural gas utility customers, increased Energy Trust revenues from about $30 million in 2002 to $148.9 million in 2016.

[2] OPUC 2016 Stat book – 10 Year Summary Tables: https://www.puc.state.or.us/docs/statbook2016.pdf

to acquire in their territory, helping to offset the need for new generating resources to meet projected load growth.

Energy Trust Forecast Overview and High-Level Results

Energy Trust developed a 20-year DSM energy efficiency resource forecast for PGE using Energy Trust's resource assessment modeling tool (hereinafter 'RA Model') to identify the total 20-year cost effective modeled energy efficiency savings potential. Energy Trust then deploys this cost effective potential exogenously to the RA model into an annual energy efficiency savings projection based on past program experience, knowledge of current and developing markets, and future codes and standards. This final 20-year savings projection is provided to PGE for inclusion in their forecasts. The 2019 IRP results show that PGE can save 179.2 average megawatts (aMW)[3] in the next five years from 2018 to 2022 and over 547.6 by 2037.[4] These results represent a 19% and 30% increase respectively in cost-effective DSM potential over the prior IRP in 2016. The two main drivers of this increased potential are:

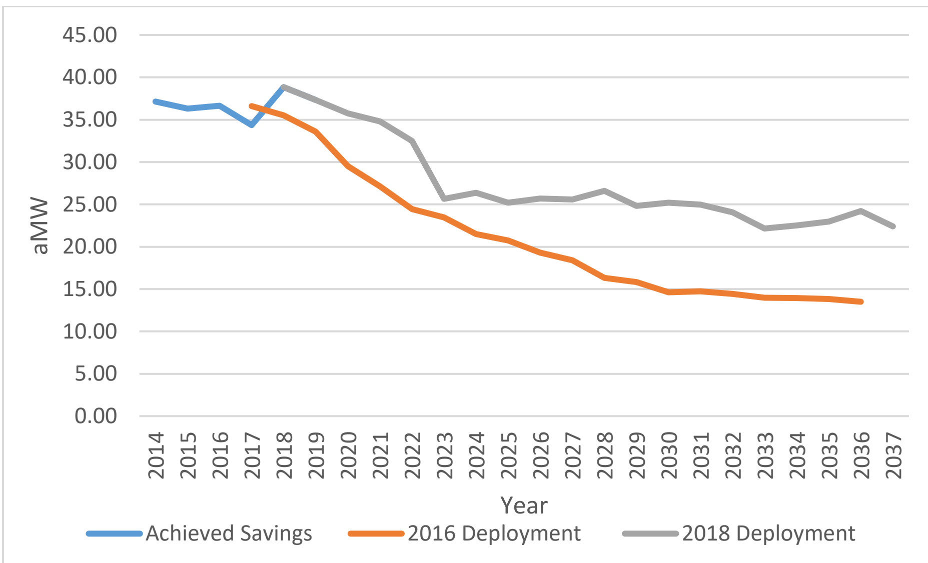
1. Measure additions and updates: Energy Trust added ten new emerging technologies to the model and updated measure level assumption for several of the existing measures
2. Updates to final savings projection methodology: Based on stakeholder meeting feedback, Energy Trust incorporated a 'megaproject adder' to its forecast and adopted deployment methodologies that better align with the Northwest Power and Conservation Council (NWPCC) acquisition assumptions from their 7th Power Plan.

Figure *1* links actual historic savings going back to 2010 to the new savings projection for the 2019 IRP. It also compares the 2019 IRP forecast to the 2016 IRP forecast.

[3] Unless explicitly noted, the savings discussed in this chapter and appendices, depicted in all tables and the following figures showing savings projections are in 'gross' savings at the meter and include additional savings that will be achieved by offsetting losses that would otherwise result from sending electricity through the utility's Transmission and Distribution system (line losses). Energy Trust publicly reports its Oregon savings and goals in "net" savings, which are adjusted including free ridership and spillover (market effects). Free ridership refers to customers participating in Energy Trust programs when program information or the incentive did not influence the customers' decision to invest in an energy efficiency solution. Spillover refers to the savings from customers that proceed with an energy-efficiency action because Energy Trust is present in the market and influenced them, but they did not participate directly in an Energy Trust program. Gross savings are not adjusted for these market effects and most accurately reflect the reductions PGE will see on their system.

[4] Includes over 20.64 aMW of market transformation savings resulting residential lighting standards going into effect. Also includes 21.76 aMW from a mega-project adder incorporated into the savings forecast.

Figure 1 - Annual Savings Projection Comparison for 2016 and 2019 IRPs, with Actual savings since 2014

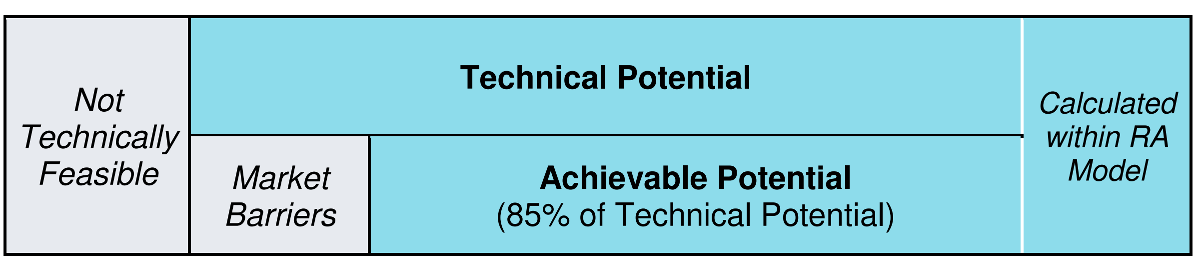


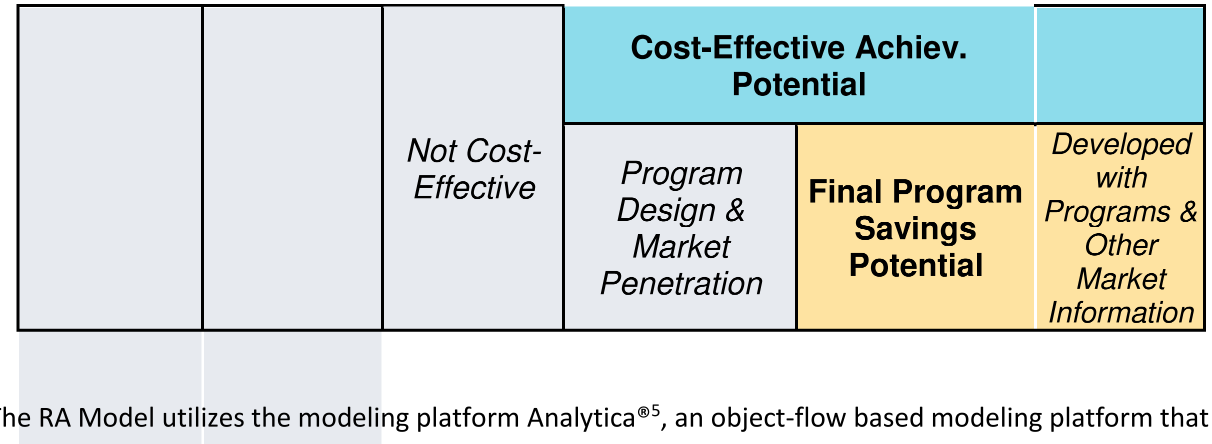
Energy Trust 20-Year Forecast Methodology

20-Year Forecast Overview

Energy Trust developed a 20-year DSM resource forecast for PGE using Energy Trust's RA Model to identify the total 20-year cost-effective modeled energy efficiency savings potential, which is 'deployed' exogenously of the model to provide an estimate of the final savings forecast. There are four types of potential that are calculated to develop the final savings potential estimate, which are shown in Figure 2 and discussed in greater detail in the sections below.

Figure 2 – Types of Potential Calculated in 20-year Forecast Determination





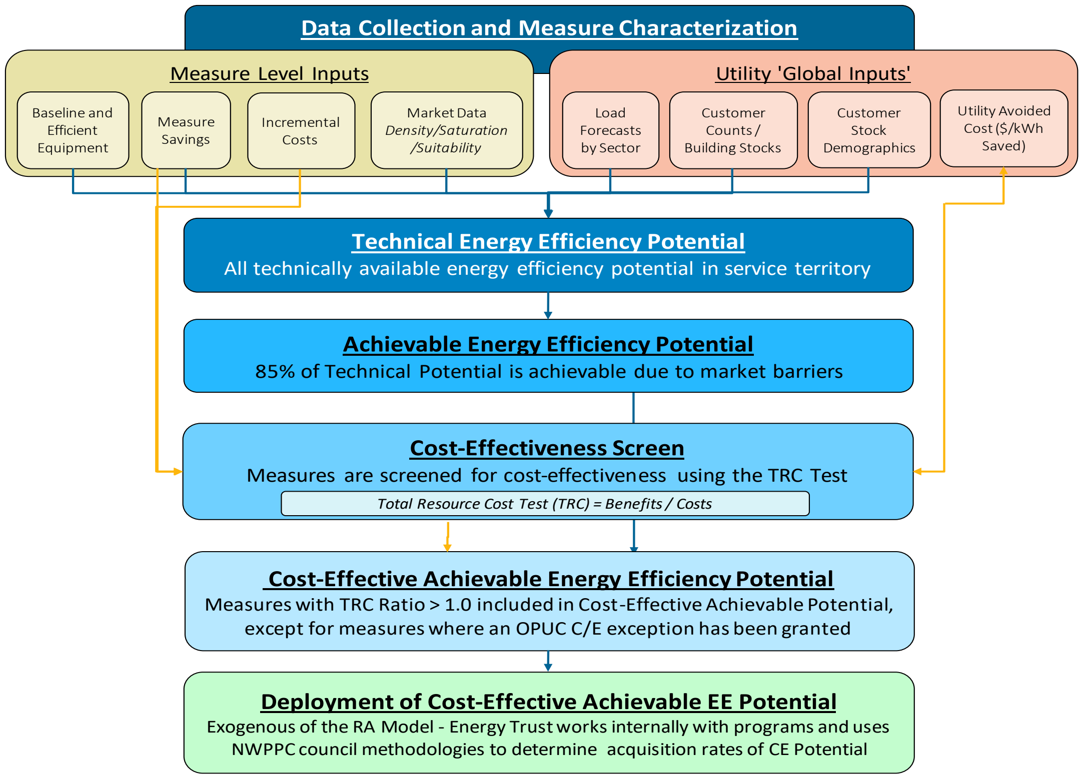
The RA Model utilizes the modeling platform Analytica®[5], an object-flow based modeling platform that is designed to visually show how different objects and parts of the model interrelate and flow throughout the modeling process. The model utilizes multidimensional tables and arrays to compute large, complex datasets in a relatively simple user interface. Energy Trust then deploys this cost-effective potential exogenously to the RA model into an annual energy savings projection based on past program experience, knowledge of current and developing markets, and future codes and standards.

20-Year Forecast Detailed Methodology

Energy Trust's 20-year forecast for DSM savings follows six overarching steps from initial calculations to deployed energy savings, as shown in Figure 3. The first five steps in the varying shades of blue nodes - Data Collection and Measure Characterization to Cost-Effective Achievable Energy Efficiency Potential - are calculated within Energy Trust's RA Model. This results in the total cost-effective potential that is achievable over the 20-year forecast. The actual deployment of these savings (the acquisition percentage of the total potential each year, represented in the green node of the flow chart) is done exogenously of the RA model. The remainder of this section provides further detail on each of the steps shown below.

Figure 3 - Energy Trust's 20-Year DSM Forecast Determination Flow Chart

[5] http://www.lumina.com/why-analytica/what-is-analytica1/



1. Data Collection and Measure Characterization

The first step of the modeling process is to identify and characterize a list of measures to include in the model, as well as receive and format utility 'global' inputs for use in the model. Energy Trust compiles a list of commercially available and emerging technology measures for residential, commercial, industrial and agricultural applications installed in new or existing structures. The list of measures is meant to reflect the full suite of measures offered by Energy Trust, plus a spectrum of emerging technologies.[6] Simultaneous to this effort, Energy Trust collects necessary data from the utility to run the model and scale the measure level savings to a given service territory (known as 'global inputs').

- ***Measure Level Inputs:***
  Once the measures to include in the model have been identified, they must be characterized in order to determine their savings potential and cost-effectiveness. The characterization

[6] An emerging technology is defined as technology that is not yet commercially available, but is in some stage of development with a reasonable chance of becoming commercially available within a 20-year timeframe. The model is capable of quantifying costs, potential, and risks associated with uncertain, but high-saving emerging technology measures. The savings from emerging technology measures are reduced by a risk-adjustment factor based on what stage of development the technology is in. The working concept is that the incremental risk-adjusted savings from emerging technology measures will result in a reasonable amount of savings over standard measures for those few technologies that eventually come to market without having to try and pick winners and losers.

inputs are determined through a combination of Energy Trust primary data analysis, regional secondary sources[7], and engineering analysis. There are over 30 measure level inputs that feed into the model, but on a high level, the inputs are put into the following categories:

1. ***Measure Definition and Equipment Identification***: This is the definition of the efficient equipment and the baseline equipment it is replacing (e.g. a ductless mini-split heat pump replacing residential electric resistance space heat). A measure's replacement type is also determined in this step – Retrofit (RET), Replace on Burnout (ROB), or New Construction (NEW).
2. ***Measure Savings****:* the kWh or therms savings associated with an efficient measure calculated by comparing the baseline and efficient measure consumptions.
3. ***Incremental Costs****:* The incremental cost of an efficient measure over the baseline. The definition of incremental cost depends upon the replacement type of the measure. If a measure is a RET measure, the incremental cost of a measure is the full cost of the equipment and installation. If the measure is a ROB or NEW measure, the incremental cost of the measure is the difference between the cost of the efficient measure and the cost of the baseline measure.
4. ***Market Data:*** Market data of a measure includes the density, saturation, and suitability of a measure. A density is the number of measure units that can be installed per scaling basis (e.g. the average number of showers per home for showerhead measures). The saturation is the average saturation of the density that is already efficient (e.g. 50% of the showers already have a low flow showerhead). Suitability of a measure is a percentage input to represent the percent of the density that the efficient measure is actually suitable to be installed in. These data inputs are all generally derived from regional market data sources such as NEEA's Residential and Commercial Building Stock Assessments (RBSA and CBSA).

- ***Utility Global Inputs:***

  The RA Model requires several utility level inputs to create the DSM forecast. These inputs include:

  1. ***Customer and Load Forecasts****:* These inputs are essential to scale the measure level savings to a utility service territory. For example, residential measures are characterized on a scaling basis 'per home', so the measure densities are calculated as the number of measures per home. The model then takes the number of homes that PGE serves currently and the forecasted number of homes to scale the measure level potential to their entire service territory.
  2. ***Customer Stock Demographics****:* These data points are utility specific and identify the percentage of stock that utilize different heating fuels for both space heating and water heating. The RA Model uses these inputs to segment the total stocks to the stocks that are applicable to a measure (e.g. gas storage water heaters are only applicable to customers that have gas water heat).
  3. ***Utility Avoided Costs[8]:*** Avoided costs are the net present value of avoided energy purchases and delivery costs associated with energy efficiency savings

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[7] Secondary Regional Data sources include: The Northwest Power Planning Council (NWPPC), the Regional Technical Forum (the technical arm of the NWPPC), and market reports such as NEEA's Residential and Commercial Building Stock Assessments (RBSA and CBSA)

[8] More information on the components and methodology for avoided cost is available at https://www.energytrust.org/wp-content/uploads/2018/01/Energy-Trust-Avoided-Cost-Update-for-Oregon-2018.pdf

represented as $s per kWh saved. These values are provided by PGE based generally upon the avoided costs generated in the 2016 IRP. Avoided costs are the primary 'benefit' of energy efficiency in the cost-effectiveness screen. The avoided costs values used in PGE's resource assessment model are specific to PGE and differ slightly from the values used by Energy Trust when evaluating cost-effectiveness for statewide offerings.

2. Calculate Technical Energy Efficiency Potential

Once measures have been characterized and utility data loaded into the model, the next step is to determine the technical potential of energy that could be saved. Technical potential is defined as the total potential of a measure in the service territory that could be achieved regardless of market barriers, representing the maximum potential energy savings available. The model calculates technical potential by multiplying the number of applicable units for a measure in the service territory by the measure's savings. The model determines the total number of applicable units for a measure utilizing several of the measure level and utility inputs referenced above:

Total applicable units =	*Measure Density * Baseline Saturation * Suitability Factor * Heat Fuel Multipliers (if applicable) * Total Utility Stock (e.g. # of homes)*
Technical Potential =	*Total Applicable Units * Measure Savings*

The measure level technical potential is then summed up to show the total technical potential across all sectors. This savings potential does <u>not</u> take into account the various market barriers that will limit a 100 percent adoption rate.

3. Calculate Achievable Energy Efficiency Potential

Achievable potential is simply a reduction to the technical potential by 15 percent, to account for market barriers that prevent total adoption of all cost-effective measures. Defining the achievable potential as 85 percent of the technical potential is the generally accepted method employed by many industry experts, including the NWPCC and National Renewable Energy Lab (NREL).

Achievable Potential =	*Technical Potential * 85%*

4. Determine Cost-effectiveness of Measures using TRC Screen

The RA Model screens all DSM measures in every year of the forecast horizon using the Total Resource Cost (TRC) test, a benefit-cost ratio (BCR) that measures the cost-effectiveness of the investment being made in an efficiency measure. This test evaluates the total present value of benefits attributable to the measure divided by the total present value of all costs. A TRC test value equal to or greater than 1.0 means the value of benefits is equal to or exceeds the costs of the measure, and is therefore cost-effective and contributes to the total amount of cost-effective potential. The TRC is expressed formulaically as follows:

TRC = Present Value of Benefits / Present Value of Costs

Where *the Present Value of Benefits* includes the sum of the following two components:

a) Avoided Costs: The present value of electricity saved over the life of the measure, as determined by the total kWh saved multiplied by PGE's avoided cost per kWh. The net present-value of these benefits is calculated based on the measure's expected lifespan using PGE's discount rate.
b) Non-energy benefits are also included when present and quantifiable by a reasonable and practical method (e.g. water savings from low-flow showerheads, operations and maintenance (O&M) cost reductions from advanced controls).

Where *the Present Value of Costs* includes:

a) Total participant incremental cost

The cost-effectiveness screen is a critical component for Energy Trust modeling and program planning because Energy Trust is only allowed to incentivize cost-effective measures, unless an exception has been granted by the OPUC. Energy Trust is governed by policy directives to obtain all reasonably attainable cost-effective potential[9].

5. Quantify the Cost-Effective Achievable Energy Efficiency Potential

The RA Model's final output of potential is the quantified cost-effective achievable potential. If a measure passes the TRC test described above, then the *achievable savings* (85% of technical potential) from this measure is included in the cost-effective achievable potential. If the measure does not pass the TRC test above, the measure is not included in the cost-effective achievable potential. However, the cost-effectiveness screen can be overridden for some measures under three specific conditions:

1) The OPUC has granted an exception to offer non-cost-effective measures under strict conditions or,
2) When the measure isn't cost-effective using utility specific avoided costs but the measure is cost-effective when using blended electric avoided costs for all of the electric utilities Energy Trust serves and is therefore offered by Energy Trust programs.
3) The measure is not cost-effective in our model, but may appear cost-effective in program settings, where costs are combined with other measures or are highly variable from project to project. For example, some commercial new construction measures may be screened on a project by project basis relying on a system based performance approach to cost-effectiveness. While these measures may not be individually cost-effective they still occur within programs as the project as a whole is cost-effective.

6. Deployment of Cost-Effective Achievable Energy Efficiency Potential

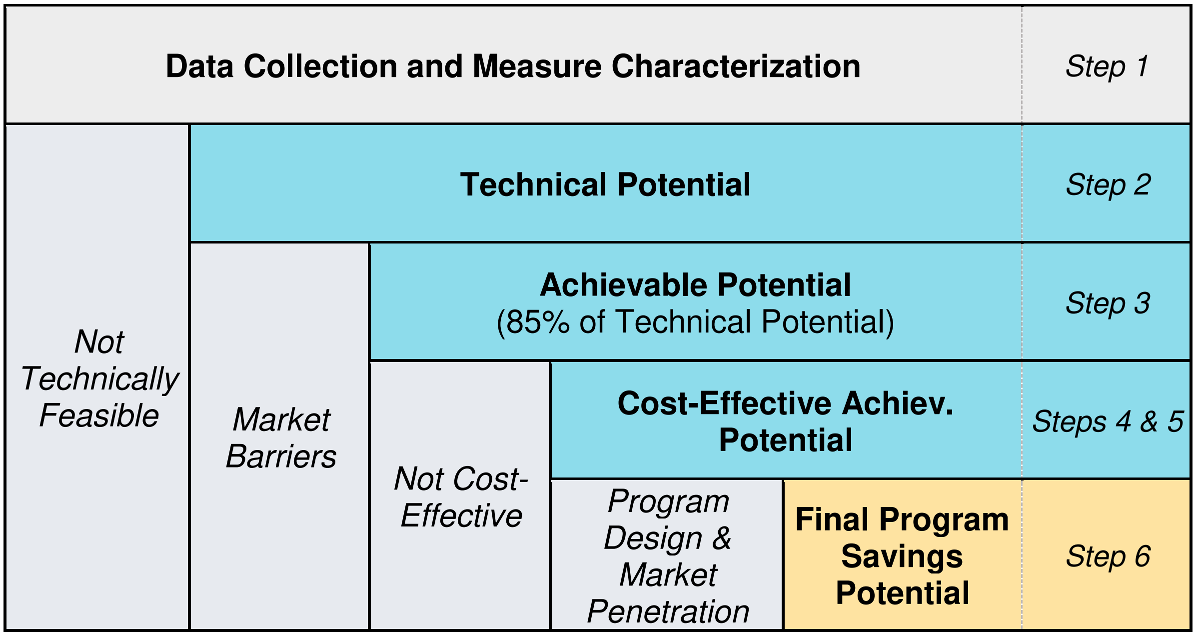
After the model determines the 20-year cost-effective achievable potential, Energy Trust develops a savings projection based on past program experience, knowledge of current and developing markets, and future codes and standards. The savings projection is a 20-year forecast of energy savings that is projected to result in a reduction of load on PGE's system. This savings forecast includes savings from program activity for existing measures and emerging technologies, expected savings from market transformation efforts that drive improvements in codes and standards, and a forecast of what Energy Trust is describing as a 'megaproject adder'. The 'megaproject adder' is characterized as savings that account for large unidentified projects that consistently appear in

[9] As directed in OPUC docket UM-551 and 2017 ORS 757.054

Energy Trust's historic savings record and have been a source of overachievement against IRP targets in prior years for other utilities that Energy Trust serves.

Figure 4 below reiterates the types of potential shown in Figure 2, and how the steps described above and in the flow chart fit together.

Figure 4 - The Progression to Program Savings Projections



Changes from 2016 IRP to 2019 IRP

Energy Trust hosted a stakeholder meeting in September 2017 to get feedback on Energy Trust's forecast process. Attendees included utilities, OPUC staff, and other regional stakeholders like the Northwest Energy Coalition. Some of the most significant themes that emerged from this process include:

Energy Trust annual savings achievements have been consistently exceeding IRP targets.

- Utilities and stakeholders are interested in receiving a forecast based on more than just "firm" resources achieved through program activity.
- Utilities are interested in the best projection Energy Trust can provide. Achievements should fluctuate on both sides of the forecast over time.
- Forecast has been missing some estimation of future resources that Energy Trust cannot currently identify.
    - New large single loads that utilities have difficulty forecasting and associated large efficiency 'mega-projects'.
    - Emerging Technology of the future that has not yet been developed to the point where Energy Trust includes it in its model.
- Short-term forecasts are most important to utilities and the OPUC in the following order. 1-2 years, 3-5 years, 6-10 years, and 11-20 years.

As a result of this feedback, Energy Trust made several changes to improve its IRP forecasts. Incremental improvements made to PGE's energy efficiency forecast include:

- Inclusion of additional behavioral savings and near net-zero homes and buildings
- Increased coordination with program managers and a move to think about forecast in three time periods
  - 1-2 years (short term) - Rely on programs and align with savings goals from most recent budget
  - 3-5 years (midterm) - Programs and planning work together to extend program trends based on market intelligence
  - 6-20 years (long term) - Planning forecasts long-term acquisition rate
- Addition of forecast "megaproject adder" to account for large unidentified projects. These have previously not been forecast as loads or opportunities and have resulted in significant forecasting error. The addition is based on past large project savings averages.
- Adopted deployment methodologies that better align with the Northwest Power and Conservation Council (NWPCC) acquisition assumptions from their 7th Power Plan.

Forecast Results

Forecast results will be shown in several different sections, as the RA model has different output capabilities that are applied to project energy savings potential in a variety of different views, including by segment, end use, and in supply curves. The final savings projection is provided by segment and program delivery type. The RA Model produces results by potential type of potential, as well as several other useful outputs, including a supply curve based on the levelized cost of energy efficiency measures. This section discusses the overall model results by potential type and provides an overview of the supply curve.

Forecasted Savings by Sector

Table 1 summarizes the technical, achievable, cost-effective achievable, and final deployed cost-effective achievable potential for PGE's system in Oregon. The savings in the table represent the total 20-year cumulative energy savings potential identified in the RA Model and Energy Trust for each of the four respective types of potential identified in Figure 2 and Figure 4, prior to deployment of the savings into the final savings projection.

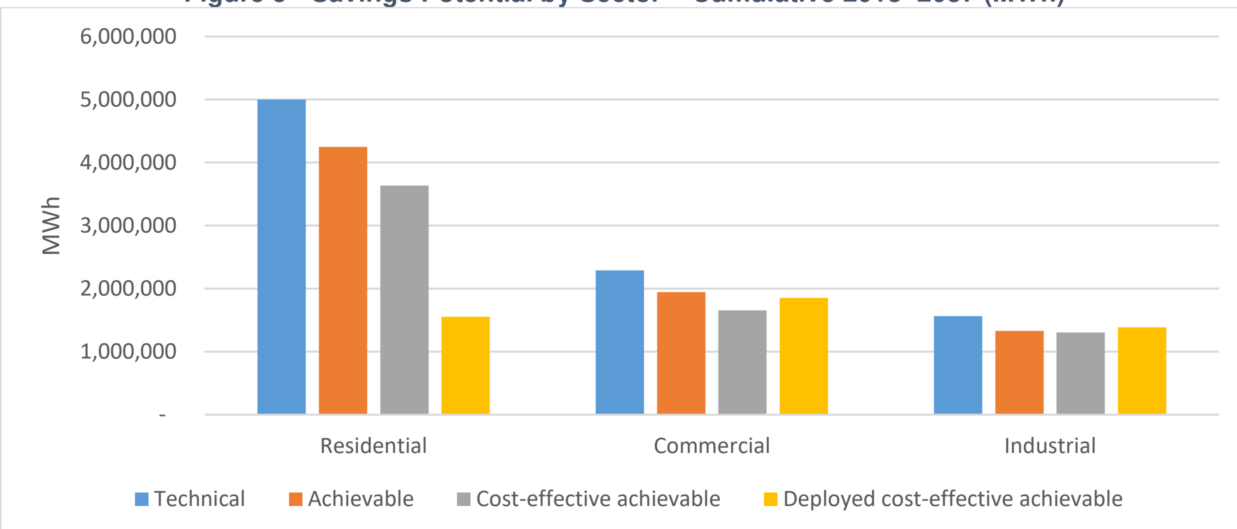
Table 1 - Summary of Cumulative Modeled Savings Potential - 2018–2037

Sector	Technical Potential (aMW)	Achievable Potential (aMW)	Cost-Effective Achievable Potential (aMW)	Deployed Cost-Effective Achievable Potential (aMW)
Residential	571	485	415	177
Commercial	261	222	189	212
Industrial	179	152	149	158
Total	**1011**	**859**	**754**	**548**

Figure 5 shows cumulative forecasted savings potential across the three sectors Energy Trust serves, as well as the type of potential identified in PGE's service territory.

The residential sector, represented by single family, multifamily, and manufactured homes represents the largest source of efficiency potential within PGE's territory. However, Energy Trust programs are projected to acquire more commercial savings over the 20-year forecast period. Commercial savings within the deployed cost-effective forecast are 39% of the overall savings, while residential is 32% and industrial is 29% of overall savings.

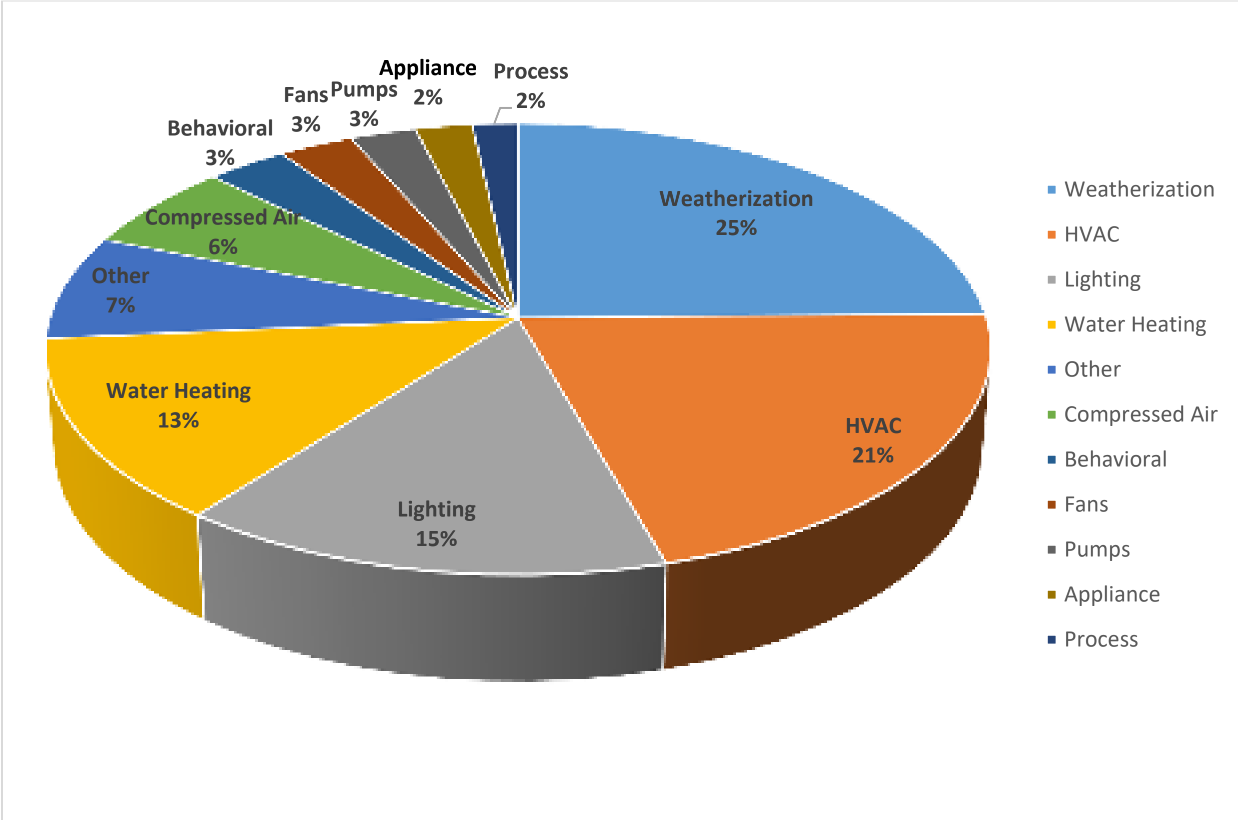
Figure 5 - Savings Potential by Sector – Cumulative 2018–2037 (MWh)



Cost-Effective Achievable Deployed Savings by End-Use

Figure 6 below provides a breakdown of PGE's 20-year cost-effective DSM savings potential by end use.

Figure 6 – 20-year Cost-Effective Achievable Cumulative Potential by End Use



The top saving end uses are HVAC and weatherization as heating and cooling make up a large portion of load within all sectors. The New Home pathways are packages of savings in new construction homes that span several end-uses most commonly weatherization and HVAC. A portion of the water heating end-use however is attributable to new construction homes due to how Energy Trust assigns end uses to the offered New Homes pathways. Energy Trust assigns an end-use to each of the offered New Homes pathways based on the most significant saving end-use of the package. For example, one cost-effective New Home pathway that was identified by the model (because it achieves the most savings for the least cost) was designated as a water heating end-use, though the package includes several other efficient mechanical electric equipment measures. In addition to the New Homes pathway savings, the water heating end-use includes water heating equipment from all sectors, as well as showerheads and aerators. Weatherization and HVAC end uses represent the savings associated with space heating equipment, retrofit add-ons, and most new construction packages. Behavioral consists primarily of potential from Energy Trust's commercial strategic energy management measure, a service where Energy Trust energy experts provide training to facilities teams and staff to identify operations and maintenance changes that make a difference in a building's energy use. The "Other" category includes plug load end use measures and measures that have unique end-uses such as industrial welders.

Contribution of Emerging Technologies

As mentioned earlier in this report, Energy Trust includes a suite of emerging technologies (ETs) in its model. The emerging technologies included in the model are listed in Table 2.

Table 2 - Emerging Technologies Included in the Model that are pertinent for PGE

Residential	Commercial	Industrial

• Path 5 Emerging Super Efficient Whole Home • High Performance Manufactured Home • Window Replacement (U<.20) • Window Attachments • Advanced Insulation • Behavior Competitions • Heat Pump Dryers	• Advanced Ventilation Controls • DOAS/HRV • DHW Circulation Pump • Advanced Package A/C RTUs • Zero Net Energy Path • AC Heat Recovery, HW • Hybrid Indirect-Direct Evaporative Cooler • Advanced Refrigeration Controls • Advanced Window Technologies	• Wall Insulation- VIP, R0-R35 • Switched reluctance motors

Energy Trust recognizes that emerging technologies are inherently uncertain and utilizes a risk factor to hedge against that risk. The risk factor for each emerging technology is used to characterize the inherent uncertainty in the ability for ETs to produce reliable future savings. This risk factor was determined based on qualitative metrics of:

- Market risk
- Technical risk
- Data source risk

The framework for assigning the risk factor is shown in

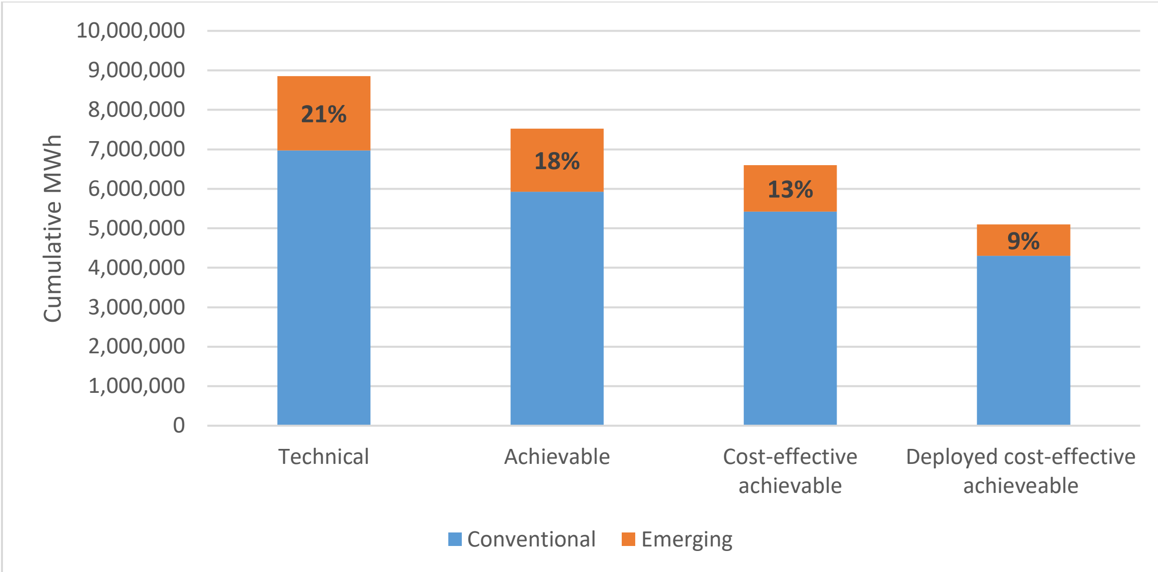
Table 3. Each ET was assessed within each risk category; a total weighted score was then calculated. Well-established and researched technologies have lower risk factors while nascent, unevaluated technologies (e.g., CO2 heat pump water heaters) have higher risk factors. This risk factor was then used as a multiplier of the incremental savings potential of the measure.

Table 3 - Emerging Technology Risk Factor Score Card

	ET Risk Factor				
Risk Category	**10%**	**30%**	**50%**	**70%**	**90%**
Market Risk (25% weighting)	**High Risk:** • Requires new/changed business model • Start-up, or small manufacturer • Significant changes to infrastructure • Requires training of contractors. Consumer acceptance barriers exist.			**Low Risk:** • Trained contractors • Established business models • Already in U.S. Market • Manufacturer committed to commercialization	
Technical Risk (25% weighting)	**High Risk:** Prototype in first field tests. A single or unknown approach	Low volume manufacturer. Limited experience	New product with broad commercial appeal	Proven technology in different application or different region	**Low Risk:** Proven technology in target application. Multiple potentially viable approaches.
Data Source Risk (50% weighting)	**High Risk:** Based only on manufacturer claims	Manufacturer case studies	Engineering assessment or lab test	Third party case study (real world installation)	**Low Risk:** Evaluation results or multiple third party case studies

Figure 7 below shows the amount of emerging technology savings within each type of DSM cumulative potential. While emerging technologies make up about 20% of the technical and achievable potential, once the cost-effectiveness screen is applied, the relative share of emerging technologies drops to about 13% of total cost-effective achievable potential. This is due to the fact that many of these technologies are still in early stages of development and are quite expensive. Though Energy Trust includes factors to account for forecasted decreases in cost and increased savings from these technologies over time, some are still never cost-effective over the planning horizon or do not become cost-effective until later years.

Figure 7 – Cumulative Contribution of Emerging Technologies by Potential Type



Cost-Effective Override Effect

Table 4 shows the savings potential in the RA model that was added by employing the cost-effective override option in the model. As discussed in the methodology section, the cost-effective override option forces non-cost-effective potential into the cost-effective potential results and is used when a measure meets one of the following three criteria:

1. A measure is offered under an OPUC exception.
2. When the measure isn't cost-effective using PGE-specific avoided costs but the measure is cost-effective when using blended electric avoided costs for all of the electric utilities Energy Trust serves and is therefore offered by Energy Trust programs.
3. The measure is not cost-effective in our model, but may appear cost-effective in program settings, where costs are combined with other measures or highly variable from project to project[10].

Table 4 - Cumulative Cost-Effective Potential (2018-2037) due to Cost-effectiveness override (aMW)[11]

Sector	Yes CE Override	No CE Override	Difference
Residential	415	388	28
Commercial	189	184	5
Industrial	149	117	32
Total DSM:	**754**	**689**	**65**

[10] Some measures can have high degrees of variations in savings and costs. If a measure is cost-effective in the RA model then all savings attributable to the measure are included. Conversely, if a measure is not cost-effective in the RA model then zero savings will be shown in the model. While costs are updated frequently to reflect changing markets there may be instances where some instances of installation are cost-effective and others are not. Many of these types of projects are screened individually for cost-effectiveness in Energy Trust's custom program offerings.
[11] Table 4 represents cost-effective achievable potential added from the cost-effectiveness override and not the final deployed savings projection.

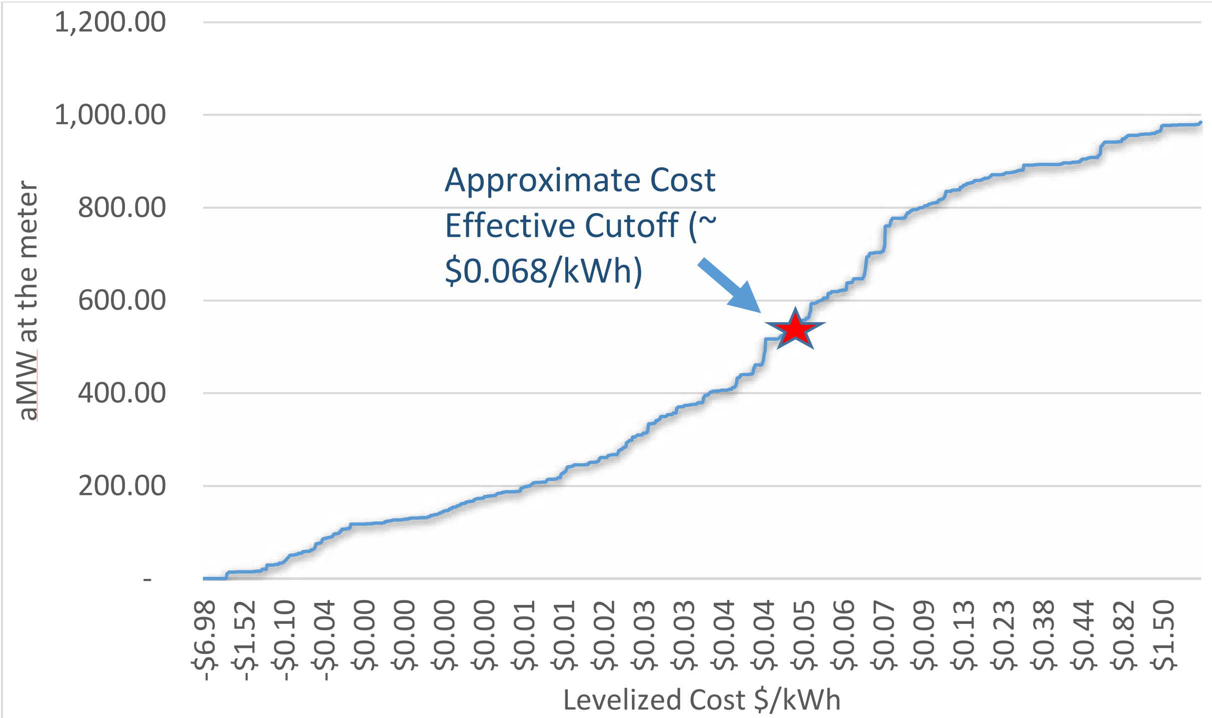
In this IRP, 9% of the cost-effective potential identified by the model is due to the use of the cost-effective override for measures.

Supply Curves and Levelized Cost Outputs

An additional output of the RA Model is a resource supply curve developed from the levelized cost of energy of each measure. The supply curve graphically depicts the total potential in average megawatts that could be saved at various costs for all measures. The levelized cost for each measure is determined by calculating the present value of the total cost of the measure over its economic life, per kWh of energy savings ($/kWh saved). The levelized cost calculation starts with the customer's incremental TRC of a given measure. The total cost is amortized over an estimated measure lifetime using the PGE's discount rate provided to Energy Trust. The annualized measure cost is then divided by the annual kWh savings. Some measures have negative levelized costs because non-energy benefits amortized over the life of the measure are greater than the total cost of the measure over the same period.

Figure *8* below shows the supply curve developed for this IRP that can be used for comparing demand-side and supply-side resources. The cost threshold shown with a star on the supply curve line represents the approximate levelized cost cutoff that corresponds with the amount of TRC determined cost-effective deployed DSM potential in the 2019 IRP, when ordering all measures based on their levelized cost.

Figure 8 – Electric Supply Curve ($ per kWh saved)



Deployed Results – Final Savings Projection

The results of the final savings projection show that Energy Trust can save 179 aMWs across PGE's system in the next five years from 2018 to 2022 and 548 aMWs by 2037. This represents a 19 percent cumulative load reduction by 2037[12] and is an average of just over a 1.0 percent incremental annual load reduction. The cumulative final savings projection is shown in Table 5 compared to the technical, achievable and cost –effective achievable potential.

Table 5 - 20-Year Cumulative savings potential by type, including final savings projection (aMW at the meter)

Sector	Technical Potential	Achievable Potential	Cost-Effective Achievable Potential	Final Savings Projection
Residential	571	485	415	177
Commercial	261	222	189	212
Industrial	179	152	149	137
Mega Projects[13]	-	-	-	21
Total	**1,011**	**859**	**754**	**548**

[12] Cumulative savings assumes customers will continue to purchase equipment equal or higher efficiency equipment after the measure reaches the end of its useful life and therefore savings in this instance are assumed to persist in future years.
[13] The mega-project adder is not a line item in the model, but based on analysis of previous Energy Trust program data and added during the deployment.

The final deployed savings projection is just over half of the modeled cost-effective achievable potential. There are several reasons for this additional step down in savings:

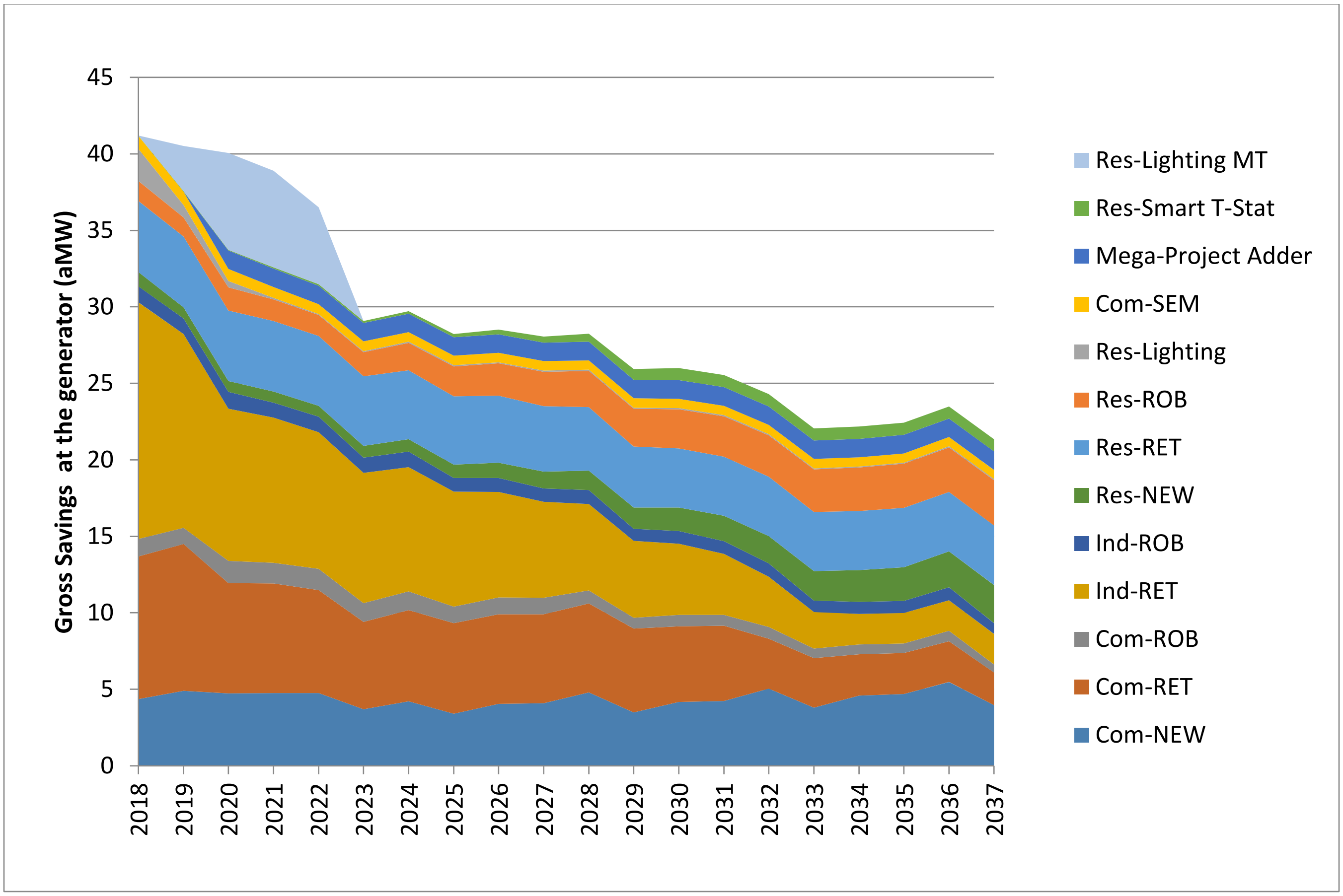
1) "Lost Opportunity Measures" – Measures that are meant to replace failed equipment (ROB) or new construction measures (NEW) are considered lost opportunity measures because programs have one opportunity to influence the installation of efficient equipment over code baseline when the existing equipment fails or when the new building is built. This is because these measures must be installed at that specific point in time, and if a program administrator misses the opportunity to influence the installation of more efficient equipment, the opportunity is lost until the equipment fails again. Energy Trust expects that most of these opportunities will be met in later years as efficient equipment becomes more readily adopted. However, in early years, the level of acquisition for these opportunities is smaller and ramps higher as time progresses.
2) "Hard to Reach Measures" – some measures that show high savings potential are notoriously hard to reach and are capped at about 40 percent of total retrofit potential. These measures include residential insulation and windows.

The final deployed savings projection for the commercial sector is higher than the cost-effective savings identified in the model due to program goals including savings from market transformation. Market transformation savings represent energy efficiency savings resulting from commercial code adoption in Oregon in prior years. As presently constructed, the model does not have a way to represent these savings in an easily defined manner and is represented by setting ramp rates at higher than 100 percent in early years to show that the savings from new construction measures are more than just incremental beyond current code. As a result the final deployed savings is higher than the cost-effective achievable savings identified in the model by about 12 percent.

Figure 9 below shows the annual deployed savings projection by sector and measure type. The steep decline in savings from 2022-2023 is a result of complete market transformation of lighting resulting from the Energy Security Independence Act (EISA) setting a relatively efficient baseline for all most lighting types[14]. Energy Trust's forecast believes these savings will take fully be realized by markets by 2023 as compliance and replacement of inefficient bulbs will take time. While Energy Trust's programs will not claim the majority of savings resulting from this market transformation, the savings will still be reflected on PGE's system and therefore have been included in the final deployed savings projection. Most other sector and measure types ramp down or remain stagnant over the forecast period.

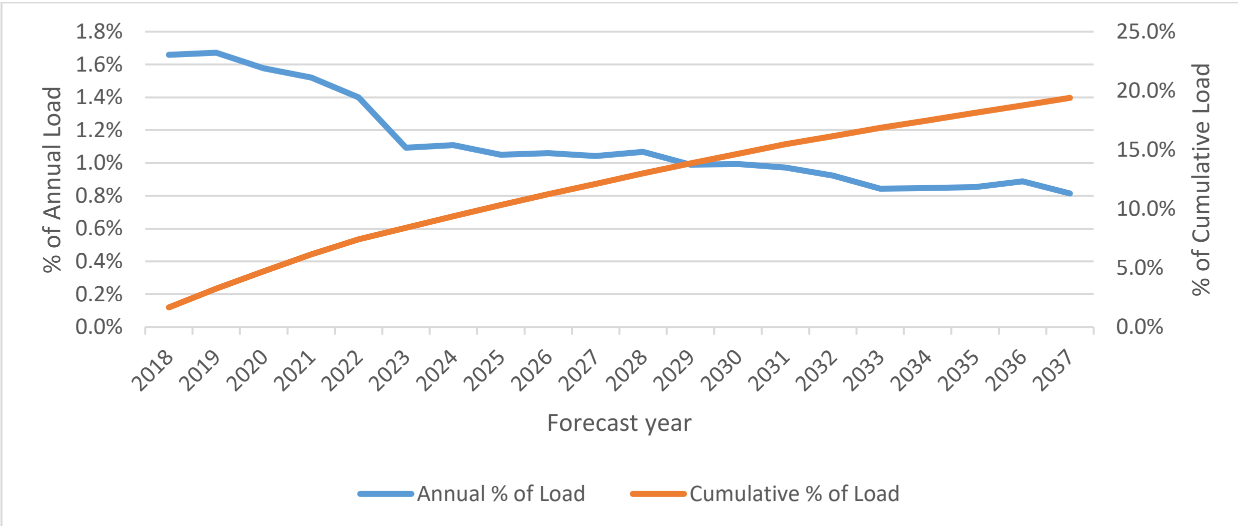
[14] Signed on December 19, 2007 the Energy Independence Security Act (EISA) includes provisions to increase the efficiency of products buildings and vehicles. Starting January 1, 2020, it will be against the law to sell most halogen and incandescent light bulbs in the U.S. An existing federal minimum energy efficiency standard of 45 lumens per watt (LPW) comes into effect on this date and no currently available halogen or incandescent lamps are able to meet it.

Figure 9 – Annual Deployed Final Savings Potential by Sector and Measure Type (aMW at the generator)



Finally, Figure 10 shows the annual and cumulative deployed savings as a percentage of PGE's load forecast. Annually, the savings as a percentage of load varies from about 0.8% at its lowest to 1.7% at its highest, as represented on the *left* Y-axis of the graph and the blue line. Cumulatively, the savings as a percentage of load builds to almost 20% by 2037, shown on the right Y-axis and the orange line.

Figure 10 – Annual Forecasted Savings as a Percentage of Annual Load Forecast



Deployed Results – Peak Hour Results

Regionally and in the state of Oregon, the NWPCC 7th Power Plan has identified an increased need and focus on peak savings contributions of energy efficiency and its impact on capacity investments. This new focus has led some utilities to embark on targeted load management efforts for avoiding or delaying distribution system reinforcements. Additionally, the OPUC has directed Energy Trust to report peak impacts in the appendices of our annual report beginning in 2017[15]. Peak hour factors are the percentage of annual savings that are expected to occur on a peak hour during the course of a year. Energy Trust calculates peak demand factors using Equation 1, where load factors and coincidence factors being derived from the NWPCC library of load profiles.

Equation 1 – Calculation of Peak Factors from Load and Coincidence Factors

*Peak factor = (1 yr/8760) * Load Factor * Coincidence Factor*

Figure 11 below shows the annual, deployed peak hour savings potential based upon the results of the 20-year forecast. Each measure analyzed is assigned a load shape and the appropriate peak factor is applied to the annual savings to calculate the overall DSM contribution to peak hour capacity. Both the commercial and residential sector achieve 38% of overall peak savings over the 20 year period with the remaining 24% coming from the industrial sector. The annual peak savings are shown in Table 6 below [16]

[15] See Appendix 8 of Energy Trust's "*2017 Annual Report to the Oregon Public Utility Commission & Energy Trust Board of Directors*" available at https://www.energytrust.org/wp-content/uploads/2018/04/2017.Annual.Report.OPUC_.pdf

[16] Peak results do not include energy savings from mega-project adder and residential lighting market transformation categories

Figure 11 - Annual Deployed Peak Savings Contribution by Season (MW)

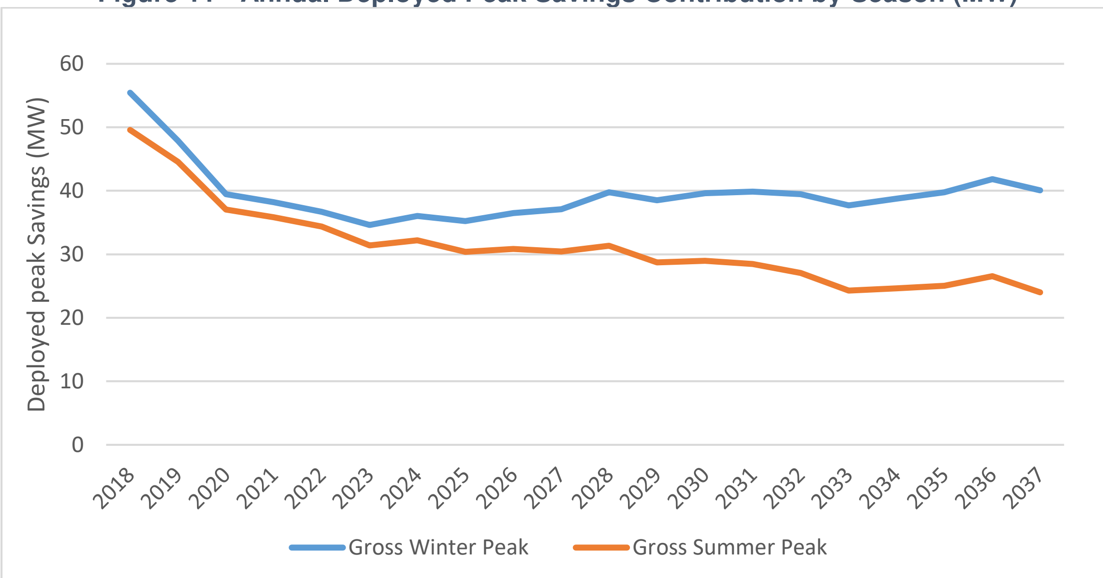


Table 6 - Cumulative Deployed Peak Savings Contribution by Sector (MW)

Sector	Winter Gross Peak Savings (MW)	Summer Gross Peak Savings (MW)
Commercial	260	282
Residential	384	151
Industrial	148	193
Total	**793**	**626**

External Study C. Distributed Energy Resource Study

Distributed Resource and Flexible Load Study

Integrated Resource Planning System-Level Report

Prepared for:

Portland General Electric

Submitted by:
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Boulder, CO 80302

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Reference No.: 201598

April 2019

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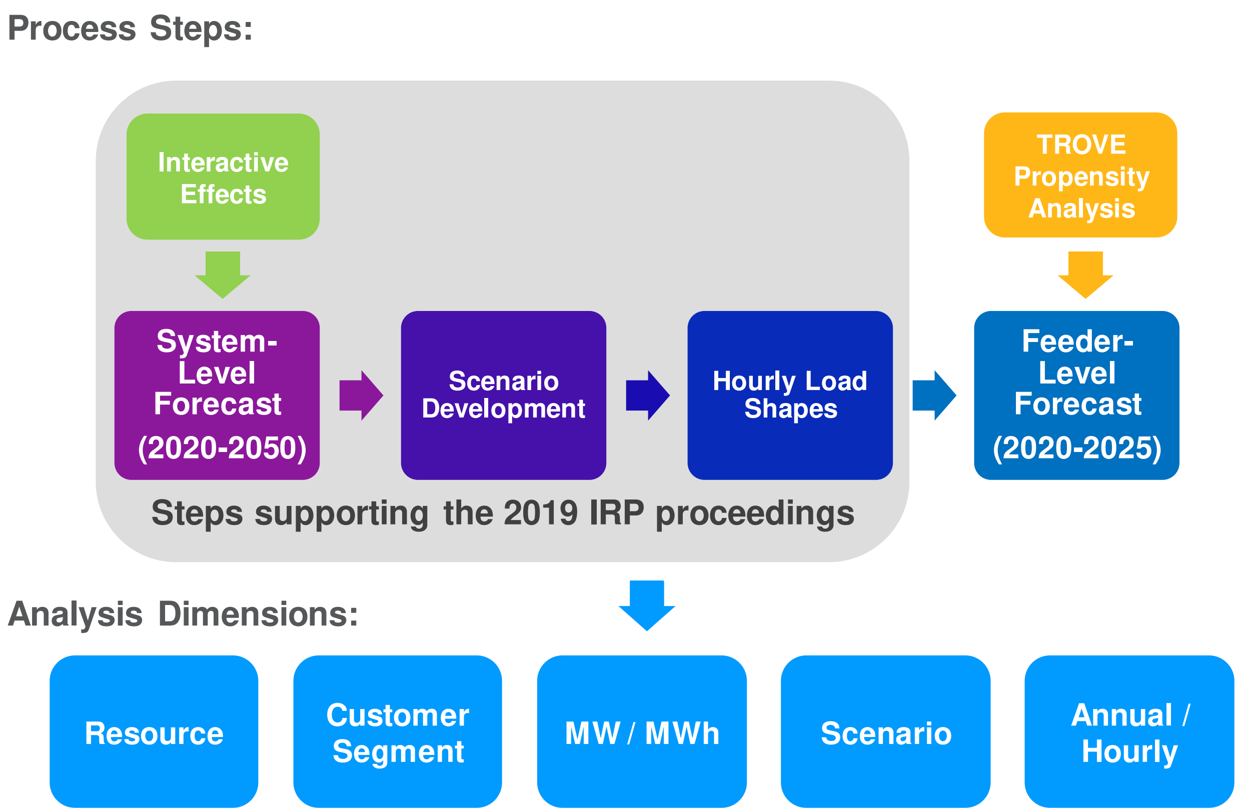
1. INTRODUCTION

The objective of the Distributed Resource and Flexible Load study was to estimate the impacts of distributed energy resources (DER) to support Portland General Electric's (PGE) planning and forecasting needs. PGE commissioned this study in response to the planning needs of multiple different departments within PGE, with each department requiring different aspects and dimensions of the data to help answer their specific planning questions. Figure 1 provides an overview of the overall study and the various dimensions of the analysis. The scope of this report focuses on the interactive effects, system-level forecast, system-level scenario development, and system-level hourly load shapes prepared on behalf of PGE's Integrated Resource Planning (IRP) department to help support the 2019 IRP proceedings.

Figure 1. Overview of Distributed Resource and Flexible Load Study*

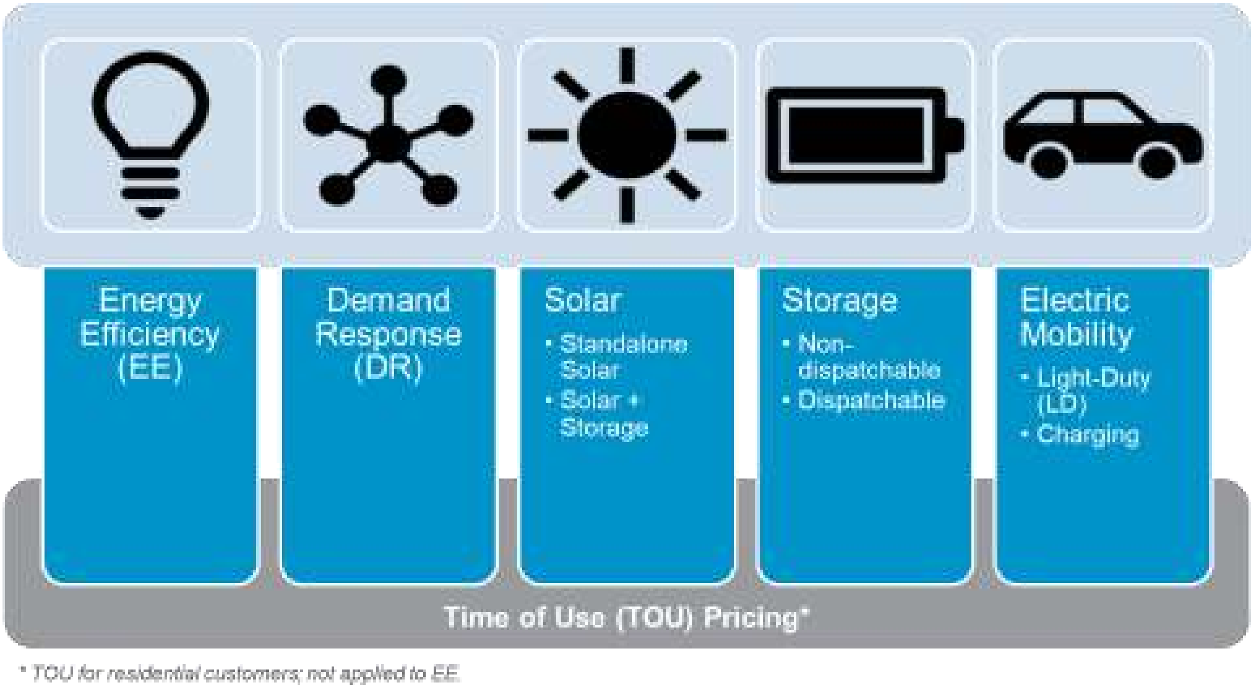


Source: Navigant

** The scope of this report focuses on the interactive effects, system-level forecast, system-level scenario development, and system-level hourly load shapes, highlighted by the gray box.*

Figure 2 presents the distributed resources addressed in this study, which included Energy Efficiency, Demand Response (DR), Solar PV, Storage, and Electric Mobility, as well as a cross-cutting Residential Time of Use (TOU) Pricing rate, as discussed more in the sections below.

Figure 2. Scope of Distributed Resources in Study



Source: Navigant

For each of the distributed resources highlighted in the scope, Navigant generated a system-level forecast across the following dimensions, based on the granularity of the input data available and PGE's different departmental needs:

- **Time:** Annual from 2020-2050
- **Customer Segment:** Residential Single-Family, Residential Multi-Family, Residential Manufactured, Commercial, and Industrial
- **Impact:** Energy, demand and vehicle counts (for electric mobility)
- **Scenario:** Base, Low, and High

2. METHODOLOGY AND ASSUMPTIONS

Navigant applied an integrated approach to estimating the energy and demand impacts associated with each distributed resource. This involved accounting for both the isolated effects of each technology or program, as well as the interactions between resources that are likely to have the greatest impact from a system planning perspective. The following sections describe the methodology and assumptions applied to each distributed resource and interaction, as well as how these assumptions vary by scenario.

2.1 Light Duty Vehicles

Navigant used its Vehicle Adoption Simulation Tool (VAST™) model to develop a system-level forecast of light-duty plug-in electric vehicles (LDV) in PGE's service area. VAST™ uses an enhanced systems dynamics innovation diffusion model to forecast adoption of various powertrain-fuel configurations in the plug-in electric vehicle (PEV) market at the local level with inputs specific to PGE's service area.

The model determines the long-run technology adoption potential of vehicles based on changing dynamics of competing vehicle, infrastructure, and consumer attributes. The competition model is driven by a Total Cost of Ownership (TCO) analysis that estimates the market potential of a particular vehicle technology, conditioned on its availability, consumer eligibility, and consumer awareness.

The LDV forecasts span 2020 to 2050 and include the following splits:

- Ownership: Individual/Fleet
- Powertrain: Battery Electric Vehicle (BEV)/Plug-In Hybrid Electric Vehicle (PHEV)

Within the Base scenario, Navigant assumed that 10% of Residential customers with LDVs also participate in PGE's TOU rate.

2.2 Solar PV and Storage

Navigant used its Renewable Energy Simulator (RESim™) model, a systems dynamics discrete choice model for solar PV, storage, and joint solar PV + storage adoption forecasting, to estimate energy and capacity impacts associated with solar PV and storage systems in PGE's service area. The technologies assessed in this model include standalone solar PV, standalone non-dispatchable storage, standalone dispatchable storage, solar PV + non-dispatchable storage, and solar PV + dispatchable storage. The market share for each of these technology combinations is driven by a levelized cost, logit-decision maker approach, which accounts for the ratio of levelized cost of electricity (LCOE) to consumer offset rates (also called levelized value of electricity or LVOE), conditioned on technology acceptance and awareness.

Navigant and PGE defined[1] the non-dispatchable and dispatchable storage use cases and value streams as follows and summarized in Table 1:

- **Non-dispatchable storage:** The operation (charge/discharge) of the storage system is solely accessible to the customer. The customer can use the storage for demand charge avoidance, arbitrage (if on a TOU rate), and reliability purposes. Navigant assumed the storage would have

[1] These definitions are consistent with the PGE's storage potential study: *Energy Storage Potential Evaluation*. Prepared by Navigant. Prepared for Portland General Electric. Oregon Public Utilities Commission Docket – UM 1751. October 2017. https://edocs.puc.state.or.us/efdocs/HTB/um1856htb165749.pdf.

on-board software to maximize value to the customer through optimally timed charging and discharging for rate arbitrage and peak-shaving opportunities.

- **Dispatchable storage:** PGE pays the customer an incentive to use the storage for capacity, ancillary services, and transmission and distribution benefits, while the customer can still use the storage for reliability purposes, but not demand charge avoidance or rate arbitrage.

Table 1. Storage Use Cases and Value Streams

Use Case	Utility Value Streams			Customer Value Streams			Customer Compensation Mechanism
	Generation Capacity	Bulk Energy & Ancillary Services	T&D Locational Benefits	Power Reliability	TOU Arbitrage	Demand Charge Management	
Dispatchable	U	U	U	C			Utility rebate; power reliability benefits
Non-dispatchable				C	C	C	Reduction in bills; power reliability benefits

U = Utility value stream; C = Customer value stream

Within the Base scenario, Navigant assumed that 10% of Residential customers with standalone solar PV, standalone storage, or solar PV + storage also participate in PGE's TOU rate.

2.3 Demand Response

Navigant estimated the peak demand savings available from DR programs in PGE's expected portfolio, including the influence of the following categories[2] of programs on DR load profiles:

- Non-residential Direct Load Control (DLC)
- Non-residential Pricing
- C&I Curtailment
- Residential DLC
- Residential Pricing/Behavioral DR
- EV DLC

Navigant forecasted the impacts of DR for 2020 to 2050 by season (i.e., Summer and Winter) and scenario (i.e., Base, Low, High). Navigant applied assumptions about the start year, end year, ramp period, and maximum eligibility and participation rates for each program based on discussions with the

[2] For a complete list of programs included in each category, see Table 4 in Appendix B.

PGE team and PGE's most recent DR potential study.[3] Navigant calibrated the near-term participation forecast to PGE's program participation targets through 2023.

[3] *Demand Response Market Research: Portland General Electric, 2016 to 2035*. Prepared for Portland General Electric. Prepared by The Brattle Group. January 2016. https://www.portlandgeneral.com/-/media/public/our-company/energy-strategy/documents/2016-02-01-demand-response-market-research.pdf

Table 5 in 3.6.3Appendix BAppendix B contains the calibrated participation assumptions.

As mentioned in Section 2.6, this analysis also included a forecast of the potential available from a DLC program for LDVs.

Within the Base scenario, Navigant assumed that Residential customers participation in PGE's TOU rate ramps to 20% to achieve PGE's target of approximately 150,000 customers by 2023. In the Base scenario, TOU customers are assumed to be ineligible for participation in other DR programs. In the High scenario, customers may participate in both TOU and another DR program.

2.4 Energy Efficiency

Navigant used the Energy Trust of Oregon (Energy Trust)'s November 2017 Savings Forecast[4] and extrapolated using a five-year moving average to determine the gross savings at the meter for a time horizon of 2020 to 2050. To be consistent with other DERs in this study, Navigant used the gross savings at meter (without line losses) from the Energy Trust study.

As indicated in Section 2.5, Navigant used the Cost-Effective EE forecast for the Base scenario and the All Achievable EE forecast for the High scenario. This study did not include a Low scenario for EE. For each scenario, Navigant included the impacts for each of the Residential, Commercial, and Industrial segments. Navigant excluded the Residential-Lighting (Market) and Mega-Project Adder programs, which were labeled as "Other" in the Energy Trust study.

2.5 Scenarios

For each of the distributed resources, Navigant forecasted three scenarios: Base, Low, and High. Each scenario corresponded to a different set of initial conditions for technology costs, policies, carbon prices, and pricing in each forecasting model, as agreed upon with PGE. Table 2 and Table 3 detail the assumptions for the Low and High scenarios respectively.

[4] In November of 2017, the Energy Trust of Oregon produced 20-year (2018-2037) All Achievable and Cost-Effective EE forecasts for PGE's 2016 IRP. PGE provided the results of that study, along with the accompanying assumptions, to Navigant for use in this study.

Table 2. Low Scenario Drivers

<table>
<tr><th>Technology / Driver</th><th>Technology Costs</th><th>Policies</th><th>Carbon Prices</th><th>Pricing</th></tr>
<tr><td>Overall Effect</td><td>Higher technology costs</td><td>Less favorable policies for DER</td><td>Lower carbon prices in electricity and gasoline</td><td>No TOU participation</td></tr>
<tr><td>EE</td><td colspan="4">Energy Trust Cost-Effective Scenario (same as Base Case)</td></tr>
<tr><td>DR</td><td colspan="2">-50% by 2030</td><td>No change*</td><td rowspan="4">0% residential TOU</td></tr>
<tr><td>Solar</td><td>High PV $</td><td rowspan="2">Decreased marketing</td><td rowspan="3">Low carbon $</td></tr>
<tr><td>Storage</td><td rowspan="2">High Li-Ion $</td></tr>
<tr><td>EV</td><td>Decreased vehicle availability + vehicle production + marketing</td></tr>
</table>

* Given no energy impacts estimated

Table 3. High Scenario Drivers

<table>
<tr><th>Technology / Driver</th><th>Technology Costs</th><th>Policies</th><th>Carbon Prices</th><th>Pricing</th></tr>
<tr><td>Overall Effect</td><td>Lower technology costs</td><td>More favorable policies for DER</td><td>Higher carbon prices in electricity and gasoline</td><td>Opt-out TOU participation</td></tr>
<tr><td>EE</td><td colspan="4">Energy Trust All-Achievable Scenario</td></tr>
<tr><td>DR</td><td colspan="2">+50% by 2030</td><td>No change*</td><td rowspan="4">Opt-out residential TOU**</td></tr>
<tr><td>Solar</td><td>Low PV $</td><td rowspan="2">Increased marketing and ITC continues through 2050</td><td rowspan="3">High carbon $</td></tr>
<tr><td>Storage</td><td rowspan="2">Low Li-Ion $</td></tr>
<tr><td>EV</td><td>Increased vehicle availability + vehicle production + marketing</td></tr>
</table>

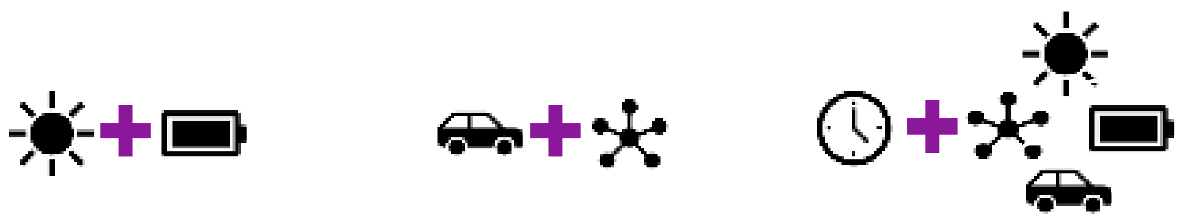
* Given no energy impacts estimated
** Opt-out rate based on opt-out rate assumed in PGE DR potential study

2.6 Interactive Effects

For the purposes of this study, interactive effects refer to the effects of one distributed resource on the load shape of another distributed resource, beyond the simple addition of the two resources' load shapes. For example, a standalone storage system in a Residential home may be expected to operate differently from one that works in conjunction with a solar PV system installed on the roof.

Navigant focused on the interactions that were likely to impact the forecasts the most significantly in a quantifiable manner (see Figure 3), with the acknowledgement that some interactions are still too uncertain to quantify. The following subsections provide more detail on each of these interactions.

Figure 3: Interactive Effects Addressed in Study



Solar + Storage
Captures interactions in impacts and participation for solar + storage at a customer site

Light-Duty Vehicles + DR
Explicitly accounts for Light-Duty Vehicle participation in Direct Load Control

Pricing (TOU) + Other DER
Scenario analysis examines influence of pricing on the other DERs, including other DR types

Source: Navigant

2.6.1 Solar and Storage

As well as competing different technology combinations against each other in a discrete choice formulation, Navigant's RESim™ model captures the interactions between solar and storage, when both are present at a single customer site. RESim™ dynamically adjusts customer adoption and usage of solar + storage to account for these interactions and optimize the customer's bill savings. As an example, RESim™ optimizes for a customer's storage charging (i.e., from solar) and discharging behavior to maximize customer value from bill management and peak shaving.

2.6.2 LDV and DR

This interaction accounts for the participation of LDVs in a DLC DR program. Navigant forecasts that LDV adoption will lead to a corresponding rise in chargers eligible[5] for a DLC program. Navigant used its Vehicle Adoption Simulation Tool (VAST™) model to forecast charger counts for the time period of 2020 to 2050. Navigant then estimated the average charging demand available from each charger during

[5] For EV DLC eligibility and impact assumptions, see Source: Navigant
Table 6 in Appendix B.

PGE's coincident peak and the portion that participates in a DLC program to determine the aggregate peak reduction potential.

2.6.3 Pricing (TOU) and Other DER

This interaction accounts for the influence of TOU pricing on DR, solar PV, storage, and LDV in the following ways:

- **DR**: Navigant forecasts the impact of TOU participation on the participation and impacts of other DR programs. In the Base scenario, customers who participate in TOU are not eligible to participate in other DR programs. In the High scenario, TOU customers can participate in other DR programs, with the impacts adjusted to avoid overstating the impacts of both programs combined.

- **Solar PV and Storage:** The impact of TOU rates on solar PV and storage is accounted for by optimizing the storage charging and discharging behavior to take advantage of the bill management opportunities available under a TOU rate and optimize the customer's bill savings.

- **LDV:** Navigant modeled a decrease in average electricity cost, assuming a vehicle charges during off-peak hours, which reduces the cost of a PEV, increases adoption, and changes the charging profile.

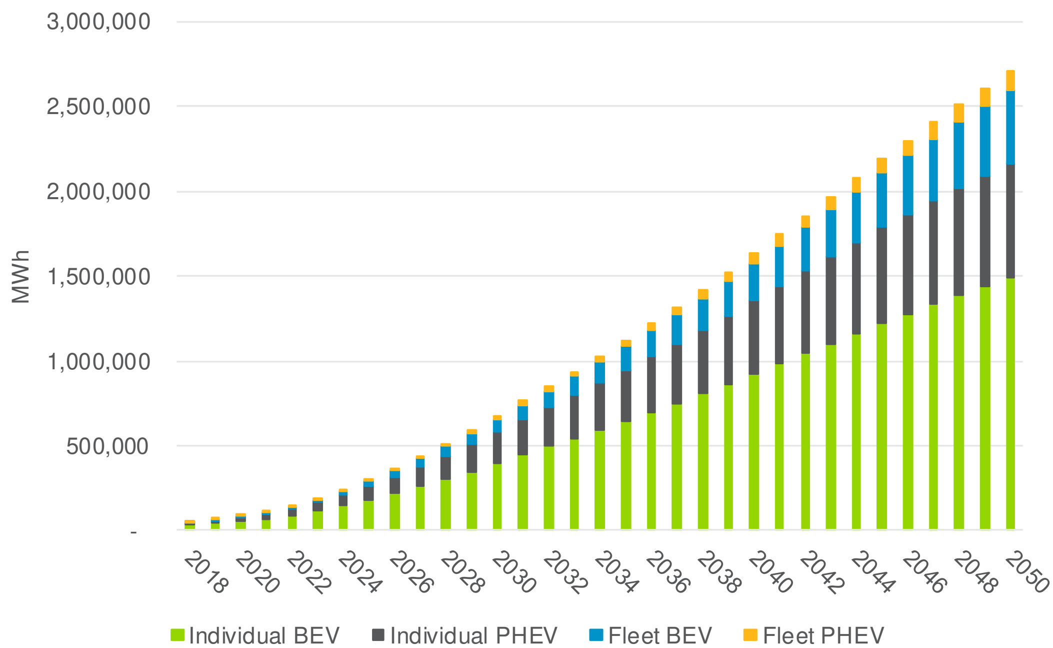
3. RESULTS

The following section presents the key results from the study for each distributed resource under the Base scenario. For High and Low scenario results, please see Appendix A.

3.1 Light Duty Vehicles

LDV adoption in PGE's system is forecasted to grow by about 60x between 2020 and 2050, with BEV adoption expected to be slightly ahead of PHEV adoption due to a more competitive Total Cost of Ownership (TCO). Navigant estimates the number of light-duty PEVs in operation in PGE's service area at the end of 2020 will be approximately 27,000 vehicles (1.4% of the market). By 2050, this number is forecasted to grow to nearly 857,000 vehicles (nearly 35% of the market). In 2050, light duty BEVs account for 54% of all PEVs, but nearly 71% of all energy consumed by PEVs.

Figure 4. PGE System-Level Base Case LDV Energy Forecast (MWh)



Source: Navigant

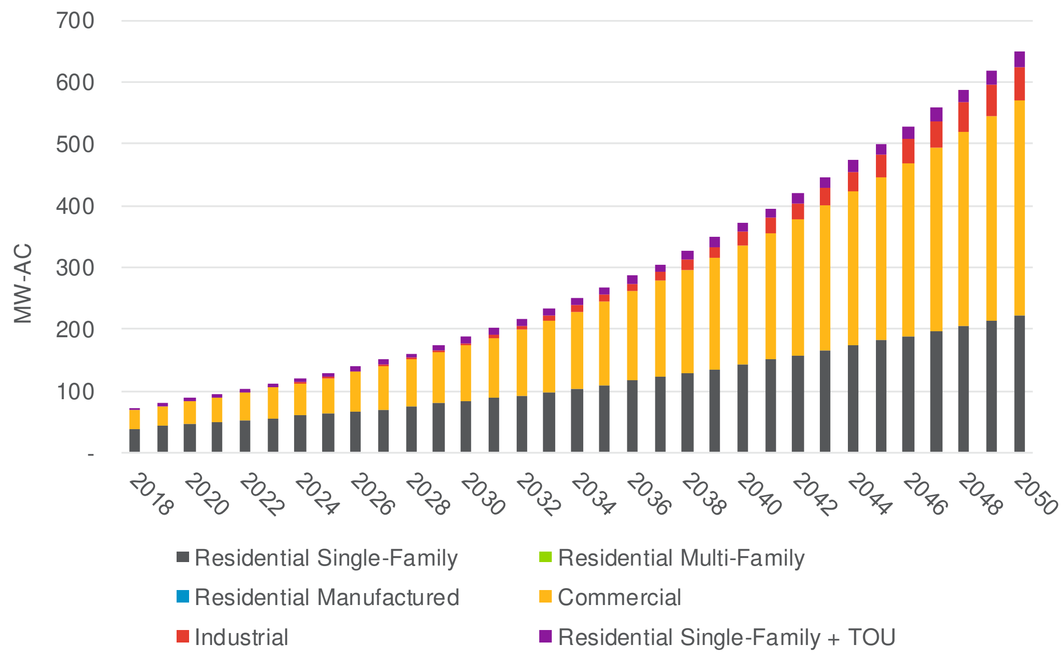
3.2 Solar PV

3.2.1 By Customer Segment

Solar PV growth is forecasted to be driven primarily by Residential Single-Family and Commercial customers, given logistical limitations for other customer segments, with about 2.5x growth forecast before 2030 and about 9x growth forecast by 2050. The growth in these two customer segments is largely driven by their large building stocks, the opportunity for bill savings and financial gain from net metering, and growing awareness of solar PV technology.

Navigant assumes negligible adoption of solar PV by Residential Multi-Family customers due to split incentives between owners and renters, and the lack of access to suitable roof space for installation of solar PV systems in the absence of major policy or technology changes. Additionally, Navigant assumes negligible adoption of solar PV by Residential Manufactured home customers due to the infeasibility of installing roof-mounted solar PV systems and unfavorable economics of installing ground-mounted solar PV systems at these building types.

Figure 5. PGE System-Level Solar PV Forecast by Customer Segment (MW-AC)



Source: Navigant

3.2.2 By Use Case

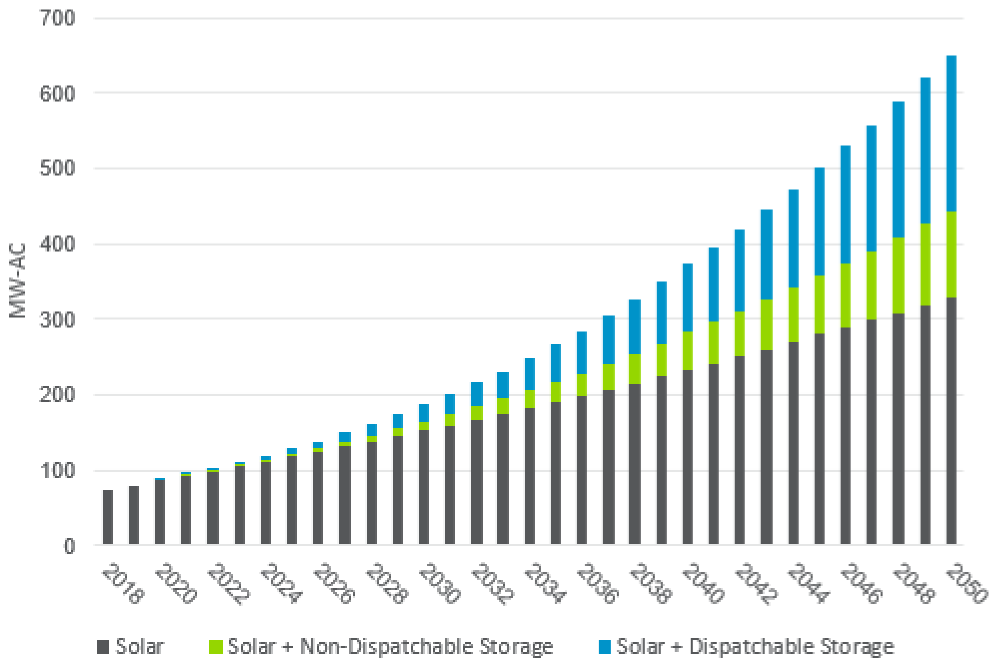
The growth of standalone solar PV is expected to be modest and continue into the future. This growth is driven by the opportunity for bill savings, as well as net metering allowing for value from providing electricity back to the grid.

Solar + storage comprises a much smaller market share, relative to standalone solar because of the tradeoff between the cost of adding the storage system and the relative financial benefits.

The costs of both dispatchable and non-dispatchable storage systems are largely driven by the storage system size determined for each customer segment. For dispatchable storage systems, the primary benefit to the customer comes in the form of a financial rebate. The rebate varies by customer segment based on their respective storage system size.

For non-dispatchable storage systems, the financial benefits from rate arbitrage and peak-shaving for a customer segment depend on their respective rate plan and typical load profiles.

Figure 6. PGE System-Level Solar PV Forecast by Use Case (MW-AC)



Source: Navigant

3.3 Storage

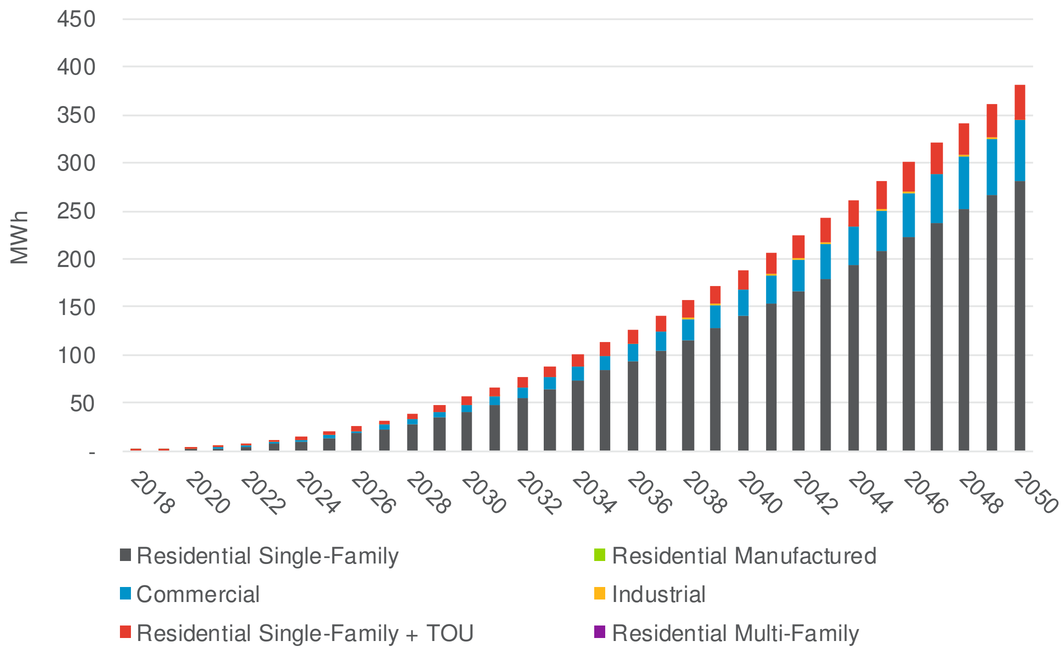
3.3.1 By Customer Segment

Storage growth across all use cases is forecast to be driven primarily by Residential Single-Family customers, both with and without a TOU rate, and Commercial customers. These two segments of customers comprise the majority of forecasted storage adoption due to the number of customers available within these segments, the financial benefit offered by their storage systems, and the perceived value of resiliency.

Additionally, customer segments with a TOU rate are forecasted to have a higher adoption rate of non-dispatchable storage than other customer segments, as they take advantage of bill management opportunities.

Navigant assumes negligible adoption of storage by Residential Multi-Family customers due to split incentives between owners and renters and the lack of access to suitable space for installation of storage systems in the absence of major policy or technology changes. Additionally, Navigant assumes negligible adoption of storage by Residential Manufactured Home customers due to the structural barriers to installing storage systems at these building types. These assumptions are consistent with actual trends and barriers observed in the industry currently, although these may be addressed through future policy or technology changes.

Figure 7. PGE System-Level Storage Forecast by Customer Segment (MWh)

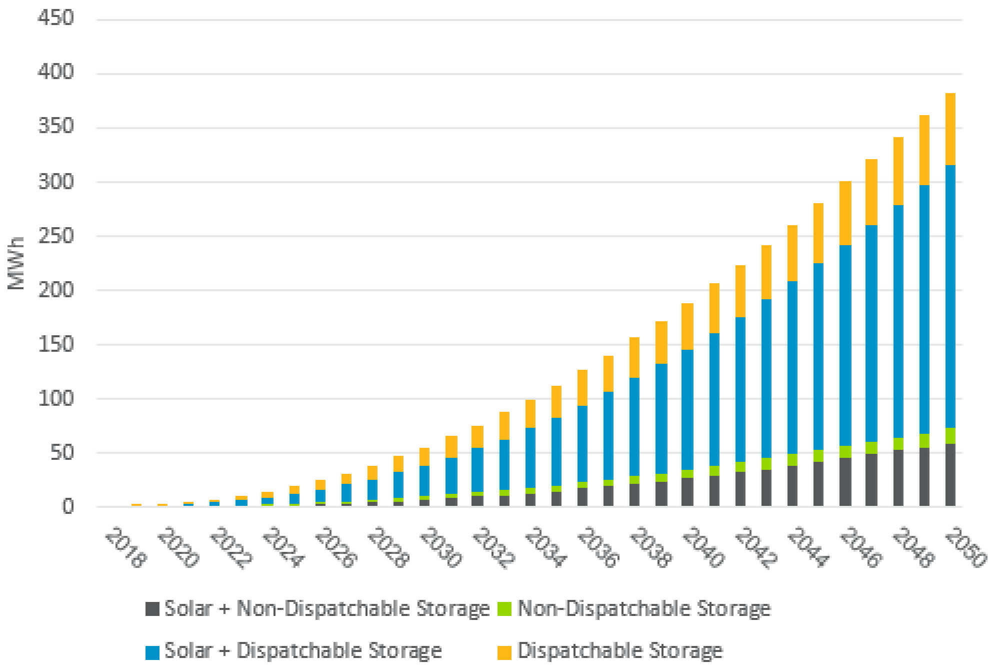


Source: Navigant

3.3.2 By Use Case

Non-dispatchable storage is expected to grow rapidly, but total installed capacity is limited by customer familiarity, economics, and competition with solar PV. Overall, dispatchable storage is expected to gain more market share than non-dispatchable storage due to assumed incentive levels making dispatchable storage more economically attractive to customers, though this varies by sector.

Figure 8. PGE System-Level Storage Forecast by Use Case (MWh)



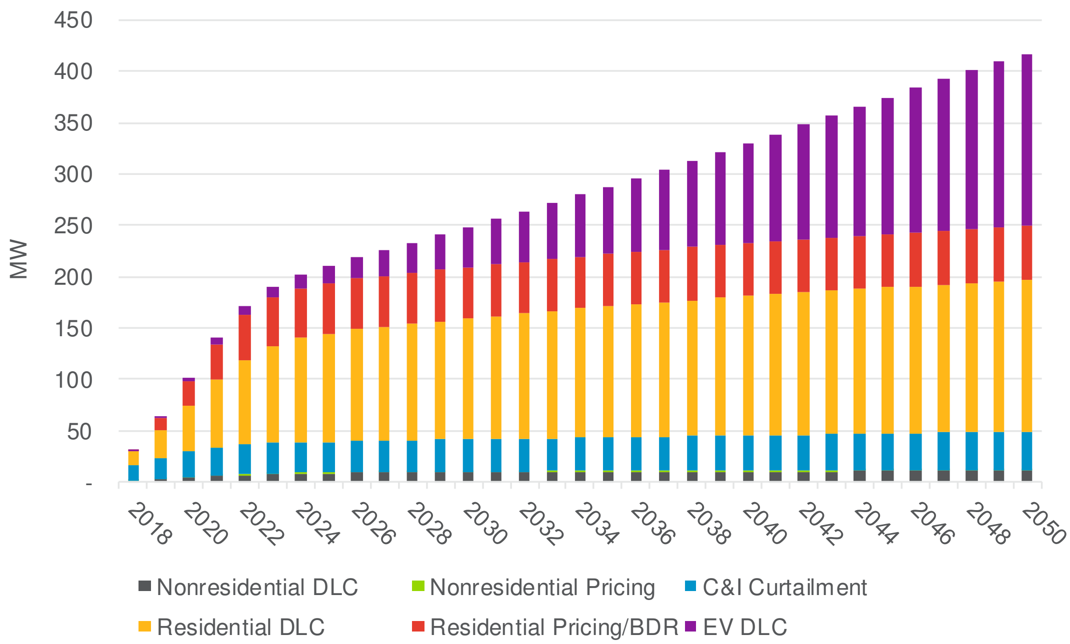
Source: Navigant

3.4 Demand Response

3.4.1 Summer

In the near-term, Summer DR is expected to be largely driven by Residential DLC for central A/C and smart water heating. Over time, LDV DLC grows to be almost equal to Residential DLC by 2050. Residential Pricing/BDR also contributes a significant amount of potential from TOU pricing and a Peak-Time Rebate pricing program.

Figure 9. PGE System-Level Summer Peak Demand Reduction Forecast (MW)

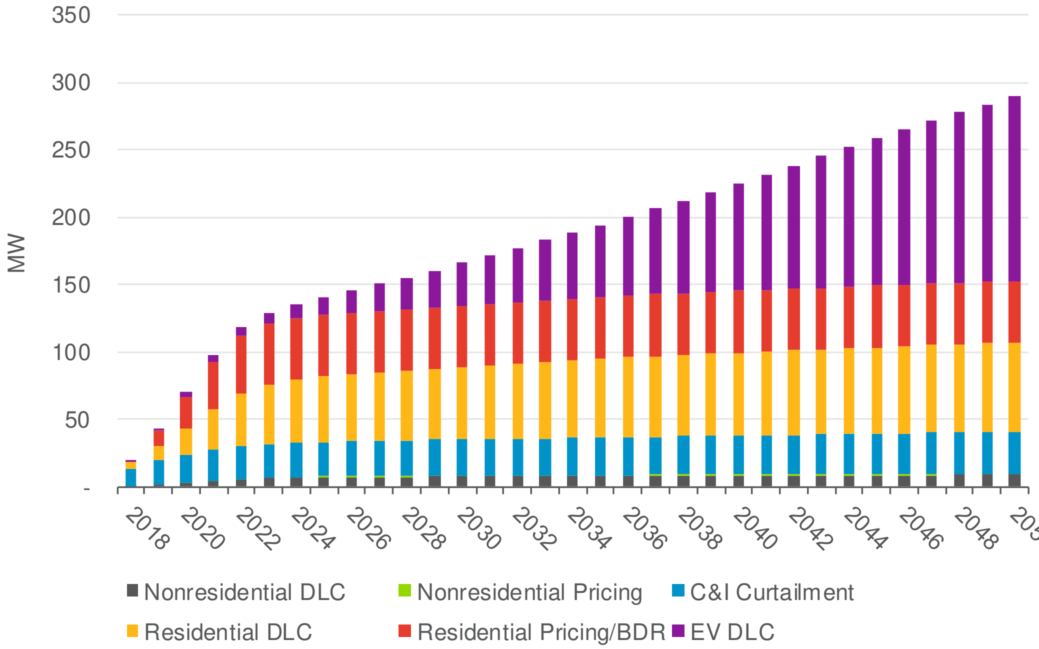


Source: Navigant

3.4.2 Winter

Winter DR is forecast to be lower than Summer DR, given the absence of DLC for central A/C and, hence, less potential from Residential DLC. Given that LDV DLC is not expected to vary as significantly between seasons, it is forecast to be greater than Residential DLC by 2050. Residential Pricing/BDR also contributes a significant amount of potential from TOU pricing and a Peak-Time Rebate pricing program.

Figure 10. PGE System-Level Winter Peak Demand Reduction Forecast (MW)

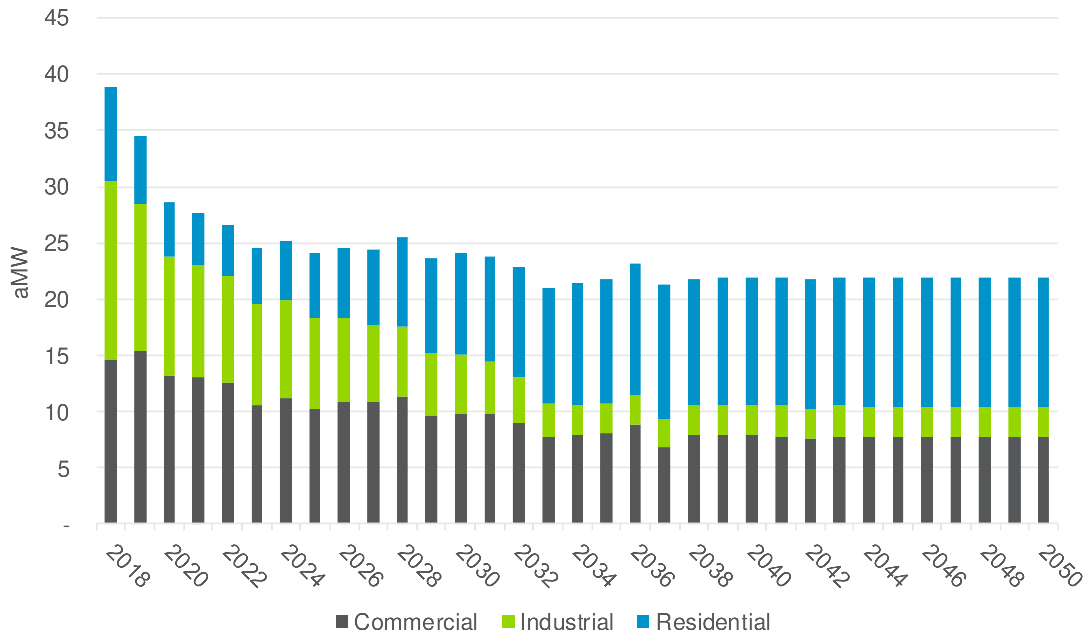


Source: Navigant

3.5 Energy Efficiency

The contribution from Residential EE grows relative to C&I EE, as C&I potential slows over time due to saturation of the C&I retrofit market. EE potential for new, retrofit, and replacement Residential measures continue to grow steadily through 2050. The total cumulative EE is forecast to be nearly 800 aMW by 2050.

Figure 11. PGE System-Level Cumulative Energy Efficiency Average Savings Forecast (aMW)



Source: Navigant

3.6 Load Profiles

The following subsections present the results from Navigant's load profile analysis for selected resources under the Base scenario. For High and Low scenario results, please see Appendix A.

3.6.1 Light Duty Vehicles

LDVs impact the system-wide load profile by adding load during vehicle charging periods. In the absence of managed charging, the peak of LDV charging tends to occur between 4 and 8 pm, which is coincident with PGE's peak, as shown in Figure 12. This is driven by charging after work hours with home chargers.

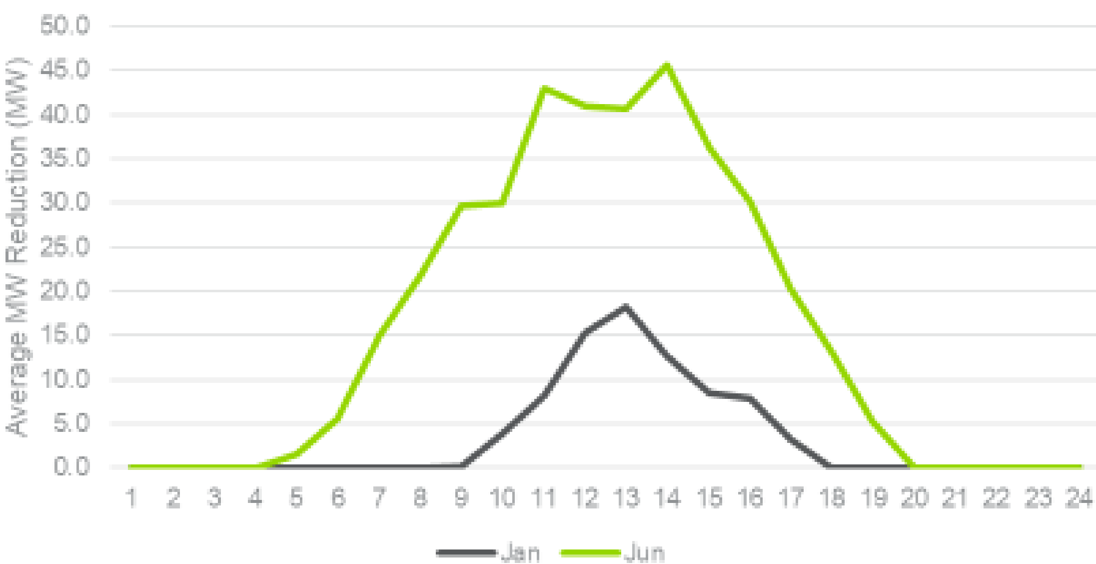
Figure 12. LDV Load Profile: System Average MW Reduction on 2020 Weekday

Source: Navigant

3.6.2 Solar

The sizeable system-wide load reduction from standalone solar PV is driven by the relatively large number of customers forecasted to have solar PV and its corresponding ability to address energy needs in hours when the sun is out. The difference between forecasted January and June load reductions shown in Figure 13 is indicative of available solar energy during Winter and Summer months respectively.

Figure 13. Solar Load Profile: System Average MW Reduction on 2020 Weekday

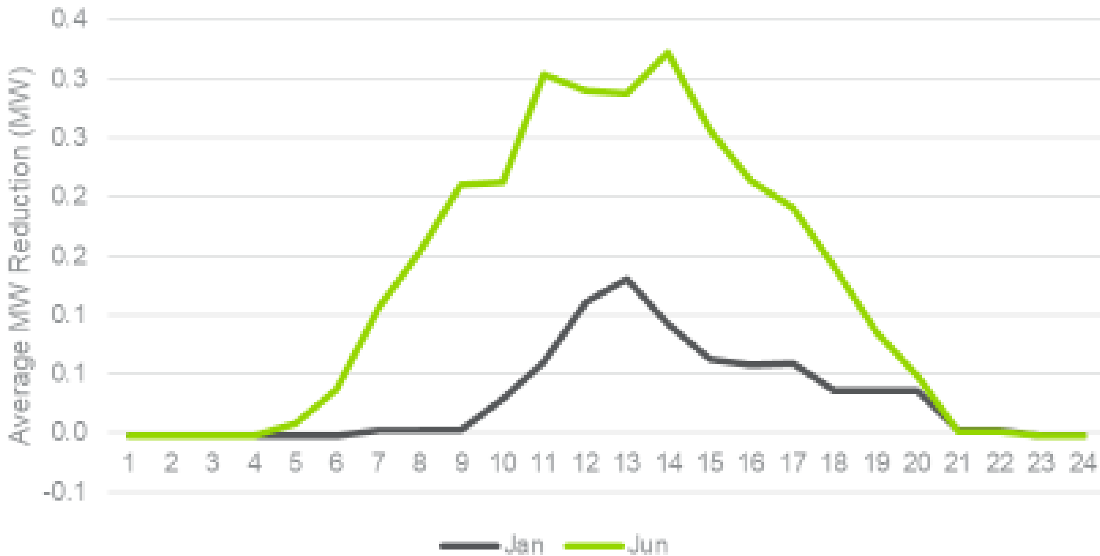


Source: Navigant

3.6.3 Solar + Storage

The system-wide load reduction from solar + non-dispatchable storage systems is driven by both the solar PV system addressing customers' energy needs directly, and the storage system reducing load while providing value through rate arbitrage and peak shaving. The difference between forecasted January and June load reductions shown in Figure 14 is indicative of available solar energy during Winter and Summer months respectively.

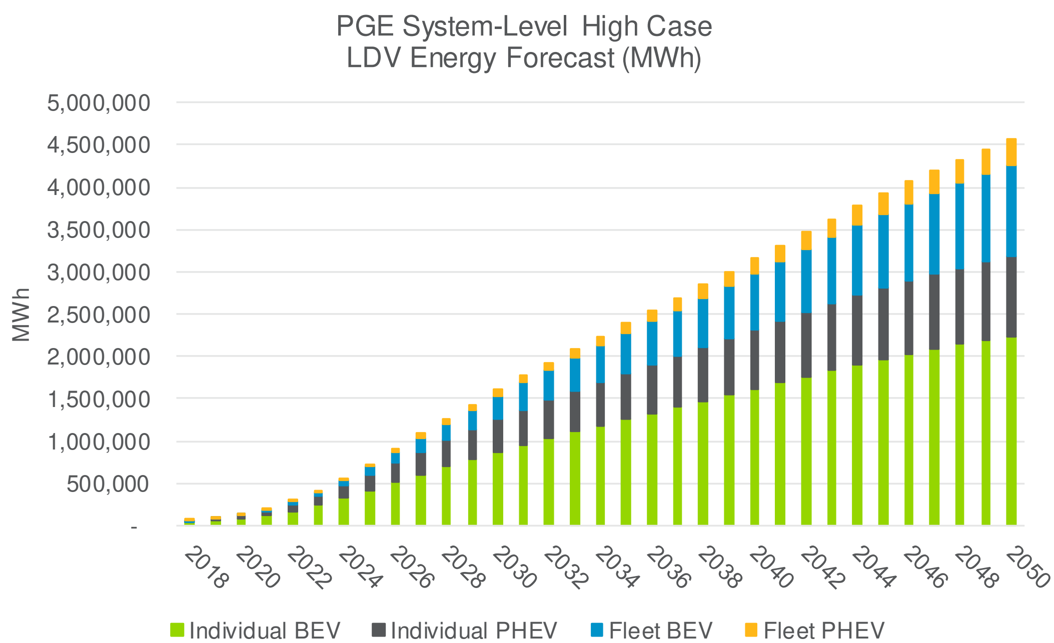
Figure 14. Solar + Storage Load Profile: System Average MW Reduction on 2020 Weekday



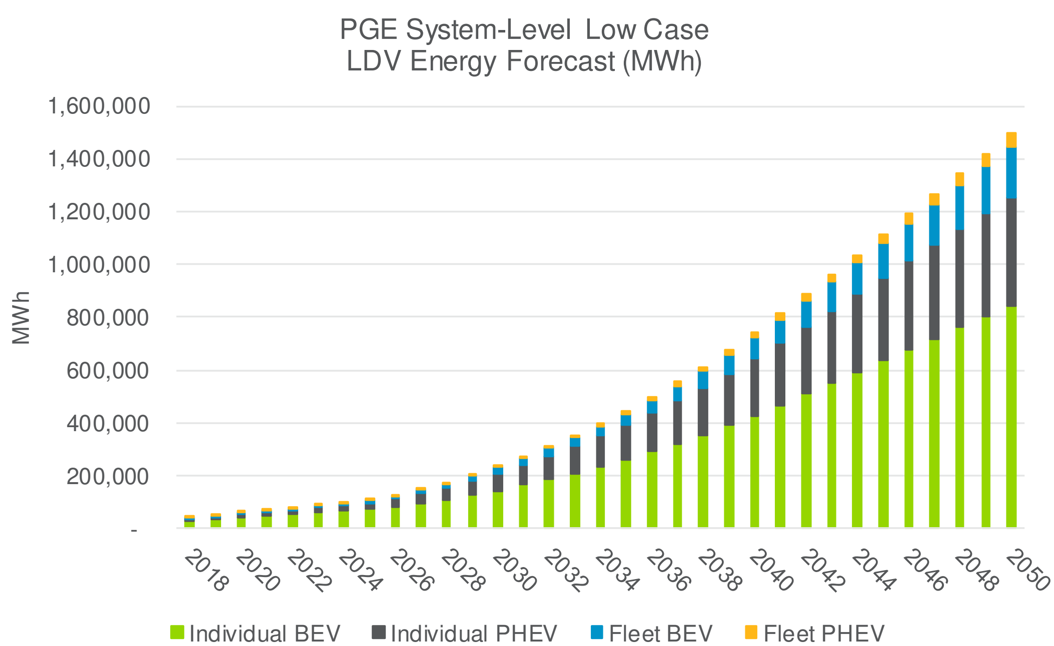
Source: Navigant

APPENDIX A. HIGH AND LOW SCENARIO RESULTS

A.1 Light Duty Vehicles



Source: Navigant

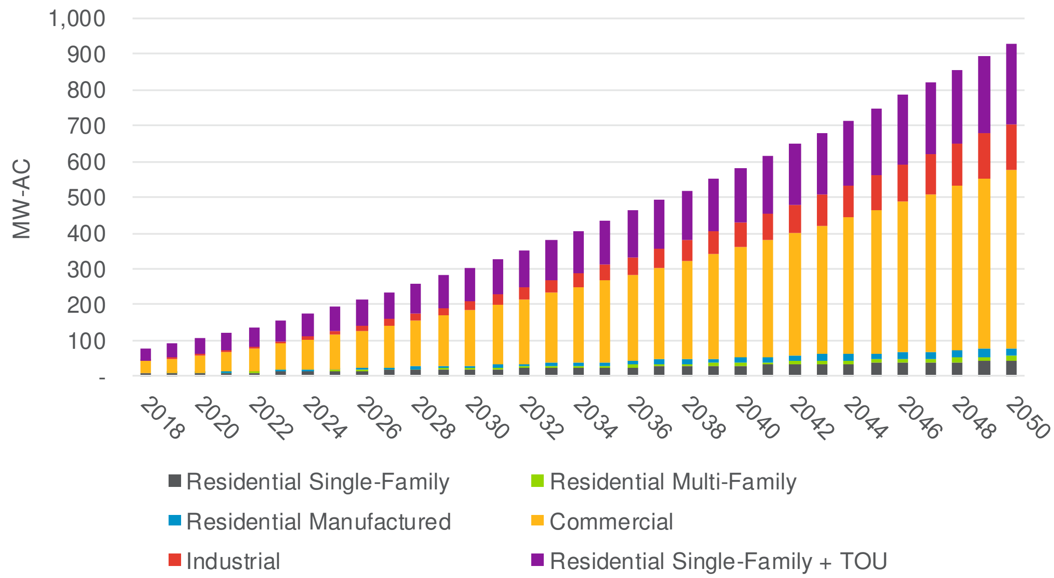


Source: Navigant

A.2 Solar PV

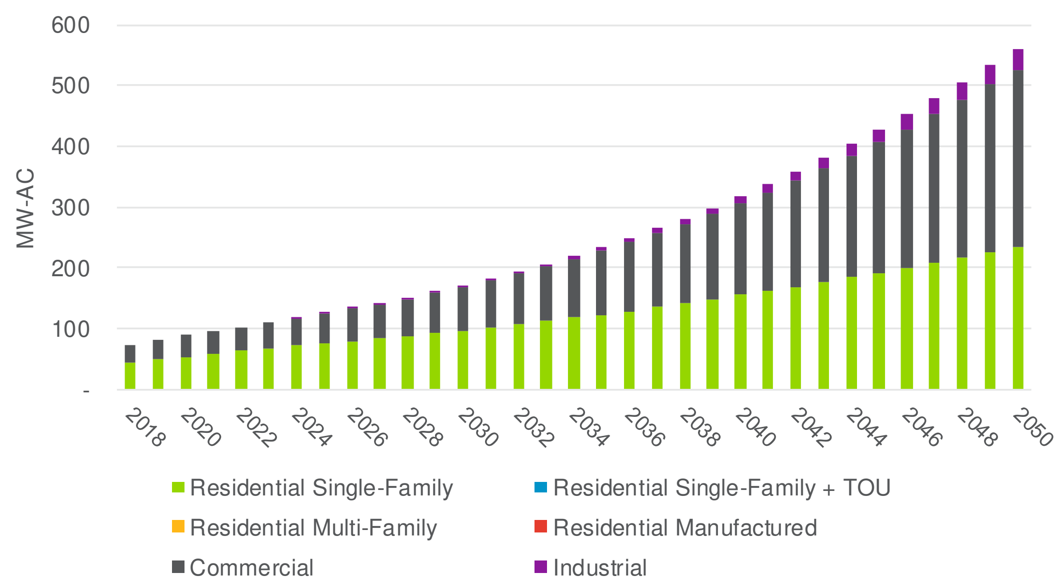
A.2.1 By Customer Segment

PGE System-Level High Case
Solar PV Forecast by Customer Segment (MW-AC)



Source: Navigant

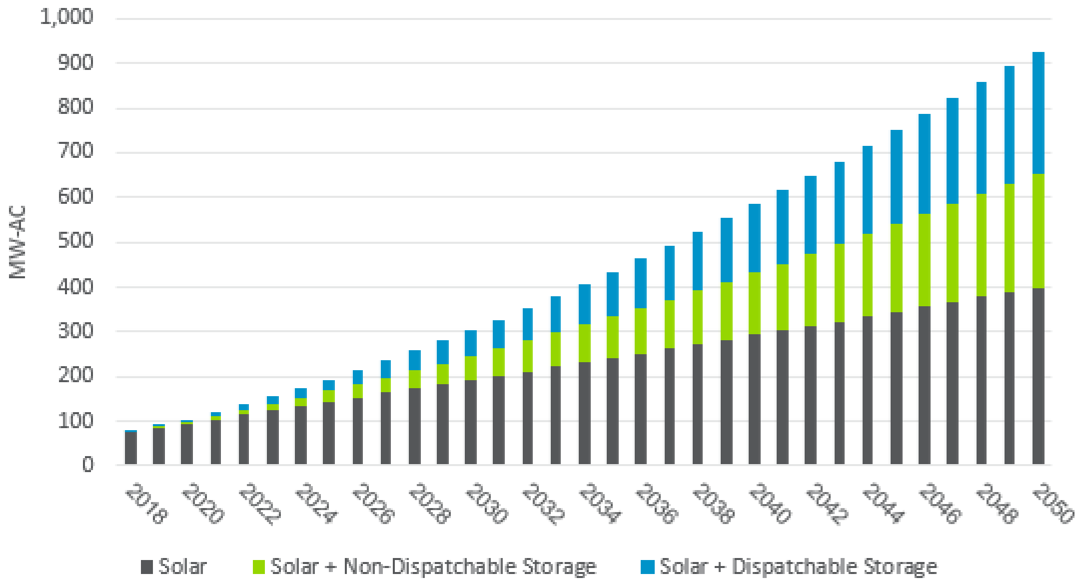
PGE System-Level Low Case
Solar PV Forecast by Customer Segment (MW-AC)



Source: Navigant

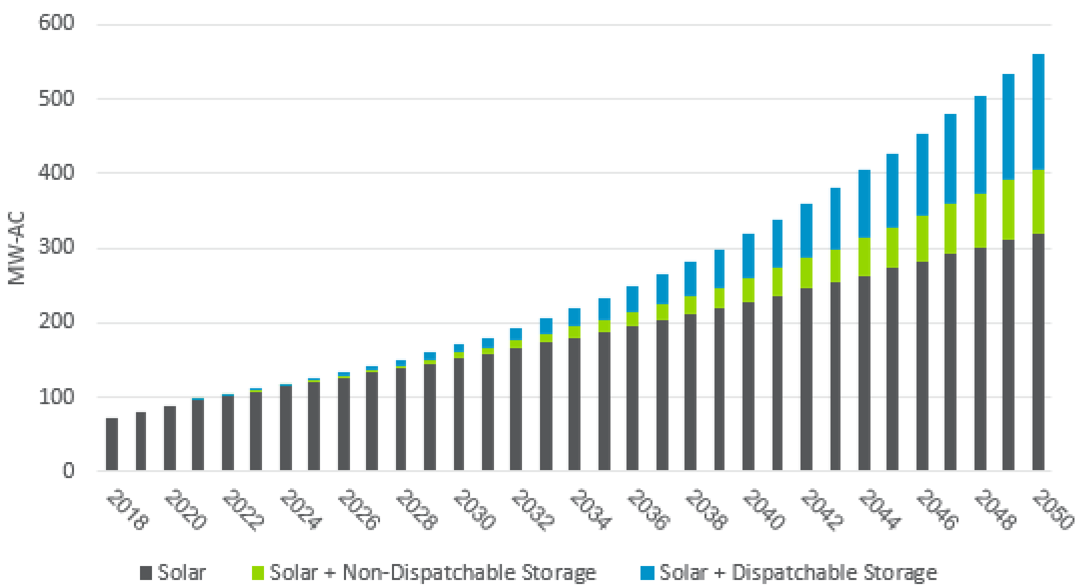
A.2.2 By Use Case

PGE System-Level High Case
Solar PV Forecast by Use Case (MW-AC)



Source: Navigant

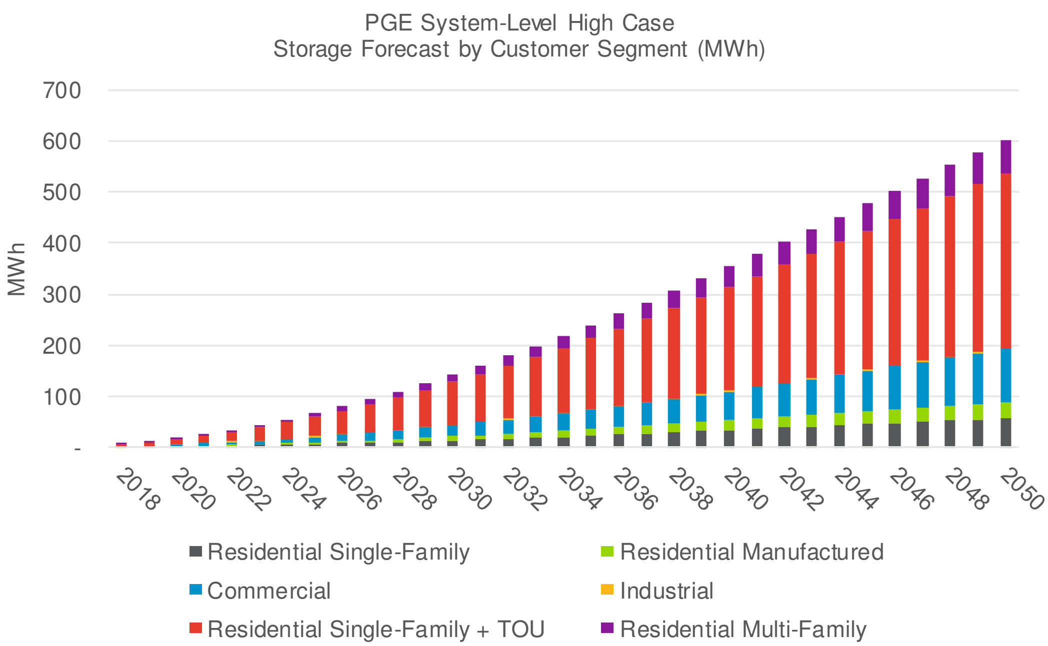
PGE System-Level Low Case
Solar PV Forecast by Use Case (MW-AC)



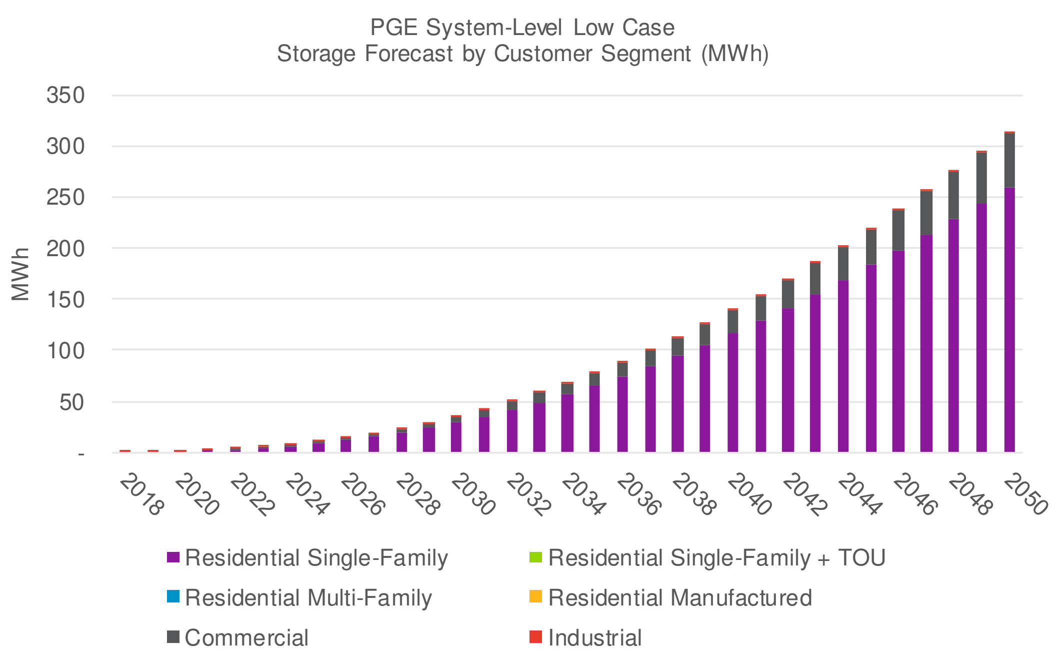
Source: Navigant

A.3 Storage

A.3.1 By Customer Segment



Source: Navigant



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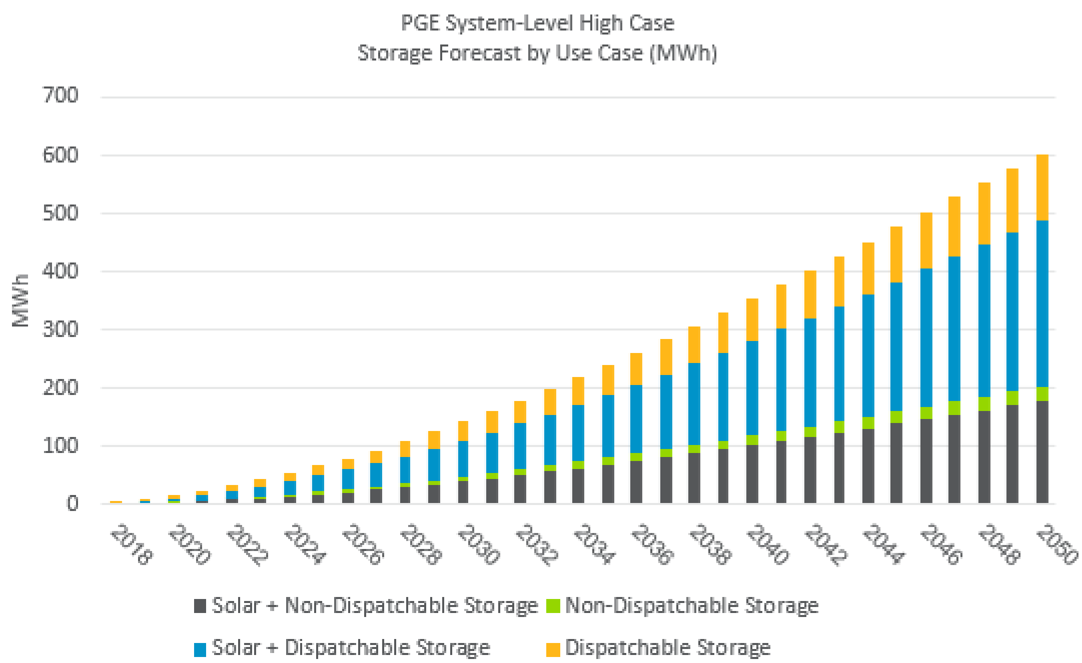
A.3.2 By Use Case



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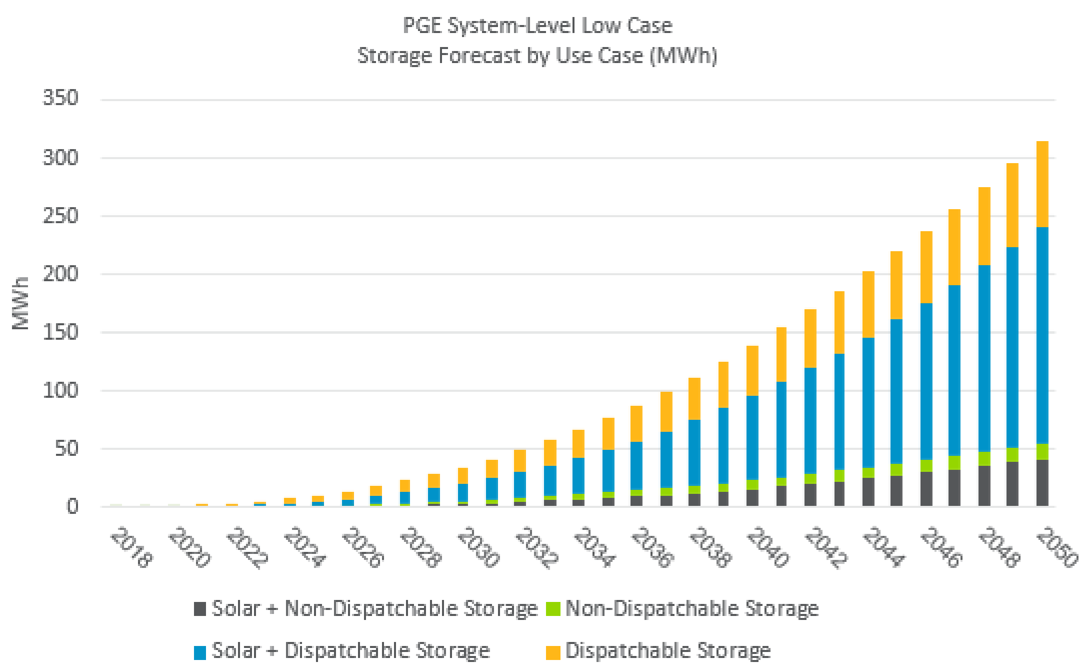
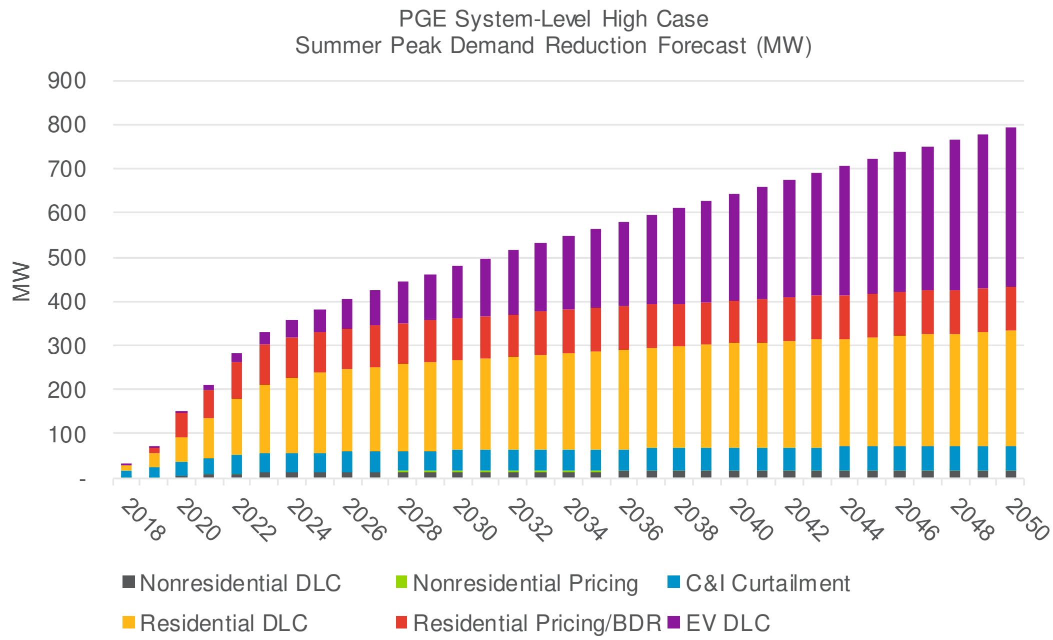


Source: Navigant

A.4 Demand Response

A.4.1 Summer



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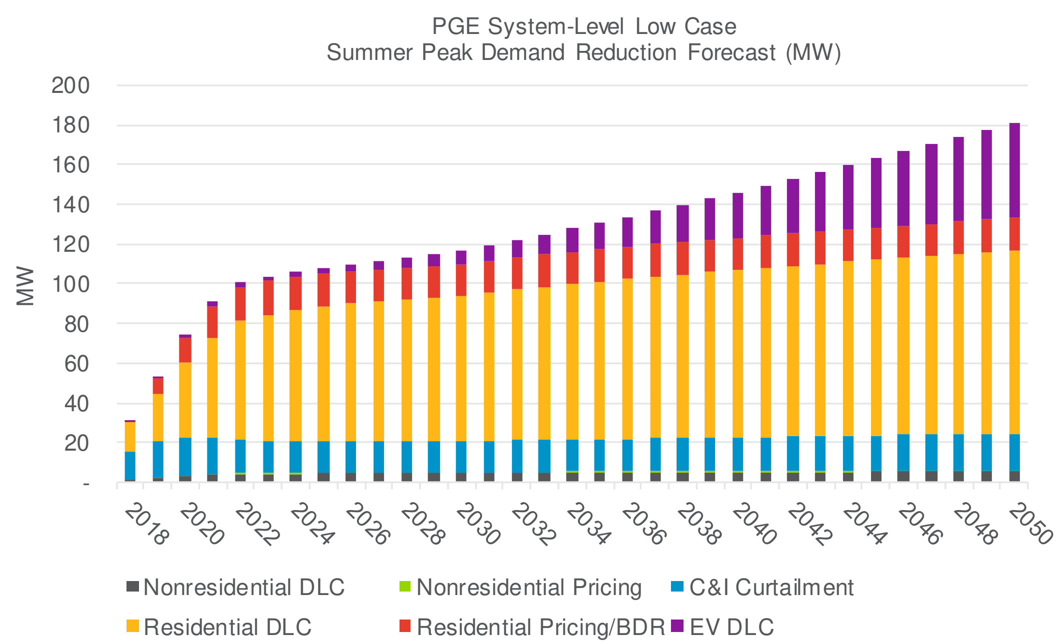
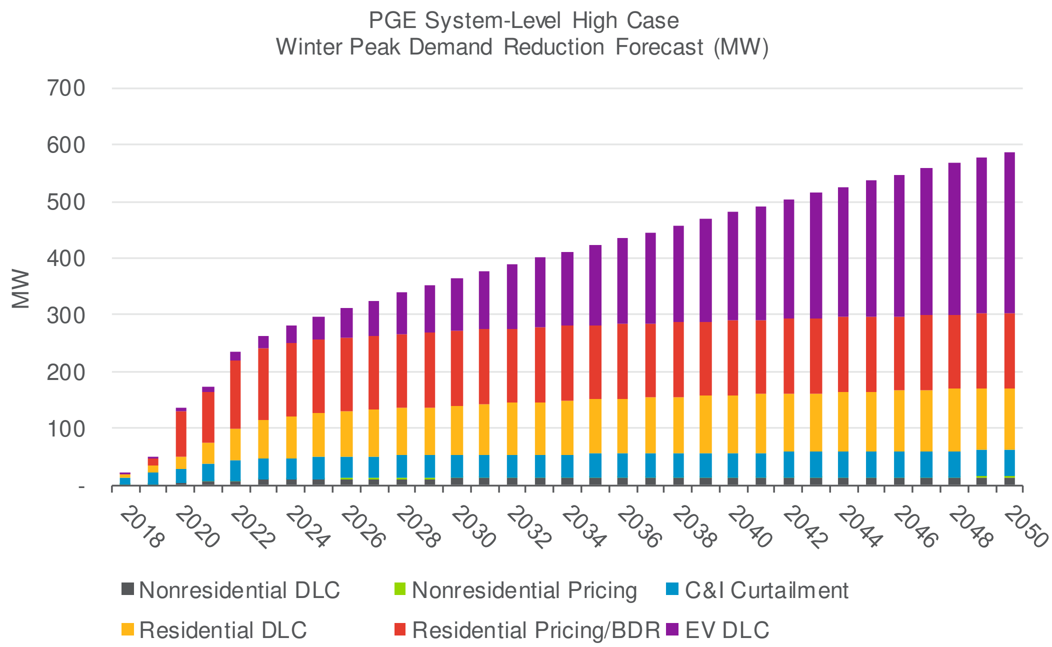


Source: Navigant

A.4.2 Winter



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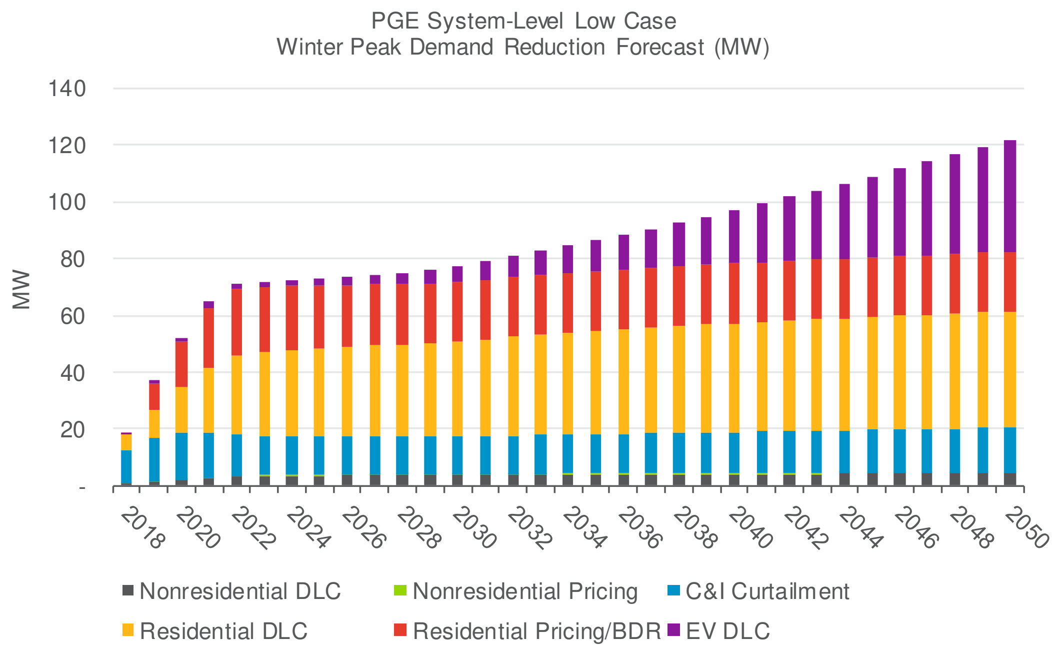
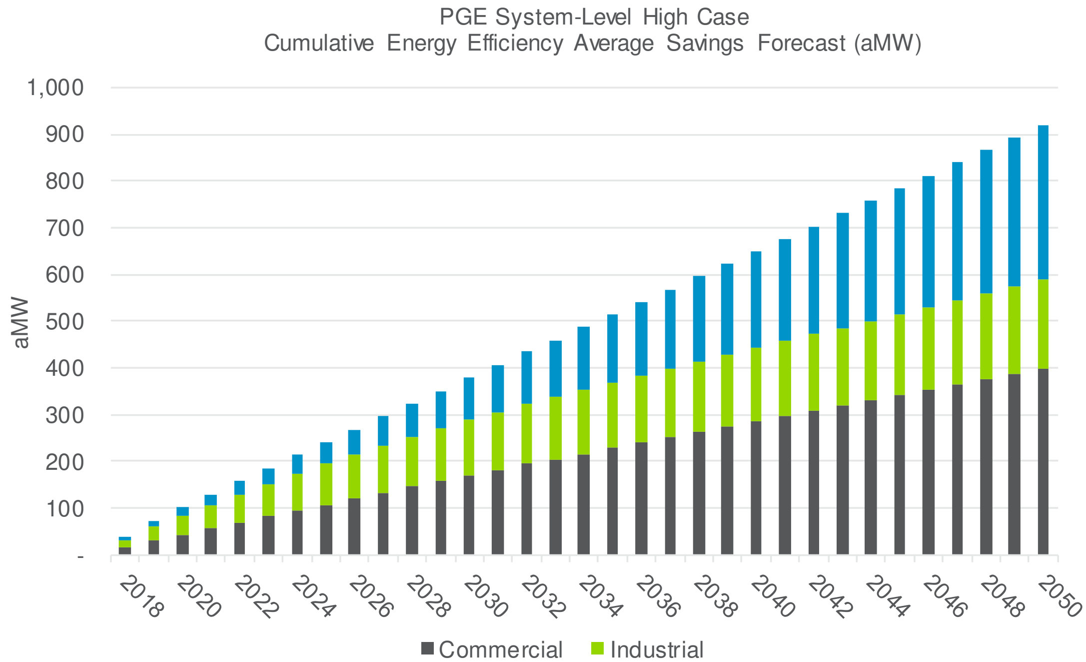


Source: Navigant

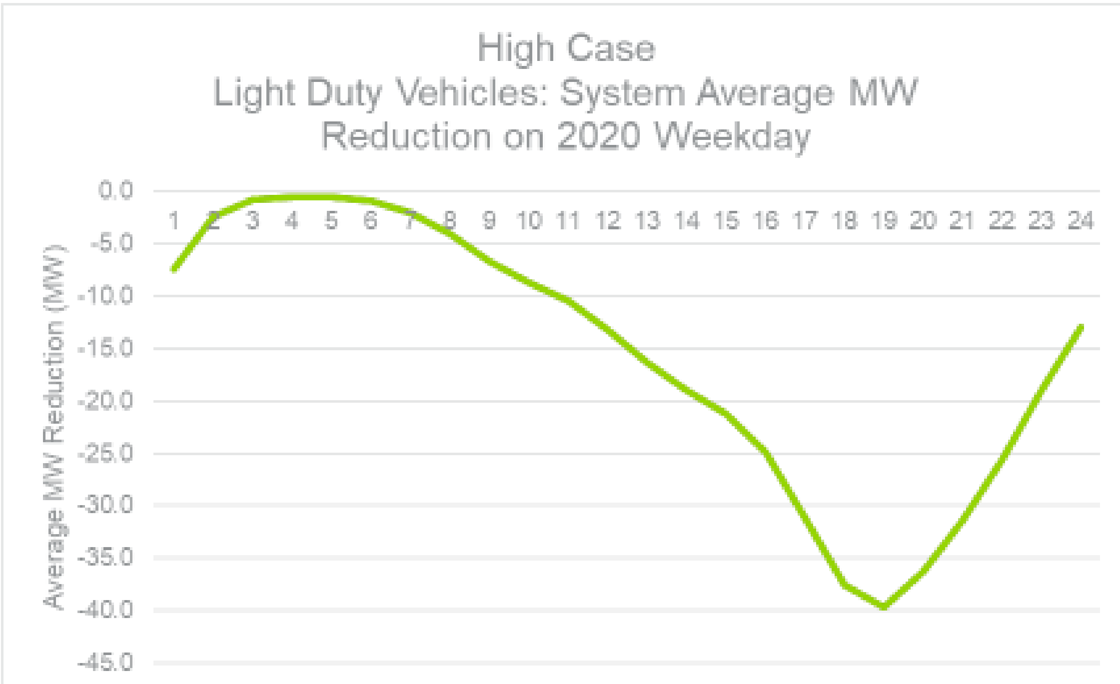
A.5 Energy Efficiency



Source: Navigant

A.6 Load Profiles

A.6.1 Light Duty Vehicles



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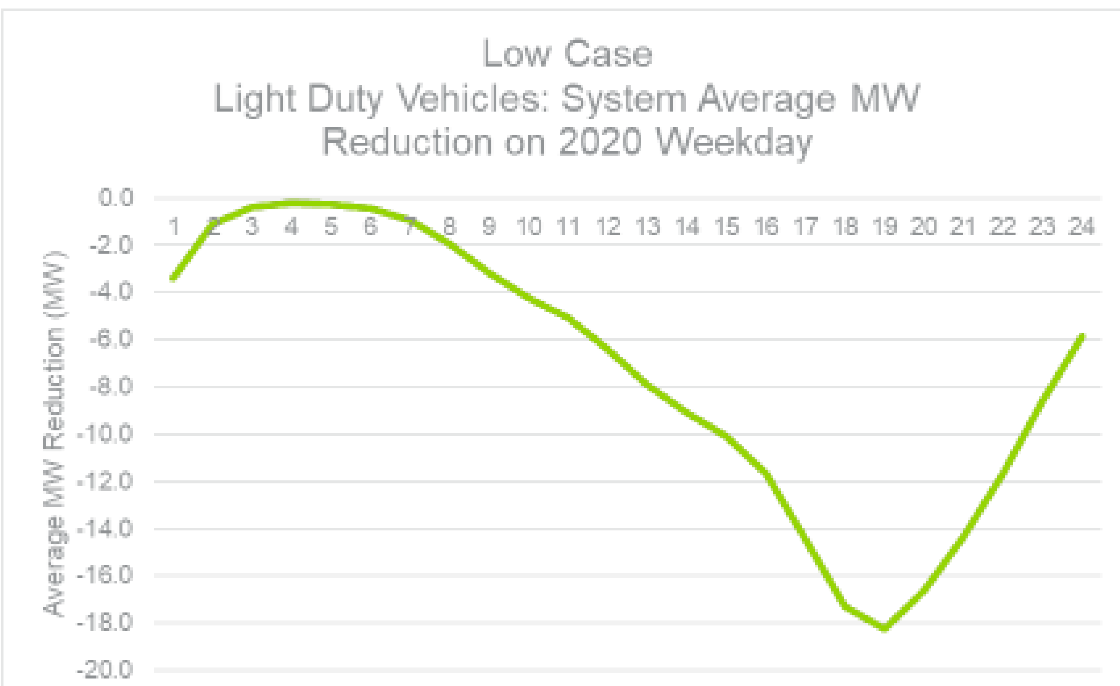
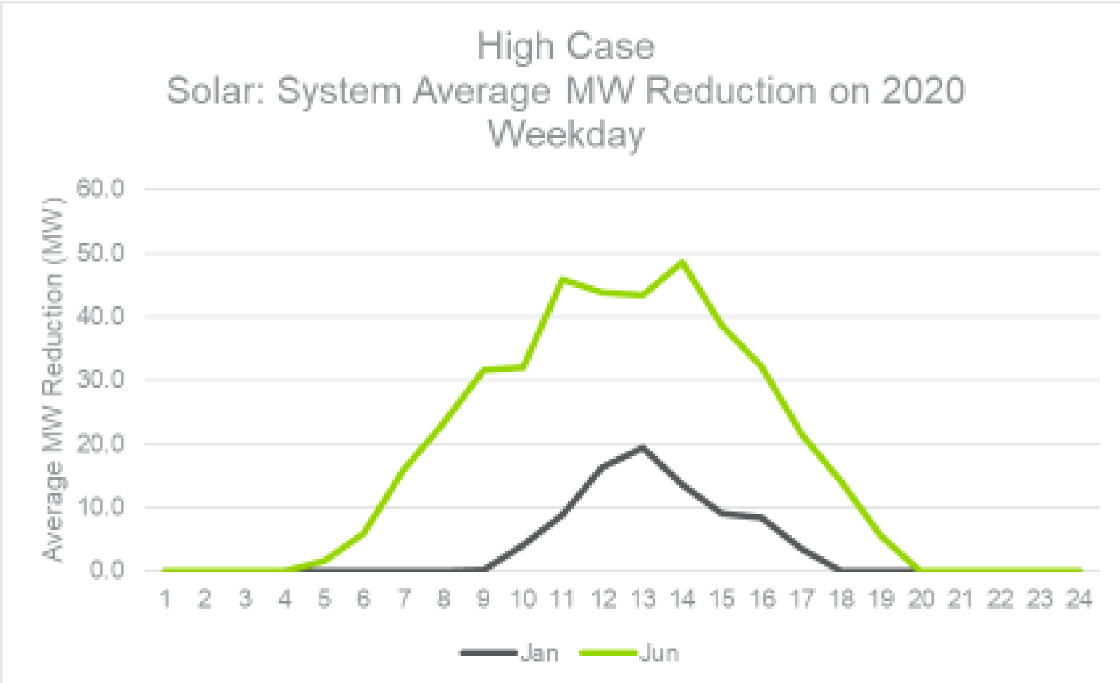


Source: Navigant

A.6.2 Solar



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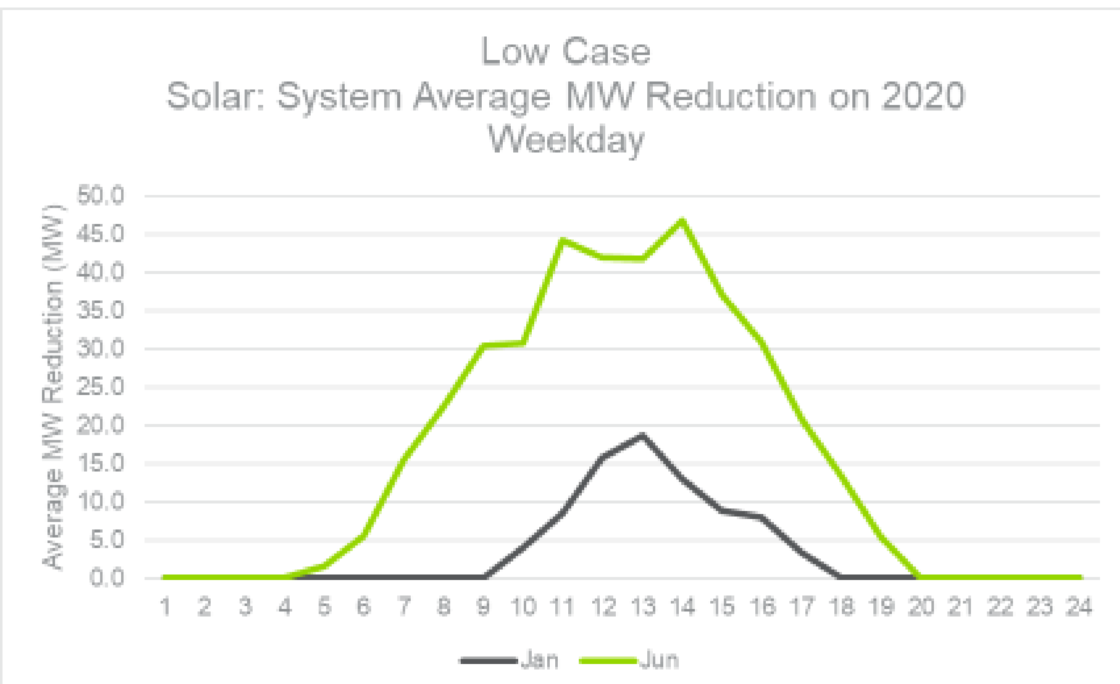
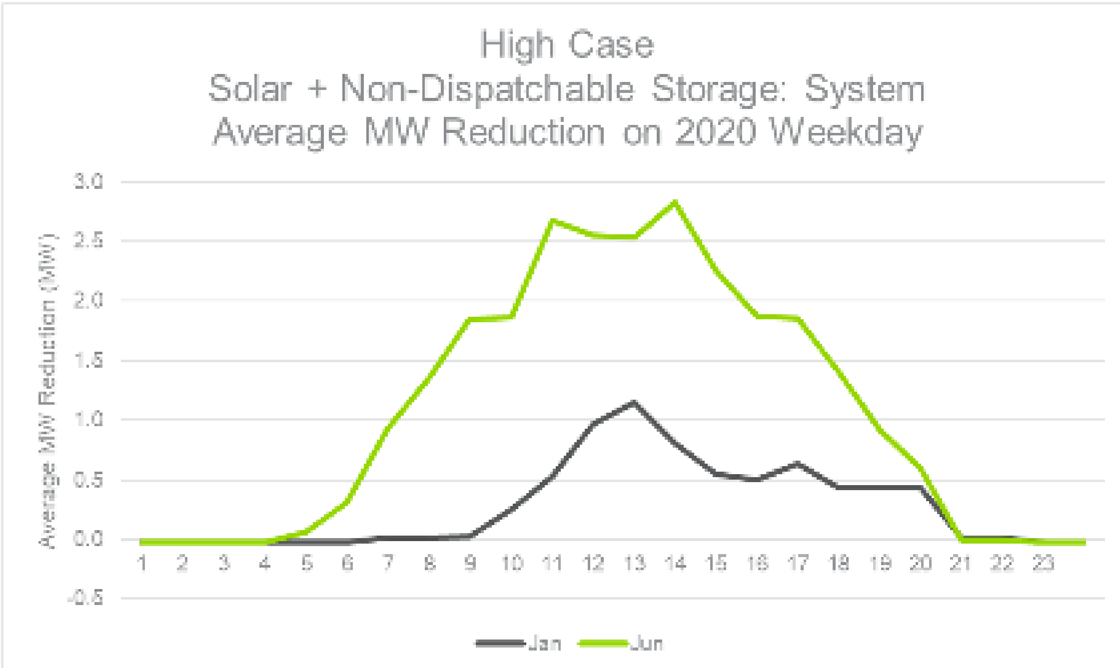


Source: Navigant

A.6.3 Solar + Storage



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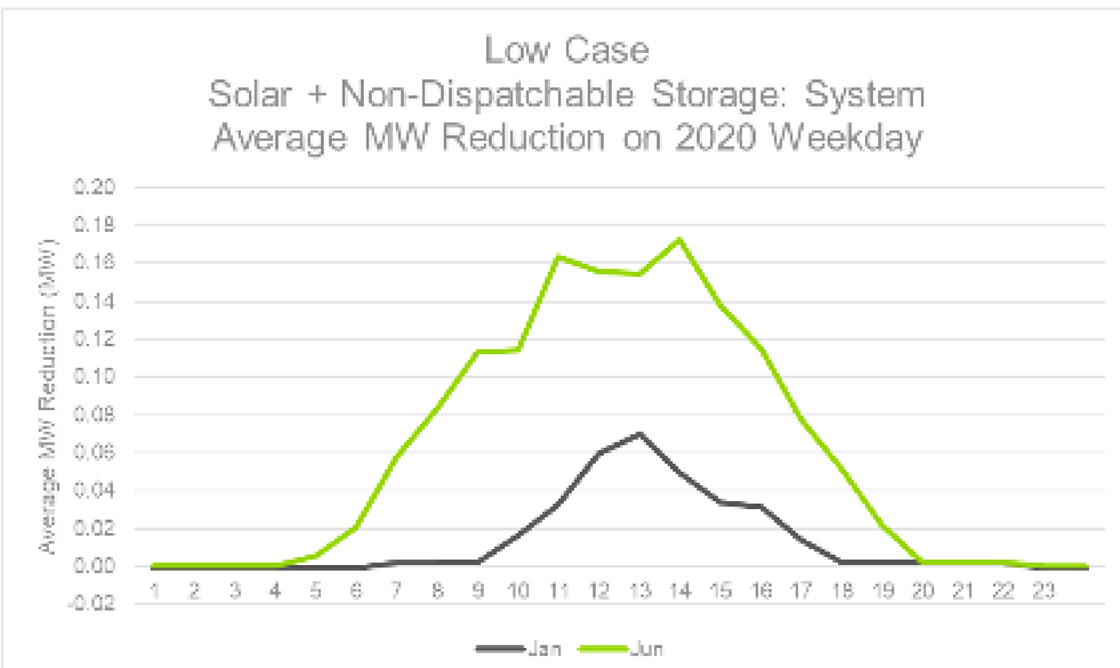

Source: Navigant

APPENDIX B. KEY INPUTS AND ASSUMPTIONS

This appendix documents some of the detailed key inputs and assumptions within the Distributed Resource and Flexible Load Study.

Table 4: DR Program Types

Program Type	Program
Residential Pricing/ BDR	Time of Use (TOU)
	Peak Time Rebate (PTR)
	Peak Time Rebate (PTR) w/Tech
	Behavioral DR (BDR)
Residential DLC	Bring Your Own Thermostat (BYOT) - AC/Space Heating
	Bring Your Own Thermostat (BYOT) - AC
	Bring Your Own Thermostat (BYOT) - Space Heating
	AC/Space Heating DLC
	AC DLC
	Space Heating DLC
	Smart WH DLC
	Water Heating DLC
Nonresidential Pricing	Peak Time Rebate (PTR)
	Peak Time Rebate (PTR) w/Tech
Nonresidential DLC	AC/Space Heating DLC
	AC DLC
	Space Heating DLC
	Water Heating DLC
	Third-Party DLC
C&I Curtailment	Medium C&I Curtailment
	Large C&I Curtailment
EV DLC	EV DLC

Table 5: DR Participation Assumptions

Program Type	Program	Season	Start Year	Steady State Year	Steady State Participation Rate
C&I Curtailment	Large C&I Curtailment	Summer	2016	2030	11%
C&I Curtailment	Large C&I Curtailment	Winter	2016	2030	11%
C&I Curtailment	Medium C&I Curtailment	Summer	2016	2030	6%
C&I Curtailment	Medium C&I Curtailment	Winter	2016	2030	6%
EV DLC	EV DLC	Summer	2016	2021	20%
EV DLC	EV DLC	Winter	2016	2021	20%
Nonresidential DLC	AC DLC	Summer	2018	2030	3%
Nonresidential DLC	AC DLC	Winter	2018	2030	0%
Nonresidential DLC	AC/Space Heating DLC	Summer	2018	2030	3%
Nonresidential DLC	AC/Space Heating DLC	Winter	2018	2030	1%
Nonresidential DLC	Space Heating DLC	Summer	2018	2030	0%
Nonresidential DLC	Space Heating DLC	Winter	2018	2030	1%
Nonresidential DLC	Third-Party DLC	Summer	2015	2027	1%
Nonresidential DLC	Third-Party DLC	Winter	2015	2027	2%
Nonresidential DLC	Water Heating DLC	Summer	2020	2030	1%
Nonresidential DLC	Water Heating DLC	Winter	2020	2030	1%
Nonresidential Pricing	PTR	Summer	2020	2030	11%
Nonresidential Pricing	PTR	Winter	2020	2030	11%
Nonresidential Pricing	PTR w/Tech	Summer	2016	2021	13%
Nonresidential Pricing	PTR w/Tech	Winter	2016	2021	13%
Residential DLC	AC DLC	Summer	2018	2021	12%
Residential DLC	AC DLC	Winter	2018	2021	0%
Residential DLC	AC/Space Heating DLC	Summer	2018	2021	12%
Residential DLC	AC/Space Heating DLC	Winter	2018	2021	52%
Residential DLC	BYOT - AC	Summer	2016	2019	20%
Residential DLC	BYOT - AC	Winter	2016	2019	0%
Residential DLC	BYOT - AC/Space Heating	Summer	2016	2019	20%
Residential DLC	BYOT - AC/Space Heating	Winter	2016	2019	16%
Residential DLC	BYOT - Space Heating	Summer	2016	2019	0%
Residential DLC	BYOT - Space Heating	Winter	2016	2019	16%
Residential DLC	Smart WH DLC	Summer	2017	2021	23%
Residential DLC	Smart WH DLC	Winter	2017	2021	23%
Residential DLC	Space Heating DLC	Summer	2018	2021	0%
Residential DLC	Space Heating DLC	Winter	2018	2021	52%
Residential DLC	Water Heating DLC	Summer	2017	2025	16%

Program Type	Program	Season	Start Year	Steady State Year	Steady State Participation Rate
Residential DLC	Water Heating DLC	Winter	2017	2025	16%
Residential Pricing/BDR	Behavioral DR	Summer	2016	2021	13%
Residential Pricing/BDR	Behavioral DR	Winter	2016	2021	13%
Residential Pricing/BDR	PTR	Summer	2019	2025	14%
Residential Pricing/BDR	PTR	Winter	2019	2025	14%
Residential Pricing/BDR	PTR w/Tech	Summer	2019	2021	17%
Residential Pricing/BDR	PTR w/Tech	Winter	2019	2021	17%
Residential Pricing/BDR	TOU	Summer	2019	2023	20%
Residential Pricing/BDR	TOU	Winter	2019	2023	20%

Source: Navigant

Table 6: Key Program/Technology Assumptions

Program/ Technology	Assumption	Value
General	All impacts provided at the meter level, as opposed to the busbar level	N/A
DR	High Scenario TOU Opt-Out Rate	15%
Solar	Capacity Factor	0.121436064
Storage	Total Energy	14 kWh (approximately 4 hours)
	Real Power, max continuous	5 kW (charge and discharge)
	Real Power, peak (10s, off-grid/backup)	7 kW (charge and discharge)
	Round trip efficiency	90%
EV DLC	Eligible Technology	Level 2 Home Chargers
	Average Coincident Demand	3.2 kW
	Ratio of Actual to Theoretical Peak	47%
	EV Seasonal Demand Change	+/- 10%

Source: Navigant

APPENDIX C. GLOSSARY

Acronym	Definition
BDR	Behavioral Demand Response
BEV	Battery Electric Vehicle
BYOT	Bring Your Own Thermostat
C&I	Commercial and Industrial
DER	Distributed Energy Resource
DLC	Direct Load Control
DR	Demand Response
EE	Energy Efficiency
HDV	Heavy-Duty Vehicle
ICEV	Internal Combustion Engine Vehicle
IRP	Integrated Resource Planning
LCOE	Levelized Cost of Electricity
LDV	Light-Duty Vehicle
LT	Light Truck
LVOE	Levelized Value of Electricity
MDV	Medium-Duty Vehicle
MHDV	Medium and Heavy-Duty Vehicles
PC	Passenger Car
PEV	Plug-In Electric Vehicle
PGE	Portland General Electric
PHEV	Plug-In Hybrid Electric Vehicle
PTR	Peak Time Rebate
TOU	Time of Use
TCO	Total Cost of Ownership
VAST™	Vehicle Adoption Simulation Tool

External Study D. Characterizations of Supply Side Options

THERMAL AND PUMPED STORAGE GENERATION OPTIONS

Supply Side Resource Plants

HDR Project #10104560

Portland General Electric

October 4, 2018

THERMAL AND PUMPED STORAGE SUPPLY SIDE RESOURCE OPTIONS

SUPPLY SIDE RESOURCE PLANTS

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Appendix A – Heat Balance Diagrams

Appendix B – Technology Maturity / Cost Forecast

Appendix C – Cost Estimate Summaries

Appendix D – Drawdown Schedules

Appendix E – Modeling Inputs Summary Tables

Executive Summary

Portland General Electric (PGE) is preparing its 2019 integrated resource plan (IRP) and is evaluating several supply-side resources including thermal, renewable, and storage technologies. HDR Engineering, Inc. (HDR) was retained by PGE to assist with the overall 2019 IRP effort by characterizing the operational and cost attributes of various power generation technologies. HDR provides consulting, design, and Owner's engineering services for all aspects of power generation, including thermal, hydro, renewable, and energy storage projects. The parameters developed for each technology include estimated performance and operating characteristics, capital costs, operating costs, and implementation schedules. The range of technologies considered include several natural gas fired generating options, a geothermal technology, and a pumped storage hydro technology. The resulting parameters for the various technologies are summarized in Table E-1 for representative project sites in the Pacific Northwest. The following summarizes the basis for development of the parameters for each of the technologies:

1. Performance has been estimated for all options based on supplier feedback and performance estimating software.
2. Plant steady state emissions were estimated.
3. Conceptual level project capital costs have been developed based on an overnight, turnkey engineer, procure, and construct (EPC) delivery in 2018$.
4. End of life decommissioning, net of salvage value, were estimated.
5. Technology maturity / cost forecasts were projected.
6. Conceptual level operations and maintenance (O&M) costs, including both fixed and variable O&M, were estimated and are presented in $/kW-yr and $/MWh, respectively.
7. Conceptual level project implementation schedules identifying key project milestones and duration of key project activities from EPC contractor notice to proceed (NTP) to the commercial operation date (COD) of the facility are presented.
8. Capital drawdown schedules were developed.
9. Input parameters for dispatch modeling were derived from the O&M costs and various operating characteristics developed for each option.

Additional details and results regarding the development of the generating resource characteristics are further summarized in this report. The information developed for the IRP activities are intended to represent the current energy industry landscape and are based on supplier-, site-, and project-generic technologies. Technology attributes are suitable for comparative purposes, should not be used for budget planning purposes, and are subject to refinement based on further evaluation and review.

Table E-1. Summary of Technology Attributes.[1234]

	Unit Type	1x0 96 MW Aero SC	1x0 356 MW Frame SC	1x1 517 MW Frame CC	6x0 109 MW RICE	30 MW Biomass	30 MW Geo-thermal	1200 MW Pumped Hydro
Fuel	Type	Natural Gas	Natural Gas	Natural Gas	Natural Gas	Wood	NA	NA
Average Day Capacity, New & Clean[1]	(MW)	96	356	517	109	30.5	30	1,149
Average Day Net HHV Heat Rate, New & Clean[1]	(Btu/kWH)	8,930	9,135	6,232	8,453	13,450	NA	NA
Average Day Degraded Capacity[1]	(MW)	93	347	503	108	30	23	
Average Day Degraded Heat Rate[1]	(Btu/kWH)	9,094	9,298	6,362	8,534	13,731	N/A	
Capital Cost[2]	$/kW	$1,154	$531	$906	$1,265	$5,935	$6,216	$2,252
Capacity Factor[3]	(%)	10%	10%	75%	20%	92%	93%	37%
Fixed O&M[4]	($/kW-yr)	$5.61	$2.10	$6.57	$5.15	$110.84	$119.53	$11.31
Variable O&M[4]	($/MWH)	$5.20	$9.69	$3.57	$5.42	$5.28	$2.39	$0.37
Project Schedule	(months)	22	22	36	18	43	36	60-96

[1] Average day conditions is 55 F. Thermal heat rates are presented on a higher heating value (HHV) basis.
[2] $/kW capital cost metrics divide estimated project costs by the average new and clean capacity for a given technology. Costs are 2018 US$.
[3] Capacity factors for dispatchable technologies assumed in order to develop O&M costs.
[4] O&M costs are divided by average life of plant degraded net plant output at average day conditions. Costs are 2018 US$.

1 Introduction

Portland General Electric (PGE) is preparing its 2019 integrated resource plan (IRP) and is evaluating several supply-side resources including thermal, renewable, and storage technologies. HDR Engineering, Inc. (HDR) was retained by PGE to characterize a select group of thermal generating resources and a pumped hydro resource. The developed resource characteristics will be used by PGE for development of modeling inputs and assumptions to be used in its 2019 IRP development and dispatch models. These technology characteristics include estimated performance and operating attributes, capital costs, and operating costs for the various generating technologies. The technology options considered include several natural gas fired generating alternatives, geothermal generation, and pumped hydro energy storage generation. The following report summarizes the assumptions, calculations, and analyses to characterize the resource options and discusses current market conditions that may alter the accuracy of these inputs or the ability of PGE to implement the technologies considered in this study.

The following thermal and pumped hydro storage generating resource options were considered:

1. Simple Cycle (SC) Aeroderivative Combustion Turbine Generator (CTG) – Nominal 96 MW capacity.
2. Simple Cycle Frame Combustion Turbine Generator – Nominal 356 MW capacity.
3. Combined Cycle (CC) Combustion Turbine Generator – Nominal 517 MW capacity in a 1x1 configuration.
4. Simple Cycle Reciprocating Engine Generators (RICE) – Nominal 109 MW capacity in a 6x0 configuration.
5. 30 MW Biomass Fired Steam Plant
6. 30 MW Geothermal Plant
7. 1200 MW Pumped Storage Hydro Plant

HDR has developed the following characteristics for each of the generation options:

1. Plant Capacity and Performance
2. Operational Characterization
    a. Ramp rates
    b. Availability / Reliability
    c. Minimum Up / Down Times
    d. Start-Up Times
    e. Maintenance Cycle / Durations
    f. Approximate Footprint
    g. Plant Emissions
    h. Water Requirements
    i. Technical Maturity
3. Plant Capital Costs
    a. Project Costs
    b. Owner's Costs

4. Project Schedule
5. Operations and Maintenance Costs
    a. Fixed Costs
    b. Variable Costs

The details and results of the plant characteristics developed by HDR are further discussed in the following sections of this report and are summarized in Appendix E.

2 Study Basis and Assumptions

The following basis was used for establishing performance, costs, and operating characteristics for the various generating resource options considered in this study.

2.1 Site Characteristics

The generation technologies described in this report have been presented on the basis that installations are assumed to be located in the Pacific Northwest.

Summer, average, and winter day ambient climate information was developed based on the site conditions indicated in Table 2.1-1. Plant part load performance was also developed at ISO ambient conditions.

Table 2.1-1. Site Ambient Conditions

Site Conditions		Summer	Average	Winter	ISO
Dry Bulb Temperature	F	90	55	20	59
Wet Bulb Temperature	F	67.18	48	18.33	51.47
Relative Humidity	%	30%	60%	75%	60%
Site Elevation	ft	1000	1000	1000	1000

2.2 Plant Performance

2.2.1 Performance

Plant performance (i.e., output, efficiency, etc.) was estimated for all technologies based on performance estimating software, previous project developments, feedback from equipment suppliers, and/or published performance information.

For the thermal generation options, performance was developed based on prime mover performance provided by original equipment manufacturers (OEMs), ThermoFlow performance estimating software, and estimates of facility auxiliary loads. Heat balance diagrams were developed for summer and average day ambient conditions at full load. Full load heat balance diagrams for the thermal options are provided in Appendix A.

Average life of plant degraded plant performance was also developed based on the capacity factor and dispatch identified in Table 2.3-4. Part load operating conditions were also developed at ISO conditions at average life of plant degraded performance. In all degraded cases, it was assumed that at least one complete maintenance interval or major overhaul was completed during the life of the plant.

2.2.2 Air Emissions

For the thermal technologies, plant air emissions were estimated at steady-state, full load operation based on supplier-provided emission profiles and assumed fuel characteristics. Emissions estimated for this evaluation are not intended to be used for permitting activities and are intended to provide a comparison between the different thermal technologies.

2.2.3 Water Resources

Plant water consumption and wastewater discharge was estimated for the thermal technologies based on conceptual plant water management systems typically applied to current applications. Water users typically included:

- CTG Evaporative Coolers (summer operation only)
- NOx water injection (aeroderivative CTG)
- Steam cycle makeup
- Wet cooled heat rejection system makeup due to evaporative losses and blowdown
- Miscellaneous users, primarily consisting of plant personnel water usage

Wastewater discharge primarily is from:

- Wet cooled heat rejection system blowdown
- Steam cycle blowdown
- Evaporative cooler blowdown

Evaporative losses and water replenishment from the reservoir are not included for the pumped hydro energy storage resource option.

2.2.4 Fuel Assumptions

Natural gas was evaluated as the fuel source for the combustion turbine and reciprocating engine options. Fuel gas is assumed available at a utility interface on-site at 600 psia with a fuel heating value of 22,029 Btu/lb.

For the biomass generating option, a typical chipped wood biomass fuel was assumed. The biomass fuel analysis is characterized in Table 2.2-2.

Table 2.2-2. Biomass Fuel Analysis

Biomass Fuel		
Type: Biomass--Wood		
Fuel supply temperature	77	F
LHV (moisture and ash included)	3695	BTU/lb
HHV (moisture and ash included)	4429	BTU/lb
Ultimate Analysis (weight %)		
Moisture	48.91	%
Ash	2.03	%
Carbon	25.69	%
Hydrogen	2.35	%
Nitrogen	0.53	%
Chlorine	0.02	%
Sulfur	0.06	%
Oxygen	20.41	%
Total	100	%
Proximate Analysis (weight %)		
Moisture	48.91	%
Ash	2.03	%
Volatile Matter	42.1	%
Fixed Carbon	6.96	%
Total	100	%
Other Properties		
Specific Heat @ 77F, dry	0.4036	BTU/lb-R
Specific Heat @ 572F, dry	0.6114	BTU/lb-R
Bulk density	16	lbm/ft^3
Mercury content (dry basis)	0	ppmw
Ash Analysis (weight %)		
SiO2	17.78	%
Al2O3	3.55	%
Fe2O3	1.58	%
CaO	45.46	%
MgO	7.48	%
Na2O	2.13	%
K2O	8.52	%
TiO2	0.5	%
P2O5	7.44	%
SO3	2.78	%
Other	2.78	%
Total	100	%

2.3 Operating and Maintenance Cost Assumptions

For each technology resource considered, operating and maintenance (O&M) costs are presented and are broken into fixed and variable costs. O&M costs are estimated based on a combination of previous HDR project experience or vendor information available such as combustion turbine long term service agreement pricing.

While these costs vary from technology to technology, the fundamental breakdown between fixed and variable costs can be summarized as follows:

Fixed O&M: Fixed O&M costs are costs that are not generally dependent on the generation rate of the facility. These costs take into account plant operating and maintenance staff, fixed long term service agreement costs, and other fixed maintenance costs for equipment. Fixed staffing costs utilized in the analysis are defined below in Table 2.3-1. Typical plant staffing levels used for characterizing staffing costs are summarized in Table 2.3-2. For the simple cycle options, it is assumed the plant is located at an existing plant site with minimal staff additions. No taxes, insurances, corporate general and administrative costs (G&A), fixed fuel transportation, or fixed transmission costs have been included.

Table 2.3-1. Fixed Staffing Costs.

Fixed Cost	Cost in 2018 $
Annual Cost for Salaried Staff	$140,000
Annual Cost for Hourly Staff	$100,000

Table 2.3-2. Plant Staffing Level Basis.

Staffing		Simple Cycle / Engines	1x1 Combined Cycle	Biomass	Geothermal	Pumped Hydro
Incremental Salaried Staff		1	6	9	4	3
Incremental Hourly Staff		2	18	19	10	25

Fixed costs developed for this evaluation are presented on a $/kW-yr basis computed by dividing the estimated fixed annual O&M costs by the average life of plant degraded full load net plant output at average day ambient conditions.

Variable O&M: Variable O&M costs are those expenses that are dependent on electrical production/operation of a facility. Variable O&M costs presented herein generally are non-fuel variable O&M costs unless stated otherwise. Non-fuel variable costs include costs for delivery and disposal of all materials utilized in the power generation process, including ammonia, lime, limestone, activated carbon, water, water treatment chemicals, ash and waste disposal. Also included are major equipment and maintenance costs, including replacement material and components and outsourced labor to perform major maintenance on the combustion turbines, steam turbines, boilers, air quality control equipment, material handling systems, and other major equipment. It was assumed that at least one complete maintenance interval or major overhaul was completed during the life of the plant for all options.

Commodity costs required for determining variable maintenance costs are summarized in Table 2.3-3.

Table 2.3-3. Consumable Costs.

Consumable	Unit Cost in 2018 $
Ammonia	$166.52 / Ton (as 19% NH3)
Makeup Water	$1.50 / kgal
Demin Water	$3.50 / kgal
Cycle Chemical Feed	$0.015 / Ton steam produced
Waste Water Treatment	$1.00 / kgal
Engine Lube Oil	$7.00 / kgal
Sand (CFB bed material)	$7.20 / Ton
Limestone	$14.00 / Ton
Fly Ash Disposal (Offsite)	$20.00 / Ton

Variable O&M costs are presented herein on a $/MWh basis however, for some technologies, variable O&M costs can be broken down into electric production-based ($/MWh) and/or operation-based ($/hour of operation or $/start) costs. Operation based costs are generally included in the CTG or RICE long term service contract costs.

O&M costs have been developed for each technology option based on the following general plant dispatch profile in Table 2.3-4.

Table 2.3-4. Plant Dispatch.

Plant Annual Dispatch Basis		
Simple Cycle / Engines	10%	peaking dispatch
Combined Cycle	75%	intermediate to baseload dispatch
Biomass / Geothermal	90%	baseload
Pumped Hydro	37%	8 hours storage duration, daily dispatch

2.4 Capital Cost Basis & Uncertainty Basis

Total project capital costs were developed assuming an engineer, procure and construct (EPC) contracting basis and are presented in this report based upon a project full notice to proceed (FNTP) in 2018. These costs assume that each of the technologies considered will be installed within the Pacific Northwest. Oregon specific wage rates and productivity factors have been utilized for the natural gas and biomass project estimates. General adjustments have been applied to the other technology options to consider an Oregon based installation.

Total capital cost estimates are broken down into project capital and Owner's costs. Project capital costs include the following:

- The costs associated with the procurement of major equipment (equipment costs)

- Costs associated with construction labor (construction costs)
- Costs associated with the procurement of commodities such as piping, valving, insulation, instrumentation, etc. (materials and supplies costs)
- Project indirects
- Construction management
- Engineering
- Contingency
- EPC fees and insurance

Owner's costs have generally been developed as a percentage of project capital costs and include the following (unless otherwise noted within the report[5]):

- Project management (0.6%)
- Engineering support (0.4%)
- Construction management (0.3%)
- Owner contingency (10%)
- Plant operations during commissioning (0.4%)
- Insurance during construction (0.8%)
- Initial spares (0.6%)
- Construction utilities (0.3%)
- Project development and permitting (excludes Oregon Energy Facility Citing Council (EFSC) carbon offset payments) (1.1%)
- Miscellaneous (0.4%)
- Long term service agreement (LTSA / continuing service agreement (CSA) initiation fees (0.38%)
- Land purchases, assuming $2,310 per acre land cost.

Project development costs for geothermal also include field well development costs that typically are incurred by the Owner prior to EPC FNTP and are included in the Owner's costs.

The following additional general site assumptions have been used:

- Costs are inclusive of the plant site boundary.
  - For natural gas projects, this is from the utility gas yard interface on-site to the high side of the generator step up transformers.
  - Potable water, service water, make-up water, fire water, and waste water will interface with a local utility at the site boundary.
- Project costs generally assume a greenfield installation. The simple cycle resources assume they will be located at an existing site with minimal shared infrastructure.
- Sufficient space is available at the site for construction activities, including lay-down.

[5] Pumped hydro Owner's costs are estimated to be approximately 20%.

- No costs have been included for transmission interconnect costs, escalation, accrued finance during construction (AFDC) charges, finance fees, or sales tax.

All project total capital costs that are expressed as $/kW values in this report are derived by dividing the project costs by the net plant capacity under new and clean average day operating conditions.

All costs presented herein are based upon current day cost expectations and actual project data and quotations where available. They are intended to reflect the current status of the industry with respect to recent materials and labor escalation; however, due to the volatility of the power generation marketplace, actual project costs should be expected to vary. Each project cost summary provides an indication of estimated accuracy of the total project cost values based on whether the estimate is an American Association of Cost Engineering International (AACE) Class 4 or 5 estimate (depending on technology). The expected standard deviation of the cost has been calculated based on the accuracy of the cost estimate. Estimate uncertainty is characterized further in Table 2.4-1, where low corresponds to a low range of estimation (or underestimation) and high corresponds to a high range of estimation (or overestimation).

Table 2.4-1. Estimate Uncertainty

Estimate Class	Accuracy Range	
	Low	High
Class 5	-20 to -50 %	+30 to +100%
Class 4	-15 to -30%	+20 to +50%

Decommissioning costs have also been estimated, net of salvage value, and assume the site will be restored back to a brownfield condition, which removes all material and structures down to 2 to 3 ft. below grade. For geothermal, it is assumed the well heads are filled and capped. For pumped hydro, it is assumed the reservoir embankment has been breached and tunnels are filled and left in place below grade. Decommissioning costs are presented in 2018 US dollars and reflect HDR's opinion of current market conditions and salvage costs and do not include escalation to the end of project life. These costs have been estimated based on similar project experience or as a percentage of capital costs.

2.5 Technology Maturity

As more experience is gained through the application of a power generation technology, the capital costs would be expected to decrease as the design, fabrication, and installation of a technology becomes more mature. To estimate the effects of maturity on a generation technology, and the potential reductions in plant capital costs over time, cost trends were developed using data from the Energy Information Administration's (EIA) 2017 Annual Energy Outlook (AEO) National Energy Modeling System (NEMS). Cost forecasting data from NEMS was applied to the estimated capital costs as a basis for forecasting future costs for each technology option evaluated. All costs are referenced in 2018 US dollars and are forecasted from 2018 to 2050. In most cases, the NEMS forecasted cost projections did not start until 2020 or 2021, so costs were estimated to be unchanged from 2018 until the start of the NEMS forecast. Figure 2.5-1 summarizes the results of the estimated future project costs. Further details are included in Appendix B. It is also noted that the geothermal cost forecast assumes that the most viable sites will be utilized first and, once those sources are depleted, project costs will increase over time due to the decrease in the quality of the geothermal sites to be utilized (hence the oscillating cost curve).

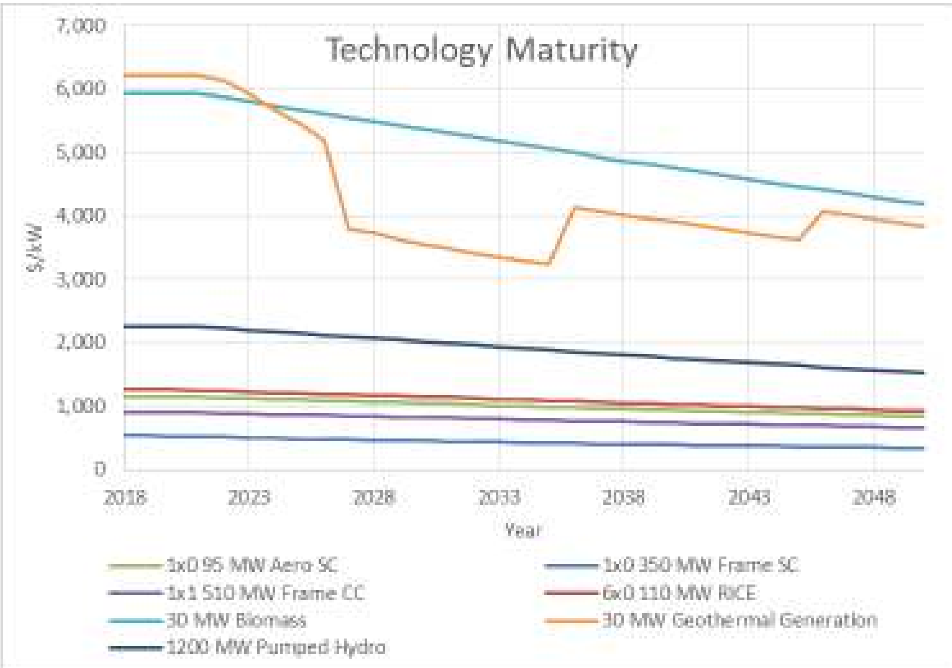

Figure 2.5-1. Technology Maturity / Cost Forecast

2.6 Project Schedule and Cash Flow Basis

The estimated project schedules presented herein are based upon current day EPC contracting approaches and methodologies. As such, for natural gas fired generation resources, it is expected that a significant portion of preliminary engineering and equipment sourcing activities are completed prior to the FNTP of the project. This will typically involve the procurement of the major equipment and the EPC contract assuming limited notice to proceed (LNTP) is awarded for these contracts prior to an FNTP.

While some project schedules estimated for this work include some developmental activities, the majority of the schedules and durations are generally presented from Full Notice to Proceed to the commercial operation date (COD) of the facility. It is expected that the air permit will be received and project financing activities will be completed prior to the project FNTP.

In the case of geothermal, significant costs are typical incurred for field well development prior to FNTP.

For monthly cash flow determinations a general project cash flow schedule has been utilized and adjusted as appropriate for each technology. A general representation of the curve is presented in Figure 2.6-1. Annual cash flow forecasts are provided for each technology from FNTP to the commercial operation date (COD).

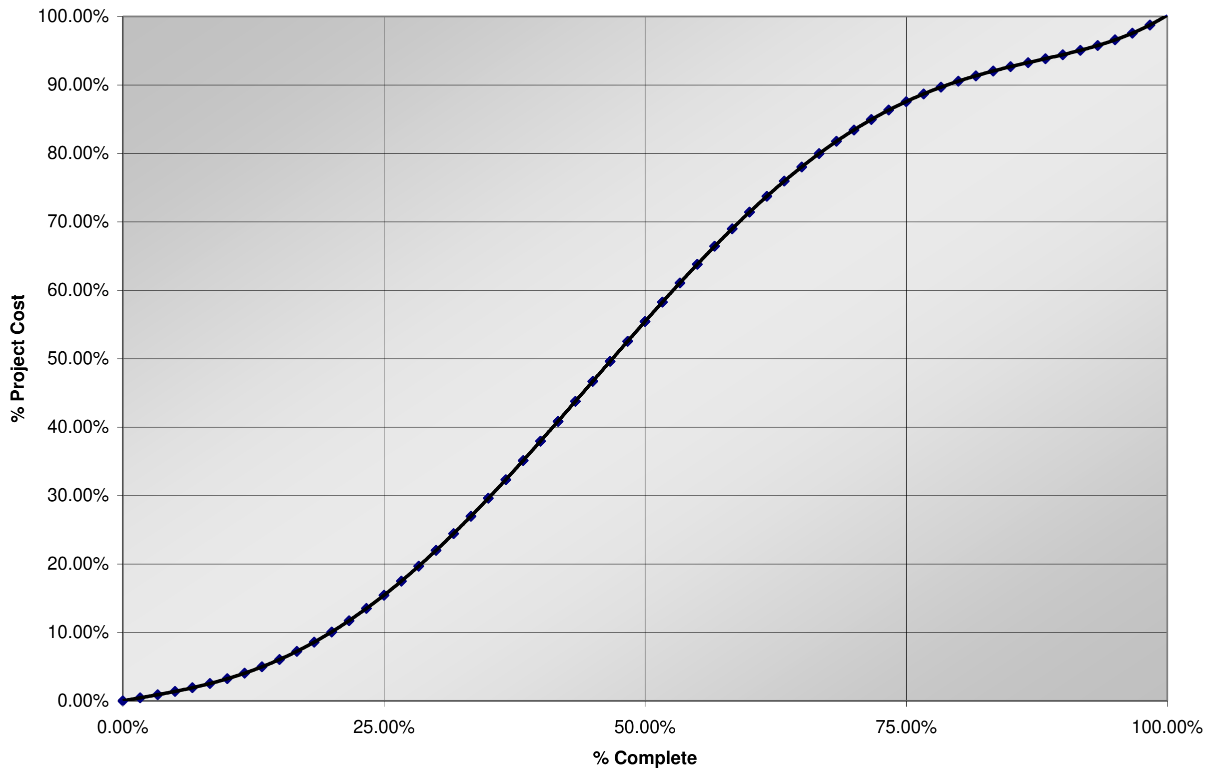

Figure 2.6-1. Representative Cash Flow Curve.

Annual cash flow forecasts are presented for each technology on a calendar month basis from FNTP to the commercial operation date (COD) in Appendix D.

3 Natural Gas Generation Resources

3.1 Technology Overview

Both Natural gas combustion turbines (CTG) and natural gas reciprocating engines (RICE) are commonly implemented technologies for utility scale power generation using pipeline natural gas as a fuel source.

Simple cycle combustion turbine plants are commonly used to supply peaking electric power due to their low capital cost, swift construction, quick starts and ability to operate cost effectively over a low range of capacity factors compared to other power generation facilities.

A combined cycle plant involves the addition of a heat recovery steam generator (HRSG) to the combustion turbine exhaust which provides steam to a steam turbine generator. The result is a significant increase in thermal efficiency over that of a simple cycle combustion turbine. Combined cycle plants offer key attributes of high efficiency, cost effective low emissions technology and relatively fast construction and startups beneficial to supplying base or intermediate load electric power.

Similar to simple cycle CT plants, simple cycle RICE installations are generally used to supply peaking power and to operate in load following scenarios. RICE technology is favorable for peaking applications due to its wide range of operability and rapid response capability. Generally, in utility power generation applications, RICE technology is smaller in scale and has better efficiency as compared to simple cycle CT technology. As compared to simple cycle CTs, RICE facilities are less susceptible to thermal performance variances due to changes in ambient conditions such as temperature and elevation.

The attributes of each natural gas resource evaluated are characterized as follows:

Simple Cycle Aero Derivative Combustion Turbine Generator

- 1 x 0 GE LMS 100 PA+ combustion turbine generator evaluated
- Water Injection for NO_x Control
- Wet Cooled Intercooler w/ a mechanical draft cooling tower for heat rejection
- Selective Catalytic Reduction (SCR) and Oxidation Catalyst for NO_x and CO emissions reduction
- Evaporative Cooling included
- Simple Cycle / Peaking Application
- Natural gas only fuel source

Simple Cycle Frame Combustion Turbine Generator

- 1 x 0 GE 7HA.02 combustion turbine generator evaluated
- Dry Low NO_x Combustion Technology

- Selective Catalytic Reduction (SCR) and Oxidation Catalyst for NO_x and CO emissions reduction
- Evaporative Cooling included
- Simple Cycle / Peaking Application
- Natural gas only fuel source

Combined Cycle Combustion Turbine Generator

- 1 x 1 GE 7HA.02 combustion turbine generator configuration evaluated
- Dry Low NO_x Combustion Technology
- Selective Catalytic Reduction (SCR) and Oxidation Catalyst for NO_x and CO emissions reduction
- Evaporative Cooling included
- Combined Cycle / Intermediate to Base Load Application
- Natural gas only fuel source
- Wet mechanical draft cooling tower with surface condenser
- Single shaft combustion turbine / steam turbine with common generator
- Triple pressure heat recovery steam generator w/ nominal 2400 psig, 1050 F / 1050 F main steam, reheat steam conditions

Simple Cycle Reciprocating Engine Generators

- 6 x 0 Wartsila 18V50SG reciprocating engine generators evaluated
- Radiator / jacket water utilizes fin fans for heat rejection
- Selective Catalytic Reduction (SCR) and Oxidation Catalyst for NO_x and CO emissions reduction
- Simple Cycle / Peaking Application
- Natural gas only fuel source

3.2 Commercial Status

Natural gas CTG's and RICE technology are well proven and commercially available technologies for power generation. The major combustion turbine and RICE manufacturers all have significant experience throughout the world. RICE units generally range in size from 100 kW to 18 MW and current combustion turbines range in size from 1.5 MW to 370 MW.

3.3 Operational Considerations

3.3.1 Plant Performance

Overall estimated new and clean net plant output and net plant heat rate are depicted for each of the natural gas resource options in Table 3.3-1. The simple cycle RICE options plant performance is presented for a single unit in operation.

Table 3.3-1. New and Clean Natural Gas Plant Performance

Thermal Cycle Performance		1x0 96 MW Aero SC	1x0 356 MW Frame SC	1x1 517 MW Frame CC	6x0 109 MW RICE (1 Unit)
Summer, 90F, 100%					
Net Output	kW	92,005	346,920	506,547	18,241
Net Heat Rate (HHV)	Btu/kWh	9,042	9,212	6,258	8,485
Average, 55F, 100%					
Net Output	kW	95,553	355,630	517,016	18,241
Net Heat Rate (HHV)	Btu/kWh	8,930	9,135	6,232	8,453
Winter, 20 F, 100%					
Net Output	kW	96,829	377,334	540,487	18,241
Net Heat Rate (HHV)	Btu/kWh	8,882	9,022	6,237	8,440

Plant performance has also been developed at part load operating conditions from 100% load to minimum emission compliance load (MECL) for each of the natural gas resource options based on average life of plant degraded performance at ISO conditions of 59F, 60% humidity and 0 ft. elevation. Table 3.3-2 presents the unit turn down performance. The RICE performance is depicted for a single unit in operation and MECL has been depicted at approximately 30 percent load. Some engine manufactures have recently indicated the ability to turn down to 10 percent load while maintaining emission compliance, but performance data was not available at this operating point. Figure 3.3-1 further depicts plant performance as a function of load.

Table 3.3-2. NG Plant Part Load ISO Performance, Average Life of Plant Degraded

Degraded Thermal Cycle Performance		1x0 96 MW Aero SC	1x0 356 MW Frame SC	1x1 517 MW Frame CC	6x0 109 MW RICE (1 Unit)
ISO 100%					
Net Output	kW	92,525	344,522	500,248	17,997
Net Heat Rate (HHV)	Btu/kWh	9,113	9,310	6,362	8,537
ISO 75%					
Net Output	kW	69,231	259,089	395,752	13,381
Net Heat Rate (HHV)	Btu/kWh	9,682	10,114	6,580	9,011
ISO MECL					
Net Output	kW	47,057	105,747	199,687	5,141
Net Heat Rate (HHV)	Btu/kWh	11,060	14,368	7,595	11,209

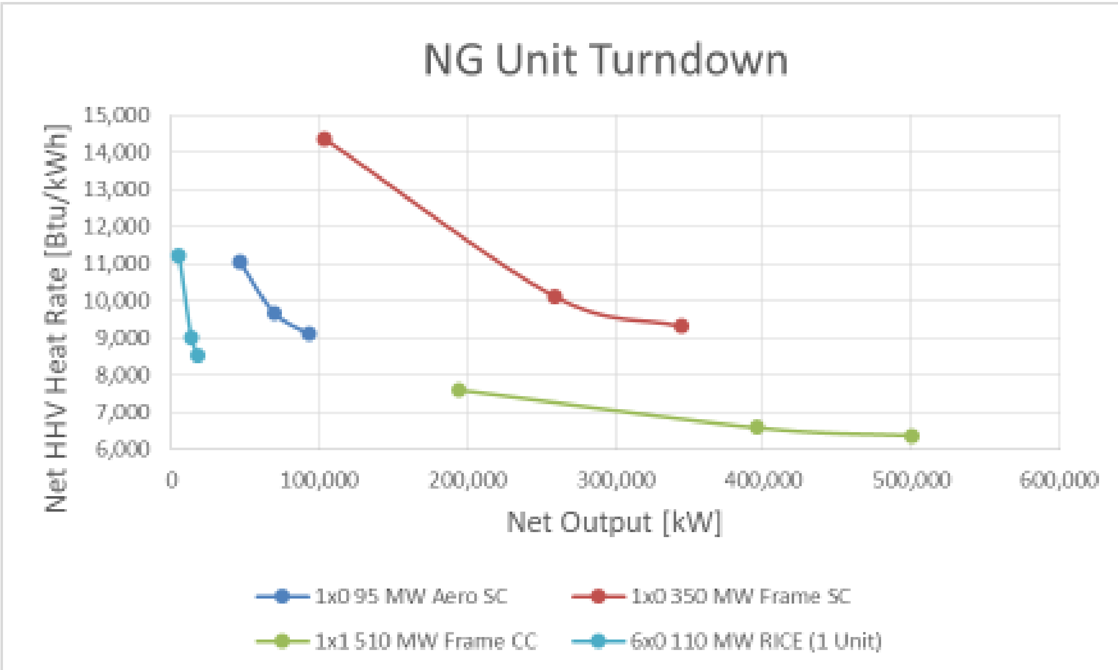

Figure 3.3-1. NG Plant Part Load ISO Performance, Average Life of Plant Degraded

3.3.2 Other Operating Characteristics

Other operating characteristics for the natural gas generation resources include ramp rate, minimum run times and minimum down times, and startup times. These are summarized for each natural gas resource in Table 3.3-3. The following assumptions and clarifications pertain to Table 3.3-3:

- Cold and warm start-up times are estimated from ignition to full plant load and assume the unit has been offline for more than 48 hours and 8 hours respectively. The combined cycle plant is designed for an emission compliant start such that the bottoming cycle is designed to allow for an unrestricted CTG start to MECL.
- Ramp rates depicted are for normal unit operation from MECL to full plant load and a single unit ramp rate is depicted for the RICE engine option.
- Minimum run times are representative of a typical 30 minute startup to full load and plant emission compliance. A 23 minute shutdown time from MECL to flameout for the CTG's and 1 minute shutdown for engines in addition to time to reduce from full load to minimum emission compliance load. It is possible to start the units and operate for shorter durations, but increased O&M costs may be incurred.
- An increased cold start maintenance factor may be incurred for some of the CTG options if started in under 1 hour.

Table 3.3-3. NG Plant Miscellaneous Operating Characteristics.

		1x0 96 MW Aero SC	1x0 356 MW Frame SC	1x1 517 MW Frame CC	6x0 109 MW RICE (1 Unit)
Ramp rate	MW/min	50	50	50	15.8
Minimum run time	minutes	60	60	60	35
Minimum down time	minutes	15	15	15	15
Start-up time to full load at warm start	minutes	10	21	60	5
Start-up time to full load at cold start	minutes	10	21	150	5

Startup fuel consumption for warm and cold starts has been estimated based on the startup times in Table 3.3-3. Table 3.3-4 summarizes estimated startup fuel, per start.

Table 3.3-4. NG Plant Startup Fuel Requirements

Startup Fuel Consumption, per start		1x0 96 MW Aero SC	1x0 356 MW Frame SC	1x1 517 MW Frame CC	6x0 109 MW RICE (1 Unit)
Cold start fuel	MMBtu/start	64	513	3,632	5.79
Warm start fuel	MMBtu/start	64	513	1,453	5.79

3.4 Reliability, Availability, & Maintenance Intervals

To address maintenance intervals for the natural gas generating resource options, typical industry degradation and outage intervals were used. Plant degradation for combustion turbine generators and reciprocating engine generators consists of recoverable and non-recoverable degradation. Recoverable degradation represents degradation that occurs between equipment maintenance intervals and can be recovered after completion of the maintenance. For CTG's, the maintenance intervals typically consist of:

- Offline and online compressors washes
- Hot gas path overhauls (25,000 factored fired hours), 15 day outage
- Major overhaul (50,000 factored fired hours), 25 day outage

For combined cycle plants, the steam turbine major overhauls typically coincide with the combustion turbine major overhauls. CTG overhaul intervals are based on factored fired hours, which can include fired operating hours and/or unit starts and stops.

For large reciprocating engine generators, the major equipment maintenance intervals occur as follows:

- Cylinder heads, gas system (18,000 fired hours), 8 day outage
- Valves, turbocharge, actuator (24,000 hours), 5 day outage
- Cylinder heads, vales, gas system, starting air distributor, vibration damper (36,000 hours), 14 day outage
- Valves, actuator (48,000 hours), 3 day outage

Expected average, life of plant degraded performance is summarized in Table 3.4-1 for each natural gas resource. The average life of plant performance is estimated based on expected plant degradation that will be experienced between maintenance cycles based identified above and the plant dispatch and capacity factors identified in Table 2.3-4. The RICE resource option performance is presented for a single unit.

Table 3.4-1. Natural Gas Average Life of Plant Degraded Plant Performance

Degraded Thermal Cycle Performance		1x0 96 MW Aero SC	1x0 356 MW Frame SC	1x1 517 MW Frame CC	6x0 109 MW RICE (1 Unit)
Summer 100%					
Net Output	kW	89,677	338,159	492,574	17,997
Net Heat Rate (HHV)	Btu/kWh	9,203	9,374	6,386	8,566
Average 100%					
Net Output	kW	93,087	346,591	502,611	17,997
Net Heat Rate (HHV)	Btu/kWh	9,094	9,298	6,362	8,534
Winter 100%					
Net Output	kW	94,313	367,602	524,931	17,997
Net Heat Rate (HHV)	Btu/kWh	9,047	9,186	6,372	8,520

To address reliability and availability for the various natural gas generation options, plant forced outage rates, planned outage rates, and mean average outage duration are summarized in Table 3.4-2. Plant forced outage rates are based on typical industry component forced outage rates. Componentes are generally broken down as combustion turbine, steam turbine, heat recovery steam generator, air quality control systems, and balance of plant equipment. Forced outage rates represent a full outage event. For the plant configurations considered, this would be typical as the prime equipment, such as the CTG's, are single units. In the case of the multi-unit RICE plant, partial forced outages may be incurred that would result in a reduced plant rating, but the forced outage rates presented are for a single RICE engine only (each unit would have the same forced outage rate). Multiplying a number of units by the forced outage rate will provide the partial forced outage rate for a given plant capacity with that many units out of service.

Planned outage rates are based on the maintenance schedules and durations identified above and the plant capacity factors identified in Table 2.3-4.

Table 3.4-2. NG Plant Availbility/Reliability

Availability/Reliability		1x0 95 MW Aero SC	1x0 350 MW Frame SC	1x1 510 MW Frame CC	6x0 110 MW RICE (1 Unit)
Forced Outage Rate		2.38%	2.38%	3.88%	3.30%
Planned Outage Rate		1.73%	1.73%	2.19%	1.84%
Mean Annual Outage Duration	days	6.3	6.3	8.0	6.7

3.5 Other Performance Impacts

As a high level sensitivity, plant performance impacts have been estimated for differences in plant elevation as well as for dry cooling verse wet cooling heat rejection systems.

Plant Elevation Impacts:

- Plant output for a simple cycle plant can be expected to be reduced by approximately 1.5% for every 500 ft. of increased elevation. The plant heat rate of the turbine does not change significantly with elevation.
- For combined cycle plants, plant output is expected to be reduced approximately 1.5% on an average day and heat rate will increase 1.5% on an average day for every 500 ft. of elevation change.
- In comparison, the output and heat rate of RICE generators do not vary with elevation when below 5,000 feet of elevation.

Dry Cooling Heat Rejection System Impacts: Plant performance can be impacted by dry cooling heat rejection systems for both the combined cycle plant and the large aeroderivative CTG plant, which utilizes an intercooler system that must reject heat from the gas turbine compressor to the atmosphere.

For a combined cycle plant, typical plant performance impacts are:

- 2.5% decrease in output
- 2.5% increase in heat rate

For a large aeroderivative CTG simple cycle plant, use of a dry intercooler heat rejection system will result in the following approximate performance impacts:

- 1 to 2.5% decrease in output (average / summer day)
- 1.6 to 1.1% increase in heat rate (average / summer day)

3.6 Staffing Requirements

Staffing requirements to maintain full time operation of the facility have been developed for each thermal option. Required staff numbers are divided into hourly and salaried groups. For each technology, the number of staff required was assumed based on the plant configuration under consideration for the technology. Typical staffing levels for the simple cycle power plant are expected to be minimal as they are assumed to be located at an existing power generation facility and include:

- Two salaried staff
- One hourly staff

For combined cycle power plants considered, staffing levels are typically greater and include:

- Six salaried staff
- Eighteen hourly staff

3.7 Environmental Considerations

3.7.1 Emissions

Plant emissions rates and air quality control equipment assumed for each generation technology are those typically expected to be achievable and are representative of recent projects incorporating the same fuels and technologies. Emissions rates are provided on a lb/mmBtu heat input and lb/MWH basis. The emissions presented here are representative of controlled emissions at the discharge of the stack.

Air emissions for primary pollutants are presented in Table 3.7-1 for the various natural gas generating resource options. These rates are representative of limits which would be expected in an approved air permit for a project located in the Pacific Northwest.

Table 3.7-1. NG Plant Expected Emissions

Plant Emissions		1x0 96 MW Aero SC	1x0 356 MW Frame SC	1x1 517 MW Frame CC	6x0 109 MW RICE (1 Unit)
NOx	lb/mmbtu	0.0081	0.0081	0.0081	0.0203
	lb/MWH	0.073	0.075	0.051	0.172
Particulate Matter PM10 Total	lb/mmbtu	0.0057	0.0057	0.0057	0.0057
	lb/MWH	0.051	0.052	0.036	0.048
SO2	lb/mmbtu	0.0014	0.0014	0.0014	0.0014
	lb/MWH	0.013	0.013	0.009	0.012
CO	lb/mmbtu	0.0123	0.0049	0.0049	0.0370
	lb/MWH	0.112	0.045	0.031	0.314
VOC	lb/mmbtu	0.0035	0.0014	0.0014	0.0351
	lb/MWH	0.032	0.013	0.009	0.298
CO2	lb/mmbtu	118	118	118	118
	lb/MWH	1067	1087	738.5	1001

3.7.2 Water Consumption / Wastewater Discharge

For the thermal technologies, water consumption rates are estimated based on a rough conceptual design of the resource option and assume a blowdown discharge stream to a nearby water body or municipal sewer system. For the large aeroderivative simple cycle CTG and the combined cycle options, a wet cooling tower was assumed for heat rejection. Table 3.7-2 summarizes water consumption and wastewater discharge for each generation option. These rates are based on the assumption that the facility design incorporates recycling and reuse of water to the greatest extent possible.

Table 3.7-2. NG Plant Water Consumption and Discharge

Water Consumption		1x0 96 MW Aero SC	1x0 356 MW Frame SC	1x1 517 MW Frame CC	6x0 109 MW RICE (1 Unit)
Summer					
Total Water Consumption	gal/MWH	175	10.2	251	0.822
Waste Water Discharge	gal/MWH	40.7	2.07	50.4	0.822
Average					
Total Water Consumption	gal/MWH	148	0.042	183	0.137
Waste Water Discharge	gal/MWH	29.6	0.042	36.7	0.137

3.8 Land Requirements

Land requirements for each of the natural gas generating technologies are summarized in Table 3.8-1. The land requirements represent the area within the plant fence and assume utility interconnections for fuel, electrical transmission, water, and wastewater discharge occur at the site boundary. Land requirements for the RICE engine plant are for a six (6) engine plant size.

Table 3.8-1. NG Plant Land Requirements

	1x0 96 MW Aero SC	1x0 356 MW Frame SC	1x1 517 MW Frame CC	6x0 109 MW RICE
Length, ft	500	680	800	420
Width, ft	380	400	470	360
Area, Acres	4.4	6.2	8.6	3.5

3.9 Project Cost

Table 3.9-1 summarizes the estimated total project costs for each of the natural gas thermal resources considered for a 2018 notice to proceed. The breakdown of estimated EPC costs and estimated Owner's costs are also shown for reference. The calculated standard deviation from the total overnight plant cost and the estimated end of plant life decommissioning costs are also referenced.

Table 3.9-1. Natural Gas Plant Project EPC and Owner's Costs (Total Plant)

Project Costs (2018 US $)		1x0 96 MW Aero SC	1x0 356 MW Frame SC	1x1 517 MW Frame CC	6x0 109 MW RICE (1 Unit)
Total Plant Cost	$1,000	$ 110,184	$ 188,976	$ 468,486	$ 138,427
Total Plant Cost	$/kW	$ 1,154	$ 531	$ 906	$ 1,265
EPC Plant Cost	$1,000	$ 95,091	$ 162,327	$ 404,333	$ 119,469
Owner's Cost	$1,000	$ 15,093	$ 26,649	$ 64,154	$ 18,958
Std Deviation from Total Plant Costs	$/kW	$ 311	$ 143	$ 244	$ 341
End of Life Decomissioning Costs	$1,000	$ 1,100	$ 1,600	$ 2,500	$ 3,200

Total plant cost ($/kW) values are based on the plant new and clean net average day output.

3.10 Implementation (Schedule)

The estimated project schedules for the natural gas generating resource options are based upon current day EPC contracting approaches and methodologies. As such, for the natural gas fired facilities, it is expected that a significant portion of preliminary engineering and equipment sourcing activities are completed prior to the FNTP of the project. This will typically involve the procurement of major equipment and of the EPC contract with some level of LNTP awarded for these contracts prior to an FNTP. Figures 3.10-1, 3.10-2, 3.10-3, and 3.10-4 summarize a typical project implementation schedule for an aeroderivative simple cycle CTG, frame simple cycle CTG, RICE, and a combined cycle project from NTP to COD.

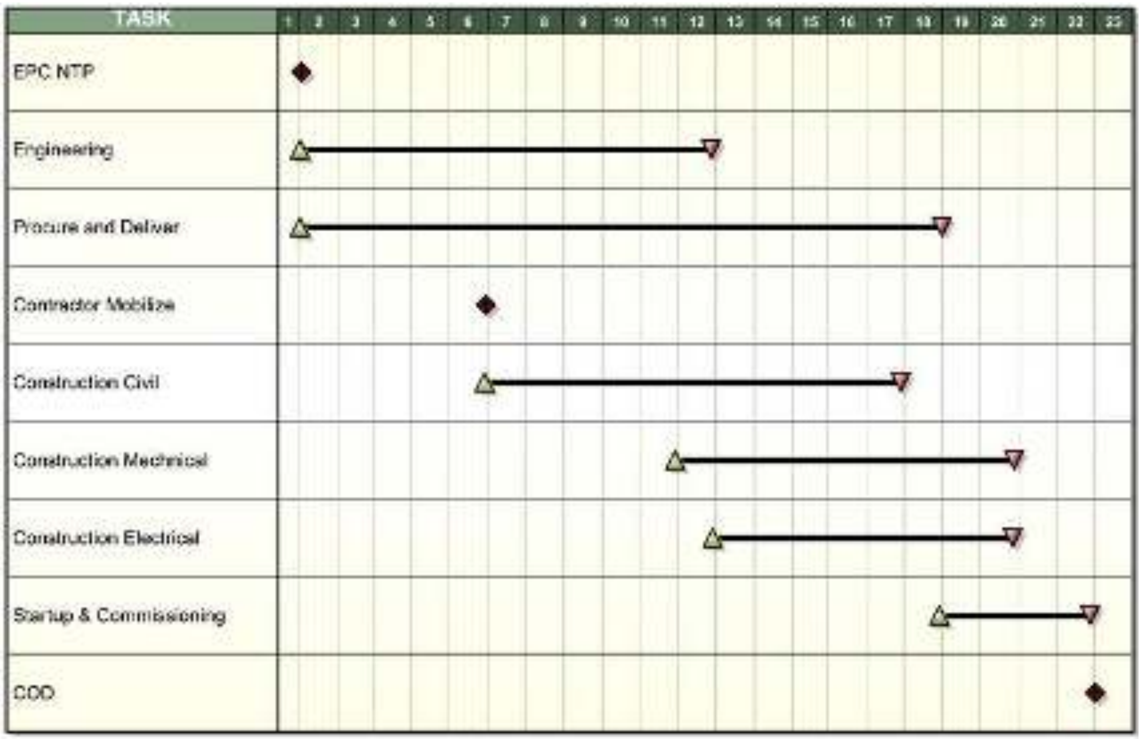

Figure 3.10-1. 1x0 95 MW Aero SC Conceptual Project Schedule.

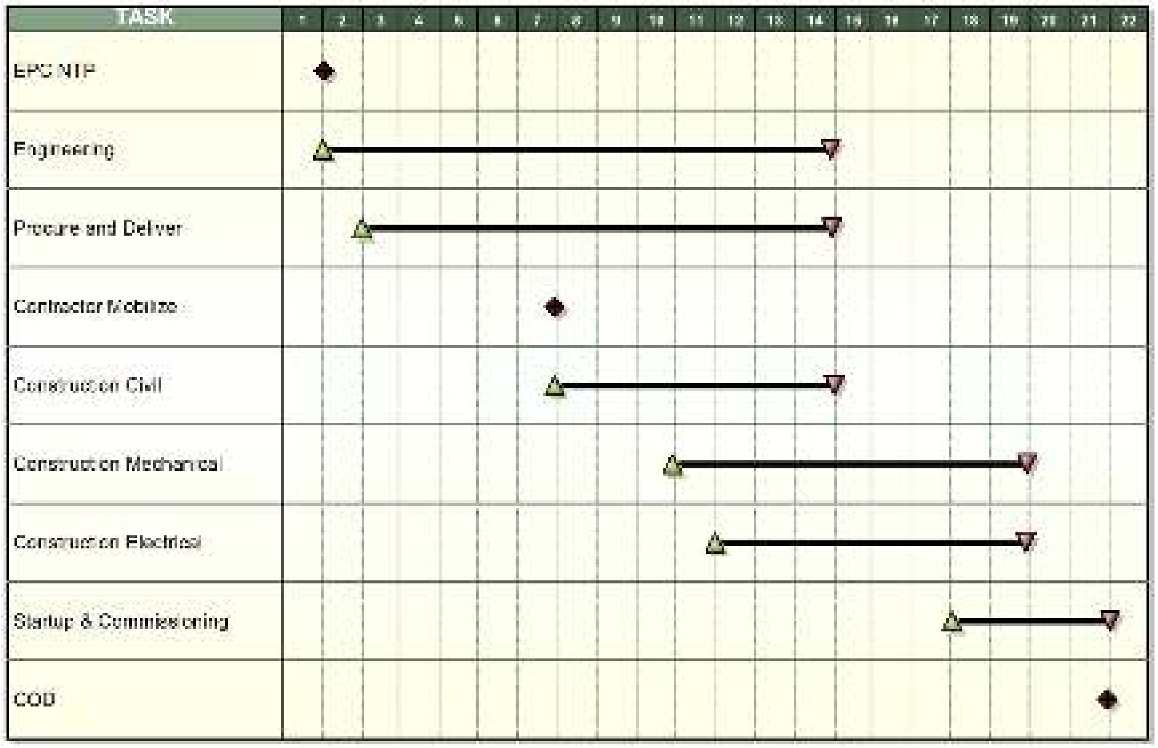

Figure 3.10-2. 1x0 350 MW Frame SC Conceptual Project Schedule

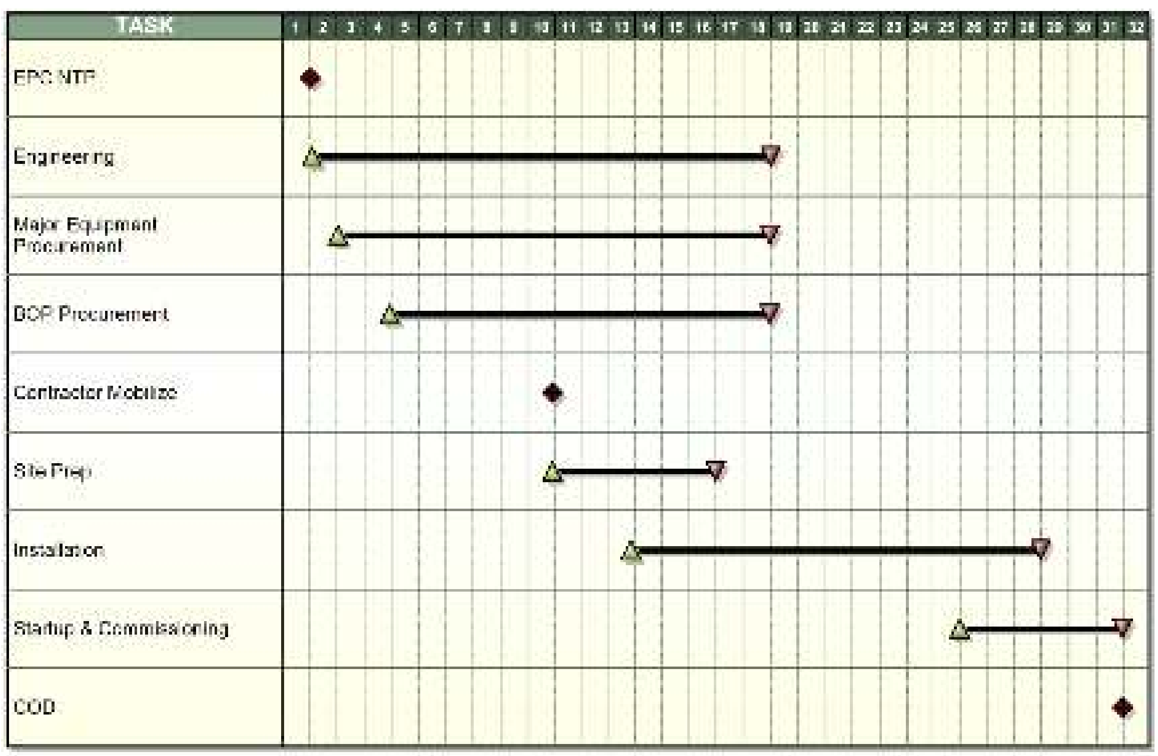

Figure 3.10-3. 1x1 510 MW Frame Combined Cycle Conceptual Project Schedule.

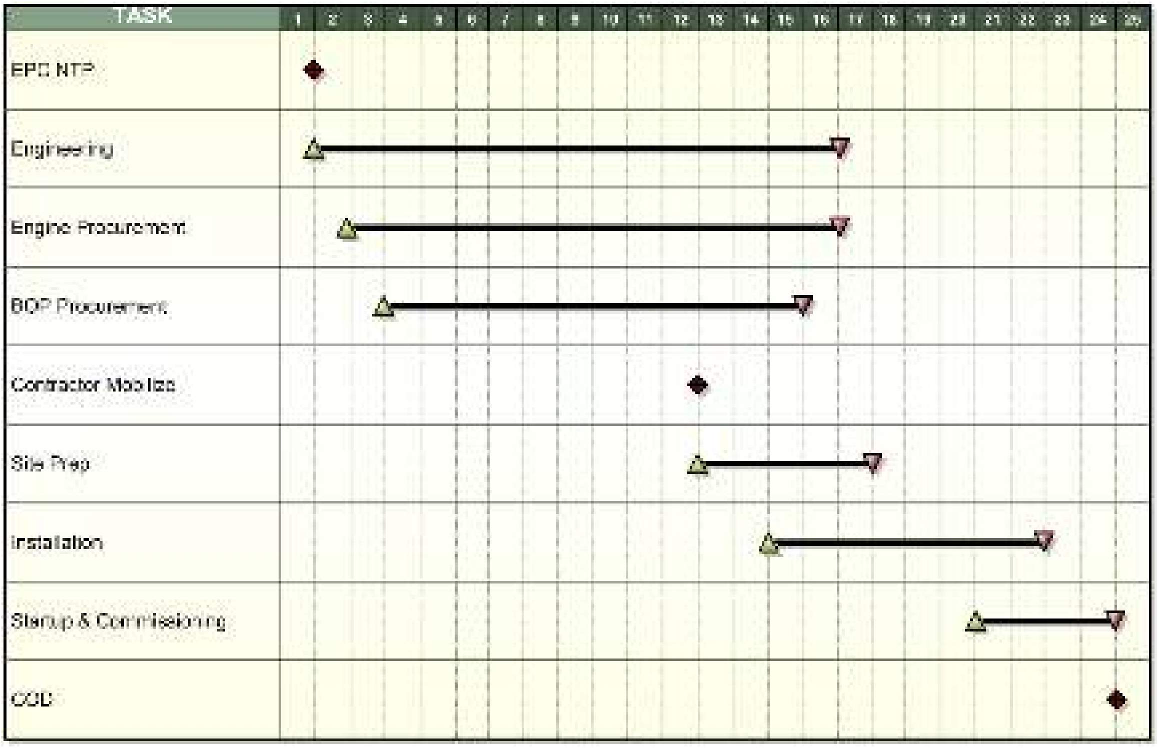

Figure 3.10-4. 6x0 110 MW RICE Conceptual Project Schedule.

3.11 Operating Costs

The estimated fixed and variable O&M costs for each natural gas technology are presented in Table 3.11-1. Simple cycle CTG and RICE options assumed a peaking dispatch profile and intermediate load dispatch profile as identified in Table 2.3-4.

Operation and maintenance costs are also inclusive of gas turbine long term maintenance contract, steam turbine, HRSG, and balance of plant equipment costs, spare parts inventory, and other consumable costs including aqueous ammonia, water, and water discharge. Startup fuel and land lease costs are not included. Plant staffing has been included as defined in Section 3.6.

Table 3.11-1. NG Plant Fixed and Variable Operating Costs

Operating Costs, 2018 $, Degraded		1x0 96 MW Aero SC	1x0 356 MW Frame SC	1x1 517 MW Frame CC	6x0 109 MW RICE (1 Unit)
Summer					
Fixed O&M	$/kW-yr	5.61	2.10	6.57	5.15
Variable O&M	$/MWH	5.20	9.69	3.57	5.42

Additional breakdown of the O&M costs are included in the modeling input tabs in Appendix E.

4 Biomass Steam Generation Resource

Biomass power production is derivative from traditional solid fuel power plants in that a large boiler is used to combust fuel and generate steam that then drives a turbine to produce electricity. Many different suitable fuel sources exit for combustion in a biomass power plant. The main fuel sources for solid biomass plants are wood or other agricultural byproducts such as shells or husks. Biomass plants have also been constructed to burn solid waste from garbage and fuels derived from used automobile tires. The viability of a biomass plant is generally dependent on the availability of a nearby source of biomass waste to be burned in the plant's boiler. For the purpose of this study a 30 MW wood burning biomass steam plant has been considered with the following features:

30 MW Biomass Steam Plant

- Circulating fluidized bed (CFB) steam generator
- Single Pressure, non-reheat steam cycle
- Selective non-catalytic reduction for NO_x emissions
- Fabric filter for particulate matter emissions
- Woody biomass fuel source, delivered to site by truck
- Wet mechanical draft cooling tower with surface condenser

4.1 Technology Overview

Biomass plants operate based on the traditional Rankine cycle that governs the operation of coal fired steam power plants. A biomass fuel, such as wood chips, is burned in a large boiler or steam generator. This steam is then piped at high pressure to the inlet of steam turbine to turn the generator and produce electric power. The steam exhausted from the outlet of the turbine is sent to a condenser where it is returned to its liquid state to be cycled back into the boiler. Biomass plants generally employ fluidized bed boiler technology either with a bubbling fluidized bed (BFB) or a circulating fluidized bed boiler (CFB). Other boiler types such as stoker boilers can also be considered. Ultimately the choice of boiler for a biomass installation is dependent on the desired output and the intended fuel. For the purpose of this analysis, a CFB type boiler was considered. This was paired with a single stage steam turbine and a water cooled condenser using a wet cooling tower. Boiler technology for these plants traditionally consisted of stoker type boilers. A bubbling bed boiler (BFB) or circulating fluidized bed (CFB) boiler is more commonly used today and can achieve lower emissions, though. For the purpose of this evaluation, a CFB boiler has been assumed.

4.2 Commercial Status and Current Market

Biomass power production is well developed and commercially available method of developing electric power. The technologies implemented in biomass power plants are heavily adapted from solid fuel coal plants which have a long history of operation in the United States. The major limiting factor for the implementation of a biomass plant is the availability of a suitable fuel source. Generally, a large quantity of economical nearby biomass fuel is required to allow the installation of a biomass facility. Despite these restrictions, there are currently approximately

16.8 GW of installed biomass capacity in the United States alone[6]. Biomass power plants currently installed in the United States range from less than 5 MW of output up to 150 MW of output.

4.3 Operational Considerations

4.3.1 Plant Performance

Overall estimated new and clean net plant outputs and net plant heat rates are depicted for a 30 MW CFB biomass plant in Table 4.3-1.

Table 4.3-1. 30 MW Biomass Power Plant New and Clean Performance

Thermal Cycle Performance		30 MW Biomass
Summer 100%		
Net Output	kW	29,985
Net Heat Rate (HHV)	Btu/kWh	13,653
Average 100%		
Net Output	kW	30,478
Net Heat Rate (HHV)	Btu/kWh	13,450
Winter 100%		
Net Output	kW	30,731
Net Heat Rate (HHV)	Btu/kWh	13,354

As part of this analysis, heat rate curves for unit turn down from 100% load to MECL operation were generated for the biomass plant based on operation at ISO conditions of 59F, 60% humidity and 0 ft. elevation. Table 4.3-2 below tabulates the turn down performance used to generate the heat rate curves. Figure 4.3-1 further depicts plant performance as a function of load.

[6] Statista, www.statista.com

Table 4.3-2. 30 MW Biomass Plant Part Load ISO Performance, Average Life of Plant Degraded

Degraded Thermal Cycle Performance		30 MW Biomass
ISO 100%		
Net Output	kW	30,278
Net Heat Rate (HHV)	Btu/kWh	13,753
ISO 75%		
Net Output	kW	22,274
Net Heat Rate (HHV)	Btu/kWh	14,021
ISO MECL		
Net Output	kW	13,932
Net Heat Rate (HHV)	Btu/kWh	15,000

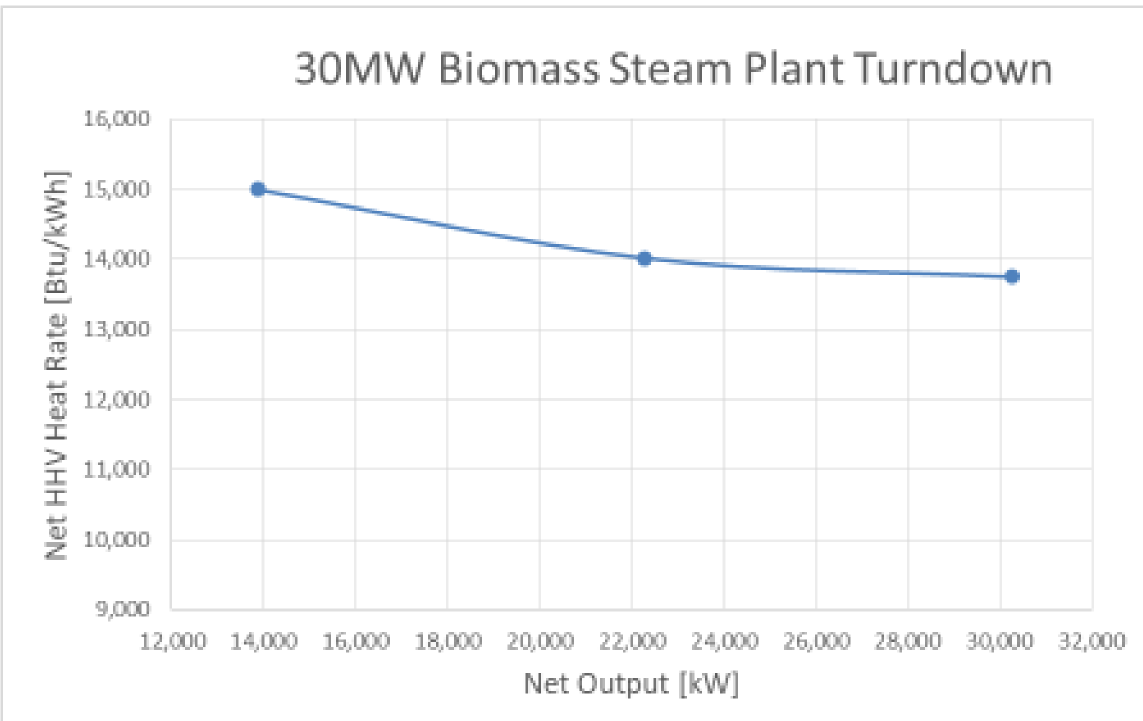

Figure 4.3-1. 30 MW Biomass Plant Part Load ISO Performance, Average Life of Plant Degraded

4.3.2 Other performance Characteristics

Other operating characteristics of the biomass steam generation resource includes ramp rate, minimum run times, minimum down times, and startup times. These characteristics are summarized for a 30 MW biomass steam generation resource in Table 4.3-3. The following assumptions and clarifications pertain to Table 4.3-3:

- Cold and warm start-up times assume the unit has been offline for more than 48 hours and 8 hours respectively and are from ignition to full steam turbine load.
- Ramp rates depicted are for normal unit operation from MECL to full plant load for a typical steam turbine generator.
- Minimum run times and down times are typical recommended run times for modeling purposes and may vary based on Owner operating preferences.

Table 4.3-3. Biomass Plant Miscellaneous Operating Characteristics

		30 MW Biomass
Ramp rate	MW/min	2
Minimum run time	minutes	240
Minimum down time	minutes	60
Start-up time to full load at warm start	minutes	240
Start-up time to full load at cold start	minutes	720

Startup fuel consumption for warm and cold starts has been estimated based on the startup times in Table 4.3-3. Table 4.3-4 summarizes estimated startup fuel, per start. Natural gas or oil is typically used for startup fuel.

Table 4.3-3. Biomass Plant Startup Fuel Requirements

Startup Fuel Consumption, per start		30 MW Biomass
Cold start fuel	MMBtu/start	2,050
Warm start fuel	MMBtu/start	683

4.4 Reliability, Availability, & Maintenance Intervals

Plant degradation for a biomass plant consists primarily of degradation from the bottoming cycle, including the steam turbine generator performance. Expected average, life of plant degraded performance is summarized in Table 4.4-1 for a 30 MW biomass steam plant. The average life of plant performance is estimated based on typical industry degradation and outage intervals that will be experienced between maintenance cycles based on a 60,000 hour steam turbine overhaul schedule and the plant dispatch and capacity factors identified Table 2.3-4

Table 4.4-1. 30 MW Biomass Plant Average Life of Plant Degraded Plant Performance

Degraded Thermal Cycle Performance		30 MW Biomass
Summer 100%		
Net Output	kW	29,985
Net Heat Rate (HHV)	Btu/kWh	13,887
Average 100%		
Net Output	kW	30,363
Net Heat Rate (HHV)	Btu/kWh	13,731
Winter 100%		
Net Output	kW	30,527
Net Heat Rate (HHV)	Btu/kWh	13,673

To address reliability and availability for a biomass steam generation plant, forced outage rates, planned outage rates, and mean average outage duration is summarized in Table 4.4-2. Plant forced outage rates are based on typical industry component forced outage rates. Componentes were generally broken down as and include the steam generator/boiler, STG, AQCS, and balance of plant equipment. Planned outage rates assume a 14 day annual outage most years and a longer 56 day outage corresponding with a steam turbine overhaul every 60,000 operating hours.

Table 4.4-2. 30 MW Biomass Plant Plant Availbility/Reliability

Availability/Reliability		30 MW Biomass
Forced Outage Rate		3.07%
Planned Outage Rate		6.03%
Mean Annual Outage Duration	days	22

4.5 Environmental Considerations

4.5.1 Emissions

The expected emissions for the 30 MW biomass plant after all applicable emissions control equipment are depicted in Table 4.5-1. It is expected that the plant would utilize selective non-catalytic reduction (SNCR) for the mitigation of NO_x emissions and a boiler bed limestone injection for the mitigation SO_2 emissions as required. A baghouse is included for control of particulate emissions. The emissions presented here are based on the biomass fuel composition described in section 2. Actual emissions can vary depending on the final composition of the biomass fuel selected.

Figure 4.5-1. 30 MW Biomass Emissions

Plant Emissions		30 MW Biomass
Plant Heat Input (Summer), HHV	**mmbtu/hr**	409
Plant Net Output (Summer)	**MW**	30
NOx	**lb/mmbtu**	0.0290
	lb/MWH	0.396
Particulate Matter PM10 Total	**lb/mmbtu**	0.0540
	lb/MWH	0.737
SO2	**lb/mmbtu**	0.0320
	lb/MWH	0.437
CO	**lb/mmbtu**	0.30
	lb/MWH	4.096
VOC	**lb/mmbtu**	0.0351
	lb/MWH	0.480
CO2	**lb/mmbtu**	213
	lb/MWH	2904

4.5.2 Water Consumption / Wastewater Discharge

The main water user for the 30 MW biomass plant considered in this analysis is the wet cooling tower used to supply cooling water to the condenser. The plant will also require a certain amount of makeup water to supplement flow lost in the steam drum blow down. Expected makeup and discharge water flows for the plant are summarized in Table 4.5-2.

Table 4.5-2. Biomass Plant Water Consumption

Water Consumption		30 MW Biomass
Summer		
Total Water Consumption	gal/MWH	851
Waste Water Discharge	gal/MWH	170
Average		
Total Water Consumption	gal/MWH	650
Waste Water Discharge	gal/MWH	130

4.6 Land Requirements

Land requirements for a biomass steam generating technology are summarized in Table 4.6-1. The land requirements represent the area within the plant fence and assume utility interconnections for fuel, electrical transmission, water, and wastewater discharge occur at the site boundary.

Table 4.6-1. 30 MW Biomass Plant Land Requirements

	30 MW Biomass
Length, ft	740
Width, ft	560
Area, Acres	9.5

4.7 Project Cost

Table 4.7-1 summarizes the estimated total project costs for a 30 MW biomass steam plant. The breakdown of estimated EPC cost and estimated Owner's costs are also shown for reference. The calculated standard deviation from the total overnight plant cost and the estimated end of plant life decommissioning costs are also referenced.

Table 4.7-1. Biomass Plant EPC and Owner's Costs

Project Costs (2018 US $)		30 MW Biomass
Total Plant Cost	$1,000	$ 180,199
Total Plant Cost	$/kW	$ 5,935
EPC Plant Cost	$1,000	$ 155,511
Owner's Cost	$1,000	$ 24,688
Std Deviation from Total Plant Costs	$/kW	$ 1,599
End of Life Decomissioning Costs	$1,000	$ 4,166

Total plant cost ($/kW) values are based on the plant new and clean net average day output.

4.8 Implementation Schedule

The estimated project schedules for a 30 MW biomass steam generating plant are based upon current day contracting approaches and methodologies. Similar to the natural gas resource options, it is expected that a significant portion of preliminary engineering and equipment sourcing activities are completed prior to the FNTP of the project. A 30 MW CFB biomass plant can be expected to take 3 to 4 years to construct from the time of EPC notice to proceed to the final commercial operation date. Figure 4.8-1 below depicts a typical implementation schedule and depicts the major milestones of the project from NTP to COD.

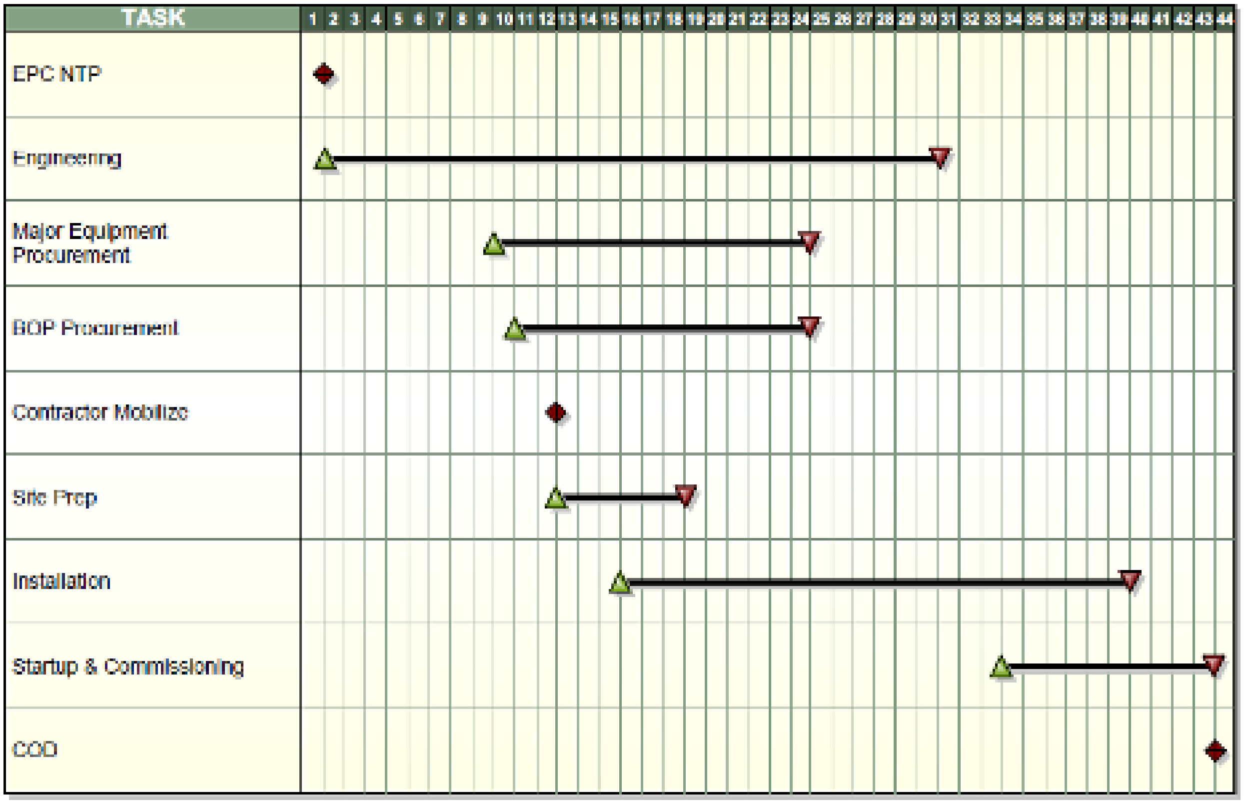

Figure 4.8-1. 30 MW Biomass Conceptual Project Schedule.

4.9 Operating Costs

The estimate fixed and variable O&M costs for a 30 MW biomass plant is summarized in Table 4.9-1. A base load dispatch profile has been assumed.

Operation and maintenance costs are also inclusive of steam generator, steam turbine, HRSG, and balance of plant equipment costs, spare parts inventory, and other consumable costs including aqueous ammonia, water makeup, and water discharge. Startup fuel is not included.

Staffing requirements to maintain full time operation of the facility have been developed for a 30 MW biomass power plant is estimated to include:

- Nine (9) salaried staff
- Nineteen (19) hourly staff

Table 4.9-1 Fixed and Variable Operating Costs

Operating Costs, 2018 $, Degraded		30 MW Biomass
Summer		
Fixed O&M	$/kW-yr	111
Variable O&M	$/MWH	5.28

Additional detail and breakdown of O&M costs are included in the modeling input tabs in Appendix E.

5 Geothermal Generation Resource

Geothermal Power is similar to other turbine power stations in that heat from a fuel source is used to heat water or another working fluid. The working fluid is then used to turn a turbine. For Geothermal Power the heat is from the thermal energy stored in the Earth's crust. High temperature thermal reservoirs are the most beneficial for utility-scale electricity production, but are geologically limited to locations where geothermal pressure reserves are found. For the purpose of this study, a 30 MW geothermal flash plant was assumed viable in the Pacific Northwest. The characteristics of the geothermal generation technology evaluated are further defined as follows:

30 MW Geothermal Plant

- Flash Steam Plant Evaluated
- Wet mechanical draft cooling tower with surface condenser

5.1 Technology Overview

Geothermal energy consists of the thermal energy stored in the Earth's crust. Reservoirs of geothermal energy are generally classified as being either low temperature (<300°F) or high temperature (>300°F). Figures 5.1-1 and 5.1-2 provide geothermal maps that estimate the geothermal fluid temperatures at 3 km and 6 km depth.

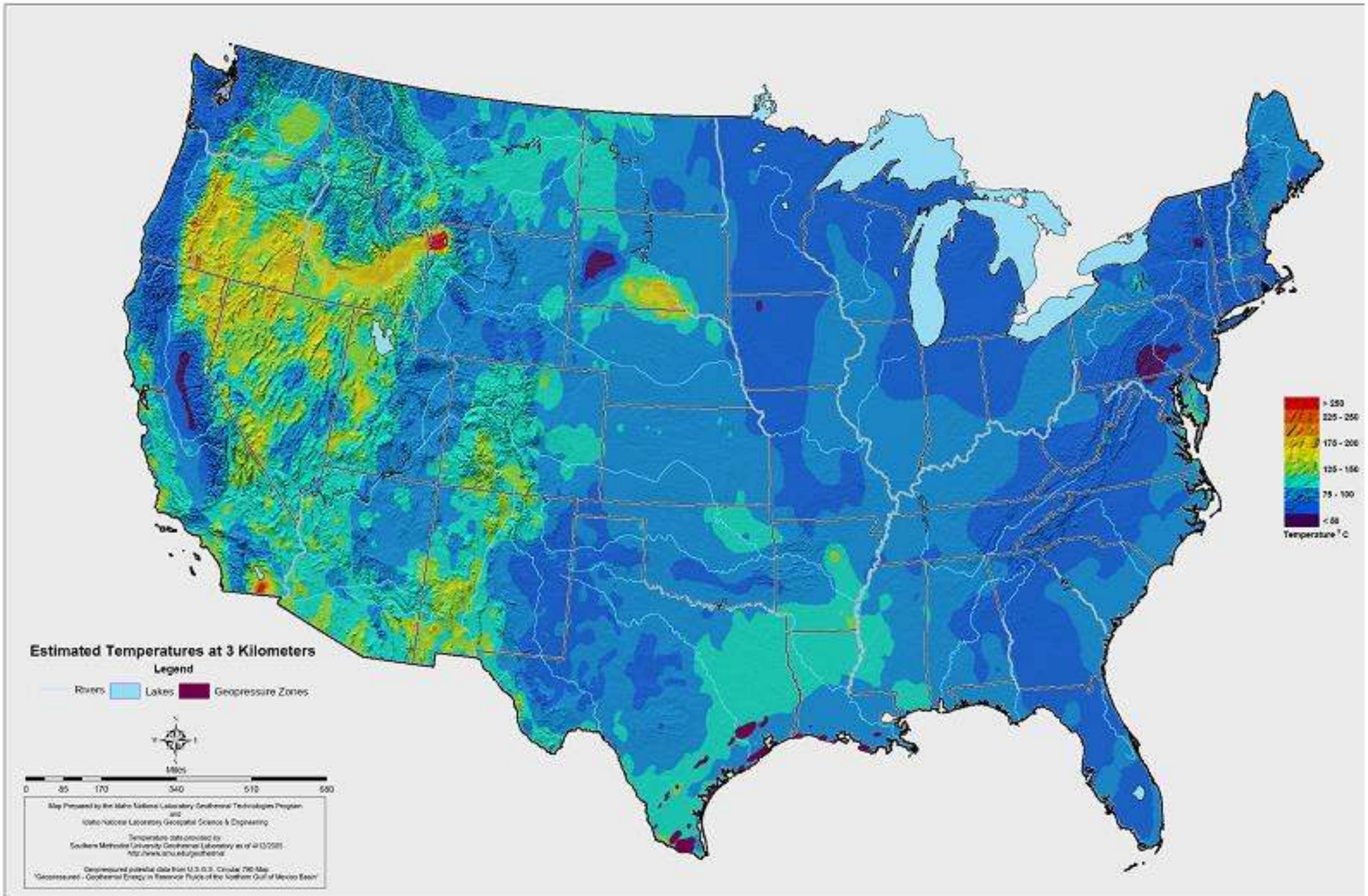

Figure 5.1-1. US Geothermal Map Estimating Earth Temperature at 3 kilometers.

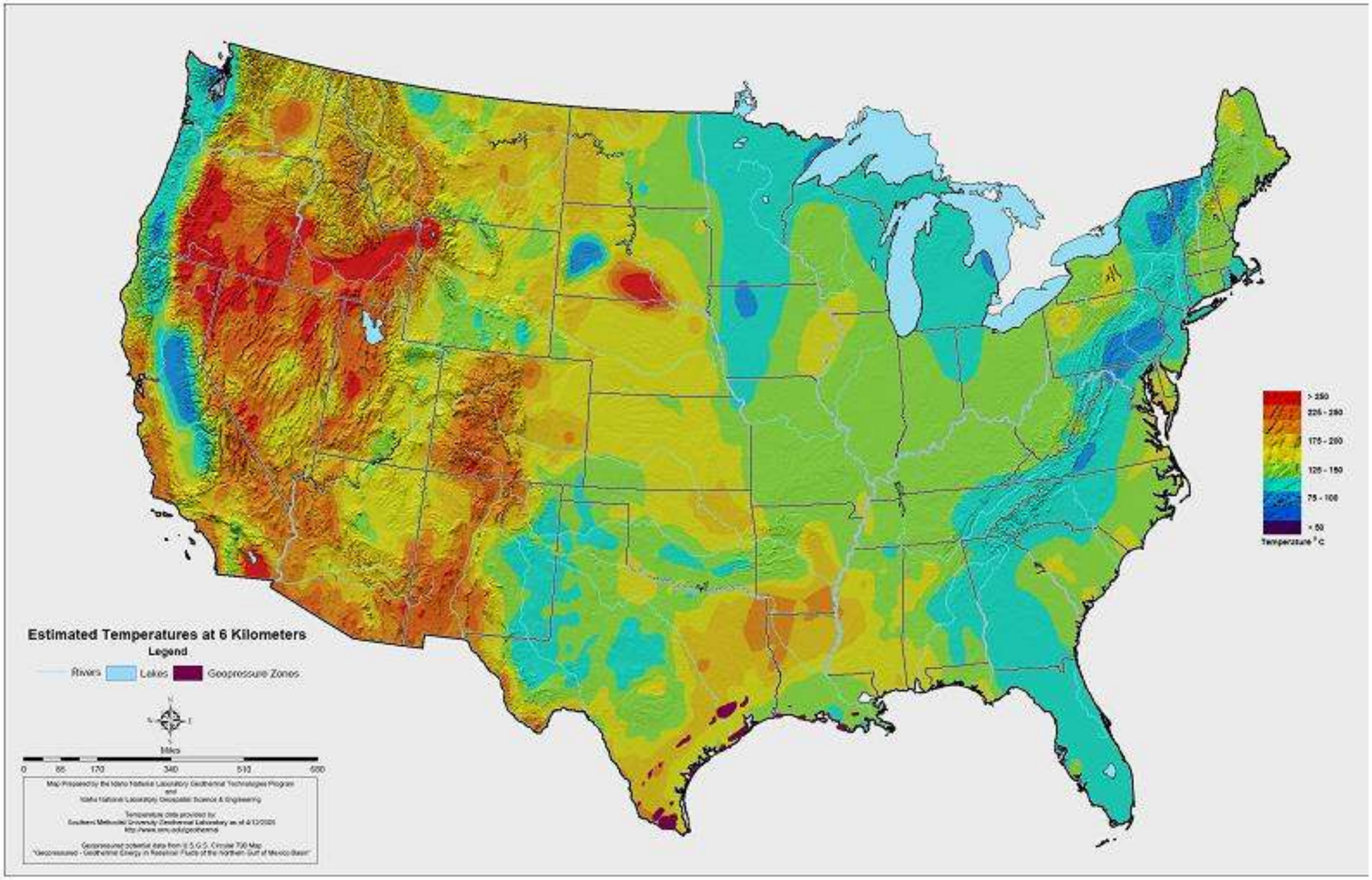

Figure 5.1-2. US Geothermal Map Estimating Earth Temperature at 6 kilometers.

High temperature reservoirs are the most beneficial for commercial production of electricity. Currently, three types of geothermal power plants are commercially developed: dry steam, flash steam, and the binary cycle.

Dry steam power plants were the first type of geothermal technologies designed and implemented. Dry steam power plants extract steam from geothermal reservoirs within the Earth's crust where it is piped directly into a steam turbine generator for electric power production. The steam turbine exhaust flow is condensed and injected back into the geothermal reservoir to be reheated.

Flash steam geothermal power plants utilize hot water from geothermal reservoirs that flows up through wells within the Earth's crust under its own pressure. Temperatures of hot water from the flash steam reservoirs are typically greater than 360°F. The free flowing, hot, pressurized water flows upward, decreasing in pressure until some of the hot water boils into steam. The steam is separated from the water and expanded through a steam turbine generator for electric power production. The steam is then condensed and mixed with the hot water that did not flash and is injected back into the reservoir to regain heat energy, completing this cyclical sustainable resource. Flash steam power plants also install pumps where necessary to pump the hot water out of the Earth's surface. Once reaching the surface, the hot water pressure is suddenly reduced allowing some of the water to flash into steam. Flash steam power plants are the most common geothermal power plants.

Binary cycle power plants also utilize water from the Earth's crust similar to flash steam power plants. However, the water temperatures are considerably lower than water used for flash steam plants. Typical water temperatures range from 225°F to 360°F. Binary cycle plants implement a non-contact heat exchanger to extract heat from the hot water to vaporize the working fluid (usually an organic compound with a low boiling point). Once the working fluid is vaporized it is expanded through a turbine. The water is then injected back into the ground to be reheated. Binary cycle geothermal power plants are more efficient than flash steam geothermal plants.

5.2 Commercial Status and Current Market

Geothermal power plants are well proven and commercially available technologies for power generation. There has been vast implementation of geothermal power facilities throughout the world. Long-term sustainable geothermal power production has been demonstrated at the Lardarello field in Italy since 1913, at the Wairakei field in New Zealand since 1958, and at The Geysers field in California since 1960.

Geothermal heat extraction is similar to extraction processes utilized for the oil and gas, coal, and mining industries. Equipment, knowledge and techniques have been adapted and implemented for use in geothermal development taken from the industries mentioned above, therefore the equipment and technology exists commercially to drill into geothermal reservoirs or permeable rock.

Currently there is approximately 14 GW of installed geothermal capacity globally with an estimated 18 GW of capacity that will be installed by 2021. Of the different types of technologies typically utilized, flash technology represents approximately 60 percent of the installed capacity, dry steam technology represents 25 percent of the installed capacity, and binary cycle plant technology is utilized in the remaining plants[7].

5.3 Operational Considerations

Geothermal power stations have much in common with traditional power generating stations. They use many of the same components, including turbines, generators, transformers, and other standard power generating equipment, but also include a pumping and re-injection system.

The primary risk associated with geothermal power generation technology is the integrity of the geothermal energy source and of the geothermal wells constructed for the recovery of this energy. The longevity of a geothermal facility is primarily a function of the geothermal energy source. Some installations may require the drilling of additional wells over the life of the project to continue the supply of energy.

5.3.1 Performance Data

Overall estimated new and clean net plant output is depicted for a 30 MW geothermal plant in Table 5.3-1 at average day conditions.

Table 5.3-1. New and Clean 30 MW Geothermal Plant Performance

Thermal Cycle Performance		30 MW Geo-thermal
Average 100%		
Net Output	kW	30,000
Net Heat Rate (HHV)	Btu/kWh	NA

Table 5.3-2 summarizes the expected plant performance at turn down from 100% to minimum plant load.

[7] 2016 US & Global Geothermal Power Production Report, Geothermal Energy Association

Table 5.3-2. 30 MW Geothermal Plant ISO Part Load Performance, Average Life of Plant Degraded

Degraded Thermal Cycle Performance		30 MW Geo-thermal
ISO 100%		
Net Output	kW	22,787
Net Heat Rate (HHV)	Btu/kWh	NA
ISO 75%		
Net Output	kW	17,090
Net Heat Rate (HHV)	Btu/kWh	NA
ISO MECL		
Net Output	kW	7,500
Net Heat Rate (HHV)	Btu/kWh	NA

5.3.2 Other performance Characteristics

Other operating characteristics include ramp rate, minimum run times, minimum down times, and startup times. These parameters are summarized for a 30 MW geothermal plant in Table 5.3-3.

- Cold and warm start-up times assume the unit has been offline for more than 48 hours and 8 hours respectively and are reflective of a typical steam turbine and steam generator ramp rate profile for these conditions.
- Ramp rates depicted are for normal unit operation from MECL to full plant load for a typical steam turbine generator.
- Minimum run times and down ties are typical recommended run times for modeling purposes and may vary based on Owner operating preferences.

Table 5.3-3. Biomass Plant Miscellaneous Operating Characteristics.

		30 MW Geo-thermal
Ramp rate	MW/min	2
Minimum run time	minutes	240
Minimum down time	minutes	60
Start-up time to full load at warm start	minutes	60
Start-up time to full load at cold start	minutes	420

5.4 Reliability, Availability, & Maintenance Intervals

Plant degradation for a geothermal plant consists primarily of loss in well production over time, scaling that may occur within equipment from the geothermal fluid deposits, and degradation from the bottoming cycle, including the steam turbine generator performance. Expected average, life of plant degraded performance is summarize in Table 5.4-1 for a 30 MW geothermal plant based on an estimated well head performance degradation over time and variation in well head production annually. No new wells are assumed to be developed over the project life or water injected into wells to replenish the wells. Consistency of well head production for geothermal projects can vary from site to site.

Table 5.4-1. 30 MW Geothermal Plant Average Life of Plant Degraded Plant Performance

Degraded Thermal Cycle Performance		30 MW Geo-thermal
Average 100%		
Net Output	kW	23
Net Heat Rate (HHV)	Btu/kWh	NA

To address reliability and availability for a geothermal generation plant, forced outage rates, planned outage rates, and mean average outage duration is summarized in Table 5.4-2. Plant forced outage rates are based on typical industry component forced outage rates for a steam plant. Forced outage rates and plant availability statistics for geothermal plants vary greatly and due to differences in maintenance practices and well head production. Components include the steam generator/boiler, STG, balance of plant equipment and well gathering field equipment. Plant forced outage rates, planned outage rates, and mean average outage duration is summarized in Table 5.4-2. Planned outage rates are based on a 14 day annual outage annually and a 56 day outage corresonding with a 60,000 hour steam turbine overhaul schedule for a base load facility.

Table 5.4-2. 30 MW Geothermal Plant Availbility/Reliability

Availability/Reliability		30 MW Geo-thermal
Forced Outage Rate		3.04%
Planned Outage Rate		4.93%
Mean Annual Outage Duration	days	18.0

5.5 Environmental Considerations

5.5.1 Emissions

There are negligible air emissions for the proposed geothermal power plant.

5.5.2 Water Consumption / Wastewater Discharge

Flash steam plants typically use wet mechanical draft cooling towers for heat rejection from the condenser of the steam turbine generator and other balance of plant systems. The makeup water to the cooling tower typically is assumed to be supplied from the geothermal wells and therefore external water requirements are expected to be minimal. Cooling tower blowdown is assumed to be injected into the geothermal reinjection wells.

5.6 Land Requirement

Land requirements for a 30 MW geothermal plant are summarized in Table 5.6-1 and include the wells (and required spacing), gathering field, and power plant. Land well field area is assumed to be approximately 225 acres per well and includes production wells, injection wells, and an allowance for failed wells and exploratory drilling. Total well count is approximately 13 to 14. The actual geothermal power plant land requirement is expected to be 5 to 10 acres. All land is assumed to be purchased and is included in the Owner's costs.

Table 5.6-1. 30 MW Geothermal Land Requirements

	30 MW Geo-thermal
Length, ft	-
Width, ft	-
Area, Acres	3,000

5.7 Capital Cost

Table 5.7-1 summarizes the estimated total project costs for a 30 MW geothermal plant. The breakdown of estimated EPC cost and estimated Owner's costs are also shown for reference.

Approximately 39 million dollars (2018$) for well field development prior to FNTP is also included in the Owner's costs. These well field development costs should not be used in the draw down schedule provided in Appendix D.

The calculated standard deviation from the total overnight plant cost and the estimated end of plant life decommissioning costs are also referenced.

Table 5.7-1. Geothermal Plant Project Costs

Project Costs (2018 US $)		30 MW Geo-thermal	
Total Plant Cost	$1,000	$	186,927
Total Plant Cost	$/kW	$	6,216
EPC Plant Cost	$1,000	$	116,751
Owner's Cost	$1,000	$	70,176
Std Deviation from Total Plant Costs	$/kW	$	1,215
End of Life Decomissioning Costs	$1,000	$	1,862

Total plant cost ($/kW) values are based on the plant new and clean net average day output.

5.8 Implementation Schedule

The estimated project schedule for a geothermal generating resource option is based upon current day contracting approaches and methodologies. Geothermal power plants typically have a timeline of 3 years from a notice to proceed for drilling and equipment and construction contracts through Commercial Operation. The steam turbine generator would be the piece of equipment with the longest lead time estimated to be approximately 20 months. In the past, the main issue of concern for implementing a geothermal power plant has been the difficulty in permitting and leasing geothermal lands, which can lead to long development timeframes prior to project notice to proceed (two to three years or more can be expected). Figure 5.8-1 summarizes a typical project implementation schedule for a 30 MW geothermal installation from NTP to COD. The schedule assumes the bidding of major equipment and of the EPC contract with some level of limited notice to proceed awarded for these contracts prior to an FNTP.

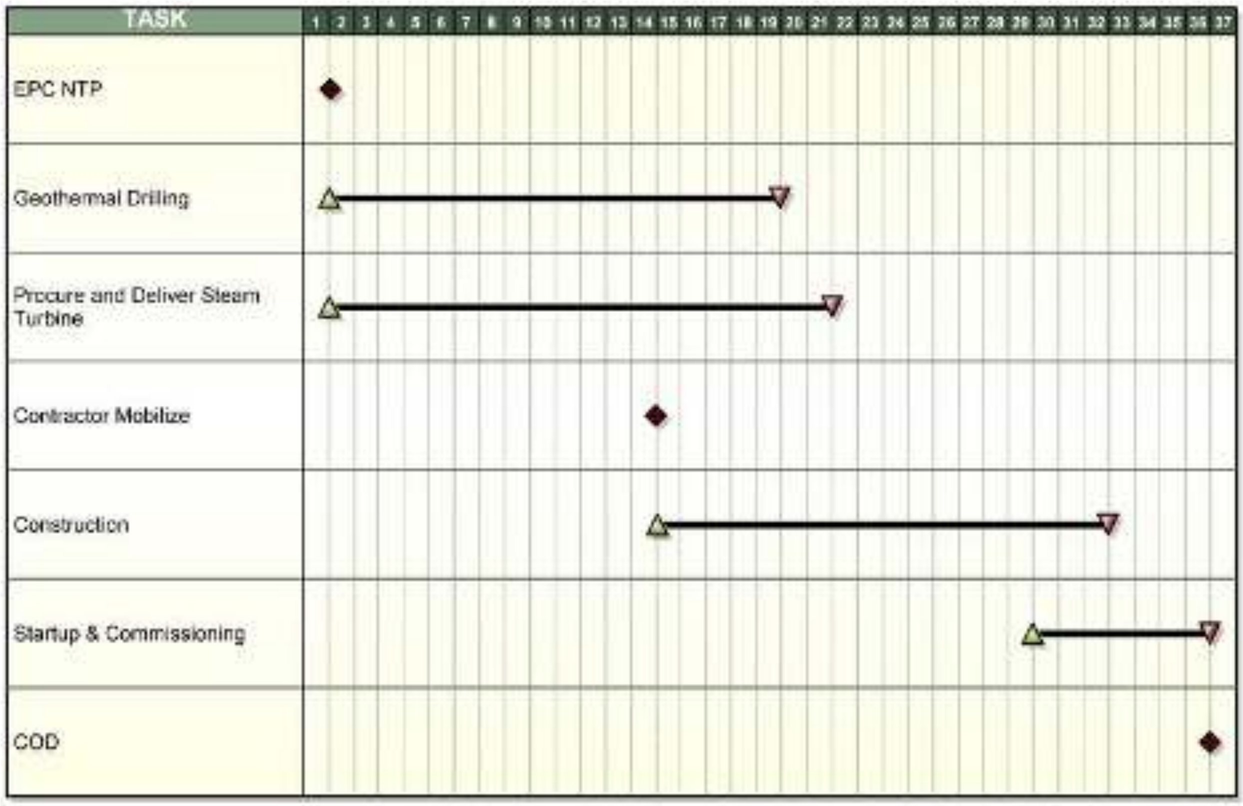

Figure 5.8-1. Geothermal Conceptual Project Schedule

5.9 Operating Costs

The estimate fixed and variable O&M costs for a 30 MW geothermal plant are summarized in Table 5.9-1. A base load dispatch profile has been assumed. Land is assumed to be purchased and is included in Owner's costs.

Staffing requirements to maintain full time operation of the facility have been developed for a 30 MW geothermal power plant and are estimated to include:

- Nine (9) salaried staff
- Nineteen (19) hourly staff

Operating and maintenance costs also include steam turbine, boiler/flash plant, and balance of plant maintenance as well as well and gathering field maintenance costs.

Table 5.9-1 Geothermal Fixed and Variable Operating Costs

Operating Costs, 2018 $, Degraded		30 MW Geo-thermal
Summer		
Fixed O&M	$/kW	120
Variable O&M	$/MWH	2.39

Additional detail and breakdown of O&M costs are included in the modeling input tabs in Appendix E.

6 Pumped Hydro Energy Storage Resource

Pumped hydro is an energy storage technology that mimics the operation of a hydroelectric power plant. A typical station consists of two reservoirs separated in elevation. At times of high energy demand when excess energy is needed, water is released from the upper reservoir through a turbine to produce electric. At night or during other periods of low electric demand, cheaper off peak electricity is supplied to pump water back from the lower reservoir to the high reservoir. Pumped hydro storage facilities can achieve maximum outputs greater than 2,000 MW.

The following attributes characterize the pumped hydro energy storage project considered:

<u>1,200 MW Pumped Hydro Energy Storage (PHES)</u>

- 3 x 400 MW nominal, variable speed, closed loop system evaluated
- 8 Hour discharge duration / reservoir storage capacity
- Average Static Head: 2,900 ft.

6.1 Technology Overview

Pumped hydro stations generate electricity by releasing water from a reservoir at a high elevation to flow downward through a water turbine into another reservoir. These plants differ from conventional hydroelectric plants in that the process can be reversed and the water pumped back to the higher elevation reservoir and stored to be released at a later time. In most pumped hydro installations these two processes are accomplished by a single reversible pump-turbine which can both generate electricity when operating as a turbine and also pump water when electricity is fed to the generator and the turbine is used as a pump. Modern pumped hydro facilities take advantage of variable speed pump-turbines to give the operators greater dispatch flexibility. Overall, pumped hydro facilities are net consumers of electricity. In other words it requires more electricity to pump the water up to the higher reservoir than is generated when the water is released to produce electricity. This is due to net process losses and auxiliary loads that are required for the operation of the plant in lieu of generating resources. For this reason, pumped hydro facilities are considered to be energy storage assets. Pumped hydro facilities require the presence of either natural occurring or man-made bodies of water. These water bodies are generally very large.

6.2 Commercial Status and Current Market

Pumped hydro storage is the most mature energy storage technology in today's power industry market. The first U.S. pumped-storage plant was developed in the 1920s to balance loads from fossil fuel plants within a very nascent grid. A typical pumped storage plant is designed for more than 50 years of service life, but many projects that were constructed in the 1920's and 1930's are still operational today. The lifecycle of pumped hydro facility is comparable to that of a traditional hydroelectric facility. Similar to other rotating power technologies, a generator-motor rewind or upgrade can be expected after approximately 20 years of service, with the pump-turbine equipment lasting for a longer period of time with routine maintenance. Today, there are approximately 40 pumped storage projects operating in the United States that provide more than 20 GW of capacity[8].

6.3 Operational Considerations

6.3.1 Performance Data

The performance and operating characteristics for a 1,200 MW closed loop, variable speed pumped hydro facility are presented in Table 6.3-1.

Table 6.3-1. 1,200 MW Pumped Hydro Performance Characteristics

1200 MW Pumped Hydro Performance and Operational Characteristics		
Capacity	MW	1200
Storage Duration	hrs	8
Average Storage Head	ft.	2,900
Number of Turbine/Pump Units		3
Average Plant Turnaround Efficiency		80%
Generation Mode (per unit)		
At minimum head		
Min MW		183
Max MW		366
At maximum head		
Min MW		111
Max MW		400
Pumping Mode (per unit)		
At minimum head		
Min MW		354
Max MW		517
At maximum head		
Min MW		401
Max MW		517

8 Energy Storage Association, www.energystorage.org

6.3.2 Other performance Characteristics

Other operating characteristics of a modern, variable speed pumped hydro energy storage, including ramp rate, minimum run times and minimum down times, and startup times are summarized in Table 6.3-2.

Table 6.3-2. 1,200 MW Pumped Hydro Plant Miscellaneous Operating Characteristics.

		1200 MW Pumped Hydro (1 Unit)
Ramp rate	MW/min	255
Minimum run time	minutes	0
Minimum down time	minutes	0
Start-up time to full load at warm start	minutes	2
Start-up time to full load at cold start	minutes	2

Typical time for a modern plant to switch between pumping and generation modes of operation is also approximately 3 minutes.

6.4 Reliability, Availability, & Maintenance Intervals

Estimated plant forced outage rates, planned outage rates, and mean average outage duration are summarized in Table 6.4-1 for a single 400 MW unit of the 1,200 MW pumped hydro storage plant.

Table 6.4-1. 1,200 MW Pumped Hydro Storage Plant Availbility/Reliability

Availability/Reliability		1200 MW Pumped Hydro (1 Unit)
Forced Outage Rate		1.00%
Planned Outage Rate		3.84%
Mean Annual Outage Duration	days	14

6.5 Environmental Considerations

6.5.1 Emissions

Pumped hydroelectric energy storage facilities generally have no associated air, water, or solid byproduct discharges or emissions.

6.5.2 Water Consumption / Wastewater Discharge

No makeup water costs for pumped energy storage have been included in this analysis. There is also no discharge water.

6.6 Land Requirement

Land costs for a pumped hydro storage plant must include both the upper and lower resevoirs as well as the upper and lower connecting tunnels. For a 1200 MW nonminal project with 8 hours of storage, or roughly 4,800 acre-ft of water storage capacity, total land requirements are estimated at approximately 1000 acres. The land purchase costs are included as part of the Owner's costs in the project costs.

6.7 Capital Cost

Table 6.7-1 presents the estimated total project costs for a 1,200 MW pumped hydro storage plant with 8 hours of storage capacity. Estimated EPC cost and estimated Owner's costs are broken out from total project costs for reference. Owner's costs for pumped hydro storage are estimated at approximately 20 percent of total project costs as development costs are typically higher and with longer timeframes.

The calculated standard deviation from the total overnight plant cost and the end of plant life decommissioning costs are also referenced.

Table 6.7-1. 1,200 MW Pumped Hydro Storage Costs

Project Costs (2018 US $)		1200 MW Pumped Hydro
Total Plant Cost	$1,000	$ 2,701,984
Total Plant Cost	$/kW	$ 2,252
EPC Plant Cost	$1,000	$ 2,160,000
Owner's Cost	$1,000	$ 541,984
Std Deviation from Total Plant Costs	$/kW	$ 587
End of Life Decomissioning Costs	$1,000	$ 25,870

Total plant cost ($/kW) values are based on the plant new and clean net average day output.

6.8 Schedule

The schedule for the development and construction of a pumped hydro energy storage plant can vary considerably depending on a number of factors, including the amount of civil work required to construct the water storage basins and the permitting required to implement the project. Based on historical information, the total construction time from receipt of Federal Energy Regulatory Commission (FERC) license to commercial operation can be anywhere from 5 years to 8 years for projects similar to that evaluated herein.

6.9 Operating Costs

The estimate fixed and variable O&M costs for a 1200 MW pumped hydro plant are summarized in Table 6.7-1. Operating costs do not include electric purchases during pumping. Pumping costs are determined by dividing the dispatched plant load by the average plant turnaround efficiency of 80% and multiplying by the cost of electricity.

Staffing requirements to maintain full time operation of the facility is estimated to include:

- Six (6) salaried staff

- Twenty-eight (28) hourly staff.

O&M costs are inclusive of turbine, generator, and balance of plant and facility routine maintenance and major overhaul costs. Land purchases are included as part of Owner's costs in the project costs.

Table 6.7-1. Pumped Hydro Storage Fixed and Variable Operating Costs

Operating Costs, 2018 $, Degraded		**1200 MW Pumped Hydro**
Summer		
Fixed O&M	$/kW	11.3
Variable O&M	$/MWH	0.372

Appendices

RENEWABLES AND BATTERY OPTIONS

Supply Side Resource Plants

HDR Project #10108345

Portland General Electric

October 10, 2018

RENEWABLES AND BATTERY SUPPLY SIDE OPTIONS

SUPPLY SIDE RESOURCE PLANTS

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APPENDICES

Executive Summary

Portland General Electric (PGE) is preparing its 2019 integrated resource plan (IRP) and is evaluating several supply-side resources including thermal, renewable, and storage technologies. HDR Engineering, Inc. (HDR) was retained by PGE to assist with the overall 2019 IRP effort by characterizing the operational and cost attributes of various power generation technologies. HDR provides consulting, design, and Owner's engineering services for all aspects of power generation, including thermal, hydro, renewable, and energy storage projects. The parameters developed for each technology include estimated performance and operating characteristics, capital costs, operating costs, and implementation schedules. The range of technologies considered included wind generation, solar photovoltaic, and lithium-ion battery energy storage. The resulting parameters for the various technologies are summarized in Table E-1 for representative project sites within the PGE's service territory and surrounding regions. The following summarizes the basis for development of the parameters for each of the technologies:

1. Performance has been estimated for all options based on supplier feedback, performance estimating software, or Vaisala (a wind performance estimating sub-consultant).
2. Conceptual level project capital costs have been developed based on an overnight, turnkey engineer, procure, and construct (EPC) delivery in 2018$.
3. End of life decommissioning, net of salvage value, were estimated.
4. Technology maturity / cost forecasts were projected.
5. Conceptual level operations and maintenance (O&M) costs, including both fixed and variable O&M, were estimated and are presented in $/kW-yr and $/MWh, respectively.
6. Conceptual level project implementation schedules identifying key project milestones and duration of key project activities from EPC contractor notice to proceed (NTP) to the commercial operation date (COD) of the facility are presented.
7. Capital drawdown schedules were developed.
8. Input parameters for dispatch modeling were derived from the O&M costs and various operating characteristics developed for each option.

Additional details and results regarding the development of the generating resource characteristics are further summarized in this report. The information developed for the IRP activities are intended to represent the current energy industry landscape and are based on supplier-, site-, and project-generic technologies. Technology attributes are suitable for comparative purposes, should not be used for budget planning purposes, and are subject to refinement based on further evaluation and review.

Table E-1. Summary of Technology Attributes.

	Unit Type	100 MWa, Ione Oregon	100 MWa, Columbia Gorge	100 MWa, SE Washington	100 MWa, Loco Mountain Montana	25 MWa, Single-axis Tracking, Christmas Valley Oregon	Li-On Battery - 2 Hour	Li-On Battery - 4 Hour	Li-On Battery - 6 Hour
Plant Capacity	MW	306	245	234	234	95	100	100	100
Capital Cost	$/kW	$1,508	$1,539	$1,531	$1,520	$1,510	$916	$1,554	$1,902
Capital Cost (Batteries)	$/kW-hr	-	-	-	-	-	$458	$388	$317
Capacity Factor	(%)	32.7%	40.8%	42.9%	42.9%	24.8%	Daily Dispatch	Daily Dispatch	Daily Dispatch
Fixed O&M	$/kW-yr	$37.0	$37.0	$37.0	$37.0	$21.9	$23.5	$31.1	$42.6
Variable O&M	$/MWH	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
Land Lease[1]	$/MWH	1.70	1.70	1.70	1.70	4.22	-	-	-
Project Schedule	months	29	27	27	27	13	18	18	18

1

[1] Battery options assume $2310/acre annual land lease cost and is included in the Owner's costs/Capital costs.

1 Introduction

Portland General Electric (PGE) is preparing its 2019 integrated resource plan (IRP) and is evaluating several supply-side resources including thermal, renewable, and storage technologies. HDR Engineering, Inc. (HDR) was retained by PGE to characterize select renewable and battery energy storage system resources. The developed resource characteristics will be used by PGE for development of modeling inputs and assumptions to be used in its 2019 IRP development and dispatch models. These technology characteristics include estimated performance and operating attributes, capital costs, and operating costs for the various generating technologies. The technology options include several wind generation sites, a solar photovoltaic (PV) generation site, and lithium-ion battery energy storage systems (BESS). The following report summarizes the assumptions, calculations, and analyses to characterize the resource options and discusses current market conditions that may alter the accuracy of these inputs or the ability of PGE to implement the technologies considered in this study.

The following thermal and pumped hydro generating assets have been considered in this report:

1. Wind Generation – 100 MWa Annual Output
    a. Ione, Oregon
    b. Columbia River Gorge, Oregon
    c. Southeast Washington (Columbia County)
    d. Loco Mountain, Montana (near Colstrip Transmission Line in Meagher County)
2. Solar Photovoltaic (PV), Christmas Valley – 25 MWa Annual Output
3. Lithium-ion Battery Energy Storage System – 100 MW Capacity
    a. 2 hour storage duration
    b. 4 hour storage duration
    c. 6 hour storage duration

HDR has developed the following inputs for each of the generation options:

1. Plant Capacity and Performance
2. Operational Characterization
    a. Availability / Reliability
    b. Approximate Footprint
    c. Maintenance Cycle / Durations
    d. Technical Maturity
3. Plant Capital Costs
    a. Project Costs
    b. Owner's Costs
4. Project Schedule
5. Operations and Maintenance Costs
    a. Fixed Costs
    b. Variable Costs

The details and results of the plant characteristics developed by HDR are further discussed in the following sections of this report and are summarized in Appendix C.

2 Study Basis and Assumptions

The following basis was used for establishing performance, costs, and operating characteristics for the various generating resource options considered in this study.

2.1 Site Characteristics

The technology described in this report have been presented on the basis that installations are located in the Pacific Northwest at the following locations:

- Christmas Valley, Oregon (Solar PV)
- Ione, Oregon (Wind)
- Columbia River Gorge, Oregon (Wind)
- Southeastern Washington (Wind)
- Loco Mountain, Montana east of Rocky Mountains near Colstrip Transmission (Wind)

2.2 Plant Performance

2.2.1 Performance

Plant performance (i.e., output, efficiency, etc.) was estimated for all technologies based on performance estimating software, previous project developments, feedback from suppliers, and/or published performance information.

For the solar PV plant, performance was estimated using PVsyst software for a single axis tracking unit at the Christmas Valley, Oregon site.

Vaisala, a subconsultant to HDR, developed average annual wind energy production, historical wind resource, and generation profile data for all four wind sites. Historical wind data was obtained for a 38-year period and expected annual net generation was developed for a single wind turbine and then extrapolated to a 100 MW average (MWa) annual output.

Battery performance was estimated for expected round trip efficiencies for current lithium-ion battery technology based on recent project experience and industry and/or vendor specific data from similar projects.

2.3 Operations and Maintenance Cost Assumptions

For each technology considered, operating and maintenance (O&M) costs are presented and broken into fixed and variable costs as well as land lease/royalty costs. O&M costs are estimated based on a combination of previous HDR project experience and/or vendor information available.

While these costs vary from technology to technology, the fundamental breakdown between fixed and variable costs can be summarized as follows:

Fixed O&M: Fixed O&M costs are costs that are not generally dependent on the generation rate of the facility. These costs take into account plant operating and maintenance staff, fixed long term service agreement costs, and other fixed maintenance costs for equipment. Fixed staffing costs utilized in the analysis are defined below in Table 2.3-1. Typical plant staffing levels used for characterizing staffing costs are summarized in Table 2.3-2. No taxes, insurances, corporate general and administrative costs (G&A), or fixed transmission costs have been included.

Table 2.3-1. Fixed Staffing Costs.

Fixed Cost	Cost in 2018 $
Annual Cost for Salaried Staff	$140,000
Annual Cost for Hourly Staff	$100,000

Table 2.3-2. Plant Staffing Level Basis.

Staffing	Wind	Solar PV	BESS
Incremental Salaried Staff	3	1	0
Incremental Hourly Staff	2	2	0

Fixed costs developed for this evaluation are presented on a $/kW-yr basis computed by dividing the estimated fixed annual O&M costs by the net plant installed capacity or the average life of plant net degraded capacity where stated. Fixed O&M costs presented herein do not include costs associated with insurances, property taxes, or corporate general and administrative (G&A) costs.

Variable O&M: Variable O&M costs are those expenses that are dependent on electrical production/operation of a facility. Variable O&M costs include costs associated with consumption and disposal of materials associated with operation, as well as variable costs associated with operating facility equipment, such as major equipment maintenance and maintenance costs, including replacement material and components and outsourced labor to perform major equipment maintenance. Variable O&M costs are presented on a levelized annual $/MWh basis.

Land Lease/Royalty Costs: Land lease and royalty costs are those expenses associated with land leases and royalty payment fees that are often associated with renewable generation projects. Land lease payments go to the developer and are often based on a fixed annual cost or a variable cost based on the annual generation and presented in $/MWh. Royalty payments are based on the annual generation and also presented in a $/MWh basis.

2.4 Capital Cost Basis & Uncertainty Basis

Total project capital costs were developed assuming an engineer, procure and construct (EPC) contracting basis and are presented in this report based upon a project full notice to proceed (FNTP) in 2018. These costs assume that each of the technologies considered will be installed within the Pacific Northwest or Montana region, depending on the site location. General adjustments to account for wage rate and productivity factors have been applied to the different project site locations to account for regional differences.

Total capital cost estimates are broken down into project capital and Owner's costs. Project capital costs include the following:

- The costs associated with the procurement of major equipment (equipment costs)
- Costs associated with assembly and construction labor (construction costs)
- Costs associated with the procurement and installation of commodities such as electrical infrastructure and foundations (materials and supplies costs)
- Costs associated with site development, access, and staging
- Project indirects
- Construction management
- Engineering
- Contingency
- EPC fees and insurance

Owner's costs have been developed as 10 percent of the project capital costs and generally include the following (unless otherwise noted within the report):

- Project management
- Engineering support
- Construction management
- Owner contingency
- Plant operations during commissioning
- Insurance during construction
- Initial spares
- Construction utilities
- Project development

The following additional general site assumptions have been used:

- Project location on a site/land generally suitable for development
- General adjustments for labor and wage rates based on location in Oregon, Washington, or Montana.
- Electric scope of supply up to the high side of the GSU transformer (costs associated with grid interconnection and network upgrades excluded)
- Sufficient space is available at the site for construction activities, including lay-down.
- No costs have been included for land purchases, transmission interconnect costs, escalation, interest during construction, or sales tax.

All project total capital costs that are expressed as $/kW values in this report are derived by dividing the project costs by the total net plant installed capacity.

All costs presented herein are based upon current day cost expectations and actual project data and quotations where available. They are intended to reflect the current status of the industry with respect to recent materials and labor escalation; however, due to the volatility of the power generation marketplace, actual project costs should be expected to vary. Each project cost summary provides an indication of estimated accuracy of the total project cost values based on an American Association of Cost Engineering International (AACE) Class 4 estimate. The expected standard deviation of the cost has been calculated based on the accuracy of the cost estimate. Estimate uncertainty is characterized further in Table 2.4-1, where low corresponds to a low range of estimation (or underestimation) and high corresponds to a high range of estimation (or overestimation).

Table 2.4-1. Estimate Uncertainty

Estimate Class	Accuracy Range	
	Low	High
Class 4	-15 to -30%	+20 to +50%

Decommissioning costs have also been estimated, net of salvage value, and assume the site will be restored back to a brownfield condition, which removes all material and structures down to 2 to 3 ft. below grade. Decommissioning costs are presented in 2018 US dollars and reflect HDR's opinion of current market conditions and salvage values and do not include escalation to the end of project life. These costs have been estimated based on similar project experience or as a percentage of capital costs. It is anticipated that the Li-ion cells will have salvageable value at the end of project life, and is expected to result in zero additional costs to Owner for removal from site and recycling.

2.5 Technology Maturity

As more experience is gained through the application of a power generation technology, the capital costs would be expected to decrease as the design, fabrication, and installation of a technology becomes more mature. To estimate the effects of maturity on a generation technology, and the potential reductions in plant capital costs over time, cost trends were developed using data from the Energy Information Administration's (EIA) 2017 Annual Energy Outlook (AEO) National Energy Modeling System (NEMS). Cost forecasting data from NEMS was applied to the estimated capital costs as a basis for forecasting future costs for each technology option evaluated. All costs are referenced in 2018 US dollars and are forecasted from 2018 to 2050. In most cases, the NEMS forecasted cost projections did not start until 2020, so costs were estimated to be unchanged from 2018 until the start of the NEMS forecast. Figure 2.5-1 summarizes the results of the estimated future project costs. Further details are included in Appendix A (note that wind technology costs are similar, but small variations can be seen in Appendix A). It is also noted that lithium-ion battery technology cost forecasts are based on the renewable energy diurnal storage technology cost forecast provided from NEMS.

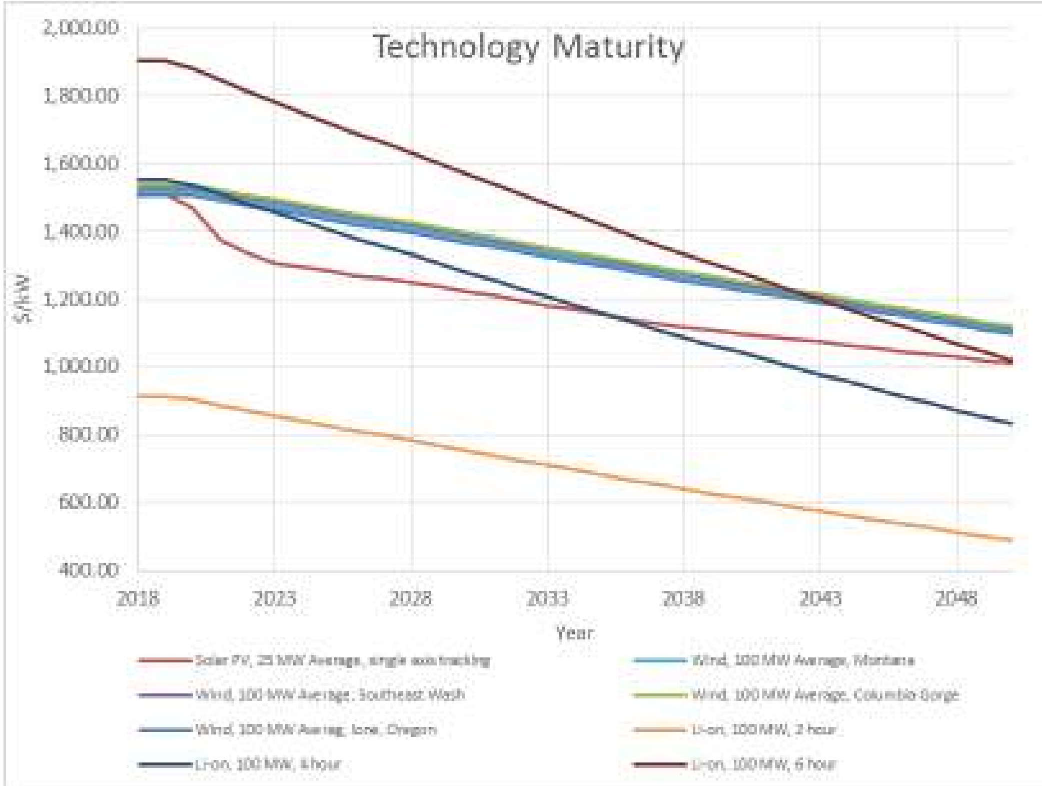

Figure 2.5-1. Technology Maturity Model

2.6 Project Schedule and Cash Flow Basis

The estimated project schedules presented herein are based upon current day EPC contracting approaches and methodologies. As such, it is expected that a portion of preliminary engineering and equipment sourcing activities are completed prior to the FNTP of the project. This will typically involve the procurement of the major equipment and the EPC contract assuming limited notice to proceed (LNTP) is awarded for these contracts prior to an FNTP.

While some project schedules estimated for this work include some developmental activities, the majority of the schedules and durations are generally presented from Full Notice to Proceed to the commercial operation date (COD) of the facility. It is expected that the permits will be received and project financing activities will be completed prior to the project FNTP.

For monthly cash flow determinations, a general project cash flow schedule has been utilized and adjusted as appropriate for each technology. A general representation of the curve is presented in Figure 2.6-1. Annual cash flow forecasts are provided for each technology from FNTP to the commercial operation date (COD) in Appendix B.

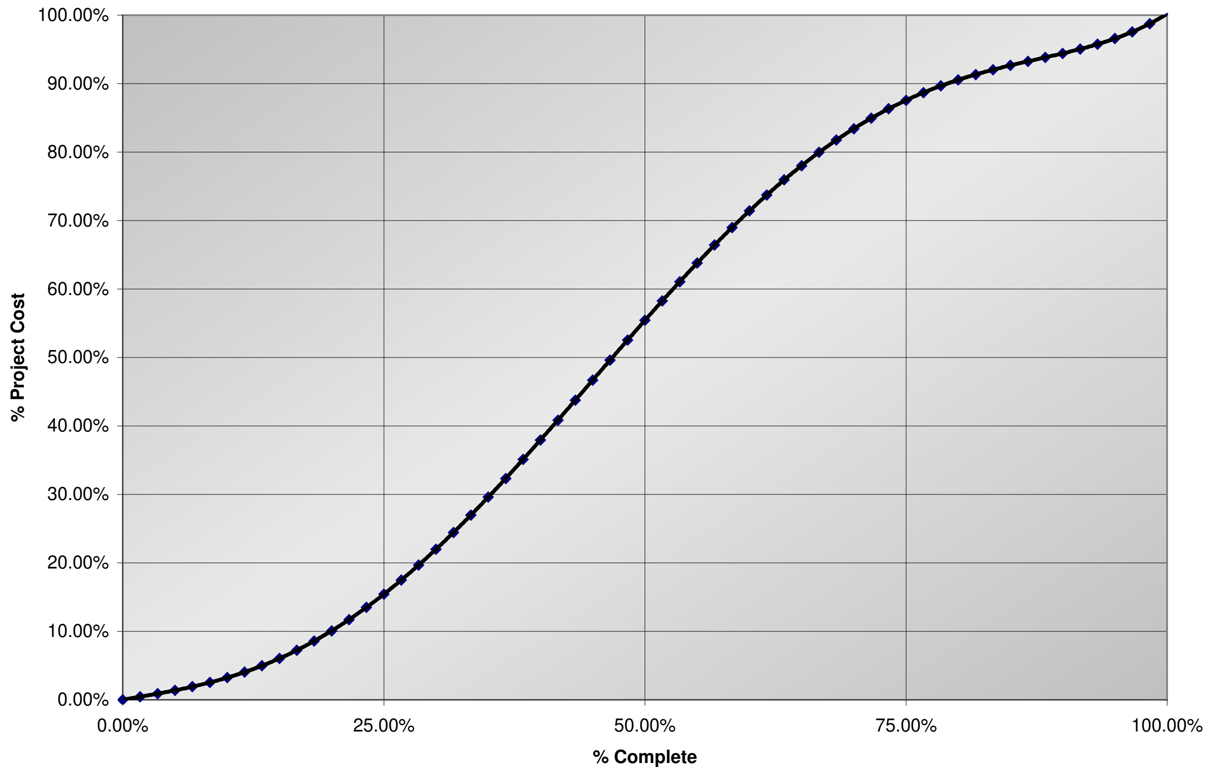

Figure 2.6-1. Representative Cash Flow Curve.

3 Wind Generation Technology

The U.S. is one of the largest and fastest-growing wind power generation markets in the world. In the last decade, there has been significant growth in wind capacity in the U.S. because of advancements in wind generation technology, federal tax incentives, and other policy incentives. Standalone wind is an intermittent power generation resource in that it is not fully dispatchable in the typical sense; however, output from wind installations can be curtailed when required.

Regional trends in the Pacific Northwest are consistent with trends across the U.S. According to the U.S. Department of Energy, wind energy production as a percentage of total electric generation is 11.2% for Oregon, 6.5% for Washington, and 7.6% in Montana[2]. For total wind installed capacity as of the end of 2017, Oregon has installed 3,213 MW, Washington has installed 3,075 MW and Montana has installed 695 MW[3]. During 2017, five wind projects totaling 50 MW achieved commercial operation in Oregon. No wind projects achieved commercial operation in 2017 in Washington and Montana. However, approximately 427 MW of wind power was under construction across the three states at the end of 2017.

For the purpose of this evaluation, a 100 MWa wind generation facility was evaluated in four regions of Oregon, Washington, and Montana: Columbia Gorge Oregon; Ione, Oregon; Southeast Washington (Columbia County); and East Central Montana (Loco Mountain region in Meagher County). It is noted that wind resources can vary regionally and the wind resources have been characterized to be representative of the surrounding areas centered at the location of interest and are inclusive of 38 years of historical weather and wind resource data.

3.1 Technology Overview

Wind power is generated by converting the kinetic energy of wind into electricity by rotating turbine blades that are connected to an electrical generator. Higher wind speeds (better wind resource) typically result in more efficient facilities and higher annual capacity factors. A map of wind speeds in the U.S. is shown below in Figure 3.1-1.

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[2] U.S. Energy Information Administration. https://www.eia.gov/electricity/data.php

[3] American Wind Energy Association. U.S. Wind Industry Fourth Quarter 2017 Market Report. https://www.awea.org/gencontentv2.aspx?ItemNumber=11255

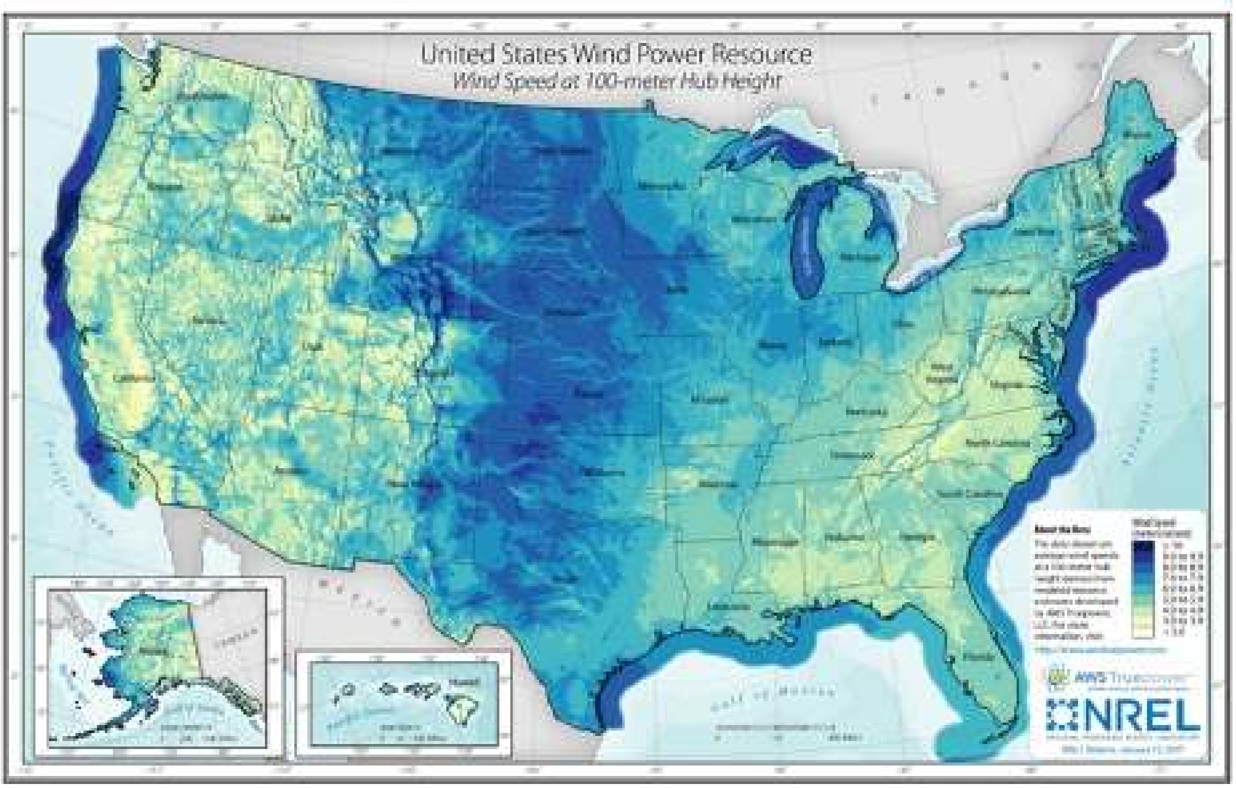

Figure 3.1-1. U.S. Wind Speeds at 100m Hub Height

A wind turbine ideally would be located where wind flow is non-turbulent and constant year round without excessive or extreme gusts. Wind speed typically increases with altitude and is higher over open areas without windbreaks such as trees or buildings. Favorable sites for wind turbines include the tops of smooth, rounded hills, open plains, and mountain gaps that funnel and intensify wind. Wind data is typically collected for a year or more via meteorological towers to determine general viability of a site.

Adequate spacing between the wind turbines must be maintained to reduce wind energy loss from interferences from nearby turbines. To minimize efficiency losses, wind turbines are commonly spaced three to five rotor diameters apart along an axis that is perpendicular to the prevailing wind direction and five to ten rotor diameters apart along an axis that is parallel to the prevailing wind direction.

3.2 Commercial Status

Wind power generation equipment, knowledge, and installation techniques have been adapted and implemented globally and is a well proven, commercially available technology for power generation. Advances in wind turbine designs have improved achievable plant efficiencies as compared to older wind power plants and increasingly allowing wind turbines to be more economically implemented in lower wind power class regions.

3.3 Operational Considerations

Wind farms are typically designed for a 25 year life, but well maintained turbines can last up to 30 years depending on the service conditions at the site and historical maintenance practices. Typical wind turbine sizes range from nominally 1.5 MW to 5 MW. For this analysis, a Vestas V136 3.6 MW with a hub height of 105 meter (m) was reviewed. The Vestas turbine model was considered because it was appropriate for the wind regimes in the Oregon, Washington, and Montana and it represents the recent industry trend of installing higher capacity turbines greater than 2 MW.

Note that the Federal Aviation Administration (FAA) does not have a height restriction on wind turbines. However, wind turbines with blade tip height that reaches greater than 500 feet would be within the FAA's altitude designation for general aviation aircraft and may require a longer permitting process for the FAA siting permit.

The characteristics of the wind generation technology considered are as follows:

- Vestas V136-3.6 wind turbines
- 105 m hub height for all sites
- 3.6 MW capacity per turbine
- 136 m rotor diameter

3.3.1 Plant Performance

Each wind site is sized to approximately 100 MWa. The actual nameplate capacity and estimated annual net capacity factor for each wind site location is provided below in Table 3.3-1.

Plant performance was estimated using a Vestas V136-3.6 power curve at a 105 m hub height. The net capacity factors were estimated from available wind resource data and include all losses up to the project busbar (i.e., transmission losses are not included). Wind resource data was gathered by Vaisala from meteorological towers across the region and corrected for long-term variability over a typical project lifetime by analyzing historical diurnal (daily), seasonal, and annual weather and atmospheric data from the last 38 years. Long-term data sources included information from the National Oceanic and Atmospheric Administration and the National Aeronautics and Space Administration.

Table 3.3-1. Wind Turbine Site Nameplate Capacities and NCFs

Wind Site	Nameplate Capacity (MW)	Annual NCF (%)
Ione, Oregon	306.0	32.7%
Columbia Gorge	244.8	40.8%
Southeast Washington	234.0	42.9%
Loco Mountain Montana	234.0	42.9%

3.4 Reliability, Availability, & Maintenance Intervals

Plant forced outage rates, planned outage rates, and mean average outage duration is summarized in Table 3.4-2 on a per turbine base.

Table 3.4-2. Wind Plant Plant Availbility/Reliability (One Turbine)

Availability/ Reliability		100 MWa Wind
Forced Outage Rate, per turbine	%	2.5%
Planned Outage Rate, per turbine	%	1.1%
Maintenance cycle and average maintenance duration	days/WTG/year	4

3.5 Land Requirements

The land required for a wind farm is divided between total overall footprint and direct, permanent footprint. The actual land use depends on many factors including wind resource, land ownership, terrain, land type (e.g., crop land, shrub land, forest), and wind turbine layout configuration. The four sites evaluated in this study would typically be located on grasslands or pasture. From site permits of actual operating and approved projects submitted to the Oregon Energy Facility Siting Council[4], the projects with turbines greater than or equal to 2.5 MW per turbine show an average total land area (i.e. the total area within overall site boundary) of approximately 48.2 acres (19.5 hectares) per installed MW and an average direct, permanent impact area (i.e. the land area directly impacted by turbine locations, access roads, and other site facilities) of 1.8 acres per installed wind turbine. HDR applied the average land use for total land area and direct, permanent impact area to all four sites. Table 3.5-1 summarizes land use requirements for each wind turbine site considered.

Table 3.5-1. Wind Turbine Site Land Requirements

		100 MWa, Ione Oregon	100 MWa, Columbia Gorge	100 MWa, SE Washington	100 MWa, Loco Mountain Montana
Number of Turbines		85	68	65	65
Total Land Area	acres	14,700	11,800	11,300	11,300
Approx. direct footprint* (permanent), per turbine	acres/turbine	1.8	1.8	1.8	1.8

3.6 Project Cost

Table 3.6-1 summarizes the estimated total project costs for each of the wind resource sites considered for a 2018 notice to proceed. The breakdown of estimated EPC costs and estimated Owner's costs are also shown for reference. The calculated standard deviation from the total overnight plant cost and the end of plant life decommissioning costs are also referenced. It is noted that project capital costs are based on a turnkey EPC contracting and approach methodology, which assumes the EPC contractor procures the major equipment, including the wind turbines. The wind turbines typically represent a large portion of the project

[4] https://www.oregon.gov/energy/facilities-safety/facilities/Pages/Facilities-Under-EFSC.aspx

cost ranging approximately $800/kW to $1,000/kW. EPC contingency costs, fees, and markups can increase project costs as compared to a project with Owner/developer procured turbines.

The turbines are assumed to be installed on land not owned by the project developer resulting in an assumed land lease cost, which is not included in the capital costs (but is provided in O&M costs).

Decommissioning costs include removal of the turbine from the foundation, partial removal of concrete foundation pedestal, extracting salvageable material, and reclaiming of disturbed areas (except for access roads, which are left in place for land owner use). The estimated salvage values for steel and copper are based on surveys published by the United States Geological Survey. Based on similar project experience and industry data available, HDR used an overall net cost of $35/kW for wind project decommissioning.

Table 3.6-1. Wind Plant Project EPC and Owner's Costs (Total Plant)

Project Costs, 2018$		100 MWa, Ione Oregon	100 MWa, Columbia Gorge	100 MWa, SE Washington	100 MWa, Loco Mountain Montana
Total Plant Cost	$1,000	461,400	376,700	358,300	355,700
Total Plant Cost	$/kW	1,508	1,539	1,531	1,520
EPC Cost	$1,000	415,300	339,000	322,500	320,100
Owner's Cost	$1,000	46,100	37,700	35,800	35,600
Std Deviation from Total Plant Costs	$/kW	424	432	430	427
End of Life Decomissioning Costs	$1,000	10,700	8,600	8,200	8,200

3.7 Implementation (Schedule)

Project schedules for a 100 MWa generation resource have been estimated and are based upon current day EPC contracting approaches and methodologies. The schedule assumes that the procurement of the major equipment including the wind turbines are the responsibility of the EPC contractor.

Wind power plants have a timeline ranging from 18 to 36 months for the EPC period (i.e. EPC contractor NTP through COD) depending on many different factors. A wind power generating facility with an output of 230MW similar to the SE Washington and Loco Mountain Montana sites will have an overall duration of approximately 26 months for the EPC period while a larger facility similar to the Ione North site with an output of 306 MW will have a duration of 28 months. The schedule duration varies based on the number of wind turbine at each location. A typical, 28 month project schedule is depicted in Figure 3.7-1. The estimated variation in overall EPC period and construction period for each of the selected sites, based on plant site and other site factors, are further shown below in Table 3.7-1. The construction period is from on-site EPC contractor mobilization through COD.

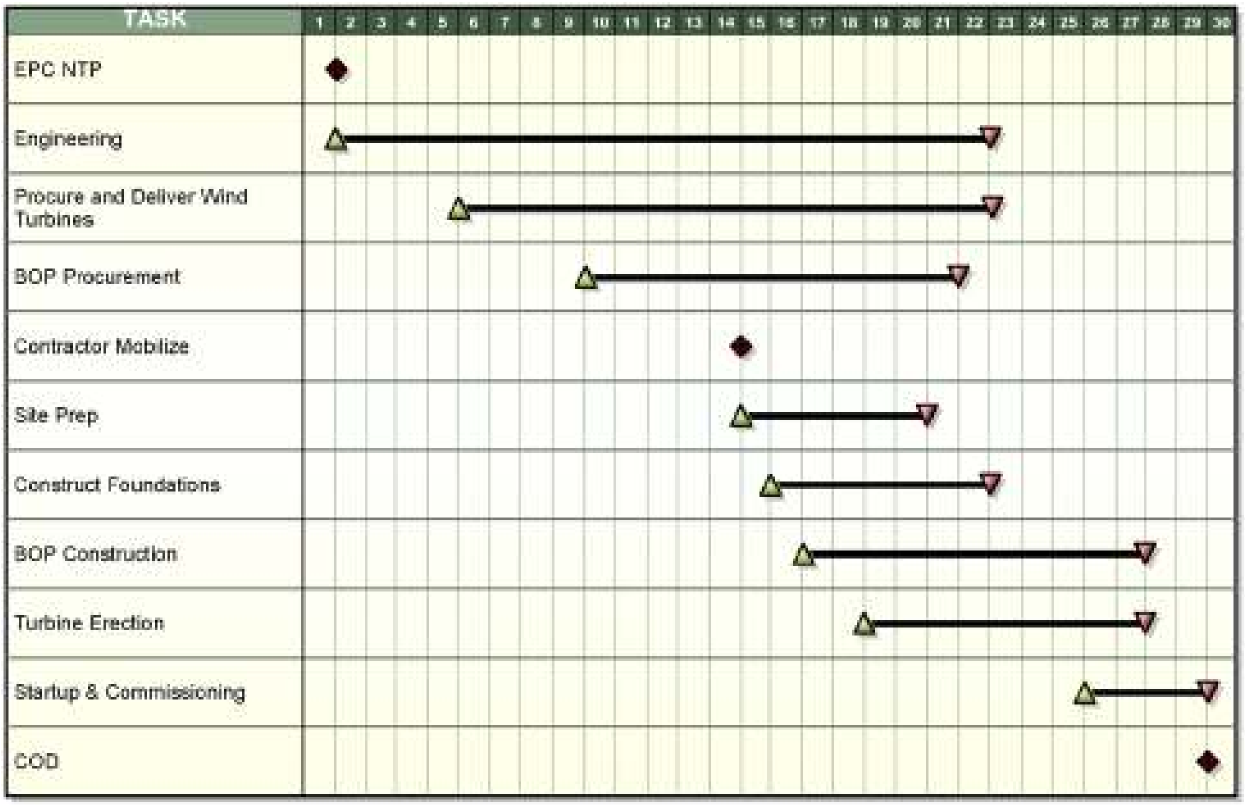

Figure 3.7-1. 100 MWa Wind Conceptual Project Schedule (Typical)

Table 3.7-1. Site Wind Plant Project Schedule Variation

Wind Site	EPC Period (months)	Construction Period (months)
Ione, Oregon	28	15
Columbia Gorge	26	13
Southeast Washington	26	13
Loco Mountain Montana	26	13

3.8 Operating Costs

The estimated fixed and variable O&M costs for each wind site are presented in Table 3.8-1. Operation and maintenance costs are inclusive of plant staffing and major turbine parts and maintenance costs, including replacement parts and outsourced labor to perform major maintenance. The O&M costs for wind projects are generally presented as a combined fixed and variable O&M component as shown in Table 3.8-1.

Plant staffing has been included as defined in Table 2-1 and 2-2. Staffing for the proposed wind power plants often utilize a remote monitoring/operating system with minimal on-site staff. Wind turbine maintenance labor is typically contracted in an O&M services contract.

Land lease costs have also been estimated and are typically paid to land owners as compensation for using their land. Royalties may also be paid to land owners as a small percentage of the project revenue. Based on HDR's project experience, the land lease and royalty costs for all four wind sites are estimated to be $1.70/MWh at the plant busbar.

Table 3.8-1. Wind Plant Fixed and Variable Operating Costs

Operating Costs, 2018$		100 MWa, Ione Oregon	100 MWa, Columbia Gorge	100 MWa, SE Washington	100 MWa, Loco Mountain Montana
Fixed O&M	$/kW-yr	37.0	37.0	37.0	37.0
Variable O&M	$/MWH	0	0	0	0
Land Lease/Royalties	$/MWH	1.7	1.7	1.7	1.7

4 Solar PV Technology

Solar PV technology uses solar cells or photovoltaic arrays to convert light from the sun directly into electricity. Utility-scale solar PV systems made up 1.3% of the total net generation in the U.S. in 2017[5].

For the purpose of this study, a 25 MWa AC solar plant was analyzed in Christmas Valley, Oregon, with the following characteristics:

- Single-axis tracking
- Inverter DC/AC ratio is 1.30
- 18% efficient solar panels from a representative vendor such as Hanwha
- Total installed nameplate capacity of 95 MW AC

4.1 Technology Overview

PV cells are made of different semiconductor materials and come in many sizes, shapes, and ratings. Utility scale PV technologies are generally mono/poly silicon or thin film. Solar cells produce direct current (DC) electricity and therefore require a DC to alternating current (AC) converter to allow for grid connected installations.

The PV arrays are mounted on structures that can either tilt the PV array at a fixed angle or incorporate tracking mechanisms that automatically move the panels to follow the sun across the sky. The fixed angle is determined by the local latitude, orientation of the structure, and electrical load requirements. Tracking systems provide more energy production. Single-axis trackers are designed to track the sun from east to west and dual-axis trackers allow for modules to remain pointed directly at the sun throughout the day. This evaluation considers a single-axis tracking configuration.

The amount of electricity produced from PV cells depends on the quantity and quality of the light available and performance characteristics of the PV cell. The largest PV systems in the country are located in the Southwestern regions where, as shown in Figure 4.1-1, where the strongest solar resources are available.

[5] U.S. Energy Information Administration (EIA)

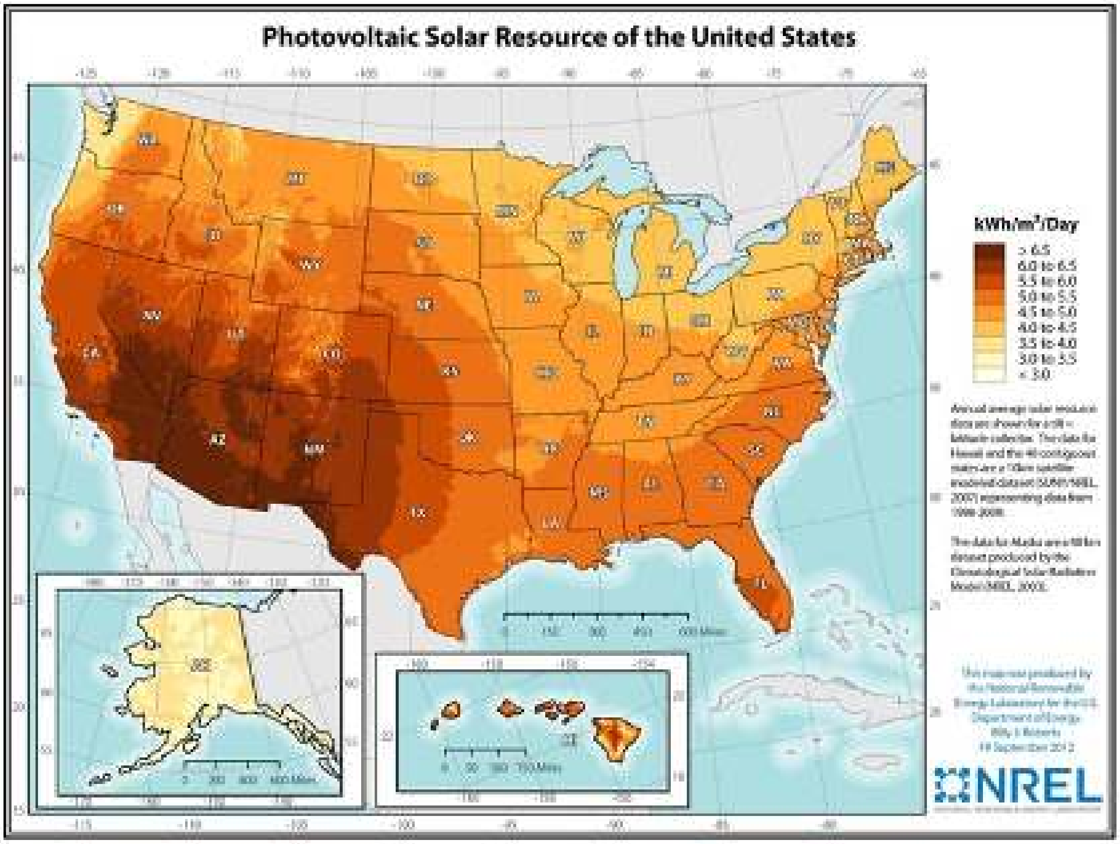

Figure 4.1-1. United States Photovoltaic Solar Resource

4.2 Commercial Status and Current Market

PV cells are commercially available with a significant installed operating base. There currently is over 50 GW of installed solar PV capacity in the U.S.[6] In 2017, approximately 10 GW of solar PV was installed, which represented 30 percent of the new electric generating capacity installed within the U.S.

The Federal Investment Tax Credit (ITC) has been instrumental in supporting the deployment and growth of solar energy in the U.S. The ITC currently offers a 30% tax credit towards the investment cost of solar systems. For a solar project to get the 30% ITC, it must begin construction by December 31, 2019, but it does not have to go into service until December 31, 2023. The percentage steps down to 26% and 22% for projects that start construction in 2020 in 2021, respectively. The project costs presented in Section 4.6 do not account for impacts associated with ITC credits.

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[6] 2017 Solar Market Insight Report, Solar Energy Industries Association (SEIA)

Recently, the U.S. imposed a 30% tariff on imported crystalline-silicon solar cells and modules that went into effect February 7, 2018. The tariffs start at 30% of the cell price in 2018 and then gradually drop to 15% by February 7, 2021. Per SEIA, the 30% tariff can be expected to increase year 1 PV module prices by roughly \$0.10/W or \$100/kW. The technology forecast curve in Appendix A does not include pricing impacts that may be associated with the tariff.

4.3 Operational Considerations

4.3.1 Plant Performance

A 25 MWa solar facility site was selected in Christmas Valley, Oregon. The nameplate capacity of the facility is 95 MW as shown in Table 4.3-1 below. The power of a panel degrades over time at an estimated annual rate of 0.5%. The NCF shown below in Table 4.3-1 represents the degraded annual capacity factor over the life of the plant. 1.

Table 4.3-1. Solar Site Nameplate Capacity and Net Annual Averaged Degraded Capacity Factor

Solar PV Site	Nameplate Capacity (MW)	Annual NCFs (%)
Christmas Valley	95	24.8%

4.4 Reliability, Availability, & Maintenance Intervals

Plant forced outage rates, planned outage rates, and mean average outage duration are summarized in Table 4.4-2.

Table 4.4-2. Solar Plant Plant Availbility/Reliability

Availability/ Reliability		Solar PV 25 MWa
Forced Outage Rate	%	0%
Planned Outage Rate	%	2%
Mean Annual Outage Duration	Days/year	7.3

4.5 Land Requirements

The land area required for Solar PV applications can be extensive depending on a variety of factors including the land and design. It is envisioned that approximately 38 arrays of 2.5 MW each would be installed. Each array would consist of about 8,764 modules of 370 Wp capacity each. An approximate land requirement of 475 acres was estimated for a 25 MWa Solar PV installation. This estimate is based on HDR project experience and is derived based on ground cover ratio and panel energy densities from a variety of HDR projects.

4.6 Project Cost

Table 4.6-1 summarizes the estimated total project costs for a 25 MWa Solar PV Site. The breakdown of estimated EPC cost and estimated Owner's costs are also shown for reference. The calculated standard deviation from the total overnight plant cost and the estimated end of plant life decommissioning costs are also referenced.

The estimated solar project cost includes the modules, structures, inverters, the balance of the system, and engineering and management services.

Solar PV project decommissioning costs are estimated based on recent, similar project experience and industry data. Decommissioning costs include removal of PV panels, removal of above ground panel racking, removal of below ground cables and racking foundations (piles), extraction of salvageable material, removal of access roads, and reclamation of disturbed areas. The estimated salvage values for steel, copper, and aluminum are based on surveys published by the United States Geological Survey. Based on recent studies, HDR assumed an overall net cost of $20/kW for solar PV project decommissioning.

Table 4.6-1. Solar PV Plant EPC and Owner's Costs

Project Costs, 2018$		25 MWa, Single-axis Tracking, Christmas Valley Oregon
Total Plant Cost	$1,000	143,450
Total Plant Cost	$/kW	1,510
EPC Cost	$1,000	130,409
Owner's Cost	$1,000	13,041
Std Deviation from Total Plant Costs	$/kW	424
End of Life Decomissioning Costs	$1,000	1,900

4.7 Implementation (Schedule)

Project schedules for a 25 MWa generation solar PV resource have been estimated and are based upon current day EPC contracting approaches and methodologies. As such, it is expected that a portion of the preliminary engineering and equipment sourcing activities, site acquisition, and project permitting activities are completed prior to FNTP of the project. This will typically also involve the procurement of major equipment and of the EPC contract with some level of LNTP awarded for these contracts prior to FNTP.

Currently, solar PV installations have a timeline of approximately 1 to 2 years from EPC NTP through COD. A conceptual project implementation schedule is provided below in Figure 4.7-1.

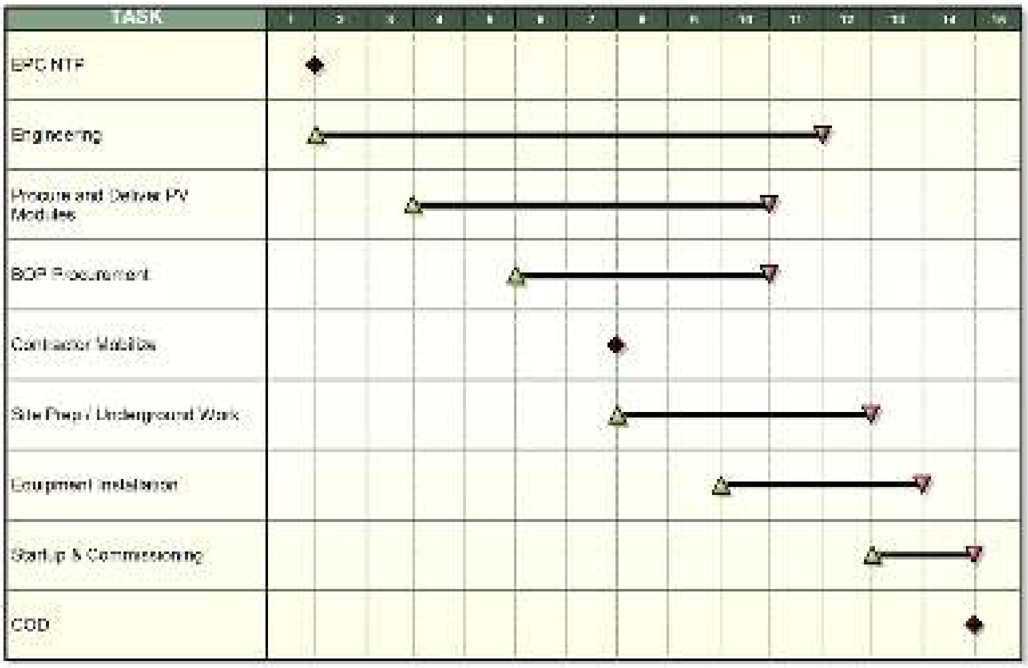


Figure 4.7-1. 25 MWa Solar PV Conceptual Project Schedule

4.8 Operating Costs

The estimated fixed and variable O&M costs for a 25 MWa solar PV site are presented in Table 4.8-1. Operation and maintenance costs are inclusive of plant staffing and major equipment parts and maintenance costs, including replacement parts and outsourced labor to perform major maintenance.

Plant staffing has been included as defined in Table 2-1 and 2-2. Staffing for the proposed solar PV power plant often utilizes a remote monitoring/operating system with minimal on-site staff. The majority of the staff is typically associated with maintenance and cleaning of the solar fields.

Land lease costs have also been estimated and are typically paid to land owners as compensation for using their land. Based on HDR's project experience, the land lease costs for a solar PV site is estimated to be $4.22/MWh.

Table 4.8-1. Solar PV Fixed and Variable Operating Costs

Operating Costs, 2018$		**25 MWa, Single-axis Tracking, Christmas Valley Oregon**
Fixed O&M	$/kW-yr	21.9
Variable O&M	$/MWH	0
Land Lease/Royalties	$/MWH	4.22

5 Battery Energy Storage System

Grid-connected battery energy storage systems (BESS) are maturing and have steadily increased in commercial deployment in the electric industry. For this resource option, a lithium-ion battery energy storage system was considered with the following characteristics:

- 100 MW installed capacity
- 2-hour, 4-hour, and 6-hour storage capacity evaluated
- A typical container/module size of 5 MWh was assumed.

5.1 Technology Overview

Lithium Ion (Li-ion) batteries utilize the exchange of lithium ions between electrodes to charge and discharge the battery. When the battery is in use (discharging) the charged electrons move from the anode to the cathode and in the process, energize the circuit that it is connected to. Electrons flow in the reverse direction during a charge cycle when energy is drawn from the grid. Due to its characteristics, Li-ion technology is well suited for fast-response applications like frequency regulation, frequency response, and short-term spinning reserve applications. Additionally, compared to other BESS, the Li-ion technology provides the highest energy storage density resulting in its adoption in several different markets ranging from consumer electronics to transportation (electric vehicles).

5.2 Commercial Status and Current Market

The market for utility-scale energy storage systems such as batteries is relatively early in development, but it is growing and evolving at a very rapid pace. The global energy storage market is expected to exceed 40 GW by 2022 from currently installed estimates of about 6 GW[7].

The increasing demand for battery storage in consumer electronics and the transportation sector as well as the emerging demand from the energy sector is propelling advances in the technology and manufacturing capacity for Li-ion. This is also aiding the trend of declining initial capital cost for this technology. Li-ion battery technology is a relatively mature technology, having been first proposed in 1970 and released commercially in 1991.

Other battery storage technologies include sodium sulfur, lead-acid, zinc iron and zinc bromine flow technologies; however, Li-ion is the most prominent and widely used for utility scale BESS. This is primarily due to technology maturity and risks that are better understood, the number of established and credit worthy Li-ion battery manufacturers in the market place, their ability to provide long term performance guarantees and warranties typically required by the electric utility industry, and the existence of reliable integrators that have a successful track record of installing turnkey EPC BESS projects for several years.

[7] Energy Storage Association

5.3 Operational Considerations

A 100 MW BESS \resource with one discharge cycle per day was considered with various hours of dispatch. Major components of a BESS station include the battery containers, battery management system (BMS), power conversion system (PCS) enclosures, plant control systems, and balance of plant systems including the cooling system, station load transformers, pad mounted medium/high voltage transformers, and grid interconnection gear with metering, site utilities, foundations and plant fencing. It is noted that the certain vendors may design the BESS in a multistory building with appropriate HVAC, lighting and security. While such a configuration may result in a slightly smaller footprint the overall EPC costs are anticipated to be similar.

The BESS plant consists of a number of containers that house the storage cells. The specific capacity of a container varies from manufacturer to manufacturer, but typical size of 5 MWh was used for this analysis.

5.3.1 Performance Data

Table 5.3-1 summarizes the estimated performance data for a typical 100 MW Li-ion BESS with 2 hours, 4 hours, and 6 hours of dispatch capability. As shown, battery efficiency improves with larger systems.

Table 5.3-1. BESS Performance

Lithium Ion BESS			
Capacity (MW)	100	100	100
Max Storage Limit (MWh)	200	400	600
Discharge Duration (hours)	2	4	6
Round Trip Efficiency	82%	87%	89%

5.4 Reliability, Availability, & Maintenance Intervals

Plant forced outage rates, planned outage rates, and mean average outage duration is summarized in Table 5.4-1. Forced and Planned outage rates are based on a single container/module. Plant capacity is therefore only reduced by 5 MWh's during scheduled or unscheduled outages per container, dependent on the number containers out. Partial outage rates for mutliple containers can be estimated by multiplying the number of containers out by the single container forced outage rate to determine the forced outage rate for a specific capacity level.

Table 5.4-1. BESS Availbility/Reliability

Availability/ Reliability		BESS
Forced and Planned Outage Rate	%	<2

Availability/ Reliability		**BESS**
Mean Annual Outage Duration	Days/year	3-5 Days

5.5 Land Requirement

An outdoor battery storage configuration was considered for this resource option. The approximate land requirement was estimated based on manufacturer and industry data and is expected to be about 2.17 acres for the 200 MWh BESS, 3.3 acres at 400 MWh, and about 5 acres for the 600 MWh BESS system.

5.6 Project Cost

Table 5.6-1 summarizes the estimated total project costs for each BESS resource evaluated. The breakdown of estimated EPC cost and estimated Owner's costs are also shown for reference. Owners cost also includes an allocation of costs for leasing a project site at 2,310 $/acre according to the average 2017 Farm Real Estate values in Oregon reported by the U.S. Department of Agriculture[8]. The calculated standard deviation from the total overnight plant cost and the estimated end of plant life decommissioning costs are also referenced.

The EPC cost for an installed BESS includes the costs of the energy storage equipment, power conversion equipment, power control system, balance of system including site utilities, grid interconnection and installation costs.

For Li-ion systems, battery cells are arranged and connected into strings, modules, and packs which are then packaged into a DC system meeting the required power and energy specifications of the project. The DC system includes internal wiring, temperature and voltage monitoring equipment, and an associated battery management system responsible for managing low-level safety and performance of the DC battery system.

Decommissioning costs are presented as net salvage value and assume the site will be taken back to a brownfield site, which removes all material and structures down to 2 to 3 ft. below grade. Per market sources it is anticipated that the Li-ion cells will have salvageable value at end of project life, and is expected to result in zero additional costs for removal and recycling. Net decommissioning costs to owner for remaining balance of plant is indicated in Table 5.6-1.

[8] United States Department of Agriculture. Land Values 2017 Summary. https://www.usda.gov/nass/PUBS/TODAYRPT/land0817.pdf. August 2017.

Table 5.6-1. BESS Plant Project Costs

Project Costs, 2018$		Li-On Battery - 2 Hour	Li-On Battery - 4 Hour	Li-On Battery - 6 Hour
Total Plant Cost	$1,000	91,600	155,400	190,200
Total Plant Cost	$/kW	916	1,554	1,902
Total Plant Cost	$/kWhr	458	388	317
EPC Cost	$1,000	82,400	139,900	171,200
Owner's Cost	$1,000	9,200	15,500	19,000
Std Deviation from Total Plant Costs	$/kW	267	462	567
End of Life Decomissioning Costs	$1,000	500	750	1,000

5.7 Implementation (Schedule)

Project schedules for a 100 MW BESS resource have been estimated and are based upon current day EPC contracting approaches and methodologies. As such, it is expected that a portion of the preliminary engineering and equipment sourcing activities, site acquisition, and project permitting activities are completed prior to FNTP of the project. This will typically also involve the procurement of major equipment and of the EPC contract with some level of LNTP awarded for these contracts prior to FNTP.

The BESS integrator's scope of supply typically includes most of the systems up to the inverter terminal where AC power is available to the GSU transformer. Accordingly, the BESS integrator can deliver the major systems within approximately 12 months from NTP. Additional site engineering, foundation and substructure work, permitting, site utilities and utility interconnection work is generally completed by a general/EPC contractor. A typical 100 MW BESS project can be commissioned and estimated to be in commercial operation within 20 months from NTP. A typical project implementation schedule for a 100 MW BESS installation is provided in Figure 5.7-1. Schedule differences for the different storage capacity options are expected to be minimal.

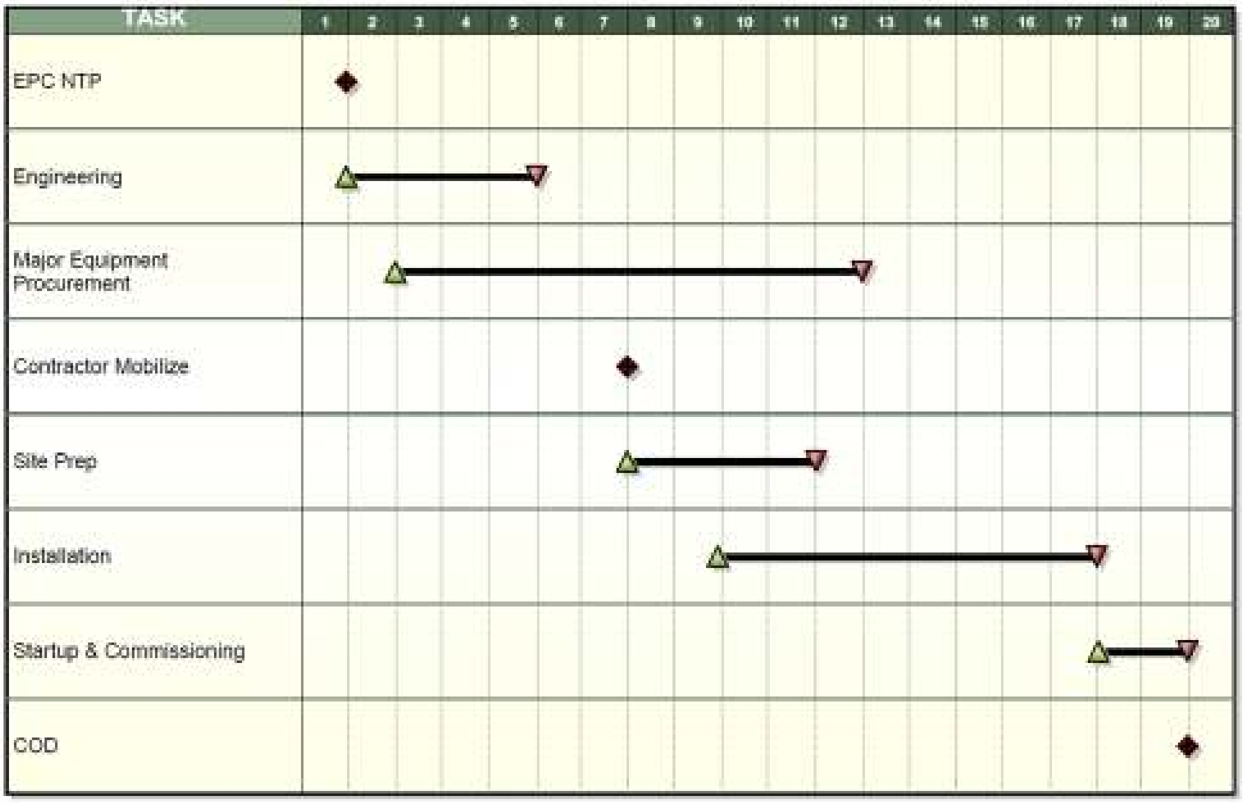


Figure 5.7-1. 100 MW BESS Conceptual Project Schedule

5.8 Operating Costs

The estimated fixed and variable O&M costs for each BESS resource option are presented in Table 5.8-1. Operation and maintenance costs are inclusive of plant staffing and major equipment parts and maintenance costs, including replacement parts and outsourced labor to perform major maintenance.

Plant staffing has been included as defined in Table 2-1 and 2-2. Staffing for the proposed BESS plant often utilizes a remote monitoring/operating system with minimal on-site staff. Maintenance labor is assumed to be contracted in an O&M services contract.

As indicated in Section 5.6 above, an allocation of 2,310 $/acre/yr has been included in the Owners Cost for a leasing the project site.

The major component of the O&M cost for a Li-ion BESS system is related to energy and capacity augmentation. Augmentation maintains the BESS capability to serve the Owner's requirement for the term of the agreement. These costs are typically covered in the fixed O&M costs. Additional fixed O&M costs include 24x7 remote monitoring, remote troubleshooting, performing scheduled maintenance activities, inverter replacements, emergency and unscheduled maintenance support, periodic reporting, training and continuous improvement, software licensing and updates, HVAC maintenance, auxiliary electrical loads, landscaping, and mechanical/electrical inspections and updates. No additional staffing costs are included as it is assumed that the BESS will be completely unmanned.

For Li-ion BESS, the Fixed O&M costs indicated below includes both the fixed and variable O&M costs associated with maintaining the electrical output of BESS for the life of the system, and the augmentation service agreement. The total annual augmentation agreement is estimated based on the 1 full cycle/day discharge rate. Utility energy costs for charging the battery is not included in the O&M costs.

For the Li-ion BESS, levelized fixed and variable O&M costs are estimated below in Table 5.9-1.

Table 5.9-1. BESS Plant O&M Costs

Operating Costs, 2018$		Li-On Battery - 2 Hour	Li-On Battery - 4 Hour	Li-On Battery - 6 Hour
Fixed O&M	$/kW-yr	23.5	31.1	42.6
Variable O&M	$/MWH	0	0	0
Land Lease/Royalties	$/MWH	0	0	0

Appendices

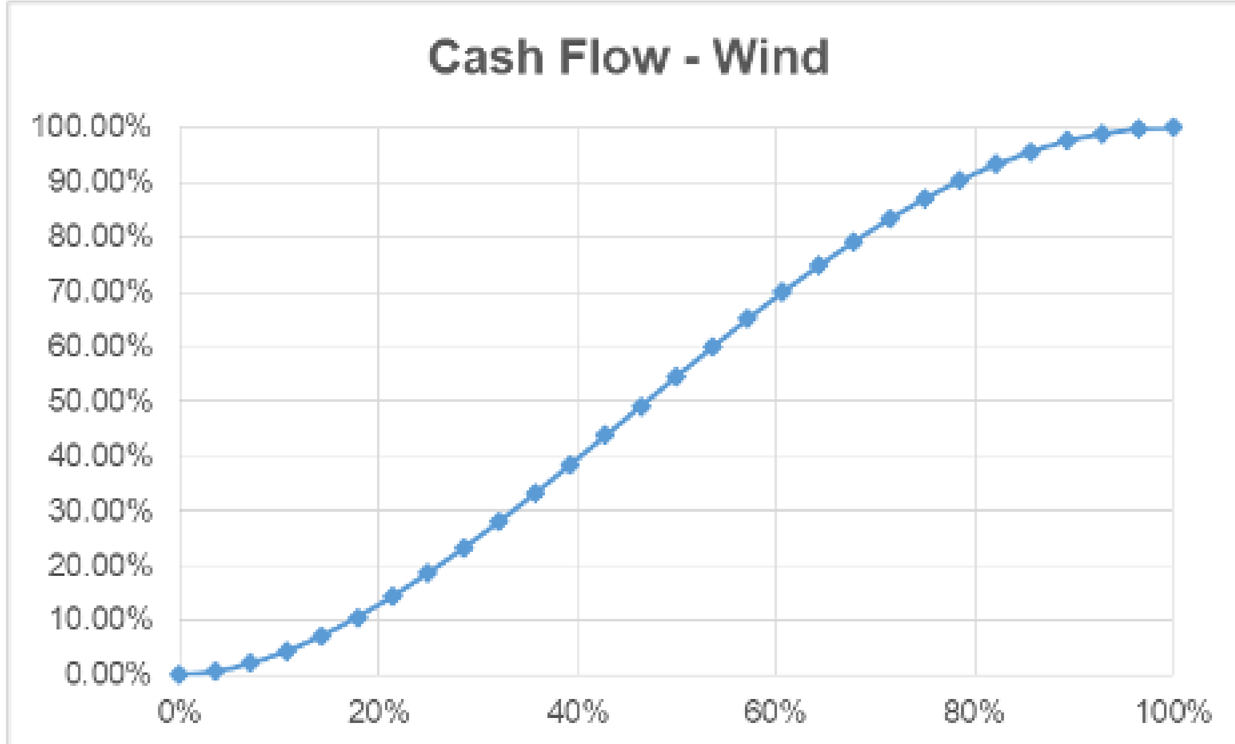
Appendix A – Technology Maturity / Cost Forecast

2018 US $/kW, FNTP Year

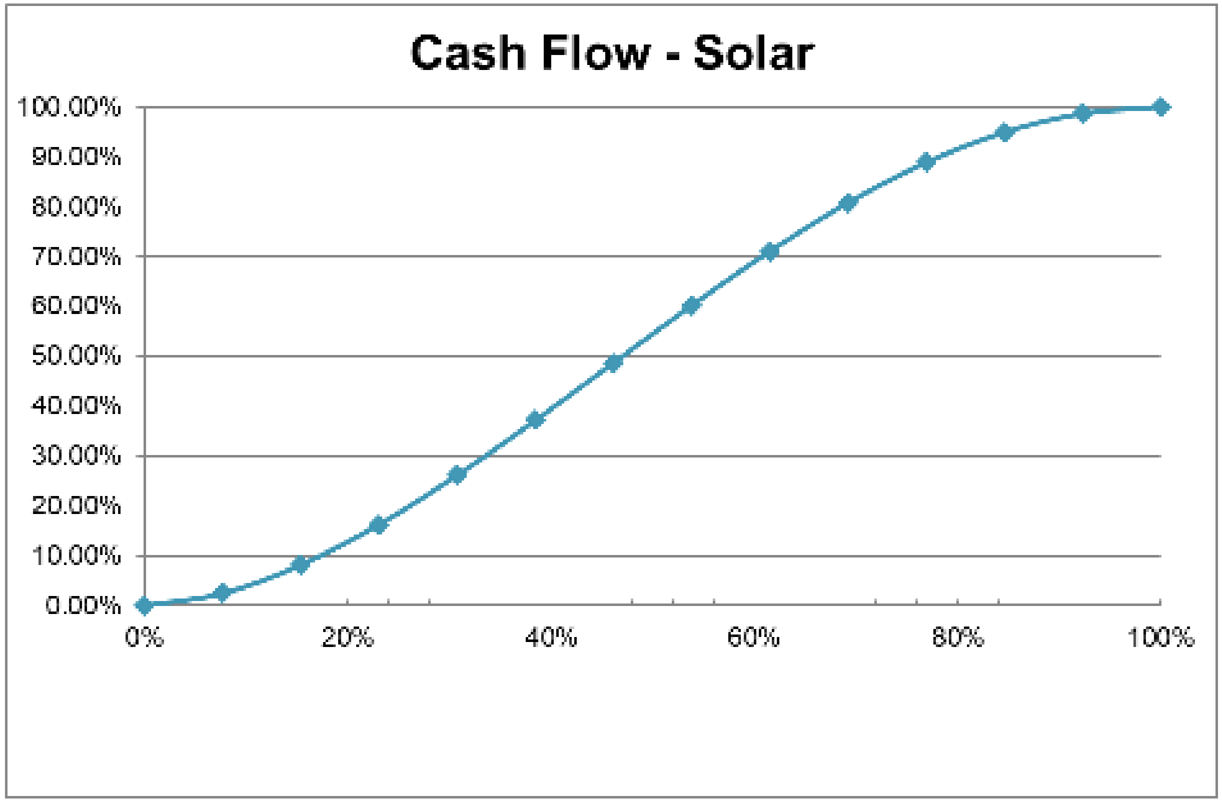
Technology	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047	2048	2049	2050
Solar PV, 25 MW Average, single axis	1,510	1,510	1,469	1,374	1,335	1,307	1,294	1,282	1,271	1,261	1,250	1,237	1,225	1,212	1,198	1,183	1,169	1,155	1,141	1,128	1,119	1,110	1,101	1,092	1,084	1,075	1,065	1,056	1,047	1,038	1,029	1,020	1,011
Wind, 100 MW Averag, Ione, Oregon	1,508	1,508	1,508	1,493	1,478	1,464	1,449	1,436	1,422	1,410	1,397	1,383	1,369	1,355	1,341	1,326	1,312	1,298	1,284	1,269	1,256	1,242	1,229	1,217	1,203	1,191	1,177	1,164	1,151	1,138	1,125	1,112	1,099
Wind, 100 MW Average, Columbia Gorge	1,539	1,539	1,539	1,523	1,508	1,494	1,479	1,465	1,451	1,439	1,426	1,411	1,397	1,383	1,368	1,354	1,339	1,324	1,310	1,295	1,281	1,268	1,255	1,242	1,228	1,215	1,201	1,188	1,174	1,161	1,148	1,135	1,122
Wind, 100 MW Average, Southeast Wash	1,531	1,531	1,531	1,515	1,500	1,487	1,472	1,457	1,443	1,432	1,419	1,404	1,390	1,376	1,361	1,346	1,332	1,317	1,303	1,289	1,275	1,261	1,248	1,235	1,222	1,209	1,195	1,182	1,168	1,155	1,142	1,129	1,116
Wind, 100 MW Average, Montana	1,520	1,520	1,520	1,504	1,490	1,476	1,461	1,447	1,433	1,421	1,408	1,394	1,380	1,366	1,351	1,337	1,322	1,308	1,294	1,279	1,266	1,252	1,239	1,226	1,213	1,200	1,187	1,173	1,160	1,147	1,134	1,121	1,108
Li-on, 100 MW, 2 hour	915	915	905	889	873	858	842	827	812	799	784	770	755	741	726	711	697	683	669	655	641	628	615	602	589	577	564	551	539	527	515	502	491
Li-on, 100 MW, 4 hour	1,554	1,554	1,537	1,509	1,482	1,457	1,430	1,405	1,379	1,356	1,332	1,307	1,282	1,258	1,233	1,208	1,184	1,160	1,136	1,112	1,089	1,067	1,045	1,023	1,001	980	958	936	915	895	874	853	833
Li-on, 100 MW, 6 hour	1,902	1,902	1,881	1,847	1,814	1,783	1,750	1,719	1,688	1,660	1,631	1,600	1,569	1,540	1,509	1,479	1,449	1,420	1,391	1,361	1,333	1,306	1,279	1,252	1,225	1,199	1,172	1,146	1,120	1,095	1,070	1,044	1,020

Appendix B – Drawdown Schedules

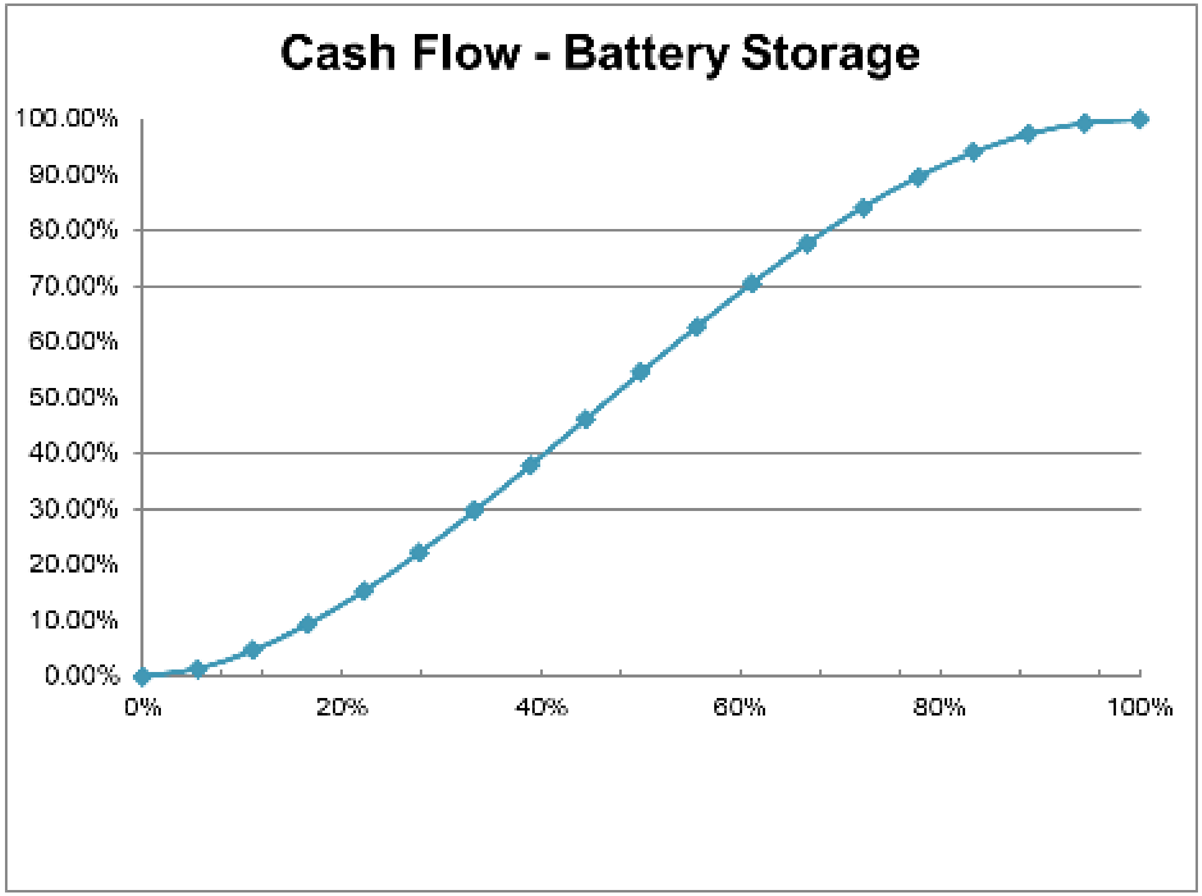
Month	% Complete	0.00%	Cumulative Accrual
0	0%	0.00%	0.00%
1	4%	0.65%	0.65%
2	7%	1.52%	2.17%
3	11%	2.22%	4.39%
4	14%	2.82%	7.21%
5	18%	3.36%	10.57%
6	21%	3.82%	14.39%
7	25%	4.23%	18.62%
8	29%	4.58%	23.20%
9	32%	4.86%	28.06%
10	36%	5.09%	33.14%
11	39%	5.25%	38.39%
12	43%	5.35%	43.75%
13	46%	5.40%	49.14%
14	50%	5.38%	54.53%
15	54%	5.31%	59.83%
16	57%	5.17%	65.01%
17	61%	4.99%	69.99%
18	64%	4.75%	74.74%
19	68%	4.46%	79.20%
20	71%	4.12%	83.32%
21	75%	3.74%	87.06%
22	79%	3.33%	90.39%
23	82%	2.87%	93.26%
24	86%	2.39%	95.65%
25	89%	1.89%	97.54%
26	93%	1.36%	98.90%
27	96%	0.82%	99.72%
28	100%	0.28%	100.00%



Month	% Complete	0.00%	Cumulative Accrual
0	0%	0.00%	0.00%
1	8%	2.47%	2.47%
2	15%	5.72%	8.19%
3	23%	8.11%	16.29%
4	31%	9.86%	26.16%
5	38%	11.01%	37.17%
6	46%	11.56%	48.73%
7	54%	11.51%	60.23%
8	62%	10.88%	71.11%
9	69%	9.71%	80.82%
10	77%	8.08%	88.91%
11	85%	6.06%	94.97%
12	92%	3.76%	98.73%
13	100%	1.27%	100.00%



Month	% Complete	0.00%	Cumulative Accrual
0	0%	0.00%	0.00%
1	6%	1.40%	1.40%
2	11%	3.27%	4.67%
3	17%	4.72%	9.39%
4	22%	5.90%	15.30%
5	28%	6.86%	22.15%
6	33%	7.58%	29.73%
7	39%	8.07%	37.80%
8	44%	8.34%	46.14%
9	50%	8.38%	54.53%
10	56%	8.20%	62.73%
11	61%	7.81%	70.53%
12	67%	7.21%	77.75%
13	72%	6.44%	84.18%
14	78%	5.50%	89.69%
15	83%	4.43%	94.11%
16	89%	3.24%	97.36%
17	94%	1.98%	99.34%
18	100%	0.66%	100.00%



Appendix C – Modeling Inputs Summary Tables (See Excel File)

External Study E. Market Capacity Study

Northwest Loads and Resources Assessment

Prepared for Portland General Electric

January 2019

Energy+Environmental Economics

Northwest Loads and Resources Assessment

Prepared for Portland General Electric

January 2019

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Table of Contents

1 Study Scope & Overview

In 2017, the Oregon Public Utilities Commission (OPUC) acknowledged Portland General Electric's (PGE) request to conduct a study related to the treatment of existing surplus capacity available in the market for PGE's 2019 Integrated Resource Plan. The specific questions PGE was seeking to answer were:

+ How future changes in resources and loads in the Pacific Northwest might affect the region's overall capacity position; and
+ The implications of these factors have for PGE's long-term planning assumptions of market purchases of available surplus capacity

The Pacific Northwest has historically been in a surplus condition for capacity. As a result, some utilities in the region have relied on the purchase of surplus capacity from the markets to cost-effectively meet their resource adequacy targets and peak demand needs. However, a number of recent studies of the capacity availability in the region have shown that the region is expected to be short on capacity in the near-term. This study examines the expected changes in loads and resources for the region and its implications for PGE's long-term resource planning assumptions with regards to the availability of market purchases of surplus capacity.

A number of existing studies conducted by entities within the region have examined similar questions. These studies generally point to several emerging trends that will impact the load-resource balance of the Northwest in the future:

+ Increasing peak loads, especially in the summer;
+ Anticipated coal plant retirements;
+ Limited anticipated additions of thermal power plants in the coming years;
+ Addition of new renewables to meet regional policy goals; and
+ A continued high level of energy efficiency achievement by utilities.

These trends are expected to reshape the regional load-resource balance in the next few years.

PGE hired Energy & Environmental Economics (E3) to conduct a study to inform its integrated resource planning process by examining these trends and their implications for the region's load-resource balance. To understand the variability in expected surplus capacity in the region and its relationship to some of the key assumptions, E3 reviewed existing studies examining the forecasted regional balance of loads and resources and developed a simple, flexible Excel spreadsheet tool ('E3 model' or 'the model') to investigate a range of scenarios for the region. E3 used the model to create 3 scenarios – a 'Base Case', reflecting expected trends within the industry, as well as 'High Need' and 'Low Need' scenarios that provide upper and lower bounds on the availability of surplus capacity. The key inputs, assumptions and results for the different scenarios are described in the following sections.

The remainder of this report is organized as follows:

+ Section 2 begins with a summary of the existing studies looking at the capacity position for the region;
+ Section 3 describes the approach used by E3 to develop its heuristics-based model;
+ Section 4 describes the scenarios and input assumptions used in the model to create recommendations for capacity position; and
+ Section 5 concludes with a range of scenario-based recommendations for market capacity purchases available for PGE.

2 Review of Findings in Existing Studies

2.1 Overview of Studies

To understand the ranges for plausible forecasts for load and resource buildout and retirements, as well as regional imports and exports for the region, E3 reviewed existing studies published by key regional entities such as the Northwest Power and Conservation Council (NWPCC, or 'the Council'), Bonneville Power Administration (BPA) and Pacific Northwest Utilities Conference Committee (PNUCC).

The Council publishes two key documents that look at expected changes to loads and resources for the region:

+ The Pacific Northwest Power Supply Adequacy Assessment ('2023 Adequacy Assessment') is a short-term outlook that assesses the loss of load probability in a snapshot operating year, typically 5 years out, and,
+ The Northwest Conservation and Electric Power Plan ('7th Power Plan') takes a longer-term approach of looking at load and resource changes expected through a longer time horizon. The most recent document has provided an outlook through 2035

BPA publishes an annual study called the 'White Book' reviewing the loads and resources expected for both the Federal hydro system and the Northwest region footprint (which uses the same geography used by the Council). For this analysis, E3 reviewed the 2017 Pacific Northwest Loads and Resources Study ('2017 White Book') published by BPA.

The Pacific Northwest Utilities Conference Committee (PNUCC) is another regional entity that publishes the expected trends in loads and resources for the Pacific Northwest. E3 reviewed the 2018 PNUCC Northwest Regional Forecast of Power Loads and Resources ('2018 PNUCC study') for this analysis.

Across all of the studies, the key assumptions that are varied are:

+ Expected load growth in the region, and levels of achievable energy efficiency (EE) and demand response (DR) resources
+ Resources available to meet peak loads in the region, which include assumptions on thermal retirements, expected renewables build, as well as the uncontracted independent power producer (IPP) resources that can sell power into the Pacific Northwest as well as to regions outside of the Pacific Northwest footprint such as California
+ Analytical approach used in evaluating system energy and capacity needs (deterministic versus stochastic, or probability based), and the metrics used to reflect the needs (whether it's a planning reserve margin or a loss of load probability metric).
+ Treatment of different types of variable and use-limited resources (e.g. wind, solar, hydro, storage) in their contribution to meeting system resource adequacy needs.

The descriptions for each of the studies and the key assumptions and conclusions from the studies reviewed are detailed below.

2.1.1 NWPCC 2023 ADEQUACY ASSESSMENT

The Council publishes an annual outlook for a future operating year, typically 5 years out, to assess resource adequacy with a probabilistic approach. The Council, in collaboration with the Resource Adequacy Advisory Committee (RAAC), uses its probability-based resource adequacy model GENESYS to provide loss of load probability (LOLP) statistics as well as other adequacy metrics such as the size of potential shortages, their frequency, and their duration. For the system to be deemed adequate in terms of power supply, the Council targets an annual LOLP of less than 5%—meaning that, on average, loss of load events will occur in fewer than one in twenty years. The adequacy analysis uses an aggregate regional approach to assess power supply, and the individual utilities may have different results from those examined by the Council at a regional level. The Council tests the impacts of differing peak loads and availability of market imports from California in its assessment to provide a range of LOLP results.

2.1.2 NWPCC 7TH POWER PLAN

The Council also develops and publishes a power plan for an adequate, efficient, economic and reliable power supply for the region every five years; the most recent of these, the 7th Power Plan (the 'Power Plan'), was released in 2016. In the process of developing its plan, the Council incorporates feedback from a variety of technical and policy advisory stakeholder groups that represent interests of utilities, state energy offices, and public interest groups. The purpose of the plan is to address different sources of uncertainties facing the electric system in the Northwest and to provide guidance on the resources that could be used to achieve a reliable and economic power system over a 20-year period.

The Power Plan provides a resource strategy based on differing assumptions on load growth, energy efficiency, demand response and procurement of other resources. As a part of this evaluation, the Power Plan inherently examines the balance of loads and resources within the region, identifying the potential long-term need for new capacity as well as resource strategies to meet it.

2.1.3 2017 BPA WHITE BOOK

Every year, BPA publishes the "White Book," which is an outlook on the Federal System and Pacific Northwest region's loads and resources for the upcoming 10-year period. BPA uses the White Book for long-term planning purposes for its service territory, as well as to make information and data available for interested regional entities. For the purpose of this study, E3 focused on the Pacific Northwest regional analysis provided in the White Book.

In its regional analysis, BPA estimated the future loads and export obligations and compared those to forecasts for generation and contractual purchases to estimate regional energy and capacity surpluses or deficits. The White Book results are provided for both winter energy and capacity needs, at a monthly as well as annual time step. However, the BPA White Book does not provide a capacity and energy surplus or deficit analysis for the summer.

2.1.4 2018 PNUCC NORTHWEST REGIONAL FORECAST OF POWER LOADS AND RESOURCES

Similar to BPA, the PNUCC publishes its annual outlook for the region's demand and power supply. In order to develop its forecasts for regional loads and resources, the PNUCC document uses information gathered from utilities and provides an outlook on the Northwest power system accessible to key stakeholders.

2.2 Literature Review Takeaways

There are differences in some of the key assumptions and analytical approaches used by the regional entities to provide estimates of the region's net capacity position. The key assumptions and how they are treated across the studies are described in Table 1.

Despite these differences in assumptions, the results from the studies are broadly consistent. The BPA White Book, the NWPCC 2023 Adequacy Assessment as well as PNUCC study show a net winter capacity need for the region by 2021. The NWPCC 7th Power Plan provides a range of net capacity positions for 2021 from a surplus of approximately 700 MW to a deficit of approximately 1 GW. If IPPs that are not contracted to specific regional entities are not available as dependable resources to meet peak needs, the winter capacity need would be realized as early as 2019. Because the PNUCC study does not include in-region IPPs among its dependable resources for the region, it shows a winter capacity need of 1.8 GW by 2019 and a summer capacity need of 0.3 GW starting in 2021.

Table 1 Key assumptions for different existing studies included in the literature review.

Assumption	NWPCC 2023 Adequacy Assessment	NWPCC 7th Power Plan	2017 BPA White Book	2018 PNUCC Study
Analytical Approach	Stochastic	Deterministic	Deterministic	Deterministic
Peak Load Forecast	Distribution of peak loads for 80 temperature year	Ranges of weather-normalized load forecasts	BPA load forecasts	Non-coincident peak (NCP) of all participating utilities
Resources	Existing and planned, IPPs included	Existing, IPPs included	As per utility IRPs, IPPs included	Existing and committed; IPPs not included
Adequacy Metric	LOLP standard of 5%	Adequacy Reserve Margin (ARM) instead of PRM	Reserve margin requirement based on operating reserves and transmission losses	Planning Reserve Margin (PRM) of 16%
Hydro Capacity	A wide range of hydro conditions modeled stochastically in GENESYS	P2.5% 10-hour sustained peaking ability	BPA internal Hourly Operating and Scheduling Simulator (HOSS) model	8th percentile based on average water
Wind Capacity	ELCC endogenously calculated in GENESYS	5% assumed contribution to ARM	Wind capacity not counted as firm	5% assumed contribution to peak

3 Modeling Approach

3.1 Modeling Methodology

To inform input assumptions for PGE's IRP, E3 developed a model to determine the future trajectory of loads and resources under different assumptions for the Northwest region to estimate the net capacity position expected for the region in future. The model was informed by existing studies, and can be used to vary key assumptions to test their impact on the expected regional capacity surplus or deficit.

The model created to inform this study uses a "planning reserve margin" (PRM) approach to examine the balance of loads and resources within the region. The concept of a PRM—a common convention used to estimate the amount of dependable capacity needed by a utility or region to serve load based on a margin needed above average conditions to account for weather excursions, unplanned plant outage, as well as contingency reserves —is used by individual utilities both within the Northwest and throughout the country. While the Northwest region does not have a formal PRM requirement as a reliability standard, the concept remains a useful approach to evaluate the balance of loads and resources within the region.

3.2 Model Calibration Approach

The PRM approach used herein is not intended to supplant the more detailed loss-of-load-probability modeling conducted by the Council in its studies. Rather, E3 calibrated its model to provide results consistent with the Council's 2023 Adequacy Assessment. The Council's adequacy assessment uses a sophisticated stochastic modeling approach to estimate the loss of load probability metrics for the region and is arguably the most robust study of reliability needs in the region. The purpose of calibrating the model is twofold: 1) calibrating the model to the Council's adequacy assessment helps benchmark to the best available information for the region, and 2) the model can then be used to test additional scenarios and sensitivities not provided in existing regional studies.

In order to calibrate the E3 model to the Council's adequacy assessment, E3 used a three-step process:

1) Align input assumptions for regional load and available generation resources with the 2023 Adequacy Assessment;

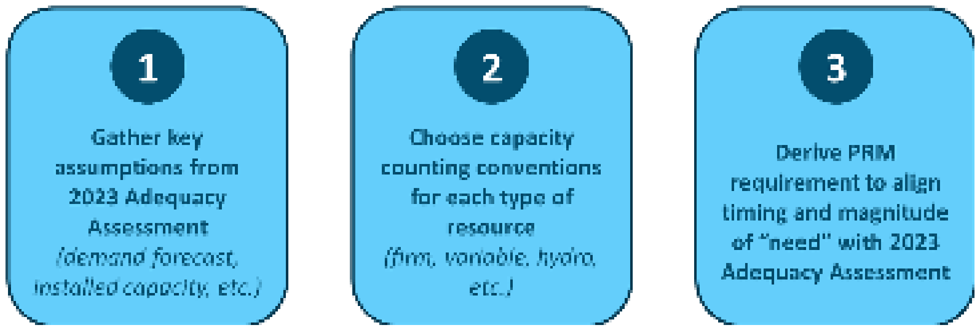
2) Select conventions used in the model to translate nameplate capacity to dependable capacity[1] for each resource; and

3) Adjust the PRM requirement (% of regional peak demand) to align regional surplus/deficit with the 2023 study.

This approach is illustrated in Figure 1 below.

[1] These conventions are informed by the 7th Power Plan where applicable, as discussed in Section 3.3.2.

Figure 1 Calibration approach and the derivation of the PRM used in the model.



Through this process, E3 was able to translate the probability based stochastic modeling used by the Council in its adequacy assessment into a simple heuristic-based planning metric. Some of the key differences between the Council's GENESYS model used for estimating regional capacity position and the spreadsheet based E3 model with the simplified PRM treatment are highlighted in Table 2.

Table 2. Key differences between the NWPCC 2023 Adequacy Assessment GENESYS model and the spreadsheet based E3 model.

Category	GENESYS	E3 Model
Approach	Stochastic	Deterministic
Adequacy Metric	LOLP	PRM
Analysis Horizon	One year snapshot	15-year outlook
Hydro	Stochastic simulation of 80+ years	Assumed contribution (%) to winter & summer peak
Renewables	Stochastic simulation of hourly renewable output	Assumed static ELCC (%)

3.3 Assumptions Used in Calibration

3.3.1 LOADS AND RESOURCES

As discussed in section 3.1, E3 used the NWPCC 2023 Adequacy Assessment to align key inputs including summer and winter peak loads net of expected energy efficiency, levels of demand response in the summer and winter, contracted as well as market imports and exports from outside of the Northwest footprint, capacity of thermal resources, and availability of in-region IPP resources.

Table 3 Summary of 2023 seasonal loads and nameplate resources in the Northwest.

Loads	2023 Load MW (Winter)	2023 Load MW (Summer)
1-in-2 Peak Demand (including cost-effective EE)	34,070	27,176
Firm Exports	462	477
Total Load	34,532	27,653
Resources	**Nameplate Capacity MW (Winter)**	**Nameplate Capacity MW (Summer)**
Thermal (includes IPPs)	14,679	12,973
Hydro	34,697	
Solar	448	

Wind	6,264	
Other	1,200	
DR	740	1056

3.3.2 DEPENDABLE CAPACITY CONVENTIONS

For each resource type included in the model, E3 chose a convention to translate the region's nameplate capacity to an estimate of dependable capacity. The conventions generally used are:

+ The contributions of thermal and demand response resources are assumed to be 100% of nameplate capacity;
+ The contribution of hydro resources, due to energy limits related to hydro conditions, are based on their 10-hr sustained peaking capability; and
+ The contribution of variable renewable resources, including wind and solar, are based on assumed "Effective Load Carrying Capability"—a measure of the equivalent firm capacity for variable resources.

The resulting quantities of dependable capacity available to the region in the summer and winter seasons are shown in Table 4 and Table 5 below; additional detail and justification for the conventions used to attribute dependable capacity to hydro and renewable resources is subsequently discussed.

Table 4 Summary of 2023 winter nameplate and dependable capacities of resources in the Northwest.

Resources	Nameplate Capacity MW (Winter)	Dependable Capacity % (Winter)	Dependable Capacity MW (Winter)
Thermal (includes IPPs)	14,679	100%	14,679
Hydro	34,697	51%	17,790
Solar	448	26%	116
Wind	6,264	5%	313
Other	1,200	65%	784
DR	740	100%	740
Total	**58,028**		**34,422**

Table 5 Summary of 2023 summer nameplate and dependable capacities of resources in the Northwest.

Resources	Nameplate Capacity MW (Summer)	Dependable Capacity % (Summer)	Dependable Capacity MW (Summer)
Thermal (includes IPPs)	12,973	100%	14,679

Hydro	34,697	44%	15,404
Solar	448	81%	363
Wind	6,264	5%	313
Other	1,200	65%	784
DR	1056	100%	1056
Total	**56,638**		**32,599**

3.3.2.1 Thermal Resources

In this study, the contribution of thermal resources towards the regional reserve margin requirement is assumed to be equal to their nameplate capacity. This convention is commonly used by utilities who rely on a planning reserve margin requirement.

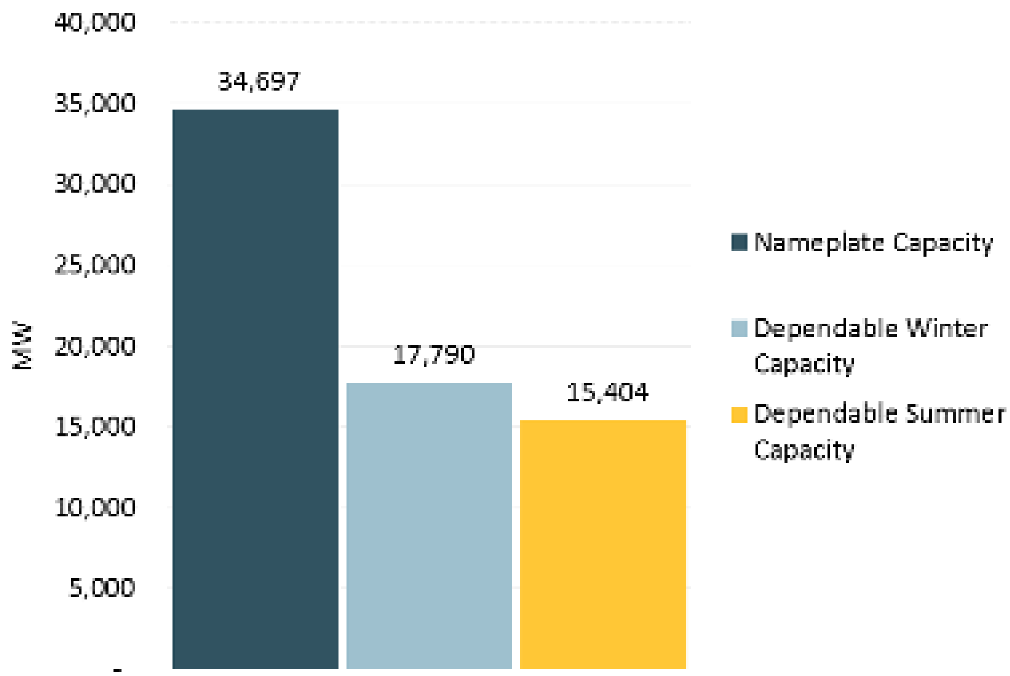
3.3.2.2 Demand Response Resources

The treatment of demand response (DR) resources in this study is simplified and their full capacity is assumed to contribute towards the regional reserve margin requirement. This may overstate the dependable capacity of DR resources because in reality they are energy limited, and have limits on the number of times they can be called as well as the duration of those calls.

3.3.2.3 Hydro Resources

The Pacific Northwest region has more than 34 GW of nameplate hydro capacity and extensive hydro reservoirs. However, the full capacity of these resources is typically not counted towards meeting the region's peak loads due to their energy limited nature as well as other non-power constraints on the hydro system. For the E3 model, a simplified static view of the hydro system was needed. E3 selected the sustained dependable capacity values provided in the 7th Power Plan. The values are higher for the winter than for the summer. The nameplate capacity, the dependable winter capacity and the dependable summer capacity for the hydro fleet is shown in Figure 2.

Figure 2. Seasonal dependable capacity of hydro resource fleet in the Northwest.



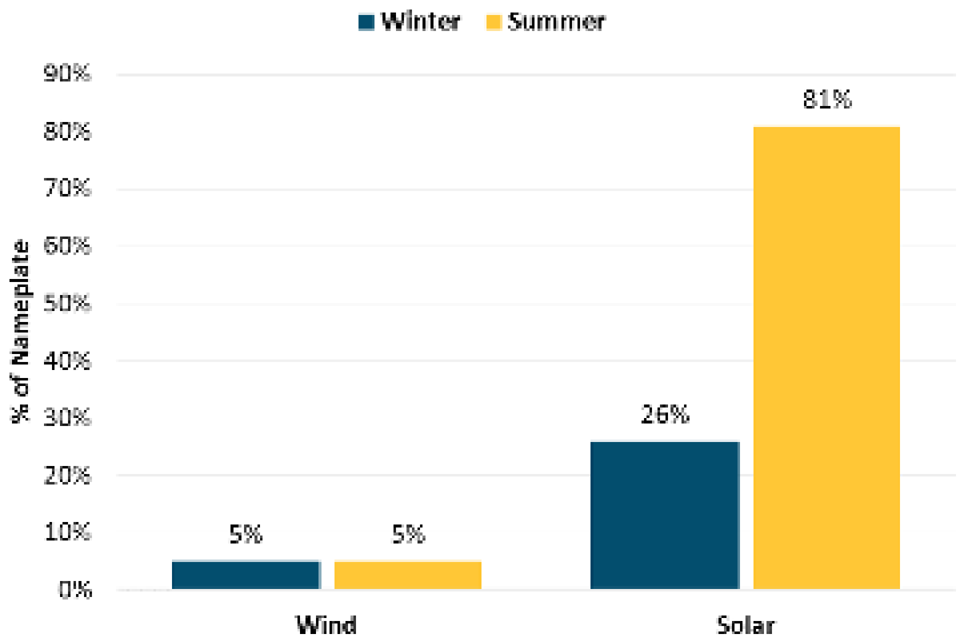
Even though this convention used for PRM purposes, it does not mean that the planning horizon assumes critical water conditions for the study period. With a different convention used for hydro dependable capacity, a different PRM would be calculated, but the identified capacity need would still be the same.

3.3.2.4 Renewable ELCC

Variable renewable resources do not usually contribute their full nameplate capacity towards meeting system peak needs. Due to their intermittent generation, to estimate the contribution of renewables to system peak, effective load carrying capacity (ELCC) of renewables is used. The ELCC metric helps translate the renewable production as a fraction of nameplate capacity during a peak load event.

For developing estimates for wind and solar ELCC, E3 used the Council's 7th Power Plan. In Chapter 11 of the 7th Power Plan, the Council provides a system adequacy assessment. In this assessment, the 7th Power Plan provides assumptions related to dependable capacity of wind and solar resources. For wind resources, E3 used the Power Plan's assumption of 5% ELCC for wind resources for both winter and summer. For solar resources E3 used the 'Associated System Capacity Contribution' (ASCC) metric of 26% in the winter and 81% in the summer, which is the closest to an ELCC metric provided in the Power Plan. The variable renewables ELCC assumptions by season are provided in Figure 3.

Figure 3 Seasonal ELCC for wind and solar resources as a fraction of their nameplate capacity.



3.3.3 PLANNING RESERVE MARGIN REQUIREMENT

After aligning the input assumptions with the Council's adequacy assessment and 7th Power Plan, E3 derived a planning reserve margin in a simplified manner that yielded approximately the capacity need for winter 2023 published by the Council. The planning reserve margin therefore is directly tied to the input assumptions used in deriving it. The metric is treated as a calibration parameter and would change if the underlying assumptions, such as the dependable capacity of hydro resources or renewables ELCC, are changed.

Table 6 below summarizes these assumptions and how they are used to derive the PRM metric in the E3 model for the winter. The same PRM metric is then used for the summer analysis as well.

Table 6 Summary of winter assumptions used in model calibration and derivation of the planning reserve margin.

Resource	Dependable MW	Additional Detail
Total Dependable Capacity	34,422	
Imports	2,565	2,500 MW from CA + 65 MW firm imports
Generic Need identified in 2023 RA Assessment	700	
Total Resources	**37,687**	
Loads	**Load MW**	
1-in-2 Peak Demand	34,070	
Firm Exports	462	
Total Load	**34,532**	
Reserve Margin Need	**~10%**	**Ratio between Total Resources & Total Load**

4 Scenario Inputs and Assumptions

In order to create a reasonable range of expected capacity surplus or deficit for the region, E3 developed three scenarios using the model. The base scenario uses the assumptions aligned with the Council's 2023 Adequacy Assessment, extended through 2035. For the Low Need and High Need scenario, E3 varied key drivers such as loads, energy efficiency, demand response (DR) and availability of market imports from California. The scenario-specific loads, EE and DR assumptions were derived using a combination of inputs from the Council's 2023 Adequacy Assessment and the 7th Power Plan.

The resource assumptions were obtained from the Council's Power Plant database[2] and updated to reflect new information where applicable. The Power Plant database was published in 2015, so the coal retirement announcements since then have been reflected in the database by E3. The hydro and renewables dependable capacity are held constant across scenarios to maintain consistency with the derived planning reserve margin.

For the assumption of market imports available for the Northwest from California, E3 used a combination of the Council's 2023 Adequacy Assessment

[2] Can be accessed at https://www.nwcouncil.org/energy/energy-topics/power-supply

assumptions and internal analyses related to expected capacity position for California in the summer and winter.

A summary of the assumptions used in the three scenarios is provided in Table 7.

Table 7. Key assumptions across the Low Need, Base Case, and High Need scenarios.

Assumption	Low Need	Base Case	High Need
Load Forecast *(pre-EE)*	1.46%/yr (W); 1.73%/yr (S)	1.74%/yr (W); 1.92%/yr (S)	1.94%/yr (W); 2.21%/yr (S)
Energy Efficiency *(treated as a resource)*	**100%** of cost-effective EE	**100%** of cost-effective EE	**75%** of cost-effective EE
Demand Response	NWPCC Low	NWPCC Med	NWPCC High
Thermal Generation	Announced retirements		
Hydro Generation	Constant at today's levels		
Renewable Generation	Current plans		
Market Imports	3400 MW through 2023, 2100 MW by 2030 (W); 1400 MW in the near term, 0 in the long term (S)	2500 MW (W); 0 (S)	3400 MW through 2021, 0 after 2023 (W); 0 (S)

The detailed assumptions for each category are described in sections 4.1 to 4.6 below.

4.1 Load Forecast

E3 relied on a combination of the Council's adequacy assessment and 7th Power Plan to develop a reasonable range of low, mid and high load forecast trajectories. The 2023 Adequacy Assessment document is a near-term reliability outlook for a single snapshot year and is a more appropriate reference source for near-term peak load forecasts. The 7th Power Plan, by contrast, is a long-term planning document with less of a focus on near-term peak load forecasting. The 7th Power Plan is a more appropriate source for reasonable ratios between low, mid and high future load trajectories that incorporate uncertainty in drivers of loads. As a result, E3 used the 2023 Adequacy Assessment study to determine the mid scenario loads, but supplemented it with the ratios between low to mid and mid to high scenarios from the 7th Power Plan to create a range of load forecast assumptions. The mid scenario gross-load forecast (i.e. before the impact of energy efficiency or DR) was developed using a 3 step-approach as shown in Figure 4:

1) Begin with Council's 2023 Adequacy Assessment peak load forecast (which includes cost-effective energy efficiency)
2) Add back in the embedded cost-effective energy efficiency (treated explicitly as a resource in the E3 model)
3) Extrapolate the gross loads using the compound average growth rate for the 2020-23 period

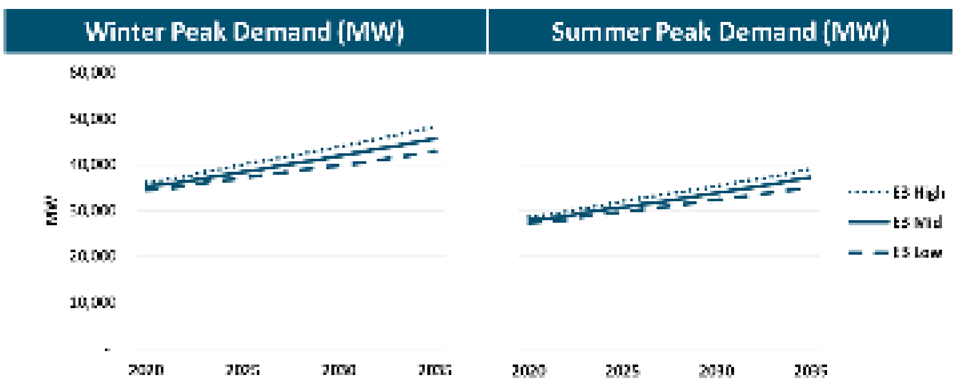
The derivation of the Base Case forecast consistent with the 2023 Adequacy Assessment and the resulting forecast is shown in Figure 4.

Figure 4. Development of mid scenario gross load forecast.

To develop a range of forecasts, E3 applied the ratios of mid to low loads and mid to high loads obtained from the 7th Power Plan to incorporate the expected ranges in pre-EE loads.

The resulting pre-EE load growth rates for peak loads in the winter are in the 1.5% - 1.9% range, whereas for summer they are higher, in the 1.7% - 2.1% range. The scenario specific peak load assumptions for winter and summer are shown in the figure below. Even though the summer peak grows at a rate higher than the winter peak, as seen in the figure below, it stays lower than the winter peak levels.

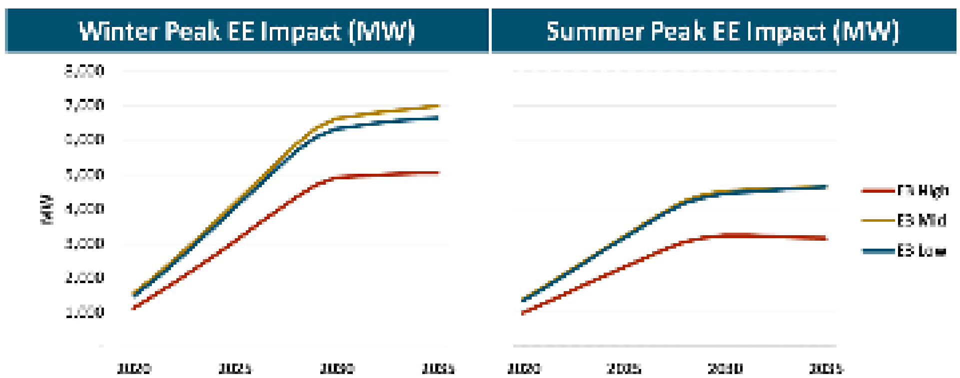
Figure 5. Seasonal peak load forecasts for the Low Need, Base Case, and High Need scenarios.



4.2 Energy Efficiency

In the E3 model, future achievement of energy efficiency is treated as an incremental supply resource (rather than embedding its effect in the demand forecast). This study relies on the estimated deployment of cost-effective energy efficiency identified by the Council in its 7th Power Plan; the Council's forecast achievement of efficiency is used directly in the Base and Low Need scenarios and derated by 25% in the High Need scenario. The assumed contribution of energy efficiency towards meeting peak loads is shown in Figure 6. Due to the achieved energy efficiency assumed to be 75% of the levels identified in the 7th Power Plan, the High Need scenario energy efficiency values are lower than the Base Case scenario assumptions.

Figure 6. Seasonal impact of energy efficiency on regional peak loads by scenario.



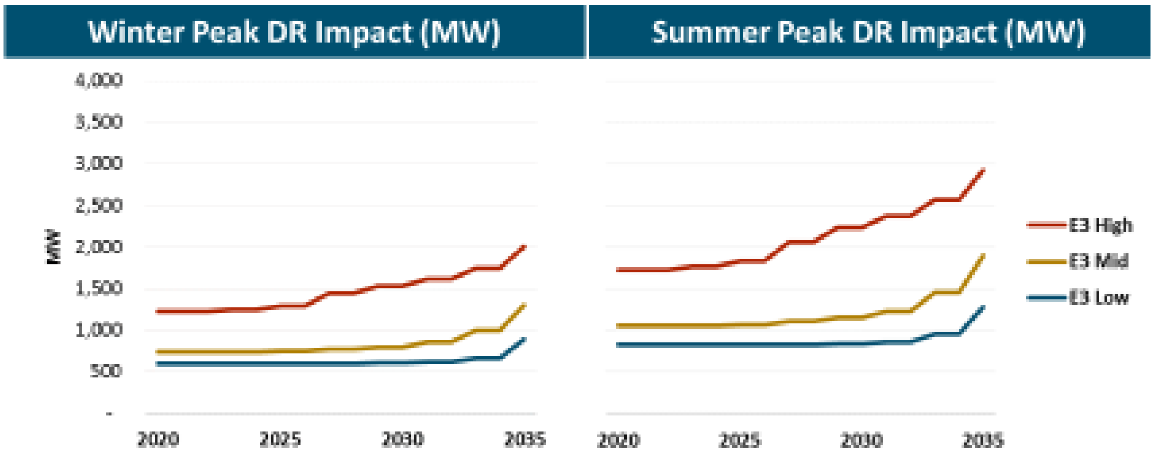
4.3 Demand Response

Similar to energy efficiency, E3 modeled demand response as a resource in the E3 model. To maintain consistency with loads and energy efficiency, the low, medium, and high DR assumptions from 7th Power Plan were used for the Low Need, Base Case, and High Need scenarios. The winter values from the 7th Power Plan were reduced by approximately one third, consistent with the Council's approach in the 2023 Adequacy Assessment, which adjusted the winter DR values due to "ongoing concerns about barriers to its acquisition."[3] The resulting

[3] The DR contribution to peak is not further adjusted to account for reduced capacity contribution due to impacts of call limited, time limited and snap back behavior.

assumptions for DR contribution to peak loads by season for the different scenarios are shown in Figure 7 below.

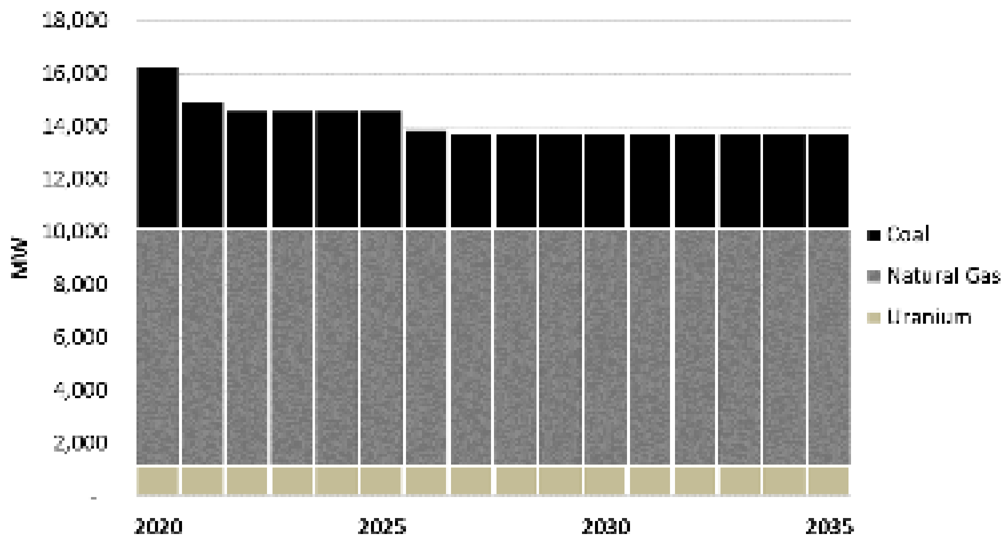
Figure 7 Seasonal impact of demand response on regional peak loads by scenario.



4.4 Thermal Resources

E3 used the Council's Power Plant database as a starting point to determine the available nameplate capacities of all the generators in the region. The total dependable capacity levels by thermal technology types were benchmarked to the Council's 2023 Adequacy Assessment. The coal retirement dates were updated to reflect the latest planned retirement schedules. The nuclear and gas resources were assumed to stay online for the study horizon.

Figure 8 Dependable capacities for coal, natural gas and nuclear resources in the Northwest over time.

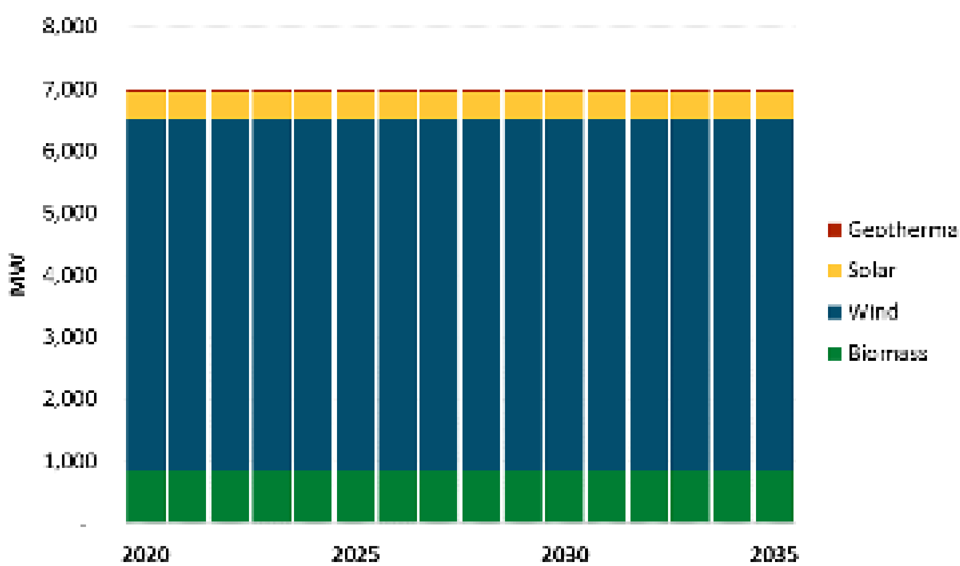


Among thermal resources, there are resources in the Northwest that fall under the category of 'independent power producers' or IPPs. These resources are physically located in the Northwest, but if not contracted to a particular in-region entity, may sell power to out of region markets. For IPPs, E3 assumed their full dependable capacity (~2.3 GW in 2023) was available for in-region demand needs in the winter, consistent with the assumption made by the Council in its modeling. For the summer, the IPPs availability is derated (1000 MW in 2023) to account for the likelihood of these resources selling into California, which is a summer peaking system, again consistent with the Council's 2023 Adequacy Assessment.

4.5 Renewables Resources

Nameplate capacities for renewables resources, both existing as well as planned, were obtained from the Council's power plants database. The planned renewables resources in different stages of development are provided in the power plants database. Consistent with the Council's adequacy assessment assumptions, E3 included the renewables resources that were under construction or were in advanced stages of development as demonstrated by a site certificate, engineering procurement and construction contract, and/or an announced construction schedule. As described in section 3.2.2, the nameplate capacities were translated to ELCC metrics using static assumptions for both wind and solar.

Figure 9. Nameplate capacities for existing renewable resources in the Northwest.

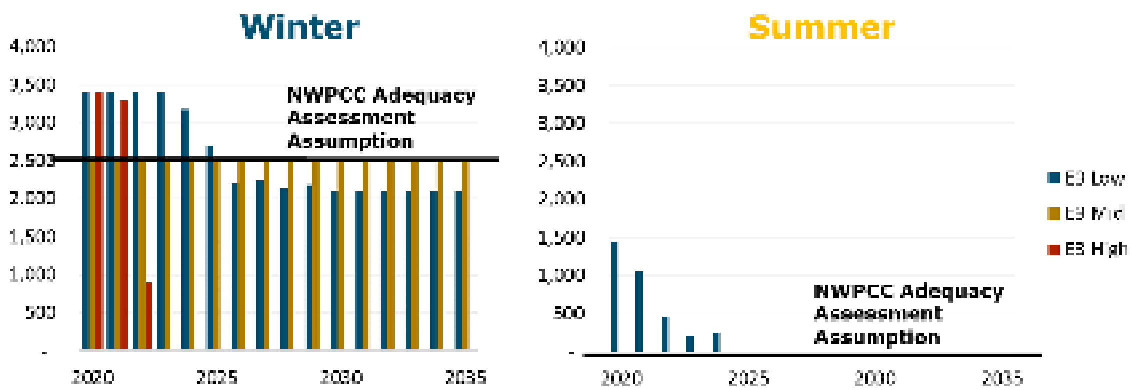


4.6 Availability of California Imports

The availability of imports from California into the NW was varied by scenario. For the mid scenario, the assumptions were aligned with the Council's adequacy assessment. For the Low Need and High Need scenarios, E3 estimated the available surplus for the NW through an analysis of CAISO load-resource balance for the winter and summer. For its CAISO calculations, E3 relied on the California Energy Commission's (CEC) load forecasts and California Public Utilities Commission's (CPUC) integrated resource planning model's resource availability assumptions.

The maximum import availability is capped at 3400 MW, which is the 95th percentile transfer capability on the transmission system from California to the Northwest.

Figure 10. Annual availability of imports into the Northwest from California by season for the three modeled scenarios.



As seen in Figure 10, in the near-term, the winter surplus is higher than the Council's adequacy assessment assumption for the low need and high need scenarios. This is because in the near-term, E3 calculations for the CAISO loads and resources balance show a surplus in the winter. In the longer-term, E3 calculations used for the low as well as high scenario show imports from California into the Northwest being less than those assumed by the Council's adequacy assessment due to a combination of increasing winter loads in California as well as once-through cooling thermal plant retirements. For the summer, the low scenario calculations by E3 assume low load growth in the summer resulting in a surplus of capacity in the near term. For the mid and high scenarios, California does not have surplus power to export to the Northwest in the summer.

5 Results and Conclusions

Using the assumptions described in Sections 3 and 4 for the different scenarios, E3 developed:

+ A range of capacity position estimates for the NW region as a whole
+ A range of available market surplus capacity for PGE

To allocate the available regional surplus to PGE, if any, E3 used PGE's peak load share of the regional peak for summer and winter. Using data on peak load forecasts obtained from PGE, E3 calculated the winter share for PGE to be ~10% and the summer share to be ~12%.

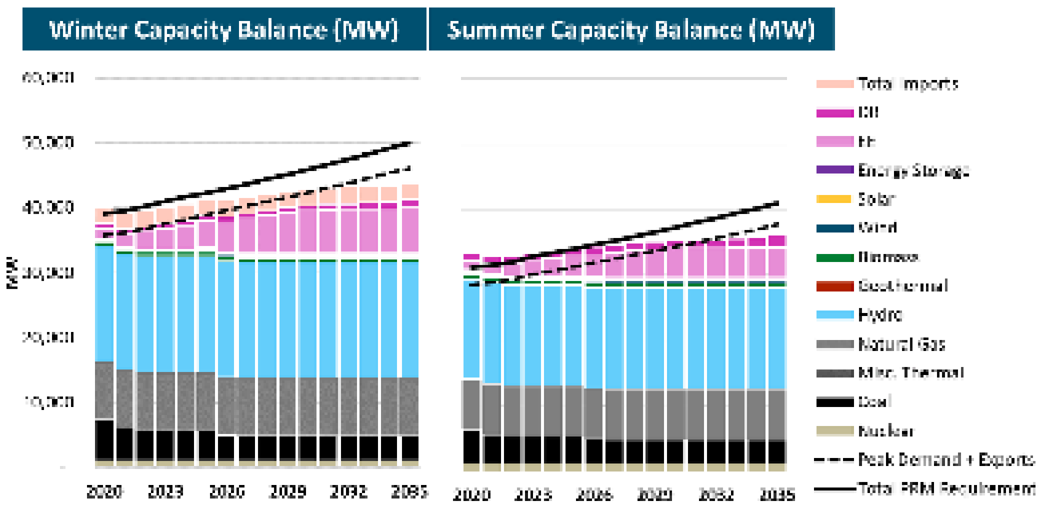
It should be noted that this study does not impose additional constraints, such as transmission system constraints, which may impact the ability of PGE to utilize regional capacity to serve customer loads.

5.1 Regional Results Summary

Across the three scenarios, winter load-resource balance is reached between 2021 and 2026 for the winter, and 2023 to 2029 for the summer.

Figures below shows the seasonal capacity position results for the three scenarios annually.

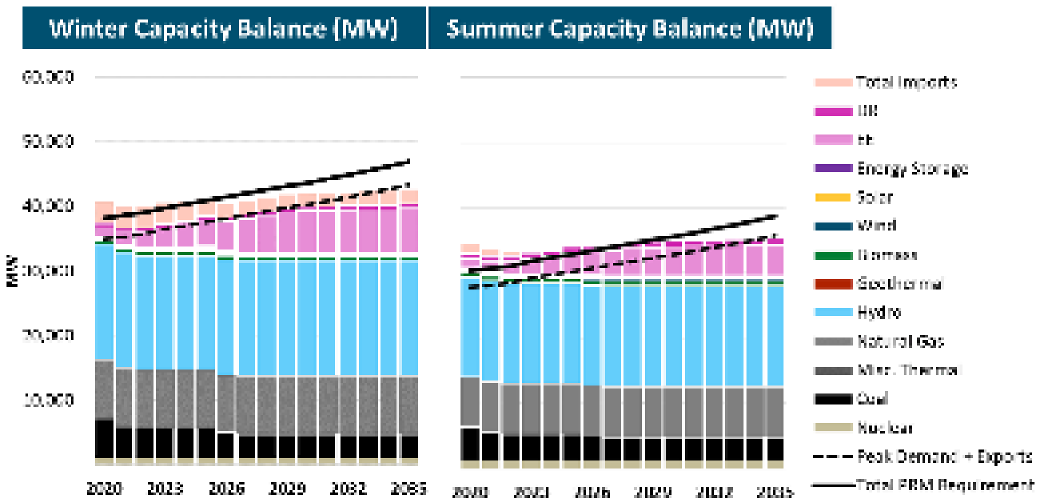
Figure 11. Base Case scenario annual capacity position results for the Northwest by season.



For the Base Case, the region maintains a capacity surplus until 2020 in the winter and 2025 in the summer. The winter capacity deficit seen starting in 2021 is consistent with the Council's adequacy assessment outlook as well as the BPA White Book.

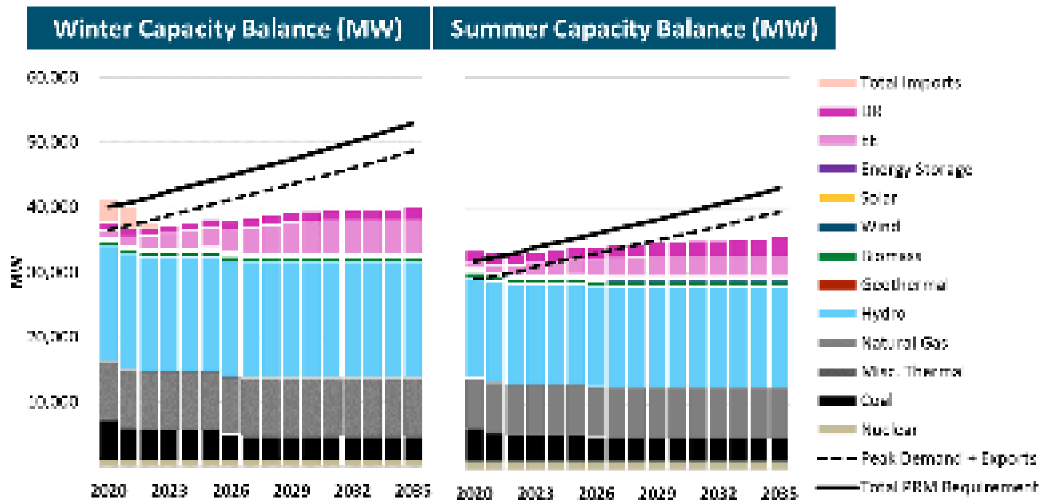
For the Low Need scenario, a combination of lower loads and higher imports available from California pushes out the capacity deficit year to 2026 for the winter and 2029 for the summer as shown in Figure 12.

Figure 12. Low scenario annual capacity position results for the Northwest by season.



Lastly, for the High Need scenario, the assumption of higher loads and lower availability of imports from California results in a winter capacity deficit for the region in 2021 which is greater in magnitude than the Base Case, and a summer capacity deficit in 2023 as shown in Figure 13.

Figure 13. High scenario annual capacity position results for the Northwest by season.



The summary for the year in which the region has a net capacity short position for the different scenarios is provided in Table 8 below.

Table 8. Year in which the region experiences a capacity deficit for the three different scenarios.

	First Year of Capacity Deficit	
Scenario	Winter	Summer
Low Need Scenario	2026	2029
Base Case	**2021**	**2026**
High Need Scenario	2021	2023

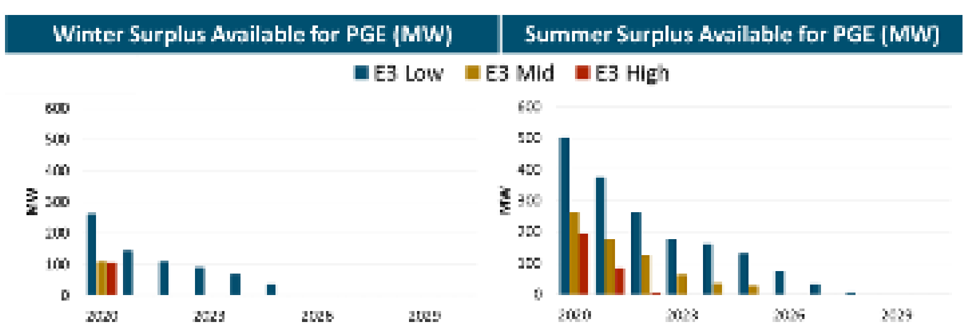
5.2 PGE Market Surplus Results Summary

To derive recommended input assumptions for PGE's IRP analysis, this study assumes the share of regional surplus capacity available to PGE is roughly equal to its load-ratio share within the broader region. In years of capacity surplus for the region, PGE is allocated its peak share of the available surplus by season. This approach results in the following seasonal results across scenarios:

+ In the winter, the Low Need scenario shows a capacity surplus available for PGE through 2025. In the Base Case and High Need scenarios, there is no winter market surplus starting in 2021.
+ In the summer, the market surplus is available through 2022 for all scenarios, which is later than the winter estimates. Even though summer peaks are growing at a higher rate than the winter, the winter in the region is more constrained in its ability to meet peak loads.

Figure 14 shows the resulting market surplus capacity PGE can rely on for its planning purposes.

Figure 14. Net annual surplus market capacity available for PGE by scenario.



5.3 Key Takeaways and Additional Considerations

As seen in section 5.2, PGE can rely on 100 MW – 250 MW of winter market surplus in 2020 depending on load growth in the region and availability of market imports from California. For the summer, PGE can rely on 100 MW – 500 MW of market surplus through 2021 and a smaller amount thereafter depending on load growth and imports availability.

The E3 model primarily examined the effect of loads, EE, DR and imports available from California to create its recommendations for seasonal market surplus. However, thermal plant retirements not captured in this modeling exercise could result in a net short position for the region sooner. Similarly, the development of new resources could push out the need for new capacity and enable a higher level of market purchases of surplus capacity for PGE.

Lastly, the IPP resources located in the region, if contracted to entities outside of the Northwest, could result in a net capacity deficit sooner.

External Study F. Flexible Adequacy Report

FLEXIBILITY ADEQUACY STUDY

Ana Mileva

Blue Marble Analytics | https://www.bluemarble.run

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Flexibility Literature Review

Background

Traditional industry reliability metrics such as the 1-in-10 loss of load expectation (LOLE) standard can be used to understand the probability of reliability events because of generator outages. These metrics focus on peak load conditions, requiring that a planning reserve margin, i.e. some capacity above peak load, be held to ensure reliability. They assume that the operational capability will exist to avoid any additional loss of load due to operational flexibility shortages. We use the term “flexibility” to describe the system’s ability to avoid reliability events due to the variability and uncertainty of net load.[1] While maintaining a planning reserve margin may have so far been sufficient to ensure load was met even if some generators experienced outages, the assumption that a capacity-adequate system will be sufficiently reliable is coming under scrutiny with higher shares of variable renewables. Capacity-adequacy may not be sufficient to avoid certain operations-related reliability events. Accordingly, accounting for the flexibility needs and characteristics of the system – e.g. large ramps or forecast errors – is needed to ensure an adequate level of reliability.

Unlike the well-established standards for capacity adequacy, widely used and accepted industry-standard metrics of power system flexibility and flexibility-adequacy do not currently exist. Few utilities have explicitly considered flexibility in their integrated resource plans (IRPs) and much of the literature on flexibility is still in the thought-leadership phase (Table 1). Though not widely used, the literature does provide metrics that could be utilized to measure various aspects of system flexibility and incorporated into planning processes.

[1] Net load is the load minus variable energy production.

Table 1. Literature reviewed

Entity	***Study***	***Type***	***Flexibility Metrics***
PGE [1]	2016 IRP	IRP	Reliance on intra-day capacity product; curtailment
Puget Sound [2]	2017 IRP	IRP	Unserved energy; reserve shortages; curtailment
PNM [3]	2017 IRP	IRP	LOLE Flex, EUE Flex; curtailment
CAISO [4]	Final Flexible Capacity Needs Assessment 2019	Planning	Max 3-hour net load ramps by season
NWPCC [5]	Seventh Power Plan	Planning	Upward flexibility (headroom) over different time horizons (e.g. by month, time of day, etc.)
BPA, EPRI, NWPCC [6]	2015 Flexibility Assessment Methods DRAFT	Thought-leadership	Upward flexibility (headroom) over different time horizons (e.g. by month, time of day, etc.)
EPRI [7], [8]	Various	Thought-leadership	Periods of flexibility deficit; insufficient ramping resource expectation; expected unserved ramping
LBNL [9]	Flexibility Inventory for Western Resource Planners	Thought-leadership	Flexibility "inventory" & demand-supply balance screening
CES-21 Program [10]	Flexibility Metrics and Standards Project	Thought-leadership	LOLE Flex (multi-hour and intra-hour)
IEA [11]	Harnessing Variable Renewables	Thought-leadership	Flexibility "inventory"
LLNL [12]	Flexibility Metrics to Support Grid Planning and Operations	Thought-leadership	Literature review
NREL [13]	Advancing System Flexibility for High Penetration Renewable Integration	Thought-leadership	Literature review
Anderson and Matevosyan (2017) [14]	"Flexibility studies in system planning at ERCOT," IEEE	Academic	Headroom; expected unserved ramp
Lannoye et al. (2012) [15]	"Evaluation of Power System Flexibility," IEEE	Academic	Insufficient Ramping Resource Probability

Screening Metrics for Flexibility

Flexibility Demand

Understanding the demand for flexibility is the first step in studying system flexibility. This may require measuring both the variability and the uncertainty of net load, i.e. a calculation of the magnitude and/or distribution of net load ramps and net load forecast errors over different timescales.

No established method exists for measuring flexibility demand and incorporating it into system planning, and the timescales of interest appear to differ from system to system. For example, the California Independent System Operator (CAISO) incorporates flexibility requirements into its resource-adequacy analysis by considering the projected maximum 3-hour net load ramp by month [4]. The CAISO also has an intra-hour "flexible ramping" market product and is working on aligning its treatment of flexibility in planning and operations [16]. Intra-hour flexibility needs are often the main concern for system planners. In its 2017 Integrated Resource Plan (IRP), for example, Puget Sound Energy (PSE) calculates "flexibility" reserves on a month-hour basis based on the 95 percent confidence interval for the anticipated deviation of net load at the real-time 5-minute interval level compared to the day-ahead hourly value [2]. Two thought-leadership studies, by the International Energy Agency (IEA) [11] and Lawrence Berkeley National Laboratory (LBNL) [9], track flexibility demand over four time intervals, 15 minutes, 1 hour, 6 hours, and 36 hours, assuming three times the standard deviation of the ramp and forecast error distribution must be covered over each time interval for net load.

Flexibility Supply

A simple method for understanding the available flexibility – the flexibility supply – is to provide an inventory of the system's resources and their flexibility characteristics such as ramp rates, minimum loading levels, minimum up and down times, etc., and the system's import and export capacity [9]. In addition to the generator operational characteristics, a more sophisticated methodology developed in [11] and [9] attempts to account for the system's operational conditions at a high level by estimating "typical dispatch" to describe the likely state of a generator and hence its likely upward and downward available flexibility. The estimate is based on historical data and depends on the generator type, merit order, and the load conditions (peak or low load). Finally, the effective ramping capability (ERC) is a metric proposed in [17]. Based on the traditional metric describing a unit's capacity contribution – the effective load-carrying capability (ELCC) – the ERC attempts to estimate a unit's contribution to meeting changes in net load. On the demand side, a measure of flexibility could be the fraction of load under an interruptible tariff [18].

Flexibility Demand-Supply Balance

Understanding the balance between flexibility supply and demand is critical to system-planning. A few high-level screening metrics exist for comparing flexibility supply and demand. As part of the transmission-planning process at the Western Electricity Coordinating Council (WECC), for example, planners have used the ratio of natural gas-fired combustion turbine (CT) capacity and 15 percent of hydropower capacity to the nameplate capacity of wind as the "flexible resource indicator" [19]. A more sophisticated "early warning" indicator used in [9] is the "flexibility ratio" (the ratio of the calculated flexibility supply and flexibility demand); if it is more than 1, sufficient flexibility exists to avoid reliability events, and the changes in the ratio over time can provide useful information about the trend in system flexibility balance.

The authors of [9] validated their screening methodology against the results of PSE's own analysis in its 2013 IRP, and found the former indicated more flexibility problems. As potential reasons for the difference, they point to their more conservative estimate of hydro flexibility and risk tolerance as well as the fact that PSE used hour-ahead unit commitment – not historical typical dispatch – to determine if combustion turbines should be started to provide more flexibility. While a screening methodology may be useful to provide a first-pass indicator of flexibility sufficiency, a more thorough treatment of the system's operating conditions, capabilities, and constraints may be needed to provide a deeper understanding of system flexibility.

Using Production Cost Simulation for Flexibility Analysis

A number of traditional metrics from production cost simulation can potentially be used as proxies for system flexibility [13]. Metrics that can indicate insufficient flexibility include unserved energy (e.g. in [2], [3]), operating reserve shortages (e.g. in [2]), renewable curtailment (e.g. [1], [2], [3]), price spikes (similar to [1]), negative prices, Control Performance Standard (CPS) violations such as a positive or negative Area Control Error (ACE) (e.g. [2]), etc. Large differences between the day-ahead and real-time prices can also suggest inflexibility [12].

A few metrics that can be derived from production cost simulation results can be used to more directly measure system flexibility. These include:

$LOLE_{FLEX}$

Traditional LOLE models could be adapted to account for system operations and ensure that the power system can maintain a certain level of reliability with both capacity and flexibility considered in estimating the probability of reliability events. An alternative is to use production cost simulation to understand flexibility-related problems and add those to any capacity-adequacy events in order to gauge overall system reliability. However, a challenge with using the production cost simulation results for unserved energy for flexibility analysis is to avoid double-counting, i.e. it is necessary to distinguish between loss of load due to flexibility shortages and those that can be attributed to capacity shortages. The $LOLE_{FLEX}$ metric used in [3] and [10] can measure loss of load due to flexibility shortfalls. Whenever a loss of load event is detected, it is first necessary to check if additional capacity was available but not dispatched/committed. If the answer is no, then the loss of load event is due to inadequate capacity and is added to the traditional LOLE metric ($LOLE_{Capacity}$). If the answer is yes, then the loss of load event can be attributed to a flexibility shortfall ($LOLE_{Flex}$). $LOLE_{Flex}$ is then further subdivided into $LOLE_{Multi\text{-}HourRamp}$ if a ramp deficiency is observed and $LOLE_{IntraHour}$ if not.

A key advantage of $LOLE_{Flex}$ is that is based on the traditional LOLE metric, putting the magnitude and frequency of flexibility-related reliability events in context. However, no established standard exists for the amount of $LOLE_{Flex}$ that a system may allow. Furthermore, the metric does not provide information on the state of the system, i.e. how close it may be to experiencing a shortage, if no loss of load is observed.

Net Upward/Downward Flexibility

A metric that could provide further information about the times when the system may be under flexibility stress – even when no reliability events occur – is the net upward flexibility for upward shortages (loss of load) and net downward flexibility for downward shortages (overgeneration). We also use the terms headroom and footroom for the net upward and downward capability respectively.

Headroom is the total amount of capacity available in a given time period minus the capacity used to meet system requirements such as load and reserves. It measures the additional upward capability available to ramp up the system's resources. The available headroom can be further limited by a generator's ramp rate over a certain time period.

The Electric Reliabiltiy Council of Texas (ERCOT) has used the net flexibility metric, part of the InFLEXion tool developed by the Electric Power Research Institute (EPRI) [14]. The metric measures the magnitude of available upward or downward capability for a given time and time horizon, and it can provide an informative visual representation of the highest-stress times for the system.

Insufficient Ramp Resource Expectation (IRRE)

IRRE is a probabilistic metric developed by [15] that measures the expected number of events when a power system will be unable to meet the net load ramps over a given time horizon. For the purpose, one must compare the distribution of ramps and the distribution of available flexibility (based on historical data or production cost simulation time series results and generator operational characteristics) [13]. The IRRE approach is similar to the traditional LOLE metric from resource-adequacy studies but applied to operational flexibility [20]. Calculating IRRE requires a large amount of data for robustness. In contrast to the traditional LOLE standard, no standard exists for what an acceptable IRRE should be for a power system.

Periods of Flexibility Deficit (PFD), Expected Unserved Ramping (EUR), and Flexibility Well-Being Assessment

The PFD is similar to IRRE, but it does not use a probabilistic approach. PFD is a deterministic metric that can be used to keep track of the number of flexibility deficit events during a certain time period (e.g. a simulated year) by comparing the available flexibility from the simulated production time series and the net load ramps directly rather than creating probability distributions [13]. A drawback of the metric is that it can only be used to measure frequency but not the magnitude of flexibility shortage events. EUR can be used as a complementary metric, as it measures the magnitude of flexibility events. In combination, the two metrics can be used to create a "flexibility well-being assessment," e.g. low-frequency-high-magnitude and high-frequency-low-magnitude events could be deemed problematic but events that occur less frequently or are smaller may not [8]. However, no standard exists for what levels of PFD and EUR levels are acceptable and what levels may warrant action.

Conclusions

The literature on flexibility metrics and flexibility adequacy is still limited. While flexibility is often mentioned, no widely-accepted definitions and metrics of flexibility exist, and neither is there an industry standard for what constitutes flexibility adequacy.

In the IRP context, production cost simulation has been the main tool for system flexibility analysis. Some relevant questions for PGE's flexibility analysis include:

- What are the most important flexibility timescales for PGE's system (e.g. intra-hour load-following, hourly or multi-hour ramps, day-ahead forecast error, etc.)?
- Are there seasonal trends in flexibility supply-demand balance? A number of entities have observed such trends, although the exact dynamics vary from system to system. Understanding the seasonal patterns of flexibility demand and supply on the PGE's system is an important step in planning and operating a flexibility-constrained system.

PGE System Flexibility Analysis

Flexibility Metrics

To investigate the flexibility of PGE's power system, we use the ROM production cost model. Additional details about ROM can be found in section 7.2.1.1 of the 2016 PGE IRP and Appendix D of the 2013 PGE IRP. The ROM flexibility analysis focuses largely on upward flexibility challenges. Market access for sales from the system is constrained to the transmission limit, resulting in low curtailment levels. In designing the study, we have two key considerations:

1) While a number of metrics from production cost simulation exist that could indicate insufficient flexibility – for example, unserved energy or reserve shortfalls – it is important to distinguish between reliability events that can be attributed to insufficient flexibility and those due to inadequate capacity.
2) Even when not observing reliability events, our goal is to understand the underlying flexibility state of the system, i.e. how close to a flexibility-related violation the system might be.

We use two main metrics in this analysis: unserved energy due to flexibility shortages (USE_{Flex}) and system headroom. The former metric is adapted from [10] and the latter from [5], [6], and [14].

USE_{Flex}

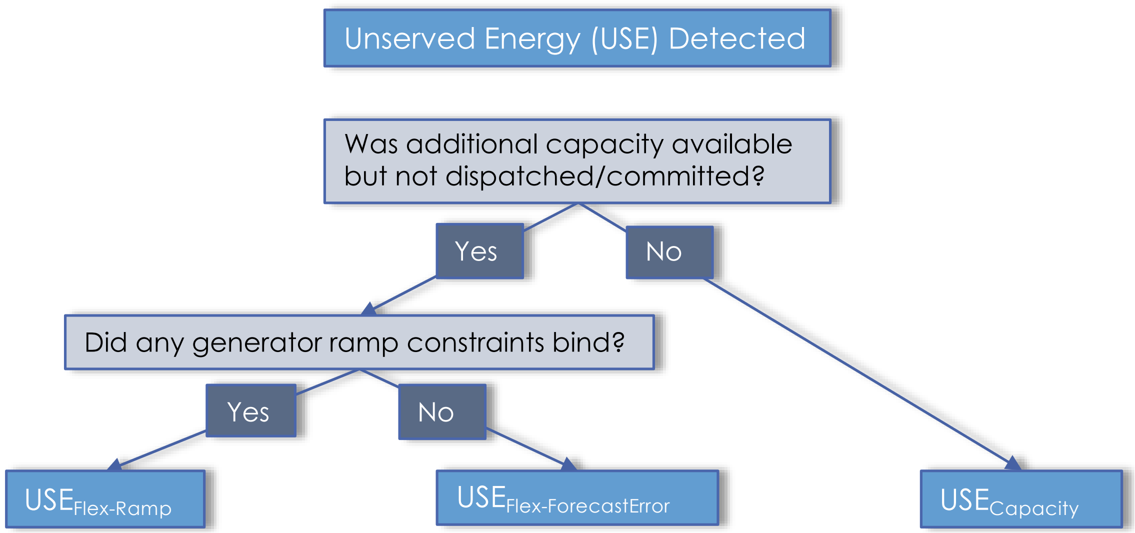
The first metric we use to analyze and understand the flexibility of PGE's system is USE_{Flex}. Unserved energy is the main way in which problems due to upward flexibility challenges – either large ramps or forecast error – manifest themselves. Since we only simulate a single "average" year for hydro conditions, renewable resource output, and load, this is not a metric of "expectation" or "probability" like $LOLE_{Flex}$, but rather an accounting of the frequency and magnitude of these events in the modeled future year.

In order to decide whether the observed violations are due to insufficient flexibility or to inadequate capacity, we adapt the method used in [10]. Whenever we observe unserved energy, we follow the decision process described in Figure 1.

The first decision point is to determine whether capacity is available on the system that is not dispatched and/or committed. If not, we ascribe the reliability event to insufficient capacity and add the shortage to $USE_{Capacity}$, the unserved energy attributable to resource inadequacy, not flexibility inadequacy. If additional capacity is available during the time with unserved energy but is not running, we attribute the unserved energy to insufficient flexibility and further divide these events into two flexibility types.

The second decision point allows us to understand whether the flexibility event is caused by insufficient ramping capability or by forecast error. In the former case, capacity is available and running, but output cannot be adjusted fast enough to follow net load, manifesting itself as a binding ramp constraint; in the latter case, there are no binding ramp constraints and the reliability event occurs because of a difference between the net load forecast (usually in the day-ahead commitment stage) and the realized net load that the system is not able to adjust to, e.g. because of under-commitment of resources.

Figure 1. Decision Tree for Determining USE Type

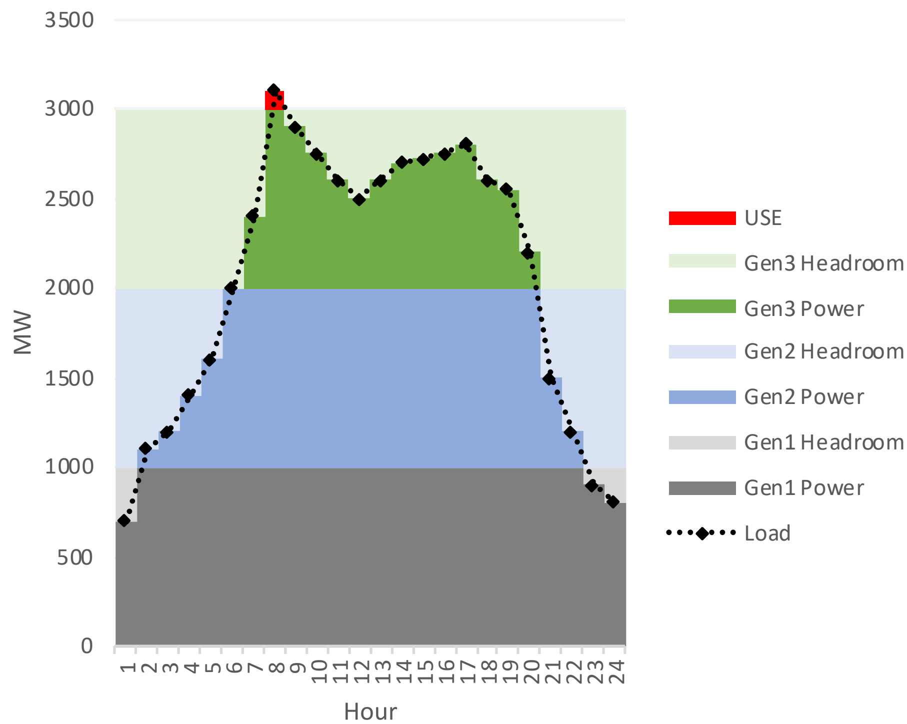


System Headroom

In addition to reliability events due to flexibility shortages, we also investigate when the system is under flexibility stress, i.e. how close the system may be to experiencing an event even when no shortages occur. In particular, we use the "system headroom" metric as an indicator of available flexibility.

System headroom is the amount of capacity available in a given time period minus the capacity used up in order to meet system requirements such as load and reserves, i.e. how much additional upward capability is available to ramp up the system's resources within a certain amount of time. In the illustrative example in Figure 2, an illustrative system has three generators, each with a capacity of 1,000 MW. Initially, load is under 1,000 MW, so the first generator is serving load with some of its capacity and providing headroom with the rest; the full capacity of the other two generators can count toward the system headroom. As load goes up during the day, the amount of available headroom gradually decreases until it reaches zero: this is where the available resources are exactly equal to load. If load continues to increase beyond the point where headroom is zero, the system experiences USE. The available headroom may be further limited by a generator's ramp rate over a certain time period.

Figure 2: Net Upward Capability (Headroom) Illustrative Example



Model Set-up

The Resource Optimization Model (ROM), a production cost model specific to Portland General Electric (PGE), is used to simulate an annual view of the PGE system. ROM is a multi-stage optimal commitment and dispatch model. Within ROM, scenario and system inputs were updated for 2025. ROM models a set of average-year conditions for the year of interest; these inputs include load, variable energy resource output, and hydro output. The variable energy resources include those currently existing and contracted for 2025.

Market access for purchases is consistent with the 2019 IRP Market Capacity Study in the on-peak summer and winter periods, and is constrained to transmission limits in other time periods. Market access for sales is constrained to transmission limits. For modeling purposes, an expensive day-ahead (DA) on-peak capacity product is available to the system to provide capacity. The DA on-peak capacity product is available in 100 MW increments for the 16-hour on-peak block. If selected in the DA, the DA on-peak capacity product is also present in the hour ahead (HA) and real time (RT) stages. Availability of the expensive, inflexible DA on-peak capacity product allows the system to reach resource adequacy when market availability is very limited in the on-peak summer and winter periods.

PGE's description of ROM can be found in the Section 4.6 and the Modeling Details Appendix of the 2019 PGE IRP.

Base Case Results

USE_{Flex}

In our study set-up, unserved energy is the main indicator of possible insufficient upward flexibility. We use the USE_{Flex} method described above to determine whether the unserved energy events are flexibility-related, and whether they are driven by ramping constraints or by forecast error.

In the Base Case, unserved energy in the real-time stage occurs 0.16 percent of the time for a total of 800 MWh over the course of the year (Table 2). All unserved energy occurs during times when the DA capacity product is not fully committed, i.e. additional resources are available on the system that are not utilized, so the unserved energy events are flexibility-related, not the result of inadequate capacity. None of the generator ramping constraints binds during the times with unserved energy: the flexibility events are caused by forecast error, not insufficient ramping capability. All real-time unserved energy in the Base Case is therefore $USE_{Flex\text{-}ForecastError}$.

Table 2. Unserved Energy in the Base Case

Real Time Unserved Energy (USE)	
# Timepoints	57
% Timepoints	0.16%
Total MWh	800
Max MW	178

Seasonally, the unserved energy is concentrated in the winter morning peak hours (Table 3). Hour 8 in February experiences the most unserved energy: 25 percent of the time for an average of 21 MW short of meeting load. The morning peak "shoulder" hours (hours 7 and 8) and the evening peak hours (hours 19 and 20) experience unserved energy 4 to 5 percent of the time, averaging 1 to 3 MW of unserved load. Some unserved energy also occurs in the morning and evening peak hours in January, but the magnitude is small (<1 MW on average).

Table 3. Seasonal Distribution of Unserved Energy in the Base Case. Top: MWa USE by Month and Hour; Bottom: USE Event Frequency by Month and Hour

Hour Ending

MWa USE

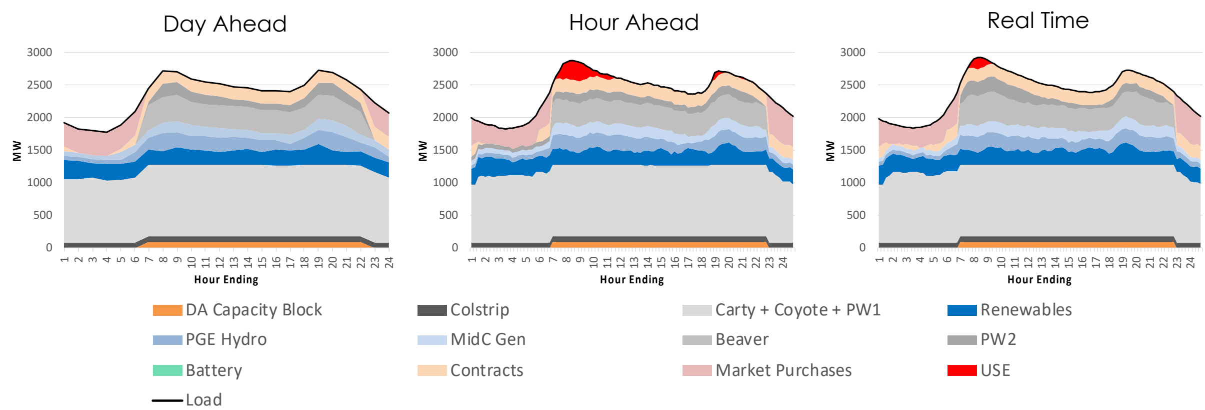
	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
Jan	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Feb	0	0	0	0	0	0	3	21	1	0	0	0	0	0	0	0	0	0	2	1	0	0	0	0
Mar	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Apr	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
May	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Jun	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0.0	0	0	0	0	0	0
Jul	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Aug	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Sep	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Oct	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Nov	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Dec	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0

% Time with USE

	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
Jan	0%	0%	0%	0%	0%	0%	0%	4%	0%	0%	0%	0%	0%	0%	0%	0%	1%	2%	2%	0%	0%	0%	0%	0%
Feb	0%	0%	0%	0%	0%	0%	5%	25%	4%	0%	0%	0%	0%	0%	0%	0%	0%	1%	4%	3%	0%	0%	0%	0%
Mar	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
Apr	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
May	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
Jun	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
Jul	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	1%	0%	0%	0%	0%	0%
Aug	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
Sep	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
Oct	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
Nov	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
Dec	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%

The observed USE is caused by load forecast error and under-commitment of the DA capacity product. An example operating day illustrates the flexibility challenges encountered by the system (Figure 3). This is the system's DA schedule, HA schedule, and RT dispatch on the February day with the highest peak and total level of unserved energy in the ROM flexibility analysis Base Case results. The DA peak load forecast for this day is moderate at around 2,750 MW in hours ending 8 and 9, so the model commits only 100 MW of DA capacity. Intra-day, however, the load is higher than anticipated: the morning peak net load is 200 MW higher in RT than forecasted in the DA. While the hydro system and gas generators adjust their output to help meet the morning peak, the system does not have sufficient recourse actions intra-day to compensate for the load forecast error, and unserved energy occurs during hours ending 7, 8, and 9. Additional resources do exist – more DA capacity could have been committed in the DA stage – but within the day, the system is not able to adapt to the change in load conditions. The observed unserved energy is a flexibility event caused by forecast error and the inability to re-commit DA capacity within the day.

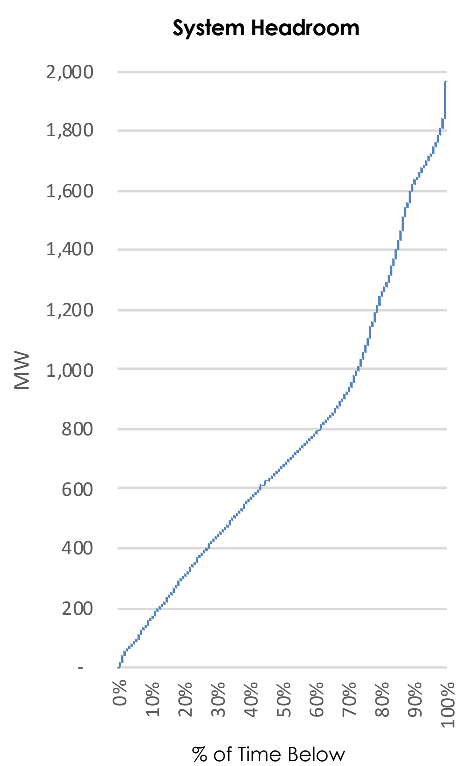
Figure 3. Hourly DA Schedule, HA Schedule, and RT Dispatch on a February Day



System Headroom

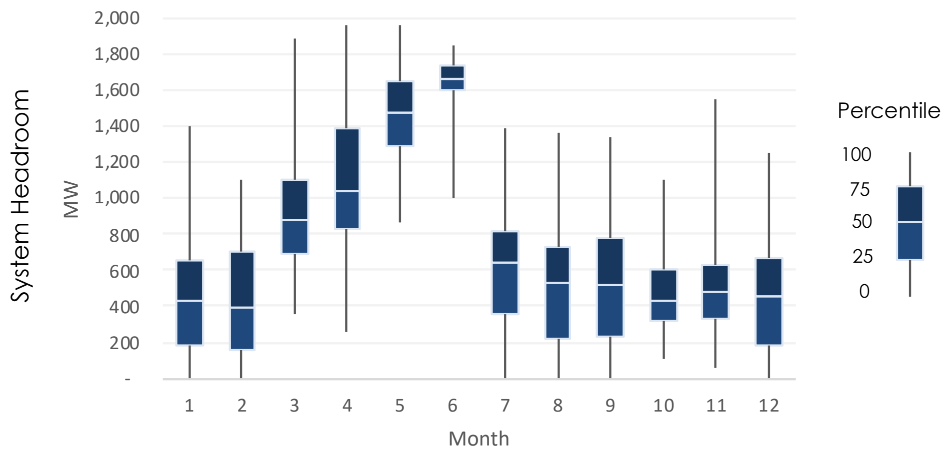
In addition to USE_{Flex}, the main metric of flexibility shortage, the underlying flexibility state of the system, i.e. how close the system may be to experiencing a flexibility-related event even if no shortages are observed, is also of interest. Figure 4 shows a duration curve of system headroom in the Base Case. The available system headroom can reach up to 2000 MW but is 200 MW or less 10 percent of the time, and 100 MW or less 5 percent of the time in the modeled year.

Figure 4. Duration Curve of System Headroom in the Base Case



On a seasonal basis (Figure 5), PGE's system is most constrained in the winter when system headroom is 200 MW or less 25 percent of the time and reaches zero in all three winter months. While no USE occurs in the summer in the Base Case, the system headroom metric shows that summer headroom conditions are only slightly better than those in the winter, with headroom of just over 200 MW 25 percent of the time in August and September, and also reaching zero in July, August, and September. System headroom is most plentiful in the spring months, followed by the fall months.

Figure 5. System Headroom Quintiles by Month in the Base Case



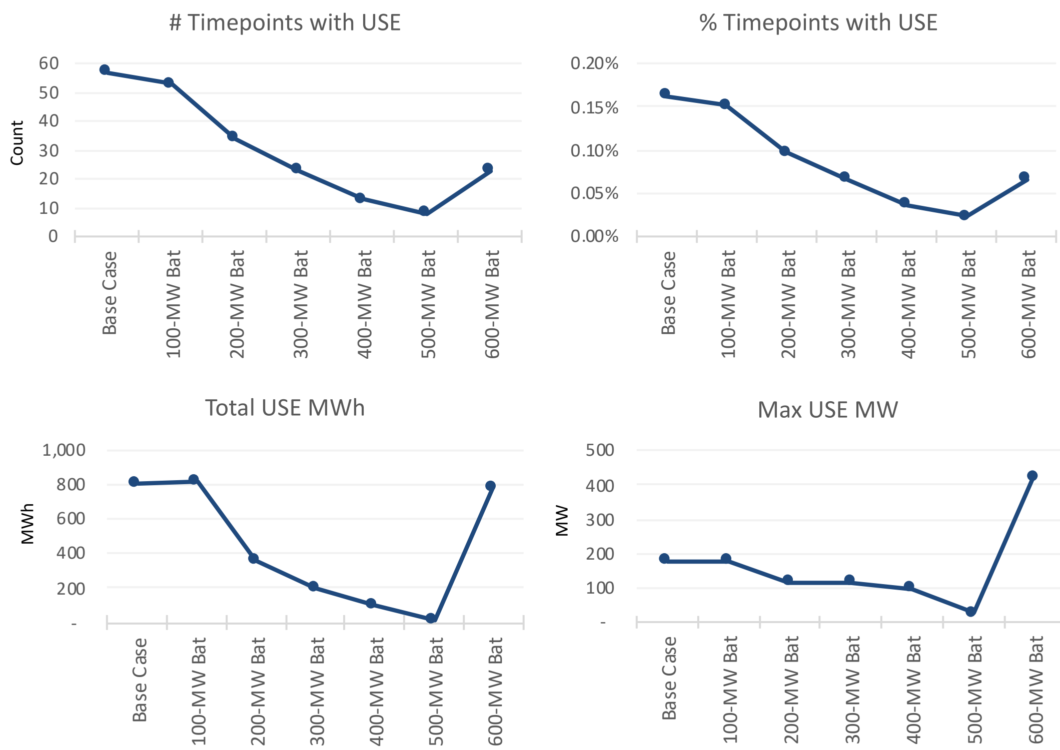
Addressing Forecast Error with Batteries

USE_{Flex}

To address the unserved energy caused by the system's inability to adjust to net load forecast error intra-day in the Base Case, we run several more cases in which we progressively replace 100-MW blocks of the inflexible DA-capacity with 100-MW batteries with 4-hour duration. While batteries are traditionally thought of as a "flexible" resource, the findings of this analysis indicate that their contribution to system reliability and operational role should be carefully investigated.

As shown in Figure 6 below, 4-hour battery capacity is added to replace the DA capacity blocks, USE generally declines up to a point. A 500-MW 4-hour battery replacing 500 MW of DA capacity reduces the amount of unserved energy to 13 MWh from the 800 MWh observed in the Base Case. However, with a larger 600-MW battery, the USE level increases again and the case with a 100-MW battery also has a higher amount of USE than the Base Case.

Figure 6. USE Comparison in the Base Case and Battery Cases



The results from the battery cases suggest that batteries can provide flexibility services but that they also have certain operating characteristics and constraints that system planners may need to account for.

In this analysis, the batteries provide two main sources of flexibility value to the system: 1) their ability to adjust their output within the day in response to forecast error and 2) their superior ability to shape energy (relative to the DA capacity product) even if they do not adjust their real-time output relative to their day-ahead schedule.

Figure 7 shows the DA schedule and RT dispatch in the Base Case (top) and 200-MW Battery Case (bottom) on the February day with the highest level of USE in the Base Case. On this day in the Base Case, the model commits 100 MW of DA capacity in the DA stage; it then encounters a load forecast error intra-day and the inability to commit additional DA capacity within the day to compensate for the higher load results in unserved energy during the morning peak hours. If a 200-MW battery is available (replacing 200 MW of DA capacity), the model does not commit any DA capacity on this day. Instead, it uses the battery to help meet load during the morning peak. Figure 8 shows the battery's DA schedule and RT dispatch. In the DA stage, the battery is scheduled to provide around 120 MW during the morning peak, a similar total amount to the 100 MW of DA capacity in the Base Case. Unlike the DA capacity, however, when faced with the load forecast error within the day, the battery is able to adjust its output in response to the higher than anticipated morning load and dispatch at a higher level than scheduled in the day-ahead in order to reduce the amount of unserved energy during the morning peak hours.

Figure 7. Hourly DA Schedule and 15-Minute RT Dispatch in the Base Case (top) and 200-MW Battery Case (bottom) on a February Day

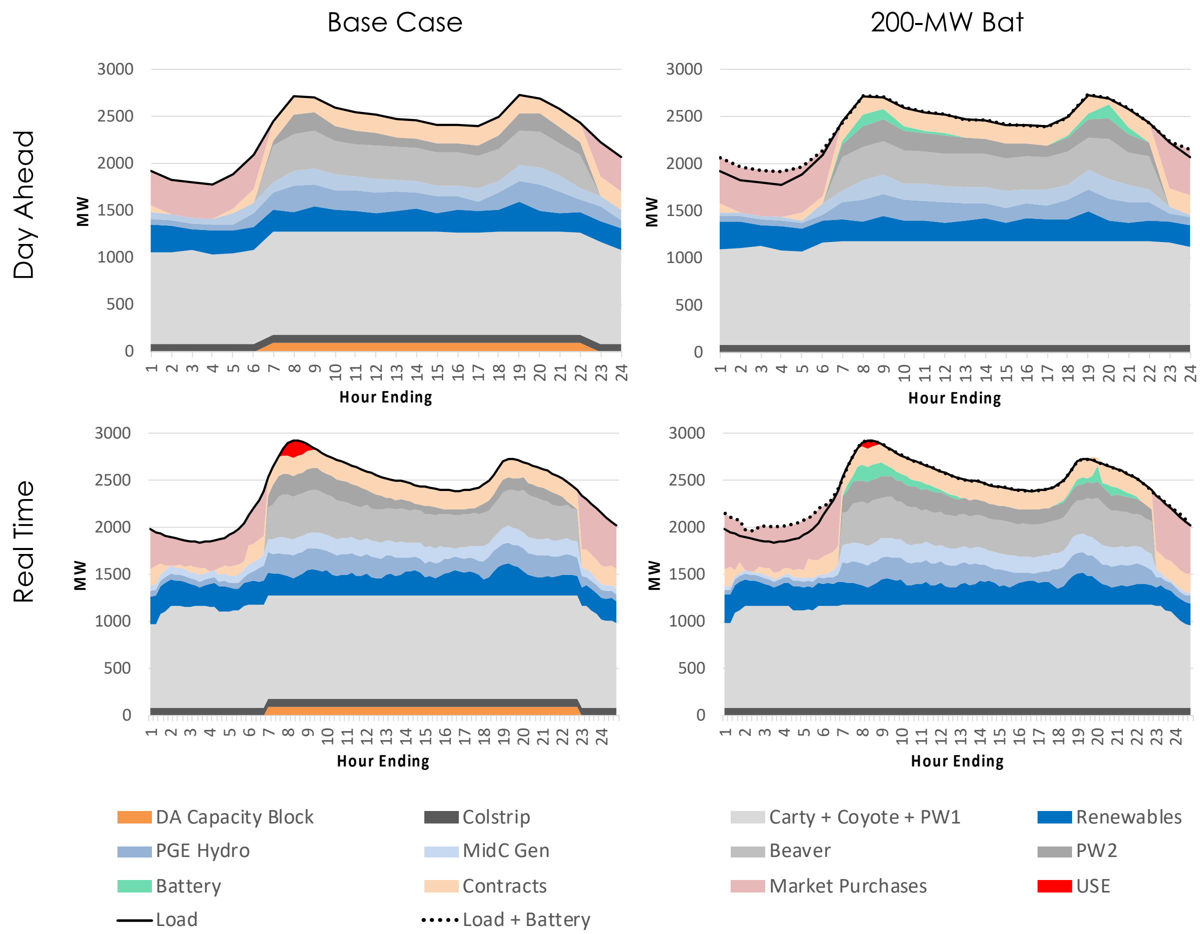
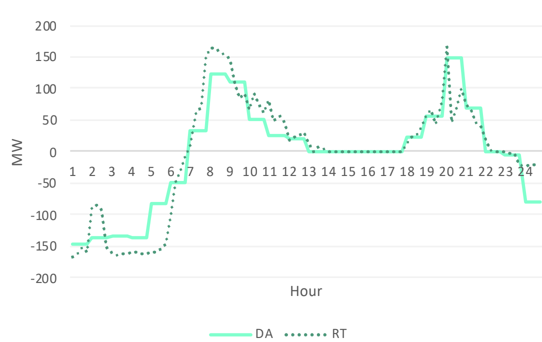


Figure 8. DA Schedule and RT Dispatch of 200-MW 4-Hour Battery on a February Day



A second way in which a battery can add to the system's flexibility is its ability to shape energy. Figure 9 shows the DA schedule and RT dispatch in the Base Case (top) and 400-MW Battery Case (bottom) on the February day with the highest level of USE in the Base Case.

Figure 10 focuses on the battery's DA schedule and RT output in the 400-MW Battery Case. In this scenario, the battery's dispatch in the RT stage is not substantially different from its DA schedule. The benefit the battery provides to the system is not that it can adjust its output within the day; rather, the value to the system is that, relative to the inflexible block of DA capacity, the battery is able to concentrate more energy during the morning hours (starting in the DA stage), therefore making more capacity available on peak. In the 400-MW Battery Case, spare resources are therefore available to compensate for the forecast error.

Figure 9. Hourly DA Schedule and 15-Minute RT Dispatch in the Base Case (top) and 400-MW Battery Case (bottom) on a February Day

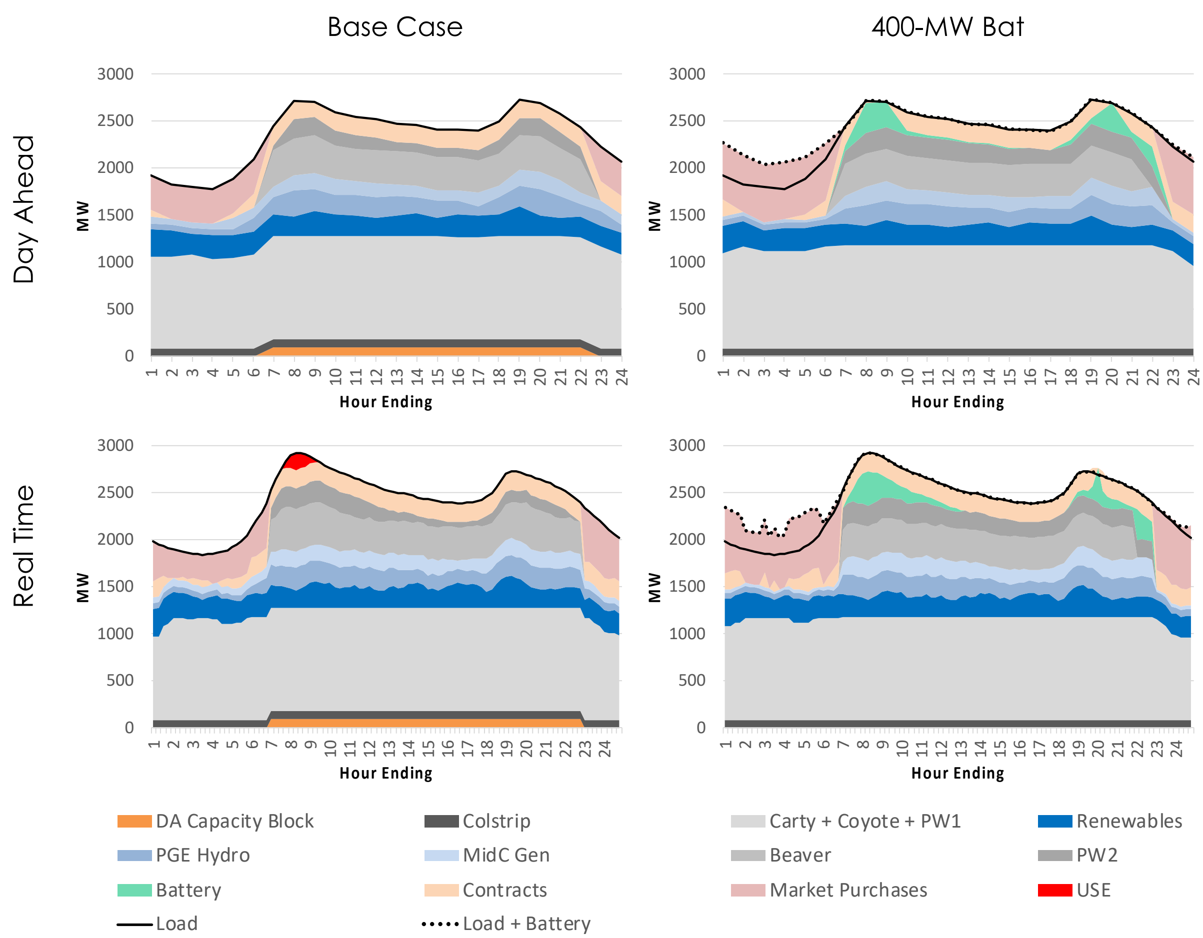
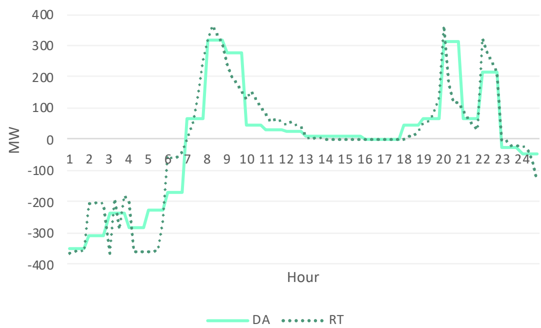


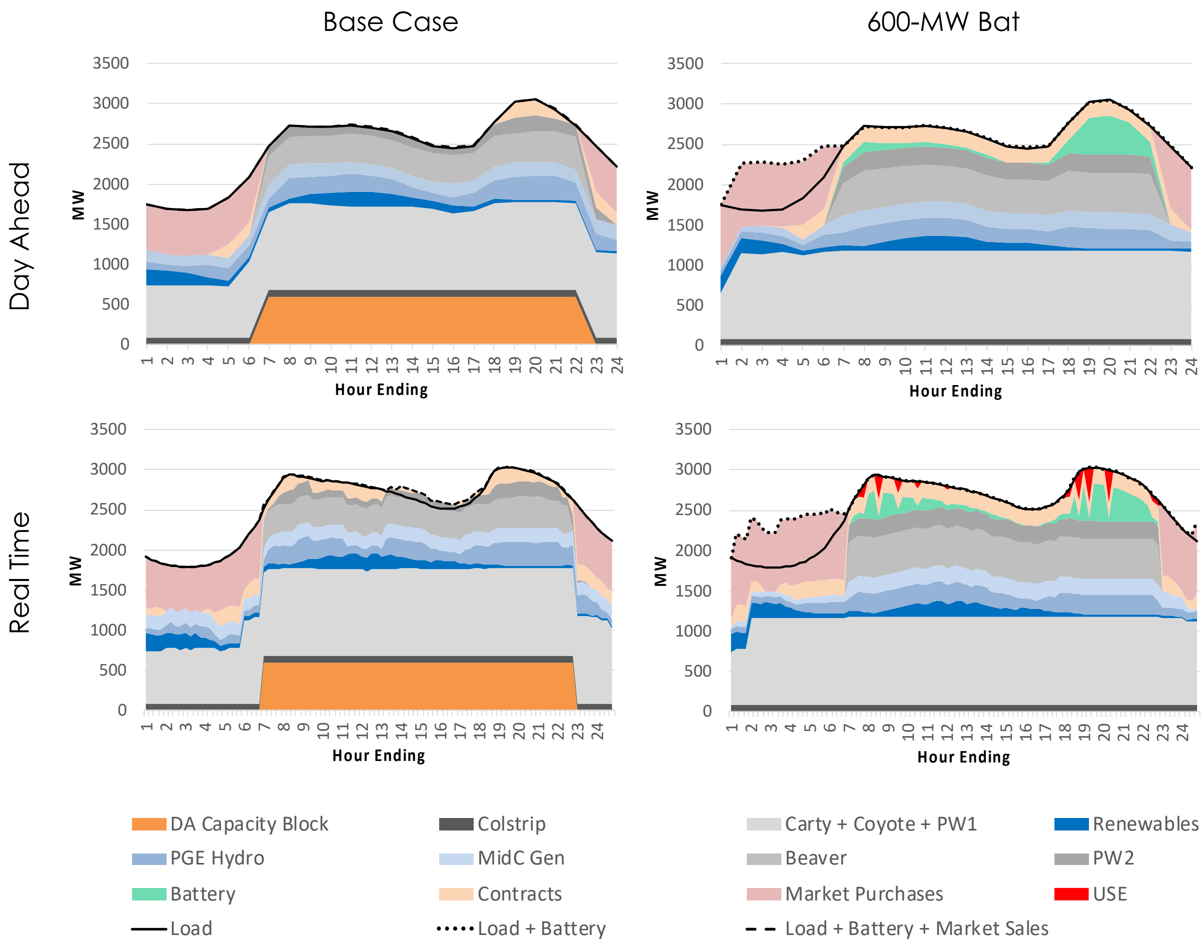
Figure 10. DA Schedule and RT Dispatch of 400-MW 4-Hour Battery on a February Day



While batteries can provide flexibility value to the system, their particular operating characteristics may also create challenges to system planning and operations. Figure 11 shows the system's HA schedule and RT dispatch in the Base Case (top) and the 600-MW Battery Case (bottom) on a different February day. On this day, the model commits 600 MW of DA capacity in the Base Case. If it has a 600-MW battery available, it schedules that capacity instead of the DA capacity product. The battery helps to meet the evening peak and the model also uses it along with increased output from Port Westward 2 and the available contracts in order to replace the energy that in the Base Case is provided by the DA capacity in the middle of the day.

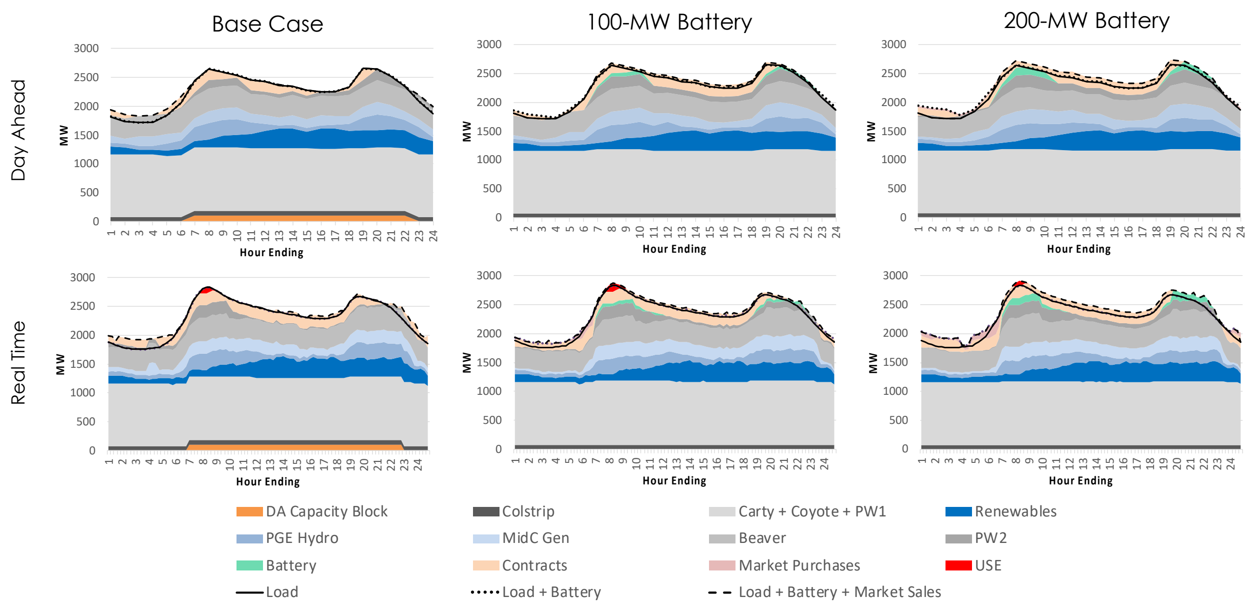
On this February day, the system once again experiences forecast error: within the day, real-time load is higher than anticipated throughout the morning and daytime. While in the Base Case, the model calls on available contract capacity to compensate for the load forecast error, in the 600-MW Battery Case, the system is unable to adjust and experiences USE. The battery is scheduled to charge fully during the night and release the energy during the morning and evening peak hours. When load is higher than anticipated during the day, the system encounters a problem of inadequate energy availability. The battery is fully charged by hour 7 in both the DA scheduling and RT dispatch stages. However, a 4-hour 600-MW battery can only provide 2,400 MWh before having to charge again while the 600-MW DA capacity in the Base Case provides 9,600 MWh of energy. On this day, the 600-MW Battery Case has limited energy available above what is scheduled in the DA stage, and experiences unserved energy as a result when load is higher than anticipated.

Figure 11. Hourly DA Schedule and 15-Minute RT Dispatch in the Base Case (top) and 600-MW Battery Case (bottom) on February Day



In this analysis, batteries could cause higher USE in another way. Figure 12 shows the system DA schedule and RT dispatch on a sample February day in the Base Case (left), 100-MW Battery Case (middle), and 200-MW Battery Case (right). On this day, 100-MW of DA capacity are committed in the Base Case. When a battery is available, the model does not commit any DA capacity; instead, the battery is used to help meet the morning and evening peaks. Furthermore, the battery availability makes it possible sell into the market on-peak in the DA stage, resulting in a more optimal DA schedule. However, when a forecast error is encountered intra-day, the DA market sale exacerbates the unserved energy experienced by the system in the 100-MW Battery Case. In that case, the 100-MW battery is used instead of 100 MW of DA capacity during the morning peak, and there is no spare capacity that can be used to cover the ~40 MW market sales scheduled in the DA. In the 200-MW case, the same dynamic is in place: the model schedules to sell ~80 MW into the market. In that case, however, the energy-shaping value of the battery – 200 MW of capacity are now available during the morning instead of the 100 MW of DA capacity scheduled in the Base Case – outweighs the additional burden imposed by the DA market commitment, and USE is lower than in the Base Case.

Figure 12. Hourly DA Schedule and 15-Minute RT Dispatch in the Base Case (left), 100-MW Battery Case (middle), and 200-MW Battery Case (right) on a February Day



System Headroom

While some of the operational characteristics of batteries may cause operational challenges for the system that should be explored further, in general, the availability of batteries increases the available system headroom in the cases investigated here. The headroom duration plots for the Base Case and each of the battery cases are shown in Figure 13. The 5th percentile of available system headroom (Figure 14) goes up from less than 100 MW in the Base Case to 160 MW in 100-MW Battery Case; it increases by an additional 50 MW for each 100 MW of batteries added thereafter until 400-MW of batteries are available; it then increases by an additional 40 MW in the 500-MW Battery Case and the 600-MW Battery Case each.

Figure 13. Duration Curve of System Headroom in the Base Case and the six battery cases.

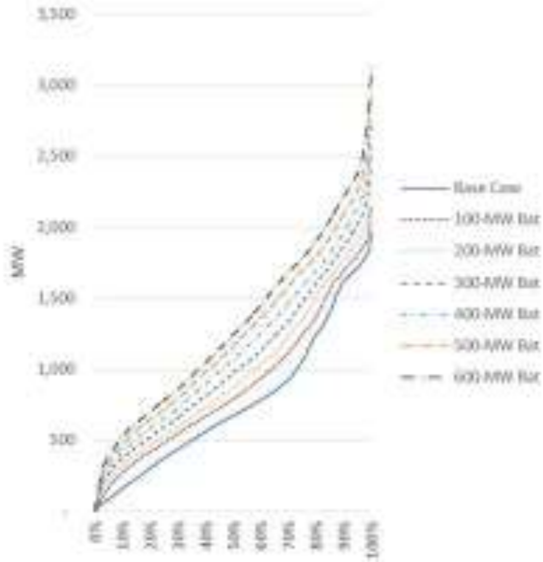
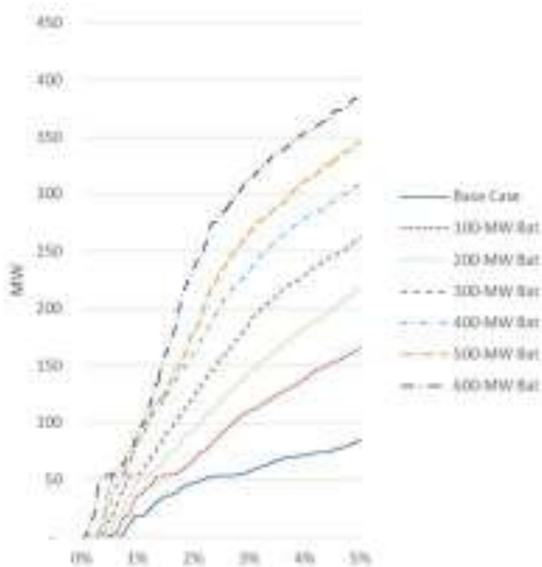


Figure 14. Duration Curve of System Headroom in the Base Case and the Six Battery Cases, Zoomed In to the 5th Percentile.



Addressing Forecast Error with Conservative DA Commitment

In order to verify that USE could be reduced with changes in the system's DA scheduling in favor of a more conservative approach ensuring resources are online in case of forecast error, we develop a proxy case for highly conservative operational practices. We refer to this case as the Conservative Bookend Case or the CB Case. In this bookend case, we remove variable renewable output from the DA commitment stage but keep it available in the HA and RT stages. This forces the model to commit additional DA capacity to compensate for the lack of variable renewable output; as variable renewable production does materialize in the HA and RT stages, more total resources are now available within the day, so the system has greater flexibility to deal with forecast error.

The CB Case does not characterize realistic operating practices nor does it consider legislative or other policy requirements; it is a modeling exercise in which we try to address USE due to extreme forecast error by forcing the model to schedule additional DA capacity. The extra commitment of expensive DA resources results in additional system cost. We do not attempt to make any conclusions about the relative cost of bookend conservative operations and other approaches for addressing flexibility violations. Rather, we seek to understand how such highly conservative operations would affect USE and flexibility adequacy.

USE_{Flex}

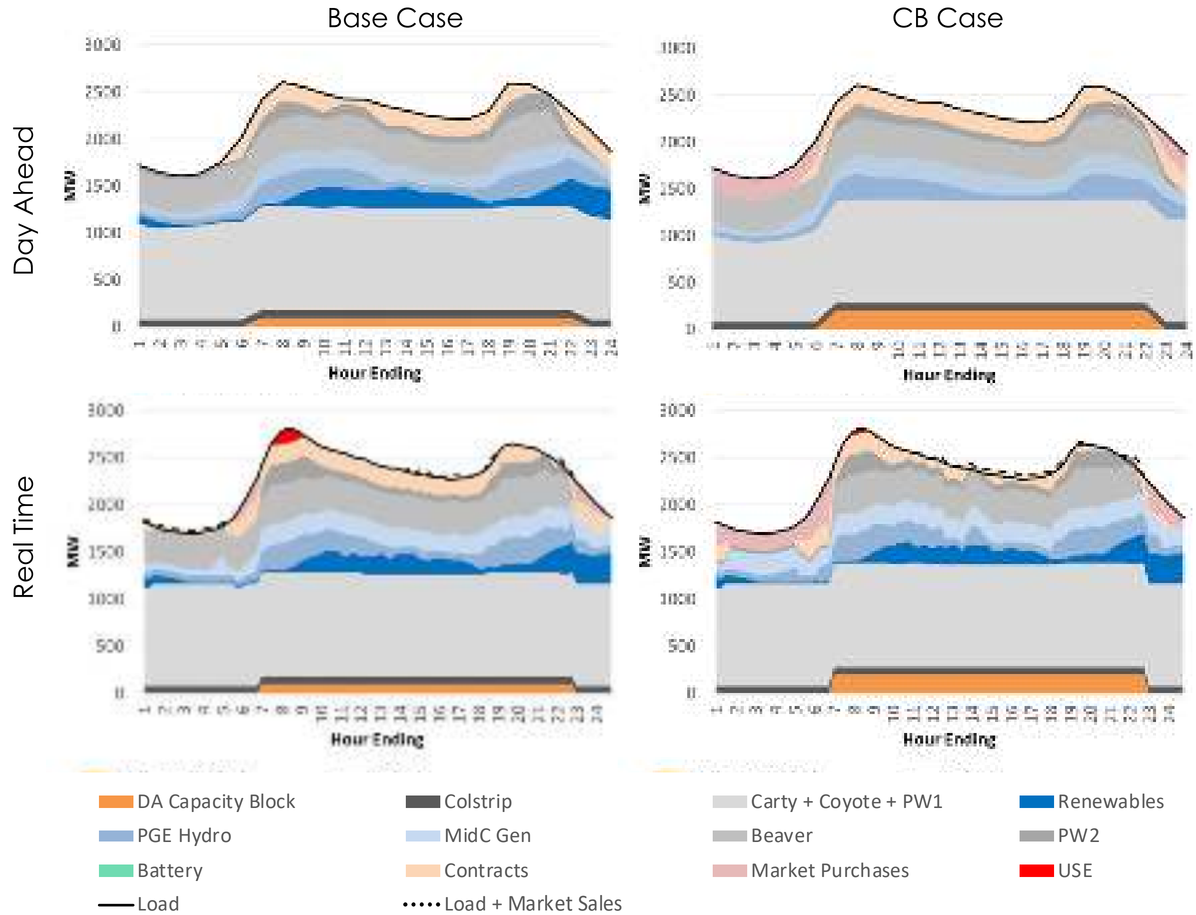
Conservative commitment results in substantially lower USE relative to the Base Case. In the CB Case, total real-time USE is 37 MWh (Table 4), down from 800 MWh in the Base Case.

Table 4. Unserved Energy in the CB Case

Real Time Unserved Energy (USE)	
# Timepoints	10
% Timepoints	0.03%
Total MWh	37
Max MW	62

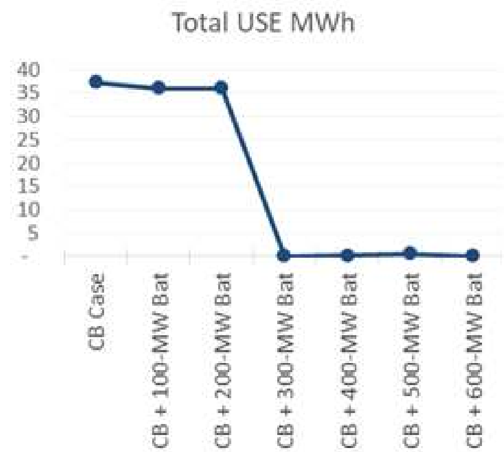
Figure 15 shows an example day to explain how conservative DA commitment reduces USE. The lack of variable renewable production in the DA stage of the CB Case causes the model to commit 300 MW of DA capacity relative to 100 MW of DA capacity in the Base Case. With more total resources available within the day, the impact of forecast error is now lower and less USE is incurred on this day relative to the Base Case.

Figure 15. Hourly DA Schedule and 15-Minute RT Dispatch in the Base Case (top) and CB Case (bottom) on February Day



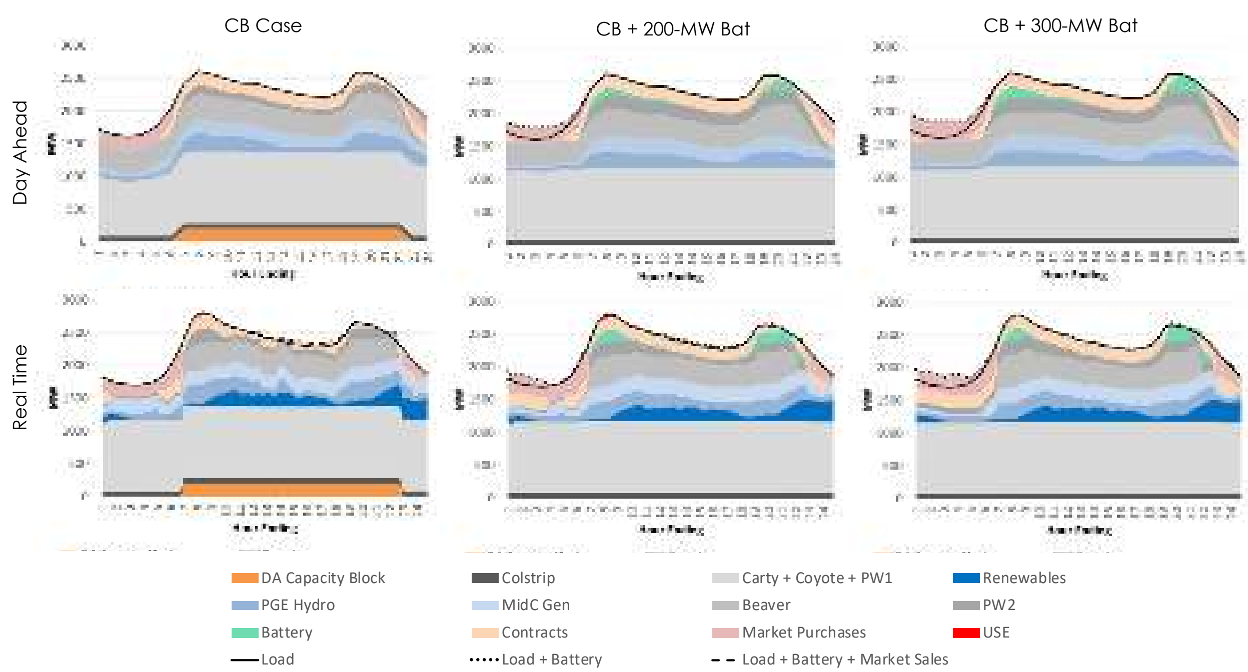
Finally, we develop several cases depicting how the example conservative bookend DA commitment combined with the replacement of inflexible, expensive DA-capacity with battery capacity ranging from 100 MW to 600 MW impacts results. With conservative commitment, unserved energy reaches zero with the addition of 300 MW of batteries (Figure 16). As committing extra DA capacity provides the system with additional available energy, the system does not encounter the same energy shortages as it does in the base 600-MW Battery case.

Figure 16. USE Comparison in the CB Case and Battery Cases



With conservative commitment, the USE reduction benefits are low until battery capacity additions reach 300 MW. This can be attributed to the fact that in the CB Case, almost all of the USE occurs on a February day that has 200 MW of DA capacity commitment. On this day (Figure 17), the availability of up to 200 MW of batteries, therefore, does not provide additional capacity over what is available in the CB Case (the 200-MW battery is committed *instead of* the 200 MW of DA capacity in the CB Case). With higher battery capacities, the system can adjust battery output and shape energy to provide more than 200 MW during the morning and evening peaks when a forecast error and USE occur, reducing the total amount of USE.

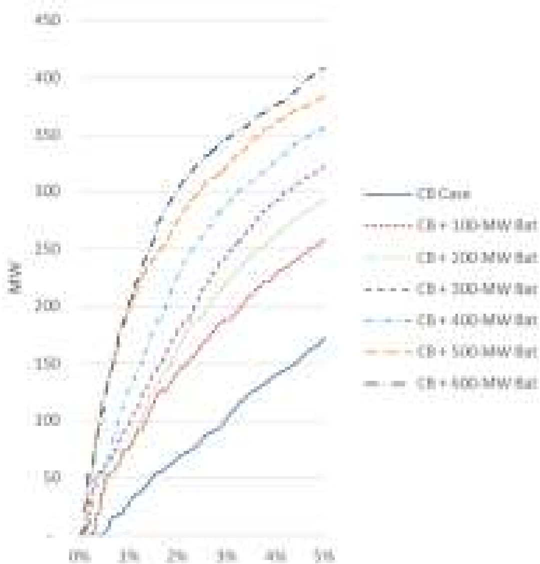
Figure 17. Hourly DA Schedule and 15-Minute RT Dispatch in the CB Case (left), CB + 200-MW Battery Case (middle), and CB + 300-MW Battery Case (right) on a February Day



System Headroom

The 5th percentile of available system headroom in the CB Case is 170 MW, up from less than 100 MW in the Base Case. It increases to more than 250 MW when 100-MW of batteries are added to the CB Case, and by about 25 MW for each 100-MW increment of battery capacity thereafter (Figure 18).

Figure 18. Duration Curve of System Headroom in the CB Case and the Six CB + Battery Cases, Zoomed In to the 5th Percentile.



Conclusions

The goal of this flexibility study was to investigate whether the PGE system has adequate operational flexibility to maintain reliability as it evolves in the near- and mid-term. The results presented here indicate that the PGE system may encounter upward flexibility challenges on this timeframe.

In this analysis of an average-year set of conditions for 2025, forecast error is the main driver of upward flexibility shortages. The PGE system appears to have considerable ramping capability, but load and renewable forecast errors along with inflexible resource commitment timing can cause flexibility-related reliability events. High-priced contracts that provide capacity in the day-ahead are not adequate to meet the system's flexibility requirements because they are not dispatchable within the day. Such expensive day-ahead capacity contracts can create problems on days with high flexibility demand (in the form of forecast error) and procuring some level of flexible capacity may be necessary to address the flexibility shortages.

Battery procurement could provide operational flexibility to the system, generally enhancing the system's ability to adapt to forecast error within the day. This analysis, however, also indicates that batteries are not a perfectly flexible resource and can create operational challenges of their own. Further investigation is needed of battery operating characteristics and constraints to understand the optimal level of battery procurement as well as any other resources that may need to be procured along with the batteries.

The addition of flexible battery capacity dispatchable within the day could offer one solution to the system's flexibility-related reliability events. We also demonstrate that bookend conservative commitment can mitigate the flexibility challenges but suggesting realistic changes in operational practices is outside the scope of this study. In addition, we do not investigate cost impacts: we compare only indicators of flexibility adequacy such as USE_{Flex} and system headroom, not relative economics.

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