Chapter 10. Resource economics

As Portland General Electric (PGE) makes the energy transition to a decarbonized system, there are many elements to be considered. The economics of resources represent a crucial element of these dynamics within IRP analyses. In this chapter, we describe the relevant costs associated with each resource and summarize the associated benefits. We also visualize how resource comparisons can occur outside portfolio analysis by comparing resources on a net cost basis, which becomes the basis for the avoided cost approach.

Chapter highlights

- Resource costs are primarily a function of fixed costs in the current planning environment.
- With different resources providing disparate benefits, such as providing energy benefits and storage providing capacity benefits, resource competition is evolving within those two categories.
- The inclusion of non-cost-effective Distributed Energy Resources (DER) provides insight into how their role can be further magnified in a decarbonized future.
- The relative costs and benefits of different energy and capacity resources that will form the basis for resource selections in portfolio analysis are displayed.

10.1 Fixed costs

Fixed costs for new resource options in the 2023 IRP consist of fixed capital carrying costs and fixed operating costs. Fixed cost calculations are based on resource-specific data and PGE-specific assumptions, including the cost of capital, long-term inflation and taxes. To streamline resource modeling, costs that are technically variable in nature (as in, costs vary with a resource's energy generation) are included in the fixed cost calculation (**Table 45**). These costs generally have a fixed generation pattern in PGE's dispatch modeling **Appendix H, 2023 IRP modeling details**. As a result of this dispatch modeling treatment, the annual generation of variable wind and solar resources is known and can be assumed as a fixed quantity. A summary of the types of items included in PGE's fixed cost modeling is provided in the following table.

Table 45. Fixed cost calculation data and assumptions

Fixed capital carrying costs	Fixed operating costs	Variable operating costs treated as fixed
Book and tax depreciation	Fixed operation and maintenance costs	Production tax credits (benefit)
Required return	Fixed wheeling costs	Variable energy resource (VER) integration
Property tax and federal and state income tax	Fixed fuel transportation costs	Land lease

Fixed costs for new resources are incorporated into portfolio analysis by applying the annualized fixed cost (on a kW-year basis) for each year in which the resource is included in the portfolio. Annualization of fixed costs occurs over the entire economic life of each resource. Annualized fixed costs are specified by resource vintage (commercial operation date or "COD") to capture the effects of capital cost declines and other time-varying parameters.[276] For each technology, the 2023 IRP analysis examines three different capital cost scenarios (Low, Reference, High) that capture uncertainties in future cost declines (**Figure 68, Figure 69** and **Figure 70**). Resources for which Reference Case capital cost data were derived from the Energy Information Administration Annual Energy Outlook (EIA AEO) information use the EIA reference cost trajectory. All other data are sourced from the National Renewable Energy Laboratory (NREL) Annual Technology Baseline (ATB). These cost projection futures are based on the following possible paths for technological advancement:[277]

Low – NREL ATB Advanced Scenario – Innovations far from market-ready today are successful in the future and have become widespread in the marketplace. New technology architectures could look different from those observed today – public and private R&D investment increases.

Reference – NREL ATB Moderate Scenario – Innovations observed in today's marketplace become more widespread and nearly market-ready innovations come into the marketplace. Public and private research and development (R&D) investment continues at current levels. This scenario may be considered the expected level of technology innovation.

[276] Commercial operation date is defined as the date after which all testing and commissioning have been completed and is the date on which a facility starts to generate power to earn revenue.
[277] NREL. 2021 Electricity ATB, available at: https://atb.nrel.gov/electricity/2021/definitions

High – NREL ATB Conservative Scenario – Historical investments come to market with continued industrial learning. Technology is like that deployed in the marketplace today, with a few changes from technological innovation. Public and private R&D investment decreases.

Figure 68. Fixed cost scenarios for new lithium-ion battery storage resource options

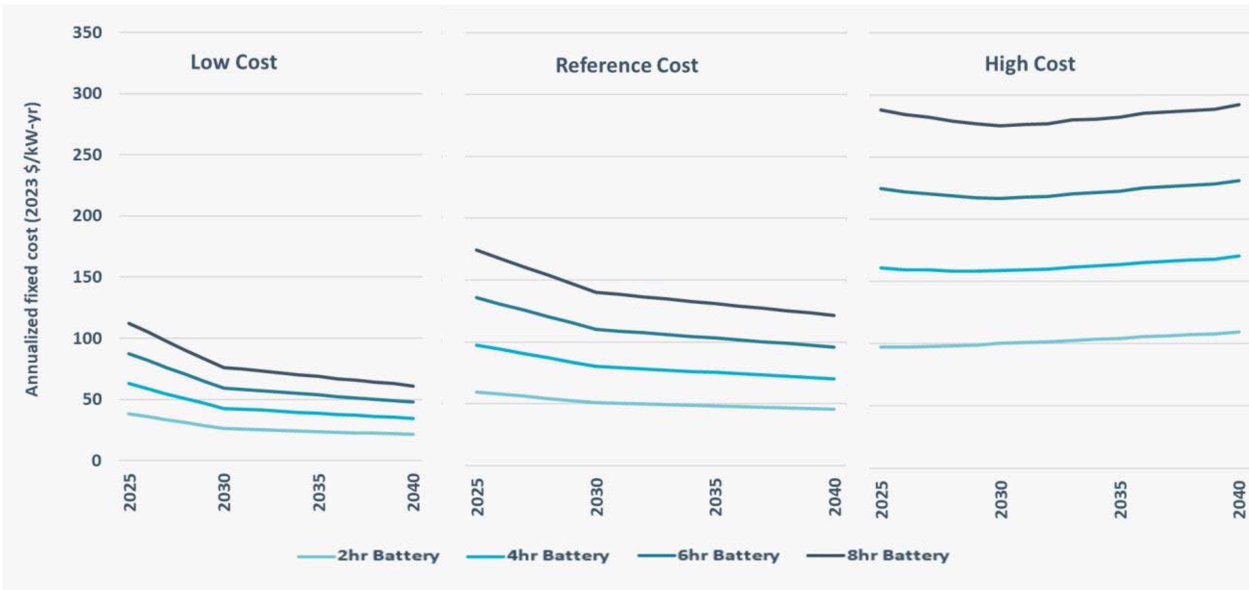


Figure 69. Fixed cost scenarios for new solar Photovoltaic (PV) resource options

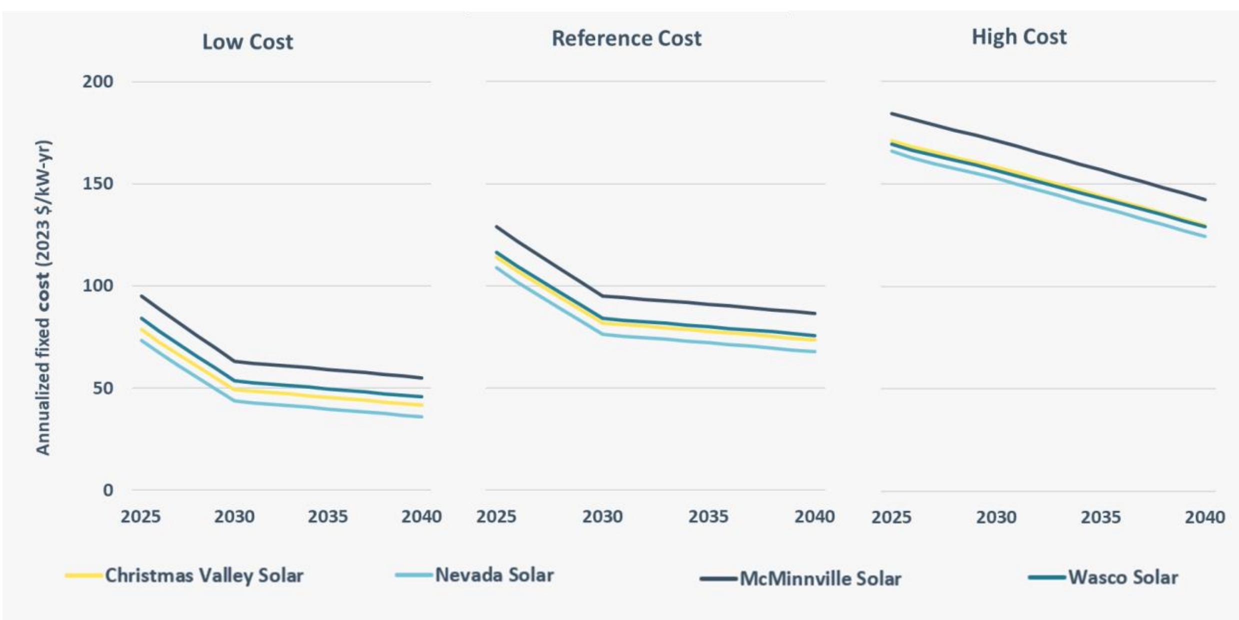
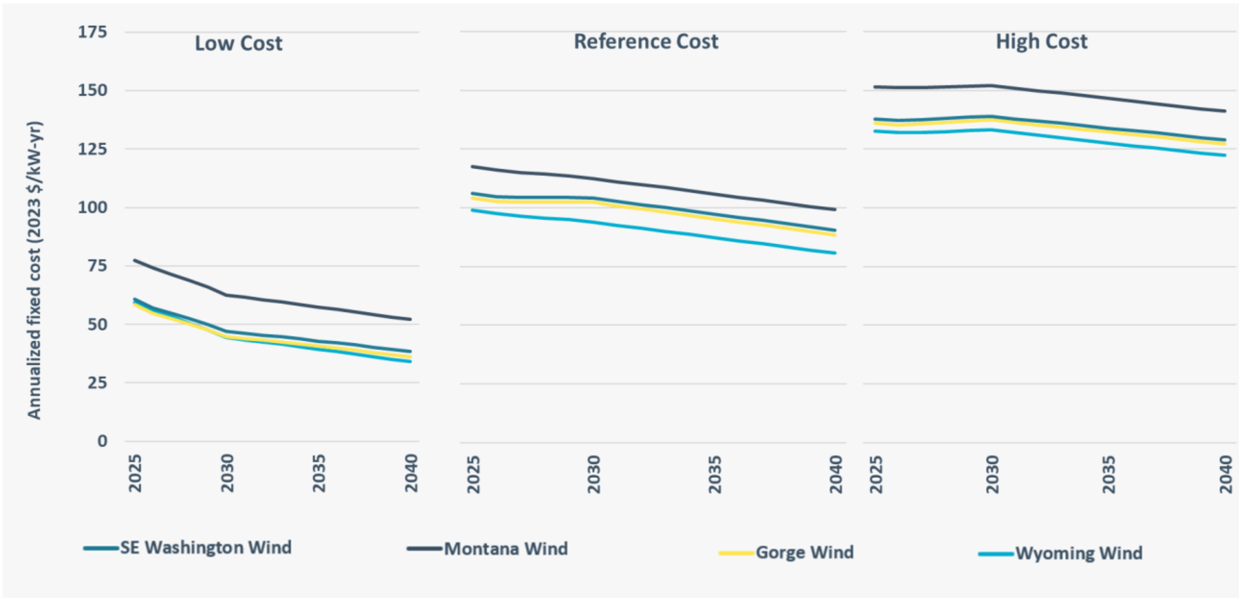


Figure 70. Technology maturity outlook for new onshore wind resource options



10.2 Variable costs

PGE assessed the total levelized variable cost of candidate new resources by performing hourly simulations from 2023 to 2043 of their dispatch across multiple price and input futures. The PZM simulation is used for this analysis as it can maximize resource value given resource availability, input prices and operational constraints. Total variable costs are composed of variable operation and maintenance costs, fuel and start-up costs and the costs associated with emissions, where applicable.[278] **Table 46** summarizes the levelized variable costs for each resource option under the Reference Case over the economic life of each resource option.

[278] All renewable resources are modeled as "must-run" with a fixed hourly shape that is varied by month as identified in **Appendix M, Supply-side options.** Daily operation might impose shutdowns for system balancing reason or because of transmission bottlenecks but such events cannot be foreseen and are therefore not embedded in resource evaluation. Although it is not possible to forecast the expected curtailment for any single resource, a simulation of regional potential curtailment of the total installed wind and solar resources for the Oregon and Washington macro area is presented in **Appendix N, Renewable curtailment**.

Table 46. Levelized variable cost (2023$/MWh) COD 2026[279]

	Levelized variable cost (2023$/MWh)	
	Reference Case	**Range**
Biomass	$51.44	$8.83 - $67.47
Combined-cycle combustion turbine (CCCT)	$20.50	$3.66 - $36.26
Combined-cycle combustion turbine carbon capture sequestration (CCCT_CCS)	$43.16	$5.53 - $149.5
Nuclear	$11.60	$2.61 - $12.11
(Simple-cycle combustion turbine (SCCT)	$28.39	$4.9 - $43.77
Small modular reactor (SMR)	$11.81	$2.52 - $12.91

10.3 Flexibility value and integration cost

Flexibility value and integration cost are critical components of variable and capacity resource economics. As defined in **Section 6.8, Flexibility adequacy**, flexibility adequacy needs encompass multiple operational value streams, including load following, regulation, spin, non-spin and renewable integration (ramping and forecast error mitigation). PGE defines flexibility value as the benefits provided by resources that help meet the system's flexibility adequacy target. Integration costs are the inverse of this benefit, generally attributed to VERs as their intermittent behavior increases the megawatts (MW) needed to meet flexibility adequacy targets.

PGE estimated the flexibility value and integration cost of new resources using Grid Path simulations of the PGE service area.[280] When additional resources are added to the system, some new resources can be used to serve load and avoid higher-cost market purchases, as well as enable the re-dispatch of existing resources, thereby affecting the flexibility needs of the system. At the same time, other resources may increase the flexibility needed. For new

[279] Renewable resources and battery storages do not incur fuel cost and do not emit CO2. Therefore, the associated variable costs are zero and not shown in the table. The range represents the semi-deviation of variable costs across all futures.

[280] Grid Path is an open-source modeling software developed by Blue Marble Analytics. This model is used to perform the flexibility assessment in the 2023 IRP. Additional details on Grid Path are available in **Ext. Study-IV, Flexibility study**

resource options, either a flexibility value or an integration cost is calculated by subtracting the market revenues associated with dispatching the resource from a change in the total system cost achieved by including the resource in the portfolio and dividing by the resource addition size.

PGE's estimates of flexibility values and integration costs for several new resources based on a 2026 and 2030 test year are summarized in **Table 47**. The difference in flexibility value between storage resources does not appear to be significantly impacted by duration, suggesting that most flexibility value is associated with flexibility constraints on short time scales (less than two hours).

Table 47. Flexibility value ($/kW-yr.) of new resources in 2026 and 2030

Resource	2026	2030
2-hour Battery	8.35	16.71
4-hour Battery	9.77	18.75
6-hour Battery	10.68	20.65
8-hour Battery	11.78	21.38
10-hour Pumped Storage	11.47	20.86

Table 48 displays the estimated costs of resource integration. As noted in the table, solar + storage resources increase integration costs in the short term but are expected to deliver system benefits (negative integration costs benefit the system) as the system evolves by 2030. This is not a function of any specific element but reflects the system's evolving nature between 2026 and 2030, driven by load growth, DERs and changes to supply.

Table 48. Integration costs ($/MWh) of new resources in 2026 and 2030

Resource	2026	2030
Gorge wind	2.57	3.90
WA wind	2.57	3.90
MT wind	0.95	1.46
Solar	2.84	3.30
Solar + Storage	0.33	-1.62

10.4 Energy value

PGE uses the PZM simulation to estimate the economic dispatch of existing generation resources, contracts and potential new resources using electricity prices and associated risk variable inputs from each price future. Economic dispatch leads dispatchable resources to generate when their dispatch costs are less than the market electricity price, subject to all modeled operational constraints.

Table 49 summarizes the Reference Case energy value and range of outcomes across the simulated price futures for each resource. These values are presented on a levelized basis, across each resource's economic life, for representative resources with 2026 commercial operation dates.

Table 49. Energy values for new resource options (2026 COD)[281]

	Levelized energy value (2023$/MWh)	
	Reference Case	**Range**
Solar PV Christmas Valley	$17.78	$2.83 - $30.08
Solar PV McMinnville	$16.85	$2.68 - $28.7
Solar PV Nevada	$19.51	$3.12 - $32.72
Solar PV Wasco	$16.50	$2.62 - $28.13
Wind Gorge	$21.97	$3.54 - $36.8
Wind MT	$26.39	$4.26 - $43.4
Wind SE Washington	$24.34	$3.92 - $40.28
Wind Wyoming	$27.18	$4.39 - $44.64
Wind Offshore	$23.55	$3.79 - $39.29
1:1 Hybrid Christmas Valley	$20.85	$3.12 - $35.05
2:1 Hybrid Christmas Valley	$18.63	$3.00 - $31.56
1:1 Hybrid McMinnville	$21.15	$3.18 - $35.69
2:1 Hybrid McMinnville	$18.29	$2.95 - $31.06
Geothermal	$24.46	$3.94 - $40.65
Biomass	$26.04	$4.09 - $64.44

[281] Ranges reflect upward and downward semi-deviations around the Reference Case across the market price futures.

	Levelized energy value (2023$/MWh)	
	Reference Case	Range
CCCT	$35.48	$6.61 - $54.19
CCCT w/ CCS	$49.81	$6.30 - $195.79
SCCT	$39.49	$6.63 - $59.41

10.5 Resource capacity contribution

In **Chapter 6, Resource needs**, the IRP describes future system capacity needs. These needs grow from a combination of expected load growth and resource loss. To fill these needs, the IRP adds new resources. To determine how much effective capacity new resources add to the system, PGE conducts an effective load-carrying capability (ELCC) study for each new resource.

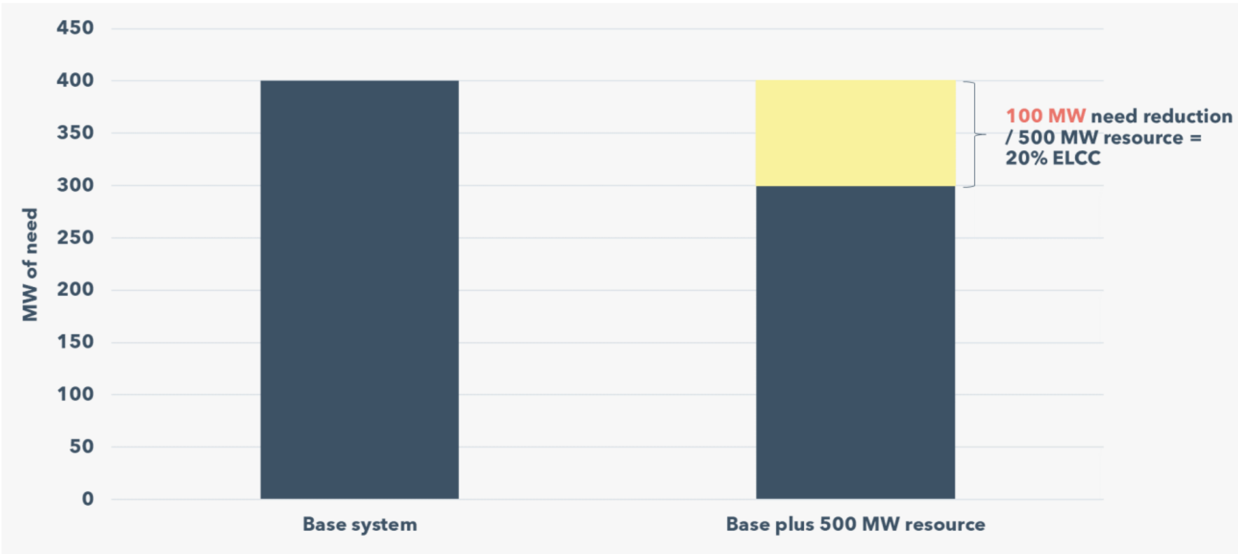
ELCC describes what percentage of a resource's nameplate capacity can be depended upon for resource adequacy needs. For example, the 100 MW nameplate capacity of a 4-hour battery may have an ELCC of 44 percent in the winter. This means that the 100 MW nameplate capacity of a 4-hour battery contributes 44 MW (100 * 0.44) towards reducing system capacity needs. If the starting system has a winter capacity need of 200 MW, after adding a 100 MW 4hr battery, the new capacity need is 156 MW (200 MW of need 44 MW of capacity).

PGE uses the Sequoia model to calculate ELCC values, following these steps:

- The model runs once to establish a baseline system capacity need
- The model runs again with a new resource added
- The difference in capacity need from the base system to the system with the resource added determines how much effective capacity the resource contributes
- The amount of effective capacity the resource contributes is divided into its nameplate to determine the ELCC value

For example, if the base system has a capacity need of 400 MW, and the same system plus a 500 MW nameplate resource has a capacity need of 300 MW. In that case, the resource provides 100 MW of effective capacity (400 minus 300). The effective capacity contribution,100 MW, is divided into the resource nameplate, 500 MW, to arrive at the ELCC value of 20 percent.[282] This example is graphically shown in **Figure 71.**

Figure 71. ELCC calculation example



The 2023 IRP tests resource ELCCs in the year 2026. The base 2026 power system has a resource deficit in both seasons. ELCCs can be calculated untuned, with a system deficit or tuned, where the base power system has had resources added until it is adequate or nearly adequate. For portfolio creation, PGE runs ELCC studies in an untuned system. PGE also runs a tuned ELCC study that includes the IRP Preferred Portfolio. Full ELCC values for portfolio creation are in **Appendix J, ELCC sensitivities**. Tuned ELCC values are in **Appendix K, Tuned system ELCCs**.

The 2023 IRP uses seasonal ELCC values rather than annual values. With many resources, ELCC values differ by season. For example, storage resources tend to have higher ELCCs in the summer than in winter. A seasonal approach helps ensure that the portfolio model (ROSE-E) can select an optimal and seasonally balanced portfolio.

Table 50 has untuned system ELCCs values for the first 100 MW of the IRP supply-side resources considered inside the Action Plan window. The resources use either firm or conditional firm 200hr transmission (CF200). For IRP modeling, CF200 transmission curtails the resource during the 100 highest load hours of the year, lowering ELCC values.[283] In IRP modeling, resources typically use CF200 transmission after firm transmission is exhausted.

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[282] This approach is similar to how the Northwest Power and Conservation Council determined resource capacity contributions in the 7th Power Plan (the Council calls this approach associated system capacity contribution).
[283] See **Appendix J, ELCC sensitivities** for more detail on how transmission products influence ELCC estimates.

Table 50. ELCC values for portfolio creation in year 2026[284]

Resource (100 MW nameplate)	Summer		Winter	
	Firm Tx	CF200	Firm Tx	CF200
Gorge Wind	47%	29%	39%	26%
SE WA Wind	15%	10%	35%	29%
MT Wind	28%	14%	61%	46%
McMinnville Solar	27%	9%	6%	6%
Wasco Solar	14%	6%	5%	4%
Christmas Valley Solar	23%	7%	8%	8%
McMinnville Solar Hybrid (1:1)	106%	55%	53%	43%
McMinnville Solar Hybrid (2:1)	72%	35%	30%	24%
Christmas Valley Hybrid (1:1)	102%	56%	55%	47%
Christmas Valley Hybrid (2:1)	63%	33%	33%	30%
2-hr battery	49%		27%	
4-hr battery	69%		44%	

ELCC values tend to decline due to resource saturation. For instance, the ELCC value of 100 MW of solar is higher than the ELCC value of 1,000 MW of solar. This occurs for various reasons, including:

- As more resource is added, the number of outages available to solve decreases. For example, if 500 MW of solar is added to a system, some outages during daylight hours may be solved. As a result, the next increment of solar added will have fewer outages available to solve and have a lower ELCC value.
- For storage resources, higher levels of resources may not be able to fully charge due to a lack of system energy. For example, there may be sufficient energy to charge 100 MW of a 4-hr battery reliably but not enough energy to charge 1,000 MW of a 4-hour battery. As a result, the 100 MW battery may have a higher ELCC value than the 1,000 MW battery.

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[284] 2- and 4-hour batteries are modeled to be on-system. Accordingly, there are no transmission limitations included in ELCC calculations, equivalent to having firm transmission.

ELCC values reflect the percentage of the resource nameplate MW that can be relied upon for effective capacity. They do not reflect the total MW of effective capacity provided by the resource, which is equal to the ELCC value multiplied by the nameplate. Although 100 MW of a 4-hour battery in the winter has an ELCC of 44 percent, and 500 MW of a winter 4-hour battery has an ELCC of 32 percent, the 500 MW battery provides more effective MW of capacity (160 MW vs. 44 MW, in this example). More discussion on ELCCs is in **Appendix J, ELCC sensitivities**.

10.6 Capacity value

Portfolio analysis addresses system capacity needs through resource additions such that the resource contributions meet or exceed the model's seasonal capacity need constraints. More details on the modeling process are available in **Appendix H, 2023 IRP modeling details**.

Like in the 2019 IRP, the value of capacity outside of portfolio analysis is calculated by developing the net cost of capacity. The net cost of capacity is the cost required to get 1 kilowatt (kW) of capacity contribution from the next least cost capacity resource available to meet capacity needs, as shown in the following formula:[285]

$$Net\ cost\ of\ capacity\ for\ 1kW\ of\ capacity\ contribution\ =$$

$$(fixed\ costs + transmission\ costs\ + integration\ costs - tax\ credits - energy\ value - flexibility\ value)/_{ELCC}$$

Figure 68 (**Section 10.1, Fixed costs**) highlights the considerable uncertainty in the relative fixed cost trajectories of capacity resources such as batteries. **Table 47** in **Section 10.3, Flexibility value and integration cost**, quantifies the integration flexibility value of new capacity resources. ELCC of the first 100 MW of each resource is described in **Section 10.5, Resource capacity contribution**.

PGE has analyzed the Preferred Portfolio to determine the next least cost capacity resource available to meet capacity needs in 2026. The Preferred Portfolio is described in **Section 11.5, Preferred Portfolio**. From a capacity standpoint, the Preferred Portfolio adds 232 MW of 4-hr storage resource in 2026 to address the bulk of the capacity needs resulting from expiring contracts and load growth. Beyond this, through 2030, additional capacity is added through energy-dense resources such as wind, solar, community-based renewable energy (CBRE) and proxy transmission access to Nevada to add energy and capacity. Evaluating all

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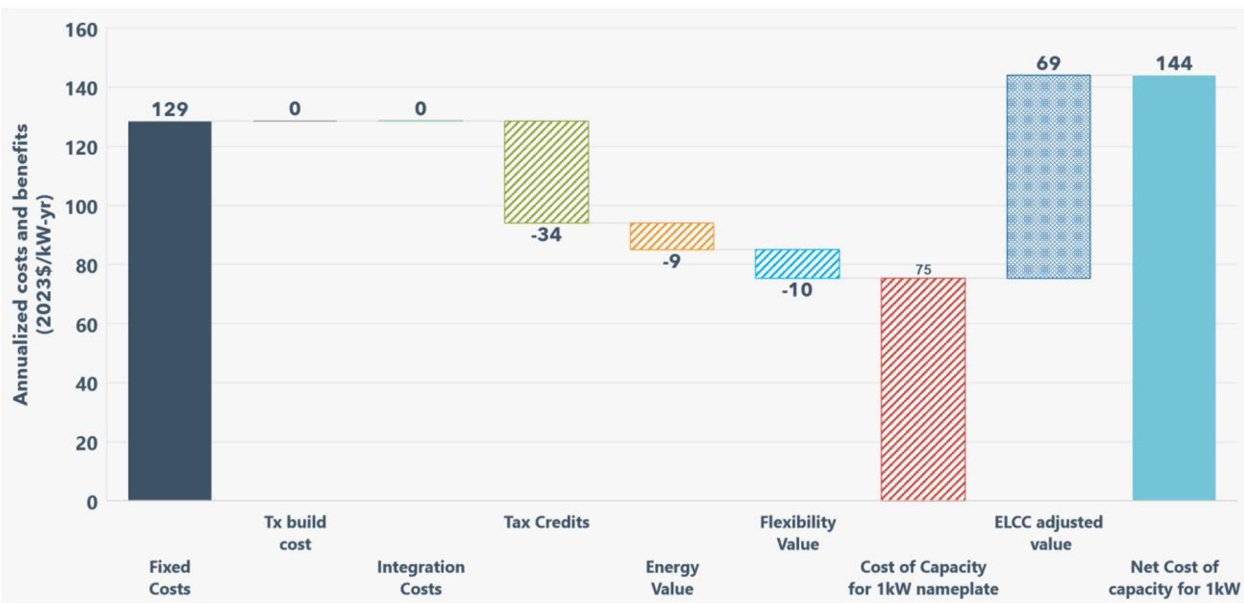
[285] This equation is also commonly referred to as the equation to determine the net cost of new entry (Net CONE) and is used to determine the cost of capacity when applied to the marginal resource that selected for capacity.

these resources based on the net cost of the capacity equation, we also determine that the next least cost capacity resource available to meet near-term capacity needs is a 4-hour battery.

The evaluation of the net cost of the capacity of a 4-hour battery is shown in **Figure 72**. The cost of the capacity of 1kW nameplate is calculated as the sum of all the applicable costs net of any benefits, including tax credits. This value, $75/kW-yr., represents the cost of capacity to procure a 1kW nameplate of batteries. PGE has calculated the cost of capacity to provide 1kW of capacity contribution, the metric that enables a fair comparison across resources. This is done by adjusting the capacity value of the 1kW nameplate by the ELCC of the battery at the marginal quantities of nameplate selected in the Preferred Portfolio. The ELCC of the 232MW nameplate of 4hr battery resource is 52 percent; by dividing $75/kW-yr. by 52 percent we determine that the net capacity cost is $144/kW-yr., which represents the avoided cost of capacity. The ELCC adjustment noted in **Figure 72** reflects the change in value after converting it from a 1kW nameplate to 1kW of capacity contribution, which is the metric that allows for a fair comparison across resources.

Figure 72. Deriving the cost of 1 kW of capacity contribution from a 4-hour battery



Using this new avoided cost of capacity of $144/kW-yr., the following equation can determine the capacity value of a resource at a nameplate value:

$$Capacity\ value\ of\ resource\ A\ =\ Capacity\ contribution\ of\ resource\ A\ *\ \$144/kW-yr$$

Table 51 shows the capacity value of the resources considered within the IRP. For capacity resources, the ELCC and corresponding capacity value (in $/kW-yr.) are shown to indicate the amount of capacity required of each resource to provide 100 MW of capacity contribution.[286] For energy resources, the ELCC and corresponding capacity value (in $/MWh) are shown corresponding to 100-megawatt average (MWa) addition sizes after accounting for the corresponding levelized capacity factors. These values reflect the effects of the declining marginal ELCC curves.

Table 51. ELCCs and associated capacity values[287, 288]

Resource	Annual ELCC for 100 MWa energy addition	Capacity value (2023$/MWh)
Gorge Wind	39%	15
Montana Wind	39%	15
SE Washington Wind	23%	9
Christmas Valley Solar	14%	9
McMinnville Solar	16%	12
Wasco Solar	14%	9
Energy efficiency bin 2	108%	156
Energy efficiency bin 1	118%	169
Christmas Valley 1:1 solar hybrid	78%	112
McMinnville 1:1 solar hybrid	78%	113
Nevada Solar + market access	100%	144
Wyoming Wind + market access	100%	144

[286] *E.g.*, if 500 MW of a capacity resource is required to achieve a 100-MW capacity contribution, the corresponding ELCC at 100-MW capacity contribution equals 20 percent.
[287] Energy efficiency bins represent the aggregate impact of several smaller energy efficiency technologies and strategies that are similar in their levelized costs. These are described in **Section 8.2.1, Additional energy efficiency.**
[288] The annual ELCCs shown in **Table 51** calculated with the average of the seasonal ELCC are for informational purposes and are meant to be directional indicators of capacity value. The actual value of capacity is estimated within portfolio analysis and is dependent on seasonal ELCCs.

10.7 Cost of clean energy

In previous IRPs, production cost and capacity expansion models used to develop portfolio analysis could rely on the market to meet energy needs based on available market prices. House Bill (HB) 2021 sets emissions targets, which are applied as emission constraints in the IRP. These constraints limit access to both specified and unspecified market purchases in the wholesale market that have embedded carbon content.[289] Thus, if the total energy needs of the system surpass the energy generated by both the existing non-emitting resources and the carbon-embedded energy, the model must rely on adding incremental generating resources to meet energy need. This represents a new cost associated with meeting energy needs through non-emitting resources. Conversely, this is a value to resources that avoid this new cost.

Within the IRP's portfolio analysis, these costs are accounted for; decisions about new resource additions fairly estimate all the costs and benefits associated with each potential supply-side option. However, the costs and benefits of many resources are currently estimated outside of the IRP. Current methods estimate energy value in one of two ways:

- The first relies on previous assumptions about market access.[290]
- The second involves determining the net cost of a new off-system VER. However, this option is only applied to resources assuming available transmission capacity.

If either of these methods is applied under the constraints the PGE faces today, they could significantly underestimate the energy value of potential new resources. Doing so would lead to a misidentification of resource economics, resulting in a higher cost system. The existing emissions and transmission constraints signal a need to reassess which values are used when comparing the costs of resources outside the IRP. Additional study is required to understand how estimating a new resource's energy value should be calculated outside the IRP.

10.8 Resource net cost

In **Section 10.6, Capacity value**, PGE applied the concept of the net cost of new entry to assess the capacity value. In this section, we apply the same concept to visualize the relative economics between resources and the dynamics seen within portfolio analysis. This approach was also used in the 2019 IRP and is common industry practice when evaluating resource economics. In this discussion, we define the net cost of new entry as the sum of all costs, such

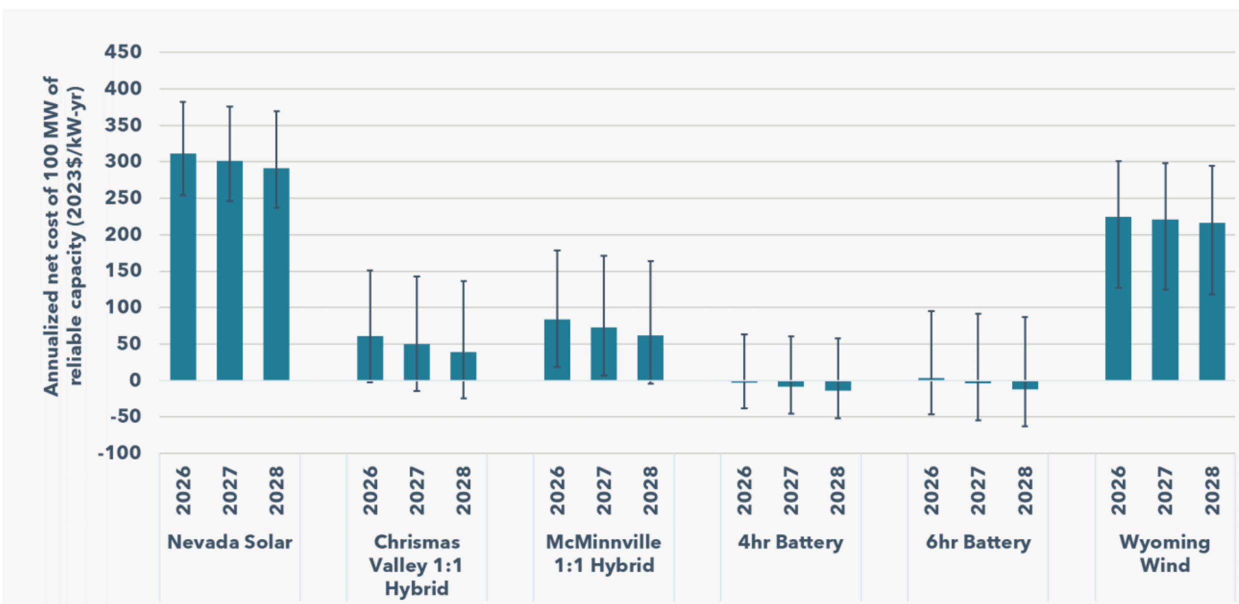
[289] Oregon Department of Environmental Quality (ODEQ) greenhouse gas (GHG) reporting rules (under ORS 468A.280) assign emissions to unspecified sources of energy that serve Oregon retail load.
[290] Generally involving summing the hourly product between generation and market prices.

as fixed, variable and integration costs, net of any benefits, such as tax incentives, and any value provided to the portfolio, including energy, flexibility, rCBI and capacity values. The following sections visualize the net cost of different capacity (in $/kW-yr.) and energy resources (in $/MWh).

10.8.1 Net cost of capacity resources

Figure 73 visualizes the net cost for the different capacity resources available in portfolio analysis. The 1:1 Christmas Valley solar+storage hybrid resource shows a net cost of $61/kW-yr. (2026 COD) while the net cost of a 4hr battery is -$3/kW-yr, highlighting the premium PGE customers would have to pay to procure that resource for capacity over a battery. The relative net costs also highlight the order of selection. For example, absent transmission constraints based only on the information in **Figure 73**, a model adding capacity while minimizing cost would select storage resources before any of the transmission expansion options.

Figure 73. Net cost for 100 MW of capacity contribution of capacity resources by COD[291]



[291] The "Error bars" of the column graph represent the aggregate uncertainty of the costs and benefits when estimating net costs. Uncertainty in costs stem from technology cost futures. Uncertainty in benefits stem from variation in energy value across price futures. The uncertainty in energy value is calculated as the upward and downward semi-deviation of the energy value relative to the Reference Case price future. Price futures are described in **Section 4.5, Uncertainties in price forecasts**.

10.8.2 Net cost of energy resources

The impact of transmission quality and availability is a significant element in the net cost of energy resources. To show this **Figure 74** illustrates the net costs of 100-megawatt average (MWa) of Gorge Wind (2026 COD) with the available transmission, with conditional firm transmission and with the South of Allston (SoA) upgrade cost, respectively. Changes to the transmission quality (from long-term firm to conditionality value firm) decrease the resource's capacity contribution and therefore capacity value. The difference of $6/MWh in the net cost between long-term firm and conditional firm transmission products represents the loss in value when selecting conditional firm transmission for the Gorge Wind resource. Additional costs of transmission upgrades are more intuitive as they increase the net costs of the resource.

Figure 74. Net cost for 100 MWa of Gorge Wind (2026 COD)

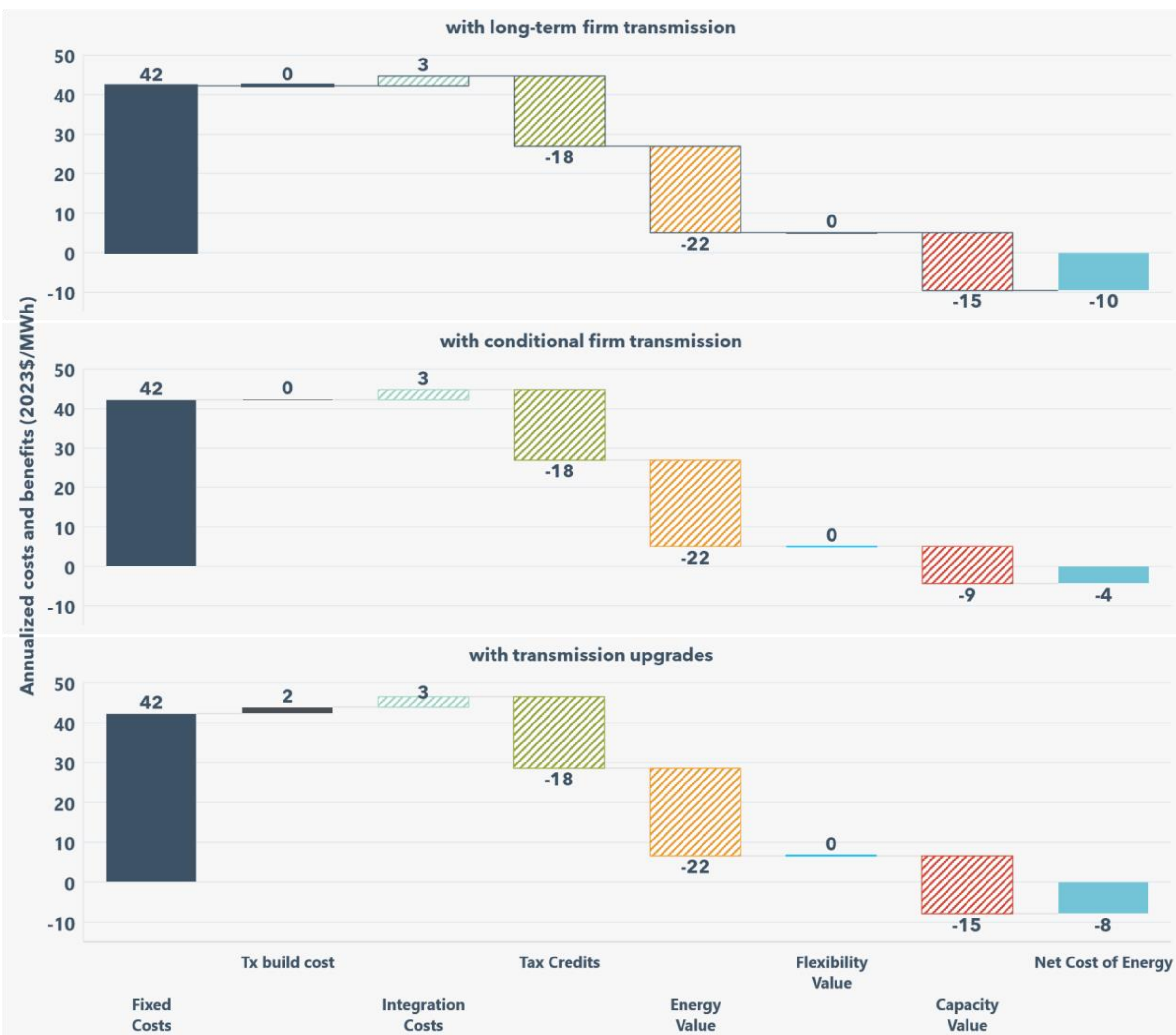


Figure 75 shows the net cost of 100 MWa of the new Wyoming transmission option to highlight the costs of new transmission and associated market access costs, showing the large incremental cost PGE customers will likely need to pay to address transmission constraints and access other regional markets. This premium also highlights why distribution-connected resources become increasingly cost-competitive, despite having higher fixed costs than their supply-side counterparts.

Figure 75. Net cost for 100 MWa of Wyoming Wind transmission (2026 COD)

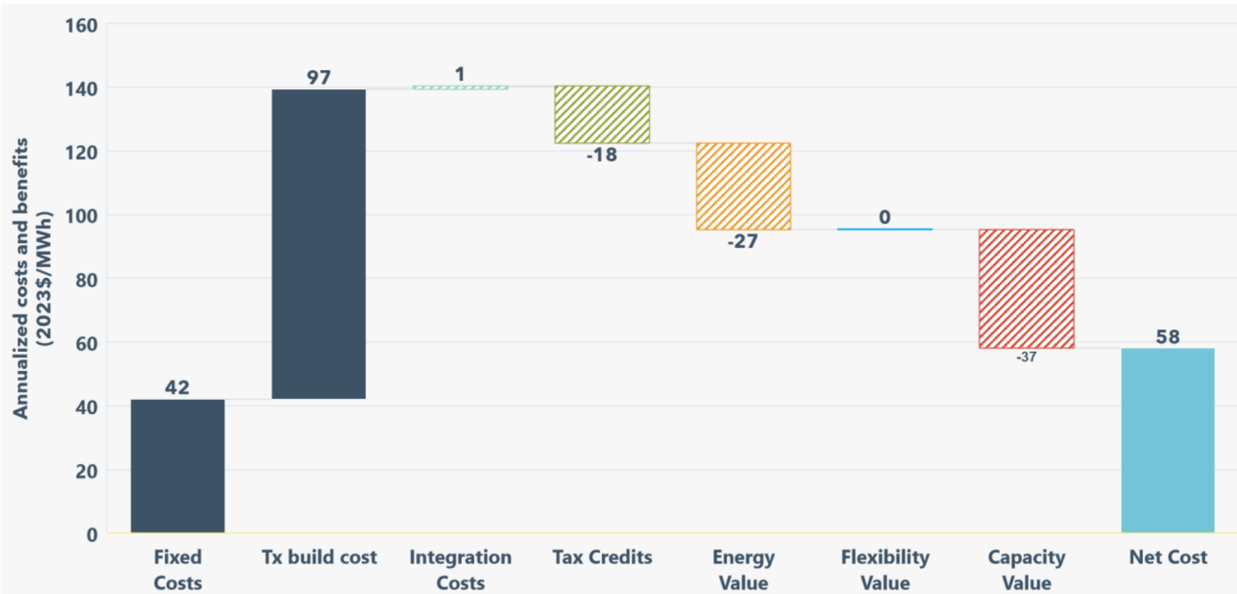
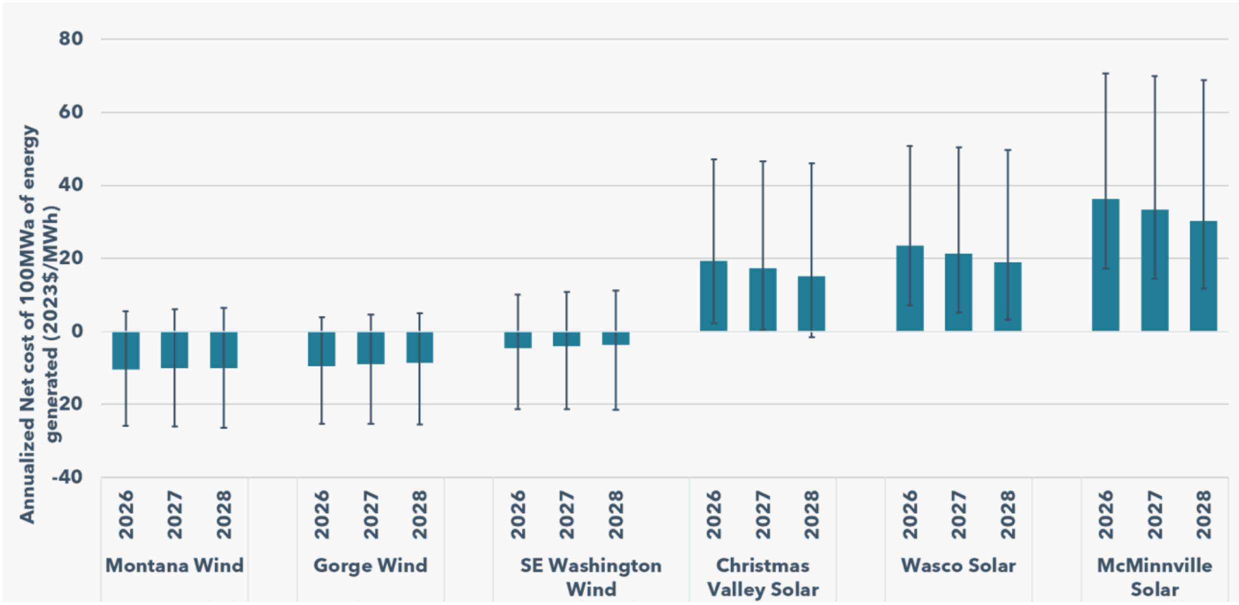


Figure 76, like **Figure 73**, shows the net cost of different resources. However, **Figure 76** focuses on energy resources such as solar and wind and represents the net cost for 100 MWa of a new solar and wind. While net costs of new resources described previously provide helpful insights for understanding the economic tradeoffs between specific resource actions, this simplistic view of resource economics neglects risks associated with future uncertainties and potential interactions between resources and constraints. These are investigated through portfolio analyses described in **Chapter 11, Portfolio analysis**.

Figure 76. Net cost for 100 MWa of solar and wind resources by COD



10.9 Resource community benefits indicators

Resource community benefits indicators (rCBI) aim to inform and provide a mechanism to track progress on specific outcomes achieved through CBRE actions. For this first Clean Energy Plan (CEP) filing, PGE developed a 'CBRE favored' approach, like the 1980 Northwest Power Act for energy efficiency.[292] These methods leverage the logic that in planning, we cannot necessarily know which benefits are applicable for each resource as they depend on many factors, such as the resource location and the nature of the resource. For rCBIs, PGE created a CBRE resource within the construct of its resource portfolio that reduces the fixed cost of the three proxy resources evaluated by 10 percent. When considering which resource to select to meet system needs, the capacity expansion model ROSE-E will evaluate the costs and benefits associated with all resources available; the rCBI benefit will lead to the selection of CBREs over an otherwise equivalent resource. **Figure 77** illustrates the impact of the rCBI benefit in the net cost calculation. See **Section 7.1.3, Resource community benefits indicators**, for more details on rCBI.

[292] Northwest Power Act, 16 United States Code Chapter 12H (1994 & Supp. I 1995). Act of Dec. 5, 1980, 94 Stat. 2697. Public Law No. 96-501, S. 885, §839a(4)(D), available at: https://www.congress.gov/96/statute/STATUTE-94/STATUTE-94-Pg2697.pdf

Figure 77. Net cost of a microgrid CBRE (2026 COD)