Technical Appendix G: New Generating Resources

Contents

Methodology for Assessing New Generating Resource Technology Options for the Power Plan

Identifying and analyzing new generating resources is a key step in developing a cost-effective, least-risk, adequate, and reliable strategy for the region. Generating resource technologies are defined and assessed based on their cost, operating and performance characteristics, and development potential in the region. Resources that are proven and commercially available to meet future needs are further developed into "reference plants." Each reference plant has a designated plant size and configuration representative for the Pacific Northwest,[1] with technical characteristics and performance parameters, cost estimates (capital, operating and maintenance, levelized), and other attributes such as estimated construction time and economic life. These reference plants become inputs to the Council's optimization models (e.g., OptGen) as options, along with rooftop solar, energy efficiency, and demand response, for selection to meet future resource needs.

For the Ninth Plan, utility-scale reference plants were developed for onshore wind, solar photovoltaics (PV), standalone battery storage, solar PV + battery storage, natural gas combined cycle turbine, and natural gas simple cycle combustion turbines (peaking plants, or "peakers"). The Council also developed reference plants for resources with limited availability including pumped storage, conventional geothermal, and offshore wind and three proxy emerging technology reference plants. These emerging technology reference plants are intended to represent the potential technological advancements that could provide value to the region in the future, and include clean long-duration storage (iron-air battery), clean baseload resource (small modular reactor), and clean peaker/medium-duration storage (hydrogen turbine with onsite production/storage).

What is a Reference Plant?

A reference plant describes an electricity generating resource technology and its theoretical application in the region. It includes estimates of typical costs, logistics, and operating specifications. These reference plants become resource options, along with demand-side resources for the Council's power system models to select to fulfill future resource needs. The Council develops a defined set of reference plants that represent the range of resources to be considered in planning.

[1] These reference plants are also used in the Council's analysis of west-wide market buildouts, some assumptions around the plant characteristics are updated accordingly to better suit the larger west.

How are Reference Plants Used in Planning?

The Power Act directs the Council's power plan to put forth a general strategy for implementing conservation measures and developing generating resources.[2] The Council uses reference plants as a means of characterizing generating resource options for modeling, because they represent the different attributes of different resources for the model to consider.

Components of a Generic Reference Plant

Each reference plant is made up of the components summarized in Table G - 1, defined for each resource. Having the same collection of characteristics differentiated by resource allows the model to best compare and determine the appropriate resource mix.

Table G - 1: Reference Plant Components

Components	Definition
***Resource Attributes*: Defines how a generating technology serves the grid.**	
Technology Type	The type of technology being defined (e.g. a renewable resource, a thermal plant).
Configuration	The number of units (and installed nameplate capacity of each unit) that make up the complete reference plant. Also includes other plant specifications such as air emissions controls, cooling etc.
Capacity	Refers to the nameplate capacity of a plant, which is the maximum amount of electricity a plant can generate when it's fully functional, in optimal conditions, and, if applicable, using the maximum amount of fuel. This is often the manufacturer's rated output of the generator.
Economic or Operating Life	Assumed useful operating life of the plant.
Timing	Includes both *construction time*, which is the amount of assumed time for a project to come online from conception to commissioning, and the *availability date*, or the first year a plant could be selected to be built.
Transmission Access	Assumed transmission required to connect to the grid.
***Financials*: Details what a resource costs, the component parts of those costs, and how those costs are accumulated and recouped over the course of a resource's lifetime.**	
Overnight Capital Cost	An estimate of the project development and construction cost. "Overnight" refers to what the cost would be if the plant were built instantly, or over one night. This cost constitutes the engineering, procurement, and construction (EPC) costs, owner's costs (costs incurred by the project developer – permits, licenses, land, project

[2] Northwest Power Act, §4(e)(2), 94 Stat. 2706

Components	Definition
	development costs, infrastructure, taxes, regulatory compliance costs, etc.), and decommissioning costs.
Fixed Operations & Maintenance	An estimate of the fixed operation and maintenance cost for the reference plant, including operating and maintenance, labor and materials, and administrative overhead. Both routine maintenance and major maintenance and capital replacement are assumed to be included.
Variable Operations & Maintenance	An estimate of the variable operation and maintenance cost for the reference plant, including all costs that are a function of the amount of power produced. This includes consumables such as water, chemicals, lubricants, catalysts, and waste disposal.
Fixed Fuel Cost	The primary type of fuel burned (natural gas, oil, coal, etc.), its location of origin, and cost.
Transmission Cost	Cost of the assumed transmission type, incorporated into the cost of the resource.
***Operating Characteristics*: Describes how the generating technology works.**	
Capacity Factor	An estimate of the ratio of actual annual output to nameplate capacity can vary by location especially for renewables.
Heat Rate	A measure of the efficiency of which a generator converts fuel into electricity. The reference plant heat rates are based on full load, expressed as higher heating values (HHV).
Generation Shape	Refers to when a plant generates power and how much it generates, which can vary by time of day, time of year, location etc.
***Developmental Potential*: Identifies how the generating resource fits into the grid & works with other resources.**	
Location	The general geographic location of the reference plant, which is important in properly accounting for plant attributes (e.g. capacity factor, transmission access).
Transmission/Gas Pipeline Access	A resources available access to necessary infrastructure for it to come online and serve load.
Maximum Build-out	The maximum amount of reference plant units (in megawatts) that the model can select over the 20-year planning horizon.

Methodology for Defining Reference Plant Components

The process of detailing each reference plant and defining their characteristics by technology began with research, looking at manufacturer data, power purchase agreements (PPAs), project-specific publicly available specs, technical handbooks, reports from US Energy Information Association (EIA), Department of Energy (DOE), national labs, and regional integrated resource plans (IRPs) to gather a broad range of data points to be compared and vetted by the regional experts on relevant advisory committees. How those characteristics were defined for each resource and with what level of granularity was dependent on the sort of data available, some of those nuances in process are outlined below. The specifics like the costs of each resource, the resources availability, the timing and their generation shape, to name a few of the most impactful assumptions, will be detailed by resource in the sections to come, the intent of this section is to describe the development of those characteristics and how they will be presented in the reference plant.

Availability

Availability refers to when and where a resource can be selected by the model and how much of the resource will be available. This includes a resource's earliest selection date as well as how long it takes that resource to be developed and start providing energy to the grid. It also refers to how much energy a single reference plant is sized to produce, its nameplate capacity, as well has how efficiently it provides that electricity to the grid. This could be identified by a resource's capacity factor, heat rate round trip efficiency, or other factors, depending on the resource.

The way resources are selected is another piece of their availability. Resources that are more commutable or scalable can be selected continuously. For example, the wind resource in a particular zone can be any size, so long as there's space on the grid to deliver it, because it's just a matter of adding another turbine. The same holds true for solar and batteries. However, some resources don't operate as modularly, so they are ascribed a discrete size. A gas plant operates a specific turbine that produces a specific amount of electricity. Similarly, pumped storage, geothermal, and hydrogen plants are all a defined size in the model, because they produce a discrete amount of energy by plant. This differentiation is determined by the type of resource and described in the applicable resource's sections.

Primary resources are all available at the beginning of the study, because they're proven, deployable, commercially available and significant. Some limited availability resources aren't selectable right away due to complications of siting and licensing that come up when trying to build a resource with constrained geographic applications. Emerging technologies are not available at the beginning of the study, and the specifics of their availability are based on advisory committee assumptions about the timing of the proxy technologies' commercial readiness.

A final aspect of availability is the location of the resource. This is not relevant for all resources but for some it's especially important. The model will not select a resource in a place it wouldn't realistically be built. For example, it can't build a wind farm in downtown Seattle. New modeling capabilities for the Ninth Plan allow for more granularity in resource selection by zone, making identifying and defining any locational variation more impactful. A resource's cost, operating characteristics, and size can be affected by where it is located. This is especially relevant for renewables, because the natural resource they're capturing and converting into electricity differs across the region. When and how much the sun shines differs for a solar panel in Idaho compared with the Willamette Valley. The reference plant descriptions specify the details of this variability and how locations were decided.

Costs

The process for developing these financial parameters involves gathering analysis of available cost data from manufacturers, developers, PPAs, project-specific publicly available reported information, technical handbooks, reports from the EIA, DOE, national labs, and IRPs, among other sources. Next, the cost data is normalized to a consistent year dollar, configuration, capacity, and heat rate, among other factors. Finally, that normalized data is plotted to look for trends and outliers to determine the best estimate of current and future costs. Plots for overnight capital costs as well as operations and maintenance costs will be included in each reference plant description.

Environmental Costs

The Northwest Power Act requires that the Council compare the incremental system costs of different generating and conservation resources and give priority to those resources which the Council determines to be cost-effective[3]. For supply side resources, those costs are developed using the method described above. In addition to those financial costs, the Council also includes any quantifiable environmental costs and benefits directly attributed to that resource over its effective life. This is done through the development of a methodology to determine and apply these quantifiable environmental costs and benefits. This methodology's development and implementation are a required element of the power plan and is described in more detail in Technical Appendix C – Methodology for Quantifiable Environmental Costs and Benefits.[4]

The Act also requires that in developing the power plan's resource strategy that the Council give "due consideration" to environmental quality and fish and wildlife concerns.[5] These are broader considerations than fit within the methodology for quantifying environmental costs and benefits, and include the Council's Fish and Wildlife Program, compliance with clean energy regulations, climate model analysis etc. The environmental effects of supply-side generating resources are discussed narratively in Technical Appendix C – Methodology for Quantifiable Environmental Costs and Benefits, and while not quantified into monetary costs, can still be considered in the selection of resources and the development of the Council's resource strategy.

Shared Assumptions

There are several assumptions made early in the reference plant development process that are used across all the reference plants to ensure consistency and enable comparison across resources.

Financing

Table G - 2 summarizes the shared financial assumptions.

[3] Northwest Power Act, Section 4(e)(1).
[4] Northwest Power Act, Section 4(e)(3)(C).
[5] Northwest Power Act, §4(e)(2), 94 Stat. 2706

Table G - 2: Financial Assumptions for Reference Plants

Parameters	Ninth Plan Assumption		
Federal income tax rate	21%		
State income tax rate	6.45%		
Property tax	0.9%		
Insurance	0.3%		
	Utility	**Merchant/IPP**	**9P Assumption**
Debt fraction	50/50	55/45	52/48
Debt interest rate (nominal)	3.5%	6.27%	4.61%
Return on equity (nominal)	7.17%	9.74%	8.20%

It's important to consider how resources are financed – as well as by whom – when comparing their present value across resources. In the Ninth Plan, a blend of utility and merchant financing was assumed at a ratio of 60 percent utility financed 40 percent merchant/independent power producers. This assumption is based on who is building power plants nationally as informed by EPA's power sector modeling, which is used by the EIA to produce their annual energy outlook report.[6]

These assumptions are built into the Council's financial revenue requirements model. They are used to calculate the levelized fixed costs of supply-side resources, which are compared against each other as well as demand-side resources in modeling. More information on how these financing assumptions compare to demand-side financing can be found Technical Appendix A –Global Assumptions.

Transmission

There are costs associated with connecting a resource to the grid via electric transmission. To get their generation onto the grid, a resource must acquire transmission access often via contract with a transmission operator. Bonneville Power Administration (BPA) operates 75% of the region's high-voltage transmission system. The Council looked to the agency's most recent transmission tariff as a proxy for all transmission costs. This can be a nuanced calculation dependent on the individual circumstances of the resource being connected. However, the Council opted to use BPA's long-term firm point-to-point (PTP) transmission service rate as a surrogate for all transmission costs, because it is the most straightforward, reliable transmission option. BPA's 2024 Transmission, Ancillary, and Control Area Service Rate Schedules and General Rate Schedule Provisions set the long-term firm

[6] Documentation of financing assumptions for EPA's power sector modeling are available at https://www.epa.gov/system/files/documents/2021-09/chapter-10-financial-assumptions.pdf.

PTP rate at $1.64/kW-mo, which works out to $19.76/kW-yr.[7] This is incorporated into a resource's fixed costs in addition to any other annual operation and maintenance expenses. It is added to the fixed O&M of every resource that connects to the transmission system. The only resources that are excluded are small-scale solar, which operate on the distribution system, as well as batteries, because they're on-system resources that do not require dedicated transmission capacity.

These costs do not include wheeling costs, which are tied to usage of the line and not to a particular resource. Wheeling costs are contractual, variable costs that are associated with transmitting power. They are added up per wheeling segment traveled, and are accounted for in the model per megawatt hour.

Maximum Buildout

For the Ninth Plan, the Council is not limiting primary model resource builds beyond the physical constraints of the system. This approach relies on the model to test the economics of a given future, not being constrained by contractual encumberments. The future will be constrained by system operations and policies, among other factors. The Council recognizes that there might be limits on various resources from siting or supply chain limitations (e.g. transformers). The implications of such limitations will be explored through the Resource and Transmission Risk Scenario, which is described in more detail later in this appendix.

Cost Curves

Technology improves in both performance and price over time, and the Council relies on cost curves to estimate costs across the 20-year planning period. These learning curves vary based on the maturity of the technology but apply to all technology types. The National Laboratory of the Rockies's Annual Technology Baseline's (NLR ATB)[8,9] cost curves were utilized as a well-supported and documented industry standard. In past power plans the moderate cost curve provided by NLR was used, however, recent industry uncertainty has prompted the Council to adopt the conservative curve for the Ninth Plan Figure G - 1 provides an overview of each cost curve and how they compare across resources. More mature technologies, like natural gas or wind see a slower de-escalation while more recently emergent resources such as solar and batteries see a steeper decline, especially in the near term. This follows the logic of exponential learning curves where increased production prompts cheaper costs due to economies of scale, experience, process improvements etc. In the 20-year horizon of the Plan, these trade-offs between cost and scale are used to predict future costs.

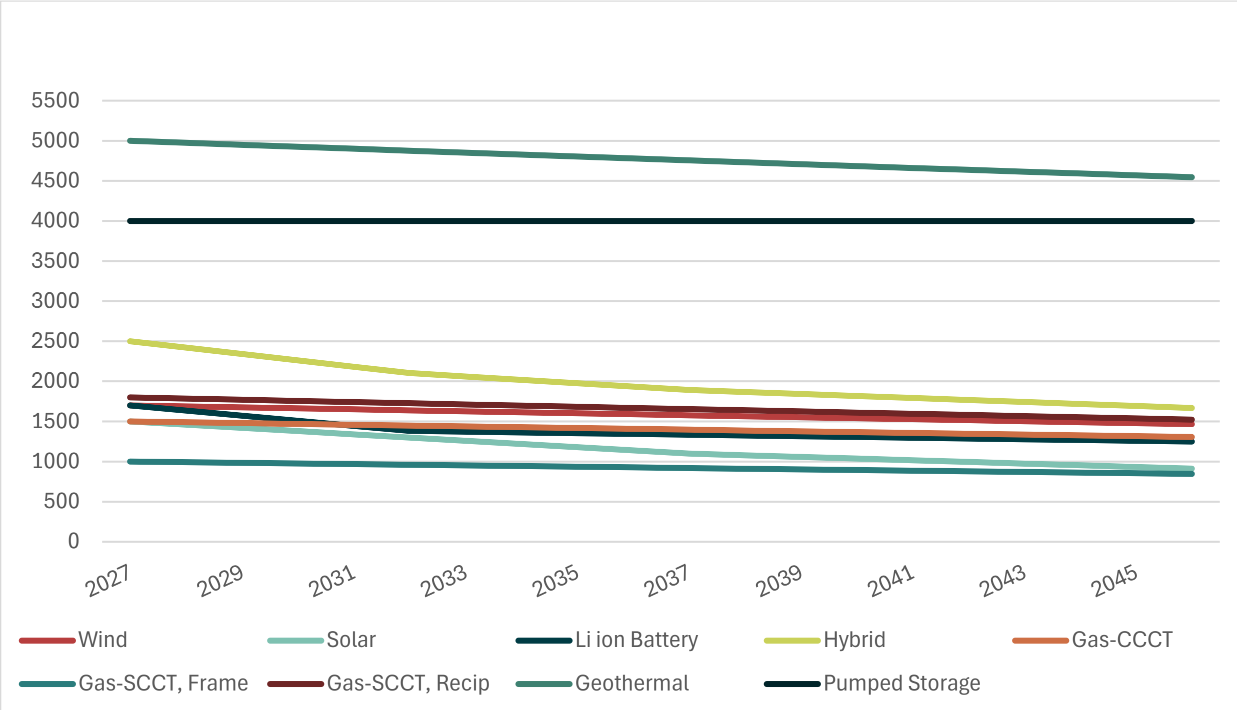
[7] https://www.bpa.gov/-/media/Aep/rates-tariff/current-transmission-rates/2024-Transmission-Rates/2024-Final-Proposal-Transmission-Rate-Schedules-and-GRSPsFERC-approved.pdf.

[8] The National Laboratory of the Rockies is formerly known as the National Renewable Energy Lab or NREL. The name changed in December 2025. The website continues to have an NREL in the URL and many of the resources continue to be cited as NREL resources.

[9] More information on the ATB is available at https://atb.nrel.gov/electricity/2024/data.

In addition to Figure G - 1, cost curves for each resource are broken out and included in each reference plant description throughout the document.

Figure G - 1: Forward Cost Curve for Primary Resource Reference Plants



Locational Cost Adjustment

Locational cost adjustment factors from the 2025 EIA Energy Outlook[10] were applied to resources' overnight capital costs. This adjustment is based on labor rates and the environmental effect on material costs for each location. These factors are specific to each resource and by representative city, but broadly it is more expensive to build in the west of the region (Seattle/Portland) than the east (Spokane/Boise/Great Falls). This adjustment is only made when there are other differentiating factors between resources by location. For example, wind and solar have capacity factors that vary enough by location to warrant separation, and gas plants have distinct fuel costs along the east/west divide. The factors given by location and resource in Table G - 3 are applied in their specific resource reference plant descriptions provided later in this section.

[10] Adjustment factors by resource and location can be found in Appendix A. Labor Location-Based Cost Adjustments of the EIA's Capital Cost and Performance Characteristics for Utility-Scale Electric Power Generating Technologies: https://www.eia.gov/analysis/studies/powerplants/capitalcost/pdf/capital_cost_AEO2025.pdf.

Table G - 3: Regional Location-Based Cost Adjustments by Resource

	Solar	Solar+ Battery	Wind	Gas: CCCT	Gas: SSCT
Portland, OR	1.058	1.061	1.108	1.099	1.095
Seattle, WA	1.088	1.088	1.1598	1.152	1.145
Spokane, WA	1.0233	1.0253	1.0376	1.034	1.032
Great Falls, MT	0.992	0.991	0.983	0.984	0.984
Boise, ID	1.009	1.011	1.0229	1.013	1.013
Cheyenne, WY	NA	NA	0.9825	NA	NA

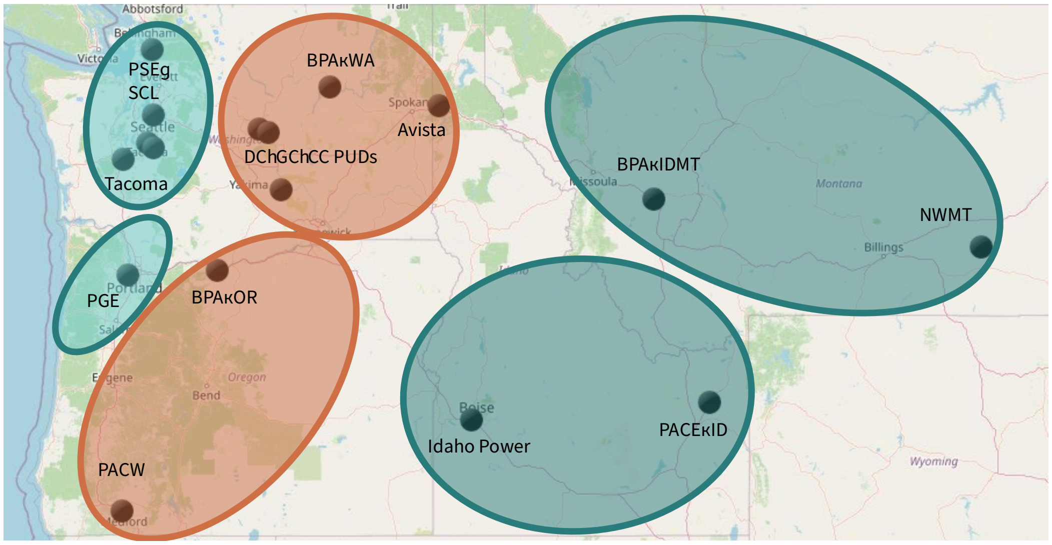
Generation Shape

Weather-dependent resources, primarily wind and solar, are assigned daily and monthly production shapes to represent how that resource produces energy. These shapes vary by location in the region, and the expanded locational granularity of the updated models allow us to better represent those differences. For both wind and solar, representative shapes that apply to broader portions of the region were selected. For example, a solar profile in Portland is very similar to one in Seattle, so both those locations have been assigned the same generation shape. Those locations and the zones they encompass are shown in Table G - 2.

The precise shapes are a separate modeling input,[11] but the maps shown in Figure G - 2 and Figure G - 3 provide a visual representation of those groupings by resource.

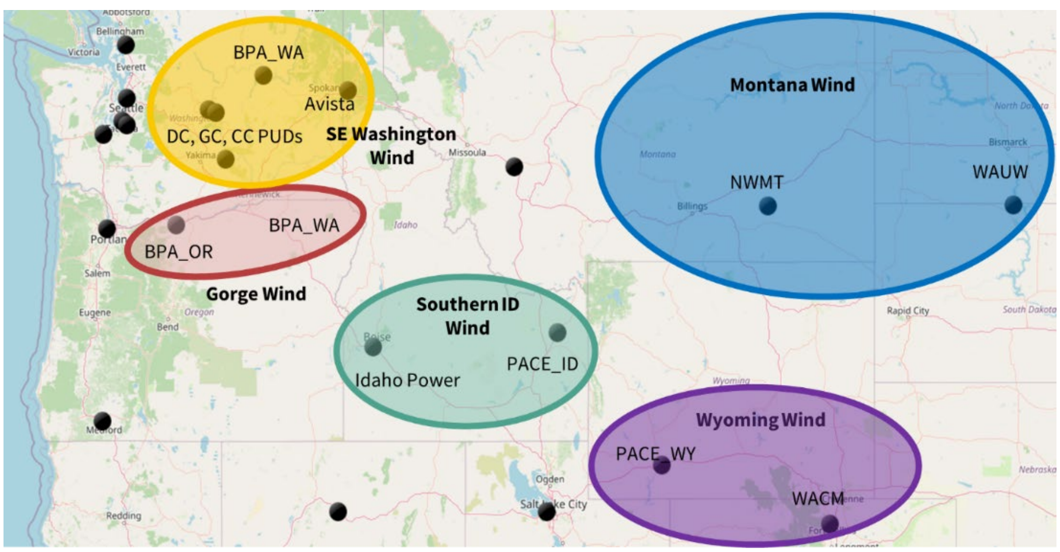
[11] Weather and how it is used to model generation is described in Technical Appendix D – Climate Model Data and Assumptions

Figure G - 2: Solar Reference Plant Locations



The solar shapes in Figure G - 2 are grouped by color and then split by wildfire smoke profiles that will be applied on top of those shared shapes. More details on the grouping of these zones is discussed in the solar reference plant definition section below.

Figure G - 3: Wind Reference Plant Locations



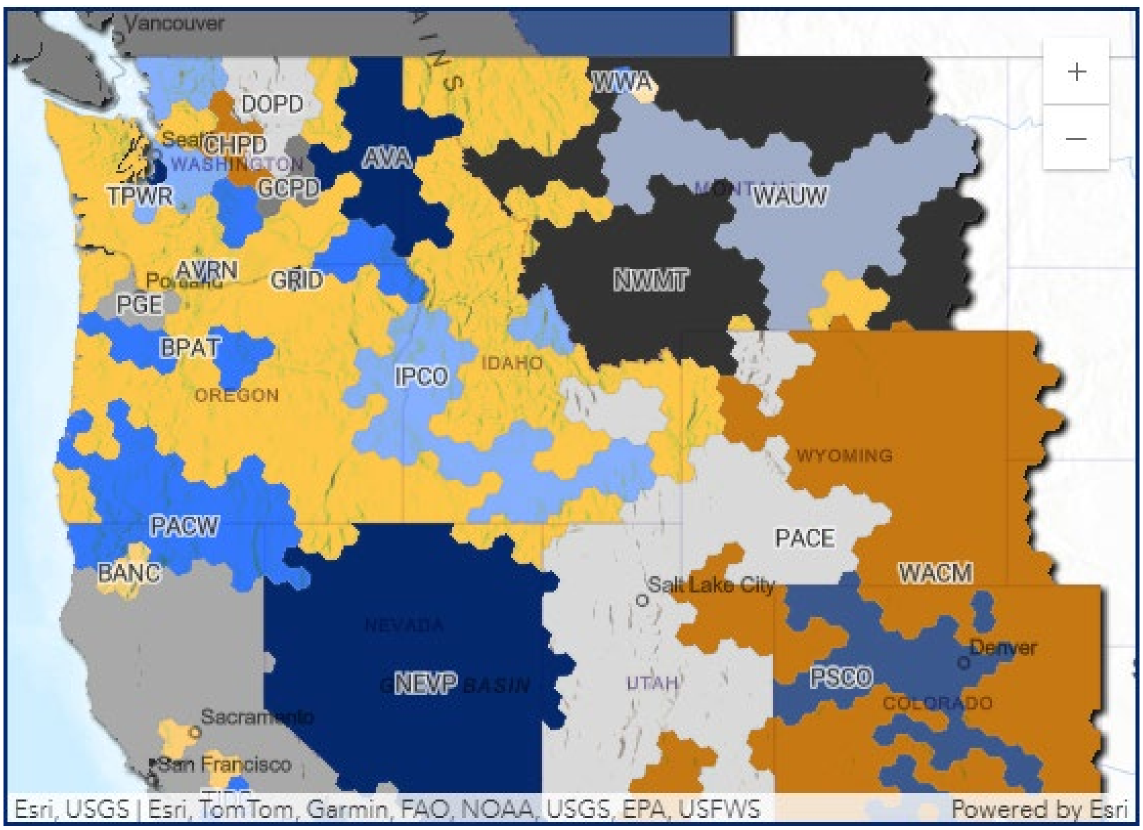
The representative wind shapes cover less of the region, as wind farms have larger footprints and cannot be built as widely as solar can be. The alignment of the zones encompassed by the broader groupings shown in Figure G - 3 are described in more detail in the land-based wind reference plant definition section.

Location assignments by resource by zone

In the Council's models, the region is split into seventeen smaller sub-regions or "modeling zones." The modeling zones correspond approximately to the Northwest's balancing authorities, or portions of its balancing authorities. The Council simplified the model by clustering resources by shared characteristics, described in the two sections above and explained in more detail later in this appendix. The Council deemed it unnecessary to develop 17 different reference plants for every resource, as there are not significant enough identifiable differences in the resource attributes to warrant such granularity. Rather, the Council grouped the zones based on similar characteristics per plant.

summarizes these assignments while Table G - 5 describes the zone abbreviations. These modeling zones roughly align with the balancing authorities mapped in Figure G - 4, to get an idea of the geographic location of the zones.

Figure G - 4 WECC Balancing Authorities Mapped[12]



[12] https://wecc-spdp-weccgeo.hub.arcgis.com/pages/bulk-power#c25n8scx9.

Table G - 4: Modeling Zone Reference Plant Assignments

Resource Type	Resource Technology	Location Cluster	Zone
Solar[13]	Stand-alone	Northwest	North: N/A South: PGE
		Central	North: BPA WA, AVA, DC PUD, CC PUD, GC PUD South: BPA OR, PAC W
		East	North: BPA IDMT, NWMT South: PAC E ID, IPCO
	Small-Scale	Northwest	North: PSE (North, Central, Olympia) SCL, TPWER South: PGE
		Central	North: BPA WA, AVA, DC PUD, CC PUD, GC PUD South: BPA OR, PAC W
		East	North: BPA IDMT, NWMT South: PAC E ID, IPCO
	Hybrid	Northwest	North: PSE (North, Olympia) SCL, TPWER South: PGE
		Central	North: BPA WA, AVA, DC PUD, CC PUD, GC PUD South: BPA OR, PAC W
		East	North: BPA IDMT, NWMT South: PAC E ID, IPCO
Wind	N/A	Gorge	BPA OR, BPA WA
		SE Washington	BPA WA, AVA, DC PUD, CC PUD, GC PUD
		S Idaho	IPCO, PAC E ID
		Montana	BPA IDMT, NWMT, WAUW
		Wyoming	PAC E WY, WACM
Gas	Combined Cycle	Eastside	IPCO, BPA IDMT, NWMT, AVA
		Westside	PSE Olympia
		BPA Blend[14]	BPA WA

[13] North and south designations refer to the wildfire profile applied to each zone, discussed later in the appendix.
[14] The BPA zone spans the east and west sides and therefore warranted a blended value. This is also consistent with the T&D deferral values.

Resource Type	Resource Technology	Location Cluster	Zone
	Peaker	Eastside	IPCO, BPA IDMT, NWMT, AVA
		Westside	PSE (Central, North, Olympia)
		BPA Blend	BPA WA
Emerging Technology	Clean Baseload	N/A	AVA, BPA IDMT, BPA WA, IPCO, NWMT, PSE Olympia
	Clean Long Duration Energy Storage	N/A	BPA IDMT, NWMT, PAC E ID, IPCO, BPA WA, AVA, DC PUD, CC PUD, GC PUD, BPA OR, PAC W, PSE (North, Central, Olympia) SCL, TPWER, PGE
	Clean Peaker	N/A	BPA IDMT, NWMT, PAC E ID, IPCO, BPA WA, AVA, DC PUD, CC PUD, GC PUD, BPA OR, PAC W, PSE (North, Central, Olympia) SCL, TPWER, PGE

Table G - 5: Modeling Zone Names and Abbreviations

Modeling Zone Name	Modeling Zone Abbreviation
Avista Utilities	AVA
Bonneville Power Administration, Idaho and Montana	BPA_IDMT
Bonneville Power Administration, Oregon	BPA_OR
Bonneville Power Administration, Washington	BPA_WA
Chelan County PUD	CCPUD
Douglas County PUD	DCPUD
Grant County PUD	GCPUD
Idaho Power Company	IPCO
NorthWestern Energy	NWMT
PacifiCorp, East (Idaho & Wyoming)	PACE
PacifiCorp, West (Oregon & Washington)	PACW
Portland General Electric	PGE
Puget Sound Energy, Central	PSE_Central
Puget Sound Energy, North	PSE_North
Puget Sound Energy, Olympia	PSE_Olympia
Seattle City Light	SCL
Tacoma Power	TPWER
Western Area Power Administration, Colorado-Missouri Region	WACM

Modeling Zone Name	Modeling Zone Abbreviation
Western Area Power Administration, Upper Great Plains West	WAUW

Sources

Many of the attributes being defined for each resource, especially costs, rely on comprehensive literature reviews plotted on a single axis so they can be compared. Some of these sources have data for multiple resources, like NLR's Annual Technology Baseline, while others are more specific, like Gas Turbine World's 2024 handbook. All of the sources relied on for the plotted costs throughout the resource sections below are named in Table G - 6. The table also identifies the applicable resources by source and how it will be abbreviated through the rest of the appendix.

Table G - 6: Data Sources Referred to Throughout Appendix[15]

Source	Resources	Abv.
EIA's Capital Cost and Performance Characteristics for Utility-Scale Electric Power Generating Technologies[16]	Wind, Solar, Battery, Natural Gas, Conv. Geothermal, Pumped Hydro, SMR	(AEO 2025)
LBNL's Land-Based Wind Market Report 2024[17]	Wind	(LBNL 2024)
LBNL's Utility Scale Solar Market Report 2024[18]	Solar, Solar+Storage	(LBNL 2024)
NLR's Annual Technology Baseline[19]	Wind, Solar, Battery, Natural Gas, Conv. Geothermal, Pumped Hydro, Offshore Wind, SMR	(ATB 2024)
Lazard's Levelized Cost of Energy+ Ed.17[20]	Wind, Solar, Solar+Storage	(LCOE+ 2024)
PNNL's Energy Storage Grid Challenge Cost and Performance Database[21]	Battery	(ESGC 2024)
Gas Turbine World-2024 Handbook[22]	Natural Gas	(Gas Turbine World)
EIA Annual Energy Output 2023[23]	SMR	(AEO23 EIA)

[15] All sources and a detailed look at how they were used by resource can be found compiled here: https://nwcouncil.box.com/v/9thPlanRefPlantCosts.
[16] https://www.eia.gov/analysis/studies/powerplants/capitalcost/pdf/capital_cost_AEO2025.pdf.
[17] https://emp.lbl.gov/wind-technologies-market-report.
[18] https://emp.lbl.gov/publications/utility-scale-solar-2024-edition.
[19] https://atb.nrel.gov/electricity/2024/utility-scale_battery_storage.
[20] https://www.lazard.com/research-insights/levelized-cost-of-energyplus.
[21] https://www.pnnl.gov/projects/esgc-cost-performance/download-reports.
[22] https://gasturbineworld.zinioapps.com/publications/gas-turbine-world-handbook/42029/issues/658295.
[23] https://www.eia.gov/analysis/studies/powerplants/capitalcost/pdf/capital_cost_AEO2025.pdf.

Source	Resources	Abv.
NLR/DOE Techno-Economic Analysis[24]	H2	(NLR/DOE Techno-Econ Analysis)
E3 Western Long Term Market Potential[25]	H2	(E3 Western Market Potential)
NLR H2@ Scale report[26]	H2	(NLR H2@ Scale)
PNNL 2020 Grid Energy Storage Tech Cost and Performance Assessment[27]	H2	(PNNL 2020)
DOE Hydrogen Program Record[28]	H2	(DOE Hydrogen Program Record)
Form Energy Correspondence[29]	FE Air	(Form E)
PGE 2023 Integrated Resource Plan [30]	Wind, Solar, Battery, Natural Gas, Conv. Geothermal, Pumped Hydro, Offshore Wind, SMR, H2	(PGE 2023)
PacifiCorp 2025 Draft Integrated Resource Plan[31]	Wind, Solar, Battery, Natural Gas, Pumped Hydro, Offshore Wind, SMR, H2, Fe Air	(PAC 2025)
PacifiCorp 2023 Integrated Resource Plan[32]	Conv. Geothermal, H2	(PAC 2023)
Idaho Power 2023 Integrated Resource Plan[33]	Wind, Solar, Battery, Natural Gas, Conv. Geothermal, Pumped Hydro, SMR, H2, Fe Air	(ID Power 2023)
Avista 2025 Integrated Resource Plan[34]	Wind, Solar, Battery, Natural Gas, Pumped Hydro, Offshore Wind, SMR, H2, Fe Air	(Avista 2025)

[24] https://www.cell.com/joule/fulltext/S2542-4351(21)00306-8.
[25] https://www.ethree.com/wp-content/uploads/2020/07/E3_MHPS_Hydrogen-in-the-West-Report_Final_June2020.pdf.
[26] https://docs.nrel.gov/docs/fy21osti/77610.pdf.
[27] https://www.pnnl.gov/sites/default/files/media/file/Final%20-%20ESGC%20Cost%20Performance%20Report%2012-11-2020.pdf.
[28] https://www.hydrogen.energy.gov/docs/hydrogenprogramlibraries/pdfs/24005-clean-hydrogen-production-cost-pem-electrolyzer.pdf.
[29] https://formenergy.com.
[30] https://portlandgeneral.com/about/who-we-are/resource-planning/combined-cep-and-irp.
[31] https://www.pacificorp.com/energy/integrated-resource-plan.html
[32] Ibid
[33] https://www.idahopower.com/energy-environment/energy/planning-and-electrical-projects/our-twenty-year-plan.
[34] https://www.myavista.com/about-us/integrated-resource-planning.

Source	Resources	Abv.
Puget Sound Energy 2023 Integrated Resource Plan Progress Report[35]	Wind, Solar, Battery, Natural Gas, Pumped Hydro, Offshore Wind, SMR	(PSE 2023)
NorthWestern 2023 Integrated Resource Plan[36]	Natural Gas	(NWestern 2023)

New Resource Options

The Council considers a wide range of resource options in developing a power plan. Table G - 7 includes a list of all generating resources considered in the Ninth Plan.

Table G - 7: Resources Considered

Primary	Limited Availability	Emerging
Utility Scale Solar PV	Conventional Geothermal	Enhanced Geothermal
Onshore Wind	Offshore Wind	Small Modular Reactors
Small Scale Renewables	Pumped Storage	Carbon Capture & Sequestration
Gas CCCT	Biomass	Hydrogen Gas Turbine
Gas SCCT – Frame	Hydro Upgrades	Allam Cycle Gas
Gas SCCT – Reciprocating Engine	Biogas	Wave, Tidal
Gas SCCT – Aeroderivative	Small Hydro	Long Duration Storage
Battery Storage (Li-ion)	Combined Heat & Power	
Renewables + Storage		

This list was pared down with the help of regional experts and advisory committee feedback, and compiled into a final list of resources. The final list was developed into reference plants and fed into the model. The goal is a streamlined list that still represents the full breadth of resource options available to the region.

The Council mostly did not develop full reference plants for resources with limited, or small-scale, developmental potential in the Pacific Northwest. In some instances, the Council selected one technology type over other similar options, such as single gas peaker technology or a specific renewable resource to pair with storage. In other cases, the resource is not being built in the region,

35 https://www.pse.com/en/IRP/Past-IRPs/2023-IRP.

36 https://northwesternenergy.com/about-us/gas-electric/montana-electric-supply-planning/montana-integrated-resource-plan-2023.

like biomass or small hydro. The resources that were precluded from reference plant development are described with some detail below. While these resources are not explicitly modeled, they are still considered viable resource options for future power planning needs.

The treatment of emerging resources, the red column in Table G - 7, is described later in this appendix.

Aeroderivative Turbines

Aeroderivative turbines are a type of simple cycle gas turbine technology. They are characterized by their light weight, highly efficient, and flexible design. When selecting which gas turbine technology to include in the Ninth Plan, reciprocating engines and frame turbines were chosen as the representative gas peaker technologies. Aeroderivative turbines are less commonly built in the region and are more expensive and less modularly flexible than the frame turbines or reciprocating engines.

Renewables Plus Storage

While solar is the most common renewable paired with batteries, it is not the only resource that can be co-located with storage. Wind + storage and a wind + solar + storage resource were both considered in the resource selection process. These pairings are not yet common practice in the region, likely because wind generation is less consistent than solar production (which has a similar shape every day), therefore resulting in a less reliable pair for shorter duration storage. Ultimately, the Council decided to just develop a reference plant for solar + storage.

Biomass and Biogas

Biomass refers to an organic material that can be converted to energy through direct combustion or converted into gaseous or liquid fuels. In the region, much of the biomass capacity is fueled by burning spent pulping liquor and woody residues from the logging/paper industry. Biological conversion of biomass produces biogas through the anaerobic digestion of organic materials, like food waste, manure etc., resulting in a gaseous mixture that can be combusted like natural gas. While biomass is utilized for electricity production in the region, it is not a common fuel choice. However, in some planning it is being looked at as a potential ‘renewable’ alternative to other combustibles. The Council opted to not develop a reference plant for the resource based on this limited regional use.

Hydro Upgrades and Small Hydro

Hydropower upgrades increase existing capacity by replacing or improving turbines, generators, etc. and small hydro refers to small turbines that can capture energy from irrigation infrastructure, low-head stream flows, water treatment plant outfalls etc. with a smaller footprint or impact on the surrounding environment than a traditional hydroelectric dam. These technologies are highly site specific and not often utilized at scale in the region. This minimal development led the Council to not develop a reference plant for these technologies.

Combined Heat and Power

Combined heat and power plants produce electricity and another useful thermal energy (heat, steam) that is more efficient than if both sources of energy were to be produced separately. These are most often used in industrial applications to make more efficient use of process heat. These tend to be closed systems, where the industrial plant utilizes the process heat to produce electricity which it then uses in its own operations, rather than serving the larger grid. Many of the industries that deployed cogeneration - like paper and aluminum- have left the region, making it a less viable new resource option.[37] The Council concluded a reference plant for the technology wasn't needed.

Final Suite of Reference Plants

After deliberating on the full suite of resource options in Table G - 7, the Council landed on a reduced list to use as reference plants. Table G - 8 provides the final list of resources for which the Council developed reference plants for inclusion in the modeling.

Table G - 8: Final Resource Selection

Primary	Limited Availability	Emerging
Utility Scale Solar PV	Conventional Geothermal	Clean Long-Duration Storage Proxy
Onshore Wind	Offshore Wind	Clean Baseload Proxy
Small Scale Solar	Pumped Storage	Clean Peaker/Medium-Duration Storage Proxy
Gas (CCCT, SCCT – Frame/ – Reciprocating Engine)		
Battery Storage (Li-ion)		
Solar + Storage		

Primary Resources

Generating resources that are deemed proven, commercially available, and deployable on a large scale in the region at the start of the study period are Primary Resources. These resources have the potential to play a major role in the future regional power system. To ensure a deep understanding of these resources and their potential, the Council performs an in-depth, quantitative characterization.

[37] The Power Act (Northwest Power Act, §4(e)(1), 94 Stat. 2705) gives priority to first, conservation, second, renewable resources, and third generating resources utilizing waste heat. Industrial cogen falls under this third priority category. It was considered but not developed further into a full reference plant for the above describe reasons.

Onshore Wind

Wind power is a naturally occurring, renewable form of energy that is harnessed and transferred into electricity through power plants made up of individual turbines. Wind turbines primarily consist of a tower, two or three blades, hub and rotor, and a nacelle (consisting of interconnected low and high-speed shafts, a gear box, and a generator). As the wind blows, the turbine blades (connected at the hub and attached to the rotor) are rotated, with the rotor causing the low-speed shaft to spin within the nacelle. Housed in the gearbox, the low-speed shaft is connected to the high-speed shaft, which increases the speed of the rotation. The gearbox is attached to the generator, which produces electricity. Wind turbines typically possess weathervanes and anemometers (an instrument to measure wind speed) that transfer information to a controller. Between the controller computer system and remote operators, a wind turbine can be turned on and off depending on the wind speed as well as positioned depending on the wind direction.

For more information about wind development in the region see Technical Appendix B – Existing System Parameters and Policies.

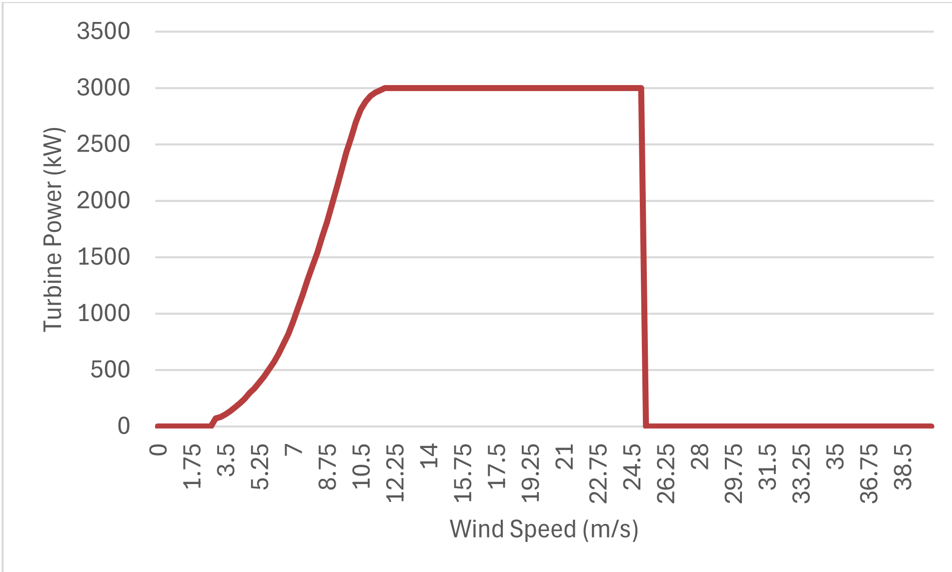
Availability

Onshore wind is available to be built at the beginning of the study period and takes 3 years for development and construction. There are potentially some limiting factors to account for when considering the development of wind, such as siting constraints, available land and community pushback, and supply constraints especially with uncertainty around tariffs and transformer supply. Some of the land considerations are factored in when selecting the wind locations, discussed in detail below. Most land consideration limits are thought to be fairly universal across resources and will be tested in scenario analysis, the specifics of which are described in a later section.

Wind is one resource that the model can select continuously, so there isn't a plant size consideration to be made. However, a specific turbine type had to be selected for the modeling of wind generation over the course of the study. This required considering recent turbine types being used in the region,[38] with some concessions made for available data. Power curves of turbines currently in production are often proprietary. The turbine model chosen for the Ninth Plan representative wind resource is the Vestas v112-30, whose power curve is illustrated in Figure G - 5. The power curve shows the turbine's electric power output by wind speed. How this turbine performance is then processed into wind generation is described in Technical Appendix D – Climate Model Data and Assumptions.

[38] File 3_2_Wind2024: https://www.eia.gov/electricity/data/eia860.

Figure G - 5: Turbine Power Curve[39]



Location

Wind resources vary across the region. The Council's goal in evaluating the differences in generation required balancing computing and analytical workload with the value of the insights gained into the variability of the region's wind resource. Combining all wind resources in the region into a single capacity factor would be over-generalizing, and result in inaccurate data. Modeling precise wind regimes in every modeling zone would be too granular.

The Council compiled annual wind generation at different weather stations across the region into five differentiable zones. Wind generation in the Columbia River Gorge is different from Southeast Washington, which was distinct from Southern Idaho. The analysis also captured different capacities in Montana and Wyoming. These zones nicely mapped to where, historically, wind plants have been built in the region, further supporting the choice.

These zones and historical builds are shown in

Figure G - 6. After selecting these locations as representative of the region, synthetic future generation curves, like those shown in Figure G - 7, were generated for every hour of every day for each location for the whole study. More on this development process is detailed in Technical Appendix D – Climate Model Data and Assumptions.

[39] https://samrepo.nrelcloud.org/help/wind_turbine.html.

Figure G - 6: Existing Regional Wind Clusters Mapped

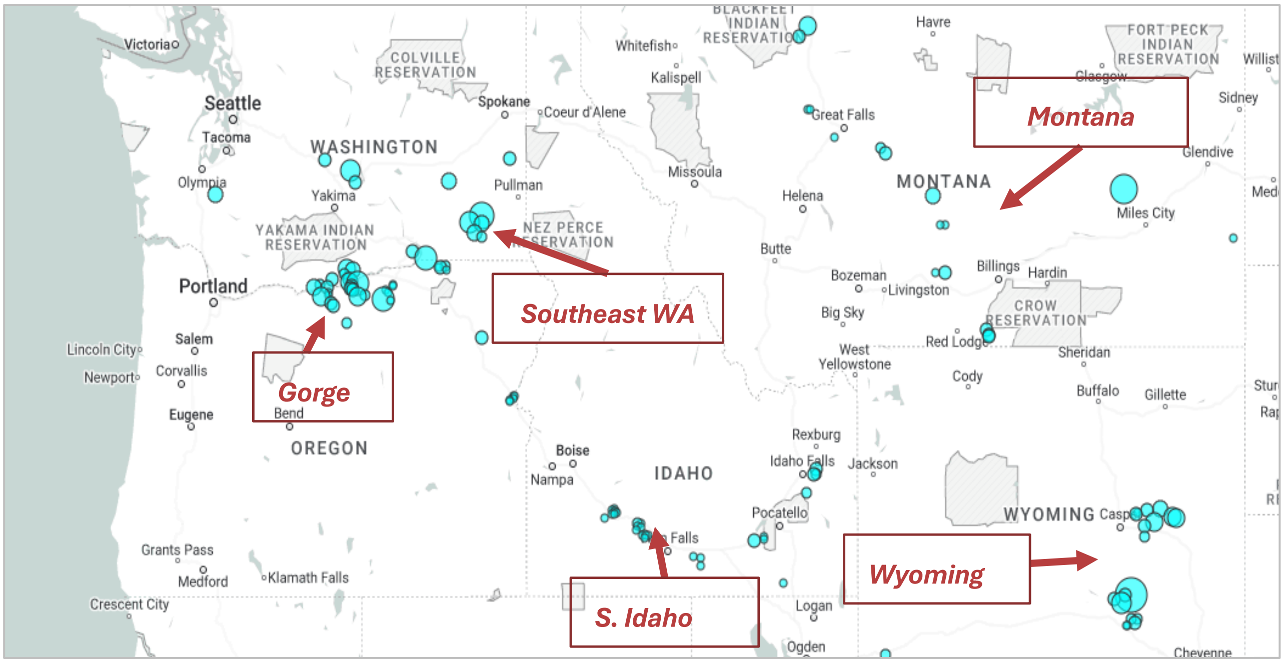
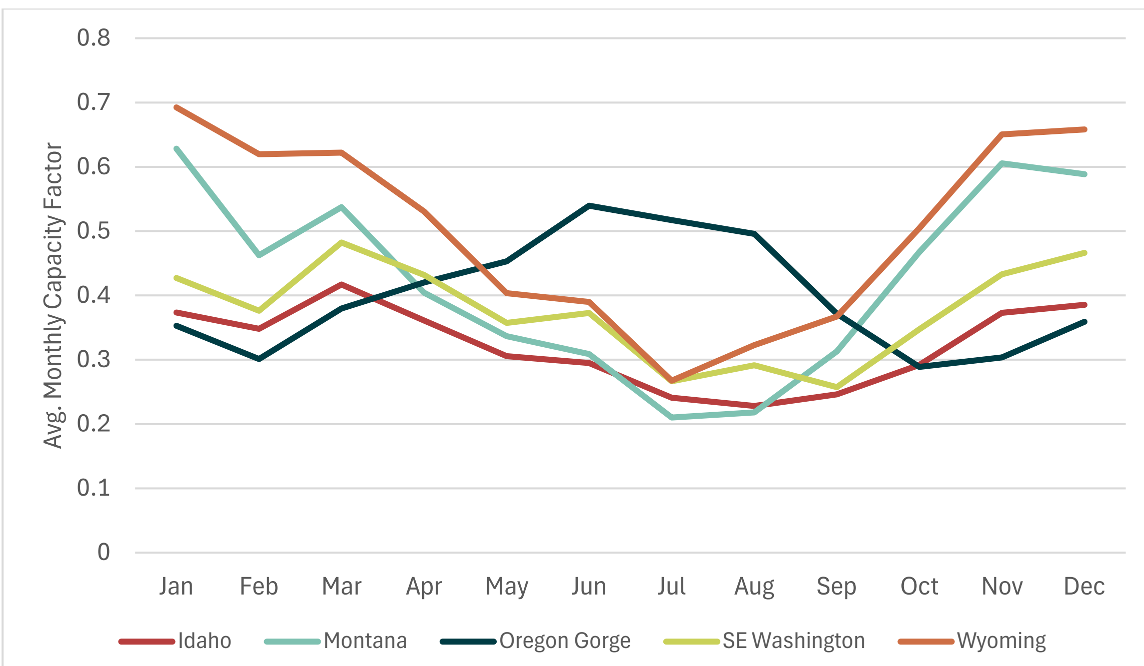


Figure G - 7: Average Monthly Capacity Factors Across Regional Wind Generation Clusters



Out of Region Wind Locations

The broader WECC is modeled in the plan development process to inform wholesale market availability. To forecast this market availability the Council uses AURORA to estimate the buildout of future resources throughout the western grid and generate wholesale power prices via production cost modeling. More on this market modeling methodology and the results can be found in Technical

Appendix L – Wholesale Market Availability Results. The resource options included in the capital expansion module in AURORA to be selected to meet forecasted WECC-wide load are the same as those described in this appendix. However, resources with locational variability, like wind and solar, required the development of additional generation curves to represent the diversity of the resource across the WECC. The selection of these representative locations, shown in Figure G - 8. Developing the accompanying generation profiles was done with a similar process as for in-region resources. These renewable availability forecasts were included in the AURORA capital expansion modeling as expected shapes based on historical climate data. Average monthly capacity factors by location are shown in Figure G - 9, to illustrate the spread of wind regimes represented across the larger WECC.

Figure G - 8: Out of Region Wind Locations

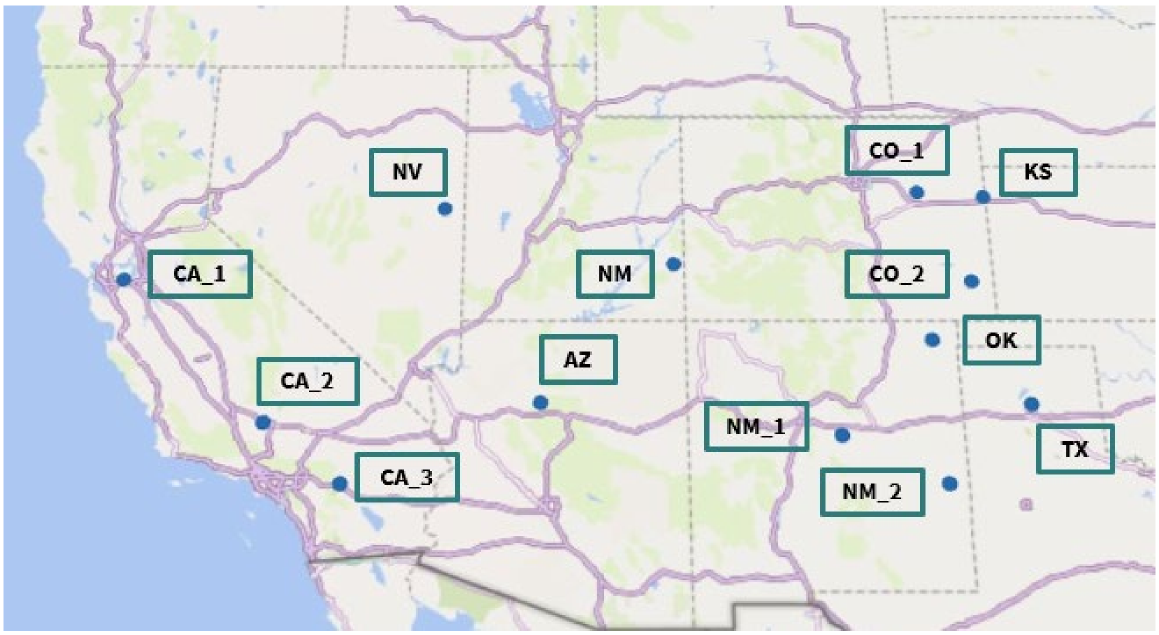
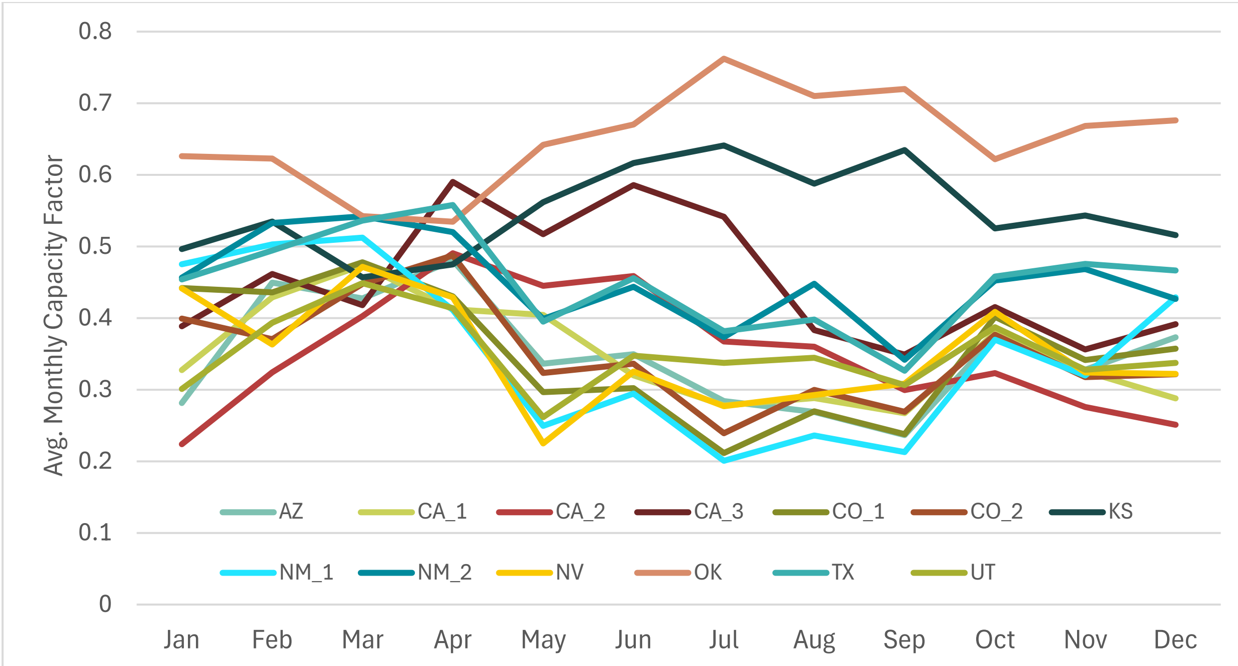


Figure G - 9 : Average WECC-Wide Monthly Wind Capacity Factors



Costs

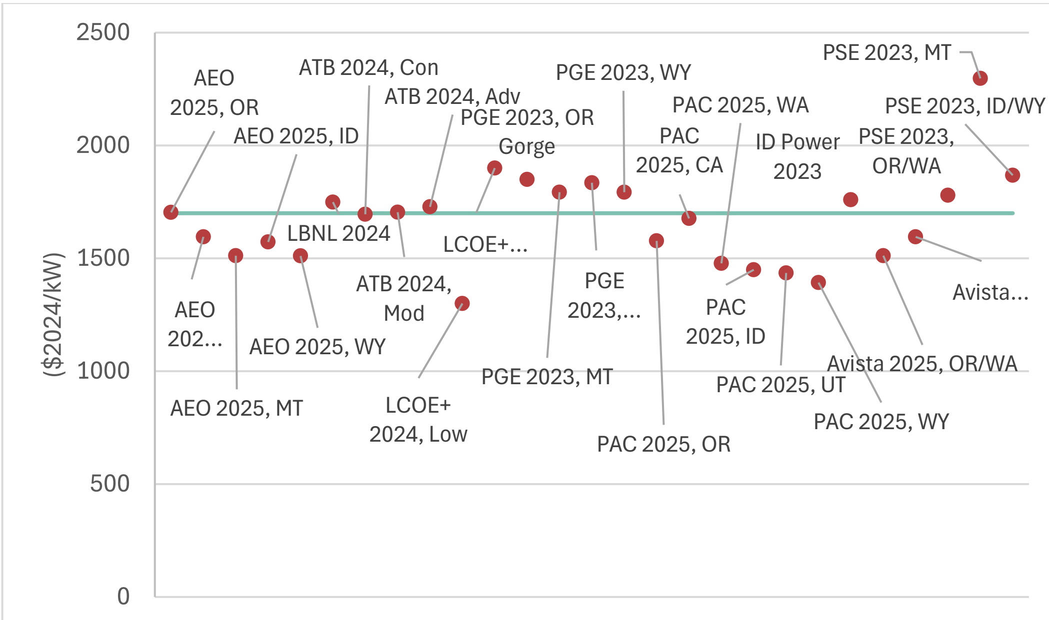
The capital costs of onshore wind technologies have declined significantly since they peaked in 2008-2009. According to the Lawrence Berkeley National Lab, from 2008 to 2020 the installed cost of wind declined by more than 50%, though recent years have seen that trend flatten as the technology has matured and faced some supply chain issues - particularly in 2021 and 2022.[40]

As wind turbine technologies have improved significantly over the last ten years, so too have the costs. Project performance and energy output has grown alongside increases in hub heights (size of the tower), rotor blades, and nameplate capacity of the generators. This has resulted in lower overall capital and installed costs (in $/kW), as well as the levelized cost of energy. Turbine generators are expected to continue to increase in capacity, and costs are expected to continue to decline, although to what extent is uncertain.

Figure G - 10 and Figure G - 11 show the data plots and analysis that were used to develop the Ninth Power Plan reference plant cost estimates. Note that figures capture data from various onshore wind capacities, configurations, and technologies.

[40] https://eta-publications.lbl.gov/sites/default/files/land-based_wind_market_report_2024_edition_executive_summary.pdf.

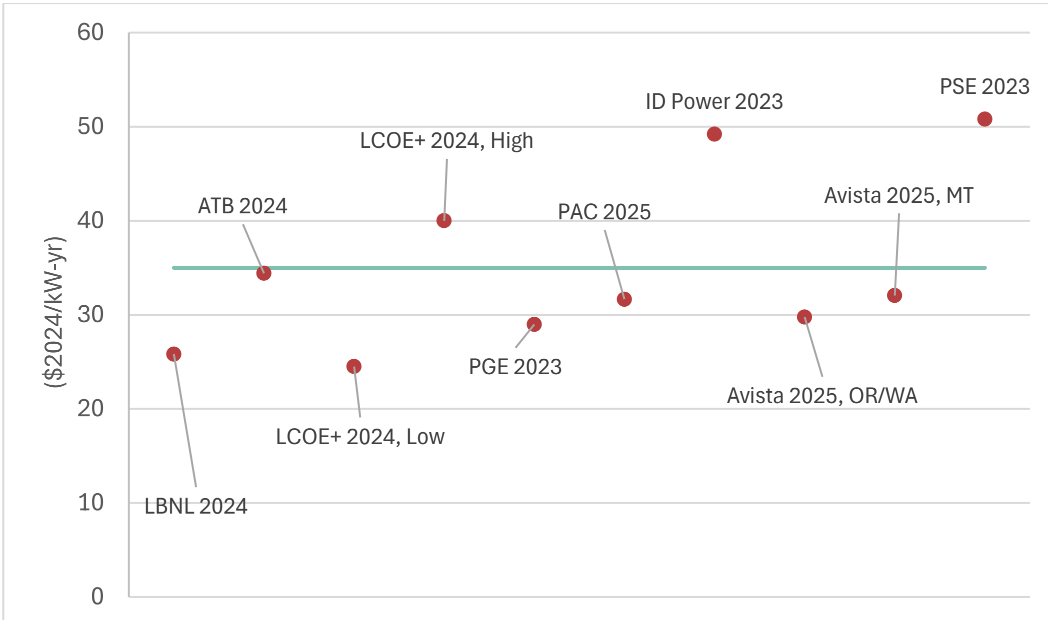
Figure G - 10: Literature Review of Land-Based Wind Overnight Capital Costs[41]



The literature review of onshore wind overnight capital costs, seen plotted in Figure G - 10, coalesces around $1700/kW, shown by the light blue line. This final cost is not a pure average of available data, or a simple eyeballing of the plot, but an educated estimate arrived at through research, professional judgment and advisory committee expertise.

[41] To avoid redundancy, all sources and their acronyms plotted on this and future charts are described in Table G - 6.

Figure G - 11: Literature Review of Land-Based Wind Fixed Operations & Maintenance Costs



Similarly, Figure G - 11 shows there is a clustering of wind fixed operations and maintenance costs around $30/kW-yr.

Figure G - 12: Forward Cost Curves for Land-Based Wind Overnight Capital Costs

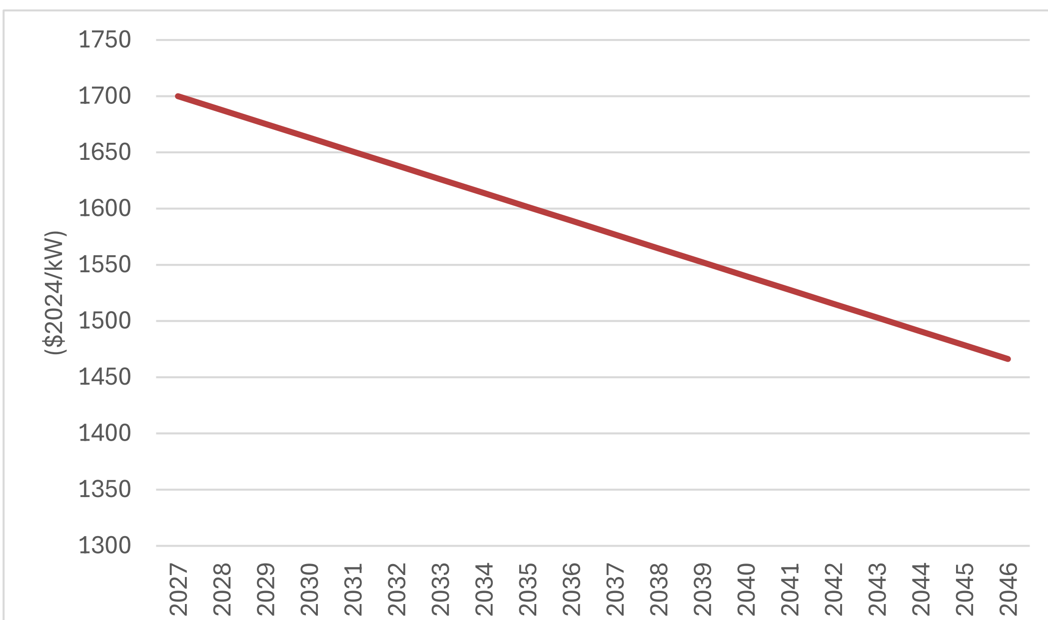


Figure G - 12 shows the same cost curve for wind displayed in Figure G - 1 but on its own axis for a clearer view. Overnight capital costs over the course of the study decrease to below $1500/kW over 20 years.

Locational Cost Variation

As discussed in the shared assumptions section about locational cost adjustments, locational cost adjustment factors are applied to the capital costs of resources that have otherwise been differentiated by location. For wind, the Council applied locational cost adjustments to align with the five different zones developed to capture capacity factor variation. There is some work aligning the factors provided by the EIA,[42] described in Table G - 3, to the locations selected for reference plants. That cross-walking for wind is shown in Table G - 9, where Gorge wind is given the Portland cost adjustment, SE Washington is given Spokane's etc. Those adjustments are applied by location to the starting wind capital cost in Table G - 10.

Table G - 9: Onshore Wind Locational Cost Variation by Resource Cluster

	Locations	Cost Variation Multiplier
Gorge	Portland	1.1080
SE Washington	Spokane	1.0376
S Idaho	Boise	1.0229
Montana	Great Falls	0.9830
Wyoming	Cheyenne	0.9825

Table G - 10: Locational Variation of Land-Based Wind Capital Costs

	Variation	Land-Based Wind, OCC
Starting Point	*n/a*	*$1700*
Gorge	1.108	$1883.60
SE Washington	1.3076	$1763.92
S Idaho	1.023	$1738.93
Montana	0.983	$1671.10
Wyoming	0.9825	$1670.25

Summary Table

In an effort to capture all the resource characteristics in one accessible and legible place, each reference plant description will conclude with a comparable table summarizing all that has been

[42] https://www.eia.gov/analysis/studies/powerplants/capitalcost/pdf/capital_cost_AEO2025.pdf.

discussed in the preceding section. The summary of the onshore wind reference plant is captured by Table G - 11.

Table G - 11: Land-Based Wind Reference Plant Summary Table

Reference Plant	Onshore Wind – Gorge	Onshore Wind –SE. Washington	Onshore Wind – Southern Idaho	Onshore Wind – Montana	Onshore Wind – Wyoming
Configuration	Vestas V112-3.0, 100m hub height				
Location – Modeling Zones	BPA OR, BPA WA	BPA WA, AVA, DC/CC/GC PUD	IPCO, PACE ID	BPA IDMT, NWMT, WAUW	PACE WY, WACM
Year Available to Model	At start of study				
Development/Construction Period (Years)	3				
Capacity Factor	(See **Figure** G - 7)				
Overnight Capital Cost ($/kW)	1827	1768	1717	1666	1666
Fixed O&M Cost ($/kW-yr)	30				
Variable O&M ($/MWh)[43]	0				
Economic Life (years)	30				

Utility-Scale Solar

Solar power is a naturally occurring, renewable resource that converts energy from the sun (solar radiation) into electricity. Solar photovoltaic (PV) installations consist of PV cells assembled into modules, ground-mounted (as opposed to rooftop) on panels to fixed-tilt or tracking systems (single or dual axis). Because the electricity is generated in direct current (DC), it is fed through an inverter to convert the electricity output to alternating current (AC). From the inverter, it is connected to the electricity grid through a transformer and substation. PV modules are typically manufactured from semiconductor materials, primarily crystalline silicon (c-Si) and cadmium tellurium (CdTe). Fixed-tilt are stationary installations, permanently set at an optimum angle to absorb the most solar radiation. Tracking systems allow for the modules to rotate on a single or dual axis, effectively “tracking” the

[43] The operations and maintenance of renewable resources, like wind, are primarily fixed annual costs that occur independently of the plant’s production. Variable O&M costs are a function of a plants usage, incurring per megawatt hour, and as renewable fuels, sun and wind, are free they don’t result in any consumable costs, unlike fossil fuel plants.

greatest solar radiance throughout the day. While the range in spatial acreage can vary based on each project design and logistics, a basic rule of thumb is that one megawatt capacity of solar PV tends to equal about five to seven acres of land.

In the Pacific Northwest there is a tendency to install single-axis tracking systems, rather than fixed-tilt mounted systems. The Northwest has lower solar radiance (as compared to the desert Southwest, for example), so using a technology that can track and capture more energy from the sun increases energy output.

For more information about solar development in the region see Technical Appendix B – Existing System Parameters and Policies.

Availability

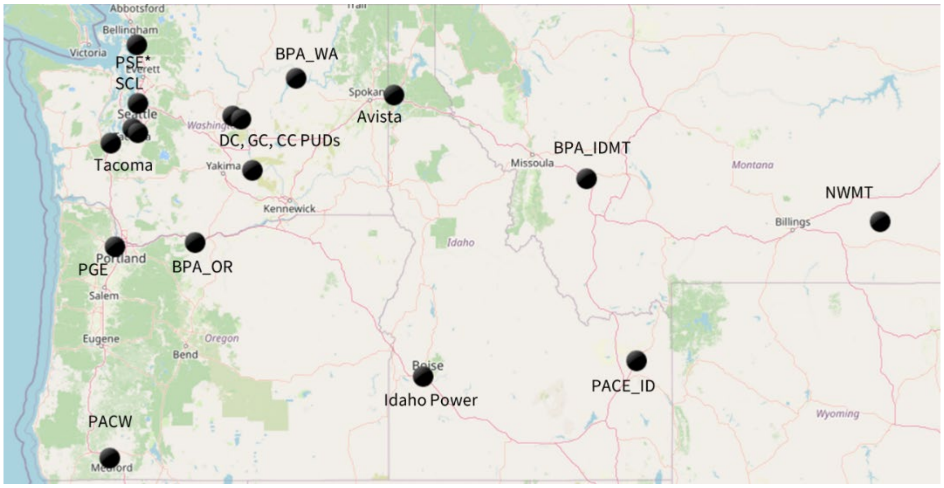
Utility-scale solar is available to be selected at the beginning of the study period and takes two years for development and construction. Solar is another continuous resource and therefore does not have a defined plant capacity.

Location

Similarly to wind, there is significant variation in solar generation across the region. This variability led to a similar exercise of trying to capture that variation without needing to define a solar reference plant for each modeling zone. An exploration of solar generation across the region, shown in Figure G - 14, saw zones cluster into three groups with comparable generation shapes. The locations of those zones are mapped in Figure G - 13.

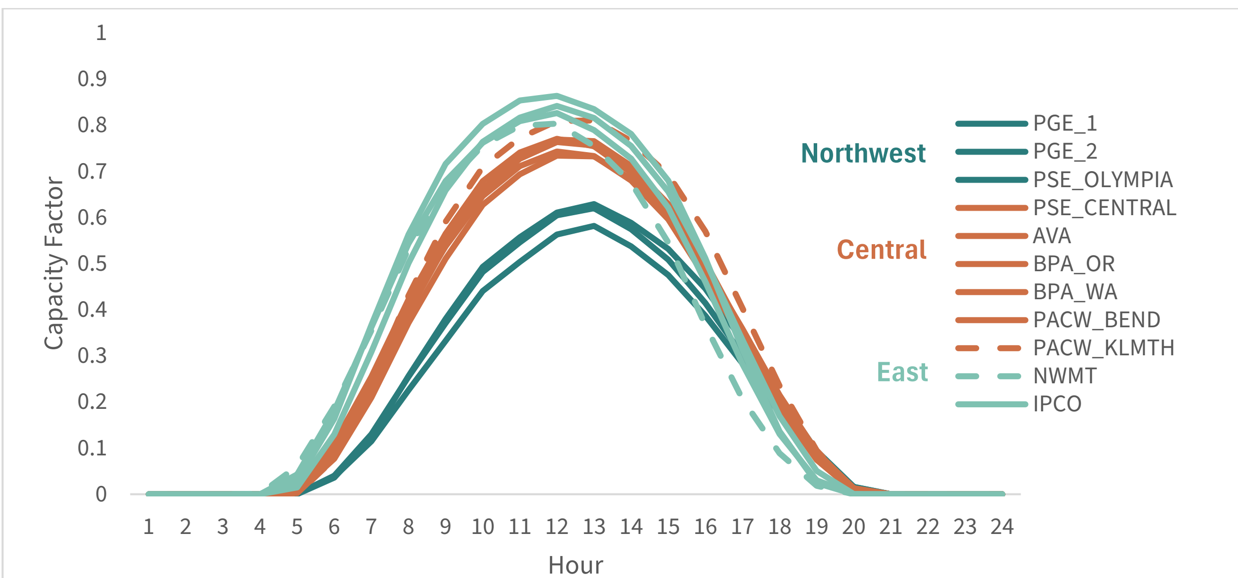
As might be anticipated, there is a higher generation shape for eastern zones like PACE and Idaho Power, a moderated shape for the central region including BPA OR and WA, PACW, and lower generation in the furthest west zones such as PSE and PGE. Figure G - 15 displays how these three broader clusters encompass existing resource locations as well.

Figure G - 13: Modeling Zones Mapped[44]



As might be anticipated, there is a higher generation shape for eastern zones like PACE and Idaho Power, a moderated shape for the central region including BPA OR and WA, PACW, and lower generation in the furthest west zones such as PSE and PGE. Figure G - 15 displays how these three broader clusters encompass existing resource locations as well.

Figure G - 14: Clustering of Solar Shapes

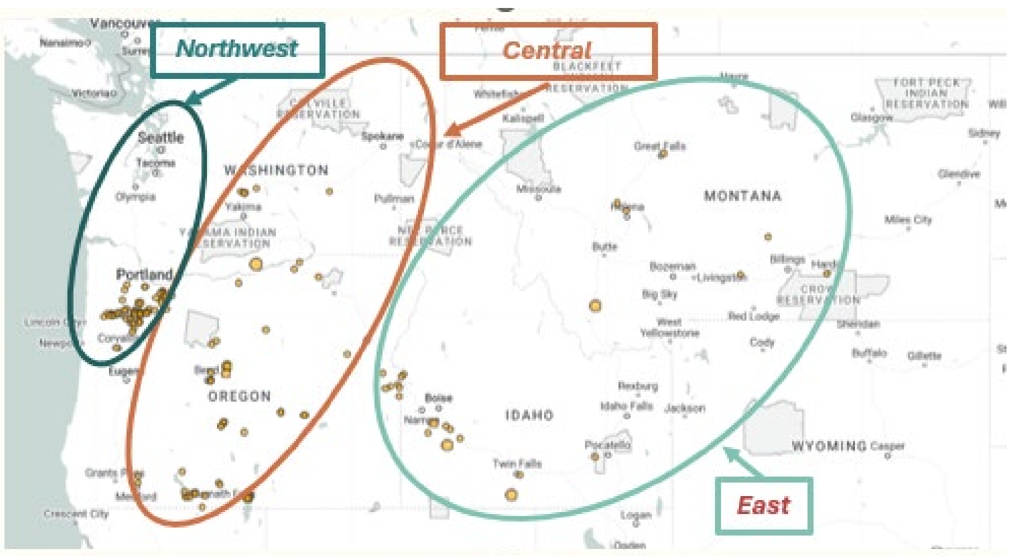


The exploration of in-region solar capacity factor shapes in Figure G - 14 suggests three potential clusters which are observed daily (shown in this chart) & monthly. These capacity factors are synthetic, based on historical solar generation from Time Series Lab. The exact numbers shown above

[44] Mapped black dots identify GENESYS zones which are not identical to those in OptGen, but are close enough to illustrate the methodology being described here.

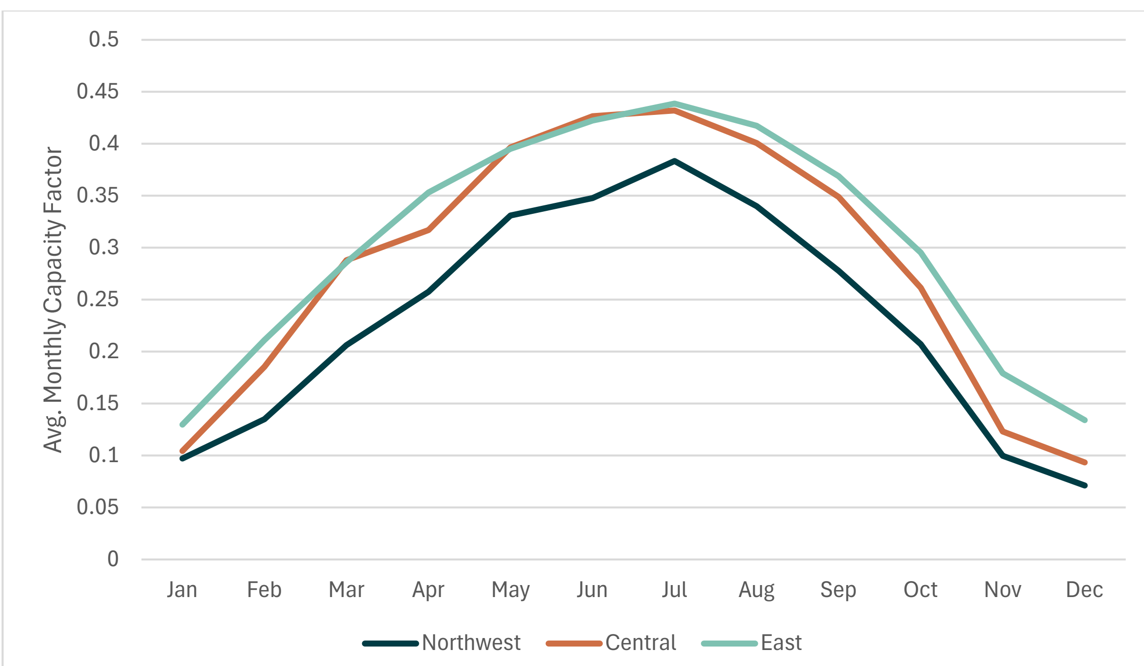
are pre-climate change processing and bias correction, and are therefore just illustrative of hourly generation by BA, not the actual solar capacity factors used in modeling. Final capacity factors are illustrated in Figure G - 16.

Figure G - 15: Regional Solar Generation Shape Clustering



After selecting the representative locations, synthetic future generation curves were developed for each, like those shown in Figure G - 16, but for every hour of every day for each location for the whole study. More on this development process is detailed in Technical Appendix D – Climate Change Data and Assumptions.

Figure G - 16: Average Monthly Capacity Factors Across Regional Solar Generation Clusters

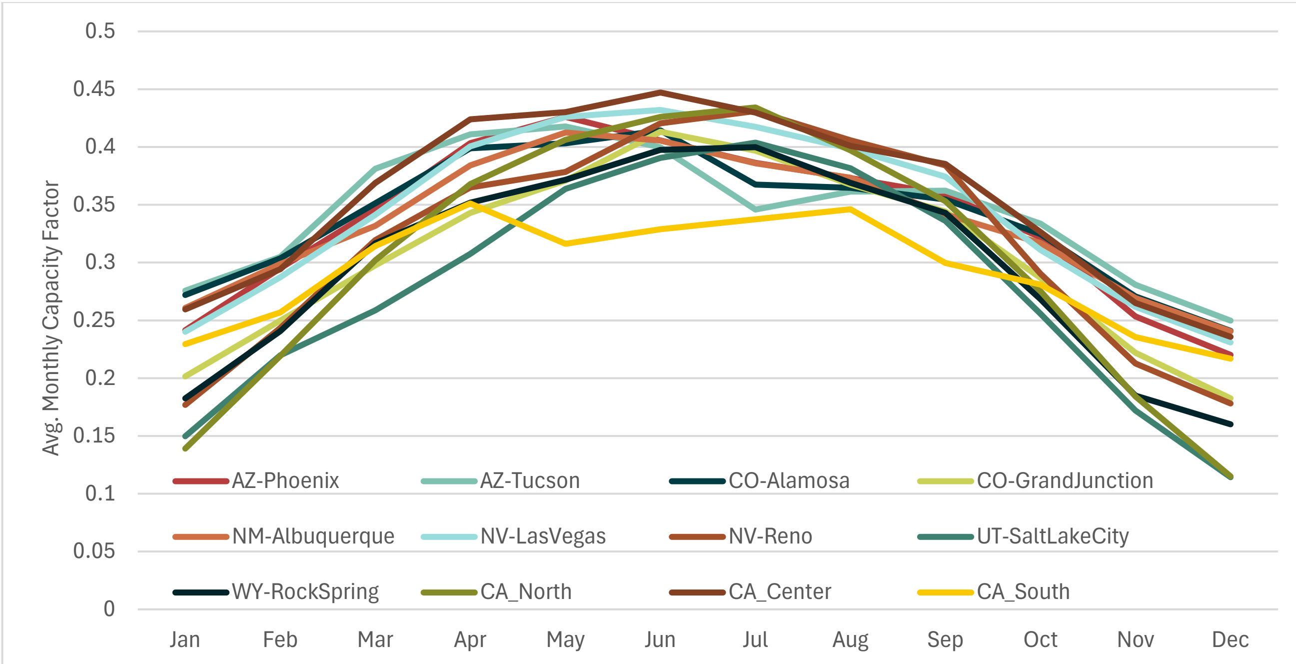


Out of Region Solar Locations

As with the wind resource, to accurately represent solar in the market availability study, the Council had to develop additional renewable availability forecasts to capture the locational diversity of the resource. The specific locations selected to represent the broader WECC's solar resource are shown mapped in Figure G - 17 below. Those locations' generation curves are broadly illustrated in Figure G - 18 as average monthly capacity factors.

Figure G - 17: Out of Region Solar Locations

Figure G - 18: Average WECC-Wide Monthly Solar Capacity Factors



Operational Risk of Wildfire

In recent years, greater attention has been given to the operational risk of wildfires on the bulk power system. The Council initially considered the adequacy risk of wildfires in the region from the perspective of transmission derating in the 2027 Adequacy Assessment[45] in one of the evaluated scenarios. The scenario was considered as a stress test, and derated three transmission lines between BPA, PacifiCorp West, and Idaho Power by 50-90% for an entire week in July. While that specific scenario was deemed adequate (all adequacy metrics were satisfied), it does not mean that there is no adequacy risk to the region from wildfires. Rather, it was a deterministic representation of a single wildfire event. In preparation for the Ninth Plan, the Council sought to transition from a standalone “wildfire scenario” to “wildfire-informed” planning included in all scenarios.

To that end, the scope of wildfire operational risks in the Ninth Plan centers on wildfires’ impacts on bulk transmission and generation and its influence on new resource decisions and adequacy. This was done via literature review, subject matter expert interviews, and advisory committee engagement in an effort to enhance the modeling and fine tune risk assumptions.[46,47]

[45] Pacific Northwest Power Supply Adequacy Assessment for 2027, Council Document Number 2023-1, Jan 17, 2023 https://www.nwcouncil.org/fs/18158/2023-1_adequacyassessment.pdf.
[46] https://www.nwcouncil.org/calendar/approach-to-modeling-operational-risks-from-wildfires-webinar-2025-03-07/
[47] https://www.nwcouncil.org/fs/19395/2025_05_11.pdf.

Through this process, the two main bulk system operational risks that were determined to be appropriate to model were transmission derates and smoke-modified solar capacity factors. However, it was judged that the methodology required to represent transmission derates consistent with the effect on solar generation in the model setup would not be possible to implement within the Ninth Plan timeline. Further methodological and model development will be pursued to capture the effect in future plans. Instead, the wildfire risk in this plan is focused only on smoke-modified solar capacity factors.

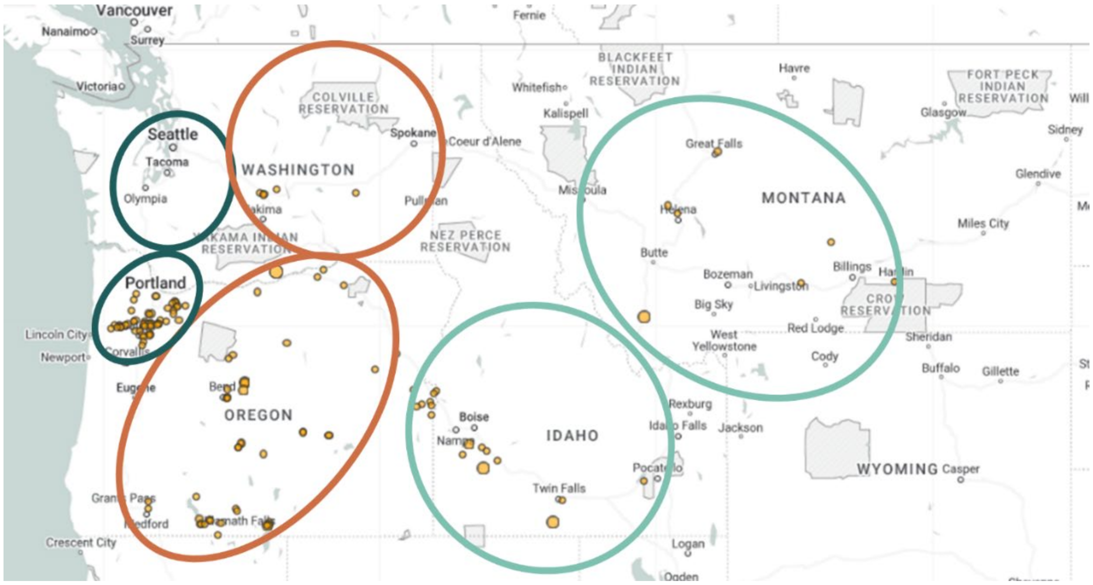
Smoke-Modified Solar Capacity Factor:

Research indicates that the impact of smoke on reducing solar generation can range from average daily reductions of 5-40%.[48,49,50,51,52] Coupled with the reduced capacity, there is also an increase in balancing up reserves, with one NLR report examining California fires finding a ~10% solar reduction but 53-64% reserve increase.[53] Given these potential impacts, it was deemed important to include smoke risks in the hourly annual solar capacity factors used in Council models.[54]

The first step was to define the smoke areas in the region. As solar shapes were already grouped into the three zones seen in Figure G - 15, it was recommended to further divide the three zones into their own state areas and evaluate smoke in those perimeters, for a total of six smoke zones seen in Figure G - 19.

[48] Ali, Amjad Jebril, Long Zhao, and Mohammad Heidari Kapourchali. "Data-driven-based analysis and modeling for the impact of wildfire smoke on PV systems." *IEEE Transactions on Industry Applications* 60.2 (2023): 2076-2084.
[49] Gilletly, Samuel D., Nicole D. Jackson, and Andrea Staid. "Evaluating the impact of wildfire smoke on solar photovoltaic production." *Applied Energy* 348 (2023): 121303.
[50] York, S. "Smoke from California wildfires decreases solar generation in CAISO." *US Energy Information Administration* (2020).
[51] Maguire, Gavin. "California Wildfires Dim Solar Generation during Power Demand Peak | Reuters." *Reuters*, 31 July 2024, www.reuters.com/markets/commodities/california-wildfires-dim-solar-generation-during-power-demand-peak-2024-07-31.
[52] Cai, Mengmeng, et al. *Final technical report: impact of wildfires on solar generation, reserves, and energy prices*. No. NREL/TP-5D00-86640. National Renewable Energy Laboratory (NREL), Golden, CO (United States), 2023.
[53] Ibid
[54] See Technical Appendix K – Modeling Framework for more information on the Council's modeling methodology.

Figure G - 19: Regional Solar Generation Shape Clustering for Wildfire Modification

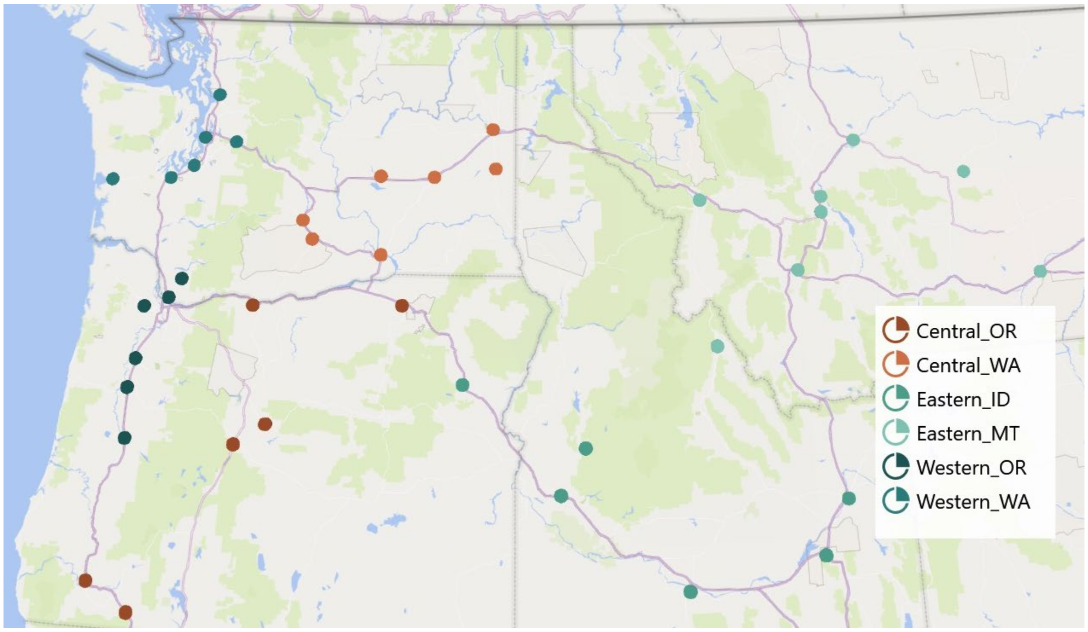


Second, the Council approximated the days with smoke present using historical observations from 2015-2024 using collected particulate matter 2.5 (PM2.5)[55] data from several monitoring stations in each zone. While PM2.5 has limitations as a proxy for wildfire smoke, the Council assumed that locations that had levels higher than normal background levels (for example from emitting industries) could suggest the prevalence of wildfire smoke.[56]

Figure G - 20 and Figure G - 21 show the location of the PM2.5 monitoring sensors with daily measurements provided from the U.S. Forest Service AirFire Research Team,[57] which include sensor level data across each state for the last 10 years (2015-2024). These locations were selected based on the presence of existing solar projects, seen in Figure G - 21, possible locations of future projects, and available data for 2015-2024 with as little missing data as possible.

[55] PM2.5 are fine inhalable particles, with diameters that are generally 2.5 micrometers and smaller. They are dangerous to human health due to their small size and resulting ability to permeate the respiratory system.
[56] Gilletly, Samuel D., Nicole D. Jackson, and Andrea Staid. "Evaluating the impact of wildfire smoke on solar photovoltaic production." *Applied Energy* 348 (2023): 121303.
[57] https://www.airfire.org.

1 **Figure G - 20: AirFire PM2.5 Sensor Locations by Group**[58]



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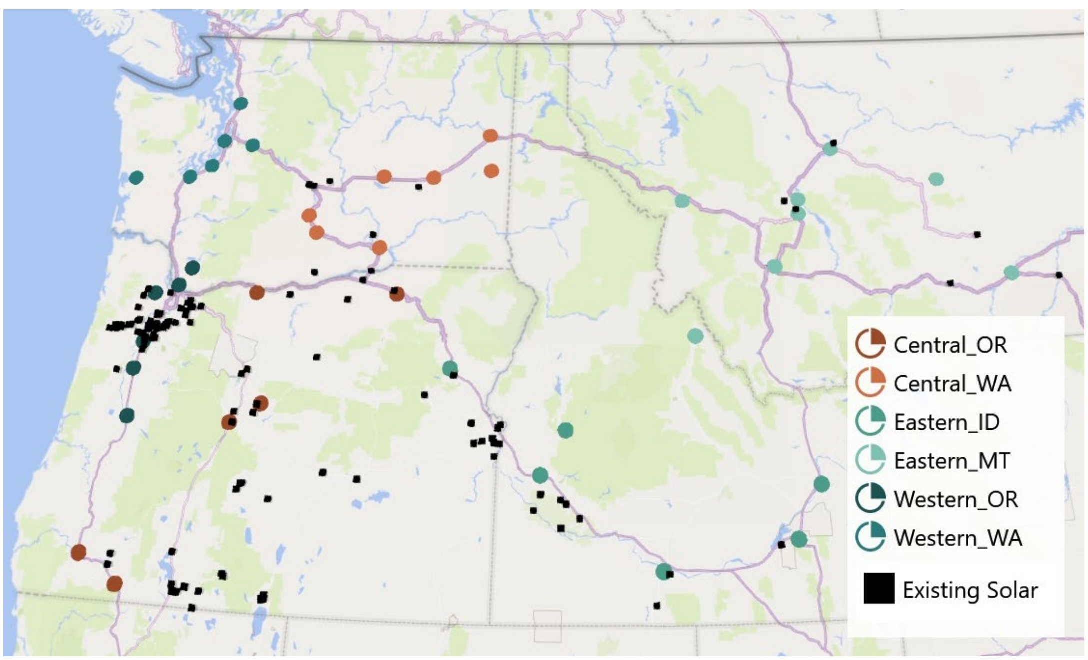
3 **Figure G - 21: AirFire PM2.5 Sensor Locations Near Spread of Existing Solar Projects in Region**[59]



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5

[58] https://www.airfire.org.
[59] Ibid.

As each subregion has 6-7 sensors and their aggregate was determined to be the daily average of the zone. The Council needed to define a “wildfire smoke day” and did so assuming any day at or above 35 μg/m3 was a result of wildfires. Because the Council’s models do not have the ability to represent nuances within a zone (e.g. different capacity factors for two solar plants within the same zone), the Council needed an approach that captured the impacts of smoke while not over representing localized impacts that would ultimately not be considered in the modeling.

After determining the location and frequency of wildfires, the next step was to define the solar reduction factor, or how much the presence of smoke impacts the production of solar. Given the findings from several studies centered around 10% reduction, staff determined a range of 8-12% reduction to be uniformly randomly assigned to any day with an average PM2.5 value at or above 35 μg/m3. Lastly, these daily smoke and solar reduction factors were then used to create annual profiles, based on the available 2015-2024 data, which are then used to modify the existing solar capacity factors. The analysis highlights the smoke patterns in the region with Figure G - 22 showing the average PM2.5 values at different times that correspond to major fires.

Figure G - 23: Average Daily PM2.5 per Smoke Zone for Council Models (2022-2024)

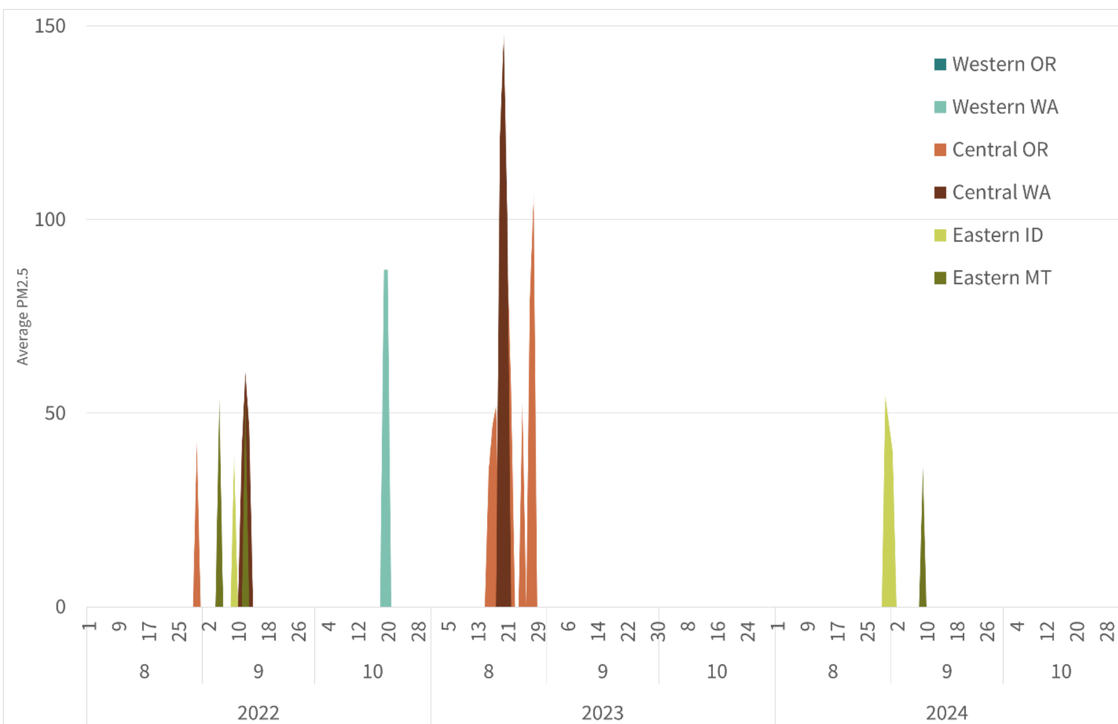
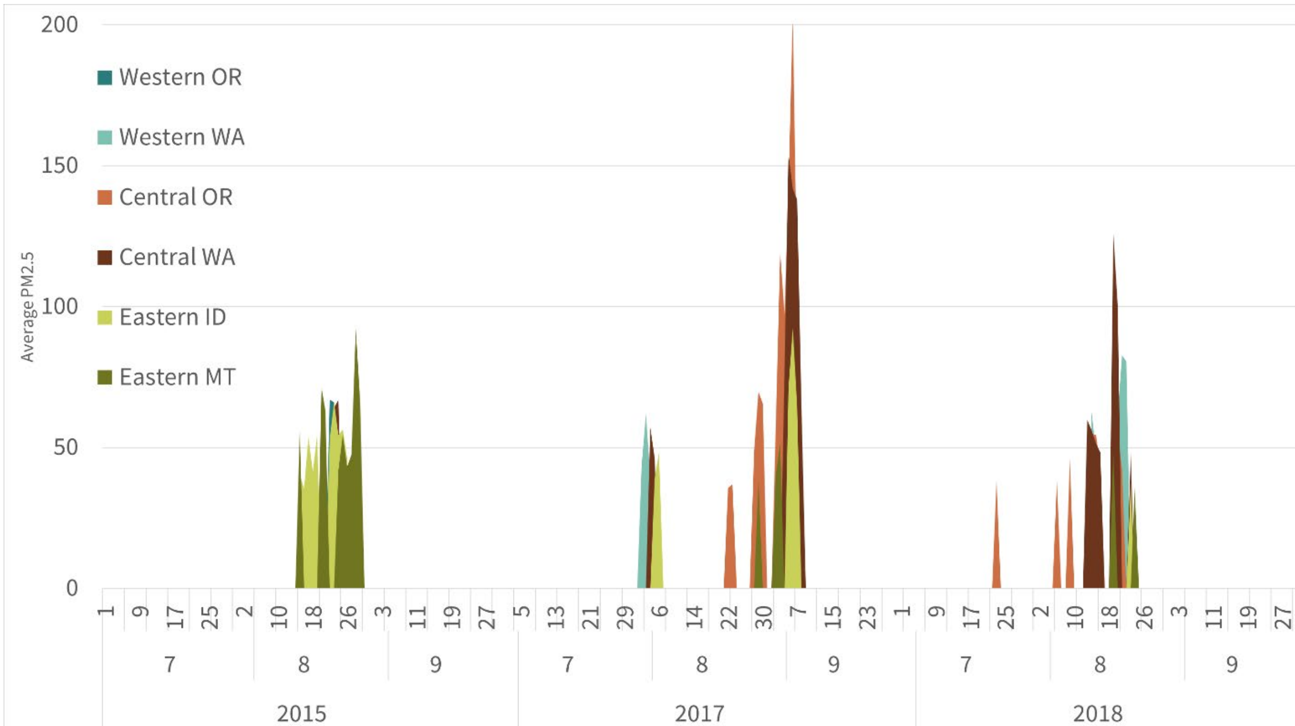


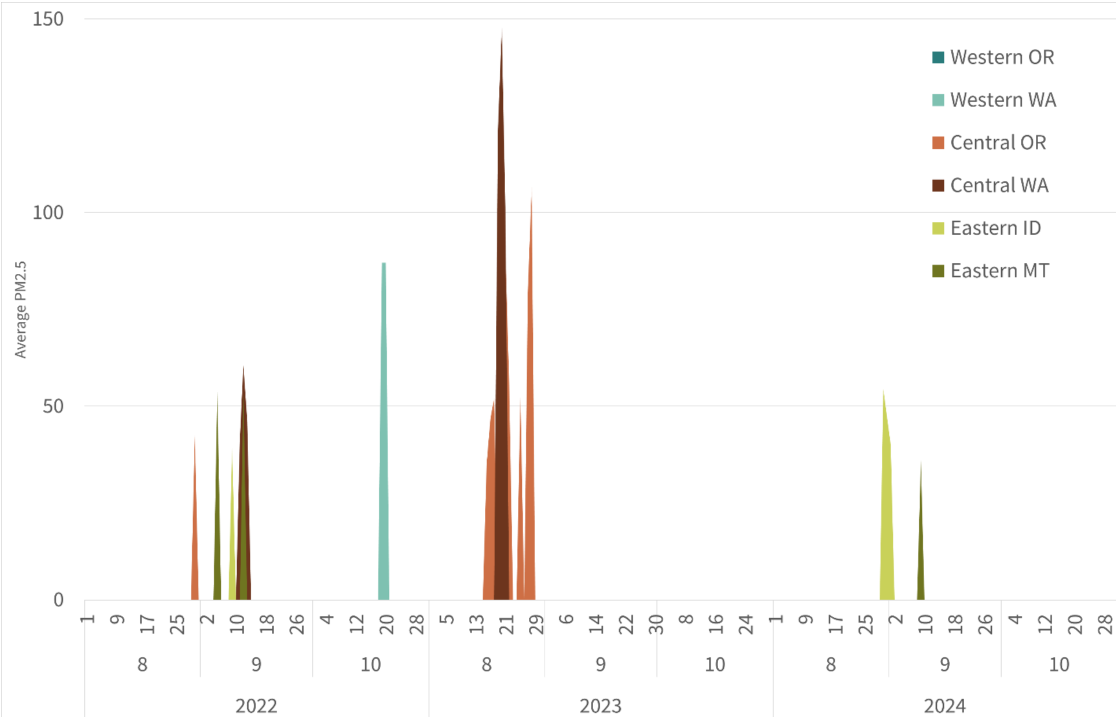
Figure G - 24 translates these into number of smoke days per year in each smoke zone.

Figure G - 22: Average Daily PM2.5 per Smoke Zone for Council Models (2015-2019)[60]



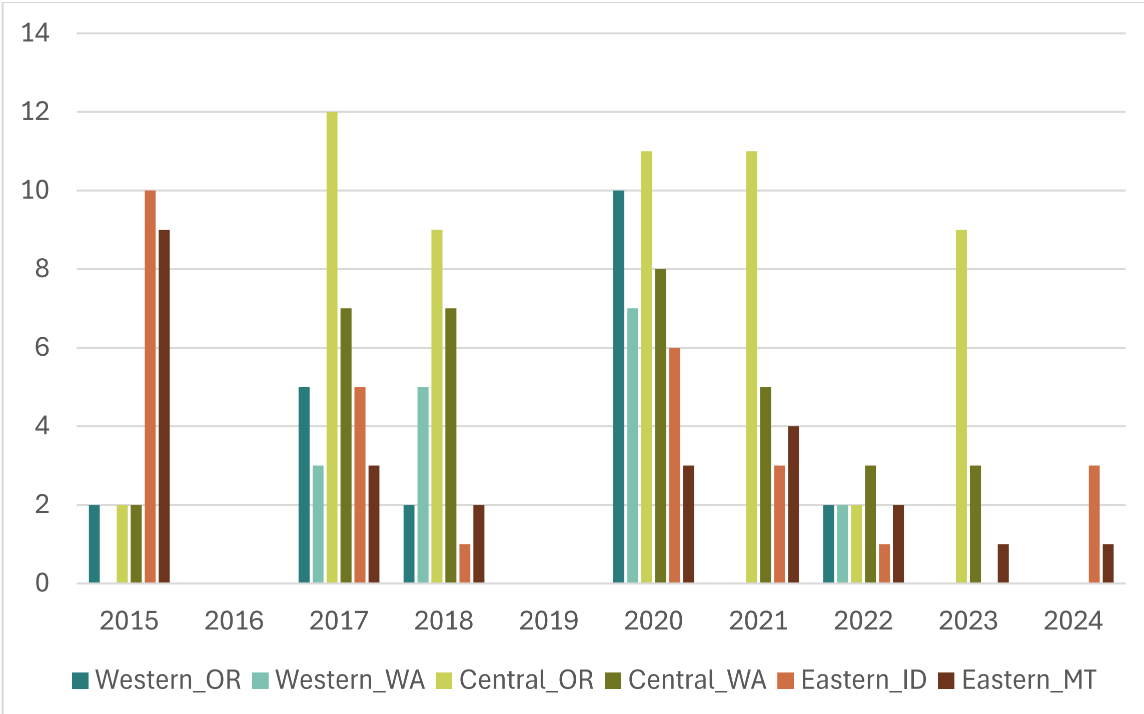
[60] Years and months without any days with an air quality above 35 μg/m3 have been excluded from this figure for the sake of legibility

Figure G - 23: Average Daily PM2.5 per Smoke Zone for Council Models (2022-2024)[61]



[61] Years 2020 and 2021 were high smoke years and are pulled out into their own charts as further illustration of the data. See Figure G - 21 and Figure G - 22.

Figure G - 24: Modeled Number of Smoke Days per Year



The years 2020 and 2021 offer examples of how the whole region was impacted by smoke, seen in Figure G - 25 and Figure G - 26. These graphs show the days across the summer months of 2020 and 2021 with the highest PM2.5 levels. Figure G - 25 shows a large event in September of 2020 that impacted the whole region across zones. Figure G - 26 shows a broader time span where more discrete wildfire events occurred in different zones across the season.

Figure G - 25: Example of Wildfire Days from the Summer of 2020 Across Zones

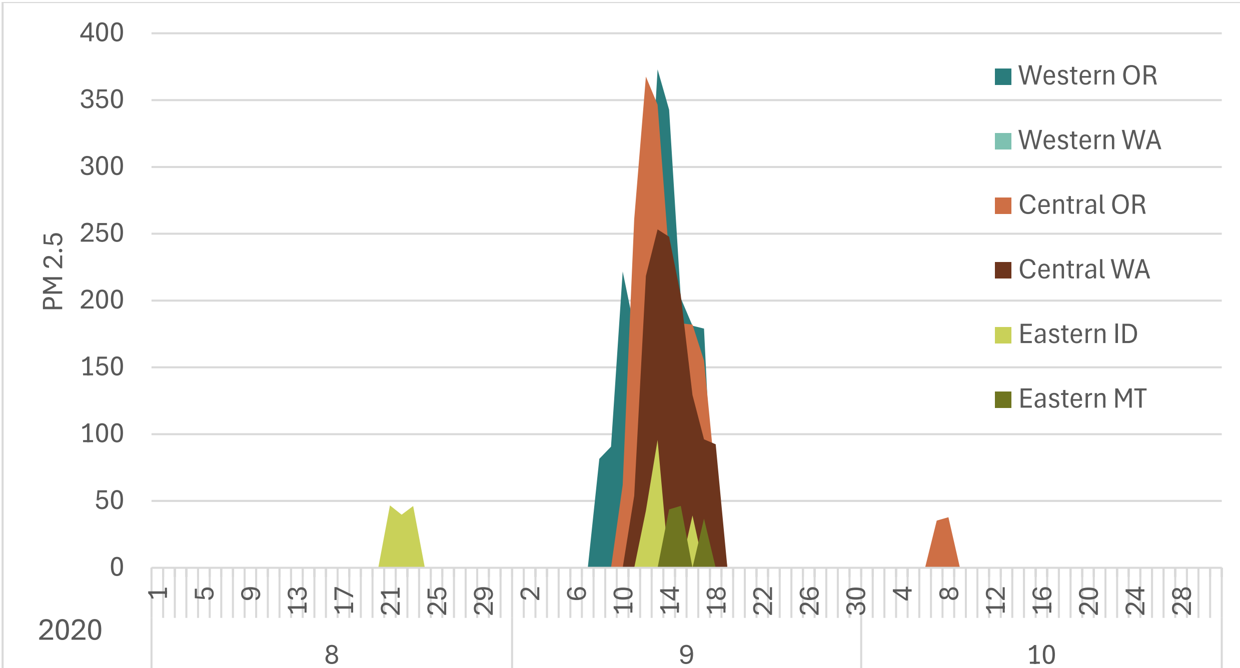
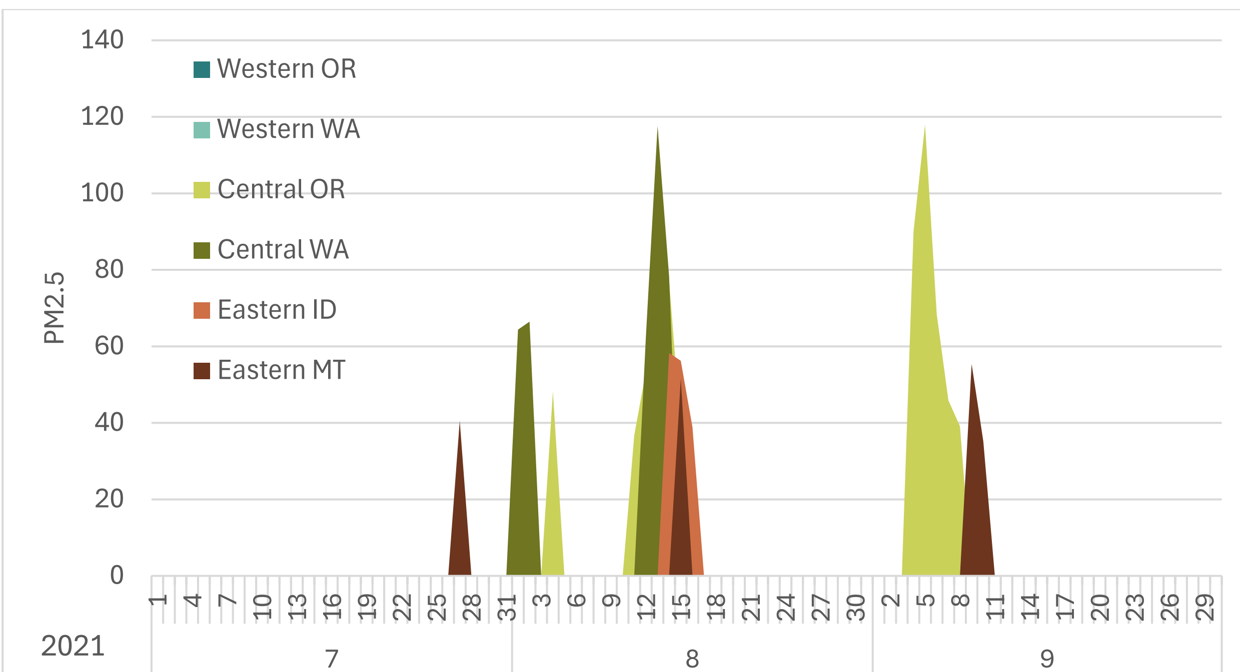
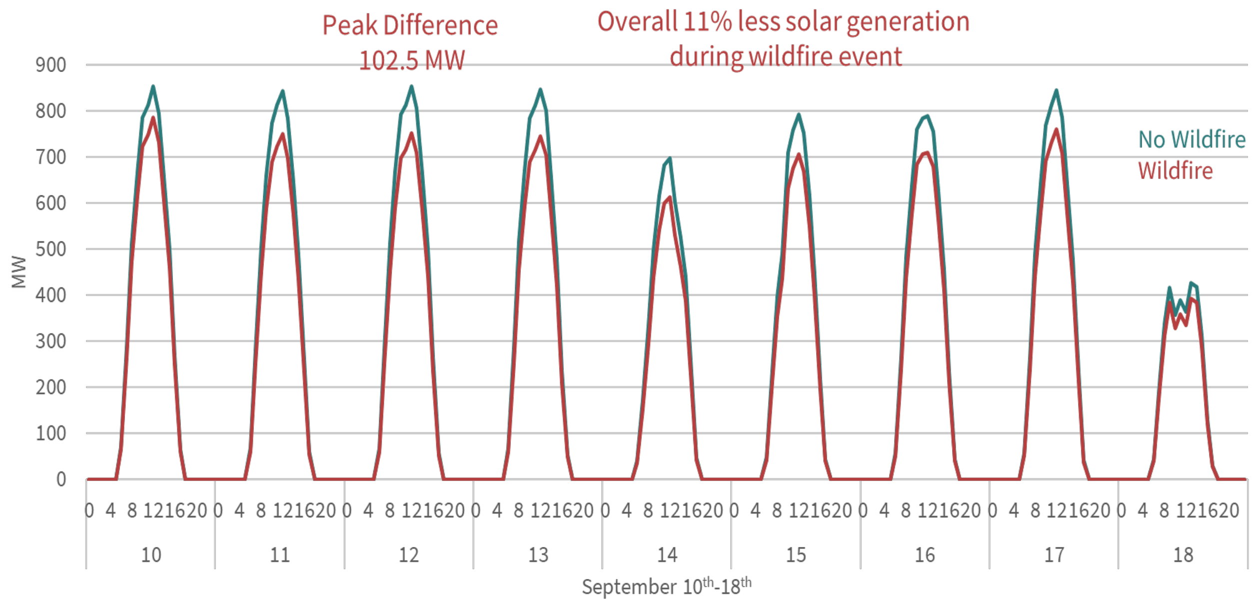


Figure G - 26: Example of Wildfire Days from the Summer of 2021 Across Zones



An example of how the data is used is seen in Figure G - 27 for a theoretical 1,000 MW solar project in central Oregon and how it would perform under a "2020 September wildfire" event. The teal line shows the solar generation under no wildfire conditions, and the red shows the reduction in the same week after the smoke reduction modification. In this example, there's a peak reduction of 102.5 MW, and 11% less generation in general throughout the week.

Figure G - 27: Theoretical Example of Applied Smoke Reduction Modification

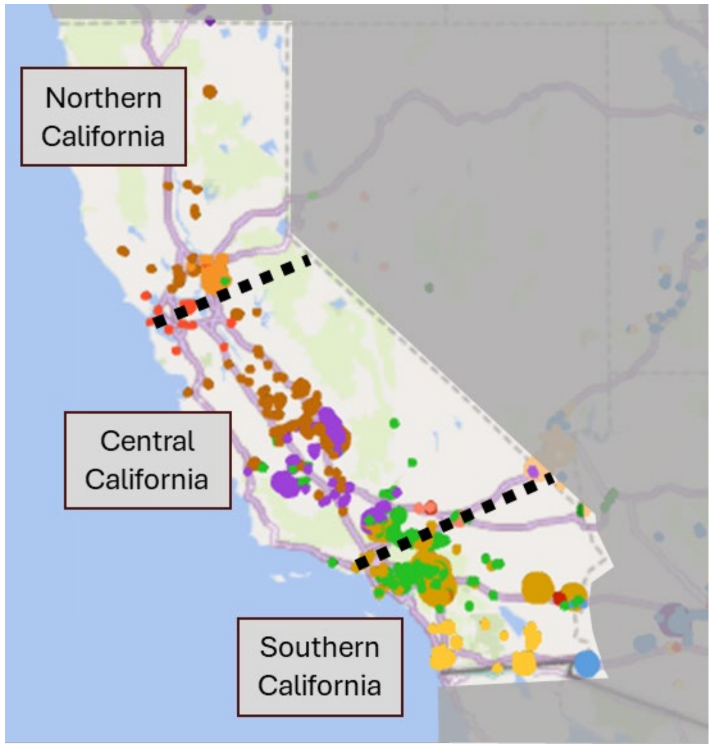


In practice, it is possible that actual fires will have greater or smaller impacts, but from a modeling representation, this approach further enhances risk representation within current modeling capabilities. The modified solar generation shapes are used to inform adequacy in GENESYS and resource decisions in OptGen to deliver a finer locational value due to the risk of wildfire smoke, and future work will aim to enhance the alignment with transmission derates as well.

California

Because California has significant amounts of solar and a history of major wildfires, this influences regional market dynamics. The Council determined it important to also capture the risk of smoke impacts in California. Figure G - 28 shows the location and clusters of most California solar projects and how the state was divided into northern, central and southern smoke zones. A similar approach to the one described above for the region was taken in California to come up with smoke days and solar reduction profiles.

Figure G - 28: California Solar and Smoke Zones



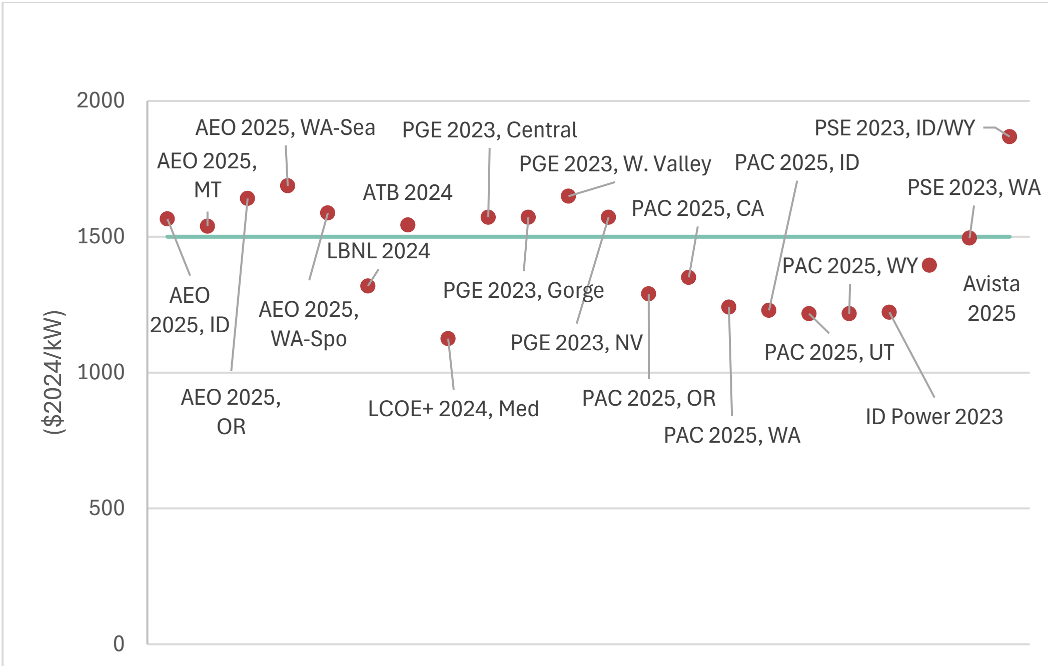
Costs

The installed cost of utility-scale solar PV has declined significantly since the first major installations in the late 2000s and early 2010s. Over the past decade, the median installed cost of utility-scale solar projects has declined 75% since 2010 according to LBNL.[62] This decline in solar costs has been driven by efficiencies and improvements across all components, in particular the module (panel), hardware, and soft costs.

Figure G - 29 and Figure G - 30 show the data plots and analysis that were used to develop the Ninth Power Plan reference plant cost estimates. Note that these figures capture data from various solar PV capacities, configurations, and technologies.

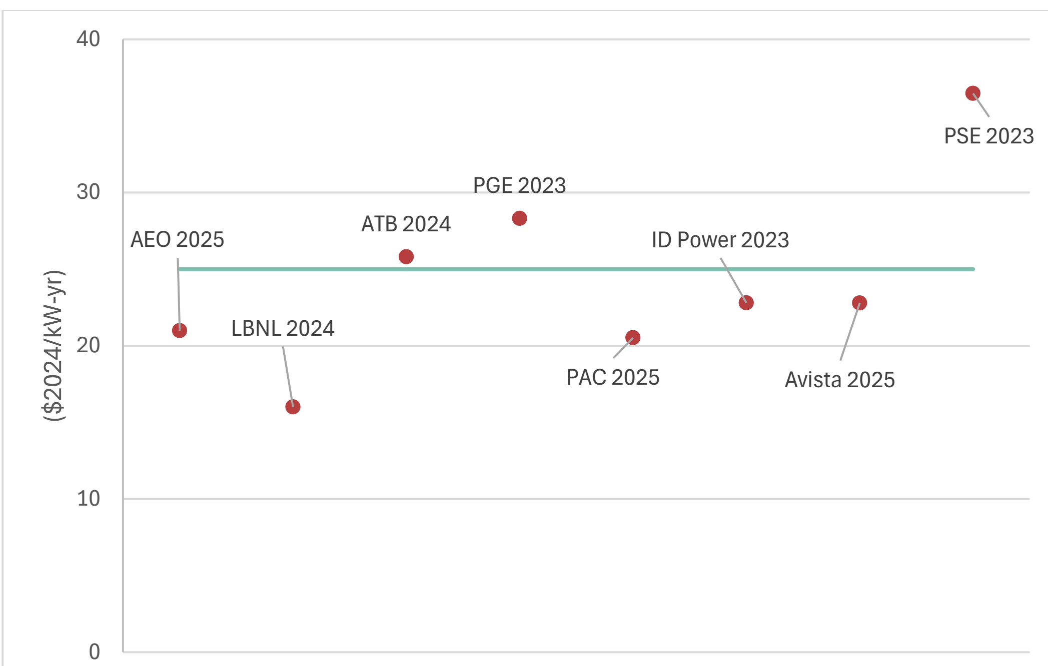
[62] https://emp.lbl.gov/publications/utility-scale-solar-2024-edition.

Figure G - 29: Literature Review of Utility Scale Solar Overnight Capital Costs



The literature review of utility-scale overnight capital costs, seen plotted Figure G - 29, groups around $1500/kW, shown by the light blue line. This final cost is not a pure average of available data, or a simple eyeballing of the plot, but an educated estimate arrived at through research, professional judgment and advisory committee expertise.

Figure G - 30: Literature Review of Utility Scale Solar Operations & Maintenance Costs



Similarly, Figure G - 30 shows there is a clustering of utility-scale solar fixed operations and maintenance costs around $25/kW-yr.

Figure G - 31: Forward Cost Curves for Utility-Scale Solar Overnight Capital Costs

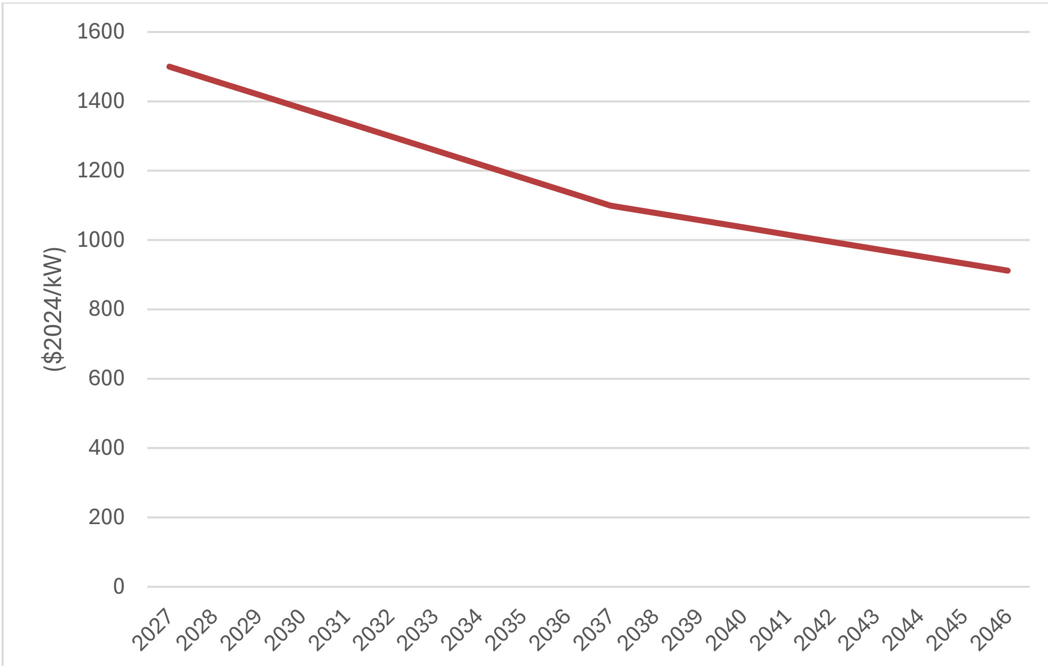


Figure G - 31 shows the same cost curve for utility-scale solar displayed in Figure G - 1, but on its own axis for a clearer view. Overnight capital costs over the course of the study deescalate to under $900/kW over 20 years, with a steeper decline in the first 10 years.

Locational Cost Variation

As discussed in the shared assumptions section about locational cost adjustments, locational cost adjustment factors are applied to the capital costs of resources that have otherwise been differentiated by location. Because solar has multiple reference plants to account for differences in capacity factors, the Council also applies locational cost adjustment factors. The location groupings are chosen agnostic to the adjustment factors and so there is some work behind aligning the factors provided by the EIA, described in Table G - 3, to the locations selected for the solar reference plants. That cross-walking is shown in

Table G - 12, where northwest solar zone is given the average of Portland and Seattle's cost adjustments, central solar is given Spokane's etc. Those adjustments are applied by location to the starting solar capital cost in Table G - 13.

Table G - 12: Solar Locational Cost Variation by Resource Cluster

	Locations	Cost Variation Multiplier	
		Utility Scale & Small Scale	*+ Battery*
Northwest	Porland, Seattle	1.073	1.075
Central	Spokane	1.023	1.025
East	Great Falls, Boise	1.001	1.001

Table G - 13: Locational Variation of Utility Scale Solar Capital Costs

	Variation	Utility-Scale Solar, OCC
Starting Point	*n/a*	*$1500*
Northwest	1.073	$1609.50
Central	1.023	$1534.95
East	1.0005	$1500.75

Summary Table

The summary of the utility-scale solar reference plant is captured by Table G - 14.

Table G - 14: Utility-Scale Solar Reference Plant Summary Table

Reference Plant	Solar PV – Northwest	Solar PV – Central	Solar PV – East
Configuration	Mono PERC c-SI with single axis tracker		
Location – Modeling zones	PGE	BPA OR/WA, AVA, PACW, DC/CC/GC PUD	BPA IDMT, PACE, IPCO, NWMT
Year Available to Model	At start of study		
Development/Construction Period (Years)	2		
Inverter Loading Ratio (DC:AC Ratio)	1.4:1		
Capacity Factor	See shape (Figure G - 16)		
Overnight Capital Cost ($/kW)	1612	1575	1500
Fixed O&M Cost ($/kW-yr)	25		
Variable O&M ($/MWh)[63]	0		
Economic Life (years)	30		

Small-Scale Solar

Small-scale solar in the Ninth Plan refers to primarily community solar applications that are local solar facilities shared by multiple community subscribers who receive credit on their electricity bills for their share of power produced. The 'small-scale' title casts a broader net and avoids confusion around legal definitions of community solar that vary by jurisdiction. However, most small-scale solar facilities being built in the region are some form of community solar and are usually less than five megawatts of electrical capacity. Unlike residential or commercial solar development, these solar resources are generally built on leased land. Because of this, these resources can provide homeowners, renters, and businesses equal access to the economic and environmental benefits of solar energy regardless of the physical attributes or ownership of their home.

Oregon and Washington have both passed community solar enabling legislation, which has driven their development in recent years. Washington passed the Washington Community Solar Program (2SHB 1814) in 2022 which set the project size and payment rate for eligible plants with the intention of expanding equitable access of renewable energy benefits through community solar projects. The Oregon Community Solar Program was passed in 2017 (SB 1547) and directed the Oregon Public

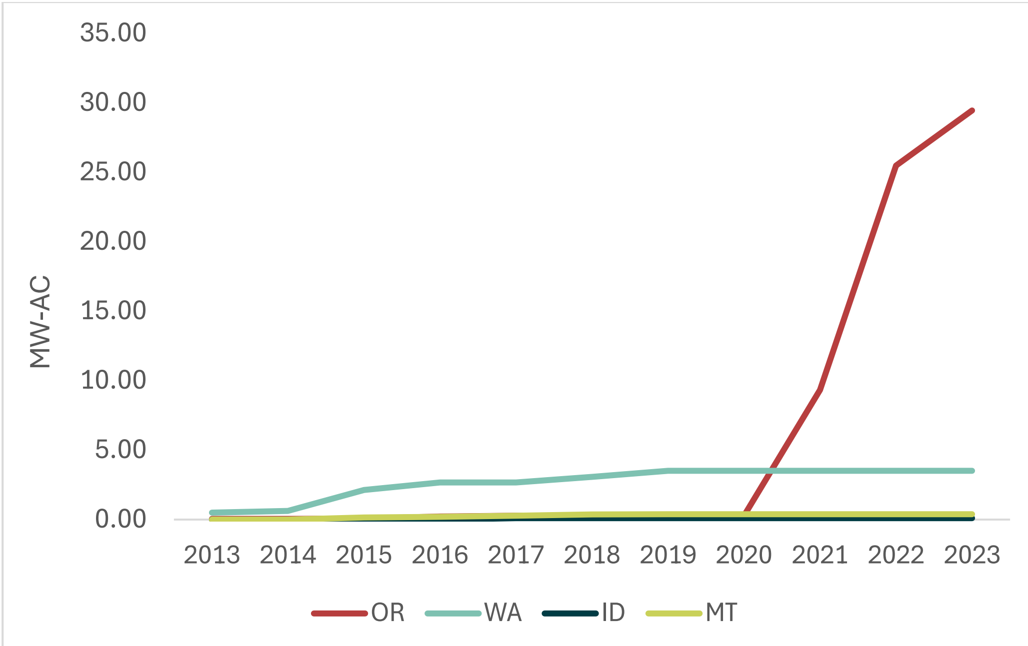
[63] Solar does not incur any variable costs for the same reason as wind, renewable O&M costs are fixed, not reliant on the production of the plant.

Utility Commission to define the size, participation etc. of a community solar project, which it did via OAR 860-88 in 2022. Oregon’s renewable portfolio standard also requires at least 8% of Oregon's aggregate electrical capacity come from small-scale, community renewable energy projects, though not explicitly defined as community solar, with a capacity of 20 MW or less. This concerted legislative effort can be seen in the recent uptick in small-scale solar development particularly in those states, illustrated Table G - 15 and Figure G - 32 below.

Table G - 15: Small-Scale Solar Regional Project Details

States	# of Projects	Total Installed Capacity (MW-AC)	Average Size of Project (MW-AC)
Idaho	2	0.1	0.05
Montana	8	0.38	0.05
Oregon	23	29.44	1.28
Washington	35	3.51	0.10
Grand Total	**68**	**33.44**	**0.49**

Figure G - 32: Capacity Installed Small-Scale Solar[64]



Availability

Small-scale solar is available at the beginning of the study and takes only half a year for development and construction.

Small-scale solar is more expensive on a per-kW basis relative to utility-scale solar. However, it does offer the small size advantage and is therefore able to be built faster and in more locations. The generation shapes of small-scale solar mirror those of utility-scale, but due to its size the resource is available in all modeling zones.

Also, similar to utility-scale solar, small-scale solar can be selected on a continuous basis by the model. In reality, by virtue of being small in scale, this resource's capacity would be limited to 3 MW-20 MW per individual plant. However, in a given zone the model does not see individual plants, just total resource built in that particular zone, so specifying an exact capacity is not necessary.

Costs

Community or small-scale solar share many of the same costs as utility-scale solar, but is more expensive than utility-scale primarily due to "soft costs" or initial costs incurred from acquiring numerous subscribers. Community solar systems also incur unique costs for ongoing subscriber management, such as bill management, ongoing marketing, and customer acquisition costs to

[64] Data from Figure G - 28 and Table G - 15 are from NLR's Sharing the Sun Community Solar Project Database (https://data.nrel.gov/submissions/233).

manage customer turnover. Those cost components are shown in Figure G - 33. The data behind this figure is from NLR's Solar-PV cost benchmarks analysis.[65] The Council did not use these exact costs, but instead leveraged the data on the relationship between the different components of the cost in defining the final reference plant costs.

Figure G - 33: Component Cost of Community Solar Installations

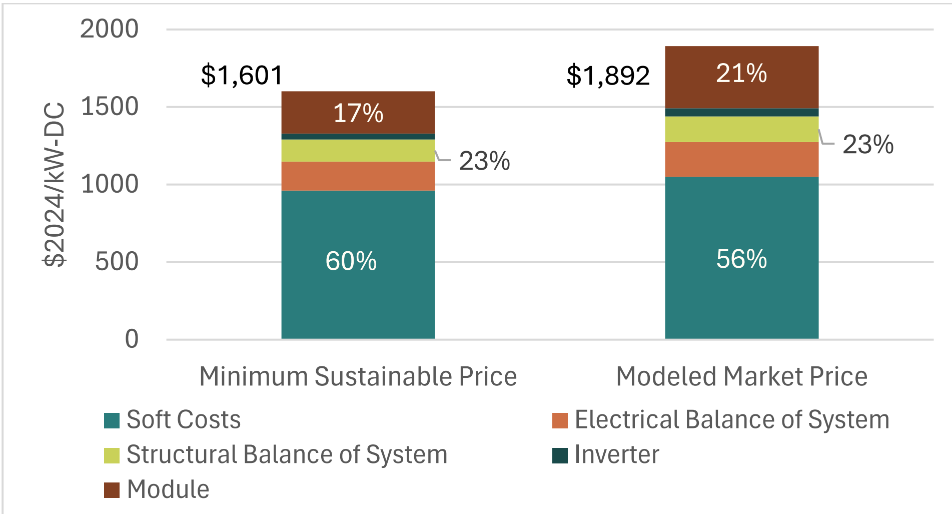


Table G - 16 summarizes the small-scale solar costs used in the Ninth Plan. The cost values were developed through literature review and then adjusted based on professional judgment of regional experts. The final cost was, in part, based on the utility scale solar costs with adjustments made for the soft costs described above.

Table G - 16: Literature Review of Small-Scale Solar Costs

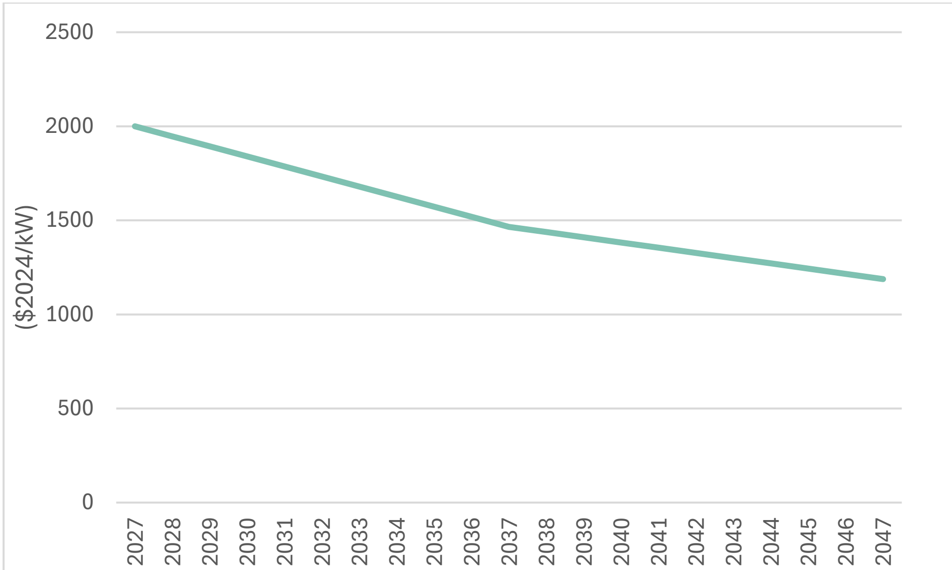
Source	Overnight Capital Cost ($/kW)	Fixed O&M ($/kW-yr)	Capacity (MW)
PAC IRP (2025)	1960	19	20 MWac
NLR	1660-1960	13 (+22.47 for program management)	3 MWdc[66]
PGE IRP (2023)	2400		50MWac

Figure G - 34 shows the same cost curve for small-scale solar displayed in Figure G - 1 but on its own axis for a clearer view. Small-scale solar's cost curve mirrors utility-scale solar as they are the same

[65] Data from NLR U.S. Solar Photovoltaic System and Energy Storage Cost Benchmarks, With Minimum Sustainable Price Analysis: Q1 2023: https://docs.nrel.gov/docs/fy23osti/87303.pdf.
[66] This NLR report notes that the per-unit cost results are meant to be generally applicable to systems with PV sizes between about 1.5 and 6 MWdc.

technology, applied differently. Overnight capital costs over the course of the study deescalate to around $1100/kW over 20 years.

Figure G - 34: Forward Cost Curves for Small-Scale Solar Overnight Capital Costs



Locational Cost Variation

Small-scale solar mirrors the locational differentiation of utility-scale solar, as they are capturing the same renewable resource. More detail on that process is included in the utility-scale solar section and will not be replicated here. Those adjustments by zone are applied by location to the starting solar capital cost in Table G - 17.

Table G - 17: Locational Variation of Small-Scale Solar Capital Costs

	Variation	Small-Scale Solar, OCC
Starting Point	*n/a*	*$2000*
Northwest	1.073	$2146.00
Central	1.023	$2046.60
East	1.0005	$2001.00

Summary Table

The summary of the small-scale solar reference plant is captured by Table G - 18.

Table G - 18: Small-Scale Solar Reference Plant Summary Table

Reference Plant	Small-Scale Solar
Configuration	Ground mounted single axis

Reference Plant	Small-Scale Solar
Location	All zones
Year Available to Model	Start of study
Development Period (Years)	1
Construction Period (Years)	6 mo.
Capacity Factor	See shape(Figure G - 16)
Overnight Capital Cost ($/kW)	2000
Fixed O&M Cost ($/kW-yr)	35
Variable O&M ($/MWh)[67]	0
Economic Life (years)	30

Lithium-Ion Battery

Utility-scale, standalone (not paired directly with a generating resource) battery storage allows for the capture and storage of energy for future use. Conventional batteries are composed of cells which contain two electrodes, a cathode and an anode, and electrolyte in a sealed container. During discharge a reduction-oxidation reaction occurs in the cell and electrons migrate from the anode to the cathode. During recharge, the reaction is reversed through the ionization of the electrolyte. Many different combinations of electrodes and electrolytes have been developed. Battery storage systems are not geographically dependent and can be utilized at multiple locations and for a variety of applications.

Lithium-ion (Li-Ion) battery technology has long been used in consumer electronics and electric vehicles and is now emerging as the dominant choice for battery storage systems. Utility-scale Li-Ion batteries are typically a collection of tens of thousands of small batteries (approximately AA size) connected and packaged together to form a larger resource. The fundamental composition of each cell is several stacks of brittle thin film anode/cathode pairs separated by an electrolyte. During discharge, lithium ions migrate from the anode into the porous crystalline solid cathode to form a chemical bond which releases energy through a metal current collector to provide power to the grid. This reference plant is for a 4-hour lithium-ion battery, meaning it discharges its full rated power for four consecutive hours. 4-hour durations have been and are anticipated to continue to be the most typical in the utility-scale market.[68]

[67] Resources without fuel do not have variable O&M costs.
[68] https://atb.nrel.gov/electricity/2024/utility-scale_battery_storage.

For more information about battery development in the region see Technical Appendix B – Existing System Parameters and Policies.

Availability

Lithium-Ion batteries are available beginning of study and require two years for development and construction. Unlike more weather dependent, renewable resources, batteries operate the same across the region and so only one reference plant was developed.

Batteries are another resource selected continuously, because their capacity is easily scaled within a single plant so a set size is not necessary.

Round trip efficiency (RTE) refers to the ratio of useful energy output to useful energy input. It is an important factor to consider in understanding how efficiently this technology can store and discharge energy, and how much electricity is loss in the process. A literature review of assumed RTE for lithium-ion batteries, shown in Table G - 19 below, sees fairly cohesive percentages ranging from 85%-90%. With the expertise of the Generating Resource Advisory Committee, 88% RTE was selected for this reference resource.

Table G - 19: Battery Storage Efficiency Literature Review

Source	Round-Trip Efficiency
NLR's Annual Technology Baseline 2024	85%
NLR Technical Report on Cost Projections for Utility-Scale Battery[69] Storage	85%
PNNL's ESGC and Performance Database 2024	83-85%
Lazard’s Levelized Cost of Storage	90%
PGE 2023 IRP	86%
PacifiCorp 2025 draft IRP	85%
Avista 2025 IRP	87%
Puget Sound Energy 2023 IRP Progress Report	85%

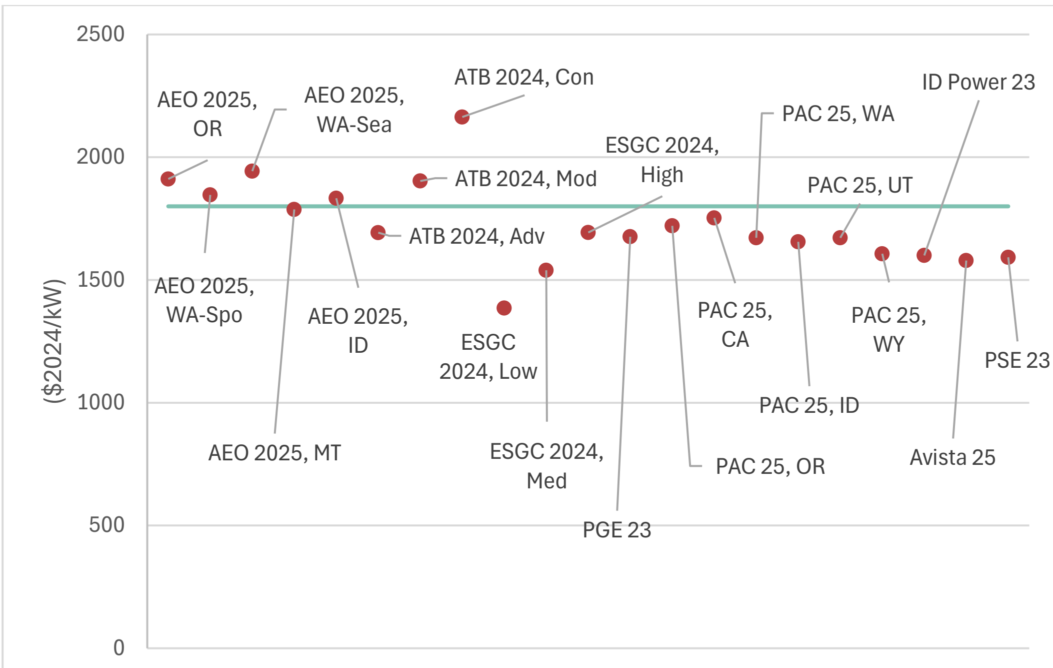
[69] https://docs.nlr.gov/docs/fy23osti/85332.pdf.

Costs

As batteries have become a more essential piece of electricity grids in the U.S., costs have dropped significantly. This follows similar trends of recent decades for resources like natural gas, wind, and then solar. Lithium-ion batteries costs have fallen more than 70% over the past 10 years.[70]

Figure G - 35 and Figure G - 36 show the data plots and analysis that were used to develop the Ninth Power Plan reference plant cost estimates.

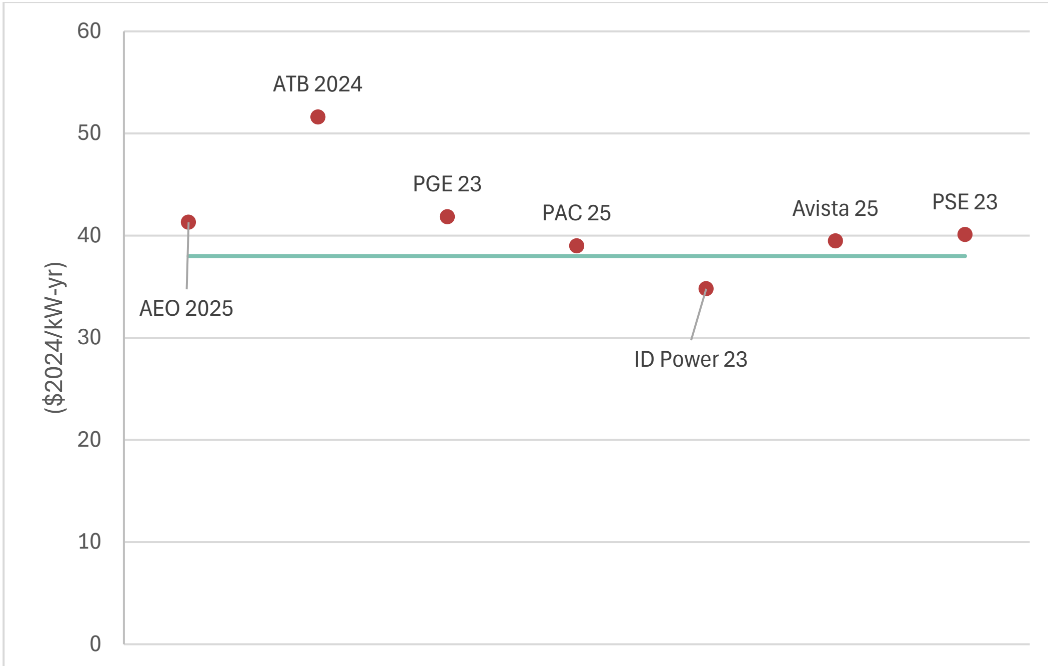
Figure G - 35: Literature Review of Li-Ion Battery Overnight Capital Costs



The literature review of Li-ion Battery overnight capital costs, seen plotted Figure G - 35, aggregates around $1800/kW, shown by the light blue line. This final cost is not a pure average of available data, or a simple eyeballing of the plot, but an educated estimate arrived at through research, professional judgment and advisory committee expertise.

[70] https://about.bnef.com/insights/clean-transport/lithium-ion-battery-pack-prices-fall-to-108-per-kilowatt-hour-despite-rising-metal-prices-bloombergnef/#:~:text=BNEF's%20industry%2Dleading%20battery%20price,renewables%20integration%20around%20the%20world.%20%E2%80%9D.

Figure G - 36: Literature Review of Li-Ion Battery Fixed Operations & Maintenance Costs



Similarly, Figure G - 36 shows there is a clustering of Li-ion battery fixed operations and maintenance costs around $38/kW-yr.

Figure G - 37: Forward Cost Curves for Li-Ion Battery Overnight Capital Costs

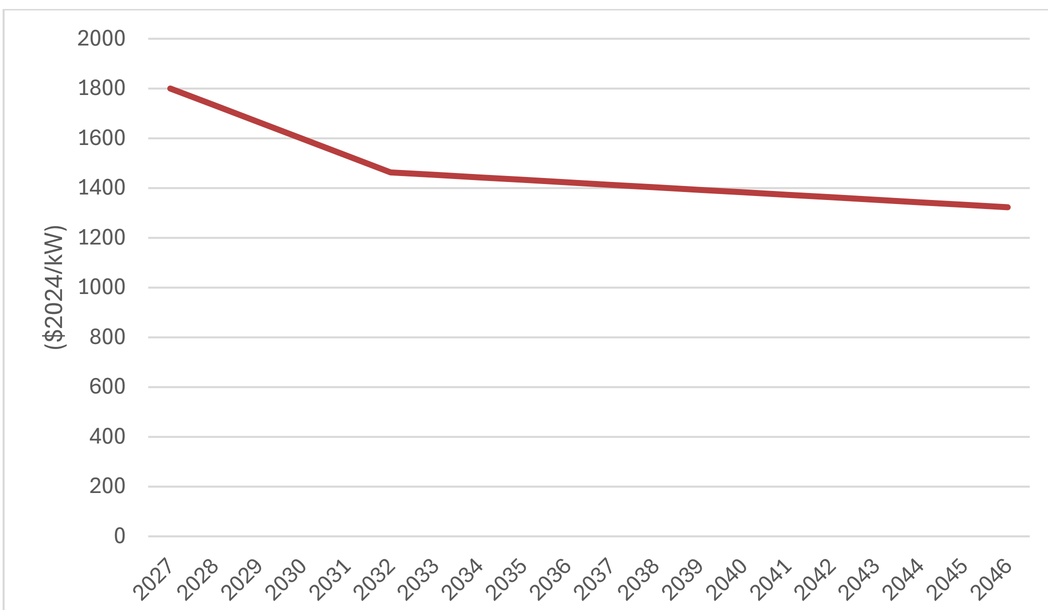


Figure G - 37 shows the same cost curve for batteries displayed in Figure G - 1 but on its own axis for a clearer view. Overnight capital costs over the course of the study deescalate to below $1400/kW over 20 years, with an especially steep decline over the first five years.

Summary Table

A summary of the Li-ion battery storage reference plant is captured in Table G - 20.

Table G - 20: Li-Ion Battery Storage Reference Plant Summary Table

Reference Plant	Utility Scale Lithium-Ion Battery Storage
Configuration	4-hour duration, lithium-ion battery
Year Available to Model	Start of study
Development/Construction Period (Years)	2
Roundtrip Efficiency	88%
Overnight Capital Cost ($/kW)	1800
Fixed O&M Cost ($/kW-yr)	38
Variable O&M ($/MWh)	0
Economic Life (years)	15

Solar Plus Battery

Co-locating renewables with storage helps avoid curtailment of energy, reduce integration costs, provide grid services, and reduce transmission costs by sharing a single point of interconnection. As both utility-scale solar PV, wind, and battery storage costs decline, opportunities to pair the resources together are gaining traction. The Ninth Power Plan includes a reference plant for a co-located solar PV plus battery storage system (also referred to as solar + storage).

There are two major technology configurations for co-located solar and battery: AC-coupled and DC-coupled. An AC-coupled system means that there are two inverters, one for the solar and one for the battery – equivalent to two distinct systems that are located at the same site. There are cost reductions in balance-of-system costs for this type of configuration, for example shared siting, land, interconnection, and fixed transmission costs. A DC-coupled system has only one inverter for both the solar and the battery. This configuration receives all the same balance-of-system benefits as the AC-coupled system, plus the reduced cost of one inverter instead of two. However, the major benefit of a DC-coupled system is that for solar projects with an inverter loading ratio greater than 1.0 (solar module capacity is overbuilt compared to the inverter capacity), instead of clipping the energy when it exceeds the maximum rating of the inverter, it can be directly transferred to the battery and stored for later use.

Availability

Solar + storage is available at beginning of study and takes two years to develop and construct. Like solar, the hybrid resource has an assumed 30-year economic life but that includes a battery replacement at year 15. The cost of that replacement is incorporated into the fixed O&M costs.

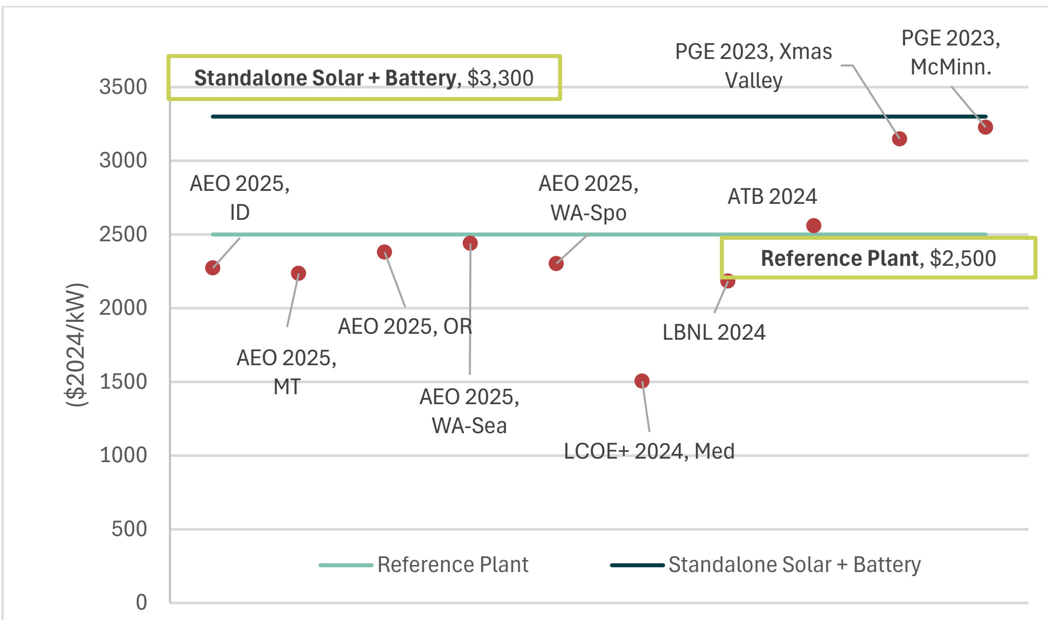
This hybrid resource reference plant was built up as a combination of the solar and the battery reference plants with paralleled characteristics as appropriate. For example, available locations and their accompanying production curves for the representative solar + storage resource are the same as the utility-scale solar reference plant. The battery charge and dispatch are based on that shape.

Costs

One of the benefits of co-locating storage and solar is the cost savings from shared equipment, particularly inverter cost savings. Additional savings are possible in land cost and some construction and development expenses, such as shared installation roads and equipment.

Figure G - 38 and Figure G - 39 show the data plots and analysis that were used to develop the Ninth Power Plan reference plant cost estimates.

Figure G - 38: Literature Review of Solar + Storage Overnight Capital Costs



The literature review of solar + storage overnight capital costs, seen plotted in Figure G - 38, coalesces around $2500/kW, shown by the light blue line. The dark blue line at $3300/kW is the cost of a standalone solar plant ($1500/kW) and a standalone battery ($1800/kW) combined, showing about a 25% savings from colocation. This final cost is not a pure average of available data, or a simple eyeballing of the plot, but an educated estimate arrived at through research, professional judgment and advisory committee expertise.

Figure G - 39: Literature Review of Solar + Storage Fixed Operations & Maintenance Cost

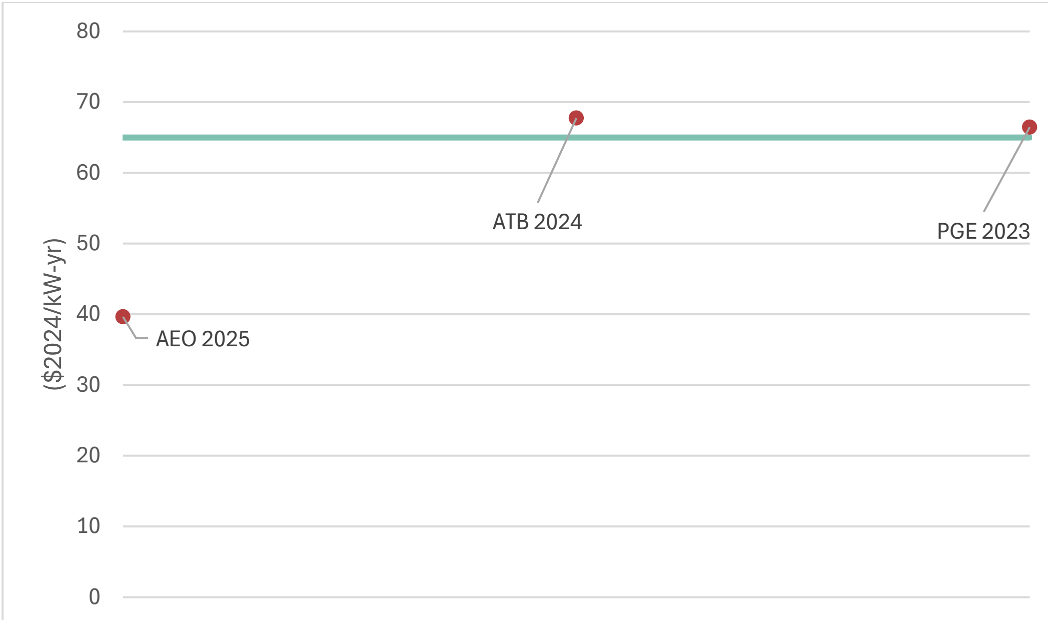


Figure G - 39 shows there is a clustering of solar + storage fixed operations and maintenance costs around $65/kW-yr. This number is inclusive of the cost of battery replacement halfway through the solar system's lifetime.

Figure G - 40: Forward Cost Curves for Solar + Storage Overnight Capital Costs

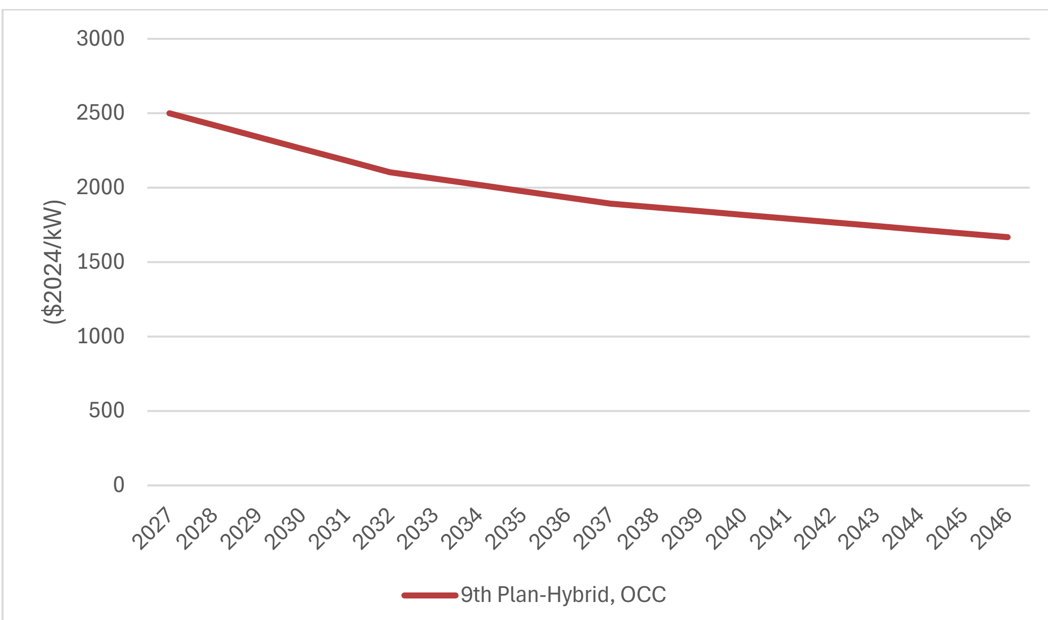


Figure G - 40 shows the same cost curve for solar + storage displayed in Figure G - 1 but on its own axis for a clearer view. Overnight capital costs over the course of the study deescalate to almost $1600/kW over 20 years.

Locational Cost Variation

Solar + storage mirrors the locational differentiation of utility-scale solar, as they are capturing the same renewable resource. More detail on that process is included in the utility-scale solar section and will not be replicated here. Those adjustments by zone are applied by location to the starting solar capital cost in Table G - 21.

Table G - 21: Locational Variation of Solar + Storage Capital Costs

	Variation	Solar + Storage, OCC
Starting Point	*n/a*	*$2500*
Northwest	1.0745	$2686.25
Central	1.025	$2563.25
East	1.001	$2502.50

Summary Table

The summary of the solar + storage reference plant is captured by Table G - 22.

Table G - 22: Solar + Storage Reference Plant Summary Table

Reference Plant	Solar + Battery Storage
Configuration	Solar Co-Located with DC-Coupled 4-hour Li-Ion Battery
Location	Available in all zones except for PSE Central
Year Available to Model	Start of study
Development/Construction Period (Years)	2
Capacity (MW)	1:1 pairing[71]
Capacity Factor/RTE	See shape (Solar) 88% RTE (Battery)
Overnight Capital Cost ($/kW)	2500
Fixed O&M Cost ($/kW-yr)	65
Variable O&M ($/MWh)	0
Economic Life (years)	30

[71] Like solar and battery, the model can select the hybrid resource continuously and so can be selected at any size, but the solar and the battery will be equivalent. So, for example, if a 100 MW solar resource is built, it would be paired with a 100 MW or 400 MWh battery.

Natural Gas

Natural gas turbine technologies are a proven and mature source of electricity generation. They also continue to adapt to the needs of the regional power system. As more variable energy resources have come online, it has become increasingly important for gas resources to provide flexibility (fast start, ramping abilities) and greater efficiency (less fuel is combusted to generate more electricity). There are two major types of natural gas resources that the Council assessed for the Ninth Power Plan: combined cycle combustion turbines (CCCT) and gas peakers (which include simple cycle combustion turbine (SCCT) technologies and reciprocating engines).

Simple Cycle

Gas peakers are generating units that can ramp up and down quickly to meet spikes in demand. Newer more flexible and efficient models can be used to follow the variable output of wind and solar resources. Because of the availability and abundance of hydropower, relatively few gas peakers have been constructed in the Northwest, compared to regions with a predominance of thermal electric capacity. In general, gas peakers produce electricity at a much lower capacity factor when compared to CCCTs, and run only when needed. However, over the last 20 years the region called on their gas peaker fleet more frequently, with average capacity factors increasing sharply since the early 2000s.

Simple-cycle gas turbines have been used for decades to help serve peak loads. A simple-cycle gas turbine generator plant consists of a combustion gas turbine (sometimes multiples) driving an electric power generator. The three primary simple cycle gas turbine technologies available today are frame, aeroderivative, and intercooled.

- **Frame** turbines are used for stationary power generation and are generally less expensive and more rugged and reliable than other simple cycle types. They are also traditionally less efficient with a higher heat rate and higher emissions.
- **Reciprocating Engine** generating units (Recips) are modular reciprocating engines that drive a generator. This design makes them particularly flexible and more efficient than other peaker technologies.
- **Aeroderivative** turbines are based on engines developed for aircraft propulsion and are characterized as light weight, highly efficient, and flexible. Aeroderivative are generally more expensive than frame turbines. As discussed above, this technology was not developed into a separate reference plant.

Combined Cycle

Combined cycle combustion turbines (CCCT) are highly efficient generating resources that can provide baseload and dispatchable power. A CCCT plant consists of one or more gas turbine generators each exhausting to a heat recovery steam generator (HRSG). The HRSG captures the exhaust heat and produces steam that is supplied to a steam turbine generator and condenser to produce additional electricity. The productive use of the gas turbine exhaust energy greatly increases the efficiency and output of CCCT plants as compared to simple-cycle gas turbines. This increasingly versatile technology can be used both as a replacement to retiring baseload coal power, and as a complementary firming power source to hydropower and renewable generation. The high efficiency of combined cycle plants coupled with the low carbon content of natural gas fuel results in the lowest carbon dioxide production rate of any fossil fuel generating technology.

In the Northwest, operation of existing CCCT plants depends largely on the variability in annual hydro generation. During low water years, when hydro conditions are below average, thermal resources (primarily natural gas CCCT and coal units) tend to run at higher capacity factors to make up for the lower amount of hydroelectric power. During high water years, utilization of CCCT plants may decline. There are many other factors that may impact regional CCCT utilization, such as load, renewable power generation levels, plant outages, fuel prices, and wholesale electricity prices.

For more information about natural gas development in the region see Technical Appendix B – Existing System Parameters and Policies.

Availability

Natural gas resources are available at the beginning of the study. Combined cycles take four years of development and construction, simple cycle frame turbines take three years, and reciprocating engines take two years.

There are limitations to where natural gas plants can be built which are represented in the Council's modeling. Emitting resources, such as coal and natural gas, are regulated by clean policies,[72] which act as an intentional dampener on their future development. In the region, Oregon has a law that bans new gas plants in the state. While Washington doesn't explicitly ban natural gas, their escalating carbon tax and 100% clean target will limit a plant's useful life, making them potentially less financially viable.

An additional limiting factor is available pipeline access. While all resources are impacted by their access to transmission (a resource can't be built if there's no space for it to connect to the transmissions system), a gas plant must also have access to fuel by way of natural gas pipelines. Currently, the existing gas pipeline system faces significant constraints. These include capacity bottlenecks where, especially during the winter, the region operates at maximum capacity with little room for additional demand. While new infrastructure could provide more capacity, due to regulatory hurdles and other challenges, a large new expansion for the power system would be difficult to accomplish in the next few years. New gas plants have some ability to work within these constraints, but that access is not unlimited, and there is minimal pipeline capacity available today.

The Council has represented this limitation in two ways, both with an added cost associated with fuel firming and with a maximum build limit in the model. Council staff have estimated that within the action plan period, or the first 6 years of the study, an additional 3,000 MW of new gas plants in the

[72] More about polices and how they affect resource development can be found in Technical Appendix B—Existing System Parameters and Policies.

region are plausible, assuming the new plants include storage facilities and potentially participate in limited pipeline expansions.[73] After the action plan period that cap rises to 10,000 MW for the remainder of the study, with the assumption that a larger pipeline expansion could occur. Within both constraints, new gas also has additional fuel firming costs associated with connecting to a system that is essentially fully subscribed, which are discussed later in this section.

Unlike renewable resources, a gas plant's production is not particularly affected by where it is located. However, fuel costs vary across the region, and the reference plants have therefore been split into east and west to account for the gas price they have access to. The BPA modeling zones span the east and the west with access to both fuel prices, and so have been split into a third and final reference plant location. More on the Council's fuel price forecast can be found in Technical Appendix E – Fuels Forecasts.

Finally, gas plants do have capacity and efficiency considerations that differentiate between the turbine technologies. A combined cycle combustion turbine has a discrete size associated with the turbine technology that is not easily resized the way the resources described so far can be. Additionally, each turbine type has an associated heat rate or the power plant's thermal efficiency. This measure calculates the amount of energy required to generate one kilowatt-hour of electricity and represents how efficiently a plant converts fuel into electricity. Larger combined-cycle turbines are more efficient than the smaller simple-cycle turbines, and therefore have lower heat rates. The capacities and heat rates of each natural gas turbine technology were explored via literature review, and refined with the help of the Council's advisory committees. Those reviews are shown in Table G - 23, Table G - 24, and Table G - 25 below.

Table G - 23: Combined Cycle Combustion Turbine Operating Characteristics Literature Review

Source	Size (MW)	Heat Rate (Btu/MWh)
NLR's Annual Technology Baseline	727	6.33
	649	6.06
	992	6.18
Gas Turbine World-2024 Handbook	627	5.609
	1227	5.645
EIA's AEO 2025	627	6.266
	1227	6.226
PacifiCorp 2025 IRP	649	6.04
PGE 2023 IRP	407	6.561

[73] The Council discussed this assumption with regional industry stakeholders. Stakeholders noted that it was challenging to estimate an exact value for this cap, that the ability to site new gas would vary on location, and some stakeholders stressed that additional gas would be difficult to site without pipeline upgrades.

Idaho Power 2023 IRP	300	6.363
PSE 2023 Progress Report	727	6.624
Avista 2025 IRP	312	6.82
NorthWestern 2023 IRP	250	
Final Reference Plant	**500**	**6.25**

Table G - 24: Simple Cycle – Frame Peaker Operating Characteristics Literature Review

Source	Size (MW)	Heat Rate (Btu/MWh)
NLR's Annual Technology Baseline	233	9.72
Gas Turbine World-2024 Handbook	419	8.236
EIA's AEO 2025	419	9.142
PacifiCorp 2025 IRP draft	233	9.717
PGE 2023 IRP	227	10.042
Idaho Power 2023 IRP	170	9.717
Puget Sound Energy 2023 Progress Report	233	9.904
Avista 2025 IRP	180	10.04
Final Reference Plant	**250**	**9.50**

Table G - 25: Simple Cycle – Alternate Peaker Operating Characteristics Literature Review

Source	Qualifier	Size (MW)	Heat Rate (Btu/kWh)
PacifiCorp 2025 IRP (draft)	Aero x 4	211	9.447
Idaho Power 2023 IRP	Recip	50	8.699
Puget Sound Energy 2023 Progress Report	Recip	21.4	8.445
Avista 2025 IRP	Recip	185	8.19
NorthWestern 2023 IRP	Aero	50	
	Recip	18	
Final Reference Plant	**Recip**	**100**	**8.50**

Costs

Overnight Capital and O&M Costs

The figures below show the data plots and analysis that were used to develop the Ninth Power Plan reference plant cost estimates. Specifically overnight capital costs for combined cycle combustion turbines (CCCTs), frame simple cycle combustion turbines (SCCT-Frame) and alternative simple cycle combustions turbines (SCCT-Alt) are captured by Figure G - 41, Figure G - 42, and Figure G - 43 respectively. Fixed O&M costs are in Figure G - 45, and Figure G - 46.Variable Operations and Maintenance (O&M) costs for CCCTs and both types are SCCTs are show in Figure G - 47, Figure G - 48, and Figure G - 49.

The literature reviews of natural gas plant overnight capital costs are seen plotted in Figure G - 41 through Figure G - 43. In each figure, different source costs can be seen clustering around a median, represented by the light blue line. For CCCTs that middling cost is $1500/kW, SCCT-Frame costs group around $1000/kW, and the more expensive simple cycle plants costs collect around $1800/kW. These final costs are not pure averages of available data, or a simple eyeballing of the plots, but an educated estimate arrived at through research, professional judgment and advisory committee expertise.

Figure G - 41: Literature Review of Combined Cycle Combustion Turbine Overnight Capital Costs

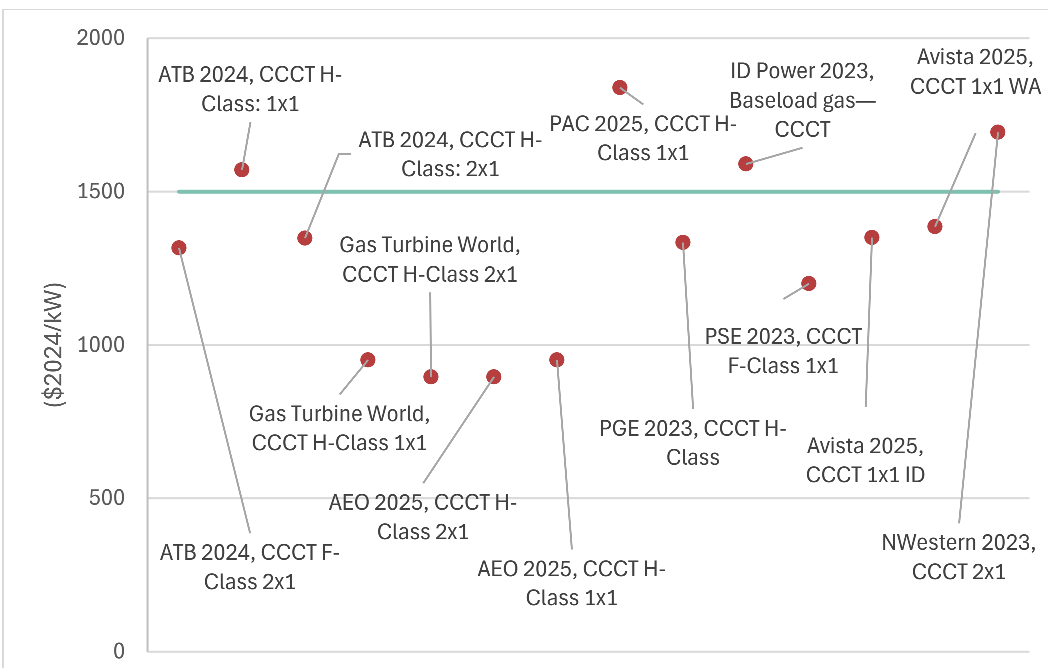


Figure G - 42: Literature Review of Frame Simple Cycle Combustion Turbine Overnight Capital Costs

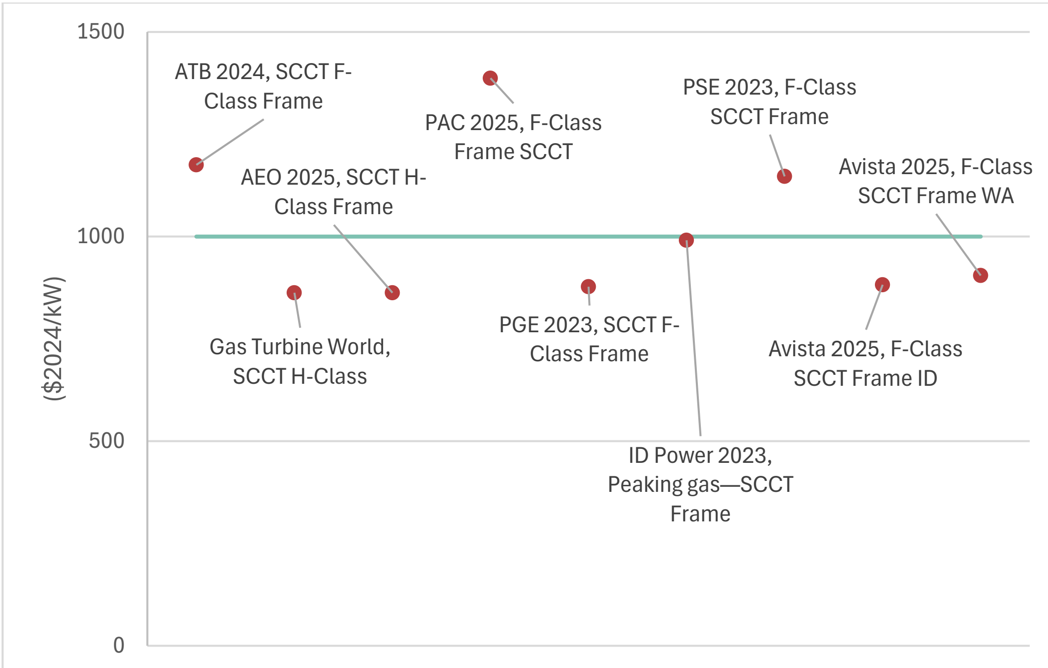
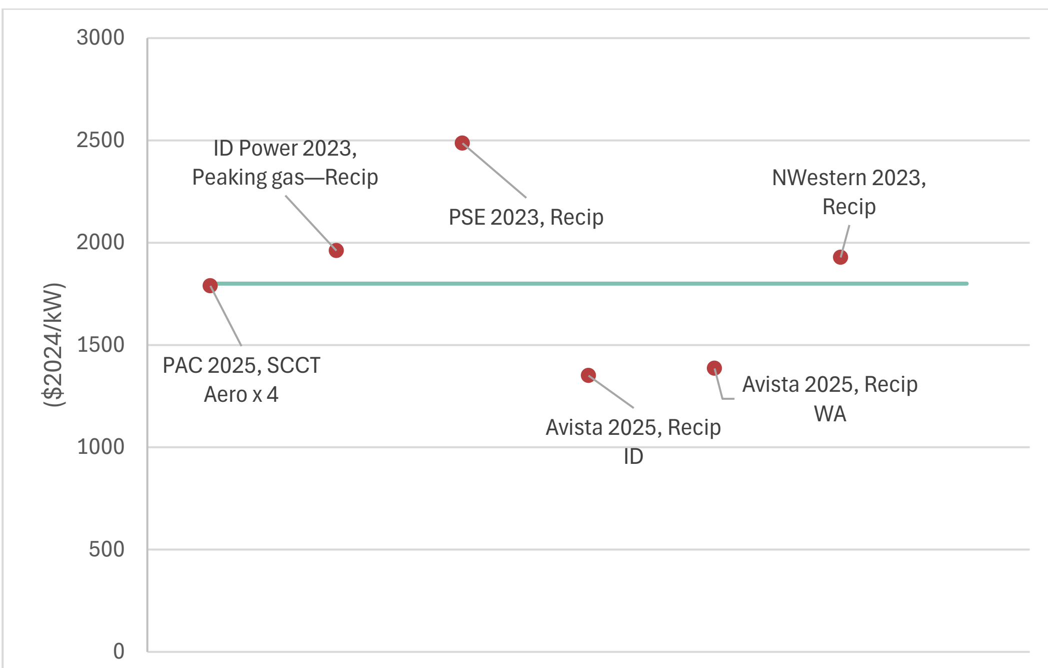


Figure G - 43: Literature Review of Alternative Simple Cycle Combustion Turbine Overnight Capital Costs



Like overnight capital costs, a literature review of fixed operations and maintenance costs for natural gas plants was performed and plotted. Costs for CCCTs, Frame SSCTs, and Alternative SCCTs can be seen grouping around $28/kW-yr, $16/kW-yr, and $17/kW-yr respectively. Applying the firming fuel cost adder discussed in the section above raises those costs to $58/kW-yr for CCCTs, $21/kW-yr and $22/kW-yr for Frame and Recip SSCTs.

Figure G - 44: Literature Review of Combined Cycle Combustion Turbine Fixed Operations & Maintenance Costs

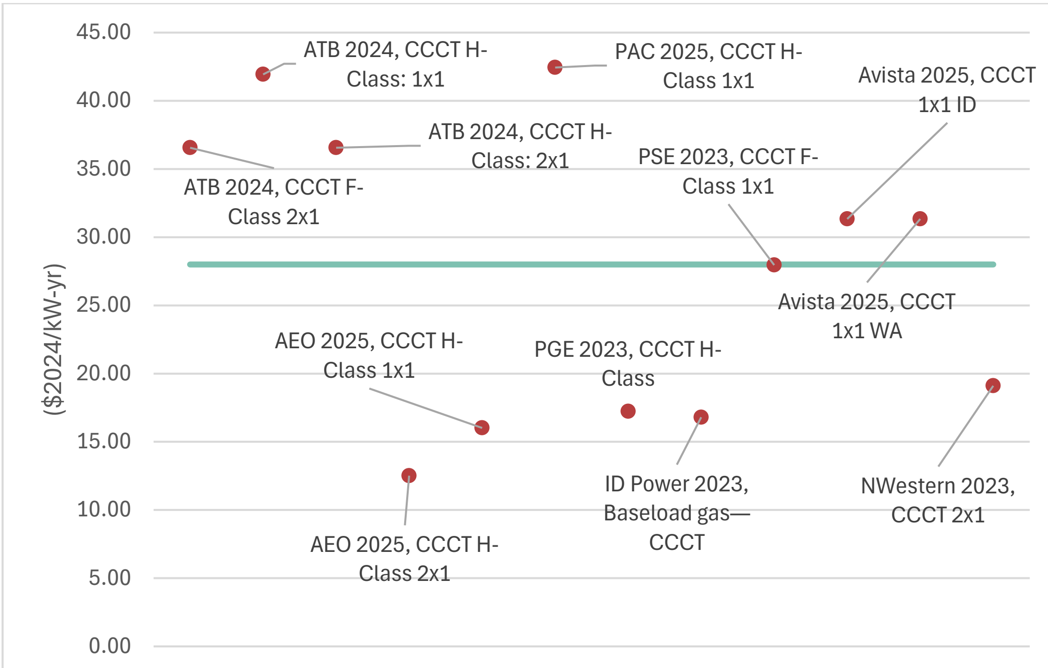


Figure G - 45: Literature Review of Frame Simple Cycle Combustion Turbine Fixed Operations & Maintenance Costs

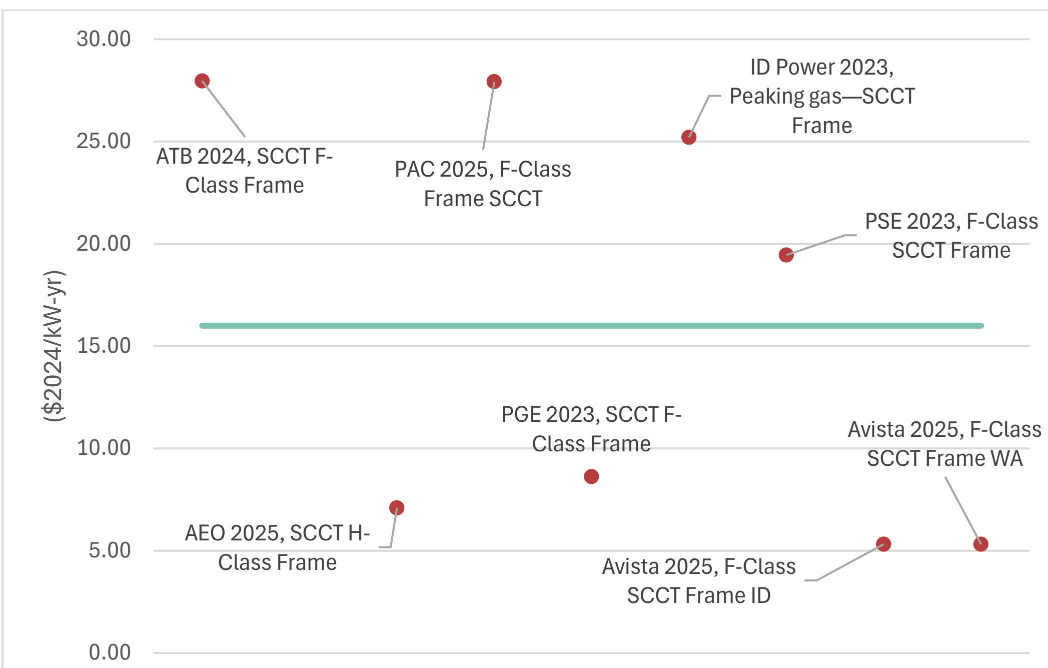
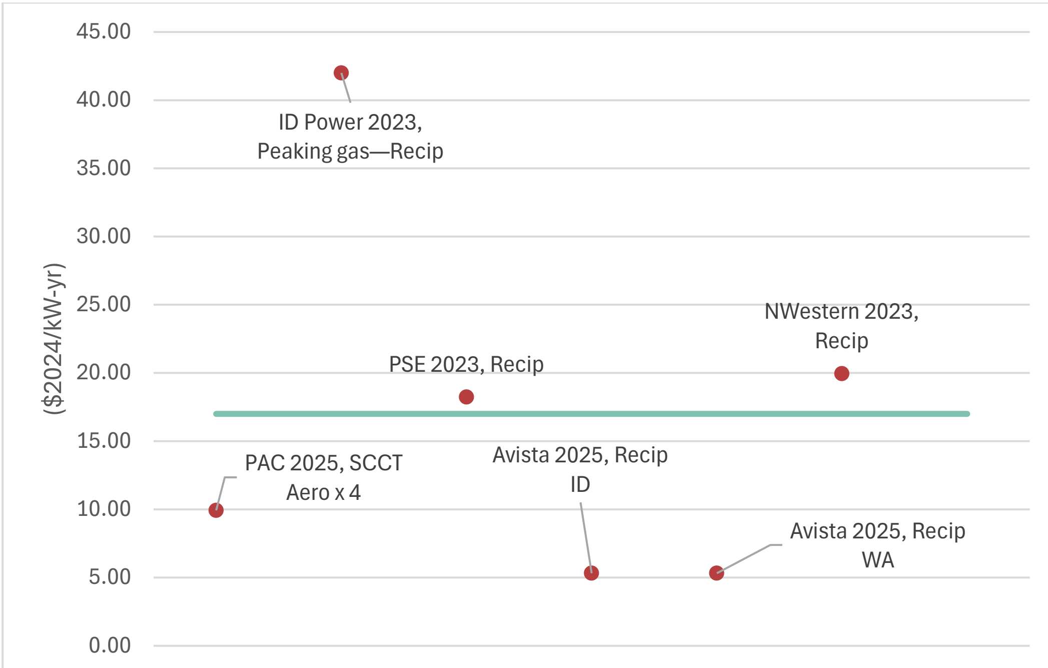


Figure G - 46: Literature Review of Alternative Simple Cycle Combustion Turbine Fixed Operations & Maintenance Costs



Unlike renewable resources, natural gas plants, in addition to fixed O&M costs, accrue *variable* O&M costs as a function of the amount of power they produce. This includes consumables such as water, chemicals, lubricants, catalysts, and waste disposal but does not include fuel costs. Because these costs are generation dependent, the values are levelized by the cost per unit of energy generation and presented in $/MWh.

As with other costs, a literature review of variable operations and maintenance costs for natural gas plants was performed and plotted. Costs for CCCTs, Frame SSCTs, and Alternative SCCTs can be seen grouping around $4/MWh, $3.50/MWh, and $5/MWh respectively.

Figure G - 47: Literature Review of Combined Cycle Combustion Turbine Variable Operations & Maintenance Costs

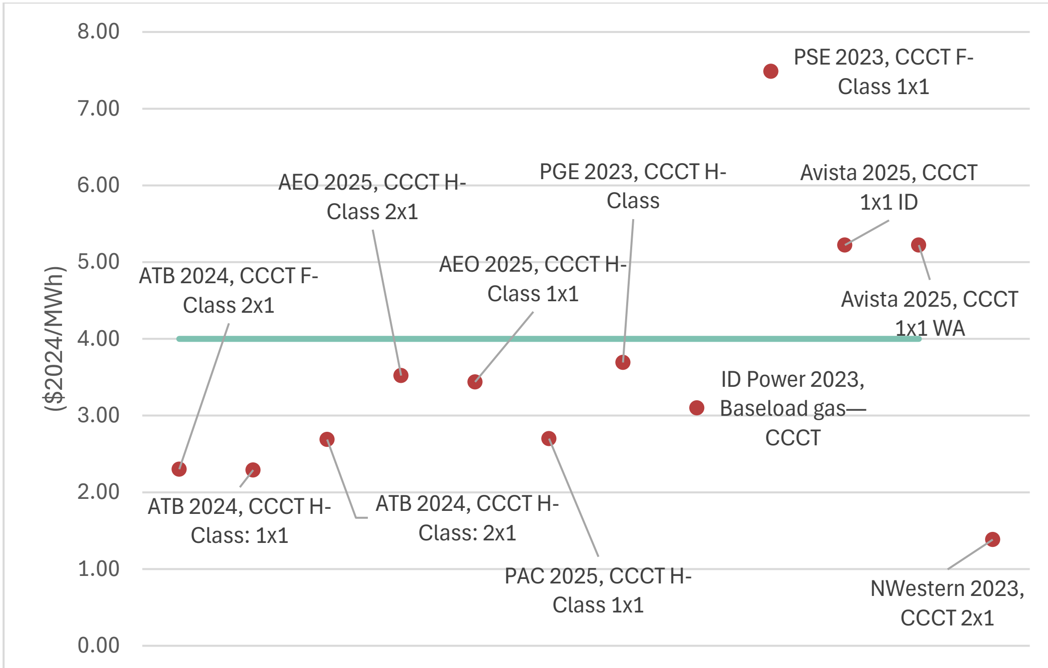


Figure G - 48: Literature Review of Frame Simple Cycle Combustion Turbine Variable Operations & Maintenance Costs

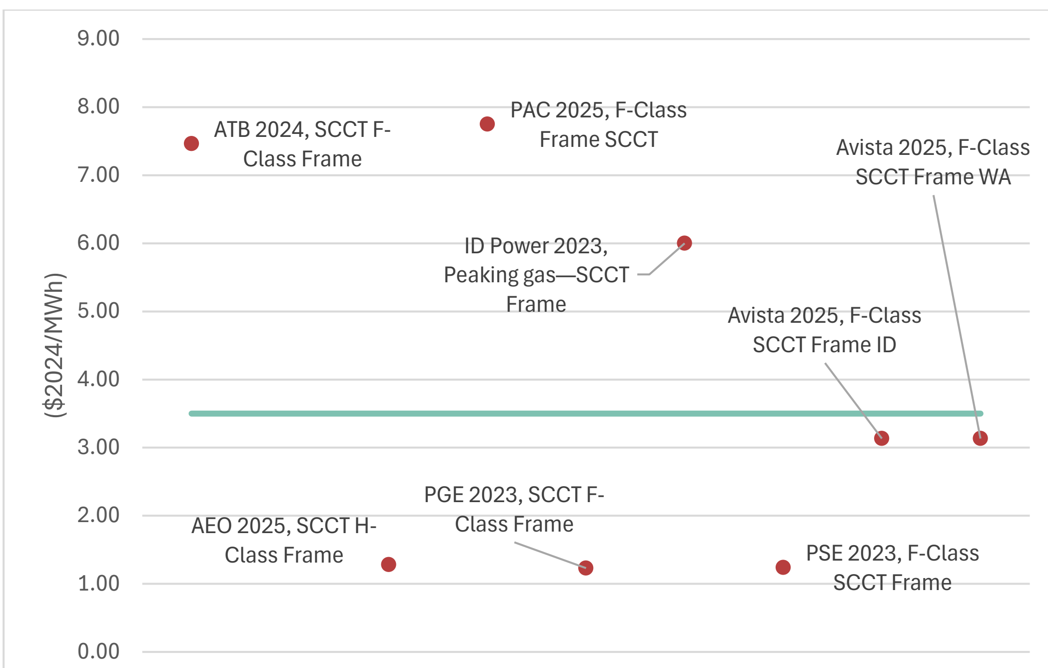


Figure G - 49: Literature Review of Alternative Simple Cycle Combustion Turbine Variable Operations & Maintenance Costs

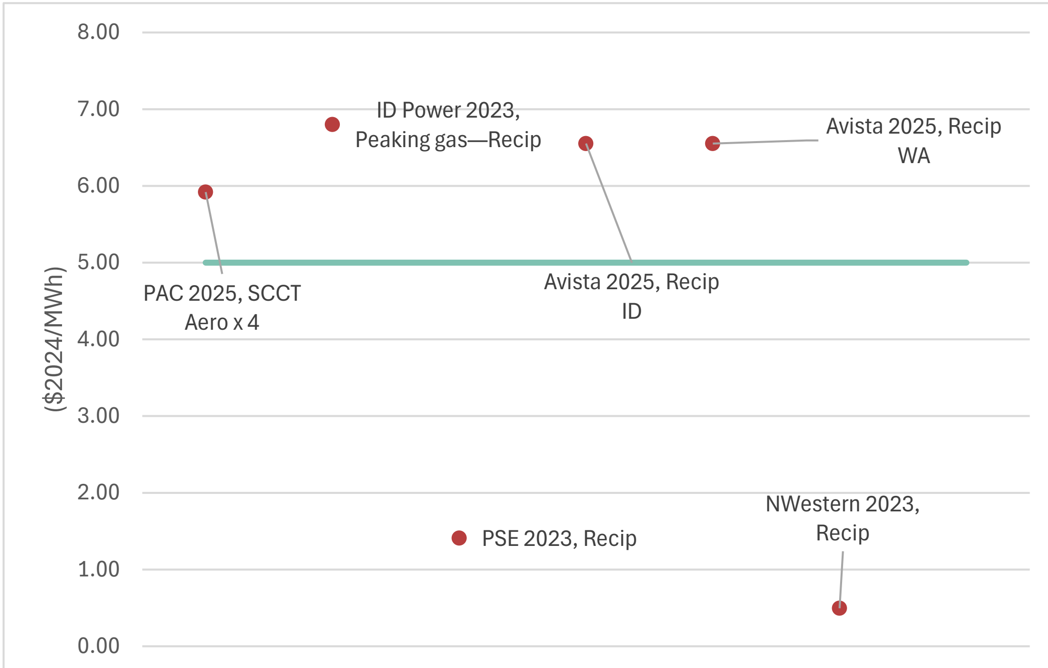


Figure G - 50: Forward Cost Curves for Gas Turbine Overnight Capital Costs

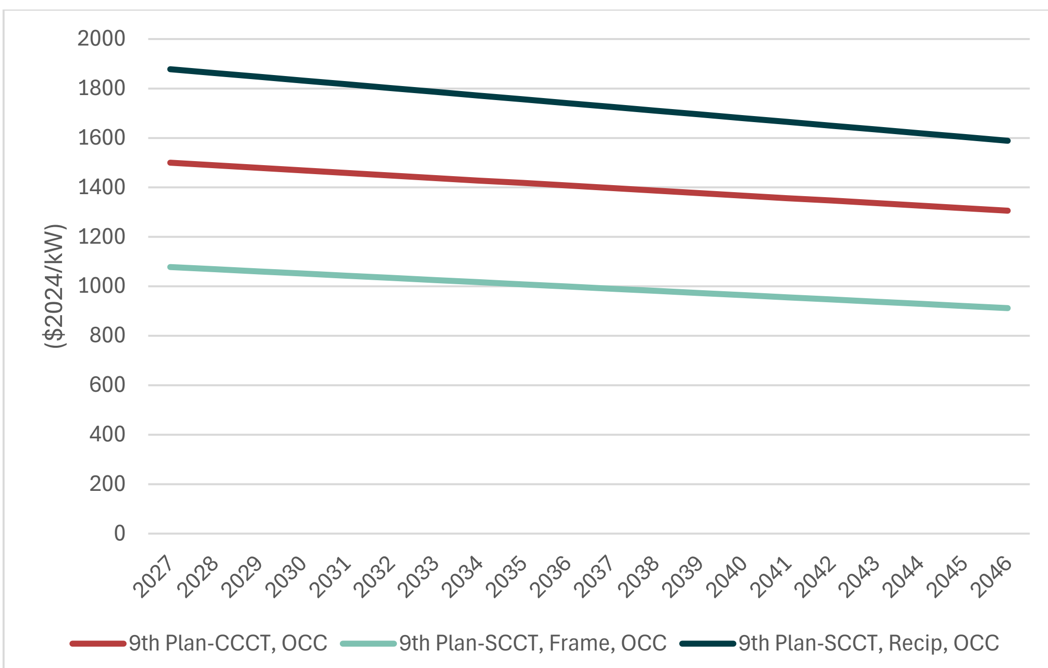
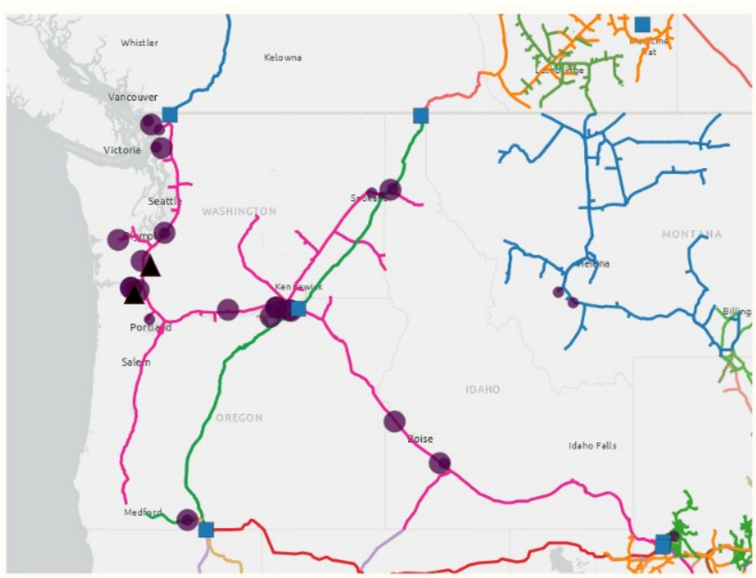


Figure G - 50 shows the same cost curves for natural gas plants displayed in Figure G - 1 applied to each type of natural gas plant included in the Ninth Plan and on its own axis for a clearer view. Overnight capital costs over the course of the study decrease by about 15% for combined cycle combustion turbines and almost 20% for the simple cycle turbines over 20 years.

Firming Fuel Cost Adder

The major pipelines in the Northwest (in Figure G - 51: Williams NWP in pink, and Gas Transmission Northwest in green) are running at high utilization rates, particularly at peak, with little to no firm gas contracts available. Considering that reality, and in alignment with what gas utilities are planning in their IRPs and seeing in their RFPs, a price adder for new gas plants is included to account for the firming of fuel supply.

Figure G - 51: Major Northwest Gas Pipeline



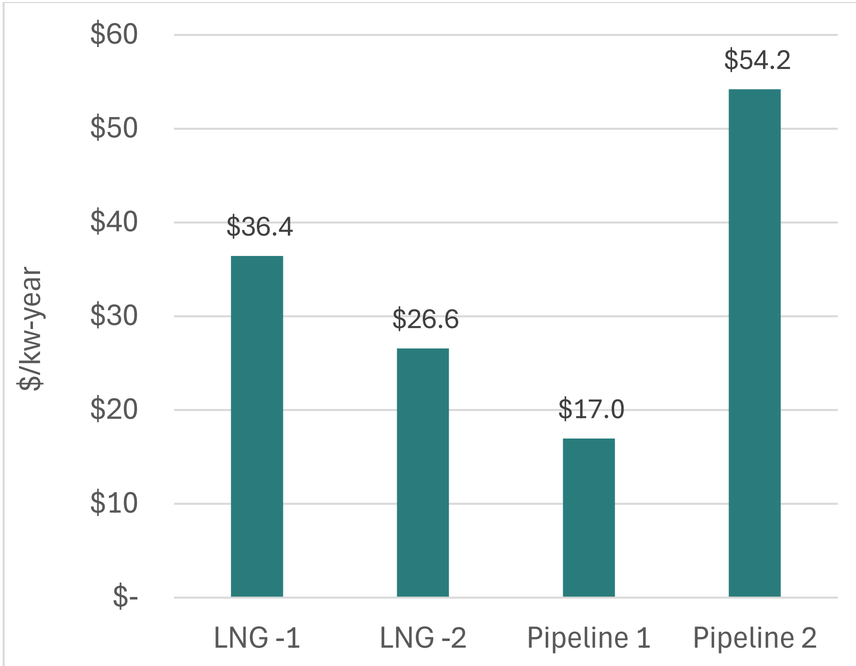
Firming Fuel Cost Adder - Simple Cycle Combustion Turbine – Fuel Oil Tank

Lower capacity gas plants (i.e. reciprocating engines and frame simple cycle combustion turbines) are small enough and run infrequently enough that a fuel tank and 48 hours of fuel a year provides sufficient backup for any peak event where pipeline access is not available. The 48 hours of fuel should be sufficient for most interruptions – with the plant coming down at night to stretch fuel for about three days of run-time. This results in a slight increase in capital costs (+$78/kW) and fixed operations and maintenance costs (+$5/kW-year)

Firming Fuel Cost Adder - Combined Cycle Combustion Turbine – Pipeline Upgrade/LNG peak shaving

Larger capacity gas plants (namely CCCT) require more fuel than a tank could realistically provide. As backup for these plants, two possible solutions were considered: a pipeline upgrade and liquified natural gas peak shaving. Both options would provide a gas plant with access to fuel when pipeline utilization is at its peak that they wouldn't otherwise have without a firm contract. These firming solutions are seen in utility planning and actual applications, and therefore are used to inform cost estimates. As with all reference plant decisions, the goal is a general price adder, acknowledging that the best solution for firming that supply will differ by utility situation and gas plant location.

Figure G - 52: Costs of Different Gas Firming Methodologies



Discussions with regional experts suggested that the low pipeline costs, shown in Figure G - 52, are no longer available as a means to firm a gas plant's fuel supply. Simpler and easier upgrades like compressor upgrades and software changes have already been implemented at most plants. Advisory committee members recommended those very low pipeline costs be discounted when coming up with a final cost. The best estimate, with the support of these experts, was an additional cost of $30/kW-year to be added to the fixed O&M cost of a CCCT.

The final costs of including the fuel supply firm gas adder to all gas technologies are summarized in Table G - 26.

Table G - 26: Final Gas Plant Costs Including Firming Cost Adder

Turbine Type	Capital Cost ($/kW)	Fixed O&M ($/kW-yr)	Variable O&M ($/MWh)
SCCT-Frame	$1000	$16	NA
SCCT-Frame: Adder	$78	$5	NA
SCCT-Frame: Total	**$1078**	**$20**	**$3.50**
SCCT-Recip	$1800	$17	NA
SCCT-Recip: Adder	$78	$5	NA
SCCT-Recip: Total	**$1878**	**$21**	**$5**
CCCT	NA	$28	NA
CCCT: Adder	NA	$30	NA

Turbine Type	Capital Cost ($/kW)	Fixed O&M ($/kW-yr)	Variable O&M ($/MWh)
CCCT: Total	**$1500**	**$58**	**$4**

Locational Cost Variation

The Council used locational cost adjustments aligning with the three zones created for fuel costs. The location groupings are chosen agnostic to the adjustment factors and so there is some work behind aligning the factors provided by the EIA, described in Table G - 3, to the locations selected for the natural gas reference plants. Which adjustment factor is applied to which reference plant is described in Table G - 27, where an eastside gas plant is given the average of Spokane, Great Falls, and Boise's cost adjustments, westside is given Portland and Seattle's, and BPA is given an average of the east and west side. Those adjustments are applied by location to the starting natural gas plant capital cost in Table G - 28.

Table G - 27: Natural Gas Plant Locational Cost Variation by Resource Cluster

	Locations	Cost Variation Multiplier	
		Combined Cycle	**Simple Cycle**
Eastside	Spokane, Great Falls, Boise	1.0102	1.0097
Westside	Portland, Seattle	1.1255	1.1200
BPA	Eastside/Westside	1.0679	1.0648

Table G - 28: Locational Variation of Natural Gas Plant Capital Costs

	Combined Cycle			Simple Cycle	
	Variation	**CCCT, OCC**	**Variation**	**Frame, OCC**	**Recip, OCC**
Starting Point	*n/a*	*$1500*	*n/a*	*$1078*	*$1878*
Westside	1.1255	$1688.25	1.120	$1207.36	$2103.36
Eastside	1.0102	$1515.30	1.0097	$1088.42	$1896.15
BPA	1.0679	$1601.78	1.0648	$1147.89	$1999.76

Summary Table

The summary of the natural gas reference plants is captured by Table G - 29.

Table G - 29: Natural Gas Reference Plant Summary Table

Reference Plant	CCCT H-Class 1x1	SCCT-Frame	SCCT-Reciprocating Engine
Configuration	1x1	1x__	__x18
Location	IPCO, BPA IDMT, NWMT, AVA, PSE Olympia, BPA WA	IPCO, BPA IDMT, NWMT, AVA, PSE(Olympia, Central, North), BPA WA	
Year Available to Model	Beginning of Study		
Development/Construction Period (Years)	4	3	2
Capacity (MW)	500	250	100
Heat Rate (Btu/kWh)	6250	9500	8500
Overnight Capital Cost ($/kW)	$1500	$1078	$1878
Fixed O&M Cost ($/kW-yr)	$58.00	$21.00	$22.00
Variable O&M ($/MWh)	$4.00	$3.50	$5.00
Economic Life	30 years		

Limited Availability Resources

Resources designated limited availability are commercially available resources with limited development potential in the region. These resources are given a mix of qualitative and some quantitative analysis. These resources are assigned a harder availability limit based on their physical constraints in the region. The reference plants created for limited availability resources in the Ninth Plan include conventional geothermal, offshore wind, and pumped storage.

Conventional Geothermal

Conventional geothermal is a renewable, clean energy resource with zero or low carbon emissions. The amount of emissions depend on the technology used, with flash steam technology emitting minimal excess steam and dry steam and binary cycle having zero emissions. The region has a significant, naturally occurring geothermal resource, especially in Southern Oregon and Idaho, but development has been limited. Conventional geothermal is a resource that requires the natural occurrence of heat, water, and permeability beneath the earth's surface. This combination makes development costly and uncertain. There has been recent development in geothermal technology that may reduce the cost and risk of the resource, but it is unproven on a commercial scale. Further discussion of enhanced geothermal technology is available in the emerging technology section of this appendix.

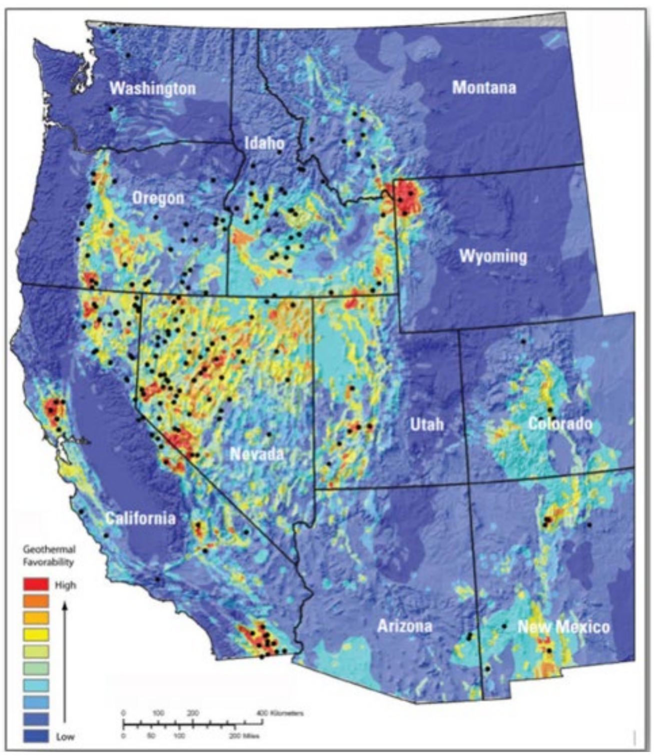
Availability

The Council considers geothermal a limited resource due to its highly site-specific nature. The USGS geothermal potential assessment, with some allowances for undiscovered potential, was used to inform an estimate of about 462 MW of conventional geothermal potential in the region, specifically Oregon and Idaho .[74] Figure G - 53 shows the areas that are favorable for geothermal, with the warmer colors indicating more favorable areas. More on the geothermal resource in the region can be found in Technical Appendix B – Existing System Parameters and Policies.

Geothermal is available at the beginning of study but has one of the longest development and construction timelines of 7 years, due to its extended and potentially fruitless exploration period.

Both the geothermal resource's capacity factor and its net capacity are based on the assumptions in NLR's ATB.[75] The Council's geothermal reference has a capacity factor of 80% and a discrete capacity of 30 MW.

Figure G - 53: Map of Geothermal Favorability in the West[76]

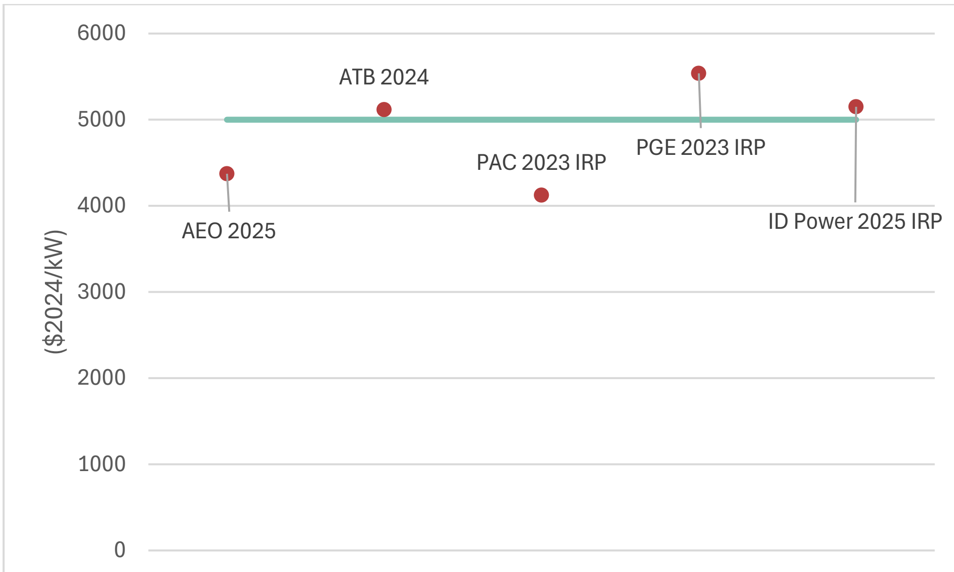


[74] USGS assessment of geothermal resources: https://pubs.usgs.gov/fs/2008/3082/pdf/fs2008-3082.pdf.
[75] https://atb.nrel.gov/electricity/2024/geothermal.
[76] https://pubs.usgs.gov/fs/2008/3082/pdf/fs2008-3082.pdf: Map of favorability of occurrence for geothermal resources in the western US. Warmer colors equate with higher favorability. Identified geothermal systems are represented by black dots.

Costs

Figure G - 54 and Figure G - 55 show the data plots and analysis that were used to develop the Ninth Power Plan geothermal reference plant cost estimates.

Figure G - 54: Literature Review of Conventional Geothermal Overnight Capital Costs



The literature review of conventional geothermal overnight capital costs, seen plotted Figure G - 54, coalesce around $5000/kW, shown by the light blue line. This final cost is not a pure average of available data, or a simple eyeballing of the plot, but an educated estimate arrived at through research, professional judgment and advisory committee expertise.

Similarly, Figure G - 55 shows there is a clustering of geothermal fixed operations and maintenance costs around $130/kW-yr.

Figure G - 55: Literature Review of Conv. Geothermal Fixed Operations & Maintenance Costs

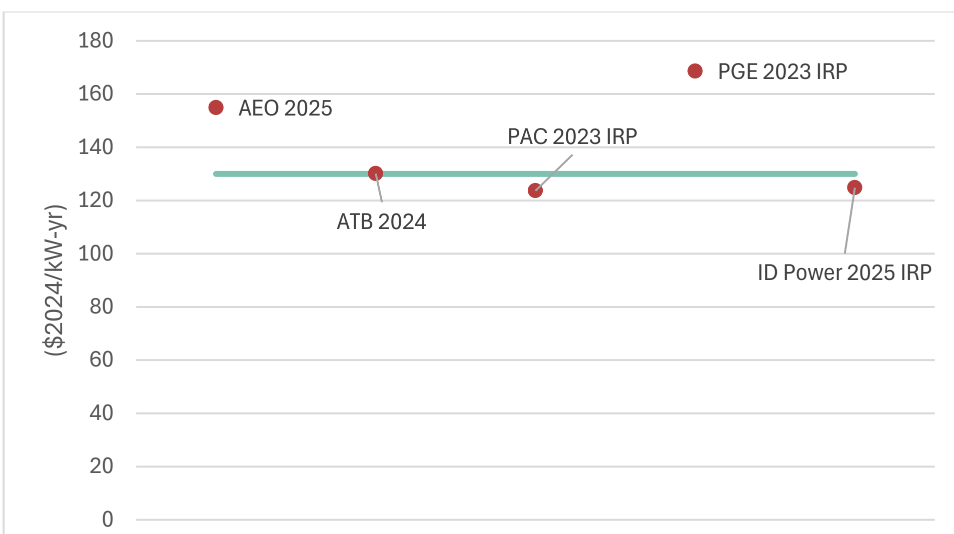


Figure G - 56: Forward Cost Curves for Conventional Geothermal Overnight Capital Costs

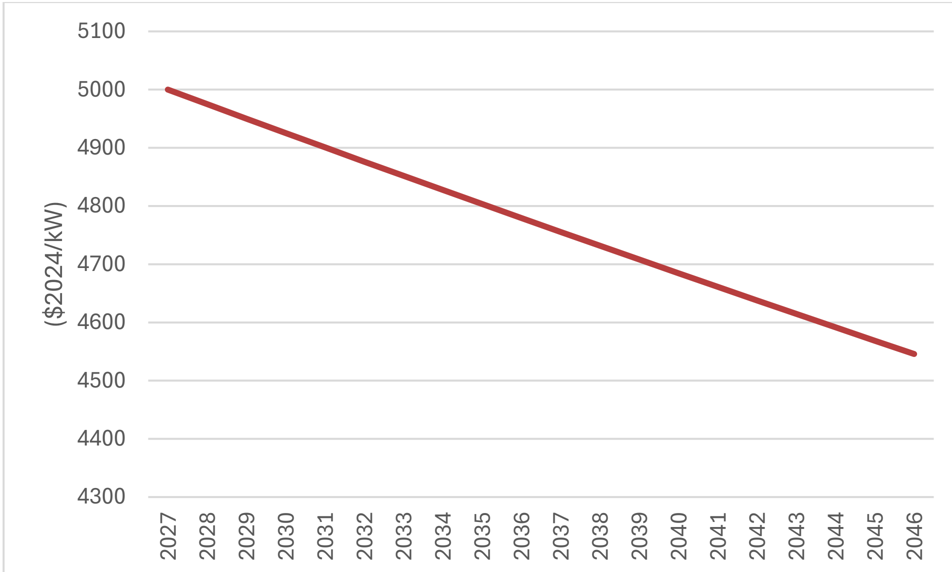


Figure G - 56 shows the NLR cost curve for geothermal. Overnight capital costs over the course of the study deescalate to below $4600/kW over 20 years.

Summary Table

The summary of the conventional geothermal reference plant is captured by Table G - 30.

Table G - 30: Conventional Geothermal Reference Plant Summary Table

Reference Plant	Conventional Geothermal
Configuration	Binary, Closed loop
Location	East of the Cascades (OR/ID)
Available Date	2024
Development/Construction Period (Years)	7
Capacity (MW)	30 (net)
Avg Capacity Factor	80%
Overnight Capital Cost ($/kW)	$5,000
Fixed O&M Cost ($/kW-yr)	130
Variable O&M ($/MWh)	0
Economic Life (years)	30
Maximum Buildout	462 MW (22 plants)

Offshore Wind

While offshore wind is an established resource in other parts of the world, it is still emerging in the Pacific Northwest. Offshore wind turbines are like their onshore counterparts, except that they tend to be much larger in size and energy output. A typical onshore wind turbine installed today is about 3 MW, while an offshore wind turbine is closer to 10 MW. There are multiple turbine technologies that can be used, depending on the area and depth of the body of water. In shallow waters, a fixed-bottom turbine can be deployed, where the device is installed and connected to a foundation in the seabed (or floor of another body of water). Once the water depth gets to around 60 meters and greater, a fixed-bottom installation is no longer feasible. Instead, a floating turbine is required – a turbine that sits atop a floating platform that is tethered to the seabed to prevent it from drifting. Floating turbine technologies are less well established than fixed-bottom, but they open up significantly more potential for offshore wind in terms of access to more viable wind speed sites.

Availability

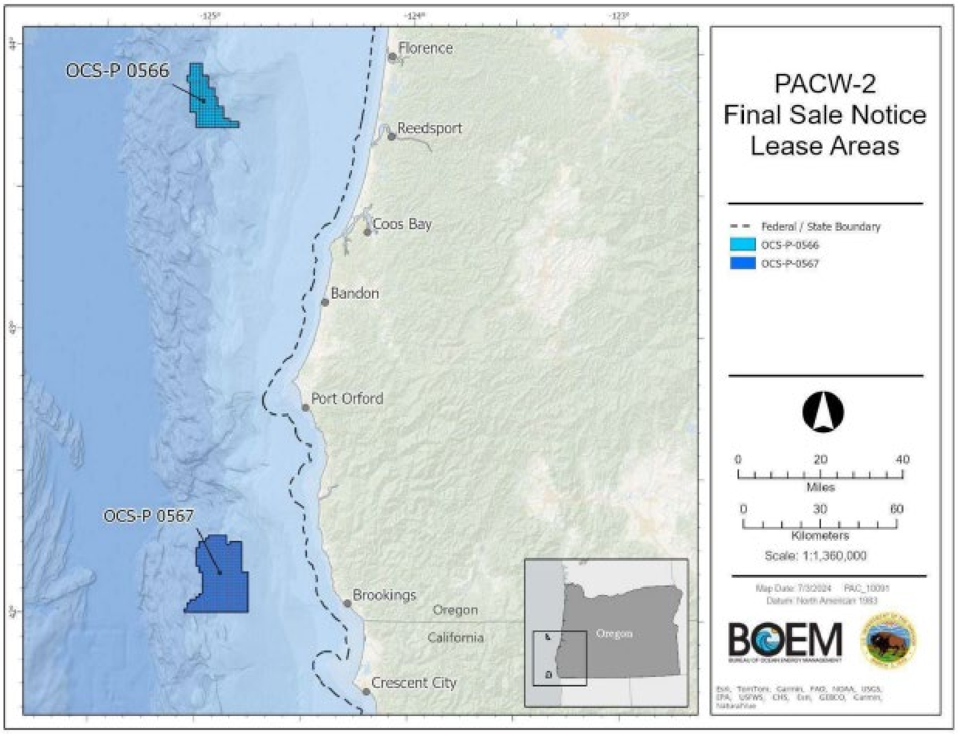
Offshore wind is only available in federally designated leasing areas; two such areas have been identified in the region off the Oregon Coast near Coos Bay and then further south near Brookings, shown on the map in Figure G - 57. The Coos Bay lease area has a capacity of 991 MW and Brookings is 2,166 MW for a total offshore wind capacity of about 3GW in the region. More description by lease area can be found in Table G - 31 below.

The latest estimates of timing from Bureau of Ocean Management (BOEM) have the earliest online dates for offshore wind plants in either of those lease areas at 2032. However, the Council ultimately used a more conservative assumption of 2035 based on increased uncertainty from federal policy changes.

Table G - 31: Oregon Lease Area Descriptive Statistics

Lease Area	Acres	Installation Capacity	Minimum Depth	Maximum Depth	Closest Dist. to Shore
Brookings OCS-P 0567	133,792	2,166 MW	567 m	1,531 m	18 miles
Coos Bay OCS-P 0566	61,203	991 MW	635 m	1,414 m	32 miles
Total	194,995	3,157 MW	--	--	--

Figure G - 57: Map of Offshore Wind Final Lease Areas[77]

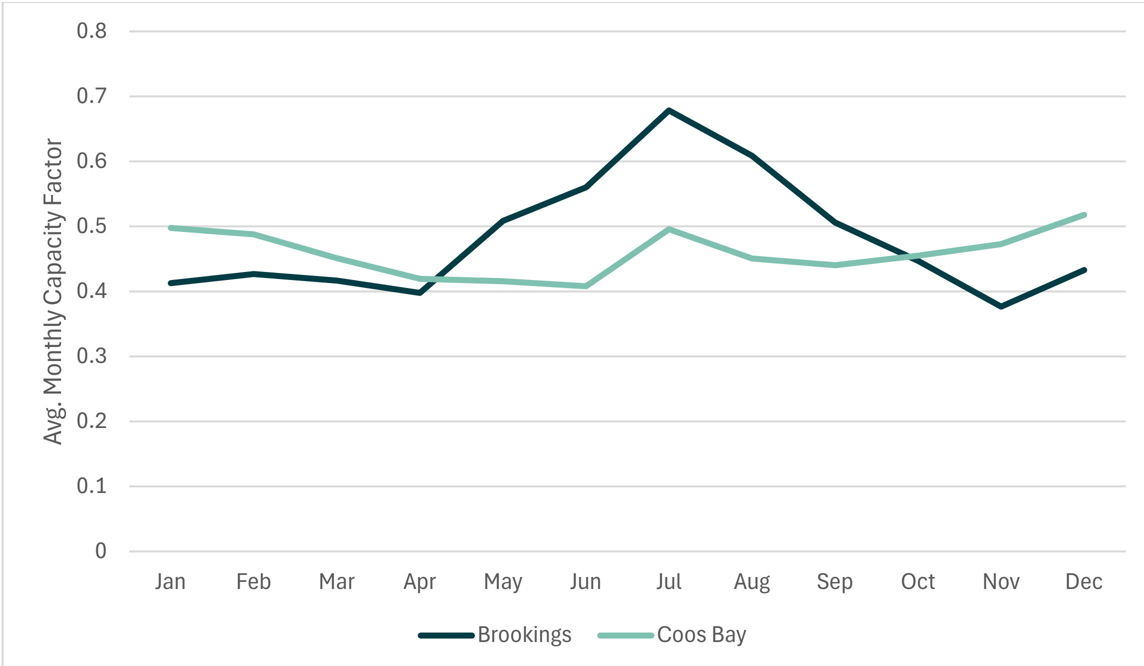


Generation Shapes

Like other renewable resources, offshore wind locations have associated capacity factors based on synthetic wind generation profiles. Development of the weather profiles and resulting generation are discussed with more detail in Technical Appendix D – Climate Model Data and Assumptions Similar to onshore wind, synthetic future generation curves were generated for every hour of every day for each lease area for the whole study. Figure G - 58 shows the average of monthly capacity across a year to illustrate the general variation in shape between the call zones. The annual generation shapes also illustrate the difference between onshore and off-shore wind. Off-shore wind has an average capacity factor of around 50% while onshore wind is perhaps less consistent than the off-shore resource and averages around 30-40% depending on the location.

[77] OCS-P 0566 refers to Coos Bay call area. OCS-P 0567 refers to Brookings call area on the map. BOEM final sale notice decision memorandum: https://www.boem.gov/sites/default/files/documents/renewable-energy/state-activities/Oregon%20FSN%20Decision%20Memo%20PACW2_0.pdf.

Figure G - 58: Average Monthly Offshore Wind Capacity Factors at Regional Call Areas



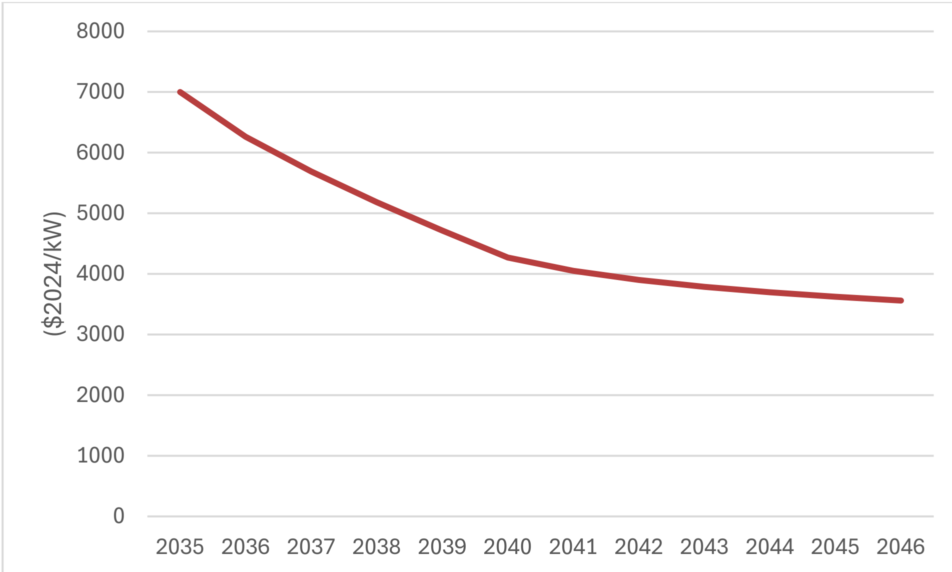
Cost

The final costs for the offshore wind reference plant are primarily informed by the NLR Annual Technology Baseline.[78] The Council chose this source since floating offshore wind does not yet exist in the US, and NLR is the primary resource for much of the existing offshore wind development research. This same source is used by many others in their planning of offshore wind. The overnight capital cost of $7000/kW and a fixed O&M of $100/kW-yr rely on NLR as the source.

NLR's cost curve for offshore wind is displayed in Figure G - 59. Overnight capital costs over the course of the study deescalate to just below $4000/kW over 20 years, with a steeper curve over the first five years.

[78] https://atb.nrel.gov/electricity/2024/offshore_wind.

Figure G - 59: Forward Cost Curve for Offshore Wind Overnight Capital Costs



Summary Table

The summary of the conventional geothermal reference plant is captured by Table G - 32.

Table G - 32: Offshore Wind Reference Plant Summary Table

Reference Plant	Offshore Wind
Configuration	15MW turbine, 248-meter rotor diameter, 150-meter hub height, semisubmersible (floating technology)
Location	Brookings call area Coos Bay call area
Availability Date	2035
Development Period (Years)	5
Construction Period (Years)	3
Capacity Factor	~50%
Overnight Capital Cost ($/kW)	$7,000
Fixed O&M Cost ($/kW-yr)	$100
Variable O&M ($/MWh)	0
Economic Life (years)	30
Maximum Buildout	3 GW

Pumped Storage

Pumped storage hydropower is an established and commercially mature energy storage resource, but there has been limited development in the Pacific Northwest to date. A typical project consists of an upper reservoir and a lower reservoir connected by a water transfer system with reversible pump-generators. Energy is stored by pumping water from the lower reservoir to the upper reservoir and generated by releasing water from the upper reservoir through the turbines to the lower reservoir. Most existing pumped-storage projects were designed to shift energy from off-peak hours or low demand periods to times of peak demand. Advances in technology have made it possible for pumped storage to better provide capacity, frequency regulation, voltage and reactive support, load following, and longer-term shaping of energy from variable resources. These improvements include shifting to adjustable variable speed pumps rather than fixed speed pumps and employing ternary units that allow the turbine and pump to operate simultaneously.

Availability

Pumped storage projects require suitable topography and geologic conditions for either constructing upper and lower reservoirs at significantly different elevations within close proximity, or for taking advantage of naturally occurring water flows and existing/natural reservoirs. In addition, a nearby water supply is required for initial reservoir charge and occasional replenishment for losses due to evaporation. The Council developed 10 reference plants totaling 4000 MW of potential, based on the projects currently in development in the region and what is realistically achievable over the next two decades. Figure G - 60 shows the planned locations in the region that informed these reference plants and Table G - 33 provides more information on the specific projects.

As a storage resource, pumped storage has a round-trip efficiency, which is again the ratio of energy discharged to the grid to the energy received from the grid to bring the storage system to the same state of charge. Pacific Northwest National Laboratory (PNNL) identified a range of RTEs for pumped storage resources of 70%-87%.[79] The Council selected a middle estimate of 80% RTE, in alignment with NLR's ATB.[80]

[79] https://www.pnnl.gov/sites/default/files/media/file/Final%20-%20ESGC%20Cost%20Performance%20Report%2012-11-2020.pdf.
[80] https://atb.nrel.gov/electricity/2024/pumped_storage_hydropower.

Figure G - 60: Map of Planned and Operating Pumped Storage Resources in the Region[81]

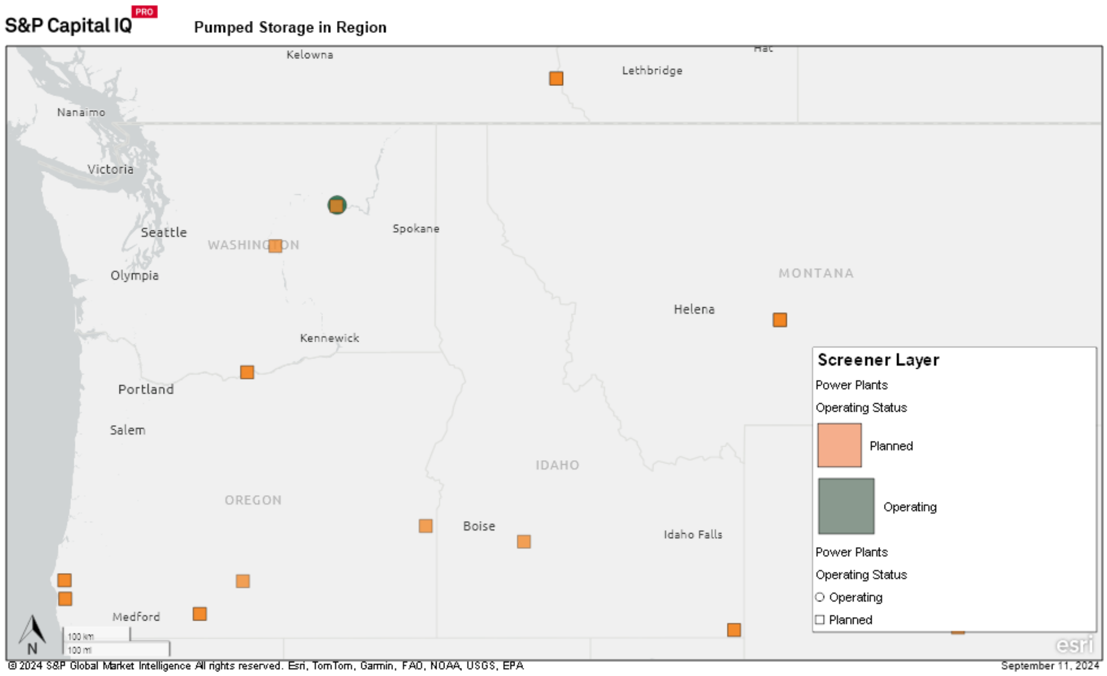


Table G - 33: Location and Capacity of Planned Regional Pumped Storage[82]

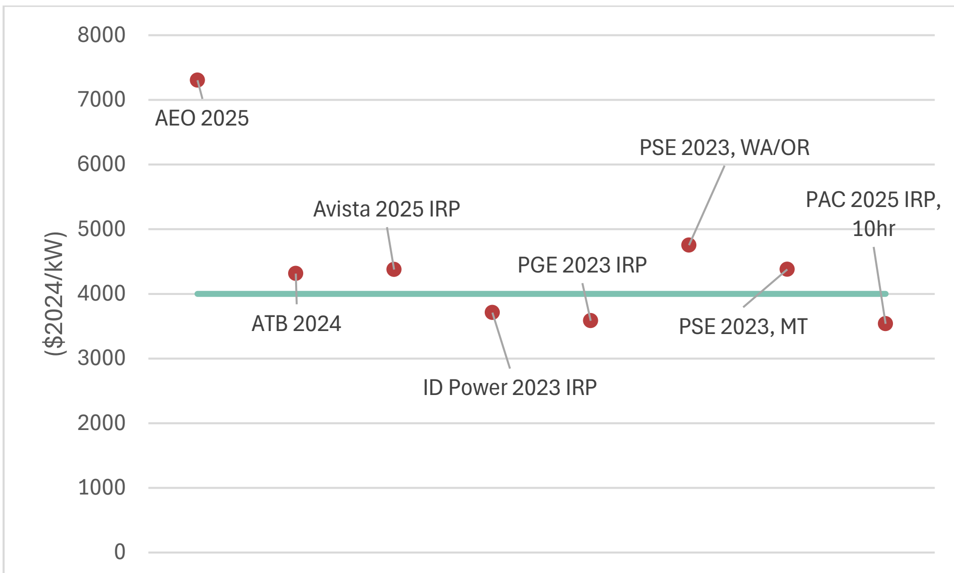
Plant name	State	Planned Capacity (MW)
Badger Mt	WA	500
Banks Lake	WA	500
Goldendale	WA	1200
Gordon Butte	MT	400
Cat Creek	ID	720
Dry Canyon	ID	1800
Elephant Rock (Neptune1)	OR	318
Owyhee	OR	600
Soldier Camp	OR	550
Swan Lake	OR	390
Winter Ridge	OR	500

[81] S&P Global.
[82] Ibid.

Cost

The literature review of pumped storage overnight capital costs, seen plotted in Figure G - 61, coalesces around $4000 /kW, shown by the light blue line. This final cost is not a pure average of available data, or a simple eyeballing of the plot, but an educated estimate arrived at through research, professional judgment and advisory committee expertise.

Figure G - 61: Literature Review of Pumped Storage Overnight Capital Costs



There is not a cost curve for pumped storage. Per NLR's designation, pumped storage is considered a fully mature technology with no observable recent changes in cost or innovation.[83]

Summary Table

Pumped storage resource characteristics are collated in a table summarizing all that has been discussed in the preceding section. The summary of the reference plant is captured in Table G - 34.

[83] https://atb.nrel.gov/electricity/2024/pumped_storage_hydropower.

Table G - 34: Pumped Storage Reference Plant Summary Table

Reference Plant	Pumped Storage - 8 hour
Configuration	Closed loop, variable speed pump
Configuration	400 MW/8hr
Year Available to Model	2029 (5 yr lead time)
Development/Construction Period (Years)	2
Capacity (MW)	400[84]
Round trip Efficiency	80%
Overnight Capital Cost ($/kW)	4000
Fixed O&M Cost ($/kW-yr)	15
Variable O&M ($/MWh)	0
Economic Life (years)	50
Max Buildout	10 Plants (4000MW)

Emerging Resources

The Power Act requires that the Council give priority to cost-effective resources,[85] which in part requires the technology to be forecast as "reliable and available within the time it is needed."[86] The previously described resource categories, Primary and Limited Availability, fall within that definition and are treated accordingly. The Emerging Technology category is considered not yet "available and reliable." Despite not being "reliable and available" today, the Council analyzes these emerging resources to inform potential long-term strategies for resource development.

Proxy Reference Plant Approach

The emerging technology resources receive qualitative discussion of the status of their regional potential and are represented as proxies for future technology in analysis. The Council's approach to emerging technology has evolved across power plans, sometimes naming a specific resource or building a single proxy to represent all possible resources. For the Ninth Plan, the Council has opted for an expansion of the proxy approach, developing three emerging technology proxies in the hopes of revealing more about the system's needs. These three proxies are based on specific technologies that

[84] Approximate, pumped storage capacity is based off of previously cited projects, as explained above.
[85] Northwest Power Act, §4(e)(1).
[86] Northwest Power Act, §3(4).

embody sets of characteristics, but they may not be the only technologies that might fill the gap their selection identifies.

The intention behind building proxy resources is to avoid affording too much certainty around future technologies that are not yet proven on the scale necessary to the region. By building proxies that are representative of a set of characteristics, rather than a particular technology, the hope is to provide space to test within those characteristics. Even if those characteristics do not come to bear, these proxies still reveal something about regional system needs. The proxies are also available far enough out in the planning period that there will be time to revisit any assumptions by the next power plan if it becomes clear that adjustments are needed.

The Council has developed three proxy plants that represent a set of resource attributes and will provide insight into which of those potential attributes might provide the most value for the power system in the long-term. Those proxies, their representative technologies, and the information they provide are listed below. They will be described in more detail later in the section.

- **Clean Long Duration Storage**: Helps the grid better integrate variable resources, provides operational flexibility, and offers demand shifting on a seasonal scale. Represented by an iron-air battery.
- **Clean Baseload**: Offers reliability and firm supply to the grid. Represented by a small modular nuclear reactor.
- **Clean Peaker and Medium Duration Storage**: Mitigates high peak demand, while extending operational flexibility and shorter term, daily/hourly demand shifting. Represented by a hydrogen peaker plant with on-site production and storage.

Shared Emerging Technology Assumptions

Similar to the other resource types, emerging technologies share some assumptions across resources. These cross-cutting pieces are especially relevant to these proxy resources as they provide a level of parity and allow for more straightforward comparisons between resources. The nature of the proxies being so uncertain led to the conclusion that some equivalencies would be useful in the absence of certainty.

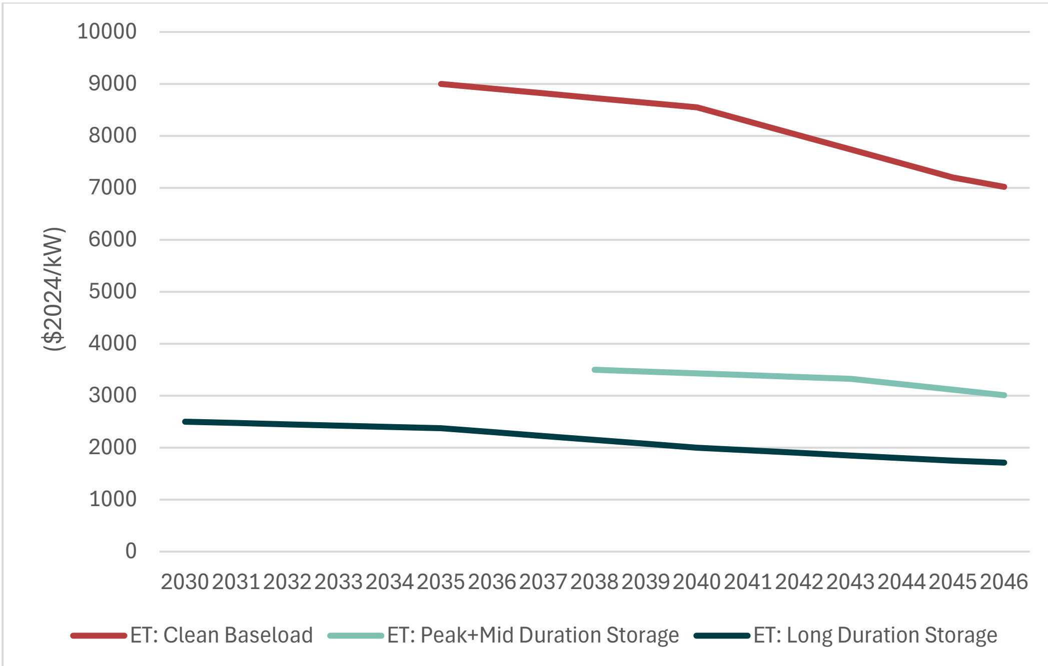
Cost Curves

For consistency, the cost curve for all emerging tech is based on the SMR curve developed in the NLR ATB[87]. SMRs, as the emerging technology that has been around the longest, has the most data and research around its potential costs. As in past plans, the Council has used the cost curves developed by NLR across emerging technologies under the assumption that these currently non-commercial

[87] https://atb.nrel.gov/electricity/2024.

technologies' costs might de-escalate in a similar manner as they mature and are more widely adopted. Figure G - 62 shows the final forward cost curves assumed for these technologies.

Figure G - 62: Forward Cost Curves of Emerging Technologies



Availability

Given the uncertainty around emerging technology characteristics, there was an effort to align, as appropriate, online dates, development period, and maximum buildouts so that technologies might be better compared to each other based on the above-described characteristics rather than the simple fact that they were more available or available earlier.

As was described for each primary and limited availability resource, the available online date of a resource refers to when the resource is available for the model to select and the development period denotes how long a resource takes, after being selected, to come online and be operational. For emerging technologies, the aspects of timing are fairly uncertain and fall outside of the first six years of the Ninth Plan horizon (also known as the action plan period). The iron-air batteries of the long duration storage proxy are currently operational, if not yet quite commercial, but the other two proxies are not. The assumptions outlined below are informed estimates, but an effort was made to align their timing so as to not favor one over the other.

A resource's maximum buildout sets the maximum amount of reference plant units that the model can select over the whole 20-year planning horizon. This is not stipulated for most primary resources, but it is assumed that emerging technology will be more limited in the early stages of their commercial availability. There was an attempt to align the amount of each resource available for the model to select in an endeavor to treat the proxies equivalently. These final availability decisions are shown in Table G - 35.

Table G - 35: Emerging Technology Availability[88]

Technology	Available online date	Max. Build
ET-Baseload (SMR)	2040	3000 MW (~5 units)
ET-Peaker + Med Duration Storage (H2)	2040	3000 MW (~10 units)
ET-Long Duration Storage (Iron air battery)	2032	1000 MW (by 2040) 2000 MW (by end of study)

Clean Baseload

Characteristics

One potential future need of the energy system is a clean baseload resource. It is often discussed that the modern grid, defined by high adoption of variable resources, aging and retiring coal plants, and a push for cleaner generation, lacks a firm supply. This resource can act as an underlying constant upon which the rest of the system is built, is big enough to fill any gaps, is consistently reliable, and is always on. The clean baseload proxy plant allows us to test if and under which conditions that need arises.

There are a number of resources currently under development, though not yet commercially available, that could fulfill these characteristics and meet potential future baseload need of the system. The intention of the proxy approach is, again, to not be overly prescriptive of the specific technology but to focus on the characteristics of the resource and what they mean for the region. A representative technology was selected as the basis for the proxy, due to relative technology maturity and regional interest, but there are other technologies that could address the same need. A few of those technologies are described at the end of the section.

Proxy Specifics: Small Modular Reactor

Small modular nuclear reactors (SMRs) were selected as the proxy resource in the 2021 Power Plan due to general enthusiasm and interest for the technology in the region and more broadly at the time. SMRs have stayed top of mind since the 2021 Power Plan with many regional IRPs including them in their models. Additionally, various tech companies have announced partnerships and plans to serve their data center loads with SMRs. The largest in-region announcement is Amazon's partnership with Energy Northwest and X-energy to build 320 MWs near the Columbia Generating Station, which represents a fraction of their planned 5 GWs of SMR development. Similar partnerships between tech companies and SMR developers are happening across the country with Oracle announcing 1 GW of

[88] The limits described in this table reflect what the GRAC thought were reasonable for availability limitations. The actual modeling did not implement these limits. Staff does not believe this changes results in the near-term. Further discussion of this disconnect can be found in Technical Appendix N—Scenario Modeling and Results.

SMRs, Google and Kairos Power planning 500MW, and Oklo and Switch penning a deal for 12 GW of SMRs by 2044. This high level of investment in SMR development made SMRs a logical choice to base this proxy on.

The emerging SMR technology's smaller size and modular construction is intended to reduce capital cost and investment risk, as compared to a conventional full-sized nuclear unit. It aims to do this by using a greater degree of factory assembly, shortening construction lead time, and better matching plant size to customer needs and finances through scaling of multiple units. The smaller plant size of SMRs may also permit greater siting flexibility, load following capability, and cogeneration potential. They can also benefit system reliability through reduction in "single shaft" outage risk with multiple independent reactor-generator pairings. One of the major challenges with any nuclear power plant is responsibly and safely storing and disposing of used fuel. While SMRs use less fuel, the technology does not resolve this concern entirely. More on the environmental effects of nuclear power and historical and current development can be found in Technical Appendix B – Existing System Parameters and Policies.

Availability

Many aspects of the SMR's availability have already been discussed above in the shared assumptions section. However, the technology has additional considerations to be made around capacity and efficiency. As with the other thermal resources, SMRs are modeled with a discrete size based on a literature review of available sources and conference with Council advisory committees. The same approach was taken to determining the heat rate, or thermal efficiency, of the resource. Those sources are shown in Table G - 36 below.

Table G - 36: SMR Operating Characteristics Literature Review

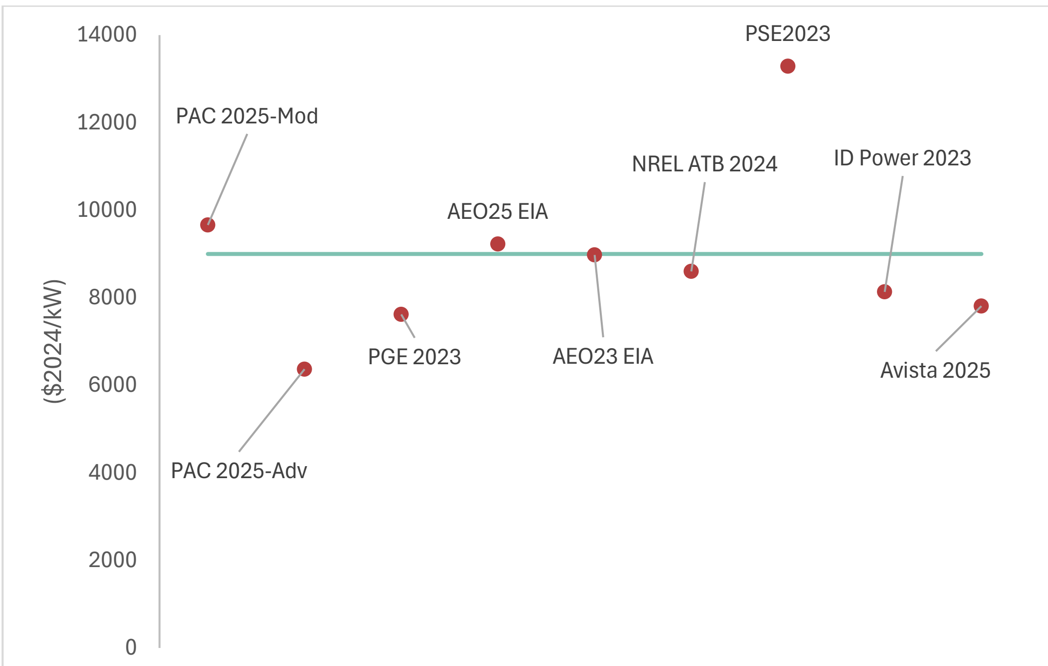
Source	Capacity	Heat Rate (HHV Btu/KWh)
PAC IRP-Moderate Tech Case	600MW	9180
PAC IRP-Advanced Tech Case	600MW	9180
PGE IRP	600MW	10046
AEO24 EIA	480MW	10046
AEO23 EIA	600MW	10447
NLR ATB	300 MW	9180
PSE IRP	600 MW	
ID Power IRP	100 MW	10461
Avista IRP	100MW	10443
Final Reference Plant	600MW	9800

Costs

Of the emerging technologies, SMRs have the most resources to draw on when exploring their potential costs and other operating characteristics. SMRs have been an emerging technology for longer than some of the other resources, and so there has been more time spent building up these technical resources.

The literature review of SMR overnight capital costs, seen plotted Figure G - 63, coalesces around \$9000/kW, shown by the light blue line. This final cost is not a pure average of available data, or a simple eyeballing of the plot, but an educated estimate arrived at through research, professional judgment and advisory committee expertise.

Figure G - 63: Literature Review of Small Modular Nuclear Reactor Overnight Capital Costs



Fixed O&M costs as well as Variable O&M costs seen in Figure G - 64 and Figure G - 65 similarly cluster around a median cost, represented by the light blue lines. Fixed O&M around \$120/kW-yr and Variable O&M at \$4.50/MWh.

Figure G - 64: Literature Review of Small Modular Nuclear Reactor Fixed O&M Costs

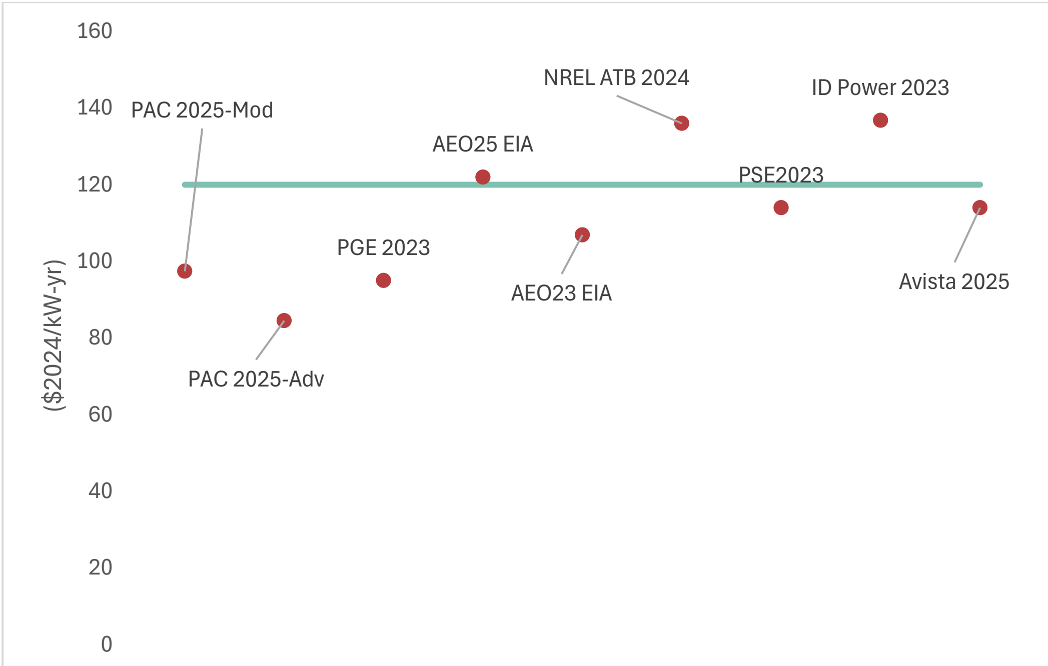
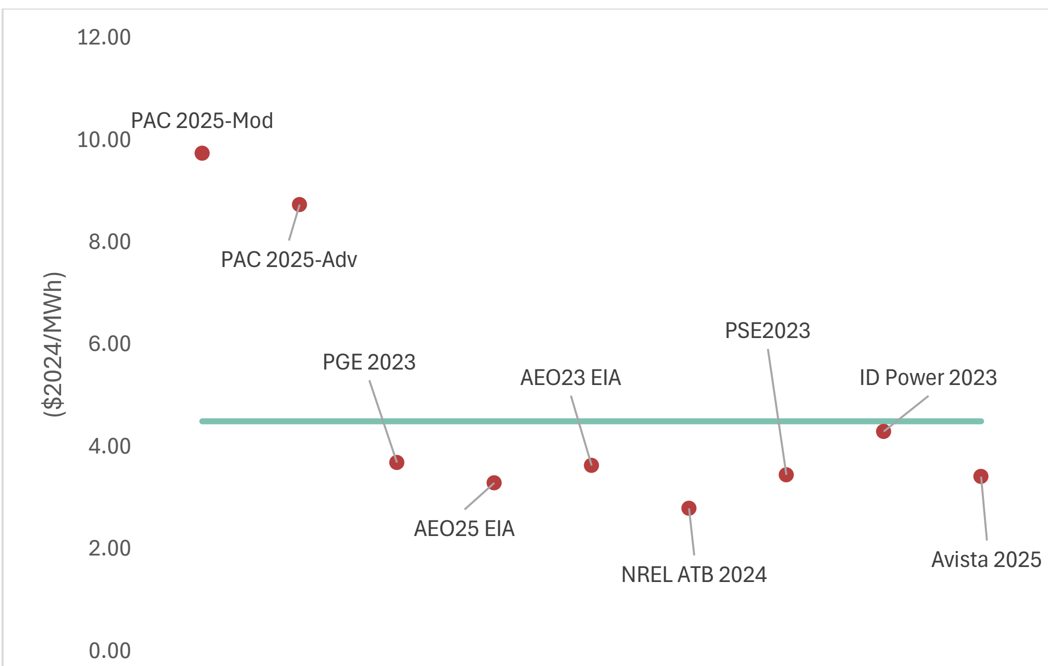


Figure G - 65: Literature Review of Small Modular Nuclear Reactor Variable O&M Costs



Alternative Technologies

Small Modular Reactors are not the only emerging technology that could fulfill the characteristics described by the clean baseload proxy. Other technologies covered by this proxy plant are described below.

Enhanced Geothermal

While conventional geothermal requires the natural occurrence of heat, water, and permeability, enhanced geothermal systems (EGS) only require the presence of hot rock. The permeability of the rock and the fluid are engineered through sub-surface fracturing and injection wells. Because hot rock exists everywhere beneath the Earth's surface (at varying depths), the geographic potential for EGS as a resource is greater than conventional geothermal. In addition to EGS, there is a further emerging technology known as "super hot rock" EGS, which taps into rock 400° Celsius and greater and at depths 5 kilometers and greater (often closer to 20 kilometers) – significantly amplifying the energy potential of the resource. However, to tap into super hot rock EGS, technological advances must occur in drilling equipment and techniques to safely reach the depths required.

Wave Energy

Beyond traditional hydroelectric power, there are other energy resources that can be derived from the naturally occurring phenomenon in the Earth's oceans and rivers and harnessed into electricity, including currents, tides, and waves. While all are considered emerging, wave energy appears to be an appealing match for the Pacific Northwest power system because of the high energy potential along the Pacific coastline from California to Alaska. Wave power devices and converters capture energy through motion at the surface or through the pressure fluctuations from the waves below the surface. While highly seasonal and subject to storm-driven peaks, wave energy is relatively continuous and predictable. In the region there is a grid-connected, pre-permitted, open ocean wave energy test facility, which is the only one of its kind in the nation.[89] This project, operated by PacWave and Oregon State University, is a meaningful step in testing the viability of wave energy in the US and moving the technology towards commercial.

Summary Table

The summary of the reference plant is captured in Table G - 37.

[89] https://pacwaveenergy.org.

Table G - 37: Clean Baseload Proxy Resource Reference Plant Summary Table

Reference Plant	Clean Baseload Proxy
Configuration	Small Modular Reactor
Year Available to Model	2035
Development/Construction Period (Years)	5
Capacity (MW)	600
Heat Rate	9800 Btu/kWh
Overnight Capital Cost ($/kW)	9000
Fixed O&M Cost ($/kW-yr)	120
Variable O&M ($/MWh)	4.50
Economic Life (years)	30
Max Buildout	3000 MW

Clean Long Duration Storage

Characteristics

A more dynamic and variable grid requires more flexibility to operate effectively. An energy system more reliant on renewables, and therefore a variable fuel source, can still be a balanced and reliable one thanks to its capabilities to store excess energy that is produced when there's less demand, and shift it to be used when it's needed. Recent storage adoption trends reinforce this. The most common and available storage resource currently is the lithium-ion battery, which is discussed above. This shorter duration storage can store 4-8 hours of electricity, which means that shifting is only happening within a day. Storage that has a longer duration (the ability to shift between days or seasons) might be beneficial to the system by providing further variable resource integration and operational flexibility. The intention of the clean long duration storage proxy is to test that assertion, as well as to test which resources it pairs well with and how the system might use that flexibility.

There is more than one long duration storage resource that exhibits these characteristics and could provide flexibility to the future system. A single representative technology was selected as the basis for the proxy, due to relative technology maturity and regional interest, but there are other ways to address the same need that have the potential for storing energy for longer durations. Those broad storage mechanisms and some of the ways they are employed are described at the end of the section.

Proxy Specifics: Iron Air Battery

With factories in production and successfully completed test projects, the long duration energy storage technology closest to commercial readiness is the iron air battery.

Iron air batteries employ reverse rusting. On discharge the battery uses oxygen from the air to convert iron metal into rust. When charging an electrical current, the battery converts the rust back to iron and releases oxygen. The battery features a thin sheet cathode on one side, an anode made of powdered iron held together with mesh on the other, and a water-based electrolyte in the middle. Air passes through the cathode and reacts with the electrolyte creating negatively charged hydroxide ions on the inside surface of the cathode. That surface crowds with ions and they then move toward the iron, latching on and creating iron hydroxide, or rust. That causes the ions give up electrons, which are guided out of the battery in the form of an electrical current. After 100 hours, that iron is totally rusted through, and the battery runs out.

To recharge the battery – to "unrust" it – a current is sent back through the system, reversing the chemical reactions. Introducing electrical current into the system breaks the rust back down into its oxygen and iron components. The oxygen leaves the cell as bubbles; the iron is left whole and metallic again.[90]

This cycle is durable and repeatable, though not particularly efficient – the round-trip efficiency is about 40%. The batteries operate modularly, with each power block only requiring a third- to a half-acre per megawatt. This relatively small footprint and modularity make these batteries easy to site near where they're most needed. Compare the footprint to the approximately five acres per megawatt needed for a solar farm, as well as the 24-125 acres per megawatt for a wind facility.[91]

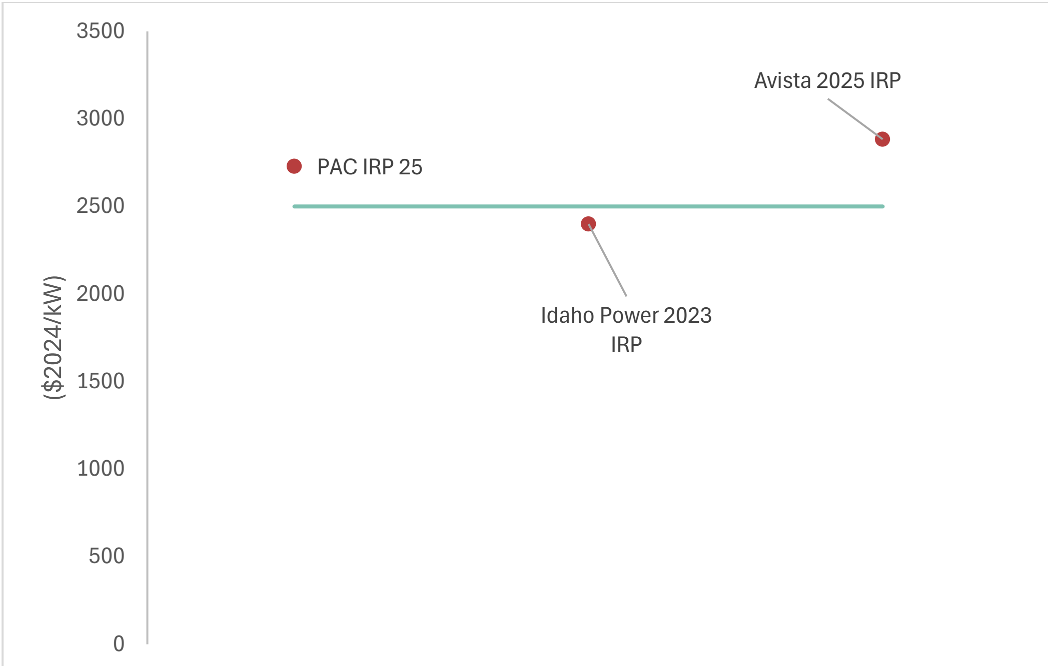
This proxy plant is specifically based on Form Energy's Iron Air Battery, because they are currently the only producer of the technology.[92] Early in Ninth Plan's time period, the technology's availability is based on Form's current production capabilities. However, later in the power plan period, the maximum buildout allowed by the models is expanded to capture future development in this space – either by Form or by other technologies that fill the same niche.

Costs

Iron air batteries show up in regional IRPs and there has been significant interest for the technology in the region. However, it is not yet in the larger national reports and studies that fill out many other technologies' literature reviews. Figure G - 66 below shows what data were collected.

[90] https://www.pbs.org/wgbh/nova/article/iron-air-battery-renewable-grid.
[91] https://www.energy.gov/sites/prod/files/2019/05/f63/gagne-rule-thumb-ppt.pdf.
[92] https://formenergy.com/technology/battery-technology.

Figure G - 66: Literature Review of Iron Air Battery Overnight Capital Costs



The literature review of iron air battery overnight capital costs coalesces around $2500/kW, shown by the light blue line. This final cost is also informed by conversations with Form Energy about the specifics of their technology and their recommendation for modeling its operations. The information they shared with Council staff is shown in Table G - 38 and was intended to support modeling of the iron air technology in planning applications such as IRPs or, in the case of the Council, a regional power plan. These numbers were then gut-checked by the Council's Generating Resource Advisory Committee, so as to not take marketing numbers at face value.

Table G - 38: Iron-Air Cost and Performance from Form Energy Performance Specs[93]

Discharge duration at full rated capacity	100 hours
SKU1 (1x charge power), All-in installed capital cost ($/kWh)*	$15 – $20
SKU2 (2x charge power), All-in installed capital cost ($/kWh)*	$18 – $23
Fixed O&M ($/kW-year, Yr 1 dollars)	$15 – $20
Round trip efficiency**	40 – 45%
Charge efficiency	69 – 73%
Discharge efficiency	58 – 62%

[93] https://formenergy.com/wp-content/uploads/2025/01/Navigating-the-Pacific-Northwests-Energy-Challenges.pdf.

Annual discharge throughput limit	1,500 – 2,000 equivalent hours at full power
Enclosure lifetime	15 – 20 years
Power degradation	0% / year
Energy capacity degradation	2% / year
Energy efficiency degradation	0.5% / year

* Landed costs of the AC modular power block at ~100mw scale, inclusive of EPC, developer costs, and grid interconnection costs.
** AC-AC round trip efficiency, full charge and full discharge at rated power, inclusive of losses from power conversion and auxiliary loads.

Alternative Technologies

Other technologies can store energy for longer durations than the standard 4-hours of lithium-ion batteries. A few additional forms of storage are described below.

Electrochemical Energy Storage

Electrochemical energy storage stores energy of chemical reactions, where electrical energy is converted to chemical energy and vice versa. Metal anode batteries are the most straightforward example of the storage type, with lithium-ion batteries being one of the most common commercial storage types. However other metal types can be applied as in lead-acid and sodium sulfur batteries. Flow batteries are another type of electrochemical storage, working by pumping negative and positive electrolytes through energized electrodes in electrochemical reactors (stacks), allowing energy to be stored and released as needed. Vanadium redox flow batteries are currently the most technologically mature flow battery type, with a number of pilots and small-scale plants installed and operating across the world.[94]

Iron air batteries are another means of harnessing electrochemical storage. The iron air battery forms the basis of our proxy reference plant.

Mechanical Energy Storage

Mechanical energy storage stores kinetic or potential energy by compression, gravity, or rotation, prototypically exemplified by pumped hydro storage. Other versions of mechanical storage are gravity-based, which raises concrete blocks to store energy and lowers them to generate electricity, and compressed air energy storage (CAES)/liquid air energy storage (LAES), which use compression and expansion to store excess energy. Many of these forms of mechanical energy storage are being pursued in the industry. Hydrostor has developed a CAES technology with projects globally, as well as

[94] https://batterycouncil.org/battery-facts-and-applications/about-flow-batteries.

in California, under development.[95] While Energy Vault has gravity energy storage systems already operating, more are scheduled in the coming years.[96]

Thermal Energy Storage

Thermal energy storage stores energy as heat. One version of such storage technology is sensible heat (molten salts), which heat low-cost materials (such as salt) to high temperatures to generate steam. Another version is latent heat, which uses phase change technology to liquefy air at low temperatures and then convert it back into gas to drive electricity production. The most common version of this storage type is concentrated solar power that stores solar energy thermally and then dispatches it as a battery.[97] This technology has existed for some time, but has not reached the commercial penetration of traditional solar PV.

Summary Table

The summary of the reference plant is captured in Table G - 39.

[95] https://hydrostor.ca/projects.
[96] https://www.energyvault.com/products/g-vault-gravity-energy-storage.
[97] https://www.solarpaces.org/how-csp-thermal-energy-storage-works.

Table G - 39: Clean Long Duration Storage Proxy Resource Reference Plant Summary Table

Reference Plant	Clean Long Duration Storage Proxy
Configuration	Iron Air Battery-100hr
Year Available to Model	2030
Development/Construction Period (Years)	2
Round trip Efficiency	40%
Overnight Capital Cost ($/kW)	2500
Fixed O&M Cost ($/kW-yr)	20
Variable O&M ($/MWh)	0
Economic Life (years)	30
Max Buildout	1000 MW (2040) +2000 MW (by 2046) 3000 MW total

Clean Peaker with Medium Duration Storage

Characteristics

Another potential problem that might arise on the existing grid is high peak loads that must be met quickly, yet only briefly. In the current system those spikes in demand are often met by natural gas peaker plants, which are on-demand and can be turned on and off quickly. However, as policies push towards decarbonization, a clean alternative might be necessary to fill that gap. This need can be served by a storage resource that operates on a daily or hourly scale, or by a similar combustion technology utilizing a cleaner fuel. The proposed clean peaker/mid-duration storage proxy plant would serve as that resource. Including it in this plan will test the grid's need for such a technology, as well as the type of resource mix selected around it. However, as with the other emerging technology proxies, there are other technologies that could do the same job. A few of these technologies are described below.

Proxy Specifics: Hydrogen Combustion Turbine with Onsite Electrolysis

The technology selected to serve as the basis for the proxy is an all-hydrogen burning combustion turbine with onsite hydrogen production and storage via clean electrolysis. Hydrogen was selected as the representative technology because there is a lot of interest in hydrogen in the region and nationally. Many utility IRPs also consider hydrogen. These plants operate similar to the traditional combustion technologies of coal and natural gas, but rely on a non-emitting fuel. This makes it potentially a nice fit for the existing system to meet clean policies. However, there is no existing infrastructure for hydrogen, and most forecasts do not show significant hydrogen for power use until the 2040s.[98] Non-power applications are forecast sooner,[99] and discussion of that and its implications for the grid can be found in Technical Appendix F – Electricity Demand Forecast.

The proxy hydrogen resource selected as the basis for the reference plant does not rely on new pipeline infrastructure or a whole hydrogen economy. Rather, it behaves like a peaker plant with onsite production and storage. The process of splitting water into hydrogen and oxygen gases requires a significant amount of electricity, which the Council models similar to other storage resources with a load impact. This results in a resource that essentially operates as a medium duration storage plant. The hydrogen would be produced by electrolysis via polymer electrolyte membrane (PEM) electrolyzer and stored onsite in 24-hour tanks, ready to be used when needed.

Availability

Many of the operating characteristics of the hydrogen proxy are based on the simple cycle frame turbine because that technology combusts the hydrogen fuel and produces electricity. This means that the discrete size of the proxy plant is set at 250 MW in a mirror of the SSCT frame reference plant. Similarly, the heat rate, or the thermal efficiency of combusting the hydrogen for electricity, is the same as the frame plant, 9800 Btu/kWh.

The medium duration aspect of the proxy resource is from the PEM electrolyzer, which produces the hydrogen vie electricity. As a storage resource it has a system efficiency measured through the discharge/recharge cycle. The ratio of useful energy output to useful energy input, or the round-trip efficiency, is relatively low, meaning the process is fairly inefficient with an RTE of 40%.[100,101]

Costs

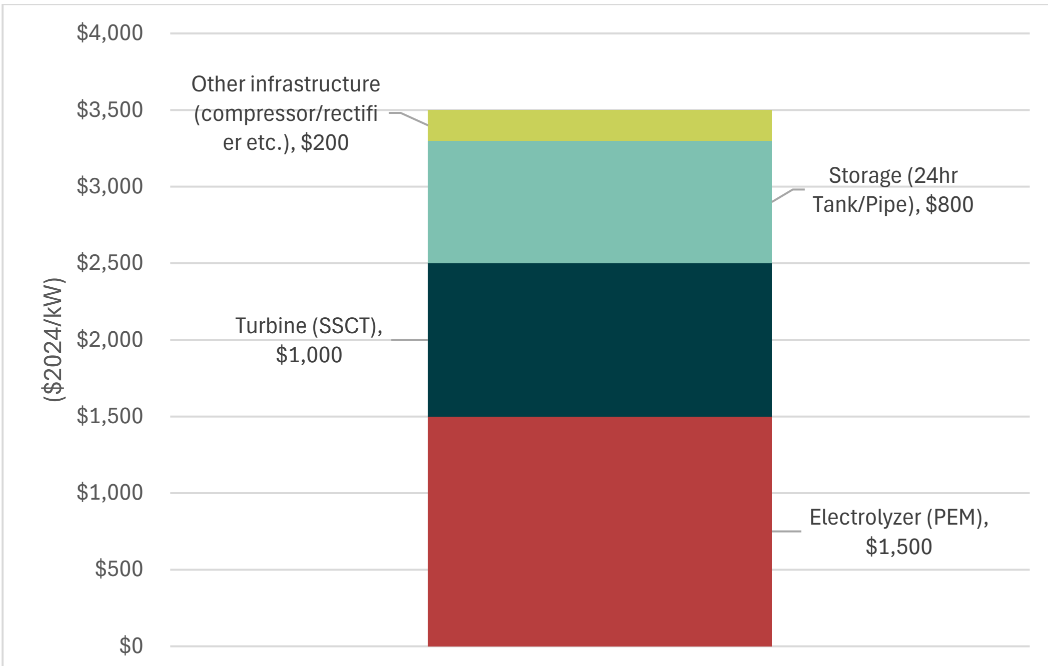
This hydrogen proxy plant total cost was built up by combining the component parts necessary to operate the plant as described. Those parts are described below and their costs are shown in Figure G - 67.

- PEM electrolyzer: Produces the hydrogen on site and is the main cost component.
- Storage system: Stores the produced hydrogen for future use in a 24-hour tank/pipe. Geologic storage was considered, but was determined to be too geographically constraining.

[98] https://h2fcp.org/system/files/cafcp_members/2024%20DOE%20Pathways%20to%20Commercial%20Liftoff%20-%20Clean%20Hydrogen.pdf.
[99] https://www.hydrogen.energy.gov/docs/hydrogenprogramlibraries/pdfs/us-national-clean-hydrogen-strategy-roadmap.pdf?sfvrsn=c425b44f_5.
[100] https://www.sandia.gov/app/uploads/sites/163/2022/03/ESHB_Ch11_Hydrogen_Headley.pdf.
[101] https://www.cell.com/joule/fulltext/S2542-4351(21)00306-8.

- Combustion turbine: Uses the hydrogen fuel to produce electricity. This technology is essentially the same as a new simple cycle turbine and its costs were based off the simple cycle turbine reference plant costs.
- Any additional infrastructure: Includes things such as the compressor and rectifier which are necessary for running the plant.

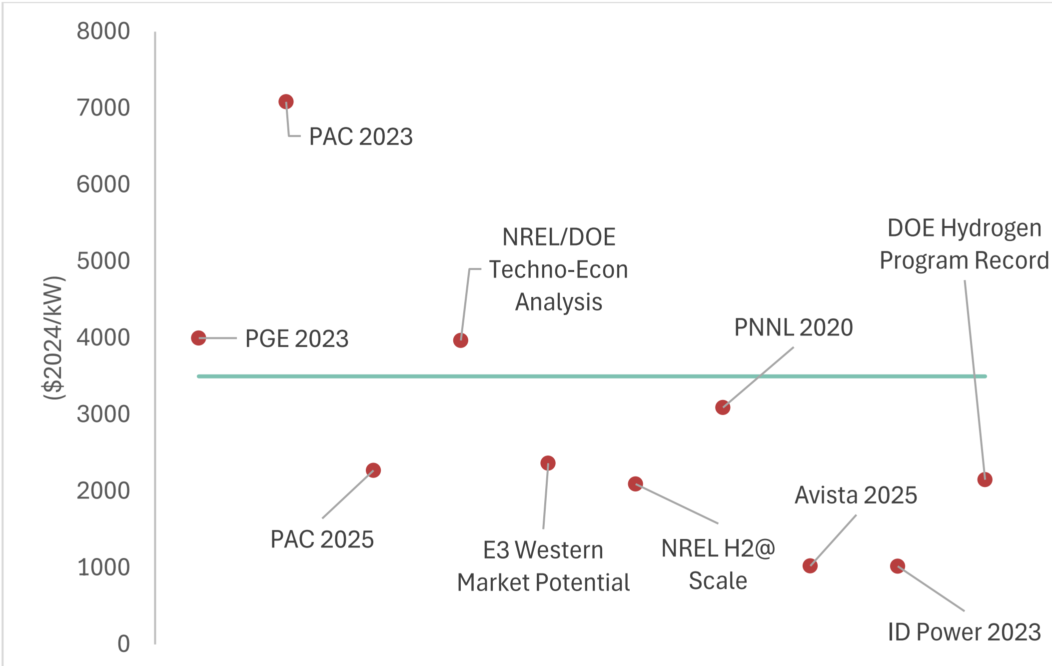
Figure G - 67: Hydrogen Proxy Plant Costs[102]



The data points in Figure G - 68 are not perfectly comparable costs, as the different sources refer to different configurations of different components. The most complete cost for our purposes is from the NLR/DOE Techno-Economic Analysis.[103] The literature review seen plotted in Figure G - 68, groups around $3500/kW, shown by the light blue line. Variable and fixed O&M for the hydrogen proxy resource are based off of the simple cycle combustion turbine operation costs for lack of alternative cost data for hydrogen specific plants.

[102] https://www.cell.com/joule/fulltext/S2542-4351(21)00306-8.
[103] Ibid.

Figure G - 68: Literature Review of Hydrogen Peaker Overnight Capital Costs



Alternative Technologies

Flywheel Energy Storage

Flywheels store energy by spinning a rotor in a low-friction enclosure, which changes speed when moving energy to or from the grid. They are mainly used in this peaking capacity for grid management, especially frequency control due to their rapid discharge. Flywheel storage power systems are currently operating at various scales across the world. The largest deployment of grid-scale flywheel storage is a 30 MW plant in China that was connected to the grid in 2024.[104] Beacon Power operates 2 20MW plants in Pennsylvania and New York State,[105] while Temporal Power operates smaller scale installations (2-5 MW) in Canada and Aruba.[106] While the technology has proven its reliability, it is not yet commercially available at scale.

Alternative Hydrogen Sources (Ammonia and Hydrogen via Pyrolysis)

Hydrogen can be used in a simple cycle turbine as a clean fuel alternative to natural gas. There is more than one way to produce hydrogen fuel. All modes of producing hydrogen take energy and can therefore be used as a form of storage.

[104] https://www.ess-news.com/2024/09/13/china-connects-its-first-large-scale-flywheel-storage-project-to-grid.
[105] https://beaconpower.com/operating-plants.
[106] https://ieso.ca/en/Powering-Tomorrow/2017/High-Performance-Flywheel-Energy-Storage-Systems-Temporal-Power.

Ammonia is the most efficient carrier for transporting and storing hydrogen as it takes up less space than hydrogen in its gaseous form. Applying high heat to ammonia (NH3) can 'crack' it into nitrogen (N2) and hydrogen (H2) once it is transported to its destination. Ammonia production is not necessarily clean, as it is typically derived from natural gas via steam methane reforming. Currently ammonia is primarily used in producing fertilizer, but there has been recent interest in its potential role in a future hydrogen economy.[107]

Hydrogen can also be produced via pyrolysis, which is a process that applies high heat to methane gas in an oxygen-free environment to produce hydrogen and a solid carbon byproduct. Northwest Natural began a three-year pilot project in 2024 that explores potential hydrogen applications with hydrogen produced via pyrolysis, particular blending hydrogen with natural gas to reduce the carbon intensity of its combustion.[108] The Council's Generating Resources Advisory Committee discussed this technology as a less electricity intensive process for producing hydrogen. Ultimately, the Council did not develop this into a reference plant due to insufficient data about large-scale project costs and availability, as well as the usage of natural gas.

Summary Table

The summary of the reference plant is captured in Table G - 40.

[107] https://kleinmanenergy.upenn.edu/research/publications/ammonias-role-in-a-net-zero-hydrogen-economy.
[108] https://s23.q4cdn.com/611156738/files/doc_news/NW-Natural-and-Modern-Hydrogen-Unveil-Clean-Hydrogen-Production-Carbon-Capture-Project-in-Portland-2024.pdf.

Table G - 40: Clean Peaker w. Medium Duration Storage Proxy Resource Reference Plant Summary Table

Reference Plant	Clean Peaker & Mid-Duration Storage Proxy
Configuration	Hydrogen peaker plant with onsite electrolysis
Year Available to Model	2038
Development/Construction Period (Years)	2
Capacity (MW)	250[109]
Roundtrip Efficiency & Heat Rate	40% 9800 Btu/kWh[110]
Overnight Capital Cost ($/kW)	3500
Fixed O&M Cost ($/kW-yr)	16
Variable O&M ($/MWh)	6.50
Economic Life (years)	30
Max Buildout	3000 MW

Levelized Cost of Energy

One way to compare the cost of a generating resource against another is to look at the levelized cost of energy (LCOE), which is a metric used to estimate the price of electric generation across a resource's expected economic life. It is calculated as the cost per unit of energy a resource is expected to generate (under an assumed level of dispatch, or capacity factor) and which also includes variable costs such as fuel. Although the initial capital cost for solar and wind may be higher than gas resources, with minimal operating costs (no fuel purchases), the overall cost of producing energy can be significantly less.

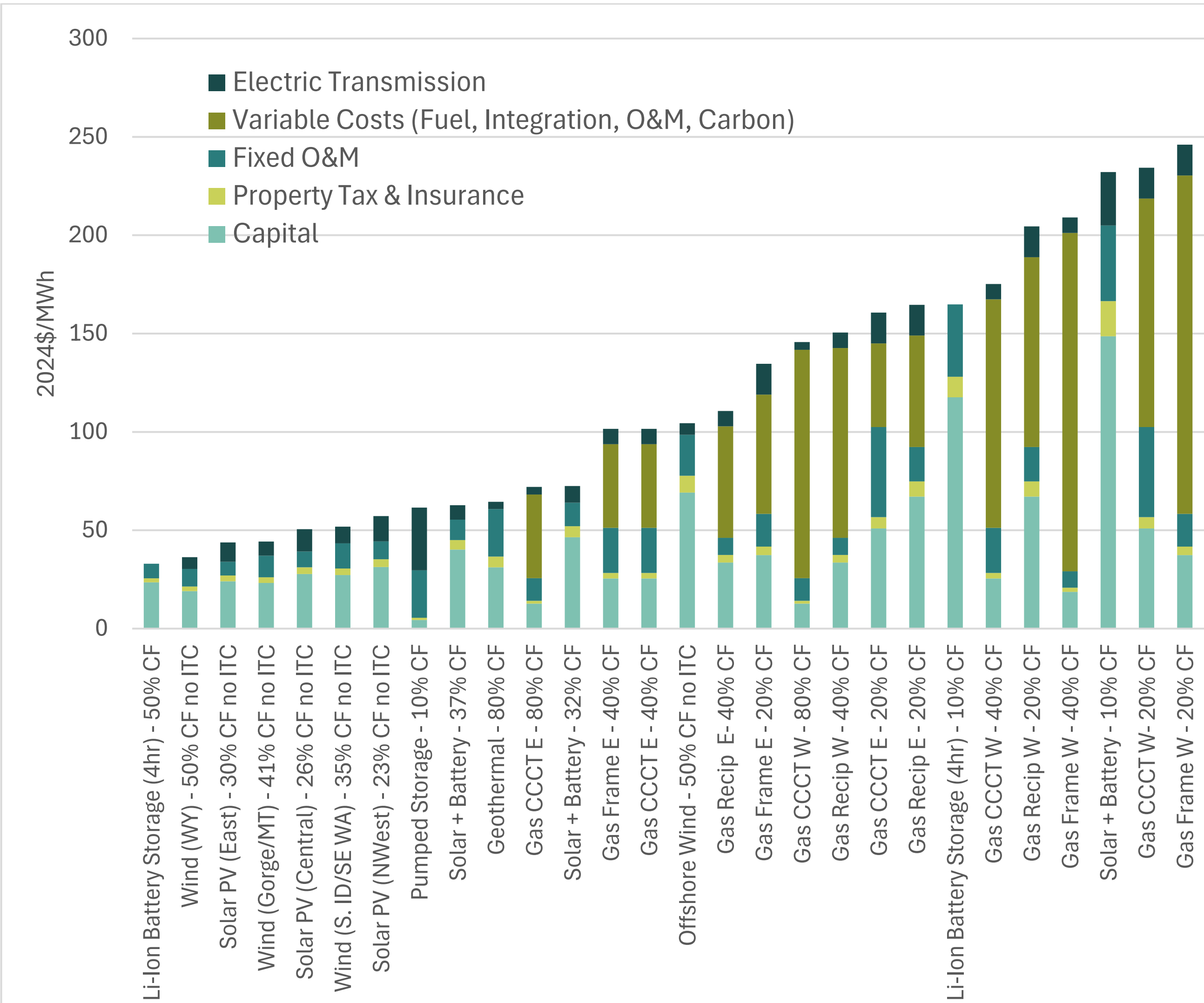
The Council does not use any of the static levelized cost of energy for generating resource reference plants for modeling (as shown in Figure G - 69) because the models are capable of performing dynamic dispatch. LCOE calculations rely on a static assumption of dispatch, which are not accurate in all hours of a dynamic system. Reflecting an assumed dispatch of 60%, for example, would indicate substantially better economics than would be realized if the actual dispatch was closer to 10% in some hours. LCOE calculations are highly dependent on the amalgam of underlying assumptions behind a resource and all of the costs and values accrued over its expected life. These assumptions often vary across studies or sources, making LCOEs complicated to compare.

[109] Based off of the size of a simple cycle combustion turbine.
[110] Based off of the size of a simple cycle combustion turbine.

MicroFin

MicroFin Is the Council's financial revenue requirements model used to calculate levelized fixed cost and LCOE that allow resources to be competed against each other. The levelized costs produced by MicroFin can be used as an illustrative metric for comparison between generating resource alternatives. Figure G - 69 shows the levelized costs of some of the Ninth Plan reference plants in order of least to most costly.

Figure G - 69: Reference Plants' Levelized Cost of Energy Estimates



As described in the section above, these costs on their own aren't particularly useful due to the flattening assumptions required to achieve a static representation of a dynamic system. However, it can reveal some useful trends when considering the resources in relationship to each other. For example, it is notable in Figure G - 69 that the bulk of the natural gas resource's costs are the olive green bar for variable costs, namely fuel, which puts them closer to the end of the chart over the resources with no fuel costs. Another trend the figure illustrates is the importance of a resource's capacity factor. Higher capacity renewable resources, like wind in Wyoming or solar in the east portion of the Northwest where those resources are more abundant, drive the levelized costs down.

Uncertainty

These reference plants are intended to represent a typical given resource and are therefore generalizations by design. The work of power planning always takes place under uncertainty, and some of that uncertainty comes from the necessary imprecision of these defined resource choices. One way the Council is accounting for that uncertainty in the Ninth Plan is through scenario analysis. The Ninth Plan includes the Resource and Transmission Risk Scenario designed to test the impact and risk of changing resource availability, resource costs, and transmission availability. Different sensitivities will explore how changing resource characteristics might change the resource mix selected by the model. This analysis is intended to help the Council learn which resources and in what amounts can be robust across the range of uncertainty, and what resources or suite of resources should be built to mitigate different risks. Figure G - 70 describes the resource and transmission risk sensitivities and what questions they will be testing.[111]

Figure G - 70: Scenario Analysis Sensitivity Identified and Described

Constrained New Resources and Transmission Options	How would new resource additions change with limitations on what the region can build?
Changing Transmission Availability	How does the pace of transmission development impact new resource selection for the region?
Changing Emerging Technology Costs	How does the uncertainty around the cost of emerging technologies impact the new resource selection?
Limited Short-Duration Storage Availability	How would new resource additions change if the amount of new storage available was limited?
Slower Demand Side Resource Availability	How would new resource additions change if demand side resources took longer to develop?
Evolving Federal Policy Landscape	How do changes at the federal level impact resource decisions in the region?

[111] More information on the scenarios and sensitivities explored in the Ninth Power Plan can be found in Appendix N – Scenario Modeling and Results.

Constrained World Sensitivity

The Constrained World Sensitivity is designed to capture the risk associated with the ability to build new resources and transmission, as well as uncertainty around emerging resource opportunities.

For primary and limited availability supply-side resources, the Council assumed higher costs and limited the near-term availability (the first six years). This sensitivity also assumes a ten-year delay of emerging technology resources.

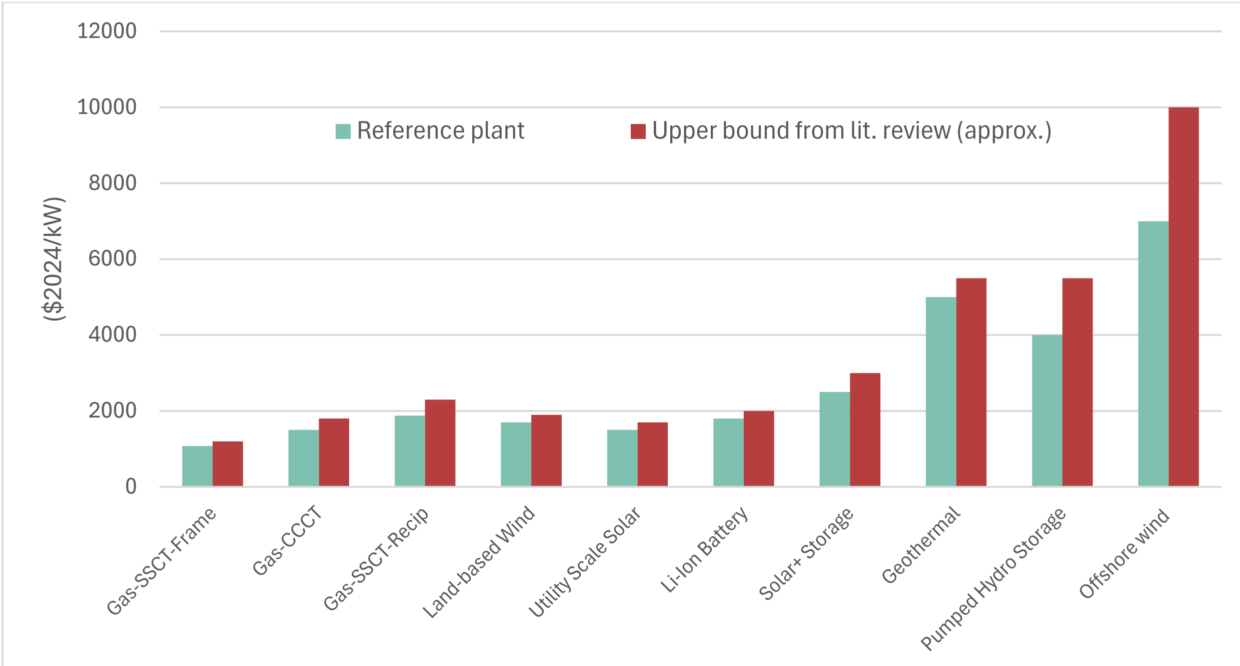
The higher resource costs are based on the upper bound price found in the literature review of each resource. Notably, the limited availability resources have a larger range, likely by virtue of being site-specific and more challenging to generalize. These high costs are captured in Table G - 41 and Figure G - 71.

Table G - 41: Upper Bound Capital Cost from Resource Literature Review

	Upper bound from lit. review [112](2024$)	Reference Plant Overnight Capital Cost (2024$)	Cost Change (2024$)	Percent Change in Cost
Gas-SSCT-Frame	1200	1078	122	11%
Gas-CCCT	1800	1500	300	20%
Gas-SSCT-Recip	2300	1878	422	22%
Land-based Wind	1900	1700	200	12%
Utility Scale Solar	1700	1500	200	13%
Li-Ion Battery	2000	1800	200	11%
Solar+ Storage	3000	2500	500	20%
Geothermal	5500	5000	500	10%
Pumped Hydro Storage	5500	4000	1500	38%
Offshore wind	10000	7000	3000	43%

[112] Details behind these higher cost levels can be found in this workbook: https://nwcouncil.box.com/v/9thPlanRefPlantCosts. They have been rounded to the nearest hundred for ease, and to avoid false precision.

Figure G - 71: Resource Cost Change in Constrained World Scenario



The build limit in this scenario is set to roughly half the limit assumed in for the reference build limit of other sensitivities. Table G - 42 shows the assumed annual build limit in megawatts for each year modeled in the scenario modeling.

Table G - 42: Annual Build Limit in Constrained World Sensitivity

Year	2028	2030	2032
Annual Build Limit (MW)	2,600	6,900	12,100

Limited Battery Storage Sensitivity

The Limited Battery Storage Sensitivity explores the impacts of near-term limitations on the availability of short-duration, lithium-ion, batteries. It limits the amount of battery acquisition that can occur in the action plan period, or the first six years of the study. The dampened availability will be set by a similar logic of the build limit in the constrained world scenario, based on the annual real world planned builds for upcoming years. The cumulative build maximum is shown by two-year increments in Table G - 43, with 3000MW of batteries allowed by 2028, 3500MW by 2030 and 4350MW by 2032 at the end of the action plan period.

Table G - 43: Annual Build Limit in Limited Battery Storage Sensitivity

Year	2028	2030	2032
Planned Batteries Only (MW)	3000	3500	4350

Variable Emerging Technology Costs Sensitivity

Recognizing the inherent uncertainty in emerging technology costs, this sensitivity explores the price points different emerging resources might make more sense for future needs.

This sensitivity will test both an increase in cost by 50% and a decrease in cost of 25%. This is based on the range of SMR costs in the literature review. This range is shown in Figure G - 72. The high end, shaded in blue, shows the 50% increase and the low end is captured by the 25% decrease, shaded in yellow. The cost variance is applied to the emerging technology overnight capital costs in Table G - 44.

Figure G - 72: Illustrative Cost Range of Emerging Technology Proxy

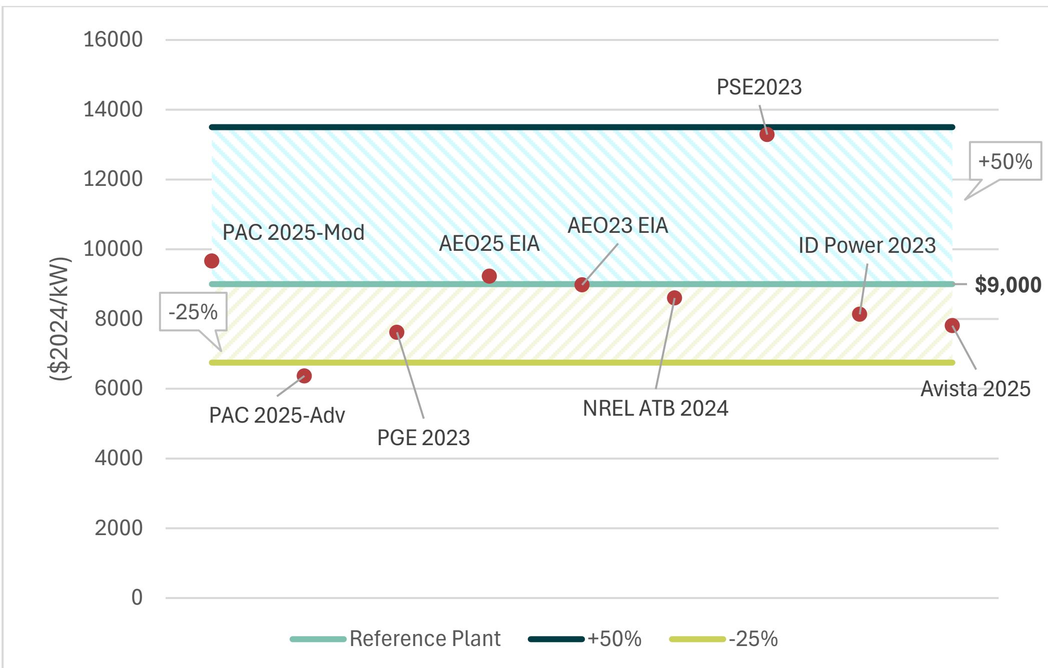


Table G - 44: Variable Capital Costs of Proxy Emerging Technologies for Scenario Analysis

ET Resource	25% Less	Proxy Plant OCC (2024$)	50% More
Clean Baseload (SMR)	$6750	$9000	$13500
Clean Mid-Duration Storage (H2)	$2625	$3500	$5250
Clean Long-Duration Storage (FE-air)	$1875	$2500	$3750

Evolving Federal Landscape

Over a 20-year planning horizon, there are always elements of policy uncertainty, and this sensitivity is designed to test how much policy decisions at the federal level impact resource decisions in the region. This felt especially pertinent given the distinct policy shift between administrations that occurred in the early days of this planning cycle. Most of the Ninth Plan will reflect the current administration's policies, because those are the ones currently enacted as law. However, one scenario explores changing hydro operations began analysis before the One Big Beautiful Bill Act was enacted in July 2025, and therefore reflects previous policies.[113]

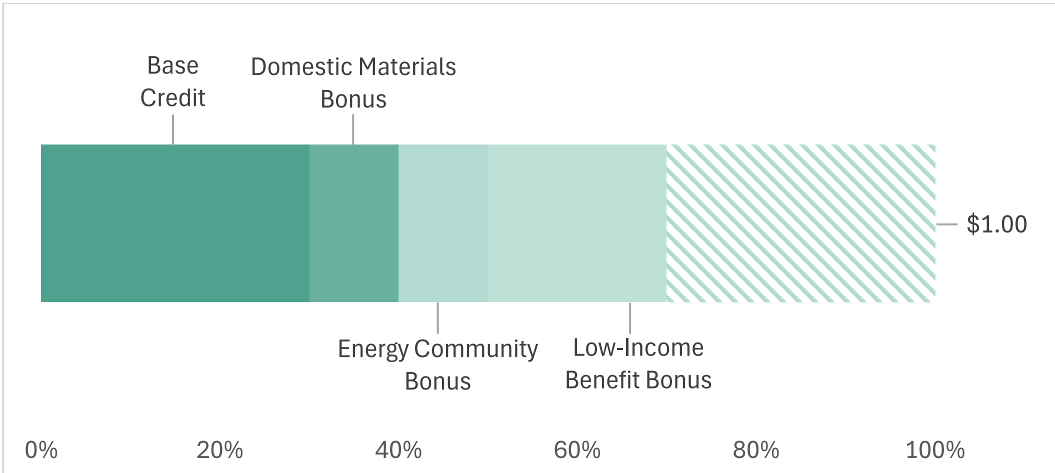
By design, one other sensitivity will not reflect current policy, which is the evolving federal landscape sensitivity. In this sensitivity, new clean resources will receive tax credits, similar to those enacted by the Inflation Reduction Act (IRA). The sensitivity also assumes the new source emissions requirements under the Clean Air Act as updated by the IRA. These tax credits will apply to all non-emitting technologies and the clean air requirements will concern new combined cycle combustion turbines. These assumptions will be based on those from the IRA and would come into effect in 2030. The other sensitivities in the new resource and transmission risk scenario will reflect the current policy landscape without clean tax credits for renewables, specifically wind and solar, or updated emissions requirements. More about the broader application and reasoning of this sensitivity is described in Technical Appendix B – Existing System Parameters and Policies.

Tax Credits

The Inflation Reduction Act (IRA) extended and expanded tax credits for clean generating resources, making tax credits technology neutral and allowing developers to choose between the investment (ITC) or production (PTC) tax credits for their project.

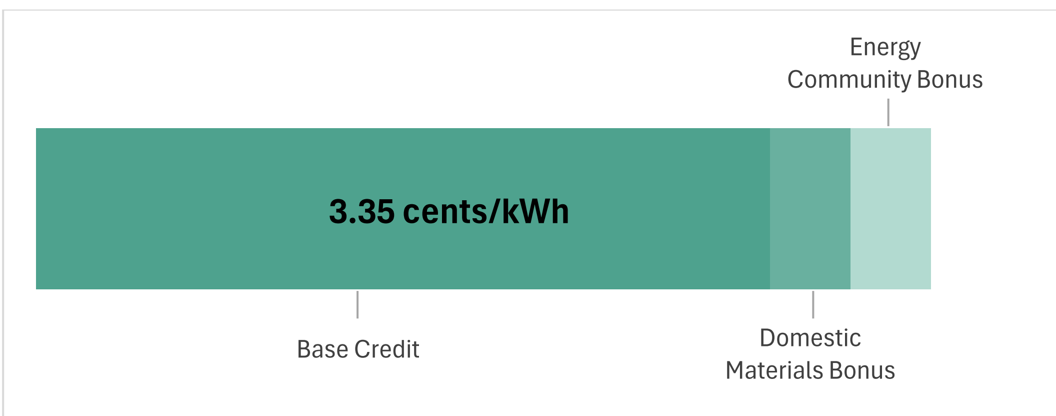
[113] This scenario is described in Technical Appendix N – Scenario Modeling and Results.

Figure G - 73: Investment Tax Credit, Per Dollar Spent on Eligible Project



Per the IRA, resources taking the investment tax credit (ITC) could receive up to 70% back for every dollar spent in the development of the eligible resource. For the plan's purposes, in the evolving federal landscape sensitivity clean resource will receive the 30% base credit. The domestic materials, energy community, and low-income bonus were less universal and more site specific, so they were excluded from modeling of generic resources.

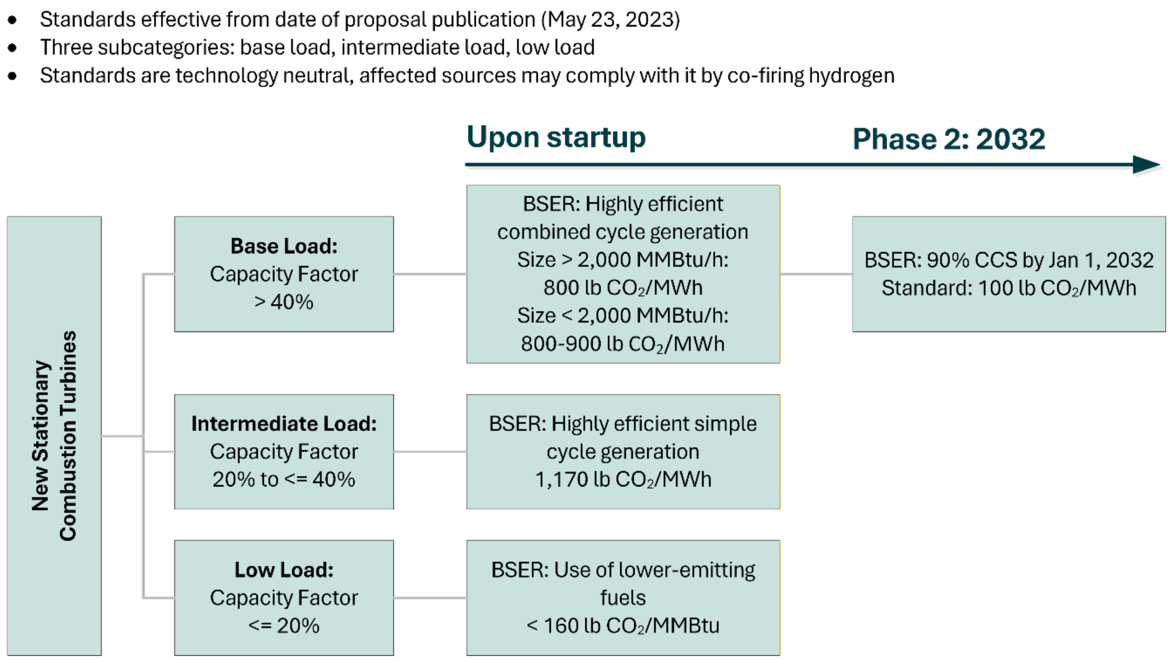
Figure G - 74: Production Tax Credit, Per Kilowatt Produced by Eligible Project



The IRA also made a production tax credit (PTC) available for any clean resource. This means that for the production of 1kW, the producer could get up to 3.35 cents. However, for this sensitivity the Council chose to just model the ITC at the Generating Resource Advisory Committee's recommendation. It was decided that the ITC would be selected more often given how the political volatility of the current moment tends to create uncertainty around the ongoing availability of any tax credits, making the upfront payment of the ITC more appealing.

Clean Air Act Assumptions

Figure G - 75: Clean Air Act 111(b) Standard for New Stationary Combustion Turbines



(Figure adapted from the EPA’s Final Standards for New Stationary Combustion Turbines)

The new administration withdrew one other aspect of the IRA pertaining to updates to the Clean Air Act, specifically to 111(b) concerning emissions standards for new stationary combustion turbines. The policy change applied specifically to base load combustion turbines with a capacity factor above 40%, which was read to mean combined cycle combustion turbines, as simple cycles operate a much lower capacity factors traditionally. The updated standard, described in Figure G - 75, requires baseload turbines to adopt 90% carbon capture and storage by 2032. The way this will be represented in modeling for this sensitivity is by limiting the capacity of new combined cycle combustion turbine to below 40% after 2031, as a sort of proxy for the carbon capture, which is still a fairly emergent technology. After the roll-back of the IRA, the standard reverted to best system of emission reduction (BSER). In practice, this means baseload natural gas will be able to operate without any capacity limitations in the other scenarios.