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August 11, 2025

VIA ELECTRONIC FILING TO: PUC.FilingCenter@puc.orgeon.gov

Public Utility Commission of Oregon
Attn: Filing Center
201 High St. SE, Suite 100
Salem, OR 97301

RE: UM 2377 – PUC Investigation of Rule C and I, Marginal Cost Study Treatment: Opening Testimony and Sponsored Exhibits of Intervenors Climate Solutions, Columbia Riverkeeper, Community Energy Project, Green Energy Institute, and Oregon Environmental Council ("Coalition").

Dear Filing Center:

Attached for filing, please find the Coalition's Opening Testimony and sponsored exhibits for the above-referenced proceeding. The consolidated PDF for filing includes testimony and exhibits of Cole Souder (Exhibit Coalition/100–111) and Andy Eiden (Exhibit Coalition /200–213).

Please feel free to reach out to me directly with any questions about this filing.

Sincerely,

/s/ Cole Souder
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CERTIFICATE OF SERVICE
UM 2377

I hereby certify that on August 11, 2025, I served CLIMATE SOLUTIONS, COLUMBIA RIVERKEEPER, COMMUNITY ENERGY PROJECT, GREEN ENERGY INSTITUTE, AND OREGON ENVIRONMENTAL COUNCIL'S OPENING TESTIMONY AND SPONSORED EXHIBITS upon the Commission and each party's representative(s) designated to receive service.

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BEFORE THE PUBLIC UTILITY COMMISSION
OF OREGON

UM 2377

In the Matter of PUBLIC UTILITY COMMISSION OF OREGON Investigation into Marginal Cost Study Treatment and Costs for Large Customers and Further Modifications to Portland General Electric Company's Rule C and Rule I	CLIMATE SOLUTIONS, COLUMBIA RIVERKEEPER, COMMUNITY ENERGY PROJECT, GREEN ENERGY INSTITUTE, AND OREGON ENVIRONMENTAL COUNCIL'S OPENING TESTIMONY

OPENING TESTIMONY

OF

CLIMATE SOLUTIONS, COLUMBIA RIVERKEEPER, COMMUNITY ENERGY PROJECT, GREEN ENERGY INSTITUTE, AND OREGON ENVIRONMENTAL COUNCIL

August 11, 2025

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Souder/1

BEFORE THE PUBLIC UTILITY COMMISSION
OF OREGON

UM 2377

In the Matter of

PUBLIC UTILITY COMMISSION OF OREGON

Investigation into Marginal Cost Study Treatment and Costs for Large Customers and Further Modifications to Portland General Electric Company's Rule C and Rule I

OPENING TESTIMONY

OF COLE SOUDER

ON BEHALF OF CLIMATE SOLUTIONS, COLUMBIA RIVERKEEPER, COMMUNITY ENERGY PROJECT, GREEN ENERGY INSTITUTE, AND OREGON ENVIRONMENTAL COUNCIL

(Non-Confidential)

August 11, 2025

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I. Introduction

Q. Please state your name and your business address

A. My name is Cole Souder, and my business address is 10101 S. Terwilliger Blvd., Portland, OR 97219.

Q. By whom are you employed and in what capacity?

A. I am employed by the Green Energy Institute at Lewis & Clark Law School as a Staff Attorney. The Green Energy Institute at Lewis & Clark Law School (GEI) is a nonprofit energy and climate law and policy institute within Lewis & Clark Law School's top-ranked environmental, natural resources, and energy law program.

I have worked at the GEI since September 2024. My responsibilities include engaging in a variety of dockets in front of the Public Utility Commission both on behalf of GEI and other organizations on issues related to both gas and electric utilities, researching decarbonization pathways that local governments can adopt, and advocating for policies that will result in superior utility service at reasonable costs.

Q. Please summarize your professional and educational experience.

A. Please see my resume and witness statement attached as Exhibits Coalition/101, Souder/1 and Coalition/102, Souder/2. I began engaging on data center tariff issues in UE 430, where I submitted comments advocating for more robust customer protections from the cost-based risks data centers present. I have also work on utility rate cases (UG 490 and UG 520) and other electric utility dockets, including PGE's 2023 RFP. I graduated from Lewis and Clark Law School in 2024, and prior to that received a Masters in History from San Francisco State University, with a research focus on the intersection of race, economics, and politics.

Q. What did you review in preparation for this testimony?

A. I have reviewed the filings in UE 430 as well as the Company's discovery responses in UE 430 and UM 2377.

Q. Have you previously testified before the Oregon Public Utility Commission?

A. No, I have not previously testified.

Q. On whose behalf are you submitting testimony?

A. I am submitted testimony on behalf of Climate Solutions, Columbia Riverkeeper, Community Energy Project, the Green Energy Institute at Lewis & Clark Law School, and Oregon Environmental Council.

Q. Are you sponsoring any exhibits?

A. Yes, in addition to my resume (Coalition/101) and witness qualification statement (Coalition/102), I am sponsoring Exhibits Coalition/103 through Coalition/112. All sponsored exhibits from are attached to this testimony.

Q. How is your testimony organized?

A. My testimony is organized by the following sections:

- Section I: Introduction
- Section II: Background on Data Centers and the Need to Protect Customers from Stranded Asset and Cost-Shifting Risks
- Section III: Rule C and Rule I
- Section IV: HB 2021 Compliance
- Section V: Conclusion

II. Background on Data Centers and the Need to Protect Customers from Stranded Asset and Cost-Shifting Risks.

Q. Please describe PGE's original proposal in UE 430.

A. In UE 430, PGE proposed a series of changes to its Rule I and Rule C tariffs ("UE 430 Proposal"). The Company broke large load customers into three groups. Category 1 covered customers less than 1 MW, Category 2 covered customers between 1 MW and 30 MW, and Category 3 covered customers greater than 30 MW.[1] Category 2 was also broken into two subcategories, 2a and 2b, depending on the need for substation transformer upgrades and line extension costs.[2]

Most important here are the terms of the UE 430 Proposal that applied to Category 3 customers. These policies included the following:

- Customer deposit: a refundable system allocation deposit, determined in the energy service agreement.
- Minimum billing demand: for distribution, flat billed demand based on revenue required; for transmission, 80 percent of the allocated system capacity
- Load Ramp: none.
- System Allocation fee: two year's minimum capacity demand, refundable.
- Capacity buffer before exceedance penalty: 10% over allocated capacity or 5 MW, whichever is less.
- Contract Period: 8 to 30 years.

[1] In the Matter of PORTLAND GENERAL ELECTRIC COMPANY, Investigation into New Load Connection Costs, Docket No. UE 430, PGE/100, Fagen-Frayer/28.
[2] Id.

- Exit Fee: remaining net book value of distribution assets allocable to the customer three years past the termination year adjusted for salvage, plus three years' worth of distribution revenues.
- Credit requirement: letter of credit equal to the distribution-related exit fee required for customers that do not maintain investment-grade creditworthiness.[3]

Q. Why do customers need protection from data center driven load growth?

A. Data centers are going to be the main driver of load growth in PGE's service territory over the next few decades. In its 2023 IRP/CEP Update, PGE showed that these new large customers are the overwhelming drivers of load growth as compared to other customer groups. For example, the reference case expects a twenty-year average annual growth rate of 1.9%, but when new large (30 MW or greater) customers are removed, the expected growth rate lowers to 0.1%.[4] Over that 20-year period, then, new large loads are expected to be responsible for more than 90 percent of load growth.[5]

That load growth risks spreading costs to other customers in a variety of ways, which are described in more detail below. In PGE's territory, a 1 MW, high-load factor customer is roughly the equivalent of 840 residential customers.[6] As loads increase, the problem becomes more apparent. A 10 MW load translates to about 8,400 residential customers and a 100 MW compares to 84,000 residential customers. Even conservatively assuming only 2 persons per

[3] In the Matter of PORTLAND GENERAL ELECTRIC COMPANY, Investigation into New Load Connection Costs, Docket No. UE 430, PGE/100, Fagen-Frayer/46 (Dec. 20, 2024), available at https://edocs.puc.state.or.us/efdocs/HTB/ue430htb333702025.pdf.
[4] Coalition/103, Souder/57.
[5] Dividing new large load's contribution to the growth rate (1.8%) by total growth rate (1.9%) = 94.7%.
[6] PGE's residential customers use about 1.063 kWh an hour. PGE Quick Facts, Portland General Electric, available at https://portlandgeneral.com/about/info/quick-facts. Assuming a 1 MW, high-load factor customer averages 900 kWh/hour.

household, then, a 400 MW load is about the equivalent of serving the residential needs of the city of Portland. But modern data centers are growing much larger than even 400 MW; some are beginning to approach 1 GW or larger. The scale of these new loads requires substantial infrastructure buildouts to receive service while maintaining system reliability, meaning potentially hundreds of millions of dollars in capital expenditures by a serving utility to meet the needs of just a couple of customers.

This dynamic can expose residential customers to catastrophic levels of stranded assets and inequitable cost-shifting. The largest data centers serve new artificial intelligence (AI) technologies that, although potentially promising in some realms, are still limited in both their functional capabilities and its profitability. The potential for efficiency gains in this new field may result in current estimated energy needs to perform tasks being entirely out of proportion from the energy needs just a decade from now, resulting in energy infrastructure with no load to pay for it. When those in the Pacific Northwest think about the possibility of massive utility capital expenditures being made to serve a load that does not materialize, one word comes to mind: Whoops.

The size of the large new data centers makes them difficult to serve as well, as even relatively small variations in their energy use can require the serving utility to expend vast sums to quickly acquire needed capacity and energy to serve one customer. In AI-based data centers, shifts of many dozens of MWs can occur in seconds.[7] The standard utility cost-sharing model is ill-equipped to handle a situation where a very small number of customers are driving both capital and operational expenses that traditionally are shared among all ratepayers on the assumption that in general, resources are shared by a system. That made

[7] Coalition/200, Eiden/20 (Fig. 4).

sense when the different rate classes grew together as a region grew over several decades—residential, commercial, and industrial customers grew together, so the costs incurred were spread among the different groups. But now, those other customers' usage is flat, and a handful of customers will drive growth on a GW scale.

And this is occurring at a time when PGE is already tasked with substantial capital projects to decarbonize our grid while maintaining system reliability. Whether PGE can meet its HB 2021 targets as it stands based on the utility's challenges in recent years to begin acquiring non-emitting resources at the rate necessary to reduce emissions 80 percent by 2030 is an ongoing concern. Adding hundreds of MWs of high-load factor customers will make that task even harder, especially given the federal roadblocks such as a rollback in wind and solar development tax credits.[8]

Q. Do data centers present other risks beyond the cost of energy?

A. Yes. Data centers—in particular the larger varieties that serve AI—can negatively impact the communities that surround them in several ways. These data centers can make the power for surrounding homes worse by distorting the frequency and thereby reducing the power quality.[9] These distortions can reduce the efficiency of appliances and cause wear on their functionality, creating the need for more frequent replacements, the costs of which fall on the owner.[10] Their size and ability to add hundreds or thousands of MWs of new load to a

[8] Kyle Sweeney, et al., "Navigated OBBBA: phaseouts, prohibited foreign entity rules, and other new rules," The Tax Law Center, (Jul. 11, 2025), available at https://taxlawcenter.org/blog/navigating-obbba-phaseouts-prohibited-foreign-entity-rules-and-other-new-rules

[9] Leonardo Nicoletti, et al., "AI Needs so Much Power, It's Making Yours Worse," Bloomberg. (Dec. 27, 2024), available at https://www.bloomberg.com/graphics/2024-ai-power-home-appliances/.

[10] Id.

utility's profile in a short period of time is also driving a potential reliability crisis, according to the U.S. Department of Energy.[11]

Data centers also bring with them a host of environmental concerns. Apart from their ravenous consumption of energy, they also require significant amounts of water to function, with newer, larger data centers expected to consume millions of gallons of water a day.[12] Energy generation has its own water usage component as well, which means that larger data centers have an even greater water use impact for not just area in which they are located, but the broader region as well.[13] Neighbors of a Meta-owned data center in Georgia have seen their wells run dry "within a year" of the data center's operation.[14] Meta's website notes that the Georgia data center is designed for "minimizing water use" and that its proud to "prioritize on-site water efficiency" using technology that "is significantly more water-efficient that the industry standard," which may just go to prove that no amount of stewardship can protect the waters around a data center.[15] Data centers can also contribute to local air pollution[16] and climate change, which is discussed in the Oregon context below.

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[11] Coalition/104, Souder/2.
[12] Eli Tan, "Their Water Taps Ran Dry When Meta Built Next Door," New York Times, (Jul. 16, 2025), available at https://www.nytimes.com/2025/07/14/technology/meta-data-center-water.html; see also, Michelle Fleury & Nathalie Jimenez, "'I can't drink the water' – life next to a US data centre," BBC, (Jul. 10, 2025), available at https://www.bbc.com/news/articles/cy8gy7lv448o.
[13] "The Energy & Water Use Impacts of Building System Design for Data Centers: Design Considerations for Oregon & Washington," PAE, at 5 (Feb. 14, 2025), available at https://critfc.org/wp-content/uploads/2025/03/data-center-report.pdf.
[14] Id.
[15] "Meta's Stanton Springs Data Center," Meta, at 2, (last visited July 25, 2025), available at https://datacenters.atmeta.com/wp-content/uploads/2025/02/Meta_s-Stanton-Springs-Data-Center.pdf.
[16] Adrian Sainz, "NAACP files intent to sue Elon Musk's xAI company over Memphis supercomputer air pollution," PBS News, (Jun. 17, 2025), available at https://www.pbs.org/newshour/nation/naacp-files-intent-to-sue-elon-musks-xai-company-over-memphis-supercomputer-air-pollution.

And although *future* uses of AI could result in positive environmental impacts through grid optimization, improved weather forecasting, or geothermal development, it is *currently* helping the oil and gas industry expand production.[17]

While the energy-cost concerns associated with data centers are reason enough to set up a specialized regime to protect other utility customers, these other social harms warrant a protective approach that only allows data centers to connect to PGE's grid if they are going to pay for the cost of doing so.

III. Rule I and Rule C

Q. What are your proposals on Rule I and Rule C?

A. Our proposals are as follows:

- The rules developed in this docket should apply to the category of customer identified in HB 3546 (the "POWER Act"), i.e. data centers (and cryptocurrency mining operations) greater than 20 MW in size.
- The customer deposit methodology PGE proposed in UE 430 (two years' minimum capacity demand) but subject to return at the end of the contract period.
- Minimum billing demand:
    - Transmission: 90% of allocated system capacity
    - Distribution: flat-billed demand based on revenue requirement
    - Generation: 80% of allocated system capacity until 2040; then, 90% of allocated system capacity

[17] Katie Brigham, "AI Could Help Decarbonize the Grid. It's Already Helping Find More Oil," Heatmap News, (Jul. 16, 2025), available at https://heatmap.news/energy/microsoft-exxon-chevron-ai.

- No Load Ramp
- Exit Fee
    - The remaining collective cost of minimum billing demand for generation and transmission for the length of the contract.
    - The remaining flat billing demand charges for distribution for the length of the contract plus three years.
    - The remaining net book value of the distribution assets allocable to the customer three years past the termination year, adjusted for salvage.
- Exceedance penalty, triggered if actual demand exceeds allocated capacity, calculated as:
    - 4 x Tariff rate for Transmission x (Actual Demand – Allocated Capacity)
    - 1.5 x tariff rate for usage x (Actual Demand – Allocated Capacity)
- Contract period of 15 to 30 years

Q. What are the primary goals that you hope your Rule I and Rule C policies will achieve?

A. The Rule I and Rule C policies advocated for here are meant to achieve two goals. First, they are designed to incentivize data centers to correctly predict their capacity needs because both over and underestimating capacity can lead to inequitable cost-shifting. If a data center overestimates its capacity, an electric utility will overbuild infrastructure to serve load that does not exist. Those incremental costs will then be spread across all of the utility's customers. Underestimating capacity also presents a problem. If a data center's actual capacity consistently exceeds the capacity for which the utility planned, the utility may need

to "quickly find additional supply for these customers, incurring costs that will be spread to all customers."[18]

Second, the Rule I and Rule C policies are designed to prevent stranded assets years down the road. While smaller data centers have loads of "only" a few dozen MWs, larger "hyperscalers" can have capacities that approach 1 GW,[19] with plans to develop sites as large as 2 GW.[20] The size of these facilities, even the small ones, often necessitate costly distribution infrastructure, as well as transmission upgrades and new generation resources to serve the load. Transmission, distribution, and generation assets have useful lives lasting decades.[21] But, for reasons detailed below, data centers are not as tethered to a particular facility once it is up and running as other large industrial loads. This dynamic raises the risk that a utility will build distribution infrastructure, acquire generation assets, and upgrade its transmission system to serve a load that no longer exists, leaving the utility's other customers on the hook for expenses that provide them little to no benefit. Similarly, there remains the risk that the power needs for artificial intelligence are over-inflated, and efficiency gains in computation or a lack of market will result in the power demand for AI being much lower than currently predicted. While this future might be more beneficial in terms of managing a

[18] In the Matter of PACIFICORP dba PACIFIC POWER, Request for a General Rate Revision, Docket No. UE 433, Order No. 24-447, at 100 (Dec. 19, 2024), available at https://apps.puc.state.or.us/orders/2024ords/24-447.pdf.
[19] "Google CEO: We're working on 1GW data centers, seeing money going into SMRs," Data Center Dynamics, (Sept. 23, 2024), available at https://www.datacenterdynamics.com/en/news/google-ceo-were-working-on-1gw-data-centers-seeing-money-going-into-smrs/.
[20] Rich Miller, "The Gigawatt Data Center Campus is Coming," Data Center Frontier, (Apr. 29, 2024), available at https://www.datacenterfrontier.com/hyperscale/article/55021675/the-gigawatt-data-center-campus-is-coming
[21] See e.g. Coalition/105, Souder/1; Coalition/106, Souder/1.

constrained grid, it also can result in stranded assets that were built on the assumption of higher data center power needs.

In Virginia, the Joint Legislative Audit and Review Commission (JLRAC) released a report showing that although data centers were currently paying their cost of service, growing demand from those customers would soon drive up the rates paid by all customers because "current utility rate structures are not designed to account for sudden, large cost increases from the construction of new infrastructure to serve a relatively small number of very large customers."[22]

Q. Why should this docket apply to data centers 20 MW and larger?

A. The rules established in this docket are best applied to the category of customer identified in the POWER Act: those that use 20 megawatts or more and primarily engaged in the services of a data center.[23] Whether or not this docket is viewed as a POWER Act implementation docket, it covers many of the topics related to cost-allocation that the POWER Act addresses. The interconnected nature of the items that make up the wide-ranging scope list for this docket require consistent application of the rules to a given customer class to avoid accidental loopholes and poorly designed incentive structures. With that said, the Coalition remains open to the idea that "hyperscalers"—data centers with capacities above 100MW—may require additional protections for other customers beyond those established for customers 20MW and larger due to their size and differing load profile from smaller co-locating and cloud-based data centers. Briefly, data centers that power AI

[22] "Report to the Governor and the General Assembly of Virginia: Data Centers in Virginia 2024," Joint Legislative Audit and Review Comm'n, at 45 (Dec. 9, 2024), available at https://jlarc.virginia.gov/pdfs/reports/Rpt598.pdf.
[23] H.B. 3546, sec. 1(d), 2025 Leg., Reg. Sess. (Or. 2025); North American Industry Classification System, Sec. 518210.

have more variable loads, whereas colocation and cloud-based data centers maintain consistently high load factors. Whether the same set of policies are appropriate for different types of data centers is something that can only be determined with more information from both PGE and data centers; there is not currently sufficient public information about data center load profiles, and the information that is available may not be relevant to the specific data centers coming into PGE territory.

Some jurisdictions have applied new tariff rules at very low capacities, between 0.5 MW and 5 MW. The benefit of such an approach avoids some of the arbitrariness of distinguishing between two similarly sized large loads—effectively, even smaller loads are subject to the additional protections for other customers. Other utilities in Indiana and Colorado have taken the opposite approach, applying their rules only to very large facilities that approach or exceed 100MW, on the understanding that these hyperscaled customers present unique risks that even otherwise very large facilities do not. Indeed, in UE 433, the Commission allowed for protections against stranded asset and cost-shifting risks that applied to customers over 50 MW.[24]

In UE 430, PGE stated that it set its threshold at 30 MW because "it captures, objectively, where high distribution costs to serve start. The customers in this category tend to have dedicated substation transformers of a larger size with costs in the tens of million."[25]

[24] In the Matter of PACIFICORP, dba PACIFIC POWER, Request for a General Rate Revision, Docket No. UE 433, Order No. 24-447, at 100 (Dec. 19, 2024), available at https://apps.puc.state.or.us/orders/2024ords/24-447.pdf.
[25] In the Matter of PACIFICORP, dba PACIFIC POWER, Request for a General Rate Revision, Docket No. UE 433, Order No. 24-447, at 100 (Dec. 19, 2024), available at https://apps.puc.state.or.us/orders/2024ords/24-447.pdf.

I do not necessarily believe that PGE's line of 30 MW is unjustifiable. The same can be said, however, for the POWER Act's 20 MW threshold.

Q. What Rule C and Rule I policies address the first goal, identified above, of getting prospective data centers to accurately estimate their capacity?

A. The minimum billed demand provisions and, to a lesser extent, the exit fee provision are designed to prevent overestimation. The exceedance penalty is meant to prevent underestimation. Working in conjunction, these policies incentivize data centers to accurately predict their load.

Q. What is minimum billed demand and how does a minimum billed demand prevent overestimating capacity requirements?

A. Minimum billed demand provisions bill customers for distribution, transmission, or generation at a certain percentage of their allocated capacity even if their actual demand was below that level for a given month. The customer is billed at their actual demand if it is above the minimum demand threshold. A related concept is "flat billed demand" that bills the customer a flat rate regardless of their actual demand. Because both minimum and flat billed demand provisions are used for the same purpose, they are referred to collectively as minimum billed demand in this Opening Testimony.

Minimum billed demand provisions disincentivize overestimating a data center's capacity because the customer's minimum payment is tied to the allotted capacity for the facility. The greater the allocated capacity, the greater the minimum payment. Companies are therefore incentivized to not overestimate their capacity needs because doing so will increase the minimum payments they must make.

This policy can also manage some of the potential for cost shifting if a data center does overestimate its capacity requirements. For example, say a data center requests a capacity of 35 MWs, but only needs 30 MWs. If, say, there is a minimum transmission charge set at 90% of allocated capacity, then the company will, at the very least, be billed as if it is using 31.5 MW, even if it is only using 30 MW consistently. The extra 1.5 MW of billed demand can help offset the costs associated with serving those extra 5 MW of demand.

Q. How does an exit fee prevent overestimating capacity requirements?

A. An exit fee, i.e. the fee that a data center company must pay if it exits its contract with the utility, is tied to the cost of the incremental infrastructure necessary to serve a data center and can prevent overestimating capacity for the same reasons as a minimum billed demand. Indeed, one aspect of an appropriate exit fee would be the value of the remaining minimum payments. Under this scheme, overestimating one's capacity on the front end exposes the data center company to a higher potential exit fee than if it asked for the proper capacity in the first place.

Q. What is an exceedance penalty and how does it prevent underestimating capacity?

A. An exceedance penalty is an additional charge that a customer is subject to if its usage exceeds a certain capacity. In UE 433, for example, the Commission approved an exceedance penalty of three times the normal transmission rate.[26] Exceedance penalty provisions also can contain a "buffer"—an amount over a customer's allocated capacity that the customer can use before the penalty applies. In its UE 430 Proposal, PGE asked for a

[26] In the Matter of PACIFICORP, dba PACIFIC POWER, Request for a General Rate Revision, Docket No. UE 433, Order No. 24-447, at 100 (Dec. 19, 2024), available at https://apps.puc.state.or.us/orders/2024ords/24-447.pdf.

buffer of 10 percent of a customer's allocated capacity or 5 MW, whichever was lower.[27] The Commission approved a 10 percent buffer in UE 433.[28]

Intuitively, an exceedance penalty aims to prevent a customer from underestimating their capacity demand by literally penalizing such behavior. Absent such a provision, a large customer may be incentivized to underestimate their capacity to avoid being assigned additional costs for, say, distribution upgrades, or to set a minimum billing demand at a lower level. The extent of the disincentive depends on two factors: the level of the penalty and the existence/extent of a buffer.

Q. How do minimum billing demand provisions, exit fees, and exceedance penalties work together to incentivize customers to accurately predict their capacity requirements?

A. The provisions that are designed to get customers to accurately predict their capacity needs must work in tandem. It goes without saying that policies to prevent overestimation necessitate those that prevent underestimation, and vice versa. Otherwise, the customer will be actively incentivized to either under or overestimate their capacity requirements to avoid the one-sided penalty.

But more consideration is needed than just the existence of provisions to prevent both over and underestimations. The respective deterrence of each should be compared against the other and, to the extent possible, brought into alignment. Mismatching, say, a very protective minimum billing demand with a lenient exceedance penalty has functionally the same effect as having no exceedance penalty at all—the customer in that scenario will be incentivized to

[27] UE 430, PGE/100, Fagen-Frayer/32.
[28] Docket No. UE 433, Order No. 24-447, at 100.

err on the side of underestimating their capacity requirements to obtain lower minimum billed demand payments.

Q. What minimum billed demand provisions do you propose in your Opening Testimony?

A. We propose three types of minimum billed demand provisions. First, for distribution I proposes a flat billed demand set at the actual revenue requirement for distribution resources serving a particular load. This proposal is the same as the one PGE proposed in UE 430. Second, for transmission, I propose a minimum billed demand set at 90 percent of allocated capacity. Finally, for generation, I propose a minimum billed demand set at 80 percent of allocated capacity until 2040, then 90 percent thereafter.

Q. Why does a flat billed demand set at the actual revenue requirement for distribution achieve the goal of customers accurately estimating their capacity needs?

A. We agree with PGE's prior statement that, with this provision in place, "customers are incentivized to forecast their needs realistically since billing is based on actual distribution infrastructure costs."[29] Along with the exit fee (discussed below), setting distribution charges as flat billed demand based on the revenue requirement to recover the costs of its allocated distribution capacity will mean that customers that overestimate their capacity needs (and are actually allocated capacity at that level) are on the hook month by month for a higher level of baseline investment.

Q. Why are you asking for a minimum billing demand for transmission set at 90 percent of a customer's allocated capacity?

[29] UE 430, PGE/200, McFarland-Macfarlane/15.

A. A minimum billing demand for transmission set at 90 percent of allocated capacity is appropriate because it accurately reflects the fact that large customer projects—those that will add at least 20 MW of new load—have high load factors and will drive the need for new transmission to serve load growth in the next few decades.

In UE 430, PGE advocated for an 80 percent minimum billed demand.[30] The Company stated that it did not assign transmission investments directly to customers and bill as flat billed demand, as it did for distribution, because transmission is a system resource that is part of an integrated network, meaning "there is no way to prevent other customers from benefiting from an incremental transmission system expansion."[31] PGE stated that the 80% threshold aligned with its existing Schedule 90 load factor threshold.[32] Finally, PGE supported the proposal as relatively protective for other customers when compared to the minimum billing demand thresholds other utilities have put in place for similar large loads.[33]

PGE's reasoning is unconvincing. The fact that transmission is a system resource only goes so far as to indicate that a minimum billed demand approach is more appropriate than a flat billed demand and that the minimum billed demand threshold should probably not be set at 100% of allocated capacity. As opposed to distribution resources that serve a single customer, when a data center's capacity dips below its allocated capacity, transmission (and generation) resources are freed up for other customer's use because everyone is using the

[30] UE 430, PGE/100, Fagan-Frayer/32.
[31] Id., Fagan-Frayer/33.
[32] UE 430, PGE/200, McFarland-Macfarlane/26; Portland General Electric, Schedule 90, at 1 (Dec. 23, 2024), available at https://assets.ctfassets.net/416ywc1laqmd/4Za197MdOo6BMzYxXc0w5G/a84a06d40727a78f01b101409f22bb25/Sched_090.pdf.
[33] UE 430, PGE's Reply Comments, at 5 (Feb. 19, 2025), available at https://edocs.puc.state.or.us/efdocs/HAC/ue430hac335010026.pdf.

same transmission system. And while PGE was right to set its minimum billed demand higher than what other utility commissions have approved across the country, that does nothing to show that an 80 percent threshold is in fact correct—it only shows that those other jurisdictions set their threshold too low. PGE seems to have abandoned these twin justifications in favor of its third piece of evidence, that the threshold is set at the existing Schedule 90 load factor threshold.[34]

But instituting a minimum billed demand at 90 percent will provide other PGE customers two forms of protection from new data center loads. First, as detailed above, its relatively more stringent threshold creates a greater impetus for new data center customers to predict their capacity needs more accurately, i.e., not overestimate. Second, it prevents under-recovery from the data centers if their actual usage is lower than their allocated capacity, avoiding inequitable cost-shifting from large loads to other customers.

Thus, the 90 percent threshold does a better job of allocating the costs of serving data centers in a manner that is proportional to the costs of serving those customers.[35] In acquiring the necessary resources to serve a load, PGE "plans to have system capacity in the transmission, distribution, and generation systems available beyond what has been requested by the customer to allow for anticipated fluctuations across the system as no load is perfectly consistent."[36] Under PGE's formulation, setting minimum billed demand at the average load factor for data centers makes sense because it guarantees that data centers are paying for what they, as a class, use. And because transmission is a system resource, PGE makes the assumption that other customers will use the 20 or so percent of the resources that data

[34] Coalition /107, Souder/1.
[35] H.B. 3546, sec. 2(2)(a)(A), 2025 Leg., Reg. Sess. (Or. 2025).
[36] Coalition /108, Souder/1.

centers are not using (i.e. the resources available because actual data center load is below its allocated load). But PGE has not shown that its other customers need, let alone use, the transmission resources that were built out for large loads at the times that those loads are not using them to their full capacity. Especially in an era when data centers are driving almost all of the new load growth on the system, it stands to reason that other PGE customers will not, in fact, benefit from the investments PGE makes to serve data center customers. A 90 percent minimum demand threshold, then, recognizes that although sometimes other customers will benefit from the assets a data center is not using when its actual load is below its allocated load, that will not always be the case. The higher minimum billed demand, then, assumes that when PGE plans to have the transmission (and generation) to serve a data center at a certain capacity, plus a little extra because "no load is perfectly consistent," and a data center uses less than that level of capacity, other customers only have a need for *some* of the extra capacity PGE planned for.

Q. Why are you advocating for a minimum billed demand for generation?

A. For two reasons. First, establishing a minimum billed demand for generation is a crucial lever to ensure that the broader minimum billed demand scheme meaningfully influences a data center to accurately predict its capacity needs. Data centers' main costs stem from electricity consumption, and the main component of an electricity bill comes not from distribution or transmission charges, but from actual usage. Thus, a minimum billed demand provision for generation will be the most effective incentive for a data center customer to not overestimate its capacity needs.

Second, new large loads are going to require PGE to acquire substantial generation resources over the course of the next two decades. In its 2023 IPR/CEP Update, the

Company stated that "these new large loads significantly increase PGE's need to acquire new resources, increasing total load by about 20 percent by 2044."[37] This creates the impetus to ensure that data centers are obligated to pay for generation PGE acquires to serve them—otherwise, other customers may be saddled with the bill for GWs worth of new generation that is not needed.

Q. Why, then, are you asking for a lower minimum billed demand for generation?

A. Like transmission, generation is often a shared resource, particularly non-emitting generation resources during our current period of decarbonization. Because new gas generation cannot be built in Oregon,[38] incremental generation sources will generally be non-emitting. Even without new data center load, PGE would have to acquire substantial resources to meet HB 2021's emission reduction requirements. Non-emitting resources that are acquired to meet new data center load can contribute to this broader decarbonization mission when data center usage is below its allocated capacity, i.e., the "unused" portion of their allocated generation can go towards delivering non-emitting energy to other customers, at least during certain times of the day or year. Thus, generation is a system resource that can serve two purposes. Like transmission, access to additional generation during peak hours can provide stability to the grid in general. But it also has the added benefit, outside of peak hours, to displace otherwise emitting resources, reducing PGE's emissions as it comes into compliance with HB 2021.

Of course, the value of marginal non-emitting energy to displace emitting energy decreases as PGE gets closer to its zero-emission requirement in 2040. Once PGE is

[37] Coalition/103, Souder/152.
[38] ORS 469.413.

delivering emissions-free energy to customers, the ability to tap into unused renewable resources "allocated" to a data center will only provide value as a means of meeting peak load, but likely will not displace otherwise emitting resources. At that time, the minimum billed demand should be raised to account for the fact that other customers are less likely to need the marginal generation a data center is not using, and thus the incremental generation acquired to serve data center load will be providing fewer system benefits than in previous years.

One further consideration that will be developed more fully in future testimony is whether additional policies should be in place to account for PGE's actual emissions portfolio in the period between 2025 and 2040. PGE's monthly emissions forecast shows that, in 2030, only 0.675% of emitting generation will occur from April through June combined, and only 3.36% of emitting generation if July is included.[39] During these months, only rarely will additional renewables be needed to deliver zero-emission energy to customers. Perhaps in light of the timing of PGE's emissions, a minimum billed demand threshold for generation that changes throughout the year would be appropriate.

Q. PGE did not propose a minimum billed demand for generation in its UE 430 Proposal. Would such a policy be a first-of-its-kind approach?

A. No. In fact, a minimum billed demand for generation is a common practice in jurisdictions that have established new large load tariffs to address the risks data centers present. For example, the Indiana Utility Regulatory Commission approved a settlement that established an 80 percent minimum billed demand threshold for both transmission and

[39] See Coalition/103, Souder/158 (total emitting generation of 5178 MWa. 35 MWa emitting generation from April-June, and 174 MWa from April-July. 35 / 5178 = 0.00675; 174 / 5178 = 0.0336).

generation[40] and AEP Ohio has a minimum demand charge that ranges between about 73% and 85%.[41]

As noted above, establishing a minimum billed demand that applies to generation is an effective lever to achieve the policy goals of this docket because generation-based costs are a substantial component of a data center's utility bill, and indeed of a data center's expenses in general. Failing to impose a minimum billed demand to generation undermines the functionality of the other minimum billing demand provisions because transmission and distribution costs are relatively small compared to the total energy costs on a data center's bill.

Q. Please explain your exit fee proposal.

A. The exit fee proposal has three components: 1) for transmission and generation, the value of all future monthly payments if demand was at 100% of allocated capacity for the length of the contract, 2) for distribution, the value of all flat billed demand for the length of the contract, 3) the remaining net book value of the distribution assets allocable to the customer three years past the termination year adjusted for salvage.

The distribution-related components—recovery of the remaining flat billed demand charges and the remaining net book value of the distribution assets allocable to the customer three years past the termination year adjusted for salvage—are essentially the same as the exit fee in the UE 430 Proposal.[42] The exit fee proposal is designed to protect PGE's other customers from the risk of stranded assets in the event a data center leaves PGE's system

[40] Coalition/109, Souder/32–33.
[41] Ohio Power Company, Schedule DCT, at 3–4, available at https://dis.puc.state.oh.us/ViewImage.aspx?CMID=A1001001A25G11B21315A00184.
[42] UE 430, PGE/200, McFarland-Macfarlane/15.

before it has paid for the assets PGE invests in to serve the data center. Recovery of the remaining distribution system assets is necessary because those assets are not system assets—therefore, any amount not recovered from the data center customer for which PGE built the infrastructure will be stranded unless a new customer comes in and is able to use those assets. Additionally, the data center should be responsible for remaining payments for generation and transmission as if its demand was at 100% of its allocated capacity for the remainder of the contract.

This admittedly would be a more stringent exit fee provision than what other utilities require. But that is a feature, not a bug. Transmission and generation assets have decades-long depreciable lives, much longer than the maximum length contract recommended here, and about four times as long as the minimum contract length the Coalition recommends. Other jurisdictions have set exit fees as the minimum demand charges for a certain number of years. AEP Ohio set its exit fee as 3 years of minimum demand charges, while Indiana Michigan Power set its exit fee as 5 years of minimum demand charges.[43]

But those exit fees undermine the value of the policies protecting against stranded assets and cost-shifting in a large load tariff. When a utility acquires and builds transmission and generation resources for a data center, they do so to meet that customer's allocated capacity, plus some extra to maintain reliability. PGE is no different, as it "plans to have system capacity in the transmission, distribution, and generation systems available beyond what has been requested by the customer for anticipated fluctuations across the system as no

[43] Ohio Power Company, Schedule DCT, at 5, available at https://dis.puc.state.oh.us/ViewImage.aspx?CMID=A1001001A25G11B21315A00184; Coalition/109, Souder/36.

load is perfectly consistent."[44] Data centers that sign a contract to receive service in PGE territory and cause PGE to spend millions of dollars to serve that data center should be held to the terms of that contract. An exit fee worth the value of the expected transmission, generation, and distribution charges for the length of the contract fairly ensures that a data center does not leave other customers footing the bill when it decides to leave PGE's territory.

Notably, this proposal does not seek the remaining book value minus salvage for generation and transmission resources, which recognizes the nature of those resources as benefiting the system and other customers. After the end of the contract period, those resources should continue to provide those benefits to other customers, and long-term load growth from building electrification in the 2030s and 2040s should provide sufficient need for marginal generation and transmission to warrant those other customers paying for what remains of the undepreciated portion of those assets.

Q. Please explain your recommendation for the exceedance penalty.

A. The exceedance penalty should have two components: a multiplier of 4x for transmission costs above allocated capacity and a multiplier of 1.5x for generation above allocated capacity. This penalty will protect customers from inequitable cost-shifting that can occur if a large customer exceeds its allocated capacity, requiring PGE to find additional transmission and generation to serve the load.

Q. Why are you recommending an exceedance penalty that has both a transmission and generation component?

[44] Coalition/108, Souder/1.

A. As noted above, exceedance penalties are a crucial component of the policy mixture that encourages large load customers like data centers to accurately predict their capacity needs. Exceedance penalties are the only tool discouraging a data center from underestimating its capacity. But discouraging underestimation is just as, if not more, important than preventing overestimation, because exceeding allocated capacity causes immediate costs that are socialized to all customers. As the Commission acknowledged in Order 24-447, "simply securing the level of needed capacity at the pace requested, particularly if loads are underestimated, poses a significant risk of diverting utility resources from other customer priorities."[45]

This proposal only differs from PGE's UE 430 Proposal insofar as it has an additional generation-based penalty. A penalty tied to both generation and transmission recognizes that when a very large load exceeds its capacity, the utility will incur both generation and transmission costs beyond what the utility has planned for that will be spread to all customers. While the 4x transmission penalty provides a disincentive to underestimate one's capacity needs, the additional generation penalty helps strengthen that disincentive to bring it into relative alignment with the level of disincentive to overestimate capacity established by the minimum billed demand provisions and the exit fee.

Q. Does an exceedance fee need to be a monetary penalty?

A. No. At least one other utility has designed a non-monetary exceedance penalty. AEP Ohio can, with Commission approval, suspend service to a large load customer that exceeds its capacity allocation by 1 MW or more.[46] While I do not recommend such an approach

[45] UE 433, Order 24-447, at 99.
[46] Ohio Power Company, Schedule DCT, at 2, available at https://dis.puc.state.oh.us/ViewImage.aspx?CMID=A1001001A25G11B21315A00184

here, future testimony may discuss at the possibility that a service suspension exceedance penalty may be appropriate in certain circumstances.

Q. Should the exceedance penalty have a buffer beyond allocated capacity before it sets in?

A. No. In UE 433, the Commission declined to establish a buffer to the excess demand charge for large loads adopted in that proceeding, stating: "Unlike overestimating demand, a company underestimating its demand may necessitate that the utility quickly find additional supply for these customers, incurring costs that will be spread to all customers."[47] As the Commission implied, exceeding allocated capacity generally creates costs in the immediate term, which are then spread to other customers. Even a "small" buffer of 10 percent or 5 MW, which PGE recommended in UE 430, could leave customers footing the bill for substantial power costs. To put a 5 MW exceedance in perspective, the average PGE residential customer uses 9318 kWh of electricity a year, which amounts to 1.064 kWh/hour.[48] A 5 MW exceedance for one hour, i.e. 5000 kWh, is the equivalent of adding 4,700 residential customers to PGE's system for that hour.[49] The scale of large data center loads is such that even small exceedances can have substantial system-wide effects. Exceedances, then, should be discouraged to the maximum reasonable extent.

Q. Do you have any other testimony to offer on exceedance penalties?

A. Although our proposal does not have this framework at this time, a penalty that scales up as the extent of the exceedance increases may be appropriate because each incremental

[47] UE 433, Order 24-447, at 100.
[48] Quick Facts, Portland General Electric, (last visited July 22, 2025), available at https://portlandgeneral.com/about/info/quick-facts (9318 / 365 / 24 = 1.06369)
[49] 5000 / 1.060369 = 4700.61.

additional resource that needs to be acquired to serve that additional load is likely to be more expensive than the last. Such a policy should be based on the MW of exceedance (rather than percentage of allocated capacity) because it's the amount of additional load that must be acquired that determines cost (i.e., a 10 MW exceedance will cause the same incremental costs regardless of whether the data center is allocated 30 MW or 300 MW). The Coalition may provide additional testimony on this aspect and amend its exceedance penalty proposal in future testimony accordingly.

Q. Why do you recommend a minimum contract length of 15 years?

A. In UE 430, PGE proposed a minimum contract length of 8 years. But that length is simply too short in comparison to decades-long lifespan of generation and transmission assets that might be built for data centers. The depreciable lives of transmission substation equipment (62 years), transmission towers and fixtures (70 years), transmission poles and fixtures (52 years), and overhead conductors and devices (65 years) are all orders of magnitude longer than an 8-year minimum contract.[50] Indeed, even a 15-year (or 30-year) contract does not come close to covering the full depreciable lives of assets that may be built to serve a customer under that contract. The 15-year minimum proposed here is not inconsistent with the POWER Act, which states that any contract for the provision of electric service between an electric company (PGE) and a data center must have a specified duration and be for a duration of at least 10 years or longer.[51]

Paired with the exit fee provision advocated for above, a longer minimum contract ensures a greater share of the infrastructural costs associated with a new data center are

[50] Coalition/105, Souder/1; Coalition/106, Souder/1.
[51] H.B. 3546, sec. 5(1)(b)(A)(ii), 2025 Leg., Reg. Sess. (Or. 2025).

recovered by that data center rather than other customers. The fifteen year minimum is also more aligned with the minimums seen in other jurisdictions with relatively larger load thresholds to qualify for the large load tariff. For example, AEP Indiana Michigan's tariff, which applies to large loads over 70 MW, has a 12- to 17-year minimum contract, depending on the customer's load ramp.[52] AEP Ohio, which has a 25 MW threshold, has an 11-year minimum contract (a three-year ramping period + 8 years).[53] A 15-year minimum fits with these schemes given an expected load threshold of at least 20 MWs that should result from this proceeding, providing assurances that a reasonable amount of data center-related costs are recovered from those customers while also not imposing an overly burdensome contract length. Of course, data centers will be free to sign longer contracts as well.

Q. How do these provisions interplay with energy efficiency and demand response?

A. Attempting to ensure that data centers will accurately predict their capacity needs, and use energy in line with their allocated capacity, is in direct tension with the general desire for customers to become more energy efficient over time and to engage in demand response programs that can shave peak demand. Incentivizing customers to stay within a particular band of capacity disincentivizes those customers taking actions that could lower demand outside of that band.

Energy efficiency presents a particular problem, because the adoption of energy efficient technologies lowers a data center's demand to perform a particular set of tasks permanently. Why would a data center customer adopt new, energy-efficient technologies if it is going to have to pay the same minimum billed demand for generation and transmission

[52] Coalition/109, Souder/32–33.
[53] Ohio Power Company, Schedule DCT, at 5, available at https://dis.puc.state.oh.us/ViewImage.aspx?CMID=A1001001A25G11B21315A00184

and flat billed demand for distribution? From the perspective of other customers, do they want a data center only making minimum billed demand payments, and therefore underpaying for the resources designed to serve their allocated capacity month after month?

Q. How do data centers consider energy efficiency?

A. Energy efficiency at a data center can be broken into two components: 1) IT efficiency and 2) non-IT efficiency. IT efficiency can be measured in terms of Data Center Infrastructure Efficiency (DCIE), and non-IT efficiency is measured in terms of Power Usage Effectiveness (PUE).[54]

The DCIE is the percentage of total energy usage at a data center used by IT equipment (IT energy).[55] Both the hardware and software of the computing at a data center can be a source of energy efficiency. For example, state-of-the-art chips, the hardware on which data centers run, see efficiency gains with each new generation.[56] Meanwhile, efficiencies in underlying algorithms, how hard an AI model "thinks" about an answer, length of output, and time latency (the delay between an input and output) can increase or reduce the power necessary for a data center run.[57]

A data center's PUE is the ratio of a facility's total energy usage to IT energy usage.[58] Global PUEs fell dramatically from an average of about 2.5 in 2007 to 1.58 in 2018 but have

[54] Coalition/110, Souder/12.
[55] Id.
[56] Energy and AI, International Energy Agency, at 43 (Apr. 2025), available at https://iea.blob.core.windows.net/assets/601eaec9-ba91-4623-819b-4ded331ec9e8/EnergyandAI.pdf.
[57] Id.; Coalition/110, Souder/18–19.
[58] Coalition/110, Souder/12; "The Energy & Water Use Impacts of Building System Design for Data Centers: Design Considerations for Oregon & Washington," PAE, at 5 (Feb. 14, 2025), available at https://critfc.org/wp-content/uploads/2025/03/data-center-report.pdf.

largely leveled off since.[59] Non-IT efficiency is driven by more efficient cooling, venting, lighting, and electrical systems.[60] Although improvements to non-IT efficiency can be beneficial by reducing demand, they may present non-energy tradeoffs. For example, more efficient liquid-based cooling technologies can save energy but use more water, and therefore may negatively impact surrounding waters.[61] One other valuable consideration is the difference between a data center's average PUE and peak PUE—while reducing both can be an important goal, reducing peak PUE may deliver more tangible benefits as it reduces data centers' load during system peaking (given that peak PUE is associated with high temperatures and therefore summer peaking load for the whole system).[62]

Q. How can energy efficiency be encouraged without increasing the risk of spreading costs to other customers to pay for infrastructure built to serve data centers?

A. Encouraging energy efficiency is often the first step in smart management of utility systems. By lowering usage, the adoption of more efficient technologies saves money for both the adopter (through lower usage) and other customers (by preventing capital expenditures to serve otherwise-higher load), contributes to system reliability, and reduces greenhouse gas emissions. For these reasons, the Energy Trust of Oregon has been tasked with acquiring all cost-effective energy efficiency for customers.

But whether energy efficiency has inherent positive value to individual and system-wide customers is more complicated for large loads subject to the policies proposed in UE

[59] Coalition/110, Souder/11; "The Energy & Water Use Impacts of Building System Design for Data Centers: Design Considerations for Oregon & Washington," PAE, at 5.
[60] "The Energy & Water Use Impacts of Building System Design for Data Centers: Design Considerations for Oregon & Washington," PAE, at 5.
[61] Id., at 12–13
[62] Id., at 11.

430 and this docket. Major efficiency gains in the IT energy (ITE) needs of a data center could drive a data center's usage far below its allocated capacity, increasing the potential of stranded assets. In a practical sense, this scenario is functionally indistinguishable from a data center overestimating its capacity needs.

Of course, ITE efficiency may be met not with a reduction in energy usage, but an increase in the tasks performed at a given data center. Increased efficiency may not, then, drive down demand, but simply allow data center customers to get more bang for their buck. This may be a preferable outcome if it prevents the addition of incrementally more data centers that require their own infrastructure to energize.

From a policy perspective, then, how and to what extent to encourage energy efficiency is cross-pressured against the other policy goals of avoiding stranded assets and inequitable cost-shifting from data centers to other customers are questions of central importance. Arguably, at least in the creation of a new facility, a data center company is sufficiently incentivized to adopt all feasible energy efficiency measures, given the long-term savings on its energy bills. But once a data center in energized and subject to provisions like the minimum billed demand, they may not be encouraged to adopt additional energy-saving measures that reduce capacity needs below the minimum billed demand threshold.

Q. Do you have any recommendations related to energy efficiency at this time?

A. No, although I refer to the Opening Testimony of Andy Eiden, who describes energy efficient technologies and strategies that could be encouraged with policies developed in this docket.[63] That said, a few general policy questions are important to outline at the start of the docket so PGE, Staff, and intervenors can work towards a solution that effectively

[63] Coalition/200, Eiden/31.

encourages data centers to adopt energy efficient techniques and technologies without undermining the central goal of this docket, i.e., to assign data centers their costs of service and prevent cost-shifting to other customers. Are ITE efficiency gains best utilized to reduce a data center's capacity requirement or to allow a data center to do more with its allocated capacity? To what extent does increasing ITE efficiency prevent the need for a data center company to build out an additional facility in PGE or non-PGE territory? Is the market incentive to adopt ITE efficiencies sufficient to encourage those technologies, or should there also be a utility rate incentive? For non-IT energy efficiency, what average and peak PUEs are reasonably achievable? To what extent (if at all) should other ratepayer protections be lessened to encourage data centers to adopt technologies that result in a lower PUE at the outset of energization? And given that PUE is as much a function of IT energy use as non-IT energy use, is PUE even a valuable metric to determine whether a data center is adopting efficient technologies on a desirable timeline? The Coalition believes the answers to these questions are best developed with some level of collaboration to strike the proper balance with the other goals of this docket.

Q. What role can data centers play in demand response?

A. The extent to which data centers could or would engage in demand response is a matter of some contention. Although researchers have shown both the potential for data centers to engage in demand response,[64] and that substantial benefits from even a small amount of load flexibility,[65] in practice data centers have exhibited low participation in

[64] Girish Ghatikar, et. al., "Demand Response Opportunities and Enabling Technologies for Data Centers: Findings from Field Studies," Lawrence Berkeley National Laboratory, (Aug. 2012), available at https://www.osti.gov/servlets/purl/1174175/.
[65] Tyler H. Norris, et al. "Rethinking Load Growth: Assessing the Potential for Integration of Large Flexible Loads in US Power Systems," Nicholas Institute for Energy, Environment, and

demand response programs.[66] Those that write encouragingly about the potential almost universally cite to the same 2023 blog post about Google's ability to shift non-urgent workloads to other times and locations to reduce a given data center's usage when the serving utility is experiencing high-demand.[67]

Indeed, Google recently announced deals to engage in demand response with Indiana Michigan Power and the Tennessee Valley Authority.[68] According to Michael Terrell, Google's Head of Advanced Energy, the company will begin utilizing its ability to deliver demand response by targeting AI learning workloads.[69] Terrell cautioned, though, "data center demand flexibility is still in the early stages" and that there "are limits to how flexible a given data center can be, since high levels of reliability are critical" for certain services like Google Search and Google Maps.[70] Although this news is hopefully the first major step in making data center demand response a widespread reality, the same underlying latency and reliability concerns will likely prevent most data centers from engaging in demand response programs.

That said, data center demand response is a more cohesive energy-reduction strategy than energy efficiency with the other cost-based goals of this docket because of its temporary

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Sustainability, (2025), available at https://nicholasinstitute.duke.edu/sites/default/files/publications/rethinking-load-growth.pdf (hereinafter "Rethinking Load Growth").

[66] Id., at 9.

[67] Varun Mehra and Raiden Hasegawa, "Supporting power grids with demand response at Google data centers," (Oct. 3, 2023), available at https://cloud.google.com/blog/products/infrastructure/using-demand-response-to-reduce-data-center-power-consumption;

[68] Michael Terrell, "How we're making data centers more flexible to benefit power grids," Google (Aug. 4, 2025), available at https://blog.google/inside-google/infrastructure/how-were-making-data-centers-more-flexible-to-benefit-power-grids/.

[69] Id.

[70] Id.

nature. Unlike energy efficiency, demand response actions do not fundamentally disrupt the function of the cost-shifting prevention policies because it does not lower demand indefinitely. Instead, demand response can be targeted to only those hours when reduced data center load provides distinct benefits to the system through peak shaving that outweigh the general benefit of data centers maintaining their usage near their allocated capacity. It does seem, too, that AI-based data centers have more load-flexibility than traditional cloud-based centers that rely on instantaneous exchanges of inputs and outputs, which may indicate a greater ability (and therefore willingness) to engage in demand response. That may not continue to be the case, however, as AI-learning is overtaken by inference tasks (i.e., responding to an inquiry) that have the same latency-first business models that make collocated and cloud-services data centers reluctant to engage in demand response.[71]

Q. How should demand response be encouraged?

A. Encouraging data center participation in timely demand response is complicated by the fact that, at least to date, modest economic incentives from utilities do not overcome the cost to implement the technology and personnel necessary to engage in demand response.[72] As noted above, implementing a minimum billed demand regime further disincentivizes demand response, as the data center company will be unable to achieve cost savings from reducing demand. Rather than be a justification to set minimum billed demand at a lower level, the Coalition believes the best way to balance the competing interests of cost-shifting protections and demand response participation is to temporarily (and voluntarily) lower a

[71] "Rethinking Load Growth," at 11.
[72] Id., at 9.

data center's allocated capacity during certain hours of the year when PGE forecasts peak load events.

Generally speaking, PGE should be able to communicate to data center customers with some advance (24 hours, 48 hours, etc.) of peaking load (however it may be defined). Data center customers can then commit to certain load reductions during those specified hours (either by reducing usage or shifting to on-site generation and storage). For billing purposes during those hours, the allocated capacity would be lowered to the level the data center customer agrees to for those specified hours. By lowering data center demand predictable amounts during hours of peak load, PGE can free up capacity and resources to serve other customers. The program would function similarly to the Schedule 86 nonresidential demand buy back rider, for reference.[73]

This recommendation is preliminary; I look forward to working with other parties to develop a workable framework that encourages data center customers to engage in a demand response program that does not undermine the core goal of this docket: to develop a framework to ensure data center loads do not result in stranded assets and inequitable cost-shifting to other customers.

IV. HB 2021 Compliance

Q. What are PGE's HB 2021 compliance requirements and is PGE on track to meet those requirements?

[73] Schedule 86, Portland General Electric Company, available at https://assets.ctfassets.net/416ywc1laqmd/7gMSwggamPH0dhACy3TsAk/6dabf5c3cad4907623e0edcefd86d134/Sched_086.pdf.

A. PGE must reduce the emissions associated with energy delivered to Oregon customers 80% by 2030, 90% by 2035, and 100% by 2040.[74] PGE's baseline emissions, representing average yearly emissions from 2010 to 2012, is 8.1 million metric tons of CO2e (MMTCO2e).[75] The Company must also show that it is making "continual progress" towards meeting those goals in its clean energy plans.[76]

PGE reported 5.9 MMTCO2e of emissions associated with energy served to Oregon customers in 2024, representing a 27.2% reduction from its baseline (although only a 15.8% reduction since 2012, when emissions were about 7 MMTCO2e).[77] Therefore, to meet its 2030 emission reduction requirement, PGE must reduce the emissions associated with energy delivered to customers 72.5% from its current level by 2030.

PGE's recently filed CEP/IRP Update reflects optimism that it will be able to meet its 2030 emission reduction requirement through massive resource acquisitions in 2029 and 2030.[78] These additions include nearly 1400 MW of Wind, over 1000 MW of solar, and 1750 MW of storage.[79] Part of this extensive need is the result of a lackluster energy acquisition in the Company's 2023 RFP, which resulted in a planned acquisition of only 85 MWa of renewable resources, far less than the stated need of 753 MWa.[80] To its credit, PGE acquired substantial battery resources in its 2023 RFP to sure up its capacity needs in the mid-decade.

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[74] ORS 469A.410.
[75] ORS 469A.400(1)
[76] ORS 469A.415(4)(e), (6).
[77] Coalition/103, Souder/27.
[78] Id., Souder/147.
[79] Id.
[80] In the Matter of PORTLAND GENERAL ELECTRIC COMPANY, 2023 All-Resource Request for Proposals, Docket No. UM 2274, Staff Report, at 3 (Nov. 12, 2024), available at https://edocs.puc.state.or.us/efdocs/HAU/um2274hau332923033.pdf.

Q. How do new large loads like data centers affect PGE's ability to meet its HB 2021 requirements?

A. As PGE noted in its CEP/IRP Update, "HB 2021 targets are absolute emissions targets, not carbon intensity targets, and are unforgiving of the load growth forecasted for the region and PGE's service territory."[81] In practice, this means that new load growth needs to be entirely with non-emitting resources, while also, as noted above, driving down emissions from existing load by 72 percent in the next 5 years.

Perhaps obviously, then, new load is not the same as existing load for HB 2021 compliance purposes: rather, new load is even more burdensome than existing load, at least until 2040. And data centers, more so than any type of customer, are driving load growth in the near and medium term. As noted above, PGE is expected 1.9% annual load growth over the next twenty years, but only 0.1% growth if new large loads are removed.[82]

Q. Do data center load profiles create any difficulties as it relates to meeting their load with renewable resources?

A. Yes. Data centers are often referred to as "continuous-use" customers, with load profiles that show relatively constant usage across time.[83] A minimum billed demand provision is feasible for data centers for this very reason—they are expected to use essentially all their allocated capacity almost all the time. But that characteristic is not particularly compatible with intermittent renewable energy resources like wind and solar, requiring even greater buildouts of those resources, and well as the transmission to connect

[81] Coalition/100, Souder/18.
[82] Coalition/100, Souder/57.
[83] Lazar, Chernik, and Marchs, Electric Cost Allocation for a New Era: A Manual, RAP, at 263 (Jan. 2020), available at https://www.raponline.org/wp-content/uploads/2023/09/rap-lazar-chernick-marcus-lebel-electric-cost-allocation-new-era-2020-january.pdf;

those resources and storage to maximize those resources' output, to meet a data center's relatively constant energy need.

Q. Does unrestrained data center load growth threaten PGE's ability to meet HB 2021?

A. Yes. Absent reasonable protections, data centers can be connected without regard to the availability of additional renewable resources to meet that demand. For example, PGE is predicting to acquire essentially no new renewable resources until 2029 beyond the 375 MW of solar from its 2023 RFP, which will provide only 81 MWa to the system.[84] The Company is also adding about 500 MW of non-emitting contracts through 2028, and another 200 MW worth before the end of the decade.[85] In the near term, then, it is unlikely that new data center load will be met with renewable resources, driving up the Company's emissions before 2029.

At the same time that these large loads are driving up demand, several factors are undermining the supply of new resources, emitting and non-emitting alike. The problem isn't that data centers will need all the power a utility has, at least in PGE's territory. The problem is, as Peter Freer, Meta's former Director of Energy Strategy, stated on a recent podcast, "the immediacy of this demand, they need all the *next* power for these data centers . . . right now it's trying to vacuum up every possible available megawatt."[86] And although the creation and deployment of new, cheap, renewable technologies can very well be described as a technological revolution on par with other industrial revolutions (at least globally),[87] that

[84] Coalition/103, Souder/147.
[85] Id.
[86] "What's Really Holding Back New Data Centers," Shift Key with Robinson Meyer and Jesse Jenkins, at 26:13–26:42 (Mar. 26, 2025).
[87] Yuki Numata, Laurens Speelman, and Marissa Gantaman, "The Energy Transition is a Technological Revolution — with a Deadline," Rocky Mountain Inst., (Aug. 10, 2023), available at https://rmi.org/the-energy-transition-is-a-technological-revolution-with-a-deadline/.

innovation is increasingly turning to serve data centers.[88] That last point, that new renewable technologies that can provide firm renewable load are looking to serve data centers first and foremost, is not necessarily a bad thing, as data center companies could provide necessary capital to take these nascent technologies into the mainstream. At least in the next five to ten years though, data centers' seemingly insatiable appetite for new generation could spur an electricity affordability crisis as new electricity demand outpaces new electricity supply.[89]

The situation has gotten worse in 2025. The Trump Administration has performed an all-out assault on renewable projects, most recently (and notably) with the elimination of renewable energy tax credits in the One Big Beautiful Bill,[90] which a Bloomberg report predicted will lead to a 41% reduction in clean energy installations after 2027.[91] Adding to the financial stress is additional regulatory burden that is targeting renewables on the federal and local level. The U.S. Department of the Interior recently released a Secretary Order requiring "all decisions, actions, consultations, and other undertakings . . . related to wind

[88] Katie Brigham, "Climate Tech Companies are all Data Center Companies Now," Heatmap News (July 24, 2025), available at https://heatmap.news/climate-tech/data-center-energy-efficiency.
[89] Robinson Meyer, "The Electricity Affordability Crisis is Coming," Heatmap News, (July 23, 2025), available at https://heatmap.news/politics/electricity-price-crisis.
[90] Earlier drafts of the bill contained policies that would have been even more detrimental to the work being done to comply with HB 2021 as well as the purposes of this docket. For a time, the bill included an excise tax on renewable energy. Tracy J. Wholf, "Senate removes excise tax on renewable energy industry from Trump domestic policy bill," CBS News, (Jul. 1, 2025), available at https://www.cbsnews.com/news/senate-removes-excise-tax-renewable-energy-industry-trump-domestic-policy-bill/. A draft also include a provision that barred state regulation of artificial intelligence for 10 years. Molly Taft, "A Political Battle is Brewing over Data Centers," Wired (Jun. 10, 2025), available at https://www.wired.com/story/a-political-battle-is-brewing-over-data-centers/.
[91] Anne Fischer, "The rise and fall of clean energy deployment following OBBB," PV Magazine (July 18, 2025), available at https://pv-magazine-usa.com/2025/07/18/the-rise-and-fall-of-clean-energy-deployment-following-obbb/.

and solar energy facilities" to pass through "multiple layers of political review."[92] The Interior Department then one-upped itself, issuing another secretarial order that appears to direct the agency to deny all wind or solar permits unless the agency believes the project can generate the same amount of energy on a per-acre basis as gas or nuclear power.[93] Increasingly, counties and local governments are passing laws that slow or altogether curtail the development of renewable energy: 605 counties have rules restricting renewable development, accounting for 17% of the landmass of the continental United States.[94] Meanwhile, tariffs on core infrastructure components like copper and steel have prices for those inputs surging. Even emitting generation, favored by the current administration, may not be able to keep up as the backlog for new turbines extends into the next decade.[95]

Again, HB 2021's requirements are in terms of absolute emissions, not emissions intensity. Serving new load with non-emitting resources makes no progress towards meeting PGE's requirements, but does eat up valuable and finite capital, resources, and capacity to reduce emissions.

Q. What pathways are available to prevent data centers from jeopardizing PGE's ability to meet its HB 2021 requirements?

[92] Jael Holzman, "Internal Agency Memo Calls for Political Review of Solar, Wind Projects," Heatmap News, (July 16, 2025), available at https://heatmap.news/politics/interior-wind-solar-memo
[93] "Order No. 3438: Managing Federal Energy Resources and Protecting the Environment," Sec. of the Interior, (Aug. 1, 2025), available at https://www.doi.gov/document-library/secretary-order/so-3438-managing-federal-energy-resources-and-protecting.
[94] Robinson Meyer, "The Permitting Crisis for Renewables," Heatmap News (July 7, 2025), available at https://heatmap.news/politics/laws-restricting-renewable-energy
[95] Advait Arun, "The Natural Gas Turbine Crisis," Heatmap News (Feb. 26, 2025), available at https://heatmap.news/ideas/natural-gas-turbine-crisis.

A. First, PGE could establish a queueing system, under which a new data center load cannot connect until new non-emitting resources are available to meet the needs of that data center. Data centers that bring their own non-emitting resources sufficient to meet their load can skip the queue. This structure could be beneficial for two reasons: 1) by preventing new loads from coming online until incremental non-emitting resources are available, it avoids a situation where rapid connections of new loads drives up PGE's emissions at a time when those emissions need to be going down and 2) it incentivizes large loads to bring their own non-emitting resources onto the system, freeing up capital for PGE to spend on non-emitting resources that go towards the reduction of its emissions to serve existing customers.

Some practical limitations exist to this scheme. First, such a scheme must have guardrails to ensure that new non-emitting resources are not going entirely to allow new data centers to connect to PGE's system, i.e., avoid a situation where all the "next power" is going to clearing the data center connection queue.[96] PGE's focus in procuring non-emitting resources should be emission reductions, not clearing its queue of data centers waiting to energize. Second, the direct access cap would likely need to be lifted, as PGE has only 33aMW remaining in its Long-Term Direct Access program in May of 2025.[97]

[96] What's Really Holding Back New Data Centers," Shift Key with Robinson Meyer and Jesse Jenkins, at 26:13–26:42 (Mar. 26, 2025).
[97] In the Matter of ALLIANCE OF WESTERN ENERGY CONSUMERS, Petition for Investigation Into Long-Term Direct Access Programs, Docket No. UM 2024, AWEC's Opening Testimony, AWEC/100, Kaufman/2, (May 2, 2025), available at https://edocs.puc.state.or.us/efdocs/HTB/um2024htb336553026.pdf.

Relatedly, data centers could be encouraged to connect to "energy parks," areas with sufficient wind, solar, and battery resources to meet the needs of the connected load.[98] Energy parks can be fully isolated from the grid or be "export-only" where they provide energy to their connected load and then export to the grid as a flexible generator.[99] Data centers that develop their own energy parks, whether they be fully isolated or export-only, also free up some capital for their serving utility to spend on other goals and reduce some of the risks of stranded assets because the data center would pay for and own the underlying resources. In practice, though, this option would likely only be available to smaller data centers, as the resource buildout necessary to fully serve a hyperscale data center with intermittent renewable energy would likely be prohibitive from an upfront cost and land availability perspective.

Second, new data center loads could be prevented from connecting to PGE's system if PGE is not in compliance with HB 2021. This process would function on a yearly basis—if PGE's emissions report to the Department of Environmental Quality (DEQ) shows it was not in compliance with HB 2021 for the previous year, it cannot connect new data centers until at least the next year's report. This approach assumes PGE can properly manage its non-emitting acquisitions and load growth concurrently, until the Company shows that it cannot.

Q. Do data centers present opportunities to bring non-emitting generation to Oregon and aid in statewide emissions reductions?

[98] Eric Gimon, et al., "Energy Parks: A New Strategy to Meet Rising Electricity Demand," Energy Innovation, at 8 (Dec. 2024), available at https://energyinnovation.org/wp-content/uploads/Energy-Parks-Report.pdf.
[99] Id.

A. Yes, theoretically. Data centers' access to capital can allow them to invest themselves in renewable energy and capacity procurement that can be utilized by their serving utility in times of need. If these large customers utilize their vast resources to build behind the meter resources that are then available for utility use at times of need or, alternatively, available to displace the need to make market purchases or otherwise utilize emitting resources, the large customers could aid in PGE's quest to comply with HB 2021.

Data centers also present a potential benefit in that they are not as constrained by cost-effectiveness principles as a regulated utility. As touched upon above, this could allow these capital-rich companies to invest in technologies that can provide firm non-emitting energy, like geothermal, as well as other technologies that could provide greater reliability than methods utilities currently use, like longer-term (100 hour) batteries.[100] PGE has recently shown that the utilization of long-term batteries can substantially reduce the amount of overall storage resources necessary to reliably meet capacity needs, particularly during winter months.[101] Beyond bringing these technologies into a utility's resource mix, data center investment in these technologies can spur further cost-reducing development, making those resources more affordable for utility procurement in the future.

Finally, data centers can support further decarbonization in Oregon by providing the heat source for thermal energy networks (TENs). TENs utilize a connected network of underground pipes to transfer heat, allowing buildings that are a part of the network to heat

[100] Katie Brigham, "Climate Tech Companies are all Data Center Companies Now," Heatmap News (July 24, 2025), available at https://heatmap.news/climate-tech/data-center-energy-efficiency.
[101] Coalition/103, Souder/168.

and cool with non-emitting energy using heat pumps.[102] Because data center waste heat is constant (due to their high load factors), they can serve as the underlying heat source to power a TEN.[103] These projects are already being piloted.[104] The benefits for building decarbonization purposes from this use of data center waste heat could be substantial:

> "If surrounding buildings previously heated with gas, oil, or propane furnaces, they switch to heat pumps to access the data center's heat. In the process, these buildings eliminate onsite combustion for heating and reduce their own emissions. If surrounding buildings previously relied on electric resistance heating, transitioning to heat pumps will significantly decrease their electricity consumption."[105]

Data centers that are placed near other buildings should be built "thermal ready," i.e., with the ability to transfer waste heat to nearby buildings so those buildings can either electrify or reduce energy usage by utilizing a more efficient form of electric heating, as TENs can deliver energy up to six times more efficient than electric resistance heating.[106]

It goes without saying that data centers consistently produce waste heat that, traditionally, must be cooled to allow processors to function to their main capability. Data center waste heat is "an untapped opportunity" to develop TENs, which can help decarbonize

[102] Ana Maria Camargo, et al., "The Future of Heat: Thermal Energy Networks as an Evolutionary Path for Gas Utilities Toward a Safe, Equitable, Just Energy Transition," ACEEE, at 3–4 (2024), available at https://www.aceee.org/sites/default/files/proceedings/ssb24/assets/attachments/20240722163127593_770c2285-1b3b-4b4c-a1ed-09d4a7ad7e28.pdf; Ashley Besic, "Can Data Centers Heat our Buildings," Building Decarbonization Coalition, at 7 (Jul. 16, 2025), available at http://buildingdecarb.org/wp-content/uploads/BDC_Can-Data-Centers-Heat-Our-Buildings_Brief.pdf.
[103] Besic, "Can Data Centers Heat our Buildings," Building Decarbonization Coalition, at 8.
[104] Ana Maria Camargo, et al., "The Future of Heat: Thermal Energy Networks as an Evolutionary Path for Gas Utilities Toward a Safe, Equitable, Just Energy Transition," ACEEE, at 4–5.
[105] Besic, "Can Data Centers Heat our Buildings," Building Decarbonization Coalition, at 9.
[106] Id.

buildings in nearby residential and commercial neighborhoods.[107] A data center-heated TEN in Seattle is expected to save 80,000 MWh of electricity over 25 years.[108]

Data centers that help develop the technologies that will provide efficient, clean energy can be a valuable resource in achieving system-wide decarbonization in Oregon. In turn, an Oregon economy that can offer businesses reliable, affordable, and clean energy will be well positioned in the middle of the century to attract more investment and spur economic opportunities for state residents. If data centers are coming to PGE territory, it is crucial that they agree to utilize their unique characteristics (and access to capital) to aid Oregon's transition to a green economy.

Q. Do you have concluding thoughts about the data center loads and HB 2021 compliance?

A. PGE has a substantial obligation to achieve an 80 percent reduction in emissions associated with serving Oregon load by 2030, let alone achieve the additional reduction requirements in 2035 and 2040. Many factors, including federal distaste for new wind and solar projects and the practical ability to acquire thousands of megawatts of resources in a few short years, make this job more difficult than it may have appeared to be even just last year. Added to that list of factors is the recent uptick in expected data center load growth, which could eat up all of the next set of new, non-emitting resources in the region, preventing their use to reduce existing emissions. Beyond even the practical limitations that could prevent PGE from meeting HB 2021, the need to also deliver non-emitting resources to new

[107] Ashley Besic, "Can Data Centers Heat our Buildings," Building Decarbonization Coalition, at 1 (Jul. 16, 2025), available at http://buildingdecarb.org/wp-content/uploads/BDC_Can-Data-Centers-Heat-Our-Buildings_Brief.pdf.
[108] Id., at 12.

data center load could cause the utility to hit the law's "cost cap," removing PGE's need to meet its emission reduction obligations, which would be a disservice to its other customers that are expecting the provision of reliable, clean energy at a reasonable price. I look forward to working with PGE, Staff, and the other intervening parties to find a solution that ensures PGE will meet its HB 2021 obligations on time over the next 15 years.

V. Conclusion

Q. Do you have any conclusory thoughts at this stage?

A. Yes, a few. The issues addressed here are central to the role of the Commission to achieve adequate service for all customers and the public generally at fair and reasonable rates.[109] Adequate service certainly includes traditional notions of reliability and safety, but increasingly so includes additional environmental factors including the climate change impacts of the energy delivered in customers. The role of the Commission to achieve for customers reliable, safe, and clean energy at a fair and reasonable price is the crux of the task in front of the parties and the Commission in this docket. Rapid load growth driven by a handful of customers threatens the ability of PGE hold up its end of the regulatory compact, to serve customers with adequate electric service that doesn't break the bank.

Indeed, the core problems this docket seeks to resolve are intertwined with the very purpose of utility regulation. Along with the desire to prevent utilities from extracting monopoly profits from customers, the regulatory regime sought to prevent utilities from granting preferential treatment to customers from whom it could expect to earn higher profits. PGE has not hidden the fact that it welcomes these new data center loads, viewing them as an "opportunity" without specifying how exactly these large loads are going to help

[109] ORS 756.040(1).

procure renewable energy that actually drives down emissions or reduces costs for customers.[110] As noted above, data centers can provide valuable capital and technological development in renewables that benefit other customers in the long run. But at a time when federal policy seems purposefully designed to drive up utility rates across the country, residential, commercial, and other industrial customers need to be protected from further rate impacts that do little to improve the service they receive, and indeed undermine PGE's ability to meet its legislatively mandated emissions reduction requirements.

The Coalition agrees that PGE has an opportunity in front it: the opportunity to become a leader in delivering affordable, clean energy to its entire customer base. In the long run, the state will be better served if its largest utilities can deliver to customers reliable, non-emitting energy on a nearer timeline than other regions. The introduction of large data center loads threatens both the state's affordability and climate goals if not properly managed.

Q. Does this conclude your testimony?

A. Yes.

[110] Coalition/103, Souder/12, 28, 38, 44; Coalition/111, Souder/2.

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Coalition/103
Souder/1



Portland General Electric

2023 Clean Energy Plan and Integrated Resource Plan Update

This document contains forward-looking statements, including those regarding implementation of our business plans, technology transitions, our business, strategies and financial performance, our offerings of new services, and other statements that are not historical fact, and actual results could differ materially from these forward-looking statements. Risk factors that could cause actual results to differ are set forth in the “Risk Factors” section, as well as other sections of our Annual Report on Form 10-K, available on our website at investors.portlandgeneral.com/financial information/sec-filings, as well as, or in addition to, other filings with the SEC. All forward-looking statements are based on management’s estimates, projections, and assumptions as of the date of filing, and we undertake no obligation to update any such statements.

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Introduction

Portland General Electric Company (PGE or Company) submits this 2023 Clean Energy Plan and Integrated Resource Plan Update to inform the Oregon Public Utility Commission (OPUC or Commission) of the Company's actions since acknowledgment of the 2023 Integrated Resource Plan (IRP). The OPUC's Order 24-096 acknowledged, with conditions, PGE's 2023 IRP on April 18, 2024. Additionally, the Commission directed PGE to update PGE's Clean Energy Plan (CEP) in PGE's subsequent CEP/IRP Update.

An IRP Update addresses specific inputs that may have changed since the most recent IRP was acknowledged, without attempting to fully revise the IRP. This IRP Update refreshes the analysis filed with the 2023 IRP and provides status reports on actions and requirements associated with the Commission Order.

PGE does not propose modification to the acknowledged 2023 IRP Action Plan and PGE is not requesting acknowledgement of the 2023 CEP/IRP Update. We continue to find that the recommended Action Plan is in the long-term interest of our customers, providing the best path forward to ensure system reliability and continued progress toward delivering a clean, affordable energy future for Oregon.

The 2023 IRP Action Plan proposed conducting one or more RFPs to meet the Company's carbon-free energy and capacity needs through 2028. Negotiations from PGE's 2023 RFP Final Shortlist are ongoing, and PGE has requested approval of the proposed 2025 RFP. Procuring resources through these solicitations will aid PGE's ongoing efforts to demonstrate continual progress for HB 2021 and will enable PGE to address the portfolio's forecasted reliability needs.

Reliability and affordability remain the foundation of PGE's role in supporting customers and Oregon's economy. The Company's CEP/IRP demonstrates how PGE can achieve our responsibilities to deliver affordable services for our customers while maintaining progress to meet HB 2021 emissions targets.

PGE recognizes the importance of stakeholder engagement and dialogue regarding the Company's resource plans. This Update has benefited from monthly participation in PGE's IRP roundtables since the acknowledgment of the 2023 IRP. PGE looks forward to continued engagement with the Commission and stakeholders in upcoming meetings and in response to the 2023 CEP/IRP Update as filed.

Chapter 1. CEP Update

1.1 Overview

House Bill (HB) 2021 is a transformative public policy that has set Portland General Electric (PGE) on a path toward decarbonizing the power supply for Oregon retail customers.[1] PGE has engaged in robust planning, analysis, stakeholder and community engagement to inform its approach to decarbonization and to demonstrate progress toward the specific greenhouse gas (GHG) emissions targets detailed in HB 2021. Throughout the planning process, PGE remains committed to balancing affordability for customers, the reliability of the grid, and emissions reduction.

The inaugural Clean Energy Plan (CEP), filed in 2023 with the Integrated Resource Plan (IRP) was an important first step in charting a course toward emissions targets in 2030, 2035 and 2040 that balances affordability and reliability for customers. PGE has furthered this work through the continued stakeholder and community engagement and monthly roundtables that have informed this Update. PGE will continue to learn and adapt strategies as customers' needs, the market, and technologies evolve.

This chapter summarizes the results of updated modeling and portfolio analysis which form the basis of this CEP Update and details the Company's progress toward HB 2021 emissions targets.

CEP Update: Key Highlights

- PGE is not requesting Oregon Public Utility Commission acknowledgement of this Update and maintains its Commission-acknowledged Action Plan.
- PGE continues to identify a significant need to procure non-emitting resources and capacity to keep pace with new customer demands, system reliability, and to make progress toward emissions targets.
- PGE is working to continue to reduce emissions and maintaining reliable service by replacing emitting generation and market purchases with non-emitting energy and capacity resources.
- Uncertainties regarding the ability to meet emissions targets at prices that are affordable for customers on the timelines specified by HB 2021 have grown, due to factors outside PGE and its customers' control. These factors include lengthy permitting and siting processes and likely changes to federal policies including tax incentives which are anticipated to significantly increase the costs of new clean resources and tariffs that impact supply-chain availability and costs.
- Transmission is a significant factor impacting the economics and timing of resource additions. Transmission solutions are integral to maintaining reliability and providing long-term pathways for decarbonized power supply. The constraints limiting transmission expansion will drive a greater role for customer-sited

[1] House Bill (HB) 2021 codified as ORS 469A.400 to 469A.475, effective 09/25/2021.

resources such as demand response (DR), energy efficiency (EE), distributed solar/storage and community-based renewable energy (CBRE) resources, highlighting the importance of PGE's efforts to improve utilization of these resources through a virtual power plant (VPP).

- Updated analysis, based on what is currently known, finds 2030 emissions targets can be met by technologies and resources that are currently known and commercially available, though costs have increased and the timing of resource additions may be constrained based on what is commercially available in the market. While the costs presented as part of this modeling exercise do not represent actual changes to customer prices, the analysis is suggestive that, on a planning basis, system costs are likely to increase significantly in order to comply with HB 2021.
- Decarbonization pathways to 2040 will require further technological advancement of non-emitting resources and transmission to meet the region's energy and capacity needs.

PGE must continue to operate its existing portfolio efficiently and seek to procure the best combination of resources that balances costs, risks and maintains safe and reliable service for customers. As detailed in the inaugural Clean Energy Plan, decarbonizing PGE customer's power supply will require resource acquisition and integration at a significant pace and scale. The planning environment has evolved significantly since the original filing. Some of the planning changes, including changes to federal policy, resource cost increases, significant industrial load growth, and long-lead time for transmission expansion, all present challenges to the pace and affordability of PGE's path to emissions targets. Other changes to the planning environment, including progress on regional energy market development, regional resource adequacy sharing frameworks, and active state policy regarding large industrial customers and fair cost allocation provide important tools for PGE to most efficiently meet PGE customers resource needs at the lowest cost possible. External factors that affect critical dependencies are further described in **Section 1.5**.

Electricity is a critical service for local communities and the economy. Customers already rely on the utility for their essential electricity needs. Looking to the future, customer reliance on electricity will increase as they electrify their vehicles, homes and businesses. Our local industrial customers, who are advancing national interest through pursuit of advanced semi-conductor manufacturing, information technologies and artificial intelligence capabilities, need abundant and reliable service. Working to serve this industrial growth with fair cost allocation supports our local economy and has the opportunity to lower the average cost of service. Providing electrical service for all of PGE's customers with increasingly fewer emissions will require significant new investment in energy resources and distribution and transmission infrastructure to prepare for the smart, clean energy grid of the future. While PGE faces some significant changes in the planning environment, PGE's commitment to energy access, affordability, and an increasingly non-emitting electricity supply is steadfast.

PGE will continue to actively manage costs for customers throughout the transition to an energy mix while working to reduce emissions. This includes careful and inclusive planning through

PGE's Clean Energy Plan, Integrated Resource Plan, and Distribution System Plan processes, competitive procurement through Requests for Proposals (RFPs) for resources, joining the California Independent System Operator's (CAISO) Extended Day-Ahead Market (EDAM), as well as continuous efforts to improve operational efficiency, safety, and system and equipment reliability. PGE has actively pursued federal and state grant funding and tax credit opportunities to offset investment costs and support key decarbonization initiatives on behalf of customers, including infrastructure upgrades, though the future of many of those programs and grants is now in jeopardy due to the change in federal policy. PGE also supports efforts to connect customers with the unprecedented federal tax incentives and rebates available, ranging from electric vehicles to heat pumps to rooftop solar. PGE will continue to leverage available tools to prioritize affordability. Some recent examples are further described in **Section 1.4.1 Annual goals**.

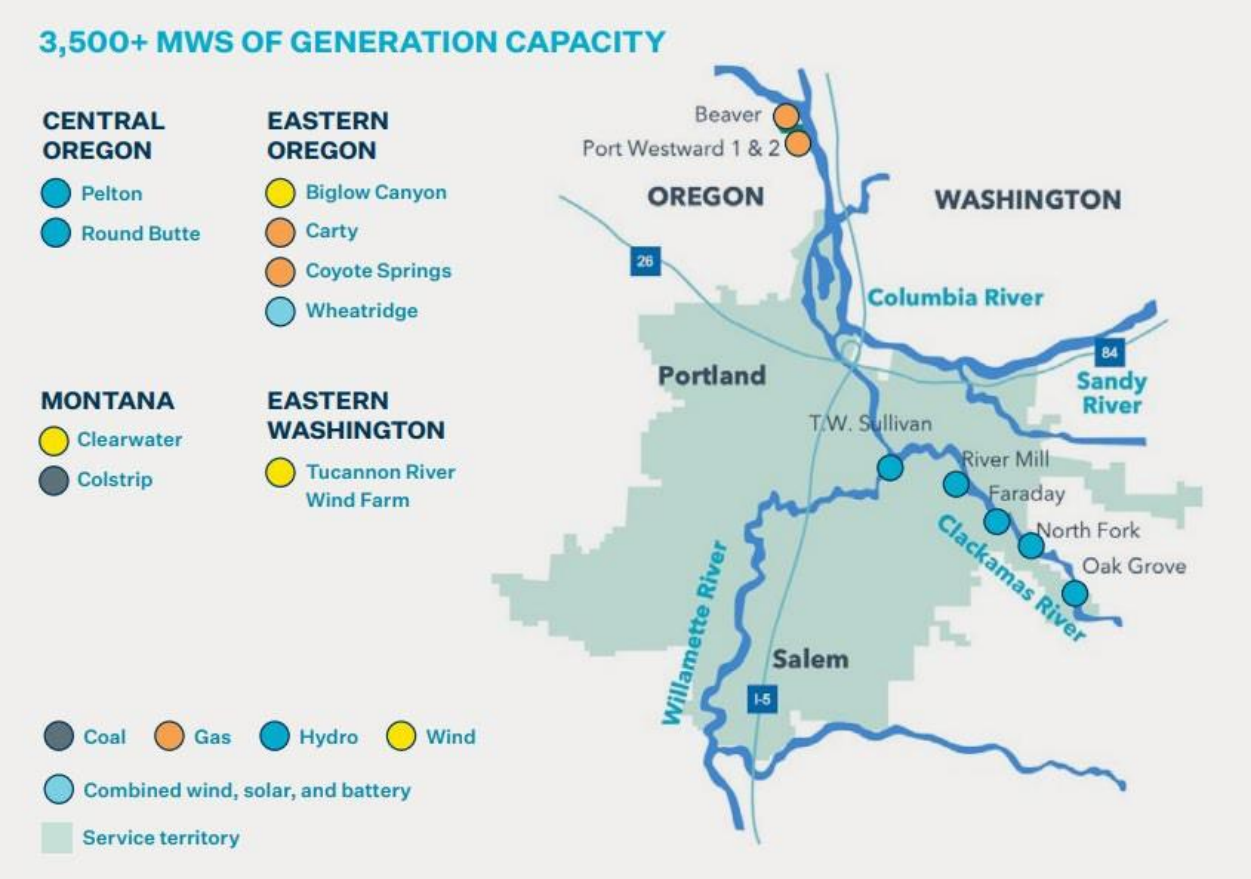
1.2 Historical emissions trends and resource mix

PGE customers include some of the world's most sophisticated corporate renewable energy buyers and local municipalities with ambitious climate action goals. Portland, Beaverton, Multnomah County, Hillsboro, Salem and many other municipalities have developed climate action plans that encourage finding new and innovative ways to reduce the carbon intensity of electricity service, while also supporting electrification efforts, fostering economic development and modernizing the grid to enhance resilience to extreme weather. Many companies in PGE's service territory have publicly adopted ambitious clean energy or emissions goals, including Oregon Health and Science University, Nike, Intel, STACK Infrastructure, Daimler and others. As large electricity buyers, they look to PGE to support their decarbonization efforts.

PGE supports customers' climate and sustainability goals by decarbonizing the electricity supply and offering innovative voluntary programs that enable customers to go further and faster. PGE offers programs for large businesses, cities and counties that match their electricity needs with new renewable energy facilities in the region. Convenient options are also available for small business and residential customers to support clean energy development by purchasing renewable energy certificates from energy generation throughout the U.S. In 2021, PGE became the first utility in North America to sign The Climate Pledge to achieve net zero emissions across company operations (Scope 1, 2 and 3 emissions) by 2040, ten years ahead of the United Nations' Paris Agreement. PGE then collaborated with state lawmakers and stakeholders to pass Oregon's 100 percent Clean Electricity Law (HB 2021) to establish emissions targets for electric utilities in Oregon.

PGE meets the growing clean energy demands of customers with a diverse mix of generation facilities shown in **Figure 1**, owned in whole or in part, or through contract. Today, PGE's generation portfolio consists of seven hydroelectric facilities, five natural gas facilities, three wind facilities, one combined wind/solar/ battery facility and a partial ownership stake in an out-of-state coal facility. PGE previously announced the acquisition of 475 MW of new battery storage projects, of which 275 MW achieved commercial operations in December 2024 with the remaining 200 MW scheduled for service in mid-2025.

Figure 1. PGE generation portfolio



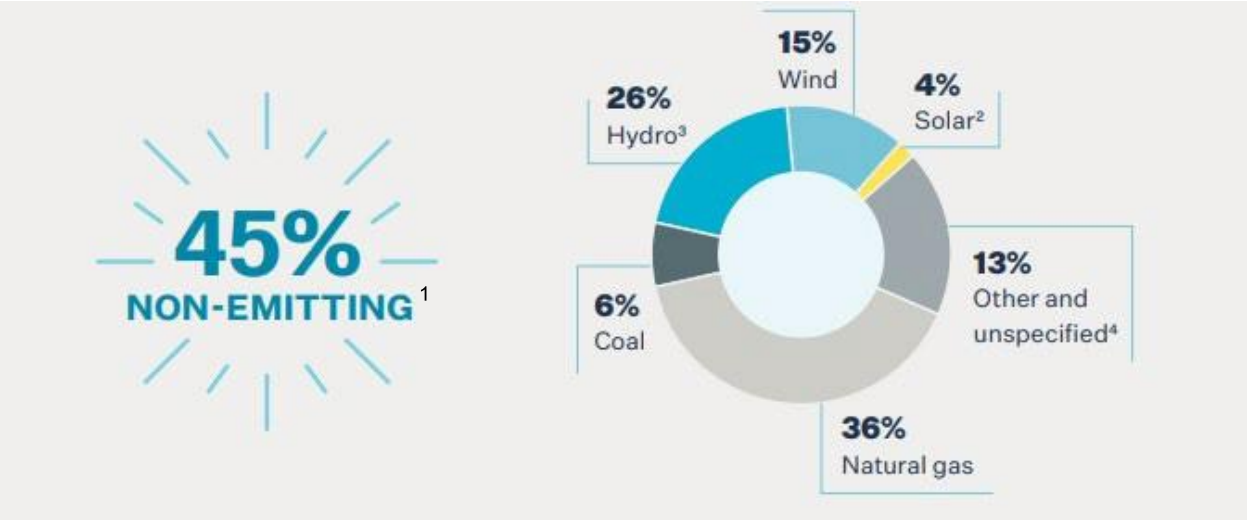
Customer-sited resources, including rooftop solar, batteries and standby generation play an increasingly critical role in the resource portfolio. For example, customer-sited rooftop solar generation contributed an additional 264,826 MWh of non-emitting energy in PGE service territory in 2024. PGE manages the output of owned power plants in conjunction with available power supplies on the wholesale market to deliver power to customers at the lowest possible price. PGE actively coordinates with transmission providers like the Bonneville Power Administration and other utilities and energy suppliers across the region, to secure transmission access and additional power on contract for customers. PGE also owns major transmission rights to the Pacific Intertie and participates in the CAISO Energy Imbalance Market (EIM) and the soon-to-be established EDAM. These options provide additional flexibility to buy and sell power and to access a more diverse and increasingly clean mix of generating resources.

In 2024, PGE made strong progress toward advancing a resource mix for total system load that is increasingly clean. The percentage of total load comprised by non-emitting resources grew from 35 percent in 2023 to 45 percent in 2024. As a result, the carbon intensity of the total power supply declined to 0.27 MMTCO2e per MWh in 2024, despite load growth. While natural gas remains the largest component of the generating mix and provides much-needed capacity to meet resource adequacy and reliability requirements — hydropower, wind and utility-scale solar continue to grow on the system, in addition to customer sited renewable energy resources like rooftop solar. Wind output alone grew by 56 percent, reaching record breaking levels of wind

generation on the system in 2024 primarily due to the addition of the Clearwater Wind facility in Montana. Not only does this facility have a high energy output rate, but it also generates power when other wind resources closer to home in Oregon and Washington are less productive. This exemplifies the importance of resource diversity in the portfolio – and is a critical decarbonization strategy.

Unspecified emissions are reported as part of annual GHG reporting to the Oregon Department of Environmental Quality (ODEQ) when the underlying source of generation for energy purchased from the market, including from CAISO's Energy Imbalance Market, is unknown or not otherwise specified in a contract. Following best practice and ODEQ rules, an emissions rate is assigned to unspecified purchases in recognition that the power pool in Western states still includes fossil fuel generation. Throughout 2024, PGE reduced emissions from unspecified sources, from 16 percent of the resource mix in 2023 to 14 percent in 2024. As Western states decarbonize and energy markets such as CAISO adopt more precise mechanisms for tracking and reporting the carbon content of resources dispatched and allocated through energy markets, emissions associated with unspecified purchases should continue to decline. **Figure 2** summarizes PGE's total system resource mix for 2024.

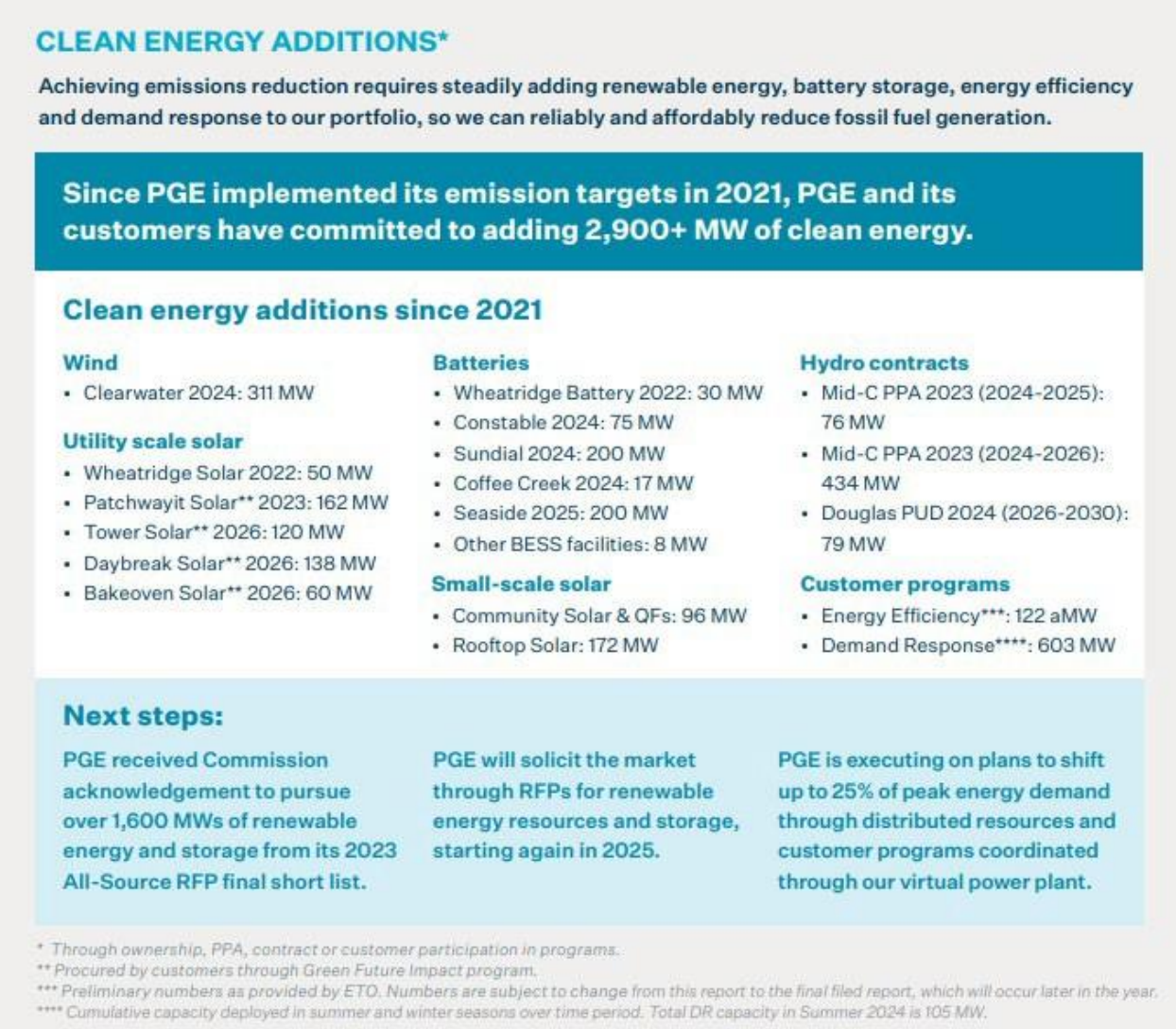
Figure 2. PGE total system resource mix



1. Percentages above represent 2024 resource mix from PGE's total load, inclusive of wholesale volumes.
2. Represents owned and contracted solar resources, does not include the 264,826 MWh of customer owned rooftop resources.
3. Hydro amounts include purchases from Bonneville Power Administration, which may have an immaterial amount of emissions associated with them, per ODEQ rules.
4. Unspecified is purchased power for which a specific generating resource is not defined and could be any of the generation types (e.g., wind, hydro, gas)

PGE recently concluded the largest open-application request for proposal (RFP) for clean energy resources to augment the portfolio to date and has applied to return to the market with another RFP in 2025. This and subsequent RFPs will be necessary to meet customers' energy needs and work towards PGE's emissions targets. PGE's steady progress in procuring clean energy and investing in grid-edge technologies and customer programs will reduce reliance on fossil fuels and drive a cleaner resource mix in the coming years. Additions since 2021 are shown in in **Figure 3**.

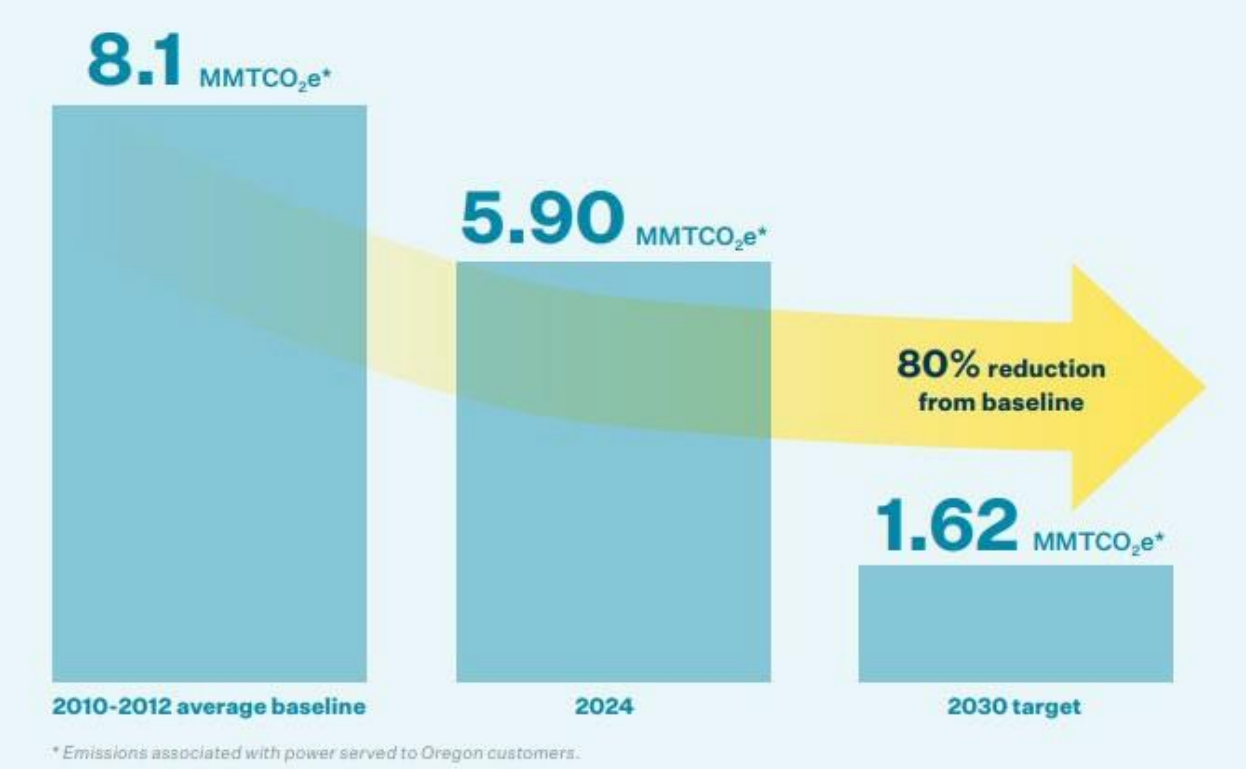
Figure 3. Clean Energy Additions



As shown in **Figure 4**, preliminary estimates subject to ODEQ final approval of emissions associated with power served to Oregon customers in 2024 equated to approximately 5.90 million metric tons of CO_2e.[2] This is a 10 percent decrease in retail emissions reported in 2023, largely driven by additional hydropower and the addition of the Clearwater Wind facility. It also represents a 27 percent reduction in baseline emissions established for HB 2021 compliance.

[2] The 2024 emissions estimate is preliminary pending reporting and third-party verification, as required by the Oregon Department of Environmental Quality (ODEQ).

Figure 4. 2024 GHG emissions in context



Like most utilities, PGE's emissions are driven by the fossil fuels combusted to generate electricity. PGE is actively planning and executing strategies for a balanced transition from thermal generation to increasingly cleaner generation sources while providing reliable energy service that can affordably meet customers' energy needs. Year-to-year variations in reported emissions may be driven by changes in economic factors that affect load or changes in weather that affect hydro conditions, renewable capacity and peak energy needs, that are increasingly hard to forecast. This is discussed further in **Section 1.4.2 GHG emissions**.

Achieving emissions reduction requires steadily adding, to the extent available, renewable energy, battery storage, energy efficiency and demand response to the portfolio to reliably and affordably reduce fossil fuel generation. Customer-sited resources, including rooftop solar, batteries and standby generation play an increasingly critical role in the overall resource portfolio as PGE decarbonizes.

In 2023, PGE published its combined Clean Energy Plan and Integrated Resource Plan, a twenty-year roadmap for meeting customer energy needs at the lowest possible costs while transitioning from fossil fuel generation. PGE demonstrated a potential path toward the 80 percent emissions reduction target in 2030 that involves resources and technologies that are economically and technically feasible in the region today. No single technology right now can replace the role of natural gas generation in the electric power system. Clean energy of all types — including customer rooftop solar generation, community-scale microgrids that combine batteries and solar, utility-scale wind, batteries — energy efficiency and demand response

programs and customer dispatchable standby generation will all be needed to replace the energy and backstop capacity that natural gas currently provides. Looking ahead to deeper decarbonization targets in 2035 and beyond, PGE anticipates the need for access to a broader geographic diversity of resources and technologies to replace fossil fuels on the grid. This will require solutions to current regional transmission constraints and adopting future non-emitting technologies as they become cost-effective. This could include green hydrogen, offshore wind, nuclear, long-duration storage and carbon capture and storage.

When the Legislature passed HB 2021 in 2021, PGE was anticipating flat to minimal load growth, consistent with trends for the electric sector across the country. Since the passage of HB 2021, PGE and the region are forecasting significant industrial load growth, led primarily by the expansion of data centers, AI technologies, and advanced manufacturing. HB 2021 targets are absolute emissions targets, not carbon intensity targets, and are unforgiving of the load growth forecasted for the region and PGE's service territory.

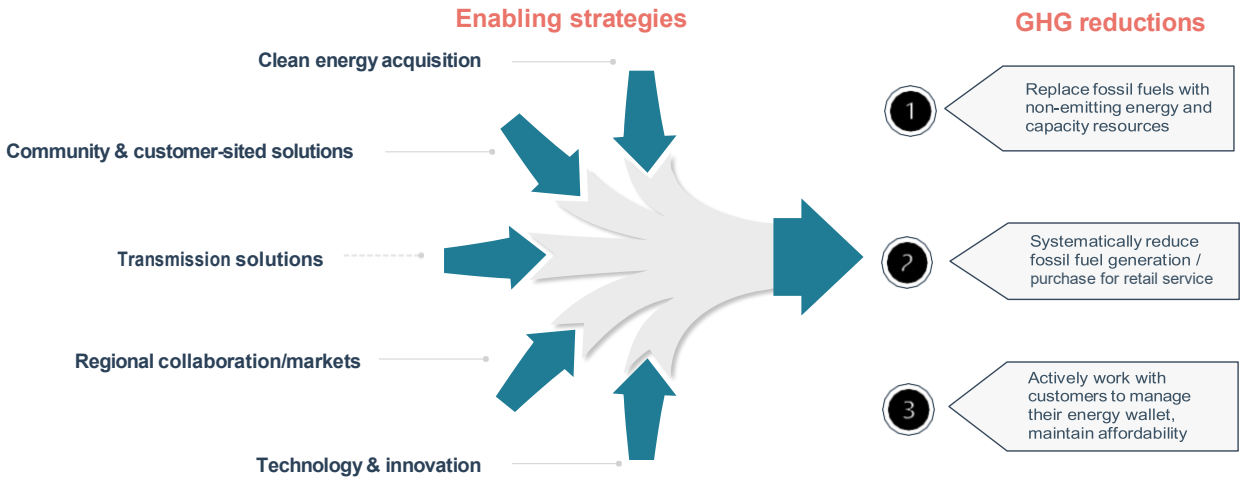
This CEP/IRP Update reflects a significant increase in need for procurement of new generation and storage capacity to keep pace with new customer demand as well as to make progress toward emissions targets. The utility is also considering ways to allocate relevant costs fairly to customers that have a high demand for electricity, such as new data centers. Mitigating residential and small commercial customer price impacts and maintaining reliability are core priorities as PGE decarbonizes its power supply while keeping all customer prices as low as possible.

PGE's decarbonization planning centers on customers' needs and investments in new non-emitting resources and the grid that make progress toward the HB 2021 emissions targets for 2030, 2035 and 2040. At the highest level, the approach to reducing emissions involves:

- Increasing purchase and integration of non-emitting energy and capacity resources.
- Systematically reducing the generation and purchase of fossil fuels for Oregon retail customer load.
- Actively working with customers to help them manage their energy use and total energy expenditures.

This approach is bolstered with key, enabling strategies to be able to deliver a reliable, affordable, clean energy supply, displayed in **Figure 5**.

Figure 5. Decarbonization strategies



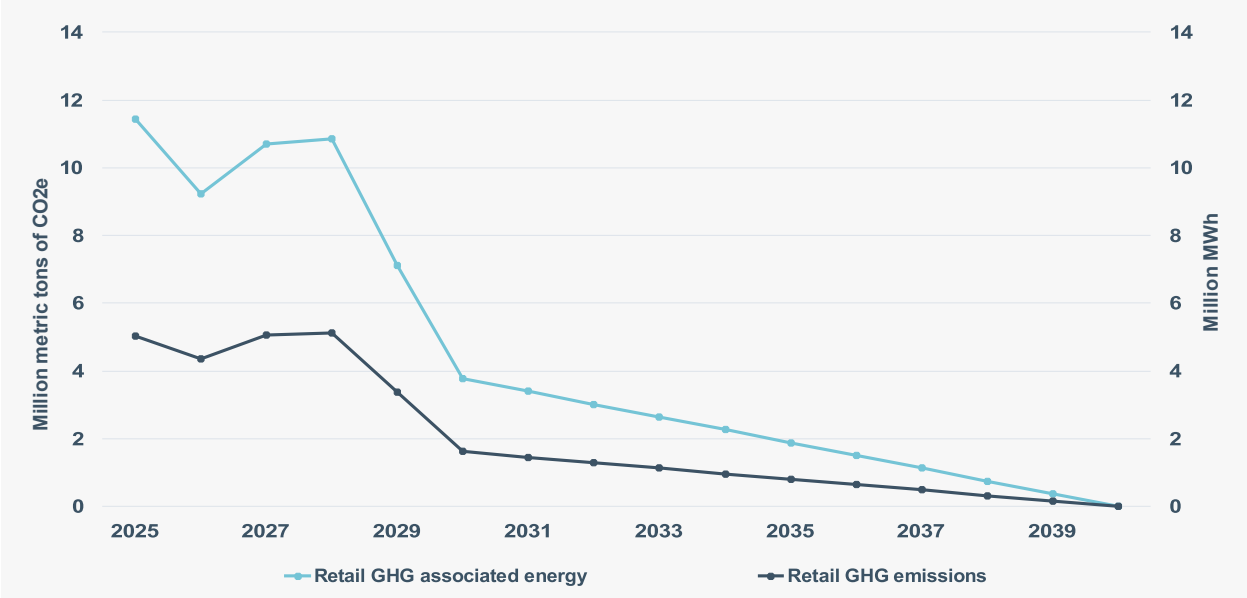
This high-level approach to decarbonization involves gradually reducing fossil fuel generation and purchases for Oregon retail customers and replacing it with non-emitting energy resources and capacity, as well as key enabling strategies to facilitate a reliable and affordable transition. The IRP estimates PGE's energy and capacity needs subject to HB 2021 emissions constraints. It creates a Preferred Portfolio of resources to meet those needs and details an Action Plan to guide the company's procurement and related resource actions over the next 2-4 years.

1.3 Pathways to emissions targets

One of the CEP's primary objectives is to detail a path to compliance with the HB 2021 targets. It shows that the Preferred Portfolio and Action Plan that PGE has developed in its IRP are consistent with steps the company could take in the near-term to make progress toward the emissions targets in 2030, 2035 and 2040, according to the best methods available at the time of analysis. Moreover, the CEP describes how the company will demonstrate continual progress toward those targets. This section summarizes how strategies to decarbonize, resource needs and the Action Plan inform a path to the emissions targets that balance affordability and reliability for customers.

Updated data and analysis described in **Section 3.5.1 HB 2021** result in an updated emission reduction glidepath also presented here in **Figure 6**.

Figure 6. GHG emissions and energy associated with serving Oregon retail load (Reference Case)



PGE's glidepath identifies expected thermal generation and market purchases with associated emissions retained for retail load. Since the 2023 CEP/IRP, PGE has updated the earliest available resource addition year to 2029. This means that while PGE continues to add customer sited non-emitting resources like distributed solar in every year, large utility scale projects are assumed unavailable for addition until the beginning of 2029 due to the considerable time required to procure and construct such resources. One important exception is the assumed addition of solar and storage resources that PGE is working to acquire through the 2023 RFP. While 2023 RFP procurement is not yet finalized, PGE forecasts for this CEP proxy resources shown in **Table 1**, added to the portfolio on January 1, 2028. This is further described in **Chapter 5 Resource options** and **Chapter 6 Resource plan**.

PGE is planning for accelerated procurement through RFPs between now and 2030. PGE has initiated the regulatory process in 2025 to conduct an RFP, which is expected to continue to seek non-emitting resources to meet needs that remain after the 2023 RFP process has concluded. PGE aims to issue this 2025 RFP to market over the summer, with negotiations likely in winter 2026 and possible resource online dates from 2029 to 2032. However, actual procurement from this 2025 RFP is yet unknown and therefore not included in this analysis.

Additional programs are offered by PGE to acquire clean energy outside the RFP processes. For example, the Green Future Impact program enables interested businesses and cities to drive procurement of new renewable energy facilities to directly support their load needs.

Progress toward the HB 2021 emissions targets will require investment and be driven by integrating additional non-emitting resources into PGE's system. The Preferred Portfolio represents the best set of incremental resource additions that balance cost and risk for customers while making progress toward HB 2021 emissions targets. External factors will challenge the pace and scale of PGE's transformation, but ultimately, resource acquisition can

enable the replacement fossil fuel generation and purchases with non-emitting alternatives to support emissions reductions toward HB 2021 targets. Beyond achieving emissions reductions, new large loads, reliability needs, and broader economic trends also impact costs.

PGE seeks to acquire and integrate non-emitting resources, resulting in declining reported emissions associated with serving retail load, under average weather and other conditions. The realities of market procurement, transmission and system integration may lead to step-changes in resources becoming available to PGE customers, resulting in non-linear emissions reductions into the future toward the HB 2021 targets. Work to further develop the virtual power plant (VPP) to enhance utilization of distributed energy resources (DERs) and community-based renewable energy (CBRE) resources will also continue in parallel over this time frame.

Figure 7 details the incremental resource actions by year between now and 2035. The figure also includes PGE's existing portfolio of resources, including proxy assumptions for the 2023 RFP (actual procurement not yet known), and declining GHG-emitting energy retained to serve retail load.

Figure 7. Preferred Portfolio resource pathway through 2035

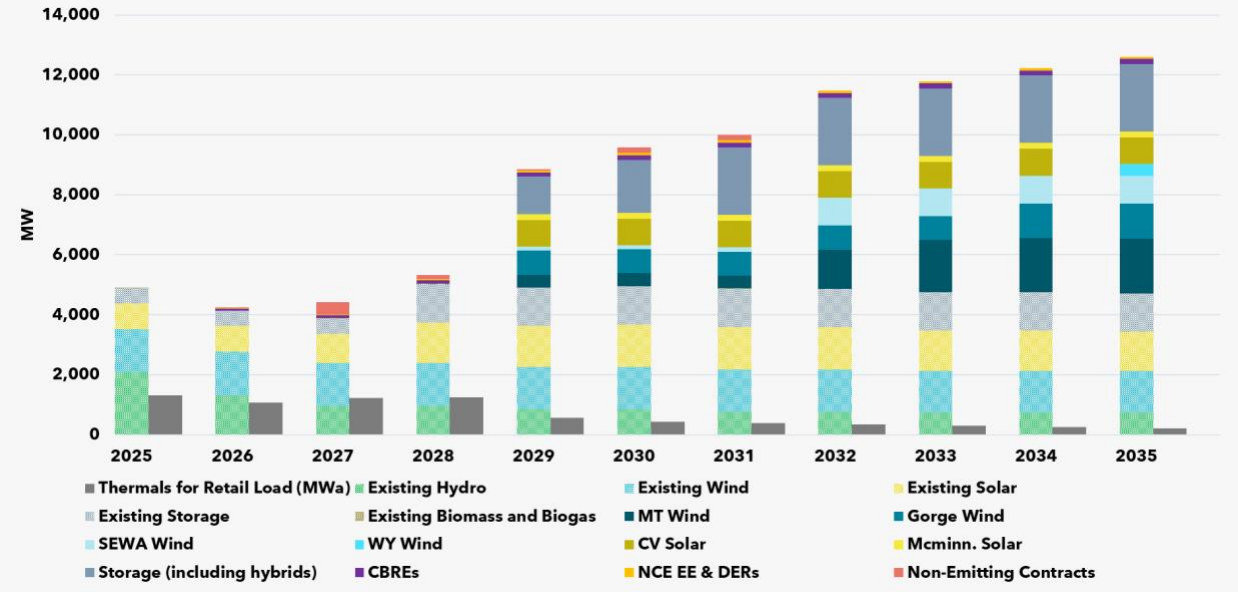


Figure 8 shows the Preferred Portfolio incremental resource additions through 2030 along with changes to PGE's existing portfolio of resources for a view of total generating capacity. The capacity of existing thermals shown in **Figure 8** does not reflect emissions target-driven reductions in emitting energy retained for retail load. After accounting for changes (reductions) to the existing mix, total capacity in the portfolio grows by roughly 1.5x in these five years to add sufficient capacity to maintain resource adequacy in light of forecasted load growth with a focus on clean energy to also meet the 2030 HB 2021 emissions target. Most of these resources are added in the model in 2029, as shown in **Figure 7** and **Table 1**, though external factors such as transmission access and RFP procurement processes and associated timelines continue to be significant factors impacting the economics and timing of actual changes to PGE's system.

Figure 8. Total resource changes from 2025 to 2030

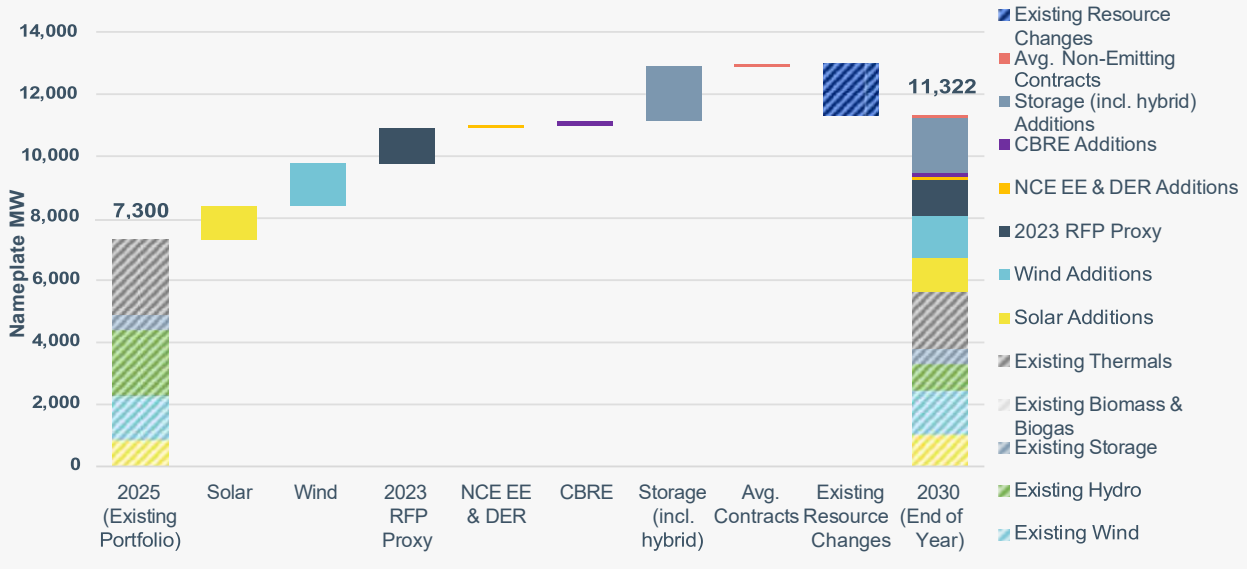


Table 1 provides a summary of total resource actions from 2025 through 2030 as cumulative buildout within this timeframe. The analysis demonstrates the ability to meet the 2030 target using resources that are currently known and have been commercially available. Between now and 2030, PGE's thermal fleet is assumed to dispatch economically, as it does presently, to meet resource adequacy and cost-minimization for PGE's customers and the region.

Table 1. Cumulative resource buildout of the Preferred Portfolio 2026-2030 (MW)

Resource	2026	2027	2028	2029	2030
Wind	0	0	0	1362	1362
Solar (including hybrids)	0	0	0	1089	1089
Storage (including hybrids)	0	0	0	1250	1750
CBREs	66	85	110	133	155
NCE EE (MWa)	0	21	38	58	68
NCE DERs	3	8	12	13	15
Transmission	0	0	0	0	0
Non-Emitting Contracts	16	422	120	33	190
Cost-effective EE (MWa)	104	138	173	208	245
Cost-effective DR	142	172	199	225	248
2023 RFP Proxy Solar (incl. hybrids)	0	0	375	375	375
2023 RFP Proxy Storage (incl. hybrids)	0	0	775	775	775

As PGE adds non-emitting energy and capacity resources, it anticipates systematically reducing the amount of thermal output from natural gas and coal for Oregon retail load to meet emissions targets (see **Figure 27**).

The market for thermal generation is increasingly constrained across the West, with clean energy or GHG requirements in place in almost every state in the Western Interconnect. Thermal generation sold into the Western Interconnect may be subject to the GHG or clean energy requirements of other states. For example, fossil fuel energy exported to California and Washington incurs direct carbon pricing obligations. Public policies such as these, and the massive buildout of non-emitting resources anticipated across the region, lowers economically dispatched thermal output in forward modeling post-2030.

Two key planning needs become apparent when looking beyond 2030 to the 90 percent emissions reduction requirement in 2035 and the zero-emission requirement by 2040. First, there is a need for additional dispatchable non-emitting resources to be developed and available to us in the region to meet resource adequacy needs. In this analysis, the model leverages transmission to access proxy non-emitting resources from around the West to meet reliability needs that increase after 2030 (see **Table 30**). Second, part of the capacity needs leading into 2040 could potentially be offset by existing thermal plants if they were to transition to non-emitting fuels or carbon capture by 2040. It is possible that if supplies become commercially available sooner, PGE's thermal fleet could combust hydrogen or an alternative low-carbon fuel sooner. Almost all of PGE's existing thermal fleet is capable of combusting a blend of hydrogen or renewable natural gas. Informed by least-cost and least-risk planning, the current Preferred Portfolio relies on new non-emitting resources rather than changes at existing thermal plants to reduce emissions.

As described in **Chapter 6 Resource plan**, IRP portfolio analysis determines the best combinations of resource technologies and quantities to meet energy and capacity needs under different scenarios. This informs the creation of the Preferred Portfolio, the company's Action Plan, and a path to HB 2021 emissions targets. The insights gleaned from the construction and comparison of different portfolios informed the creation of PGE's Preferred Portfolio and a balanced path to HB 2021 emissions targets, specifically finding that:

- On a planning basis, system costs are likely to increase in order to reliably meet load growth as well as to comply with HB 2021.
- External factors such as federal policy changes, transmission access, and RFP procurement processes and associated timelines continue to be significant factors impacting the economics and timing of non-emitting resource additions to PGE's system.
- Regional coordination is important for managing costs, as indicated by the portfolio sensitivity analyses focused on resource adequacy and non-emitting market purchases.

PGE's 2023 CEP/IRP Action Plan remains robust, and therefore, PGE is not requesting modifications or seeking acknowledgment of this Update. Updated analysis described throughout this report suggests resource need has increased, driven mainly by growing demand and the need to maintain resource adequacy. The Action Plan referenced in **Chapter 7** remains the best set of near-term resource options for the company to consider in reliably building towards HB 2021's emissions targets while minimizing costs. With uncertainties in the planning

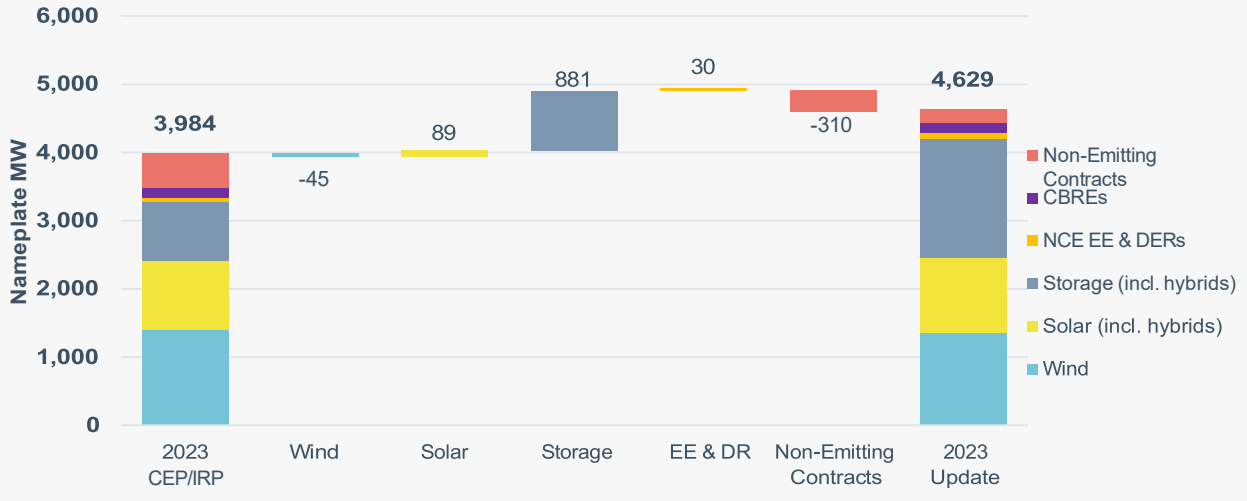
environment, rapidly changing policy landscape, and results of current and future procurement processes, the Action Plan will be reviewed and refined in the 2026 IRP.

1.4 Progress in the CEP Update

This Update includes a range of model assumption refinements aimed at refreshing PGE's planning analytics and incorporating feedback and staff direction from LC 80 Order 24-096. Some key refinements to analysis include changes to supply-side resource costs and options, electricity price forecast, capacity contribution values, and significant developments in transmission planning.

These changes lead to important implications for resource planning further described in this report. For example, updated resource economic assumptions show significantly higher prices in some years, affecting the evaluation and selection of resources in portfolio analysis. The reduced capacity contribution of storage resources (particularly in winter) highlights a critical planning challenge regarding the interaction between storage and energy resources in a system with growing demand and thus energy deficits. Refinements to transmission options included in modeling now reflect more realistic estimates of project timelines, achievable capacity, and market access benefits. These changes highlight the growing urgency of PGE's transmission needs as the company works toward decarbonization goals while facing anticipated increasing load growth and system constraints. **Figure 9** compares the resource additions in the updated Preferred Portfolio to data presented in the 2023 CEP/IRP for model year 2030. Growing demand and updates to supply-side resource costs are main drivers in the differences of model additions, which is broken out by resource type.

Figure 9. Cumulative resource additions through 2030 in the updated Preferred Portfolio compared to 2023 CEP/IRP



As the forward-looking planning environment evolves, PGE is still able to demonstrate measurable impacts and progress across the same metrics that were presented in the 2023

CEP.[3] PGE will measure progress toward HB 2021 emissions targets in a variety of ways, such as in megawatts of non-emitting resources added to the system, in addition to tons of emissions reductions. Measuring progress with multiple metrics is important for two key reasons. First, emissions reductions are predicated on adding non-emitting resources and capacity to reduce thermal generation and purchases for meeting load and resource adequacy requirements. Second, emissions associated with retail sales reported to ODEQ between now and 2030 will exhibit year-to year variation, due to factors like weather that impacts hydro conditions, renewable capacity and peak loads or other events that the utility could not reasonably forecast or control.

1.4.1 Annual goals

HB 2021 does not explicitly set GHG limits for years prior to 2030. ORS 469A.415 (4)(e) states that electric utilities, like PGE, must demonstrate continual progress towards meeting clean energy targets in a Clean Energy Plan (CEP). HB 2021 did not define progress as actual annual emissions reductions. PGE interprets this progress as planned actions to gradually replace fossil fuel resources with non-emitting ones, aiming to meet the 2030, 2035, and 2040 emissions targets. Concurrently with the IRP Action Plan, PGE's decarbonization strategy is multi-faceted to support reliable and affordable power through clean energy procurement, customer-sited solutions, technology and innovation, and regional solutions to resource adequacy.

Since the 2023 CEP/IRP, PGE has continued to make progress in acquiring clean energy resources and investing in advanced grid technologies and customer programs to reduce reliance on fossil fuels and meet future emissions targets.

On customer programs, 122 MWa have been saved from energy efficiency measures since 2021. Demand response capacity totaled 105 MW in 2024. Customer actions reduced record load by more than 90 MW at the hottest time of the day during an August 2023 heat wave, avoiding outages and increasingly volatile power market purchases during extreme weather events. PGE is executing on plans to shift up to 25 percent of peak energy demand through resources including distributed resources and customer programs coordinated through the virtual power plant. Additionally, customer-sited rooftop solar additions increased in 2023 and 2024.

Importantly, PGE is conducting a request for offers (RFO) for CBRE resources, informed by engagement with and input from community representatives, PGE's CBIAG, potential bidders, and Oregon Public Utility Commission (OPUC) Staff. Since CBRE is a new type of resource acquisition, PGE has been providing information and exploring appropriate regulatory treatment through regular updates to OPUC Staff. The RFO is open through November, with three rounds of evaluation. More details and results anticipated in 2026.

PGE has also expanded utility-scale clean energy and capacity resources. In part due to the 2021 RFP, PGE expanded the resource and geographic diversity of the non-emitting resource portfolio

[3] In the Matter of Public Utility Commission of Oregon, House Bill 2021 Investigation into Clean Energy Plans, Docket No. UM 2225, Order No. 22-390 (Oct 25, 2022), Attachment #1 at Topic #8, available at https://apps.puc.state.or.us/orders/2022ords/22-390.pdf.

when the 311 MW Clearwater Wind facility in Montana began generating test energy in 2023, coming fully online in early 2024. PGE procured 492 MW of new battery storage in 2024, the largest acquisition by a utility outside of California, including the 75 MW Constable Battery Energy Storage System. PGE also executed, renewed and extended three cooperative agreements for hydropower from regional public utility districts, included here as part of the baseline portfolio. In November 2024, the OPUC acknowledged the shortlist of projects from a 2023 RFP that was filed shortly after the 2023 CEP.[4] PGE ranked the final shortlist of up to 1,600 MWs of renewable energy into two groups, prioritized based on performance in the scoring evaluation, representing the optimal intersection of value to customers at least-cost and least-risk. A follow-on RFP has been initiated in 2025 to continue to address needs.

PGE continues to investigate transmission actions, a critical need to meet growing demand, maintain system reliability, and further support decarbonization while balancing costs and risks. In late 2023, PGE and the Confederated Tribes of Warm Springs (CTWS) received a $250 million grant from the U.S. Department of Energy (DOE) to enhance the Bethel-Round Butte line and support imported power. PGE broadly continues to leverage federal, state, and local funds to support clean energy and efficiency initiatives. For example, PGE is currently working with the City of Portland and $40,000 in grant funding for installing electric vehicle chargers. Other avenues to help lower costs and increase system reliability are also moving forward. In 2024, PGE announced its intent to join the California Independent System Operator's (CAISO) Extended Day-Ahead Market (EDAM), expected to begin operations in 2026. Participation will provide access to more clean energy resources from across the West.

PGE's 2024 Environmental, Social and Governance Report shares further information about the company's commitment to sustainability along with information about strategic projects that illustrate progress in advancing a sustainable future and commitment to the community. To read the full 2024 Report, "Advancing Toward a Clean Energy Future," visit www.portlandgeneral.com/sustainability.

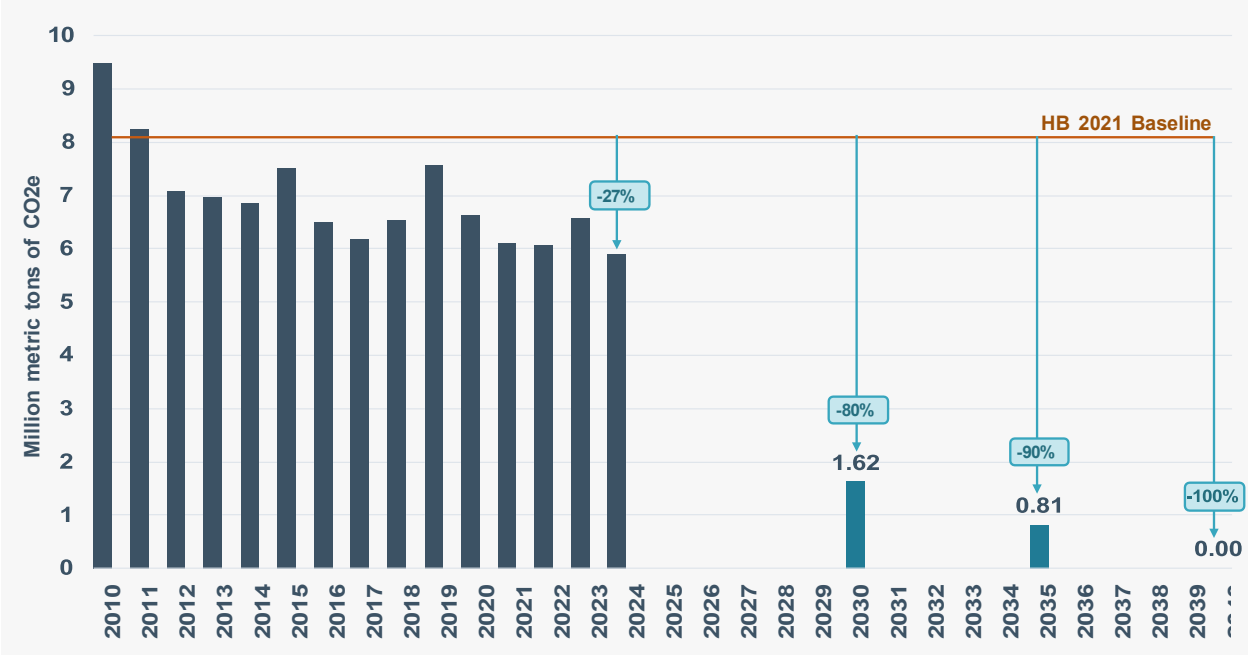
To examine the optimal progress toward the 2030 emissions target in portfolio analysis, PGE analyzed various GHG glidepaths in the 2023 CEP/IRP. Ultimately, the Preferred Portfolio that informed the Action Plan was constructed in a way that minimized the costs and risk of new resource acquisitions and maximized the provision of community benefits by thoroughly investigating key decision points with the potential to impact costs. This included selecting a linear GHG-emissions reduction pathway that met HB 2021 requirements while mitigating costs relative to more aggressive pathways and reducing risks compared to less-aggressive pathways. Choices that minimize cost or risk were also made regarding additional DERs, the inclusion of CBRE resources and opportunities to expand transmission availability. For more information, see Chapter 11 Portfolio analysis in the 2023 CEP/IRP.

[4] In the Matter of Public Utility Commission of Oregon, PGE Request for Waiver of 2023 RFP Process, Docket No. UM 2274, Order No. 24-425 (Nov 25, 2024), available at https://apps.puc.state.or.us/orders/2024ords/24-425.pdf.

1.4.2 GHG emissions

GHG emissions from generation and power purchases fluctuate year to year, often due to variations in economic conditions, temperature, wind/solar conditions, water conditions and other external factors. For example, higher-than-expected temperatures can increase the need for mechanical cooling (air conditioning), which increases demand and the emissions associated with serving that retail electrical load.[5] Water conditions can change hydroelectric power availability, with low water years, such as 2023, increasing reliance on GHG emitting generation. An increase or decrease in macroeconomic activity can alter energy demand and the emissions associated with serving retail load. **Figure 10** demonstrates the variability of year-to-year reported emissions, with a declining trend from 2010 through 2024.

Figure 10. Historical emissions for Oregon retail load service and HB 2021 targets



Due to these annual GHG variations, the OPUC has stated that utilities should "achieve the 2030 and 2035 clean energy targets under typical or expected weather and hydro conditions…".[6] This implies that emissions may be higher or lower than the targets due to variability, but under average conditions meet the targets.

The IRP assumes future load growth after cost-effective energy efficiency and distributed energy resources (DERs) are acquired and incorporated into PGE's system. Therefore, emissions reductions occur due to non-emitting resource procurement displacing coal or gas generation

[5] Since non-emitting resources dispatch first, an increase in load above the expected basis would likely be met by gas, coal or market purchases.
[6] In the Matter of Public Utility Commission of Oregon, House Bill 2021 Investigation into Clean Energy Plans, Docket No. UM 2225, Order No. 22-446 (Nov 14, 2022), Appendix A at 31, available at https://apps.puc.state.or.us/orders/2022ords/22-446.pdf.

(as opposed to reductions from net demand reduction). In actual reporting, the non-linear historical GHG decline seen in **Figure 10** is due to various factors, including but not limited to:

- Weather variations: for example, the same power system will produce different emission levels in a mild temperature year vs. an extreme temperature year, such as 2023.
- Procurement timelines: GHG emissions decline when PGE acquires additional non-emitting energy. These acquisitions will occur in blocks and may lead to staircase-like GHG reductions over time. However, while each portion of resource procurement may lead to a 'blocky' reduction of GHG emissions, from a portfolio perspective, balancing regulatory, operational, financial and resource procurement risks points to the advantages of continual acquisition of non-emitting resources over time. Achieving continual emissions reductions will necessitate procurement of non-emitting resources throughout the decade, which is likely to provide the best opportunity to add resources that offer an optimal combination of geographic location, resource characteristics, technological advancements and access to needed transmission rights.
- Unexpected economic conditions impacting loads: higher or lower than expected load may impact GHG emissions. Higher loads could arrive from faster-than-expected industrial growth (potentially from large data centers) and/or faster-than-expected electrification.

ORS 469A.420(4)(a) requires PGE to provide the OPUC with its two most recent annual emissions reports that have been filed with the Oregon Department of Environmental Quality (ODEQ) reflecting emissions associated with retail sales. Information from these reports for years 2022 and 2023 as well as reports going back to 2010 is available on ODEQ's website[7] and is shown in **Figure 10**. At the close of 2022, PGE disclosed emissions of 6.0 million metric tons of CO_2e, a 25 percent reduction in baseline emissions from power served to Oregon retail customers. Emissions associated with power served to Oregon retail customers in 2023 equated to approximately 6.6 million metric tons of CO_2e. This is an increase from the amount reported in 2022, largely driven by the low hydropower and wind output seen throughout the region and in PGE's service territory. Throughout 2023, PGE reduced emissions from unspecified sources, which represented roughly 17 percent of the retail resource mix in 2023, compared to 21 percent in 2022. Data for 2024 show further emissions decreases to 5.9 million metric tons of CO_2e.

For the CEP Update, PGE is required to compare any GHG emissions reports filed with ODEQ since the CEP with the emissions forecast in the CEP.[8] Reported emissions for 2023 and 2024 are roughly 11 percent higher than those forecasted for retail sales for those same years in the 2023 CEP/IRP. The retail sales emissions forecast for planning assumes average conditions. As described above, actual weather and temperature conditions for these years were considered to

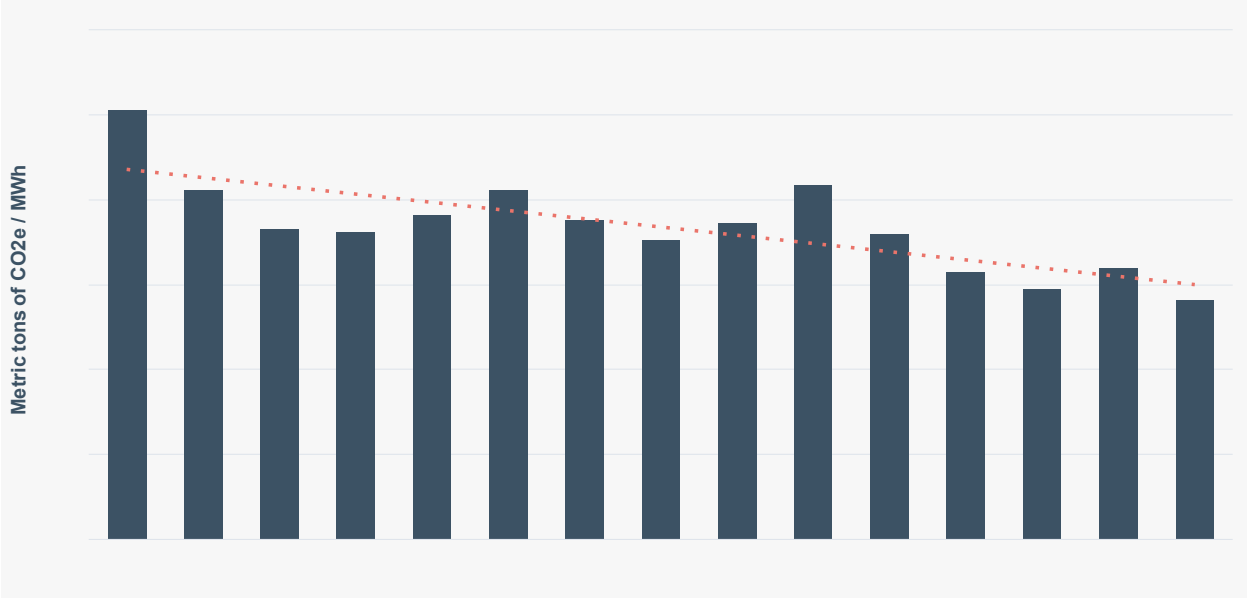
[7] ODEQ, Greenhouse Gas Emissions Reported to DEQ, available at: https://www.oregon.gov/deq/ghgp/Pages/GHG-Emissions.aspx.
[8] In the Matter of Public Utility Commission of Oregon, House Bill 2021 Investigation into Clean Energy Plans, Docket No. UM 2225, Order No. 22-390 (Oct 25, 2022), Attachment #1 at Topic #8, available at https://apps.puc.state.or.us/orders/2022ords/22-390.pdf.

be above average, resulting in greater reliance on emitting resources than was forecast. Relatedly, HB 2021 does not explicitly set GHG limits for years other than the target years of 2030, 2035 and 2040. ORS 469A.415 (4)(e) states that electric utilities, like PGE, must demonstrate continual progress towards meeting clean energy targets in a CEP. HB 2021 did not define progress as actual annual emissions reductions. However, PGE has been making progress toward decarbonization and 2024 emissions are 27 percent below HB 2021's 2010-2012 average baseline level of emissions.

1.4.3 GHG emissions intensity

Because of the correlation between retail load and emissions, GHG emissions intensity, defined as metric tons of CO_2e per megawatt hour (MWh), is a useful decarbonization metric as it normalizes changes in load to better account for the resource mix that is serving that load. **Figure 11** shows PGE's Oregon retail GHG intensity from year 2010 through 2024. In 2024, PGE made strong progress toward advancing a resource mix that is increasingly clean, resulting in a decline in the carbon intensity of the retail power supply despite anticipated load growth. While GHG intensity provides useful information, HB 2021 requires an absolute reduction in utility GHG emissions, not a decrease in GHG intensity.

Figure 11. Historical GHG intensity for Oregon retail load service



1.4.4 Average electric rates for Oregon customers

HB 2021 does not set requirements relating to electricity rates nor does PGE present information on rates in the CEP or IRP due to the disconnect from this forward-looking planning document from actual rates, which are based on real investment decisions. Some $/MWh prices aligning with total costs represented in the IRP are included in **Section 6.2.1 Yearly cost estimates**. These yearly price impacts do not represent actual customer rates as they only focus on planned

generation and transmission expansion cost changes and do not incorporate any other cost changes across PGE. The metric can still be indicative for evaluating options to decarbonize.

1.4.5 Community impacts and benefits

PGE has supported Oregon communities with reliable, affordable and safe power for over 130 years. While many things have changed over that time, PGE's core responsibility to power Oregon homes and businesses has not. It has become increasingly apparent that climate change poses significant risks to the electric sector across all regions of the country. Extreme weather and natural disasters threaten utility infrastructure, contribute to energy market volatility and render the balancing of energy supply and demand more challenging. Climate change has been witnessed first-hand at PGE in the form of record-breaking winter and summer energy peaks, damaging and disruptive storms, and increasing wildfire risk.

PGE's commitment to equity is important across all areas of the business, but especially when it comes to the disproportionate impacts of climate change on vulnerable communities. PGE aims to decarbonize the system in ways that can benefit communities disproportionately impacted by climate change, as required by HB 2021. In the 2023 CEP/IRP, Chapter 7 (Community benefits indicators (CBIs) and community-based renewable energy) described efforts to apply an equity lens to resource and decarbonization planning. Chapter 14 Community equity lens described efforts throughout PGE's planning process to create an inclusive process in which all communities served can participate and be heard.

For the 2023 CEP/IRP, PGE conducted a CBRE potential study and incorporated the results into portfolio analysis to assess the contributions of these resources toward meeting the system requirements and providing community benefits.[9] CBRE resource potential and associated CBIs are included in portfolio analysis to understand the implications that their relative costs, system benefits and CBIs have on various metrics considered within the planning framework and across various portfolio options. In 2024, PGE engaged Resource Innovations (formerly Cadeo) to conduct research into CBIs. Based on this research and stakeholder feedback, PGE refined its approach to how CBIs are considered in analysis as well as expanded the list of CBIs which is further discussed in **Section 5.5 Community benefits indicators (CBIs)**.

Integration of CBIs provides an opportunity for PGE to extend resource planning to include the values and priorities of the communities PGE serves. CBIs have evolved into an analytical framework for addressing resilience, equity, environmental impact, public health, and economic development, ensuring that resource planning considers benefits that are tangible, measurable, and equitable.

By analyzing CBIs within the IRP, PGE can account for community benefits in quantifiable ways to inform resource portfolio decisions. Proxy metrics are used for CBIs that are difficult to quantify, monetize, or lack sufficient data. Outside the IRP analysis, informational CBIs provide a critical

[9] Incorporating CBIs and CBREs into PGE's overall portfolio planning process was described in the 2023 CEP/IRP Chapter 11, Portfolio analysis. The approach to CBI development, including informational CBIs not included in IRP portfolio analysis, was described in Section 7.1, Community benefits indicators.

mechanism for establishing baselines and tracking progress toward achievement of other CBIs based on program delivery and performance.

The challenges identified—including data gaps, proxy metric limitations, and diverse stakeholder priorities—highlight the need for continued research, collaboration, and refinement. Through expanded and continued stakeholder engagement, localized data development, and the adoption of advanced methodologies, PGE is well-positioned to continue to address these challenges and further enhance the impact of CBIs.

1.5 High-level opportunities, potential barriers, critical dependencies

PGE's critical barriers to long-term decarbonization efforts are the same as those faced throughout the industry and global economy. Major barriers include the pace of development for commercially available non-emitting generation technologies, the availability of transmission to access renewable resources, affordability constraints, supply chain disruptions, and permitting and regional interconnection limitations. Solutions will depend on regional cooperation between utilities and jurisdictions, federal policy and financial support.

Current uncertainties in the future of federal policies, tariffs, and supportive tax incentives for renewable energy will meaningfully impact the affordability of PGE's clean energy transition. Further, tariffs on imported goods can impact materials supply chains, slowing timelines and increasing costs of new clean resource buildout. There is much uncertainty about the anticipated cost impacts of final tariffs on solar and energy storage components imported into the United States, but it is likely that the cost of power and energy storage will rise. Procurement delays, supply chain constraints, increased uncertainties in available transmission inventory, siting challenges and operational risks associated with adding large quantities of resources in a short period of time can also delay PGE's timeline.

PGE faces additional procurement challenges related to unresolved exposure to wildfire risk. To achieve the resource procurement targets related to HB 2021, and our customer's reliability needs, PGE must procure multiple gigawatts of new clean resources. The capital investments necessary to construct and commission such resources are significant. Wildfire risk is growing in Oregon, threatening the safety of the communities we serve, as well as utility assets and the overall financial health of the utility. This risk is reflected in higher capital costs, which drive up the costs of clean energy projects. While PGE anticipates working with Independent Power Producers under multiple commercial structures (e.g., Power Purchase Agreements), PGE will likely face barriers to secure low-cost contracts given the perceived risk of utility financial losses related to wildfire. This challenge is not easily resolved; despite successfully accomplishing robust wildfire mitigation that protects human safety, business partners are forced to increase prices to recognize the unresolved financial exposure that PGE presents as counterparty.

Any significant change in statutes, rules or guidelines that would require PGE to alter its strategy or restrict optionality in the pursuit of non-emitting resources could delay emissions reductions or threaten reliability and affordability for customers. Relatedly, load growth forecasts continue to increase, further impacting PGE's ability to swiftly decarbonize given existing technologies, costs, and the imperative to maintain a reliably system.

PGE will be ready to continue to adapt strategies accordingly and will continue to engage regulators, stakeholders, and communities in the next full CEP/IRP. This engagement will be in part informed by forthcoming Commission direction in UM 2273 on the planning requirements relating to HB 2021's cost cap provisions. Moreover, in light of many changes to the federal policy landscape, the broader macroeconomic environment, Oregon's economy, and unanticipated load growth that is outpacing the integration of renewables and storage technologies, it is likely that policy makers and stakeholder will initiate discussions soon on the appropriateness of Oregon's clean energy policies and whether changes or additional supports are necessary. There will be critical junctures on the way to 2030, 2035 and 2040 emissions targets that may require material changes in decarbonization pathways analyses. Resource needs for reliability and the pace of acquisition of non-emitting energy and capacity will be tracked closely and if PGE has concerns around maintaining reliable operations or if there are delays beyond the utility's control, adjustments to the implementation approach will be needed to overcome timeline, affordability, reliability, or other constraints. At the same time, if new technologies or transmission options on- and off-system do not materialize, PGE will likely not be able to access the diverse resources the system needs to decarbonize and maintain reliability. Successful solutions depend on regional coordination and cooperation, as well as on federal, state, or local tax credits and other support for siting and permitting resources and evolving grid strategies.

To execute on a long-term plan, the quantities of non-emitting resources estimated to be available on the market need to be actualized as well as cost-effective. New transmission is needed to gain access to off-system resources or reliability of the system is at risk. Nearer the 2040 target and an absolute zero emissions requirement, new technologies that can replicate thermal generation dispatchable capacity, such as advanced nuclear, hydrogen or carbon capture and storage will be needed across the region to support decarbonization and resource adequacy.

1.6 Acknowledged Actions, Order requirements and other updates

Along with the CEP updates provided in **Section 1.4**, the Update addresses Actions and Requirements that were stipulated in the OPUC's Acknowledgement Order, Order 24-096.[10] This section provides a summary of how the Actions and Requirements were addressed and where that information can be found in this Update. The information and analysis that has been updated from the 2023 CEP/IRP is also summarized as well as those which remain unchanged in this filing.

Table 2 provides a summary of the Actions and Requirements and the location where additional details can be found.

[10] In the Matter of Public Utility Commission of Oregon, PGE 2023 CEP and IRP, Docket No. LC 80, Order No. 24-096 (Apr 18, 2024), pp.18-22 and Appendix A, Attachment 1, pp.26-27, available at https://apps.puc.state.or.us/orders/2024ords/24-096.pdf.

Table 2. Actions and Requirements crosswalk

Action/Requirement	Applicable Section(s)
A. Conditions and Direction Related to PGE's Action Plan	
Staff Recommendation 1: CBRE Actions	Acquisition of CBREs is discussed in **Section 7.1.2.** Additional information regarding PGE's CBRE activities is available on PGE's website at: https://portlandgeneral.com/about/who-we-are/resource-planning/cbre-procuring-clean-energy
Staff Recommendation 2: Energy/Capacity Actions – Long lead-time resource RFI …before issuing its next utility-scale RFP, PGE file a proposal to develop a long lead-time resource RFI… facilitate a workshop on the RFI findings, and allow sufficient time for stakeholder review of its RFI before proposing its next steps.	PGE's RFI results are discussed in **Section 5.6**; findings from the RFI were presented at a Roundtable: https://assets.ctfassets.net/416ywc1laqmd/2GF5BwVt9cR1MXtEpn6fli/e719ec6879183abd984928db360fe410/RFI_slides_jdg_web_1197.pdf
Staff Recommendation 3: • PGE shall conduct hourly production cost simulation of its preferred portfolio under the Reference Case in a manner that separately tracks hourly purchases and hourly sales. PGE will use this analysis to revise its GHG emissions forecast and to revise its submission to DEQ. • PGE shall update the Preferred Portfolio accordingly and provide a brief narrative explanation of the key planning insights derived from this exercise.	**Appendix D** outlines the steps that PGE has taken to update its GHG emissions forecasting to incorporate hourly analysis of its energy and emissions accounting. **Section 6.2.2** discusses hourly energy and emissions accounting results. PGE resubmitted the forecast for DEQ review in June 2025 prior to the filing date for this Update.
Transmission Analysis and Alternatives …we require a more complete analysis of the need and evaluation of the full range of available transmission solutions than was provided here, including non-wires alternatives when appropriate. PGE will need to present a risk-informed, cost-benefit analysis of all available transmission solutions for the 2030 time frame, including factors such as the associated timeline and cost risks, anticipated rate impacts, and the presence of longer-term or broader regional benefits.	**Sections 4.5 and 4.6** discusses transmission options for Portfolio Analysis.
B. Direction for Future Planning	

Action/Requirement	Applicable Section(s)
Staff Recommendation 4: Customer Actions and Guidance for Avoided Cost Update …direct PGE to work with Staff to propose a new method for calculating avoided costs in docket UM 1893… we direct PGE to collaborate with Staff and ETO to modernize the approach to long-term energy efficiency planning to use the best currently available information on energy efficiency and technical potential in future IRP and CEP updates.	PGE actively participated in the UM 1893 docket. PGE delivered this presentation on Redeveloping Avoided Costs for Energy Efficiency https://edocs.puc.state.or.us/efdocs/HAH/um1893hah329014025.pdf The Order adopting energy efficiency avoided cost data for use by Energy Trust is available here https://apps.puc.state.or.us/orders/2025ords/25-017.pdf Discussion of updates to the IRP price forecast as it relates to the UM 1893 docket is included in **Section 5.1.4**.
Staff Recommendation 5: Direct PGE in the next CEP/IRP Update to include an SSR compliance assessment. The SSR analysis should state the projected SSR compliance position broken out by relevant resource types and outline the actions the Company plans to take to fill any identified SSR shortfalls.	PGE's Small Scale Renewables Plan is discussed in **Section 6.4**.
Staff Recommendation 6 - Improved Engagement: …direct PGE to collaborate with Staff, stakeholders, peer utilities, and the CBIAGs in a dedicated collaborative to develop clear, actionable improvements to community and stakeholder engagement in subsequent CEP/IRPs.	PGE provided an update on improvements to community and stakeholder engagement in subsequent IRPs and CEPs here https://edocs.puc.state.or.us/efdocs/HAD/lc80had335791056.pdf
Staff Recommendation 7 – CBI by Next Update: …PGE must demonstrate development of CBIs ... we expect that some set of informational-only metrics be developed in time to be included with PGE's next RFP. If PGE cannot develop such metrics by its next CEP/IRP update, PGE must provide a detailed explanation of the barriers and constraints, along with a proposal for how and when PGE and its community stakeholders will be able to address them.	PGE has advanced the integration of CBIs into resource planning processes. Development, refinement, and application of CBIs is discussed in **Section 5.5**.
Staff Recommendation 8 – Report on Federal Incentives with Next Update: PGE should provide as much visibility into future opportunities as possible.	**Appendix A** provides an update on PGE's federal grant funding.

Action/Requirement	Applicable Section(s)
Staff Recommendation 9 - QF Renewals and Success Rates: …direct PGE to recalculate its IRP inputs using an assumption of 75 percent for QF renewals and the QF success rate for Schedule 202 projects. However, we read this narrowly and clarify that the avoided cost pricing inputs are not material to the IRP itself, but to the avoided cost price filing. We stress that the pricing inputs must be corrected due to their impact on the avoided cost price filing and decline to adopt PGE's recommendation to instead incorporate this change through an update.	**Appendix C** provides updated analysis for QFs.

Table 3 identifies the components of the 2023 CEP/IRP that were updated in this Update.

Table 3. Updated components of the 2023 CEP/IRP

Updated Component	Applicable Section(s)
Market development	**Section 2.2**
Transmission coordination	**Section 2.3**
Semiconductor and datacenter growth	**Section 2.4**
Load forecast	**Section 3.1**
2023 RFP	**Section 3.2**
Energy needs	**Section 3.3**
Capacity needs	**Section 3.4**
Regulatory-driven needs	**Section 3.5**
Transmission options and strategy	**Section 4.6**
Supply-side resource economics	**Section 5.1.2**
Demand Response forecast and economics	**Section 5.2**
Energy efficiency forecast and economics	**Section 5.3**
Small scale renewable (SSR) resources	**Section 5.4, 6.4**
CBIs	**Section 5.5, 6.5**
Long lead time resources	**Section 5.6**
Portfolio analysis	**Section 6.1**
Hourly energy accounting	**Section 6.2.2**
Preferred portfolio	**Section 6.2**
Resource Net Costs	**Section 5.1.9**
Federal funding opportunities	**Appendix A**
Non-emitting energy market (Brattle)	**Appendix F**

PGE's 2023 IRP Update does not revisit or update all analyses contained in the 2023 CEP/IRP. Instead, the 2023 CEP/IRP Update focuses on components that have the most impact on PGE's resource plan. The decision to forego updates in these following areas is driven by prioritization of critical elements that have a more direct impact on PGE's IRP outcomes. **Table 4** lists components that PGE will not be updating along with their corresponding location in the 2023 CEP/IRP.

Table 4. Components of the 2023 CEP/IRP not changed in this Update

2023 CEP/IRP Component	2023 CEP/IRP Location
Flexibility analysis	Section 6.8
Resiliency Chapter	Chapter 13
Tuned ELCCs	Appendix K
Market capacity study	Appendix G
Economics of CBREs	Section 8.3
CBRE Potential	Section 7.2
Utility vs PPA analysis	Section 8.6

Chapter 2. Planning environment

PGE's long-term planning adapts to evolving laws, policies, technological advancements, economic conditions, and climate change impacts. These factors influence resource economics, customer prices, community benefits, and ultimately shape PGE's resource decisions to serve its customers effectively. This chapter explores the broader planning context influencing the overall resource strategy to meet customers' energy needs reliably while keeping prices as low as possible and achieving emissions reduction requirements.

Key Highlights

- Under the new Federal Administration, the EPA is reconsidering the powerplant emission limit final rules established on April 25, 2024, under Section 111 of the Clean Air Act. The details of this and other policy changes at the federal level remain uncertain, though Congress is actively evaluating proposals that would remove federal tax incentives for new non-emitting generation and storage resources. The analysis in this Update mainly contemplates current known final rules, with the exception of sensitivity analyses that exclude tax credits, further described in **Section 6.6 Federal tax credit availability scenarios**.
- PGE has signed an implementation agreement for CAISO's Extended Day-Ahead Market (EDAM) go-live in October 2026.
- PGE is currently developing regional alignment on Resource Adequacy planning standards as a precursor for a regional reliability program.
- The Western Transmission Expansion Coalition's (WestTEC) West-Wide Transmission Study Project represents a new regional effort to address transmission constraints.
- Large industrial customer growth is expected to increase regional electric demand across the Western Interconnection.

Developments Since 2023 IRP

The planning environment has evolved significantly since the 2023 CEP/IRP filing, with changes to federal regulations and policies, progress on market design implementation, and increased focus on regional transmission planning. Additionally, this Update addresses the challenge and opportunity of unprecedented industrial load growth, highlighting PGE's regulatory efforts to ensure appropriate cost allocation for large customer connections.

Strategic Implications

Load growth for industrial customers is expected to significantly increase the quantity of generation, storage and transmission resources required to maintain system reliability and reduce emissions. Change in Oregon ratemaking policy also creates an opportunity to equitably serve large industrial customers while building infrastructure that supports reliability for all customers. Other opportunities to maximize the efficiency of PGE's resource portfolio are advancing through participation in EDAM and regional resource adequacy frameworks. The change in federal administration creates considerable near-term uncertainty regarding tax credit support for clean energy resources.

Staff Recommendations Incorporated

This section addresses Staff Recommendation 8 referenced in LC 80 Order No. 24-096, which directs PGE to include a report on federal incentive implementation and its key impact on the company's Action Plan.[11]

2.1 EPA powerplant rules

When planning for PGE's customer needs, PGE must monitor trends that impact the Western Interconnect of the North American power system. One important trend relates to federal policy and regulations imposing compliance requirements on thermal generation resources. For example, on April 8, 2025, President Trump granted a two-year compliance exemption for various affected facilities subject to the Mercury and Air Toxics Standards, including the Colstrip facility in Montana for which PGE has partial ownership. Pursuant to section 112 of the Clean Air Act, these rules set emissions limits for filterable particulate matter for coal-based generating units.

The implementation of these and other rules is undergoing significant challenges under the current Administration and is being targeted for reconsideration by the United States Environmental Protection Agency (EPA). Additionally, several states and industry groups have filed lawsuits against them in federal court. These challenges and agency reconsideration actions will take time, and the outcomes remain uncertain. PGE will continue to evaluate EPA rules to assess the impact they may have on PGE resource plans.

2.2 Market development

Regional market integration offers PGE and other western utilities opportunities to lower costs, enhance reliability, and integrate diverse resources through the efficient use of existing resources. To maximize the use of existing transmission infrastructure and benefit from least cost resources available in a regional energy market, PGE has elected to participate in CAISO's EDAM. As a separate effort to address regional resource adequacy challenges, PGE has

[11] OPUC. Acknowledgement of 2023 Integrated Resource Plan and Clean Energy Plan. Docket No. LC 80, December 14, 2023. Retrieved from https://edocs.puc.state.or.us/efdocs/HAU/lc80hau325590032.pdf.

engaged in the Western Resource Adequacy Program (WRAP), led by the Western Power Pool (WPP). The WRAP has established a region-wide approach for assessing and addressing resource adequacy with future opportunities for providing operating efficiencies, diversity, and sharing of pooled resources.

The combination of a regional resource adequacy program such as WRAP, which will facilitate capacity adequacy for each participant, and EDAM, which will enable the most efficient economic dispatch of all resources to meet load, is expected to support delivery of reliable power at the lowest possible cost for customers.

2.2.1 CAISO's Extended Day Ahead Market

PGE currently participates in the Western Energy Imbalance Market (WEIM) for dispatch optimization inside the hour, which is operated by the CAISO and supports over 80 percent of the load in the Western Interconnection. The WEIM lowers energy costs for customers, enhances reliability through wide area visibility and integrated generation dispatch, and supports renewable resource integration. The WEIM has proven to be a critical tool for maintaining reliability during extreme weather events, brining energy from areas of surplus to those experiencing peak events. Since joining the WEIM in 2017, PGE has supported the development of regional solutions that enhance reliability, promote clean energy, and incrementally advance western markets to lower costs for customers.[12]

Based on PGE's day-ahead market comparative analysis, PGE selected EDAM as the preferred market choice to maximize the benefits of a day-ahead market for PGE's customers. The benefits of participation are outlined in an informational filing titled Comparative Analysis of CAISO's EDAM and SPP's Markets.[13] In addition, PGE has identified a review of markets access assumptions to determine the impact of EDAM on the expansion in market capacity as an item for review in the 2026 CEP/IRP. On July 2, 2024, PGE signed an implementation agreement with CAISO for participation in EDAM with market go-live in October 2026. This day-ahead market complements PGE's participation in the current bi-lateral market, in which PGE already operates. PGE considers dual participation to be necessary until there is greater market participation in EDAM across Western Electricity Coordinating Council (WECC) market participants. Additionally, on April 3, 2025, PGE filed revisions to its Open Access Transmission Tariff (OATT) for EDAM participation with the Federal Energy Regulatory Commission (FERC).[14]

EDAM leverages CAISO's existing day-ahead market, cost efficiently building on the successful WEIM platform. EDAM offers a cost-effective, incremental option that builds upon the successes

[12] For example, PGE has chaired the WEIM Regional Issues Forum, and is co-chair of the West-wide Governance Pathways Initiative.
[13] Portland General Electric. (2024, March 21). Comparative analysis of the CAISO's EDAM and the SPP's markets: PGE informational filing on commitment to the California Independent System Operator's extended day-ahead market (OPUC Docket No. LC 80). Oregon Public Utility Commission. https://edocs.puc.state.or.us/efdocs/HAH/lc80hah327479040.pdf
[14]Federal Energy Regulatory Commission. (2025, April 3). Portland General Electric Company submits tariff filing per 35.13(a)(2)(iii): Revisions to Portland General Elec. OATT to implement EDAM to be effective 6/2/2025 (ER25-1868) [Filing Type: 10; Document Accession No. 20250403-5095]. https://elibrary.ferc.gov/eLibrary/filelist?accession_number=20250403-5095

and proven economic benefits of WEIM, while maximizing the value of PGE's existing investments in market software and communication systems to join the only currently operating day-ahead market in the West. With over 50 percent of the load in the western interconnection current committed to or leaning towards EDAM, the market offers a contiguous transmission footprint with significant resource diversity and transfer capacity. This contiguous footprint allows the EDAM to better optimize the diverse resources, including wind, solar, hydro, and thermal resources. The EDAM offers a robust platform for continued market evolution for PGE.

EDAM optimizes all supply and demand across the market footprint while respecting transmission limitations to produce optimized day-ahead schedules. All generation and load within a participating EDAM Balancing Authority Area (BAA) must either economically bid or self-schedule in the market. These transactions are then re-optimized in the existing WEIM sub-hourly 15- and 5-minute markets. EDAM requires participants to demonstrate sufficient energy, capacity, flexibility, and transmission on a day-ahead basis, consistent with forecasted demand.

The EDAM transmission framework is designed to maximize transmission availability while respecting the OATT rights and legacy contracts of participants. The transmission availability within the EDAM design seeks to maximize the amount of transmission capability made available to the market across a variety of transmission service arrangements. Prior to the day-ahead market run, each EDAM Entity will identify the firm and conditional firm transmission capacity that can be made available to support reliable transfers. Any additional unsold firm available transfer capability (ATC) will be made available to support transfers between EDAM BAA's. The transmission service provider maintains the responsibility to plan and operate the transmission system within the BAA and administer cost allocation in accordance with the OATT.

EDAM accounts for the costs arising from state GHG accounting and reduction policies that price GHG. CAISO has convened a regional stakeholder process to modify the GHG framework to account for a non-priced GHG-capped state policy. PGE is actively participating in this process with Oregon regulatory agencies to develop an emissions report which may enable GHG attribution for EDAM and WEIM market purchases under HB 2021 reporting requirements.

The benefits of EDAM are expected to grow following the expansion of the market footprint. With an eye to the potential for future expansion, the market is revisiting its governance model. EDAM has adopted a joint authority governance model informed by the regional West-wide Governance Pathways Initiative that includes oversight roles for state commissions through the Body of State Regulators and for stakeholders though the Regional Issues Forum. Notably, the West-wide Governance Pathways Initiative aims to develop and establish a new and independent entity with an independent governance structure capable of overseeing an expansive suite of West-wide wholesale electricity markets and related functions. Senate Bill 540 was recently introduced in the California legislature to enable California investor-owned utility participation in this new regional organization. For more information on the West-wide Governance Pathways Initiative, please visit the Western Interstate Energy Board website.[15]

[15] Western Interstate Energy Board. https://www.westernenergyboard.org/wwgpi/

As PGE moves towards participation in EDAM, several regulatory and procedural milestones are required prior to go-live. The first major step is a tariff filing that is currently pending with FERC[16] PGE will also need to file with FERC for Market-Based Rates (MBR) to ensure that no single market participant has market power. Finally, PGE must demonstrate to FERC that it meets the Readiness Criteria established in the CAISO tariff. Details on these filings and other EDAM implementation milestones can be found on the WEIM website[17]. It is also likely that a tariff update with the OPUC will be required to enable some programs to be adequately represented in EDAM.

For more information on CAISO's EDAM, please visit the CAISO website.[18]

2.2.2 Western Resource Adequacy Program (WRAP)

WRAP is an industry-initiated and led resource adequacy planning standard and compliance framework designed to meet the growing resource adequacy challenge and enhance reliability in the region. On April 16, 2024, in docket AR 660, the OPUC adopted new resource adequacy (RA) rules which mirror the WRAP program requirements in many ways. Participation in the state RA program is mandatory for IOUs and ESSs that do not voluntarily participate in WRAP.

The WRAP is a planning standard and compliance framework that seeks to take advantage of and maximize regional diversity in resources and load to enhance reliability for all customers across the WRAP footprint. The program experienced numerous delays since FERC initially approved the tariff in early 2023. First scheduled to become binding Summer 2025, participants expressed concern in their ability to meet capacity requirements due to supply chain issues and increases in peak-load driven by electrification and data centers. [19,20] In September 2024, a revised transition plan was accepted by the Western Power Pool Board of Directors and the program is now scheduled to be binding beginning Winter 2027-2028. Although the regional RA planning standard established by WRAP will not become binding until Winter 2027-2028 at the earliest, it is a first step towards a common reliability planning standard. As the region moves to align with the WRAP planning standard, PGE continues to explore options to operationalize this planning standard to achieve enhanced reliability through diversity sharing.

In addition to WRAP, in UM 2143, the OPUC adopted Staff recommendation to open a formal rulemaking on resource adequacy. The OPUC then adopted new rules in Docket AR 660 requiring electric companies and electric service suppliers to provide a Binding Forward

[16] Federal Energy Regulatory Commission. (2025). Portland General Electric Company submits tariff filing per 35.13(a)(2)(iii): Revisions to Portland General Elec. OATT to implement EDAM to be effective 6/2/2025 (FERC Docket No. ER25-1868) [Filing Type: 10]. https://elibrary.ferc.gov
[17] California Independent System Operator. (n.d.). Extended Day-Ahead Market Implementation and Onboarding. Western Energy Imbalance Market. Retrieved June 3, 2025, from https://www.westerneim.com/Pages/ExtendedDayAheadMarketImplementation.aspx
[18] California Independent System Operator. Western Energy Markets: Extended Day-Ahead Market (EDAM). CAISO, 2024, https://www.westerneim.com/Pages/ExtendedDayAheadMarket.aspx.
[19] FERC Order Accepting Proposed Tariff re Northwest Power Pool under ER22-2762. Feb. 10, 2023
[20] WRAP Participant Letter, April 24, 2024

Showing consistent with state program requirements.[21] The company believes that the reliability challenges facing PGE and the greater Western region warrant the continued development of State RA rules, especially considering recent delays in the WRAP. The efficiencies presented by the pooling of resources will be an important tool to address PGE's future capacity needs at lowest costs.

As a result of UM 2143 and AR 600, PGE has modified its resource adequacy modeling under the 'State RA Requirements' scenario. This method uses WRAP standards instead of using the PGE resource adequacy method in portfolio analysis. Results of this analysis are presented in **Section 6.3.5 State RA requirements**.

2.2.3 Hydroelectric Contract Availability and Competition

PGE is facing increased competition for existing resources such as Mid-Columbia hydroelectric power and BPA marketed Federal hydroelectric power, driven by rising demand from data centers and growing Public Utility Districts (PUDs) loads. This heightened competition is raising market prices, and as a result, PGE must pay higher contract rates to secure access to carbon-free, dispatchable, and highly flexible resources — ultimately impacting the cost of delivering reliable, clean energy to our customers.

2.3 Transmission coordination

This section describes the Western Transmission Expansion Coalition (WestTEC) effort and how this effort will help PGE pursue cost-effective transmission projects. As of March 2025, the WestTEC effort is in the study phase. Therefore, the information discussed here is the most up-to-date as of finalization of this 2023 CEP/IRP Update.

2.3.1 Western Transmission Expansion Coalition (WestTEC)

The objective of the Western Transmission Expansion Coalition (WestTEC) West-Wide Transmission Study Project (Project) is to produce an actionable 10-year and 20-year transmission study based on transmission portfolios that enhance Western reliability while also considering economic efficiencies and state policy goals.[22]

WestTEC includes collaboration between diverse sectors of the energy industry, states, and tribes. The project will address interregional and interstate transmission needs spanning the Western Interconnection, including the collective footprint of the existing three regional planning organizations for the West (NorthernGrid, the California Independent System Operator, and WestConnect) as well as interties with Canadian Provinces.

The goal of the 10-year and 20-year transmission study is to provide a high quality, high confidence foundation for future transmission build decisions and actions that can be

[21] Oregon Public Utility Commission. (2023, September 22). Order No. 23-340: UM 2143/AR 660 – Staff's recommendation adopted [Docket No. UM 2143; signed by Commissioners Megan Decker, Letha Tawney, and Mark Thompson]. https://apps.puc.state.or.us/orders/2023ords/23-340.pdf
[22] Western Transmission Expansion Coalition. (2024, July 19). Study plan (Draft V4). Western Power Pool. https://www.westernpowerpool.org/private-media/documents/WestTEC_Study_Plan_Draft_V4.pdf

undertaken by the industry. WestTEC uses an independent consultant to focus on identifying interregional and interstate transmission expansion solutions that are based on an assessment of the consolidated and coordinated needs of western utilities, not just a single utility or regional planning organization. Consistent with methodologies identified in FERC Order No. 1920 (**Appendix H.2 FERC Order 1920 process**), WestTEC measures important regional transmission benefits including production cost savings, reduced congestion, and mitigation of extreme weather events.[23] Following the completion of the WestTEC studies, specific transmission solutions will be available for study in the IRP.

The WestTEC 10-year horizon transmission study will be complete in August 2025 and the 20-year horizon transmission study will be complete in September 2026. Given that the first study will not be completed until August 2025, nearer term transmission projects will not go through the Project.

For additional details on scheduled transmission projects, see **Section 4.2 PGE transmission projects.** The transmission options modeled in the 2023 CEP/IRP Update are described in **Section 4.6 Transmission options for portfolio analysis**. The cumulative transmission buildout selected in the Preferred Portfolio is presented in **Section 6.2 Preferred Portfolio**.

2.4 Industrial load growth

This section outlines the general trends in electricity demand, with a particular focus on the Pacific Northwest and the role of large industrial customers, such as data centers and semiconductor producers, in driving this demand as well as the regulatory and policy responses in Oregon.

2.4.1 General trends in electricity demand across the Western Interconnection

While the western interconnection has historically seen modest growth in electricity demand, recent developments signal a period of rapid expansion, particularly in industrial sectors such as technology and manufacturing. Several key factors are contributing to this shift including the transportation electrification, manufacturing, and building electrification. A significant driver of industrial load growth is the expansion of data centers. These facilities provide cloud storage, computing power, and digital infrastructure and require significant electricity to power servers, cool buildings, and maintain continuous operations.

2.4.2 Industrial load growth in the Pacific Northwest

The Pacific Northwest is particularly attractive to large industrial customers due to its cooler climate, which reduces cooling costs, proximity to the Trans-Pacific Submarine Cables that terminate in Hillsboro, and access to abundant renewable energy from hydropower, wind, and solar sources—leading to relatively lower electricity costs. Due to these factors, the region has seen significant recent investment. The Oregon CHIPS Act (SB 4) provides state funding and regulatory support to strengthen Oregon's semiconductor industry by aligning with the federal

[23] FERC Order No. 1920, issued on May 13, 2024 and FERC Order No. 1920-A, issued on November 21, 2024.

CHIPS and Science Act. It streamlines permitting and invests in site development to help Oregon compete for federal semiconductor manufacturing incentives.[24]

Industrial load growth presents substantial opportunity and benefit for PGE's customers. PGE's service of industrial load growth includes infrastructure that supports reliability for all customers. Additional benefits may accrue to all customers should large industrial backup generation or other resources tied to these customers be made available for grid reliability and flexibility. As noted below, PGE is also actively involved on several fronts to ensure that costs to serve the rapid industrial load growth is appropriately allocated to the customers driving the expense.

2.4.3 Regulatory and policy responses to large customer demand growth

The 2025 Legislature enacted House Bill 3546, requiring the creation of a separate rate class for large energy use facilities and allocating the costs of serving these large energy use facilities in a manner that is equal or proportional to the cost of serving the class.[25] The bill also requires utilities to enter contracts to serve certain large energy use facilities.

PGE has revised its tariff to provide for appropriate cost allocation to the growing large industrial customers including through the addition of new study fees, minimum demand charges, and deposits, aiming to prevent stranded assets and incentivize large customers to invest in grid resiliency. PGE's revised tariff also includes provisions to mitigate cost-shifting risks, particularly for distribution and transmission investments, while providing that costs are appropriately allocated, and large customers pay for the cost to connect and serve their energy needs.[26] Whether these changes remain in place or are revised as well as implementation of HB 3546 are issues under consideration by OPUC in a pending docket, UM 2377, creating uncertainty regarding industrial load cost allocation, particularly with data centers.[27] This leads to uncertainty in the cost forecasts in the IRP.

In UM 2024, OPUC is reviewing Oregon's Direct Access Program, which allows large customers to contract directly with third-party electricity service suppliers. In UM 2024, OPUC is conducting a holistic review of the Direct Access Program. The review includes but is not limited to transition adjustment charges, election windows for customers to opt into the DA program, default pricing for Direct Access customers, and all load serving entities (including energy service suppliers and utilities) resource adequacy.

The impacts of large customer industrial load growth are evaluated within the Update as a scenario within portfolio analysis. A detailed description of the results of this scenario can be found in **Section 6.3.3 Large industrial customer growth**.

[24] Oregon State Legislature. (2023). Oregon CHIPS Act, S.B. 4, 82nd Leg., 2023 Regular Sess. https://olis.oregonlegislature.gov/liz/2023R1/Measures/Overview/SB4
[25] As of this publication, the bill awaits the Governor's signature.
[26] UE 430, Investigation into PGE's New Load Connection Costs.
[27] UM 2377, PUC Investigation of Rule C and I, Marginal Cost Study Treatment.

2.5 Federal administration changes

There has been a change in the Federal Administration since the 2023 CEP/IRP. During its first 100 days in 2025, the Trump Administration has taken a range of actions aimed at energy independence and deregulation, the full impacts of which are uncertain but likely to delay and increase the cost of renewable energy development and roll back environmental regulations. Due to uncertainties or lack of new final rules, most anticipated changes are not incorporated into this analysis.

2.5.1 Tax credit policy

The Inflation Reduction Act (IRA) of 2022 authorized approximately $270 billion in energy security and climate resilience investments, with a central focus on enhancing and expanding tax-based incentives for clean energy deployment.[28] A cornerstone of the IRA was the long-term extension and modernization of the Investment Tax Credit (ITC) and the Production Tax Credit (PTC), which had historically faced repeated expirations and short-term renewals that constrained planning and investment.[29] The IRA extended these credits for projects that begin construction before January 1, 2033, and transitions to a technology-neutral credit regime beginning in 2025. On a forward going basis, the IRA awards tax incentives based on the emissions profile of the generation source rather than technology type.[30] The IRA introduced tax credit transferability allowing eligible taxpayers to transfer all or part of certain tax credits to unrelated parties in exchange for cash, creating a new market for credit buyers and sellers.[31] This provision aimed to simplify financing, reduce dependence on complex tax equity structures, and make clean energy investment more accessible to a broader set of developers, utilities, and nonprofit entities.

While the Inflation Reduction Act (IRA) of 2022 provides funding and tax credits (including the ITC and PTC) through at least 2032, the current administration has introduced significant uncertainty regarding the future of the IRA and its provisions. In the executive order issued on January 20, 2025, the administration placed an immediate pause on the disbursements of funds appropriated through the IRA.[32] Federal Judges have issued orders requiring the administration to resume IRA funding, but the effect on the overall policy environment has been chilling to clean energy development, with potential modifications to key provisions affecting the stability and predictability of clean energy investments.[33] Congress is also working to phase out and condition many IRA tax credits, including the 45Y and 48E tax credits that provide significant value for PGE customers as PGE invests in clean energy. The outcome if this legislative effort is not yet known.

[28] Inflation Reduction Act of 2022, Pub. L. No. 117-169, Title I, Subtitle D.
[29] IRC § 48 (ITC) and IRC § 45 (PTC), as amended by IRA §§ 13102 and 13101
[30] IRC §§ 45Y and 48E, created by IRA §§ 13701 and 13702
[31] IRC § 6418
[32] Executive Order 14154, "Unleashing American Energy" (January 20, 2025), https://www.whitehouse.gov/presidential-actions/2025/01/unleashing-american-energy/.
[33] *State of New York v. Trump*, Case 1:25-cv-00039-JJM-PAS, D.R.I., (February 10, 2025), https://storage.courtlistener.com/recap/gov.uscourts.rid.58912/gov.uscourts.rid.58912.96.0_6.pdf.
Woonasquatucket River Watershed Council v. Department of Agriculture, Case 1:25-cv-00097-MSM-PAS, D.R.I., (April 15, 2025), https://storage.courtlistener.com/recap/gov.uscourts.rid.59116/gov.uscourts.rid.59116.45.0.pdf.

In response to this shifting policy landscape, PGE's IRP Update includes portfolio sensitivity analysis assessing the impacts of reverting to a pre-IRA planning environment. The details regarding the design of this scenario are introduced in **Section 5.1.3 Tax credit sensitivities** and results of the scenario analysis are provided in **Section 6.6 Federal tax credit availability scenarios**.

2.5.2 Grant funding

PGE and joint applicants were awarded USDOE grant funding in 2024 through the Grid Resilience and Innovation Partnerships (GRIP) Program to support some transmission projects. There is uncertainty whether these federal dollars will be fully awarded or not as payments were paused by the time of this Update publication. The analysis assumes this funding is awarded to support the selected projects described in **Section 4.6 Transmission options for portfolio analysis**. Further, **Appendix A Federal grant funding** details grants awarded to PGE. The delivery of these grants remains uncertain due to developing policy priorities at the Federal Administration.

2.5.3 BPA

Federal Administration changes have impacted BPA processes and workforce. The Transmission Service Request Study and Expansion Process (TSEP) to evaluate and address transmission service requests has been paused. Significant workforce reductions and current rehiring processes may impact operations, load service, and resource procurement.

On September 30, 2028, the existing settlement of the Residential Exchange Program (REP) is set to expire. PGE is still in active conversation and negotiation with BPA to make sure PGE customers receive an equitable share of the benefits of the Federal system. There is significant uncertainty associated with the impact of the expiration of the existing REP settlement and the level of REP benefits that BPA will make available to PGE's residential and eligible small farm customers. However, the OPUC has estimated that removal of the existing REP benefits that customers currently receive through the BPA REP program would create a cost impact to customers equivalent to around a 3.6 percent rate increase.

The ultimate implications of changes at BPA are uncertain but have the potential to impact day to day grid operations and slow regional transmission investment and development necessary for reliability and growth. This Update does not contemplate these complications.

Chapter 3. System needs

This chapter quantifies the drivers of energy and capacity needs in the 2023 CEP/IRP Update. The analyses described below provide the foundational metrics for addressing resource adequacy, decarbonization objectives and other policy requirements while minimizing long-term costs and risks. Previous modeling approaches for evaluating PGE's demand, supply, and policy requirements were described in the 2023 CEP/IRP's Chapter 6 – Resource needs and in the 2023 CEP/IRP Addendum, Chapter 2 – Need changes.[34,35] Additionally, this chapter discusses the 2023 Request for Proposal (RFP) results and the competitive bidding process initiated following the 2023 CEP/IRP.

Key Highlights

- Twenty-year average annual growth rates are estimated at 2.8 percent annually, a 1.2 percentage point increase from the 2023 CEP/IRP Addendum forecast. Growth is driven primarily by unprecedented industrial sector expansion, especially in semiconductor manufacturing and data centers.
- Resources assumed to be added following the conclusion of the 2023 RFP reduce long term capacity needs and make important contributions to addressing near-term capacity deficits.
- PGE continues to procure resources as part of the 2025 RFP. Such resource additions are likely to enter the system approximately 2029, limiting near-term emissions reductions.
- Monthly assessment of PGE's long-term energy need increases resource need relative to annual energy accounting.

Developments Since 2023 IRP

Since the 2023 IRP, PGE updated its load forecast methodology, shifting from a dual-horizon econometric analysis to an econometric model which spans the entire planning horizon and incorporates recent hourly demand data. This adjustment better captures current trends, including rapid industrial growth and changing residential energy use patterns post-COVID-19. Monthly energy need analysis was introduced to reflect the variability in renewable energy generation more accurately. Additionally, forecasts for distributed energy resources (DER) have been refined, further impacting projected energy and capacity needs.

Strategic Implications

The updated forecasting methods and revised growth projections underscore the urgency and scale of PGE's resource planning efforts. The significant industrial sector

[34] 2023 CEP/IRP
[35] 2023 CEP/IRP Addendum: System Needs and Portfolio Analysis Refresh

expansion necessitates timely resource procurement and infrastructure development to manage unprecedented demand increases.

Staff Recommendations Incorporated

This section discusses IRP Updates which incorporate Staff Recommendations #3, #5, and #9 from Order No. 24-096. Recommendation #3 is advanced by representing non-emitting resource needs in a more granular accounting of PGE's forecasted emission through the quantification and incorporation of monthly energy needs in portfolio modeling. Recommendation #5 is addressed by explicitly accounting for Small-Scale Resource need in the IRP modeling. Lastly, Recommendation #9 is incorporated by assuming 75 percent renewal rate of QF resources in IRP inputs for capacity and energy.

3.1 Econometric load forecast

PGE customer's load forecasts have grown since the 2023 CEP/IRP filing which is demonstrated in this section's discussion of the PGE's May 2024 load forecast. The Addendum to PGE's 2023 CEP/IRP increased the load forecast from the initial filing and, unless noted, comparisons to the 2023 CEP/IRP refer to the Addendum.[36] PGE's load forecast includes two methodological changes to the Energy and Peak Forecasts which account for current trends and differences compared to the previous filing.[37] Additionally, PGE presents a high and low load forecast which include wider bounds in the near term to reflect increased uncertainty in industrial segment growth. Load forecasts exclude direct-access customers, consistent with 2023 CEP/IRP – Section 6.1.1 and in response to Order No. 07-022, IRP Guideline 9.[38]

The industrial segment is expected to be the focus of growth in PGE's service area due to the semiconductor industry and data centers. As **Section 2.4.2 Industrial load growth in the Pacific Northwest** describes, PGE's service area has experienced a dramatic increase in semiconductor and data center investment, a segment that is positioned to grow dramatically as cloud computing and AI demands increase. As this growth is unprecedented, the pace and scale of the electricity demand required to serve these needs introduces increased uncertainty in the outlook.

Forecasts of distributed energy resources (DERs), including rooftop solar, transportation and building electrification, are additional to the underlying econometric load forecast (base forecast). The energy and peak load impact of DERs, further referred to as electrification, are

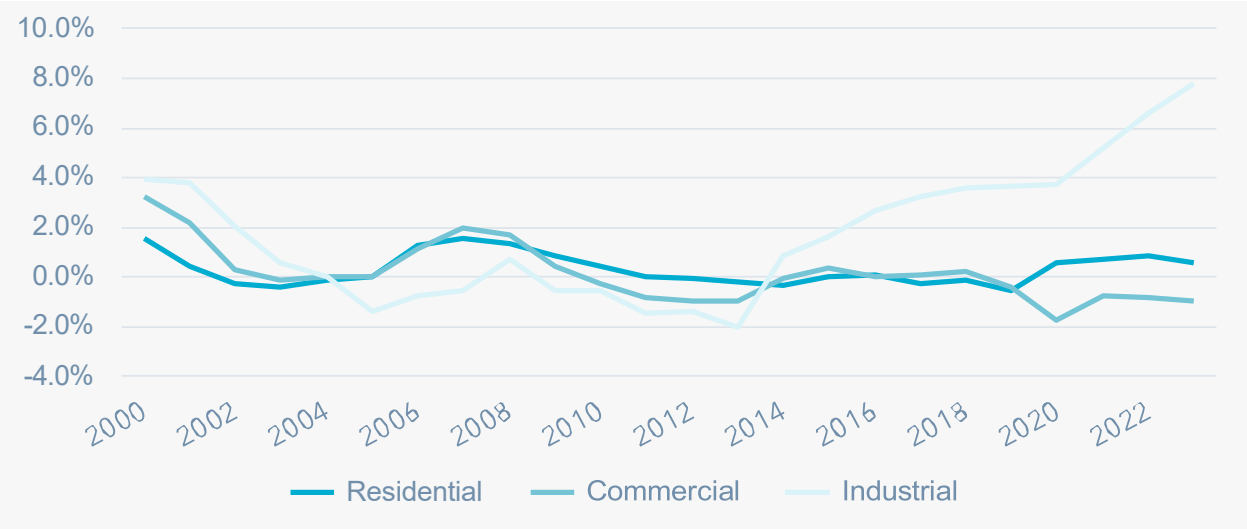
[37] May 2024 Forecasts are the vintage used in the 2023 CEP/IRP Update. More recent vintages are not used as load forecasts are one of the furthest upstream inputs in the modeling process. The Sept. 2024 forecast estimates suggest a nominal change in average energy deliveries and seasonal peak loads across the planning horizon, and more recent forecasts are not expected to materially change the 2023 CEP/IRP Update's final recommendations.
[38] In the Matter of Public Utility Commission of Oregon, Investigation Into Integrated Resource Planning, Docket No. UM 1056, Order No. 07-002 (Jan 8, 2007) at 19, available at: https://apps.puc.state.or.us/orders/2007ords/07-002.pdf

estimated in PGE's AdopDER model, as discussed in **Section 5.2.2 Cost-effective demand response**. In the sections below, electrification forecasts from AdopDER are combined with results from the base forecast to provide a more complete forecast of energy and peak load estimates across the planning horizon. Resource need representations presented in **Sections 3.3 Energy need** and **Section 3.4 Capacity need** also consider the cumulative load forecasted for both PGE's base service area demand and the incremental impact of electrification.

3.1.1 Energy forecast

Recent years have marked a period of meaningful change in how PGE's customers use energy. **Figure 12** shows energy deliveries growth by customer class presented using a five-year rolling average growth rate. Across the past decade the industrial segment has offset relatively flat energy usage in the residential and commercial segments due to growth in high-tech and data center sectors. Growth from these sectors is estimated to account for approximately 75 percent of load growth between 2025-2030 (**Figure 17**), 50 percent of 2030 seasonal capacity need, and 30 percent of portfolio resources in 2030 (**Section 6.3.3 Large industrial customer growth**). Increased growth in industrial energy deliveries is expected to continue as Oregon's semiconductor industry grows and data center demand from cloud and AI uses expands. This rapid load growth presents economic opportunities for the region and is driving new policy and planning considerations to ensure PGE's system remains reliable and affordable in the face of unprecedented change. As part of these new considerations, the 2023 CEP/IRP Update includes a new model structure for PGE's energy deliveries forecast that allows for direct incorporation of individual large customer load growth projections.

Figure 12. Five-year average growth rates by class



3.1.1.1 Energy Forecast Methodological Changes

PGE's updated energy deliveries forecast includes two primary components: econometric forecast models by rate schedule and customer specific forecasts for a selection of large

customers. As part of the 2023 CEP/IRP Update, the Company revised the econometric forecast model.

The econometric portion of PGE's model ties energy deliveries to macro-economic drivers, primarily residential building permits and employment. PGE's residential models segment customers by dwelling type and estimates both usage per customer and customer count. The commercial models are segmented by rate schedule and energy deliveries are estimated directly.

A key update to the econometric model is that PGE no longer splits its forecast into two horizons as it has in the past (1–5-year vs long term). A single set of regression models now span the full horizon of the 20-year CEP/IRP planning horizon. **Table 5** summarizes the groupings used for the econometric regression models.

Table 5. Structure of regression models

Dependent Variable	Model Groups
Usage Per Customer	Residential Single Family, Multi Family and Manufactured Home
New Connect	Single Family, Multi Family and Manufactured Home
Monthly Energy Deliveries	Non-residential Rate Schedules: 32, 38, 83, 85, 89 Other Residential Misc. Schedules: Irrigation, Area Lighting, Street Lighting and Traffic Signals

3.1.1.2 Large customer forecast

Consistent with the 2023 CEP/IRP, the large customer forecast is an individual forecast for a subset of large customers with high energy intensity, such as large non-residential customers on Rate 89, and 90.[39] These customers can experience stepwise changes in operations which are often communicated by the customer to PGE but are not easily predicted by reliance on regional macroeconomic drivers. Information used to develop these forecasts includes customer requests, segment industry reports, historic load-ramps, and comparisons to like customers. The state legislature and OPUC are actively discussing policy regarding industrial customer cost allocation as part of HB 3546 and UM 2377.[40,41] These efforts will further refine methods for differentiating large customer load in future planning cycles.

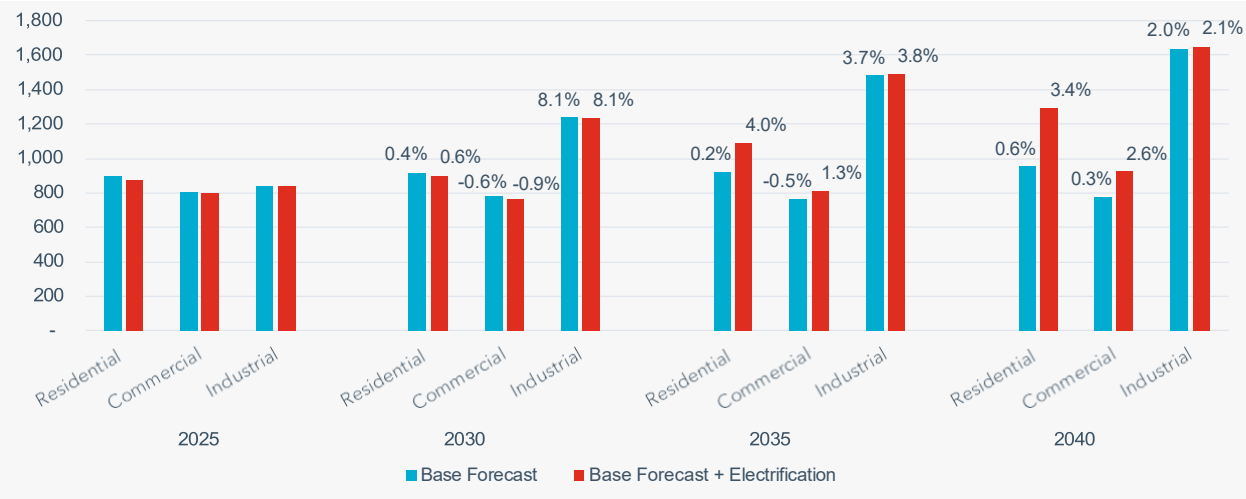
3.1.1.3 Resulting Energy Forecast

PGE's average growth rate for energy over the next 20 years is forecasted to be 1.9 percent, not including the impacts of electrification. This growth rate increases to 2.8 percent after including

[39] https://portlandgeneral.com/about/info/rates-and-regulatory/tariff
[40] Oregon HB 3546
[41] UM 2377

electrification estimates from PGE's AdopDER model.[42] Both the residential and commercial sectors are expected to remain relatively flat through 2030, with energy efficiency mostly offsetting customer growth in the near-term. After 2030, demand from non-industrial customers grows with increased electrification. The industrial sector is forecast to grow rapidly, driven primarily by semiconductor and data center sector growth. **Figure 13** shows the magnitude of customer class load at five-year increments and growth rates associated with the preceding five-year period. Industrial total usage is forecasted to surpass the residential and commercial sectors by 2030.

Figure 13. Energy forecast at five-year increments, with annual average growth rates



3.1.1.4 Energy High and Low Forecasts

PGE creates high and low load forecasts to account for different economic futures. The health of Oregon's economy impacts PGE's load growth, with residential driven by population and commercial driven by employment. In addition to the population and employment scenarios, PGE accounted for different large customer growth futures. The industrial sector has the widest bounds, accounting for the increased uncertainty in this sector. **Table 6** presents a growth rate summary comparing PGE's reference, high and low load forecasts for the base forecast and including the effects of electrification as estimated in AdopDER.

PGE notes that strong demand for industrial load service contributes to the uncertainty of the load forecast. PGE has received service requests from many large industrial customers whose requested load service is not included in the Reference case load forecast. PGE's choice to exclude many of these industrial requests is supported by PGE's judgement on the maturity of these requests and the absence of commitments from such customers. Ongoing policy discussions regarding the fair allocation of system costs to such customers discussed in **Section 2.4.3** contributes to the uncertainty of PGE's industrial load forecast. PGE's High load forecast

[42] AdopDER provides electrification estimates for residential and non-residential segments. Non-residential electrification estimates are weighted 90/10 (commercial/industrial) as most programs are targeted to commercial customers.

partially captures the potential of still stronger industrial service demand to be further assessed following these policy determinations.

Table 6. High, reference, and low forecasts

	High		Reference		Low	
	Base	Base + Electrification	Base	Base + Electrification	Base	Base + Electrification
Total Energy	3.31%	4.11%	1.94%	2.87%	0.58%	1.12%
Residential	1.02%	2.65%	0.44%	2.25%	-0.15%	0.71%
Commercial	0.50%	1.78%	-0.05%	1.13%	-0.75%	-0.06%
Industrial	7.48%	7.55%	5.14%	5.22%	2.87%	2.94%

3.1.1.5 IRP Update Comparison to 2023 CEP/IRP

Table 7 shows twenty-year average annual growth rates by customer segment for the 2030 CEP/IRP Update compared against the previous 2023 CEP/IRP and Addendum: System Need and Portfolio Analysis Refresh filings. The May 2024 update resulted in an increase in forecasted annual growth rates, from 1.6 percent in the filed addendum to 1.9 percent. The residential and commercial sectors both saw moderate decreases in forecasted growth prior to the inclusion of electrification. After including electrification, estimates for residential and commercial sectors grew by an additional 1.8 and 1.1 percentage points, respectively. The industrial sector increased from the Addendum estimate of 3.9 percent to 5.1 percent in the May 2024 Forecast, prior to electrification. Overall, the five-year forecast remained consistent with the prior update while the long-term growth rate saw an increase. This increase is primarily driven by the methodology update presented in **Section 3.1.1.1 Energy Forecast Methodological Changes**.

Figure 14 presents a graphical comparison of the forecast vintages including a segment build of the most recent, May 2024 load forecast.

Figure 14. Comparison across load forecast vintages

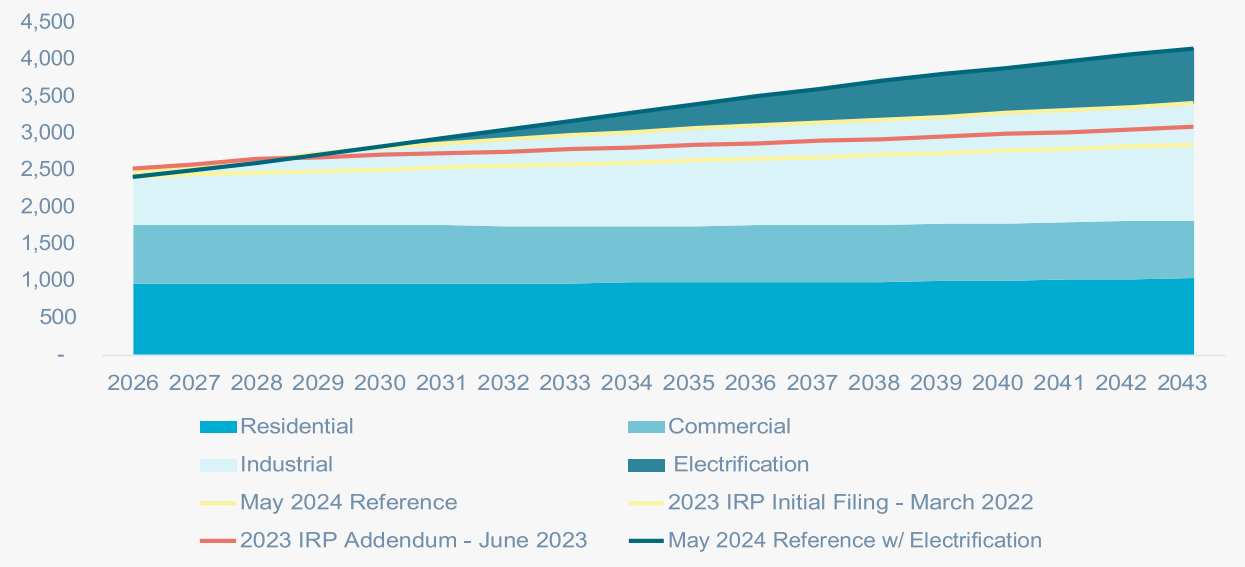


Table 7 presents a tabular growth rate summary comparison of the forecast vintages.

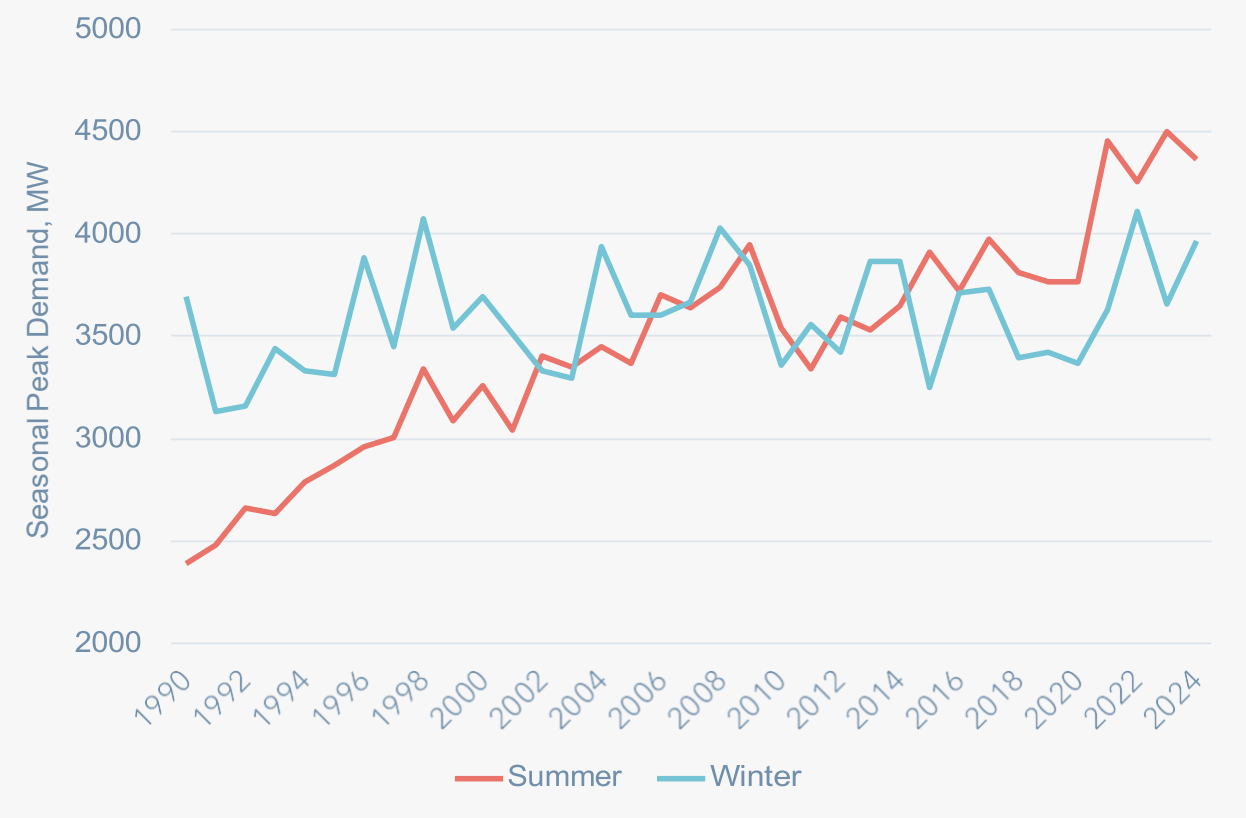
Table 7. Twenty-year average annual growth rates

	2023 CEP/IRP (March 2022)	2023 CEP/IRP Addendum (June 2023)	May 2024 Reference	May 2024 Reference + Electrification
Total Energy	1.2%	1.6%	1.9%	2.8%
Residential	0.5%	0.6%	0.4%	2.2%
Commercial	0.0%	0.0%	-0.1%	1.1%
Industrial	3.5%	3.9%	5.1%	5.2%

3.1.2 Seasonal peak demand forecast

In addition to increased industrial deliveries, PGE has also experienced persistent increases in its summer system peak demand. **Figure 15** presents the historical net system peak demand for the PGE service area from 1990-2024 for both the winter and summer seasons.

Figure 15. Actual seasonal net system peak demand, in MW



Recent events, such as wildfire smoke in 2020, the heat dome of 2021, increased AC saturations, and the rise in work-from-home have led to shifts in the utilization of home cooling systems.

To address these trends, PGE updated the peak demand forecast methodology. In addition to capturing recent trends, this methodology also allows for changes in load shape as the industrial class grows at an accelerated rate.

3.1.2.1 Peak Forecast Methodological Changes

In the 2023 CEP/IRP, PGE utilized a monthly regression model that related the single-hour peak demand to average monthly demand. This model trained with one observation per month, using historical data back to 2000. This resulted in few observations for training a summer peak event given the short nature of Oregon's summers. Further, these training observations reflected periods in time where the saturation and utilization of air conditioning in the home was less prevalent. Using this method, the temperature inputs used to forecast seasonal peak demand were based on a simple average of 15 years of peak day events.

For the May 2024 forecast, PGE updated its peak demand model with a focus on better capturing recent response to warm summer temperatures. The updated peak demand model uses hourly data by customer class – residential, commercial, and industrial – for 2019-2023 to better capture current usage trends during peak events. By using hourly data, the training set includes more cooling and heating events and can better capture the impact of weather on usage. The fixed effect model includes various weather variables, rooftop solar capacity, and

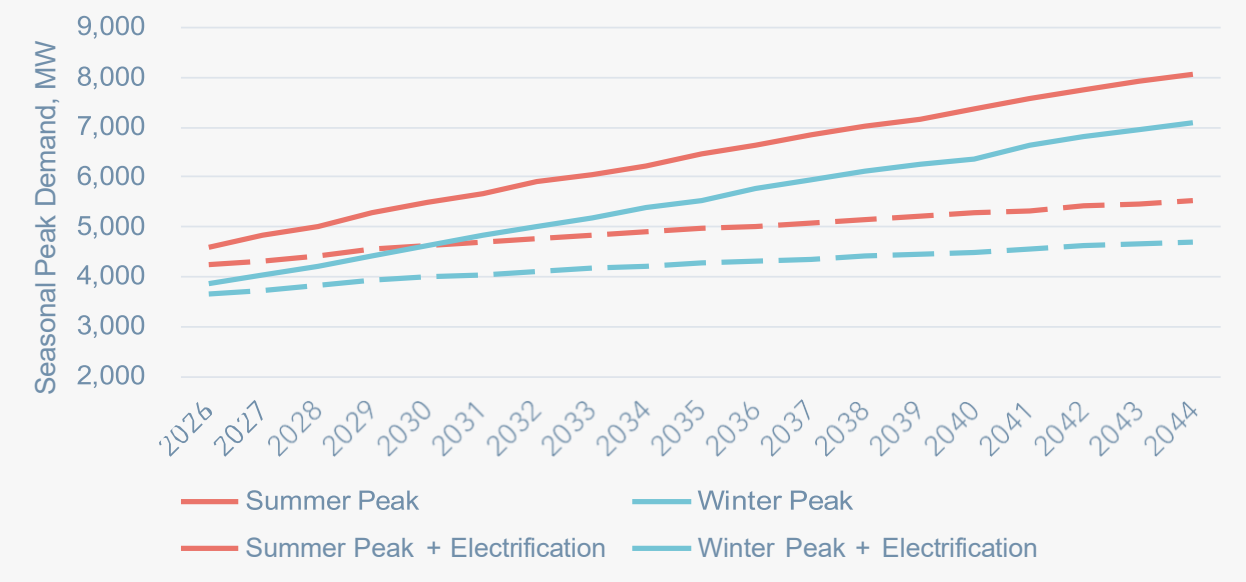
indicator variables to control for monthly, day of the week, extreme weather and COVID-19 impacts as explanatory variables.[43]

To develop the peak demand forecast, weather year simulations are created using historical hourly weather data for the period 2008-2023 with shifted day of week start to reflect 105 total simulations. These simulations are scaled by class to the average monthly energy forecast to capture growth. The expected seasonal peaks reflect the average system peak across the simulations in the given season. Probabilistic outputs were also created based on the standard deviation of simulated peak. This approach allows for data to feed directly into the Sequoia model, as described in **Section 3.4.2 Changes to modeling capacity need**.

3.1.2.2 Resulting Peak Forecast

PGE's base forecast average growth rate over the next 20 years is forecasted to be 1.5 percent for the summer peak and 1.4 percent for the winter peak, as shown in **Table 8**. After including the peak load impacts of electrification, average growth rates increase to 3.3 percent and 3.4 percent for summer and winter, respectively. **Figure 16** shows the trajectory of PGE's forecasted seasonal peak demand forecasts for the summer and winter seasons with and without electrification.

Figure 16. Forecasted seasonal peak demand, in MW



3.1.2.3 Peak High and Low Forecasts

PGE creates a high and low peak forecasts that correspond with the high and low load forecasts. In each scenario, the growth is front weighted to the five-year horizon, corresponding with the higher forecasted growth rate in the short-term. **Table 8** shows a comparison of the growth rate

[43] Weather variables include heating degree hours (HDH), cooling degree hours (CDH), and lagged HDH and CDH. HDH and CDH were calculated based using the observed temperature at each hour compared to a set base temperature (such as 65°F) with HDH being total degrees below set point and CDH being total degrees above.

of seasonal peak demand across the reference, high and low load forecasts both with and without the effects of electrification.

Table 8. Forecast twenty-year average growth rates

	High		Reference		Low	
	Base	Base + Electrification	Base	Base + Electrification	Base	Base + Electrification
Summer Peak	2.6%	4.2%	1.5%	3.3%	0.4%	1.8%
Winter Peak	2.5%	4.4%	1.4%	3.4%	0.3%	2.0%

3.1.2.4 IRP Update Comparison to Previous Filings

The May 2024 update reflected an increase in the peak forecast for both the summer and winter peak.[44] This increase is driven by the increased forecasted load growth as well as the updated methodology described in **Section 3.1.2.1 Peak Forecast Methodological Changes**. Though the peak forecasted growth rate has increased, it remains lower than the forecasted energy annual growth rate. **Table 9** shows a comparison of the growth rate of seasonal peak demand across the forecast vintages, including effects from electrification as estimated in AdopDER.

Table 9. Forecast peak 19 year (2026-2044) average annual growth rates

	2023 CEP/IRP (March 2022)	2023 CEP/IRP Addendum (June 2023)	May 2024 Reference	May 2024 Reference + Electrification
Summer Peak	0.7%	0.9%	1.5%	3.2%
Winter Peak	0.7%	0.8%	1.4%	3.5%

3.1.3 Load forecasts – excluding large customer load

To provide transparency into the drivers of PGE's resource need, additional analysis was performed to disaggregate large industrial load from PGE's forecast. As described in **Section 3.1.1.2 Large customer forecast**, semiconductor and data center loads are responsible for significant increases in PGE's forecast.[45]

3.1.3.1 Methodology: Excluding load from large customers

PGE's econometric load forecast methodology includes three core modeling elements: a monthly forecast of energy deliveries by rate schedule, a monthly forecast of large customer

[44] May 2024 Load Forecast Update discussed in Jul. 11, 2024 CEP/IRP Roundtable 24-3
[45] Similar segmentation was not performed in PGE's AdopDER model for electrification forecasts. It is assumed that all electrification in the industrial segment is associated to non-large customer projects.

usage, and an hourly simulation which creates the peak demand output. To isolate the impact of growth from large industrial load, PGE focuses on the large customer forecast, holding all customers who are projected to add at least 30 MW of load in coming years at levels consistent with PGE's forecasted values for 2025. This categorization by size is consistent with Category 3 large non-residential customers in PGE's proposed modification to its tariff filed in Advice No. 24-38/UE 430.

This approach does not attempt to capture the nuance associated with timing of individual customer load growth but instead selects a point in time and illustrates the magnitude of forecasted growth associated with large customer projects thereafter based on PGE's May 2024 Reference case Load Forecast.[46]

3.1.3.2 Resulting forecast – excluding large customer load

Removing growth associated with large customer load after 2025 results in lower energy deliveries and seasonal peak demand forecasts. The twenty-year average annual growth rate for the May 2024 Reference total energy forecast is estimated to reduce from 1.9 percent to 0.1 percent, prior to electrification. After including electrification, forecasts that exclude large customer load estimate a 1.3 percentage point reduction in the total energy twenty-year average annual growth rate, as shown in **Table 10**.

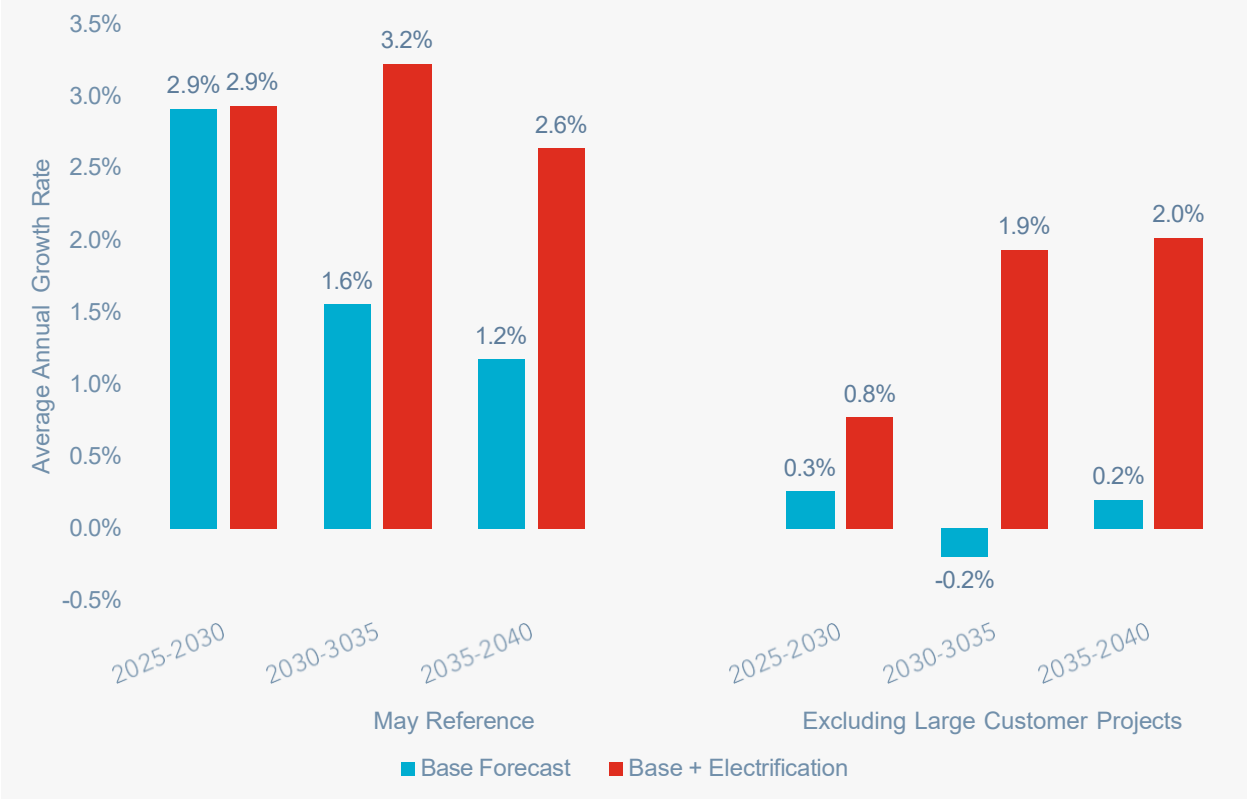
Table 10. Twenty-year average annual growth rate comparison, Excluding Large Customer Projects

	May 2024 Reference	May 2024 Reference + Electrification	May 2024 Reference, Excluding Large Customer Projects	May 2024 Reference + Electrification, Excluding Large Customer Projects
Total Energy	1.9%	2.8%	0.1%	1.5%
Summer Peak	1.5%	3.2%	0.3%	2.3%
Winter Peak	1.4%	3.5%	0.2%	2.5%

The reductions in load estimates from forecasts that exclude large customer load is greatest in the near term where line of sight to large customer load is most certain and growth is expected to be greater. **Figure 17** compares the five-year average annual growth rates consistent with the May 2024 Reference load forecast and the forecast which excludes large customer load, with and without electrification. These estimates suggest large customer load comprises the majority of PGE growth prior to 2030, after which electrification in the residential and commercial segments begins to account for an increasing share of forecasted growth.

[46] This methodology is forward looking and does not differentiate existing large loads.

Figure 17. Comparison of annual average growth rates for energy forecast at 5-year increments



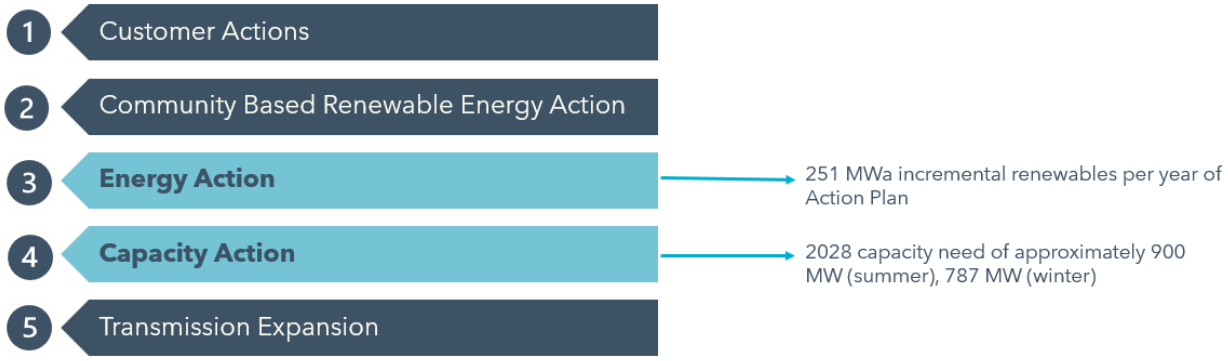
3.2 2023 RFP results

3.2.1 Target and need

In the 2023 RFP, PGE pursued non-emitting resources to facilitate a reliable energy supply for the service area while reducing the greenhouse gas emissions associated with energy generated to serve customers. PGE's 2023 CEP/IRP found that the company has a need for additional capacity resources beginning in 2026, with an additional capacity need in 2028. Further, the 2023 CEP/IRP Action Plan identified that procuring additional energy resources is needed to support the reduction of greenhouse gas emissions within PGE's portfolio. The 2023 RFP was designed and approved, subject to conditions, to seek resources to address these needs within a 2025-2027 commercial online date (COD) window, consistent with PGE's 2023 CEP/IRP Action Plan.[47] PGE's 2023 CEP/IRP Action Plan items are shown in **Figure 18**, with the targets for energy and capacity actions targeted by the 2023 RFP shown in light blue.

[47] See Order No. 24-011, as modified by Order Nos. 24-024 and 24-085.

Figure 18. PGE's 2023 CEP/IRP Action Plan, and associated targets for 2023 RFP[48]



As shown above, the 2023 CEP/IRP Action Plan included both a capacity and energy action: the capacity action identified a need in 2028 of 905 MW in summer and 787 MW in winter.[49] The response from the market to the 2023 CEP/RFP was robust, and PGE's final shortlist included 361 MW of capacity contribution from renewable resources, plus an additional 695 MW of capacity contribution from dispatchable capacity options in the form of lithium-ion battery storage. In the RFP, PGE sought the identified capacity needs entirely from non-emitting resources and has identified resources which, after contemplating the latest IRP capacity modeling updates, reduce PGE's 2028 capacity need to 0 MW and 195 MW for summer and winter, respectively. Because negotiations are ongoing, there is still uncertainty in which resources will become part of PGE's portfolio.

PGE evaluated the costs, risks, and benefits of renewable procurement volumes to make progress toward the identified energy action outlined in PGE's 2023 CEP/IRP Action Plan. While PGE saw a robust response to the 2023 RFP, the total number of renewable energy resources recommended for procurement based on customer value was not sufficient to fully address PGE's 2025-2027 energy action as described in the Action Plan in the 2023 CEP/IRP. Where the 2023 CEP/IRP recommended 753 MWa of renewable energy acquisition, the total generation available from of renewable options on PGE's initial shortlist for this RFP was approximately 350 MWa. PGE's final shortlist Group A, which identified 96 MWa of renewable energy resources and 775 MW of lithium-ion batteries, and Group B, which identified 885 MW of lithium-ion batteries, included projects that are likely to represent least-cost, least-risk for customers.[50] PGE continues to negotiate with the remaining Group A projects and aims to finalize contracts over the course of 2025.

PGE did not include four unique renewable projects on the final shortlist, which together represented an additional 1,000 MW of resources. The primary reason these projects were not included in the final shortlist was their anticipated impact to customer affordability. PGE is continuing to actively seek additional clean energy resources from the market that offer reliability

[48] See PGE's Request for Acknowledgment of the Final Shortlist of Bidders, p. 5
[49] See PGE Response to Staff's Round 2 Comments and Recommendations, p.42
[50] On December 12, 2024, one of the projects in Group A notified PGE that it was withdrawing from commercial negotiations.

and efficiency at the lowest costs to customers. PGE is currently advancing the 2025 All-Source RFP to seek additional non-emitting energy and capacity resources. PGE plans to issue the RFP to the market in the third quarter 2025 and compile a final shortlist in early 2026.[51]

3.2.2 2023 RFP proxy

On November 25, 2024, the OPUC acknowledged, subject to conditions, PGE's 2023 RFP final shortlist of bids.[52] PGE commenced commercial negotiations to acquire resources from the final shortlist Group A.[53] The final shortlist Group A consists of four projects with the following general characteristics:

1. Hybrid 250 MW solar & 250 MW battery
2. Hybrid 125 MW solar & 125 MW battery
3. Standalone 400 MW battery
4. Standalone 41 MW solar

Because negotiations for project acquisition are ongoing, there is still uncertainty in which resources will become part of PGE's portfolio. To account for the expected addition of resources to the portfolio, PGE's models include a proxy set of resources that represents an informed estimate of the quantity of resource acquisitions from the 2023 RFP. The RFP proxy serves as a placeholder for the resources in PGE's modeled portfolio.

The RFP proxy represents the energy and capacity benefits contributed to PGE's portfolio by the expected resources from the final shortlist so they can be accounted for in calculation of energy need, capacity need, and proxy resource ELCCs. The RFP proxy used in IRP Update modeling consists of 375 MW of solar/battery hybrid resources and 400 MW of standalone 4-hr battery storage, representing Group A resources.[54] Since identifying the resources in the final shortlist Group A, the 41 MW standalone solar project withdrew from commercial negotiations and energy and capacity are not included in the RFP proxy.[55] Subsequent to the final definition of modeling assumptions in the Update, the 250 MW solar & 250 MW battery hybrid project also withdrew from commercial negotiations. Because modeling was already underway, the energy and capacity of the 250 MW solar & 250 MW battery hybrid is included in the RFP proxy. The updated needs in 2028 with the inclusion of the RFP Proxy are 0 MW and 195 MW for summer and winter, respectively.

[51] Docket No: UM 2371
[52] OPUC Docket No. UM 2274 Final Order available here: https://apps.puc.state.or.us/orders/2024ords/24-425.pdf
[53] The shortlist is bifurcated into an A group and a B group of resources. The RFP proxy is based on the resources in group A only and references to the final shortlist in this section refer to group A resources only. PGE's decision on whether to pursue group B bids will depend upon the outcomes of commercial negotiations for group A bids.
[54] Final shortlist Group B resources are not included in the RFP proxy.
[55] On December 12, 2024, the 41 MW standalone solar project notified PGE that it was withdrawing from commercial negotiations.

3.3 Energy need

Energy need is the difference between PGE's forecasted load (demand) and the supply of energy available to serve load from existing owned and contracted resources in the baseline portfolio, defined in terms of average Megawatts (MWa). Energy need is an important input to portfolio analysis as one of the main drivers of the need for new resource additions. This section describes the energy need forecast used for portfolio analysis, calculated with the most up to date information available at the time of analysis.

PGE presented an annual energy position forecast in the 2023 CEP/IRP and subsequently updated it in the 2023 CEP/IRP Addendum.[56] The Addendum incorporated an updated load forecast and changes to the baseline portfolio that occurred after the writing of the 2023 CEP/IRP. The net effect of updates made to the annual energy position from the 2023 CEP/IRP to the Addendum were to increase PGE's energy need.

PGE has incorporated additional updates into modeling since the Addendum, which has led to another update to PGE's forecasted energy need. Modeling updates incorporated into IRP Update that impact annual energy need include an updated load forecast (**Section 3.1 Econometric load forecast**), updated forecasts of cost-effective DERs (**Section 5.2.1 Passive DERs**) and EE (**Section 5.3 Energy efficiency**), and updates to PGE's baseline resource portfolio. The load forecast used in the Update includes higher energy demand compared to the forecast from the IRP Addendum. Updated forecasts of cost-effective DERs and EE have increased since the IRP Addendum. These resources offset energy usage and reduce the quantity of load to be served, decreasing annual energy load resource balance.

Updates to the baseline portfolio since the Addendum include the RFP proxy, the addition of new contracts and an updated Qualifying Facilities (QF) forecast. The three new hydro contracts in the base portfolio include one with Grant PUD from 2024-2026 and two with Douglas PUD, one spanning 2024-2025 and one from 2026-2030.[57] Additionally, included in this update is a new contract with Calpine for a 250 MW share of the Hermiston combined-cycle natural gas plant in Hermiston, OR from 2025 through 2029.[58] Baseline portfolio updates have increased the quantity of energy in PGE's portfolio, decreasing annual energy need.

The incremental impact of each of the updates and resulting 2030 Reference Case needs are shown in **Figure 19**. In 2030, the increase in annual energy in PGE's baseline portfolio and increased EE and DERs outweigh the increased need associated with the new load forecast and other modeling updates, resulting in a decrease in PGE's annual energy load-resource balance from 1307 MWa to 1204 MWa. PGE's annual energy load-resource balance, including Reference, Low, and High need futures, is shown for the 20-year planning horizon in **Figure 20**.

[56] 2023 CEP/IRP and Addendum to the 2023 CEP/IRP
[57] Hydro contract details available in PGE 2024 10k filing, page 15.
[58] Consistent with the methodology used in the 2023 CEP/IRP, the quantity of emitting energy retained to serve PGE's load is limited to quantities that are compliant with HB 2021 GHG emissions targets based on the linear GHG reduction glidepath. The quantity of energy retained from the Calpine project is determined by the IGHG model. The impact of Calpine on PGE's retained quantity of emitting energy is described in **Section 3.5.1 HB 2021**.

Figure 19. Incremental impacts of updates on 2030 Reference Case energy need

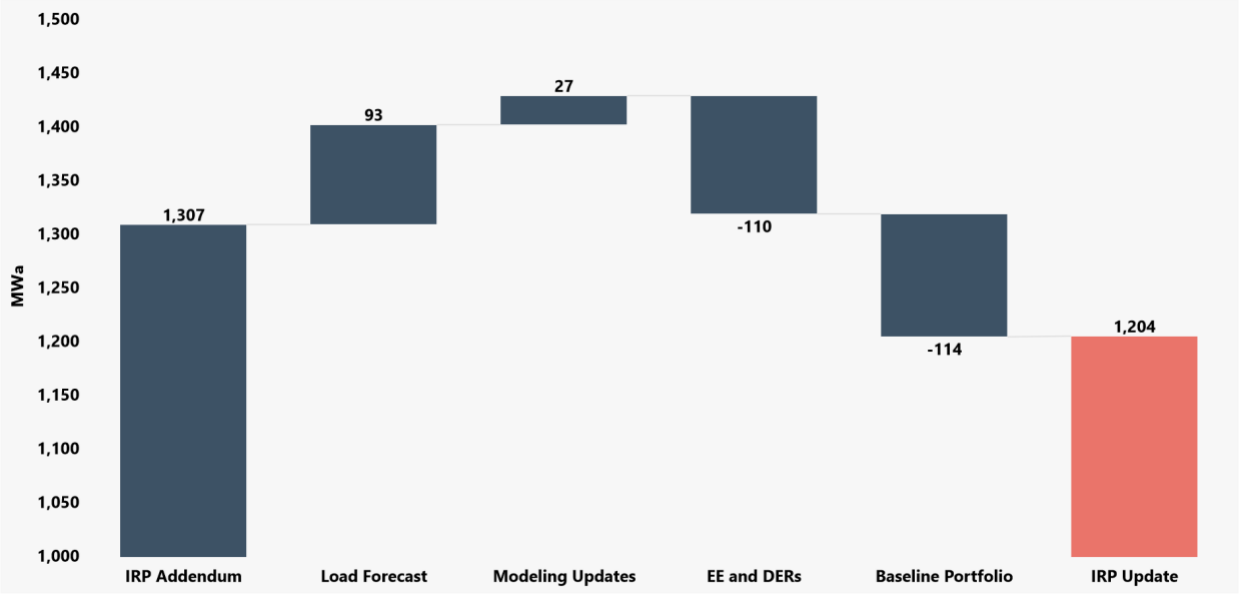
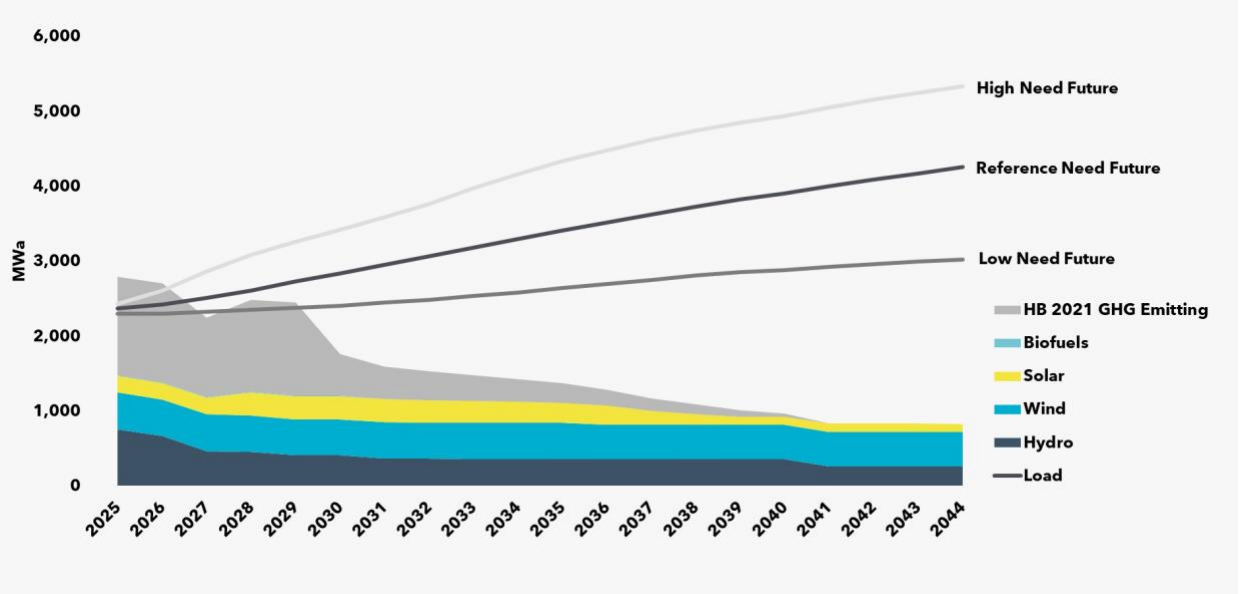


Figure 20. Annual energy-load resource balance from 2025 through 2044

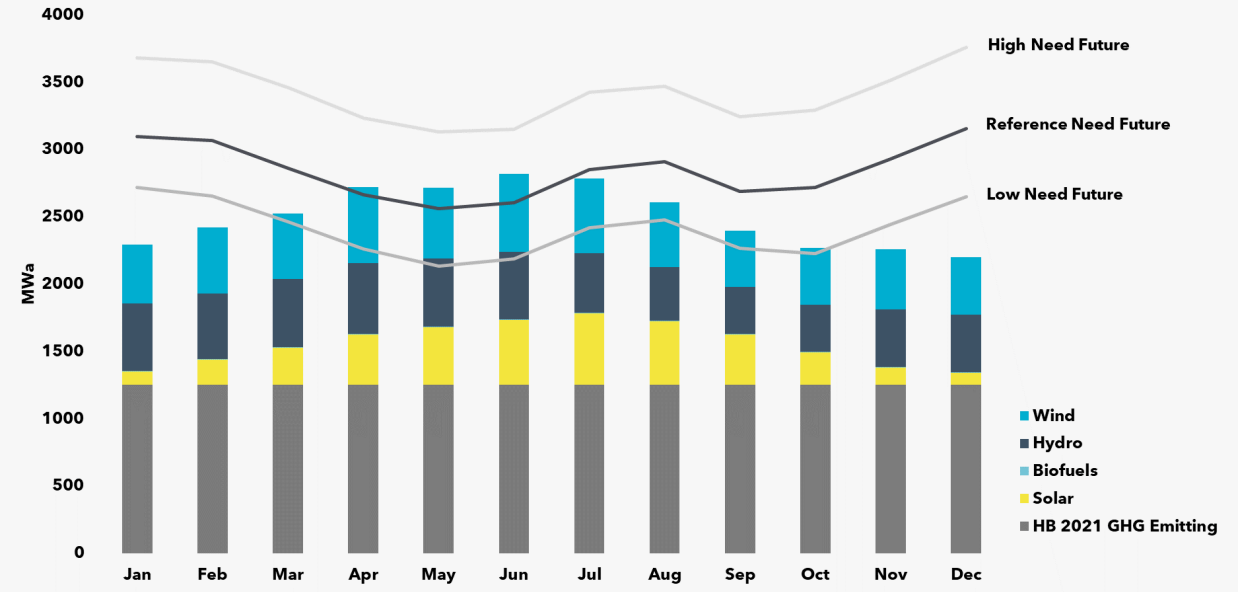


The gap between load and the stacked area of annual energy from PGE's baseline portfolio retained to serve retail load under HB 2021-compliant assumptions in **Figure 20** represents the minimum energy need remaining to be filled by incremental resource additions in portfolio analysis. For this Update PGE has calculated a monthly energy-load resource balance to further inform the magnitude of PGE's energy need. Because load and energy generation from renewable resources are both influenced by weather and the presence or absence of sunshine and wind, there are distinct seasonal patterns to energy supply and demand. PGE's load tends to

peak in the summer and winter when temperatures are very hot or cold and is lower during the mild temperatures of the spring and fall. Solar facilities produce the most energy in the summer and the least in the winter. Patterns of wind production are less predictable than solar but still display seasonality that varies by location. On average, the wind in PGE's baseline portfolio tends to produce the most in the spring and early summer. Hydro generation is also seasonal, with peak generation coinciding with spring runoff.

These dynamics in load and expected resource generation are shown for 2028 in **Figure 21**. The quantity of energy from renewable resources is calculated using monthly average capacity factors, which represents the percent of the time that a facility is expected to be generating throughout any given month. Energy from dispatchable sources cannot be allocated using static average capacity factors like non-dispatchable resources because the timing of their generation is determined by economic and operational decision making, so in **Figure 21** they are depicted as flat across each month of the year.[59]

Figure 21. 2028 monthly load-resource balance

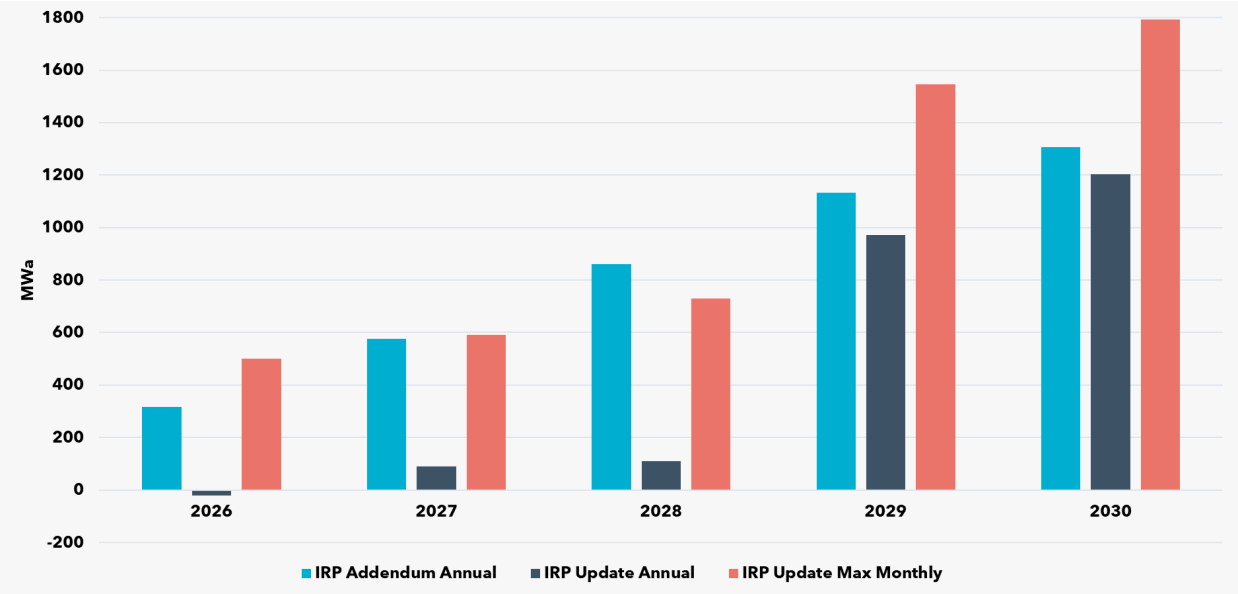


Seasonal dynamics can have important implications for resource planning and influence the optimal quantity and mix of resources in the portfolio. The magnitude of energy need in a given month may exceed the energy need on average across the year, increasing the quantity of resources needed. The timing of energy need throughout the year may be more correlated with some resource options than others, impacting which resources most optimally meet energy needs. Monthly energy-load resource balance accounting enables PGE to capture and consider seasonal variations in resource planning.

[59] The monthly allocation of energy from dispatchable sources is accounted for in portfolio analysis and is discussed in **Section 6.1.2 Energy need**.

The Update relies upon monthly energy needs to inform portfolio analysis. Resources are added to portfolios to ensure that each portfolio is forecasted to achieve monthly energy load resource balance. **Figure 22** compares PGE's annual energy load resource balance to the monthly energy load resource balance that is incorporated into PGE's portfolio analysis. Consistent with the above figure, this comparison assumes that energy from dispatchable sources is evenly distributed throughout the year, while PGE's portfolio analysis methodology allows dispatchable energy to be allocated throughout the year to minimize maximum monthly energy needs consistent with comprehensive portfolio economics. PGE's choice of incorporating monthly energy needs into portfolio analysis is responsive to Staff's condition, adopted by the OPUC in the 2023 CEP/IRP which expressed concern the previous filings reliance on annual energy metrics to demonstrate continual progress toward PGE's HB 2021 emissions targets.[60] By incorporating monthly energy needs into portfolio analysis, PGE's IRP Update better represents the seasonal aspects of PGE's decarbonized energy needs. Additional analysis which directly assesses the ability of the Preferred Portfolio to meet emissions targets on at an hourly granularity is discussed in **Section 6.2.2 Hourly energy and emissions accounting results**.

Figure 22. Comparison of Annual to Monthly Energy Need



3.4 Capacity need

Capacity need estimates the effective capacity, expressed in MW, required to achieve a resource-adequate portfolio. These estimates come from PGE's resource adequacy model, Sequoia. Sequoia estimates capacity need under a "1 day in 10 years" reliability metric, interpreted as 2.4 loss of load hours (LOLH) annually. PGE first developed Sequoia during the

[60] Staff Recommendation #3 from IRP Acknowledgement Order 24-096. Available here: https://apps.puc.state.or.us/orders/2024ords/24-096.pdf

2019 IRP Update.[61] The following section discusses the 2023 CEP/IRP Update need across the planning horizon, describes the effect of model updates made since PGE's CEP/IRP Addendum: System Need & Portfolio Refresh, and compares capacity need across different need futures that capture supply and demand uncertainty.

3.4.1 Seasonal need – reference case

The 2023 CEP/IRP Update estimates capacity need in summer (April-September) and winter (October-March). **Figure 23** shows PGE's seasonal capacity need across the 20-year planning horizon compared to capacity need previously estimated in Addendum filing.[62] PGE's near-term capacity need decreased since the addendum because of supply side additions, namely bilateral contracts, and resource additions modeled by the RFP Proxy. The updated summer capacity need is estimated at 47 MW in 2026. This capacity need grows to 485 MW in 2027 with the expiration of Grant PUD hydro contracts, then drops to 0 MW in 2028 as RFP Proxy Resources enter the modeled supply stack. In 2027, a winter capacity need of 159 MW is estimated and is expected to continuously grow.

PGE notes sources of uncertainty in short-term capacity need estimates. PGE's Econometric Load Forecast represent average expected outcomes and include a range of possible values. The 2023 CEP/IRP Update represents uncertainty in load forecasts by modeling different need futures, which could decrease or increase short-term need significantly (**Figure 23**). Another source of uncertainty relates to PGE's supply portfolio. Absent executed agreements, the 2023 CEP/IRP Update includes RFP Proxy resources assuming a January 1, 2028 commercial operations date. Resources may reach commercial operations before or after the assumed date. PGE can address remaining short-term need through commercial agreements to access existing resources. Structured or bilateral contracts can be agreed upon to provide capacity from existing resources. Additionally, regional sharing mechanisms from state resource adequacy requirements may provide additional capacity.[63]

Looking beyond the short-term, capacity needs in both seasons increase significantly in 2030 due to the exit of Colstrip and expiration of the Calpine contract. Capacity need grows steadily until 2040 where it is assumed all gas plants exit the portfolio, resulting in an approximately 2 GW increase in need.[64]

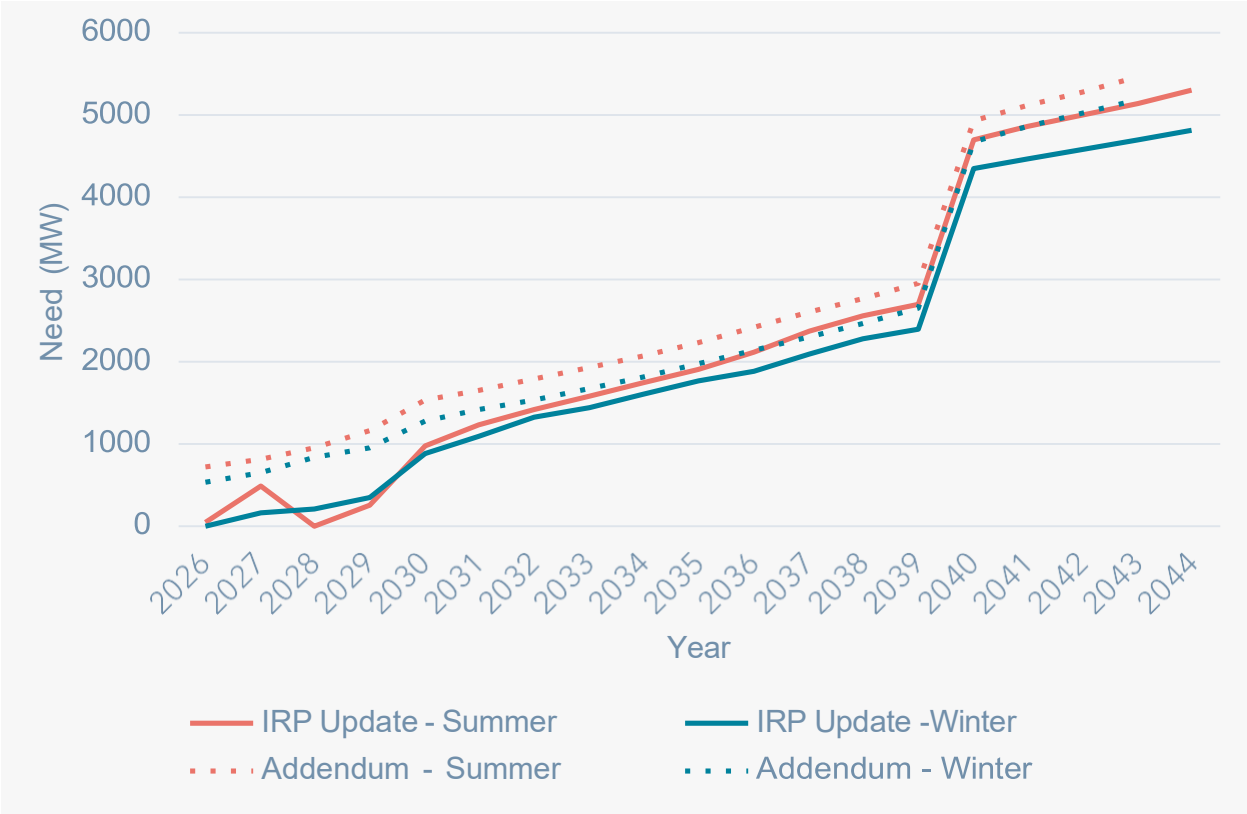
[61] The following resources provide descriptions of Sequoia from past roundtables and filings: 2019 IRP Update Sequoia overview - Appendix K; 2023 CEP/IRP Sequoia overview – Appendix H.3; May 2021 CEP/IRP Roundtable; March 2022 CEP/IRP Roundtable; January 2023 CEP/IRP Roundtable; August 2024 CEP/IRP Roundtable

[62] PGE's 2023 CEP/IRP Addendum: System Need & Portfolio Refresh

[63] OPUC Docket AR 660 – Resource Adequacy Rules

[64] Due to infeasibility of model solutions in Sequoia for years with a very high need and little dispatchable resources, out of model adjustments were made to extrapolate latter years in the planning horizon. Infeasible years for the reference and high need futures are 2041-2044, and 2044 for the low need future. The average annual growth rate of need for 3 years prior to the greatest feasible year for each season and need future are used to extrapolate need. The average annual growth rate used to extrapolate need is approximately 8%, 6% and 4% for reference, high and low need futures, respectively.

Figure 23. 2023 CEP/IRP Update Capacity Need – Reference Case



3.4.2 Changes to modeling capacity need

The 2023 CEP/IRP Update includes multiple changes to Sequoia as part of refreshing PGE's capacity need estimates. The updates include methodological and other input related changes that aim to improve the representation of Sequoia's assessment of demand and supply in PGE's system. **Figure 24** and **Figure 25** display the incremental effect of major updates affecting PGE's capacity need estimates for both summer and winter, respectively. The incremental changes in capacity need depicted depend on the order in which updates are sequenced, while the final capacity need does not.[65] Updates were ordered to show methodological effects first, followed by changes in input assumptions. Updated capacity need in 2028 shows a net decrease for both summer and winter.

3.4.2.1 Updated analysis period

As part of the 2023 CEP/IRP Update, Sequoia was updated to allow modeling of the most recent 30 years of historical load and generation data, shifting the analysis period from 1992-2021 to 1994-2023. This shift in analysis period allows Sequoia to model more recent weather effects on

[65] For example, the 155 MW increase and 57 MW decrease of summer and winter capacity need resulting from Load Updates, respectively, are relative to the changes which resulted from the "Updated Analysis Period" vintage of Sequoia modeled prior. Reordering these changes would not alter the 0 MW summer and 195 MW winter capacity needs for 2028.

load and variable energy resources. This change in methodology results in a 46 MW increase in summer need and 14 MW increase in winter need.[66]

3.4.2.2 Load forecast updates

Two updates to load forecasts used in Sequoia are included in the 2023 CEP/IRP Update. First, PGE's Corporate Load Forecasts (CLF) hourly historical simulation is used in place of the previous historical simulation. Second, the load forecast version is updated from May 2023 to May 2024. As part of the 2023 CEP/IRP Update, PGE's CLF developed a historical simulation of hourly load (**Section 3.1 Econometric load forecast**). This simulation replaced the previous approach which scaled historical weather-dependent load to approximate forecasted monthly peak and average energy for future years. Scaling the weather-dependent load shape required a linear estimation which aimed to represent future load shapes, a process which was less precise and irreproducible iteration-to-iteration. The new CLF approach produces the hourly historical simulation necessary for Sequoia, resulting in a more efficient and reproducible method. Lastly, forecasts used to estimate load were updated from May 2023 to May 2024. In total, these load forecast updates result in a 57 MW decrease in winter capacity need and a 155 MW increase in summer capacity need for 2028.

3.4.2.3 Supply-side updates

The various supply-side updates that are part of the 2023 CEP/IRP Update (**Section 3.3 Energy need**), resulted in a 313 MW, 218 MW and 615 MW reduction in summer need for new contracts in the base portfolio, revised DER estimates, and RFP Proxy Resources, respectively. In winter, the supply-side updates resulted in a 335 MW, 91MW and 162 MW reduction in capacity need from new contracts in the base portfolio, revised DER estimates, and RFP Proxy Resources, respectively.

[66] Reference **Appendix B Sequoia methodological update** for additional detail.

Figure 24. Incremental Changes to Capacity Need - Summer 2028 Reference Case

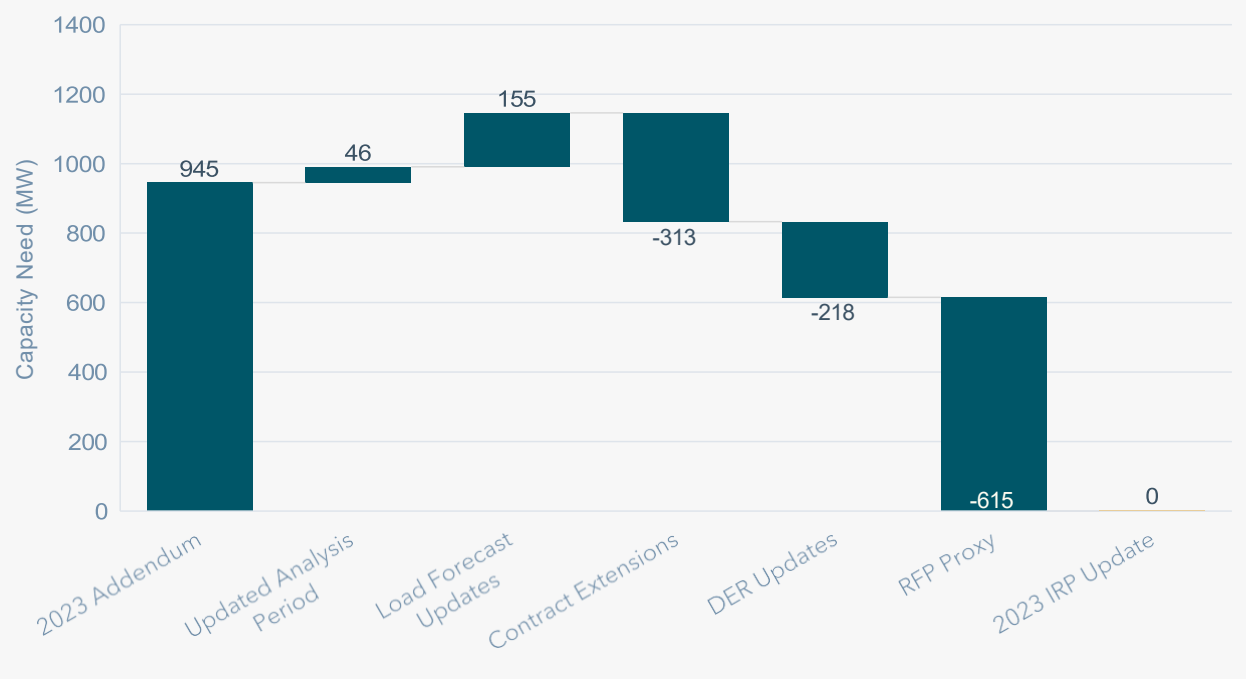
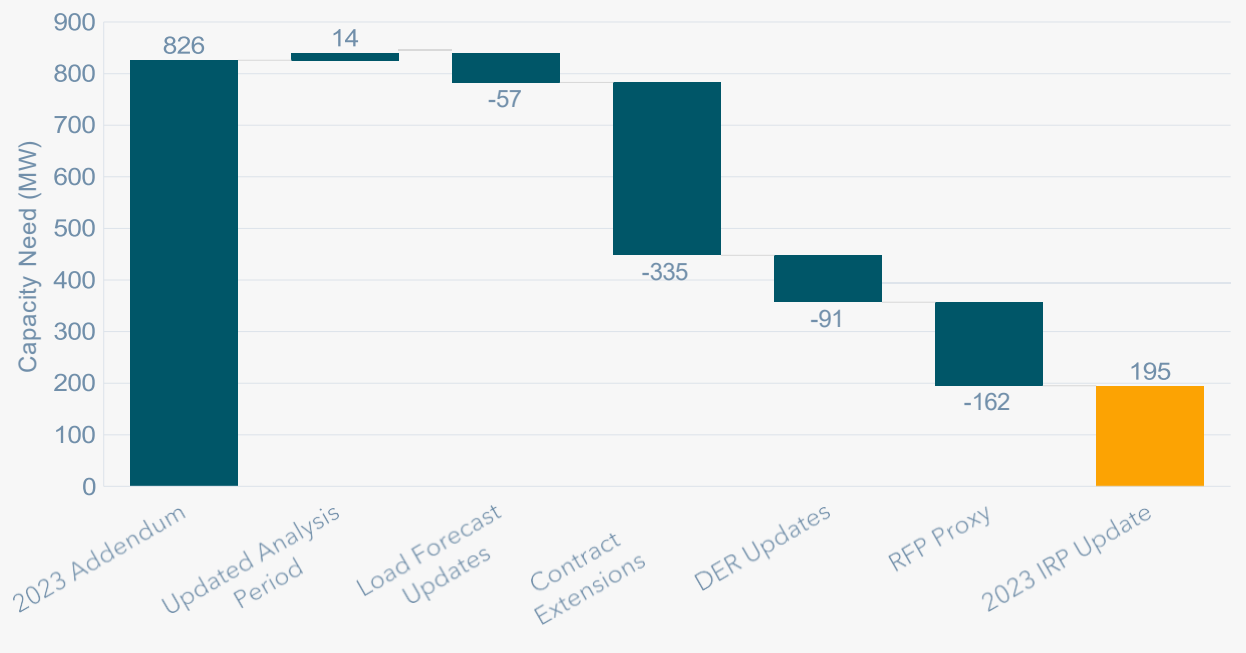


Figure 25. Incremental Changes to Capacity Need - Winter 2028 Reference Case

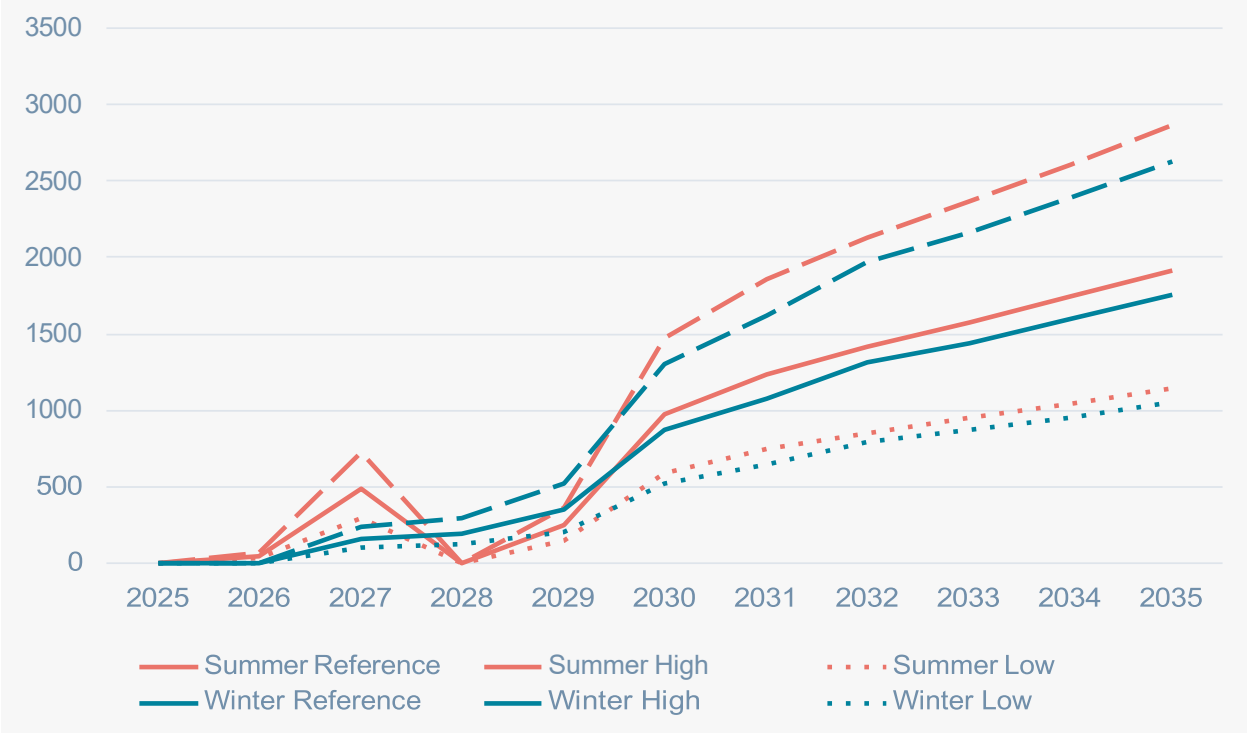


3.4.3 Capacity need under different futures

The 2023 CEP/IRP Update models capacity need across low and high need futures to capture uncertainty in both supply and demand side variables. **Figure 26** shows the capacity needs of the low and high need futures and the Reference Case. The figure suggests the different futures

approximate a uniform shift of reference case needs, resulting in 0 MW of need prior to 2030 in both seasons, except summer 2027. The high need future results in approximately 700 MW more need on average in each season for years 2030-2035.

Figure 26. Capacity need under different need futures: 2026-2035



3.5 State policy requirements

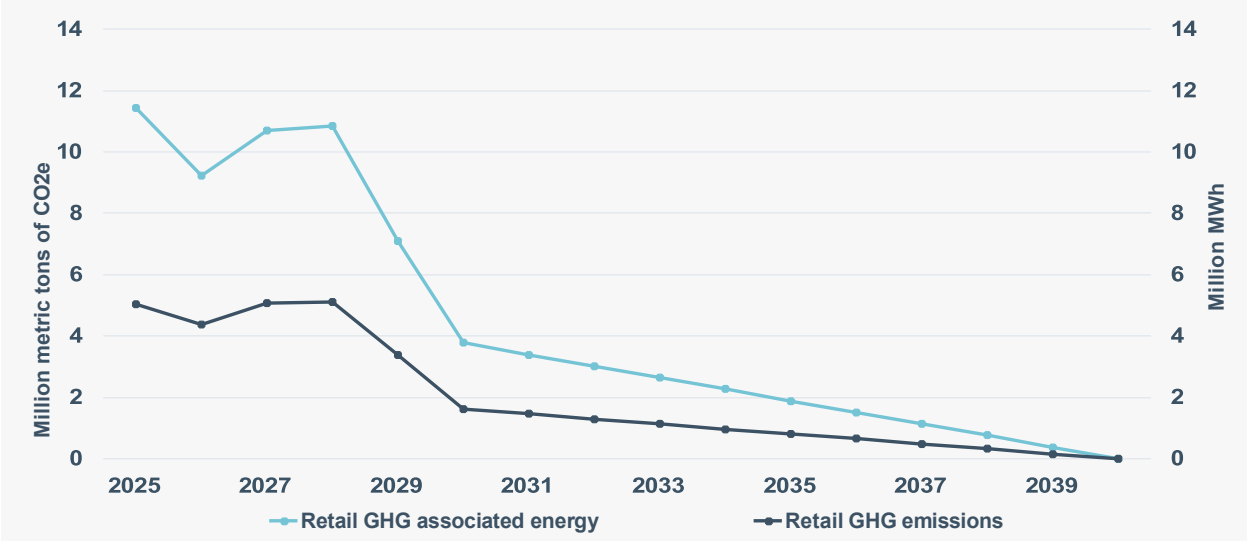
This section describes how State policy requirements are imposed through the utility regulatory framework and updates PGE made to reflect these constraints as part of the 2023 CEP/IRP Update.

3.5.1 HB 2021

The 2023 CEP/IRP was the first resource plan published by PGE that addressed the requirements of HB 2021. The emissions targets of HB 2021 remain unchanged from the 2023 CEP/IRP Update; compliance with these requirements is incorporated as the default assumption in modeling, including the creation of the Preferred Portfolio and the Action Plan. More details on modeling specifics can be found in those chapters of this document.

PGE continues to rely on a linear GHG reduction glidepath to inform the modeling as it was found to provide the best combination of cost, risk, and rate of emissions reduction amongst a variety of glidepaths tested in the Appendix I C-level analysis of the 2023 CEP/IRP. The impact of this glidepath is a limit of the thermal generation and market purchases with associated emissions retained for retail load. Updated data and analysis described in Chapter 3 inform an updated emission reduction glidepath presented in **Figure 27**.

Figure 27. GHG emissions & energy associated with serving Oregon retail load (Reference Case)



The 2023 RFP procurement results are not yet final but could add resources by the beginning of 2028. While further resource procurement will allow for more portfolio additions, these are unlikely to come online before the beginning of 2029 due to the time needed for procurement processes and construction timelines. Consequently, all current resources are necessary to meet demand and maintain reliability until 2029. Modeling does not include any additional non-emitting resources until the beginning of 2029 at the earliest. This situation limits the near-term emissions reductions achievable by PGE over the next three years. As a result, the updated emissions glidepath in the near-term reflects emissions levels more consistent with recent history given inability to alter the current generating mix prior to 2029.

PGE is accelerating procurement through RFPs between now and 2030. PGE has requested approval of its 2025 RFP in Docket UM 2371 to continue to seek resources to meet needs that remain after the conclusion of the 2023 RFP. Possible resource procurements from the 2025 RFP are presently unknown and therefore not included in this analysis.

Figure 28. Total (retail + wholesale) GHG emissions under the adjusted linear reduction glidepath (Reference Case)

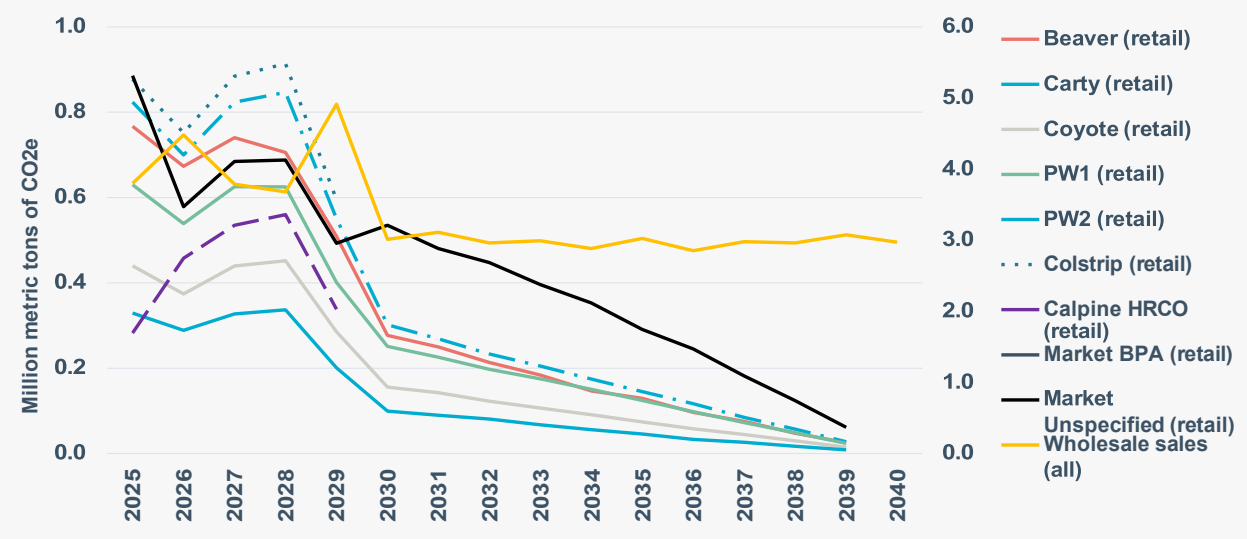


Figure 28 reflects GHG emissions projections from thermal generation and market purchases under the updated decarbonization glidepath. The lines specific to individual resources show retail GHG emissions. The specified wholesale sales category captures GHG emissions from sales from all sources not accounted for in retail sales that in the Update forecast support customer affordability through reduced net-variable power costs and reflect ongoing participation in the wholesale market to support reliability of the regional power system.

To achieve the HB 2021 emissions target in 2030, integration of non-emitting resources onto PGE's system will enable a systematic reduction in fossil fuels serving Oregon retail load and subsequent GHG reductions. As non-emitting energy and capacity resources are added, the amount of thermal output from natural gas and coal for Oregon retail load is reduced to meet the emissions targets. The market for thermal generation is increasingly constrained across the West, with clean energy or GHG requirements in place in almost every state in the Western Interconnection. Thermal generation sold into the Western Interconnection is therefore increasingly subject to the GHG or clean energy requirements of other states. For example, fossil fuel energy exported to California and Washington incurs direct carbon pricing obligations. These policies, and dramatic addition of non-emitting resources anticipated across the region, contribute to reducing the quantity of economically dispatched thermal output in PGE's forecasts.

3.5.2 RPS obligation

RPS requirements were included in the 2023 CEP/IRP and will continue to be accounted for in portfolio analysis in the 2023 CEP/IRP Update. PGE's RPS obligation, which is a function of the forecasted load, has been updated to reflect the updated load forecast used in the Update. Updated RPS requirements are shown in **Table 11**. The Preferred Portfolio's compliance with RPS requirements is demonstrated in **Section 6.2 Preferred Portfolio**.

Table 11. Updated RPS obligations Reference need future

Year	RPS requirement (% of retail sales)	RPS requirement (MWa)
2025	27%	482
2030	35%	748
2035	45%	1155
2040	50%	1470

This filing has not made any updates to assumptions regarding the Company's REC bank since the 2023 CEP/IRP. In Order No. 24-096, the OPUC directed PGE to provide a more detailed RPS analysis in the next CEP/IRP, and PGE intends to include this analysis and broader REC strategy in the 2026 plan.[67]

3.5.3 Small scale renewables standard

Following Commission direction, this Update will explicitly account for Oregon's small-scale renewable (SSR) requirement in its modeling.[68] The SSR requirement that, starting in 2030, 10 percent of aggregate electric capacity in PGE's portfolio be composed of renewable facilities 20 MW or smaller in size is incorporated into portfolio analysis. In this update, PGE has added a new constraint and a new SSR proxy resource option in ROSE-E to ensure that the Preferred Portfolio is compliant with SSR requirements. The SSR proxy resource option is described in **Section 5.4 SSR resource**. The quantity of resources forecasted to be required to meet the 10 percent requirement, which is dependent on the quantity of resources added in the Preferred Portfolio, is presented and discussed in **Section 6.4 Small scale renewables plan**.

[67] Direction for future planning on RECs can be found on page 22 of the final order, available at: https://apps.puc.state.or.us/orders/2024ords/24-096.pdf.
[68] The SSR requirement is included based on Commission direction in the LC 80 final order. See page 11 at: https://apps.puc.state.or.us/orders/2024ords/24-096.pdf.

Chapter 4. Transmission landscape

PGE owns transmission assets and holds transmission contract rights for reliable delivery of electricity from generation resources to load. Additional transmission rights will be required for PGE to access more diverse resources, decarbonize, and maintain adequacy. However, there is a limited amount of existing transmission available for future resources to use. This chapter provides an update on relevant evolving topics discussed more fully in the 2023 CEP/IRP and provides an overview of PGE's current transmission environment, projects in PGE's system planning, and options in IRP modeling.

Key Highlights

- The transmission system serving PGE customers is highly constrained, with limited existing transmission available for future resources, particularly on BPA's system which supports limited resource additions prior to further transmission upgrades.
- The North of Pearl (NOPE) flowgate has emerged as a significant constraint since August 2023, creating operational challenges that could be exacerbated by ongoing regional trends that are causing increasing south to north flows near Portland. Multiple projects are required to address reliability risks related to this flowgate.
- Transmission plays an essential role to access diverse generation resources that are unavailable within PGE's service territory. Several transmission projects in various stages of development have been identified to help PGE access new renewable resources from diverse geographic areas.

Developments Since 2023 IRP

This Update reflects significant developments in PGE's transmission planning since the 2023 CEP/IRP. The North of Pearl flowgate, which BPA established in August 2023, has created operational constraints during periods of renewable resource imports from California and the desert southwest across PGE's service territory. For the Bethel-Round Butte (also known as Warm Springs Power Pathway) project, PGE and the Confederated Tribes of Warm Springs have successfully secured a $250 million Grid Resilience and Innovation Partnerships (GRIP) Program grant, enabling survey work to begin. PGE has further refined additional transmission options in the modeling based on third-party analyses from Energy Strategies and Energy GPS, reflecting more realistic estimates of project timelines, achievable capacity, and market access benefits.

Strategic Implications

These changes highlight the growing urgency of PGE's transmission needs as the company works toward decarbonization goals while facing increasing load growth and system constraints. The emergence of the North of Pearl flowgate creates new operational challenges that will require collaborative solutions with BPA. The GRIP funding for the Bethel-Round Butte project improves its economics and solidifies its role as a valuable upgrade. Overall, the refined analysis of transmission options, further described in **Section 4.6 Transmission options for portfolio analysis,** provides a clearer picture of the timing and benefits of various projects, which will inform PGE's strategy for planning sufficient transmission capacity to access diverse resource zones and potentially lower cost markets.

Staff Recommendations Incorporated

The Update addresses several conditions from LC 80 Order 24-096. Broadly, the Update refined and expanded analysis of transmission and local resources as alternatives to large-scale transmission expansion. PGE has conducted a more comprehensive analysis of transmission constraints and potential solutions as supported by third party analysis. The company has expanded its evaluation of transmission options beyond BPA's system to include potential projects that would access more diverse climate zones, responding to stakeholder concerns about transmission development matching the urgency of PGE's needs. The update also reflects PGE's continued assessment of the Bethel-Round Butte 500 kV upgrade, which was identified by the OPUC as a project to study for increasing PGE's import capability.

4.1 Transmission and regulatory environment

PGE-owned and contracted-for generating resources to serve load are both directly connected to PGE’s transmission system and remote to PGE’s system. PGE’s transmission portfolio — comprised of PGE-owned assets and held transmission rights — is designed to ensure reliable delivery of electricity from this broad array of generation resources to load. Variable energy resources that generate non-emitting electricity will need to be added to meet growing load and decarbonize towards the targets of HB 2021. Increasingly these resources are expected to be developed in new geographic areas, with their delivery to PGE’s system requiring expanded transmission infrastructure and growing interconnectedness in the West.

4.1.1 Regulatory environment

As a vertically integrated investor-owned utility that is regulated by the Federal Energy Regulatory Commission (FERC), PGE is obligated by FERC to functionally separate its Transmission Function (PGET) from its Merchant function (PGEM). PGET is required to plan and operate PGE’s transmission system in a non-discriminatory manner that provides open access to all transmission customers, including PGEM. This means PGET cannot unduly preference PGEM and, by extension, the retail customers that PGEM serves. PGET’s transmission customers include

PGEM, Oregon-defined Electricity Service Supplier (ESS) customers, BPA, and transmission customers who utilize PGE's transmission system to transmit power across the region.

PGEM is responsible for purchasing transmission rights – on PGET's transmission facilities and other regional providers – to deliver power to PGE's service area to meet PGE's load obligations. PGEM holds extensive rights on PGET's transmission system, as well as the BPA transmission system, the largest transmission provider in the Pacific Northwest.

Consistent with Federal requirements, PGE must plan and build its transmission system to meet the needs of all PGET transmission customers, including PGEM, ESS customers, and all other transmission customers.[69] Transmission customers typically utilize PGE's transmission system to serve load contained within PGET's system footprint or to transfer power through PGET's system to other transmission systems.

Transmission customers who serve load located within PGE's Balancing Authority Area (BAA) generally use a transmission service called Network Integration Transmission Service (NITS). Transmission customers who move power through PGET's transmission system for delivery to a point on another transmission system typically use Point-to-Point (PTP) transmission service. For PGET to develop its transmission plans for most NITS customers, with the State of Oregon-defined Electric Service Supplier (ESS) customers being the exception, PGE uses the ten-year load-and-resource (L&R) forecasts supplied by NITS customers along with PTP transmission service commitments and requests. ESS customers are not currently obligated to designate generation resources to serve their loads because they are allowed to take a secondary form of NITS service under Oregon law.

PGET uses the NITS customers' L&R forecasts and the best available information, including transmission service requests, generation interconnection requests, and information from neighboring transmission providers' transmission planning and construction activities, to determine the need and timing for investments in the transmission system. The bulk of PGET's NITS customer-driven needs comes from PGEM, which supplies energy and capacity for PGE's retail customers. Oregon's HB 2021 is central to PGE's strategy and the resource decisions of PGET's transmission customers, including PGEM, resulting in the need to develop new transmission system investment and deployment plans. The 2025 L&R letter from PGEM to PGET documents the expectation that PGEM's future resource needs will change, given the need to meet growing load and comply with HB 2021. PGET works with its customers, including PGEM, to plan the PGET transmission system to maintain reliable service as its customers' resource mixes change over the next several years.

While PGE's transmission customers, except ESSs, are required to provide annual L&R forecasts looking ten years into the future, transmission development in the West requires lengthy planning, rights-of-way (ROW) acquisition, permitting, and construction timelines that often take years. As such, PGET cannot rely solely on the L&R forecasts to plan future transmission investments and must plan its transmission system on a longer time horizon.

[69] Such as the principles of FERC Order Nos. 890 and 1000 and requirements of PGE's FERC-approved open access transmission tariff (OATT).

4.1.2 PGE's transmission system

PGE's transmission system serves roughly half of Oregon's population and powers approximately two-thirds of Oregon's commercial and industrial activity. It is highly integrated with other transmission systems in the west due to the highly networked nature of the regional transmission system.

The PGE service area is a compact area located primarily in Oregon's Willamette Valley. PGE owns and operates its transmission system and BAA to deliver energy to retail customers while also providing transmission service to other wholesale transmission customers as required by FERC and in accordance with PGET's OATT. Most of PGE's existing, owned transmission assets are within the PGE service area. PGE also owns transmission assets in central and southern Oregon and Montana. PGE is obligated to plan, build, and operate the transmission system in a manner that reliably delivers power to serve customer load and the needs of PGET's OATT transmission customers.

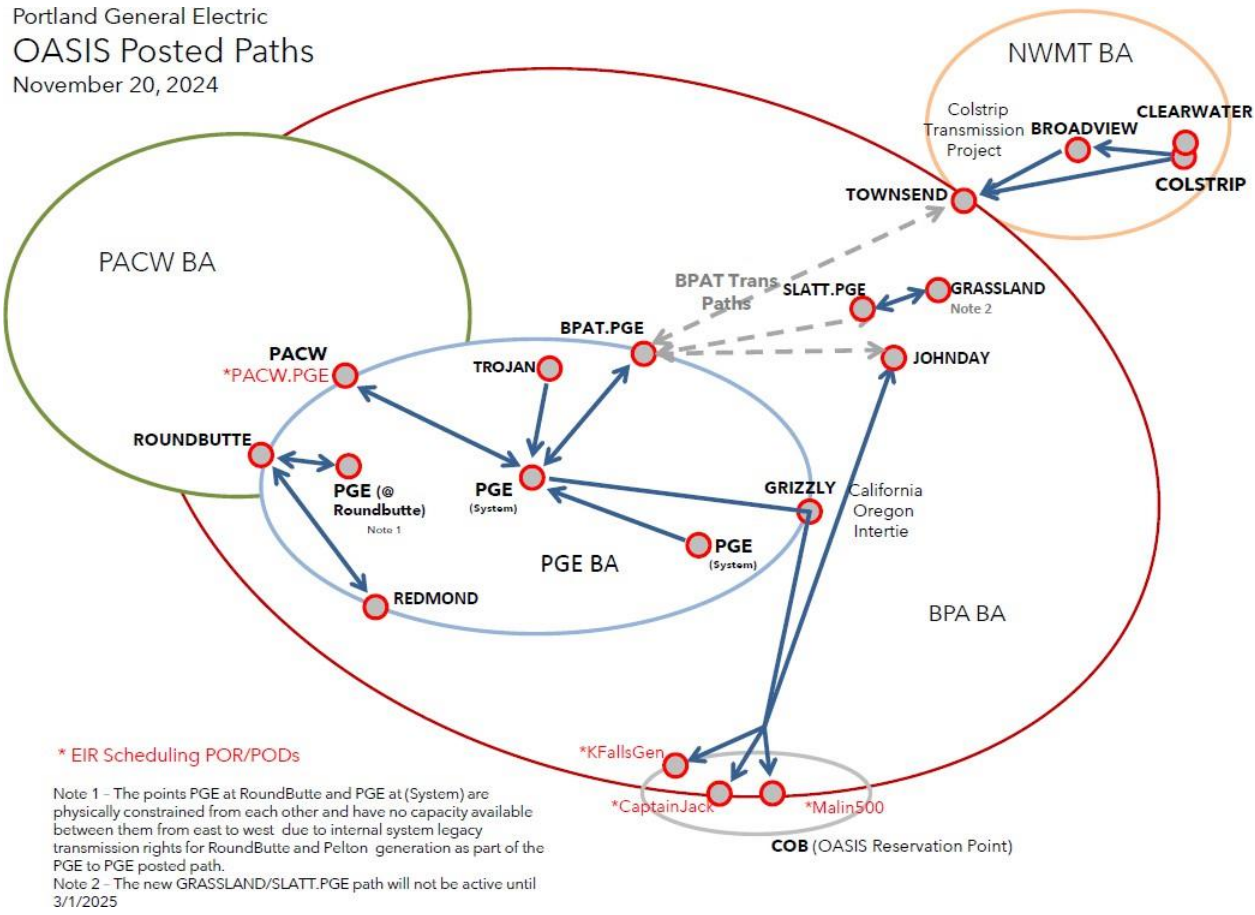
The PGE transmission system has 268 miles of 500 kV, 334 miles of 230 kV, and 559 miles of 115 kV lines, 454 circuit miles of 57 kV lines, and includes 176 substations and switching stations.[70]

4.1.3 Transmission system topology

PGE's transmission system (**Figure 29**) is highly interconnected with and exists almost entirely within the footprint of BPA. PGE is also interconnected to the western part of PacifiCorp's system, albeit with a much smaller transfer capability than PGE's interface with BPA. PGE's interface with PacifiCorp is primarily used to meet obligations within the Energy Imbalance Market (EIM). PGE is a co-owner of the Colstrip Transmission System, two 500 kV transmission circuits in Montana that runs between Colstrip and BPA's system in western Montana. Additionally, PGE owns one of the three 500 kV circuits in central Oregon that comprise the Northwest AC Intertie (NWACI), which is part of the California-Oregon Intertie, that connects Oregon to California. PGE jointly owns NWACI with BPA and PacifiCorp, and it is operated by BPA.

[70] An asset reclassification of PGE's 57 kV assets as transmission has been approved by the OPUC and is currently under review with FERC.

Figure 29. Oasis posted paths



4.1.3.1 BPA and Pacific Northwest transmission system

BPA is a federal power marketing administration (PMA) that operates approximately 75 percent of the transmission in the Pacific Northwest, consisting of more than 15,000 miles of high-voltage transmission lines. BPA operates transmission in Idaho, Oregon, Washington, western Montana and small parts of eastern Montana, California, Nevada, Utah and Wyoming.[71]

4.1.3.2 PGE and BPA

PGE's system is largely surrounded by BPA's transmission system. PGE has long relied on BPA transmission to deliver energy from throughout the west to serve PGE load. PGE currently holds over 4000 MW of long-term firm transmission under contract with BPA. The rights held on BPA's system deliver energy from discrete points, either on BPA's system or from the edge of BPA's system to PGE. These rights are known as point-to-point transmission rights and the points of receipt and delivery are set in perpetuity. This means that if a resource that would normally utilize

[71] BPA transmission system: https://www.bpa.gov/-/media/Aep/about/publications/maps/bpa-transmissionlines-and-facilities.pdf.

certain rights is unavailable, the unused transmission rights cannot be used to access different points on BPA's system. As discussed by BPA and stakeholders throughout BPA's recent Transmission Study and Expansion Processes (TSEP), BPA's system is effectively fully subscribed, and incremental transmission requests are unlikely to be granted until the early to mid-2030s, pending significant upgrades. Additionally, BPA has recently announced a pause to their TSEP process entirely while they attempt to develop reforms to their transmission service request process. As such, future transmission planning and procurement activity recommended throughout this chapter is a way to expand and diversify transmission options as the energy associated with serving load is decarbonized. It is important to recognize that the identification and development of transmission solutions are long-lead-time activities that often take longer than the Action Plan window time horizon of the IRP. Given this dynamic, it is necessary to engage in transmission planning and development on a forward-looking basis beyond the Action Plan window. See the description of the West-Wide Transmission Study Project (**Section 2.3.1 Western Transmission Expansion Coalition (WestTEC)**), a 10-year and 20-year transmission study addressing interregional and interstate transmission needs spanning the Western Interconnection.

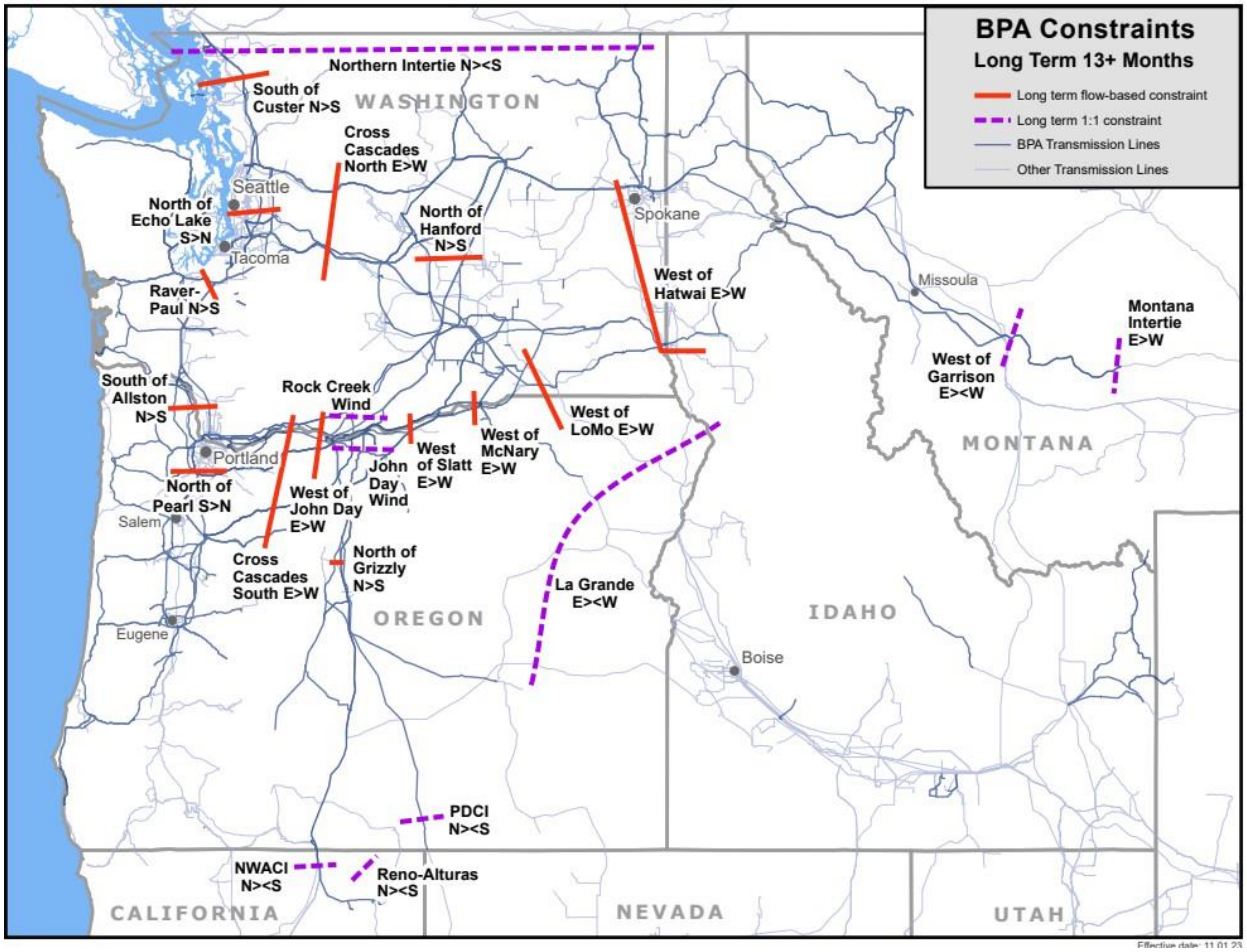
4.1.3.3 Paths and flowgates

To get to PGE's system, power generated or purchased from remote locations must travel through different paths and flowgates on the region's transmission system. A flowgate is a collection of transmission lines and facilities that collectively start in a geographically similar area and terminate in a different geographically similar area. These flowgates are typically operated by BPA and are shown in **Figure 30**. The flowgates that currently have the most significant impact on PGEM's transmission rights portfolio are North of Pearl, South of Allston, Raver Paul, West of John Day, and Cross Cascades South, all of which are constrained, with little or no ATC.

Flowgates are used by BPA as a way to monitor flow through areas of constraint on their system. Conceptually, when managed appropriately, the establishment of flowgates allows for a transmission provider to monitor system flows and take action to mitigate system constraints in the real-time operations horizon. Congestion at flowgates can be caused by different reasons including:

- Localized high loads at the receiving end of a flowgate in excess of flowgate capacity,
- Localized concentration of generation resources at the sending end of a flowgate trying in excess of flowgate capacity, and
- Flow-though, also known as loop flow, where far-flung regional load and generation dispatch scenarios create flows in excess of transmission capacity.

Figure 30. BPA Constraints[72]



The following summarizes the most significant flowgates and paths affecting energy delivery from remote resources to PGE's service area.

- The North of Pearl flowgate was instituted in August 2023 and has presented PGE with challenging operational scenarios since. The flowgate generally exists between the Wilsonville and Sherwood areas, SW of Portland. It is most constrained during periods of high renewable resource production in California and the desert southwest when it is also cool in the Pacific Northwest. Much less frequently, high Portland area loads can also contribute to high flows on North of Pearl. Further explanation of the North of Pearl flowgate will be described below.
- Some amount of energy from the majority of PGE's generating resources flows across the constrained South of Allston flowgate. This flowgate is most constrained during heavy summer and heavy winter loading periods. The South of Allston flowgate is a collection of several electrically parallel transmission lines that route from north to south just north of the

[72] Source: https://www.bpa.gov/-/media/Aep/transmission/atc-methodology/atc-long-term-constraints-11-1-23.pdf.

Portland metro area. Historically, the South of Allston flowgate was most constrained in the summer months.

- A large portion of the energy flowing from PGE's remote resources flows across the West of Cross Cascades South (WOCS) flowgate. Additionally, depending on the resource location, energy will flow across the West of John Day flowgate and the Raver-Paul flowgate. The WOCS flowgate is typically most constrained during heavy winter loading, while the West of John Day and Raver-Paul flowgates are typically most constrained during heavy spring and summer loading. PGE's Bethel-Round Butte 230 kV transmission line is part of the WOCS path.

Energy from PGE's resources in Montana first flow over the West of Garrison flowgate before reaching several other flowgates on the way to PGE's load in the Willamette Valley.

4.1.3.4 North of Pearl

The North of Pearl (NOPE) flowgate consists of a combination of BPA and PGE lines that run between BPA's Pearl substation in Wilsonville, OR to PGE's Sherwood substation in Sherwood, OR. The flowgate is comprised of BPA's Pearl-Keeler 500kV line, the Pearl BPA-Sherwood #1 & #2 230kV lines, and the McLoughlin-Pearl BPA-Sherwood 230kV line. The flowgate was instituted on August 11, 2023, a few days prior to a heatwave that blanketed much of the PNW. The NOPE flowgate was originally intended to be enabled in November 2023, prior to the winter operating season, but was expedited by BPA with the extreme heat that occurred in August 2023.

The NOPE flowgate was originally enabled for the purposes of monitoring south-to-north (S-N) flows through the Portland area. Previously, S-N flows were monitored as part of the South of Allston flowgate, but in a S-N flow pattern. BPA eventually shifted the focal point for monitoring S-N flows from the South of Allston flowgate to the more appropriate NOPE location. The South of Allston S-N flowgate was retired in early 2024.

During spring of 2024 and 2025, there have been several occasions where the North of Pearl flowgate reached S-N transmission flow levels near the upper limits of the flowgate limit high renewable resource imports from California and the desert southwest and low hydro generation output from British Columbia. Additionally, unscheduled energy flows have been observed coming into the Pacific Northwest and through PGE's service territory. These unscheduled flows, and the load and resource dispatch patterns several hundreds of miles away from PGE's system in either direction, have caused BPA to take real-time mitigation actions that included: sending congestion signals to the EIM marketplace that dispatched PGE Port Westward gas resources unexpectedly, halting short-term firm transmission sales, stopping all hourly redirects on BPA's system, and curtailing approximately 4000 MWs of transmission schedules across the region. If these scenarios had happened at higher local Portland area load levels, BPA curtailment of firm transmission schedules could have resulted in reliability concerns for PGE.

As PGE anticipates significant load growth into the future from the semiconductor and data center industrial sectors, much of the forecasted growth will locate in the Beaverton/Hillsboro area on the west side of PGE's service territory. Existing constraints north of the NOPE flowgate will limit industrial growth here. Additionally, it is expected that solar deployments will continue

in California and the desert southwest, further exacerbating the NOPE flowgate constraint. PGE and BPA are collaboratively planning how to address the NOPE constraint. Constraint mitigation will require a combination of new and upgraded transmission facilities as well as new operational scenarios that are currently being evaluated.

4.2 PGE transmission projects

Various FERC and NERC compliance and regulatory obligations require that PGE develop, engineer, procure, and construct PGET-owned transmission projects. Transmission projects can develop as a result of NERC reliability obligations, be driven by transmission or interconnection customer actions, result in response to state policy actions, load growth, and resource forecasts and requests by PGET's network transmission service customers.

Key transmission projects placed in service in 2024 include:

- A new 1.7 mile 230 kV transmission line between BPA's Keeler substation and PGE's Horizon substation, both located in Hillsboro, Oregon.
- The Evergreen Substation, a new bulk substation located in Hillsboro, Oregon that facilitates the interconnection of PGE's Constable Battery Energy Storage Facility, as well as the ability to serve new load in Washington County.

PGE revisits transmission plans and projects on a specific time cadence, with those in **Table 12** representing current plans. Future needs will continue to be evaluated over time. For the Near-Term and Long-Term Planning Horizon, PGE has identified transmission projects which will be needed to maintain compliance with the NERC TPL-001-5 standard. Each project has identified a completion date and any long lead time items that are required as a part of the work. Any construction phases which need to be scheduled are also identified and assessed to ensure that the reliability to the Bulk Electric System is not compromised during each phase of a project.

Table 12. Transmission Projects

Project Name	Anticipated In Service Date
Bethel-Round Butte 230kV Fixed Series Capacitor Project	2027 March
Bethel-Round Butte 500kV Project	2032 November
Blue Lake (Sundial) 230kV Battery Project	2025 June
Grassland 500kV Breaker Addition	2026 July
Harborton-Trojan #3 and #4 230kV	2033 May
Horizon-Keeler #1 & #2 230kV 4000A Upgrades	2029 April
Horizon-Keeler #1 230kV Reconductor Project	2026 May
Horizon-Keeler BPA #2 230 kV Project	2024 May
Jefferson Solar Project	2027 March
Madras Solar Project	2027 March
Memorial Substation Project	2025 July

Project Name	Anticipated In Service Date
Monitor Rebuild Project	2026 April
Pearl BPA-Sherwood 230 kV Project	2026 June
Reconductor Murrayhill-Sherwood 1&2	2027 May
Reconductor Murrayhill-St Marys #1, construct new Murrayhill-St Marys #2 section to create Sherwood-St Marys	2028 Q1
Reconfigure Murrayhill-Sherwood, Murrayhill-St Marys, Sherwood-St Marys	2028 Q1
Rivergate (Seaside) 230kV Battery Project	2025 June
Sherwood 115kV Project	2028 June
Shute and Sunset Facility Upgrades Project	2026 April
St Marys 115kV Breaker Replacement Project	2028 August
Sunset 115kV Bus Split Project	2027 April
Tonquin Substation Project	2026 December
Willamette Valley Resiliency Project (3 parts)	2035 May (latest part)
Hillsboro 500kV Expansion (Arden/Harrington)	2030 May

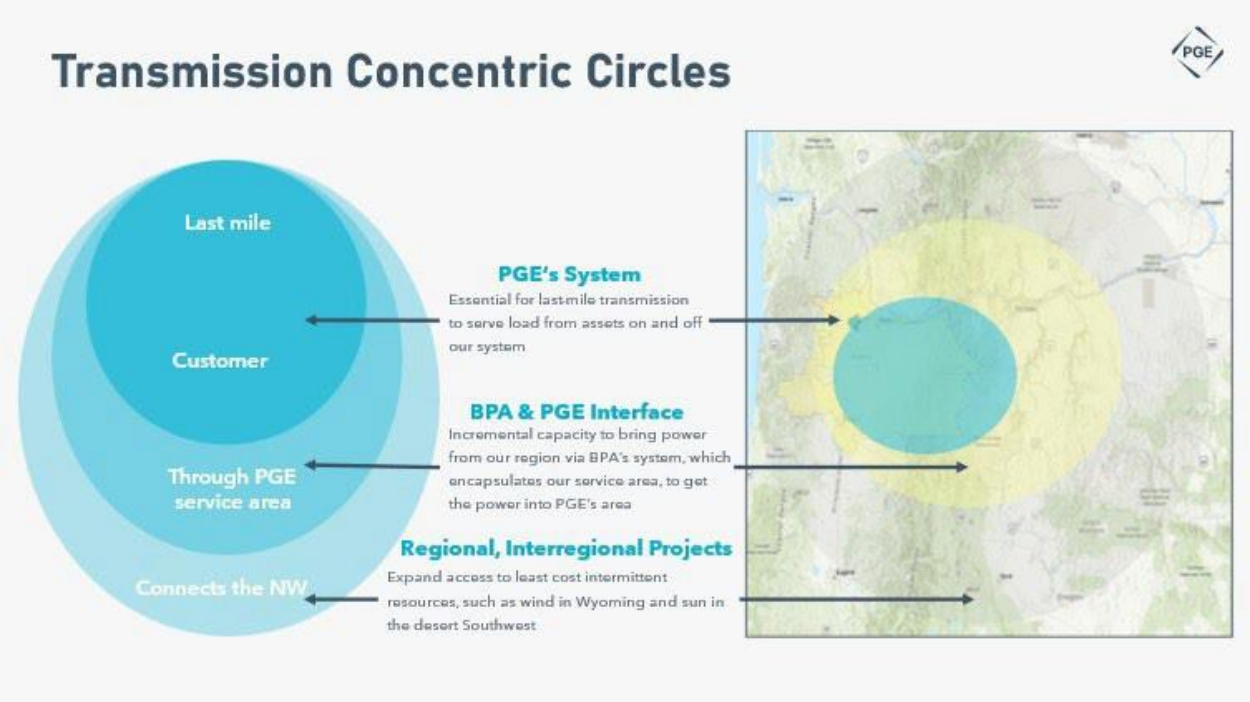
4.3 Transmission strategy/outlook

PGE will deploy a portfolio of strategies to meet future transmission needs and intends to explore expanding transmission access through the acquisition of rights on third-party systems, equity investment in regional projects as they are constructed, and PGE-developed projects, including upgrades of existing assets. PGE is also exploring Grid Enhancing Technologies (GETs), including actively putting in dynamic line ratings, with some of these projects utilizing advanced conductor and capacity enhancements. These different avenues of transmission expansion will allow PGE to optimize for the least cost and least risk plan to meet future needs and will continue to be discussed in the next full IRP.

4.3.1 Concentric circles of transmission

As PGE assesses strategies to meet load growth obligations and decarbonization goals and HB 2021 requirements, PGE must ensure transmission capacity is available from geographically diverse resources. Often, delivering energy to PGE's system requires multiple segments of transmission lines. Because PGE's network load is centralized in a compact service area, instead of dispersed out in multiple areas of load, PGE utilizes a concentric circle model to contemplate available transmission options, displayed below in **Figure 31**.

Figure 31. PGE Transmission Concentric Circles



4.3.1.1 PGE's system

The inner most circle in the model, 'Circle One', is predominantly used to move power through PGE's system for the purposes of safely and reliably serving PGE network load. It is important to remember that PGE network load includes PGE retail customer loads and also the loads of ESS customers and other transmission customers. PGE performs a series of annual transmission planning and reliability assessments. As Circle One on the system is planned, not only must PGE network load be accounted for, but also the potential for energy to flow through PGE's system enroute to other utilities in the western interconnection. These routine transmission planning efforts identify the projects necessary to reliably and safely serve PGE load, accounting for transmission service requested through PGE's service territory, and accounting for the impact regional resource dispatch patterns can have on PGE's transmission system.

4.3.1.2 Connecting PNW to PGE's transmission system

'Circle Two' in the model connects PGE's service territory to BPA's system and the rest of the PNW transmission system. Because PGE's service area is so concentrated in the northern Willamette Valley and new non-emitting generation resources will be generally located in remote geographic locations, PGE must determine how to best enable resources to reach the system. An example of Circle Two transmission would be transmission that enables energy to cross the Cascades enroute to PGE or adds additional capacity to the South of Allston flow gate flowing from north of the Portland Metro area.

4.3.1.3 Connecting the PNW to other regions

'Circle Three', the outer most circle, connects the PNW to other resource rich regions like the Dakotas and eastern interconnection, Rocky Mountains, and the Desert Southwest. Projects that connect multiple regions are often proposed and developed by large independent transmission companies who can more easily absorb the additional risk these large ambitious projects carry.

4.3.1.4 Grid Enhancing Technologies (GETs)

GETs are solutions that aid in the optimization of existing grid infrastructure. These technologies help PGE more effectively manage power flow for the aim of increasing capacity, efficiency and reliability on the system and to reduce the need for more costly grid expansion. The categories below detail GETs in use and planned for PGE's service area.

Dynamic Line Ratings (DLRs)

PGE is integrating DLRs beginning 2025 through partnership with the Electric Power Research Institute (EPRI) and BPA. DLRs are a method for determining available transfer capability of transmission lines utilizing real-time data to account for weather. DLRs can increase real-time capacities under favorable weather conditions (lower ambient temperature, higher wind speeds, and cloud shadowing) and derate capacities when weather is unfavorable. This additional operational flexibility is intended to help with reducing overloads due to unplanned outages or allow for better certainty of planned outages and system impacts. An impact analysis will be studied in 2025 and refined as the DLR system goes in-service and real time performance data becomes available over the second half of 2025.

Conductor Coating Technologies

PGE is integrating heat-dissipating overhead conductor coating technologies that reduce power loss and increase power carrying capacity. PGE's first use of the coating is for the 1.5 mile Horizon-Keeler #1 230 kV reconductor project is expected begin construction in 2026.

Topology Optimization

PGE utilizes switching of circuit breakers on the existing system to optimize power flow. PGE operations teams have long used this tool to more effectively change system flows as an alternative to costly options such as generation redispatch. PGE is upgrading a 230kV circuit breaker at the McLoughlin substation in 2025 to support this topology optimization practice.

Advanced Conductors

PGE is working with EPRI and other utilities on the Grid Enhancing Technologies for a Smart Energy Transition (GET SET) initiative to design and construct high temperature Aluminum Conductor Steel Supported (ACCS) lines in the territory. PGE has utilized ACCS conductors since 2006 to help ensure efficient power transmission and mechanical reliability across long-distance transmission lines and these new high temperature low sag conductors are already integrated in PGE's transmission planning studies.

4.3.2 Existing PGE projects/local transmission plan

*Refers to the inner circle in **Figure 31**.*

To address the needs identified during PGE's transmission planning assessments, a local transmission plan is developed that identifies the portfolio of projects to meet the needs of PGE's customers and to maintain and operate a safe, resilient, and reliable system. Historically, PGE has focused on planning within the inner circle for reliable and load service-driven transmission given PGE's unique geographic footprint within BPA's system. This was primarily because BPA traditionally had ample ATC on their transmission system that PGE has been able to leverage to transfer new remote generation resources to PGE's system. With the recognition that ATC inventories on BPA's system have been fully allocated, and that changes in resource dispatch patterns have created a paradigm shift in regional flow patterns on the west-wide transmission system, PGE's transmission planning and strategy have necessarily evolved from an approach based primarily on reliability and load service to a more proactive approach that aligns with future load service needs (described in **Chapter 3 System needs**) as PGE decarbonizes. It is important to recognize the significant transmission planning and project development efforts already underway that are necessary for reliable load service and proper cost allocation within PGE's load service area. PGE's local transmission plan has identified more than 20 projects, discussed in **Section 4.2 PGE transmission projects**.

4.3.3 BPA projects important to PGE

*Refers to all circles in **Figure 31**.*

PGE's and BPA's transmission systems are highly interconnected, both in PGE's service area and around Oregon and the PNW. Because of the highly networked nature of PGE's transmission systems, PGE has been collaboratively working with BPA to ensure BPA has sufficient system reinforcements planned that, in concert with PGE's planned transmission projects, will enable PGE to reliably serve load. As a result of this collaborative system planning, PGE and BPA have identified a suite of projects, both joint PGE-BPA projects and BPA-only projects as shown in **Table 13**, necessary for the safe and reliable operation of the region's transmissions system. Several joint projects are inflight that will help address the NOPE flowgate constraint. In addition to joint projects, BPA has identified several projects that only involve work to their infrastructure that will have significant impact for PGE and its customers. Several of them are currently in-flight or in the scoping phase.

Table 13. PGE-BPA and BPA-only Transmission Projects

PGE-BPA Transmission Projects	BPA-only Transmission Projects
Pearl-Sherwood-McLoughlin Bifurcation & Reconductor	Big Eddy-Chemawa Upgrade (Evolving Grid 1.0)
N. of Sherwood Reconductor	Keeler Transformer Bank Addition (Evolving Grid 1.0)
Horizon-Keeler #1 reconductor	Pearl-Keeler 500kV #2 (Evolving Grid 2.0)
Horizon-Keeler 4000A upgrades	North of Marion Upgrades (Evolving Grid 2.0)
Ross-Rivergate (BPA Evolving Grid 1.0 Project)	Ostrander-Pearl #1 Line Upgrade (Evolving Grid 2.0)
Harborton 230 kV Rearrangement	
Willamette Valley Resiliency Project	

Figure 32. PGE-BPA transmission projects

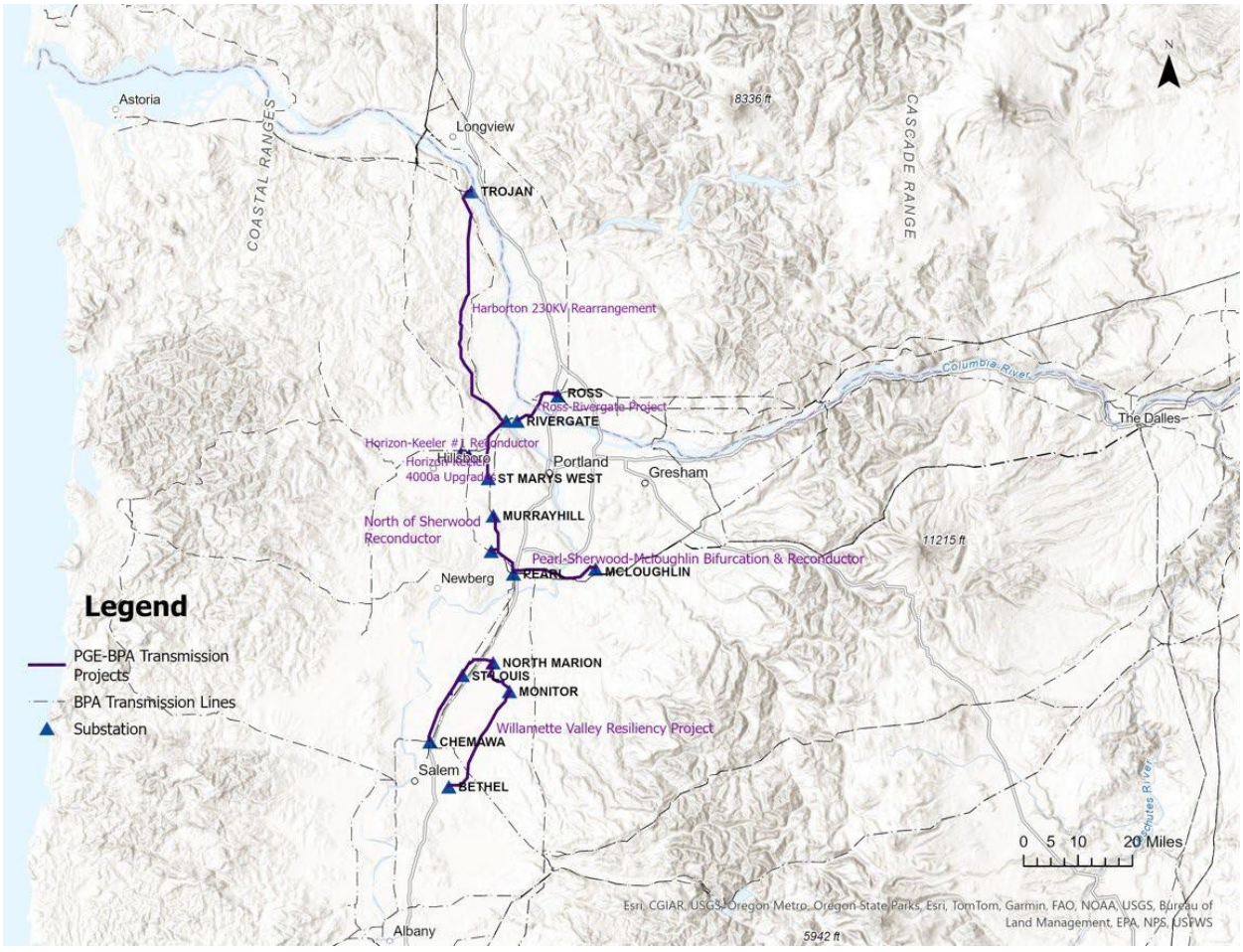
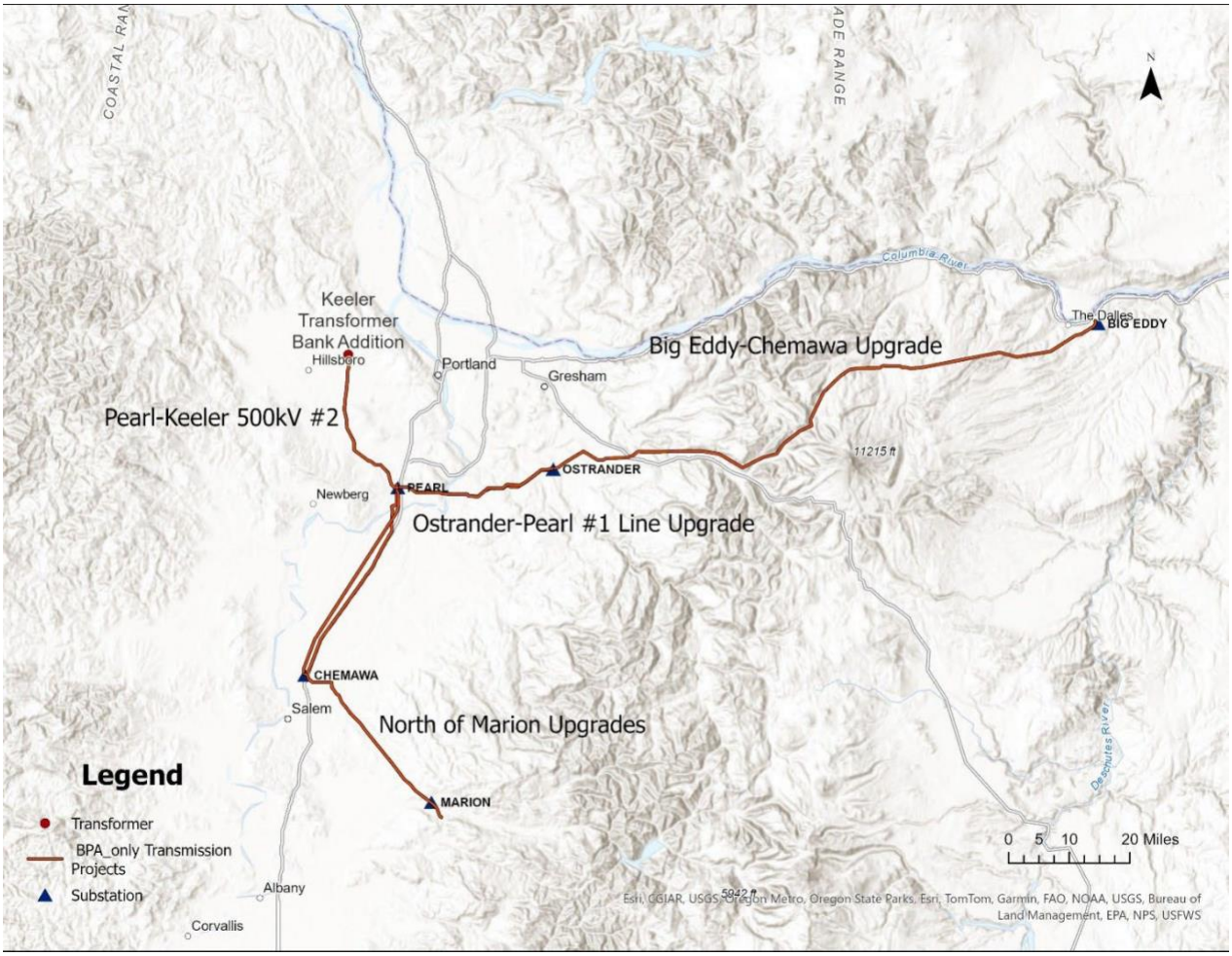


Figure 33. BPA-only transmission projects



4.4 Assessment of available BPA point-to-point transmission

Limitations on the region's transmission system constrain PGE's ability to access Pacific Northwest (PNW) renewable resources. For the 2023 CEP/IRP, PGE conducted a study of transmission service requests directed toward PGE in BPA's Transmission Study Request (TSR) Study and Expansion Process (TSEP) reports in order to estimate the quantity of transmission currently available. As part of the transmission-related assumptions and modeling in the 2023 CEP/IRP, PGE included these estimates of available capacity on BPA's transmission system as a resource build constraint in portfolio analysis. The total ATC available in the 2023 CEP/IRP was 1818 MW.[73]

PGE has refreshed these estimates for the Update with the most up-to-date data available. The updated values, shown in **Table 14**, are included as constraints on resource additions in portfolio analysis.[74] The total ATC has increased by 688 MW compared to the 2023 CEP/IRP to

[73] See Appendix H.7 of the filed 2023 CEP/IRP.
[74] The updated numbers and methodology were described by PGE in the October 2024 Roundtable Meeting. Available here:

2506 MW. Total ATC determines the quantity of resources that can be added to PGE's portfolio without incurring the costs associated with transmission upgrades or expansion (as described in **Section 4.6 Transmission options for portfolio analysis**).

Regional transmission constraints in the 2023 CEP/IRP required that each MW of new renewable resource had 1 MW of associated transmission capacity. In the Update, this assumption has been updated, with each MW of transmission capacity now allowing access to 1.33 MW of renewable resources (requiring that 75 percent of new resources have associated transmission rights).[75] This increases the quantity of accessible resources from 2506 MW to 3341 MW. Excluding offshore wind, which has additional constraints that push earliest COD in portfolio analysis out to 2036, this results in access to 2451 MW of off-system renewables prior to the first available transmission upgrade option in 2032. Transmission availability is identified by transmission zones, with the transmission zone associated with each proxy resource identified in **Table 15**.

Table 14. Transmission ATC by resource zone

Transmission Zone	Long-Term Firm	Conditional Firm	Total ATC
Christmas Valley	201	466	667
Gorge	179	418	667
McMinnville	45	105	150
Montana	96	224	320
Offshore	201	467	668
SE Washington	31	73	104
Total	753	1753	2506

https://assets.ctfassets.net/416ywc1laqmd/6Gv0U2lLocu2YCSnHv4JRP/43c13f8b70898a4476a4655f5f783fd4/IRP_Roundtable_October_24-6.pdf#page=23

[75] This modeling change was discussed in PGE's January 2025 Roundtable. Link: https://assets.ctfassets.net/416ywc1laqmd/7rqJJm9XGJaw6HPuh9Oz4L/7e071838b5f9cdfd7a9d9185b1fe0b53/CEP_IRP_Roundtable_January_25-1-74-.pdf#page=8

Table 15. Transmission zones of proxy resources

Transmission Zone	Proxy Resources
Christmas Valley	Christmas Valley Solar Christmas Valley Hybrids
Gorge	Gorge Wind Wasco Solar
McMinnville	McMinnville Solar McMinnville Hybrids
Montana	Montana Wind
Offshore	Offshore Wind
SE Washington	Southeast Washington Wind

4.5 Third-party assessment of PGE regional transmission options

In response to Staff comments on the transmission action item and modeling from LC 80 Order 24-096, PGE contracted with two third-party consultants to more thoroughly evaluate viable transmission options and their modeled benefits.

First, PGE contracted with Energy Strategies to assess transmission options identified by PGE, their general viability and any alternative, related CODs, and firm MW access assumptions.[76] Three key categories of changes resulted from Energy Strategies' analysis, which were incorporated as seven transmission options into PGE's modeling as discussed in **Section 4.6 Transmission options for portfolio analysis**:

1. Two alternative projects were identified to replace PGE's options of TransWest Express for accessing Wyoming Wind Proxy Resources and Western Bounty for access to Nevada Solar Proxy Resources. Energy Strategies proposed these alternatives due to policy, price, and timeline risks with WesternBounty and TransWest Express.
2. CODs were adjusted outward into the future based on Energy Strategies' understanding of project statuses and best estimates of completion timelines.
3. MW access assumptions were adjusted downward to account for Energy Strategies' assessment of ATC and rights on the identified transmission paths.

Second, PGE contracted with Energy GPS to conduct a market liquidity analysis for energy markets adjacent to the Pacific Northwest.[77] This analysis developed an understanding of the added benefit that a given transmission project may provide through its connection to a broader but nearby market. To estimate the additional market access benefits of a transmission project, Energy GPS analyzed correlations in PGE's hours of greatest load with high load hours in CAISO, Desert Southwest (DSW), Midcontinent ISO (MISO) North, and Southwest Power Pool (SPP) North

[76] PGE's January 2025 Roundtable - Transmission Options. See also **Appendix J Transmission options study**.
[77] PGE's November 2024 Roundtable - Transmission - Step 3 - Market Access.

markets. The analysis resulted in two key conclusions, which PGE incorporated into each modeled transmission option's market access benefits:

1. It is reasonable to assume transmission to SPP North or MISO North can provide access to energy and capacity during critical hours for both summer and winter.
2. It is reasonable to assume transmission to DSW or CAISO markets can provide access to energy and capacity during critical hours during winter.

4.6 Transmission options for portfolio analysis

The transmission necessary to reach resource rich geographical locations can often rely on multiple segments of transmission infrastructure to reach from generation site to where demand is located. PGE continues to analyze and explore all publicly known transmission project opportunities in the west that could be useful in serving PGE loads but generally do not directly connect to PGE. PGE identified a list of potential transmission projects within the BPA-PGE interface (Concentric Circle 2, as described in **Section 4.3.1 Concentric circles of transmission**) and greater region (Concentric Circle 3). These projects would provide access to proxy BPA resources such as Gorge Wind and Christmas Valley Solar, and proxy interregional resources such as North Dakota Wind and Nevada Solar. The resulting list provides known possibilities that may allow PGE to expand access to off-system renewable resources and markets. PGE continues to conduct analysis of these projects and will update this assessment in the 2026 CEP/IRP.

The remainder of this section describes project specific details of options modeled in the 2023 CEP/IRP Update based on Energy Strategies' analysis and the assumptions used in modeling transmission options.

Figure 34 illustrates the transmission options recommended for study by Energy Strategies.

Figure 34. Overview of PGE Transmission Options



4.6.1 Bethel-Round Butte upgrade

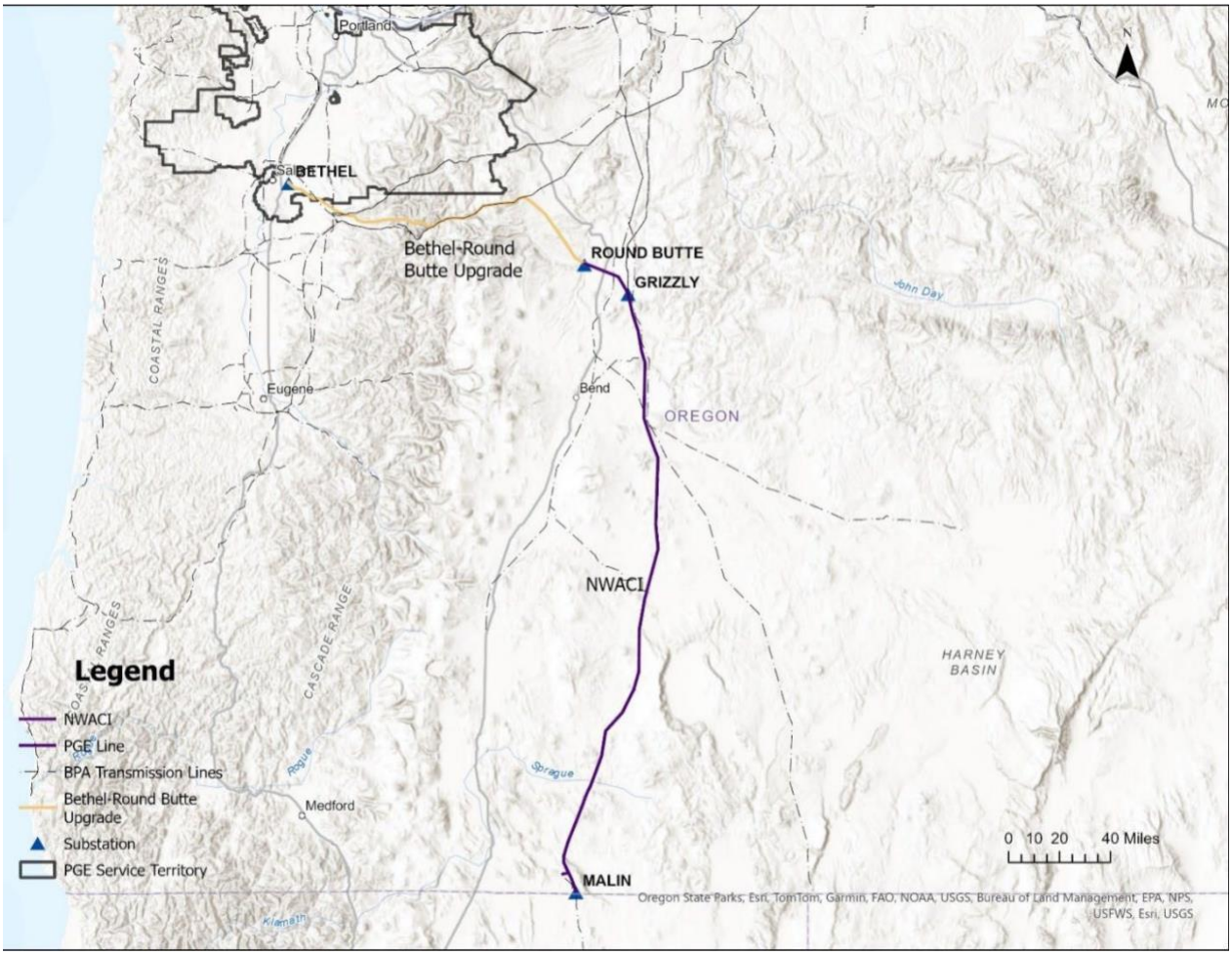
Bethel-Round Butte transmission project is a 98-mile 230 kV line upgrade running between PGE's Bethel and Round-Butte substations at the south-east edge of PGE's service territory. The project plans to rebuild the existing transmission line from 230 kV to 500 kV and build a second 500 kV line, enabling up to 3000 MW of additional resources from the BPA-PGE interface, or Concentric Circle 2 (**Section 4.3.1 Concentric circles of transmission**), to reach PGE's service territory. Resources within the BPA-PGE interface include: Wind Gorge, Wind SE WA, Solar CV, Solar MCMN, Solar Wasco, CV hybrids, and MCMN hybrids, and are resources that are assumed accessible by way of one wheel across BPA transmission infrastructure. Additionally, the project would increase access through the California Oregon Border (COB) to the CAISO market of 600 MW in winter.[78] The estimated commercial operation date (COD) for the upgraded line is 2032.

[78] PGE's November Roundtable - Transmission - Step 3 - Market Access.

The 2023 CEP/IRP characterized the Bethel-Round Butte transmission option as a valuable upgrade to the PGE system, necessary to integrate the scale of non-emitting resources required to offset fossil fuels.

In partnership with The Confederated Tribes of Warm Springs (CTWS), an application was submitted to the USDOE for a Grid Resilience and Innovation Partnerships (GRIP) Program grant for the Bethel-Round Butte upgrade. The GRIP application was successful, and a $250 million award was made to PGE's partners, the CTWS. The CTWS and PGE are currently in the process of developing the project.

Figure 35. Bethel-Round Butte Upgrade

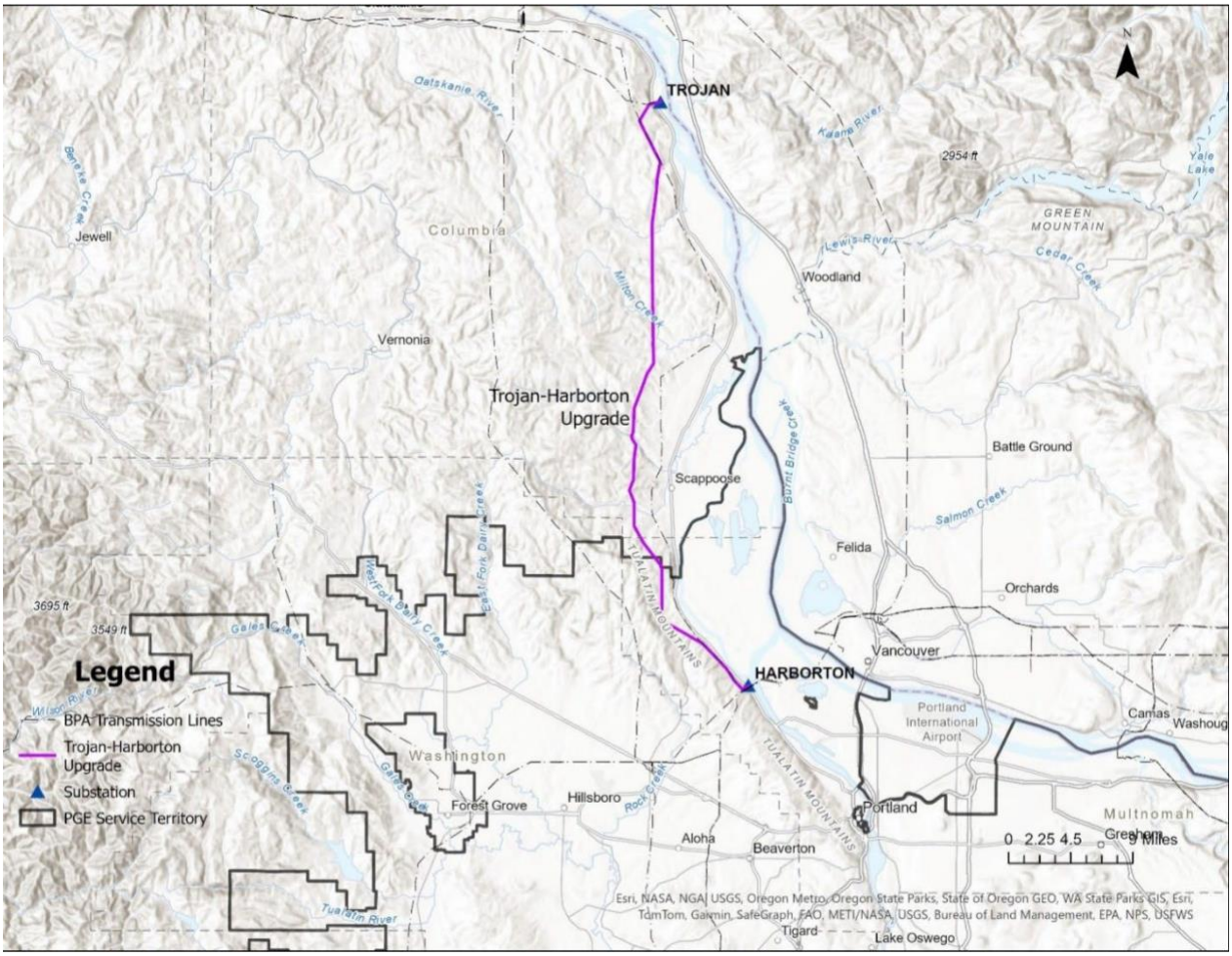


4.6.2 Harborton-Trojan upgrade

Harborton-Trojan Upgrade is a 34-mile 230 kV transmission option between these two PGE substations at the north-west edge of PGE's service territory. The project would run parallel to two existing PGE transmission lines, in service since the 1970s. PGE currently owns the right-of-way (ROW) necessary to complete this upgrade. The project is estimated to enable up to 800 MW from resources within the BPA-PGE interface to reach PGE customers, subject to cooperative

study and agreement with other South of Allston path owners, BPA and PacifiCorp. The anticipated COD of the project is 2035. It is assumed that the Harborton-Trojan option will provide no additional market-access benefits.[79]

Figure 36. Harborton-Trojan Upgrade



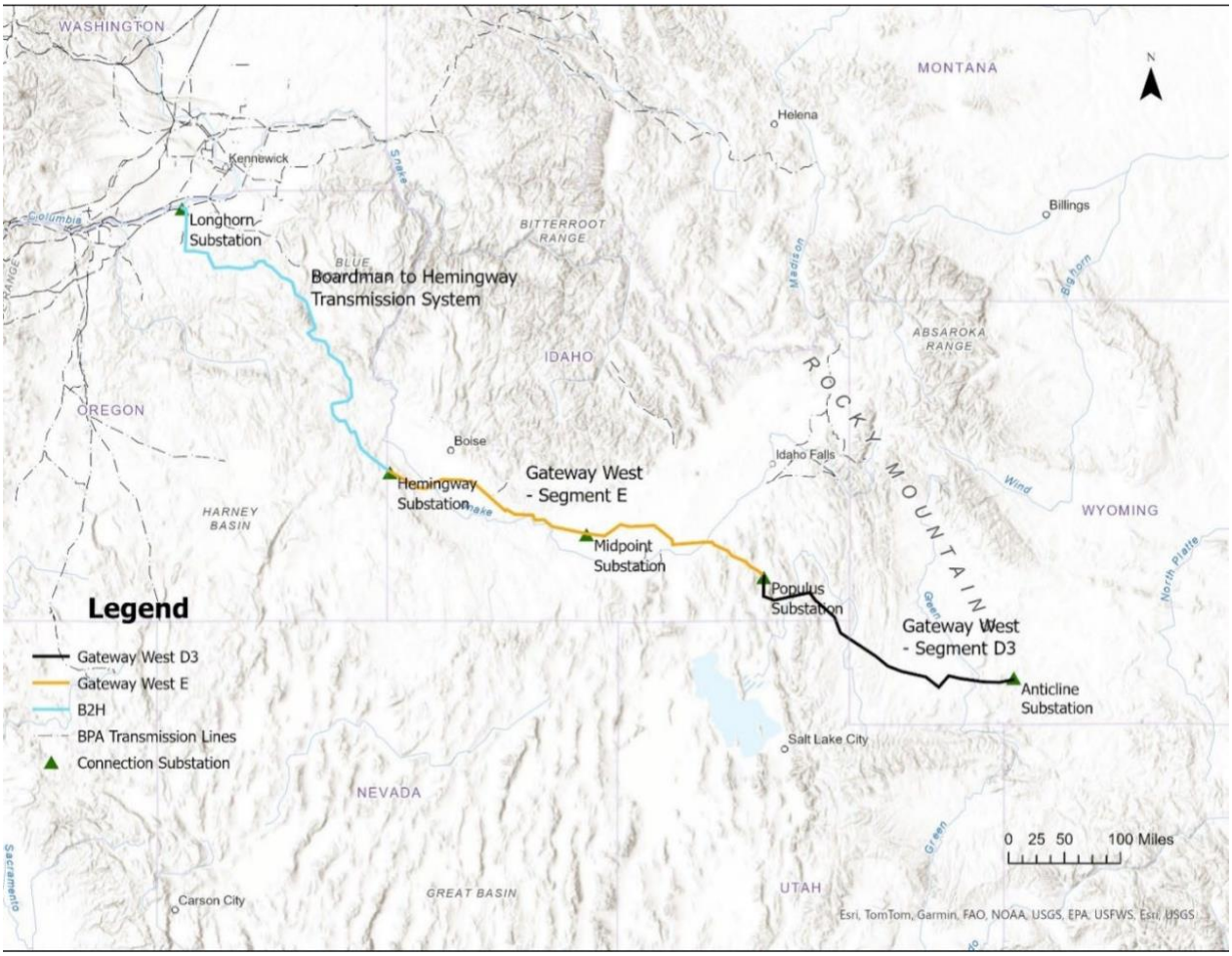
4.6.3 Gateway + B2H + Longhorn (Gateway)

The Gateway transmission option is modeled as the preferred path to access Wyoming Wind proxy resources. The Gateway option begins in western Wyoming, traversing 200 miles from Anticline to Populus substation along the Gateway West D-3 leg. The second segment covers 500 miles on Gateway West E segment where it terminates in Hemingway and then traverses 270 miles along the Boardman to Hemingway (B2H) leg. Finally, Longhorn to PGE is identified as a viable wheel to bring the energy to PGE service territory. The Gateway transmission option is estimated to provide up to 400 MW of capacity for Wyoming Wind by 2035. The 2035 COD reflects the expected timeline for new BPA Transmission Service Requests (TSRs) on the Longhorn to PGE leg. Additionally, Gateway is assumed to provide an additional 400 MW of

[79] PGE's November Roundtable - Transmission - Step 3 - Market Access.

market access during winter.[80] Securing firm transmission access for the Gateway option in the 2030's is uncertain due to competition with Pacific Power and Idaho Power Company and the required timely granting of transmission service requests.

Figure 37. Gateway Transmission Option



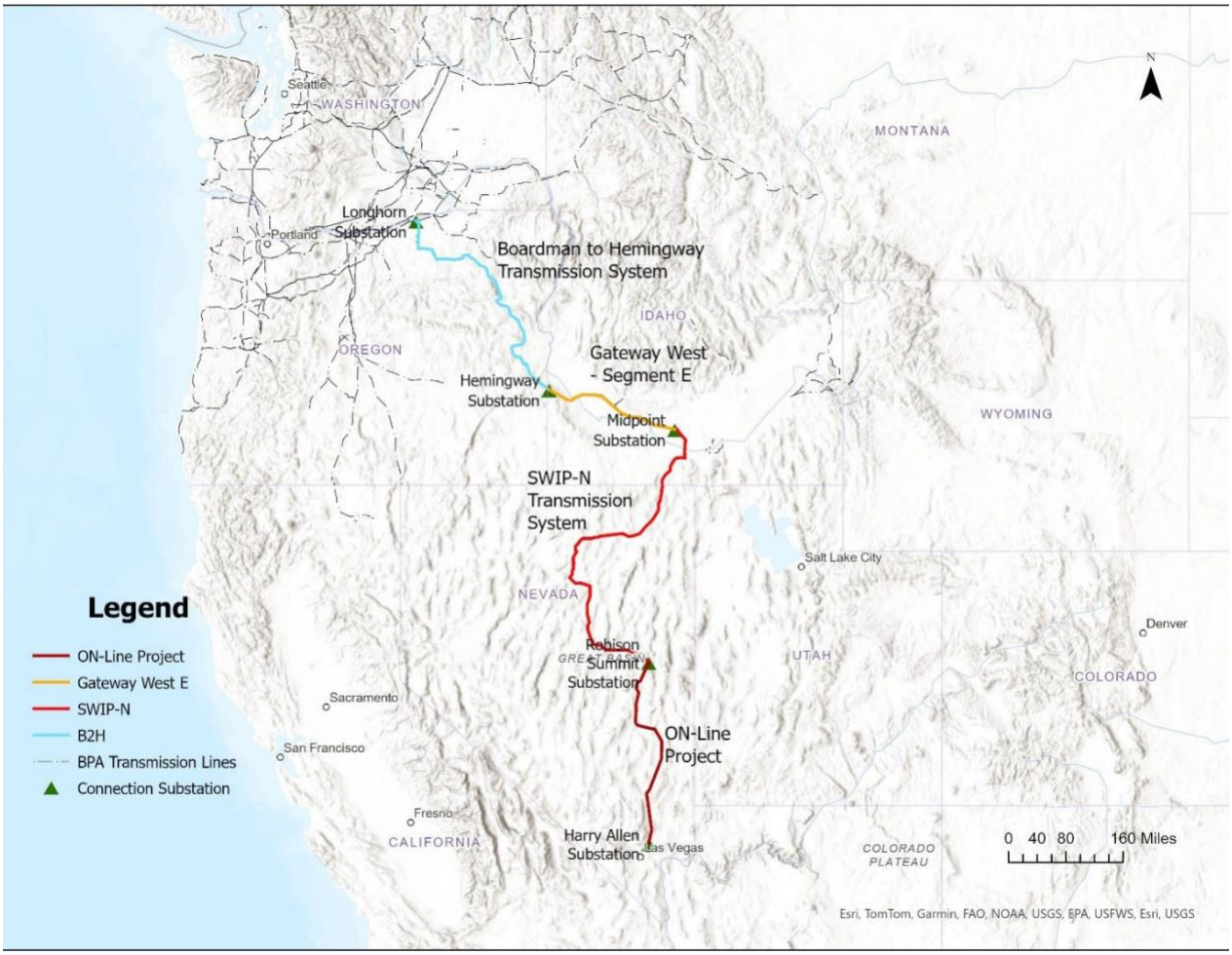
4.6.4 NVE + SWIP-N + Gateway + B2H + Longhorn (SWIP-N)

The SWIP-N transmission option includes approximately 673 miles of AC segments along the Southwest Intertie Project – North, Gateway West 8, and Boardman to Hemingway transmission projects. The option is composed of five segments, two of which are modeled as wheels. The first segment is represented as one wheel that captures PGE's need to move energy across the existing or committed NVE projects (Desert Link, ON-Line, Greenlink West, Greenlink North). Next, the option traverses the 275-mile Southwest Intertie Project – North project, then passes 128 miles along Gateway West 8 leg. The SWIP-N option utilizes the Boardman to Hemingway segment and a Longhorn to PGE wheel to bring energy to the PGE service territory. SWIP-N is estimated to provide capacity up to 400 MW of Nevada Solar by 2035 and an additional 400 MW

[80] PGE's November Roundtable - Transmission - Step 3 - Market Access.

of market access in winter.[81] The 2035 COD reflects the expected timeline for new BPA TSRs on Longhorn to PGE leg.

Figure 38. SWIP-N Transmission Option



4.6.5 North Plains Connector

The North Plains Connector (NPC) option includes a 412-mile 500kV HVDC incremental line segment and two additional wheels to reach PGE.[82] PGE has signed a non-binding memorandum of understanding with the developers of this line for a 20 percent stake (600 MW) in the 3000 MW line. Following PGE's MOU, on August 6, 2024, the US Department of Energy (USDOE) selected the NPC, in partnership with the State of Montana, for a $700 million GRIP grant. Pending the outcome of development and execution of definitive agreements, this significant GRIP grant is modeled to buy down the development costs for participation in the NPC project. Additionally, this grant apportioned $70 million for the upgrade of the Colstrip Transmission System (CTS).

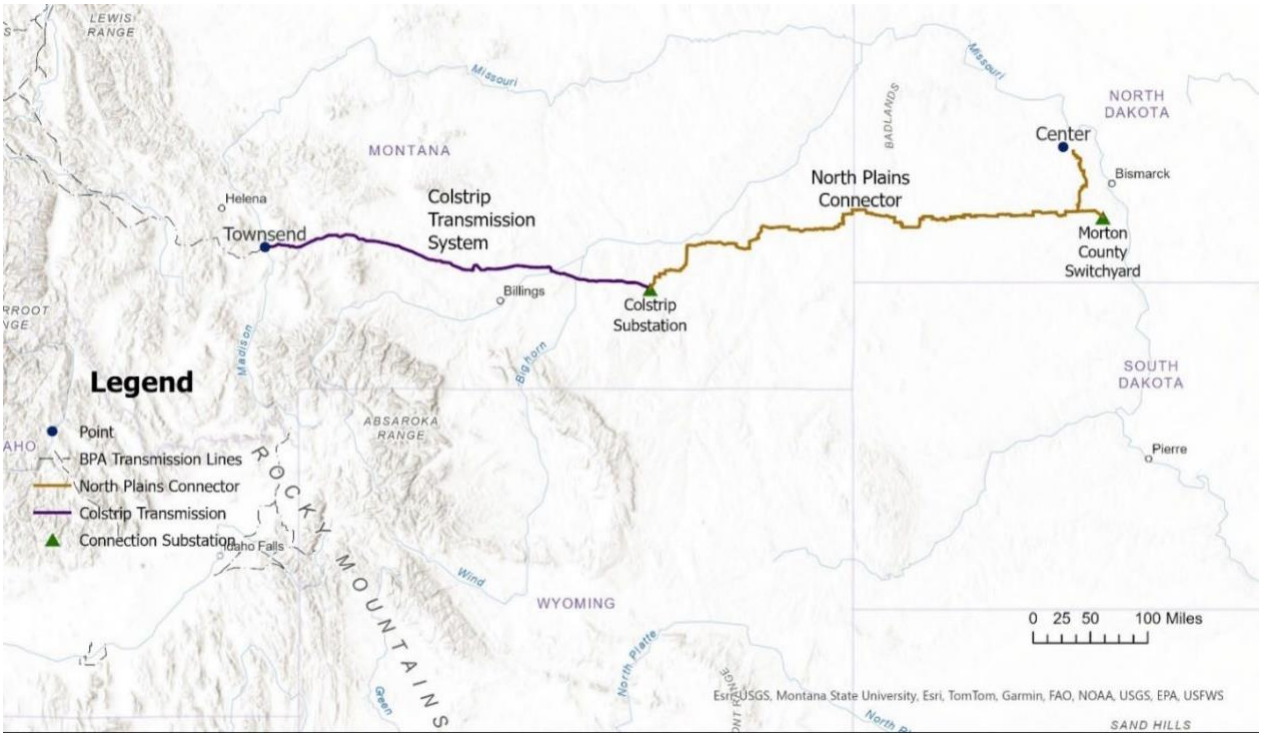
[81] PGE's November Roundtable - Transmission - Step 3 - Market Access
[82] The tariff charges incurred to transit both CTS and the Montana Intertie (Townsend-Garrison) are assumed equivalent to the rate of a BPA PTP+SCD wheel.

The NPC would allow PGE to utilize 270 MW of existing firm transmission to replace generation from Colstrip Units 3 & 4 with energy from some of the highest capacity factor renewable resources estimated as part of the 2023 CEP/IRP Update (Table 20). Further, the NPC connects to the Southwest Power Pool (SPP), and the Mid-Continent Independent System Operator (MISO) Zone 1 Market, where historical data suggests a surplus of supply during approximately 80 percent of PGE's highest demand hours.[83] As such, the NPC is a valuable transmission option for addressing PGE's winter reliability challenges as discussed in **Section 6.2.3 Preferred Portfolio resource adequacy testing**.

The NPC option is modeled to provide capacity up to 600 MW of North Dakota Wind proxy resource by 2038. This COD reflects expected timing to receive requested BPA and Northwestern (NWMT) TSRs. Six hundred MW represents what is assumed commercially available and aligns with PGE's existing transmission rights of 270 MW on CTS plus approximately 300 MW of firm and short-term rights on Northwestern path associated to PGE's Clearwater project. In addition, PGE has submitted TSRs for an additional 720 MW across BPA's and NWMT's system. Access to the benefits associated with the assumed 600 MW of potential capacity on this line requires that at least some of the additional submitted TSRs be approved. If submitted TSRs do not come to fruition, PGE's access to the capacity of the line would be only the current 270 MW of PGE's rights along the CTS. The 270 MW of firm transmission access across the CTS are available with the exit of Colstrip Units 3 & 4, assumed after 2029.[84] However, modeled access to these resources is not captured from 2030 to 2037. The NPC is modeled to provide access to an additional 600 MW of both summer and winter market access through its connection to the Eastern Interconnection, the SPP and MISO Zone 1.

[83] PGE's November Roundtable - Transmission - Step 3 - Market Access
[84] PGE's November Roundtable - Transmission - Step 3 - Market Access

Figure 39. North Plains Connector

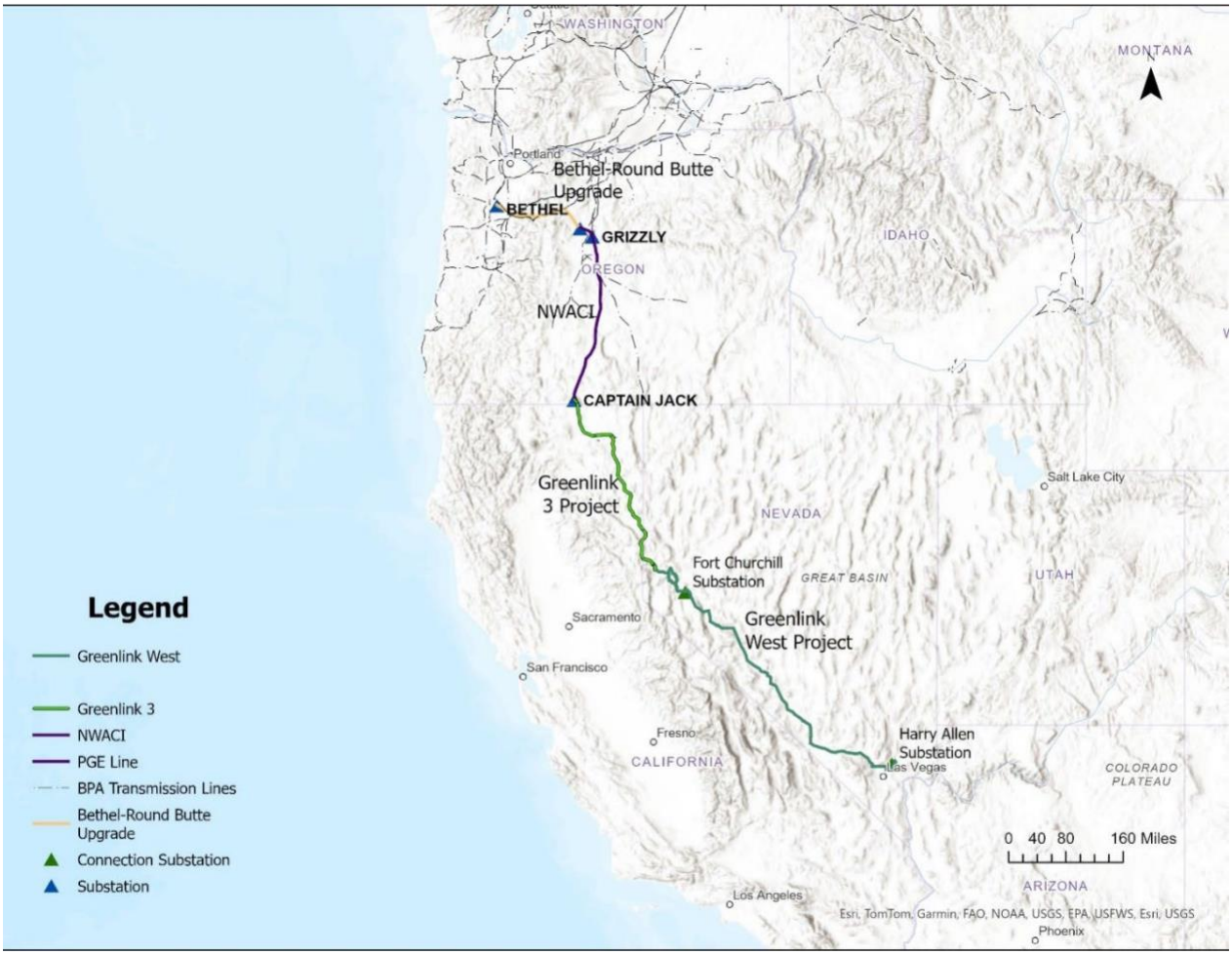


4.6.6 NVE + Greenlink 3 + Cpt. Jack to Grizzly + BRB upgrade (Greenlink)

The Greenlink transmission option includes 300 miles of additional AC circuits, and one wheel along Nevada Energy (NVE) infrastructure. The Greenlink option is modeled with four line segments from generation site to PGE's service territory. The first segment is comprised of one wheel that captures PGE's need to move energy across the existing or committed NVE projects (Desert Link, ON-Line, Greenlink West, Greenlink North). Second, the path incurs 300 miles of incremental costs from Ft. Churchill substation in eastern Nevada to the Captain Jack substation near Path 66 at COB. Energy is then moved from Captain Jack to the Grizzly Substation, a point along the Northwest AC Intertie (NWACI) and adjacent to PGE's transmission footprint, using existing PGE rights. Finally, the path assumes the Bethel-Round Butte Upgrade is in place to bring the energy to PGE's service territory. The Greenlink option is estimated to provide PGE up to 627 MW of proxy solar resources from Nevada with an expected availability date of 2035. The COD reflects estimated timing of the Greenlink 3 segment from Fort Churchill to Captain Jack. Further, an additional 627 MW of market access in the winter is assumed.[85]

[85] PGE's November Roundtable - Transmission - Step 3 - Market Access.

Figure 40. Greenlink Transmission Option

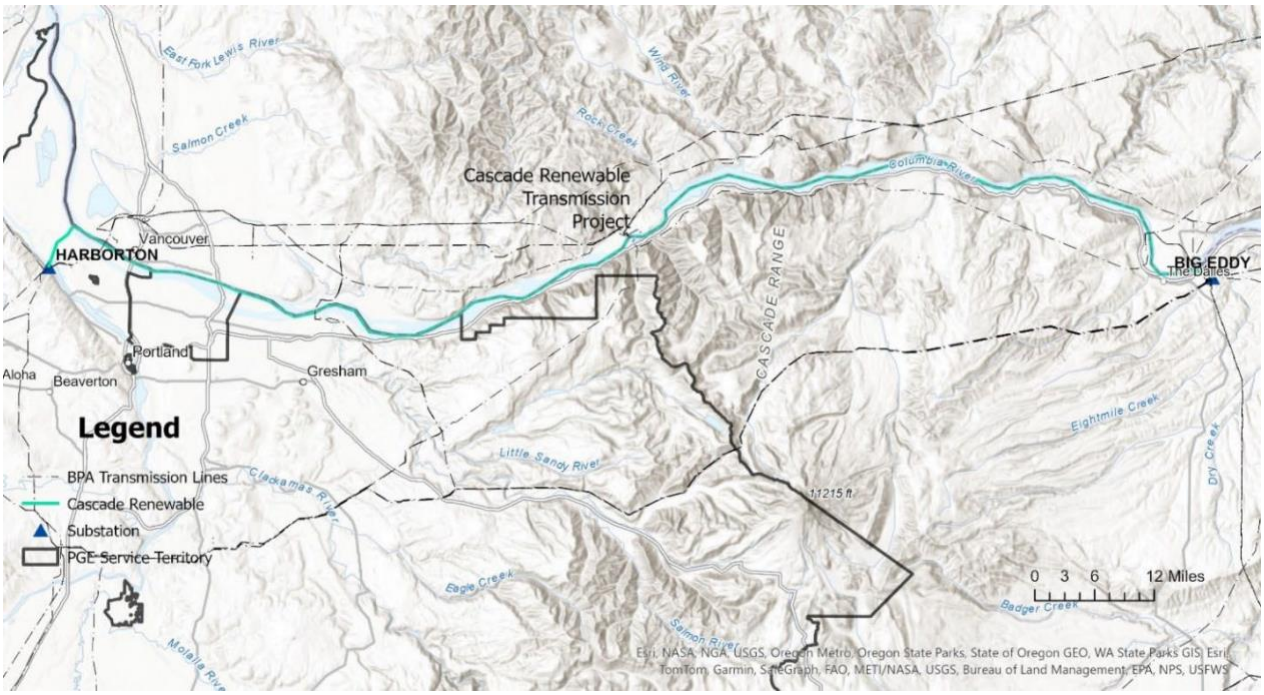


4.6.7 Cascade Renewable Transmission project

The Cascade Renewable Transmission Project (CRT) is an underwater HVDC transmission option of 100 miles that would route from BPA's Big Eddy substation near The Dalles, OR to PGE's Harborton Substation in NW Portland. The project is modeled as one incremental line of additional transmission. The project would allow up to 1100 MW of new east-west transmission capacity for PGE to access off-system proxy resources in the Pacific Northwest, such as Christmas Valley Solar and Southeast Washington Wind. The project will require additional BPA and PGE transmission expansion for PGE to access these benefits and is estimated available by 2038. Additionally, The CRT is assumed to provide no additional market access benefits.[86] PGE is not currently participating in CRT.

[86] PGE's November Roundtable - Transmission - Step 3 - Market Access.

Figure 41. Cascade Renewable Transmission Project



4.6.8 Transmission options summary

Table 16 provides a summary of the seven transmission options discussed above and their assumptions used for portfolio analysis.[87] PGE will continue to review and refine these options as part of the 2026 CEP/IRP.

Table 16. Transmission options

Project	COD[88]	Generation Resource	MW Available to PGE	Summer Market Access (% of MW Avail.)	Winter Market Access (% of MW Avail.)	Real-Levelized Cost ($/kW-mo)
Bethel-Round Butte	2032	BPA Resources	3000	0%	20%[89]	$ 5.52
Harborton-Trojan	2035	BPA Resources	800	0%	0%	$ 5.61
Gateway	2035	Wyoming Wind	400	0%	100%	$ 8.17

[87] BPA Generation resources refer to all Proxy Resources located within Concentric Circle 2 (**Section 4.3.1 Concentric circles of transmission**), including: Wind Gorge, Wind SE WA, Solar CV, Solar MCMN, Solar Wasco, CV hybrids, and MCMN hybrids.
[88] Project Commercial Operation Dates (CODs) represent the greatest COD for the underlying transmission segments.
[89] Assumed equivalent to PGE's existing rights at the California Oregon Border (COB).

Project	COD[88]	Generation Resource	MW Available to PGE	Summer Market Access (% of MW Avail.)	Winter Market Access (% of MW Avail.)	Real-Levelized Cost ($/kW-mo)
SWIP-N	2035	Nevada Solar	400	0%	100%	$ 9.56
North Plains Connector	2038	Montana & North Dakota Wind	600	100%	100%	$ 9.83
Greenlink	2035	Nevada Solar	627	0%	100%	$ 9.98
Cascade Renewable Tx Project	2038	BPA Resources	1100	0%	0%	$ 12.13

4.6.9 Transmission cost assumptions

The U.S. Department of Energy (DOE) "National Transmission Planning Study" and data from the GRIP are the primary sources used to calculate cost estimates for both AC and DC transmission options. All AC options are modeled as 500 kV single-circuit lines estimated at $2,048,670/mi and all DC options are modeled as 500kV HVDC circuits estimated at $4,600,000/mi.[90,91] Additionally, the DOE study provides terrain multipliers for AC options that are used to scale per mile estimates.[92] Federal cost share of GRIP awards was then subtracted from the estimated cost of a transmission option, where applicable.[93] These assumptions along with a project's estimated transfer capacity are used to derive costs for incremental transmission lines, those uncommitted projects that would require PGE ownership. Costs estimated are based on publicly available data and should be interpreted as a general estimate of the direct cost of line construction and do not account for additional development costs such as profit, balance of plant, permitting, procurement, and overheads.

Some transmission options required existing energized or committed projects to bring (wheel) energy home to PGE's service territory. Additional costs to wheel energy for such segments are included in the total cost for an option. The assumed rate for a wheel is $1.96 /kW-mo, based on BPA Point-to-Point Scheduling, System Control and Dispatch (PTP + SCD) costs for 2024. Lastly,

[90] U.S. Department of Energy. *The National Transmission Planning Study*. Ch 3. p.127.
[91] U.S. Department of Energy. The National Transmission Planning Study. Ch 3. p.70.
[92] Terrain multipliers are not identified for HVDC projects. Public information on project specific costs for HVDC options was used to calculate terrain multipliers for those HVDC projects.
[93] https://www.energy.gov/gdo/grid-resilience-and-innovation-partnerships-grip-program-projects.

all projects are assumed to carry a $4.81 /kW-mo real-levelized cost for operations and maintenance in 2024 dollars.

Chapter 5. Resource options

There are many resource options to be considered as PGE makes the energy transition to a decarbonized system. For analysis, PGE identifies all technologically and commercially feasible generation resource options. The economics of resources represent a crucial element of dynamics within IRP analyses for evaluating the characteristics of resources that could plausibly be deployed in the region. This chapter describes relevant costs and benefits associated with each resource assessed in this analysis update. These dynamics drive the decisions in portfolio analysis for evaluating resource options, optimizing for costs and benefits. Resource comparisons that can occur outside portfolio analysis are also visualized on a net cost basis.

Key Highlights

- Resource costs have increased, primarily driven by fixed costs in the current planning environment, with different resources providing disparate benefits in either energy generation, capacity, or storage capabilities. The potential effect of a reduction in tax credits is investigated.
- The inclusion of non-cost-effective Distributed Energy Resources (DERs) provides insight into how these resources can play an enhanced role in a decarbonized future.
- Community Benefits Indicator (CBIs) assumptions have been expanded and refined to better incorporate stakeholder feedback and provide measurable metrics across resilience, health, environmental impacts, energy equity, and economic impacts.

Developments Since 2023 IRP

This Update includes several key changes to resource economic assumptions including updated financial parameters; an adjusted electricity price forecast methodology incorporating forward price curves through 2028; updated supply-side resource costs; and refined capacity contribution values evaluated for 2030 using the Sequoia model. Further, portfolio sensitivity analysis considers current uncertainties regarding federal-level policies, including analysis without clean energy tax credits.

Additionally, the Update incorporates a new North Dakota wind resource option enabled by potential participation in the North Plains Connector transmission project and pushes back the earliest assumed availability for Oregon offshore wind to 2036 due to delays in the BOEM lease auction process.

Strategic Implications

These changes lead to several important implications for resource planning. The updated electricity price forecast shows significantly higher prices between 2025-2029, affecting the economic evaluation of resources. The reduced capacity contribution of

storage resources (particularly in winter) highlights a critical planning challenge regarding the interaction between storage and energy resources in a system with significant energy deficits. Importantly, the availability of federal clean energy tax credits has meaningful impacts on resource costs discussed in this chapter as well as total portfolio costs discussed in **Chapter 6**.

The North Dakota wind resource provides a new geographic diversity option, which is potentially valuable for addressing seasonal needs. Further, the updated CBIs framework provides a more comprehensive method for evaluating community benefits in resource decisions.

Staff Recommendations Incorporated

The Update addresses multiple Staff recommendations from LC 80 Order 24-096. For CBRE actions (Staff recommendation #1), PGE added a Small-Scale Renewable (SSR) proxy resource to model compliance with the 10 percent requirement. Regarding energy efficiency, PGE collaborated with Energy Trust of Oregon to develop guiding principles for complementary funding and establish funding targets with reporting requirements (Staff recommendation #4). On energy/capacity actions, PGE conducted a Request for Information (RFI) for long lead-time resources (Staff recommendation #2) and presented findings in 2024.[94] PGE also advanced CBI integration into resource planning and expanded RECs discussion through stakeholder engagement (Staff recommendations #6 and #7).

5.1 Resource economics

PGE's resource planning conclusions regarding best available generation technology and forecasted costs are driven by resource cost and performance assumptions. The candidate supply-side resources considered for portfolio construction in this Update are the same as those evaluated in PGE's 2023 CEP/IRP except for two changes that are discussed below. This section provides revisions to several key components of resource economics. Some of these updates result from updates to inputs, financial assumptions, and resource costs. These values flow into the portfolio analysis presented in **Chapter 6 Resource plan**.

5.1.1 PGE financial parameters

This Update uses revised financial parameters as of June 2024, which are summarized in **Table 17**.[95]

[94] PGE RFI Key Insights presentation, December 2024, https://assets.ctfassets.net/416ywc1laqmd/2GF5BwVt9cR1MXtEpn6fli/e719ec6879183abd984928db360fe410/RFI_slides_jdg_web_1197.pdf.

[95] Given the lead time for analysis, June 2024 represents the most recent financial parameter snapshot practicably possible for inclusion.

Table 17. 2025 IRP Update Financial Parameters

Component	Value
Composite Income Tax Rate	27.50%
Incremental Cost of Long-term Debt	5.79%
Long-term Debt Share of Capital Structure	50.00%
Common Equity Return	9.50%
Common Equity Share of Capital Structure	50.00%
Weighted Cost of Capital	7.65%
Weighted After-Tax Cost of Capital	6.85%
Long-Term General Inflation	2.04%

5.1.2 Supply-side resource costs

As mentioned above, the incremental supply-side resources considered in this Update are generally consistent with those evaluated in PGE's 2023 CEP/IRP. National Renewable Energy Laboratory (NREL) and Energy Information Administration (EIA) research still serves as the source for resource cost and performance parameter information. In this Update, PGE is generally using supply-side resource information from two sources:

- The NREL 2024 Annual Technology Baseline (ATB) updated in July 2024.[96]
- The EIA-commissioned Sargent & Lundy report, "Capital Cost and Performance Characteristics for Utility-Scale Electric Power Generating Technologies" released January 2024.[97]

These two reports represent the most recent updates from NREL and EIA, respectively, at the time of PGE's analysis in this Update. **Table 18** provides a summary of these assumptions by resource. Additional resources that PGE views as potentially available post-2030 are discussed below in **Section 5.6 Long lead-time resources**.

Table 18. Supply-side resource assumptions for portfolio construction - 2028 COD (2025$)

Resource	CF / RTE (%)	O/N Capital[98] ($/kW)		Fixed Costs[99] ($/kW-yr)	LCOE[100] ($/MWh)	
		IRP	Update		IRP	Update
Wind Gorge	44%	1,609	1,643	118	28	31

[96] NREL (National Renewable Energy Laboratory). 2024. 2024 Annual Technology Baseline. Golden, CO: National Renewable Energy Laboratory, https://atb.nrel.gov/.
[97] https://www.eia.gov/analysis/studies/powerplants/capitalcost/pdf/capital_cost_AEO2025.pdf.
[98] Overnight capital – is the upfront cost to construct the resources without consideration for the cost of funds during construction, includes interconnection costs but does not include the cost of incremental transmission unless otherwise noted.
[99] Real levelized fixed cost – is the annualized fixed cost (capital and operating) of the resource across the assumed economic life, in constant year dollars.
[100] Levelized cost of energy – is the annualized cost of the resource on a per MWh generated basis.

Resource	CF / RTE (%)	O/N Capital[98] ($/kW) IRP	O/N Capital[98] ($/kW) Update	Fixed Costs[99] ($/kW-yr)	LCOE[100] ($/MWh) IRP	LCOE[100] ($/MWh) Update
Wind MT	42%	1,560	1,531	136	32	36
Wind SE WA	42%	1,597	1,604	118	30	33
Wind WY[101]	44%	-	1,531	103	125	338
Wind ND[102]	41%	-	1,560	143	-	371
Solar Christmas Valley (CV)	27%	1,269	1,453	145	42	62
Solar McMinnville (MCMN)	21%	1,324	1,491	146	60	78
Solar Wasco	25%	1,269	1,453	145	45	65
Solar Mead[103]	32%	1,269	1,503	155	184	389
CV hybrid 1	-	2,278	2,912	280	212	112
CV hybrid 2	-	1,772	2,182	215	131	84
MCMN hybrid 1	-	2,329	2,982	285	303	146
MCMN hybrid 2	-	1,824	2,236	219	192	109
2-hour battery	86%	800	990	94		
4-hour battery	86%	1,212	1,617	153		

A pattern of increased costs for resources is observable in **Table 18**. Overnight capital costs have increased for nearly all resource technologies. Forecasted capital costs for storage resource have increased by over 30 percent which contributes to higher portfolio costs as analyzed in the Preferred Portfolio described in **Section 6.2**. Resource costs for solar resources have also increased significantly while increases in costs for wind resources is more modest.

Cost increases across generation and storage technologies may be driven by many factors including macro-economic concerns related to inflation, disrupted supply chains, and strong demand. The resource cost assumptions do not directly consider emerging issues such as federal policy uncertainties, variations in the macroeconomic environment (e.g., inflation, recessions), or the status of international trade agreements (e.g., duties or tariffs). Instead, a range of potential resource cost outcomes, including low-, reference-, and high-cost cases, are considered in portfolio construction.

5.1.2.1 Resource-specific updates

1. Onshore wind

A North Dakota-sited wind resource is added to the set of resources considered in portfolio construction for this Update. PGE's potential participation in the North Plains Connector (NPC)

[101] LCOE includes the cost of incremental transmission.
[102] LCOE includes the cost of incremental transmission.
[103] LCOE includes the cost of incremental transmission.

transmission project enables access to this resource. See the discussion of the NPC in **Section 4.6.5 North Plains Connector**. This resource is located near the eastern terminus of the NPC. Overnight capital cost estimates are based on EIA research. PGE's analysis assumes an earliest availability date of 2032. Other onshore wind resources in this Update are consistent with those considered in PGE's 2023 CEP/IRP.

2. Offshore wind

On September 27, 2024, the Bureau of Ocean Energy Management (BOEM) announced a delay in the auction for potential lease areas offshore Oregon due to "insufficient bidder interest at this time."[104] Just one of the five qualified companies indicated bidding interest in the planned auction. The auction for two lease areas was planned for October 15, 2024. As a result of these delays in the lease auction process, the earliest assumed availability for Oregon offshore wind is moved to 2036 (from 2032 in PGE's 2023 CEP/IRP) due to this delay in development opportunity.

5.1.3 Tax credit sensitivities

The Reference Case in this 2023 CEP/IRP Update assumes the same tax credit environment for generation and energy storage resources as described in PGE's 2023 CEP/IRP.[105] This environment was shaped by the federal governments passage of the Inflation Reduction Act (IRA) in 2022. Key assumptions for modeling include:

- Tax credits continue across the analysis period for modeling purposes. This assumption removes the possibility of tax credit expiration influencing the portfolio construction process.
- Non-emitting generating resources qualify for 100 percent of the production- or investment-based tax credits (PTC and ITC, respectively).
- Standalone storage resources qualify for 100 percent of the investment-based tax credit without the need for normalization.
- Tax credits are assumed to be fully monetized in the year they are generated.

To help understand the potential impact on resource economics of changes to this set of assumptions, two sensitivities are considered:

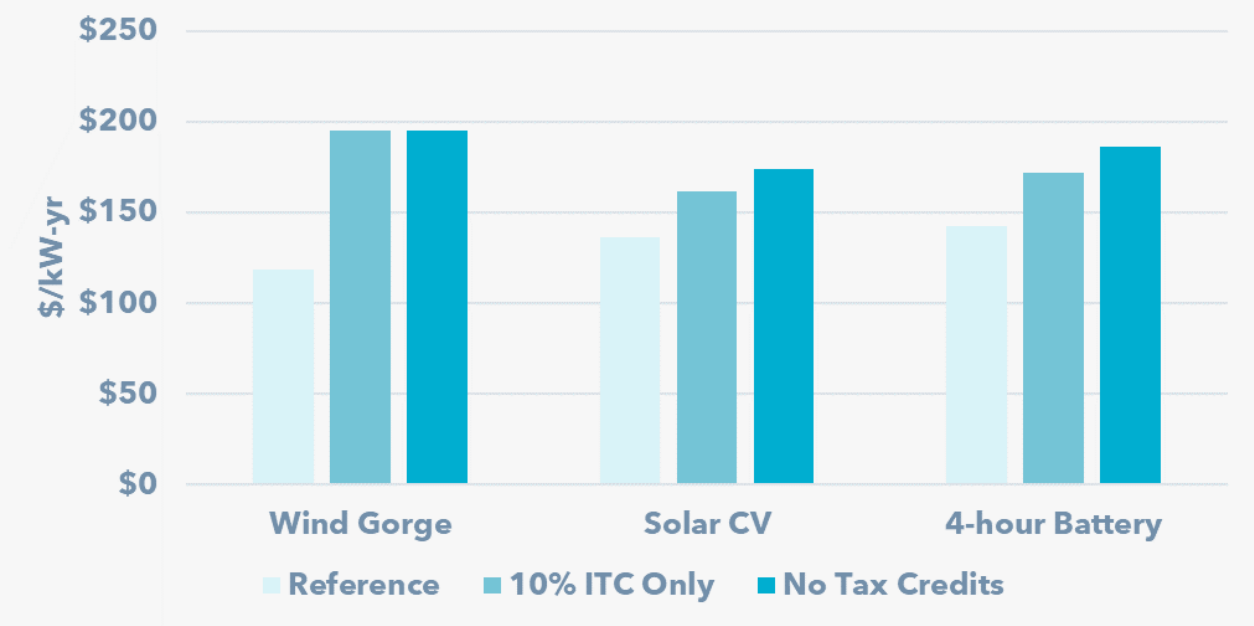
1. Federal tax credit policy reverts to a roughly "pre-IRA" state:
    a. The PTC is not available for new non-emitting generating resources, and
    b. The ITC is available at a rate of ten percent for solar and energy storage resources.
2. Federal policy removes tax credits entirely for new non-emitting generating and energy storage resources that are placed in service after December 31, 2028.

Resource costs relative to the Reference Case in both scenarios as summarized below in **Figure 42**. The sensitivities assume that credits continue to be fully monetized when generated for

[104] https://www.boem.gov/newsroom/press-releases/boem-postpones-oregon-offshore-wind-energy-auction.
[105] Tax credits are discussed in Section 2.1 and 8.1.6 of the 2023 CEP/IRP (see pages 42 and 173).

purposes of determining resource costs. Removing the PTC as modeled from a generic wind resource results in an approximately 64 percent increase in the cost of that resource on a real-levelized basis. Reducing the ITC to ten percent increases solar and battery storage resource costs by approximately 19-20 percent; removing the ITC entirely results in a further ten percent increase in costs for these resources. This analysis assumes wind resources are not eligible for the ITC and, thus, the resource cost is unchanged in the "10 percent ITC Only" and "No Tax Credit" sensitivities.

Figure 42. Tax credit scenario real-levelized costs 2030 COD (2025$/kW-year)



As is observed in **Figure 42**, the availability of federal tax credits has a significant impact on the assumed cost of generation and storage resources. Specifically, without the availability of federal tax credits through 2035 generation costs are expected to increase by as much as 64 percent and storage resources by 30 percent. The customer cost increases associated with changing these assumptions are significant and analyzed further in **Section 6.6 Federal tax credit availability scenarios**.

5.1.4 Electricity price forecast

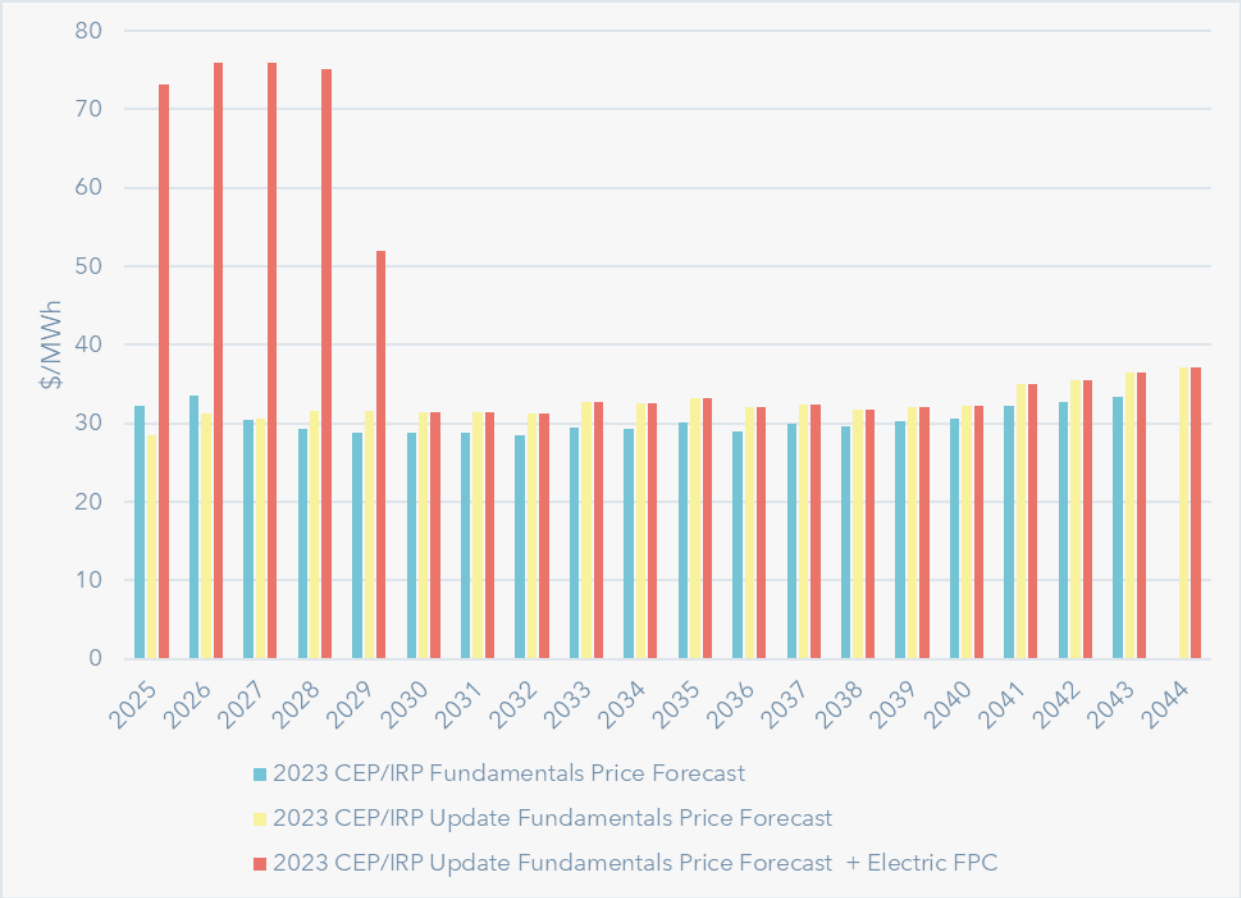
OPUC Staff provided feedback on the 2023 CEP/IRP regarding the PGE electricity price forecast, which is used in the calculation of energy efficiency avoided cost data.[106] Between 2025 and 2029, the PGE electricity forward price curve (FPC) was significantly higher than PGE's fundamental price forecast. The fundamental price forecast is produced by PGE's IRP team in Aurora using forecasted supply and demand conditions across the WECC. The FPC used by IRP

[106] Public Utility Commission of Oregon. (2024, April 30). Staff report: Request for approval of energy efficiency avoided cost data to be used by Energy Trust (Docket No. UM 1893). https://edocs.puc.state.or.us/efdocs/HAU/um1893hau328091055.pdf

is the same as produced for the 2025 AUT. Staff recommended that the Energy Trust of Oregon use a blended price when calculating the avoided costs of energy efficiency.

In response, PGE adjusted the methodology used in the electricity price forecast for this Update to align with Staff's recommendation in UM 1893. For the years 2025 through 2028, the PGE electricity FPC replaces the long-term fundamentals price forecast. After 2029, the IRP electricity price forecast is based on the fundamentals forecast. In 2029, the price forecast is calculated as the hourly average blend of the two forecasts for each of the 39 price futures. **Figure 43** shows the results of incorporating the FPC into the IRP price forecast compared to the fundamentals price forecast in the 2023 CEP/IRP and the 2023 CEP/IRP Update.

Figure 43. Reference IRP Price Forecasts from 2025 – 2044



5.1.5 Supply-side resource energy value

PGE uses Aurora to estimate the energy value of dispatching existing generating resources, contracts, and candidate new resources using electricity prices and associated risk variable inputs from each price future.

The Reference case energy value and range of outcomes across the simulated price futures for each resource are summarized in **Table 19**. These values are levelized across each resource's economic life, for resources with 2028 commercial operation dates.

Table 19. New resource option energy values (2028 COD)[107]

Resource	Levelized energy value (2025$/MWh) Reference case	Range
Solar CV	$23.51	$15.36 - $34.54
Solar MCMN	$22.52	$14.77 - $33.12
Solar Wasco	$22.03	$14.45 - $32.41
Wind Gorge	$27.70	$17.91 - $41.19
Wind MT	$32.53	$20.81 - $47.98
Wind SE WA	$30.03	$19.28 - $44.41
Wind ND	$31.05	$19.98 - $45.86
CV hybrid 1	$28.72	$18.96 - $40.70
CV hybrid 2	$26.00	$18.02 - $37.87
MCMN hybrid 1	$29.33	$19.47 - $41.34
MCMN hybrid 2	$25.81	$17.97 - $37.47

Energy values presented here for a 2028 COD are higher on average than those in the 2023 CEP/IRP by roughly 10 percent to 35 percent, depending on the resource. This is driven in part by the upward change in the electricity price forecast for early model years, as described in **Section 5.1.4 Electricity price forecast**.

5.1.6 Resource capacity contribution

Resource capacity contribution values were discussed in Section 10.5 of PGE's 2023 CEP/IRP. Please also see the related discussion in **Section 3.4 Capacity need** of this Update. The effective load-carrying capability (ELCC) identifies the percentage of a resource's nameplate capacity that can be depended upon when planning for resource adequacy. For example, the 100 MW nameplate capacity of a 4-hour battery may have an ELCC of 22 percent in the winter. This means that the 100 MW nameplate capacity of a 4-hour battery contributes 22 MW (100 * 0.22) towards reducing system capacity needs. If the starting system has a winter capacity need of 200 MW, after adding a 100 MW 4-hour battery, the new capacity need will be 178 MW (200 MW of need, less 22 MW of capacity).

For this Update, the capacity contributions of resources summarized in **Table 20** are evaluated in the year 2030 using Sequoia. The analysis uses the same snapshot of loads and resources as used for the updated capacity need assessment discussed in **Section 3.4 Capacity need**. Since the publication of the 2023 CEP/IRP, model updates were made to Sequoia including load forecasts, QF assumptions, and RFP proxy additions (**Section 3.4.2 Changes to modeling capacity need**). These updates reduced the 2026 capacity need, the year ELCCs were evaluated

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

in the 2023 CEP/IRP, to 47 MW in summer and 0 MW in winter. 2030 was elected as a representative year with sufficient need to test the capacity contributions of proxy resources for the 2023 CEP/IRP Update. Additionally, as part of the 2023 CEP/IRP Update it is assumed that proxy resources will acquire firm transmission equal to 75 percent of the nameplate capacity. This change reflects an attempt to align transmission modeling assumptions with state resource adequacy requirement (e.g. WRAP) and future modeling.[108]

A major finding of the Update is the reduction in ELCCs of storage resources. The cause of this reduction is due in part to an additional 775 MW of storage resources in the system with the RFP Proxy.[109] Second, the ELCC of storage resources is dependent on the amount of energy in the system, for which the 2030 base energy system has a significant energy deficit and is pronounced in winter as discussed in **Section 3.3 Energy need**. PGE considers the unique planning challenge presented by the interactions between storage and energy to be a priority item for review in future integrated resource plans. **Section 6.2.3 Preferred Portfolio resource adequacy testing** expands on the current planning framework, the concern it presents in Preferred Portfolio results, and approaches to address these concerns as part of the 2023 CEP/IRP Update and future planning efforts. Additionally, long-duration storage (LDS) was not assumed available for portfolio expansion due to the lack of commercially proven projects, as such the ELCCs for this resource are not included below. However, **Section 6.2.3 Preferred Portfolio resource adequacy testing** provides a preliminary view of the benefit LDS could provide to PGE's system and motivates further analysis of this and other emergent technology as part of the 2026 CEP/IRP.

Table 20. ELCC values for portfolio construction in year 2030, incremental 100 MW nameplate

	Summer		Winter	
Resource	Firm	Conditional Firm	Firm	Conditional Firm
Wind Gorge	40%	34%	28%	28%
Wind MT	24%	17%	58%	55%
Wind SE WA	17%	13%	43%	39%
Wind WY	32%	20%	59%	51%
Wind ND	30%	19%	54%	51%
Solar CV	23%	10%	21%	21%
Solar MCMN	26%	13%	21%	11%
Solar Wasco	27%	13%	18%	18%
Solar Mead	14%	10%	30%	30%
CV hybrid 1	76%	50%	36%	36%
CV hybrid 2	56%	34%	25%	26%

[108] See LC 80 - Attachment 2. Staff Expectations for Future IRP–Transmission Modeling, and UM 2274 SMM Condition 5.
[109] Analysis of the change in storage resource ELCCs discussed in Jan. 8th 2025 CEP/IRP Roundtable 25-1.

MCMN hybrid 1	80%	57%	32%	32%
MCMN hybrid 2	61%	34%	28%	28%
2-hour battery	31%		14%	
4-hour battery	46%		22%	

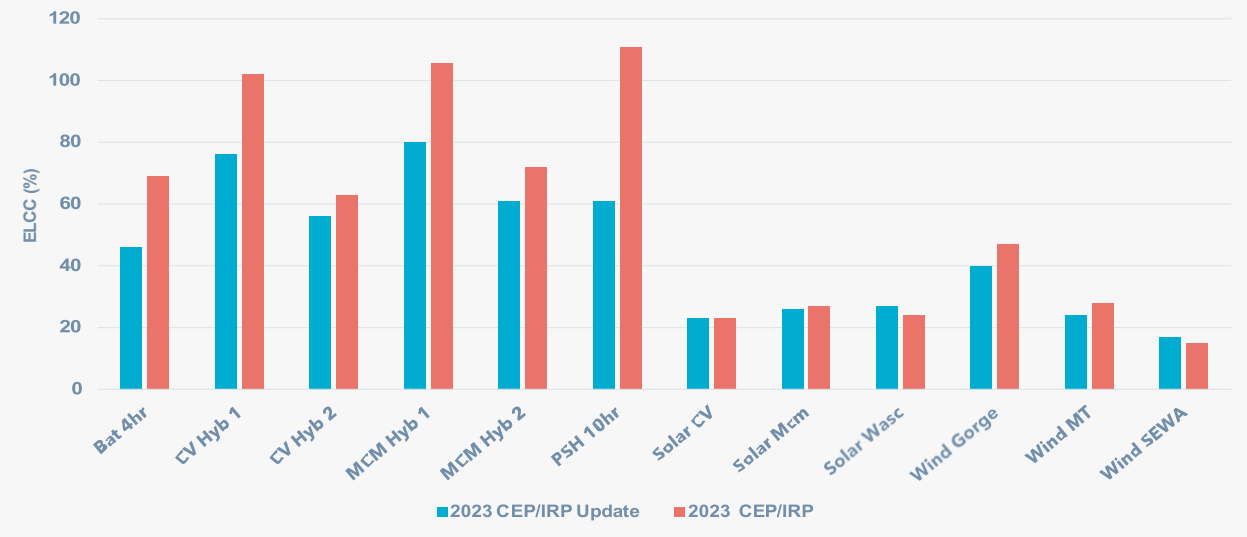
5.1.7 Comparison of resource capacity contribution to 2023 CEP/IRP

As discussed in the section above, the updates that PGE made to resource adequacy modeling, including changes to the underlying portfolio, have resulted in updated proxy resource capacity contributions. These changes can have important impacts on portfolio analysis. To understand the potential key drivers of changes in portfolio outcomes from the 2023 CEP/IRP, this section provides a comparison between the updated ELCCs and those from the 2023 CEP/IRP. Comparisons between ELCCs from the 2023 CEP/IRP and this Update for Summer and Winter are shown in **Figure 44** and **Figure 45**.

Figure 44 shows that generally Summer ELCCs for Proxy resources have decreased since the 2023 CEP/IRP. This decrease is attributed to the assumed 75 percent transmission availability assumption, discussed in the section above, and due to the additional storage and solar resources modeled in the system as part of the 2023 RFP Proxy resource discussed in **Section 3.2.2 2023 RFP proxy**.

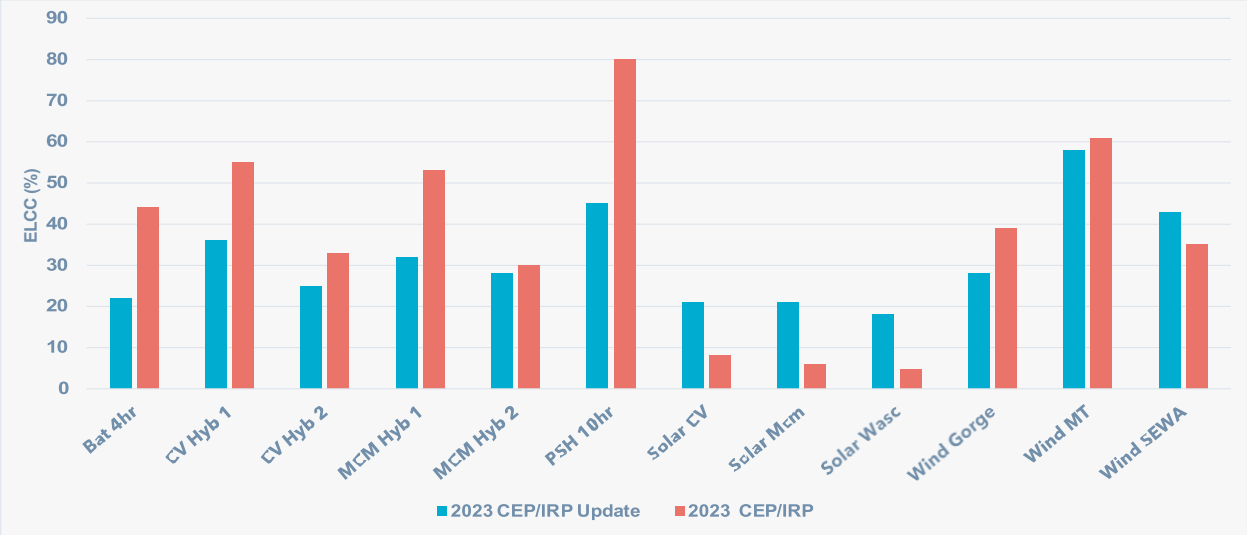
Figure 45 shows the same general trend of lower ELCCs exists in Winter. However, there is a modest increase in the value of solar proxy resources, attributed to the added benefit that midday energy plays in decreasing the likelihood that winter reliability events span across the AM and PM peaks.[110]

Figure 44. Select ELCC Comparison – Summer, Firm Transmission



[110] See **Section 6.2.3.1 Energy sensitivity adequacy assessment of Preferred Portfolio** for more discussion on the value of energy in meeting winter reliability challenges.

Figure 45. Select ELCC Comparison – Winter, Firm Transmission



5.1.8 Resource capacity value

The capacity value is a theoretical construct that uses the net cost of capacity and a resource's capacity contribution to derive a dollar value.

Using the $237/kw-yr described in **Section 6.7 Net cost of capacity resources** as the cost of capacity, with the same approach as in PGE's 2023 CEP/IRP, the capacity value of a resource at (nameplate) is:

$$\text{Capacity value} = \text{Net cost of capacity} \times \text{ELCC (\%)} \times \$237/\text{kW-yr}$$

While not used directly for portfolio analysis in this Update, the resulting capacity value is useful for the purpose of comparing resources or for calculating the administratively determined avoided cost payments for resources procured outside of competitive or negotiated processes. This value has increased meaningfully compared to the 2023 CEP/IRP driven mainly by updated assumptions regarding higher fixed costs as well as increased capacity which reduced ELCCs. This net cost of capacity value is an illustrative metric and is not directly included in portfolio analysis.

Table 21 and **Table 22** summarize the capacity values of resources considered in this Update. For capacity resources in **Table 21**, the ELCC and corresponding capacity value ($/kW-yr.) indicate the amount of capacity required of each resource to provide an incremental 100 MW of capacity contribution to the portfolio. Emergent technologies, such as LDS, geothermal, hydrogen storage, nuclear, etc. are not detailed below due to a current lack of commercially proven projects. As noted above, **Section 6.2.3 Preferred Portfolio resource adequacy testing** suggests these resources may be valuable additions in PGE's portfolio due to winter reliability challenges and motivates the need for a more thorough analysis of such emergent technologies in the 2026 CEP/IRP.

Table 21. Capacity Resource ELCCs and Capacity Values

Resource	Annual ELCC 100 MW capacity contribution	Capacity value (2025$/kW-yr.)
4-hour battery	32%	76
6-hour battery	43%	101
Wind SE WA	12%	29
Solar CV	16%	37
CV hybrid 1	55%	129
MCMN hybrid 1	55%	131

For energy resources in **Table 22**, the ELCC and corresponding capacity value ($/MWh) are shown corresponding to 100-megawatt average (MWa) addition sizes after accounting for the corresponding levelized capacity factors. The ELCC values reflect the effects of the declining marginal ELCC curves.[111]

Table 22. Energy Resource ELCCs and Capacity Values

Resource	Annual ELCC 100 MWa energy addition	Capacity value (2025$/MWh)
Wind MT	35%	23
Wind Gorge	33%	20
Wind SE WA	18%	11
Solar CV	19%	19
Solar Wasco	17%	18
Solar MCMN	17%	22

5.1.9 Resource net cost

This section provides an overview of updates to Section 10.8 of PGE's 2023 CEP/IRP on resource net cost; combining a resource's cost, energy value, flexibility value, and capacity value results in the "net cost". As discussed in Section 10.8.1 and 10.8.2 of PGE's 2023 CEP/IRP, the net cost of capacity and energy resources can be a useful tool for comparing resources on similar terms, though these results are not used directly in portfolio analysis. The net costs displayed in this section are based on the formula in **Section 5.1.9 Resource net cost** above. Based on these illustrative results, the portfolio analysis in **Chapter 6 Resource plan** meets capacity needs more economically with energy resources in select years.

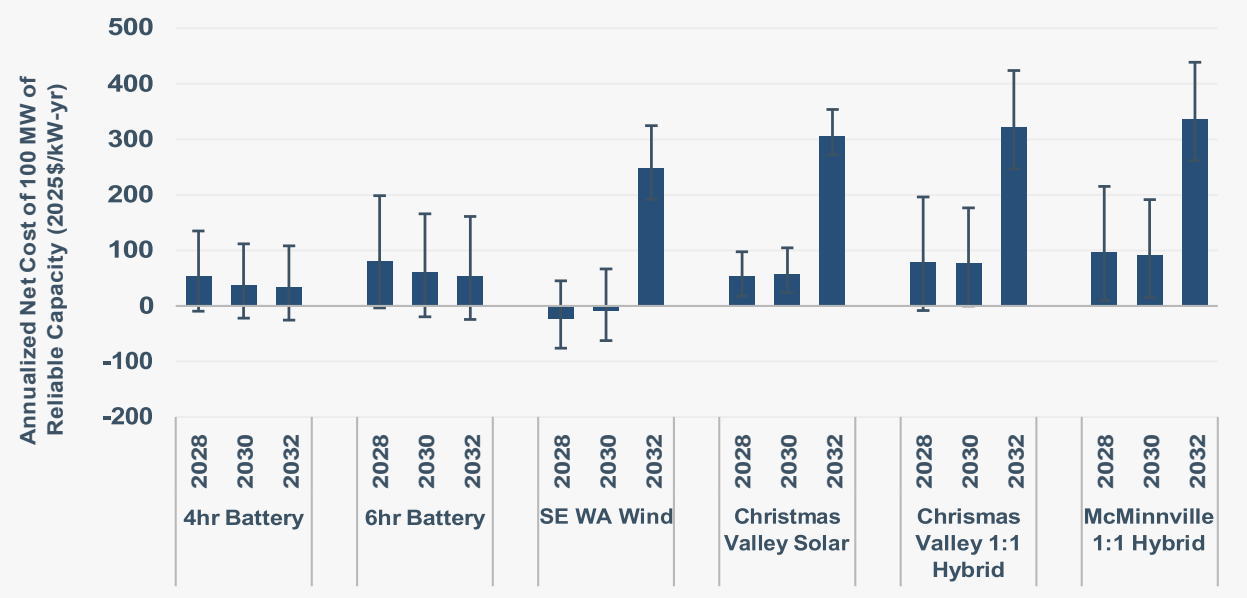
5.1.9.1 Net cost – capacity resources

Figure 46 illustrates the net cost in $/kW-yr of providing 100 MW capacity contribution to the portfolio from various select resources. From this snapshot, standalone batteries appear to be

[111] The annual ELCCs shown in this table are calculated with the average of the seasonal ELCC and are for informational purposes and meant to be directional indicators of capacity value. The actual value of capacity is estimated within portfolio analysis and is dependent on seasonal ELCCs.

the least-cost means to provide capacity to the portfolio in the near-term. These net cost of capacity values represent the total cost less energy, flexibility, and capacity contribution values. Negative net costs imply the given resource for that COD is less expensive than the portfolio-blended cost of capacity described in **Section 6.7 Net cost of capacity resources**. However, in reality, the resource may not yet be available given transmission constraints. Broadly, the relative net costs highlight the order of selection. For example, with transmission constraints beginning in 2032 for some resources, based on the information in **Figure 46**, a model adding capacity while minimizing cost would select battery resources before any of the transmission expansion options.

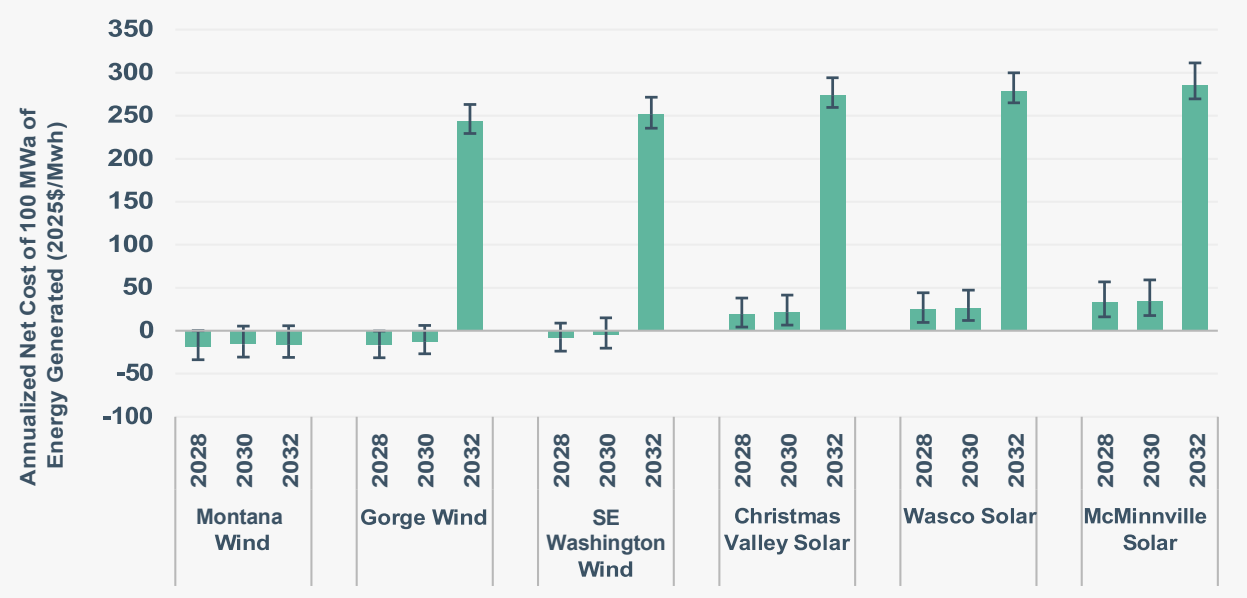
Figure 46. Net cost of 100 MW of capacity contribution by COD



5.1.9.2 Net cost – energy resources

Similarly, **Figure 47** summarizes the net cost in $/MWh of 100 MWa incremental energy contribution to the portfolio from a selection of variable energy resources. These net cost of energy values represent the levelized cost of energy less energy, flexibility, and capacity contribution values. Given the CODs shown, these net costs do not begin to include transmission access and associated costs until 2032 for select resources. This meaningfully increases costs in later years once transmission access is deemed available and this premium highlights why distribution-connected resources may become increasingly cost-competitive in a model, despite having higher fixed costs than their supply-side counterparts.

Figure 47. Net cost of 100 MWa generation by COD



While net costs of new resources 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 more thoroughly investigated through portfolio analyses described in **Chapter 6 Resource plan**.

5.2 Distributed energy resources (DERs)

PGE develops a forecast of DER adoption and hourly load impact on a regular basis. This DER forecast provides insights on how much market-based DER adoption will impact both PGE's bulk and distribution systems. It also informs how much cost-effective demand response can be made available to shape and shift load on the bulk system. As such, the DER forecast informs PGE's planning processes, including its Distribution System Plan (DSP) and the IRP. This section provides a brief description of the approach used and results from the DER forecast.

The DER forecast uses PGE's AdopDER software to model the adoption of over 60 DER technologies and technology combinations. The software uses a current, point-in-time snapshot of data from PGE systems that describes the characteristics of each PGE service point: building type and vintage, heating and cooling system, vehicle weight class(es) and fuel(s), and interconnected solar PV and storage. AdopDER also accounts for customer growth across PGE's service territory to simulate the eligibility, adoption, and load impacts for each DER over a 20-year forecast horizon through calendar year 2044.

From this starting point, AdopDER simulates both the market adoption of passive DERs and expected customer participation in current and future demand response programs—representing achievable potential within a potential study framework. For this update to PGE's 2023 CEP/IRP, three adoption scenarios (reference, high, and low) were modeled using varying inputs such as

cost assumptions, adoption trends, and policy signals. The outputs reflect how DER deployment is shaped by evolving market, regulatory, and customer dynamics.

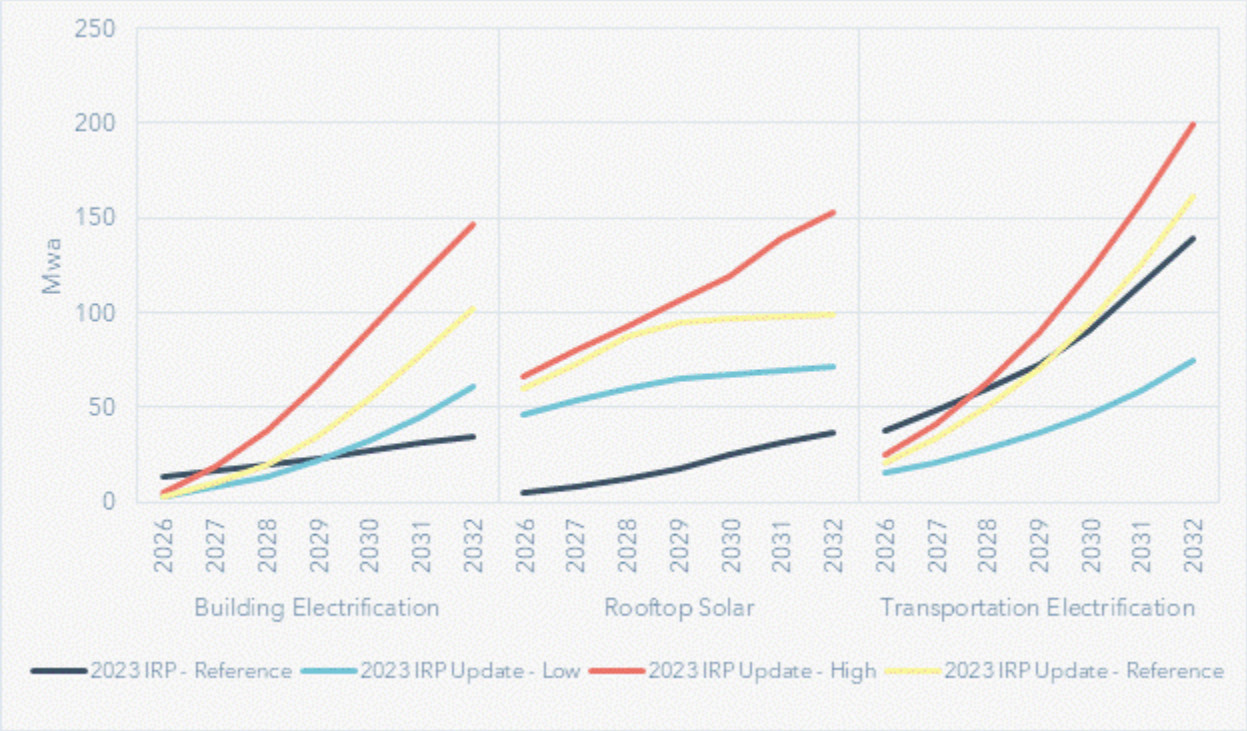
AdopDER calculates cost-effectiveness metrics for each demand response resource and modeling of these resources in the IRP is handled in distinct ways depending on whether a resource is deemed to be cost-effective, or non-cost-effective, in AdopDER. Cost-effective measures are assumed to be adopted, with their capacity benefits reducing PGE's forecasted capacity need. Measures deemed to be non-cost-effective in AdopDER are made available in portfolio analysis, competing on an economic basis for selection against supply-side resource options. To consider the potential of the entire demand response supply curve, the IRP Action Plan sets a demand response target that includes all of the cost-effective measure and any additional non-cost-effective resources identified through portfolio analysis.

This Update reflects the best available DER forecasts at the time of analysis, including results from the August 2024 AdopDER run. AdopDER is a dynamic tool, and its outputs are sensitive to underlying assumptions—such as changes in federal and state policy, economic conditions, and regional adoption patterns. These inputs are continually refined as new data becomes available. All DER forecasts are currently being updated as of May 2025 and will be incorporated into the forthcoming Transportation Electrification Plan, Distributed Systems Plan, and Flexible Load Multi-Year Plan.

5.2.1 Passive DERs

Passive DERs are represented in IRP modeling using three categories: distributed solar (PV), transportation electrification (TE) and building electrification (BE). These cost-effective DER shapes are not incorporated into the PGE load forecast regression as outlined in **Section 3.1 Econometric load forecast**. **Figure 48** shows the reference case values from the 2023 CEP/IRP are included shows the passive DER shapes by category by year (2026-2032) for the low, base and high case scenarios used in the 2023 CEP/IRP Update.

Figure 48. Passive DER shapes by category by year



5.2.1.1 Distributed solar (PV)

The annual adoption of distributed solar PV is projected to experience significant growth through the late 2020s before leveling off in the early 2030s. Multiple factors drive this growth trajectory: decreasing technology costs, rapid technological advancements, supportive state policies, and increasing customer environmental awareness. However, this trend is anticipated to begin to flatten for two primary reasons. First, key financial incentives like the Residential Clean Energy Credit and Investment Tax Credit—currently stimulating adoption—will gradually phase down after 2032, with credit percentages decreasing to 26 percent in 2033 and 22 percent in 2034, before potentially being eliminated. Second, as residential customers continue to drive the majority of distributed solar PV adoption, the diminishing availability of suitable rooftops will create a natural constraint on future growth as the most optimal installation sites become saturated. The results from the AdopDER forecast for Distribute PV do not consider risks associated with the more rapid phasing out of tax credits as discussed in **Section 2.5 Federal administration changes**.

5.2.1.2 Transportation electrification (TE)

The transportation electrification policy assumptions include the impact of the 2022 Advanced Clean Cars II rule for light-duty vehicles, which requires that auto manufacturers meet 100 percent of the market share of new vehicles with zero-emission battery electric and plug-in

hybrid electric models by 2035.[112] Similarly, medium- and heavy-duty vehicles follow the 2021 Advanced Clean Truck rules, which set aggressive electrification targets for this vehicle segment.[113] The DER forecast also accounts for PGE customers and their known fleet electrification plans (i.e., a customer has plans to electrify 100 percent of its fleet by year 2028).

In the 2023 CEP/IRP Update forecast, PGE expects a total of 270,000 light-duty battery electric vehicles by 2030, predominantly in the residential sector, and approximately 80,000 medium and heavy-duty battery electric vehicles. From these vehicle estimates, PGE expects the annual transportation electrification load to achieve 95 MWa by 2030.

Gross transportation electrification load does not account for the potential impact of associated demand response programs such as time-of-use or managed charging programs. These impacts are instead captured under Demand Response or Flexible Load resources (e.g., direct load control programs).

5.2.1.3 Building electrification (BE)

Building electrification has significant potential to both decarbonize the economy and increase the amount of electric load that PGE needs to serve its customers' needs. In the DER forecast, fuel switching from fossil fuels to electric space heating, water heating, and/or cooking technologies in existing buildings and the new construction sector drives the building electrification forecast. The rate at which these customers electrify their end-use systems includes the expected impact of the 2022 Inflation Reduction Act legislation.

Like transportation electrification, gross building electrification load across varying adoption scenarios, not accounting for the potential impact of associated demand response and direct load control programs.

5.2.2 Cost-effective demand response

Cost-Effective (CE) DER resources are included in PGE's assessment of system need. **Section 3.4 Capacity need** details PGE's approach to estimating system need for the 2023 CEP/IRP Update using PGE's resource adequacy assessment model, Sequoia. As part of estimating system need, Sequoia utilizes estimates from PGE's AdopDER model. AdopDER simulates market adoption of passive DERs and the expected participation of customers in current and potential demand response programs.[114] AdopDER accounts for key site-level factors such as access to garage parking, breaker space and equipment turnover to determine the technical, achievable, and economic potential. Twenty CE DER resources are modeled as part of the 2023 CEP/IRP Update, the same number as used in the 2023 CEP/IRP. Two inputs from AdopDER are used to estimate

[112] Final rule amendments to OAR Chapter 340, Division 257 adopted by the Oregon Environmental Quality Commission in Order DEQ 23-2022 (December 19, 2022), https://www.oregon.gov/deq/rulemaking/Documents/DEQ232022.pdf.
[113] Final rule amendments to OAR Chapter 340, Division 257 adopted by the Oregon Environmental Quality Commission in Order DEQ 17-2021 (November 17, 2021), https://records.sos.state.or.us/ORSOSWebDrawer/Recordhtml/8581405.
[114] For more information on AdopDER reference 2023 CEP/IRP Chapter 6.2 - Distributed Energy Resource (DER) impact on load

the hourly effect of each CE DER in Sequoia: hourly shape and program size by month. Hourly shapes are scaled across the planning horizon based on program size, resulting in estimated hourly contributions of each CE DER resource which grow with forecasted increases in program participation. Further, CE DER contributions are estimated for the three need futures (Low/Reference/High) used in the 2023 CEP/IRP Update. **Table 23** provides a summary of program size of CE DER resources in the 2030 Reference need future. In total, there are 1269 MW of capacity from CE DER resources on average in 2030, a 181 MW net increase in capacity from the 2023 CEP/IRP Addendum: System Need and Portfolio Analysis Refresh. The largest change in program participation is in the Rooftop Solar program, which is estimated at 668 MW of capacity on average in 2030, a 165 MW increase from the estimates used in the 2023 CEP/IRP Addendum.

Table 23. Monthly Average Program Size of CE DER Resources – 2030 Reference Case (MW)

Program	2023 CEP/IRP Update	2023 CEP/IRP Addendum	2023 CEP/IRP
Rooftop Solar	668	503	206
Building Electrification	96	51	33
Light Duty EV	95	149	101
Energy Partner Curtailment (Summer)	92	52	52
Smart Thermostat (Summer)	76	65	65
Energy Partner Curtailment (Winter)	68	46	46
Time-of-Use (Summer)	41	30	30
Smart Thermostat (Winter)	39	35	35
Time-of-Use (Winter)	23	15	15
Peak-time Rebates (Summer)	22	43	43
Peak-time Rebates (Winter)	18	28	28
Multi-Family Water Heater (Winter)	18	41	41
Multi-Family Water Heater (Summer)	10	26	26
Utility Controlled Storage (Commercial)	3	3	3
Utility Controlled Storage (Residential)	0	0	0
Customer Controlled Storage	0	0	0
EV Load Control (Winter)	0	0	0
EV Load Control (Summer)	0	0	0
Customer Controlled Storage	0	0	0
Utility Controlled Storage w/ PV	0	0	0
Total	**1269**	**1087**	**724**

Lastly, PGE adjusted AdopDER estimates of program size for years 2025-2026 to align values with PGE's Multi-Year Plan (MYP) forecasts for mature CE DER programs: Smart Thermostat, Peak-time Rebates, Time-of-Use, Energy Partner Curtailment, and Multi-family Water Heater.[115] The MYP provides more accurate short-term forecasts of eligible program adoption compared to AdopDER's bottom-up, locational approach. PGE aligned the AdopDER near-term forecasts with MW impacts from MYP to ensure consistency across all planning deliverables.

5.2.2.1 Dispatchable Stand-by Generation (DSG)

PGE's DSG program provides a valuable reliability benefit. The contingency reserves these customer-sited resources supply in the form of operating reserves free-up PGE's generating resources to serve load. Additionally, DSG resources can provide ancillary services in the form of frequency and demand response. This program was estimated to have little to no growth in the 2023 CEP/IRP and 2023 CEP/IRP Update, growing from approximately 109 MW in 2025 to 113 MW by 2030. However, more recent analysis of load growth from the industrial segment and data centers is expected to increase program participation by 120 MW.[116] Including growth from data centers as well as other C&I customers, the DSG program is expected to have 300 MW of nameplate enrollment by 2030. In anticipation of growth in the DSG PGE's rate Schedule 200 was updated to ensure customers are at least cost-neutral to participate, increasing the likelihood of enrollments and the ability of this program to avert situations that could lead to power quality problems for the power supply in the local region.[117]

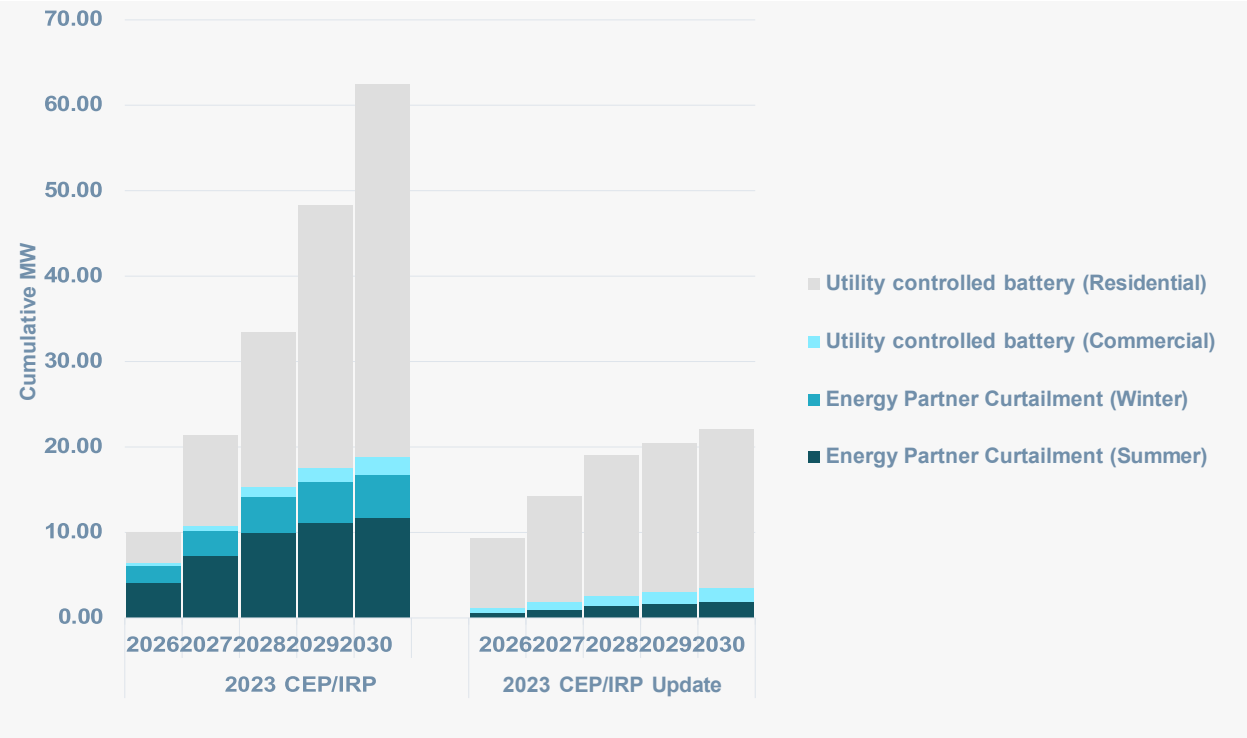
5.2.3 Non-cost-effective demand response

The 2023 CEP/IRP Update includes updated quantity and cost assumptions for four bundles of non-cost-effective (NCE) DER resources. Updated values result from the August 2024 run of PGE's AdopDER model, used to forecast metrics for NCE DERs.[118,119] The four bundles are groupings of the same site-level measures as used in the 2023 CEP/IRP described in Section 8.2 - Additional distributed energy resources and Section 8.2.2 – Additional demand response. Each bundle represents similar DER programs based on dispatch characteristics and costs. **Figure 49** compares the available quantities of NCE DER resources in the 2023 CEP/IRP Update to those used in the 2023 CEP/IRP. The cumulative total quantity of NCE DER resources decreased by 40.39 MW in 2030, due largely to a 57 percent reduction in forecasted adoption of utility-controlled battery in the residential segment. The large reduction in residential utility-controlled battery is due to a slower adoption trend for these resource as estimated in the August 2024

[115] Flexible Load Multi-Year Plan 2025-2026
[116] OPUC Staff Report Docket No. Adv 1705 - Updates Schedule 200 Dispatchable Standby Generation to increase the Aid in Construction Allowance. These more recent estimates of DSG program size were not incorporated in the 2023 CEP/IRP Update due to timing in the analysis process. Estimates will be reviewed as part of the 2026 CEP/IRP planning cycle.
[117] PGE Rate Schedule 200
[118] For a more detailed discussion of AdopDER reference: 2023 CEP/IRP's Section 6.2 – Distributed Energy (DER) impact on Load
[119] These updates do not take into account UM 2141 updates approved after August 2024 (i.e., Feb. 2025 approvals)

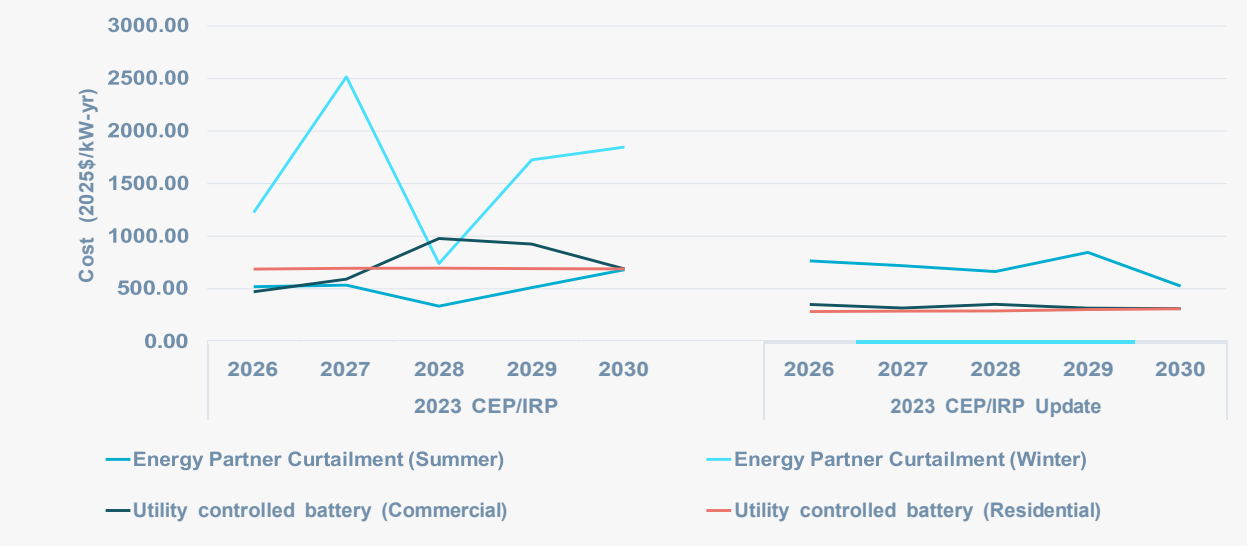
AdopDER run. Further, capacity from winter NCE Energy Partner Curtailment resources is non-existent in the 2024 AdopDER run, as the smart thermostat and cold storage curtailment programs previously bundled within are now considered cost-effective.

Figure 49. NCE DER Quantities Available in 2023 CEP/IRP and 2023 CEP/IRP Update



Cost assumptions were updated as part of the revised AdopDER results. Fixed costs for these NCE DER resources reflect weighted average site-level costs, including customer acquisition costs, upfront incentives, and upfront participation costs. Ongoing costs were also revised and included as variable costs for customers, incentives, and participants. **Figure 50** displays a comparison of costs from the 2023 CEP/IRP to values used in the 2023 CEP/IRP Update. Average costs across 2026-2030 for utility-controlled batteries in both commercial and residential segments decreased by approximately $380 /kW-yr, while average costs across the same period increased by $180 /kW-yr for summer Energy Partner Curtailment resources. Winter Energy Partner Curtailment costs are no longer reported as the estimated quantity available in the 2023 CEP/IRP Update is 0 MW, as described above.

Figure 50. Comparison of Updated NCE DER Costs (2025$/kW-yr)



5.3 Energy efficiency

PGE relies on the Energy Trust of Oregon (ETO) to identify energy efficiency measures available in the IRP using its resource assessment modeling tool. This modeling tool uses a cost-effectiveness screen on energy efficiency potential to forecast two metrics: (1) Cost-Effective (CE) energy efficiency measures and (2) Non-Cost-Effective (NCE) energy efficiency measures. The CE energy efficiency measures are incorporated into PGE's IRP load forecast and assumed to be acquired in IRP portfolio analysis. The NCE energy efficiency measures are incorporated into IRP's portfolio analysis and are considered as incremental resource additions based upon the aggregation of energy efficiency measures into discrete bins.

5.3.1 Cost-effective energy efficiency

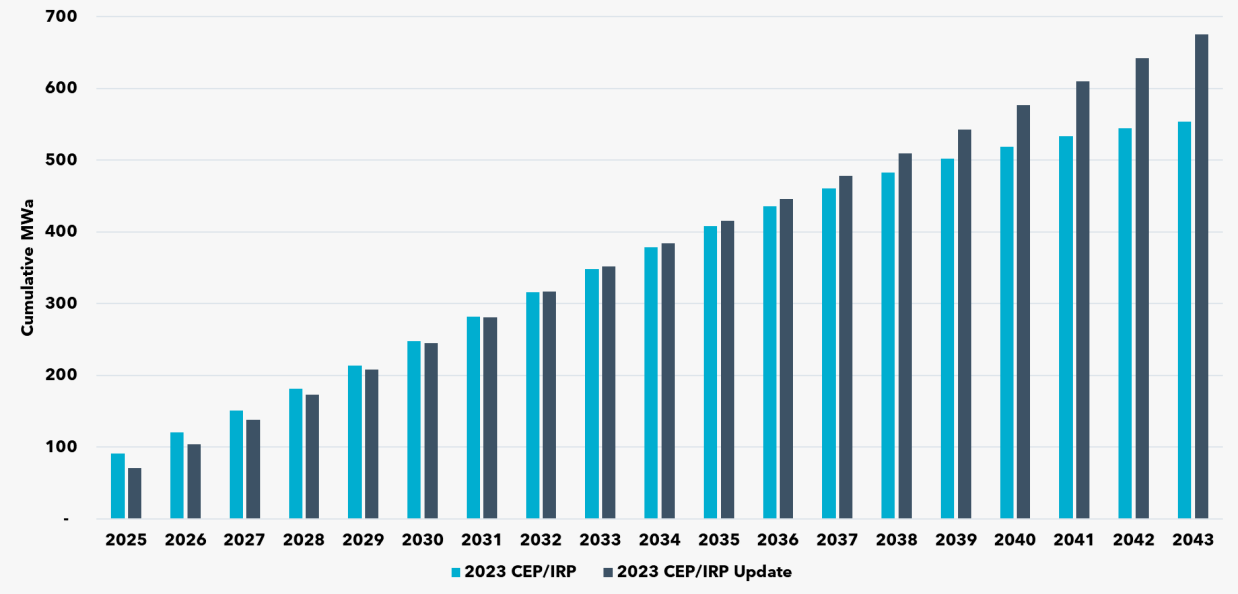
PGE receives a list of Cost-Effective (CE) Energy Efficiency measures that the ETO has found to pass its cost-effectiveness screening. The screening involves using a benefit-cost ratio to determine if the present value of benefits is equal to or exceeds the present value of the costs of the measure being evaluated. The CE Energy Efficiency forecasts are incorporated into the IRP load forecast as independent, or explanatory, variables in PGE's load forecast regression models.[120] For details on the CE achievable potential by end use and sector and final savings projections for CE energy efficiency measures, see the 2025 Resource Assessment Model provided by the Energy Trust of Oregon in **Appendix E**.

For this Update PGE incorporated an updated forecast of CE EE from the ETO. As shown in **Figure 51**, cumulative quantities of CE EE are forecast to be slightly lower through 2031 than in the 2023 CEP/IRP. Beyond 2031, CE EE quantities are increased relative to the 2023 CEP/IRP forecast, although the differences are relatively small until the late 2030's. By 2043, the updated

[120] The Energy Efficiency Savings forecast shared by the Energy Trust in November of 2023 was used as an input to the May 2024 load forecast.

forecast identifies 122 MWa more CE EE than was incorporated in modeling in the 2023 CEP/IRP. The main drivers of this increased potential CE EE savings are described in the 2025 Resource Assessment Model provided by the Energy Trust of Oregon in **Appendix E.**

Figure 51. Cost-effective energy efficiency in the 2023 CEP/IRP and IRP Update



5.3.2 Non-cost-effective energy efficiency

For PGE's 2023 CEP/IRP update, the ETO provides PGE with savings and levelized cost data for energy efficiency measures that do not pass the cost-effectiveness screening in the Resource Assessment Model. A summary of the ETO energy efficiency measures in the 2025 Resource Assessment Model provided by the Energy Trust of Oregon can be found in **Appendix E**. These Non-Cost Effective (NCE) measures are incorporated into IRP modeling via the PGE bundling methodology as candidate resources in Portfolio Analysis.

5.3.3 Bundling of NCE energy efficiency measures

PGE adopted a similar process as the Northwest Power and Conservation Council and aggregated measures into discrete bundles (or 'bins') based on the measures' levelized costs. Within these five bins the NCE energy efficiency measures are organized based on the rank of the measure's levelized cost. The bin ranges are generated by creating megawatt-average thresholds across the cumulative megawatt-average of total NCE potential. In the 2023 CEP/IRP, the bin ranges were established by prioritizing bins that contained at least 10 megawatt-average per bin. In the 2023 CEP/IRP update, the bin shapes prioritize aggregation according to average fixed cost. In portfolio analysis, the analysis of any given bin will assess the next set of potential energy efficiency measures that share similar cost structures rather than assessing the next 10 megawatt-average of the cumulative NCE potential.

From these bin shapes, PGE is able to calculate the maximum potential NCE energy efficiency savings by year. Updated bin shapes are summarized in **Table 24**. PGE then calculates costs,

capacity factors, ELCCs and energy values for each bin shape with which to characterize the NCE energy efficiency as resources available for selection in portfolio analysis.

Table 24. Cumulative NCE EE potential by Bin (MWa) through 2030

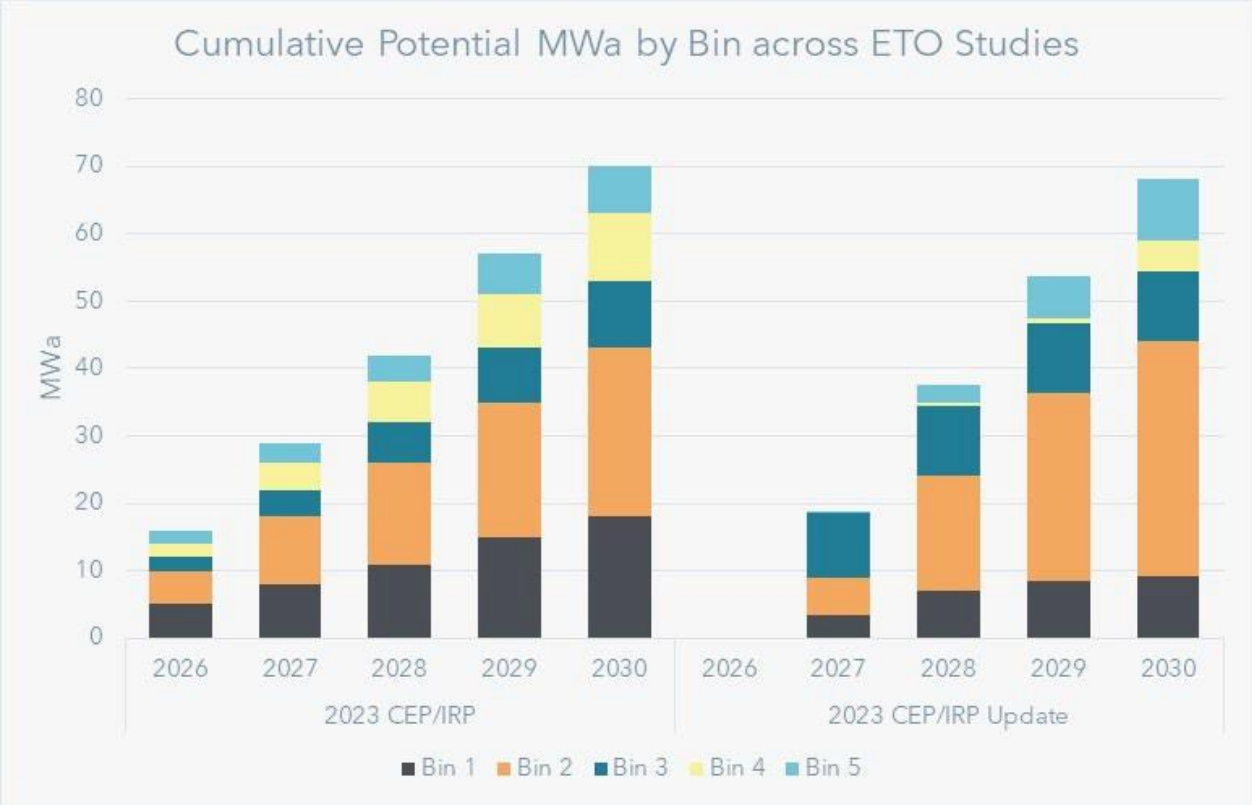
Year	Bin 1	Bin 2	Bin 3	Bin 4	Bin 5
2026	0.0	0.0	0.0	0.0	0.0
2027	3.5	5.5	9.5	0.1	0.2
2028	7.0	17.0	10.4	0.6	2.7
2029	8.6	27.8	10.4	0.7	6.2
2030	9.1	34.9	10.4	4.6	9.1

5.3.4 Comparing NCE energy efficiency in 2023 CEP/IRP to the 2023 CEP/IRP Update

The total cumulative megawatt-average of NCE energy efficiency expected by 2030 changes little between the 2023 CEP/IRP and the 2023 CEP/IRP Update, falling from 70 megawatt-average to 68.1 megawatt-average across all five bins, as summarized in **Figure 52**. The bin sizes differ between filings as the changes in the fixed costs for each NCE energy efficiency measure led to resorting across the five bins.[121]

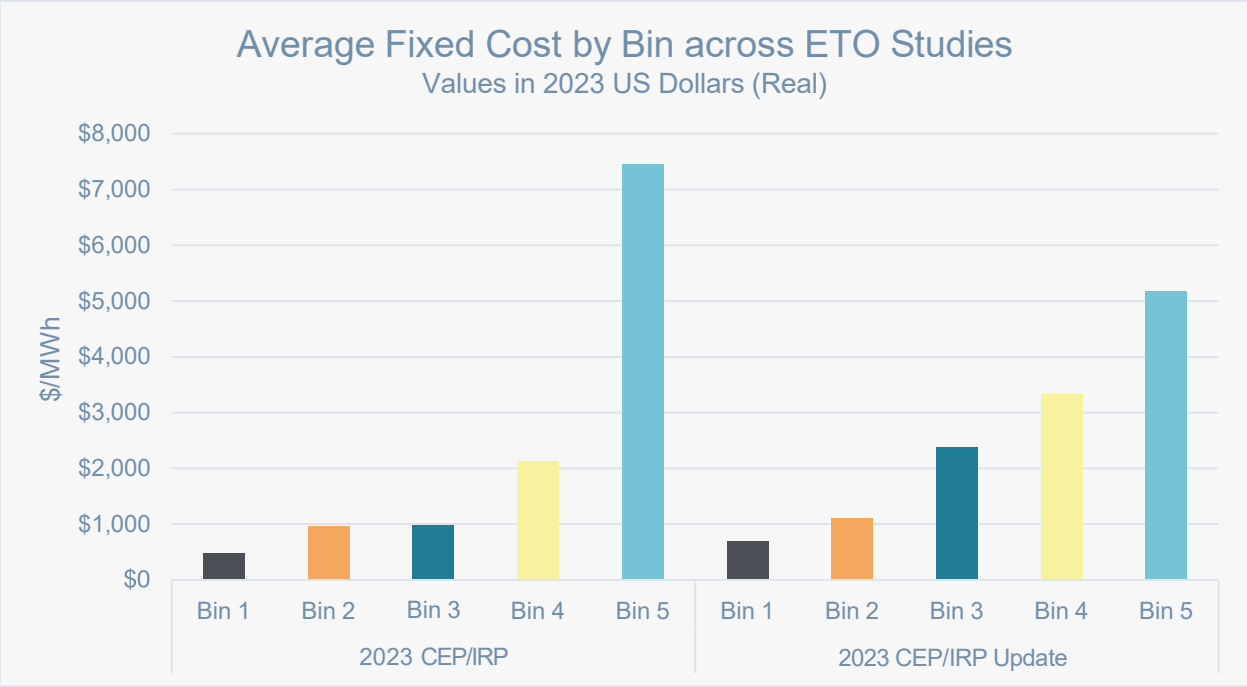
[121] In the 2023 CEP/IRP PGE was able to create roughly 10 MWa bins by aggregating programs with similar levelized costs. In the CEP/IRP Update PGE prioritized keeping bins of similar costs, which resulted in differences in MWa bin size.

Figure 52. Comparison of the Potential MWa by Bin between the 2023 CEP/IRP and the 2023 CEP/IRP Update



There is an increase in the average fixed costs for all bins, except Bin 5, as average levelized costs increased 37.2 percent over all measures, as depicted in **Figure 53**. The increases in average fixed costs are due to rising costs of EE equipment driven by inflation, changes in supply chain, post-COVID effects, and increased avoided costs, making measures that were on the margin now cost-effective. This removes lower cost measures from the list of NCE measures.

Figure 53. Comparison of the Average Fixed Cost by Bin between the 2023 CEP/IRP and the 2023 CEP/IRP Update expressed in real $ (2023)



5.3.5 Energy efficiency program and policy

This section provides an update on near-term commitments to address costs and implementation challenges present in the accelerated procurement of the Energy Efficiency identified in the 2023 CEP/IRP.[122] Those commitments include:

- Supporting Energy Trust of Oregon's development of guiding principles to actively consider utility rate impacts,
- Supporting Energy Trust of Oregon's creation of a mechanism to set targets for outside funding and requirements for regular reporting,
- Supporting Energy Trust of Oregon's formalization of the divisions of labor and funding allocations established between Energy Trust of Oregon and other entities,
- Exploring the co-deployment of flexible load and EE programs with near-term focus on how these programs can help customers participating in PGE's Income Qualified Bill Discount, and
- Continued collaboration on program demonstration in the PGE testbed and measure development that includes complementary funding.

This Update represents an articulation of PGE's understanding of the feasibility of new cost recovery mechanisms, pathways for co-deployment informed by stakeholder feedback and the

[122] OPUC. Acknowledgement of 2023 Integrated Resource Plan and Clean Energy Plan. Docket No. LC 80, December 14, 2023, Page 9. Retrieved from https://edocs.puc.state.or.us/efdocs/HAU/lc80hau325590032.pdf.

stage of readiness achieved by Energy Trust of Oregon. Some dependencies that may impact the progress on commitments made, and perhaps the Need Futures presented, include the revision to the Energy Trust of Oregon Grant Agreement, the timing and magnitude of public sector funding, changes made to avoided cost methodology on UM 1893, and Energy Trust's ability to engage and formalize roles with other public sector entities.

5.3.5.1 Utility rate impacts

Energy Trust has recently increased its focus on leveraging customer funding paid through rates with other, complementary funding sources to enable deeper retrofits, increase savings, reach more customers, and deliver overall greater value. PGE worked with Energy Trust in 2024 to refine and articulate principles for complementary funding.

Energy Trust will align its investments with Oregon's decarbonization policies by following guidance from the OPUC and supporting customer fuel choices with high-efficiency equipment incentives. They will address fuel-switch constraints and ensure efficient use of resources to advance state policy objectives. Additionally, Energy Trust may administer programs promoting clean air and decarbonization with separate funding if it aligns with their vision and purpose.

Defining leveraging, braiding and co-funding

The term "leveraging" is used loosely to cover a broad range of complementary funding strategies that bring additional, public-sector funds to support Energy Trust projects, programs, and activities. "Braiding," "co-funding," "layering" or "stacking" funding streams is a process for using multiple sources of funding to support a common program or project that results in energy savings or generation.

This complementary funding is expected to contribute through the following efforts:

- Enable: Braiding dollars for deferred maintenance overcomes a barrier to participation.
- Amplify: Energy Trust delivery infrastructure and multi-utility funding model produces economies of scale by an order of magnitude ($1 ratepayer: $10 taxpayer).
- Offset: Braiding dollars improves cost-effectiveness by reducing the incremental measure cost.

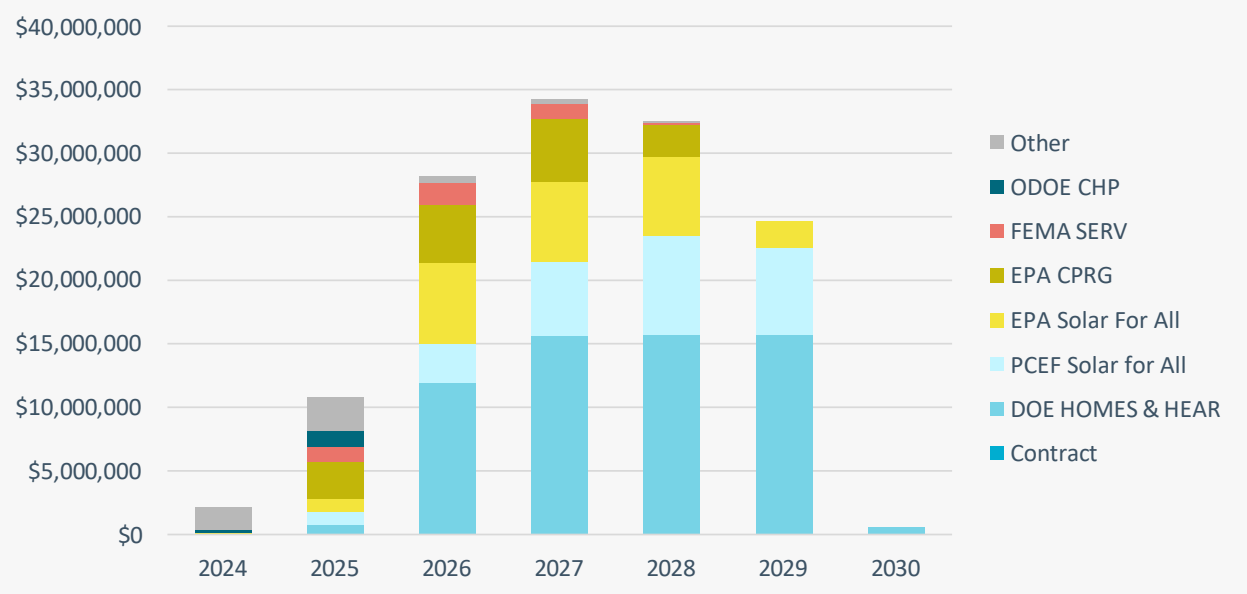
Guiding principles for leveraging funds

Energy Trust has stated that it will prioritize leveraged funding to increase energy savings and generation, improve equitable access to services, stretch customer dollars, and fill unmet customer needs. They also committed to minimizing program confusion, strengthening stakeholder relationships, ensuring continuous customer support, and enhancing contractor effectiveness. Leveraged funding examples include co-funding heat pump installations, provided it results in greater benefits for customers.

5.3.5.2 ETO funding allocation

In 2025, Energy Trust will be developing a complementary funding strategy as a component of the 2026-2030 multiyear plan. This component of the multi-year plan will outline strategies to leverage other funding in support of multiyear program strategies to achieve energy targets. Current estimates provided by ETO, across all utility funders not just PGE, are shown in **Figure 54**, though exact timing and amounts may be subject to change.

Figure 54. Estimated Energy Trust Complementary Funding Revenue by Year, Contract



PGE customers benefit from the leveraging of taxpayer dollars. Given that public sector grants and rebates fund the same end-use improvements it is important to establish an understanding of the roles and responsibilities across funding administrators and implementers so as not to duplicate efforts. This sorting and defining of roles is currently happening at the funding opportunity or contract level for Energy Trust. For example, for EPA Solar For All, this is described in the role of partners within that agreement.

5.3.5.3 Co-Deployment of Flexible Load and EE programs

Action Planning with Energy Trust of Oregon

As a result of legislative direction in HB 3141 (2021), codified as ORS 757.746(e), Energy Trust of Oregon was required to, “with public utilities, jointly develop public utility specific budgets, action plans and agreements that detail the entity’s public utility-specific action plan (USAP), resources, including coordinated activities that require joint investment and deployment.” Also, per the legislation, “Each action plan must reflect stakeholder feedback gathered through a public process managed by the entity and the relevant public utility as overseen by the commission.” This statutory direction required modification to Energy Trust's current budget development process, with more utility-specific coordination.

In June of 2022, following a series of work sessions with OPUC, Energy Trust, utility funders and customer advocates, a Budget Process Coordination and Action Plan Memorandum (the "HB 3141 Budget Coordination Memo") was formed. This memorandum represented a joint planning framework that articulated stepwise activities to support annual budget and utility-specific action planning.

Building on this plan development process the Energy Trust and PGE propose evolving from a two-year cycle to a multi-year (2026-2030) time horizon and from an activity-based plan to an outcomes-based co-deployment framework. Doing so affords the two organizations the opportunity to better maximize value for shared customers, accelerate procurement as determined in the PGE Integrated Resource Plan in compliance with HB 2021, as well as align based on organizational and program readiness.

Co-Deployment

Co-deployment with the Energy Trust encompasses a shared strategy, with common marketing, outreach, and messaging, to efficiently deliver complementary energy services to shared customers. Through co-deployment of complementary services, customers benefit from behind-the-scenes coordination with streamlined participation and total delivery cost reduction for all customers. To start, co-deployment will include targeting priority high energy burdened customers with services that lead to meaningful bill reduction and advance the shared objective of reducing energy burden. The timing of this effort is aligned with implementation of HB 2475 through the OPUC docket UM 2211, with the goal of reducing energy burden and the anticipated availability of public sector funding. Co-deployed services will initially consist of existing, feasible offerings provided by each organization today. Over time, additional services and deployment forms or pathways will be added to the framework as each organization is ready to bring in more services to market. The framework will evolve to focus on different configurations of candidate screening and more targeted delivery.

Co-deployment may take a variety of forms and pathways:

- Community outreach: Shared program marketing collateral and tabling events together
- Co-funding: A methodological approach in which PGE provides complementary funding for flex value (e.g., residential thermostats)
- Bill reduction: Referral of IQBD customers to increase EE program participation (also provides flex potential for future co-funding opportunities)
- Solar+ storage: Aligning PGE smart battery roadmap with the U.S. Environmental Protection Agency Greenhouse Gas Reduction Fund Solar for All grant funding timing
- Pilot to program: Ensuring that tested collaboration yields a hand-off to product and measure development.

5.4 SSR resource

A new proxy supply-side resource was added to represent the range of small-scale renewable (SSR) resources that may be available to help PGE meet Oregon's ten percent small-scale

renewable requirement. The inclusion of a SSR resource allows the requirement that starts in 2030 to be accounted for in portfolio analysis.

The ten percent requirement uses only one metric (i.e., 20 MW or less in size) and does not incorporate community benefits.[123] The purpose of the SSR proxy resource is strictly to analyze compliance with the ten percent requirement; consequently PGE chose to design the resource to represent projects on the upper end of the 20 MW size limit, which are less costly than smaller community-scale projects. Smaller-scale projects are already considered in portfolio analysis through the lens of CBREs.

Due to limited suitable locations within PGE's service territory to site a 20 MW renewable energy facility, the resource is assumed to be off-system. The resource cost and performance parameters of the SSR resource are based on the Christmas Valley solar proxy resource. The performance characteristics match those of the Christmas Valley solar resource. This means having the same generation profile and resulting capacity factors and energy value. The cost characteristics are scaled to account for the fact that smaller projects benefit less from economies of scale than larger projects and therefore can be expected to be more costly on a per-unit basis. In order to account for this size-cost dynamic, the $/kW fixed costs of the SSR resource are inflated by eight percent above the fixed costs of the Christmas Valley solar resource, the fixed costs of which are based on an assumed 100 MW DC project size. Analysis in Berkeley Lab's "2024 Utility-Scale Solar, 2024 Edition" report is used to estimate a cost premium associated with smaller-scale resources. In the report, projects between 5-20 MW DC were found to have a weighted mean capex cost of $1.28/W, while projects between 50-100 MW DC had eight percent lower capex costs, with a weighted mean of $1.18/W.[124]

5.5 Community benefits indicators (CBIs)

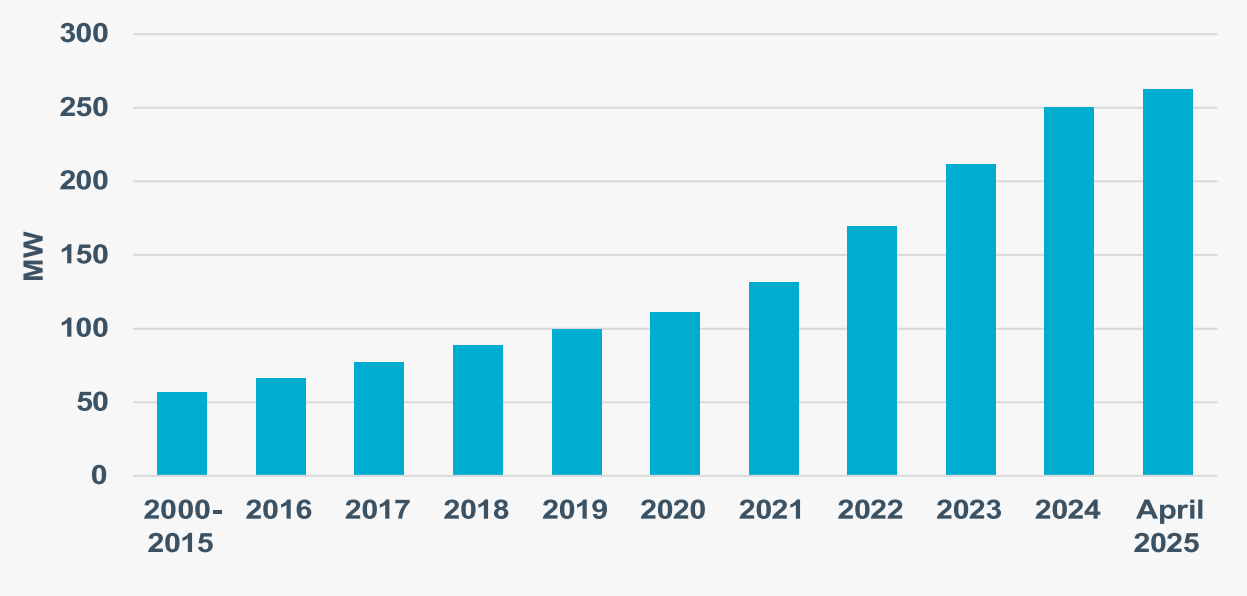
PGE has taken steps to advance the integration of community benefits indicators (CBIs) into resource planning processes, consistent with regulatory directives and community stakeholder priorities. This chapter provides an update on the development, refinement, and application of CBIs since the 2023 CEP/IRP. As guided by OPUC Order 22-390 and stakeholder input,[125] PGE has expanded its CBI framework to encompass measurable and impactful metrics across resilience, health and community well-being, environmental impacts, energy equity, and economic impacts. This update aims to share key developments, preliminary findings, and the roadmap for future efforts.

For example, PGE has long supported customer-sited resources connecting to the power grid. **Figure 55** shows rooftop solar installations have grown roughly four-fold in the past decade.

[123] While SSR resources can be CBRE's, they are not required to provide the community benefits that distinguish CBRE's from other small-scale resources. The SSR proxy resource therefore does not include any assumption of provision of community benefits beyond what would be provided by larger utility-scale resources.
[124] Berkeley Lab's "2024 Utility-Scale Solar, 2024 Edition" report can be found at http://utilityscalesolar.lbl.gov.
[125] This order, along with valuable stakeholder input, has guided PGE's approach to Community benefits indicators Oregon Public Utility Commission. (2022). Order No. 22-390 in Docket No. LC 73. Retrieved from https://apps.puc.state.or.us/orders/2022ords/22-390.pdf.

Community-based renewable energy is just a part of what PGE will quantify and track toward CBIs.

Figure 55. Cumulative Installed Rooftop Solar PV Capacity (MW)



5.5.1 Background and regulatory framework

OPUC Order 22-390 provided guidance on CBIs and their application to CEP/IRP analysis and established five CBI topic areas that must be included: health and community well-being; resilience; environmental impacts; energy equity; and economic impacts.[126] The Order also required that these topics should include at least one metric of each of three CBI categories. In 2023, PGE filed its first CEP as part of the IRP, including a set of CBIs responsive to these three CBI categories:

1. **Portfolio CBIs (pCBI)**: the CEP included a proxy value for all CBRE, set at 1 MW of CBRE equal to 1 unit of community benefit, reflecting an unspecified set of benefits associated with a hypothetical CBRE
2. **Resource CBIs (rCBI)**: PGE utilized a ten percent adder to reduce the levelized cost of CBRE projects, reflecting an approximation of the associated community benefit value of CBREs within the resource portfolio comparison process
3. **Informational CBIs (iCBI):** PGE identified a set of six iCBI and associated metrics, based on community engagement efforts and stakeholder feedback

In April 2024, OPUC issued Order 24-096, which identified the following required actions:

[126] Oregon Public Utility Commission. (2022). In the Matter of PORTLAND GENERAL ELECTRIC COMPANY, 2019 Integrated Resource Plan (Order No. 22-390). Retrieved from https://apps.puc.state.or.us/orders/2022ords/22-390.pdf

"PGE must demonstrate development of CBIs to assist in our understanding tradeoffs between cost, risk, and community benefit, and when evaluating procurement decisions.

"PGE must develop a set of informational-only metrics by its next CEP/IRP or provide a detailed explanation of barriers, constraints, and a proposal for resolution." [127]

5.5.2 Advancing CBI methodologies and integrating to the IRP

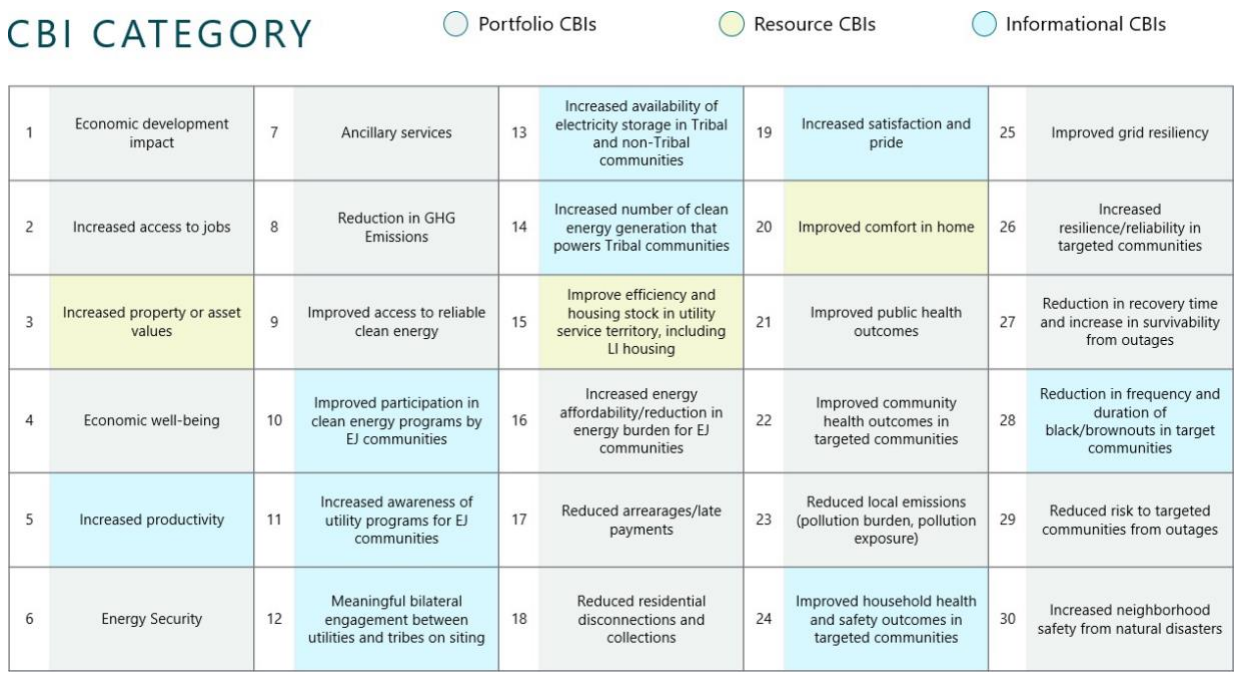
5.5.2.1 Updated CBI approach

In 2024, PGE engaged Cadeo (now Resource Innovations) to conduct research into CBIs. Based on this research and stakeholder feedback, PGE refined its approach to CBI as follows:

1. Expanded CBI List: PGE incorporated a list of 30 CBIs that was developed by Cadeo, characterized by their applicability to specific resources, monetizable value, and alignment with OPUC categories (see **Figure 56**). For more detail on how Cadeo developed this list, please see **Appendix G**.
2. Valuation Methods: Cadeo's research into monetizable CBIs has developed a method to include five pCBI categories to align and comply with OPUC requirements. For rCBIs, Cadeo reviewed several studies which they then used to quantify percentage adjustments which would reduce the levelized cost of capacity for several specific resource bundles.
3. Stakeholder Collaboration: PGE Engagement with the IRP Roundtable, OPUC Staff, and the Community Benefits and Impacts Advisory Group (CBIAG) has informed revisions to CBI metrics and methodologies. The CBIAG provided valuable feedback on the CBI framework, suggesting improvements and identifying areas for future exploration. Affordability emerged as a key concern, particularly regarding the impact of investment costs on customer rates, especially for those with higher energy burdens.
4. Integration Strategies: PGE research proposed four distinct approaches to incorporate CBIs into IRP modeling, ranging from proxy indicators to direct cost adjustments.

[127] Oregon Public Utility Commission. (2023). Docket No. LC 80, Order 240-096: PORTLAND GENERAL ELECTRIC COMPANY 2023 Integrated Resource Plan. Retrieved from https://apps.puc.state.or.us/edockets/DocketNoLayout.asp?DocketID=23636

Figure 56. List of CBIs by Category



1	Economic development impact	7	Ancillary services	13	Increased availability of electricity storage in Tribal and non-Tribal communities	19	Increased satisfaction and pride	25	Improved grid resiliency
2	Increased access to jobs	8	Reduction in GHG Emissions	14	Increased number of clean energy generation that powers Tribal communities	20	Improved comfort in home	26	Increased resilience/reliability in targeted communities
3	Increased property or asset values	9	Improved access to reliable clean energy	15	Improve efficiency and housing stock in utility service territory, including LI housing	21	Improved public health outcomes	27	Reduction in recovery time and increase in survivability from outages
4	Economic well-being	10	Improved participation in clean energy programs by EJ communities	16	Increased energy affordability/reduction in energy burden for EJ communities	22	Improved community health outcomes in targeted communities	28	Reduction in frequency and duration of black/brownouts in target communities
5	Increased productivity	11	Increased awareness of utility programs for EJ communities	17	Reduced arrearages/late payments	23	Reduced local emissions (pollution burden, pollution exposure)	29	Reduced risk to targeted communities from outages
6	Energy Security	12	Meaningful bilateral engagement between utilities and tribes on siting	18	Reduced residential disconnections and collections	24	Improved household health and safety outcomes in targeted communities	30	Increased neighborhood safety from natural disasters

5.5.2.2 Integrating CBIs into IRP modeling

Following CBI discussions and direction from UM 2225 and LC 80, PGE has utilized the same structured pathways to integrate CBIs into IRP processes:

Resource CBIs highlight the localized benefits of individual projects:

- rCBIs can be used to adjust levelized costs of specific resources. For instance, the economic and health benefits of solar panels and energy efficiency measures are quantified and incorporated into resource cost comparisons.
- These adjustments could be used to influence the cost-minimization portfolio analysis towards the selection of resources that maximize community benefits.

Portfolio CBIs reflect the cumulative benefits of resource portfolios, with emphasis on economic, environmental, and equity impacts.

- pCBIs are determined by the quantities of resources selected in portfolio analysis.
- Portfolios with higher pCBI values could be identified as higher performing in portfolio analysis (based on their broader community benefits).

Informational CBIs

- iCBIs may be used as tracking tools to monitor long-term impacts, such as the percentage of low-income households benefiting from clean energy programs, quality job creation, and increased resiliency within Tribal and energy-burdened communities.

In the initial use of Resource CBIs, a direct adjustment was applied to the levelized cost of specific energy resources to account for measurable participant benefits. While research identified a set of eight core benefit categories with the potential for monetization, only those substantiated by secondary data sources were included: property value increases and comfort improvements. Due to limited primary research on benefit valuation for specific resource types within PGE jurisdiction, this analysis relied on secondary sources and adapted benefit metrics for IRP application. PGE caveats that these benefits accrue to the participant not directly to the community (and therefore supports further refinement of this framework through planning and acquisition efforts). The assumption underlying the application of these benefits is that these participant benefits, when aggregated in a local setting, result in a community benefit. This initial assessment and application of these first rCBIs were integrated into IRP evaluations as percentage reductions to resource costs.

Examples of **rCBI Application** include the reduction of resources costs to account for:

- **Community-based renewable energy** (**CBRE) Solar** if qualified by providing tangible and resilience benefits to community is based on a 6.8 percent increase in property values, reflecting benefits tied to behind-the-meter installations for residential customers.
- **Energy efficiency (EE)**, to reflect monetization of comfort benefits at $62 per project annually for low-income households and $42 for non-low-income households.
- **Curtailment programs (Battery Storage)** based on a 2.3 percent increase in property values for residential batteries enrolled in curtailable Summer/Winter programs.

Table 25 summarizes selected rCBI applications.

Table 25. Assumed rCBI Applications

CBI	Resource Category	% Reduction to Levelized Cost	CBI Benefit Metric	Source	IRP Application Assumptions
Property Value	CBRE Solar	**269%**	6.8% increase in property value	Zillow 2024	Assumes 5 kW residential solar install; applicable to behind the meter projects; dependent on ownership structure (i.e., assumes value occurring at time of sale for home/property owner)
Property Value	Demand Response	**64%**	2.3% increase in property value	Zillow 2024	Assumes applicability for 5kW residential battery, assumes behind the meter installation
Property Value	EE	**45%**	0.5% increase in property	LBNL 2022	Applicable for home performance projects (e.g., HPwES, whole-house weatherization); reflecting Residential study.
Comfort (Shell)	EE	**10.6% LI; 7.2% non-LI**	$62/project (LI); $42/project (non-LI)	EmPOWER Maryland (2023)	Applicable for projects with shell measures (insulation, air sealing); benefit accrue annually over measure lifetime

CBI	Resource Category	% Reduction to Levelized Cost	CBI Benefit Metric	Source	IRP Application Assumptions
Comfort (HVAC)	EE	**5%**	Average of $30/project (3%) and $100/project (7%)	MA Residential NEI Study (2023); EmPOWER Maryland (2023)	Applicable for HVAC replacements using heat pumps; benefits accrue annually over measure lifetime; assuming 2000 kWh annually, 18-year EUL, and project cost of $15,000.

The rCBI benefits PGE was able to identify and quantify required two key conditions: (1) access to existing research with adaptable, quantified benefits; and (2) available data across all applicable resources for a given benefit. This consistency requirement is key for maintaining balanced resource comparisons, as including monetized benefits with the levelized costs for only some eligible resources would create an uneven evaluation framework. The approach prioritized consistency, meaning CBIs through the rCBI pathway were only applied when complete data existed across all applicable resources. Otherwise, associated benefits are considered within the pCBI approach.

Portfolio CBIs: Proxy-based Benefits

Portfolio CBIs represent those benefits which are more challenging to quantify or monetize, or that may have insufficient available data for all eligible resources (and thus present an imbalance if included for some but not all resources). For this update PGE attempted to assign these benefits to resource bundles in line with the economic, equity, health, resilience, and environmental categories laid out in OPUC guidance. PGE applied pCBIs as proxy values at the backend of the IRP modeling sequence after resource bundles were established, to characterize and identify bundles that likely accrue specific CBI benefits. PGE then considers these CBIs as part of the scorecard approach for portfolio selection.

Examples of **pCBI Application**:

- **Economic Impacts**: Included economic development, increased access to jobs, economic well-being, increased property value, and increased productivity. Economic impact benefits are identified for a wider range of resources, not limited to demand response and CBREs. This includes supply-side resources as potential economic development and job creation opportunities exist across various resource categories.
- **Energy Equity**: Benefits such as improved affordability and reduced arrearages were assigned to CBRE, energy efficiency (EE), and demand response (DR) (specifically time-of-use rates), applicable to resources targeting disadvantaged communities and those with highest likelihood of yielding bill impacts.
- **Health and Well-being**: Proxy values for improved indoor air quality and household safety were applied to weatherization and HVAC measures.
- **Environmental Impacts**: Emissions reductions were reflected across CBRE and demand-side

resources to account for their role in mitigating climate change. In the development of the IRP, the availability of pCBIs remains limited for many resource options under consideration. While pCBIs have been identified for certain distributed energy resources, such as community-based renewables and energy efficiency programs—where benefits like energy equity, local economic development, and resilience can be reasonably quantified—many supply-side resources lack studies or assessments that would inform the application of pCBI benefit.

This is primarily due to the complexity of attributing broad community benefits to large-scale generation and transmission assets, as well as the absence of standardized methodologies for quantifying their indirect social and environmental impacts.[128] **Table 26** highlights how the five topic areas for pCBIs were mapped to resource bundles, this table excludes resources such as out-of-state wind and others that do not have associated pCBIs.

Table 26. pCBI Mapping

Resource Bundle	Economic Impacts	Energy Equity	Health/ Well-being	Resilience	Environmental Impacts
CBRE Solar	✓	✓		✓	✓
Energy Efficiency	✓	✓	✓	✓	✓
Demand Response	✓	✓		✓	✓
CBRE Microgrids	✓	✓	✓	✓	✓
Battery	✓	✓			
CBRE Hydro	✓	✓		✓	✓
Gas Turbine	✓				
CV Hybrid	✓				
Wind - PGE territory	✓				
Solar - PGE territory	✓				

There are detailed applicability requirements for all CBIs, therefore resource-specific applicability must be carefully considered. These requirements relate to factors including measure characteristics, program design, geographic targeting, and baseline conditions. For

[128] These results are consistent with PGE's statements in UM 2225 about the inability to create useful and rigorous estimates of community benefits indicators to be applied in IRP analysis.

example, CBIs unlocked through energy efficiency often relate to specific measures, such as weatherization or HVAC improvements. When IRP resource bundles include various end-uses and technologies, these CBIs may only apply to a subset of the energy savings. Additionally, some CBIs focused on equity outcomes require geographic considerations, such as savings occurring within locations designated as environmental justice or tribal communities. Other CBIs aimed at achieving customer-level economic impacts related to energy affordability will be contingent upon resources that can achieve higher levels of bill savings.

5.5.3 Challenges and next steps

PGE faces several challenges integrating CBIs into its IRP process. One significant issue is the limited availability of jurisdiction-specific studies to substantiate the valuation for certain CBIs. Local conditions such as weather, the characteristics of the residence, customer awareness, power generation mix and location, distribution grid infrastructure status, and more can influence the valuation of different types of benefits. PGE has identified a need for further primary research to reflect these local conditions and policy goals and looks forward to engaging with stakeholders on the method, scope, and objectives of this research. The company is conducting a CBRE Request for Offer (RFO) through November 2025, which serves as a valuable tool for market research on project costs and CBIs. The insights gained from this process, including evaluations by CBIAG and engagement with OPUC Staff, should be incorporated into future resource planning updates to demonstrate PGE's commitment to understanding and valuing community benefits.

Another challenge lies in the limitations of proxy metrics, which require a balance between precision and usability. These metrics must be refined to ensure they provide meaningful insights while remaining practical for use in resource planning.

PGE has identified the need for further research to fully capture the benefits of Distributed Energy Resources (DERs), particularly for those DR resources not associated with EE. This may include considering the development of a cost-test model that could potentially incorporate identified community benefits. The process may involve examining recent research methodologies for quantifying benefits. New York State Energy Research and Development Authority's (NYSERDA) Community Adder program was reviewed for concept insights, finding additional incentives for community solar projects benefiting disadvantaged communities.[129] In consideration of the principles outlined in HB 2021, PGE aims to evaluate potential strategies for improving clean energy accessibility, assess projects that may provide benefits to disadvantaged communities, and pursue clean energy and equity objectives, while maintaining a focus on meeting load requirements and striving for cost-effective solutions for customers.[130]

[129] NYSERDA. *Community Adder* webpage. Retrieved from https://www.nyserda.ny.gov/All-Programs/NY-Sun/Contractors/Dashboards-and-incentives/Community-Adder.
[130] Oregon House Bill 2021, Section 1(3)(a), 2021 Regular Session. https://olis.oregonlegislature.gov/liz/2021R1/Downloads/MeasureDocument/HB2021/Enrolled.

5.5.4 Conclusion

Integration of CBIs provides an opportunity for PGE to extend resource planning to include the values and priorities of the communities PGE serves. CBIs offer a means by which to quantify benefits such as resilience, equity, environmental impact, public health, and economic development.

The challenges identified—including data gaps, proxy metric limitations, and diverse stakeholder priorities—highlight the need for continued research, collaboration, and refinement. As detailed earlier in the section, PGE believes continued stakeholder engagement, localized data development, and the adoption of advanced methodologies are necessary to overcome these challenges and enhance the impact of CBIs.

5.6 Long lead-time resources

This section provides an updated summary of Chapter 8.5 of the 2023 CEP/IRP regarding potential future resource options that PGE considered, including new generation and transmission expansion to other regions.

5.6.1 Post-2030 resource options

In 2024, in response to docket LC 80, PGE enacted a "Request for Information" (RFI), reaching out to WECC market participants to better understand post-2030 regional resource availability.[131] Using a comprehensive questionnaire distributed amongst a variety of developer communities and trade organizations, PGE gathered information on producers across key production regions in the WECC market and included a public/stakeholder workshop on these findings in late 2024.[132] That work has granted some insights that are relevant to post-2030 resourcing and is referenced in this section of the Update.

5.6.2 Hydrogen and ammonia

Included in the Inflation Reduction Act is a new 45V Clean Hydrogen Production Tax Credit (10-year duration). The tax credit provides up to $3.00/kg of hydrogen produced based on the emission intensity of the energy used to produce hydrogen. The law lays out a series of qualifying conditions in order to receive the credit, including a calculation of the lifecycle GHG emissions of the electricity, the age of the producing asset, and other considerations. Section 45V may yet serve as an additional incentive to the implementation of green hydrogen applications.

The federal government established a multi-billion-dollar grant for green hydrogen hub development nationally, with Oregon's Pacific Northwester Hydrogen Association receiving up

[131] Staff Report, recommendation #2, filed December 14, 2023, https://edocs.puc.state.or.us/efdocs/HAU/lc80hau325590032.pdf.
[132] PGE RFI Key Insights presentation, December 2024, https://assets.ctfassets.net/416ywc1laqmd/2GF5BwVt9cR1MXtEpn6fli/e719ec6879183abd984928db360fe410/RFI_slides_jdg_web_1197.pdf.

to $1 billion for four DOE-defined development phases spanning nine years. PGE has participated in this consortium to identify an opportunity to make this additional incentive available for customers, though there is currently some uncertainty of funding under the new Trump Administration.

5.6.3 Nuclear

In Oregon, Measure 7 prohibits the construction of a new nuclear power plant in the state without a federal long-term nuclear waste repository and a statewide popular vote. However, there is growing national interest in nuclear power as a non-emitting resource with active projects appearing in neighboring states.

In their 2021 IRP, PacifiCorp identified a sodium cooled fast reactor nuclear power plant with molten salt storage as a demonstration of the commercialization of this new, potentially safer, nuclear technology. Construction on the plant began in 2024, in conjunction with TerraPower, and incorporates a storage unit that will allow the production of 500 MW for short durations, with an anticipated online date in 2030. In PacifiCorp's 2023 CEP/IRP, the company announced two other nuclear power plants to be built in Utah, on the sites of soon-to-be-retired coal plants, both to be natrium plants producing 500 MW each. However, PacifiCorp communicated its intention to pull back on these two new plants in an IRP revision in mid-2024.

In Washington, small modular reactor (SMR) projects have also moved forward as Energy Northwest has partnered with X-energy to design a program of 12 small plants, each producing 80 MW. As of Q4 2024, Amazon Web Services agreed to partner on four advanced SMRs, generating 320 MW on the Columbia River, with the plants expected to enter service in the early 2030s. Once partnerships and funding are found for the other eight SMRs, 640 MW of nuclear power may come online in Washington.

It remains to be seen if next generation nuclear technology can lower the cost, safety, and political hurdles faced by traditional nuclear power.

5.6.4 Geothermal

PGE's 2024 RFI gained information on few geothermal projects developing inside Oregon. The projects utilize experimental technology and are expected to enter service in 2030-onward. The projects together will generate approximately 75 MW of continuous non-carbon-emitting power, a sizeable addition to Oregon's current geothermal operations, but a very small fraction of the total potential geothermal energy available in the State.

Future improvements in drilling technologies will result in reduced development time and costs. Developments in EGS stimulation technology and higher success rates will also reduce costs and development timelines.

5.6.5 Post-2030 wind/solar generation

PGE's 2024 RFI reflected a potential 6 GW of wind and solar projects at various stages of development, to come online between 2030-2034. Of these 6 GW, ~2,7 GW are being produced

in Oregon, primarily in the form of wind projects with varying degrees of feasibility. With another 3.1 GW in neighboring states, also mostly in the form of wind projects (although some 300 MW of Nevada stand-alone solar are also coming online).

5.6.6 Long-term hybrid resources

The 2024 PGE RFI produced information about future hybrid projects coming online in 2030 and after. According to the RFI, some 4 GW of hybrid projects are to come online between 2032-2034: 2.5 GW in Oregon, incorporating both wind and solar resources; and the other 1.5 GW in neighboring markets. In particular, 1 GW of solar + storage units coming online in Nevada, access to which could be improved through transmission expansions options discussed in **Chapter 4**.

5.6.7 Long-duration storage

Long Duration Energy Storage (LDES) is defined as any electricity storage with greater than six hours of duration. In early 2025, the U.S. Department of Energy's (DOE) Office of Electricity announced a Notice of Funding Opportunity for up to $8 million seeking to accelerate energy storage manufacturing through pre-production design innovations to ultimately scale this technology faster to meet the nation's growing energy storage needs.

Currently lithium-ion batteries are the most common storage options on the market, but other chemical storage options include flow batteries. Longer duration batteries may soon be more widely available.

Another potential technology for longer-duration storage relies on pumped air/iron-air storage, wherein energy expended in oxidation and de-oxidation constitutes a storage technology. Organized in large battery packs, this technology permits 100+ hours of storage in testing environments and is demonstrably cost-effective when compared to lithium-ion battery storage technology. Form Energy, a company founded in 2017, is pioneering this technology across the United States.[133] For example, Great River Energy, a Minnesota Utility, is working to develop a multiday iron air battery.

As more variable energy resources are expected to arrive on both the PGE system and the greater Western Interconnection, there may be increased opportunities to use storage to shift energy from oversupply hours to hours of greater need and value.

[133] https://formenergy.com/form-energy-secures-405m-in-series-f-financing-to-expand-iron-air-battery-business-and-operations/.

Chapter 6. Resource plan

This report updates PGE's comprehensive and robust 2023 CEP/IRP portfolio analysis. The analysis presented in this chapter incorporates updates to key inputs and advancements to PGE's modeling capabilities. The portfolio analysis in the 2023 CEP/IRP identified a Preferred Portfolio based on the insights gained from the evaluation of transmission need, GHG glidepaths, the role for additional EE and DERs, CBRE's, emerging technologies, and optimization assumptions. Portfolio analysis in this Update carries forward those insights where applicable, while updating key inputs and incorporating modeling advancements to determine a new Preferred Portfolio.

This portfolio analysis incorporates PGE's most recently available forecasts of energy and capacity needs and updated resource cost information. This analysis incorporates updated characterization of the state of the existing transmission system and a comprehensive set of options to increase transmission access through upgrades or expansion. PGE also incorporated modeling advancements to GHG emissions accounting, granularity of energy accounting, and CBI reporting.

The updated modeling inputs and methods were used to inform the creation of a new Preferred Portfolio, which is described in detail in **Section 6.2 Preferred Portfolio**. The Preferred Portfolio is analyzed from multiple angles to consider annual cost impacts, resource adequacy, hourly emissions reporting, and SSR compliance. Multiple sensitivities are conducted on the Preferred Portfolio, exploring key topics of interest regarding large industrial customer growth, resource adequacy planning assumptions, the availability of federal tax credits, and the availability of non-emitting market purchases for hourly emission accounting.

Key Highlights

- The updated Preferred Portfolio demonstrates a least-cost, least-risk approach to meeting resource adequacy needs while decarbonizing in accordance with HB 2021, including 1362 MW of wind, 1089 MW of solar, 1750 MW of storage, 83 MW of NCE EE and DERs, and 155 MW of community-based renewable energy (CBRE) resources by 2030.
- Hourly emissions analysis confirms the Preferred Portfolio can comply with HB 2021 emissions limits in 2030, with thermal generation concentrated in winter months when non-emitting energy is scarce.
- Resource adequacy testing reveals winter adequacy challenges requiring substantial storage resources, suggesting the need to identify different capacity resources better suited to meet ongoing winter capacity needs.

Developments Since 2023 IRP

The 2023 IRP Update incorporates significant methodology improvements including: monthly energy accounting (versus annual in 2023 IRP), updated resource cost information, comprehensive transmission upgrade options, enhanced GHG emissions

accounting, and greater CBI reporting granularity. An expansive set of portfolio sensitivities were developed to explore key planning questions that have increased in prominence since the filing of the 2023 CEP/IRP.

Strategic Implications

The analysis reveals the critical importance of transmission options for meeting system needs, with all seven transmission options being added between 2032-2038, unlocking 6927 MW of off-system renewables. Winter adequacy challenges are more precisely identified, showing short-duration storage has limited effectiveness in winter capacity needs (seven percent ELCC) compared to summer (53 percent ELCC), highlighting the need for alternative capacity resources with greater energy storage capability or on-demand production.

Staff Recommendations Incorporated

The Update directly addresses Order 24-096 directives through updates to portfolio analysis. PGE addresses Staff Recommendation #3 by conducting hourly production cost simulation of the Preferred Portfolio to separately track hourly purchases and sales. Resulting GHG emissions impacts better demonstrates HB 2021 compliance and reveals key planning insights while allowing PGE to revise GHG emissions forecasts accordingly and provide narrative explanations of key planning insights from this exercise. Additionally, Staff Recommendation #5 is addressed through the inclusion of an SSR compliance analysis, in which PGE's compliance position is identified and potential cost impacts of compliance are considered using a SSR proxy resource in portfolio analysis.

6.1 Portfolio analysis design and scoring

PGE evaluated portfolios using the capacity expansion model, ROSE-E, over a 20-year time horizon from 2025 through 2044. Portfolios must satisfy all the constraints described in the sections that follow throughout the analysis timeline using the addition of available resources at the minimum possible cost. Portfolios are analyzed across 351 future scenarios representing combinations of conditions for need, price, and technology costs.[134] Where not otherwise stated, inputs, assumptions and methods are consistent with those described in the 2023 CEP/IRP.[135]

6.1.1 GHG emissions

PGE enforces compliance with HB 2021 GHG emissions targets in ROSE-E for the Preferred Portfolio and all scenarios except the 'Reliability Needs Only' analysis. Emissions decline according to the linear GHG glidepath described in **Section 3.5.1 HB 2021**.

[134] [39 Price] x [3 Need] x [3 Technology Cost] = 351 Future Scenarios
[135] See Chapter 11 Portfolio Analysis of the 2023 CEP/IRP, available here: https://edocs.puc.state.or.us/efdocs/HTB/lc80htb8430.pdf

6.1.2 Energy need

In the 2023 CEP/IRP, PGE required portfolios to meet energy needs on an annual basis, ensuring portfolios had sufficient energy on average throughout each year. For the first time in this Update, portfolio analysis uses a more-detailed monthly energy accounting to establish energy need, ensuring that portfolio add sufficient resources to meet projected energy needs in every month of the planning horizon. PGE's annual and monthly energy-load resource balances are presented in **Section 3.3 Energy need**.

Monthly energy accounting allows the interactions between seasonal variation in PGE's load and existing portfolio, and the generation profiles of proxy resources to be accounted for in resource selection. These seasonal dynamics can influence the optimal quantity and mix of resources in the portfolio. By increasing the granularity of accounting of energy-load resource balance from annual to monthly, ROSE-E is able to make more-optimal resource selections.

To incorporate monthly variation in energy from dispatchable sources, the monthly allocation of GHG-emitting energy is determined within ROSE-E by co-optimizing it with the selection of new resource additions. ROSE-E receives the maximum annual generation by each emitting source as an input from PGE's Intermediary GHG model (IGHG) and allocates that energy across the months of each year in a manner that minimizes the costs of new resource additions.

6.1.3 Capacity need

PGE updated forecasted summer and winter capacity needs for this analysis and they are described in **Section 3.4 Capacity need**. Portfolios are constrained to meet PGE's resource adequacy requirements in summer and winter every year. Capacity needs must be met through the addition of new proxy resources, as determined by their estimated ELCC. Proxy resource ELCCs are described in **Section 5.1.6 Resource capacity contribution**.[136] As a backstop source of capacity when the capacity from available resources is not sufficient to meet need, the model has access to a perfect capacity-fill resource (100 percent ELCC in summer and winter) to meet needs on a year-to-year basis.

6.1.4 Resource availability

ROSE-E has access to a variety of resource types to meet energy and capacity needs. These resources include renewables, storage, CBREs, distributed energy resources (DERs), and energy efficiency (EE). The variety of proxy resource types available for selection in portfolio analysis are described in **Chapter 5 Resource options**. To account for the time required for procurement through a request for proposals (RFP) process, the earliest that traditional supply-side resources can be added to the portfolio is 2029. The timing and available quantity of off-system resources is also a function of transmission availability, as described in **Section 6.1.5.1 Transmission constraints**. There is also a 500 MW annual limit on the addition of batteries to smooth the

[136] The State RA Requirements scenario relies on different capacity needs and proxy resource capacity contributions.

cadence of resource additions and prevent the model from relying on very large additions of storage in certain years.

CBREs and non-cost-effective (NCE) DERs and EE are available for selection beginning in 2026. Quantities available for selection of NCE demand response and energy efficiency have been updated for the Update and are described in **Section 5.2.3 Non-cost-effective demand response** and **Section 5.3.2 Non-cost-effective energy efficiency**. The quantity of CBRE's available for selection is unchanged from the 2023 CEP/IRP.[137] Prior to 2029, energy and capacity-fill resources are also available on an annual basis to allow the model to meet PGE's energy and capacity needs until sufficient quantities of supply-side resources become available for addition to the portfolio.

6.1.5 Transmission constraints and options

Assumptions about transmission represent one of the most impactful determinants of resource availability in portfolio analysis. These elements were incorporated into PGE's portfolio analysis for the first time in the 2023 CEP/IRP. This Update includes updated assumptions regarding constraints on the existing transmission system and the options to increase transmission capacity through upgrades and expansion. Off-system renewable resources must have associated transmission to be added to PGE's portfolio in ROSE-E. Transmission capacity can come from either estimated available regional transmission capacity (described in **Section 6.1.5.1 Transmission constraints**), or investment in additional transmission options (described in **Section 6.1.5.2 Transmission options**).

6.1.5.1 Transmission constraints

PGE's estimates of existing regional transmission availability are described in **Section 4.4 Assessment of available BPA point-to-point transmission**. Prior to 2032, when the first transmission option becomes available, the total quantity of off-system renewables available to be added to PGE's portfolio is limited to 2451 MW based on the quantity of available regional transmission capacity.

6.1.5.2 Transmission options

As part of a holistic transmission study for the Update, PGE has developed an updated set of options for transmission upgrades and expansion. The updated and expanded set of options includes three transmission upgrade options and four transmission expansion options. The quantity, timing, cost, and type of resource accessed are described in detail in **Section 4.6 Transmission options for portfolio analysis**. Both transmission upgrades and expansion increase the quantity of resources available for selection in ROSE-E. In portfolio analysis the two types of transmission actions allow access to additional resources in different ways. Transmission upgrades increase the capacity of PNW renewable resources that PGE can access across the

[137] See Chapter 7 of the 2023 CEP/IRP. Available here: https://edocs.puc.state.or.us/efdocs/HTB/lc80htb8430.pdf. PGE plans to update information about the cost and availability of CBRE resources for the 2026 CEP/IRP, leveraging information gained through the CBRE RFO described in **Section 7.1.2 CBRE action**.

regional transmission system. Transmission expansion options allow access to renewable resources and capacity markets outside of the PNW. Resources accessed through either transmission upgrades or expansion incur the cost of both the resource itself and the transmission required to deliver the energy to PGE's system.

6.1.6 Portfolio scoring

Portfolios are evaluated based on the traditional scoring metrics described in **Table 27** and the portfolio community benefits indicator (pCBI) metrics described in **Table 28**. The traditional scoring metrics for cost, variability and severity are the same that were used in the 2023 CEP/IRP and continue to provide valuable insights that ensure the Preferred Portfolio and Action Plan represent the best combination of cost and risks.

Table 27. Traditional portfolio scoring metrics

Metric	Description	Units
Cost	Net present value of revenue requirement (NPVRR), calculated for each of the 351 future scenarios for the analysis timeline (2025-2044). IRP costs consist of only those associated with existing and incremental generating resources (including associated transmission costs) and do not include other PGE costs (e.g. administrative costs, wildfire costs, etc.).	Million 2025$
Variability	Semi-deviation of NPVRR across all futures, relative to the Reference Case. This metric captures the potential variation in cost outcomes across futures, considering only futures in which NPVRR exceeds the Reference Case. Portfolios with low variability scores tend to provide more cost certainty and lessen the customer's impacts of higher-than-expected cost conditions.	Million 2025$
Severity	The tail value at risk (TailVAR) at the 90th percentile of the NPVRR across futures. This metric measures the potential magnitude of very high-cost outcomes across all futures. Portfolios with low severity scores tend to have less costly worst-case scenarios for customer cost impacts.	Million 2025$

The pCBI scoring metrics represent a substantially more thorough and detailed approach to measuring the level of community benefits provided by each portfolio than has been used in the past. pCBIs are unitless indicators that accrue for each MW of eligible resource that is added in a portfolio. A detailed description of the pCBI development, including a mapping of which proxy resources generate each of the pCBIs, is provided in **Section 5.5 Community benefits indicators (CBIs)**. Scoring outcomes for pCBIs of each portfolio analyzed are described in **Section 6.5 Portfolio CBIs.**

Table 28. Portfolio Community benefits indicator (pCBI) metrics

Metric	Description
pCBI 1 **Economic Impacts**	Economic development, increased access to jobs, economic well-being, increased productivity
pCBI 2 **Energy Equity**	Improved awareness and access to clean energy programs by environmental justice and tribal communities; increased affordability; increased efficiency of housing stock; reduced arrearages and disconnections
pCBI 3 **Health and Community Wellbeing**	Increased comfort; improved public health outcomes, particularly for environmental justice communities; reduced local emissions; improved home health and safety (including indoor air quality)
pCBI 4 **Resilience / Reliability**	Improved grid resiliency; increased resilience/reliability in environmental justice communities, including reduced recovery time and frequency of outages
pCBI 5 **Environmental Impacts**	Reduced air emissions, including CO_2 and criteria pollutants

6.2 Preferred Portfolio

PGE's updated Preferred Portfolio demonstrates the least-cost, least-risk, set of resources needed to meet resource adequacy needs while decarbonizing in accordance with HB 2021 through the year 2044. **Table 29** shows the optimized resource additions made in ROSE-E as well as cost-effective quantities of EE and DERs and the 2023 RFP proxy, through the year 2030. The supply-side energy and capacity resources added in ROSE-E represent generalizations of resources that may become available for acquisition through an RFP process in which actual projects will be compared on the basis of project-specific costs and benefits. Near-term non-emitting and capacity contracts represent opportunities that PGE could pursue through bilateral contract negotiations.

Optimized resource additions through 2030 include 1362 MW of wind, 1089 MW of solar, 1750 MW of storage, 83 MW of NCE EE and DERs, and 155 MW of CBREs. The 2030 resource mix also includes 190 MW of non-emitting contracts. This 4629 MW of incremental resource additions made through 2030 represents a 16 percent increase compared to the 3984 MW of resource additions in the final 2023 IRP Preferred Portfolio.[138] The bulk of the increase in 2030 resource additions is comprised of storage, which has roughly doubled compared to the 869 MW (including hybrid storage) in the 2023 CEP/IRP final Preferred Portfolio. The increase in storage additions is largely driven by a decrease in PGE's calculated capacity contribution of those resources. As described in **Section 5.1.7 Comparison of resource capacity contribution to**

[138] The final Preferred Portfolio from the 2023 CEP/IRP was published in PGE's response to Staff Round 2 Comments. Updated resource need reporting conventions introduce some complexities when comparing current projections of resource need to past disclosures. The comparison made here uses the updated convention of identifying hybrid storage separately for the calculation of total resource need for both portfolios. PGE's response to Staff Round 2 Comments is available here: https://edocs.puc.state.or.us/efdocs/HAC/lc80hac154444.pdf

2023 CEP/IRP, the ELCC of the 4-hr battery proxy resource has decreased by 33 percent in summer and 50 percent in winter compared to the 2023 CEP/IRP.

The selection of 68 MWa of NCE EE in optimized portfolio construction highlights the potential for accelerated procurement of EE to lower portfolio costs in a transmission-constrained planning environment over the long-term. However, as discussed in Section 11.4 of the 2023 CEP/IRP, including additional quantities of EE in the portfolio has the potential to create near-term customer cost impacts because of unique policy factors associated with these resources. Unlike other assets, additional EE is not financed or securitized, which can increase near-term cost impacts relative to other resource options. As discussed in **Section 5.3.5 Energy efficiency program and policy**, PGE is committed to working with Energy Trust of Oregon on multiple potential avenues to address the cost and implementation challenges associated with accelerated procurement of EE.

Notably, this first year of transmission availability in 2032 is five years later than the 2027 date of first-available transmission option in the 2023 CEP/IRP. The reliance on some non-emitting contracts through 2031 highlights the impact of transmission constraints on off-system resource additions prior to the first opportunity for transmission upgrades in 2032.

Table 29. Cumulative resource buildout of the Preferred Portfolio 2026-2030 (MW)

Resource	2026	2027	2028	2029	2030
Wind	0	0	0	1362	1362
Solar (including hybrids)	0	0	0	1089	1089
Storage (including hybrids)	0	0	0	1250	1750
CBREs	66	85	110	133	155
NCE EE (MWa)	0	21	38	58	68
NCE DERs	3	8	12	13	15
Transmission	0	0	0	0	0
Non-Emitting Contracts*	16	422	120	33	190
Cost-effective EE (MWa)	104	138	173	208	245
Cost-effective DR	142	172	199	225	248
2023 RFP Proxy Solar (including hybrids)	0	0	375	375	375
2023 RFP Proxy Storage (including hybrids)	0	0	775	775	775

*** Values for contracts are annual, not cumulative.**

Post-2030 results show that all seven transmission options are added to the portfolio between 2032 and 2038, unlocking access to the energy and capacity of 6927 MW of off-system

renewables (**Table 30**).[139] The addition of all 6927 MW of transmission options illustrates the importance of evaluating and consider taking action on transmission opportunities, both through upgrades and partnering-on or investing-in proposed transmission expansion projects, in order to access off-system renewables and energy markets. This aspect of the Preferred Portfolio differs substantially from the content of the 2023 CEP/IRP Preferred Portfolio, which included only 1200 MW of available transmission options (all of which were added in the Preferred Portfolio) and instead relied heavily on generic capacity and renewable resources post-2030. The comprehensive and detailed list of most-appropriate transmission options potentially available to PGE, modeled in this Update provides a substantially more well-defined look at the mix of resources that may become available to meet energy and capacity needs in the 2030's and beyond. In contrast to the generic transmission options used in the 2023 CEP/IRP, the transmission options added to this Preferred Portfolio represent specific opportunities (modeled with somewhat generalized resource cost characteristics). The transmission options, identified with the help of consultant Energy Strategies, are described in detail in **Section 4.6 Transmission options for portfolio analysis**.

Table 30. Cumulative resource buildout of the Preferred Portfolio 2031-2038 (MW)

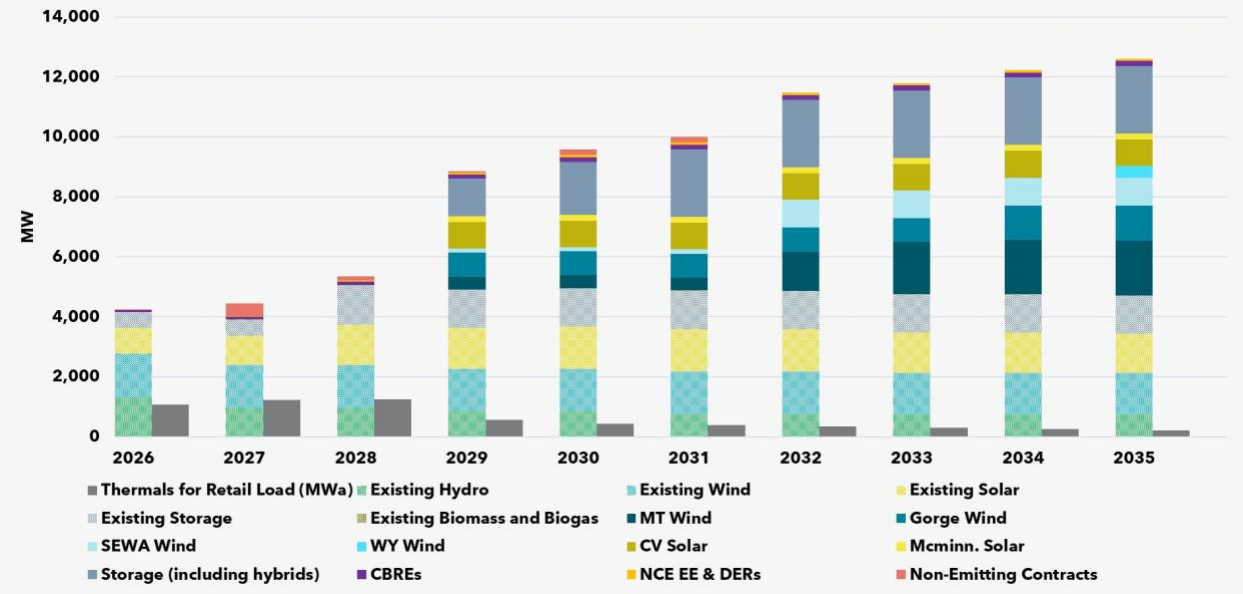
Resource	2031	2032	2033	2034	2035	2036	2037	2038
Wind	1362	2989	3420	3844	4274	4761	5352	5947
Solar (including hybrids)	1089	1089	1089	1089	1089	1089	1089	1089
Storage (including hybrids)	2250	2250	2250	2250	2732	3232	3732	4232
CBREs	155	155	155	155	155	155	155	155
NCE EE (MWa)	68	68	68	68	68	68	68	68
NCE DERs	16	16	16	16	16	16	16	16
Transmission	0	3000	3000	3000	5227	5227	5227	6927
Non-Emitting Contracts*	187	0	0	0	0	0	0	0
Cost-effective EE (MWa)	281	317	352	384	415	446	478	510
Cost-effective DR	266	284	299	312	325	336	348	356
2023 RFP Proxy Solar (including hybrids)	375	375	375	375	375	375	375	375
2023 RFP Proxy Storage (including hybrids)	775	775	775	775	775	775	775	775

*** Values for contracts are annual, not cumulative.**

[139] Some of the transmission options also provide additional capacity through access to diverse energy markets. In the 2023 CEP/IRP final Preferred Portfolio, transmission options did not provide additional capacity associated with diverse market access.

The cumulative addition of the Preferred Portfolio's incremental resources to PGE's existing resource portfolio are shown in **Figure 57**. The quantity of energy retained from existing emitting sources, in average Megawatts (MWa), can be seen to decline through time in accordance with the GHG glidepath that leads to compliance with HB 2021 emissions targets in 2030 and beyond. Incremental resource additions experience a large jump in 2029 when the first supply-side resources become available and another smaller jump in 2032, when the Bethel-Round Butte transmission upgrade unlocks access to 3000 MW of additional off-system renewable resources. The quantity of resources in PGE's existing portfolio varies through time, increasing in 2028 with the addition of 2023 RFP Proxy resources, and declining at various points in time as certain contracts expire. By 2030, the 4629 MW of incremental resource additions in the Preferred Portfolio are nearly equal to the nearly 5 GW of non-emitting resources already expected in PGE's existing portfolio at that time.

Figure 57. Preferred Portfolio Resource Additions (MW)[140]

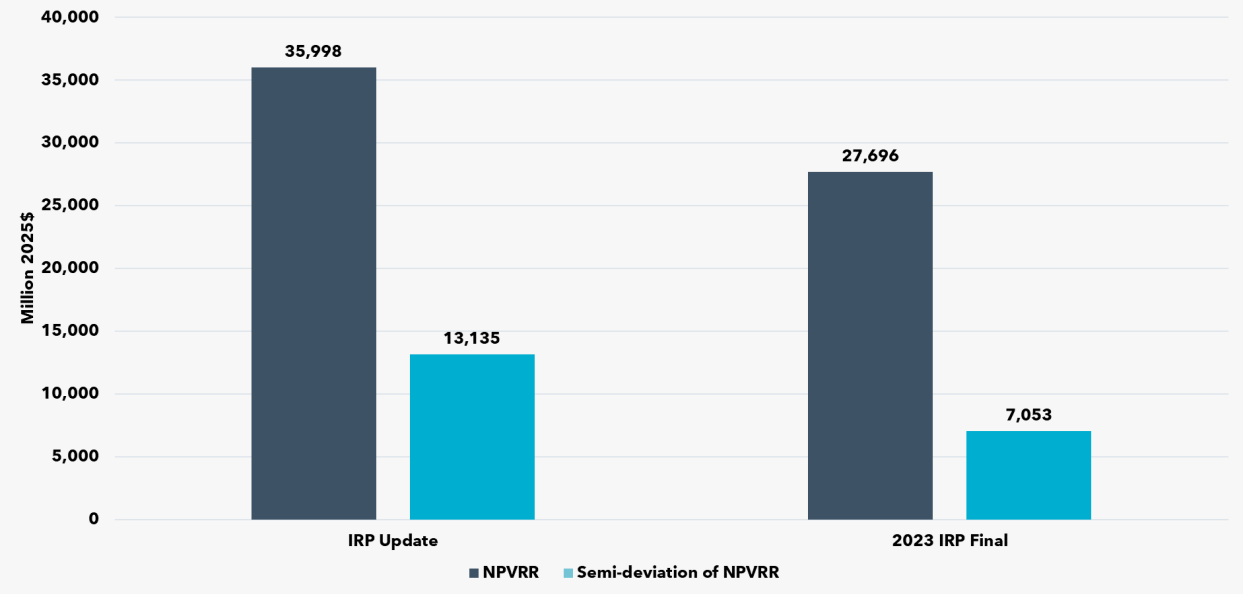


Costs of the updated Preferred Portfolio are larger than those of the final Preferred Portfolio from the 2023 CEP/IRP.[141] Across the full 20-year planning horizon the updated Preferred Portfolio has an NPVRR of $35,998 million, which is a $8,302 million increase from the $27,696 million NPVRR of the final 2023 CEP/IRP Preferred Portfolio (**Figure 58**).[142] The increase in portfolio cost is driven by a combination of increased quantity of resource additions and increased $/kW-yr resource costs projections for some types of supply-side resources, as described in **Section 5.1.2 Supply-side resource costs**. These drivers of increased cost outweigh the cost-reducing impacts of having a more well-defined set of transmission options that have reduced reliance on the expensive generic capacity and VER resources that were relied on heavily in the post-2030

[140] Existing resource quantities include 2023 RFP Proxy.
[141] The final Preferred Portfolio from the 2023 CEP/IRP was published in PGE's response to Staff Round 2 Comments. Available here: https://edocs.puc.state.or.us/efdocs/HAC/lc80hac154444.pdf
[142] Portfolio costs in the 2023 CEP/IRP were reported in 2023 $'s and have been adjusted to 2025 $'s for this comparison.

resource buildout of the 2023 CEP/IRP Preferred Portfolio. Additional detail on the annual costs of the Preferred Portfolio is provided in **Section 6.2.1 Yearly cost estimates**.

Figure 58. Cost and Risk Metrics of the Preferred Portfolio (MW)



6.2.1 Yearly cost estimates

The purpose of this section is to show yearly cost estimates of proxy new resource additions in the Preferred Portfolio under a set of utility ownership and tax credit assumptions. This section provides updated results compared to those presented in Section 11.3 of the 2023 CEP/IRP. The Preferred Portfolio was run through a version of the Annual Revenue-requirement Tool (ART) that contains updated input data. The ART uses reference load presented in **Chapter 3 System needs** and existing and incremental proxy resource costs described in **Chapter 5 Resource options**.

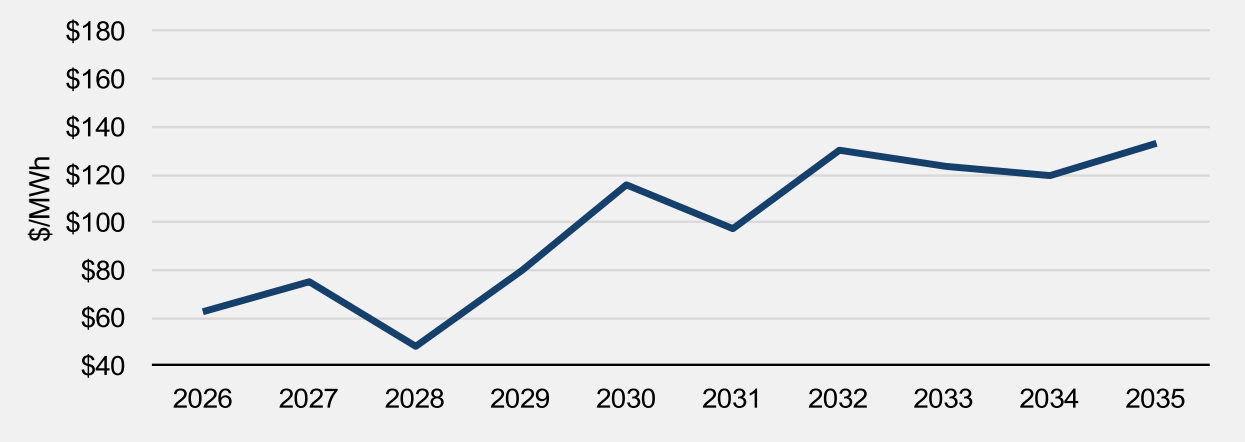
The model incorporates the impact of market sales on an annual basis and can evaluate different combinations of ownership structures and tax incentives for each portfolio.[143] Market purchases and thermal sales are calculated on an annual basis within the Intermediary GHG (IGHG) model and imported to ART. Further, ART only focuses on existing and new generating resources, including associated estimated transmission expansion costs. Estimates do not include costs from the rest of PGE, such as those associated with administrative costs, grid modernization, other transmission and distribution maintenance and upgrades, wildfire mitigation or actual generation costs. Caution is warranted in interpreting these estimates, as these values reflect a change in forecasted annual costs of real and proxy generating assets that only represent a subset of PGE's total annual cost. Accordingly, these yearly price impacts do not represent actual customer price impacts (expressed either as total or a percent) as they only focus on planned generation and transmission expansion cost changes and do not incorporate any other cost

[143] Modeling assumption of the ownership structures do not impact or reflect future procurement approaches nor prejudge outcomes of future procurement processes.

changes across PGE. Additionally, the cost impact uncertainty due to ongoing policy discussions regarding cost allocation to large industrial customers and the resulting unequal and evolving distribution of costs between customers classes is another factor making the results presented here not reflective of actual customer rate impacts. This topic is explored in more detail in through the sensitivity analysis presented in **Section 6.3.3 Large industrial customer growth**.

The price impacts can still be indicative for evaluating options to decarbonize reliably. Through an extensive analysis of resource additions amongst a variety of portfolios, PGE finds that while the incremental resource additions included in these estimates represent the least cost and risk manner to meet the emissions targets established in HB 2021, they are anticipated to raise the costs associated with generation resources relative to today. These Reference Case price changes are shown in **Figure 59** and include a 50 percent ownership assumption and full ITC/PTC tax credits available for relevant resources. This $/MWh annual price represents the modeled cost estimates divided by total PGE load described in **Section 3.1.1 Energy forecast**. Incremental resource additions, including the expansion of the existing transmission system, continue to increase the costs of generation resources through 2035 and beyond. While this analysis does not represent actual changes to customer prices, it is suggestive that, on a planning basis, system costs are likely to increase to comply with HB 2021.

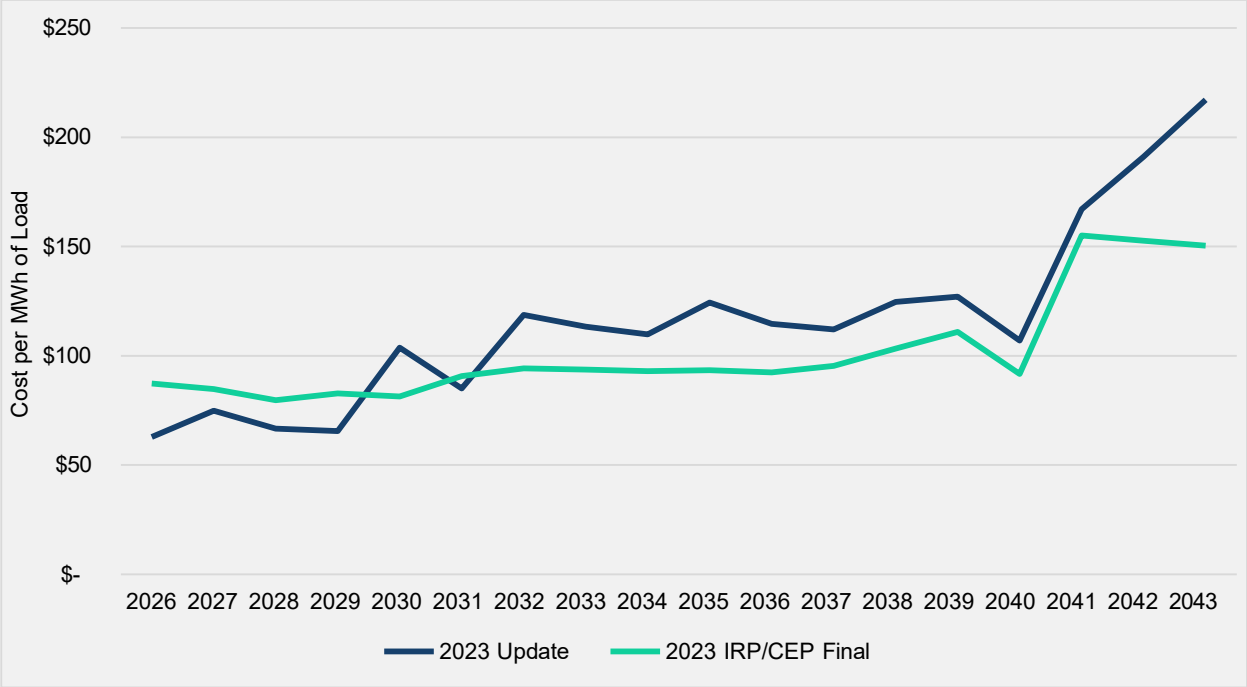
Figure 59. Reference Yearly Price Impacts ($/MWh) of the Preferred Portfolio



As discussed in previous chapters, the 2023 RFP procurement results are not yet final, but based on ongoing negotiations, no new non-emitting resources identified through this RFP can be contracted prior to a January 1, 2028 COD. Incremental resource additions (and associated costs) prior to 2029 are for CBREs and DERs. After this time, the models add much more non-emitting resources to reduce thermal generation serving retail load in order to meet HB 2021 compliance as well as maintain resource adequacy. The yearly cost forecast supports the finding described above and previously in the 2023 CEP/IRP that GHG emission reductions lead to cost increases. **Figure 60** compares the updated yearly price estimates to those presented for the Preferred Portfolio in the 2023 CEP/IRP updated for the final Preferred Portfolio. Total costs are a bit higher in the Update after 2035 and the updated retail load forecast is higher, allowing costs to be spread across more MWhs. In the updated analysis, PGE has replaced generic capacity and energy resources with actual modeled resources which are more cost effective than the generic

capacity and energy resources. These were unavailable in the 2023 IRP due to transmission limitations. While these transmission expansion options have costs associated with them, they are significantly cheaper than the generic capacity and energy resources. The overall increase in costs is due to increased resource additions and increased costs with some resource types.

Figure 60. Comparison of Reference Yearly Price Impacts ($/MWh)



Given the constraints in the planning environment associated with HB 2021 decarbonization goals, load growth, and transmission availability, the need for resource procurement identified in this Update continues to be large and is estimated to result in substantial cost impacts. Included in load growth expectations are significant increases in large new loads which account for between 30 percent to 80 percent of load growth forecast in any given year, averaging 47 percent over the 20-year period. These new large loads significantly increase PGE's need to acquire new resources, increasing total load by about 20 percent by 2044. PGE constructed a Preferred Portfolio that minimizes the costs and risk of new resource acquisitions and maximizes the provision of community benefits by thoroughly investigating key decision points with the potential to impact costs. This includes the selected GHG emissions-reduction pathway described in **Section 3.5.1 HB 2021** that complies with HB 2021 requirements while mitigating costs relative to more aggressive pathways and reducing risks compared to less aggressive pathways. Mitigating the impact of cost increases is critical and PGE will continue to study options that can help minimize costs for customers, including maximizing acquisition of cost-effective energy efficiency, continuing to explore the potential of emerging technologies as they develop and studying options to expand transmission access to cost-effective non-emitting resources.

6.2.2 Hourly energy and emissions accounting results

This section expands upon Chapter 5 of the 2023 CEP/IRP to reflect the hourly energy accounting and resulting GHG emissions impacts of the Preferred Portfolio. In the 2023 CEP/IRP, PGE demonstrated compliance with HB 2021 using annualized estimates of emissions of thermal generation and unspecified market purchases under a variety of GHG reduction glidepaths. In the December 14, 2023, Public Utility Commission of Oregon Staff report on docket LC 80, Staff identified that PGE's annual GHG emissions approximations neglected important aspects of system operations that may impact the Company's annual GHG emissions accounting. Staff highlighted the need for an hourly dispatch analysis to confirm PGE's GHG emissions projections and demonstrate its ability to comply with HB 2021. In Order 24-096, the OPUC directed PGE to resubmit a revised plan with its CEP/IRP Update in 2025 consistent with Staff Recommendation 3, stating that:

- PGE shall conduct hourly production cost simulation of its Preferred Portfolio under the reference case in a manner that separately tracks hourly purchases and hourly sales.
- PGE will use this analysis to revise its GHG emissions forecast to revise its submission to the DEQ.
- PGE shall update the Preferred Portfolio accordingly and provide a narrative explanation of the key planning insights derived from this exercise.[144]

In this Update, PGE addresses the requirements outlined above using a modified version of its PGE-Zone Model (PZM) to simulate hourly energy and emissions positions. This model is referred to as the Modified PGE-Zone Model (mPZM). The mPZM performs hourly production simulations under Reference case conditions in a manner that tracks hourly resource operation, market purchases, and market sales based upon supply and demand conditions.

The mPZM uses outputs from the PZM, the Brattle Clean Energy Surplus Model (CESM), Intermediate GHG Model (IGHG), and the Preferred Portfolio from ROSE-E portfolio development as inputs. Hourly and annual constraints are added to prevent emitting generation and unspecified market purchases from exceeding quantities specified by HB 2021 emissions limits. Additional details of how PGE applies the hourly energy and emissions accounting methodology are set forth in **Appendix D Hourly emissions methodology**. The results of this simulation indicate that, based upon forecasted market conditions, PGE's Preferred Portfolio can comply with HB 2021 emissions limits in 2030.

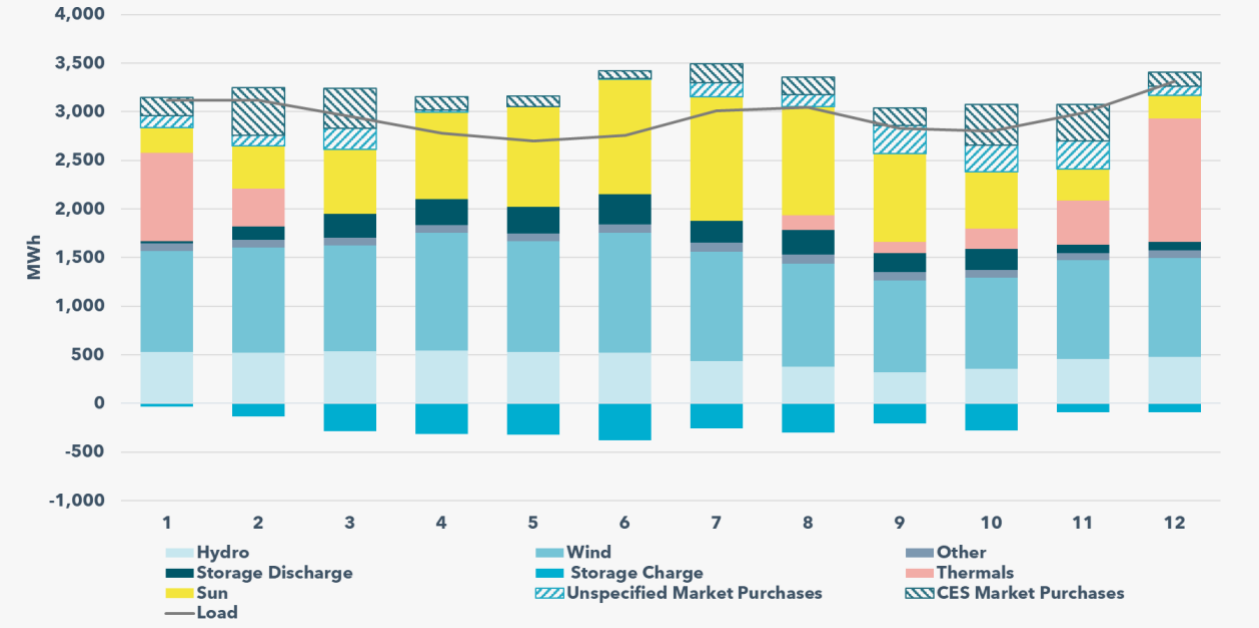
The following sections provide the results of this hourly mPZM analysis. First, a summary of monthly results demonstrates how emissions compliance is achieved; next, assumptions regarding market availability are detailed; generation from thermal resources are summarized; finally, example weeks in June and December provide greater detail on model results.

[144] https://apps.puc.state.or.us/orders/2024ords/24-096.pdf

6.2.2.1 Summary of results

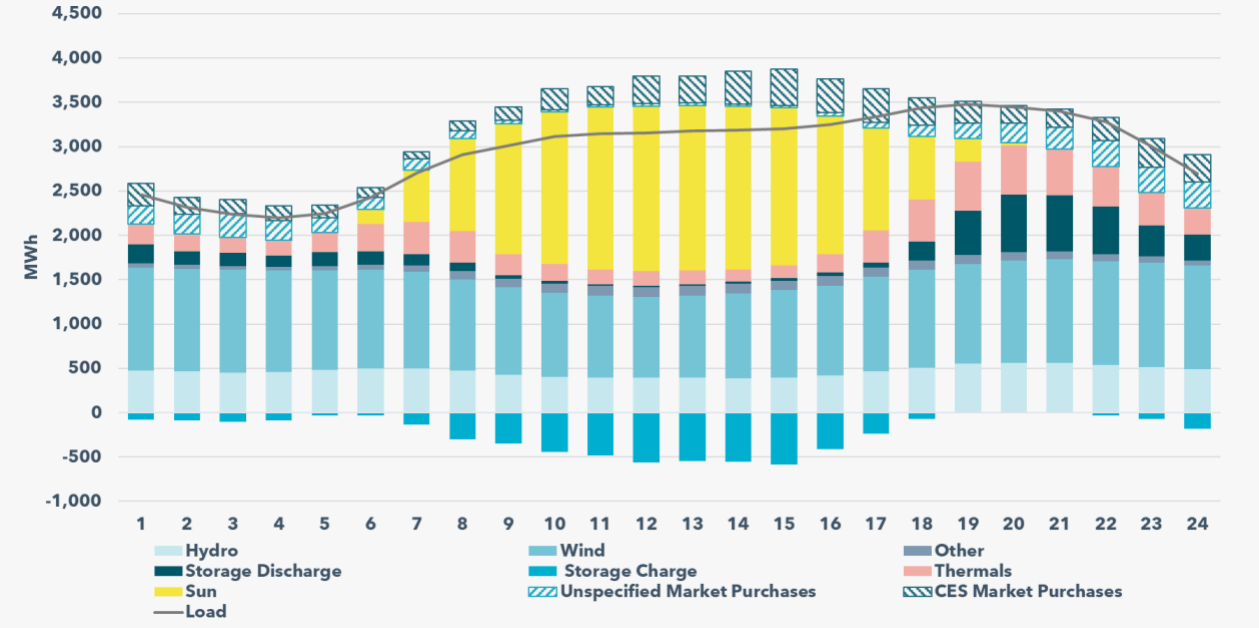
Figure 61 demonstrates the composition of supply used to meet demand for each month in 2030. Thermal generation is concentrated in the winter when non-emitting energy is scarce. Storage charging and discharging occurs in the spring, when storage opportunities to levelize net demand across the day is most present. Market purchases from non-emitting sources (clean energy surplus or "CES") are concentrated in the shoulder months across hours when the premium for such energy relative to the unspecified market (premium for clean energy or "PFC") is low. Unspecified market purchases are largley allocated outside of the spring months.

Figure 61. Monthly Modified PZM results show the simulated generation (MWh) by resource type across 2030



The composition of supply used to meet demand for the average day in 2030 is demonstrated in **Figure 62**. Thermal generation and storage discharge are concentrated over the peaks of the day. Storage charging occurs primarily during midday solar hours. Clean energy surplus market purchases are more frequent midday, during solar hours, as well, and unspecifed market purchases occur most frequently over the evening and early morning periods.

Figure 62. Hourly Modified PZM results show the simulated MWh by resource type across an average day in 2030



6.2.2.1 Assumptions of market availability

These simulations assume that when PGE's hourly position is long generation (supply exceeds retail demand), the excess generation contributes towards market sales. The thermal output dispatched by the Modified PZM optimization demonstrates the portion of thermal generation dedicated to serve retail load. Any additional wholesale sales of thermal generation will not be represented in the Modified PZM output. Any additional wholesale sales in the Modified PZM are a function of excess non-thermal resources such as periods of ample wind and solar generation and/or the presence of hydro must-run conditions. The periods in which the simulation results in PGE selling into the market are generally April—July. The timing of these long positions tends to align with periods of clean energy surplus across the WECC as the premium for clean energy is near zero during hours of most sales. This is demonstrated in **Figure 63** where the columns depict the average market sales volume (MWa) by month. The average realized price (the market price plus the premium for clean energy) is represented by the dark blue line, and the average premium for clean energy is shown as the red line. Given that non-emitting generation is greatest in the spring, as shown above, PGE market sales also tend to occur predominantly in the spring.

Figure 63. Average Hourly Revenue on Market Sales by Month



Figure 64 shows the timing of both unspecified and clean energy surplus market purchases in the mPZM simulation; the price of clean energy surplus market purchases includes the additional premium for clean energy. The methodology first assigns unspecified market purchases to hours with the highest premium, up to the portion of PGE's 2030 emission budget allocated to unspecified market purchases by the IGHG model. Clean energy surplus market purchases then fill remaining hours of need based on the quantity and timing of availability detailed in the Brattle report provided in **Appendix F Market for non-emitting energy**. Total market purchases average 382 MWa for the year, with 141 MWa allocated to unspecified purchases and 241 MWa allocated to CES purchases. Please see PGE's discussion of market developments in **Section 2.2.1 CAISO's Extended Day Ahead Market**.

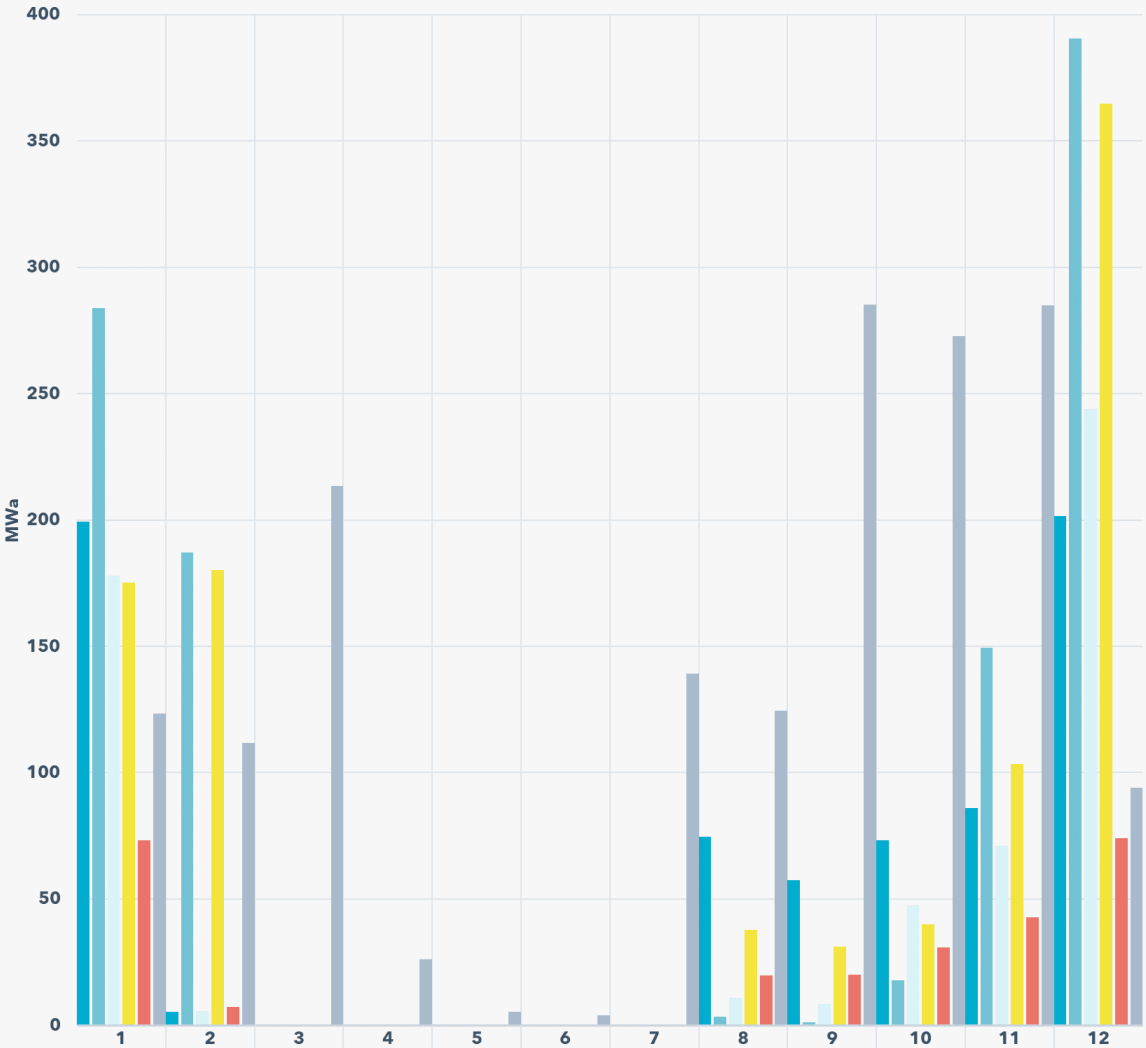
Figure 64. Timing of both unspecified and CES market purchases in the mPZM simulation



6.2.2.1 Thermal generation

Thermal generation allocated to serve PGE retail load is capped at the annual generation levels determined in the IGHG model. The mPZM optimizes emitting resource generation allocated to the retail portfolio across 2030 up to the IGHG limits. **Figure 65** shows the timing of emitting generation by month for the 2030 simulation.

Figure 65. Monthly generation (MWa) by emission source across 2030 forecast

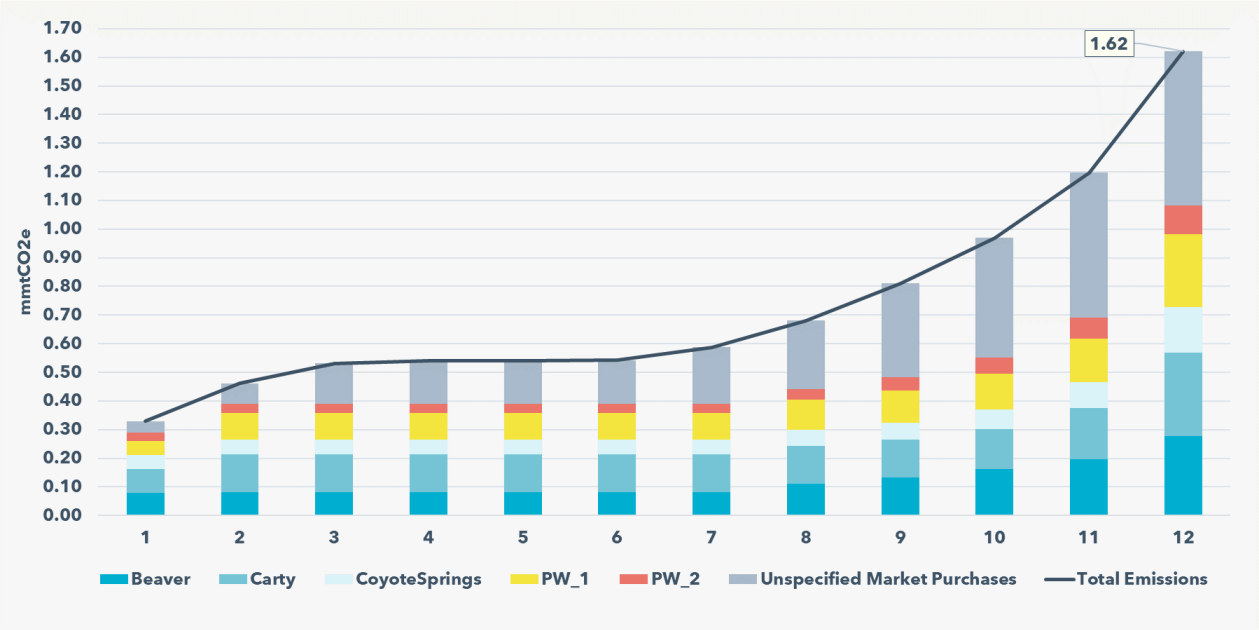


	1	2	3	4	5	6	7	8	9	10	11	12
Beaver	199	5	-	-	-	-	-	75	57	73	86	201
Carty	284	187	-	-	-	-	-	3	1	18	149	390
CoyoteSprings	178	6	-	-	-	-	-	11	8	47	71	244
PW_1	175	180	-	-	-	-	-	38	31	40	103	365
PW_2	73	7	-	-	-	-	-	20	20	31	43	74
Market	123	112	214	26	5	4	139	125	285	273	285	94

Since thermal generation and unspecified market purchases are capped, the emissions associated with serving retail load are designed to meet the HB 2021 emission limit of 1.62 million metric tons of CO_2 ($mmtCO_2e$). The timing of emissions is concentrated most heavily in the winter months as shown **Figure 66**. Approximately 60 percent of all simulated emissions occur in January, November, and December. This summary shows how PGE could use its emitting resources in a planning context, given the Preferred Portfolio and market assumptions detailed above, to meet portfolio needs within the 2030 emission targets. While the Update's simulation thermal operations in 2030 identifies how thermal output can be forecasted, PGE recognizes that many operational considerations and market complexities are challenging to

fully incorporate into planning. These differences prevent precise estimates of future operating conditions.

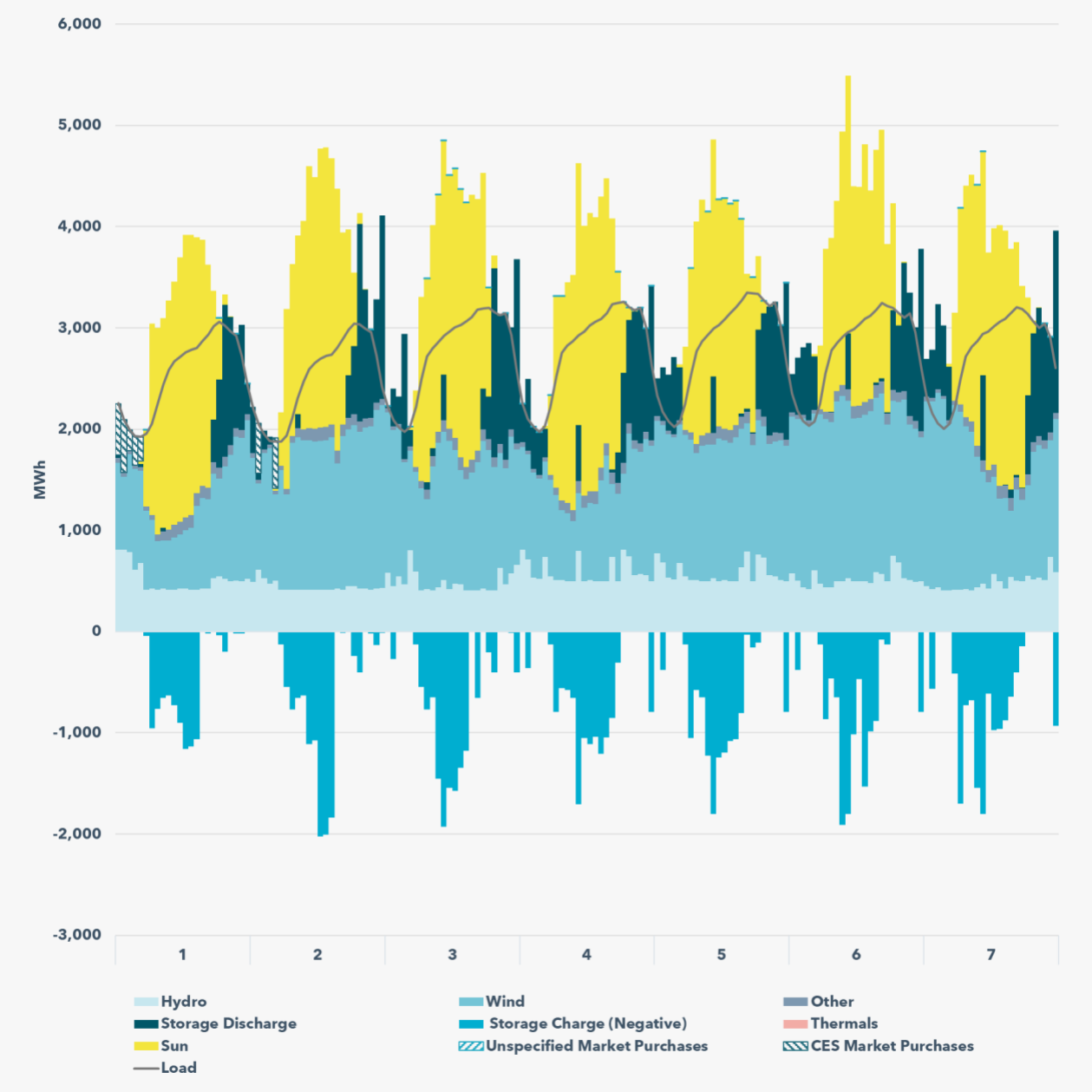
Figure 66. mPZM simulated 2030 monthly cumulative emissions (mmtCO2e) by source



6.2.2.1 Hourly generation snapshots

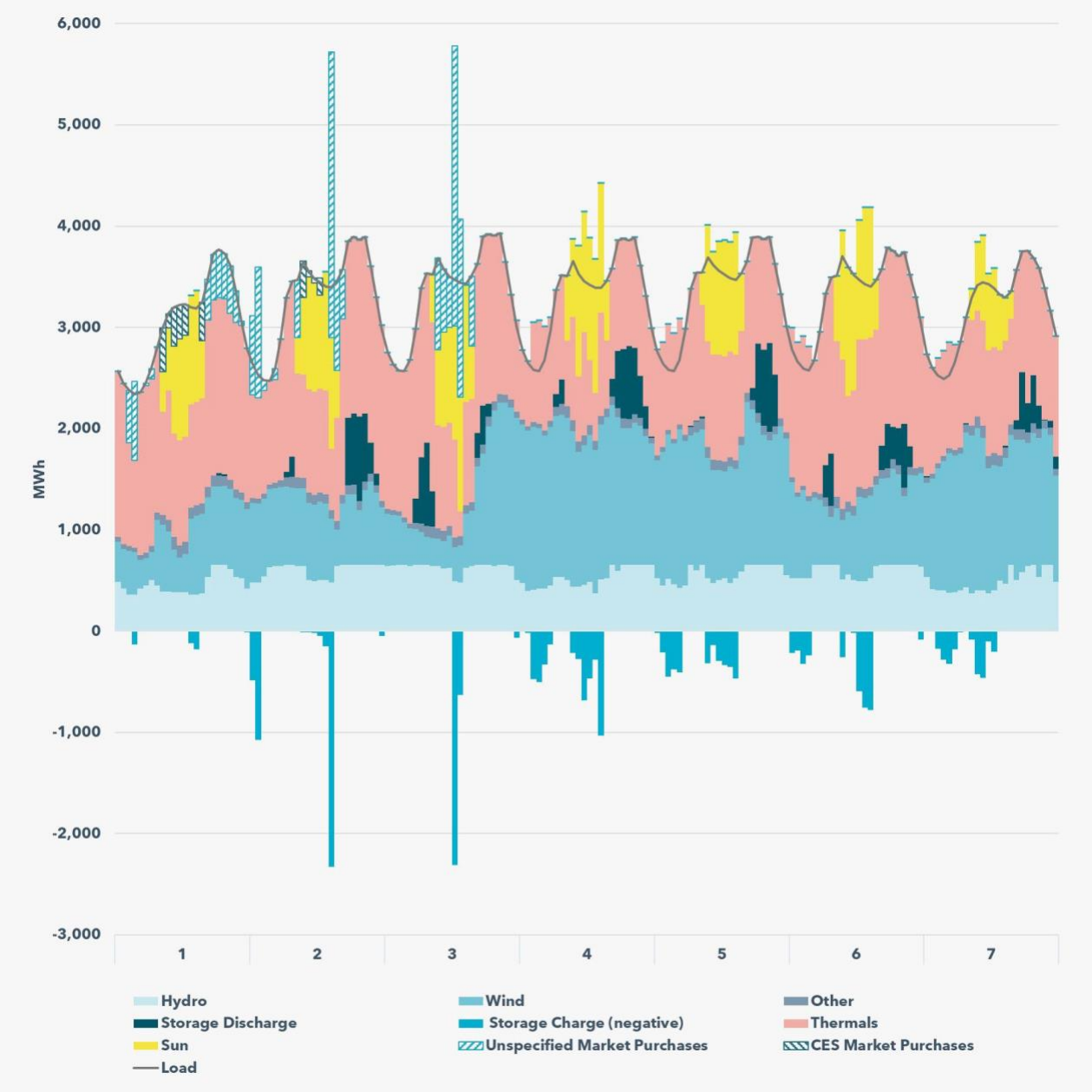
To demonstrate more granular representations of the mPZM results, sample weeks with hourly values by resource type are provided (**Figure 67**). The results include the first seven days of the month for June and December 2030 to demonstrate seasonal variation. June is punctuated by solar and wind generation with storage resources utilized to smooth the daily load-resource balance.

Figure 67. Hourly mPZM snapshots show simulated supply and demand positions by resource type in June 2030



In December 2030, thermal generation is deployed as PGE non-emitting generation is volatile and scarce while market premiums for clean energy are high (**Figure 68**). Unspecified market purchases are leveraged to charge batteries midday so they can be dispatched across evenings and early mornings.

Figure 68. Hourly mPZM snapshots show simulated supply and demand positions by resource type in December 2030



6.2.3 Preferred Portfolio resource adequacy testing

To ensure that the Preferred Portfolio can meet PGE's reliability needs, the Update analyzes the portfolio's specific resource configuration in the Sequoia adequacy model. This test evaluates how adequate the system is after including the Preferred Portfolio and assesses whether the ELCCs used in capacity expansion modeling remain valid when considering the dynamic system interactions present in a portfolio of resources.

The Company's capacity expansion model ROSE-E is constrained to meet system need (**Section 6.1.3 Capacity need**) utilizing an estimate of proxy resource capacity contributions or ELCCs

(**Section 5.1.6 Resource capacity contribution**). The estimation incudes two simplifications that PGE validates when assessing adequacy of the Preferred Portfolio. First, ELCCs are estimated in 2030 only, as estimating ELCCs in Sequoia is a computationally intensive and prolonged process. Second, ROSE-E interprets ELCCs as additive, where the addition of one resource does not affect the ELCCs of another. However, the capacity contribution of a resource is dynamic relative to system demand and supply across time. Including the Preferred Portfolio in Sequoia provides a more granular assessment of its effect on system reliability and appropriateness of the simplifications above. If abstractions used in capacity expansion modeling are representative of the dynamic system, the adequacy effect of the Preferred Portfolio would result in zero capacity need and a 2.4 loss-of-load hours (LOLH) adequacy metric.

Table 31 details the seasonal capacity need of PGE's system after including the Preferred Portfolio. These estimates show the portfolio is estimated as adequate in summer and winter seasons for 2026 through 2030, except a remaining capacity need in winter 2028 of 68 MW. As discussed in **Section 3.4 Capacity need**, structured or bilateral contracts that may be facilitated by State RA participation are tools PGE may use to procure capacity in the short-term.

Table 31. Reference Seasonal Capacity Need with Preferred Portfolio Resources

Year	Summer Need (MW)	Winter Need (MW)
2026	0	0
2027	0	0
2028	0	68
2029	0	0
2030	0	0

Analyzing the frequency of unserved energy events provides insight into how adequate the system is in future years. **Table 32** displays the LOLH metrics that correspond to the capacity need estimates above. Estimates greater than 2.4 LOLH indicate positive capacity needs. For example, the capacity need of 68 MW in winter 2028 represents a system with 2.01 hours of unserved energy per year greater than the threshold. Conversely, estimates less than 2.4 LOLH provide a measure of the degree of system adequacy. In 2030, the Preferred Portfolio additions result in an adequate system in both summer and winter. However, the higher LOLH metric in winter suggests that meeting reliability in the winter is the active constraint in PGE's capacity expansion.

Table 32. Seasonal LOLH of PGE system with Preferred Portfolio Resources

Year	Summer LOLH	Winter LOLH
2026	2.27	0.03
2027	1.45	0.20
2028	0.41	4.41
2029	0.00	0.06

Year	Summer LOLH	Winter LOLH
2030	0.06	2.25

The results above indicate that the ELCC simplifications used by ROSE-E are reasonably accurate for identifying an adequate portfolio, as shown by the approximately exact capacity built for winter 2030. Additionally, and as discussed further below, winter adequacy challenges appear to be the cause of significant resource additions in the Preferred Portfolio.

6.2.3.1 Energy sensitivity adequacy assessment of Preferred Portfolio

The Update includes an energy sensitivity analysis of the Preferred Portfolio to further PGE's understanding of cost and reliability implications driven by winter adequacy challenges. This analysis aims to identify the nature of PGE's capacity needs decomposed from PGE's energy needs.

To conduct the energy sensitivity assessment, all 4679 MW of nameplate resources in the Preferred Portfolio were partitioned into 2879 MW of resources required to meet ROSE-E's energy need including solar and wind (Energy Only Preferred Portfolio) and 1800 MW of storage resources.[145] The Energy Only Preferred Portfolio was added to the PGE system as modeled in Sequoia. Short duration storage resources were then incrementally added to examine their effect on capacity need.[146] **Figure 69** shows the changes to 2030 capacity need for winter and summer using this method.

The results indicate that short duration storage resources are effective at addressing PGE's summer capacity needs and inefficient at meeting PGE's winter capacity needs. The results clearly demonstrate the challenge of addressing winter adequacy with short duration storage resources under current system assumptions.[147] A 2030 winter capacity need of 123 MW persists after adding the Energy Only Preferred Portfolio and no additional storage resources.[148] This suggests that the 1800 MW of four-hour batteries in the Preferred Portfolio is required to resolve 123 MW of winter capacity need, a 6.8 percent ELCC. For comparison, the summer need

[145] Total value includes sum of nameplate for storage and energy resources associated with hybrids. Energy resources from hybrids were segmented and included in the base system with equivalent generation profiles. Additionally, the Energy Only Portfolio includes energy equivalent to the 123 MWa Non-Emitting Contract modeled as a hydro resource using parameters from recent hydro contracts.

[146] All incremental additions are modeled as 4-hour stand-alone energy resources with standard Sequoia assumptions, starting each simulated week fully charged. This assumption is consistent with how storage and hybrid resources are modeled in the above adequacy assessment. Additions were made in 100, 200, 400, 600, 800, 1000, 1400, 1800, and 2000 MW tranches then smoothed and interpolated using the same methodology as in the 2033 CEP/IRP and 2023 CEP/IRP Update.

[147] The Energy Only Preferred Portfolio plus 1800 MW of storage resources results in a winter capacity need of 0 MW and 2.21 LOLH, compared against the Preferred Portfolio's winter capacity need of 0 MW and 2.25 LOLH as shown in **Table 32.** The modest difference in modeling results relates to small differences in assumed charging behavior between hybrid and standalone storage resources and other portfolio modeling simplifications. Interpolation between the 1400 MW tranche an 1800 MW tranche of storage additions results in a curve suggesting approximately 1600 MW are required to achieve adequacy.

[148] As compared to the 978 MW and 886 MW capacity needs for summer and winter, respectively, prior to any additions from the Preferred Portfolio, **Section 3.4 Capacity need**.

remaining after energy additions is 213 MW. This need is resolved with an estimated 400 MW of storage additions, a 53 percent ELCC.

Figure 69. Capacity Need of Energy Only Portfolio and Cumulative 4-hour Storage Additions – 2030 Reference

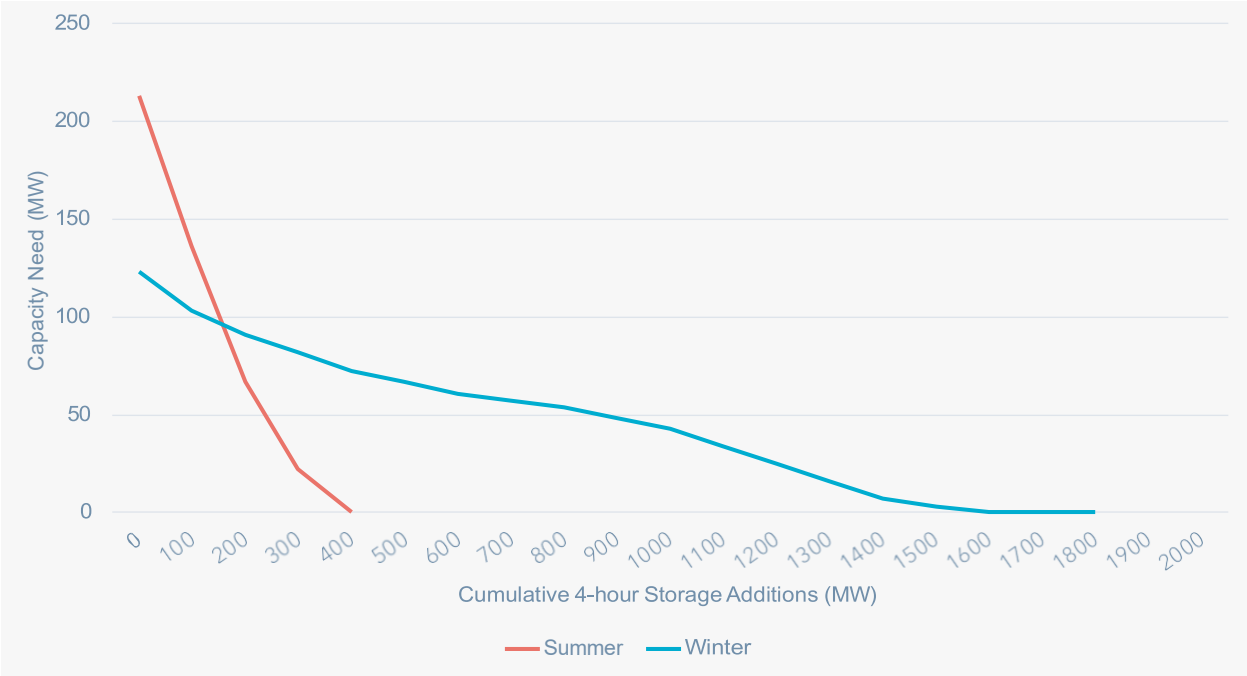
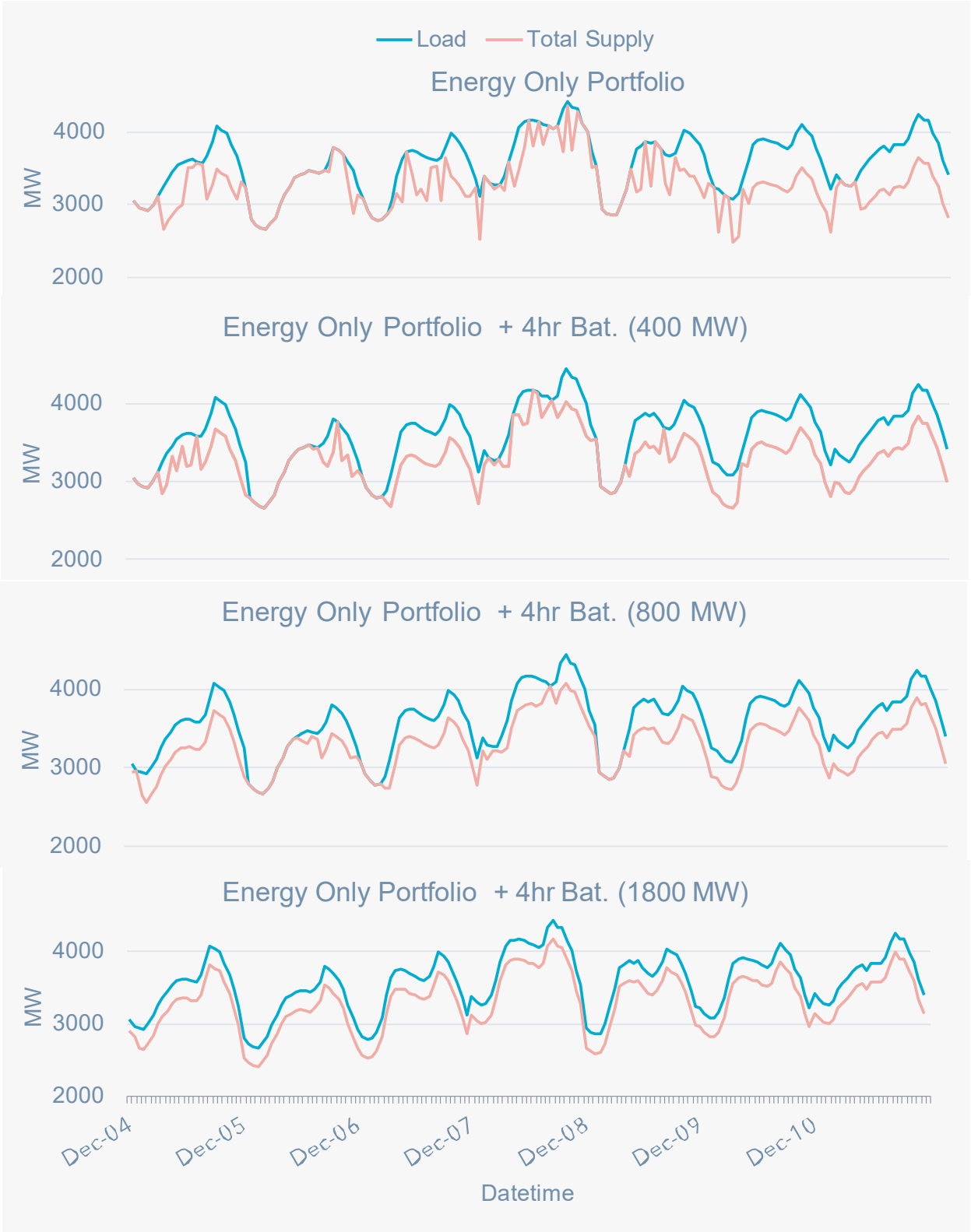


Figure 70 shows a Sequoia simulation of load and supply during a week in December 2030. This image highlights the challenge of trying to meet load in winter with short-duration storage resources. The first panel shows load and total supply in the base system with the Energy Only Portfolio, where gaps between total supply and load are unserved energy. As the quantity of storage increases the supply curve is shaped to reduce the largest hours of unserved energy. Due to insufficient energy, the optimal solution is to charge during periods of adequacy and lessen the size of unserved energy events in other hours, as is clear in Panel 4.[149] Panel 4 represents a tail event in the system, a week of energy shortfall where all 168 hours are short. Such a week has a 1 in 100,000 chance of occurring in an adequate system which includes the Preferred Portfolio. This inability of storage resources to resolve shortages when energy is short is representative of the declining marginal winter capacity curve shown in **Figure 69**.

[149] The objective function of Sequoia is to minimize the sum of the greatest hour of unserved energy of the week plus the average shortfall across the week.

Figure 70. December 2030 Weekly Adequacy Simulation



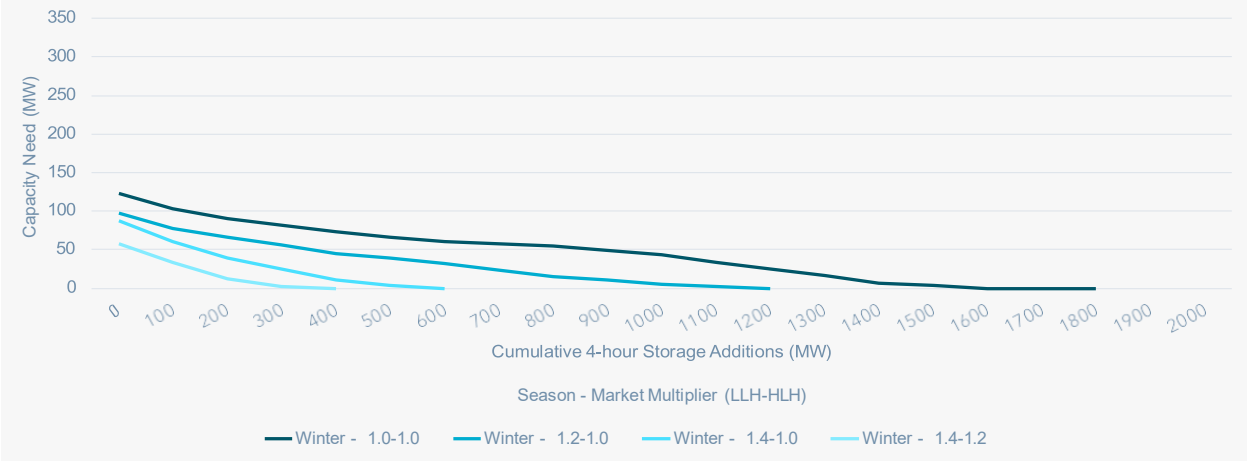
Previous regional resource adequacy studies have also reported on the challenges of meeting adequacy needs in the Pacific Northwest with short-duration storage. Energy and Environmental

Economics (E3) highlighted the steeply declining ELCC value of storage resources as a pattern that is particularly acute in the Pacific Northwest due to the quantity of hydro resources in the region.[150] This report concluded that firm capacity is an important component of a deeply decarbonized grid, and achieving decarbonization using only wind, solar, hydro and energy storage is impractical and prohibitively expensive. To compare the capacity value of dispatchable hydro resources against energy storage, the Company modeled the 2030 ELCC of the Non-Emitting Contract from the Preferred Portfolio based on parameters detailed in recent bilateral hydro agreements. The capacity value of this contract was estimated at 189 MW and when added to the system with the Energy Only Portfolio in 2030 resulted in ELCCs of 122 percent in summer and 115 percent ELCC in winter, as compared to 46 percent in summer and 22 percent in winter for 200 MW of 4-hour battery storage.

To test whether availability of energy is constraining the value of storage resources in winter, the same Energy Only Preferred Portfolio and incremental storage sensitivity analysis was conducted under various market availability assumptions. Adjustments were made by scaling Sequoia's market access assumptions for low-load hours (LLH) and heavy-load hours (HLH).[151] **Figure 71** shows the effect of this market sensitivity test on seasonal capacity need, where the market access multiplier represents the scalar for LLH and HLH, respectively. For example, in the 1.2-1.0 market access multiplier scenario an additional 20 percent (approximately 200 MW) is available during LLH and no change is assumed during HLH. In the 1.4-1.0 scenario, an additional 400 MW to the maximum availability in LLH results in winter adequacy at approximately 600 MW of incremental storage. This quantity of storage is equivalent to that included in the State RA Requirements Portfolio, 1200 MW less than the Preferred Portfolio.

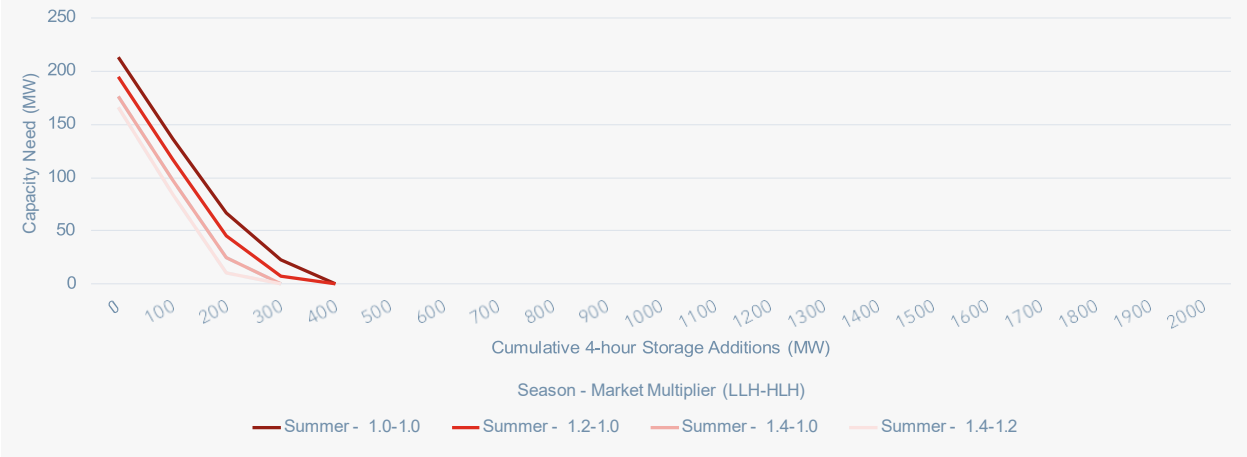
Figure 71. Capacity Need of Energy Only Portfolio with Incremental 4-hour Storage Additions and Variable Market Availability Assumptions – 2030 Reference

Panel A – Winter Capacity Need



[150] Energy and Environmental Economics. 2019. Resource Adequacy in the Pacific Northwest. San Francisco, CA.
[151] Sequoia's standard market assumptions vary by month, weekend/weekday, and hour (LLH/HLH) and are negatively correlated to load (i.e., greater load assumes less availability). In December, weekday values are limited to 999 MW and 150 MW for LLH and HLH, respectively. In August, values are limited to 999 MW and 0 MW for LLH and HLH, respectively.

Panel B – Summer Capacity Need

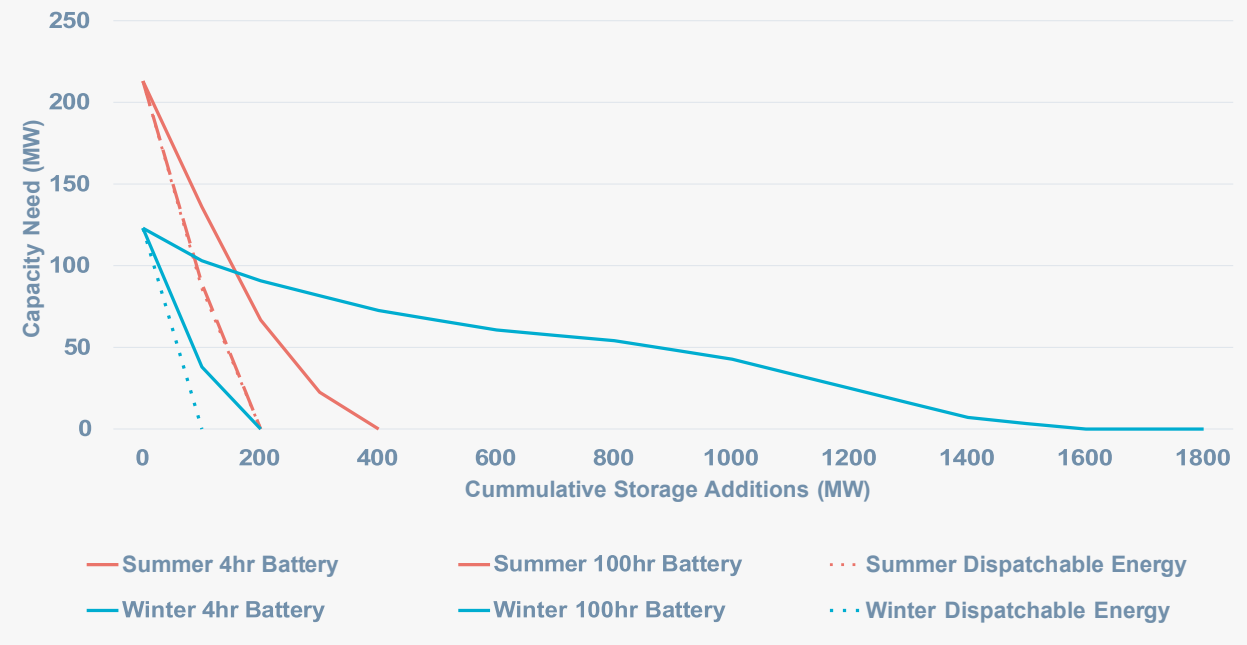


The above results highlight the sensitivity of the Preferred Portfolio to PGE's assumptions of access to regional markets. An estimated 66 percent of the 1800 MW of storage in the Preferred Portfolio is offset with approximately 400 MW of additional energy in LLH. Changing market access assumptions to arrive at a portfolio roughly equivalent to the State RA Requirement Portfolio reduces the NPVRR of resources by roughly $7 billion dollars across the planning horizon.[152] However, an Energy Only Portfolio with storage resources equivalent to the State RA Requirements portfolio is inadequate in winter 2030 as estimated in Sequoia. 60 MW of winter capacity need remain to achieve the 24-hours in 10 years metric. This capacity need equates to 3.73 LOLH, or 37 hours of unserved energy in 10 years for winter.

Finally, PGE estimated capacity contributions from emergent technologies as part of this analysis. These estimates are considered preliminary, and the Company intends to further refine them and EDAM market capacity contributions (see **Section 2.2.1 CAISO's Extended Day Ahead Market**) as part of the 2026 CEP/IRP. **Figure 72** compares capacity contributions of long-duration storage (LDS) and dispatchable energy technologies against those from 4-hour storage, as displayed in **Figure 69**.[153] This analysis suggests that approximately 200 MW of 100-hour storage and 100 MW of dispatchable energy provides effective capacity equivalent to 1800 MW of 4-hour batteries when added to the Energy Only Portfolio. Unlike 4-hour storage, the characteristics of these emergent technologies appear better suited to resolve the multi-hour reliability events characteristic to the winter season because of their ability to hold greater quantities of energy or generate energy on demand.

[152] Energy resources in the State RA Requirements Portfolio are roughly equivalent to those in the Preferred Portfolio. Value represents the difference between the NVPRR of the Preferred Portfolio and the State RA Requirements Portfolio presented in **Section 6.2 Preferred Portfolio** and **Section 6.3.5 State RA requirements**.
[153] LDS is modeled as a 100-hour battery with 35% round-trip efficiency, while dispatchable energy is modeled as perfect capacity. Long-duration storage is assumed to start each dispatch period fully charged, just as short-duration storage. Improved representation of the operational availability of LDS is suggested for the 2026 CEP/IRP.

Figure 72. Capacity Need of Energy Only Portfolio and Emergent Technology Additions – 2030 Reference



The results from this energy sensitivity analysis show that ELCCs for winter storage do not improve with additional energy availability and short-duration storage remains an inefficient marginal resource for meeting winter adequacy needs. Short-duration resources are inefficient primarily due to the length of constraining reliability events. This conclusion motivates **Section 6.7 Net cost of capacity resources**, where the Company represents the cost of marginal resource with a value that captures the capacity and energy costs required to ensure adequacy.

Further, this analysis provides insight into four considerations PGE intends to investigate in the 2026 CEP/IRP with respect to future capacity needs: (1) continue to rely on short-duration storage as the marginal resource, (2) evaluate the role of additional energy from expanded market access, (3) evaluate the role of an expanded regional sharing mechanism as part of the State Resource Adequacy requirements, and (4) review the viability of emergent technologies as the marginal resource. PGE expects it necessary to identify different long-term marginal capacity resources better suited to provide the energy and capacity necessary to meet ongoing winter adequacy challenges, such as long-duration storage, hydrogen storage resources, advanced geothermal, nuclear generation, carbon capture utilization and storage, and long-distance transmission access to geographically diverse trading hubs, such as the North Plains Connector.

6.3 Portfolio sensitivities

This section describes, and presents results for, the multiple sensitivities that are conducted on the Preferred Portfolio. Topics explored through these sensitivities include the quantity of emitting energy retained by PGE to serve retail load, large industrial customer growth, resource adequacy planning assumptions and the availability of non-emitting market purchases for hourly emissions accounting. Except where otherwise specified, PGE held the assumptions for each

sensitivity constant with those of the Preferred Portfolio in order to isolate the impacts to the topic of interest. Select results are presented for each scenario to highlight the findings of interest.

6.3.1 Reliability needs only

The ‘Reliability Needs Only’ scenario demonstrates how capacity and energy needs driven by load growth and portfolio composition changes. In this scenario, HB 2021 GHG emissions targets are not enforced. The quantity of thermal energy retained from PGE’s existing fleet of resources to serve retail load is determined by recent historical plant operations. Additionally, thermal resources continue to provide capacity beyond 2039, unlike the Preferred Portfolio, in which the capacity from thermals must be replaced with non-emitting sources in 2040. Although not constrained to HB 2021 emissions reductions, the ‘Reliability Needs Only’ scenario is compliant with RPS requirements. As in all other portfolios analyzed in the Update, this portfolio does not contemplate the addition of new natural gas resources to PGE’s portfolio.

Resource additions for the ‘Reliability Needs Only’ scenario are shown in **Figure 73**. Optimized resource additions through 2030 include 1262 MW of wind, 1189 MW of solar, 1745 MW of storage, 83 MW of non-cost-effective EE and DERs, 155 MW of CBREs, and 9 MW of non-emitting contracts. Total resource additions in 2030 are 95 percent of those in the Preferred Portfolio. The substantial incremental resource additions by 2030 without reducing thermals suggests resource adequacy, including the need to serve growing load in a reliable manner, is a main driver of PGE’s resource needs.

Results differ more substantially from the Preferred Portfolio later in the analysis time-horizon when the ability to retain thermals for capacity impacts resource additions. By 2040, the resource additions of the “Reliability Needs Only’ scenario are only 53 percent of those in the Preferred Portfolio. Driven largely by these later-year differences, the cost and risk of the ‘Reliability Needs Only’ scenario, shown in **Figure 74**, are substantially lower than the Preferred Portfolio. 20-year portfolio NPVRR for the ‘Reliability Needs Only’ scenario are $4,970 million lower than the Preferred Portfolio.

Figure 73. Resource Additions for Reliability Needs Only Scenario (MW)

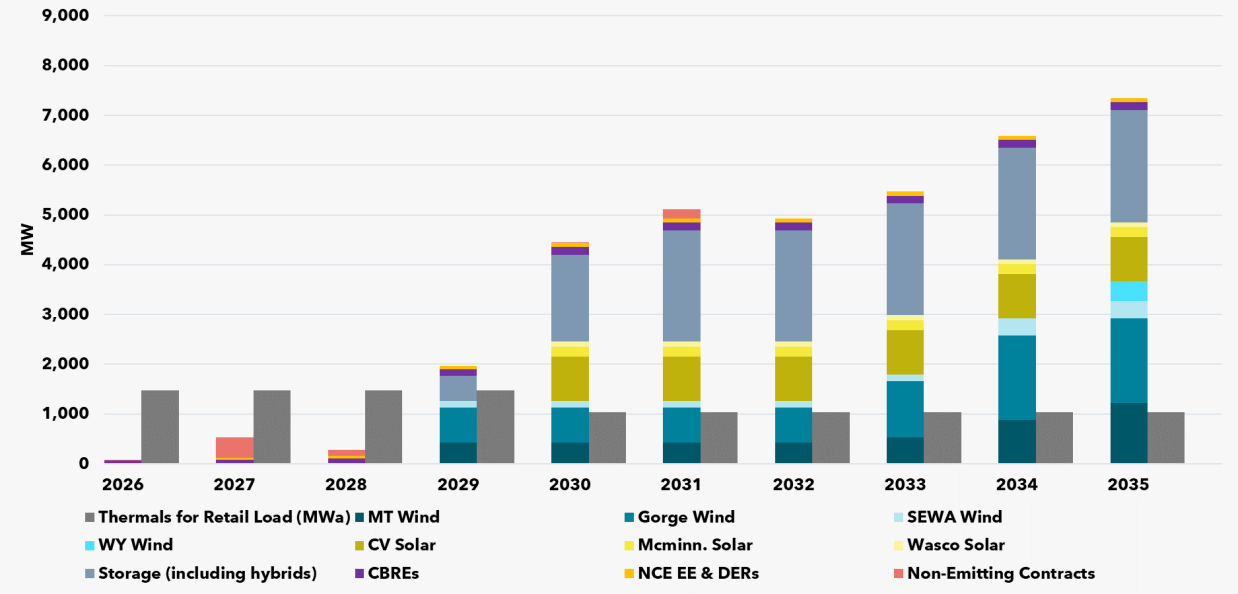
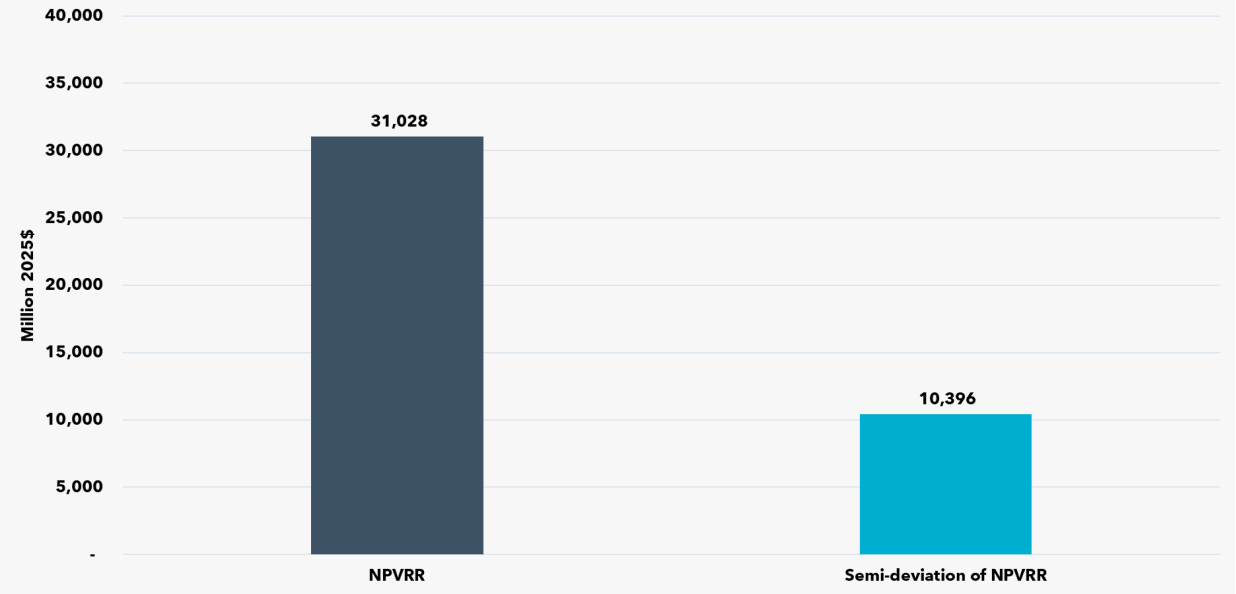


Figure 74. Cost and Risk of Reliability Needs Only Scenario



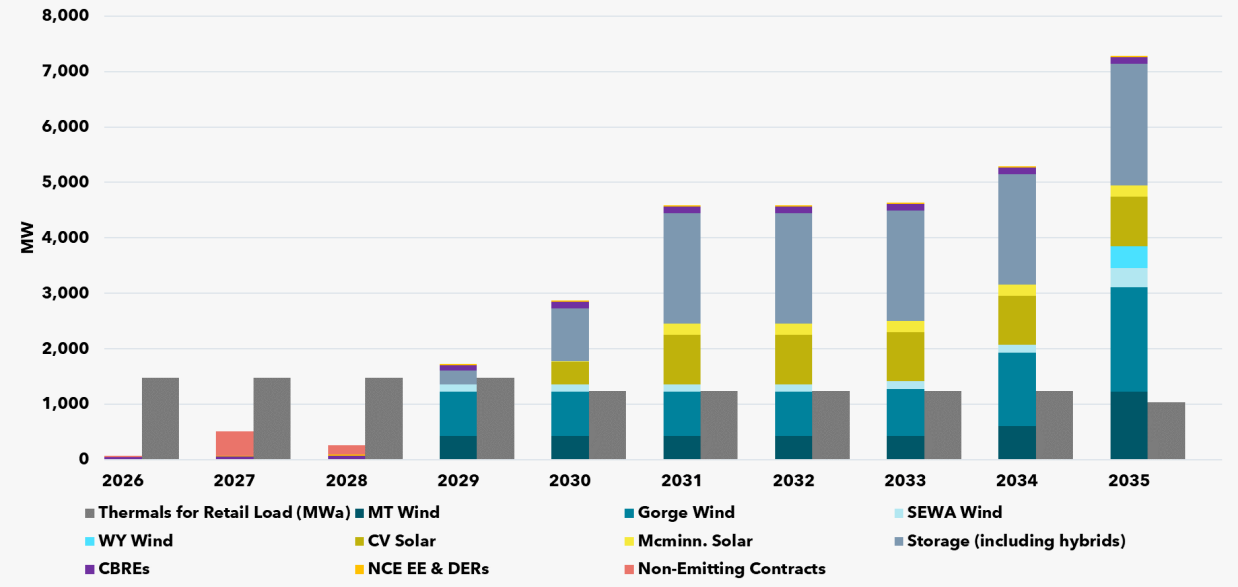
6.3.2 Further Reliability need sensitivities

The scenarios presented in this section expand upon the 'Reliability Needs Only' scenario by considering how needs are reduced assuming 1) that PGE extends a 250 MW contract for dispatchable emitting energy and 2) PGE extends a 250 MW contract for dispatchable emitting energy in addition to a 250 MW non-emitting hydro contract. These scenarios are named the 'Dispatchable Emitting Contract Scenario' and the 'Dispatchable Emitting and Hydro Contracts Scenario'. Both contract extensions are assumed to provide both energy and capacity from 2030 through 2034. Aside from the contract extension assumptions, these scenarios rely on identical

assumptions to the 'Reliability Needs Only' scenario. In contrast to the small impact on needs found when comparing the 'Reliability Needs Only' scenario, with its' reduced energy needs, to the Preferred Portfolio, the addition of capacity and energy from contract extensions in these scenarios produces substantial reductions in 2030 resource needs, as illustrated in the results below.

Portfolio resource additions for the 'Dispatchable Emitting Contract Scenario' shown in **Figure 75**. Additional quantities of emitting energy can be seen as taller gray bars in 2030 – 2034. Through 2030, the portfolio adds 1362 MW of wind, 415 MW of solar, 952 MW of storage, 24 MW of NCE EE and DERs, and 119 MW of CBREs. Total resource additions are 2872 MW through 2030, which is 1571 MW, or 35 percent, lower than in the 'Reliability Needs Only' Scenario. The decrease in resources is driven largely by decreases in the quantity of solar and storage, with CBRE's, NCE EE, and NCE DERs are also reduced.

Figure 75. Resource Additions for Dispatchable Emitting Contract Scenario

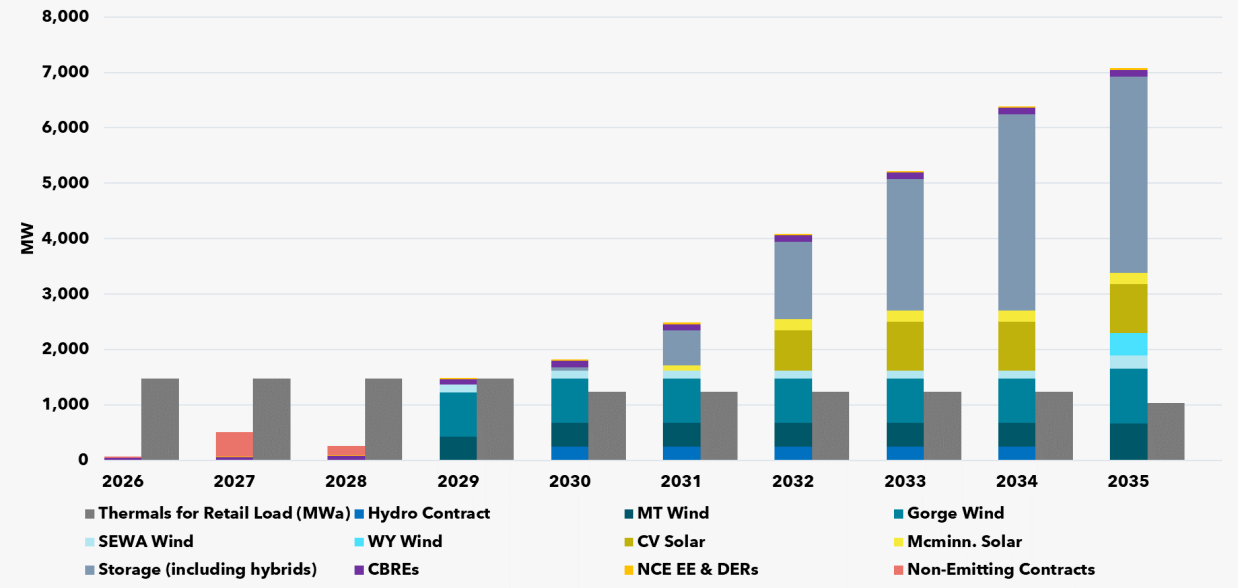


Portfolio resource additions for the 'Dispatchable Emitting and Hydro Contracts Scenario' shown in **Figure 76**. Through 2030, the portfolio adds 1362 MW of wind, 64 MW of storage, 24 MW of NCE EE and DERs, and 119 MW of CBREs. Total resource additions are 1569 MW through 2030, which is 2874 MW, or 65 percent, lower than in the 'Reliability Needs Only' Scenario. Consistent with the results of the previous scenario, the decrease in resources is driven largely by decreases in the quantity of solar and storage.

Notably, in the 'Dispatchable Emitting and Hydro Contracts Scenario' the need for transmission options is reduced, with the needs reduced enough during the 2030 – 2034 period of contract extensions that the 3000 MW Bethel-Round Butte transmission upgrade (BRB) is foregone when it becomes available in 2032. The impact of this outcome produces an initially unintuitive result when comparing the resource additions of the two contract extension scenarios in 2033 - 2034

reveals. Comparison of **Figure 75** and **Figure 76** reveal larger 2033 and 2034 resource additions in the 'Dispatchable Emitting and Hydro Contracts Scenario', which has 500 MW of contract extensions than the 'Dispatchable Emitting Contract Scenario', which has 250 MW of contract extension. Instead of investing in BRB, the 'Dispatchable Emitting and Hydro Contracts Scenario' lowers costs by relying on additional quantities of storage to meet needs in these years and delaying the addition of any transmission options until 2035.

Figure 76. Resource Additions for Dispatchable Emitting and Hydro Contracts Scenario



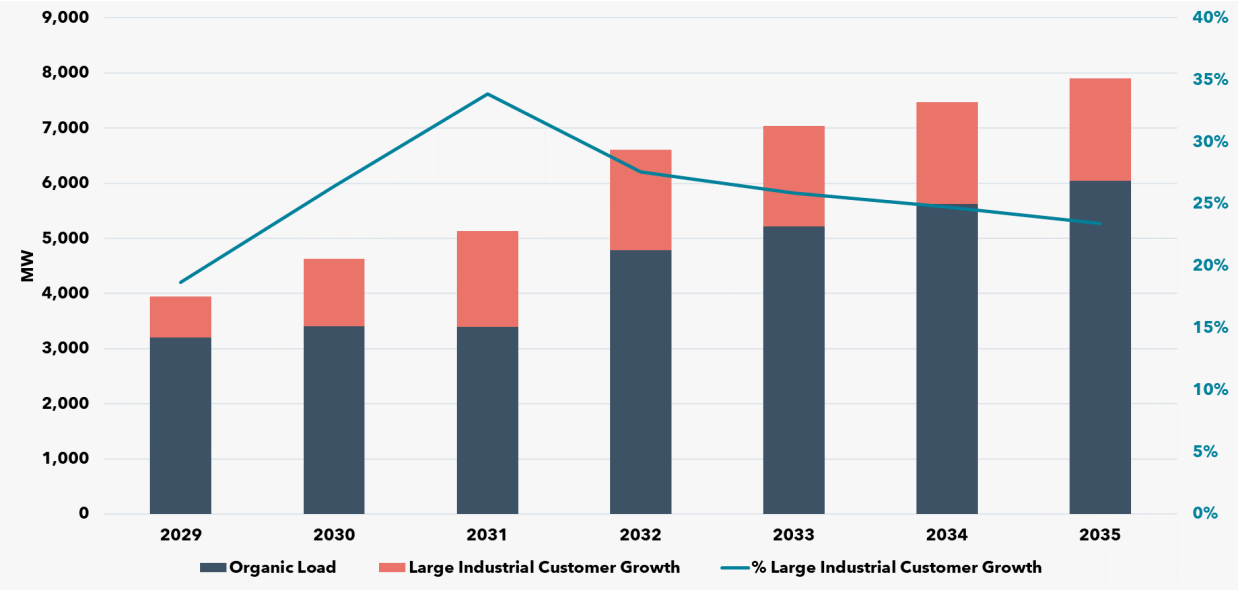
6.3.3 Large industrial customer growth

As described in **Section 2.4 Industrial load growth**, substantial electricity demand from large industrial customers is projected in the PNW in coming decades and will have implications for utility planning. PGE is taking steps to mitigate the risk of inequitable customer cost impacts associated with large industrial load growth, including through its filings in UE 430 and UM 2377, in which PGE has proposed a change to its tariff regarding cost allocation amongst customer classes. In addition, the Oregon legislature is considering law that would place data centers into a specific customer class. The Update analysis is illustrative of how new resource costs are driven by all large and growing industrial customers. There remain important differences in methodology and purpose between the IRP Update analysis and methodology that may result from UM 2377 which may limit the applicability of these results which should be considered illustrative only.

As an initial exploration of the impacts of this projected growth on PGE's planning, an analysis was conducted to identify what the quantity of resource additions in PGE's Preferred Portfolio are associated with meeting the needs created by the growth of large industrial customers. To do so, PGE created a load forecast sensitivity that excludes large industrial customer growth. This forecast and the methodology used to develop it are described in detail in **Section 3.1.3 Load forecasts – excluding large customer** . The load that remains to be served after removing the

impact of large industrial customer growth is referred to here as 'organic load'. Using this load forecast, a scenario was created that produced a portfolio of resource additions that provides sufficient energy and capacity needs to meet organic load growth and is compliant with HB 2021. The resulting capacity need for the 2030 reference case is estimated at 497 MW and 473 MW for summer and winter, respectively, roughly 50 percent of the estimated capacity need for the Preferred Portfolio. The quantity of resources associated with serving large industrial customer growth can be estimated by taking the difference in the resource buildout of the Preferred Portfolio and the 'No Large Industrial Customer Growth' scenario, which adds resources to meet organic load only. **Figure 77** shows the total cumulative resource additions in each year for the Preferred Portfolio and the 'No Large Industrial Customer Growth' scenario and shows that by 2030, about 26 percent resource additions can be attributed to growth in large industrial customer load. Resource additions associated with large industrial customer growth reach as high as nearly 34 percent in 2031.

Figure 77. Cumulative Resource Additions for Large Industrial Customer Growth



6.3.4 Market scenarios

PGE developed three market scenarios to analyze uncertainties in the potential availability of low- and non-emitting power for purchase. These scenarios vary assumptions in PGE's IGHG model which impact the quantity of emitting energy that PGE is ultimately able to retain to serve retail load. Compliance with HB 2021 is assumed for each alternative market scenario. The three market scenarios are described in **Table 33**.

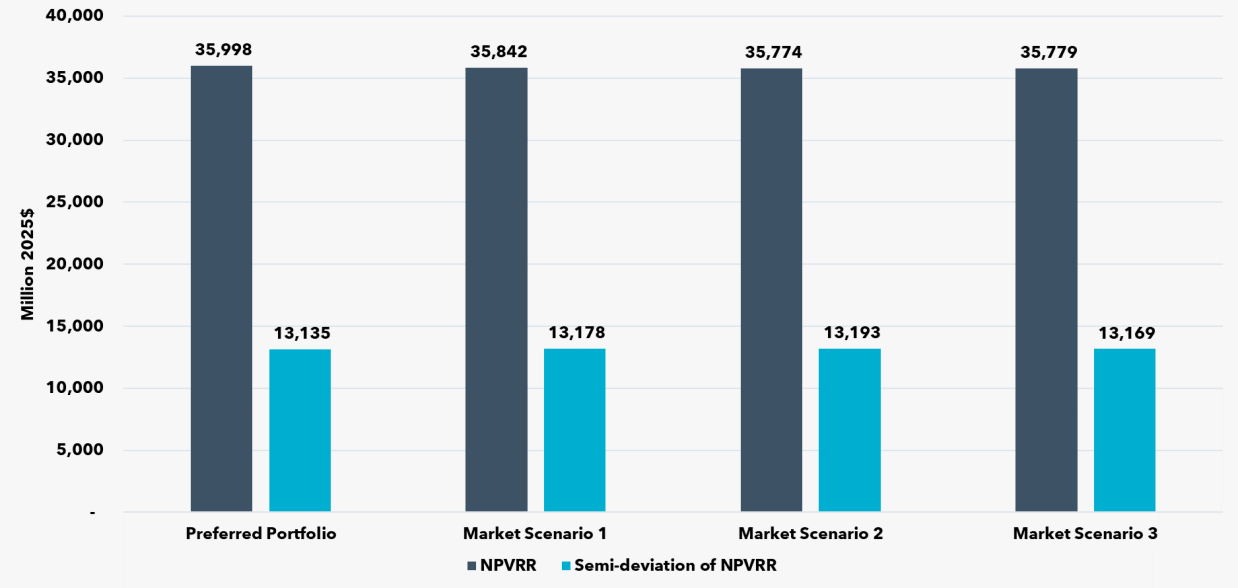
Table 33. Market Scenarios

Scenario	Description
Market Scenario 1: Specify More Power Purchases	Specify 50% of the assumed unspecified market purchases (informed by historical data) serving retail load in the IGHG

Scenario	Description
	model as non-emitting with the remaining 50% assigned the market unspecified emissions rate.
Market Scenario 2: Extend Low-Emitting Existing Purchases	Extend known low-emitting short-term specified purchases that would otherwise expire in the IGHG model.
Market Scenario 3: Lower Emission Rate	Reduce the emissions rate of unspecified market purchases in the IGHG model by 30%.

Because the assumptions in the market scenarios allow PGE to retain more emitting energy and thus reduce the energy need, resource additions are lower than in the Preferred Portfolio. However, because capacity need is unchanged, the impacts on resource buildouts and portfolio cost and risk are modest. Portfolio cost and risk metrics for the market scenarios are shown in **Figure 78**. Relative to the Preferred Portfolio, Market Scenario 1 lowers portfolio cost by $156 million, while Market Scenarios 2 and 3 produce costs $224 million and $219 million lower than the Preferred Portfolio, over the 20-year analysis time-horizon.

Figure 78. Cost and Risk of Market Scenarios



6.3.5 State RA requirements

The ‘State RA Requirements’ scenario models PGE’s resource adequacy needs using methods from the WRAP instead of using the PGE resource adequacy methods that are standard in the Preferred Portfolio and all other scenarios. The alternative methodology used for this scenario impacts capacity need and proxy resource ELCCs, as described in **Appendix I Inputs for state RA requirements portfolio**. Because of the assumed sharing of resources by regional entities, the WRAP methodology generally produces a lower estimated capacity need than PGE’s standard IRP methods. As a result, the resource additions in the ‘State RA Requirements’ scenario are substantially lower than in the Preferred Portfolio and portfolio cost is $6,817 million lower

over the planning horizon. Resource additions for the 'State RA Requirements' scenario are shown in **Figure 79**, and cost and risk metrics are shown in **Figure 80**.

Figure 79. Resource Additions in State RA Requirements Scenario (MW)

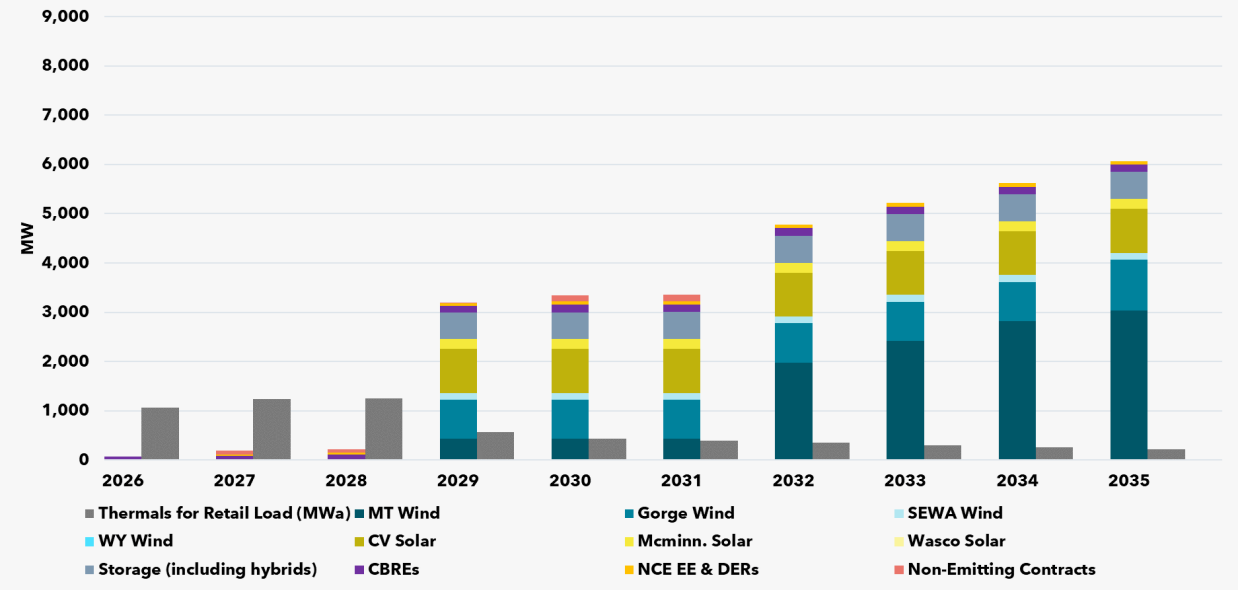
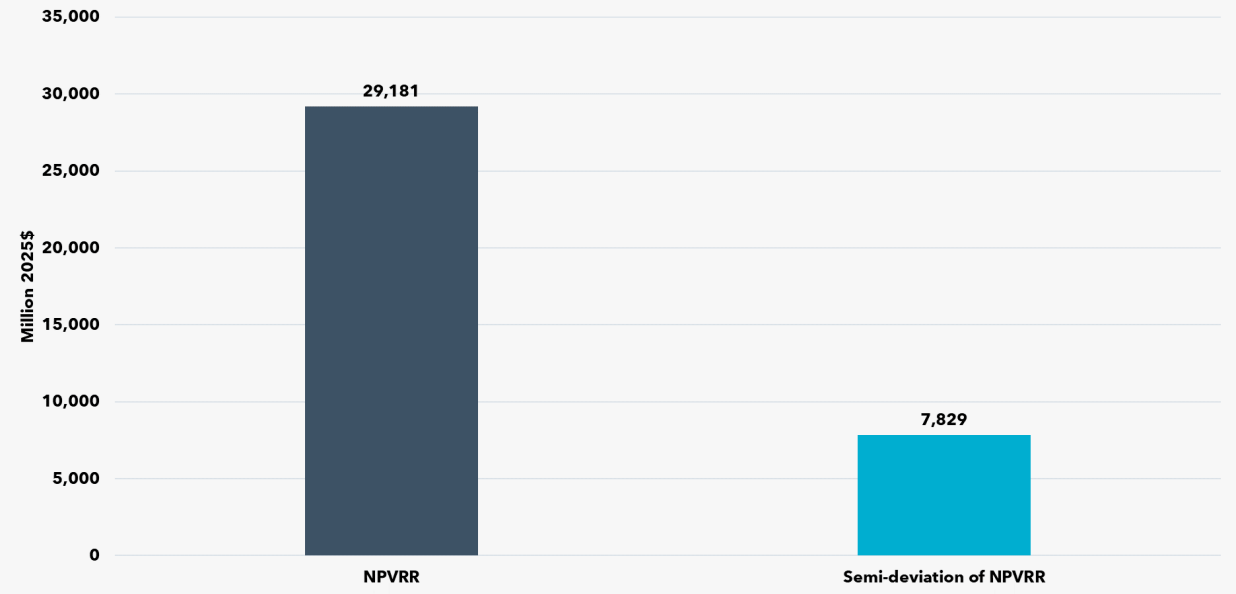


Figure 80. Cost and Risk of State RA Requirements Scenario



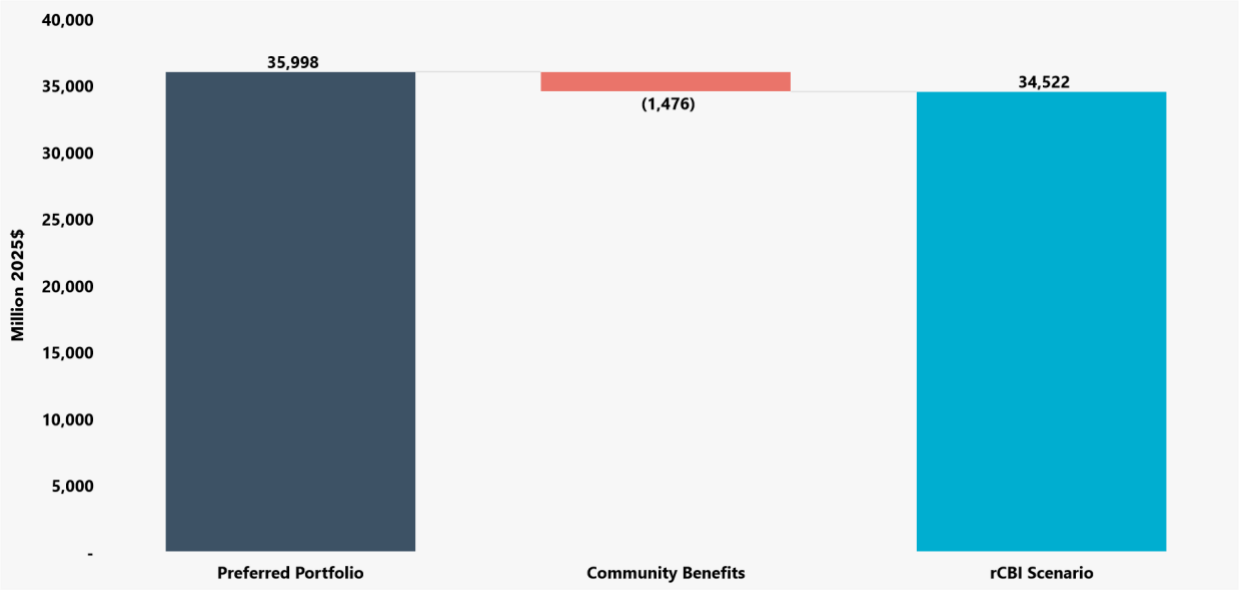
6.3.6 Resource Community Benefits Indicator (rCBI)

The 'rCBI' scenario applies reductions in fixed costs to certain CBRE, NCE DR, and NCE EE resources to reflect the societal value of community benefits associated with these resources, as described in **Section 5.5 Community benefits indicators (CBIs)**. Because the majority of NCE EE and DR, and the entirety of CBRE resources available, are added in the Preferred Portfolio,

differences in resource buildout between the 'rCBI' scenario and the Preferred Portfolio are minimal. The reduced fixed costs did result in the selection of an additional 2 MW of NCE DR resources.

The lower costs associated with these resources lowered portfolio NPVRR by $1,476 million compared to the Preferred Portfolio (**Figure 81**). This reduction in NPVRR represents the value of localized community benefits provided by the resources in the portfolio. The $1,476 million in community benefits reflects the societal benefits provided by the resources in the portfolio and does not represent a decrease in the monetary cost of the portfolio or suggest that the 'rCBI' portfolio would result in lower customer bills than the Preferred Portfolio.

Figure 81. NPVRR of Preferred Portfolio and rCBI Scenario



6.3.7 Absence of non-emitting market

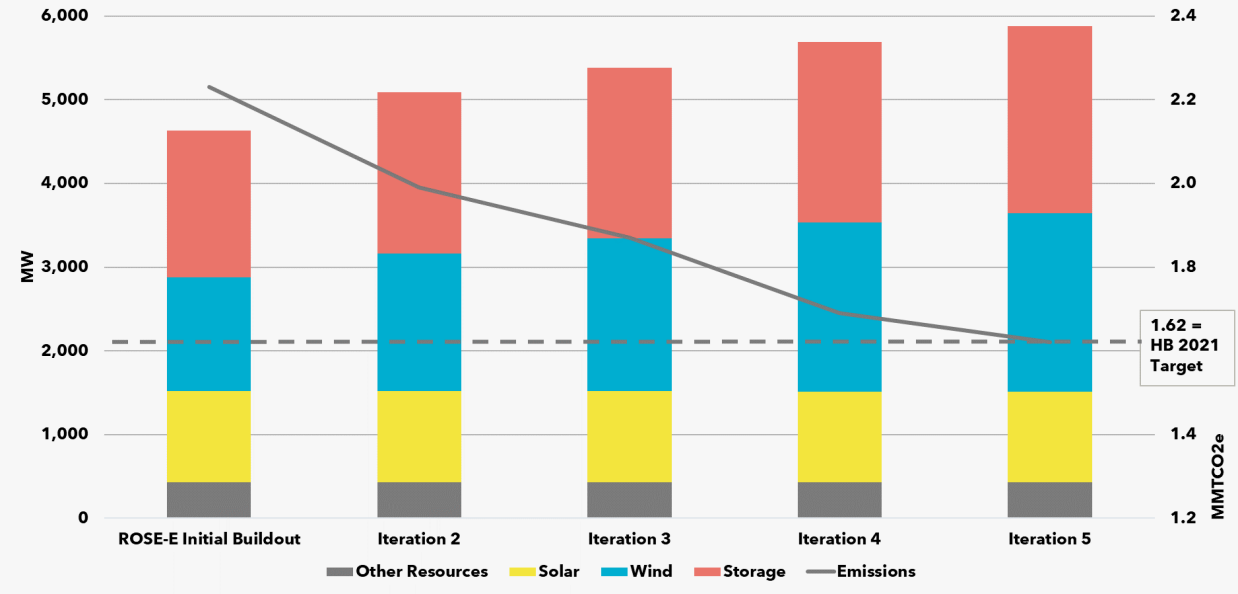
The 'Absence of Non-Emitting Market' scenario contemplates the quantity of resource additions that would be necessary to meet HB 2021 emissions targets using hourly energy accounting if PGE didn't have access to the non-emitting market energy that is available in the analysis reported in **Section 6.2.2 Hourly energy and emissions accounting results**. A detailed description of the iteration method is provided in **Appendix D Hourly emissions methodology**. In brief, the question is answered using the following approach:

1. ROSE-E determines the resources required to meet resource needs based on monthly energy sufficiency.
2. The modified PZM estimates what hours in the year would PGE be short (and by how much) under average conditions.
3. An outboard workbook creates a new energy constraint to be met and resource options are assigned a weighted capacity factor that encourages the addition of resources that are most useful in meeting that need. The new constraint is fed back into step 1 until a portfolio that meets all hourly needs is produced.

Because transmission constraints would make it impossible to add sufficient resources to meet the hourly emissions requirements in 2030, the resource additions in iterations subsequent to the initial ROSE-E buildout are not subject to transmission constraints.

Over the course of five iterations between ROSE-E and the modified PZM, incremental additions of renewable and storage resources are added until the portfolio achieves emissions of 1.62 MMTCO2e when evaluated at an hourly time-step (**Figure 82**). When the portfolio achieves emissions targets, the quantity of resource additions has increased by 1249 MW, from 4629 MW in the initial ROSE-E buildout to 5881 MW in the fifth iteration. This 21 percent increase in the quantity of resources in the portfolio illustrates that for PGE to decarbonize in isolation, substantial additional resources would be required that may exacerbate procurement challenges and cost pressure. The findings underscore the importance of access to market opportunities to purchase non-emitting energy from entities within the region.

Figure 82. Resource Addition Iterations in Absence of Non-Emitting Market Scenario



6.4 Small scale renewables plan

As required by ORS 469A.210, PGE has a 10 percent small-scale renewable requirement, requiring that 10 percent of electrical generating capacity come from renewable resources smaller than 20 MW or qualifying biomass generators starting in 2030.[154] Per Staff Recommendation #5, approved via LC 80 Order 24-096, PGE has included a SSR compliance analysis as part of this Update. This compliance analysis provided in this section assesses the forecast SSR need, resource contributions, costs, and acquisition/compliance actions. This will include results from portfolio analysis using a SSR proxy resource. It will also include a discussion of how PGE plans to acquire the needed resources to achieve compliance and a discussion on the current status and potential future status of customer sited resources for SSR compliance.

[154] Oregon ORS 469A.210 can be found at https://www.oregonlegislature.gov/bills_laws/ors/ors469a.html.

6.4.1 SSR needs assessment

The SSR need is a function of the nameplate capacity of resource in PGE's baseline portfolio and new resources added through capacity expansion modeling. In the Preferred Portfolio, PGE forecasts an aggregate SSR need of 769 MW in 2030, growing to 1292 MW by 2040 (**Table 34**).

Table 34. Total SSR Compliance Requirement by Year

Year	Preferred Portfolio
<2030	No min. requirement
2030	738 MW
2035	991 MW
2040	1314 MW

6.4.2 Contributions from baseline resource acquisition

Several ongoing resource acquisition pathways contribute to SSR development, including the Oregon Community Solar Program projects, QF development, and CBRE acquisition:

- CSP capacity in 2030: 93 MW
- QF capacity <20 MW under contract to PGE in 2030: 260 MW
- CBRE acquisition forecast for 2030: 155 MW
- Other PGE owned or contracted SSR-eligible projects modeled in 2030 portfolio: up to 51 MW

Per OPUC Order 21-464, net metered (NEM) renewables do not contribute to SSR compliance (or to PGE's aggregate electrical capacity). However, the role of net metered solar in PGE's planning has continued to evolve since 2021 as interconnected NEM solar more than doubled in three years. Improvements in inverter capabilities, increasingly common storage pairing, and advancement of grid planning and management as discussed in Distribution System Plans and PGE's Virtual Power Plant activities all have contributed to the value of solar to PGE's system. PGE's SSR compliance assessment considers NEM solar as a sensitivity. Customer solar deployment by 2030 is forecast to be 675 MW (see **Section 5.2.1.1 Distributed solar (PV)**).

6.4.3 Remaining SSR need

Table 35 summarizes PGE's 2030 SSR compliance position, with and without contributions of NEM. With NEM ineligible to contribute to compliance, PGE's forecasted incremental compliance requirement in 2030 is 179 MW of SSR resources. With all NEM solar considered as an eligible resource there is no incremental compliance need in 2030 (in this case, the first year in which an incremental need arises is 2036).

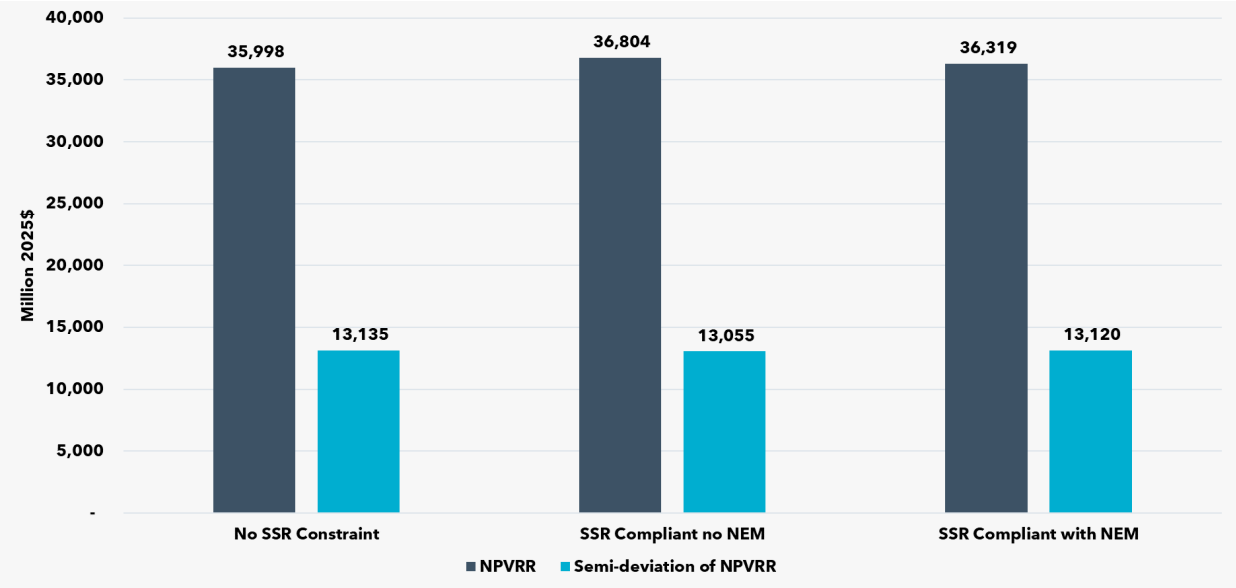
Table 35. SSR Compliance Position, 2030

Compliance Position	All NEM Remains Ineligible	All Customer Sited Eligible
2030 Compliance Need	738 MW	806 MW
Baseline Resource Contribution	560 MW	560 MW
Customer-Sited Contribution	0 MW	675 MW
Incremental Compliance Requirement	179 MW	0 MW

6.4.4 SSR compliance cost assessment

As discussed in **Section 5.4 SSR resource**, PGE used a modeling assumption that SSR resources cost eight percent more and have identical resource characteristics to utility-scale renewables. In order to assess the cost impacts of complying with SSR requirements in every year of the portfolio analysis time-horizon beginning in 2030, two portfolios were constructed. The first portfolio assumes that NEM is not eligible to contribute to compliance ('SSR Compliance No NEM'), and the second assumes that NEM is eligible ('SSR Compliance NEM'). Pairing of NEM solar with storage can increase the value of NEM resources and could plausibly be a consideration in future assessment of SSR eligibility; however, the 'SSR Compliance NEM' scenario does not incorporate any assumptions regarding storage addition. The costs of these portfolios, along with a portfolio that does not enforce SSR compliance, are shown in **Figure 83.** The cost of compliance in each of the two SSR scenarios can be illustrated by comparing the cost of these portfolios against that of the 'No SSR Constraint' portfolio. Results show that over the full analysis time-horizon, procurement of sufficient volumes of SSR resources increases net present portfolio costs by $806 million when NEM is not eligible and $321 million when NEM is eligible (due to costs incurred for compliance after 2036).

Figure 83. Cost Impacts of SSR Compliance



6.4.5 SSR acquisition strategy

As shown in **Figure 83**, significant customer benefit can be realized by reassessing the SSR eligibility of NEM capacity. This change would be fully consistent with Oregon statute as most recently revisited in HB 2021 and require only a Commission order, with no changes to administrative rules. As described in PGE's recent 2024 Distribution System Plan, PGE also is prioritizing deployment of a virtual power plant in which customer resources are harnessed for system benefit, akin to traditional supply-side resources. PGE looks forward to further progress on this topic as a key component of the SSR acquisition strategy.

In addition, PGE is pursuing the following resource acquisition actions, as discussed in the Action Plan:

- CBRE Acquisition
- All-Source Energy and Capacity procurement, in which PGE encourages offers from SSRs

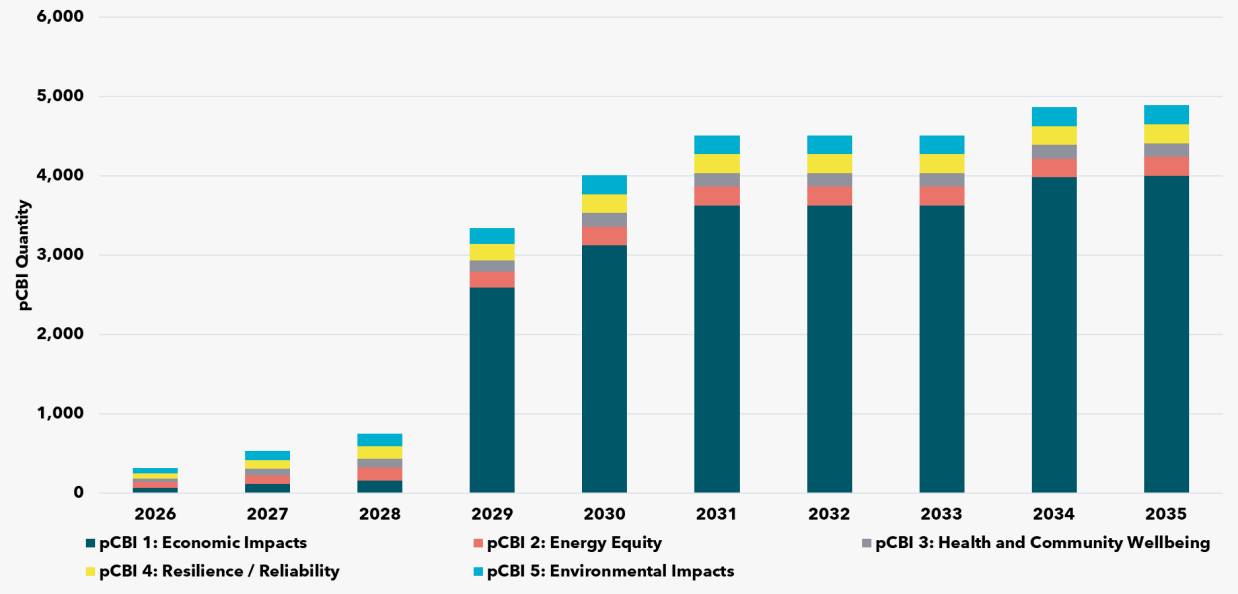
PGE believes incremental SSR procurement should only be pursued to the extent SSRs provide unique community benefits aligned with the CBRE acquisition pathway.

6.5 Portfolio CBIs

The cumulative quantity of each of the five pCBI scoring metrics through 2035 for the Preferred Portfolio are shown in **Figure 84**. A large increase in pCBIs generated can be seen in 2029, driven by the addition of substantial quantities of renewable resources, which generate economic community benefits (pCBI 1) when sited in OR. pCBIs 2-5 are generated by NCE EE and DERs and CBREs only and their quantities can be seen to increase through 2030 as additions of these resources are made to the portfolio. Because NCE EE and DERs and CBREs resources are not available for addition beyond 2030, the quantity of pCBIs 2-5 generated by the portfolio

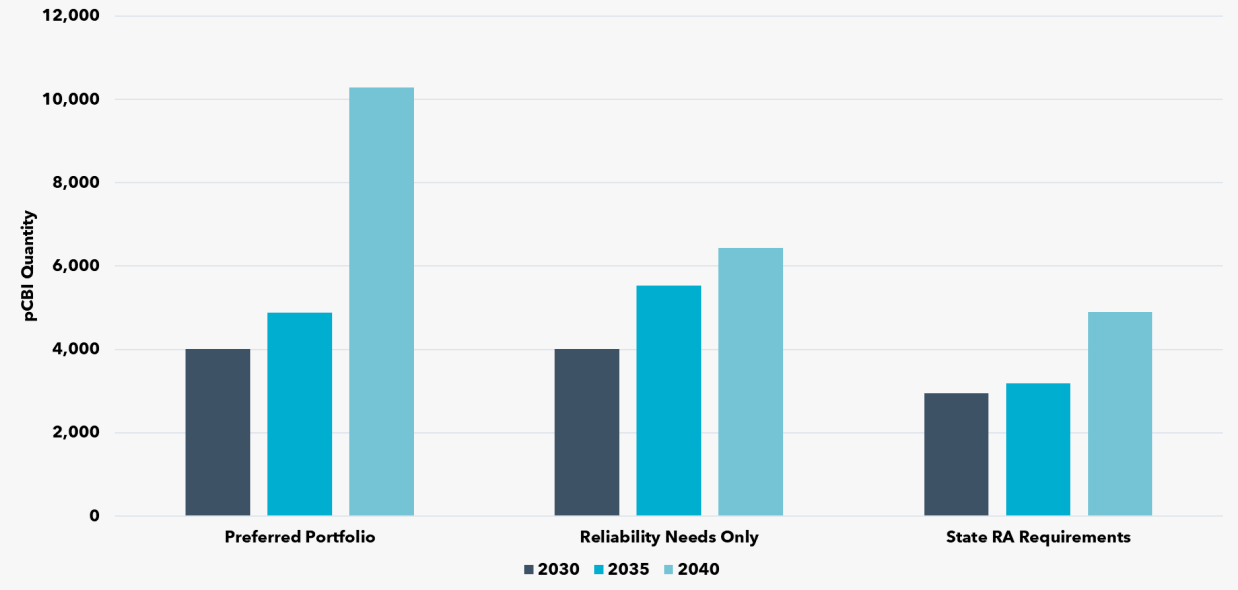
do not increase after 2030. Because of their very similar resource buildouts, the pCBIs generated by the 'rCBI' and three 'Market' scenarios are nearly identical to that of the Preferred Portfolio.

Figure 84. pCBIs of the Preferred Portfolio



Because pCBIs are unitless measures of community benefit, they are most useful in comparing the provision of benefits across alternative scenarios than as an absolute measure of community benefits. The total pCBI quantities of the Preferred Portfolio, and 'Reliability Needs Only' and 'State RA Requirements' scenarios are shown for 2030, 2035, and 2040 in **Figure 85**. Because the Preferred Portfolio has larger quantities of renewable resource additions, it generates more pCBIs than the 'Reliability Needs Only' and 'State RA Requirements' scenarios throughout the study period. In 2030 however, the 'Reliability Needs Only' portfolio generates more pCBIs than the Preferred Portfolio because it has a larger quantity OR renewables, which provide economic impact benefits (pCBI 1) than the Preferred Portfolio which relies more heavily on MT wind (which does not provide economic impact benefits due to it's out of state location). Intuitively, because larger quantities of resource additions generate more pCBIs, more expensive scenarios tend to generate more pCBIs.

Figure 85. Total pCBI Comparison

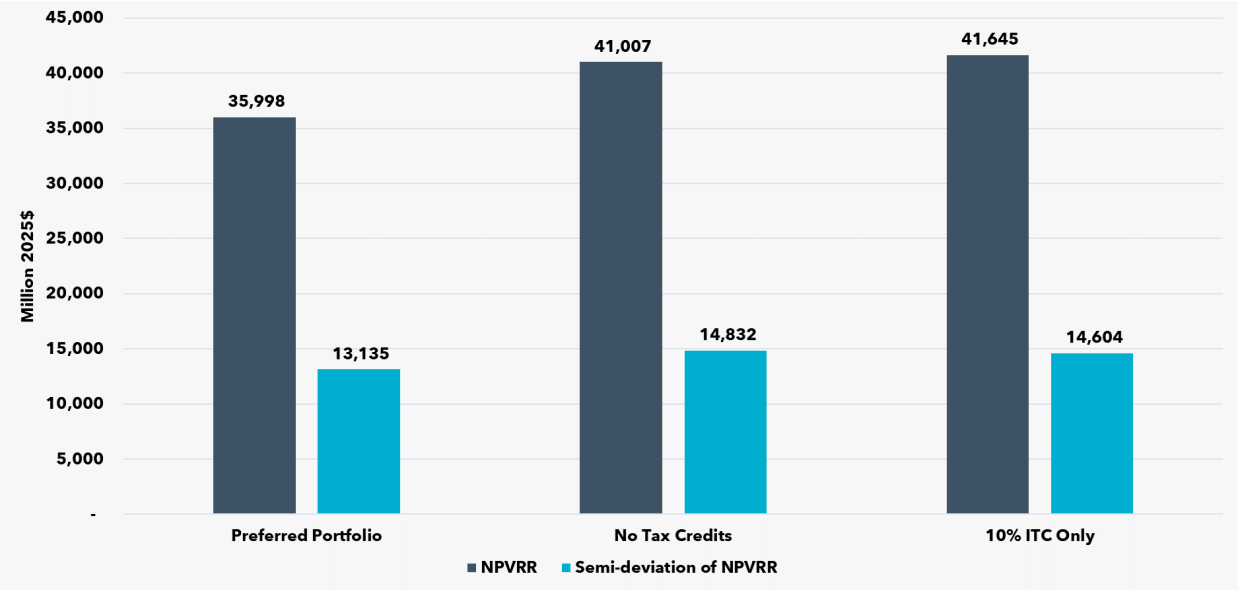


6.6 Federal tax credit availability scenarios

As noted in **Section 5.1.3 Tax credit sensitivities**, PGE's baseline resource cost assumptions assume the same tax credit environment for generation and energy storage resources as described in PGE's 2023 CEP/IRP. To help understand the potential impact on portfolio outcomes of changes to this set of assumptions, two sensitivities are considered: '10 percent ITC Only' and 'No Tax Credits'. In both scenarios, the costs of certain resources are increased relative to baseline assumptions. The impacts on resource costs of the change in assumptions in each of these scenarios are described **Section 5.1.3 Tax credit sensitivities.** The impact on portfolio composition and cost are explored through portfolio sensitivities in this section.

Both tax credit availability scenarios are modeled with identical assumptions to the Preferred Portfolio in every respect except for the changes to resource costs. The impact on portfolio costs and risk over the 20-year planning horizon in these two scenarios is shown in **Figure 86**. Intuitively, because resources are more expensive, portfolio NPVRR of each tax credit scenario is larger than the Preferred Portfolio. Relative to the Preferred Portfolio, NPVRR is $5,647 million larger in the '10 percent ITC Only' scenario and $5,009 million larger in the 'No Tax Credits' scenario. Reduction or removal of federal tax credits also increases the risk of costly outcomes outside of the Reference Case future, with increased semi-deviation of NPVRR across the 351 futures analyzed relative to the Preferred Portfolio.

Figure 86. Cost and risk of tax availability scenarios



Resource additions of the '10 percent ITC Only' and 'No Tax Credits' scenarios are shown in **Figure 87** and **Figure 88**, respectively. Portfolio resource buildouts of the scenarios are nearly identical to the Preferred Portfolio prior to 2032, with resource additions being driven by transmission constraints and the quantity of transmission available to the individual transmission zones. After 2031, the most notable changes associated with the re-optimized resource selection in both scenarios is a substitution of additional MT wind for some of the SE Washington wind in the portfolio. This effect is driven by the fact that a similar absolute increase in costs for both proxy resources produces a smaller relative increase in the cost of MT wind because it is more expensive, making MT wind relatively more cost-effective. In the '10 percent ITC Only' scenario MT wind increases by 570 MW, and in the 'No Tax Credits' scenario MT wind increases by 430 MW. The increases in resource costs did not create a meaningful shift in the relative cost-effectiveness between wind, solar, and storage resources.

Figure 87. Resource additions in 10 percent ITC scenario (MW)

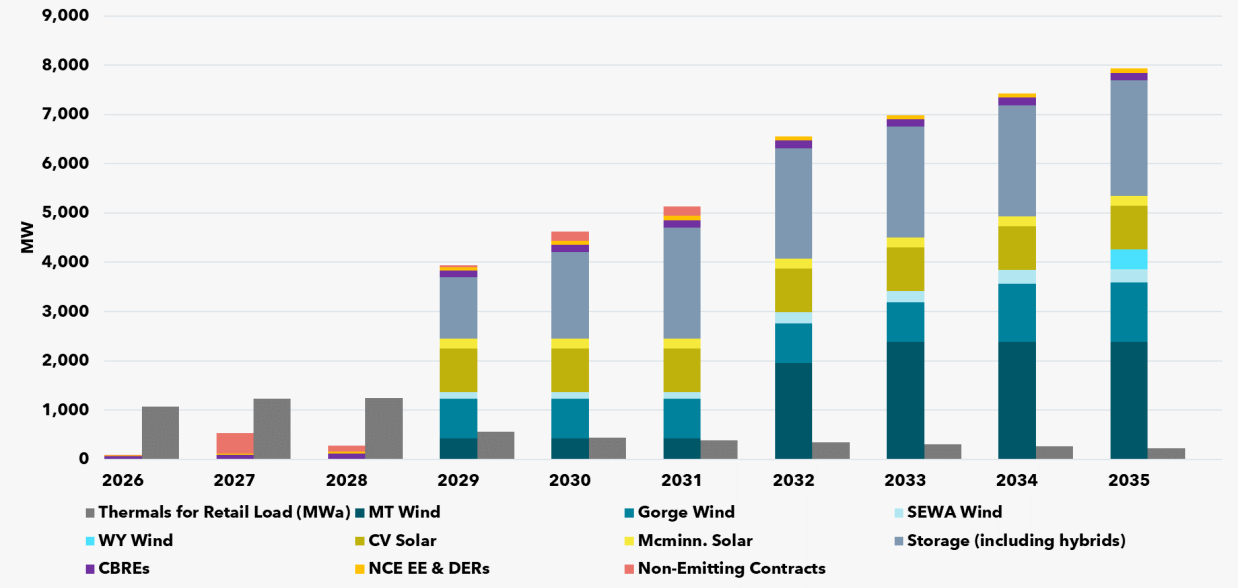


Figure 88. Resource additions in no tax credits scenario (MW)

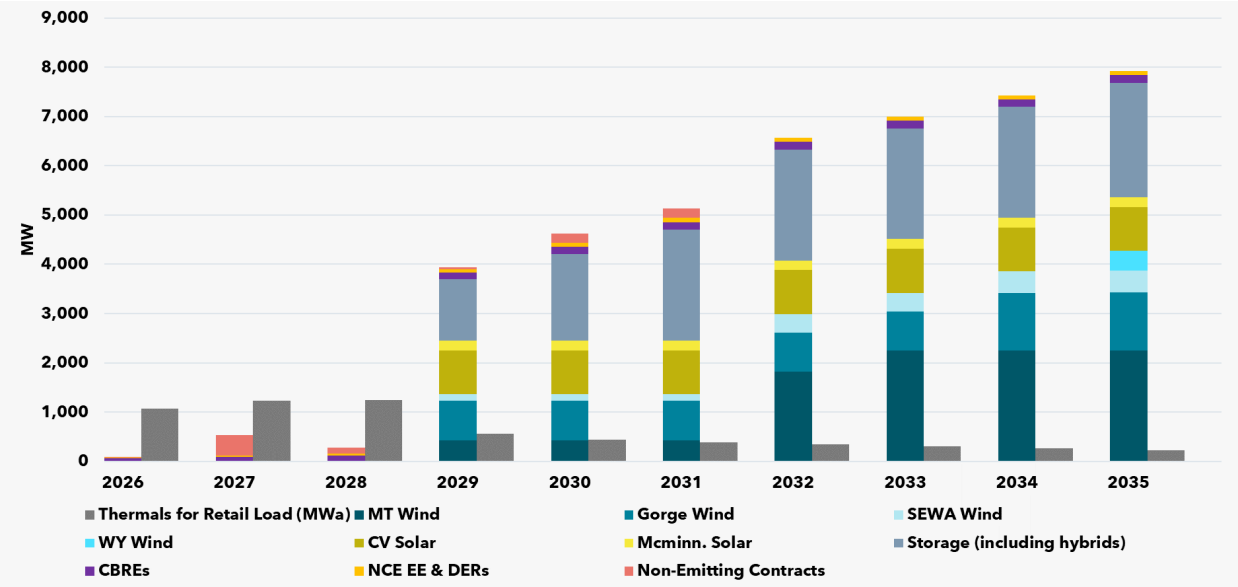


Figure 89 below reflects the annual change in the revenue requirement under all three tax scenarios. This is the incremental cost excluding the baseline existing resource costs. Those costs in addition to the existing portfolio costs results in the portfolio generation cost per MWh shown in **Figure 90**. The most notable changes occur in 2029 and 2040, where the Preferred Portfolio selects a large quantity of resources with large tax credits associated with them. Those cost savings are reduced or removed in the other scenarios.

Figure 89. Annual incremental revenue requirement by tax scenario ($k)

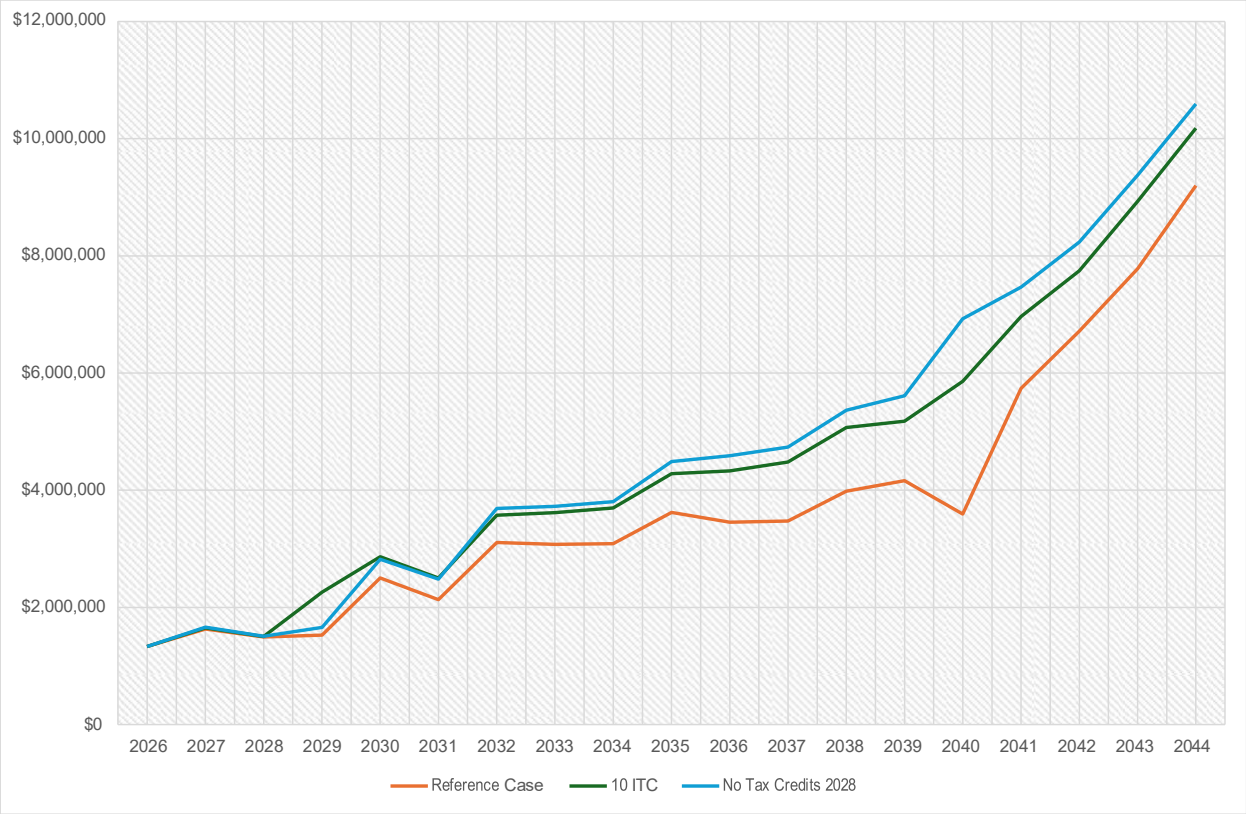
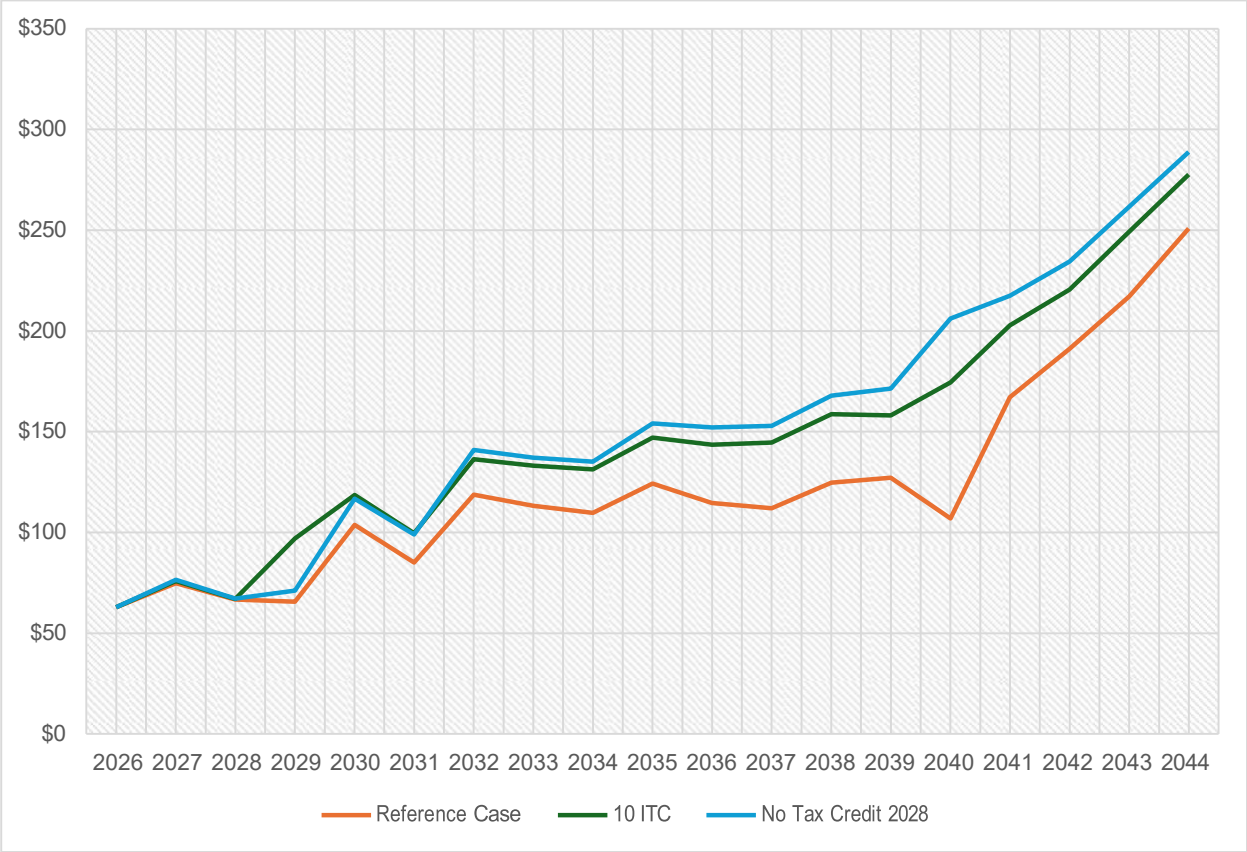


Figure 90. Annual portfolio generation cost by tax scenario ($/MWh)



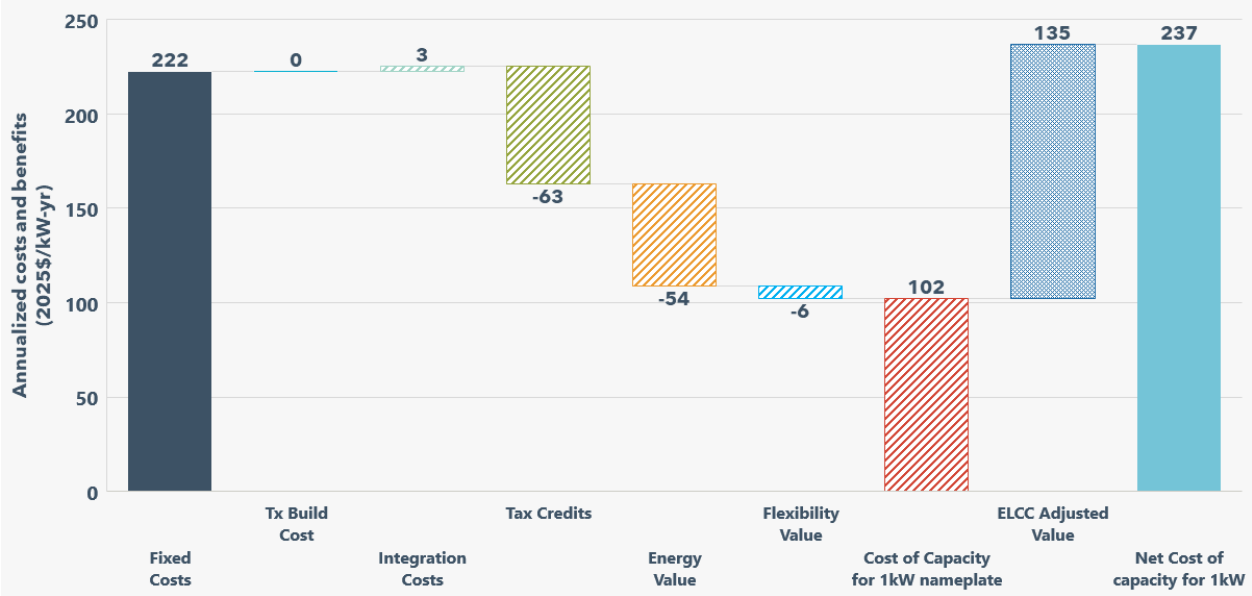
6.7 Net cost of capacity resources

Candidate resources described in **Section 5.1 Resource economics** flow into the portfolio analysis as well as provide inputs to determine resource capacity values and net costs. Additional specific cost or value assumptions to inform net costs are described below. The resource net costs are not used directly in portfolio analysis, though the resulting capacity value is useful for the purpose of comparing resources or for calculating the administratively determined avoided cost payments for resources procured outside of competitive or negotiated processes. This section provides an overview of updates to Section 10.6 of PGE's 2023 CEP/IRP on the net cost of capacity.

The components previously used to derive the net cost of capacity aligned with a 4-hour battery. However, given PGE's growing capacity needs driven by demand growth, reliability, and decarbonization targets, a battery may not be the most representative new resource due to reliable capacity performance limitations, especially in winter months. PGE continues to investigate alternative resource assumptions to inform net cost results. Presented in **Figure 91** is a bridge approach that looks across costs and benefits for each supply-side resource and weights their contribution to a portfolio-blended value based on each resource's nameplate capacity additions by 2030 in the Preferred Portfolio. Dollar amounts are presented on a levelized basis in 2025 dollars.

- The blended net cost of 1 kW nameplate is $102/kW-yr.
    - This amount is calculated as the sum of all the applicable costs net of any benefits (including tax credits) and represents the cost of capacity to procure 1 kW nameplate of the portfolio-blended proxy resource.
- The blended ELCC of the Preferred Portfolio new resource additions in 2030 is 43 percent.[155]
- The net cost of capacity is calculated by dividing $102/kW-yr by the ELCC of 43 percent, resulting in $237/kW-yr.
    - This represents the Net Cost of Capacity.
- The "ELCC adjusted value" noted in **Figure 91** represents the difference between the net cost of 1 kW nameplate and the net cost of 1 kW of capacity contribution.

Figure 91. Deriving the blended cost of 1 kW of capacity contribution



As discussed in **Section 6.2.3.1 Energy sensitivity adequacy assessment of Preferred Portfolio**, long-duration energy storage appears to possess valuable attributes for meeting PGE's future reliability needs. Preliminary analysis indicates that the net cost of capacity for a 100-hour energy storage resource could fall below the $237/kW-yr threshold detailed above. The assumptions of this initial analysis are summarized in **Table 36**.[156]

[155] This ELCC of each individual resource is based on an average of summer and winter firm capacity additions. The portfolio-blended average ELCC weights each resource's ELCC by its nameplate capacity added in the Preferred Portfolio by 2030.
[156] Cost assumptions from: https://formenergy.com/wp-content/uploads/2025/01/Navigating-the-Pacific-Northwests-Energy-Challenges.pdf

Table 36. Proxy 100-Hour Battery Storage Parameters (2030 COD)

Item	Unit	Amount
All-in Overnight Capital	2025$/kW	2,808
Fixed O&M	2025$/kW	24
Real Levelized Fixed Cost	2025$/kW-yr	218
Round-trip Efficiency	%	35
Useful Life	Years	20

Given the framework and assumptions presented above, the Cost of Capacity for 1 kW nameplate of the Proxy 100-Hour Battery Storage resource is detailed in **Table 37**.

Table 37. Proxy 100-Hour Battery Storage Net Cost of 1 kW Capacity (2030 COD)[157]

Net Cost Component	Unit	Amount
Fixed Costs	2025$/kW-yr	218
Energy Value	2025$/kW-yr	0
Flexibility Value	2025$/kW-yr	0
Cost for 1 kW nameplate	2025$/kW-yr	218
Annual ELCC (100 MW)	%	106
Net Cost of 1 kW Capacity	2025$/kW-yr	206

PGE's preliminary analysis estimates the annual ELCC for the first 100 MW addition of 100-hour energy storage at 106 percent.[158] The resulting Net Cost of Capacity for 1 kW of this resource, given the assumptions, would be $206/kW-yr. As noted above, the net cost of capacity is calculated by dividing the cost for 1 kW nameplate by the ELCC ($218 / 106 percent = $206). The Net Cost of Capacity is less than the $237/kW-yr threshold for ELCC values greater than approximately 92 percent.

[157] Energy and Flexibility values are assumed to be zero for the purposes of this exercise.
[158] Annual ELCC is the average of summer and winter ELCCs as estimated in Sequoia for the 2030 Reference case.

Chapter 7. Action Plan

PGE developed the Action Plan for the 2023 CEP/IRP based on the key findings of the Preferred Portfolio in the 2023 CEP/IRP. Though the Preferred Portfolio has been updated several times since (including this Update), PGE is not making changes to the Action Plan from the 2023 CEP/IRP, as the actions included continue to represent the best combination of cost, risk, community benefit, and emission reductions.

Chapter highlights

- PGE is not requesting Oregon Public Utility Commission acknowledgement of this Update and is therefore maintaining the Action Plan that was acknowledged as part of the 2023 CEP/IRP.
- PGE continues to identify the need for more RFPs to procure additional resources for resource adequacy, reliability, and compliance with HB 2021 GHG emissions targets.
- Updated analysis described in this Update suggests resource need has increased.

7.1 Action Plan

The five actions, as acknowledged by the Oregon Public Utility Commission in the 2023 CEP/IRP, are described in the following sections, as are the potential directional changes suggested by the updated portfolio analysis presented in **Chapter 6 Resource plan**.[159] PGE is not requesting acknowledgement of this Update, and this Action Plan is consistent with that acknowledged as part of the 2023 CEP/IRP.

7.1.1 Customer resource action

- *Action 1A. Acquire all cost-effective EE plus additional quantities identified in the CEP/IRP analysis*

PGE planned to acquire all cost-effective energy efficiency, which was forecast to be a cumulative 182 MWa for 2024 through 2028.

PGE identified 53 MWa of additional EE by 2030 as beneficial for customers over the planning horizon. Within this Action Plan window, by 2028, PGE aims to acquire 32 MWa at lowest cost.

Updated ETO forecasts described in **Section 5.3 Energy efficiency** project cost-effective EE to be 173 MWa for 2025 through 2028. PGE will continue to explore opportunities to deploy

[159] In the Matter of Public Utility Commission of Oregon, PGE 2023 IRP and CEP, Docket No. LC 80, Order No. 24-096 (Apr 18, 2024), Appendix A, p.5, available at https://apps.puc.state.or.us/orders/2024ords/24-096.pdf.

sensible EE measures. PGE will also continue to engage with ETO as guiding principles and potential securitization mechanisms regarding utility rate impacts due to cost-effective EE measures that are developed.

- *Action 1B. Incorporate customer demand response*

PGE planned to enroll distributed flexibility resources that customers choose to provide. By 2028, this is currently forecast to be a total enrollment of:[160]

- *211 MW of summer demand response (Low: 173 MW, High: 343 MW)*
- *158 MW of winter demand response (Low: 127 MW, High: 234 MW)*

Updated forecasts using PGE's AdopDER described in **Section 5.2 Distributed energy resources (DERs)** project increased program participation for a total of 1,269 MW on average from cost-effective DERs in 2030 (a 182 MW net increase from the 2023 CEP/IRP).

7.1.2 CBRE action

- *Action 2: Initiate a CBRE-focused RFP*

PGE planned to conduct an RFP targeting 66 MW of CBRE resources to come online by 2026.

PGE is conducting a request for offers (RFO) for CBRE resources to support a trajectory towards achieving the target from the 2023 CEP/IRP of 155 MW of CBREs by 2030. PGE's approach to the CBRE RFO has been informed by engagement with and input from community representatives, PGE's CBIAG, potential bidders, and OPUC Staff. Since CBRE is a new type of resource acquisition, PGE has been providing information and exploring appropriate regulatory treatment through regular updates to OPUC Staff. The RFO is open through November 2025, with three rounds of evaluation. PGE anticipates more details and results to be available for the next full CEP/IRP (2026).

7.1.3 Energy action

- *Action 3: Conduct one or more energy RFPs*

PGE planned to conduct one or more RFPs to add non-emitting resources to support progress toward meeting the 2030 emission targets established in HB 2021. The Reference Case need projected in 2030 was 905 MWa. Through 2028, PGE targeted acquiring 1,254 MWa, or one fifth of that need (251 MWa) per year in the Action Plan (2024-2028).

PGE's baseline portfolio, inclusive of proxy assumptions for procurement from the 2023 RFP, as well as increased EE and DERs, outweigh increased need associated with the new load forecast and other modeling updates. PGE's resulting energy need for 2030 described in **Section 3.3 Energy need** is estimated to be 1204 MWa. This could be thought of as 301 MWa of energy

[160] Demand response values include existing programs.

acquisition necessary in each of the next four calendar years to 2030. At the time of publication of this Update, PGE has two RFPs in progress.

7.1.4 Capacity action

- *Action 4a: Pursue capacity opportunities in the bilateral market*
- *Action 4b: Conduct one or more capacity RFPs*

PGE forecasted significant capacity needs in 2028: 905 MW and 787 MW in the summer and winter, respectively.

Updated analysis described in **Section 3.4 Capacity need** finds PGE's near-term capacity need through 2028 decreased due to supply side additions, namely bilateral contracts, and resource additions modeled as the 2023 RFP Proxy. The updated summer need is estimated at 47 MW in 2026, growing to 485 MW in 2027 with the expiration of hydro contracts with Grant PUD, then drops to 0 MW in 2028 as RFP Proxy Resources enter the modeled supply. In winter, there is 159 MW of need in 2027 that grows through the early years of the analysis period. Actual procurement from the 2023 and 2025 RFPs will seek to fill capacity needs, however, the forecasted near-term need cannot be met by RFP timelines and will therefore need to be addressed by commercial activity in bilateral market purchases.

7.1.5 Transmission expansion action

- *Action 5A: Develop a comprehensive transmission study regarding options to alleviate congestion on the South of Allston (SoA) flowgate*
- *Action 5B: Develop a comprehensive transmission study to explore options to upgrade the Bethel-Round Butte line (from 230 to 500 kV)*

Section 4.6 Transmission options for portfolio analysis describes modeled transmission expansion options through an approach that is consistent with the 2023 CEP/IRP and as informed by new third-party analysis described in **Section 4.5 Third-party assessment of PGE regional transmission options**. Continued study of transmission options will be critical to evaluating access to additional cost-effective clean energy resources ad capacity markets outside of the PNW.

7.2 Conclusion

The 2023 IRP Action Plan, as well as the 2023 and 2025 RFPs are designed to reflect PGE's values and commitment to serving customers with low-cost and clean technologies while mitigating future risks. The Action Plan was developed by estimating system resource needs using forecasts of long-term demand and projections of generation from existing and contracted assets. The difference between that estimated demand and existing supply forms the basis of forecasted system need. To fill that need, all available options and their potential costs and benefits in PGE's system were evaluated. The portfolio analysis was then tailored to answer the most critical questions PGE faces in long-term planning, comparing the relative performance of portfolios

with various combinations of supply-side options. A Preferred Portfolio was created with the best set of incremental resource additions that met system needs while minimizing cost and risk, while maximizing community benefits and considering emissions targets. Finally, an Action Plan was created to act on the key near-term drivers of the Preferred Portfolio. Concurrently with these actions, PGE will continue to work to specify sources of market purchases and accompanying emission rates, utilize funding opportunities to mitigate customer price pressure and implement transmission upgrades within PGE's Balancing Authority and connecting to BPA's system. These actions provide clarity on PGE’s priorities and become a tool for future conversation with customers, communities, stakeholders and the OPUC.

Appendices

Appendix A Federal grant funding

The Oregon Public Utility Commission directed PGE to include a report on federal incentive implementation relevant to resource procurement and transmission development.[161] This section outlines the federal grant programs PGE has engaged with, including awarded grants, denied grants, grants still in application phase and instances where PGE withdrew from the application process. As noted in **Section 2.5.2 Grant funding**, changes at the Federal Administration increase uncertainty to the delivery of funding from grants detailed below.

A. 1Grants awarded

Grid Services Demonstration Project – USDOE (GID01)

- Project partners: PGE (Lead), Bonneville Power Administration (BPA), Pacific Northwest National Laboratories (PNNL), Portland State University (PSU), University of Texas, Austin (UTA), GE Vernova
- Description: The proposed project will use technologies at the Wheatridge Renewable Energy Facility to create a demonstration concept to show how different types of active and reactive power controls can transform a renewable resource from a simple intermittent energy source to a resource capable of providing a wide range of grid services, such as inertia, voltage and frequency support. Thermal resources currently provide these services and the need to replace such grid stabilizing services will increase with thermal retirement.
- Areas of focus: Grid resiliency, grid modernization
- Project budget: $9-12 million **($4.5 million grant**; $4.5+ million match)
- Grant Phase: Execution

Park and Charge: Leveraging Utility Pole-Mounted Chargers to Increase Access to Overnight EV Charging in Portland, Oregon (GID13)

- Project partners: Portland Bureau of Transportation (PBOT) (Lead), PGE, Pacific Power, Forth, PSU, National Renewable Energy Laboratory (NREL), Columbia-Willamette Clean Cities Coalition
- Description: This project leverages PBOT's jurisdiction over parking policies and permitting of the public right-of-way (ROW) as well as PGE and Pacific Power's existing utility poles to offer an innovative charging solution that is low-cost, scalable, equitable, and accessible. This project will site and deploy 50 Level 2 EV chargers (40 by PGE) on utility-owned poles in the public ROW in existing on-street parking spaces with a focus on underserved communities who lack access to at-home charging.

[161] ORDER NO. 24-096 Staff Recommendation 8 available here: https://apps.puc.state.or.us/orders/2024ords/24-097.pdf

- Areas of focus: EV Adoption
- Project budget (PGE): $**40,000** PGE grant share
- Grant Phase: Execution

Quality Green Jobs Regional Challenge – Jobs for the Future (1st, 2nd , and 3rd phases) (GID14)

- Project partners: Oregon Clean Energy Coalition members (PGE applied on behalf of the Oregon Clean Energy Coalition)
- Description: The Quality Green Jobs Regional Challenge is an initiative that will invest nearly $5 million in communities across the country to develop and implement regional quality green job strategies reaching 25,000 individuals. The OCEWC was one of six regions chosen to participate in all three phases of the challenge. The first phase focused on engagement with key partners including labor, CBOs, employers, governments, and employers. The second phase of the grant focused on building a Quality Green Jobs Agenda included strategies for training and placing Oregonians into jobs within the clean energy sector as well as a statewide market assessment. Phase three will develop and implement an outreach and education model that will work with partners across the state to train and place 5,000 Oregonians in the clean energy sector.
- Areas of focus: Workforce development
- Project budget (PGE): $**10,000 (first phase); $75,000 (second phase); $750,000 (third phase). Pure grant,** no cost share requirement.
- Grant Phase: Execution

Bethel-Round Butte Transmission Line Upgrade (PGE a sub-applicant) - USDOE GRIP (GID05)

- Project partners: Confederated Tribes of the Warm Springs (CTWS) Lead, PGE
- Description: This project, a partnership between the CTWS and PGE, will upgrade the existing 230 kV Bethel-Round Butte Transmission line to 500 kV. The project will accelerate the much-needed development of transmission capacity, enabling new carbon-free generation in Central and Eastern Oregon to reach customer demand loads in Western Oregon, including PGE service territory. Grant funds will directly off-set PGE capital investment costs. The added capacity and associated upgrades will also increase resiliency of the transmission system as well as resiliency of the CTWS Tribal communities by increasing resources available to the Tribes to support adaptation and response strategies. Engineering studies are underway which may impact final project design. Project discussed in **Section 4.6.1 Bethel-Round Butte upgrade**.
- Area of focus: Grid modernization, reliability, decarbonization

- Project budget: ~$860 million ($**250 million grant,** $363 million match over 8 years)
- Grant Phase: Execution

Accelerating and Deploying Grid Edge Computing – US DOE GRIP Grant (GID02): DE-GD0000901

- Project partners: PGE (Lead), Oregon State University, Saturday Academy
- Description: The U.S. DOE selected Portland General Electric (PGE) for a $50 million matching funds grant to deploy Grid Edge Computing (GEC) at approximately 90,000 locations by 2029, across approximately 10 percent of its customer base. GEC is a combination of advanced computing power and software applications deployed on devices at the grid edge, accelerating PGE's grid transformation. The project will use near real-time information from edge computing devices to improve visibility of the electrical system, provide operational insights and improve outage response, and ultimately help to anticipate and mitigate the impacts of extreme weather on grid resiliency. Anticipated benefits include:
    - Local decision-making: Grid adjustments, like demand response, can potentially be made autonomously at the edge
    - Better integration of DERs: Seek to manage and optimize DERs such as EVs and storage at the grid edge
    - Near-Real-time monitoring and control: Detect and respond to grid issues, such as dynamic DER capacity constraints or issues with power quality
    - Improved reliability and resilience: Edge systems ensure critical functions are maintained even during network disruptions or cyberattacks. Customers benefit from fewer outages and more consistent energy delivery.

  Through edge computing and advanced algorithms that collect and analyze grid-edge data, this project will demonstrate how GEC can help accelerate the transformation of PGE's distribution system and help it meet clean energy targets. Advancements from this project that will accelerate grid transformation will be demonstrated through five technical use cases: 1. Real-time grid visibility, 2. Dynamic (near-real-time) DER local capacity insights, 3. DER integration and optimization, 4. Validating DER performance, and 5. Enhanced Grid Resiliency.
- Area of focus: Grid reliability, grid resiliency, grid modernization
- Project budget: Approximately $115 million ($50 million grant; $65 million match)
- Grant Phase: Post award execution

Renewable Hydrogen Production and Generation – USDOE (GID04)

- Note: June 4, 2025, PGE is withdrawing from this grant given the exit of an essential project partner, challenging project economics for utility customers, and potential federal policy changes. PGE does not see a viable path forward for the Boardman Hydrogen Project at a manageable cost.

  Note: PGE is withdrawing from this grant effective June 4th given the exit of an essential project partner, challenging project economics for utility customers, and potential federal policy changes. As a result, PGE does not see a viable path forward for this project at a manageable cost.

- Description: The project will install electrolyzers at PGE's Boardman site in Morrow County to produce hydrogen from renewable electricity, along with on-site storage and hydrogen-only peaker turbines to supply PGE customers with dispatchable non-emitting electricity. The project will also install a pipeline to the Port of Morrow to supply industrial hydrogen uses. Toward the end of the decade the project may add a hydrogen-only pipeline further east to the Port of Umatilla and Pendleton to supply additional uses of clean hydrogen. Project discussed in **Section 5.6.2 Hydrogen and ammonia**.
- Area of focus: Production of hydrogen from renewable electricity; energy storage; use of renewable hydrogen for industrial uses and power generation
- Project budget: $600K Phase 1 to PGE.
- Grant Phase: Execution

Critical Sector Job Quality – USDOL (GID03)

- Project partners: Oregon Clean Energy Workforce Coalition (PGE applied on behalf of the coalition), Clackamas Workforce Partnership, East Cascades Works, Oregon Building Trades and Construction Council, Bricklayers Local 1, Ironworkers Local 29, Cement Masons Local 555, Oregon Department of Corrections, CTWS, Oregon Higher Education Coordinating Commission
- Description: The Coalition's demonstration projects will support building the much-needed clean energy workforce in two distinct areas of the state – Clackamas County and Central Oregon. The first demonstration project will provide a 12-week pre-apprenticeship construction program to adults in custody that are getting ready to transition out of the correctional system. The second demonstration project will provide career learning and career exposure opportunities to opportunity youth (those not connected to work or school).
- Area of focus: Workforce development
- Project budget: Approximately **$3 million** from US Department of Labor; no cost share requirement
- Grant Phase: Execution

Proactive Human-Machine Teaming Enabled Cybersecure Technologies – USDOE Cybersecurity, Energy Security, and Emergency Response (CESER) (GID25)

- Project Partners: Pacific Northwest National Laboratory (PNNL) (Lead), University of Central Florida (UCF), New Jersey Institute of Technology (NJIT), Siemens Technology, PGE, and Florida Power & Light
- Description: The project will develop, validate, and field demonstrate (via red-team testing) human-machine teaming enabled AI/ML tools and algorithms (acronym: 'PROTECT') for operators to perform real-time detection, precise localization, and appropriate mitigation for a wide range of cyber-attacks on DER operations data. The proposed solutions primarily target the cybersecurity enhancement in a DER Operations Center (e.g., DMS/ADMS, DERMS, and DER Aggregators).
- Area of focus: Cyber security
- Project budget: $3.5 million over 3 years; $**200K** PGE no cost share
- Grant Phase: Execution

Forecasting Load and Demand Response during Heat Waves through Large-Scale Sensing and Data Fusion – USDOE (GID35)

- Project Partners: Lawrence Berkeley National Laboratory (LBNL) (Prime), PGE, NREL, AutoGrid
- Description: This project aims at developing novel methods and applications – based on large-scale sensing and data fusion techniques – to estimate the system load during heat waves, provide better forecasts for DR resources, unlock building demand flexibility, and provide information to utilities and ISOs on the process of planning emergency rotating power outages.
- Area of focus: Grid Resilience, Grid Modernization
- Project budget: $1.6 million, PGE In-kind only and no cost share
- Grant Phase: Close Out

Western-based Analysis of Distributed Battery Storage System Emission Benefits and Tradeoffs – USDOE (BENEFIT) (GID34)

- Project Partners: Johns Hopkins University (Prime), PGE, NREL, Columbia University, Arizona Public Service, Rocky Mountain Power, Mandalay Homes, SolarEdge, Sonnen
- Description: This team will evaluate the dispatch and emissions impacts of over 3,000 BESSs associated with residential utility programs in operation across three western-based utilities: APS, RMP, and PGE. The project team will also rely on product manufacturing partners (i.e., Sonnen, Mandalay Homes, and SolarEdge) to gather complementary data on the dispatch,

lifecycle emissions, and related impacts of over 20,000 BESSs nationwide. This information can be used to validate the existing emission benefits/opportunities for BESS, while modeling pathways to co-optimize emission reductions with benefits to the homeowner and utility grids.

- Area of focus: Grid Resilience, Grid Modernization
- Project budget: $1.6 million, PGE In-kind only and no cost share
- Grant Phase: Execution

Sensor Placement, Monitoring, and Data Analytics Platform (Sensor-MAP) – USDOE SETO (GID42)

- Project Partners: NREL (Prime), PGE, Duquesne Light Company (DLC), Open Systems International (OSI), Virginia Tech, Oakridge National Labs (ORNL)
- Description: National Renewable Energy Laboratory (NREL), in collaboration with Portland General Electric (PGE), DLC, OSI, ORNL, and Virginia Tech, proposes to develop and demonstrate Sensor Placement, Monitoring, and Data Analytics Platform (Sensor-MAP), and develop an extensible open-source software suite to perform multistage probabilistic optimal sensor selection and placement that includes observability quantification at both the system and individual state levels; steady-state and dynamic state estimation applications for distribution grids (D-SSSE and D-DSSE) with high levels of distributed energy resources (DERs), including solar photovoltaics (PV); and dashboards for enhancing situational awareness.
- Area of focus: Grid Resilience, Grid Modernization
- Project budget: $3 million, PGE In-kind only and no cost share
- Grant Phase: Negotiation

North Plains Connector – USDOE GRIP (GID20)

- Project Partners: Montana Department of Commerce (Prime), North Plains Connector LLC, Allete Inc, Standing Rock, Northern Cheyenne, Crow Agency, NorthWestern Energy, Basin Electric Power Cooperative, Montana-Dakota Utilities, Minnkota Power Cooperative, PGE, Puget Sound, Avista Utilities, Otter Tail Power Company, Berkshire Hathaway
- Description: NPC is a transformative transmission project that will establish a new 3,000 MW connection between Montana and North Dakota and the eastern and western electrical grids. Project discussed in **Section 4.6.5 North Plains Connector**.
- Area of focus: Grid modernization
- Project budget: Approximately $3.7 billion ($700 million grant (10 percent apportioned for Colstrip Transmission System upgrade); $140 million grant benefit to PGE)

- Grant Phase: Negotiation

Hydropower Incentives – USDOE (GID07, GID37, GID38, GID40)

- Project partners: PGE (Lead), Confederated Tribes of the Warm Springs
- Description: Hydropower facility resiliency, dam safety, and environmental projects at multiple facilities that meet the requirements of the FOA for improvements. Projects proposed at Pelton-Rd Butte, Blue Heron and TG Sullivan plants, and Faraday. Each FERC licensed area is eligible for up to $5 million in grants (70 percent cost share required). Administrative costs incurred by existing PGE staff.
- Area of focus: Hydropower operations
- Project Budget: **$11.3 million** from US Department of Energy for 4 sites
- Project Phase: Negotiation

A.2 Full applications submitted

Oregon Dept of Energy (ODOE) IIJA Resilience Grants - USDOE and ODOE (GID55)

- Project partners: PGE (Lead)
- Description: State formula grants from USDOE to ODOE to enhance electrical grid resiliency and mitigate impacts of wildfires. PGE proposes to expand the microgrid at the Salem Smart Power Center to enhance reliability to several City and State facilities.
- Areas of focus: Grid modernization, Grid resiliency, wildfire mitigation
- Project Budget: Up to $5.54 million ($5.54 million match)

Geothermal with Confederated Tribes of Warm Springs (CTWS) – USDOE (GID63)

- Project Partners: CTWS (Lead), PGE
- Description: Geothermal Resources' Value in Implementing Decarbonization
- Area of focus: Grid Resiliency, Grid Modernization
- Project budget: Grant $1.5M, No cost share requirement

A.3 Application interviews

Distribution System Operator with Virtual Power Plants, Dynamic Operating Envelope, and Competitive Market-Choice (DSO+3) – USDOE STRIVES Topic 1 (GID59)

- Project partners: PNNL (Lead), PGE, Oregon State University (OSU), University of Nevada, Reno (UNR)
- Description: Demonstration of a distribution system operator (DSO) model using (1) virtual power plants (VPP) operating in different modes with different parameters by different entities, (2) a topology- and physics-based dynamic operating envelope (DOE) function managed by the DSO, and (3) competitive market choice (CMC) for consumers through VPP selection and VPP diversity.
- Area of focus: Grid Modernization
- Project Budget: $3 million max grant

A.4 Grants not awarded

Bethel-Round Butte Middle Mile Fiber Project – NTIA (GID33)

- Project partners: PGE (Lead), Peak Internet, Link Oregon
- Description: The project will install a new fiber optic communications cable on the Bethel-Round Butte 230kV transmission path. Peak internet is partnering with PGE to provide broadband services to underserved communities along the transmission path and other partners will benefit from increased communications capabilities for university networks. PGE and BPA will partner to swap fibers for the benefit of both organizations in protecting critical generation and transmission infrastructure.
- Areas of focus: Broadband communications, grid resiliency
- Project budget: $65 million ($30 million grant; $35 million match)

Cybersecurity for Distributed Energy Resources – USDOE (CESER) (GID29)

- Project partners: NREL (Lead), PGE, Iowa State University, Portland State University, OpenEGrid, Avangrid, Xcel Energy
- Description: Develop a cyberattack-resilient DER infrastructure and communications architecture to comprehensively address confidentiality, integrity, and availability requirements in DER communications.
- Area of focus: Grid modernization

Carbon Optimization Framework for Energy Emissions (COFFEE) Grant (Non-IIJA) - USDOE

- Project partners: PGE (Lead), NREL, PSU

- Description: The COFFEE project aims to create a usable and repeatable guide for how to operate and optimize Battery Energy Storage Systems (BESS) and Electric Vehicle (EV) programs for decarbonization.
- Area of focus: Decarbonization
- Project budget: ~$1.5 million ($1.2 million grant, $300,000 match)

Distribution Grid Modernization for Reliability and Wildfire Risk Reduction – USDOE GRIP (GID08)

- Project partners: PGE (Lead), EPRI, PNNL
- Description: The Distribution Grid Modernization project will accelerate the modernization of the distribution grid with the implementation of a variety of technologies like distribution automation and early fault detection along with hardening techniques such as undergrounding of high voltage lines and the installation of covered conductors where appropriate within PGE's High Fire Risk Zones.
- Areas of focus: Wildfire mitigation, grid reliability, grid modernization
- Project budget: Approximately $213 million ($100 million grant; $113 million match)

Enhanced Wildfire Awareness Technologies and Visualization Platforms to Support Public Safety and Community Awareness Initiatives (PGE a sub-applicant) - USDOE GRIP (GID031)

- Project partners: EPRI (Lead), PGE, other confidential partners
- Description: The proposed project will enhance and unify situational awareness capability for wildfire incidents by deploying transformational technology solutions including AI enhanced imaging technologies and multi-purpose micro weather stations that would be integrated into a geospatially referenced data visualization system.
- Area of focus: Wildfire mitigation, grid modernization
- Project budget: Approximately $5 million ($2.5 grant; $2.5 million match)

Operation and Planning Tools for Inverter-Based Resource Management and Availability for Future Power Systems (OPTIMA) – USDOE (GID11)

- Project partners: WSU (Lead), PGE, Utilidata, SW Power Pool, Texas A&M, San Diego State University, Grid Protection Alliance
- Description: In this project, we propose the use of synchronized measurements, both synchrophasors and synchronized point-on-wave measurements, for deriving intelligence on the operational impact of IBRs on power grids.
- Area of focus: Grid modernization, Grid resiliency

Mt. Hood Corridor Resiliency Project (2022-2025) – FEMA (BRIC Grant) (GID16)

- Project partners: Clackamas County (Lead), City of Portland, PGE
- Description: The Mt. Hood Corridor Resiliency Project is a multi-phased critical infrastructure project supporting the resiliency of community lifelines in the northern region of the state. Stage 1 would underground the transmission and distribution lines that power the Bull Run Watershed, which is the primary drinking water supply for nearly one million people in the cities of Gresham, Portland, Fairview, Sandy, and Tualatin. This is the third attempt at this grant.
- Areas of focus: Wildfire mitigation, grid resiliency, grid modernization
- Project budget: Approximately $88 million ($50 million grant; $38 million match)

Undergrounding Powerlines to Reduce Wildfire Risk in National Forests 2024 – IFNF (GID46)

- Project Partners: PGE (Prime), USFS
- Description: Portland General Electric proposes partnering with the U.S. Forest Service to underground powerlines to reduce potential fire starts in a high wildfire risk zone of the Mt. Hood National Forest.
- Area of focus: Wildfire Mitigation
- Project budget: $500,000 (No Match)

Powering Climate and Infrastructure Careers Challenge - Families and Workers Fund – Private (GID28)

- Project Partners: Confederated Tribes of the Warm Springs (lead), PGE, Oregon Clean Energy Workforce Coalition
- Description: The project will support training the workforce needed to enable the state's clean energy transition with a particular focus on providing opportunities for tribal members in pursuit of the tribe's renewable energy development goals on the reservation.
- Area of focus: Workforce development
- Project budget: $1.5 million

Western Bounty Transmission - USDOE GRIP (GID19)

- Project Partners: Nevada Governor's Office of Energy (Prime), ENGIE North America, PGE, Los Angeles Department of Water and Power

- Description: A transformational project that will substantially increase transmission capacity throughout the Western Interconnection on an inter-regional basis while unlocking and enabling between 15-29GW (or more) of otherwise inaccessible high-quality remote renewable resources. Western Bounty is a multi-terminal and bi-directional voltage source converter (VSC) high voltage direct current (HVDC) system in a "hub and spoke" arrangement.
- Area of focus: Grid modernization
- Project budget: Approximately $12 billion ($1 billion grant, $11 billion match) PGE support only, no matching funds

Scale Smart Managed Charging and Enhance Grid Resilience through Enriched Grid Edge DERMS (DSO+3) – USDOE Connected Communities Topic 1A

- Project partners: PGE (Lead), OSU
- Description: Enrich PGE's Grid Edge Distributed Energy Resource Management System (DERMS) integrations to scale Smart Charge Management to more EVs in PGE's territory and to inform investigation of scalable, utility-side load optimization strategies and grid resiliency support.
- Area of focus: Grid Modernization
- Project Budget: ~$3 million

An Energy Resilience Planning Tool for PGE – USDOE CESER

- Project Partners: PGE (Prime), PNNL
- Description: PGE and PNNL have assembled an integrated team driven by common goals, led by experts in the key research areas, and supported by PNNL's institutional capabilities related to data hosting, live data feeds, high-performance computing, cybersecurity, all aspects of grid operations, T&D modeling, and energy assurance planning. PGE's EGRASS platform will leapfrog current solutions by integrating varied multi-hazard impacts into a high-resolution T&D system. The statistical analyses and microclimate forecasts will lead to more accurate outage forecast in advance of actual outages, minimizing customer impacts.
- Area of focus: Grid Resilience
- Project budget: Approximately $3.5 million ($1.2 million grant, $1.3 million match)

Wildfire and All Hazards Modeling and Mitigation Consortium – USDOE GRIP (GID09)

- Project partners: Avista Utilities (Prime), PGE, Chelan County Public Utility District, City of Drain, City of Monmouth, Consumers Power, Forest Grove Light & Power, Blachly-Lane Electric Cooperative, Clark Public Utilities, Northern Lights, Inc., Douglas Electric

Cooperative, Puget Sound Energy, Inland Power & Light Company, Kootenai Electric Cooperative, Northwestern Energy, Lawrence Berkeley National Lab, Pacific Northwest National Lab

- Description: Avista Utilities is partnering with utility experts from across the Pacific Northwest, National Laboratories, universities, and private innovators to combat increased wildfire and all hazard threats to the electrical distribution system. The consortium will develop a granular wildfire risk model and methodology, and high-definition weather model, enhancing all consortium members' ability to assess wildfire risk and inform all hazards mitigation decisions. The weather model will enable consortium utilities to better assess impacts and minimize operating risks to the electrical system from extreme weather events, including fire weather, in both real-time and for the planning horizon.
- Areas of focus: Wildfire mitigation, grid resiliency, grid modernization
- Project budget: Approximately $507 million ($250 million grant; $257 million match)

Mobile Batteries for Adaptive Resilience – USDOE GRIP (GID17)

- Project Partners: Avista Utilities (Prime), PGE
- Description: DOE funding would allow the project partners to develop and deploy an innovative battery solution to provide a more adaptive and resilient grid. Each microgrid will include one or more interfaces for fast connection of mobile energy storage systems, plus allow for expansion to include solar, EV charging, and additional storage.
- Area of focus: Grid resilience
- Project budget: Approximately $40 million ($20 million grant; $20 million match)

West Coast Real-Time Inertia Measurement Project – USDOE GRIP (GID21)

- Project Partners: RT Technologies USA INC. (Prime), CAISO/RC West, Southern California Edison, PacifiCorp, PGE, and EPRI
- Description: RT has developed an innovative, first of a kind technology which provides operators with access to unique highly accurate, continuous and direct, real-time inertia measurement and analytics data for the grid. GridMetrix® uses this patented, world-first, breakthrough method to maximize the safe and reliable integration of renewable energy. Grid operators can now make informed decisions about inertia level and renewable grid frequency stability. With a stable grid and rapidly scaling up renewables and scaling down fossil fuels, a net zero carbon grid can be achieved safely, reliably, and faster.
- Area of focus: Grid modernization
- Project budget: Approximately $30 million ($15 million grant, $15 million match)

Grid Copilot for an Electrified, Decarbonized & Empowering Grid – USDOE (GID61)

- Project Partners: GE Vernova (Prime), Florida Power & Light, Duke Energy, Commonwealth Edison, Portland General Electric, Avista Utilities, Alfred University, University of Central Florida, University of California Riverside, Amazon Web Services
- Description: Grid Copilot is powered by a physics-informed artificial intelligence (AI)-based digital twin of the grid, overcoming limitations with traditional engineering techniques, in providing real-time and predictive monitoring and situational awareness analytics, robust recommendations and automated solutions for digital grid control, big data validation and cleaning, online simulation coach to train utility workforce, and an agent to engage developers and communities suggesting a diverse mix of energy resources for accelerated interconnection.
- Area of focus: Grid Resilience/Modernization
- Project budget: Approximately $200 million ($100 million grant, $100 million match)

Weavegrid – USDOE GRIP (GID62)

- Project Partners: Weavegrid (Prime), PGE, Avista, PSE, PG&E, SCE, BGE, Xcel, Alabama Pwr, Georgia Pwr, TEP, PEPCO, Orange & Rockland, Eversource, Luma
- Description: Managed EV charging to enhance grid resilience.
- Area of focus: Grid Resiliency, Grid Modernization

Vegetation-based ignition risk characterization and comprehensive near-term wildfire risk mitigation – USDOE CESER

- Project Partners: GE Vernova (Prime), WSU, PGE
- Description: GEVAR team is proposing to create a comprehensive framework and tools to mitigate wildfire risk with optimized vegetation management and Public Safety Power Shutdown (PSPS) events as well as minimize the impact of PSPS on the communities.
- Area of focus: Grid Resilience
- Project budget: Advisory Committee Only

Hydropower Incentives – USDOE (GID39, GID41)

- Project partners: PGE (Lead), Confederated Tribes of the Warm Springs
- Description: Hydropower facility resiliency, dam safety, and environmental projects at multiple facilities that meet the requirements of the FOA for improvements. Projects proposed at Pelton-Rd Butte, Blue Heron and TG Sullivan plants, and Faraday. Each FERC licensed area is eligible for up to $5 million in grants (70 percent cost share required).

- Area of focus: Hydropower operations
- Project Budget: $11.3 million across multiple sites

A.5 Pending grant opportunities awaiting federal guidance

Distribution Grid Technology and Modernization Partnership – USDOE GRIP (GID06)

- Project partners: PGE (Prime), Umatilla Electric Coop, Eugene Water & Electric Board, Clark Public Utilities, Pacific Northwest National Labs
- Description: This project concept aims to remove barriers to participation by leveraging the ADMS and DERMS system already in service at PGE's state of the art Integrated Operations Center (IOC). A new, replicated system will be stood up for consortium utilities to manage and operate their distribution networks, in a secure geofenced segment of the system.
- Areas of focus: Grid modernization, DER integration
- Project budget: Approximately $100 million ($50 million grant; $50 million match)

Data Center Flexibility as a Grid Enhancing Technology - USDOE GRIP (GID18)

- Project Partners: Virginia Department of Energy (Prime), Maryland Clean Energy Center, Oregon Department of Energy, North Carolina Department of Environmental Quality, Amazon, Rappahannock Electric Cooperative, PGE, Georgia Power, PacifiCorp, North Carolina Electric Cooperatives, (Exelon), Intel, LevelTen Energy, Grid Forward
- Description: Utilities will invest in a range of grid-enhancing technologies to expand transmission capacity and support the more flexible interconnection of large data center loads. DC operators will leverage on-site generation, storage and load control capabilities to support regional grid operations. The utilities, operators and state energy officials will collaborate on potential new tariff designs, utility programs and cost-benefit assessments to replicate the concepts and capabilities demonstrated.
- Area of focus: Grid modernization
- Project budget: Approximately $700,000,000 ($250 million grant; $450 million match)

Agentic AI for Automated Interconnections – ConnectWerx, USDOE (GID67)

- Project Partners: ThinkLabs AI (Lead), PGE, ISO New England, NYISO, National Grid, TVA, UC Riverside
- Description: This project is expected to provide guidance on existing interconnection process and bottlenecks, data needed for building the AI models, evaluate results of AI-assisted analysis and compare against existing approach, and potential deployment in appropriate Cloud environment for end-to-end testing.

- Area of focus: Grid Modernization
- Project budget: Grant $12M+, No cost share requirement

Connected Communities – TechWerx (USDOE) (GID68)

- Project Partners: Resource Innovations (Lead), PGE
- Description: Resource Innovations will develop a platform to take in AMI and program participation data and produce per-participant, hourly grid impacts for demand response and flexible load measures that account for load diversity.
- solutions to support decarbonization and grid modernization efforts.
- Area of focus: Grid Modernization
- Project budget: Grant $1M, No cost share requirement

Appendix B Sequoia methodological update

PGE made one methodological update in Sequoia as part of the 2023 CEP/IRP Update. The result of this methodological change allows Sequoia to model the most recent 30 years of historical load and generation data, shifting the analysis period from 1992-2021 to 1994-2023. This shift in analysis period allows Sequoia to model more recent weather effects on load and variable energy resources.

Updating the analysis period in Sequoia required redefining the day-type characterization, or load bins, of historical days.[162] Consistent with past versions of Sequoia, load-bins are five equally sized percentile ranges (i.e. 0th-20th, …, 80th-100th) of weather-dependent load used to match demand with variable energy resources (VERs). Load-bins allow Sequoia to simulate various plausible load and VER generation scenarios under the assumption that temperature, load and generation from VERs are correlated. The effects from the updated analysis period are reported in two steps: 1) changes to the method used to estimate the 1992-2021 weather-dependent load from which load-bins are calculated; and 2) redefinition of load-bins using 1994-2023 weather-dependent load as estimated from the updated methodology.

For PGE's resource adequacy modeling purposes, weather-dependent load for years 1980-2019 was estimated at hourly intervals one time using a neural network model produced by external consultant, E3. IRP analysts incrementally added hourly load shapes for years beyond 2019, backward adjusting the incremental load to remove the influence of population growth, economic changes, and other influences on load that are not weather-dependent. The manual approach used to detrend load motivated the development of a more rigorous and reproducible methodology.

For the Update PGE developed a regression model to estimate weather-dependent load using fixed effects and daily weather measurements as specified in **Equation 1**.[163] Where $\widehat{Load}_{tt}$ is the estimated load in MW for hour *t*, given the daily temperature in degrees Celsius for midpoint, heating degrees, cooling degrees, maximum and minimum. XX_{iitt} represents various fixed effects as indicator variables for: year, month, hour, day of week, holiday, and weekend.

Equation 1. Weather-dependent load using fixed effects and daily weather measurements

$$\widehat{Load}_{tt} = \beta\beta_0 + \beta\beta_1 MMCCMMCCooCCccCCMMvvMMCC_{\dot{d}\dot{d}} + \beta\beta_2 HHvvCCCCCCccHHHHvvHHrrvvvvrr_{\dot{d}\dot{d}} + \beta\beta_3 CCoooovvCCccHHHHvvHHrrvvvvrr_{\dot{d}\dot{d}} + \beta\beta_4 MMCCMMMMvvMMCC_{\dot{d}\dot{d}} + \beta\beta_5 MMCCccMMvvMMCC_{\dot{d}\dot{d}} + \beta\beta_{ii} XX_{iitt}$$

[162] For more information on day-type characterization see 2019 IRP Appendix K.1.1.
[163] The IRP elected to use a random-forest algorithm due to improved out-of-sample accuracy compared to ordinary least-squares (OLS) regression. Random-forest estimation explained 98 percent of load variability with a mean absolute error (MAE) of 57 MW, while OLS estimation explained 93 percent of variability with MAE of 124 MW. **Equation 1** is specified as an OLS regression for interpretation purposes only, covariate weights for random-forest algorithms are not calculated as coefficients as in ordinary least squares.

The model was trained on a sample of 361,849 observations and tested on an out-of-sample set of 178,225 observations. Accuracy metrics on the out-of-sample set showed 98 percent of the variability in load was captured, with an average absolute error of 57 MW. After training the model, weather-dependent load was estimated by simulating historical hourly demand from 1960-2023 in MW from year 2023. Estimated capacity need for the 2028 reference case using the updated weather-dependent load profile is 11 MW and 13 MW greater for winter and summer, respectively. Finally, shifting the analysis period forward 2 years (1994-2023) and re-calculating load-bins using the updated weather-dependent load shape results in an additional 3 MW of winter and 33 MW of summer capacity need for the 2028 reference case.

Appendix C QF capacity update

As part of this Update, Qualified Facility (QF) capacity estimates were updated in Sequoia to align with contracted and online resources. Sequoia uses monthly estimates of QF MW capacity as proxied by six distinct resources: Biogas, Geothermal, Hydro, PV East, PV West, and Wind. Individual QF resources are grouped into the above categories to simplify modeling assumptions. Two assumptions are included in the estimation of QF capacity based on Order 24-96. The first is that for those QF projects that are contracted but not yet operating, it is assumed that 75 percent of the MW will reach operation. Second, a 75 percent renewal rate of QF capacity is assumed after contract termination. Estimated MW for the 2028 Reference Case are listed in **Table 38**, in addition to a comparison to pre-update modeling assumptions.

Table 38. Modeled QF Resources

Modeled QF Resource	2023 IRP (MW)	2023 IRP Update (MW)	Change (MW)
PV West	139.65	134.66	-4.99
PV East	263.25	234.25	-29
Biogas	5.2	8.92	3.72
Geothermal	0	0	0
Hydro	4.04	7.19	3.15
Wind	29.15	29.15	0

There is a net 27.12 MW reduction in QF capacity for the 2028 Reference Case. The 35 MW decrease in modeled resources is due to a 29 MW and 4.99 MW reduction in capacity for PV East and PV West, respectively. An increase of 3.72 MW and 3.15 MW of Hydro and Biogas resources, respectively, account for the remaining differences in estimated QF capacity.

Appendix D Hourly emissions methodology

This section outlines the steps that PGE has taken to update its GHG emissions forecasting to incorporate hourly analysis of its energy and emissions accounting.

These steps make assumptions about thermal generation and market purchases specified in the IGHG model to produce an hourly system position and resulting emissions impacts using the following:

- An alternative approach to production cost modeling that balances the hourly system position in Aurora to produce an hourly allocation of IGHG-constrained thermal generation, hydro and storage dispatch optimized around serving PGE retail load and provide the final validation of the Preferred Portfolio by generating a resource dispatch output that results in a system position consistent with HB 2021 compliance.
- An allocation of IGHG-allocated market purchases across hours of remaining need.
- An hourly accounting of the availability and price premium associated with a WECC-wide clean energy surplus estimate. These estimates were estimated by The Brattle Group and are used to reflect the contribution that the non-emitting market can provide in supporting PGE's hourly energy position.

D.1 Challenges with existing IRP emissions reporting

In the 2023 CEP/IRP, the PZM was used to simulate PGE existing dispatchable generation resources, contracts and new resources using economic dispatch based upon electricity prices[164]. The electricity prices contained risk variable inputs that vary across each of the 39 forecasts of electricity prices. When a resource is economically dispatched, market price exceeds the variable cost of operation.

The PZM simulation forecasts total resources generation but does not distinguish between generation associated with retail load and wholesale sales. This gap was addressed using the IGHG model. This step used the GHG emissions reduction glidepath and historical estimates of wholesale market transactions to estimate the amount of energy dedicated to wholesale sales and the amount of energy dedicated to PGE retail load service for each GHG-emitting source. The estimated amount of emitting energy used for PGE retail load service is incorporated into the capacity expansion model (ROSE-E).

By economically dispatching PGE resources to the price forecasts simulated by the WECC model, PGE is assuming the presence of a regional market in which PGE is a pure price taker. Relative to the size of the entire Western Interconnect, PGE comprises less than 3 percent of the total load as measured by peak loads. No quantity of PGE market purchases or market sales will change the WECC price forecasts. Adapting this methodology to demonstrate that PGE is compliant with HB 2021 emissions requirements is difficult given that partitioning emitting

[164] Outlined in Appendix H.1.2 of PGE's 2023 CEP/IRP.

energy to wholesale sales from retail load service is a complex modeling challenge. This is the original reason for using the intermediate IGHG Model as a bridge between production cost and capacity expansion models.

PGE can allocate thermal generation to serve retail load (up to the emissions target for HB2021 compliance) or sell it to the wholesale market. In prior analysis, PGE experimented with post-model adjustments to thermal dispatch that removed thermal dispatch directed to serve wholesale sales by prioritizing thermal generation for when retail load hours are shortest (deficit-sorting) and during hours when prices are highest (price-sorting).[165] Neither method allowed the model to co-optimize thermal generation with other dispatchable resources such as storage or hydro. The result presented an improvement in the hourly representation of PGE system, but the methodology leaned on out-of-model adjustments.

At this point there is no simple way to develop market logic in Aurora that would allow thermal units to choose between unconstrained wholesale sales and constrained retail load service within the PZM in time for the 2023 CEP-IRP update. The current methodology in the PZM uses WECC input price forecasts to dispatch resources. The methodology in which resources are dispatched to forecasted market prices is limited in its ability to represent the disaggregation of thermal generation into an unconstrained wholesale market and retail load service with an annual emissions cap.

The remainder of this appendix shows the methodology used to adapt PGE's production cost model to better represent PGE's hourly energy and emissions position in 2030. Section D.2 provides the change in model dispatch logic that addresses the challenges described in the previous section while discussing how thermal generation is allocated to retail load subject to the HB 2021 emissions constraint. Section D.3 discusses modifications to the dispatch of storage generation that result from the change in modeling logic. Section D.4 shows how non-emitting market availability is incorporated in the new hourly energy and emissions modeling.

D.2 Modifications to model dispatch logic and thermal dispatch

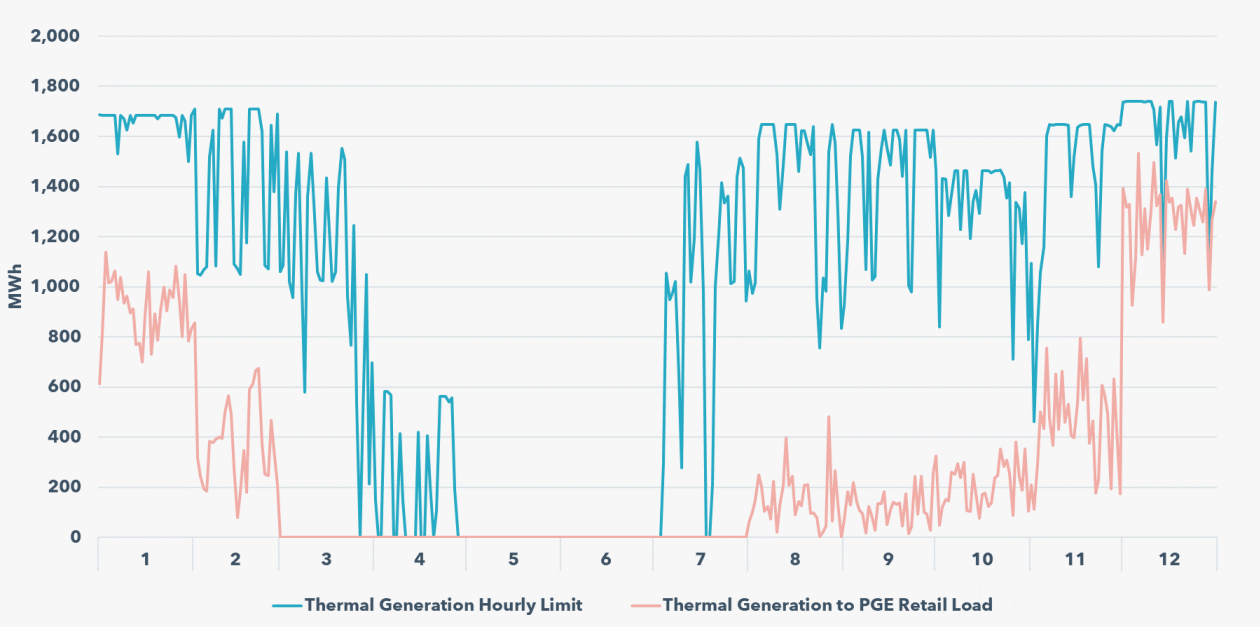
To solve the problem identified in **Section D.1**, PGE has modified the PZM to dispatch PGE resources at minimum cost subject to the constraint that retail load obligations are met with the HB 2021 annual emissions cap in place. This model is called the Modified PZM. The effect of changing the dispatch logic from dispatching resources to price to dispatching resources to meet retail load allows PGE to model how PGE's Preferred Portfolio can meet its hourly retail load requirements and comply with the annual GHG emissions limit. The model can choose the timing of the thermal dispatch from the total economic dispatch (both retail load service and wholesale sales) that is previously determined in the PZM. The Modified PZM will dispatch the portion of that thermal generation allocated to serve retail load service from the IGHG model. This is represented in the Modified PZM by an hourly cap on emissions (by thermal resource) determined by the total economic dispatch level set by the PZM. This allows the Aurora

[165] Portland General Electric Company. (2023, November 21). LC 80 – Portland General Electric Company's 2023 Clean Energy Plan and Integrated Resource Plan: Reply to Staff Round 2 Comments and Recommendations.

optimization to select the hourly profile of the total annual thermal energy dedicated to serve retail load as calculated in the IGHG Model.

Hourly thermal limits are also placed on thermal generation to prevent using thermals during hours deemed uneconomic in the PZM (where resources are dispatched against WECC-wide market prices). This is depicted as the blue line in **Figure 92**. The red line provides the timing of thermal output used to serve PGE retail load in the mPZM.

Figure 92. Thermal Generation Hourly Limits & Thermal Generation to PGE Retail Load by Month

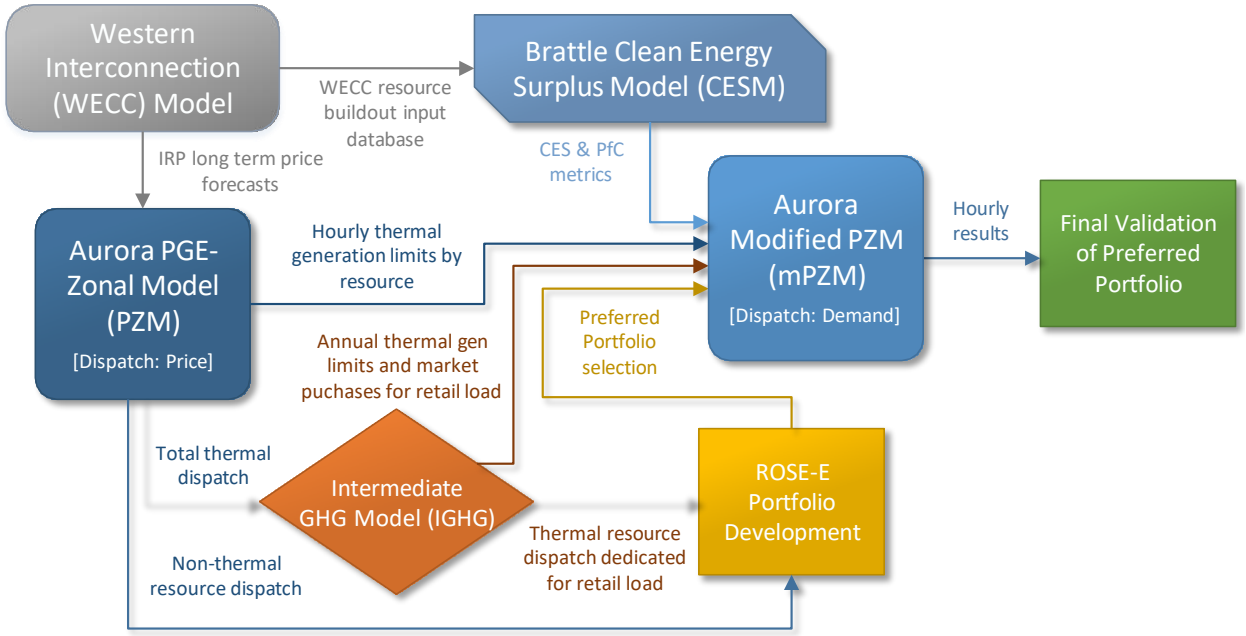


The results of the Modified PZM system dispatch are sent to the excel-based Hourly Energy and Emissions Accounting Workbook (Hourly Workbook). The Hourly Workbook is designed to apply the IGHG-allocated unspecified market purchases using the price-sorting methodology. Any remaining short energy position is applied the unspecified emission rate of 0.428 mmtCO2e in accordance with the Oregon DEQ reporting methodology in OAR Chapter 340, Division 215. From this, the emissions impact is calculated and the determination of compliance with HB 2021 is made based upon the modeled selected portfolio.

In addition, the Modified PZM incorporates hourly information about the availability of clean energy from the market and the corresponding price premium attached to this clean energy. **Section D.4 Incorporating non-emitting market generation** discusses how the market for non-emitting energy is incorporated into the Modified PZM.

Figure 93 below outlines the flow of data and connectivity between the models as it pertains to hourly energy accounting.

Figure 93. IRP modeling diagram Hourly Energy Accounting



The purpose of the Modified PZM Aurora model and hourly workbook is to (1) provide ROSE-E with information on the remaining short positions after applying the IGHG-allocated thermal generation and market purchases such that ROSE-E can weight its portfolio selection as outlined in Portfolio Analysis and (2) determine whether the portfolio of resources selected by ROSE-E provides sufficient resources to meet hourly retail load requirements and GHG-compliance needs. The Modified PZM model is focused on calculating the 2030 energy position to meet hourly retail load obligation and emissions compliance constraints and does not calculate energy values for purposes of minimizing net cost in portfolio optimization. That function remains the purpose of the PZM.

D.3 Change in storage dispatch logic

In the PZM, storage dispatch only considers the value of price arbitrage, or the ability to reshape energy across the day by charging when prices are low and discharging when prices are high. If the dispatch of thermal resources is not constrained by emissions, then this dispatch outcome is the lowest cost solution subject to the parameters chosen.

However, given the constraints imposed by HB 2021, the dispatch of storage resources should include the opportunity cost of emissions. Within any given emissions budget, an additional ton emitted from one generation resource requires a reduction of one ton from somewhere else. The opportunity cost of an additional emission is the cost of this offsetting reduction in generation. Since the cost of the offsetting reduction in generation is not included in the storage dispatch logic, the PZM results will be sub-optimal under the following outcomes:

- Storage discharged to provide energy in excess of retail load due to high prices. This energy could have been saved for another hour in which PGE is short and the market price is lower (displacing emitting resources or market purchases in future hours). The

price difference between the high-priced hour and the low-priced hour must be less than the opportunity cost of emissions.

- Storage is charged to consume energy in deficit of retail load due to low prices. This energy could have been consumed during another hour in which PGE is long and market price is higher (displacing emitting resources or market purchases in current hour). The price difference between the high-priced hour and the low-priced hour must be less than the opportunity cost of emissions.

This problem is solved by changing the model dispatch logic such that storage resources are dispatched economically to internally generated hourly prices that are solved by using model supply and demand conditions instead of by using externally-provided forecasted input prices as is used in the PZM. This change in logic prioritizes storage dispatch to move energy across the day from hours in which PGE has excess energy to hours in which PGE has excess demand instead of prioritizing storage dispatch logic to arbitrage market prices. This is useful in maximizing the displacement of emitting thermal generation using storage to meet system needs and provides a better representation at how well the Preferred Portfolio can meet PGE system needs when PGE's system is emissions constrained.

D.4 Incorporating non-emitting market generation

The yearly IGHG model in the 2023 PFC/IRP utilized an assumption that PGE was able to rely upon market purchases above the allocated market purchases in the IGHG model at times in which it was short. With this assumption, the average hourly position was 9 MWa long in 2030.[166] This conclusion relied on the assumption that PGE will be able to sell emitting generation at no price discount for market sales above those allocated by the IGHG model. Inversely, this conclusion also relied on the assumption that PGE will be able to access non-emitting generation at no price premium for market purchases above those allocated by the IGHG model.

- If this assumption was true, then this analysis indicated that meeting emissions targets with the Preferred Portfolio's set of incremental resource additions is possible under expected conditions.
- If this assumption was false, then both PGE and Staff's draft analyses were in alignment. Both pointed to a need for an increased quantity of non-emitting generation to be acquired between now and 2030 to ensure compliance with HB 2021 under expected average conditions.

PGE recognized that if there is no market to buy non-emitting energy in the hours that PGE is short, forecasted need required allocating additional emissions to those market purchases to balance. In the analysis provided in LC 80: PGE's Reply to Round 2 Comments, PGE

[166] Portland General Electric Company. (2023, September 6). *LC 80 – 2023 Clean Energy Plan and Integrated Resource Plan: Reply to Round 1 comments* (p. 53). Oregon Public Utility Commission. [https://edocs.puc.state.or.us/efdocs/HAC/lc80hac131341.pdf]

demonstrated that under the condition of no market for non-emitting generation, additional resource procurement would be needed to comply with annual cap on GHG emissions.

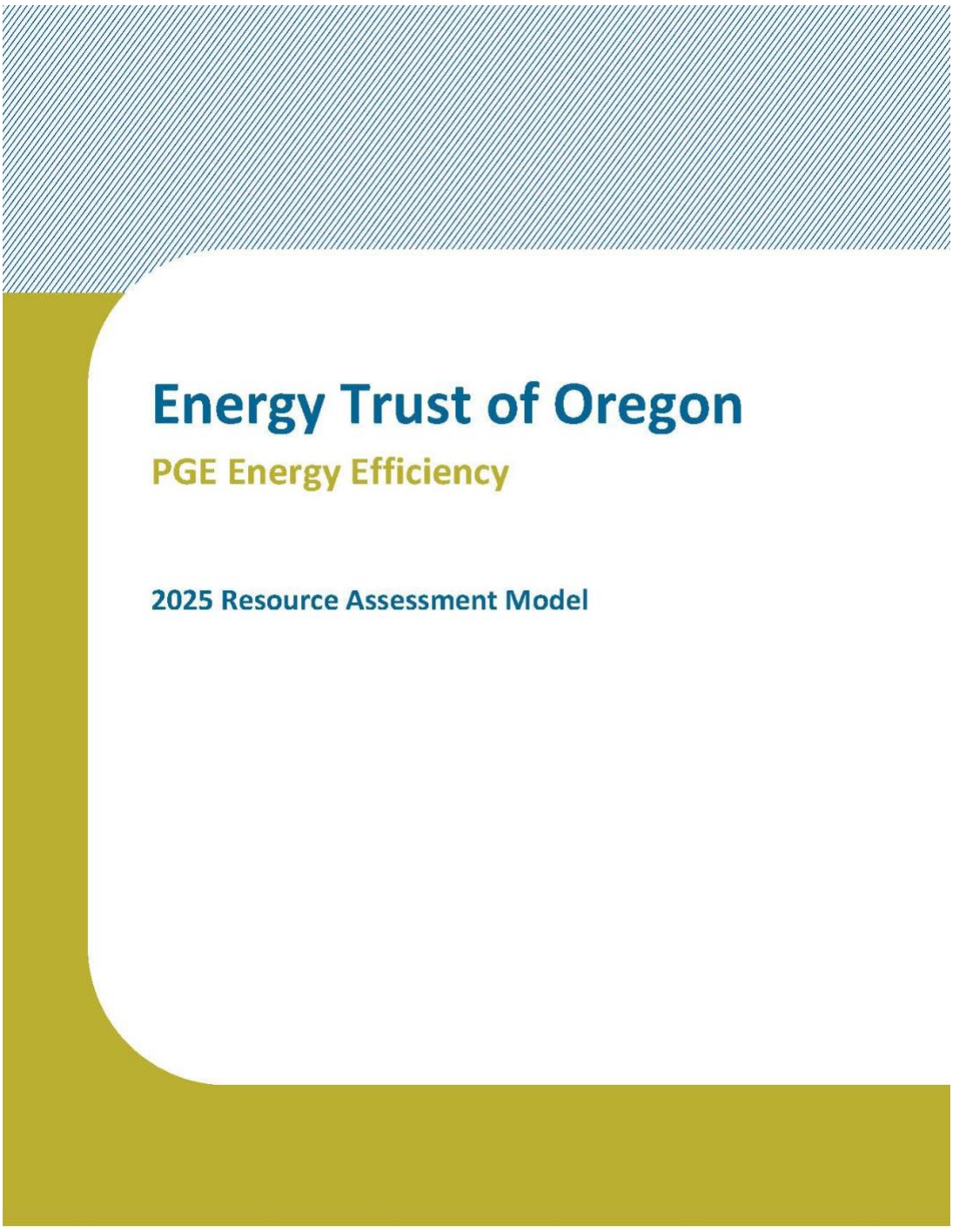
In response to these concerns, PGE contracted The Brattle Group to develop a high-level framework for estimating WECC-wide and regional analysis of the market for non-emitting energy to serve as an input into the hourly energy and emissions accounting modeling. The Brattle Group performed an analysis of the regional WECC market and provided PGE with forecasts of the availability and price premium of non-emitting or clean energy available to PGE in 2030. The Clean Energy Surplus (CES) is the clean energy available beyond that which is needed to meet annual state-level clean energy targets and the Premium for Clean (PFC) is the additional cost beyond the energy price associated with the purchase of surplus clean energy.

Brattle used PGE's IRP Aurora results from the Regional WECC model that is used to generate PGE's IRP Price Forecasts and other input parameters capturing regional data on state clean energy requirements to calculate the CES. After allocating the annual CES across hours of the year, Brattle applied deliverability constraints to determine how much CES is available to PGE in Oregon West for each hour of 2030. In addition, Brattle used the CES to calculate the PFC by hour in the analysis. For a detailed description of the Brattle Analysis, read **Appendix F Market for non-emitting energy**.

The Modified PZM incorporates the CES and PFC by including the CES as a market resource available up to the hourly deliverable energy to Oregon West Zone. This market energy is priced at the sum of the forecasted Oregon West hourly price plus the hourly PFC. The Modified PZM optimizes dispatchable generation and available non-emitting market purchases to leverage PGE's generation, contracts, and the regional diversity in clean energy to meet its HB 2021 compliance goals.

When the results of the Modified PZM analysis contains a summation of short hours less than the quantity of unspecified market purchases, the hourly workbook reallocates non-emitting market purchases to replace non-emitting market purchases to that extent that the full IGHG allocation is exhausted. This is accomplished by replacing the hours with the largest Premium for Clean first as ranked from highest to lowest. Given a budget of unspecified market purchases, total cost will be minimized by purchasing unspecified energy instead of clean energy from the market when the Premium for Clean is highest. This method is also indicative of the likelihood of finding energy in the clean energy market—it will be more difficult to procure clean energy when the Premium for Clean is non-zero.

Appendix E Energy Trust of Oregon (ETO)



Energy Trust of Oregon Background

Energy Trust of Oregon, Inc. (Energy Trust) is an independent nonprofit organization dedicated to helping utility customers in Oregon and Southwest Washington benefit from energy efficiency and renewable power. Energy Trust operates under a grant agreement with the Oregon Public Utility Commission (OPUC).

As a result of state legislation, tariffs and other requirements, Energy Trust is funded by customers of Portland General Electric, Pacific Power, NW Natural, Cascade Natural Gas and Avista. Energy Trust's model of delivering energy efficiency programs unilaterally across the service territories of the five gas and electric utilities they serve has experienced a great deal of success. Since the inception of the organization in 2002, Energy Trust has achieved total annual savings of 1,025 aMW of electricity. Additionally, Energy Trust has saved 103 million therms since gas efficiency programs began in 2003. Combined, this equates to more than 40 million metric tons of CO2 emissions avoided, and Energy Trust has played a significant factor with relatively flat energy loads observed by both gas and electric utilities from 2014 to 2023, as shown in OPUC utility statistic books.[1]

Energy Trust, with support from PGE, serves residential, commercial and industrial customers in Oregon. In 2024, Energy Trust's service to PGE customers through energy efficiency programs achieved 37.8 aMW of electric savings achieving 132% of goal. Energy Trust achieved electric savings at a utility levelized cost of 0.035$/kWh, meeting OPUC performance measures to achieve electric savings at a levelized cost below 0.046 $/kWh.

PGE actively promotes Energy Trust offerings to its customers and supports their participation in Energy Trust efficiency programs. Also, when shared technologies and programs are mutually beneficial, PGE coordinates its demand response program activities with Energy Trust's energy efficiency programs. For example, smart thermostats are used by PGE for demand response, but also provide energy efficiency savings, which the Energy Trust counts towards its energy saving goals.

In addition to administering energy efficiency programs with support from PGE, Energy Trust also provides a 20-year demand-side management (DSM) resource forecast to identify cost-effective energy efficiency savings potential. This forecast examines how much of that potential is estimated to be achieved by Energy Trust over the 20-year period. The results are used by PGE and other utilities in Integrated Resource Plans (IRP) to inform the energy efficiency resource potential Energy Trust expects to acquire in their territory, helping to offset the need for new generating resources to meet projected load growth.

Energy Trust Forecast Overview and High-Level Results

Energy Trust developed a 20-year DSM energy efficiency resource forecast for PGE using Energy Trust's resource assessment modeling tool (hereinafter 'RA Model') to identify the total 20-year cost effective modeled energy efficiency savings potential. Energy Trust then deploys this cost-effective potential exogenously to the RA model into anannual energy efficiency savings projection based on past program

[1] OPUC 2023 Stat book - IO Year Surmnary Tables: https://www.oregon.gov/puc/forms/Forms%20and%20Reports/2023-0regon-Utility-Statistics-Book.pdf

experience, knowledge of current and developing markets, and future codes and standards. This final 20-year savings projection is provided to PGE for inclusion in their Integrate Resource Planning (IRP) forecasts. The 2025 IRP results show that PGE can save 171.7 average megawatts[2] (aMW) in the next five years from 2025 to 2029 and over 675 by 2043.[3]These results represent an 11% and 22% increase respectively in deployed cost-effective DSM potential over the prior IRP in 2023. The main drivers of this increased potential are:

1. Growth in the PGE load forecast, most notably in the commercial sector.
2. Growth in avoided costs.
3. Updated measure assumptions, new measures and updated market characterizations.
4. Lighting market transformation and HB 2531. While Energy Trust will not claim the bulk of these savings, they are still expected to come off PGE's system and thus savings are included in this forecast.
5. Residential electrification.

Figure 1 depicts the full suite of savings potential identified in the model by potential type (Technical, Achievable, Cost-effective achievable).

Figure 1 - 20-year Savings Potential by Sector and Potential Type

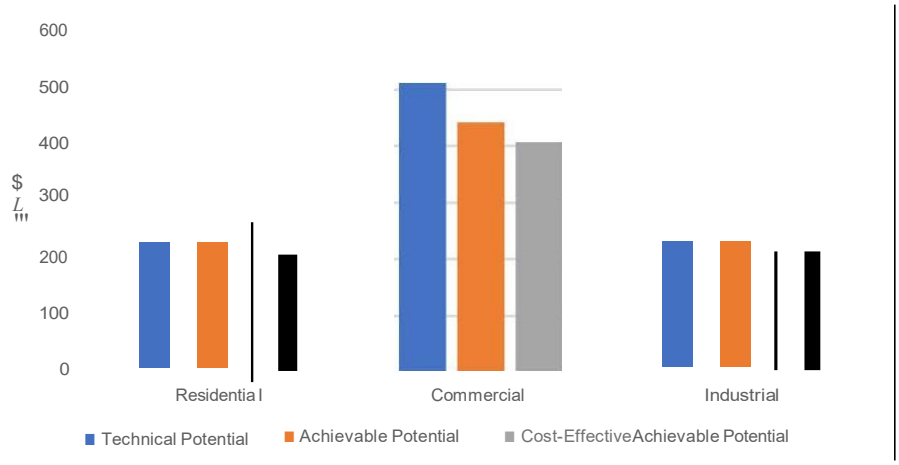
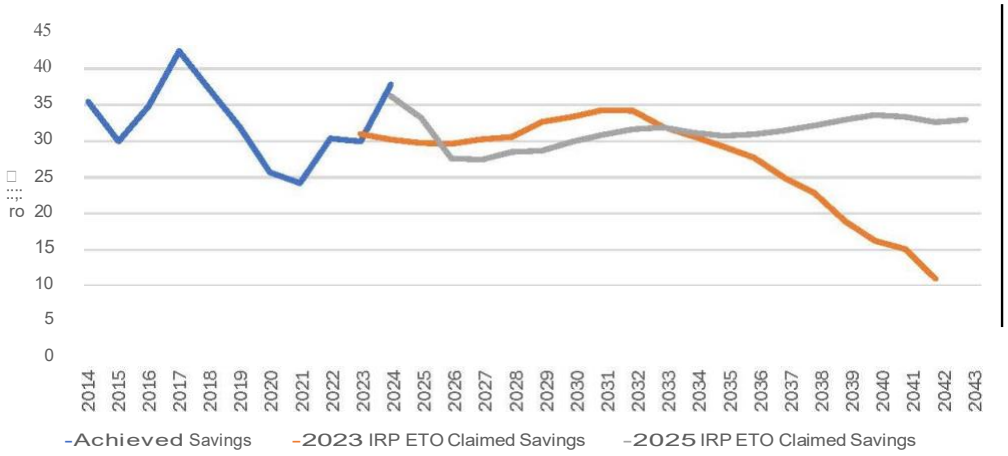


Figure 2 links actual historic savings going back to 2014 to the Energy Trust claimed savings projection for the 2025 IRP. It also compares the 2025 IRP forecast to the 2023 IRP forecast.

[2] All energy described in this report is measured at the generator.
[3] Includes 47.5 aMW of market transformation savings that Energy Trust will not claim resulting from residential and commercial lighting standards going into effect.

Figure 2 - Annual Savings Projection Comparison for 2023 and 2025 IRPs, with Actual savings since 2014



Energy Trust 20-Year Forecast Methodology

20-Year Forecast Overview

Energy Trust developed a 20-year DSM resource forecast for PGE using Energy Trust's RA Model to identify the total 20-year cost-effective modeled energy efficiency savings potential, which is 'deployed' exogenously of the model to provide an estimate of the final savings forecast. There are four types of potential that are calculated to develop the final savings potential estimate, which are shown in Figure 3 and discussed in greater detail in the sections below.

Figure 3 - Types of Potential Calculated in 20-year Forecast Determination

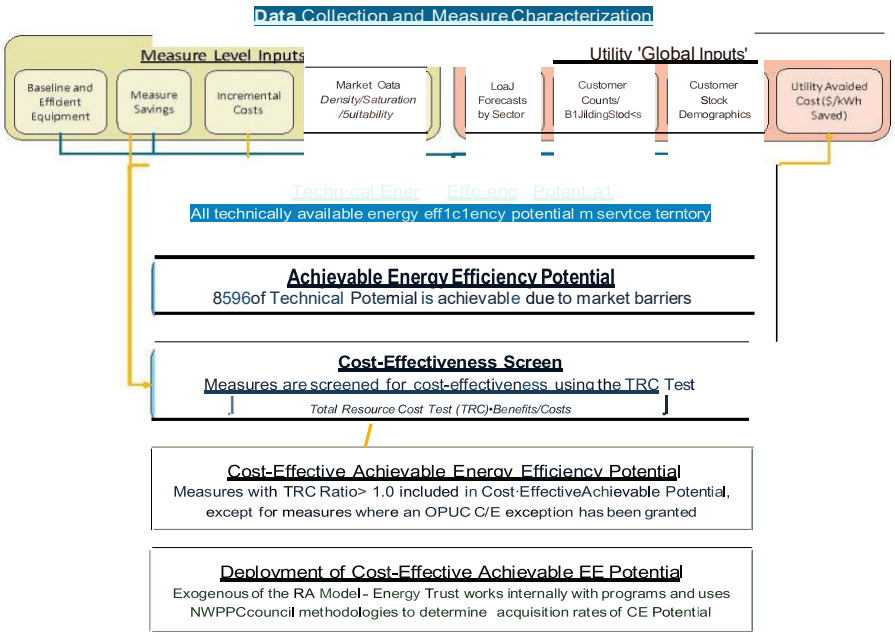
<table>
<tr><td rowspan="4">Not Technically Feasible</td><td colspan="4">Technical Potential</td></tr>
<tr><td rowspan="3">Market Barriers</td><td colspan="3">Achievable Potential</td><td rowspan="2">Calculated within RA Model</td></tr>
<tr><td rowspan="2">Not Cost-Effective</td><td colspan="2">Cost-Effective Achiev. Potential</td></tr>
<tr><td>Program Design & Market Penetration</td><td>Final Program Savings Potential</td><td>Developed with Programs & Other Market Information</td></tr>
</table>

The RA Model utilizes the modeling platform Analytica®[4], an object-flow based modeling platform that is designed to visually show how different objects and parts of the model interrelate and flow throughout the modeling process. The model utilizes multidimensional tables and arrays to compute large, complex datasets in a relatively simple user interface. Energy Trust then deploys this cost-effective achievable potential exogenously to the RA model into an annual energy savings projection based on past program experience, knowledge of current and developing markets, and future codes and standards.

20-Year Forecast Detailed Methodology

Energy Trust's 20-year forecast for DSM savings follows six overarching steps from initial calculations to deployed energy savings, as shown in Figure 4. The first five steps in the varying shades of blue nodes - Data Collection and Measure Characterization to Cost-Effective Achievable Energy Efficiency Potential - are calculated within Energy Trust's RA Model. This results in the total cost-effective potential that is achievable over the 20-year forecast. The actual deployment of these savings (the acquisition percentage of the total potential each year, represented in the green node of the flow chart) is done exogenously of the RA model. The remainder of this section provides further detail on each of the steps shown below.

Figure 4 - Energy Trust's 20-Year DSM Forecast Determination Flow Chart



[4] http://www.lumina.comiwhy-analytica/what-is-analytica1/

1. Data Collection and Measure Characterization

The first step of the modeling process is to identify and characterize a list of measures to include in the model, as well as receive and format utility global inputs for use in the model. Energy Trust compiles a list of commercially available and emerging technology measures for residential, commercial, industrial and agricultural applications installed in new or existing structures. The list of measures is meant to reflect the full suite of measures offered by Energy Trust, plus a spectrum of emerging technologies.[5] Simultaneous to this effort, Energy Trust collects necessary data from the utility to run the model and scale the measure level savings to a given service territory (known as 'global inputs').

- ***Measure Level Inputs:***
  Once the measures to include in the model have been identified, they must be characterized to determine their savings potential and cost-effectiveness. The characterization inputs are determined through a combination of Energy Trust primary data analysis, regional secondary sources[6], and engineering analysis. There are over 30 measure level inputs that feed into the model, but on a high level, the inputs are put into the following categories:
  1. ***Measure Definition and Equipment Identification:*** This is the definition of the efficient equipment and the baseline equipment it is replacing (e.g. a ductless mini-split heat pump replacing residential electric resistance space heat). A measure's replacement type is also determined in this step- Retrofit (RET), Replace on Burnout (ROB), or New Construction (NEW).
  2. ***Measure Savings:*** the kWh or therms savings associated with an efficient measure calculated by comparing the baseline and efficient measure consumptions.
  3. ***Incremental Costs:*** The incremental cost of an efficient measure over the baseline. The definition of incremental cost depends upon the replacement type of the measure. If a measure is a RET measure, the incremental cost of a measure is the full cost of the equipment and installation. If the measure is a ROB or NEW measure, the incremental cost of the measure is the difference between the cost of the efficient measure and the cost of the baseline measure.
  4. ***Market Data:*** Market data of a measure includes the density, saturation, and suitability of a measure. A density is the number of measure units that can be installed per scaling basis (e.g. the average number of showers per home for showerhead measures). The saturation is the average saturation of the density that is already efficient (e.g. 50% of the showers already have a low flow showerhead). Suitability of a measure is a percentage input to represent the percent of the density that the efficient measure is suitable to be installed in. These data inputs are all generally derived from regional market data sources such as NEEA's Residential and Commercial Building Stock Assessments (RBSA and CBSA).

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[5] An emerging technology is defined as technology that is not yet commercially available but is in some stage of development with a reasonable chance of becoming commercially available within a 20-year timeframe. The model is capable of quantifying costs, potential, and risks associated with uncertain, but high-saving emerging technology measures. The savings from emerging technology measures are reduced by a risk-adjustment factor based on what stage of development the technology is in. The working concept is that the incremental risk-adjusted savings from emerging technology measures will result in a reasonable amount of savings over standard measures for those few technologies that eventually come to market without having to try and pick winners and losers.

[6] Secondary Regional Data sources include: The Northwest Power Planning Council (NWPPC), the Regional Technical Forum (the technical arm of the NWPPC), and market reports such as NEEA's Residential and Commercial Building Stock Assessments (RBSA and CBSA)

- ***Utility Global Inputs:***
  The RA Model requires several utility level inputs to create the DSM forecast. These inputs include:
  I. ***Customer and load Forecasts:*** These inputs are essential to scale the measure level savings to a utility service territory. For example, residential measures are characterized on a scaling basis 'per home', so the measure densities are calculated as the number of measures per home. The model then takes the number of homes that PGE serves currently and the forecasted number of homes to scale the measure level potential to their entire service territory.
  2. ***Customer Stock Demographics:*** These data points are utility specific and identify the percentage of stock that utilize different heating fuels for both space heating and water heating. The RA Model uses these inputs to segment the total stocks to the stocks that are applicable to a measure (e.g. gas storage water heaters are only applicable to customers that have gas water heat).
  3. ***Utility Avoided Costs***[7]*:* Avoided costs are the net present value of avoided energy purchases and avoided system costs that result from energy efficiency savings represented as $s per kWh saved. These values are provided by PGE based generally upon the avoided costs generated by PGE as an outcome of their IRP modeling. Avoided costs are the primary 'benefit' of energy efficiency in the cost-effectiveness screen.

2. Calculate Technical Energy Efficiency Potential

Once measures have been characterized and utility data loaded into the model, the next step is to determine the technical potential of energy that could be saved. Technical potential is defined as the total potential of a measure in the service territory that could be achieved regardless of market barriers, representing the maximum potential energy savings available. The model calculates technical potential by multiplying the number of applicable units for a measure in the service territory by the measure's savings. The model determines the total number of applicable units for a measure utilizing several of the measure level and utility inputs referenced above:

Total applicable units=	*Measure Density • Baseline Saturation • Suitability Factor • Heat Fuel Multipliers (if applicable) • Total Utility Stock (e.g. # of homes)*
Technical Potential=	*Total Applicable Units • Measure Savings*

The measure level technical potential is then summed up to show the total technical potential across all sectors. This savings potential does not account for the various market barriers that will limit a 100 percent adoption rate.

3. Calculate Achievable Energy Efficiency Potential

Achievable potential is simply a reduction to the technical potential based on each measure's achievability assumption rate, to account for market barriers that prevent total adoption of all cost-effective measures. Historically the achievable potential was defined as 85 percent of the technical potential. The Northwest Power and Conservation Council (NWPCC) updated the achievability assumption for certain measures in the most recent power plan, and Energy Trust has aligned the

[7] Energy Trust uses a single electric blended avoided costs for its programs, measure development and benefit/cost metrics.

RA model with these assumptions. Many measures still have 85 percent achievability while market transformation and codes and standards are assumed to be closer to 100 percent achievability.

Achievable Potential=	*Technical Potential * achievability %*

4. Determine Cost-effectiveness of Measures using TRC Screen

The RA Model screens all DSM measures in every year of the forecast horizon using the Total Resource Cost (TRC) test, a benefit-cost ratio (BCR) that measures the cost-effectiveness of the investment being made in an efficiency measure. This test evaluates the total present value of benefits attributable to the measure divided by the total present value of all costs. A TRC test value equal to or greater than 1.0 means the value of benefits is equal to or exceeds the costs of the measure and is therefore cost-effective and contributes to the total amount of cost-effective potential. The TRC is expressed formulaically as follows:

TRC = *Present Value of Benefits/ Present Value of Costs*

Where *the Present Value of Benefits* includes the sum of the following two components:

a) Avoided Costs: The present value of electricity saved over the life of themeasure, as determined by the total kWh saved multiplied by PGE's avoided cost per kWh. The net present-value of these benefits is calculated based on the measure's expected lifespan using PGE's discount rate.
b) Non-energy benefits are also included when present and quantifiable by a reasonable and practical method (e.g. water savings from low-flow showerheads, operations and maintenance (O&M) cost reductions from advanced controls).

Where *the Present Value of Costs* includes:

a) Total participant incremental cost

The cost-effectiveness screen is a critical component for Energy Trust modeling and program planning because Energy Trust is only allowed to incentivize cost-effective measures, unless an exception has been granted by the OPUC. Energy Trust is governed by policy directives to obtain all reasonably attainable cost-effective potential[8].

5. Quantify the Cost-Effective Achievable Energy Efficiency Potential

The RA Model's final output of potential is the quantified cost-effective achievable potential. If a measure passes the TRC test described above, then the *achievable savings* (designated percentage of technical potential) from this measure is included in the cost-effective achievable potential. If the measure does not pass the TRC test above, the measure is not included in the cost-effective achievable potential. However, the cost-effectiveness screen can be overridden for some measures under three specific conditions:

1) The OPUC has granted an exception to offer non-cost-effective measures under strict conditions or,

[8] As directed in OPUC docket UM-551 and 2017 ORS 757.054

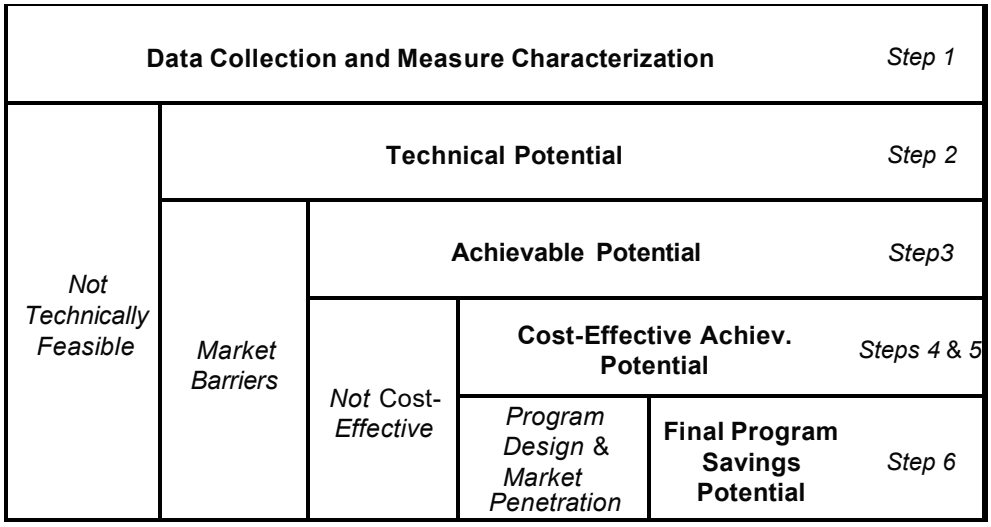
2) When the measure isn't cost-effective using utility specific avoided costs, but the measure is cost-effective when using blended electric avoided costs for all of the electric utilities Energy Trust serves and is therefore offered by Energy Trust programs.

6. Deployment of Cost-Effective Achievable Energy Efficiency Potential

After the model determines the 20-year cost-effective achievable potential, Energy Trust develops a savings projection based on past program experience, knowledge of current and developing markets, and future codes and standards. The savings projection is a 20-year forecast of energy savings that is projected to result in a reduction of load on PGE's system. This savings forecast includes savings from program activity for existing measures and emerging technologies, expected savings from market transformation efforts that drive improvements in codes and standards.

Figure 5 below reiterates the types of potential shown in Figure 3, and how the steps described above and in Figure 4 fit together.

Figure 5 - The Progression to Program Savings Projections



Forecast Results

Forecast results will be shown in several different sections, as the RA model has different output capabilities that are applied to project energy savings potential in a variety of different views, including by segment, end use, and in supply curves. The final savings projection is provided by segment and program delivery type. The RA Model produces results by type of potential, as well as several other useful outputs, including a supply curve based on the levelized cost of energy efficiency measures. This section discusses the overall model results by potential type and provides an overview of the supply curve.

Forecasted Savings by Sector

Table 1 summarizes the technical, achievable, and cost-effective achievable potential for PGE's system in Oregon. The savings in the table represent the total 20-year cumulative energy savings potential identified in the RA Model for each of the three respective types of potential identified in Figure 3 and Figure 5, prior to deployment of the savings into the final savings projection.

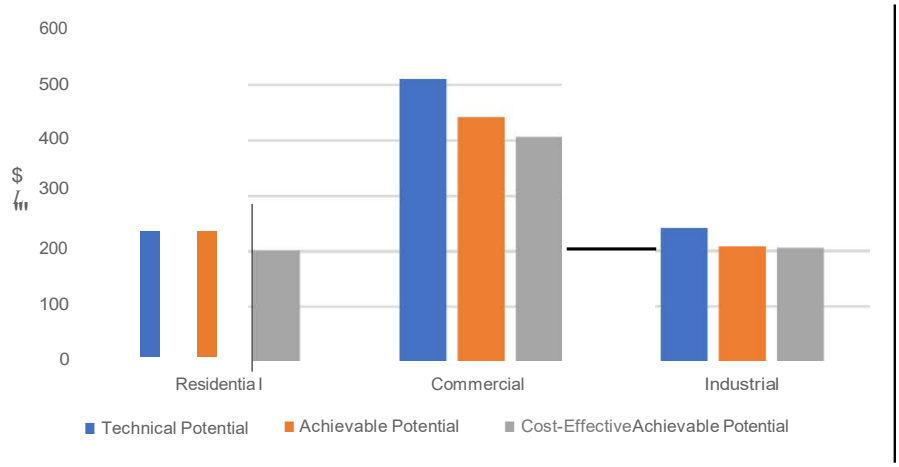
Table 1 - Summary of Cumulative Modeled Savings Potential - 2024-2043

Sector	Technical Potential (aMW)	Achievable Potential (aMW)	Cost-Effective Achievable Potential (aMW)
Residential	261	226	202
Commercial	511	442	406
Industrial	241	209	206
Total	**1,012**	**876**	**813**

Figure 6 shows cumulative forecasted savings potential across the three sectors Energy Trust serves, as well as the type of potential identified in PGE's service territory.

The Commercial sector represents the largest source of efficiency potential within PGE's territory. 86% of the industrial technical potential is cost-effective, while the residential and commercial sectors cost-effective achievable potential are 77% and 80% of technical potential respectively.

Figure 6 - Savings Potential by Sector - Cumulative 2024-2043

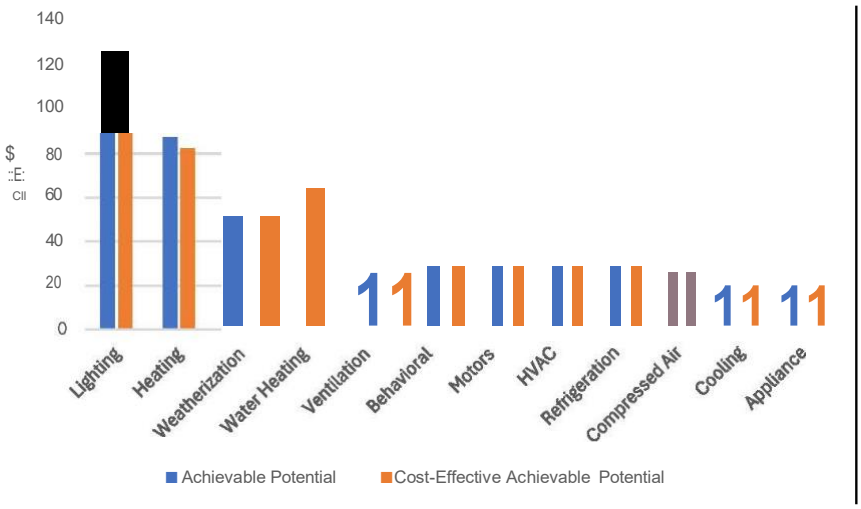


Cost-Effective Achievable Savings by End-Use

Figure 7 below provides a breakdown of PGE's 20-year cost-effective DSM savings potential by major end use. Some potential that doesn't map to a single end-use is omitted from this figure such as general new construction whole building measures and custom industrial and large commercial measures.

Lighting, heating, weatherization and water heating are the end-uses with the largest energy savings potential in PGE territory. Most of the lighting and heating potential is cost effective while a lower share of weatherization, water heating and cooling past TRC test in the model.

Figure 7 - 20-year Cost-Effective Achievable Cumulative Potential by End Use



Contribution of Emerging Technologies

As mentioned earlier in this report, Energy Trust includes a suite of emerging technologies (Els) in its model. The emerging technologies included in the model are listed in Table 2.

Table 2 - Emerging Technologies Included in the Model that are pertinent for PGE

Residential	Commercial	Industrial
• Window Attachments •Thin Triple Pane Windows • Advanced Insulation • Heat Pump Dryers • Split System CO2 Heat Pump Water Heater • Smart Line Voltage Thermostats	• Zero Net Energy Ready Construction • Hybrid Indirect-Direct Evaporative Cooler • Advanced Refrigeration Controls • Refrigeration Anti-Fogging Film • Advanced Window Technolo ies	• CO2 Refrigeration • Industrial Heat Pumps • Advanced Wall Insulation

Energy Trust recognizes that emerging technologies are inherently uncertain and utilizes a risk factor to hedge against that risk. The risk factor for each emerging technology is used to characterize the inherent uncertainty in the ability for Els to produce reliable future savings. This risk factor was determined based on qualitative metrics of:

- Market risk

- Technical risk
- Data source risk

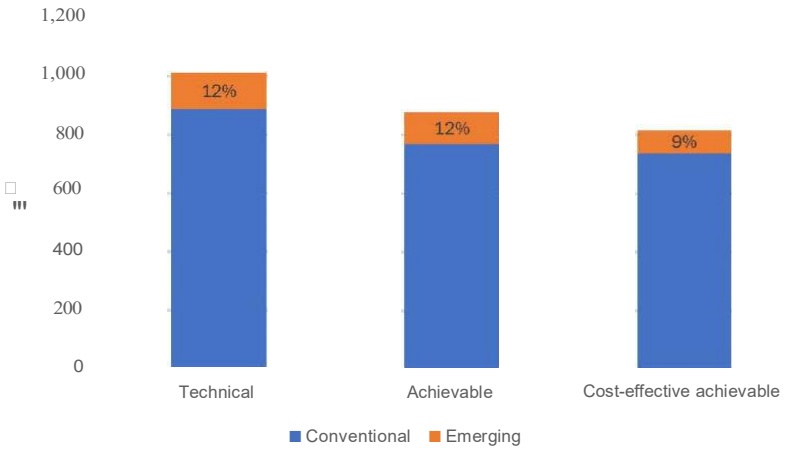
The framework for assigning the risk factor is shown in Table 3. Each ET was assessed within each risk category and a total weighted score was then calculated. Well-established and researched technologies have lower risk factors while nascent, unevaluated technologies (e.g., CO2 heat pump water heaters) have higher risk factors. This risk factor was then used as a multiplier of the incremental savings potential of the measure.

Table 3 - Emerging Technology Risk Factor Score Card

Risk Category	ET Risk Factor				
Market Risk (25% weighting)	High **Risk:** • Requires new/changed business model • Start-up, or small manufacturer • Significant changes to infrastructure • Requires training of contractors. Consumer acceptance barriers exist			**Low Risk:** Trained contractors Established business models Already in U.S. Market Manufacturer committed to commercialization	
Technical Risk (25% weighting)	High **Risk:** Prototype in first field tests. A single or unknown approach	Low volume manufacturer. Limited experience	**New** product with broad commercial appeal	Proven technology in different application **or** different region	**Low Risk:** Proven technology in target application. Multiple potentially viable a□proaches.
	High Risk: Based only on manufacturer claims	Manufacturer case studies	Engineering assessment or lab test	Third party case study (real world installation)	Low **Risk:** Evaluation results or multiple third-party case studies

Figure 8 below shows the amount of emerging technology savings within each type of DSM cumulative potential. While emerging technologies make up about 21% of the technical potential, once the cost-effectiveness screen is applied, the relative share of emerging technologies drops to about 13% of total cost-effective achievable potential. This is because many of these technologies are still in early stages of development and are quite expensive. Though Energy Trust includes factors to account for forecasted decreases in cost and increased savings from these technologies over time, some are still never cost-effective over the planning horizon or do not become cost-effective until later years.

Figure 8 - Cumulative Contribution of Emerging Technologies by Potential Type



Cost-Effective Override Effect

Table 4 shows the savings potential in the RA model that was added by employing the cost-effective override option. As discussed in the methodology section, the cost-effective override option forces non-cost-effective measures into the cost-effective potential results and is used when a measure meets one of the following three criteria:

1. A measure is offered under an OPUC exception.
2. When the measure isn't cost-effective using PGE-specific avoided costs but the measure is cost-effective when using blended electric avoided costs for all of the electric utilities Energy Trust serves and is therefore offered by Energy Trust programs.
3. The measure is not cost-effective in our model, but may appear cost-effective in program settings, where costs are combined with other measures or highly variable from project to project[9].

[9] Some measures can have high degrees of variations in savings and costs. If a measure is cost-effective in the RA model then all savings attributable to the measure are included. Conversely, if a measure is not cost-effective in the RA model then zero savings will be shown in the model. While costs are updated frequently to reflect changing markets there may be instances where some instances of installation are cost-effective and others are not. Many of these types of projects are screened individually for cost-effectiveness in Energy Trust's custom program offerings.

Table 4 - Cumulative Cost-Effective Potential (2024-2043) due to Cost-Effectiveness Override (aMW)

Sector	Total Cumulative Cost-Effective Potential With CE Override	Total Cumulative Cost-Effective Potential No CE Override	Difference
Residential	202	132	69
Commercial	406	406	-
Industrial	813	206	-
Total DSM:	**813**	**744**	**69**

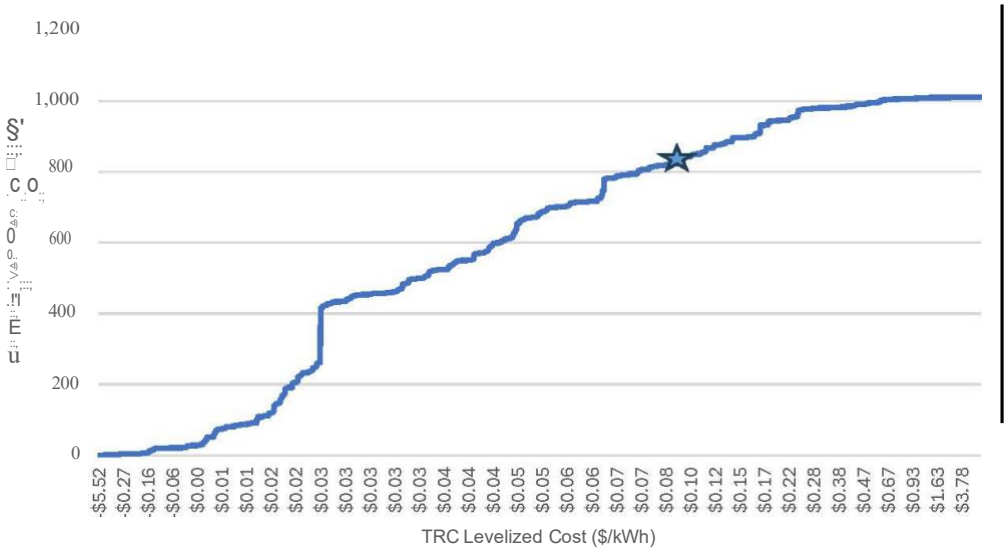
In this IRP, 9% of the cost-effective potential identified by the model is due to the use of the cost-effective override for measures. This is a higher share than in previous IRPs and is attributable to the OPUC cost-effectiveness exception for manufactured homes early replacement (14 aMW of the 69 aMW shown in Table 4). This measure generates a lot of potential due to the stock of existing manufactured homes in PGE territory, however this measure receives a low ramp-rate in the deployment process to account for market barriers and qualification criteria of homes and not all potential is deployed. Measures under exception make up 7% of the cost-effective achievable potential without the override applied to manufactured homes early replacement.

Supply Curves and Levelized Cost Outputs

An additional output of the RA Model is a resource supply curve developed from the levelized cost of energy of each measure. The supply curve graphically depicts the total potential in average megawatts that could be saved at various costs for all measures. The levelized cost for each measure is determined by calculating the present value of the total incremental cost of the measure over its economic life, per kWh of energy savings ($/kWh saved). The levelized cost calculation starts with the customer's incremental cost of a given measure. The total cost is amortized over an estimated measure lifetime using the PGE's discount rate provided to Energy Trust. The annualized measure cost is then divided by the annual kWh savings. Some measures have negative levelized costs because non-energy benefits amortized over the life of the measure are greater than the total cost of the measure over the same period.

Figure 9 below shows the supply curve developed for this IRP that can be used for comparing demand-side and supply-side resources. The star on the graph shows roughly the cutoff where savings become non-cost-effective, although some savings above the star are included due to cost-effective override.

Figure 9 - Electric Supply Curve ($ per kWh saved)



Deployed Results - Final Savings Projection

The results of the final savings projection show that PGE can save 171.7 aMW in the next five years from 2025 to 2029 and over 675 aMW by 2043. This represents a 16.5 percent cumulative load reduction by 2043[10] and is an average of 1.1 percent incremental annual load reduction. The cumulative final savings projection is shown in Table 5 compared to the technical, achievable and cost-effective achievable potential.

Table 5 - 20-Year Cumulative savings potential by type, including final savings projection (aMW)

Sector	Technical Potential	Achievable Potential	Cost-Effective Achievable Potential	Final Savings Projection[11]
Residential	261	226	202	151
Commercial	511	442	406	260
Industrial	241	209	206	203
Exogenous Savings[12]				62
Total	1,012	876	813	675

[10] Cumulative savings assumes customers will continue to purchase equipment of equal or higher efficiency equipment after the measure reaches the end of its useful life and therefore savings in this instance are assumed to persist in future years.

[11] The final savings projection includes market transformation lighting savings that will not be claimed by Energy Trust but are expected to come off PGE's system. These savings account for 44.7 aM:W of the combined commercial and industrial final savings projections and 2.9 aMW of the residential final savings projection.

[12] Exogenous savings are calculated outside of the RA model and consist of commercial and residential prior codes, industrial large projects and residential electrification.

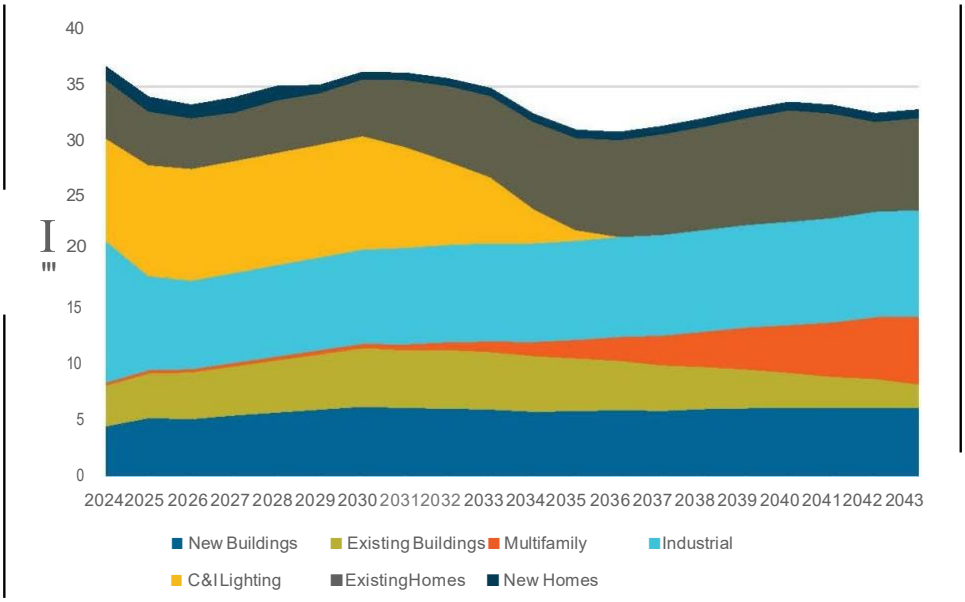
Energy Trust's general modeling principle is to deploy 100% of retrofit cost-effective achievable potential or ramp to 100% of cost-effective achievable potential for replacement and new construction measures consistent with Northwest Power and Conservation Council ramp rate methodology. However, certain measures have unique market barriers, uncertainties, or are early in their market adoption trajectory limiting their deployment. As such, the final deployed savings projections in Table 5 are a subset of the cost-effective achievable potential. This is most notable for the residential and commercial sectors which have a higher share of these measures where 100% deployment of cost-effective achievable potential is not feasible. There are several reasons why 100"/4 acquisition is unrealistic, including:

1) "Lost Opportunity Measures" - Measures that are meant to replace failed equipment (ROB) or new construction measures (NEW) are considered lost opportunity measures because programs have one opportunity to influence the installation of efficient equipment over code baseline when the existing equipment fails or when the new building is built. This is because these measures must be installed at that specific point in time, and if a program administrator misses the opportunity to influence the installation of more efficient equipment, the opportunity is lost until the equipment fails again. Energy Trust expects that most of these opportunities will be met in later years as efficient equipment becomes more readily adopted. However, in early years, the level of acquisition for these opportunities is smaller and ramps higher as time progresses.
2) "Hard to Reach Measures" - some measures that show high savings potential are notoriously hard to reach. These include multifamily and shell measures.
3) The nascent and uncertain nature of emerging technologies limit their market adoption in the forecast horizon similar to #2 above.
4) New, comprehensive measures added to the RA model including New Buildings Custom Data Center and New Homes Manufactured Home Early Replacement - Custom Data Center savings are subject to modeling uncertainty. Energy Trust modeled their adoption using program expertise and achievements from past projects and, given the magnitude of load forecast, make up a large share of the commercial sector step down in Table 5. Similarly, the Manufactured Home Early Replacement measure calculates potential for a large share of manufactured homes in PGE territory, however it is unrealistic that 100% of homes will turn over in the forecast period given its relatively high cost and labor (note this measure is under OPUC exception).

Exogenous savings are calculated outside of the RA model because they are generally accounted for in market characterization assumptions (prior codes) or their baseline is present in the utility load forecast (residential electrification). Energy Trust models prior codes using a forecast from NEEA. The inclusion of Residential Electrification is new for this round of modeling and was calculated as incremental lost opportunity savings above PGE's electrification forecast and were deployed consistent with similar lost opportunity measure adoption. Finally, Energy Trust exogenously adds industrial large projects because those savings are not characterized by the measures included in the RA model. In total exogenous savings total 62 aMW and make up 9% of the final savings projection.

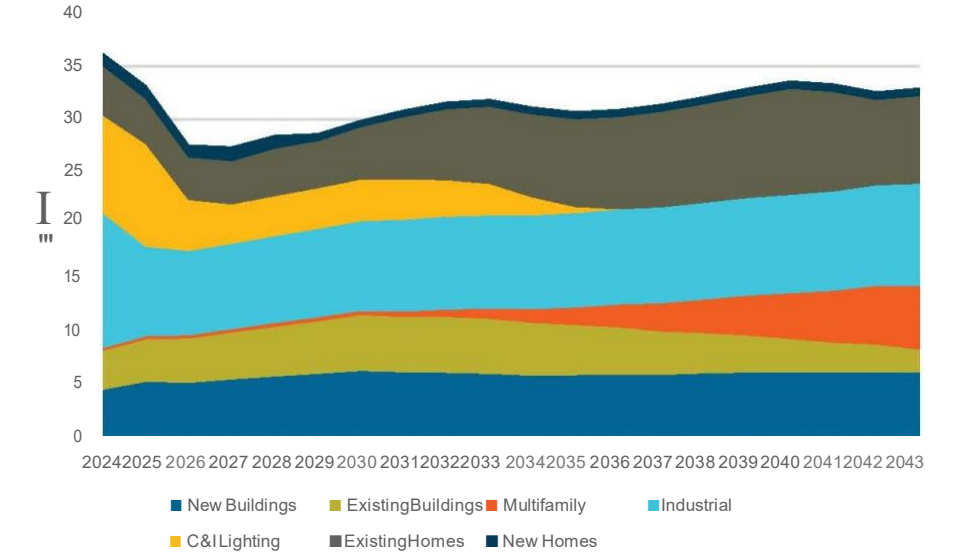
The final savings projection of 675 aMW in Table S represents 20-years of efficiency savings. The annual shape of the deployed efficiency forecast is shown in Figure 10 below.

Figure 10-Annual Deployed Final Savings Potential



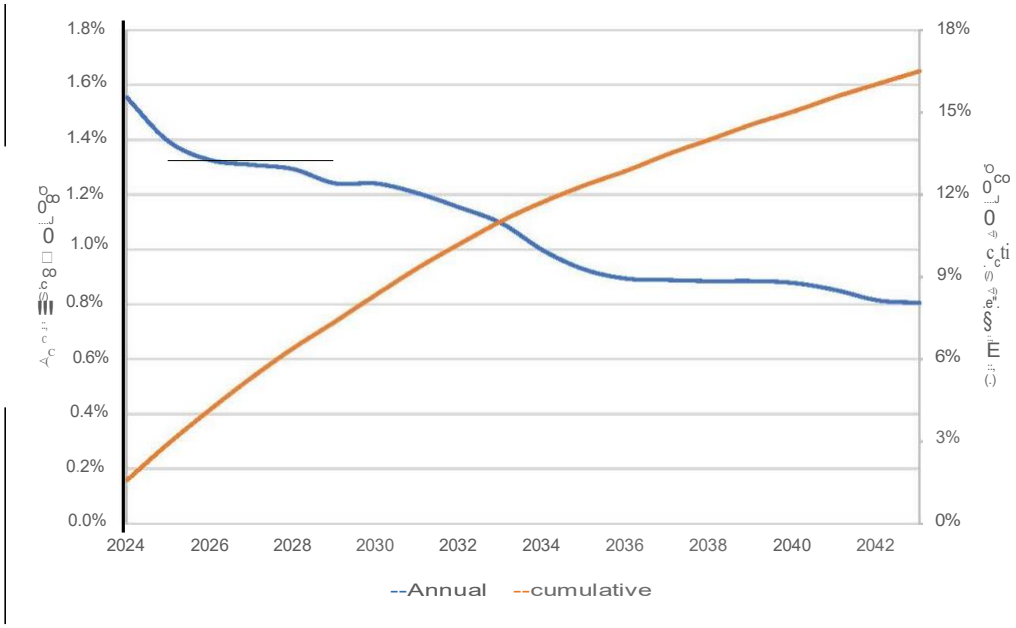
As previously noted, the final savings projection depicted in Figure 10 above includes 47.5 aMW of market transformation lighting savings that energy trust will not claim. Figure 11 below shows the annual efficiency forecast of Energy Trust claimed savings.

Figure 11 -Annual Deployed Energy Trust Claimed Savings Potential



Finally, Figure 12 shows the annual and cumulative savings as a percentage of PGE's load forecast. Annually, the savings as a percentage of load varies from about 0.8% at its lowest to 1.6% at its highest, as represented on the *left* Y-axis of the graph and the blue line. Cumulatively, the savings as a percentage of load builds to 16.5% by 2043, shown on the right Y-axis and the gold line.

Figure 12 -Annual Forecasted Savings as a Percentage of Annual Load Forecast



Deployed Results - Peak Day Results

Ongoing regional emphasis on peak and capacity management and an OPUC docket focused on electric utility Distribution System Planning (OPUC docket UM 2005) has resulted in continued interest in the contribution energy efficiency can make to managing electric utility loads. Additionally, the OPUC has directed Energy Trust to report peak impacts in the appendices of our annual report beginning in 2017[13].

Peak hour factors are the percentage of annual energy savings that occur during peak hours over the course of a year. Energy Trust calculates peak demand factors using Equation 1, where load factors and coincidence factors being derived from the NWPCC library of load profiles.

Equation 1 - Calculation of Peak Factors from Load and Coincidence Factors

*Peak/actor= (1 yr/8760) * Load Factor* Coincidence Factor*

Figure 11 below shows the annual, deployed peak day savings potential based upon the results of the 20-year forecast. Each measure analyzed is assigned a load shape and the appropriate peak factor is

[13] For the 2023 version ofthis report see Appendix 9 of Energy Trust's *"2023 Annual Report to the Oregon Public Utilily Commission & Energy Trust Board of Directors"* available at https://www.energytrust.org/wp-content/uploads/2024/04/Energy-Trust-of-Oregon-2023-Annual-Report.pdf

applied to the annual savings to calculate the overall DSM contribution to peak day capacity. Cumulatively, this is equal to 1,980 MW[14], as shown in Table 6 below.

Figure 11 - Annual Deployed Peak Savings Contribution by Season

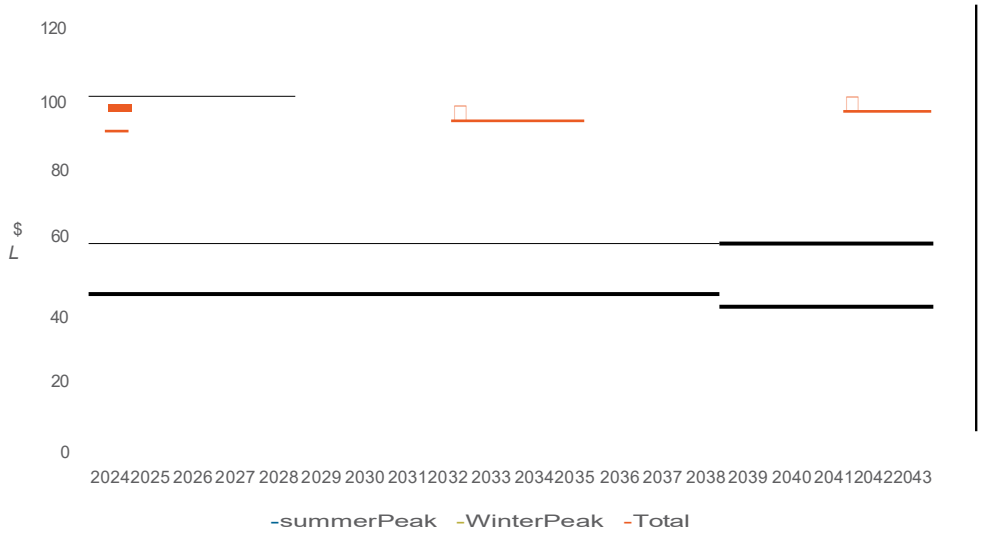


Table 6 - Cumulative Deployed Peak Savings Contribution by Sector

Sector	Cumulative Peak Savings (MW)	% of Overall Peak Savings
Residential	797	**40%**
Commercial	**643**	**32%**
Industrial	540	27%
Total	1,980	

Non-Cost-Effective Energy Efficiency

Starting in 2023, PGE requested that Energy Trust submit savings and levelized cost data from measures that did not pass the TRC cost-effectiveness screen in the Energy Trust RA model. This allows PGE to compare efficiency to supply side resources where the total resource cost of efficiency exceeds benefits calculated by utility submitted avoided costs. This modeling could highlight areas of value in addition to what is quantified in the UM 1893 avoided costs docket. This analysis is completed by PGE and the results are detailed in their IRP report. Summary values for the non-cost-effective efficiency submitted

[14] Peak results do not include energy savings from exogenous categories

by Energy Trust are shown below in Table 7. For the 2025 IRP analysis, these savings total 75.1aMW at a weighted average levelized cost[15] of $0.401/kWh.

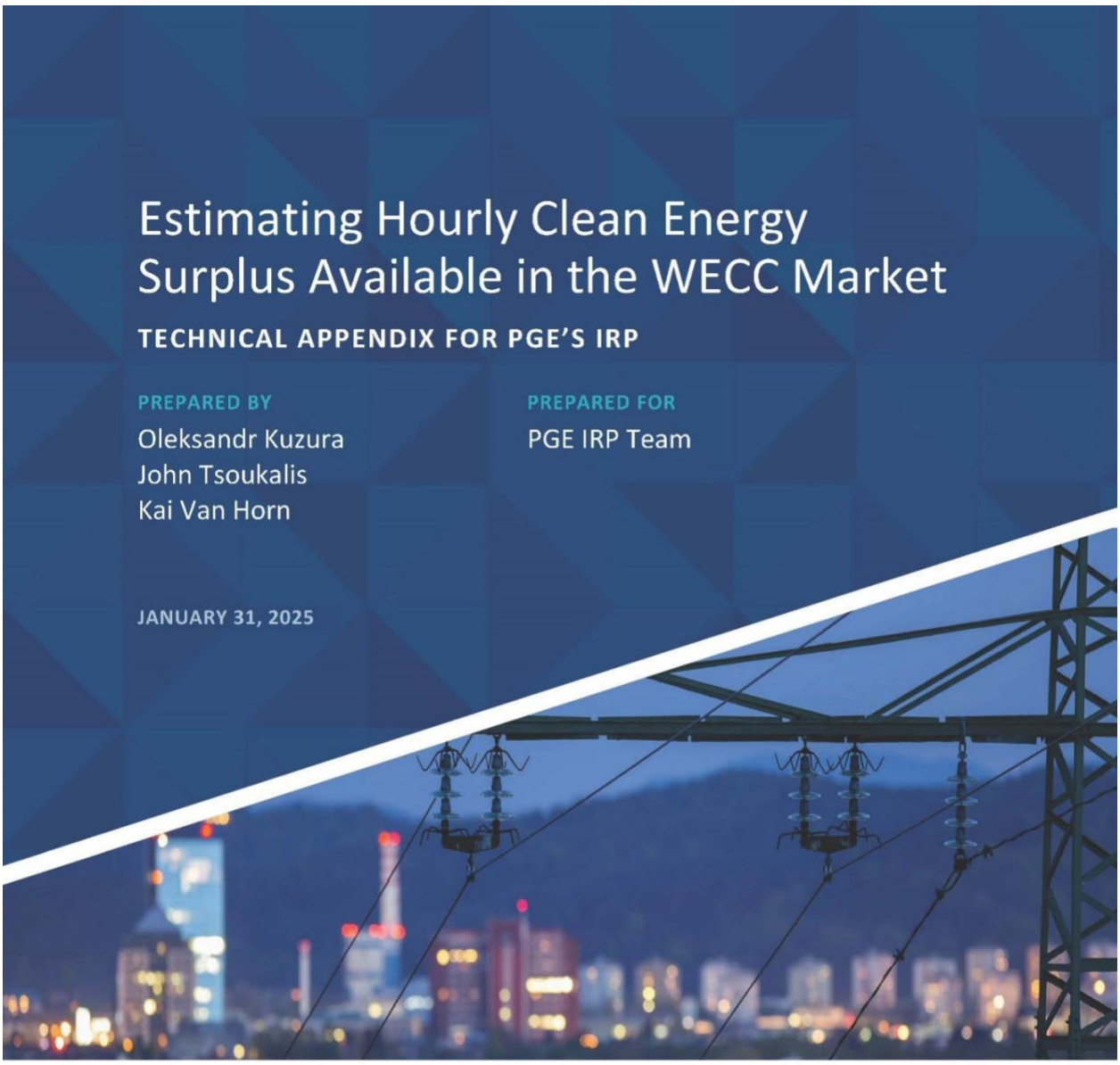
Table 7 - 20-year Non-Cost-Effective Efficiency Potential

Sector	Non-Cost-Effective Achievable Potential (aMW)[16]	Weighted Average Levelized Cost ($/kWh)
Residential	32.6	$0.406
Commercial	40.1	$0.412
Industrial	2.4	$0.149
Total	75.1	$0.401

[15] This levelized cost represents the total resource cost, levelized over measure life ($/kWh) plus a 31% administrative cost adder.

[16] The values in this column do not exactly match the difference between Achievable Potential and Cost-Effective Achievable Potential in Table 5 for several reasons including substitution between competing measures, cost-effective override, and the timing of discretionary measures on the margin of cost-effectiveness

Appendix F Market for non-emitting energy



Brattle

PGE

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I. Introduction And Background

The Oregon Public Utility Commission (OPUC) directed Portland General Electric (PGE) to adopt hourly accounting of its clean energy position and the associated greenhouse gas (GHG) implications in its 2025 Clean Energy Plan (CEP) and Integrated Resource Plan (IRP) update. This directive was issued in Docket LC 80, in which OPUC Staff declined to acknowledge PGE's 2023 CEP due to concerns about PGE's ability to procure clean energy from the market. Specifically, PGE's portfolio was forecasted to be long on clean energy during shoulder seasons and short on clean energy during peak hours, matching regional supply trends across the Western Electricity Coordinating Council (WECC) territory. OPUC Staff and stakeholders raised concerns about PGE's assumption that clean energy would be equally available year-round, noting that supply could be limited at times and might also incur a premium cost to purchase.

The Brattle team (hereby "we") was engaged by PGE to address the OPUC's request to develop and implement an hourly accounting methodology for estimating the availability and cost of purchasing clean energy. Developing this methodology required answering the following questions:

- In each hour, how much clean energy is available after accounting for resources committed to other GHG reductions for non-PGE entities in the WECC?
- What, if any, is the cost premium associated with procuring surplus clean energy in a given hour? How does that cost premium vary with available supply?

We developed the Excel-based Clean Energy Surplus Model (CESM) to estimate the hourly WECC-wide market availability of clean energy deliverable to PGE and the potential cost premiums it may incur. The CESM uses hourly results from PGE's AURORA IRP simulations and a curve capturing the relationship between clean energy surpluses and potential purchase premiums to produce an hourly time series of clean energy deliverable to PGE and the potential associated premiums. The CESM outputs are then used in PGE's calculation of its resource plans' annual GHG impacts.

This appendix describes the CESM framework, including key assumptions, data inputs, outputs, strengths, and areas for future improvements. It is organized into five sections. Section 0 provides a detailed step-by-step explanation of the CESM's surplus calculation framework.

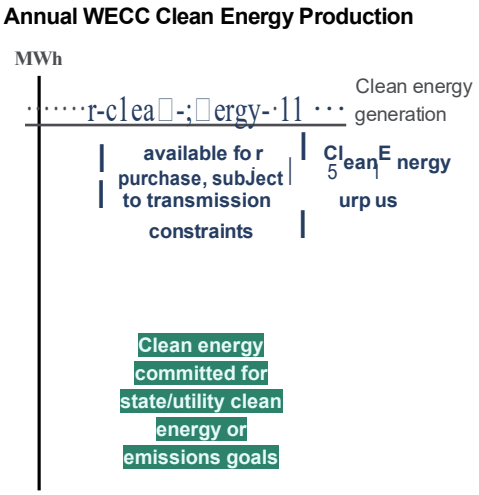
Section III details the CESM's premium calculation approach. Section IV summarizes the CESM's clean energy surplus and premium results for two AURORA simulations. Section V discusses the CESM's strengths and areas for potential future improvements.

II. Clean Energy Surplus Estimation Overview and Key Assumptions

Market purchases of clean energy could help offset PGE's emissions, but PGE's ability to access them depends on the WECC-wide clean energy supply, clean energy demand, and transmission available to PGE to import that energy. We define "clean energy surplus" (or "surplus") as the clean energy generated in the WECC beyond that which is needed to meet annual state-level clean energy requirements. Clean energy supply depends on the amount and types of generation resources available in each state and varies with regional and seasonal weather patterns and installed capacity. Clean energy demand depends on binding policy targets and voluntary goals set by states, municipalities, corporations, and other entities.[1] Transmission availability to PGE depends on the total transfer capability (TTC) over WECC transmission paths and the hourly utilization for regional trading. Figure 1 provides an illustration of the clean energy surplus as it relates to the overall availability of clean energy.

[1] We consider only binding state requirements in the CESM due to data availability constraints on voluntary targets.

FIGURE 1. ILLUSTRATIVE EXAMPLE OF CLEAN ENERGY SURPLUS

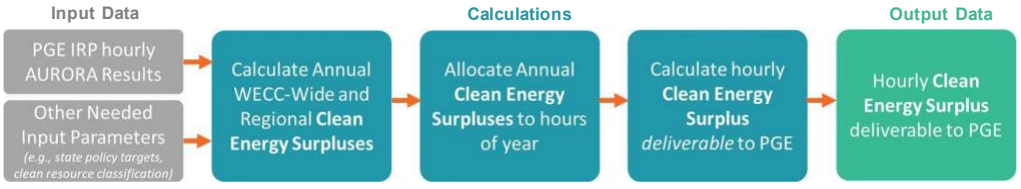


Using the CESM, we calculate hourly clean energy surpluses deliverable to PGE by:

1. Evaluating annual state-level clean energy surpluses or deficits,
2. Allocating annual regional surpluses or deficits to individual hours, and
3. Aggregating state-level results to the WECC-wide and regional levels,
4. Applying transmission constraints between PGE and the neighboring regions.

An overview of the CESM surplus calculation steps is given in Figure 2, with detailed descriptions of each step following.

FIGURE 2. SUMMARY OF CESM CLEAN ENERGY SURPLUS CALCULATION STEPS



1. Pre-Process and Aggregate Zonal AURORA Results to the State Level

PGE's IRP simulations in AURORA produce hourly load and generator dispatch results at a zonal level. The AURORA model divides the WECC into zones representing states, portions of states, and major transmission hubs as shown in Appendix C. In the CESM we assume states and transmission hubs with interconnected generation resources are the base geographic units to align with the geographic application of clean energy policy requirements. For utilities with multi-state service territories, generation and load are divided along state lines, consistent with the representation in the AURORA database.

We pre-process the AURORA results by aggregating sub-state results to the state level and combining all statewide generation into a single set of "clean" or "other" generation results. Appendix C contains a designation of resource types and a mapping of AURORA zones to states.

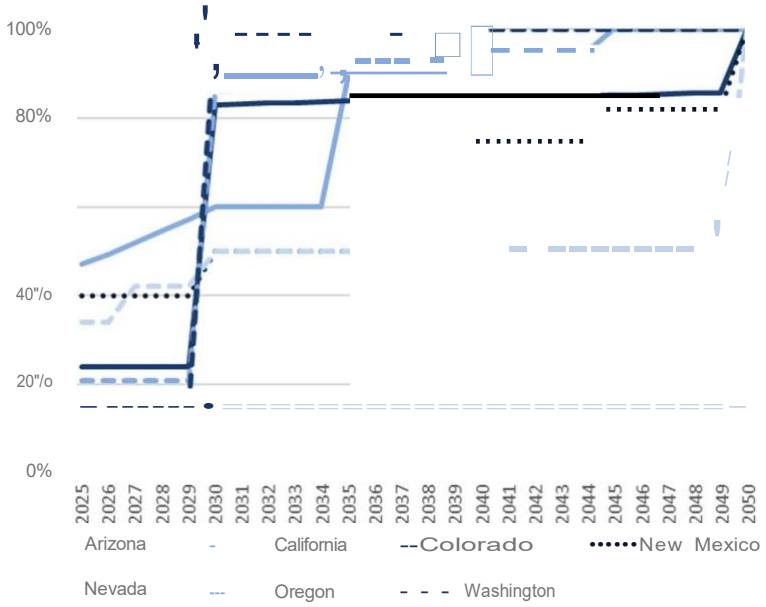
2. Calculate State-Level Annual Clean Energy Requirements

In the CESM, we assume only clean energy associated with legally binding state clean energy requirements is unavailable when calculating WECC-wide clean energy surplus. Voluntary targets from municipalities, corporations, and other entities have uncertain enforcement mechanisms. The CESM reflects additional demand from voluntary targets, such as corporate clean energy pledges or municipal clean energy programs through its calculation of purchase premiums described in Section III.

Wecalculate the total WECC-wide demand for clean energy by summing individual states' annual clean energy requirements. We calculate annual state-level clean energy requirements as the sum of each state's hourly electric demand multiplied by that state's percent-based clean energy requirement. State-level percent-based requirements are based on the LBNL's State Renewables Portfolio and Clean Electricity Standards database.[2] The CESM interpolates or extrapolates state-level targets set for specific years to derive annual clean energy targets for each of the PGE IRP study years, as needed. Figure 3 charts annual state-level targets included in the CESM, omitting data for states without policy targets.

[2] Lawrence Berkeley National Laboratory (LBNL). *U.S. State Renewables Portfolio* & *Clean Electricity Standards: 2023 Status Update,* 2023. Accessed online at https://emp.lbl.gov/publications/us-state-renewables-portfolio-clean.

FIGURE 3. STATE CLEAN ENERGY TARGETS INCLUDED IN THE CESM



3. Calculate State-Level Annual Clean Energy Surpluses or Deficits

The total volume of clean energy available to PGE for purchase depends on each state's annual clean energy generation surplus or deficit relative to its annual clean energy requirements. We assume that states prioritize meeting their annual clean energy requirements using in-state generation, and that any state-level clean energy generation in excess of state-level clean energy requirements would be available as surplus. On the other hand, any shortfalls in state-level clean energy generation relative to state-level targets reduce the total amount of clean energy surplus available WECC-wide, as we assume surpluses from other states fill requirement deficiencies before being offered to the market.

We calculate annual state-level clean energy surpluses or deficits as the difference between each state's annual clean energy policy targets and the total clean energy production that can be used to satisfy those requirements. In each hour, we assume that all clean energy generation up to a state's hourly load can be used to meet clean energy policy targets ("usable" clean energy). We assume that clean energy generation exceeding states' hourly loads would

be deemed surplus clean energy. We then calculate annual clean energy generation usable for meeting states' clean energy policy targets by summing usable clean energy generated across all hours of the year.

Next, we compare each state's annual usable clean energy generation to its annual clean energy targets. If a state's total annual clean energy generation is not enough to satisfy its annual clean energy requirements, that state is assumed to be in deficit and must rely on clean energy from other states to meet its targets. On the other hand, if a state's annual usable clean energy generation is greater than its annual clean energy requirements, that state is assumed to have an annual clean energy surplus.

4. Allocate State-Level Annual Surpluses or Deficits to Individual Hours

To calculate the hourly availability of clean energy WECC-wide and regionally, we next allocate states' gross annual clean energy surpluses or deficits to individual hours surplus availability. As a starting point, we assume that surpluses and deficits are proportional to hourly clean energy production and loads.

In the CESM we apply a heuristic to carry out this hourly allocation by assuming that states' surpluses or deficits are proportional to the difference between hourly clean energy production and demand. We implement this "proportional" approach in the CESM by deriving an annual surplus or deficit allocation factor.

For states with gross annual surplus clean energy production, we calculate the allocation factor as the difference between the state's total annual clean energy production and its total annual clean energy requirement. This factor is then applied to determine the portion of a state's hourly clean energy production that could be offered on the market. For example, a state with 100 MWh of annual clean energy production and 80 MWh of clean energy requirements would have an allocation factor of 20%. This means that the state can offer 20% of its annual clean energy production (20 MWh) and still have enough usable clean energy production to meet its annual clean energy targets (80 MWh). In an hour when the state produces 10 MWh of clean energy, it is assumed to offer 2 MWh on the market (20% of production in that hour) and keep 8 MWh (the remaining 80% of production in that hour) to count toward its own policy requirements.

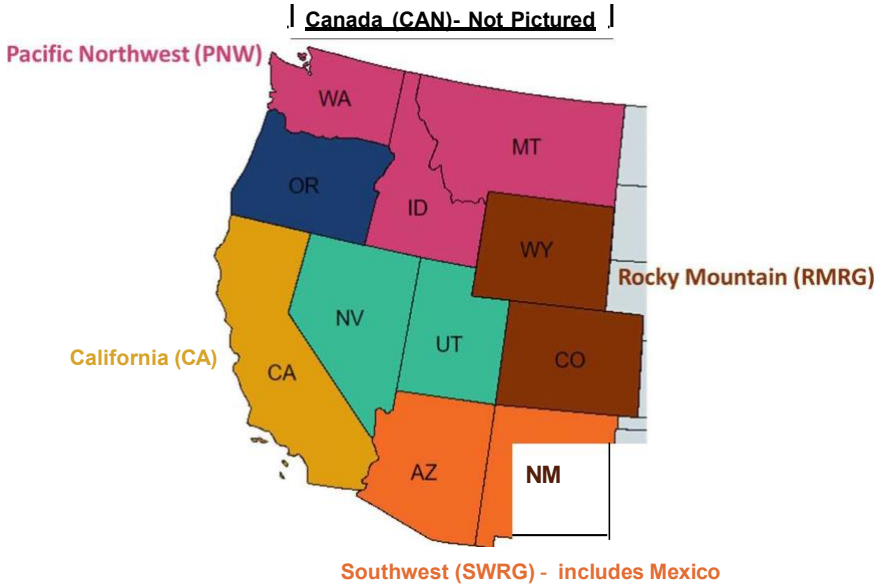
For states with gross annual deficits of clean energy, we calculate the allocation factor as the difference between the state's annual clean energy target and the state's total annual clean energy production. This allocation factor is then used to determine quantity of clean energy procurement the state would seek to procure on the market in each hour. For example, if a state's annual clean energy policy target is 100 MWh and its local annual clean energy production is 60 MWh, then the state's allocation factor would be 40%. In an hour when the state's load is 10 MWh and its local clean energy production is 8 MWh, the state would seek an additional 0.8 MWh of clean energy (40% of 2 MWh) to contribute to filling its annual deficit.

5. Aggregate Hourly State-Level Results to Regional and WECC-Wide Level

We use the CESM to calculate the WECC-wide hourly surplus or deficit by summing the hourly surpluses and deficits of each state. The Oregon-West (OR-WE) AURORA zone contains PGE and is omitted from this calculation to represent PGE's view of the WECC market.

We aggregate state-level results into regions based on states' transmission connectivity to facilitate data validation and later application of deliverability constraints (Figure 4). Assuming sufficient transmission availability among states within each region, the CESM calculates hourly regional surpluses and deficits by summing the hourly surpluses and deficits of the region's member states. For example, the proportional allocation method may suggest that Wyoming could have 10 MWh of clean energy to offer on the market the same hour that Colorado could seek to procure 5 MWh of clean energy to fill its deficit. Since these states comprise the RMRG region, the CESM would indicate a 5 MWh clean energy surplus in the RMRG region in this hour.

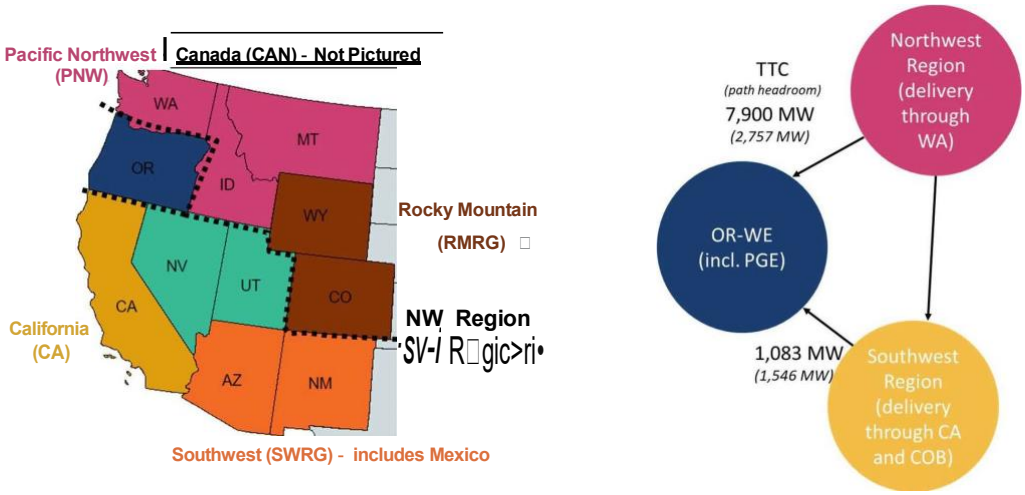
FIGURE 4. REGIONAL AGGREGATION IN THE CESM



6. Calculate Clean Energy Surplus Deliverable to PGE

We further limit the availability of clean energy surplus to PGE in the CESM based on available transmission headroom on the transmission paths connecting PGE to the rest of the system. To do so, we use the transmission path limits and power flow represented in the AURORA model between the OR-WE zone and the neighboring zones representing California, Washington, and the California-Oregon Border (COB) trading hub. For tractability in the CESM calculations, we aggregate the regions in Figure 4 into the Northwest and Southwest super-regions (Figure 5) and consider clean energy deliverability to PGE based on its transmission capacity and availability to these regions.

FIGURE 5. DIVISION OF WECC STATES INTO NORTHWEST AND SOUTHWEST REGIONS



We then calculate surplus *deliverable* to PGE in the Oregon-West zone in three steps:

1. **Balance Northwest and Southwest regional surpluses and deficits** by calculating the hourly surplus or deficit available in the Northwest and Southwest regions. This step uses a similar approach to that used for aggregating state-level results to the regional level as described in Step 5 above.

   In the CESM, we assume surplus transfers are unrestricted by transmission constraints within each super-region, except between the Rocky Mountain (RMRG) region and the rest of the Northwest. RMRG has a larger wind generation resource in Wyoming than it has transmission interconnectivity with the rest of the Northwest region. To reflect this in the CESM, we enforce a constraint between RMRG and the Pacific Northwest (PNW) region, balancing RMRG surpluses and deficits with the rest of the PNW. When RMRG surplus exceeds available headroom on the RMRG to PNW path, the rest of the RMRG surplus is assumed to be sent to the Southwest region. Any RMRG surplus beyond that which is deliverable to the Northwest and Southwest regions via available transmission headroom is assumed to be unavailable to PGE.

2. **Calculate available hourly transmission path headroom from the Northwest and Southwest regions to Oregon-West.** We calculate within the CESM the available headroom to Oregon-West based on the path ratings and hourly transmission utilization results from the AURORA model. For each transmission path, we calculate a net hourly flow by netting

out flows in the forward and reverse direction as defined in the AURORA inputs. To arrive at available headroom for the CESM, we then subtract the net flow from the path's TTC in each hour. In this initial version of the CESM, we assume no re-dispatch of storage or thermal resources to relieve congestion constraints or improve deliverability of clean energy to PGE at certain times of day. We calculate the total headroom from the Southwest region into OR-WE as the sum of the transmission headroom from California to OR-WE and from COB to OR-WE.

3. **Adjust Northwest and Southwest region surpluses for deliverability into OR-WE, accounting for transfers between the Northwest and Southwest regions.** We limit hourly transfers within the CESM from the Northwest and Southwest regions into OR-WE based on the hourly transmission headroom available into OR-WE. We additionally assume that surplus transfers can occur between the Northwest and Southwest regions as needed to ensure full utilization of transmission headroom into OR-WE. For example, if the Northwest region had 100 MWh of surplus but only 80 MW of transmission headroom available to OR-WE in some hour, then PGE could access only 80 MWh of surplus from the Northwest region in that hour. However, the CESM assumes those 20 MWh of surplus could be delivered to OR-WE via the Southwest region if there were enough transmission headroom available on the paths from the Northwest to the Southwest and from the Southwest to OR-WE.

III. Clean Energy Premium Estimation Approach

The CESM reflects an expectation that PGE may have to pay a premium to secure clean energy supplies when those supplies are relatively scarce.

We reflect this expectation in our calculations by estimating an hourly Clean Energy Premium, defined as the additional cost that PGE may have to pay beyond the energy price associated with the purchase of clean energy. Within the CESM we use a Clean Energy Premium Curve (CEPC) to translate hourly WECC-wide clean energy surpluses into hourly clean energy premiums. The CESM calculates the hourly Clean Energy Premium PGE may have to pay in three steps:

1. Create a WECC-wide CEPC for the simulation year

2. Calculate WECC-wide hourly Clean Energy Premiums
3. Implement PGE-specific Clean Energy Premium adjustments

Next, we discuss each of these steps in greater detail.

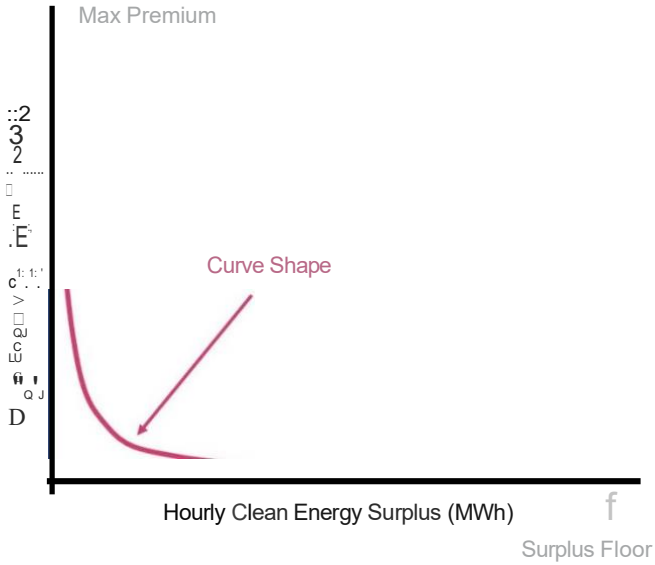
1. Create a WECC-Wide CEPC for the Simulation Year

The CEPC captures the impact of competition for scarce clean energy on the value of its clean energy attribute, broadly mimicking the price-quantity dynamics observed in other clean attribute markets. We define the CEPC separately for each model year using three parameters:

- **Curve shape** reflecting the relationship between the Clean Energy Premium and WECC-wide surplus quantity,
- **Max premium** related to the levelized cost of procuring clean energy from newly built capacity, in the case of PGE the cost of a new build wind resource, and
- **Surplus floor** threshold quantity above which the premium is assumed to be zero.

Figure 6 shows an illustrative CEPC with the above parameters labeled, followed by additional discussion of each parameter.

FIGURE 6. CLEAN ENERGY PREMIUM CURVE PARAMETRIZATION

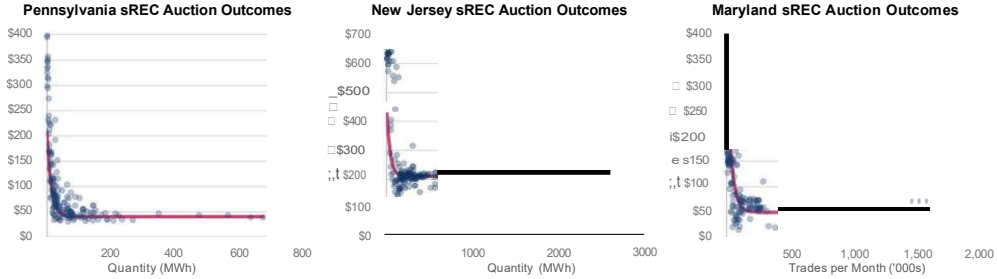


CEPC Curve Shape Parameter

We model a negative exponential relationship between clean energy surplus and premium in the CESM, assuming clean energy attributes in the WECC would have similar price-quantity dynamics as renewable energy certificates (RECs) in other markets. Historical solar REC (sREC) auction outcomes from PJM states with liquid markets show an exponential relationship between trade volumes and clearing prices (Figure 7).[3] This relationship indicates that as the supply shrinks, buyers are willing to pay increasing premiums to secure clean attributes in the market. On the other hand, if there is ample supply, premiums settle at a relatively low baseline value. The negative exponential shape used in the CESM is a normalized version of the PJM sREC auction outcome graph shapes, tuned using outputs from the AURORA model.

[3] We relied on PJM sREC auction outcomes for the CESM due to a lack of available clean attribute market data in the WECC.

FIGURE 7. PJM SOLAR REC AUCTION PRICE-QUANTITY RELATIONSHIP BETWEEN 2010-2024



CEPC Max Premium Parameter

Based on guidance from PGE, we set the CEPC Max Premium parameter based on the cost of a new build wind resource, assuming that wind would be the source of incremental supply of clean energy beyond what is available from existing resources. We set the CEPC Max Premium to $15/MWh for the year 2030, reflecting a $10/MWh levelized cost of energy (LCOE) for a new wind resource earning the Production Tax Credit and a 1.Sx scalar to reflect cost uncertainty not reflected in the LCOE. The LCOE value is based on the 2023 NREL ATB's calculation of the LCOE of a Class 4 onshore wind turbine using the moderate cost trajectory. [4]

CEPC Curve Floor Parameter

We set the Curve Floor parameter based on WECC-wide clean energy surpluses observed in the AURORA results when energy prices are below a certain threshold. Low energy prices indicate high enough clean energy production that there should be no premium associated with its procurement. This study used a $0/MWh threshold price, which indicates clean energy curtailments in the AURORA model. The Curve Floor parameter was set at the minimum WECC-wide surplus observed across all hours when the WECC-wide load-weighted average energy price was at or below the $0/MWh threshold.

2. Calculate WECC-Wide Hourly Clean Energy Premiums

We use the CESM process detailed in Steps 1 through 5 detailed in Section O above to calculate the total available WECC-wide surpluses in each hour. Since the premium does not depend on

[4] National Renewable Energy Laboratory. *2023 Annual Technology Baseline.* 2023. https://atb.nrel.gov/electricity/2023/land-based_wind.

how much of the available surplus is deliverable to PGE, we use the CEPC to calculate hourly WECC-wide premiums using the results of Step 5.

3. Implement PGE-Specific Premium Adjustments

We divide each hour's WECC-wide premium by the capacity factor of a reference wind profile in that hour to capture the impact of wind availability on the cost of producing a MWh of clean energy in each hour. A key concern for PGE's CEP is whether to rely on market purchases or to procure new clean generation capacity. An owned or contracted resource seldom produces clean energy equal to its nameplate capacity. Thus, PGE may need more than a MW of clean generation nameplate capacity to produce a MWh of clean energy when needed. Dividing the hourly WECC-wide premium by the capacity factor of a reference wind output profile in that hour serves to make comparable the cost of procuring capacity or purchasing surplus on the market.

IV. Clean Energy Accounting Results

We evaluated potential clean energy surplus availability for the year 2030 based on AURORA model results from the 2023H2 and 2024H2 production cost model databases from Wood Mackenzie. The annual regional and WECC wide generation mix and load modeled in each set of AURORA inputs is given below in Figure 8, followed by the monthly WECC-wide generation mix and load in Figure 9. Both model databases show the WECC-wide and regional generation mixes as having high proportions of clean energy and an annual surplus. WECC-wide surpluses tend to concentrate in the spring months, when loads are low and clean energy generation is high. The Northwest region has higher surplus than the Southwest region, despite higher policy requirements, due to substantial wind and hydro penetration.

FIGURE 8. ANNUAL GENERATION ASSUMPTIONS IN THE AURORA MODEL

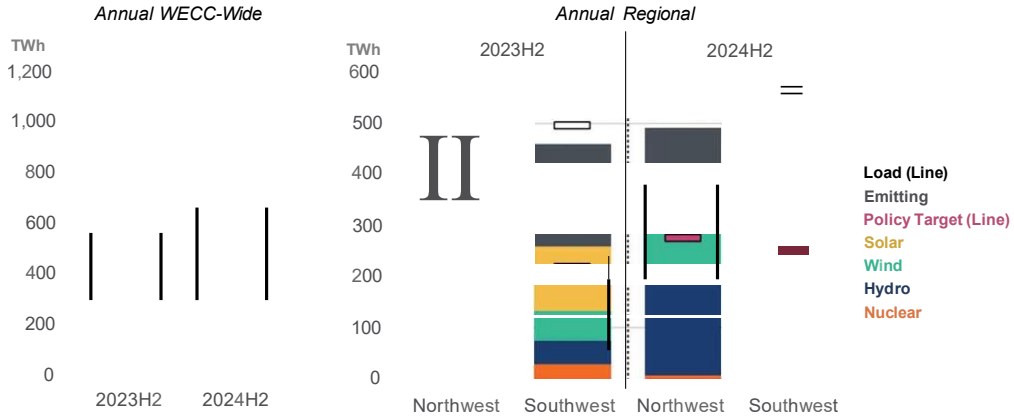
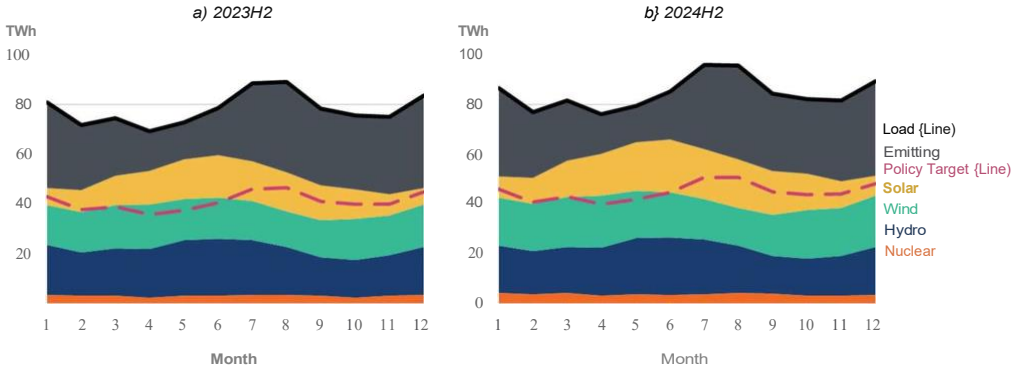
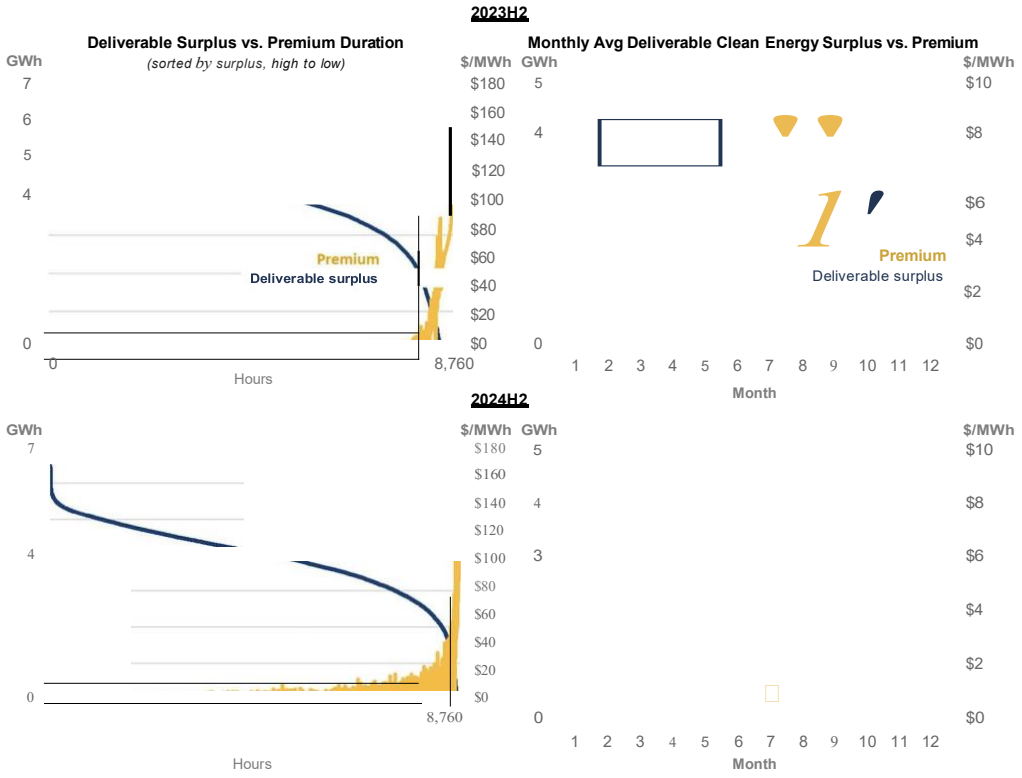


FIGURE 9. MONTHLY GENERATION ASSUMPTIONS IN THE AURORA MODEL



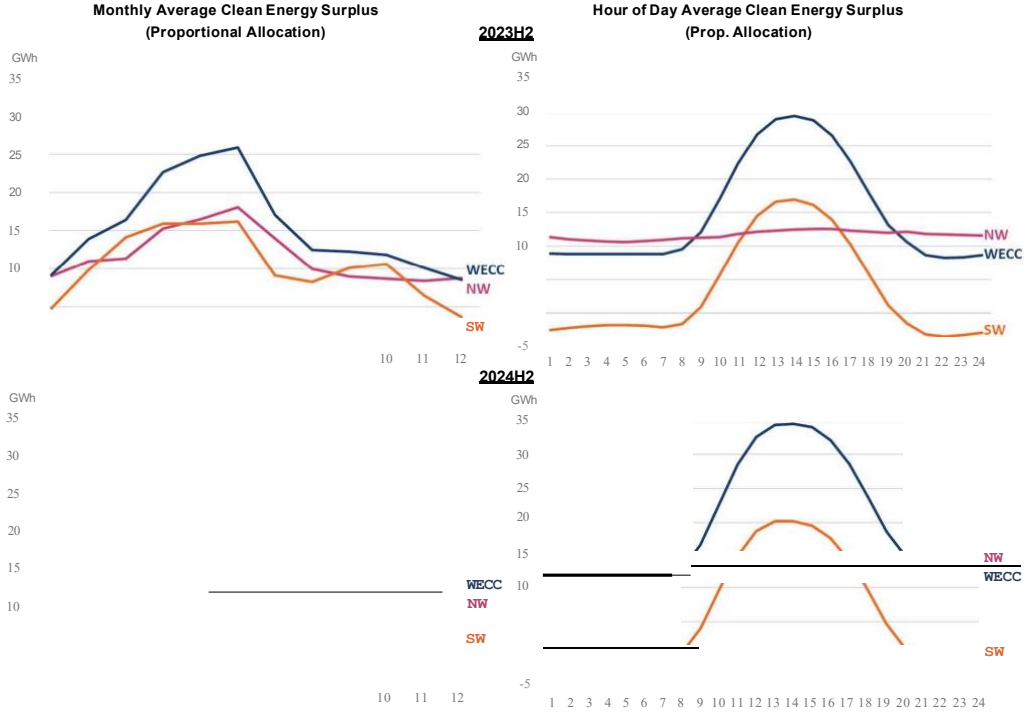
We find that deliverable surpluses are highest in the spring and early summer, roughly in line with the seasonality of clean generation. Premiums follow an inverse pattern and are highest in the winter, when surpluses are low, reflecting the price-quantity relationships defined in the CEPC. Figure 10 below plots the deliverable surpluses and premiums for both sets of AURORA data as a duration curve (left charts) and as average monthly values (right charts). The duration curves plot hourly surplus (blue line) and premium (yellow line) results arranged by surplus quantity in descending order. The monthly charts represent the simple average surplus and premium value for each month.

FIGURE 10. DELIVERABLE SURPLUS AND PREMIUM



We observe substantial variability in WECC-wide and regional surpluses across different months and hours of the day (Figure 11). The Northwest region's monthly clean energy generation patterns drive WECC-wide monthly clean energy surpluses because the Northwest region has a rich wind and hydro resource. On a daily scale, the Southwest region drives WECC-wide surplus patterns due to its large solar resource. In the right charts in Figure 11, the blue line (WECC-wide surplus) has a very similar shape to the orange line (Southwest average surplus), displaying a hump during solar generation hours. The pink line (Northwest average surplus) remains mostly flat across all hours of the day.

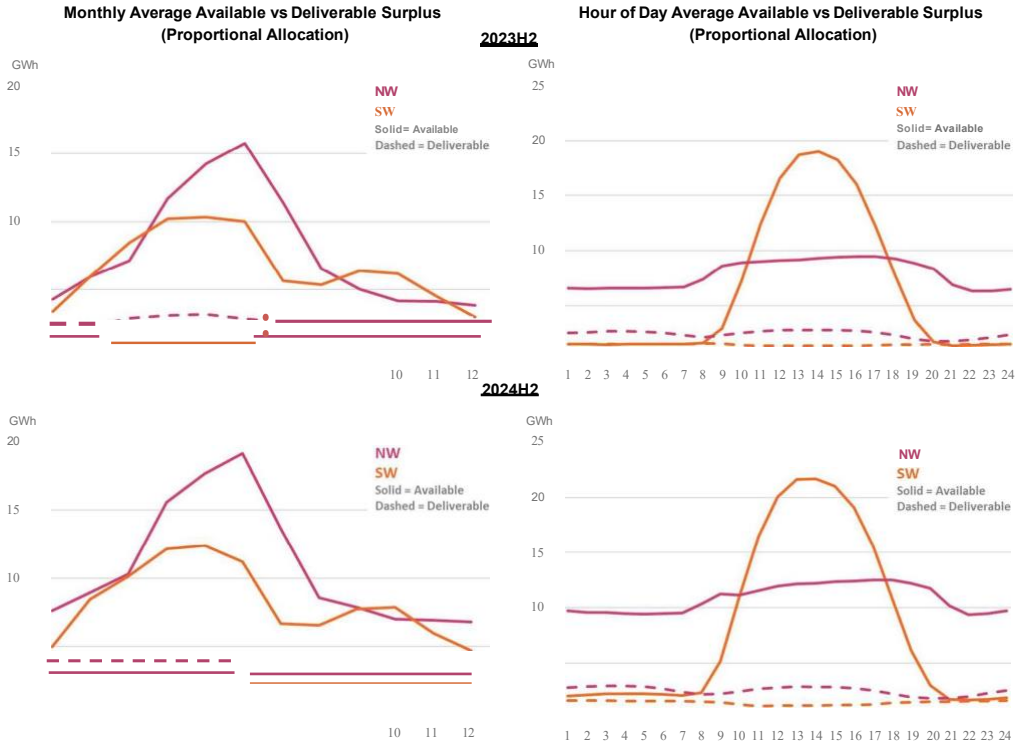
FIGURE 11. WECC-WIDE AND REGIONAL SURPLUSES[5] BY MONTH AND HOUR OF THE DAY



We found that deliverability constraints substantially curtail PGE's access to clean surplus. Figure 12 plots the available (solid line) and deliverable (dashed line) surplus for each region by month (left charts) and hour of day (right charts). PGE's deliverability constraints are most impactful during the springtime for Northwest surpluses and during the daytime for Southwest surpluses, with an overall impact of allowing just over 30% of available surplus to be delivered to PGE.

[5] Charts show average surplus quantities for hours when surpluses are available, before accounting for RMRG deliverability constraints and transfers between NW and SW regions. Aggregating to the WECC-wide level alters the timing and amounts of surpluses shown such that the NW and SW values may add to more than the WECC quantity.

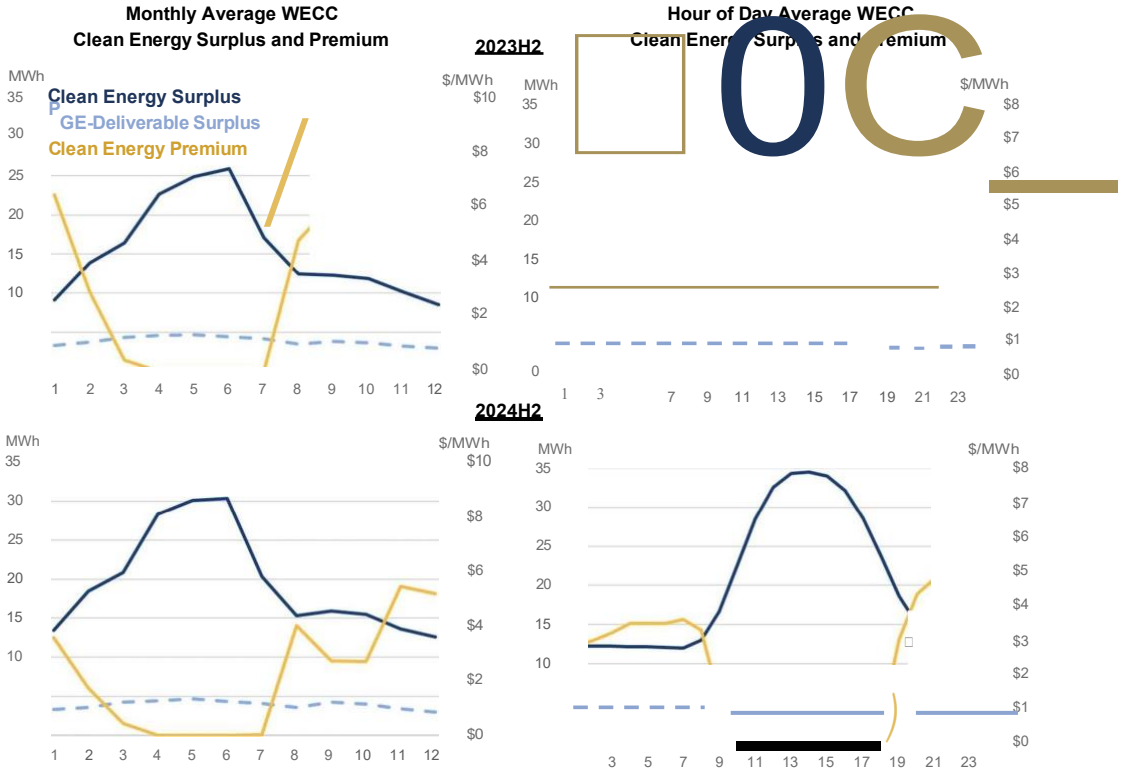
FIGURE 12. REGIONAL SURPLUS DELIVERABILITY RESULTS[6]



Hourly premium results are driven by WECC-wide surplus dynamics, reflecting the inverse relationship between surplus quantity and premium defined in the CEPC (Figure 13). Premium are based on WECC-wide surpluses and do not depend on deliverability to PGE. High WECC-wide surpluses in the spring and during the middle of the day drive down premiums during those periods.

Regional surpluses reflected in Figure 12 reflect surpluses deliverable from the respective regions. The solid lines indicate available surpluses after accounting for transfers from RMRG and between the NW and SW regions. The dotted lines indicate the regional surpluses deliverable to PGE.

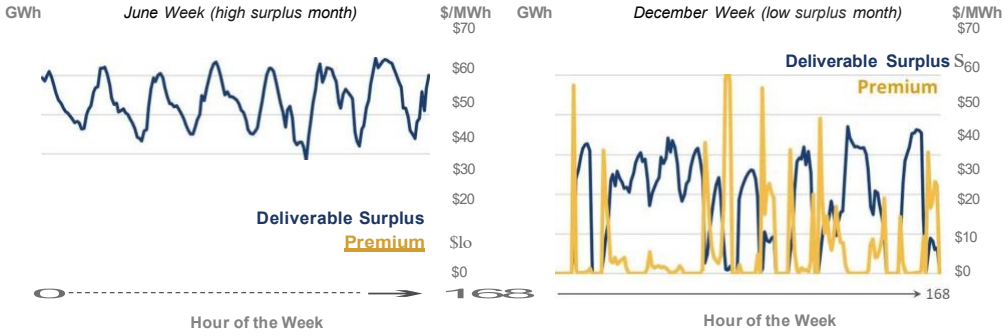
FIGURE 13. WECC-WIDE AVAILABLE AND DELIVERABLE CLEAN ENERGY SURPLUS AND PREMIUM



We examined hourly CESM results to validate the annual, monthly, and hour-of-day trends observed above. Figure 14 plots hourly results for a week in June (left chart) and December (right chart) from the 2023H2 set of results. In June, when surpluses are high, there is no premium. In the December week, surpluses vary throughout the day, often falling to zero during evening hours with peak demand.

FIGURE 14. HOURLY CESM RESULTS

Hourly PGE-Deliverable Clean Energy Surplus and associated Premium



V. Framework Evaluation and Next Steps

The CESM provides a starting point for assessing the availability and cost of clean energy surplus in the WECC and deliverable to PGE.

The strengths of this hourly surplus accounting framework include:

- Broad capture of the fundamental dynamics that drive the availability and relative value of clean energy
- Simplicity in implementation with tunable parameters
- Internal consistency with the AURORA simulations that inform other areas of the PGE IRP analyses.
- Adaptability for studying multiple future outlook scenarios.

There are several areas in which the CESM can be improved:

- Add detail when applying deliverability constraints. The CESM currently includes deliverability constraints at the seams of the OR-WE AURORA zone containing PGE, assuming no transmission limitations in delivering surpluses to the seams from more distant entities. A future refinement could add constraints for calculating clean energy deliverability

to PGE's immediate neighbors and additionally to those neighbors' neighbors. We expect this improvement would reduce surplus deliverable to PGE.

- Refine the hourly surplus/deficit allocation approach. WECC entities may have various clean energy market participation strategies, including front-loading surplus procurements, concentrating purchases during times of abundant production, or attempting to maximize premium revenues. Alternate hourly allocation approaches can capture such behaviors, thereby altering the amount of surplus available to PGE. Adjustments to the allocation approach could increase or decrease the surplus available to PGE, depending on the specifics of the approach.
- Consideration of moving surplus within days or across days with storage. Our initial approach uses storage dispatch profiles as they are in Aurora results, but the WECC entities may dispatch storage resources to alter the amount of surplus available. We expect this improvement could modestly increase the surplus deliverable to PGE because the AURORA model already optimizes storage dispatch.
- Refine the approach to calculating state targets to account for varying clean energy eligibility requirements. We expect this refinement would have little to no impact on surplus deliverable to PGE because ineligible non-emitting energy can be traded to satisfy other states' requirements.
- Include the impacts of renewable forecast uncertainty. Deviations between day-ahead forecasts and real-time clean energy production would alter the quantity of available surplus and the utilization of transmission paths. We expect this refinement would have modest impacts on deliverable surplus quantities because renewable forecast errors are small compared to base production schedules and forecasting methods continue to improve.

Appendix A: Detailed List of Assumptions

General assumptions

- Each AURORA zone falls within a single state
  - Zones that are not labeled as belonging to specific states will be mapped based on proximity

- Clean energy surplus reflects availability after accounting for clean energy commitments to other states' policy goals
- Clean energy generated outside of PGE is only committed to state-legislated targets, not corporate or voluntary goals (i.e., those goals compete with PGE for clean energy surplus)
- Curtailed clean energy is assumed to be undeliverable and thus not considered part of the WECC-wide surplus
- Same set of resource types considered "clean" for all state RPS programs
- Transmission and deliverability constraints limit WECC-wide clean energy surplus only on a regional basis, if at all

Surplus estimation assumptions

- All clean energy policy targets increase linearly by year from 2024 until their mandated achievement year, with trajectories including interim targets
- All clean energy in excess of a balancing area's (BA's) load is counted as surplus
- If this results in an annual deficit relative to policy targets for the BA, then we assume that WECC-wide surpluses in other hours are reduced proportionally to return the BA to annual compliance
- Clean energy in states without policy targets is all counted as surplus
- There are no contributions to meeting annual policy targets from banked clean energy credits
- Surplus deliverability is not meaningfully impacted by sub-zonal transmission constraints
- Sufficient TTC exists between sub-zones of NW and SW deliverability regions to balance surpluses/deficits
- No shifting of surpluses between hours within a day (e.g., by using storage)

Premium estimation assumptions

- Premium price quantity dynamic resembles that of REC markets
- Maximum premium is representative levelized net cost of new wind build for PGE with hourly adjustments for wind availability
- Minimum premium is zero

- Surplus floor will be related to AURORA surplus quantities and energy prices
- Premium curve is static across the year

Appendix B: Table of Input Data Sources

CESM Input	Source
Generator state mappings	AURORA input
Generator type mapping	AURORA input
State RPS/CES targets	Brattle assumption based on public data from LBNL
Mapping of AURORA zones to states	Brattle team assumption
RPS unit type eligibility by program	Brattle team assumption
Transmission capacity from WECC zones to PGE/trading hubs	AURORA input
Hourly flow on transmission paths	**AURORA** results
Zonal hourly load	AURORA results
Hourly generation by unit	**AURORA** results
Zonal generator-weighted LMP	AURORA results
Annual market purchase premium floor and ceiling	Brattle assumption
Clean energy premium curve shape	Brattle assumption based on PJM REC auction outcomes

Appendix C: AURORA Modeled Zonal Topology And Resource Types

Figure 15 contains the zonal and transmission topology modeled in the AURORA database.

FIGURE 15. AURORA MODELED ZONAL TOPOLOGY AND TRANSMISSION CONNECTIONS

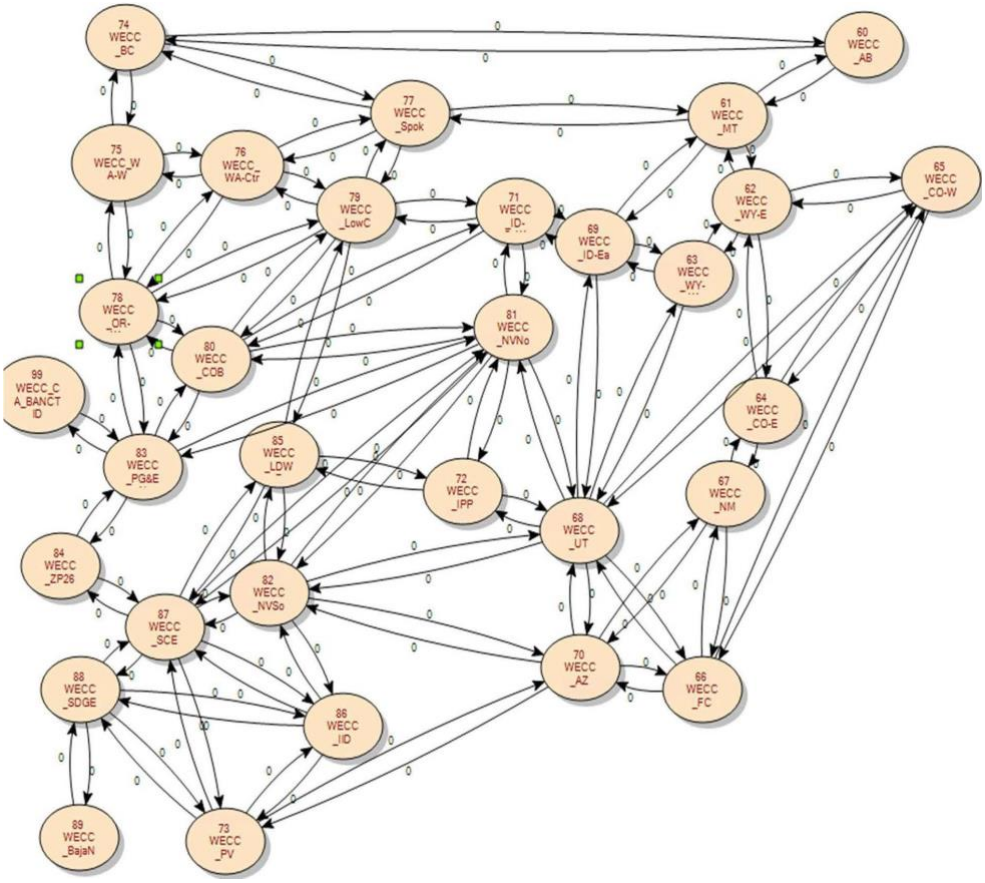


Table 1 contains a mapping of zones modeled in AURORA to WECC states.

TABLE 1. MAPPING OF AURORA ZONES TO STATES

AURORA Zone	State
WECC_Alberta	Alberta
WECC_Montana	Montana
WECC_Wyoming-RMPA	Wyoming
WECC_Wyoming-NWPP	Wyoming
WECC_Colorado East	Colorado
WECC_Colorado West	Colorado
WECC_FourCorners	New Mexico
WECC_NewMexico	New Mexico
WECC_Utah	Utah
WECC_PNW_IdahoEast	Idaho
WECC_Arizona	Arizona
WECC_PNW_IdahoSouthwest	Idaho
WECC_IPP	California
WECC_Palo Verde	California
WECC_BritishColumbia	British Columbia
WECC_PNW_WashingtonWest	Washington
WECC_PNW_WashingtonCentral	Washington
WECC_PNW_Spokane	Washington
WECC_PNW_OregonWest	Oregon
WECC_PNW_LowerColumbia	Washington
WECC_COB	COB Trading Hub
WECC_NevadaNorth	Nevada
WECC_NevadaSouth	Nevada
WECC_CA_PGandE_North	California
WECC_CA_PGandE_ZP26	California
WECC_CA_LADWP	California
WECC_CA_IID	California
WECC_CA_SCE	California
WECC_CA_SDGE	California
WECC_BajaNorth	Mexico
WECC_CA_BANCTID	California

Table 2 contains a list of resource types modeled in AURORA (both 2023H2 and 2024H2 datasets) and their designations as clean or other in the CESM.

TABLE 2. CESM AURORA RESOURCE TYPE MAPPING

AURORA Unit Type	CESM Designation
Hydro	clean
Nuclear	clean
Solar Utility	clean
Solar Utility Non-PTC	clean
Solar Utility PTC	clean
Wind Offshore	clean
Wind Onshore	clean
Wind Onshore Non-PTC	clean
Wind Onshore PTC	clean
Demand Response	load
Electric Vehicles	load
Solar Distributed	load
BatteryStorage 12 Hour	other
Battery Storage 4 Hour	other
Battery Storage 8 Hour	other
Coal	other
Energy Storage	other
Gas CC	other
Gas Cogen	other
Gas Peaking	other
Gas Stearn	other
Oil	other
Other	other

Appendix G Stakeholder engagement

June 4, 2025 CEP/IRP Roundtable 25-4

- Agenda (video, ppt)
- Examining Winter Reliability Constraints (video, ppt)
- Updated Price Forecast (video, ppt)
- Final Portfolio (video, ppt)
- Additional Tax Policy and Reliability Planning Scenarios (video, ppt)
- Report Structure (video, ppt)
- Closing Remarks | Next Steps (video, ppt)

April 25, 2025 CEP/IRP Roundtable 25-3

- Agenda (video, ppt)
- Draft Portfolio Analysis Results (video, ppt)
- Closing Remarks | Next Steps (video, ppt)

February 19, 2025 CEP/IRP Roundtable 25-2

- Agenda (video, ppt)
- Integrating Clean Energy Availability (video, ppt)
- Portfolio Design II (video, ppt)
- Market Scenarios (video, ppt)
- Large Industrial Customer Growth Details (video, ppt)
- WRAP Based Needs (video, ppt)
- Closing Remarks | Next Steps (video, ppt)
- Stakeholder Feedback and PGE Responses

January 8, 2025 CEP/IRP Roundtable 25-1

- Agenda (video, ppt)
- Update Filing Date (video, ppt)
- 75 percent Transmission Requirements (video, ppt)
- Resource Effective Load Carrying Capabilities (video, ppt)
- Energy Values (video, ppt)
- Transmission Options | Energy Strategies (video, ppt)
- Closing Remarks | Next Steps (video, ppt)

December 16, 2024 Stakeholder Engagement

- Long Lead-Time Resource RFI (ppt)

November 6, 2024 CEP/IRP Roundtable 24-7

- Agenda (video, ppt)
- CEP/IRP Update Filing Extension (video, ppt)
- Calpine (video, ppt)
- Updated Energy/Capacity Positions (video, ppt)
- Updated Emissions Projection (video, ppt)
- Transmission - Step 3 – Market Access (video, ppt)
- Portfolio Design (video, ppt)
- Closing Remarks | Next Steps (video, ppt)
- Stakeholder Feedback and PGE Responses

October 2, 2024 CEP/IRP Roundtable 24-6

- Agenda (video, ppt)
- RFP Proxy (video, ppt)
- DER Update (video, ppt)
- Transmission | Step 1: Existing Capacity (video, ppt)
- Transmission | Step 2: Future Capacity (video, ppt)
- Updated Price Forecast (video, ppt)
- Closing Remarks | Next Steps (video, ppt)
- Stakeholder Feedback and PGE Responses

September 4, 2024 CEP/IRP Roundtable 24-5

- Agenda (video, ppt)
- Transmission Options (video, ppt)
- ETO: Updated Energy Efficiency Forecast (video, ppt)
- Cadeo: CBI Study (video, ppt)
- Closing Remarks | Next Steps (video, ppt)
- Stakeholder Feedback and PGE Responses

August 7, 2024 IRP Roundtable 24-4

- Agenda (video, ppt)
- Brattle Study: Clean Energy Availability (video, ppt)
- Capacity Need (video, ppt)
- Closing Remarks | Next Steps (video, ppt)

July 11, 2024 IRP Roundtable 24-3

- Agenda (video, ppt)
- Transmission Options (video, ppt)
- Load Forecast (video, ppt)
- Resource Economics Update (video, ppt)
- Small Scale Renewables (video, ppt)
- ROSE-E Changes (video, ppt)
- Closing Remarks | Next Steps (video, ppt)

June 5, 2024 IRP Roundtable 24-2

- Agenda (video, ppt)
- North Plains Connector (video, ppt)
- Hourly Energy & Emissions Accounting
    - Discussion Framework | Part I (video, ppt)
    - Capacity Expansion | Part II (video, ppt)
- Qualifying Facility Forecast (video, ppt)
- Closing Remarks | Next Steps (video, ppt)

May 1, 2024 IRP Roundtable 24-1

- Agenda (video, ppt)
- 2024 Schedule | Feedback Form (video, ppt)
- CEP/IRP Update | Updates & Non-Updates (video, ppt)
- Community benefits indicators (CBI) Study (video, ppt)
- Transmission Study (video, ppt)
- Closing Remarks | Next Steps (video, ppt)

Appendix H Transmission planning and interconnection process

H. 1FERC Order 1000 process

PGE coordinates its planning processes with other transmission providers through membership in NorthernGrid and the Western Electric Coordinating Council (WECC). PGE uses the NorthernGrid process for regional planning, coordination with adjacent regional groups and other planning entities for interregional planning, and development of proposals to WECC. Additional information is included in PGE's OATT Attachment K, in Transmission Planning Business Practice on OASIS, and on NorthernGrid's website at https://www.northerngrid.net.

H.2 FERC Order 1920 process

FERC Order No. 1920 reforms the regional transmission planning process by establishing a new 20-year, scenario-based Long-Term Regional Transmission Planning (LTRTP) process.[167] Three diverse and plausible scenarios must be studied, and these scenarios must be re-assessed and revised at least once every five years. Sensitivity analysis of uncertain operational outcomes during multiple concurrent and sustained generation and/or transmission outages due to an extreme weather event across a wide area must also be performed for each scenario. PGE's compliance with FERC Order No. 1920 will be primarily realized through modifications to the existing NorthernGrid regional transmission planning process to incorporate the new requirements established in FERC Order No. 1920.

The new long-term scenarios must be developed using a set of seven categories of factors. These categories of factors are like those used in integrated resource planning, including criteria such as federal, state, and tribal rules and regulations for resource mix, decarbonization, and electrification. Factor Category 3 specifically requires incorporating integrated resource plans into the scenario development. The requirement for these using these factor categories in scenario-based transmission planning closely aligns the long-term regional transmission planning process with the integrated resource planning process.

FERC Order No. 1920 also requires that transmission providers measure a set of seven benefits for each scenario to evaluate LTRTP facilities over a 20-year horizon starting from the in-service date of the facility. The seven benefits go beyond traditional reliability metrics in the existing transmission planning processes to address economic benefits for transmission projects that integrate cost-effective new resources, such as lowering production costs and mitigating congestion. This again speaks to the alignment with the requirements of FERC Order No. 1920 and the integrated resource planning process.

[167] FERC Order No. 1920, issued on May 13, 2024.

Additional requirements of FERC Order No. 1920 include development of selection criteria for facilities, re-evaluation of facilities due to changing policies or reliability criteria, use of grid-enhancing technologies, cost allocation, and more transparency into the local transmission planning, regional transmission planning, and interregional transmission planning processes.

PGE appreciates the strong partnership with the relevant state entities throughout the Order No. 1920 six-month state engagement period, which began November 1, 2024, and concludes November 1, 2025. The NorthernGrid transmission providers also commenced an open stakeholder engagement process to receive feedback on the new LTRTP in March 2025 per the new requirement issued in FERC Order No. 1920-A.[168] NorthernGrid will propose on compliance the start of the long-term regional transmission planning process, which will commence no later than two years after the filing date. The states in the NorthernGrid and WestConnect regional planning organizations requested and received a compliance extension at FERC to allow for more time for cost allocation discussions. All NorthernGrid FERC-jurisdictional transmission providers must complete their compliance filing by December 12, 2025. A second compliance filing for the new interregional transmission planning requirements is due February 12, 2026.

H.3 Local transmission planning process

H.3.1 Process overview

PGE's OATT is posted on its Open Access Same-time Information System (OASIS) at http://oasis.oati.com/PGE. Additional information regarding Transmission Planning is located in the Transmission Planning folder on PGE's OASIS.

The Local Transmission Plan (LTP) is prepared within the two-year process as defined in PGE's OATT Attachment K and summarized in **Table 39**. The LTP identifies the Transmission System facility additions required to reliably interconnect and transmit forecasted generation resources and serve the forecasted Network Customers' load, Native Load Customers' load, and Point-to-Point Transmission Customers' requirements, and also includes legacy, non-OATT agreements and rollover rights over a ten-year planning horizon. Additionally, the LTP typically incorporates the results of any stakeholder-requested economic congestion studies results that were performed.

Table 39. Local Transmission Planning Cadence

		Quarter	Tasks
Near Term	Even Years	1	Select Near Term base cases and gather load data
		2	Post Study Methodology on OASIS, select one Economic Study for evaluation
		3 & 4	Select Longer Term base cases, post draft Near Term Plan on OASIS, hold public meeting to solicit stakeholder comment

[168] FERC Order No. 1920-A, issued on November 21, 2024.

		Quarter	Tasks
		4	Incorporate stakeholder comments and post final Near Term plan on OASIS
Longer Term	Odd Years	5	Gather load data and accept Economic Study requests
		6	Select one Economic Study for evaluation
		7 & 8	Post draft Longer Term plan on OASIS, hold public meeting to solicit stakeholder comment
		8	Post final Longer Term plan on OASIS, submit final Longer Term Plan to stakeholders and owners of neighboring systems

PGE updates its Transmission Customers about activities and progress made under the Attachment K planning process during regularly scheduled customer meetings. Meeting announcements, agendas, and notes are posted in the Customer Meetings folder on PGE's OASIS. Meeting dates are posted on PGE's OASIS.

H.3.2 NERC planning standards (TPL-001)

PGE's Transmission System is designed to reliably supply projected customer demand and projected Firm Transmission Service. Studies are performed annually to evaluate where Transmission upgrades may be needed to meet the performance requirements established in the NERC TPL-001-5 Reliability Standard and the WECC TPL-001-WECC-CRT-3.2 Regional Criteria. Results from the annual TPL-001 process are made available via the Local Transmission Plan document, which is posted publicly on PGE's OASIS page.

The summer (June 1st through October 31st) and winter (November 1st through March 31st) load seasons are considered the most critical study seasons due to heavier peak loads and high power transfers over PGE's Transmission and Distribution System to its customers. However, the off-peak seasons have different regional flow patterns that can result in issues not seen during peak load times. PGE defines the seasons to align with Attachment I of the RC West.[169]

PGE maintains system models within its planning area for performing the studies required to complete the system assessment. These models use data that is provided in WECC base cases in accordance with the MOD-032 reliability standard. Electrical facilities modeled in the cases have established ratings, as defined in PGE's "Facility Ratings Methodology" document and in accordance with the FAC-014 reliability standard. A facility rating is determined based on the most limiting component in each transmission facility, in accordance with the FAC-008 reliability standard.

[169] RC West Southwest Power Pool BC Hydro, "RC Guidelines for Seasonal Assessment and Coordination Process," Attachment I, page 14, https://www.caiso.com/documents/rc0680.pdf.

Reactive power resources are modeled as made available in the WECC base cases. For PGE, reactive power resources include shunt capacitor banks available on the 230 kV, 115 kV, and 57 kV systems.

Studies are evaluated for the Near-Term Planning Horizon (years 1 through 5) and the Long-Term Planning Horizon (years 6 through 10) to ensure adequate capacity is available on PGE's transmission system. The load modeled in the studies is obtained from PGE's corporate forecast, reflecting a 1-in-20 demand level for peak summer and peak winter conditions. Known outages of generation or transmission facilities with durations of at least six months are appropriately represented in the system models. However, any significant outage is studied as a result of an N-1-1 contingency and is therefore analyzed for every major season and year that PGE studies as part of the TPL process. Transmission equipment is assumed to be out of service in the base case system models if there is no spare equipment or mitigation strategy for the loss of the equipment.

Studies in the Near Term – Two Year Planning Horizon and the Near Term – Five Year Planning Horizon are performed for peak summer, peak winter, and off-peak spring conditions. Sensitivity studies are performed for each of these cases by varying the study parameters to stress the system within a range of credible conditions that demonstrate a measurable change in performance. PGE adjusts the real and reactive forecasted load and the transfers on the paths into the Portland area on all sensitivity studies. For peak system sensitivity cases, the 1-in-20 load forecast.

The load levels used in the 2024 Local Transmission Plan are available on PGE's OASIS page.

The Bulk Electric System (BES) is evaluated for steady state and transient stability performance for planning events described in Table 1 of the NERC TPL-001-5.1 reliability standard. When system simulations indicate an inability of the systems to respond as prescribed in the NERC TPL-001-5.1 standard, PGE identifies projects and/or Corrective Action Plans which are needed to achieve the required system performance throughout the Planning Horizon.

H.3.2.1 Steady state studies

PGE performs steady-state studies for the Near-Term and Long-Term Transmission Planning Horizons. The studies consider all Contingency scenarios identified in Table 1 of the NERC TPL-001-5.1 reliability standard (Categories P0-P7) to determine if the BES meets performance requirements. PGE uses the criteria defined in the WECC TPL-001-WECC-CRT-3.2 document to establish acceptable System steady state voltage limits and post-Contingency voltage deviations. The WECC System Performance Criteria requires that the change in bus voltage percentage not exceed 8 percent for N-1 contingencies. Additionally, internal PGE performance criteria require that the change in bus voltage percentage not exceed 10 percent for N-2 and N-1-1 contingencies. These studies also assess the impact of Extreme Events on the System expected to produce severe System impacts.

The Contingency Analyses simulate the removal of all Elements that the Protection System and other automatic controls are expected to disconnect for each Contingency without Operator intervention. The analyses include the impact of the subsequent tripping of generators due to

voltage limitations and tripping of Transmission Elements where relay loadability limits are exceeded. Automatic controls simulated include phase-shifting transformers, load tap changing transformers, and switched capacitors and reactors.

Cascading, or the uncontrolled successive loss of System Elements triggered by a Disturbance that results in the inability of the Elements of the BES to regain a state of operating equilibrium is defined as a System instability. Cascading is not allowed to occur for any Contingency analysis. If the analysis of an Extreme Event concludes there is Cascading, an evaluation of possible actions designed to reduce the likelihood or mitigate the consequences and adverse impacts of the event(s) is completed.

H.3.2.2 Voltage stability studies

PGE's Transmission System is evaluated for voltage stability in accordance with the WECC established criteria.[170] These performance criteria are summarized in the table below. Any voltage stability result that violates the criteria listed below is defined as a System instability. Contingencies to PGE and adjacent utility equipment at 500 kV and 230 kV are evaluated. All planning events were screened or reviewed for voltage stability requirement per WECC Criterion WR5 by simulating P0 and P1 events at 105 percent of forecasted peak load and simulating P2-P7 events at 102.5 percent of forecasted peak load. This screening indicated all planning events met the reactive margin requirement with the implementation of their associated operating procedures, RAS, or Corrective Action Plans.

H.3.2.3 Transient stability studies

PGE evaluates the transient stability performance of the BES for select Contingencies to PGE and adjacent utility equipment at 500 kV, 230 kV, and 115 kV. The studies evaluate single line-to-ground and three-phase faults to these facilities, including generators, bus sections, breaker failure, and loss of a double-circuit Transmission line. Extreme events are studied for three-phase faults with Delayed Fault Clearing.

For all 500 kV and 230 kV breaker positions, PGE implements high-speed protection through two independent relay systems utilizing separate current transformers for each set of relays. For a fault directly affecting these facilities, normal clearing is achieved when the Protection System operates as designed and faults are cleared within four to six cycles.

PGE implements breaker-failure protection schemes for its 500 kV and 230 kV facilities, and the majority of 115 kV facilities. Delayed clearing occurs when a breaker fails to operate, and the breaker-failure scheme clears the fault. Facilities without delayed clearing are modeled as such in the Contingency definition.

The transient stability results are evaluated for compliance with the following NERC and WECC System performance requirements. The simulation durations are run to 20 seconds. All

[170] "Guide to WECC/NERC Planning Standards I.D: Voltage Support and Reactive Power," prepared by the Reactive Reserve Working Group (RRWG) and approved by the Technical Studies Subcommittee (TSS) on March 30, 2006. https://www.wecc.biz/_layouts/15/WopiFrame.aspx?sourcedoc=/Reliability/Voltage%20Stability%20Guide.pdf&action=default&DefaultItemOpen=1

oscillations that do not show positive damping within 20 seconds after the start of the studied event shall be deemed unstable.

H.3.2.4 Short circuit studies

Short circuit studies are performed annually addressing the Near-Term Planning Horizon. If the short circuit current interrupting duty on a circuit breaker exceeds 97 percent of its equipment rating, PGE identifies projects and/or Corrective Action Plans which are needed to achieve the required System performance throughout the Near- and Long-Term Planning Horizon.

H.4 Other relevant transmission planning standards

H.4.1 TPL-007

Transmission system planning requirements surrounding geomagnetic disturbances are addressed in NERC Standard TPL-007-4. Geomagnetic disturbances occur when high-energy emissions from the sun, known as coronal mass ejections, interact with the Earth's magnetic field. The resulting electromagnetic disturbances can propagate along long conductors, such as transmission lines, and have been known to cause power system damage in the past.[171]

TPL-007-4 requires that PGE:

- Maintain and report information on all Bulk Electric System transformers in its service territory
- Install a geomagnetic current sensor on at least one bulk transformer it its service territory
- Coordinate on a geomagnetic disturbance study with regional stakeholders every five years
- Address any thermal or reactive power exceedances identified in this study via a Corrective Action Plan.

Historically, PGE has not experienced significant system impacts from geomagnetic disturbances. This is due to a combination of the transmission topology in the area and the nature of the soil in the Willamette Valley. During a recent geomagnetic storm in May 2024, which was the highest recorded in nearly 20 years, there were negligible effects detected on PGE's system.

The related NERC Standard EOP-010-1 governs how PGE works with NASA and the Reliability Coordinator (RC West) to address geomagnetic disturbances in the operations horizon.

H.4.2 TPL-008 (in development)

On June 15, 2023, FERC issued FERC Order No. 896 that acknowledges the "challenges associated with planning for extreme heat and cold weather events, particularly those that occur during periods when the Bulk-Power System must meet unexpectedly high demand. Extreme heat and cold weather events, which can cause public safety and economic risks, have occurred

[171] See for example, Guillon, et.al., "A Colorful Blackout: The Havoc Caused by Auroral Electrojet Generated Magnetic Field Variations in 1989" IEEE, Nov 2016. https://ieeexplore.ieee.org/document/7592967.

with greater frequency in recent years and are projected to occur with even greater frequency in the future. As such, the impact of concurrent failures of Bulk-Power System generation and transmission equipment and the potential for cascading outages that may be caused by extreme heat and cold weather events should be studied and corrective actions should be identified and implemented."[172]

Part of the Order 896 effort involves the creation of a new NERC Standard, TPL-008-1, which currently in the drafting phase (as of August 2024). It is expected to be finalized in early 2025, with the various requirements having implementation dates of 12- to 60-month.

While the standard is not yet finalized, in general, it will require Transmission Planning entities such as PGE to:

- Coordinate on the development of extreme weather base cases for both cold winter and hot summer conditions
- Model and simulate the ability of the transmission system to respond to transmission outage scenarios (i.e. contingencies) during these extreme weather events
- Develop Corrective Action Plans for any scenarios that do not meet the established acceptance criteria in the standard

The goal of this standard is to ensure that the transmission system remains robust to future extreme weather conditions.

H.4.3 FERC Order No. 2023

FERC Order No. 2023 reforms the large generator interconnection process to make it more efficient by moving to a first-ready, first-served cluster study process.[173] The new process consists of a 150-day Cluster Study (or Cluster Restudy) and a 90-day or 180-day Facilities Study. New financial and readiness requirements, including increased deposits, increased site control, and significant withdrawal penalties are aimed to reduce the number of speculative interconnection requests entering the queue and, as a result, minimize the number of withdrawals from the interconnection queue, which typically result in restudies, lengthening the interconnection study process. These improvements provide more certainty that the new resources identified in the integrated resource planning process can be energized when they are needed, minimizing delays in the interconnection study process.

Information available to prospective interconnection customers is improved with the publishing of an interconnection heatmap, which will be updated at the end of every cluster study or cluster restudy. This heat map can be utilized in the integrated resource planning process to identify on-system locations with existing capacity for new renewable resources.

New advancements were added to FERC Order No. 2023 to allow more flexibility and timeliness improvements for interconnecting new resources. First, multiple customers at the same site with the same Point of Interconnection (POI) can submit a single interconnection request. This

[172] N. Am. Elec. Reliability Corp., 183 FERC ¶ 61,191 (2023) (FERC Order), Final Rule.
[173] FERC Order No. 2023, issued on November 6, 2023.

streamlines jointly owned interconnection projects because multiple owners do not need to submit individual requests. Second, Surplus Interconnection Service can be requested for a project with a signed large generator interconnection agreement – the project no longer must be in commercial operation. This allows for more co-location of different renewable resources behind a single POI to move faster, not waiting for the energization of the first resource to be able to apply for the subsequent resource. Finally, FERC Order No. 2023 requires transmission providers to evaluate alternative transmission technologies for each identified network upgrade. These alternative transmission technologies traditionally can be constructed and energized before traditional solutions, often at a lower cost. All these improvements provide even more certainty to the interconnection process timeline for use in the integrated resource planning process.

To continue alignment with state-jurisdictional and FERC-jurisdictional large generator interconnection processes, the QF-LGIP was amended to conform with the cluster study process. This is beneficial for QF projects, as these projects will be subject to the same cost allocation and sharing as the FERC-jurisdictional projects, potentially reducing costs by spreading across more projects. The OPUC approved PGE's filing with an effective date of January 7, 2025.

PGE began the Transitional Cluster Study on January 6, 2025 to study projects in the serial queue as of May 26, 2024, which was 30 days after PGE submitted its compliance filing to FERC. There are no QF-LGIP projects in the Transitional Cluster Study, as none were in the interconnection queue as of May 26, 2024. The first Cluster Study Request Window for when new large generation projects can request interconnection will open January 1, 2026.

H.4.4 Miscellaneous

In addition to the transmission planning specific standards, there are a number of additional NERC standards in which transmission planning is involved. These include:

- Establishing requirements for generation requesting to interconnect to the Bulk Electric System (FAC-001)
- Establishing a study process for generation interconnection (FAC-002)
- Vegetation management practices near transmission lines (FAC-003)
- Development of detailed generator models, including real and reactive power capabilities (MOD-025), exciter models (MOD-026), and governor and turbine models (MOD-027)
- Coordination of transmission base case development (MOD-032) (Note: PGE and neighboring utilities coordinate this process through the Western Power Pool and the Western Electricity Coordinating Council)
- Validation of transmission base cases for both steady-state and transient stability, utilizing recorded historical events (MOD-33)

- Development of Underfrequency Load Shedding (PRC-006) and Undervoltage Load Shedding (PRC-010) schemes to maintain system stability during extreme transient events.

These related study efforts help ensure that the future state of the transmission system is modeled accurately and that planners can make the best long-term decisions regarding necessary upgrades to reliably maintain the grid.

Appendix I Inputs for state RA requirements portfolio

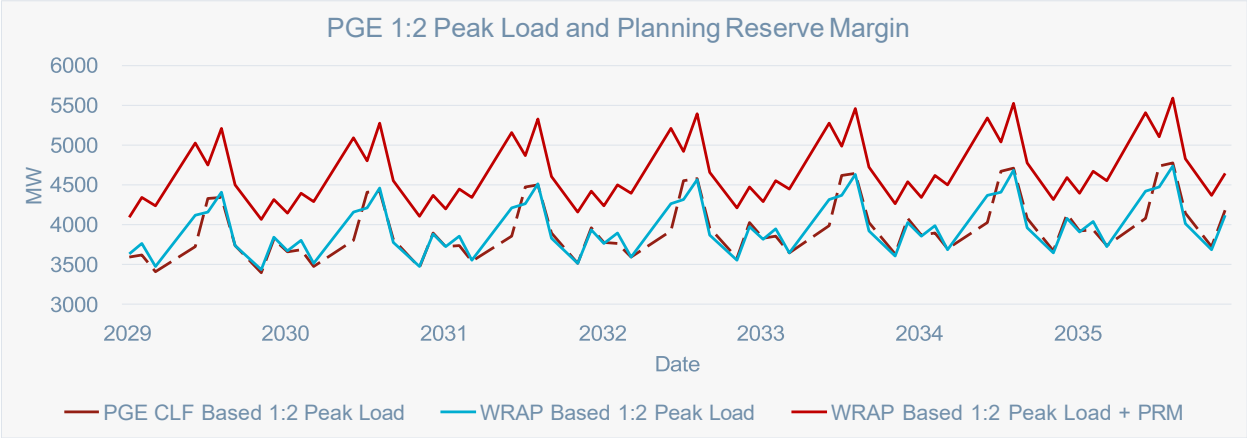
PGE used demand and supply assessment methods from the Western Resource Adequacy Program (WRAP) to analyze the adequacy of PGE's system across the IRP planning horizon. These methods provide the primary metrics needed to derive capacity need and ELCCs for portfolio modeling based on State RA Requirements, which currently rely on WRAP methodology. WRAP metrics for Summer 2026 and Winter 2025-2026 in the MID-C subregion, and WRAP's 2025 qualifying capacity contribution (QCC) estimates for PGE resources are the primary inputs for this exercise.[174,175]

I.1 WRAP based load forecast

PGE estimated load requirements using WRAP methodology for seasonal peak load forecasts plus the WRAP estimated PRM required to achieve a 1 event in 10 years adequacy metric. 5-years of historical PGE load data was used to estimate 1:2 peak load for summer (May-September) and winter (November-March) months as described in WRAP Business Practice Manual (BPM) - 103 – Participant Forward Showing Capacity Requirements.[176] A PGE specific annual growth rate of 1.2 percent was used to scale peak loads across the planning horizon.[177] This growth rate was estimated using PGE's May 2024 load forecast. WRAP's month specific PRM was applied to the resulting load forecast to arrive at estimated load requirement by month.[178] **Figure 94** shows the resulting load forecast for a portion of the planning horizon with and without the PRM. For comparison the median of maximum peak monthly load from the PGE's May 2024 Corporate Load Forecast (CLF) is show. The figure shows there is close alignment in estimated 1:2 peak loads from PGE estimates and WRAP based estimates. There is a divergence in the month of June due to a heavier weighting of the 2021 heat dome event as only 5 years of historical load data are used in the WRAP based estimates.

[174] WRAP Metrics for Summer 2026
[175] WRAP Metrics for Winter 2025-2026
[176] WRAP BPM 103
[177] WRAP's established growth rate is 1.1%, as defined in WRAP BPM-103. 1.1% was defined through and informal survey process, as described in the WRAP's Detailed Design Document – March 2023. Rather than use the establish growth rate for this exercise, PGE elected to estimate a growth rate specific its system.
[178] Preliminary values published 3-31-2024 used for winter season months.

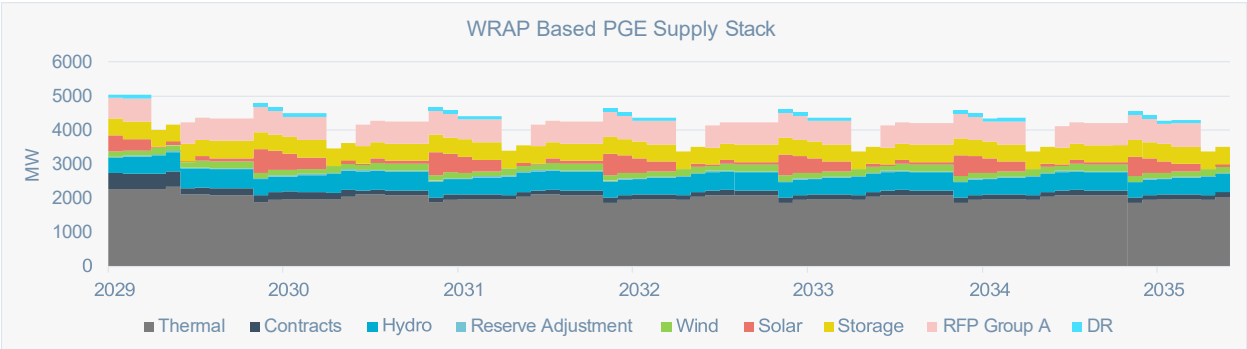
Figure 94. WRAP Based PGE 1:2 Peak Load and Planning Reserve Margin



I.2 WRAP based supply forecast

The company used WRAP provided estimates of resource specific QCC values to estimate the capacity contribution of existing PGE resources in each month of the WRAP summer and winter seasons. WRAP's Winter 25-26 Forward showing (FS) and Summer 2026 FS qualifying capacity values were used capacity assumptions across the planning horizon. Exits and entry from the supply stack were assumed in accordance with assumptions used for resource adequacy modeling in Sequoia. For example, exits were assumed based on known contract expiration dates for the related resources or structured agreements and 2023 RFP Proxy resources were assumed to enter the supply stack in January 2028. **Figure 95** displays the supply assumptions that resulted from this WRAP based forecast.

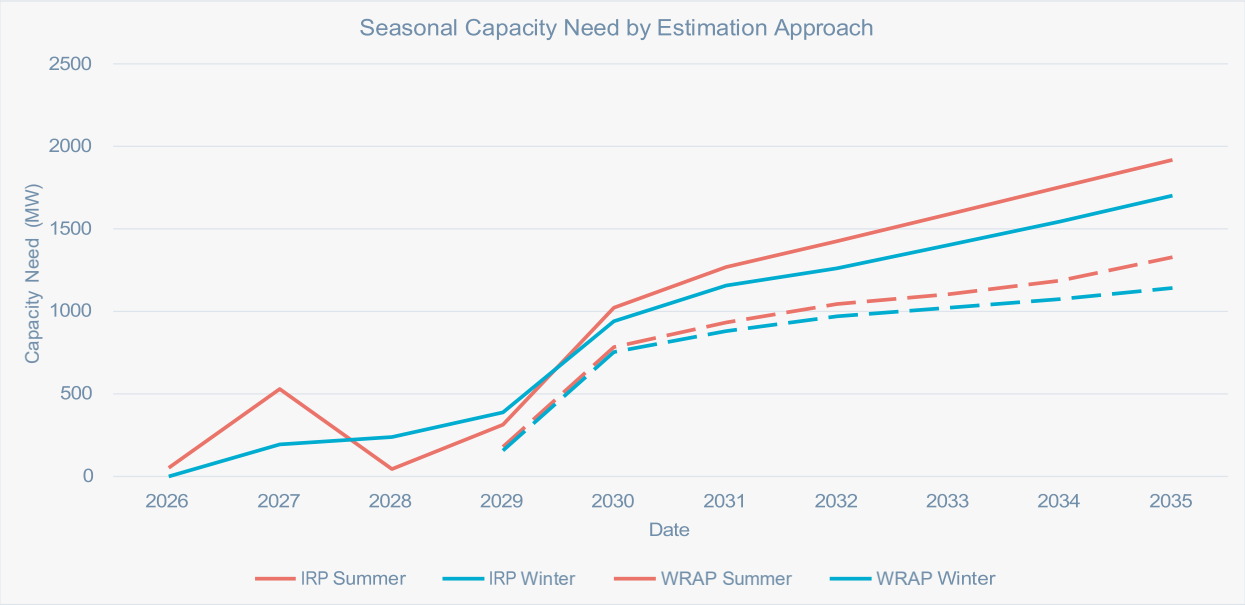
Figure 95. WRAP Based PGE Supply Stack



I.3 WRAP based capacity need

Capacity need was calculated using the difference between WRAP based forecasts of load requirements and supply, as detailed above. **Figure 96** shows the resulting capacity need as compared to the IRP derived capacity need values as estimated in Sequoia. 2030 capacity need is approximately 250 MW less using the WRAP based methods compared against the IRP estimates from Sequoia.

Figure 96. Seasonal Capacity Need by Estimation Approach



I.4 WRAP based ELCCs

PGE used ELCC estimates from WRAP's summer 2025 and winter 2025-2026 adequacy assessment for the valuation of Proxy Resources in portfolio expansion modeling. The company elected ELCC values from the +6 GW entry scenarios provided by WRAP. **Figure 97** shows a comparison of WRAP based ELCCs for the base system and +6 GW scenarios against ELCCs estimated in Sequoia for 100 MW and 2000 MW tranches. In general, summer WRAP ELCCs for storage and solar resources are significantly greater than IRP estimates for resources within the same WRAP zones. Wind resources show less divergence between the two estimation approaches, save for Gorge Wind, which has a predominantly summer generation profile.

Figure 97. Summer IRP-WRAP ELCC Comparison

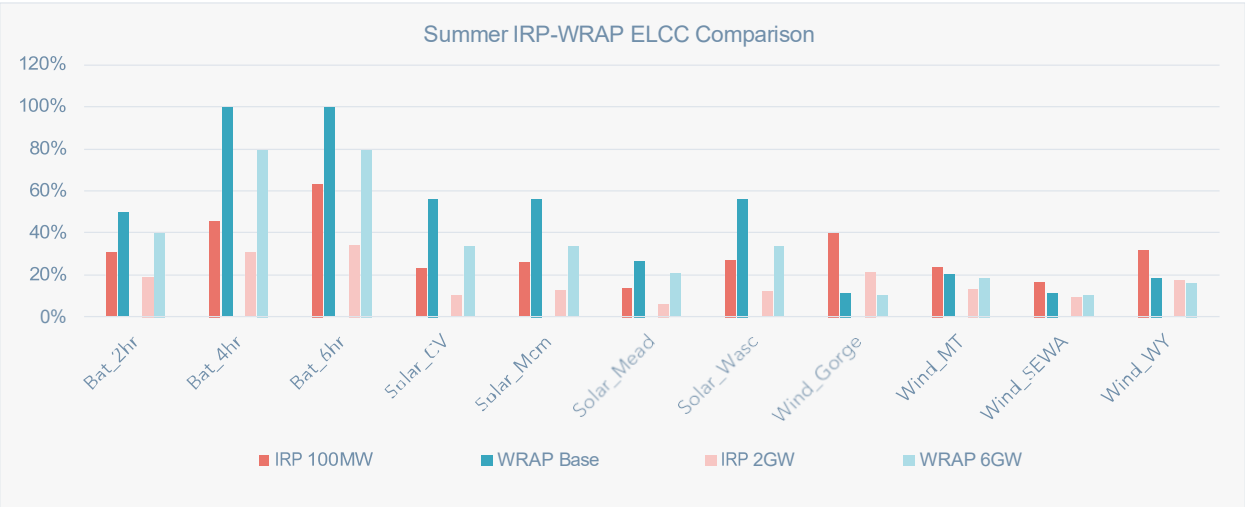
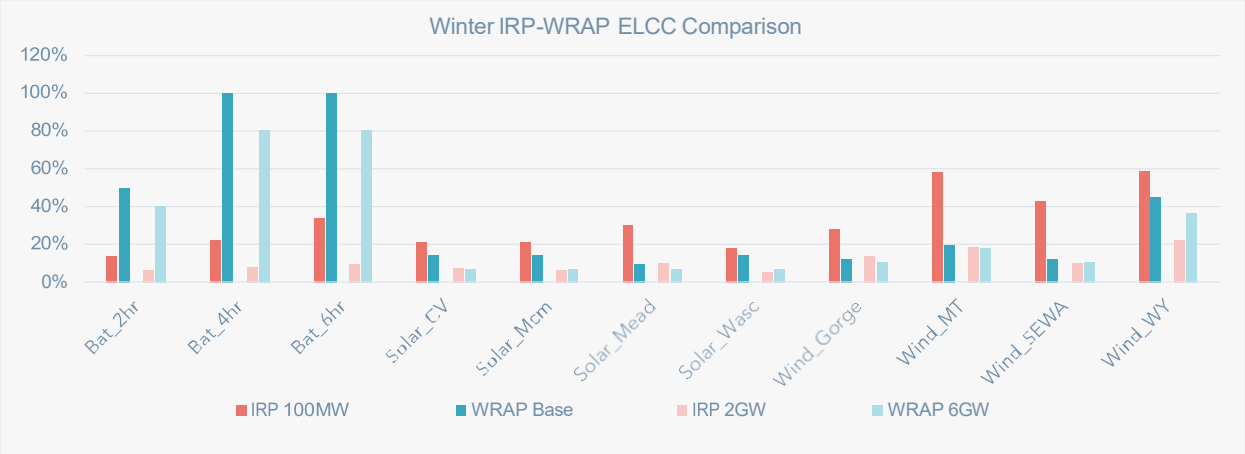


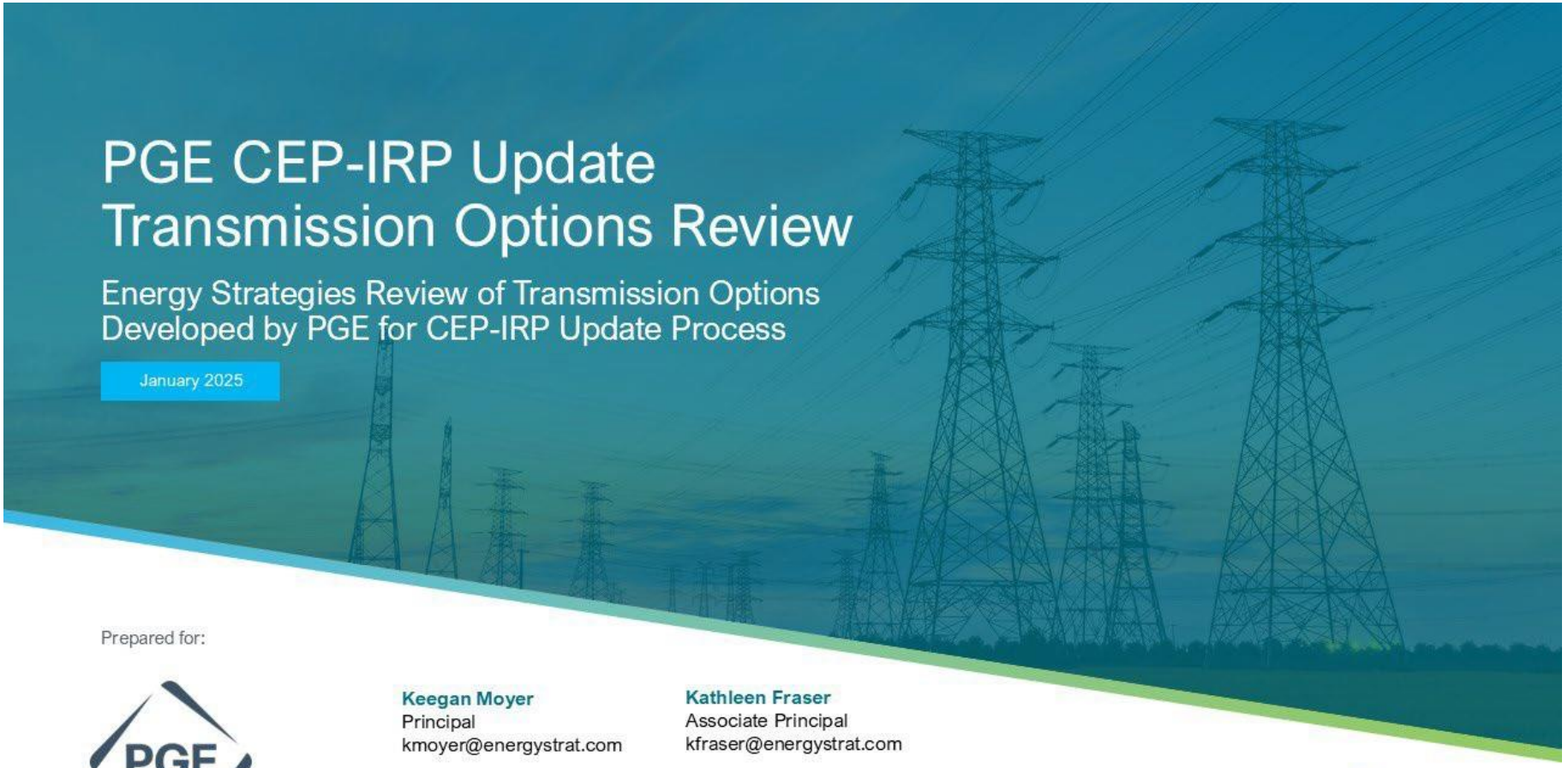
Figure 98 shows a similar comparison for the winter season. Winter WRAP ELCCs for storage resources continue to be significantly greater than IRP estimates for similar storage resources, while IRP estimates of solar and wind resources are greater.

Figure 98. Winter IRP-WRAP ELCC Comparison



For PGE's Proxy Resources without a direct overlap with WRAP ELCCs, the following assumptions were made: North Dakota Wind assigned ELCC values for WRAP Region 4 (Colorado and Wyoming), Batteries greater than 6-hour duration assigned WRAP ELCCs for 4-hour batteries, hybrids assigned the sum of WRAP based solar and 4-hr battery ELCCs, while other smaller resources (e.g., EE, DERs, CBREs) maintained ELCCs as estimated in Sequoia.

Appendix J Transmission options study

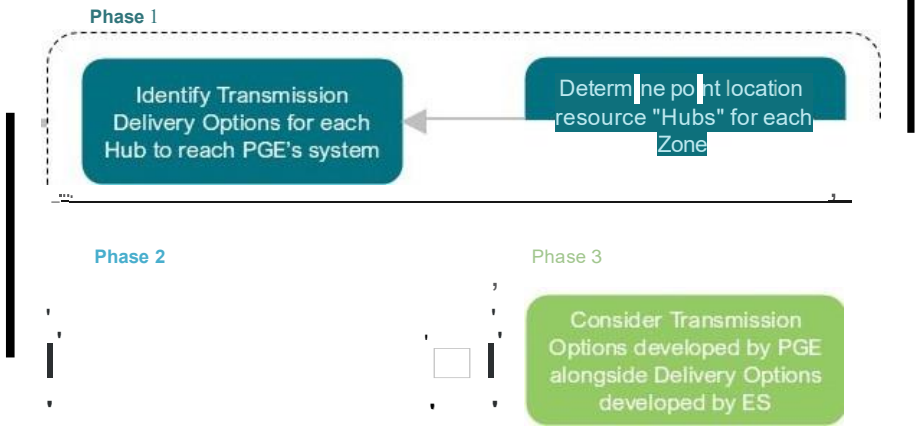


Work Scope

- **Portland General Electric (PGE) engaged Energy Strategies (ES) to identify and evaluate transmission strategies to access remote resources.**
  - Designed to help PGE evaluate options to efficiently meet load and policy requirements in its Clean Energy Plan and Integrated Resource Plan (CEP-IRP).
- **The study consists of three phases:**
  1. **Identify Transmission Delivery Options** for six Resource Zones, considering:
     - Existing transmission system (e.g., Available Transfer Capacity (ATC))
     - Known or previously proposed transmission upgrades
     - New transmission upgrades
  2. **Characterize technical and risk profiles** of each feasible delivery option.
  3. **Review Transmission Options** developed by PGE and propose alternatives based on assessment.

Resource Zones Identified by **PGE** as Input to Study Scope

Zone	Region	State	Resource Type
	Desert Southwest	Arizona	Solar
2	Desert Southwest	Nevada	Solar
3	Rockies	Montana	Wind
4	Rockies	North Dakota	Wind
5	Rockies	Wyoming	Wind
6	Rockies	Idaho	Wind & Solar



ENERGY STRATEGIES

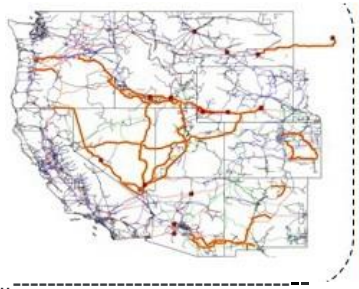
Transmission Delivery Options Development Methodology & Results

0 Resource Zones identified by PGE

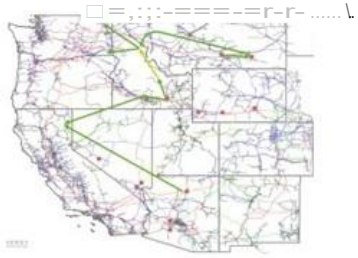
Zone	State and Resource(s)
	Arizona Solar
2	Nevada Solar
3	Montana Wind
4	North Dakota Wind
5	Wyoming Wind
6	Idaho Wind & Solar

• Establish Resource Hubs

0 Include Likely Transmission Upgrades



® Review ATC Postings on OASIS



Interim selection of Transmission Delivery Options by Energy Strategies:

State and Resource	Description		
Arizona Solar	APS ATC+ NVE Expansion+ existing NWACI + PGE Rights	183	~2035-2040
	APS Upgrade + NVE Expansion + existing NWACI + PGE Rights	550	2040+
Nevada Solar	NVE Expansion + updated NWACI + Bethel Round Butte	~600	~2035-2040
	SWIP N + Gateway West 8 + B2H <- new BPA TSRs	400	~2035-2040
Montana Wind	Existing PGE Rights after Colstrip retired	270	2030
	PGE rights + new BPA & possibly NWMTTSRs	~1000	~2035-2040
North Dakota Wind	**North Plains Connector+ PGE** rights + new BPA + NWMT TSRs	~1000	~2035-2040
Wyoming Wind	Gateway West & B2H + new BPA TSRs	400	~2035-2040
Idaho Wind & Solar	Gateway West & B2H + new BPA TSRs	400	~2035-2040
	New Hemingway-> Grizzly line+ Bethel Round Butte	~1000	2040+

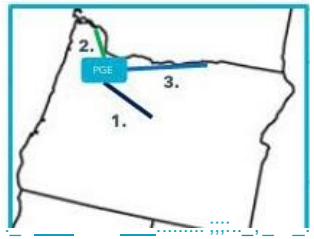
Highlighted Transmission Options Correspond to PGE Transmission Options from prior IRP roundtables

Review of PGE's Transmission Options from Prior Roundtables

- **Energy Strategies work scope included a review of Transmission Options developed by PGE:**
  - At the direction of the Oregon Public Utility Commission (PUC), PGE to update 2023 CEP-IRP Transmission Options.
  - As part of the CEP-IRP Update process and monthly public roundtables, PGE has developed 7 Transmission Options and asked Energy Strategies to review these options as a part of its broader work scope:
    1. **Are these options appropriate to meet the PUC's direction?**
    2. **What are the risks for each?**
    3. **Of the transmission alternatives identified by Energy Strategies, do any serve as viable alternatives?**

Seven Transmission Options Identified in **PGE CEP-IRP** Roundtables

1. **Bethel-Round Butte**
2. **Trojan-Harborton**
3. Cascade Renewable Transmission Project
4. **SWIP N + Gateway West 8 + B2H**
5. Western Bounty
6. North Plains Connector
7. TransWest Express



Oregon/PNW specific transmission option&

As the ES work scope did not consider stand alone intra-Oregon transmission, we will provide comments but cannot propose alternatives at this time.



Remote resource transmission options

With the consideration of remote resource zones in the ES scope, we assess the viability of these transmission options and propose alternatives as needed.

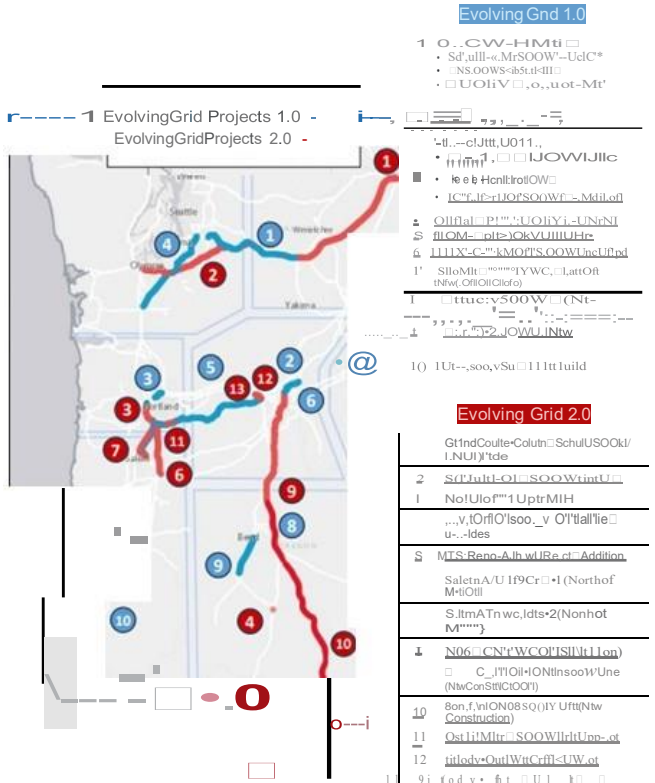
Overview of Findings from Review of PGE Transmission Options

Resource Area	PGE Transmission Option	ES Alternatives to Consider	Recommendation
North Dakota (Wind)	**North Plains Connector**	No alternatives recommended	• With PGE's Colstrip rights and NWMT + BPA TSRs, North Plains Connector is the best option. • Based on development status and need for downstream upgrades, recommend first available date no sooner than 2035 (perhaps later).
Wyoming (Wind)	**TransWest Express +CAISO**	Gateway West & B2H	• There is significant policy and pricing risk to using TransWest Express, without providing firm transmission access. • Using Gateway West may require upgrades to existing lines to increase transfer capacity.
Nevada (Solar)	**Western Bounty**	Greenlink and PGE's Rights+ Upgrades	• Western Bounty likely too early in development to reach service before mid- to late-2030s. • Combining NVE's Greenlink with PGE's rights and upgrades provides a lower risk alternative to consider.
Nevada (Solar)	**SWIP N + Gateway Wests+ B2H**	No alternatives recommended	• This transmission option represents a strong option but would require additional TSRs on the BPA introducing timing risk.

- **Resource areas evaluated by ES not captured by PGE transmission options:**
  - Arizona
  - Idaho
  - Montana
- **Resource areas and transmission options in PGE CEP/IRP Roundtables outside ES scope:**
  - OR/WA/BPA
    - Bethel - Round Butte
    - Trojan - Harborton
    - Cascades Renewable Transmission
  - CAISO

"Evolving Grid" Status Improves Transmission Service-Driven Upgrades, but Significant Uncertainty Remains

- **BPA's** Evolving Grid **initiative prioritizes significant transmission projects that are critical to meet regional needs in the PNW.**
  - Initiative supports upgrades that will improve resource deliverability in the coming decade, attempting to address cyclical nature of TSRs triggering recurring upgrades in TSEP cycles and eventually dropping out.
  - Evolving Grid is designed to provide an actionable path forward primarily for projects that were identified in SPA's 2021, 2022 and 2023 TSEP processes and relate to specific TSRs.
- **Despite this step, BPA has not yet committed to constructing these projects and many still have several years of scoping, design and NEPA milestones prior to a BPA decision to fund and construct.**
  - In-service dates for EVG 1 projects: ~2026-2032.
  - In-service dates for EVG 2 projects: not announced, but possibly mid-late 2030s.
- **Conclusion for this work: Evolving Grid 1.0 projects create capacity that is likely "already spoken for" by existing TSRs (and generation projects PGE is likely aware of via RFPs) and Evolving Grid 2.0 projects have too many uncertainties to forecast impact at this time.**
  - Therefore, for this study we assume generic "new SPA TSRs" are needed for service on or through SPA to reach PGE and recommend continued monitoring sets of Evolving Grid projects.

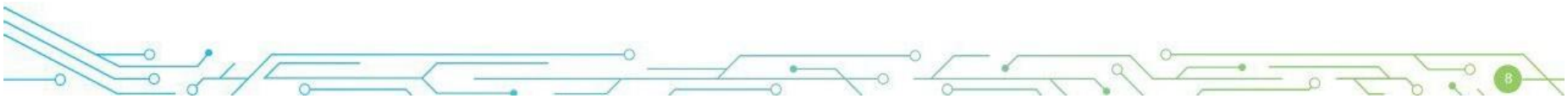


Review of PGE Proposed Transmission Options and Selected Alternatives

PGE Transmission Options Review - Overview of Contents

1. **PGE Transmission Options to access remote resources:**
   - SWIP N + Gateway West 8 + B2H
   - Western Bounty
   - North Plains Connector
   - TransWest Express Transmission Project

2. **Appendix: PGE Transmission Options specific to Oregon/PNW:**
   1. Bethel - Round Butte 500kV Upgrade
   2. Trojan - Harborton Upgrade
   3. Cascades Renewable Transmission Project



SWIP N + Gateway West 8 + 82H

Details from **PGE's CEP-IRP** Update Roundtable:

- *Thisoption entails R3E purchasing aa:::esson fivetransmission lines /eacing tot he desert southwest:*
  1. *Boardman to Hemingway (B2H)*
  2. *G.teway segment E8*
  3. *SJuthwest Intertie ffoja:i (SN/"" - f\kJrth*
  4. 01e*Nevada Transmission line(ON line)*
  5. *Desert link*
- *Thisis achievable by **2027**(line CO'.)). However; thisoption would requireadditional access* aaoss*EPA'ssystem, which is plausibly expeda:Jby **2032**(/RPCO'.)).*
- *Up to **600MW** of Nevada rolar is modeled to be enabled through thisoption.*

SWIP N + Gateway West 8 + B2H:



- **Energy Strategies' conclusions:**
  - SWIP **N** + Gateway West 8 + B2H is a viable transmission option to access Nevada generation - it involves transactions with three transmission providers: 1. NVE, 2. PacifiCorp or Idaho Power, and 3. BPA.
  - Up to 400 MW of Nevada solar can be accessed, with unallocated transmission capacity on B2H as the limiting segment (see details on next slide).
  - Boardman (Longhorn) to PGE requires additional TSRs on the BPA system.
  - Earliest Date: 2035-2040, with greatest timing risk related to receiving additional TSRs on BPA system and availability of capacity on

SWIP N + Gateway West 8 + 82H: Details

- **Energy Strategies' determination of rights on each segment:**

Segment	Description		Est. Date Available
NVE	ATC from Greenlink projects (Southsys to Northsys)	~550 (1)	2029
SWIP North	Utilizing DOE's northbound entitlements	500 (2)	2027 COD
Gateway West E8	Utilizing forecasted available transmission	600 (3)	2028 COD
82H	Use currently unallocated 218MW of PAC rights and 182MW of IPCo rights	400 (4)	2026 COD
Longhorn to PGE	New BPA TSRs - see prior slides	400	2035-2040
	Rights and Date Available entire path:	**400**	**2035-2040**

SWIP N + Gateway West 8 + B2H:



(1) ATC from OASIS Postings, Southsys to Northsys, 550MW represents minimum during 2029-2033 period (Expansion entails Greenlink West, Greenlink North).
(2) For SWIP-North, CAISO and the DOE hold a combined 10725 MW of entitlements in the northbound direction. We assume that PGE could request and acquire up to 500 MW (equal to DOE's entitlements) (sources: here and here).
(3) Gateway West Segment EB will have a transfer capacity of 2000 MW. Energy Strategies assumes PGE can request and receive 600 MW of capacity (source: PacifiCorp here).
(4) From IPCO for B2H (CPCN documents filed by IPCO here and here).

Western Bounty

Details from PGE's CEP-IRP Update Roundtable:

- *The Western fuunty Transmission □em* is *a proposed xa> MW 1-NOC/ine that rouki connect routhern California to the Grizzly substation*
- *Theprojeded oomnerdal operation date (a::D)* is ***2033***
- *Up to **3000MW** of Nevada rolar* is *roockied to be enabled through thisoption*
- *Thisoption wouki provideacress to the EP-15 market hub*
- *Mditional **Bff'.** upgrades wouki be required for thisoption to reach PGE*

Western Bounty



- **Energy Strategies' conclusions:**
  - Western Bounty early in its development cycle and unlikely to materialize before mid- to late-2030s based on historical transmission development rates.
    - ❖ Development started in 2023 with the Interregional Transmission Project (ITP) joint evaluation process only starting in 2024. Project is early stage.
  - The scope, timing and available capacity of necessary BPA upgrades would likely limit PGE's 3000 MW of proposed solar access to a smaller amount - we do not recommend assuming 3000 MW of availability.
  - As an alternative, NVE's Greenlink expansion that increases ATC on their system, together with PGE's rights on the Northwestern AC Intertie (NWACI) and the Bethel - Round Butte upgrade, could be utilized to access resources within a similar proposed timeframe

□ provided on next slide).

Western Bounty Alternative: NVE Expansion and PGE rights

- **NVE Greenlink expansion and PGE's rights and projects as an alternative to Western Bounty for access to southwest solar:**
  - With NVE's Greenlink expansion, Southsys to Northsys capacity increases, creating additional ATC which PGE can utilize.
  - Pros:
    - Less risk in terms of parties involved and permitting timelines: NVE taking lead on "Greenlink 3" (Fort Churchill-> Captain Jack).
    - The expected route for Greenlink 3 roughly falls within the "Mountain - Northwest" National Interest Electric Transmission Corridor meaning any environmental review process under NEPA could be expedited as part of DOE's National Transmission Needs Study.
  - Cons:
    - Available capacity is less than considered with Western Bounty, however the 3000 **MW** envisioned capacity on Western Bounty would be limited by BPA upgrades.
- **Conclusion: Less risk and same desired timeframe and capacity potential as Western Bounty.**

Greenlink vs. Western Bounty:



	Element	Description	Rights MW	Est.Date Available
	NVE	ATC from Greenlink projects (Southsys to Northsys)	□550 (1)	2029
2	Greenlink 3	Fort Churchill-> Captain Jack (early stage proposed by NVE)	725 (2)	2035-2040
3	Captain Jack -> Grizzly	Planned contractual updates to allow intra-region scheduling on the Northwest AC Intertie (NWACI) and use PGE's existing rights.	627 (3)	2029
4	Bethel - Round Butte Upgrade	TTC depends on configuration but not limiting segment in path	□3000 (4)	2032
		Rights and Date Available entire path:	**627**	**2035-2040**

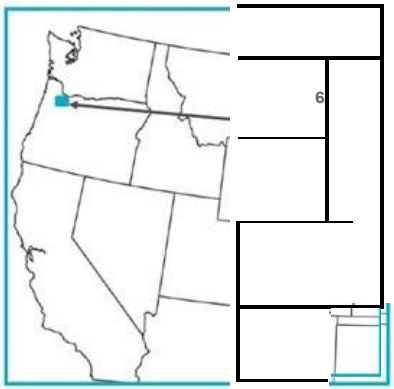
(1) ATC from OASIS Postings, Southsys to Northsys, 550MW represents minimum during 2029-2033 period (Expansion entails Greenlink West, Greenlink North).
(2) NVE IRP Filing on initial study work related to Fort Churchill-> Captain Jack (Greenlink 3) (sources: here and here)
(3) Data from PGE.
(4) Data from PGE.

North Plains Connector

Details from PGE's CEP-IRP Update Roundtable:

- *This projed isa 412-mile HVOCtransmissioo lineto beoomtruded with endpdnts near Bsmarck, North Dakota and O:istriA Mootana.*
- *PGEwrrently has270* ***MW*** *of rightsfran Cblftrip toPGE.*
- *If ncihing changes between now and2032, onlya oombined 270 MW NPCwi/1 be available fa model selection.*
- *However, theoompany has sutxnitted TfR3 for an additional 720MW aaossboth a=r>:s and NorthWeftern's □ems.*
- *Upto3000MWof North Dakota windismodeledtobeenabledthrough thisoption, subjed totheoonftraints mentiooedabove.*
- *Mditiooal/y, thisoption wouldprovidea□totheMls:J□rourreZone1market.*
- *Thisoption's o:xJ is expeded by* ***2032***

North Plains Connector:



- **Energy Strategies' conclusions:**
  - With PGE's existing rights from Colstrip, this project represents the best option to access North Dakota wind.
  - However, the timing to receive requested BPA and NWMT TSRs, as well as early stage of project development, are not consistent with a 2032 availability-we suggest a late 2030s timeframe may be more appropriate given historical greenfield transmission development timelines.
  - As already noted above, the actual MW capacity of access will be limited by PGE rights from Colstrip and pending TSRs.

TransWest Express Transmission Project

Details from **PGE's CEP-IRP** Update Roundtable:

- *This projed isa twerpart line that connects near 8ndair, WYand near Ebulder Qty, NV:*
  - *Near Sndair; WYto near Delta, UT:* 3CO'.)*MW DC*
  - *Near Delta, UTto near Ebulder Qty,NV: 1500MW* AC
- *Thisoption is being strudured asa gerrtie through C4JEJ::I which R3Ecan* aa;ess*using its rightsat the Califomia-Oegon Border (CDB) trading hub.*
  - *Thislinecould add up to approximately* 3,0CO*MW of transmission* aa;ess, *however R3EsCD8rights limit* aa;ess *to 600 MWofW)'Ol11ing Wind*
  - *No other marf<.et aa;essbenefitsassumed*
- *Theantidpated CODfor thisoption is 2027 and would not requireany additional transmission expansion.*

TransWest Express Transmission Project:



- **Energy Strategies' conclusions:**
  - PGE would need to be a subscriber on TWE and deliver to Eldorado; then make a market purchase at California Oregon Border (COB) which may be subject to paying CAISO transmission access charge (TAC).
    - This strategy would also be subject to basis risk between Eldorado and COB (or require a developer to carry this risk).
    - Would also likely need to ensure the transaction was designated as a high priority wheel-through.
    - This results in potentially high cost of transmission to access WY wind.
  - Other factors to consider include CAISO LSEs obtaining all TWE capacity (for reliability/clean energy needs), lack of ability to document delivery to PGE given lack of firm service, significant policy risk and dependence on CAISO market rules.
  - A n altemalive using Gateway West and B2H may be viable but has risks in timing and availability of capacity.

TransWest Express Alternative: Utilizing Gateway

- **Utilizing the Gateway buildout as an alternative to TransWest Express for access to Wyoming wind:**
  - Pros:
    - Provides access to Wyoming wind on a firm basis while avoiding the policy and pricing risks that would be associated with CAISO market transactions.
  - Cons:
    - Puts PGE in competition with PACand IPCo and would require timely granting ofTSRs on all systems.
- **Conclusions: Neither TransWest Express nor the Gateway alternative are ideal options**
  - PGE may be unable to secure affordable transmission access to Wyoming wind on a firm basis in the 2030s.

Gateway West vs. Transwest Express:



ID	Element	Description	Rights MW	Est. Date Available
	Gateway West: Anticline -> Populus	Completing construction of Gateway West segment D-3	400 (1)	2031
2	Gateway West: Populus -> Hemingway	Completing construction of Gateway West segment E	400 (1)	2036
3	B2H	Use currently unallocated 218MW of PAC rights and 182MW of IPCo rights	400 (2)	2026 COD
4	Longhorn to PGE	New BPA TSRs.	400	2035-2040
		Rights and Date Available entire path:	**400**	**2035-2040**

(1) Gateway West segment EBwill have a transfer capacity of 2000 MW. Energy Strategies assumes PGE can apply for 400 MW of capacity (source: PacifiCorp here).
(2) (2) From IPCO for B2H (sources: IPCOhere and here).

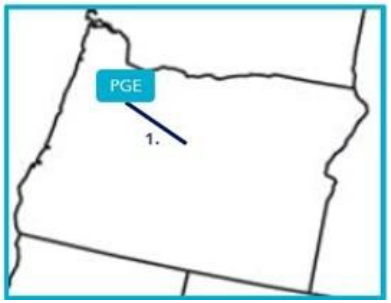
Appendix: Review of PGE Oregon/PNW Specific Transmission Options

Bethel - Round Butte 500kV Upgrade

Details from **PGE's CEP-IRP** Update Roundtable:

- *The Bethe/-RJund 9.Jttera:xJndudoring would increase the capadty on the exhiing line.*
- *Thelineis 98miles, running from the B:Ithel subiiation (near Selem) to the RJund-Butte subiiation.*
- *Theprojeded commerdal operation date (CQ'.)) is* ***2032****and will not require any other transmission expansion for PGEto* acress *these benefits*
- *R:Ibuilding thelinefrom230kVto 500kVwill increasecapacity.*
- *Thisrould support an increase of* ***2,385-4,770 MW*** *increasein 'Bff!,' rerources(off-sy.iem resourcesin the PNVV region), depending on spedfication andsubsequent path rating*proresses
- *Thisoption provides market aa;ess to the California-Q-egon border.*

Bethel - Round Butte 500kV Upgrade:



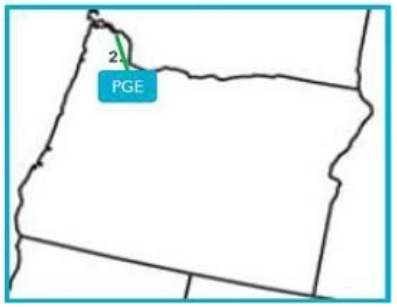
- **Energy Strategies' conclusions:**
  - As noted in the PGE 2023 CEP/IRP this upgrade is a "no regrets" option and facilitates significant access to queued resources.
  - However, depending on the reconductoring configuration chosen, the total transfer capacity is likely to reach only 3000 MW.

Trojan - Harborton Upgrade

Details from **PGE's CEP-IRP** Update Roundtable:

- Approximately 34 miles long, running between PGE's Trojan and Harborton substations, paralleling two existing lines in service since the 1970s.
- PGE currently owns the additional unused ROW necessary for the project and has since the 1970s.
- The projected commercial operation date (COD) is **2032** and will not require any other transmission expansion for PGE to access these benefits.
- This transmission project will enable **800 MW** from BPA's generation resources, subject to cooperative study and agreement with other South of Allston path owners, BPA and PacifiCorp.

Trojan-Harborton Upgrade:



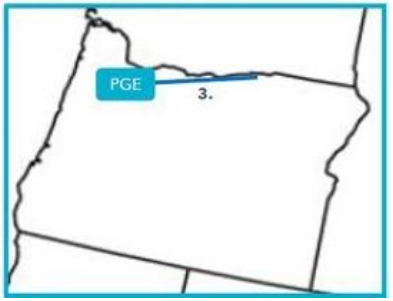
- **Energy Strategies' conclusions:**
  - With the importance of South of Allston and the control over right of way and facilities PGE possesses which are necessary to complete this upgrade, completing Trojan - Harborton upgrades appears "no regrets" similar to the Bethel - Round Butte upgrade.
  - In addition to the mentioned need to coordinate with other South of Allston path owners, timing of benefits from this upgrade is not certain:
    - Realizing the 800MW of BPA generation resources seemingly requires receipt of TSRs PGE has applied for on the BPA system and likely date to receive these TSRs is closer to 2035 than the proposed 2032 COD of this upgrade option.

Cascade Renewable Transmission Project

Details from **PGE's CEP-IRP** Update Roundtable:

- This project involves an electric transmission cable bundle, buried entirely underground and underwater, along with two converter stations located next to existing substations.
- This travels approximately 100 miles, primarily beneath the Columbia River, from the Big Eddy substation to the Harborton substation.
- The projected commercial operation date (COO) is **2032** and will require additional BPA and PGE transmission expansion for PGE to access these benefits.
- This is modeled to enable the transfer of **1,100 MW** of 'BPA' resources (off-system resources in the PNW region).
- PGE is not currently participating in this project, but involvement may be possible if selected as part of PGE's preferred portfolio.

Cascade Renewable Transmission Project:



- **Energy Strategies' conclusions:**
  - The point of delivery at Harborton makes PGE well-positioned to realize benefits from access to BPA resources.
  - The timing for 1260 MW of solar+ storage projects in BPA's Queue at Big Eddy as well as the Cascade Renewable Transmission Project's own queue position (all seeking interconnection/energization in 2029) seems aggressive given the early stage of development for this project.
    - With the challenges to work in the Columbia River, especially from a permitting perspective, late 2030s more likely as a time for project COO.



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CLEARING UP
Energy and Utility News for the Greater Pacific Northwest
July 15
2025
No. 2218

PacifiCorp Files 2025 Clean-Energy Plan in Oregon

by Greg Mason

PacifiCorp's 2025 clean-energy plan (CEP) filing in Oregon outlines the company's aggressive push to acquire the resources needed to meet the state's greenhouse gas emissions-reduction standards by 2030.

As of 2024, PacifiCorp has reduced emissions by approximately 18.7 percent from 2010-2012 average baseline levels to approximately 7.3 million metric tons of carbon dioxide equivalent. As per House Bill 2021, PacifiCorp, Portland General Electric and state-certified electricity service suppliers must achieve 80-percent emission reductions by 2030, 90 percent by 2035 and full decarbonization by 2040.

The preferred portfolio outlined in PacifiCorp's CEP includes 11.8 GW of new proxy resources to serve Oregon over the 20-year planning period. The plan includes 2,491 MW of wind, 3,184 MW of solar, 3,835 MW of storage, 2,045 MW of energy efficiency and 153 MW of demand response.

PacifiCorp's CEP was filed June 30 with the Oregon Public Utility Commission. In the near term, the company is aiming to acquire 153 MW of new renewable resources and 186 MW of storage resources before 2030.

While those targets are "relatively small given the overall need," PacifiCorp's modeling shows the company has a significant need beyond 2030 as well, Rohini Ghosh, director of clean-energy planning, told state energy regulators on July 8. PacifiCorp will need an additional 2,694 MW of new utility-scale resources, 326 MW of new small-scale renewables and 757 MW of new storage resources between 2030 and 2034, according to the CEP.

"So, while the model does tend to favor a just-in-time compliance approach and adding resources on Jan. 1, 2030, we of course recognize the risk in that strategy," Ghosh said. "We are not limiting ourselves to the resource selections that are included through the end of 2029, but rather also considering what is shown in the portfolio in 2030 as we move forward with resource procurement decisions."

Using this resource strategy, PacifiCorp's CEP forecasts Oregon-allocated greenhouse gas emissions to decrease 84.6 percent from baseline levels by 2030, 90.2 percent by 2035 and 100 percent by 2040.



Chuck Coker/Flickr

A wind turbine.

PacifiCorp has two requests for proposal processes underway specifically for Oregon: a small-scale renewable RFP, which was issued in April in hopes of acquiring up to 320 MW of small-scale capacity; and the 2025 Oregon-based RFP drafted in April (Clearing Up No. 2206).

"PacifiCorp plans to evaluate opportunities to accelerate procurement of resources identified in the preferred portfolio in 2030 when evaluating proposals from both resource solicitations," the plan says.

The CEP also illustrates potential cost challenges with acquiring these resources—especially without investment or production tax credits.

INSIDE

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Trump Orders Tighter Wind and Solar Credit Guidance

OPINIONS

Big Tax Bill is Latest Hit for Columbia Basin Tribes
Page 5



CGP Grey/Flickr

Wyoming wind turbines.

Idaho Power—not ratepayers—should bear the risk of those additional costs.

"The Company represents that it will receive the necessary permitting, and that the Company will receive the PTCs as expected to support the costs of the Jackalope Project as represented to the Commission in the Application," commissioners wrote in the order. "If both of those factors were not present, the Commission would not find it fair, just, and reasonable to approve the Application."

U.S. DOE Warns of Energy Shortages in California If Power Plants Close

by Jason Fordney

California faces the potential of energy shortfalls during evening hours in coming years if some power plants shut down, according to a new U.S. Department of Energy report that warns of energy shortages nationwide due to rising demand and generation retirements.

"In the current system and No Plant Closures cases, [the California Independent System Operator] did not experience major reliability issues, though adequacy was often maintained through significant imports during tight conditions," DOE said in the report. "In the Plant Closures case, however, the region faced substantial shortfalls, particularly during summer evening hours when solar output declines."

Generally, the Evaluating the Reliability and Security of the United States Electric Grid report describes the CAISO system as vulnerable to high loads and periods with low renewable-energy output.

The Golden State's average loss-of-load hours reached seven hours per year, DOE said, in a "plant closures" scenario, with the worst-case year showing load events affecting up to 31 percent of demand. The "normalized unserved energy" forecast was 0.0062 percent and unserved load was 23,488 MWh.

In a "worst weather year" and "plant closures" combined scenario, the maximum loss-of-load hours in a single year reached 21 and normalized unserved load hit 0.0195 percent. Unserved load was 73,462 MWh and maximum unserved load was 12,391 MW. Unserved load expressed in megawatt-hours refers to total energy demand that was not met over a period of time, while maximum unserved load expressed in megawatts is the worst-case amount of power that couldn't be served at a particular point in time.

CAISO's peak load was 79 GW in its current system model, projected to increase to about 82 GW by 2030. About 2 GW of the additional load is expected to come from new artificial-intelligence data centers, with California projected to hold 4 percent of the nation's total facilities.

The generation mix in CAISO was comprised primarily of natural gas, solar, storage and hydroelectric power in 2024, the report says, with natural gas contributing about 32 percent of nameplate, solar 31 percent, storage 13 percent and hydro 9 percent. By 2030, projected retirements would come from coal, natural gas and nuclear (the Diablo Canyon Power Plant), with any additions coming in the areas of solar and storage. DOE's model assumes 10 GW of rooftop solar—not controlled by CAISO—and less than 1 percent of demand response.

In the non-CAISO West, the region maintained resource adequacy on average in both the current-system and no-plant-closures scenarios. But the region's reliability declined in the plant-closures case, increasing loss-of-load hours and peak shortfalls in the worst year studied. In that worst year, up to 20 percent of hourly load was projected to be lost in some subregions.

Normalized unserved energy reached 0.0032 in the plant-closures scenario, with average loss-of-load hours at 17.8 and unserved load at 21,785 MWh. The maximum number of loss-of-load hours in a single year in the worst-weather-year/plant-closures scenario was 47.

Peak load in the non-CAISO West was about 92 GW in the current system model, projected to increase to about 119 GW by 2030. About 12 GW of this comes from new AI data centers, with the region as a whole slated to receive about 24 percent of the U.S. total.

Total installed generating capacity in the non-CAISO West in 2024 was 178 GW by 2030, with 29 GW of new capacity slated to be added, leading to 207 GW total in the no-plant-closures case. In the plant-closures case, 13 GW of capacity was retired, leading to a net generation change of 13 GW of capacity and 193 GW of total installed capacity on the grid.

Most retirements are coal and natural gas facilities, with additions of solar, wind, storage and natural gas. The model assumes 6 GW of rooftop solar and more than 1 GW of demand response.

The only two regions that did not fail reliability thresholds in the plant-closures case were ISO-New England and the New York ISO, but those two areas did not have additional AI data center load growth modeled, DOE said.

May 8, 2025

To: Scott Gibbens
Oregon Public Utility Commission

From: Jaki Ferchland
Senior Manager, Rates & Regulatory Affairs

Portland General Electric Company
UM 2377
PGE Response to OPUC Data Request 004
Dated April 10, 2025

Request:

What are the expected useful and depreciable lives of the 10 largest transmission substation assets that have been placed in service in the past ten years or are currently under construction?

Response:

In accordance with Docket UM 2152, the most recently approved depreciation study, FERC account 353 – Transmission Substation Equipment has an average service life of 62 years.

May 8, 2025

To: Scott Gibbens
Oregon Public Utility Commission

From: Jaki Ferchland
Senior Manager, Rates & Regulatory Affairs

Portland General Electric Company
UM 2377
PGE Response to OPUC Data Request 005
Dated April 10, 2025

Request:

What are the expected useful and depreciable lives of the 10 largest transmission line assets that have been placed in service in the past ten years or are currently under construction?

Response:

In accordance with Docket UM 2152, the most recently approved depreciation study, FERC account 354 – Transmission Towers and Fixtures has an average service life of 70 years. FERC account 355 – Transmission Poles and Fixtures has an average service life of 52 years. FERC account 356 – Overhead Conductors and Devices has an average service life of 65 years.

May 8, 2025

To: Scott Gibbens
Oregon Public Utility Commission

From: Jaki Ferchland
Senior Manager, Rates & Regulatory Affairs

Portland General Electric Company
UM 2377
PGE Response to OPUC Data Request 001
Dated April 10, 2025

Request:

Please show all evidence, information, and analysis used to derive the 80% Minimum Transmission Demand.

Response:

PGE objects to this data request on the grounds that it is not reasonably calculated to lead to the discovery of relevant or admissible evidence. The data request does not seek the discovery of facts but seeks to compel PGE to provide explanations, theories or narrative responses relating tariff changes and positions that were the subject of PGE's proposal in UE 430. In docket UM 2377, PGE and other parties in this docket will have the opportunity to submit testimony on topics within the scope of this proceeding. PGE reserves the right to explain, support, and provide further relevant evidence throughout the course of docket UM 2377 in connection with the subject matter of this data request and other relevant issues.

Subject to and without waiving the foregoing objection, PGE provides the following response:

PGE based the Minimum Transmission Demand on our existing load factor threshold for Schedule 90.[1]

[1] UE 430 PGE/200 McFarland-Macfarlane/26 at 15-18

May 30, 2025

To: Scott Gibbens
Oregon Public Utility Commission

From: Jaki Ferchland
Senior Manager, Rates & Regulatory Affairs

Portland General Electric Company
UM 2377
PGE Response to OPUC Data Request 044
Dated May 16, 2025

Request:

Does PGE view the allocated system capacity of a customer to be its, "maximum" capacity? Would PGE plan its transmission, distribution, or generation system to account for fluctuations above a customer's allocated system capacity?

Response:

Yes, PGE views the allocated system capacity of a customer to be its "maximum" capacity. PGE plans to have system capacity in the transmission, distribution, and generation systems available beyond what has been requested by the customer to allow for anticipated fluctuations across the system as no load is perfectly consistent. However, PGE expects that customers will generally adhere to their maximum capacity.

ORIGINAL

Commissioner	Yes	No	Not Participating
Huston	√		
Bennett	√		
Freeman	√		
Veleta	√		
Ziegner	√		

STATE OF INDIANA

INDIANA UTILITY REGULATORY COMMISSION

Coalition/109
Souder/1

IN THE MATTER OF THE VERIFIED PETITION OF INDIANA MICHIGAN POWER COMPANY FOR APPROVAL OF MODIFICATIONS TO ITS INDUSTRIAL POWER TARIFF – TARIFF I.P.	**)**	**CAUSE NO. 46097**
	)	**APPROVED FEB 19 2025**

ORDER OF THE COMMISSION

Presiding Officers:
Wesley R. Bennett, Commissioner
Loraine L. Seyfried, Chief Administrative Law Judge

On July 19, 2024, Indiana Michigan Power Company ("I&M" or "Petitioner") filed its Verified Petition with the Indiana Utility Regulatory Commission ("Commission") for approval of certain modifications to I&M's Industrial Power Tariff – Tariff I.P. Also on July 19, 2024, I&M filed its prepared testimony and attachments, as well as supporting work papers, of Andrew J. Williamson, I&M Director of Regulatory Services.

On July 29, 2024, Citizens Action Coalition of Indiana, Inc. ("CAC") filed a Petition to Intervene, which was granted by docket entry dated August 6, 2024.

On August 8, 2024, Amazon Data Services, Inc. ("Amazon") filed a Petition to Intervene, which was granted by docket entry dated August 16, 2024.

The Commission held a Technical Conference at 10:00 a.m. on August 22, 2024, in Room 222 of the PNC Center, 101 West Washington Street, Indianapolis, Indiana.

On September 11, 2024, the Data Center Coalition ("DCC") filed a Petition to Intervene and on September 12, 2024, Google, LLC ("Google") filed petitions to intervene. The petitions were granted by docket entries dated September 19 and 20, 2024, respectively. On September 24, 2024, Microsoft Corporation ("Microsoft") filed a petition to intervene, which was granted by docket entry dated October 2, 2024.

On October 15, 2024, the Indiana Office of Utility Consumer Counselor ("OUCC") filed the prepared testimony and attachments of OUCC Analysts Patrick A. Kelley and Derek J. Leader. Also on October 15, 2024, CAC filed the direct testimony and attachment of CAC Program Director, Benjamin Inskeep; Google filed the prepared testimony and attachments of Justin B. Farr, Director in the firm of Energy Strategies, LLC; Amazon filed the prepared testimony and attachments of Carolyn A. Berry, Ph.D., a Principal in the Energy Practice at Bates White Economic Consulting, David G. Loomis, Professor Emeritus of Economics at Illinois State University, former Executive Director of the Institute for Regulatory Policy Studies, and President of Strategic Economic Research, LLC, and Michael Fradette, Principal, Energy Strategy by Amazon Web Services, Inc. ("AWS"); and DCC filed the prepared testimony and attachment of

Kevin C. Higgins, Principal in the firm of Energy Strategies, LLC. Microsoft filed a notice of intent not to file direct testimony.

On November 1, 2024, Google, Amazon, DCC and OUCC filed a partially opposed joint motion for leave to file cross answering testimony and CAC filed its opposition on the same day. The joint motion was denied by a docket entry dated November 4, 2024.

On November 4, 2024, I&M filed the prepared rebuttal testimony, attachments and work papers of Mr. Williamson, Steven F. Baker, I&M President and Chief Operating Officer, and Alex E. Vaughan, Managing Director – Regulated Pricing Generation & Fuel Strategy for American Electric Power Service Corporation.

On November 14, 2024, the Commission issued a docket entry requesting additional information from I&M, to which I&M responded on November 15, 2024.

The Commission conducted a hearing in this Cause on November 18, 2024, at 9:30 a.m. in Room 222 of the PNC Center, 101 West Washington Street, Indianapolis, Indiana. I&M, the OUCC, CAC, Google, Amazon, DCC, and Microsoft participated in the evidentiary hearing, by counsel. At the hearing, the parties reached an agreement on a modified procedural schedule to allow the parties additional time to work towards potential settlement of the issues pending in this Cause, and the hearing was continued until December 20, 2024.

On November 22, 2024, I&M, on behalf of itself, the OUCC, and all intervenors (collectively, the "Settling Parties"), filed a Submission of Unopposed Settlement Agreement and Unopposed Motion for Acceptance of Out of Time Filing along with the Settling Parties' Stipulation and Settlement Agreement ("Settlement Agreement"). The Motion was granted by a docket entry dated December 2, 2024.

On December 4, 2024, the Settling Parties filed testimony in support of the Settlement Agreement by the following witnesses: Mr. Williamson, Michael D. Eckert, Chief Technical Advisor in the OUCC's Electric Division, Mr. Inskeep, Mr. Farr, Mr. Fradette, Mr. Loomis, and Dr. Berry.

The Commission conducted an evidentiary hearing on December 20, 2024, at 9:30 a.m. in Room 222 of the PNC Center, 101 West Washington Street, Indianapolis, Indiana. I&M, the OUCC, CAC, Google, Amazon, DCC, and Microsoft participated in the evidentiary hearing, by counsel. At the hearing, the Settlement Agreement and the Settling Parties' respective prefiled direct, rebuttal, and settlement evidence was admitted without objection.

The Commission, based upon the applicable law and the evidence of record, now finds as follows:

1. Jurisdiction and Notice. Notice of the hearing in this Cause was given and published by the Commission as required by law. I&M is a "public utility" within the meaning of Ind. Code § 8-1-2-1. Pursuant to Ind. Code § 8-1-2-42, the Commission has jurisdiction over a public utility's rates and charges. Therefore, the Commission has jurisdiction over I&M and the subject matter of this proceeding.

2. Petitioner's Characteristics and Businesses. I&M is a corporation organized and existing under the laws of the State of Indiana, with its principal office located at Indiana Michigan Power Center, Fort Wayne, Indiana. I&M is engaged in, among other things, rendering electric service in the states of Indiana and Michigan. I&M owns and operates plants and equipment within the states of Indiana and Michigan that are in service and used and useful in the generation, transmission, distribution, and furnishing of such service to the public. I&M supplies electric service to approximately 482,000 retail customers in Indiana. I&M is a wholly owned subsidiary the American Electric Power Company, Inc. ("AEP").

3. Relief Requested. I&M requests approval to update its Industrial Power Tariff – Tariff I.P. to incorporate certain terms to accommodate large load customers. As originally proposed by I&M, these modifications, also referred to as "Large Load Terms" in this filing, include: (1) applicability to customers with a contract demand in excess of 150 megawatts ("MW"), or reasonably expected to exceed 150 MW at one or more aggregated premises; (2) a contract term for an initial period of 20 years and provisions to address assignment of rights or delegations of obligations under the contract; (3) a Contract Termination Fee that would only apply should there be a permanent closure during the contract term; (4) provisions that allow a customer to reduce its contract capacity by up to 20% during the contract term; (5) a 90% monthly minimum billing demand; and (6) an increased minimum amount of collateral to be provided by the customer.

I&M now requests approval of the Settlement Agreement, which resolves all issues in this Cause.

4. I&M's Direct Evidence. Mr. Williamson presented the modified Tariff I.P. and explained the modified tariff is needed to address large load customers whose contract capacity exceeds 150 MW or is reasonably expected to grow to exceed 150 MW at one or more aggregated premises. Mr. Williamson detailed the proposed revisions to Tariff I.P., noting that the large load customers served under these new provisions will be charged for service at the same rates as other customers under Tariff I.P.

Mr. Williamson explained Petitioner is proposing to make these enhancements now because the electric utility industry is in the midst of a transformation, both in terms of customer makeup and changes occurring within the generation resources serving customers. He said the electric industry has seen increased activity and interest among large load customers over the past few years, which is occurring at the same time that utilities, including I&M, are transitioning their fleets to replace retiring generation resources. Mr. Williamson testified that in recent months, significant hyper-scaler business investments have been announced in I&M's retail service territory, which are expected to begin taking service in 2024 and 2025. He stated that once fully operational, these new customers will significantly increase I&M's Indiana retail load and require I&M to make significant transmission and generation infrastructure investments and other long-term financial commitments to provide service.

Mr. Williamson testified that the magnitude of demand for electricity associated with these customers is unprecedented and unlike any previous load additions I&M has experienced to date. He testified that as the state of Indiana continues to pursue these types of technology investments and with multiple large load customers expected to begin taking electric service from I&M in the

next year, now is the time to establish a consistent set of reasonable terms and conditions for large load customers taking service under Tariff I.P. He said the proposed tariff modifications ensure that I&M has reasonable terms and conditions of service in place that recognize and address the different needs and unique risks that large load customers present from I&M's other Tariff I.P. customers.

Mr. Williamson stated that the new large load additions are expected to increase I&M's current Indiana peak load of approximately 2,800 MW to more than 7,000 MW by approximately 2030. He said these customers operate in similar business sectors, expect to operate at very high load factors, and represent a significant change in the customer concentration risk associated with I&M's business going forward. He noted that a single 150 MW customer is equivalent to approximately 100,000 residential customers, which is approximately one fourth of I&M's Indiana residential customer base today or the entire population of Marion and Muncie, Indiana combined.

Mr. Williamson said the proposed Tariff I.P. refinements are necessary to memorialize a reciprocal commitment from large load customers that reasonably recognizes and aligns with the financial commitments that will be required by I&M to provide these customers with the level of safe, reliable, and adequate service they need to operate their energy-intensive businesses. He testified that the proposed tariff modifications will provide new and existing customers and I&M with reasonable financial protection should future conditions arise that impact the operations of a customer's facility and reduce the level of electric demand or consumption or result in the facility ceasing operation. He said that while neither I&M nor customers are expecting these situations, how these situations will be managed if they were to occur must be clear. Mr. Williamson said the modified tariff provisions will better position I&M going forward to achieve the state of Indiana's five energy policy objectives ("Five Pillars").

Mr. Williamson also discussed why it is appropriate to update Tariff I.P. versus creating a new tariff to serve large load customers. He said Tariff I.P. is appropriate for these large load customers because, while the magnitude of the load is unprecedented, the load characteristics of these customers are not dissimilar to other customers currently served under Tariff I.P. He said I&M currently has a wide range of different customers on Tariff I.P. with different load characteristics, including high-load factor customers. He stated that adding the large load customers to an existing tariff allows for consistency among customers to meet basic service needs and provides for a more timely, efficient, and predictable process to establish service. Mr. Williamson testified that for customers with unique needs, such as demand response, I&M would address those specific situations through other tariffs, riders, or mechanisms, such as a special contract.

Mr. Williamson explained that setting a 150 MW minimum demand ensures that only large loads above this threshold will be subject to the provisions in recognition of the larger needs and risks that serving those customers will create. Mr. Williamson testified that at the time of filing his direct testimony, I&M did not have a single customer or a group of customers under a common parent taking service under Tariff I.P. over 150 MW. Mr. Williamson explained how I&M will assess a customer's aggregate load with respect to this term and condition of service.

Mr. Williamson explained the reason for I&M's proposal to require a 20-year contract term for large load customers. He testified that I&M proposes to include this term due to the significant long-term investments and other financial commitments (e.g. Purchase Power Agreements ("PPAs")), primarily in generation and transmission assets, that will be required to serve these customers as part of I&M's integrated system serving its Indiana retail customers. He said that because transmission and generation costs of the integrated system must be reflected in I&M's rates for service, it is important for I&M to have a reciprocal long-term commitment from large load customers to support making the necessary long-term investments and commitments. He said an initial contract of 20 years provides reasonable assurance that these large load customers will take service over a period that reasonably aligns with the cost of I&M's significant investments and financial commitments. He noted that I&M is also seeking a reasonable notice period if a party intends to discontinue service, and that permanent closure of a customer's operation is addressed separately.

Mr. Williamson explained I&M plans to serve its expanding customer load through a diversified portfolio of new and existing generation resources with varying asset lives or contract terms. He stated that this will include both short-term (e.g., five to 15 years) and long-term (e.g., 20 to 35 years) resources. He said this diversification strategy will allow I&M to manage risk exposure in the event of a future change in load requirements while also balancing that within Indiana's energy policy. He said the proposed contract term, when combined with the other proposed tariff modifications, provides a reasonable basis for I&M to manage the costs associated with a diversified resource portfolio that will be needed to meet growing generation needs. He added that since generation resource costs are generally recovered over their respective service lives, the proposed contract term is expected to reasonably align with the costs I&M will be incurring to provide service to these customers and provides consistent contract treatment for all large load customers.

As to the proposed assignment of rights or delegation of obligations provision, Mr. Williamson said I&M proposes to include this term to clearly provide large load customers with consistent terms regarding how a situation involving assignment or delegation of rights and obligations under their contract will be handled.

Regarding the proposed permanent closure and reduction to contract capacity provisions, Mr. Williamson testified the proposals provide reasonable safeguards to all other customers. He stated that in the event of a permanent closure, I&M is asking the customer to provide formal notice to I&M within three business days of making such a determination. He said this notice, along with the payment equal to five years of minimum billing, are needed to provide I&M as much time as possible and reasonable compensation to I&M to prudently manage its ongoing transmission and generation costs in the market and within the timelines of the PJM Interconnection LLC ("PJM") capacity planning process. Mr. Williamson added that I&M's proposal also allows for coordination if a large load customer's capacity need changes. He said this flexibility was included due to customer concerns over their ability to project their capacity needs over 20 years while still recognizing I&M's long-term commitments and planning horizons. He said guaranteeing customers the ability to reduce their contract capacity by up to 20%, or more by mutual agreement, provides reasonable flexibility while limiting the magnitude of risk to I&M and other customers. He said that, consistent with current practices, a customer can request an increase to its contract capacity in total or in a given year, which I&M will evaluate based on its

ability to serve the requested capacity amount. He said all requested increases in contract capacity are subject to mutual agreement.

Regarding I&M's proposed Contract Termination Fee, Mr. Williamson testified that I&M must make long-term investments and other financial commitments in generation and transmission to meet the needs of new large loads. He said I&M understands that circumstances can change for large load customers but if a significant change in circumstances were to occur, I&M needs sufficient time to manage its commitments within regulatory and market timelines. In establishing the Contract Termination Fee, Mr. Williamson said I&M considered and evaluated the risks by performing a sensitivity analysis related to the potential cost of the generation assets needed to serve the load and the potential market for such assets in the event of a significant change in circumstances. He said this sensitivity analysis evaluated varying time horizons from 20 years to five years.

Mr. Williamson presented an analysis in Figures AJW-1 and AJW-2 of Petitioner's Exhibit 1, demonstrating the potential net cost or benefit using a range of asset costs and market conditions compared to the proposed Contract Termination Fee equal to five years of the customers' minimum bill requirement. He stated that while it is not possible to precisely predict the average cost of the portfolio of future generation resources or the market conditions that would exist at the time a large load customer would permanently close its operations, these sensitivity analyses demonstrate the proposed Contract Termination Fee covers a range of risks. He said the Contract Termination fee strikes a reasonable balance by providing a reasonable and predictable amount.

Regarding the proposed monthly minimum billing demand provision, Mr. Williamson stated that I&M proposes to include this term primarily based on the magnitude and size of these large load customers and the fact that I&M will need to make long-term investments and other financial commitments for years into the future to have adequate power supply to meet the customers' requested capacity needs. He noted the existing Tariff I.P. provisions have a minimum billing demand that is 60% of contract capacity and said without a tariff modification, a drop in billing demand to 60% by just one large load customer could have significant negative financial consequences. Mr. Williamson explained that for a large load customer, the difference between a 60% and 90% minimum billing demand can be the revenue requirement associated with the cost of service of one or more power plants. His analysis included Figure AJW-4 of Petitioner's Exhibit 1, which shows the difference between a 60% and 90% minimum billing demand, on a yearly basis, is approximately $90 million, compared to the expected yearly bill of approximately $500 million.

Mr. Williamson also discussed the proposed collateral requirements, which I&M proposed to include because the size and concentration risk of large load customers is unlike other customers. He stated that if a large load customer was to unexpectedly exit I&M's service territory and/or system, there is potential for significant financial harm to I&M and its other customers. He presented Figure AJW-5 in Petitioner's Exhibit 1 to demonstrate how I&M's expected annual revenues would shift once the hyper-scaler loads are fully realized. He testified that with the number of current commitments and potential future interest from large load customers, less than a handful of customers will be the largest single sector for I&M, even greater than I&M's existing residential, commercial, and industrial customers combined. He said it is imperative that other customers and I&M are reasonably protected in the event the unexpected occurs with these large

load customers. He added that while no reasonable term can fully insulate I&M and its other customers, the proposed term reasonably increases current requirements and provides additional protection should a customer unexpectedly cease taking service and be unable to pay its remaining charges.

Mr. Williamson testified that except for the higher collateral requirements, the proposed tariff provisions would only have impact if something unexpected occurred—meaning, if the customer's business operates consistent with the load it is contracting for, the proposed tariff modifications will have no impact on these customers. He further testified that if the Commission approves the proposed enhancements to Tariff I.P., I&M and its customers will be better protected in the event a large load customer unexpectedly reduces its load or permanently closes its operations. He added that having a Commission approved tariff in place for large load customers provides clarity to all parties for how these types of customers will be served.

5. OUCC's Evidence. Mr. Kelley testified that the OUCC strongly supports economic development and recognizes the benefits of data center investment but said current utility ratepayers in all classes should be shielded from any stranded costs that may occur. Recognizing I&M's proposed tariff includes some safeguards for existing residential, commercial, and industrial customers, he said additional safeguards are needed. Mr. Kelley stated it is crucial that the principle of cost causation be applied to the data center loads and current I&M ratepayers should not subsidize utility investment to accommodate large load requirements.

Mr. Kelley reviewed the proposed tariff modifications, the prospective large load customers, and the announced capital investment in Indiana related to those customers. He said the projected demand of the smallest hyper-scaler projects I&M plans to serve will each exceed by a factor of more than ten times the demand of I&M's current largest single industrial customer.

Mr. Kelley testified that AWS' hyper-scaler project will be the largest customer to date in I&M's service territory. He said a decrease of 20% of AWS' anticipated energy use of 2,250 MW would reduce I&M's load by 450 MW and added that a loss of that amount would be roughly equivalent to powering 375,000 homes. Mr. Kelley expressed concern because that would be comparable to turning off the electrical demand to practically all Indianapolis residents with a reported 361,641 occupied households as of the 2020 U.S. Decennial Census.

Mr. Kelley acknowledged that I&M is not seeking approval of more generation resources as part of this case but indicated the demands of potential hyper-scaler customers are relevant to whether the proposed modifications to Tariff I.P. are sufficient to protect I&M's other captive ratepayers. He said hyper-scaler operations plan to run at full capacity 24 hours per day, seven days per week, and 365 days per year. He said unlike other industrial customers, an interruptible tariff is not an option for hyper-scalers, meaning I&M will have to always provide a high volume of energy.

As to local economic impacts, Mr. Kelley said the Indiana Data Center Tax Incentive offers tax exemptions on energy and equipment for new data centers built in Indiana for up to 50 years. He said this was the longest exemption period in any state when it was passed and noted that electricity purchases for these facilities are also exempt from state sales tax. Mr. Kelley also reviewed news stories highlighting the benefits the Amazon projects will be providing to the local

community. He said the publicized investments will not help I&M or I&M's ratepayers because they do not reduce the large power demand, power demand variability, or early termination risks.

Mr. Kelley concluded that existing utility customers need to be protected in the event a hyper-scaler terminates an electric service contract early, especially if the utility has invested vast resources to specifically meet the projected demands. He said the massive demands of hyper-scalers will inevitably require new electric power generation and transmission but the construction and financing costs for these assets—and retirement costs if applicable—should be directed to these large load customers as the cost-causers. He said consistent with the "user pays" paradigm, the large load customers must also be accountable for increased maintenance costs due to additional pressures on transmission systems.

Mr. Leader addressed I&M's proposed tariff modifications, noting that the modifications would provide some protection to I&M's current residential, commercial, and industrial customers. However, he recommended the Commission take all steps necessary to mitigate the imposition of stranded costs and load reductions, if they occur, on other ratepayers.

Mr. Leader described what a hyper-scaler is, discussed the Five Pillars and presented the OUCC's concerns about affordability. He said I&M's potential investment to meet the demand of these large load customers raises concerns because of the stranded investment/cost I&M may incur if a large load customer leaves the system, coupled with the resulting impact such stranded costs may have on all other customers. Mr. Leader discussed I&M's plan to manage the costs associated with a diverse portfolio of resources. He testified that if a large load customer agrees to the terms proposed by I&M, the large load customer tariff rates will not allow I&M to recover the full cost of service to serve that customer.

Mr. Leader said the OUCC supports a 20-year minimum contract term but noted the initial term of many PPAs exceeds 20 years. He said if I&M enters into 25- or 30-year PPA contracts, the OUCC is concerned I&M's other customers will become responsible for the stranded costs if the large load customer ceases its operations or otherwise leaves I&M's system before the end of a greater than 20-year PPA. He also expressed concern with whether a large load customer would be required to pay the Contract Termination Fee if the large load customer closed within the first five years of the contract.

Mr. Leader testified that I&M's proposed Tariff I.P. modifications require a large load customer to give I&M at least five years prior written notice of any intent to reduce that customer's specified contract capacity, unless the parties mutually agree to a shorter notice period. He said the proposed tariff allows a customer to reduce its maximum contracted capacity by up to a total of 20% during the contract period; if mutually agreed, the reduction could be more. He said the OUCC is concerned that modification by mutual agreement of any of the approved Tariff I.P. terms bypass the Commission's scrutiny and oversight and could be detrimental to I&M's other ratepayers. He stated that approving the proposed Tariff I.P. modifications while simultaneously providing for these provisions to not be applicable upon the mutual agreement of only I&M and a large load customer equates to endorsing alternative contract terms that are unknown. He said doing so may adversely affect other I&M customers, may not be in the public interest, and equates to approval by I&M and the customer instead of the Commission. He testified that the OUCC

recommends the Commission require I&M to take all needed steps to mitigate impact on other ratepayers if a large load customer leaves the system.

Mr. Leader expressed concern about a large load customer reducing its load by 20%. He said if a customer using one gigawatt ("GW") of energy reduces its load by 20%, that would result in a 200 MW load loss for I&M. He testified that unless I&M could sell those 200 MWs into the market, this could result in stranded asset costs, which would be passed onto other customers and result in a sizable bill increase. He said I&M's other customers should not be at risk of bearing these costs. Mr. Leader also noted that in a discovery response, I&M indicated that a customer could reduce its load by 20% and then terminate the load with a lower fee.

6. CAC's Evidence. Mr. Inskeep testified that the new large loads anticipated for I&M's service territory are unprecedented and staggering, including facilities that will be among the single largest electric users in the state. He said without the prompt implementation of robust consumer protections and enhanced transparency, existing ratepayers are at extraordinary risk from these new large loads. He stated that I&M has proactively proposed several constructive tariff revisions that meaningfully address these concerns, while still allowing for some flexibility and customization to address individual customer circumstances. However, he recommended certain modifications.

Mr. Inskeep said the load growth projected over a very short time for new data centers does not include other expected load growth in I&M's service territory. He said other economic development, rising customer counts, building electrification, electric vehicle charging, and potential technological breakthroughs like green hydrogen, are likely to push I&M's capacity and energy needs even higher.

Mr. Inskeep discussed the costs I&M expects to incur to provide electric service to these new large load customers and said this level of investment creates new risks. He explained there is project execution risk associated with each new build, which could be magnified by undertaking many of these projects all at once due to the pressure to bring a large amount of generation online in time to meet data center load ramps. He said it could also create a cash flow risk to I&M if it is spending large amounts on projects years prior to the costs reflected in rates.

Mr. Inskeep testified that the concentration of a majority of I&M's future load and retail sales in one industry at a small handful of facilities also significantly increases risk to I&M and to ratepayers. He stated that while some power used by the data centers could be used for cloud computing, it appears that a substantial portion of the power needs is for so-called Artificial Intelligence ("AI"). He said each data center will use hundreds of megawatts of power or more, further concentrating risk at just a small handful of facilities. Mr. Inskeep stated that negative impacts to the tech industry, demand for AI and computational power, or to specific data center facilities could have a ripple effect: power demand could abruptly decline significantly, eroding I&M revenues and resulting in rate increases and credit downgrades, which would lead to a higher cost of capital, changes to cost allocation, and more rate increases to customers.

Mr. Inskeep testified that new large load customers create risks to future economic development in I&M's service territory. He said for example, customers with new or expanding load could face challenges securing sufficient capacity from I&M within a reasonable timeframe, given I&M's need to secure sufficient power for 4.4 GW of data center load. He said the addition of the large load will result in significant transmission congestion, meaning other prospective customers could have to wait years to begin service, and substantial changes to cost allocation, with far more PJM costs being allocated to I&M, more I&M company-wide costs being allocated to its Indiana jurisdiction, and more I&M-Indiana costs being allocated to the Tariff I.P. class. He said higher cost allocations could undermine affordability for other ratepayers, including non-data center prospective Tariff I.P. customers who could decide to site new facilities elsewhere.

Mr. Inskeep discussed the reliability risks associated with large data center load growth. He said the North American Reliability Corporation has established a Large Loads Task Force to better understand the reliability impacts of emerging large loads such as data centers.

Mr. Inskeep discussed the Commission's authority to approve I&M's proposed terms and conditions of service. He said failure to adequately protect existing customers could result in existing customers facing large cost shifts and being assessed unjust and unreasonable charges in contravention of the plain language of Ind. Code § 8-1-2-4.

Mr. Inskeep said he broadly supports I&M's proposed tariff revisions as necessary and reasonable, although he recommends certain revisions. He expressed agreement with I&M's decision to serve new large load customers under a published tariff rather than through individually negotiated special contracts, which are often kept confidential. He said I&M's approach is more transparent, administratively efficient, and fair to existing and potential new customers.

Mr. Inskeep agreed that a minimum 20-year contract term with a five-year advance notice of cancellation is reasonable and necessary. He testified that an even longer contract term could be reasonably justified because generation and transmission assets are typically designed and constructed to last longer than 20 years and often are depreciated over a term longer than 20 years. Mr. Inskeep said as such, a 20-year contract term still carries risk that I&M would not be made whole if the customer were to cease taking service after 20 years.

Mr. Inskeep testified that I&M's proposed term addressing the assignment of rights or delegation of obligations strikes a reasonable balance between the need for I&M to have a minimum level of certainty, while still allowing reasonable flexibility for new large loads by allowing them to transfer rights or delegate obligations to another party. He recommended the Commission approve this proposal.

Mr. Inskeep agreed that both a Contract Termination Fee and a limitation on reductions to a large load customer's contract capacity are reasonable and necessary tariff modifications. He said I&M's proposed Contract Termination Fee provides I&M and existing customers with reasonable assurance that a material portion of stranded assets caused by a large load customer would be covered by the customer, even if it were to cease operations. He said this provision would not have any negative impact on the large load customers if its facilities operate as planned.

However, Mr. Inskeep recommended the Contract Termination Fee be modified so that it is equivalent to eight years of minimum bills instead of only five years. He said this adjustment would significantly reduce the risk to ratepayers over a ten-year period and presented an analysis supporting this view. Mr. Inskeep testified that his proposed adjustment reduces the potential exposure existing customers will have should these new facilities cease operations early.

Additionally, Mr. Inskeep said I&M's proposed term to allow a customer to reduce contract capacity by up to 20% with a five-year notice is not adequately protective of existing customers, so he recommended: (1) capping individual customer reductions to 100 MW in any given year (with a five-year advance notice); and (2) capping overall reductions across large load customers to 5% of the prior calendar year's I&M-Indiana jurisdictional peak load, on a first-come, first-served basis. He said these provisions would limit the capacity reduction "cliff" I&M could otherwise face from one or more large customers reducing their contract demand by an amount so large it could be difficult to effectively manage.

Mr. Inskeep did not object to I&M's proposed revision to allow for an increase or decrease in contract capacity of more than 20% upon mutual consent but expressed concern with the opacity of the process and the criteria I&M might use to make this determination with limited, if any, Commission oversight. He stated this would, for example, allow a large load customer to reduce its demand by more than 20% and by more than 100 MW in a year if I&M could effectively manage such a reduction without negative impacts to other customers.

Mr. Inskeep strongly agreed with I&M's proposal to increase the minimum billing demand. He said that modifying the minimum billing demand in Tariff I.P. for large load customers is a prudent and reasonable adjustment to mitigate risk. He said his only concern is whether I&M's proposal to increase it to a 90% billing demand minimum goes far enough. He testified that while he thinks a strong argument can be made for further strengthening this provision (e.g., to a 95% minimum billing demand), he believes I&M's proposal strikes a reasonable balance at this time by reducing financial risk to I&M and its ratepayers while still providing some amount of flexibility to large load customers.

Mr. Inskeep testified that I&M's demand charges do not cover all its "fixed" demand-related costs. He said, according to I&M, the $10.194/kWh demand charge is comprised of only about 56% of all production costs classified as demand-related and the remaining 44% is included in the Block 1 energy charge of $0.05703/kWh. He said the minimum demand charge of $14.7/kW is comprised of approximately 69% of all production costs classified as demand-related. He said therefore, even under a 90% minimum billing demand, a large load customer might not pay its full cost of service, depending on its electricity usage.

Mr. Inskeep discussed I&M's proposed collateral requirements. He agreed with I&M that it is a necessary and reasonable term to address the size and concentration risk of large load customers and recommended it be adopted.

With respect to interconnection costs, Mr. Inskeep said it is unlikely that new large load customers will be directly assigned the costs for direct connect facilities, given the revenue from a new large load customer would exceed the threshold in I&M's tariff. He said this could shift hundreds of millions of dollars in direct connect facility costs caused by new data centers owned

by multi-trillion-dollar companies onto I&M's current ratepayers, creating significant cross-subsidization concerns. Mr. Inskeep recommended that these costs be directly assigned to the large load customer causing the costs and that I&M Schedule of Tariff Terms and Conditions of Service, 14. Extension of Service, be waived for new large loads so that they are ineligible under this provision. He said to the extent necessary to implement this proposal, he requests the Commission grant a waiver of 170 IAC 4-1-27 with respect to large load customers.

Mr. Inskeep recommended that the portion of a new large load customer's load in excess of 150 MW be "firewalled" from existing ratepayers with respect to cost allocation and cost recovery of generation costs. He proposed I&M procure a separate resource portfolio specifically for new large loads to meet their capacity, energy, and ancillary services needs where the costs would be exclusively allocated to the new large load customers. He said these customers should have the first 150 MW of load included in I&M's class cost-of-service study as if it was any other Tariff I.P. customer's load, and the large load customer would pay the Tariff I.P. rates and charges associated with the first 150 MW of load. He said I&M could establish separate additional charges that would apply to usage above 150 MW, designed to recover I&M's return of and on generation resources procured exclusively for large load customers. He said this would ensure non-discriminatory access for loads of up to 150 MW, while adding terms for the portion of loads in excess of that amount to properly allocate those costs and avoid rate subsidization.

Mr. Inskeep described the relevance of demand response and testified that notwithstanding the inflexible nature of data center loads, there are still opportunities for demand response. Mr. Inskeep discussed some options available to incent demand response. He said it is critical to take actions now to ensure that residential customers will be protected, to the maximum extent possible, from potential rolling blackouts that could arise as a result of the enormous load growth from data centers. In addition, Mr. Inskeep recommended the Commission consider holding a public technical conference, collaborative, or round table on demand response opportunities for new large load customers that would be open to all Indiana utilities and stakeholders. He said because this issue impacts multiple Indiana utilities, it would be beneficial and efficient to have a forum for coordinating on this issue and charting solutions that are consistent with Indiana's Five Pillars.

Mr. Inskeep also addressed reporting requirements, noting there has been a significant lack of transparency with these new loads—both generally, and in response to specific data requests. He recommended I&M be ordered not to enter into any new or modified nondisclosure agreements with large load customers that would preclude I&M from sharing pertinent information with parties that do not have a competitive interest. He also recommended that the Commission direct I&M to submit a quarterly report in this docket that provides certain information with respect to large load customers but indicated he was open to collaborating on such reporting requirements to further clarify and refine reporting metrics, ensure confidential information is protected, and provide an appropriate level of transparency.

7. <u>Data Center Intervenor Evidence</u>.

A. <u>Amazon</u>. Mr. Fradette provided background on Amazon's data center development in Indiana. He testified that since 2010, the Amazon family of companies have invested $25.5 billion in Indiana and have added $25 billion to Indiana's gross domestic product, helping support customers, employees, and communities. He stated that on April 25, 2024, with

the support of Governor Eric Holcomb, Amazon announced plans to invest an estimated $11 billion in Indiana to build a data center campus located in St. Joseph County, Indiana, which is expected to create at least 1,000 new jobs and is the largest capital investment announcement in Indiana's history. He also discussed the importance of data centers to the national economy.

Mr. Fradette discussed the Tariff I.P. modifications proposed by I&M and the potential impact on data center development and operations if approved. He claimed the 150 MW threshold figure appears to be random, targeted at three large load customers, and made without consideration of the negative impacts, including commercial unreasonableness imposed.

Mr. Fradette testified that a 20-year contract term obligation is excessive and not reasonable. He said I&M confirmed that it has never entered into a 20-year contract term with a non-wholesale customer and that all of its industrial customers with contracts have initial terms of five years or less, with almost all of its customers under Tariff I.P. having two-year contracts. He added that in his work on behalf of Amazon in other U.S. states, he is not aware of any other electric utility that requires a 20-year contract term within its standard tariff.

Mr. Fradette said I&M's proposals would inappropriately restrict the ability of large load customers to right-size capacity commitments over the 20-year period and create a new systemic risk that I&M would be obligated or incentivized to over-invest in long-term commitments it might otherwise more conservatively manage for the benefit of all ratepayers. He stated that large load customers do not have the same tools, rights, regulations, and access to markets as utilities do to manage this long-term risk and recommended I&M's risk-shifting proposals not be approved.

Mr. Fradette stated that the general service life of an I&M asset should not determine the length of the contract term. He contended the cost of I&M's investment to support large customers similarly is not proven to be correlated to a particular term of a service contract. He said I&M's new investments effectively pay for themselves within a matter of years at the current 60% minimum demand provision via the terms of the current Tariff I.P., while also positioning I&M to use the growth from large load customers to drive down rates for all Indiana and AEP ratepayers.

Mr. Fradette testified that Amazon forecasts its customers' demand over a ten-plus year horizon, from which Amazon develops, builds, and operates data centers globally to deliver the services its customers require. He explained that developing net new large utility loads where there is otherwise existing idle transmission capacity enables a win-win structure for the utility, regional ratepayers, the community, and Amazon. He said the utility is able to realize a new large load thereby increasing its revenues and investments, typically providing a benefit for its shareholders. He said ratepayers benefit because the cost burden of the exiting underutilized transmission infrastructure is spread across a larger pool of MWs, thus delivering cost savings for ratepayers. He said the community benefits from the incremental investment, tax revenue, and creation of new jobs. He said Amazon is able to invest in and operationalize new data center campuses to ensure it delivers the needed services to its customers, without triggering the long-lead multi-year inter- and intra-state transmission build out process.

Mr. Fradette stated that the net effect of I&M's proposed Contract Termination Fee is that a customer must pay all applicable rates and charges for at least ten years of service, potentially without the customer ever having taken or the utility providing service. He explained this is

unreasonable because: (1) I&M has made a customer's termination option conditional on the "permanent closure" of the facility; (2) the unilateral imposition of the proposed Tariff I.P. terms, including the Contract Termination Fee, is unfair and unreasonable; (3) while I&M's witness testified that five years of minimum billing is necessary to manage ongoing transmission and generation costs, I&M does not identify any of its other loads that are subject to this same condition or provide any other supporting data to back up this assertion; and (4) the termination fee calculation is inclusive of all demand related charges of I&M, which include generation capacity, transmission related charges, and I&M's use of system, overhead, and margin.

Mr. Fradette testified that as a regulated utility, I&M has multiple ways that it can reasonably dispose of excess capacity and energy commitments. He said at a minimum, any proposed termination fee must include a mechanism whereby I&M would be required to offset any such fee by mitigating its costs. He said the termination fee should simply ensure that remaining ratepayers are not left carrying the burden of stranded investments incurred to serve the incremental load; it should not include recovery of fixed costs incurred prior to the addition of the incremental load or guarantee a profit for I&M's shareholders.

Mr. Fradette said I&M's proposal to require at least five years' prior written notice of its intent to reduce the contract capacity is not reasonable because it prevents customers from right-sizing their capacity, resulting in inefficient capacity allocation, overbuilding, and related cost increases.

Mr. Fradette described I&M's proposal for a 90% monthly minimum billing demand as a commercially unreasonable take-or-pay structure, which would include charges to I&M that include generation capacity, transmission-related charges, and I&M's use of system, overhead, and margin. Mr. Fradette said this minimum billing obligation is not tied to I&M's actual costs to provide transmission and distribution services, but rather unreasonably burdens a specific type of customer with higher utility rates irrespective of I&M's costs of service. Mr. Fradette testified that a 90% minimum billing demand requires a higher committed spend from large load customers, significantly increasing costs over the proposed 20-year contract term. He said these increased costs pose a very high barrier to entry for large load customers and would likely drive away future investment in I&M's service territory.

Mr. Fradette said a 90% minimum billing demand is unprecedented. He testified that in Amazon's experience, the minimum billing demand is structured to ensure that incremental costs of service are reasonably recovered by the customer(s) benefiting from the infrastructure. Focusing specifically on regulated utility structures that have a percentage of minimum bill requirement, Mr. Fradette said Amazon has executed agreements from 0% up to 75% minimum demand obligations and in all of these incidences, the rates are transparently structured to ensure that the incremental cost of service for Amazon is equitably recovered by the utility over the contract term.

Mr. Fradette stated it would be more efficient for I&M to enter into special contracts with its three proposed customers that better reflect the mutual needs of each customer, while ensuring I&M recovers its variable costs and a portion of its fixed cost. He added that a special contract arrangement may also allow the Commission a seat at the table to ensure an appropriate and fair cost recovery. As an alternative to the proposed tariff modifications, Mr. Fradette discussed Cause No. 45975, which involved Duke Energy Indiana. He said Amazon would consider alternative

tariff provisions if I&M was obligated to build, contract, and enable a portfolio of carbon free energy sources to serve this load.

Mr. Fradette claimed I&M has not demonstrated that it will not recover more than its cost to serve large load customers if its proposals are adopted or how the proposed tariff change is a fair policy. He said large load customers will no longer be able to realize reduced electricity consumption demand when technology or other business events reduce its electric demand requirements to less than the 90% fixed usage requirement. He concluded that I&M's proposals are not supported by the evidence and therefore are unreasonable.

Mr. Loomis testified that I&M's proposed Tariff I.P. modifications violate the ratemaking principles prohibiting single-issue ratemaking, encouraging incrementalism, collaboration and negotiated settlements. He said a 20-year contract term is too long for any reasonable business to forecast their electricity needs, noting that a utility has the ability to aggregate the demand of thousands of customers and shift and redeploy resources as the needs of those customers change. Mr. Loomis stated that the Contract Termination Fee unreasonably shifts the electricity infrastructure risk from the utility onto the customer.

Mr. Loomis indicated that changes in contract terms are not the only way that I&M can protect itself from loss and stated as a regulated utility I&M has many ways to reduce risk. He stated that in the unlikely event that I&M cannot sell the electricity and capacity at a price that equals or exceeds its cost, it will receive revenue from the customer for the cancelled demand. He said I&M has not proven that the existing 60% rule needs to increase to 90%, in addition to the revenue from resale, to provide adequate compensation. He added that as a last resort, I&M can seek to adjust rates, explaining that as a regulated utility under rate-of-return regulation, I&M has the right, but not the guarantee, to earn a sufficient return on its prudently incurred rate base and recovery of its allowed operating expenses.

Mr. Loomis discussed the benefits from data centers coming to Indiana and the benefits to AEP. He also discussed alternatives to I&M's proposal, including: (1) making the tariff changes in the context of a full rate case where all the costs, customer classes, and alternatives can be examined; (2) adopting a one-year forward notice for capacity adjustment, or a time horizon of no more than three years; (3) allowing asymmetrical adjustments so that the customer can increase capacity at a higher percentage than it is allowed to decrease capacity; (4) adopting a four-year contract term rather than the 20-year term proposed by I&M; (5) allowing a new entity that would acquire a data center to assume the contract without negotiation or approval of I&M; (6) keeping the 60% minimum billing demand; and (7) eliminating the five-year termination fee with no alternative.

Dr. Berry discussed I&M's proposed 20-year contract length, 90% minimum demand charge, termination fee, maximum 20% reduction in contract capacity, and the 150 MW applicability threshold. She also discussed economic and regulatory issues related to the vertically integrated electric utilities. While she agreed that the anticipated additions of new customers at large demand levels represent a potential challenge in coming years to utilities nationwide, including I&M, she did not believe this situation should alter traditional utility planning and ratemaking or that it justified the distinct and inequitable treatment of customers as would occur under I&M's proposed tariff modifications. She testified that I&M's proposed terms and

conditions applicable only to large load customers are arbitrary, do not adhere to good regulatory ratemaking principles, and are not economically justified.

Dr. Berry stated the proposed Tariff I.P. is not fair, just, and reasonable because: (1) the new large load customers will provide benefits to I&M's existing customers by substantially increasing revenues collected under the Tariff I.P.; (2) I&M has estimated the cost of generation investments and identified some transmission investments that it is undertaking or planning to undertake to provide service to approximately four GW of new large load; (3) the revenues that I&M will receive from new large load customers far exceed the costs that I&M will incur to serve them; (4) I&M cannot identify any examples of utilities applying tariff terms and conditions comparable to its proposed Tariff I.P. changes; (5) I&M provided no alternatives to building generation to serve new large load that would reduce the potential risks of stranded assets; (6) I&M's proposed imposition of obligations and restrictions only on customers with loads greater than 150 MW constitutes a significant and arbitrary difference in treatment that is not supported by a corresponding differential impact to the system relative to similarly situated loads that would not be subject to the proposed terms; (7) I&M's proposal to lock all new large load customers into 20-year contract commitments and 90% minimum demand charges is a departure from traditional practice under utility regulatory principles and would shift risks appropriately borne by I&M to large load customers and perversely incentivize I&M to take on more risk than otherwise; (8) I&M has proposed a termination fee that does not correspond to actual costs incurred by I&M and that is applied indiscriminately to customers regardless of the costs they impose on the system; (9) I&M's proposed changes to Tariff I.P. combined with I&M's intention to make large, rate-based investments to serve load, would provide substantial benefit to I&M's shareholders while pushing virtually all risk to new large load customers; and (10) the current challenges facing I&M from anticipated new large load customers are not new to the electric industry.

Dr. Berry recommended rejecting I&M's proposal to increase the minimum demand charge from 60% to 90% and the requirement for a 20-year contract for customers with load greater than 150 MW. She indicated that a contract term of four years for large load customers would fall within a reasonable range for the contract term. She testified that given I&M's concerns about the persistence of new large loads, I&M should not plan to rely exclusively on long-term ownership of rate-based assets but should pursue available alternatives to establish a diversified supply portfolio that would reduce the risk to all customers.

Dr. Berry also recommended rejecting the proposed termination fee, adding that termination fees (if any) should be based on the actual unrecovered costs associated with each customer. Dr. Berry testified that I&M's proposal to limit a reduction in the contracted capacity of large load customers to 20% of the contract amount also should be rejected. She said all requested reductions in contract capacity should be allowed subject to a penalty if it is determined that there are unrecoverable costs associated with investments made on behalf of the large load customer. Finally, Dr. Berry recommended that the proposed modification to require a five-year notice period for large customers to terminate service should be rejected. She said all requests for termination, independent of a facility's permanent closure, should be allowed subject to a penalty if it is determined that there are unrecoverable costs associated with investments made on behalf of the large customer.

B. DCC. Mr. Higgins testified that it is reasonable for the Commission to adopt policies that accommodate load growth, such as those raised by I&M, in a thoughtful and deliberate manner so as to avoid cost shifting if investments are made to serve new load that does not fully materialize, but also to avoid imposing unjust terms on important growing industries. Mr. Higgins stated that while it is not unreasonable for the Commission to require large loads of 150 MW or greater to sign long-term contracts, it is preferable for those terms to be negotiated in the context of a special contract. He stated that a fundamental problem with the proposed 20-year contract term is that the pricing of the fixed cost of production remains open-ended, and therefore, the term (coupled with a 90% minimum demand provision) would erode I&M's incentive to negotiate long-term special contracts that not only protect the interests of I&M and other customers, but are also fair to the large load customer. He stated that to the extent the Commission determines that a default contract term is necessary in Tariff I.P., the maximum mandatory term should be no greater than ten years, with a 36-month exit notice requirement after five years, and a capacity reduction/termination fee for load reductions greater than 20% that is based on the foregone net revenues from the minimum demand charge over the remaining contract term, after accounting for the release or transfer of the terminated capacity to serve new load. He added that the tariff should permit exiting customers to negotiate mutually agreeable exit terms with I&M.

Mr. Higgins recommended that the Commission reject I&M's proposal to increase the minimum demand charge from 60% to 90% for large load customers. He distinguished between the minimum demand charge applicable to production demand and to transmission demand, observing that in the case of production demand, if a large load customer were to reduce its load significantly, or alternatively, not attain its contracted demand, generating resources that would otherwise have been utilized to serve the customer could be redeployed. Mr. Higgins stated that, based on the most recent PJM Base Residual Auction price, a 62% minimum demand charge for production would be a "hold harmless" level, and that a 70% minimum demand charge for production is conservative. He said instead of I&M's proposal, the minimum demand charge applicable to production demand should be set no greater than 70%.

With respect to the minimum demand charge applicable to transmission, Mr. Higgins used I&M's estimates of the incremental cost of transmission (between $840 million and $1.05 billion to accommodate an increase in I&M's load from 2,800 MW to 7,000 MW) to calculate a first-year revenue requirement of $3.07 per kW-month spread across 4,200 incremental MW. He stated this first-year revenue requirement is significantly less than the current embedded cost of the Off-System Sales ("OSS")/PJM Rider rate of $8.593 per kW-month. Mr. Higgins therefore stated that the 4,200 MW of new billing determinants would put downward pressure on the embedded cost rate for all I&M customers, because the new large load would pay the higher embedded cost rate. Mr. Higgins noted that even if a new large load customer entered into a ten-year contract, and its load did not materialize, the customer's contributions to the OSS/PJM Rider charge with the current 60% minimum demand charge would more than recover its pro rata share of the incremental transmission revenue requirement; and that consequently, there is no reasonable basis to increase the minimum demand charge applicable to the OSS/PJM Rider above its current 60% level. Mr. Higgins recommended that the minimum demand charge applicable to the OSS/PJM Rider should remain at 60%.

Mr. Higgins testified that it is not unreasonable for I&M to require that large loads provide enhanced collateral requirements but noted the form of collateral and the relationship to the creditworthiness of the customer are not clearly spelled out in the proposed tariff language. He recommended that the proposed collateral requirements be modified to state that a customer with a credit rating of at least A- from Standard & Poor's ("S&P") and A3 from Moody's, or cash on its balance sheet equivalent to ten times the collateral requirement, be exempt from providing collateral. Mr. Higgins also testified that I&M should commit to delivery of contract capacity on the schedule designated in the electric service agreement and that if I&M is unable to meet the contracted delivery date, remedies should be made available to the customer in the tariff.

C. Google. Mr. Farr testified that in April 2024, Google announced plans to invest $2 billion to build a new data center campus located near the City of Fort Wayne, Indiana, within I&M's service territory. He said Google's data center is a new large load that would be directly impacted by I&M's proposed modifications in this Cause. Mr. Farr explained that a data center is a facility designed to house computer systems, telecommunications equipment, and data storage infrastructure in a controlled environment where servers and networking hardware operate, supporting services like cloud computing, financial transactions, and other data-intensive applications. He said that data centers are an integral part of digital infrastructure, underpinning many features of daily life and business operations. He stated that they enable the seamless exchange of data and support the functioning of key economic sectors such as communications, finance, healthcare, retail, service industries, and manufacturing. He also explained that data centers' demand for electricity is the result of the aggregation of demand for digital services from individuals and businesses so that as demand for those services grows, and as business and personal interactions depend on more digital services, data centers' demand for electricity grows too.

Mr. Farr recommended the Commission reject I&M's proposed changes to Tariff I.P. as being an unreasonable and unjust imposition on large load customers without a factual basis of support. Mr. Farr said he supports I&M's proposal to require a customer to provide collateral equal to two years' worth of the customer's non-fuel bill. He included criteria received from I&M in discovery (Google Exhibit 1, Attachment JBF-1) and recommended the Commission adopt and memorialize this information in the tariff for clarity and transparency.

Mr. Farr testified it is reasonable for I&M to ensure that its terms of service appropriately account for the increased risk associated with the concentration of a large amount of load in only a few customers. He also testified that rather than adopting policies applicable to new large loads with the goal of insulating I&M from associated risks, the Commission should focus on providing sound planning signals to I&M to ensure the investments it pursues are reasonable and in the public interest. He recommended the Commission adopt new policies that include: (1) a 70 MW threshold for application that is sufficient to cover anticipated future load growth; (2) sufficient upfront collateral to ensure that I&M does not invest in additional infrastructure to serve speculative entities; (3) maintaining the 60% minimum demand charge; (4) a commitment term that minimizes the risk of stranded assets; and (5) fair, flexible, and transparent terms for the payment of exit fees if a customer opts to terminate or reduce its contractual commitments during the term.

Mr. Farr testified that these are key elements to consider in a policy to address customer-specific forecasting risk. He said these elements should be considered together as they interrelate with the goal of ensuring that if a specific customer requests to bring on a new large load, but the

load does not materialize as expected over a reasonable horizon, and therefore, the customer fails to fully utilize the reserved load, that customer is appropriately allocated any stranded costs actually incurred on its behalf. Mr. Farr said I&M's proposal contains terms that reflect these elements, but the specific proposal is too heavy-handed and not supported by evidence. He explained how some of I&M's proposed terms, including the 20-year contract commitment, 90% minimum billing demand, and limitations on a customer's ability to modify its contract capacity created unreasonable burdens on large load customers.

Mr. Farr also expressed concern that I&M's proposed terms were creating an imbalance between the utility and large load customers by shifting risk from I&M to those customers with no reciprocal assurances of supporting the customer's own objectives. Mr. Farr testified to the importance of I&M's consideration of comprehensive special contracts, which he said was integral to supporting the business goals of Google and I&M to the benefit of other ratepayers while still addressing risks and facilitating prudent planning and resource investment. He recommended that the Commission direct I&M to negotiate in partnership with Google to bring forward a special contract for approval that enables Google to progress on its business objectives, accelerates advanced solutions, ensures that all costs associated with Google's service are fully covered under the special contract, and protects I&M's other ratepayers from any increase in costs as the result of Google's service. He further recommended that the Commission modify the applicability terms of any changes to Tariff I.P. to explicitly acknowledge the role of special contracts in meeting the need of new large load customers.

8. I&M's Rebuttal Evidence. Mr. Baker testified that to support the state's economic development strategy, I&M will be required to integrate potentially the largest electric loads in the state of Indiana onto the electric grid in a compressed timeline. He said the tariff provisions are necessary to ensure I&M has reasonable customer protections in place to execute on these projects and address the risks incurred by I&M. He said certain positions taken by intervenors in this proceeding would create challenges in I&M's ability to effectively manage the risks associated with projects of this magnitude.

Mr. Baker discussed I&M's role in supporting economic development in I&M's service area, noting that I&M has been tasked with supporting a state economic development initiative to attract large data centers into Indiana. Mr. Baker explained that to provide electric service to unprecedented large customer loads in a safe and reliable manner and take into consideration the interest of both new and existing customers, I&M is implementing a multi-faceted strategy that includes significant generation and transmission investments. He said the proposed tariff modifications along with potential special contracts for unique customer needs are the essential framework necessary to meet all parties' needs.

He stressed the importance of understanding these strategic elements are being completed in parallel and with urgency to meet the timelines requested by the large load customers I&M is currently working with and scheduled to begin serving later this year and in early 2025. He said the timeliness of a Commission order approving I&M's proposed tariff modifications is critical to I&M's ability to serve these customers with a clear understanding of the terms of service.

Responding to Mr. Fradette's concern that I&M's proposals will negatively impact development of Amazon's data centers in I&M's service territory, Mr. Baker testified that I&M must balance the needs of all customers, including taking steps to safeguard other customers from risks associated with large loads. He explained that having a Commission approved tariff with specific terms and conditions of service for large load customers will be beneficial to I&M, the state of Indiana, and I&M's other customers. He said it will support the "speed to market" economic development strategy by providing customers a clear and well-defined path to begin taking service and provide I&M a level of certainty to make the transmission and generation investments needed with reasonable safeguards for I&M's other customers.

Mr. Baker agreed with CAC witness Inskeep's concerns that the data center development would ultimately restrict, rather than foster, additional economic development in I&M's service territory. He said there is a practical reality that when connecting these loads to I&M's transmission system, I&M will be constrained on available transmission capacity for additional growth. Mr. Baker testified that the capacity needs of the large load customers require significant resources and this in turn impacts the opportunity for other new loads (or expansions of existing customer loads) to be served without delay. He said the proposed tariff modifications recognize that I&M is making a significant commitment to these customers and that it is critical this commitment be reciprocated.

Mr. Baker testified that Amazon witness Berry's characterization of I&M's plans for acquiring the generation resources to serve large loads is inaccurate. He said I&M plans to serve the loads with a diverse portfolio of generation resources that includes both shorter terms as well as longer terms and will include both PPAs and utility ownership. He said the Amazon witnesses' argument regarding I&M self-imposing risks by selecting only utility-owned projects is misinformed and inaccurate and minimizes the role of the Commission in determining what is in the best interest of I&M and its customers.

As for Google witness Farr's concern that the Indiana resource planning and approval process puts Google in the position of having to accept I&M's resource decisions, Mr. Baker testified that I&M is currently being challenged with acquiring over 4,000 MW of PJM accredited capacity by 2030 to meet its projected load obligations. He said this is an unprecedented time in I&M's history, and likely in the state of Indiana's history, and comes at a time when PJM has expressed concerns regarding existing generation resource retirements and new generation resource availability. Mr. Baker stated that I&M is open to working with the large load customers on future generation opportunities, but it is unlikely to result in meaningful generation capacity in the short-term to meet the needs of customers and it does not obviate the need for the tariff modifications.

Regarding the specific sustainability goals of Google and Amazon, Mr. Baker testified that to the extent there are opportunities for I&M to partner with these customers on specific projects, I&M is open to having discussions about a customer-specific contract arrangement. However, he noted that such opportunities cannot adversely affect I&M's other customers and should be consistent with the Five Pillars.

Mr. Baker also addressed CAC witness Inskeep's concern that residential customers should be protected from potential rolling blackouts caused by large load customers. He testified that public safety is I&M's number one priority and I&M agrees that it is prudent for a utility to prepare

for and respond to emergency events in a manner that ensures public safety is prioritized. He said I&M regularly evaluates and practices its emergency response procedures, which include pre-determining the sections of the electric system that are subject to forced outages during load shedding events and limiting exposure for critical customer and public infrastructure loads. He added that it is important to recognize that each emergency event is unique and would require I&M to coordinate closely with PJM while having all various options available to respond to that specific situation.

Mr. Baker agreed that DCC witness Higgins' incremental cost of transmission is an appropriate estimate of the interconnection costs for the three customers with which I&M is currently working. However, he said it is important to recognize that the Tariff I.P. modifications are not being proposed only for these three specific customers but would be applicable to any future large load customers. Mr. Baker explained that I&M has started planning and communicating with PJM on the next set of transmission projects necessary to provide additional capacity for future growth and to ensure a reliable and robust transmission system in the future. He said preliminary estimates for future transmission infrastructure are billions of dollars over the next seven to ten years. He said I&M has managed this transmission capacity position closely to ensure the reliability of the grid for existing customers and maintain some amount for existing customer expansions, but it is important for all I&M customers and communities that transmission system investments are made to enable ongoing economic development opportunities.

Regarding the use of special contracts, Mr. Baker testified that I&M spent a significant amount of time discussing the special contract approach versus the tariff approach with the large load customers and conducted meetings and discussions with various stakeholders related to the impacts of the large loads. He testified that I&M concluded that for it to be able to manage the integration of these customers onto the grid in a safe, reliable, secure, and affordable manner, the proposed tariff modification is the best way to strike the appropriate balance among stakeholders.

Mr. Baker disagreed with DCC witness Higgins' view that establishing a 20-year term requirement in Tariff I.P., particularly with a 90% minimum demand provision, would erode I&M's incentive to negotiate long-term special contracts. He reiterated that for customers with unique needs beyond standard service under the tariff, I&M would address those specific situations through other tariffs, riders, or mechanisms, such as a special contract. He stated that for standard electric service, I&M will serve these customers under the Tariff I.P. terms as approved by the Commission.

Mr. Baker also responded to Amazon witness Fradette's concerns that imposing a 90% minimum billing demand obligates data centers to an unrealistic forecast over a term of 20 plus years and impacts the financial viability of investments within I&M's service territory. Mr. Baker said he found Mr. Fradette's position to be largely inconsistent with I&M's experience with the large load customers to date, noting multiple large load customers have executed service agreements with stated contract capacity commitments during the term of the agreement. Mr. Baker emphasized that I&M does not set the load ramp or contract capacity for the large load customers. He said, if anything, I&M limits the contract capacity based on the amount of transmission capacity available. He stated that Mr. Fradette's claim ignores the fact that it is the customer who has the internal business information necessary to determine the forecast and

therefore it is the customer's responsibility to provide realistic requirements that match actual business needs and intentions.

Mr. Baker explained that the acquisitions I&M makes for generation resources will have contract periods or service lives ranging from five years to 35 years. He stated that understanding expected loads over the entire 20-year integrated resource planning horizon is critical not only in determining the most appropriate resources, but also the terms and/or lives of the resources. He said these considerations highlight the importance of the proposed tariff modifications to provide I&M confidence in the resource selections it will be making early in 2025 to serve future load obligations. He said I&M can only plan and make appropriate decisions based on the contract capacity requirements provided to I&M by the large load customers.

Mr. Baker also addressed Amazon witness Fradette's opposition to I&M's proposed termination fee. Mr. Baker testified that if the level of termination fees referenced by Mr. Fradette become a reality, it will be highly valuable if I&M's proposed terms are in place. He said the proposed Tariff I.P. modifications are designed to protect I&M and its existing customers in the event the large load customers do not meet the plans they have provided to I&M. He said that if the large load customers operate as planned, the proposed modifications do not provide any additional burden on the large load customers. Mr. Baker stated that I&M has a responsibility to manage the system and provide safe and reliable service to all its customers. With the significant impacts the large load customers will have on I&M's system, he said it is critically important that those customers be held accountable to the capacity requirements they provide to I&M as an input to overall system planning.

Responding to concerns with I&M's proposed revision to Tariff I.P.'s minimum billing demand, Mr. Vaughan explained that the need for, and reasonableness of, I&M's proposed 90% minimum billing demand can be seen by comparing I&M's historical capacity requirements to serve its load to what it now faces as a result of the new large load customers. He said he could not corroborate Mr. Fradette's claim that the 90% minimum demand proposal was "unprecedented." Mr. Vaughan provided Figure AEV-2R in Petitioner's Exhibit 5 to show it is not uncommon for vertically integrated utilities (i.e., utilities providing both generation and transmission service) to have minimum demand provisions with demand ratchets in excess of 60%, and in some cases, the same or higher than the 90% I&M is proposing.

Mr. Vaughn noted that many of the rate structures associated with these higher minimum demand provisions are also what is generally described as "Demand, Energy, Customer" tariffs, where the demand costs are recovered almost exclusively through the demand charges. He said conversely, I&M's existing, approved Tariff I.P. rate recovers a material amount of demand costs (roughly 44%) through the volumetric energy charge. He stated that while I&M does not propose to modify its existing rate design in this case, it is important to recognize this difference when comparing I&M's Tariff I.P. to other tariff provisions. Mr. Vaughan testified that because a material amount of the production demand costs is being collected in an energy charge, this means the effective minimum demand being proposed by I&M is much lower than 90%, adding that from a production demand cost perspective, the proposed 90% level equates to an approximate 62% minimum demand charge in application.

In response to Amazon witness Berry, Mr. Vaughan clarified that so long as a large load customer meets its contracted capacity each month, regardless of the load factor it actually achieves, the customer should be indifferent to the proposed change in minimum billing demand as it would have no impact on its rates and charges. He stated that while I&M hopes the new large load customers will meet the forecasted usage and load factors provided to I&M, I&M must also reasonably plan for the alternative. He testified that witness Berry's testimony does not reasonably reflect the economic rationale for why I&M proposes a 90% minimum billing demand charge. He explained that as shown in Figure AEV-3R of Petitioner's Exhibit 5, the amount of non-fuel cost recovery is highly dependent upon the load's energy usage, and there is a risk of under-recovery as a Tariff I.P. customer's load factor decreases. He added that, contrary to witness Berry's assertions, this data shows the importance of increasing the minimum billing demand provision to safeguard against a scenario where the large load customer's contracted load does not materialize or the large load customer ceases operations.

Mr. Vaughan provided Figure AEV-4R in Petitioner's Exhibit 5, which he said is the same non-fuel cost recovery analysis as shown in Figure AEV-3R but modified to show the non-fuel generation cost recovery that would be achieved under the current 60% and proposed 90% minimum demand levels if the customer were to cease operations (i.e., operate at a zero load factor). Mr. Vaughan testified that this analysis shows that if a large load customer ceases operation, I&M faces significant under-recovery of its non-fuel generation costs under the existing 60% minimum demand billing provision, and increasing the minimum billing demand to 90% for large load customers is a reasonable step towards safeguarding I&M and its other customers from this risk.

Responding to Google witness Farr's testimony, Mr. Vaughan testified that based on I&M's current resource mix, I&M's average embedded fixed cost of generation capacity is roughly $690/MW-day. He said the equivalent levels of non-fuel generation cost recovery under the 90% and 60% minimum demand levels are $366/MW-day and $244/MW-day respectively. He stated that as I&M adds a significant amount of generation capacity to serve these new large loads in the coming years, it is not unreasonable to assume that the average rates in Tariff I.P. will reduce over time as the incremental cost of generation resources and increased billing units are figured into the ratemaking equation. He also disagreed with Amazon witness Fradette's suggestion that this potential benefit cuts against the need for a 90% minimum billing demand. Mr. Vaughan said this dynamic is another reason to increase the current 60% minimum demand level because lower minimum demand charges provide less protection to existing customers in the future. He stated that regardless of whether future retail rates for service go up or down, the higher minimum demand charge remains important to increase the level of confidence that large load customers will reasonably contribute to the fixed costs I&M incurs to provide service and mitigate the adverse impacts that would otherwise occur to I&M's other customers.

Mr. Vaughan also disagreed with Amazon witness Fradette's contention that I&M's proposed increase to Tariff I.P.'s minimum demand clause provides I&M with an incentive to over-invest in utility-owned resources. He said the minimum charge is based on the allocated cost of service to the class in question, regardless of whether the underlying utility infrastructure providing service is owned by I&M or contracted for from a third party. He stated the proposal is in no way an incentive for I&M to "over-invest" but rather it is a way to protect existing customers

and balance the future cost responsibility between new and existing customers should a large load customer cause some amount of stranded costs.

Mr. Vaughan also testified that from a cost-of-service or ratemaking perspective, it is not necessary for the Commission to wait for a general rate case proceeding to address I&M's proposed Tariff I.P. modifications, particularly the 90% minimum demand provision, as Amazon witness Loomis claimed.

Mr. Vaughan also responded to Amazon witness Berry's contention that the amounts paid by large load customers for local transmission costs would, like generation, go to reducing rates for other customers and represent an amount foregone by new large load customers by paying the average system cost instead of the incremental cost to serve them. He stated that this assumption is incorrect and counter to the foundational ratemaking concept of cost causation. Mr. Vaughan testified that a portion of the zonal transmission revenue requirement associated with the system that will serve I&M's peak load will be reallocated based on the coincident peak loads of the load serving entities within the zone. He said the actual incremental zonal transmission cost increase that the Indiana retail jurisdiction would receive from a 4,000 MW increase in peak demand would be closer to $431 million annually, rather than the $83.9 million referenced by witness Berry.

Mr. Vaughan testified that it is also incorrect to assume, as witness Berry does, that the only costs to serve new large load customers are the truly incremental system costs. He said these large, high load factor loads will be utilizing the existing, robust zonal transmission system and I&M's entire generation resource portfolio (existing assets plus incremental) and as such should share in the cost responsibility for the costs to serve them. Mr. Vaughan said those costs will be a mix of existing system embedded costs and incremental costs.

Mr. Vaughan agreed with DCC witness Higgins that load growth is anticipated for other load serving entities in the AEP Zone, but stated this does not change the need for the protections set forth in I&M's modified terms and conditions. He said AEP Ohio has publicly discussed upwards of 5,000 MW of load growth over a similar period as I&M is expecting to experience its large near-term growth. He stated that using the same analysis that identified $431 million in incremental transmission costs to the Indiana retail jurisdiction discussed above, but also accounting for 5,000 MW of load growth elsewhere in the zone, still results in roughly $294 million of incremental zonal transmission expense allocations to I&M's Indiana retail jurisdiction.

Regarding the assertions of Amazon witness Berry and DCC witness Higgins that only a 60% minimum demand level is needed for transmission charges to adequately protect customers, Mr. Vaughan testified that 60% is insufficient to protect existing customers because the load additions will cause a reallocation of the existing total zonal transmission revenue requirement. He said using the same assumed 4,000 MW peak addition, he estimated that an 88% minimum demand for the transmission charges collected through the PJM/OSS Rider represents the breakeven point where other customers should be indifferent from a transmission cost recovery standpoint. Mr. Vaughan noted that this analysis assumes no incremental investments in transmission infrastructure, which is a conservative assumption.

As for special contracts, Mr. Vaughan testified that in his experience with this issue across the AEP system operating companies, special contracts are generally warranted and appropriate for reasons not applicable to the large load customers. He stated that a customer simply wanting to receive service through a special contract so that it can negotiate its own unique deal is not appropriate, warranted by cost-of-service considerations, or administratively efficient.

Mr. Vaughan also responded to the direct assignment and cost allocation concerns raised by the OUCC. Mr. Vaughan agreed with Mr. Kelley that the addition of these new large load customers creates new risks and challenges. However, he expressed concern with Mr. Kelley's testimony to the extent it advocates for departing from traditional ratemaking. He said that with proper safeguards in place, all customers can benefit from traditional ratemaking and the potential for downward pressure on average rates from large load additions under this approach.

Mr. Vaughan disagreed with CAC witness Inskeep's contention that placing large load customers with existing customers could create significant cross-subsidization concerns and with his recommendation that new large load customers should be partially "firewalled" from existing customers with respect to cost allocation and cost recovery of generation costs. He explained that these concerns are better addressed in a rate case but noted that there are benefits to setting rates using average system costs, rather than directly assigning costs as Mr. Inskeep recommends.

Mr. Vaughan disagreed with Google witness Farr's statement that I&M's proposed tariff modifications will have an impact on how I&M allocates costs among customer classes, as well as how costs are allocated between jurisdictions. Mr. Vaughan stated that I&M's proposal is directed at the terms and conditions of service applicable to large load customers within the Tariff I.P. class. He said cost allocation issues, whether between customer classes or between jurisdictions, are outside the scope of this proceeding and properly addressed in the context of a rate case. He added that I&M's proposal in this case does not inhibit the ability of the Commission or parties to address cost allocation issues in a subsequent proceeding.

Mr. Williamson clarified that his direct testimony, which states that special contracts can be used to support the unique needs of customers, does not mean that those same customers should not be subject to a standard tariff for their basic or standard electric service needs. He said large load customers can receive electric service under Tariff I.P. and have a special contract to adjust their monthly electric service charges for other services, such as demand response, sustainability programs, or strategic partnerships. He noted this is done today for several of I&M's Tariff I.P. customers.

Mr. Williamson testified that prior to filing this case, I&M invested a significant amount of time over several months with multiple large load customers attempting to negotiate terms and conditions of service that could be established through a special contract framework. He stated that it became increasingly clear that it would be very difficult, if not impossible, to achieve a reasonably consistent set of terms and conditions of service amongst all the large load customers as it related to standard electric service. He said that during this same period, I&M received inquiries from other potential large load customers, indicating the number of large load customers could further increase in the future, making the consistency between special contracts even less likely to be achievable.

Mr. Williamson discussed the current status of the large load customers in I&M's Indiana retail service territory, summarizing the executed Transmission Letters of Agreement that represent approximately 3,700 MW of total load through 2030 and stating I&M will require a significant amount of new generation to serve its growing load. Mr. Williamson also discussed the potential for other large load customers to take service in Indiana in the future.

In response to the parties' specific recommendations, Mr. Williamson noted the considerable variation in the recommendations. He said on the one hand, the data center intervenors generally argue that I&M's proposed tariff modifications are unreasonable and/or too stringent. He said on the other hand, the consumer parties (i.e., OUCC and CAC) generally agree with I&M's proposed terms and conditions but suggest additional safeguards may be necessary to protect I&M's other customers. He said these differing viewpoints reinforce the need for a balanced and consistent approach that recognizes the concerns raised by all parties while ensuring I&M and its customers (both existing and prospective) have clear guidance as to how such matters will be addressed going forward. He said the proposals made by I&M in this proceeding strike an appropriate balance and should be approved.

Mr. Williamson explained why the parties' claims that the proposed tariff modifications have not been imposed elsewhere in the United States is not a valid reason to reject them. Pointing to the size of the large loads, he said the past is not representative of the future and what has not been done up to this point in time cannot be relied upon as a basis of whether the proposed modifications are reasonable and necessary in the future. He also noted the unprecedented nature of the situation facing I&M today.

Mr. Williamson disagreed with DCC witness Higgins' position regarding I&M's proposed 20-year contract term and explained why he believes I&M's proposal is not unreasonably one-sided. As to Mr. Higgins' proposed ten-year term, Mr. Williamson said the sensitivity analysis presented in his direct testimony indicates that the amount of risk is expected to decline the longer the contract term. He testified that while under some asset cost and market conditions, a ten-year contract coupled with I&M's proposed Contract Termination Fee could sufficiently cover I&M's financial risk, a longer-term contract will provide greater assurance that a large load customer terminating its contract does not result in excess capacity costs that negatively impact I&M's other customers.

Mr. Williamson also responded to DCC witness Higgin's position that it would be inefficient to lock a large load customer into capacity it did not need, particularly given the anticipated growing demand for capacity. Mr. Williamson said this is why I&M included proposed language to allow for contract capacity reductions greater than 20% upon mutual agreement. He said it is also reasonable that large load customers be limited on how much they can reduce contract capacity without any certainty that the financial implications can be managed without causing significant financial harm. He said I&M's proposal establishes reasonable guardrails beyond which a large load customer cannot unilaterally change its contract capacity.

Mr. Williamson also responded to the testimony offered by Google witness Farr and Amazon witness Loomis that 20 years is too long for any reasonable business to forecast their electricity needs. He said the 20-year contract term is designed to provide reasonable assurance that large load customers will take service over a period that reasonably aligns with the significant

investments and financial commitments I&M will make to provide service. He said not only is I&M planning for the load over a similar period of time as the proposed contract term, I&M will also be entering into financial commitments for a similar period.

Mr. Williamson also addressed Amazon witness Fradette's testimony regarding I&M's current customer contract periods and current asset service lives. Mr. Williamson testified that I&M has historically been long on generation, which enabled I&M to serve its growing load without incurring a substantial increase in I&M's overall fixed costs. He said this is not the situation today, explaining I&M will require a significant amount of generation to serve its growing load. He said this will result in a significant and long-term increase in I&M's fixed costs, which is why the large load customers contributing to these increased resource commitments need to have a corresponding commitment to maintain service with I&M. Mr. Williamson stated that Mr. Fradette fails to recognize the scale and magnitude of the large load customers, explaining that Amazon's projected load will exceed the load of I&M's Indiana retail industrial and commercial customers combined. Mr. Williamson said it is unreasonable and imprudent to assume I&M could shift and redeploy resources should the needs of large load customers decrease.

In response to DCC witness Higgins' proposal to modify the collateral requirements, Mr. Williamson testified that while cash on the balance sheet is considered a credit positive, it is only one attribute when determining a customer's credit worthiness. He said requiring both a public debt rating (Moody's/S&P), along with a liquidity covenant puts I&M in the best position to ensure that a large load customer and/or its guarantor can provide payment if an early termination occurs.

Mr. Williamson said I&M did not oppose CAC witness Inskeep's recommendation to change the contract capacity change provision to: (1) cap individual customer reductions to 100 MW in any given year (with a five-year advance notice); and (2) cap overall reductions across large load customers to 5% of the prior calendar year's I&M-Indiana jurisdictional peak load, on a first-come, first-served basis. However, he indicated that I&M's proposed terms may better balance customer flexibility with customer protections.

Mr. Williamson disagreed with Amazon witnesses Fradette and Loomis regarding the notice period to reduce contract capacity. He said that while it is true I&M's load obligations and resource commitments can change annually, that does not mean I&M can simply acquire or unwind significant amounts of long-term generation resources annually or effectively. He explained that most of the capacity in PJM is acquired before or during the Base Residual Auction and to effectively optimize excess capacity, it requires the sale to occur years in advance of product being sold. Mr. Williamson stated that while I&M's load forecast could be adjusted prior to the delivery year, it may be unable to adjust its capacity resources in a cost-effective manner to those changes. Mr. Williamson stated that for this reason, large load customers need to be responsible for their forecast and I&M's five-year notice reasonably recognizes that it is prudent utility practice to acquire generation prior to PJM's three-year forward capacity planning market.

9. Docket Entry Responses. I&M responded to several questions from the Presiding Officers. In response to a question on pre-service cost recovery, I&M responded that it "will seek to reasonably align timing of generation resource costs with the timing of its expected load requirements," noting that synchronization will be dependent on several factors. Pet. Ex. 10. Regarding how various tracker cost allocations might be adjusted, I&M responded that future

individual tracker filings would be updated to address the allocations. Finally, in response to a question regarding Commission oversight of any future service contract modifications provided for in Tariff IP, I&M responded it was not opposed to an approval role if the Commission desired such a role.

10. Settlement Agreement and Supporting Testimony. Following the prefiling of testimony, the Settling Parties, which represent varied and competing customer groups and interests, including residential and large load customers, reached a comprehensive agreement. The Settlement Agreement resolves all pending issues in this Cause. The witnesses offering settlement testimony discussed the arm's-length nature of the negotiations and efforts undertaken to reach what all parties consider to be a balanced settlement that fairly resolves all issues in the case.

I&M witness Williamson discussed the Settlement Agreement's terms and testified the Settlement Agreement is a package agreement that reasonably resolves all pending issues among the Settling Parties. He said taken as a whole, the Settlement Agreement represents the result of arm's-length negotiations by a diverse group of stakeholders with differing views on the issues raised in the docket. He testified that party experts were involved with legal counsel in the development of both the conceptual framework and the details of the Settlement Agreement and that a significant number of hours were devoted by the Settling Parties to discussions, the collaborative exchange of information, and settlement negotiations.

Mr. Williamson stated that as discussed within I&M's direct and rebuttal testimony, I&M is anticipating unprecedented load growth driven by new large load customer demand. He said I&M requires significant transmission and generation infrastructure investments and other long-term financial commitments to serve its growing Indiana retail load. He stated from I&M's perspective, it is reasonable and necessary to establish terms and conditions for service that safeguard against the cost impacts that can occur if the new load does not fully materialize or prematurely terminates. He said that while there was general agreement on the need for safeguards, the parties disagreed as to what extent, as shown in Petitioner's Exhibit 2, Figure AJW-2R.

Mr. Williamson testified this is a complex situation and there is no easy solution that perfectly satisfies every stakeholder interest. He said the Settling Parties worked cooperatively and that the settlement discussions provided the parties an opportunity to delve into each other's concerns, ideas, and interests. He testified that ultimately, the joint efforts of the Settling Parties allowed them to reach a unanimous and balanced Settlement Agreement that fairly resolves all the issues in this case and adopts important safeguards. He said I&M considered the Five Pillars during the settlement discussions and that the outcome is consistent with those pillars and the supporting testimony in this Cause. He expressed his opinion that the Settlement Agreement is in the public interest and reasonably resolves all issues in this docket without further expenditure of the time and resources of the Commission and the Settling Parties to litigate these matters.

OUCC witness Eckert testified that the Settlement Agreement resolves critical issues intended to prevent I&M's costs to serve these large load customers from being shifted to I&M's other customers. The Settlement Agreement is also intended to protect I&M and its other customers by agreeing upon the terms to which the large load customers will be bound, the extent the large load customers may reduce their capacity over that term, the collateral that must be

maintained, the exit fees, and other contract terms, including the allocation of I&M's revenue requirement among its rate classes.

Mr. Eckert testified the Settlement Agreement is the product of intense negotiations, with each Settling Party compromising on challenging issues to reach an overall agreement that balances ratepayers' interests. He said it was critical to the OUCC that the risks large load customers pose for I&M's other ratepayers be mitigated. He said that given the ratepayer benefits and the mitigation of ratepayer risks achieved under the Settlement Agreement, the OUCC, as the statutory representative of all ratepayers, concluded the Settlement Agreement is a fair resolution of the issues, supported by the evidence, is in the public interest, and should be approved.

CAC witness Inskeep testified that the Settlement Agreement is the product of intense and lengthy negotiations, with each party making compromises to reach a settlement that balances the interests of I&M, new and prospective data center customers, and existing ratepayers. He explained the Settlement Agreement maintains the same general type of modifications to Tariff I.P. as originally proposed by I&M, but with changes to certain details of the terms and conditions of service for new large load customers that reflect compromise among the parties. He said the Settlement Agreement includes other terms addressing issues of importance to certain Settling Parties, including terms addressing cost allocation, collaboration on additional topics such as demand response and a Clean Transition Tariff, reporting requirements, and funding to the Indiana Community Action Association ("INCAA") to support income-qualified Hoosiers. He concluded the terms of the Settlement Agreement are reasonable, supported by the evidence, and provide a fair resolution to the issues raised in this proceeding. He requested the Commission find that the Settlement Agreement is consistent with the public interest and approve it.

Google witness Farr testified that the Settlement Agreement is a comprehensive resolution to various concerns expressed by multiple parties, all of whom had distinct viewpoints. He expressed his opinion that this case is about balancing risks. He said as described in his direct testimony, it is reasonable for the Commission to consider tariff revisions to help ensure that I&M is planning for a prudent amount of investment and, to the degree that a specific customer's demand forecast proves inaccurate, that the financial risks of that inaccuracy be borne by the specific customer, not I&M's greater body of ratepayers. He said the Settlement Agreement achieves that objective. He expressed his belief that the Settlement Agreement's terms create the proper balance between large load customers and I&M, while also providing significant protections to I&M and other ratepayers. He testified the issues raised in this case were challenging and encompassed a complex array of opinions on how best to achieve the optimal regulatory outcome. He said despite the range of views, the Settling Parties came to the negotiating table and found consensus on terms to resolve the case that, in his opinion, protects the interests of the participating parties in a manner consistent with sound rate design principles.

Amazon witnesses Fradette, Loomis, and Berry all recommended approval of the Settlement Agreement, which they said is based on appropriate regulatory policy and rate design principles, including appropriate allocation of costs to serve large load customers. They said the parties' agreement is well within the range of outcomes from a litigated case. They further testified that the Settlement Agreement is the result of a collaborative negotiation process that supports I&M's ability to provide cost-effective, dependable service to all customers and continue pursuing

opportunities that enable third party economic development and investment of large loads, such as Amazon's data centers, within I&M's service territory.

11. Commission Discussion and Findings. Settlement is a reasonable means of resolving a controversial proceeding. We note that Indiana law strongly favors settlement as a means of resolving contested proceedings. *Mendenhall v. Skinner & Broadbent Co., Inc.*, 728 N.E.2d 140, 145 (Ind. 2000) ("The policy of the law generally is to discourage litigation and encourage negotiation and settlement of disputes."). The Settlement Agreement represents the proposed resolution of the issues in this Cause by all the parties of record. As the Commission has previously discussed, settlements presented to the Commission are not ordinary contracts between private parties. *U.S. Gypsum, Inc. v. Ind. Gas Co.*, 735 N.E.2d 790, 803 (Ind. 2000). When the Commission approves a settlement, that settlement "loses its status as a strictly private contract and takes on a public interest gloss." *Id.* (quoting *Citizens Action Coal. of Ind., Inc. v. PSI Energy, Inc.,* 664 N.E.2d 401, 406 (Ind. Ct. App. 1996)). Thus, the Commission "may not accept a settlement merely because the private parties are satisfied; rather [the Commission] must consider whether the public interest will be served by accepting the settlement." *Citizens Action Coal.,* 664 N.E.2d at 406.

Further, any Commission decision, ruling, or order, including approval of a settlement, must be supported by specific findings of fact and sufficient evidence. *U.S. Gypsum,* 735 N.E.2d at 795 (citing *Citizens Action Coal. of Ind. v. Public Service Co.,* 582 N.E.2d 330 (Ind. 1991)). The Commission's procedural rules require that settlement be supported by probative evidence. 170 IAC 1-1.1-17(d). Before the Commission can approve the Settlement Agreement, the Commission must determine whether the evidence in this Cause sufficiently supports the conclusion that the Settlement Agreement is reasonable, just, and consistent with the purpose of Ind. Code ch. 8-1-2 and that it serves the public interest. In the current Cause, the Commission has before it substantial evidence with which to judge the reasonableness of the terms of the Settlement Agreement.

While our decision is based on the entire record, the foregoing summary of the evidence facilitates our consideration. As discussed in greater detail below, the Commission concludes the Settlement Agreement, taken as a whole and modified herein, is a fair and reasonable resolution of the issues presented in this Cause, supported by the record, and in the public interest. Accordingly, the Commission approves the Settlement Agreement as set forth below.

A. Applicability. In its case-in-chief, I&M proposed that the Large Load Terms would apply based on a threshold of greater than 150 MW, which would apply to both individual and aggregated sites. I&M proposed the 150 MW minimum threshold because of the significant financial commitment I&M indicated must be made to serve loads of that magnitude or greater into the future and the customer concentration risk it represents to I&M's business and the cost of serving its customers.

The record shows the OUCC did not oppose I&M's proposal, and the CAC supported it. Google and Amazon opposed this threshold. More specifically, Google suggested a 70 MW threshold would be more appropriate to cover anticipated future load growth and account for the risk of demand uncertainty due to the number of new customers seeking service in the range of 70-150 MW. Amazon contended that I&M's 150 MW threshold appears to be random and targeted to the initial three large load customers.

I&M witness Williamson testified that as part of the give and take of settlement negotiation, the Settling Parties compromised by agreeing to a lower individual site threshold. Under the Settlement Agreement, the Large Load Terms will apply to customers taking service on I&M Tariff I.P. with contract capacity greater than or equal to 70 MW at an individual site or 150 MW on an aggregated basis ("Large Load Customer"). I&M will exercise reasonable discretion when choosing to aggregate premises as set forth in the Settlement Agreement. The Settling Parties also agreed that the Large Load Terms shall only apply to new load, or an expansion of existing load, occurring on or after January 1, 2024.

Based on the record, the Commission finds the Settling Parties' agreement on the applicability of the Large Load Terms to be reasonable. We recognize that the agreed Large Load Customer threshold of 70 MW at an individual site or 150 MW on an aggregated basis reasonably provides that customers for whom I&M would need to make significant financial investments to serve are obligated measurably more than under the existing Tariff IP. We further find that applying the Large Load Terms only to new load, or an expansion of existing load, occurring on or after January 1, 2024, reasonably safeguards I&M's existing customers in a manner more consistent with the risk of new or expanded load.

B. Mandatory Term. As discussed above, I&M originally proposed an initial contract term of 20 years. The OUCC and CAC supported this proposal. DCC proposed ten years, Google contended the contract term should minimize the risk of stranded assets, and Amazon proposed four years. In rebuttal, I&M acknowledged that a ten-year contract term coupled with I&M's proposed Contract Termination Fee could sufficiently cover I&M's financial risk under some asset cost and market conditions, but a longer-term contract was a preferable safeguard.

As shown in Section I.A.2 of the Settlement Agreement, the Settling Parties agreed to an Initial Contract Term of not less than 12 years, commencing after any Load Ramp Period ends. The Load Ramp Period can be no greater than five years. The Load Ramp Period is the later period of time from when: (a) electric service is available to the Large Load Customer or (b) the Large Load Customer is scheduled to begin taking electric service, until the time the Large Load Customer's maximum contract capacity is billed. The Contract Term is defined as the combined period of time associated with any Load Ramp Period plus the Initial Contract Term.

I&M witness Williamson testified that as part of the negotiated package, the agreement on the Initial Contract Term strikes a reasonable balance of the diverse positions amongst the Settling Parties and provides for a substantially longer commitment than I&M requires as an initial contract term from other Tariff I.P. customers.

OUCC witness Eckert testified that the agreed mandatory term helps reduce the risk of stranded asset costs for I&M and their potential recovery from I&M's other customers and/or shareholders.

CAC witness Inskeep testified that the Settlement Agreement would establish a minimum contract term for Large Load Customers of 12 years, plus the Large Load Customer's designated Load Ramp Period, if any, which can last up to five years. He said in other words, most Large Load Customers would be expected to have a 14- to 17-year contract term, assuming a two- to five-year Load Ramp Period. He said this is significantly longer than the current two-year

minimum contract term specified in Tariff I.P., and only modestly shorter than the 20-year term initially proposed by I&M. He stated the Initial Contract Term reasonably balances the need expressed by I&M for Large Load Customers to make a long-term financial commitment consistent with the large investments that I&M will be making on their behalf, concerns expressed by consumer advocates regarding potential cost shifts if a Large Load Customer were to suddenly reduce or discontinue service, and the desire expressed by large customers for additional contract flexibility.

Google witness Farr testified the Settlement Agreement specifically allows for a Load Ramp Period of not more than five years. He said this allows a customer to specify defined, stepped, load levels as it moves towards its ultimate contract demand. He added this will enable the customer to align its contract with its business needs while also ensuring that I&M is planning and investing based on an accurate signal of demand.

Amazon witness Fradette testified the mandatory term provision that the Settling Parties agreed upon after much discussion is fair, just, and reasonable, in the context of the overall settlement package. Likewise, Dr. Berry and Mr. Loomis both agreed that the mandatory term provision is fair, just, and reasonable.

The record shows there was a general acknowledgement amongst the parties that an initial contract term longer than Tariff I.P.'s current two-year minimum would be reasonable for Large Load Customers. At the same time, several parties raised concern with I&M's original proposal for a 20-year term. The parties, through the Settlement Agreement, have resolved this issue through an agreement that a Large Load Customer will be subject to a minimum contract term of 12 years, plus the Large Load Customer's designated Load Ramp Period, if any, which can last up to five years. The record shows the agreed mandatory term reasonably balances the diverse views of the Settling Parties while providing for a substantially longer commitment from Large Load Customers than I&M requires as an initial contract term from other Tariff I.P. customers. The record further shows that the minimum contract term of 12 years, when coupled with the other provisions of the Settlement Agreement, provides reasonable financial safeguards for I&M and its other customers that exceed those under the currently approved Tariff IP. The agreed mandatory term provision will also help Large Load Customers align their contract with their business needs while also ensuring that I&M is planning and investing based on accurate demand signals.

C. <u>Monthly Billing Demand</u>. I&M's direct testimony explained why it supported revising the minimum billing demand from 60% to 90% for large load customers as a reasonable way to protect I&M and its other customers by mitigating the potential volatility and variability associated with such customers. Multiple intervenor witnesses questioned the need for I&M's proposed revision to Tariff I.P.'s minimum billing demand provision. As shown in Petitioner's Exhibit 2, Figure AJW-2R, the DCC proposed 70% on production demand; 60% for the OSS/PJM Rider, and Amazon and Google proposed 60%. The record shows both the OUCC and CAC agreed with I&M's proposal.

As shown in Section I.A.3 of the Settlement Agreement, the Settling Parties agreed to an 80% minimum monthly billing demand. More specifically, Settlement Agreement Attachment A provides the Settling Parties' agreement to the following language for the Tariff I.P. monthly billing demand clause for Large Load Customers:

> The Monthly Billing Demands for Large Load Customers in kW for each plant shall be taken each month as the single-highest 15-minute integrated peak in kW, as registered at such plant during the month by a demand meter or indicator, subject to the Off-Peak Hour Provision, but the monthly demand so established shall in no event be less than the greater of (a) 80 percent of the Large Load Customer's contract capacity specified for the applicable time period of the Contract Term; or (b) 80 percent of the Large Load Customer's highest previously established Monthly Billing Demand during the past 11 months. The Metered Voltage adjustment, as set forth above, shall not apply to the Large Load Customer's minimum Monthly Billing Demand.

I&M witness Williamson testified the agreed minimum billing demand provision balances customer flexibility with assurances that Large Load Customers provide financial support for the significant transmission and generation infrastructure needed to serve such load. He said importantly, the 80% minimum billing demand provision is combined with enhanced minimum charge terms. He said the combination of these two minimum charges reflects a reasonable and balanced compromise amongst all Settling Parties and provides important financial protections for all I&M customers.

OUCC witness Eckert testified the Settlement Agreement increases the monthly billing demand for Large Load Customers from that in I&M's current Tariff I.P. He said the agreed monthly minimum billing demand provision reduces the risk of stranded assets and better ensures Large Load Customers pay their fair share of the costs I&M incurs to serve their added load.

Google witness Farr noted that under the Settlement, I&M is only applying the 80% minimum monthly billing demand to the Large Load Customer's load ramp capacity as specified in its contract. He said when coupled with the agreed-upon minimum charge provision, this allows the customer greater flexibility in its planning as it moves its facility to full operation without imposing a significant financial obligation that is not tied to its actual level of service for the period.

The record reflects the parties had differing positions and concerns regarding I&M's original proposal to increase the minimum monthly billing demand for large load customers from the current 60% to 90%. The Settling Parties resolved those concerns through Section I.A.3 of the Settlement Agreement, which provides for an 80% minimum monthly billing demand. The record shows an 80% minimum monthly billing demand reasonably balances I&M's interest in ensuring Large Load Customers provide financial support for the significant transmission and generation infrastructure needed to serve them, the Large Load Customers' interest in flexibility, and I&M's other customers' interest in mitigating the potential volatility and variability associated with Large Load Customers in an appropriate manner, particularly when consideration is given to the other provisions of the Settlement Agreement.

D. <u>Minimum Charge</u>. As shown by Settlement Agreement Attachment A, the Settling Parties agreed to the following language for the Tariff I.P. minimum charge clause for Large Load Customers:

> Large Load Customers are subject to a minimum monthly charge for each plant equal to the sum of: (a) the Monthly Service Charge; (b) the product of the Minimum Demand Charge and the Monthly Billing Demand; (c) the product of the Step 1 Embedded Capacity Charge and the Monthly Billing Demand; and (d) the sum of the product of each demand charge in all applicable demand related riders in effect at the time and the Monthly Billing Demand. The Step 1 Embedded Capacity Charge rate will be computed as follows: (Block 1 Energy Rate less Block 2 Energy Rate) multiplied by Block 1 Energy Hours less (Minimum Demand Charge less Demand Charge).
>
> The Step 1 Embedded Capacity Charge under this tariff shall be as follows:

Tariff Code	Service Voltage	Step 1 Embedded Capacity Charge ($/kW)
327	Secondary	13.289
322	Primary	12.427
323	Subtransmission	12.271
324	Transmission	10.959

> By way of example, the Step 1 Embedded Capacity Charge, under Tariff I.P. as of November 14, 2024, for Transmission Service Voltage: ($0.05058/kWh - $0.01286/kWh) *410 hrs. - ($14.70/kW-mo. – $10.194 /kW-mo.) = $10.959/kW.

I&M witness Williamson testified the Settlement Agreement restructures I&M's original minimum charge proposal to also include demand costs embedded in the Block 1 Energy Charge through the Step 1 Embedded Capacity Charge. He explained that including the Step 1 Embedded Capacity Charge in the minimum charge computation establishes an overall higher minimum charge, which ensures greater cost recovery in the event of significantly lower levels of anticipated load and/or permanent closure than compared to I&M's original proposal. He testified that reducing the minimum billing demand from 90% to 80% allows additional operational and planning flexibility for the Large Load Customer, while the addition of the Step 1 Embedded Capacity Charge allows for greater protection to I&M and existing customers by requiring a higher minimum bill than I&M's original proposal. He also said that because demand costs are recovered through various rate adjustment mechanisms, the agreed Tariff I.P. language clarifies that "all applicable demand related riders" are included in the minimum monthly charge calculation.

As an example of the greater protection to I&M and existing customers, Mr. Williamson provided Figure AJW-1S in Petitioner's Exhibit 3. He further explained that the annual minimum bill for a 1,000 MW customer provided by the Settlement Agreement is approximately $76 million higher than under I&M's original proposal of 90% minimum demand.

OUCC witness Eckert testified that under the Settlement Agreement, Large Load Customers must pay the demand component of all applicable riders in effect at the time, thereby encompassing riders with a demand component that may hereafter be approved during the Contract Term.

CAC witness Inskeep explained the calculation of the monthly minimum charge for Large Load Customers now includes the Step 1 Embedded Capacity Charge, which will be based on the greater of 80% of the customer's contract capacity or 80% of its highest monthly billing demand from the prior 11 months. He said the inclusion of the Step 1 Embedded Capacity Charge modifies the effective monthly charge to the $275 monthly fixed charge plus an aggregate minimum demand charge totaling $35.034 per kW applied against the greater of 80% of the Large Load Customer's contract capacity or its peak demand from the prior 11 months. He said the end result is that consumers are better protected if a Large Load Customer reduces their load to much less than its contract capacity in a given month.

Mr. Inskeep provided an example of how the monthly minimum charge is impacted by the Settlement Agreement. He said a new Large Load Customer with a contract capacity of 1,000 MW and a load factor of 85% is expected to pay a monthly bill of about $41 million, or $492.3 million per year. He said under the current terms of Tariff I.P., which is based on a minimum billing at 60% of contract capacity, this customer would have a minimum bill of about $14.4 million, or $173.3 million per year. I&M, in its case-in-chief, proposed increasing this to 90%, resulting in a monthly minimum of about $21.7 million, or $260 million per year. Mr. Inskeep stated that the Settlement Agreement increases the monthly minimum bill to about $28 million, or $336.3 million per year, which is roughly double the current monthly minimum charge under Tariff I.P. *See also,* CAC Ex. 2, Table 2. He said this is a significantly higher level of protection that benefits I&M and its existing customers.

The record shows that the minimum demand charge is necessary to allow I&M to reasonably recover its cost of providing service on a monthly basis. We agree it is important to safeguard against a scenario where the Large Load Customer's contracted load does not materialize or the Large Load Customer ceases operations, particularly because I&M's Tariff I.P. rate structure recovers certain production demand costs through the first block energy charge. The Settlement Agreement reasonably addresses the concerns raised by the parties related to I&M's original proposal while maintaining, and strengthening, customer protections related to the addition of Large Load Customers to I&M's system. The settlement testimony of I&M and the CAC regarding the comparative impact of the terms of the Settlement Agreement for a Large Load Customer based on usage and load factor shows a meaningfully higher minimum monthly bill under the settlement tariff as compared to I&M's existing Tariff I.P. structure.

E. <u>Collateral Requirements</u>. In its case-in-chief, I&M proposed to include additional collateral requirements for large load customers because the size and concentration risk of these customers is unlike other customers. Only the DCC raised an objection to the proposed collateral requirements. DCC witness Higgins suggested the proposed collateral requirements be modified to state that a customer with a credit rating of at least A- from S&P and A3 from Moody's, or cash on its balance sheet equivalent to ten times the collateral requirement, be exempt from providing collateral. In rebuttal, Mr. Williamson stated that requiring both a public debt rating (Moody's/S&P), along with a liquidity covenant puts I&M in the best position to ensure that a

large load customer and/or its guarantor is willing and able to provide payment in the event that an early termination occurs.

The Settling Parties agreed that the collateral requirement I&M proposed in its Verified Petition and direct testimony should be adopted. However, the Settling Parties also agreed that a Large Load Customer with a credit rating of at least A- from S&P and A3 from Moody's and liquidity greater than ten times the collateral requirement shall be exempt from the Tariff I.P. collateral requirements. A Large Load Customer that does not have a credit rating from S&P and Moody's but maintains liquidity greater than ten times the collateral requirement (evidenced by providing quarterly financial statements and certification that on the date financial statements are provided that the Large Load Customer's liquidity meets the ten times threshold) shall be exempt from 50% of the collateral requirements not to exceed an exemption of more than $250 million. For additional clarity, the Settlement Agreement also sets forth in Section 1.A.5 how the collateral requirement will be met.

Mr. Williamson testified that this negotiated part of the settlement package is consistent with his rebuttal testimony concerning public companies that have a credit rating and puts in place additional provisions to address private companies that do not have a credit rating.

The record reflects that if a Large Load Customer was to unexpectedly exit I&M's service territory and/or system, there is potential for significant financial harm to I&M and its other customers. The record further shows that with the number of current commitments and potential future interest in I&M's system from Large Load Customers, less than a handful of customers will be the largest single sector for I&M, even greater than I&M's existing residential, commercial, and industrial customers combined. While no reasonable term can fully insulate I&M and its other customers, the agreed collateral requirements reasonably increase the requirement of I&M's current Terms and Conditions of Service and provide additional protections in the event a customer does unexpectedly cease taking service from I&M and is unable to pay its remaining charges. More specifically, the collateral requirement provision agreed to by the Settling Parties maintains I&M's proposal based on credit metrics while also allowing for potential Large Load Customers without a credit rating to offset a portion of their collateral requirement through sufficient liquidity, subject to reasonable financial documentation. This reasonably protects I&M and its other customers while providing a reasonable alternative for private companies that do not have a credit rating.

F. <u>Contractual Flexibility and Exit Fee</u>. In its case-in-chief, I&M recognized that large load customers should be provided with reasonable flexibility to reduce their maximum contract capacity during the term of the contract. I&M originally proposed that a customer would be allowed to reduce its contract capacity by up to 20% but allowed for additional flexibility in mutually agreeable circumstances that are beneficial, or at least not detrimental, to the customer, I&M, and all other customers. I&M also proposed the customer give at least five years' prior written notice of its capacity reduction. In the event of a permanent closure, I&M proposed the customer shall notify I&M within three business days of making this determination. I&M also proposed to establish a minimum five-year commitment under the tariff and provide the customer the ability thereafter to exit the contract by providing a Contract Termination Fee equal to five years of the customers' minimum bill in the event of a permanent closure.

The OUCC did not oppose I&M's Contract Termination Fee but expressed concern regarding contract capacity reductions greater than 20%. The CAC proposed a termination fee of eight years of minimum bills, and caps on contract capacity reductions. Witnesses for DCC, Google, and Amazon also challenged I&M's proposal based on various arguments as summarized in Petitioner's Exhibit 2, Figure AJW-2R. For example, Google witness Farr recommended the Commission adopt fair and transparent fees to cover foregone net revenues from the minimum demand charge if excess capacity, released by a customer, is not used; but he was critical of I&M's proposed 20% limitation on the reduction of capacity over the 20-year life of the contract and the lack of a provision for I&M's ability to use any excess capacity to serve other customers or otherwise reduce a customers' financial obligations.

The Settlement Agreement maintains a Large Load Customer's flexibility to reduce its contract capacity after the first five years without paying a capacity reduction/termination fee ("Exit Fee"). The total capacity reduction under this provision is limited to 20%, except by mutual agreement between I&M and the Large Load Customer, which I&M shall only grant in circumstances that are beneficial, or at least not detrimental, to the Large Load Customer, I&M, and all other customers.

I&M witness Williamson testified this provision is consistent with I&M's initial proposal. He said the agreed flexibility recognizes there may be situations where allowance for larger contract capacity reductions without payment of an Exit Fee would make sense, if I&M was able to avoid or offset the exposure to long-term excess capacity risk. As an example, he said if I&M has not yet acquired the long-term generation needed to serve that additional increment of load in the future and could avoid that financial commitment and cost, then it may be reasonable to accept the greater reduction to the contract capacity commitment beyond the 20%.

Mr. Williamson testified that Section I.A.6 of the Settlement Agreement also addresses the notification process necessary to reduce capacity by up to 20%. He said the Settling Parties agreed that the Large Load Customer must provide I&M with at least 42 months' notice prior to the beginning of the PJM Delivery Year for which the reduction or termination is sought. He stated this notice period will provide I&M time to incorporate such changes into its capacity planning ahead of PJM's Base Residual Auction associated with the PJM Delivery Year for which the reduction or termination is sought.

Mr. Williamson testified Section I.A.6.b of the Settlement Agreement resolves the Settling Parties' dispute regarding the Contract Termination Fee. He explained the Settling Parties agreed that a Large Load Customer may terminate its contract or reduce its contract capacity beyond 20% at any time after the first five years of the contract by giving I&M at least 42 months' written notice prior to the beginning of the PJM Delivery Year for which the reduction or termination is sought, subject to payment of an Exit Fee. He said the Exit Fee shall be due and payable to I&M upon the effective date of the contract termination or the effective date of the capacity reduction.

Mr. Williamson explained the Settling Parties agreed that the Exit Fee shall be calculated as the nominal value of the remaining Minimum Charge for the terminated/reduced capacity in excess of the 20% allowed reduction for the first year of the Exit Fee Period; and for any remaining year of the Exit Fee Period, the Exit Fee shall be calculated in the same manner as the first year, minus the OSS/PJM Rider's (or the same cost addressed in another rider's) contribution to the

Minimum Charge. He said the Exit Fee Period is defined as the Large Load Customer's then remaining Initial Contract Term, or any agreed extension, and that the Settlement Agreement establishes that the Exit Fee Period shall not be less than one year and not exceed five years.

Mr. Williamson next explained why the OSS/PJM Rider's contribution to the Minimum Charge is removed from the calculation after the first year. He stated the demand related component of the OSS/PJM Rider exists currently to recover I&M's allocated share of the zonal revenue requirement for the AEP transmission zone. He said a load's contribution to the peaks used in that allocation process will drop out or be removed from the process on a one-year lag following their reduced or ceased operations. For example, he said a load that ceased operations in 2024 would still contribute to the costs allocated to I&M during the following 2025 calendar year; and would no longer contribute to the allocation of such costs to I&M in 2026. He stated this is the reason for the wording in the Settlement Agreement regarding the OSS/PJM Rider and the minimum charge. Mr. Williamson testified that the timing in which the OSS/PJM Rider recovers demand-related costs associated with the service provided to Large Load Customers was the subject of discussion amongst the Settling Parties. Ultimately, in the interest of settlement and mitigating potential short-term negative impacts to remaining customers, the Settling Parties agreed to this condition as a component of the overall package.

Mr. Williamson said the Settlement Parties' agreed in Section I.A.6.c of the Settlement Agreement that following receipt of proper notice and through the Exit Fee Period, I&M will use reasonable efforts, consistent with its obligations as a public utility, to mitigate the Exit Fee amount by evaluating the opportunity to assign the terminated/reduced capacity to serve new Large Load Customers, to expand service to existing Large Load Customers, or otherwise secure offsetting expected revenues. He said additionally, the remainder of any mitigating amounts owed to the Large Load Customer shall be delivered to the Large Load Customer, or its designated successor, after all outstanding balances have been resolved.

Mr. Williamson reiterated I&M's goal is to avoid having excess capacity in the event of a Large Load Customer ceasing operations. He said if a Large Load Customer was to exit I&M's system, the ideal scenario would be to have another Large Load Customer continuing the service at the same location or establishing service at another location resulting in a similar ongoing long-term commitment for that capacity. Because this ideal scenario may not exist, he said reasonable efforts will be used to evaluate alternative solutions consistent with I&M's obligations. He said the resolution of this issue is reasonably designed to allow I&M to find a solution to mitigate its exposure to long-term excess capacity costs while balancing that with a Large Load Customer's interest in mitigating the Exit Fee where possible.

Mr. Williamson stated Section I.A.6.d of the Settlement Agreement sets forth an agreed dispute resolution process. He said if there is an issue concerning the calculation of the Exit Fee, that either I&M or the Large Load Customer view as in need of escalation, the Settlement Agreement provides that either entity may request escalation. He said while escalation is a common business practice, including it in the Settlement Agreement provides clarity by setting out an agreed timeline for issue resolution. He said this section also clarifies that the dispute resolution process does not limit or otherwise affect the ability of either the Large Load Customer or I&M to file a formal proceeding requesting the Commission to resolve the dispute.

Finally, Mr. Williamson discussed Section I.A.6.e of the Settlement Agreement. He said I&M originally proposed that a Large Load Customer would not assign its rights or delegate its obligations without the written consent of I&M. He said that although Amazon proposed that assignment or delegation be allowed without negotiation or approval of I&M, the Settlement Agreement reasonably resolves this issue by providing that a Large Load Customer shall not assign any of its rights or delegate any of its obligations under the Tariff I.P. contract without the written consent of I&M. An assignment or delegation in violation of this section is null and void.

OUCC witness Eckert testified that the Settlement Agreement affords contractual flexibility while mitigating the potential impact on I&M's other ratepayers by not allowing a reduction during the first five years, limiting the reduction to a total of up to 20%, and requiring at least 42 months prior written notice. He said Section I.A.6.a includes further protection for I&M's ratepayers by precluding an agreement being made to reduce a Large Load Customer's capacity by more than the 20% total without payment of a capacity reduction/termination fee if the result of that reduction is detrimental to I&M's other customers. He said this safeguard helps to ensure that the rates for other ratepayers are not adversely impacted by a mutual agreement that reduces a Large Load Customer's capacity greater than a total of 20%.

CAC witness Inskeep testified the Settlement Agreement would result in an Exit Fee totaling more than $1 billion for a 1,000 MW large load customer that discontinued service five or more years prior to the end of its Contract Term. He said this is a substantial Exit Fee providing significant protection to I&M and consumers if a Large Load Customer discontinues service, as I&M will use revenues from the Exit Fee to offset remaining costs incurred to serve the customer, protecting remaining customers from rate increases associated with the loss of the Large Load Customer. He stated the Settlement Agreement also allows the opportunity for Large Load Customers to receive a refund on their Exit Fee should I&M successfully mitigate the impacts of any reduction or discontinuation of service.

Google witness Farr identified this section as an example of how the Settlement Agreement modifications establish an appropriate degree of balance. He explained that a Large Load Customer can reduce their contract capacity beyond 20% without a fee if certain specified conditions, including I&M's agreement, are met, or if those conditions are not met, by paying an Exit Fee. He noted the Exit Fee is subject to I&M's mitigation efforts to use that capacity for other purposes that would secure offsetting revenues for I&M. He said these provisions act in harmony to provide customers with reasonable flexibility in setting, and adjusting, their contract capacity while still protecting other ratepayers and I&M. He testified it is particularly important that the Exit Fee is subject to mitigation not simply through expanding service to new or existing customers, but also through other potential means. He said this reflects a more balanced approach to setting, and mitigating, the Exit Fee by properly keeping the burden on I&M to act prudently in making resource decisions.

Amazon witness Fradette noted the Settlement Agreement provides flexibility which allows a Large Load Customer: (a) to reduce contract capacity by up to 20% without a fee upon providing notice as defined in the Settlement; and (b) to reduce contract capacity by an amount greater than 20%, upon providing notice as defined in the Settlement Agreement and subject to an Exit Fee, which can be mitigated. He testified this flexibility was critical in the overall evaluation and ensures a fair, just, and reasonable resolution for all Settling Parties.

The record reflects general recognition among the Settling Parties that contractual flexibility is important for Large Load Customers, but that such flexibility must be balanced against the potential risks to I&M and other customers in the event the Large Load Customer were to significantly deviate from its contractual capacity. While we recognize I&M's goal is to avoid having excess capacity in the event of a Large Load Customer ceasing operations, we must also recognize that the ideal scenario, in which another Large Load Customer establishes service resulting in a similar ongoing long-term commitment for that capacity, may not exist. Accordingly, it is important that safeguards be established in the event a Large Load Customer reduces its contract capacity or terminates its contract early while still expecting I&M to pursue alternative, if less than ideal, solutions.

The evidence reflects that the Settling Parties have negotiated a resolution that addresses the various stakeholder concerns and positions and maintains a reasonable balance between customer flexibility and safeguards in the event a Large Load Customer must reduce or terminate load. More specifically, we find the combination of terms found in Section I.A.6 of the Settlement Agreement, when taken as a whole, create a framework whereby a Large Load Customer can have a reasonable level of contractual flexibility while ensuring that significant reductions in capacity, or termination of load, do not detrimentally impact I&M's remaining customers. In particular, we note that the Settlement Agreement's resolution of this issue is reasonably designed to allow I&M to find a solution to mitigate I&M's exposure to long-term excess capacity costs while balancing that with a Large Load Customer's interest in mitigating the Exit Fee where possible. At the same time, the record shows that the Exit Fee provided for in the Settlement Agreement is substantial, totaling more than $1 billion for a 1,000 MW Large Load Customer that discontinues service five or more years prior to the end of its contract term. We find these Settlement Agreement provisions, working in concert, provide significant protection to I&M and customers should a Large Load Customer discontinue service. However, due to the significance of these potential obligation modifications, we find the Commission should exercise its oversight of any exit or material reduction of Large Load Customer demand that I&M responded it was not opposed to in its November 15, 2024, Docket Entry response. Accordingly, any reduction in contract capacity beyond 20% that is mutually agreed upon between I&M and the Large Load Customer must also be submitted to the Commission for its review and approval before becoming effective.

G. Special Contracts. I&M requests approval of modifications to Tariff I.P. to establish a consistent framework for the terms and conditions of basic or standard service for large load customers. I&M proposed that special contracts be utilized to address unique needs or opportunities that are not available through I&M's tariffs, if, and as, they arise. In other words, under I&M's original proposal, large load customers could receive electric service under Tariff I.P. and also have a special contract to adjust their monthly electric service charges for other services, such as demand response, sustainability programs, or strategic partnerships, as is done today for several of I&M's Tariff I.P. customers.

Amazon, DCC, and Google contended that, for various reasons, it is preferrable to serve large loads through a negotiated special contract. The CAC agreed with I&M's proposal to serve large load customers under a published tariff rather than through individually negotiated special contracts because it viewed the tariff approach as more transparent, administratively efficient, and fair to existing and potential new customers.

Mr. Williamson testified this issue was the subject of substantial discussion during settlement negotiations. He said ultimately, the Settling Parties recognized that Indiana's regulatory framework allows customer-specific contracts to be brought to the Commission. He stated the Settlement Agreement balances the differing views of the parties and provides that special contract requests from potential and existing Large Load Customers shall continue to be addressed in a manner consistent with I&M's existing practices. He noted the Settlement Agreement also provides that I&M will bring those special contracts to the Commission for review and approval in accordance with Ind. Code §§ 8-1-2-24 and -25.

Google witness Farr testified that the Settlement Agreement definitively states that I&M will treat requests for special contracts consistent with the statutory provisions allowing for such contracts. He explained although I&M never proposed to eliminate such contracts, its initial proposal could be read as a limitation on the conditions under which I&M would consider this approach. He said the language in the Settlement Agreement is important to preserve opportunities for collaboration and develop shared solutions for providing service to Large Load Customers beyond the limited range of areas identified by I&M in its initial proposal.

The Commission finds the Settlement Agreement provision related to special contracts provides clarity with respect to service under Tariff I.P. and appropriately recognizes Indiana's regulatory framework that allows customer-specific contracts to be brought to the Commission. Ind. Code §§8-1-2-24 and -25.

H. Full Planning Studies. Section I.A.8 of the Settlement Agreement provides that Full Planning Studies, including steady-state and dynamic studies, required because of the potential addition of a Large Load Customer shall be paid solely by the Large Load Customer.

CAC witness Inskeep testified that this term is one of several ways the Settlement Agreement addresses concerns raised about the allocation of costs. He said this term helps alleviate concerns that portions of planning study costs could be allocated to other ratepayers in the future.

Based on the evidence presented and the overall Settlement Agreement, we find this term reasonable.

I. Collaboration. Section I.A.9 of the Settlement Agreement provides that the Settling Parties will work collaboratively on topics of interest, namely a Clean Transition Tariff, Load Shedding Events, and Demand Response.

With respect to the Clean Transition Tariff, Section I.A.9.a of the Settlement Agreement provides I&M will work collaboratively with the Settling Parties to develop a new customer program tariff proposal that enables participants to support investment in carbon-free resources while ensuring that all program costs are covered by program participants and remaining consistent with the Five Pillars.

Google witness Farr testified that the Clean Transition Tariff is an optional customer program tariff proposal that enables participants to support investment in carbon-free resources, while ensuring that participating customers cover the full cost of those investments. Acknowledging that I&M could not commit to proposing such a program, Mr. Farr said I&M's willingness to work with the Large Load Customers and other Settling Parties in the potential

development of such a program is important because it shows an understanding of the need to work together to address the complexities inherent in addressing the energy transition and customers' own business objectives.

The Settlement Agreement also provides a schedule for updating the Commission on these discussions. More specifically, the Settlement Agreement states I&M will target October 1, 2025, as the date for I&M to petition the Commission for approval of a proposal. I&M retains the right to make the ultimate decision as to whether to seek approval and its decision will be informed by the collective support for the proposal among the collaborative participants. If I&M elects not to seek approval of a proposal, the Settlement Agreement provides that I&M will notify the Commission through a compliance filing in this Cause, explaining its decision and providing the Commission with comments solicited from the collaborating participants regarding their position on the proposal.

With respect to Load Shedding Events and Demand Response, the Settlement Agreement acknowledges that I&M will continue to prioritize public safety in its emergency load reduction plans. I&M witness Williamson testified the Settlement Agreement provides that I&M will convene one or more meetings of the Settling Parties to discuss: (1) I&M's emergency response procedures, including required system actions that would be necessary to respond to an emergency load shedding event required by PJM that is caused by deficiencies in either transmission and/or generation capacity and consider the potential need to modify such procedures due to the Large Load Customers; and (2) existing and potential demand response opportunities for Large Load Customers.

Mr. Williamson noted the Settling Parties welcome a Commission representative to participate in this discussion. He said I&M will convene the initial meeting within 90 days of a final Commission order approving this Settlement Agreement and will file a report in this proceeding upon conclusion of the discussion. He said these Settlement Agreement terms and the associated activities serve to reasonably address important concerns and interests of various Settling Parties in a collaborative manner.

While the Commission need not approve the Settling Parties' agreement to work collaboratively with respect to a Clean Transition Tariff, Load Shedding Events, and Demand Response, we recognize and appreciate the parties' efforts to address utility service issues important to customers.

J. <u>Reporting</u>. CAC witness Inskeep made specific recommendations regarding ongoing reporting, which he proposed occur quarterly. Mr. Inskeep's testimony also raised concerns about transparency with these new loads, and nondisclosure agreements between CAC and the data center intervenors. On rebuttal, I&M indicated an understanding of the CAC's interest in large load customers. However, I&M witness Williamson expressed concern about the frequency of the reporting; the fact that I&M already reports on numerous matters; the importance of additional reporting requirements being clear, having a defined purpose, and providing a benefit; and the need to protect confidential and competitively sensitive information.

The Settling Parties agreed that I&M will report to the Commission on a semi-annual basis the specific information related to Large Load Customers enumerated in Section I.A.10 of the Settlement Agreement. The Settling Parties further agreed that the confidential information in the report would be provided subject to protection from public disclosure, and the confidential portions of the report would not be provided to the Large Load Customers or other competitively interested stakeholders. However, the confidential portion of the report would be provided to the OUCC and CAC subject to agreed procedures (or, in the absence of agreement, Commission ordered procedures) for the protection of the confidential information.

The first semi-annual report will be filed within six months of a final Commission order approving the Settlement Agreement. Also, upon Commission request, copies of executed electric service agreements and transmission letters of agreements shall also be provided to the Commission, subject to the protection of confidential information. Such information will also be provided to the OUCC and CAC subject to agreed-upon or, in the absence of agreement, Commission ordered, terms of protection of the confidential information. As is the case with the underlying reports, the confidential documents will not be provided to the Large Load Customers or other competitively interested stakeholders.

Section I.A.10.e of the Settlement Agreement addresses certain mechanics associated with the agreed reporting, including an agreement to work together on the terms of non-disclosure agreements as well as the content and format of the report. And if agreement cannot be reached, a request to establish such terms on these matters may be made to the Commission. Additionally, Section I.A.10.f clarifies the scope of the negotiated resolution—that the Settlement Agreement does not limit the ability of the Commission or any Settling Party to seek information in future proceedings or to request modification or discontinuance of the reporting requirements.

I&M witness Williamson testified that the Settling Parties' agreement on reporting provides for a frequency that is less often than CAC originally recommended and more often than the annual reporting preferred by I&M. He said importantly, the agreed reporting addresses the protection of confidential and competitively sensitive information to be reported, which extends to public disclosure as well as to disclosure to data centers or other entities with a competitive interest.

Mr. Williamson stated that due to the confidential and competitively sensitive nature of the information involved, it was challenging to wrestle with the desire for transparency and reporting. He said from I&M's perspective, as part of the negotiated settlement package, the reporting provisions reasonably balance the divergent concerns of the parties and provide a path for the Commission to resolve disputes on the terms of nondisclosure agreements and the content of public versions of the reports if necessary.

CAC witness Inskeep testified that the agreed upon reporting will provide, at a more frequent cadence, consumer advocates and the Commission with additional information about the electricity and capacity needs of Large Load Customers, notices by those customers to reduce their contract capacity, Exit Fees assessed by I&M, a status update on the "queue" of Large Load Customers in I&M's service territory, and summaries of investments made by I&M to serve Large Load Customers. He said the CAC is especially supportive of the provision requiring the Settling

Parties to collaborate on a non-disclosure agreement and the content and format of a public version of the report.

The record shows the Settling Parties have agreed to a set of reporting requirements that, taken as a whole, provide information regarding the addition of Large Load Customers in I&M's service area. The record further shows that protection of the confidential information to be submitted in the semi-annual reports is reasonable. The Settling Parties also agreed to the filing in this Cause of a joint motion or other request in accordance with 170 IAC 1-1.1-4(i)(2) to support the confidential treatment of specific information identified in the Settlement Agreement. We find the Settling Parties' agreed reporting requirements and procedures to be reasonable.

K. Grid-Enhancing Technologies. Section I.A.11 of the Settlement Agreement provides that following the submittal of its 2024 Integrated Resource Plan ("IRP") and prior to I&M's next IRP, I&M will conduct a study, with input from interested Settling Parties as to the scope of the study and with opportunities for stakeholder feedback, to evaluate the potential of grid-enhancing technologies. The results of the study, to the extent applicable, will be shared (subject to protection of confidential information) as part of the IRP stakeholder process and may be incorporated into the resource options considered in I&M's next IRP(s).

I&M witness Williamson testified that the discussion by witnesses in this Cause about the impact of hyper-scalers on transmission shows the importance of transmission planning and efficiency. He said to this end, the Settling Parties agreed to obtain more information for potential incorporation into I&M's IRP process.

Google witness Farr testified that I&M has committed to conduct a study to evaluate the potential of grid-enhancing technologies, including sensors, power flow control devices, and analytical tools that maximize the transmission of electricity across the existing system. He said these technologies offer the potential to expand transmission capacity in a timely and cost-efficient manner and are an important part of building a grid that is reliable and affordable. He stated this commitment under the Settlement Agreement furthers the opportunities for collaborative approaches among parties to address future investment needs.

The record includes much discussion by the Settling Parties' witnesses concerning the potential impacts of hyper-scalers on the transmission system and the importance of utility transmission planning. While we need not approve the Settling Parties' agreement concerning the exploration of grid-enhancing technology, we again recognize the parties' willingness to work collaboratively to address utility planning and service issues.

L. Grid Reliability and Addition of Large Customer Load. Section I.A.12 of the Settlement Agreement provides that I&M will meet with interested stakeholders to discuss the process and implications of interconnecting Large Load Customers, including but not limited to the appropriate bar for entry into I&M's queue, queue management, interconnection requirements, and load ramping requirements. I&M also agreed to make a good faith effort to implement reasonable improvements that are identified through the discussion.

I&M witness Williamson testified that during settlement discussions, CAC voiced a desire to learn more about grid reliability as it relates to the addition of the Large Load Customers. He described the Settlement Agreement provision addressing CAC's desire and noted I&M also agreed to make a good faith effort to implement reasonable improvements to this process that are identified from this discussion.

M. Cost Allocation. Under Section I.A.13 of the Settlement Agreement, the Settling Parties agree that the Settlement Agreement does not limit the ability of the Commission or the Settling Parties to address cost allocation issues in a subsequent proceeding.

I&M witness Williamson testified that, from I&M's perspective, this provision is reasonable because the appropriate place to address cost allocation concerns is in the context of a case where I&M is proposing a change in its rates.

CAC witness Inskeep stated this provision allows CAC and other Settling Parties to raise cost allocation issues in other cases, such as rate cases and tracker filings. He said this is a reasonable resolution to a contested issue in this case because it allows this important issue to be more extensively examined in appropriate proceedings.

The evidence demonstrates that the Settling Parties found it preferrable to delay addressing cost allocation issues to subsequent proceedings, such as a future tracker filing or rate case, rather than establishing a cost allocation or specific methodology to be used for Large Load Customers. While the Commission does not find such agreement to be unreasonable when considering the Settlement Agreement as a whole, we also recognize the additional work that will be necessary to address cost allocation so as to avoid it becoming a contested issue in every future I&M rate-related filing. This concern was reflected in our November 14, 2024 Docket Entry question. We encourage I&M to add this issue to its other formal collaborative agreements set forth in the Settlement Agreement to foster solutions that could serve to preserve the administrative efficiency of future tracker filings.

N. Cost of Service Study. The Settlement Agreement provides that prior to filing its next base rate case, I&M agrees to prepare an analysis applying a 12 coincident peak ("CP") demand allocator to the class cost-of-service study ("CCOSS"). However, the Settling Parties agree that I&M is not obligated to propose use of the 12 CP CCOSS analysis or take a position in support of or against the analysis in its next base rate case. I&M will include the analysis in its work papers filed with the Commission in its next base rate case and all parties, including I&M, will have the opportunity to take any position with respect to the analysis.

CAC witness Inskeep testified that the 12 CP study could be an incremental step towards improving existing cost allocation methodologies. He said CAC appreciates I&M's willingness to analyze this alternative cost allocation method and present its analysis as part of its next rate case, which can help lay the foundation to a constructive examination of this issue.

The overall terms of the Settlement Agreement and the supporting settlement testimony show the agreement with respect to the cost-of-service study provides a reasonable opportunity for I&M and interested parties to gain additional information in advance of I&M's next rate case to foster the administrative efficiency of that proceeding.

O. Contribution to INCAA. Section I.A.15 of the Settlement Agreement provides that Amazon, Microsoft, and Google will provide, no later than six months after their respective service energization within I&M's service territory, annual funding for a period of five years to INCAA to support income-qualified customers in Indiana.

OUCC witness Eckert testified that Amazon, Microsoft, and Google agreed to contribute to INCAA to provide customer benefits. He noted the funding will support income-qualified customers in Indiana, including supporting health and safety to enhance weatherization opportunities.

CAC witness Inskeep testified that the Settlement Agreement provides that Amazon, Microsoft, and Google each agree that no later than six months after their respective service energization within I&M's service territory, each will provide $500,000 per year for five years to INCAA to support income-qualified customers in Indiana. He said Large Load Customers are currently able to opt-out of utility demand-side management programs and thereby avoid contributing funding to these beneficial customer programs. He explained as a long-time advocate for energy efficiency and programs to improve affordability for low-income customers, CAC is particularly appreciative that the Settlement Agreement includes this substantial funding, totaling $7.5 million, for assistance to these customers.

Google witness Farr explained this funding will help INCAA provide important energy assistance to customers, including assisting with health and safety investments so that energy efficiency measures can move forward. He said this helps ensure that some customers will have access to a greater range of services than before, offering improvements to their homes and quality of life. He stated this term aligns with the three companies' own, publicly stated, interest in pursuing efficiency; and, more importantly, is a further sign of their long-term commitment to Indiana, and the communities in which they are establishing their physical presence.

The record reflects that, as part of the overall Settlement Agreement, Amazon, Microsoft, and Google agree that no later than six months after their respective service energization within I&M's service territory, each will provide annual funding for a period of five years to INCAA to support income-qualified customers in Indiana, including supporting health and safety to enhance weatherization opportunities. The respective Settling Parties' agreement on this matter will provide valuable long-term support to enhance the quality of life for income-qualified customers in Indiana.

P. Other Matters. Section I.A.16 of the Settlement Agreement provides that any matters not addressed by the Settlement Agreement will be adopted as proposed by I&M in its direct case. I&M witness Williamson testified that this type of provision is commonly included in I&M's settlement agreements before this Commission. The Commission notes that I&M's intent to align its generation cost incurrence and cost recovery from Large Load Customers reflected in its response to our November 14, 2024 Docket Entry shall be considered an I&M proposal.

Q. Tariff. Mr. Williamson testified that Settlement Agreement Attachment A is a clean copy of the Tariff I.P. updated to reflect the terms of the Settlement Agreement. He also provided a redlined document comparing the agreed tariff provisions to the ones originally proposed by I&M in Petitioner's Exhibit 3, Attachment AJW-1S.

R. Ind. Code §§ 8-1-2-0.5 and -0.6. I&M witness Williamson testified that although the current filing does not fall within the scope of the matters for which the Commission has indicated utilities should provide information regarding the Five Pillars, he said I&M nonetheless recognized that the service to the Large Load Customers should align with the Five Pillars. He explained that as a regulated utility, I&M has an obligation to provide a safe and reliable supply of electricity for its customers in accordance with Indiana's energy policy. He said the Settlement Agreement supports system reliability, resiliency, and stability by providing I&M and its customers with the financial assurances and appropriate tariff protections needed to make the significant and necessary financial commitments in generation resources and the transmission system for all I&M customers. He explained the Settlement Agreement supports affordability by providing Large Load Customers with access to the Tariff I.P. rate under normal business conditions and benefiting all customers as a result of increased load. He testified in the event of a business disruption by the Large Load Customers that causes them to deviate from their plans, the agreed tariff modifications provide protections for existing customers to minimize adverse financial impacts. He said with respect to environmental sustainability, the agreed tariff modifications will provide I&M with the financial assurances needed to make appropriate investments in a diverse portfolio of generation resources, including clean energy resources. He stated additionally, the Settlement Agreement provides for collaboration on a Clean Transition Tariff that would seek to advance clean resources for Hoosier customers.

OUCC witness Eckert testified that the Tariff I.P. modifications agreed upon in the Settlement Agreement better address the affordability objective identified in the Five Pillars and better protect I&M's other customers from the prospect of stranded costs from load reductions by Large Load Customers. More specifically, he identified the following terms as addressing the affordability pillar: (1) Mandatory Contract Term; (2) Monthly Minimum Billing Demand; (3) Minimum Charge; (4) Collateral Requirement; (5) Contractual Flexibility and Exit Fees and said these terms will provide protection to I&M's customers from the risks that attend the addition of the Large Load Customers to I&M's system. Mr. Eckert testified the Settlement Agreement also addresses reliability, resiliency, and stability. He explained how the terms related to load shedding events and demand response, grid-enhancing technologies, and grid reliability highlight how I&M and the other Settling Parties can work together to achieve reliability, resiliency, and stability. Finally, Mr. Eckert noted the Settlement Agreement addresses environmental sustainability through an agreed collaboration to develop a new customer program tariff proposal that enables participants to support investment in carbon-free resources while ensuring that all program costs are covered by program participants.

CAC witness Inskeep testified that the Settlement Agreement is consistent with the Five Pillars and will help to address reliability, affordability, resiliency, stability, and environmental sustainability as Large Load Customers come to I&M's service territory. He said the strengthened contract provisions, such as the longer contract term, minimum charge, and Exit Fee, will provide increased certainty and stability to I&M's revenues, which will allow I&M to make investments necessary for reliability, resiliency, and stability. He said these and other Settlement Agreement provisions also guard against potential cost shifts if a Large Load Customer uses less electricity than planned or discontinues service early, which is a substantial benefit to customer affordability.

Finally, Mr. Inskeep testified the Settlement Agreement will promote environmental sustainability through (1) funding provided to INCAA that will increase low-income weatherization opportunities; (2) collaboration between parties on demand response and a Clean Transition Tariff, which could help accelerate the adoption of environmentally sustainable sources of generation; and (3) collaboration between parties on grid enhancing technologies.

S. Conclusion. The testimony supporting the Settlement Agreement explains why the Settling Parties believe the Commission should find the Settlement Agreement, when considered as a whole, is reasonable and in the public interest. As noted above, all customer classes, as well as a few Large Load Customers, were represented by the Settling Parties through the settlement discussions.

The record shows I&M is beginning to provide service to Large Load Customers and the level of service required is likely to grow rapidly. Therefore, it is important that a service option be provided pursuant to terms and conditions that serve to reasonably confront the unprecedented size and unique risks of the Large Load Customers and serve to protect I&M and its other customers. The tariff approach presented is a reasonable and balanced effort to provide a tariff for standard electric service, which provides financial protection and customer flexibility, and is a transparent, consistent offering across similarly situated customers. Importantly, we find the Tariff IP modifications to offer improved ratepayer protections as compared to I&M's existing tariff. Notably, the agreed-upon tariff modifications do not preclude I&M from entering into special contracts with Large Load Customers and submitting those agreements for Commission approval as an alternative or complementary approach that might further enhance utilization of the Large Load Customer characteristics or provide further ratepayer protections. In summary, the modified tariff agreed upon in the Settlement Agreement is an improvement to I&M's existing tariff offering but we look forward to ongoing improvement efforts.

Based upon our review of the record as a whole and consideration of the Settlement Agreement terms in totality and the supporting testimony and exhibits, the Commission finds that the Settlement Agreement as modified herein represents a just and reasonable resolution of the issues. Accordingly, the Settlement Agreement as discussed and modified herein is approved.

12. Effect of Settlement Agreement. The Settling Parties agreed that the Settlement Agreement and each term, condition, methodology, and exclusion contained therein reflect a fair, just, and reasonable resolution and compromise for the purpose of settlement in this proceeding, and that the Settlement Agreement shall not constitute, and shall not be used as, precedent or be deemed an admission by any person or entity in any other proceeding before the Commission except to the extent necessary to implement or enforce the Settlement Agreement. Consequently, regarding the future citation of the Settlement Agreement or of this Order, the Commission finds our approval herein should be construed in a manner consistent with our finding in *Richmond Power & Light*, Cause No. 40434 (IURC Mar. 19, 1997).

13. Confidential Information. Motions seeking a determination that designated confidential information involved in this proceeding be exempt from public disclosure under Ind. Code § 8-1-2-29 and Ind. Code ch. 5-14-3 were filed by Amazon on August 26, 2024, and by I&M on November 4, 2024. Each request was supported by affidavit showing certain documents to be offered into evidence contained trade secret information as defined by Ind. Code § 24-2-3-2 and

within the scope of Ind. Code § 5-14-3-4(a)(4). The requests were granted by the Presiding Officers on September 6, 2024, and November 6, 2024, respectively, finding such information confidential on a preliminary basis. Subsequently, the parties submitted the designated confidential information.

After reviewing the designated confidential information, we find all such information is trade secret as defined by Ind. Code § 24-2-3-2. This information has independent economic value from not being generally known or readily ascertainable by proper means. Each moving party takes reasonable steps to maintain the secrecy of the information, and disclosure of such information would cause harm to the moving party. Therefore, we find that the information should be exempted from the public access requirements contained in Ind. Code ch. 5-14-3 and Ind. Code § 8-1-2-29 and held confidential and protected from public disclosure by the Commission.

Additionally, on December 12, 2024, the Settling Parties submitted a Joint Motion requesting that designated customer-specific and confidential information to be submitted in accordance with the reporting requirements set forth in the Settlement Agreement be exempt from public disclosure under Ind. Code § 8-1-2-29 and Ind. Code ch. 5-14-3. The Joint Motion was supported by affidavits from I&M witness Williamson and from Ms. Amanda Peterson Corio, Director of Clean Energy and Power at Google, and requests that the Commission's Order in this Cause determine that the confidential versions of the semi-annual Large Load Customer reports are exempt from public disclosure to permit I&M to submit the reports under seal.

We find it administratively efficient to address and approve the Settling Parties' request now, rather than require the Settling Parties to support each report on a filing-by-filing basis, as it is reasonably anticipated that the types of confidential information to be provided in each report will remain consistent. Based on our review of the description of the information to be provided in the semi-annual reports, we find that such information qualifies as trade secret and should be exempted from the public access requirements contained in Ind. Code ch. 5-14-3 and Ind. Code § 8-1-2-29 and held confidential and protected from public disclosure by the Commission.

IT IS THEREFORE ORDERED BY THE INDIANA UTILITY REGULATORY COMMISSION that:

1. The Settlement Agreement, a copy of which is attached to this Order, is approved as modified herein.

2. I&M's proposed Tariff I.P., as modified by the Settlement Agreement and shown in Settlement Agreement Attachment A, is approved as set forth herein.

3. Any reduction in contract capacity beyond 20% that is mutually agreed upon between I&M and the Large Load Customer must also be submitted to the Commission for its review and approval before becoming effective.

4. Prior to implementing its revised Tariff I.P., I&M shall file the tariff under this Cause for approval by the Commission's Energy Division. Such tariff shall be effective on or after the Order date subject to Division review and agreement.

5. The information submitted or to be submitted under seal in this Cause pursuant to the parties' requests for confidential treatment, including the confidential versions of the Large Load Customer reports, is determined to be confidential trade secret information as defined in Ind. Code § 24-2-3-2 and shall be held as confidential and exempt from public access and disclosure pursuant to Ind. Code §§ 5-14-3-4 and 8-1-2-29.

6. I&M shall file semi-annual Large Load Customer reports under this Cause consistent with the Settlement Agreement. I&M shall file its first report within six months of the date of this Order.

7. I&M is directed to include the 12 CP CCOSS analysis in its work papers filed with its next base rate case.

8. This Order shall be effective on and after the date of its approval.

HUSTON, BENNETT, FREEMAN, VELETA AND ZIEGNER CONCUR:

APPROVED FEB 19 2025

I hereby certify that the above is a true and correct copy of the Order as approved.

Regina K. Joyner

Digitally signed by Regina K. Joyner
Date: 2025.02.19 10:21:23 -05'00'

on behalf of
Dana Kosco
Secretary of the Commission

STATE OF INDIANA

INDIANA UTILITY REGULATORY COMMISSION

IN THE MATTER OF THE VERIFIED PETITION OF INDIANA MICHIGAN POWER COMPANY FOR APPROVAL OF MODIFICATIONS TO ITS INDUSTRIAL POWER TARIFF – TARIFF I.P.	)))))	**CAUSE NO. 46097** **APPROVED FEB 19 2025**

CONCURRING OPINION OF CHAIRMAN JAMES F. HUSTON AND COMMISSIONER WESLEY R. BENNETT

It is impossible to ignore the changing environment with respect to large load customers. Large load customers are by far the most unique of all customers in the amount of electricity they consume, the risk they pose to a system should that load change suddenly, and the cost of investment needed to serve that load as utilities seek to fulfill their obligation to serve. The legislature may well have something to say about future treatment.

STATE OF INDIANA

INDIANA UTILITY REGULATORY COMMISSION

IN THE MATTER OF THE VERIFIED PETITION OF INDIANA MICHIGAN POWER COMPANY FOR APPROVAL OF MODIFICATIONS TO ITS INDUSTRIAL POWER TARIFF – TARIFF I.P.	**)**	**CAUSE NO. 46097**

STIPULATION AND SETTLEMENT AGREEMENT

Indiana Michigan Power Company ("I&M" or "Company"), the Indiana Office of Utility Consumer Counselor ("OUCC"), and all the Intervenors in this Cause, namely: Citizens Action Coalition of Indiana, Inc. ("CAC"), Amazon Data Services, Inc. ("Amazon"), Data Center Coalition ("DCC"), Google, LLC ("Google"), and Microsoft Corporation ("Microsoft"), (collectively the "Settling Parties" and individually "Settling Party"), solely for purposes of compromise and settlement and having been duly advised by their respective staff, experts and counsel, stipulate and agree the terms and conditions set forth below represent a fair, just and reasonable resolution of the matters set forth below, subject to their incorporation by the Indiana Utility Regulatory Commission ("IURC" or "Commission") into a final, non-appealable order ("Final Order") [1] without modification or further condition that may be unacceptable to any Settling Party. If the Commission does not approve this Stipulation and Settlement Agreement ("Settlement Agreement"), in its entirety, the entire Settlement Agreement shall be null and void and deemed withdrawn, unless otherwise agreed to in writing by the Settling Parties.

I. TERMS AND CONDITIONS.

A. The Settling Parties agree that I&M's proposed modifications to I&M Tariff Industrial Power ("Tariff I.P.") shall be approved as modified below and as shown in Settlement Agreement Attachment A, which sets forth the revised Tariff I.P. reflecting the Settlement Agreement Terms.

1. **Applicability:** Terms below shall apply to customers taking service on I&M Tariff I.P. with contract capacity greater than or equal to 70 MW at an individual plant or 150MW on an aggregated basis ("Large Load Customer"). The Company will exercise reasonable discretion when choosing to aggregate premises, with such discretion based on factors including, but not limited to, premises sharing one or more of the following: common owner(s), a common parent company, common local electrical infrastructure, and common control. Large Load Customer's Initial Contract

[1] "Final Order" as used herein means an order issued by the Commission as to which no person has filed a Notice of Appeal within the thirty-day period after the date of the Commission order.

Term, load ramp, Load Ramp Period, contract capacity, and other terms of service under this Tariff will be defined in the Electric Services Agreement(s) ("ESA(s)") executed between the Company and Large Load Customer. These terms shall only apply to new load, or an expansion of existing load, occurring on or after January 1, 2024.

2. **Mandatory Term:** The Large Load Customer's Initial Contract Term will be made for a period of not less than 12 years. A Large Load Customer may designate a Load Ramp Period, which can be no greater than five years. If a Load Ramp Period is designated by the Large Load Customer, the Initial Contract Term shall commence after the Load Ramp Period ends. The Load Ramp Period is the later period of time from when: (a) electric service is available to the Large Load Customer or (b) the Large Load Customer is scheduled to begin taking electric service, until the time the Large Load Customer's maximum contract capacity is billed. The Contract Term is the Load Ramp Period plus the Initial Contract Term.

3. **Monthly Billing Demand:** As shown by Settlement Agreement Attachment A, the proposed Tariff I.P. Monthly Billing Demand clause for Large Load Customers will be replaced by:

> The Monthly Billing Demands for Large Load Customers in kW for each plant shall be taken each month as the single-highest 15-minute integrated peak in kW, as registered at such plant during the month by a demand meter or indicator, subject to the Off-Peak Hour Provision, but the monthly demand so established shall in no event be less than the greater of (a) 80 percent of the Large Load Customer's contract capacity specified for the applicable time period of the Contract Term; or (b) 80 percent of the Large Load Customer's highest previously established Monthly Billing Demand during the past 11 months. The Metered Voltage adjustment, as set forth above, shall not apply to the Large Load Customer's minimum Monthly Billing Demand.

4. **Minimum Charge:** As shown by Settlement Agreement Attachment A, the proposed Tariff I.P. Minimum Charge clause for Large Load Customers will be replaced by:

> Large Load Customers are subject to a minimum monthly charge for each plant equal to the sum of: (a) the Monthly Service Charge; (b) the product of the Minimum Demand Charge and the Monthly Billing Demand; (c) the product of the Step 1 Embedded Capacity Charge and the Monthly Billing Demand; and (d) the sum of the product of each

demand charge in all applicable demand related riders in effect at the time and the Monthly Billing Demand. The Step 1 Embedded Capacity Charge rate will be computed as follows: (Block 1 Energy Rate less Block 2 Energy Rate) multiplied by Block 1 Energy Hours less (Minimum Demand Charge less Demand Charge).

The Step 1 Embedded Capacity Charge under this tariff shall be as follows:

Tariff Code	Service Voltage	Step 1 Embedded Capacity Charge ($/kW)
327	Secondary	13.289
322	Primary	12.427
323	Subtransmission	12.271
324	Transmission	10.959

By way of example, the Step 1 Embedded Capacity Charge, under Tariff I.P. as of November 14, 2024, for Transmission Service Voltage: ($0.05058/kWh - $0.01286/kWh) *410 hrs - ($14.70/kW-mo – $10.194 /kW-mo) = $10.959/kW.

5. **Collateral Requirements:** The Settling Parties agree the Collateral Requirement I&M proposes in its Petition and Direct Testimony shall be adopted, however, a Large Load Customer with a credit rating of at least A- from S&P and A3 from Moody's and liquidity greater than ten times the Collateral Requirement shall be exempt from the Collateral Requirements. A Large Load Customer that does not have a credit rating from S&P and Moody's but maintains liquidity greater than ten times the Collateral Requirement (evidenced by providing quarterly financial statements and certification that on the date financial statements are provided that the Large Load Customer's liquidity meets the ten times threshold) shall be exempt from 50 percent of the Collateral Requirements not to exceed an exemption of more than $250 million. The Settling Parties agree the Collateral Requirement must be provided in one or more of the following forms:

   a. A guarantee from the ultimate parent or a corporate affiliate of the Large Load Customer for the full Collateral Requirement, so long as the guarantor has both (a) a credit rating of at least A- from S&P and A3 from Moody's and (b) liquidity greater than ten times the Collateral Requirement; or

   b. A standby irrevocable letter of credit ("Letter of Credit") for the full Collateral Requirement. The Letter of Credit must be issued by a U.S. bank or the U.S.

branch of a foreign bank, which is not affiliated with the Large Load Customer or its guarantor, with a Credit Rating of at least A- from S&P and A3 from Moody's. Such security must be issued for a minimum term of 360 days. The Large Load Customer must cause the renewal or extension of the security for additional consecutive terms of 360 days or more no later than 30 days prior to each expiration date of the security. If the security is not renewed or extended as required herein, the Company will have the right to draw immediately upon the Letter of Credit and be entitled to hold the amounts so drawn as security. The Letter of Credit must be in a format acceptable to and approved by the Company; or

c. Cash for the full Collateral Requirement.

6. **Contractual Flexibility:** As shown in Settlement Agreement Attachment A, the Settling Parties agree Tariff I.P. shall provide contract flexibility as follows:

a. Large Load Customer may, without payment of an Exit Fee or any penalty, reduce its contract capacity at any time after the first five years by up to 20%, in total, by giving I&M at least 42 months written notice prior to the beginning of the PJM Delivery Year for which the reduction is sought. For the avoidance of doubt, regardless of the number of notices provided, the total capacity reduction under this provision 6(a) shall not exceed 20%, unless by mutual agreement between the Large Load Customer and the Company, which the Company shall only grant in circumstances that are beneficial, or at least not detrimental, to the Large Load Customer, the Company, and all other customers.

b. Large Load Customer may terminate its contract or reduce its contract capacity beyond 20% at any time after the first five years of the contract by giving I&M at least 42 months written notice prior to the beginning of the PJM Delivery Year for which the reduction or termination is sought, subject to payment of a capacity reduction/termination fee ("Exit Fee"). The Exit Fee shall be due and payable to I&M upon the effective date of the contract termination or the effective date of the capacity reduction. The Exit Fee shall be calculated as the nominal value of the remaining Minimum Charge for the terminated/reduced capacity in excess of the 20% allowed reduction for the first year of the Exit Fee Period; and for any remaining year of the Exit Fee Period the Exit Fee shall be calculated in the same manner as the first year, minus the OSS/PJM Rider's (or the same cost addressed in another rider's) contribution to the Minimum Charge. The Exit Fee Period is defined as the

Large Load Customer's then remaining Initial Contract Term, or any agreed extension. The Exit Fee Period shall not be less than one year and shall not exceed five years.

c. Following receipt of proper notice, through the Exit Fee Period, I&M will use reasonable efforts, consistent with its obligations as a public utility, to mitigate the Exit Fee amount owed or paid by the Large Load Customer by evaluating the opportunity to assign the terminated/reduced capacity to serve new Large Load Customers, to expand service to existing Large Load Customers, or otherwise secure offsetting expected revenues. The remainder of any mitigating amounts owed to the Large Load Customer shall be delivered to the Large Load Customer, or its designated successor, after all outstanding balances have been resolved.

d. If there is an issue concerning the calculation of the Exit Fee or delivery of any mitigation amounts, that either I&M or Large Load Customer view as in need of escalation, either I&M or Large Load Customer may request escalation. Such request shall be made in writing and within 14 business days of the Large Load Customer being notified regarding the Exit Fee calculation. In such instance, management representatives for I&M and for the Large Load Customer will discuss and seek to resolve any issues. The management discussion shall occur within 14 business days of a request, unless otherwise agreed to in writing by I&M and Large Load Customer. I&M and Large Load Customer agree to use this escalation process in good faith, escalating only those matters appropriate for management's consideration. This dispute resolution process does not limit or otherwise affect the ability of either Large Load Customer or the Company to file a formal proceeding requesting the Commission to resolve the dispute.

e. Large Load Customer shall not assign any of its rights or delegate any of its obligations under the Contract without the written consent of the Company. An assignment or delegation in violation of this Section is null and void.

7. **Special Contracts:** Special contract requests from potential and existing Large Load Customers shall continue to be addressed by I&M consistent with the Company's existing practices. I&M will bring those special contracts to the Commission for review and approval in accordance with Indiana Code §§ 8-1-2-24 and -25.

8. **Full Planning Studies:** Full Planning Studies, including steady-state and dynamic studies, required because of the potential addition of a Large Load Customer shall be paid solely by the Large Load Customer.

9. **Collaboration:**

    a. Clean Transition Tariff: I&M will work collaboratively with the Settling Parties to develop a new customer program tariff proposal that enables participants to support investment in carbon-free resources while ensuring that all program costs are covered by program participants and remaining consistent with the Five Pillars in Ind. Code § 8-1-2-0.6. I&M will target October 1, 2025 as the date for I&M to petition the Commission for approval of a proposal. I&M retains the right to make the ultimate decision as to whether to file the proposal with the Commission for approval and this decision will be informed by the collective support for the proposal among the collaborative participants. If I&M elects not to petition the Commission for approval of a proposal, I&M will notify the Commission through a compliance filing in this Cause. In doing so, I&M will explain its decision and provide the Commission with comments solicited from the collaborating participants regarding their position on the proposal.

    b. Load Shedding Events and Demand Response: I&M will continue to prioritize public safety in its emergency load reduction plans. I&M will convene a meeting, and more if needed, of the Settling Parties to discuss 1) the Company's emergency response procedures, including required system actions that would be necessary to respond to an emergency load shedding event required by PJM that is caused by deficiencies in either transmission and/or generation capacity and consider the potential need to modify such procedures due to the Large Load Customers; and 2) existing and potential demand response opportunities for Large Load Customers. The Settling Parties welcome a Commission representative to participate in this meeting. The Company will convene the meeting(s) within ninety-days of a Commission Final Order approving this Settlement Agreement and will file a report in this proceeding with the Commission upon conclusion of the discussion.

10. **Reporting:**

    a. The Settling Parties agree that I&M will report to the Commission on a semi-annual basis the information identified below subject to the protection of

confidential and competitively-sensitive information ("Confidential Information") in the report. The reported Confidential Information shall be exempt from public disclosure. The confidential portions of the report shall not be provided to the Large Load Customers or other competitively interested stakeholders. The confidential portion of the report will be provided to the OUCC and CAC subject to agreed procedures (or, in the absence of agreement, Commission ordered procedures) for the protection of the Confidential Information.

b. The Settling Parties agree the confidential report shall include the following with respect to Large Load Customers:

   i. The number of executed ESAs and transmission letters of agreement ("LOAs") (semi-annual additions and cumulative total);
   ii. Contract Termination Fees assessed (number of fees assessed and dollar amount of each);
   iii. Notices of reduction to contract capacity with each MW reduction separately identified;
   iv. Status update on prospective Large Load Customers providing the number of customers and total load at the following development stages: (1) expressed interest; (2) undergoing AEP Transmission Planning internal analysis; (3) Executed LOA; (4) executed electric service agreement; (5) site in service.
   v. Summary information regarding aggregate investments made by I&M to serve Large Load Customers including, but not limited to, direct connect facilities, local network upgrades, other transmission investment, and other distribution system investment (if applicable) as quantified in executed LOAs;
   vi. Aggregate Large Load Customer MW in service; and
   vii. Aggregate Large Load Customer MWh in service.

c. The first semi-annual report will be filed within six months of a Commission Final Order approving this Settlement Agreement. Upon Commission request following the filing of any semi-annual report, copies of executed ESAs and transmission LOAs shall also be provided to the Commission, the OUCC, and CAC subject to agreed-upon or, in the absence of agreement, Commission ordered terms of protection of the Confidential Information.

d. The Settling Parties agree to the filing in this Cause of a joint motion or other request in accordance with 170 Ind. Admin. Code 1-1.1-4(i)(2) to support the

confidential treatment of the Confidential Information identified above so that the Commission order in this case may exempt the future filing of the reports agreed to herein from public disclosure and from disclosure to Large Load Customers or other competitively interested stakeholders.

e. Prior to the filing of the initial report, the Settling Parties will work together to: (1) reach agreement on the terms of non-disclosure agreements; and then (2) on the content and format of a public version of the report and any other information provided to the Commission under this provision to be filed pursuant to 170 IAC 1-1.1-4(i)(2). In the event the Settling Parties are not able to reach agreement on either (1) or (2), a request for the Commission to establish such terms may be made to the Commission.

f. The Settling Parties agree that this Settlement Agreement does not limit the ability of the Commission or any Settling Party in any future proceeding or other venue to seek information through discovery or requests for same or similar information or to request the Commission to modify or discontinue the reporting requirements.

11. **Grid-Enhancing Technologies:** Following the submittal of its 2024 Integrated Resource Plan ("IRP") and prior to I&M's next IRP, I&M will conduct a study, with input from interested Settling Parties as to the scope of the study and with opportunities for stakeholder feedback during the course of the study, to evaluate the potential of: grid-enhancing technologies, such as sensors, power flow control devices, and analytical tools that maximize the transmission of electricity across the existing system. The results of the study, to the extent applicable, will be shared (subject to agreed provisions for the protections of confidential and competitively-sensitive information, including customer specific data) as part of the IRP stakeholder process and may be incorporated into the resource options considered in I&M's next IRP(s).

12. **Grid-Reliability and Addition of Large Customer Load:** I&M (and its technical experts) will meet with interested stakeholders to discuss the process and implications of interconnecting Large Load Customers and provide an opportunity for questions and feedback from parties, including but not limited to the appropriate bar for entry into I&M's queue, queue management, interconnection requirements, and load ramping requirements. I&M will make a good faith effort to implement reasonable improvements to this process that are identified from this discussion.

13. **Cost Allocation:** The Settling Parties agree that this Settlement Agreement does not limit the ability of the Commission or the Settling Parties to address cost allocation issues in a subsequent proceeding.

14. **Cost of Service Study:** Prior to filing its next basic rate case, I&M agrees to prepare an analysis applying a 12 Coincident Peak ("CP") demand allocator to the class cost-of-service study ("CCOSS"). The Settling Parties agree that I&M is not obligated to propose use of the 12 CP CCOSS analysis or take a position in support of or against the analysis in its next basic rate case. The Company will include the aforementioned analysis in its workpapers filed with the Commission in its next basic rate case. The Settling Parties agree that all parties, including I&M, will have the opportunity to take any position with respect to the aforementioned analysis as they deem appropriate in the next basic rate case and each reserves the right to present their own alternative analysis and proposals.

15. **Contribution to INCAA:** Amazon, Microsoft, and Google each agree that, no later than six months after their respective service energization within I&M's service territory, each will provide $500,000 per year for a period of five years to Indiana Community Action Association ("INCAA") to support income qualified customers in Indiana, including supporting health and safety to enhance weatherization opportunities.

16. **Other Matters:** Any matters not addressed by this Settlement Agreement will be adopted as proposed by I&M in its direct case.

II. PRESENTATION OF THE SETTLEMENT AGREEMENT TO THE COMMISSION.

A. The Settling Parties shall support this Settlement Agreement before the Commission and request that the Commission expeditiously accept and approve the Settlement Agreement.

B. The Settling Parties may file testimony specifically supporting the Settlement Agreement. The Settling Parties agree to provide each other with an opportunity to review drafts of testimony supporting the Settlement Agreement and to consider the input of the other Settling Parties. Such evidence, together with the direct and rebuttal evidence previously prefiled in this Cause will be offered into evidence without objection and the Settling Parties hereby waive cross-examination of each other's witnesses. The Settling Parties propose to submit this Settlement Agreement and related evidence conditionally, and if the Commission fails to approve this Settlement Agreement in its entirety without any change or condition(s) unacceptable to any Settling Party, the Settlement and supporting evidence shall be withdrawn,

and the Commission will continue to hear this Cause with the proceedings resuming at the point they were suspended by the filing of this Settlement Agreement.

C. A Commission Order approving this Settlement Agreement shall be effective immediately, and the agreements contained herein shall be unconditional, effective and binding on all Settling Parties as an Order of the Commission.

III. EFFECT AND USE OF SETTLEMENT AGREEMENT.

A. It is understood that this Settlement Agreement is reflective of a negotiated settlement and neither the making of this Settlement Agreement nor any of its provisions shall constitute an admission by any Settling Party in this or any other litigation or proceeding. It is also understood that each and every term of this Settlement Agreement is in consideration and support of each and every other term.

B. Neither the making of this Settlement Agreement (nor the execution of any of the other documents or pleadings required to effectuate the provisions of this Settlement Agreement), nor the provisions thereof, nor the entry by the Commission of a Final Order approving this Settlement Agreement, shall establish any principles or legal precedent applicable to Commission proceedings other than those resolved herein.

C. The Settling Parties agree that this Settlement Agreement and each term, condition, methodology, and exclusion contained herein reflect a fair, just, and reasonable resolution and compromise for the purpose of settlement in this proceeding. The Settlement Agreement shall not constitute, and shall not be used as, precedent or be deemed an admission by any person or entity in any other proceeding before the Commission except to the extent necessary to implement or enforce this Settlement Agreement.

D. This Settlement Agreement is solely the result of compromise in the settlement process and except as provided herein, is without prejudice to and shall not constitute a waiver of any position that any Settling Party may take with respect to any or all of the items resolved here and in any future regulatory or other proceedings.

E. The Settling Parties agree the evidence in support of this Settlement Agreement constitutes substantial evidence sufficient to support this Settlement Agreement and provides an adequate evidentiary basis upon which the Commission can make any findings of fact and conclusions of law necessary for the approval of this Settlement Agreement, as filed. The Settling Parties shall prepare and file an agreed proposed order with the Commission as soon as reasonably possible after the filing of this Settlement Agreement and the final evidentiary hearing.

F. The communications and discussions during the negotiations and conferences and any materials produced and exchanged concerning this Settlement Agreement all relate to offers of settlement and shall be confidential, without prejudice to the position of

any Settling Party, and are not to be used in any manner in connection with any other proceeding or otherwise.

G. The Settling Parties agree to work collaboratively on form, wording, and timing of a joint media/public announcement of this Settlement Agreement and terms thereof. No Party will release any information to the public or media prior to the aforementioned announcement. The Settling Parties may respond individually without prior approval of the other Settling Parties to questions from the public or media related to the Settlement Agreement, provided that such responses are consistent with such announcement and do not disparage any of the Settling Parties with respect to the Settlement Agreement. Nothing in this Settlement Agreement shall limit or restrict the Commission's ability to publicly comment regarding this Settlement Agreement or any Order affecting this Settlement Agreement.

H. The Settling Parties have represented and agreed that they are fully authorized to execute the Settlement Agreement on behalf of their respective clients, and their successor and assigns, which will be bound thereby.

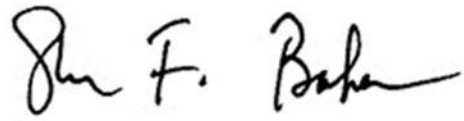
I. The undersigned Settling Parties shall not appeal or seek rehearing, reconsideration or a stay of the Commission Order approving this Settlement Agreement in its entirety and without change or condition(s) unacceptable to any Settling Party (or related orders to the extent such orders are specifically implementing the provisions of this Settlement Agreement).

J. The provisions of this Settlement Agreement shall be enforceable by any Settling Party upon approval and incorporation into a Final Order first before the Commission and thereafter in any state court of competent jurisdiction as necessary.

K. This Settlement Agreement may be executed in two or more counterparts, each of which shall be deemed an original, but all of which together shall constitute one and the same instrument.

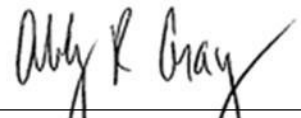
ACCEPTED AND AGREED AS OF THE 22ND DAY OF NOVEMBER, 2024.

INDIANA MICHIGAN POWER COMPANY



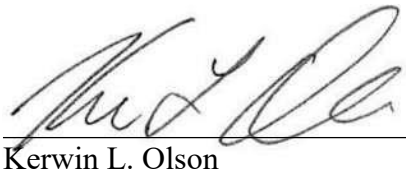
Steven F. Baker
I&M President and Chief Operating Officer
Indiana Michigan Power Center
Fort Wayne, Indiana 46802

INDIANA OFFICE OF UTILITY CONSUMER COUNSELOR



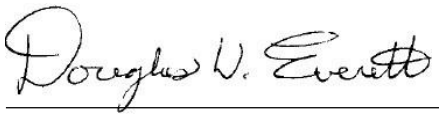
Abby R. Gray
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CITIZENS ACTION COALITION OF INDIANA, INC.



Kerwin L. Olson
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AMAZON DATA SERVICES, INC.



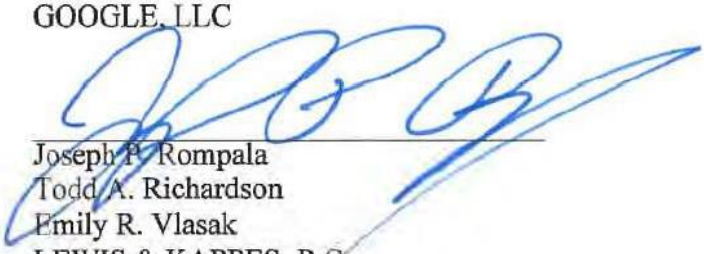
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DATA CENTER COALITION

/s/ Mark Valentine

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GOOGLE, LLC



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I.U.R.C. NO. 20
INDIANA MICHIGAN POWER COMPANY
STATE OF INDIANA

~~ORIGINAL~~FIRST REVISED SHEET NO. 21
CANCELS ORIGINAL SHEET NO. 21

TARIFF I.P.
(Industrial Power)

Availability of Service.

Available for general service customers. Customer's monthly billing demands under this tariff shall not be less than 600 kW. The customer shall contract for a sufficient capacity to meet normal maximum requirements with written contracts being required for capacity levels of 1,500 kW and greater.

Rate.

Tariff Code	Service Voltage	Demand Charge ($/kW)	First 410 kWh per kW (¢/kWh)	Over 410 kWh per kW (¢/kWh)	Monthly Service Charge ($)
327	Secondary	16.474	5.703	1.359	180.00
322	Primary	14.089	5.413	1.313	275.00
323	Subtransmission	10.825	5.333	1.296	275.00
324	Transmission	10.194	5.058	1.286	275.00

Reactive Demand Charge / Credit

Reactive demand charge for each kVAr of leading or lagging reactive demand in excess of 50% of the kW metered demand will be charged at $1.50 / kVAr.

Reactive demand charge for each kVAr of leading or lagging reactive demand less than 50% of the kW metered demand will be credited at $1.50 / kVAr.

Minimum Charge.

This tariff is subject to a minimum monthly charge equal to the sum of the Monthly Service Charge, the product of the Minimum Demand Charge and the monthly billing demand, and all applicable riders.

The Minimum Demand Charge under this tariff shall be as follows:

Tariff Code	Service Voltage	Minimum Demand Charge ($/kW)
327	Secondary	20.995
322	Primary	18.472
323	Subtransmission	15.106
324	Transmission	14.700

(Cont'd on Sheet No. 21.1)

ISSUED BY
STEVEN F. BAKER
PRESIDENT
FORT WAYNE, INDIANA

EFFECTIVE FOR ELECTRIC SERVICE RENDERED
ON AND AFTER ~~MAY 28, 2024~~ _____

ISSUED UNDER AUTHORITY OF THE
INDIANA UTILITY REGULATORY COMMISSION
DATED ~~MAY 8, 2024~~ _____
IN CAUSE NO. ~~45933~~ _____

I.U.R.C. NO. 20
INDIANA MICHIGAN POWER COMPANY
STATE OF INDIANA

~~ORIGINAL~~FIRST REVISED SHEET NO. 21.1
CANCELS ORIGINAL SHEET NO. 21.1

TARIFF I.P.
(Industrial Power)

(Cont'd from Sheet No. 21)

Applicable Riders.

Monthly charges computed under this tariff shall be adjusted in accordance with the applicable Commission-approved rider(s) listed on Sheet No. 44.

Delayed Payment Charge.

All bills under this schedule shall be rendered and due monthly. If not paid within 17 days after the bill is mailed, there shall be added to bills of $3 or less, 10 percent of the amount of the bill; and to bills in excess of $3, there shall be added 10 percent of the first $3, plus 3 percent of the amount of the bill in excess of $3.

Monthly Billing Demand.

The billing demands in kW for each plant shall be taken each month as the single-highest 15-minute integrated peak in kW, as registered at such plant during the month by a demand meter or indicator, subject to the off-peak hour provision, but the monthly demand so established shall in no event be less than 60 percent of the greater of (a) the customer's contract capacity or (b) the customer's highest previously established monthly billing demand during the past 11 months or (c) 1,000 kW. The Metered Voltage adjustment, as set forth below, shall not apply to the customer's minimum monthly billing demand.

Off-Peak Hour Provision.

Demand created during the off-peak hours (as set forth below) shall be disregarded for billing purposes provided that the billing demand shall not be less than 60 percent of the maximum demand created during the billing month nor less than 60 percent of either (a) the contract capacity or (b) the customer's highest previously established monthly billing demand during the past 11 months.

For the purpose of this provision, the on-peak billing period is defined as 7 a.m. to 9 p.m., local time, Monday through Friday. The off-peak billing period is defined as those hours not designated as on-peak hours.

(Cont'd on Sheet No. 21.2)

ISSUED BY
STEVEN F. BAKER
PRESIDENT
FORT WAYNE, INDIANA

EFFECTIVE FOR ELECTRIC SERVICE RENDERED
ON AND AFTER ~~MAY 28, 2024~~ _____

ISSUED UNDER AUTHORITY OF THE
INDIANA UTILITY REGULATORY COMMISSION
DATED ~~MAY 8, 2024~~ _____
IN CAUSE NO. ~~45933~~ _____

TARIFF I.P.
(Industrial Power)

(Cont'd from Sheet No. 21.1)

Adjustments to Rate.

Bills computed under the rates set forth herein will be adjusted as follows:

Metered Voltage

The rates set forth in this tariff are based upon the delivery and measurement of energy at the same voltage, thus measurement will be made at or compensated to the delivery voltage. At the sole discretion of the Company, such compensation may be achieved through the use of loss-compensating equipment, the use of formulas to calculate losses, or the application of multipliers to the metered quantities. In such cases, the metered kWh, kVAr values will be adjusted for billing purposes. If the Company elects to adjust kWh, kW and kVAr based on multipliers, the adjustment shall be in accordance with the following:

(1) Measurements taken at the low-side of a customer-owned transformer will be multiplied by 1.01.

(2) Measurements taken at the high-side of a Company-owned transformer will be multiplied by 0.98.

Terms of Contract.

Contracts under this tariff will be made for an initial period of not less than two years and shall remain in effect thereafter until either party shall give at least one year's written notice to the other of the intention to discontinue service under the terms of this tariff. Where new facilities are required, the Company reserves the right to require initial contracts for periods of greater than two years.

A new initial contract period will not be required for existing customers who increase their contract requirements after the original initial period unless new or additional facilities are required.

The Company shall not be required to supply capacity in excess of that contracted for except by mutual agreement.

(Cont'd to Sheet No. 21.3)

I.U.R.C. NO. 20
INDIANA MICHIGAN POWER COMPANY
STATE OF INDIANA

FIRST REVISED SHEET NO. 21.3
CANCELS ORIGINAL SHEET NO. 21.3

TARIFF I.P.
(Industrial Power)

(Cont'd from Sheet No. 21.2)

Special Terms and Conditions.

This tariff is subject to the Company's Terms and Conditions of Service.

This tariff is also available to customers having other sources of energy supply who purchase standby or backup service from the Company. Where such conditions exist, the customer shall contract for the maximum amount of demand in kW which the Company might be required to furnish, but not less than 1,000 kW. The Company shall not be obligated to supply demands in excess of that contracted for.

Customers with cogeneration and/or small power production facilities shall take service under Rider NMS (Net Metering Service Rider), Tariff COGEN/SPP or by special agreement with the Company.

Terms and Conditions for Customer at or Over 70 MW Individually or 150 MW in the Aggregate.

Applicability.

These provisions apply to customers whose contract capacity is greater than or equal to 70 MW or is reasonably expected to grow to exceed 70 MW at an individual plant, or 150 MW or reasonably expected to grow to exceed 150 MW at one or more aggregated premises, each of 1 MW or larger ("Large Load Customer"). The Company will exercise reasonable discretion when choosing to aggregate premises, with such discretion based on factors including, but not limited to, premises sharing one or more of the following: common owner(s), a common parent company, common local electrical infrastructure, and common control. Large Load Customer's Initial Contract Term, load ramp, Load Ramp Period, contract capacity, and other terms of service under this Tariff will be defined in the Electric Services Agreement(s) ("ESA(s)"), executed between Company and Large Load Customer. These terms shall only apply to new load, or an expansion of existing load, occurring on or after January 1, 2024.

Contract Term.

The Large Load Customer's Initial Contract Term will be made for a period of not less than 12 years. A Large Load Customer may designate a Load Ramp Period, which can be no greater than five (5) years. If a Load Ramp Period is designated by the Large Load Customer, the Initial Contract Term shall commence after the Load Ramp Period ends. The Load Ramp Period is the later period of time from when: (a) electric service is available to the Large Load Customer or (b) the Large Load Customer is scheduled to begin taking electric service, until the time the Large Load Customer's maximum contract capacity is billed. The Contract Term is the Load Ramp Period plus the Initial Contract Term, and shall remain in effect thereafter unless cancelled or modified pursuant to the terms hereunder. Either party shall give at least 42 months written notice to the other of the intention to discontinue service under the terms of this tariff. Such notice shall not reduce the Contract Term except as provided for in the Exit Fee provision below.

(Cont'd to Sheet No. 21.4)

ISSUED BY
STEVEN F. BAKER
PRESIDENT
FORT WAYNE, INDIANA

EFFECTIVE FOR ELECTRIC SERVICE RENDERED
ON AND AFTER _____

ISSUED UNDER AUTHORITY OF THE
INDIANA UTILITY REGULATORY COMMISSION
DATED _____
IN CAUSE NO. _____

I.U.R.C. NO. 20
INDIANA MICHIGAN POWER COMPANY
STATE OF INDIANA

ORIGINAL SHEET NO. 21.4

TARIFF I.P.
(Industrial Power)

(Cont'd from Sheet No. 21.3)

Contract Capacity Reductions.

Large Load Customer may, without payment of an Exit Fee or any penalty, reduce its contract capacity at any time after the first five (5) years of the Contract Term by up to 20%, in total, by giving the Company at least 42 months written notice prior to the beginning of the PJM Delivery Year for which the reduction is sought. For the avoidance of doubt, regardless of the number of notices provided, the total capacity reduction under this provision shall not exceed 20%, unless by mutual agreement between the Large Load Customer and Company, which the Company shall only grant in circumstances that are beneficial, or at least not detrimental, to the Large Load Customer, the Company, and all other customers.

Large Load Customer may terminate its contract or reduce its contract capacity beyond 20% at any time after the first five years of the Contract Term by giving the Company at least 42 months written notice prior to the beginning of the PJM Delivery Year for which the reduction or termination is sought, subject to payment of a capacity reduction/termination fee ("Exit Fee"). The Exit Fee shall be due and payable to the Company upon the effective date of the contract termination or the effective date of the capacity reduction. The Exit Fee shall be calculated as the nominal value of the remaining Minimum Charge for the terminated/reduced capacity in excess of the 20% allowed reduction for the first year of the Exit Fee Period; and for any remaining year of the Exit Fee Period the Exit Fee shall be calculated in the same manner as the first year, minus the OSS/PJM Rider's (or the same cost addressed in another rider's) contribution to the Minimum Charge. The Exit Fee Period is defined as the Large Load Customer's then remaining Initial Contract Term, or any agreed extension. The Exit Fee Period shall not be less than one (1) year and shall not exceed five (5) years. In the event of a permanent closure, the customer shall notify the Company within three (3) business days of making this determination.

Following receipt of proper notice, through the Exit Fee Period, the Company will use reasonable efforts, consistent with its obligations as a public utility, to mitigate the Exit Fee amount owed or paid by the Large Load Customer by evaluating the opportunity to assign the terminated/reduced capacity to serve new Large Load Customers, to expand service to existing Large Load Customers, or otherwise secure offsetting expected revenues. The remainder of any mitigating amounts owed to the Large Load Customer shall be delivered to the Large Load Customer, or its designated successor, after all outstanding balances have been resolved.

(Cont'd to Sheet No. 21.5)

TARIFF I.P.
(Industrial Power)

(Cont'd from Sheet No. 21.4)

If there is an issue concerning the calculation of the Exit Fee or delivery of any mitigation amounts, that either the Company or Large Load Customer view as in need of escalation, either the Company or Large Load Customer may request escalation. Such request shall be made in writing and within 14 business days of the Large Load Customer being notified regarding the Exit Fee calculation. In such instance, management representatives for the Company and for the Large Load Customer will discuss and seek to resolve any issues. The management discussion shall occur within 14 business days of a request, unless otherwise agreed to in writing by the Company and Large Load Customer. The Company and Large Load Customer agree to use this escalation process in good faith, escalating only those matters appropriate for management's consideration. This dispute resolution process does not limit or otherwise affect the ability of either Large Load Customer or the Company to file a formal proceeding requesting the Commission to resolve the dispute.

Large Load Customer shall not assign any of its rights or delegate any of its obligations under the Contract without the written consent of the Company. An assignment will not relieve the Large Load Customer of its financial obligation hereunder unless the Company so consents in writing. Such consent(s) shall not be unreasonably withheld. An assignment or delegation in violation of these Terms and Conditions is null and void.

Monthly Billing Demand.

The Monthly Billing Demands for Large Load Customers in kW for each plant shall be taken each month as the single-highest 15-minute integrated peak in kW, as registered at such plant during the month by a demand meter or indicator, subject to the Off-Peak Hour Provision, but the monthly demand so established shall in no event be less than the greater of (a) 80 percent of the Large Load Customer's contract capacity specified for the applicable time period of the Contract Term; or (b) 80 percent of the Large Load Customer's highest previously established Monthly Billing Demand during the past 11 months. The Metered Voltage adjustment, as set forth above, shall not apply to the Large Load Customer's minimum Monthly Billing Demand.

(Cont'd to Sheet No. 21.6)

I.U.R.C. NO. 20
INDIANA MICHIGAN POWER COMPANY
STATE OF INDIANA

ORIGINAL SHEET NO. 21.6

TARIFF I.P.
(Industrial Power)

(Cont'd from Sheet No. 21.5)

Minimum Charge.

Large Load Customers are subject to a minimum monthly charge for each plant equal to the sum of: (a) the Monthly Service Charge; (b) the product of the Minimum Demand Charge and the Monthly Billing Demand; (c) the product of the Step 1 Embedded Capacity Charge and the Monthly Billing Demand; and (d) the sum of the product of each demand charge in all applicable demand related riders in effect at the time and the Monthly Billing Demand. The Step 1 Embedded Capacity Charge rate will be computed as follows: (Block 1 Energy Rate less Block 2 Energy Rate) multiplied by Block 1 Energy Hours less (Minimum Demand Charge less Demand Charge).

The Step 1 Embedded Capacity Charge under this tariff shall be as follows:

Tariff Code	Service Voltage	Step 1 Embedded Capacity Charge ($/kW)
327	Secondary	13.289
322	Primary	12.427
323	Subtransmission	12.271
324	Transmission	10.959

(Cont'd to Sheet No. 21.7)

ISSUED BY
STEVEN F. BAKER
PRESIDENT
FORT WAYNE, INDIANA

EFFECTIVE FOR ELECTRIC SERVICE RENDERED
ON AND AFTER _____

ISSUED UNDER AUTHORITY OF THE
INDIANA UTILITY REGULATORY COMMISSION
DATED _____
IN CAUSE NO. _____

I.U.R.C. NO. 20
INDIANA MICHIGAN POWER COMPANY
STATE OF INDIANA

ORIGINAL SHEET NO. ~~21.3~~21.7

TARIFF I.P.
(Industrial Power)

(Cont'd from Sheet No. 21.6)

Collateral Requirements.

In addition to the terms in Items 4 and 14 of the Company's Terms and Conditions of Service, the Large Load Customer shall provide collateral to the Company ("Collateral Requirement") based upon the creditworthiness of the Large Load Customer and as outlined below. The amount of collateral to be provided is equal to twenty-four (24) multiplied by: (a) during the first year of the contract, the maximum expected monthly non-fuel bill; or (b) after the first year of the contract, the Large Load Customer's previous maximum monthly non-fuel bill. The amount of collateral under the foregoing calculation will be recomputed annually, and the Large Load Customer shall have to provide the recomputed amount if it is 10% or more greater than the current amount held. A Large Load Customer with a credit rating of at least A- from S&P and A3 from Moody's and liquidity greater than ten times the Collateral Requirement shall be exempt from the Collateral Requirements. A Large Load Customer that does not have a credit rating from S&P and Moody's but maintains liquidity greater than ten times the Collateral Requirement (evidenced by providing quarterly financial statements and certification that on the date financial statements are provided that the Large Load Customer's liquidity meets the ten times threshold) shall be exempt from 50 percent of the Collateral Requirements not to exceed an exemption of more than $250 million. The Collateral Requirement must be provided in one or more of the following forms:

a. A guarantee from the ultimate parent or a corporate affiliate of the Large Load Customer for the full Collateral Requirement, so long as the guarantor has both (a) a credit rating of at least A- from S&P and A3 from Moody's and (b) liquidity greater than ten times the Collateral Requirement; or

b. A standby irrevocable letter of credit ("Letter of Credit") for the full Collateral Requirement. The Letter of Credit must be issued by a U.S. bank or the U.S. branch of a foreign bank, which is not affiliated with the Large Load Customer or its guarantor, with a Credit Rating of at least A- from S&P and A3 from Moody's. Such security must be issued for a minimum term of 360 days. The Large Load Customer must cause the renewal or extension of the security for additional consecutive terms of 360 days or more no later than 30 days prior to each expiration date of the security. If the security is not renewed or extended as required herein, the Company will have the right to draw immediately upon the Letter of Credit and be entitled to hold the amounts so drawn as security. The Letter of Credit must be in a format acceptable to and approved by the Company; or

c. Cash for the full Collateral Requirement.

ISSUED BY
STEVEN F. BAKER
PRESIDENT
FORT WAYNE, INDIANA

EFFECTIVE FOR ELECTRIC SERVICE RENDERED
ON AND AFTER ~~MAY 28, 2024~~ _____

ISSUED UNDER AUTHORITY OF THE
INDIANA UTILITY REGULATORY COMMISSION
DATED ~~MAY 8, 2024~~ _____
IN CAUSE NO. ~~45933~~ _____

EPRI

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2024 White Paper

Powering Intelligence

Analyzing Artificial Intelligence and Data Center Energy Consumption



EXECUTIVE SUMMARY

Key Messages

- In the United States, powering data centers, providing clean energy for manufacturing, supporting industrial onshoring, and electrifying transportation are driving renewed electric load growth. Clusters of new, large point loads are testing the ability of electric companies to keep pace.
- Data centers are one of the fastest growing industries worldwide. Between 2017 and 2021, electricity used by Meta, Amazon, Microsoft, and Google—the main providers of commercially available cloud computing and digital services—more than doubled.
- A fundamental uncertainty in projecting data center load growth comes from the broad emergence of artificial intelligence (AI) technologies in business and daily life—punctuated by the explosion into public consciousness of generative AI models, such as OpenAI's ChatGPT, released in November 2022. While AI applications are estimated to use only 10%–20% of data center electricity today, that percentage is growing rapidly.
- AI models are typically much more energy-intensive than the data retrieval, streaming, and communications applications that drove data center growth over the past two decades. At 2.9 watt-hours per ChatGPT request, AI queries are estimated to require 10x the electricity of traditional Google queries, which use about 0.3 watt-hours each; and emerging, computation-intensive capabilities such as image, audio, and video generation have no precedent.
- To provide an early assessment of potential data center load growth at the national level, EPRI has developed low, moderate, high, and higher growth scenarios for data center loads from 2023 to 2030. Data centers grow to consume 4.6% to 9.1% of U.S. electricity generation annually by 2030 versus an estimated 4% today.
- While the national-level growth estimates are significant, it is even more striking to consider the geographic concentration of the industry and the local challenges this growth can create. Today, fifteen states account for 80% of the national data center load, with data centers estimated to comprise a quarter of Virginia's electric load in 2023. Concentration of demand is also evident globally, with data centers projected to make up almost one-third of Ireland's total electricity demand by 2026.
- With the shift to cloud computing and AI, new data centers are growing in size. It is not unusual to see new centers being built with capacities from 100 to 1000 megawatts—roughly equivalent to the load from 80,000 to 800,000 homes. Connection lead times of one to two years, demands for highly reliable power, and requests for power from new, non-emitting generation sources can create local and regional electric supply challenges.
- EPRI highlights three essential strategies to support rapid data center expansion:
    1. Data center ***efficiency improvements and increased flexibility***.
    2. ***Close coordination between data center developers and electric companies*** regarding data center power needs, timing, and flexibility, as well as electric supplies and delivery constraints.
    3. ***Better modeling tools*** to plan the 5–10+ year grid investments needed to anticipate and accommodate data center growth without negatively impacting other customers and to identify strategies for maintaining grid reliability with these large, novel demands.

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Potential Impacts of Artificial Intelligence on Data Center Load Growth

Data center operation is one of the fastest growing industries worldwide. The International Energy Agency recently projected that global data center electricity demand will more than double by 2026. In the United States, the national outlook could resemble the global outlook, but is highly uncertain.

One key uncertainty that could change the trajectory of data center load growth is the use of generative AI models. Both public and corporate imaginations were triggered by the release of OpenAI's ChatGPT on November 30, 2022. Evidence about how widely these tools will be used and how much they will change computational needs is just starting to emerge. These early applications were estimated to require about ten times the electricity—from 0.3 watt-hours for a traditional Google search to 2.9 watt-hours for a ChatGPT query—to respond to user queries. Creation of original music, photos, and videos based upon user prompts and other emerging AI applications could require much more power. With 5.3 billion global internet users, widespread adoption of these tools could potentially lead to a step change in power requirements. On the other hand, history has shown that demand for increased processing has largely been offset by data center efficiency gains.

EPRI U.S. Data Center Load Projections

Drawing on public information about existing data centers, public estimates of industry growth, and recent electricity demand forecasts by industry experts, EPRI prepared four scenarios of potential electricity consumption in U.S. data centers during the period from 2023 to 2030 (**Figure ES-1**). The blue line in the figure, running from 2000 to 2020, traces historical data center electricity consumption estimates. From 2000 to 2010, data center load grew as centers expanded across the country to support the emerging internet. From 2010 to 2017, despite continued growth in computing demands and data storage this load growth flattened due to efficiency gains and the replacement of small, relatively inefficient corporate data centers with large, cloud computing facilities. In recent years, load growth has likely accelerated, driven by emerging AI applications and COVID-era increases in demand for services like streaming and video conferencing. The light blue area highlights uncertainty in a range of data center electricity consumption estimates for 2021 to 2023. Colored bands show the four projections, which combine estimates of increased data processing needs with assumptions about efficiency gains. The widths of these bands carry forward the uncertainty about the 2023 starting load level:

- ***Low growth****—3.7% annual load growth based on a Statista projection of data center financial growth issued prior to the release of ChatGPT.*

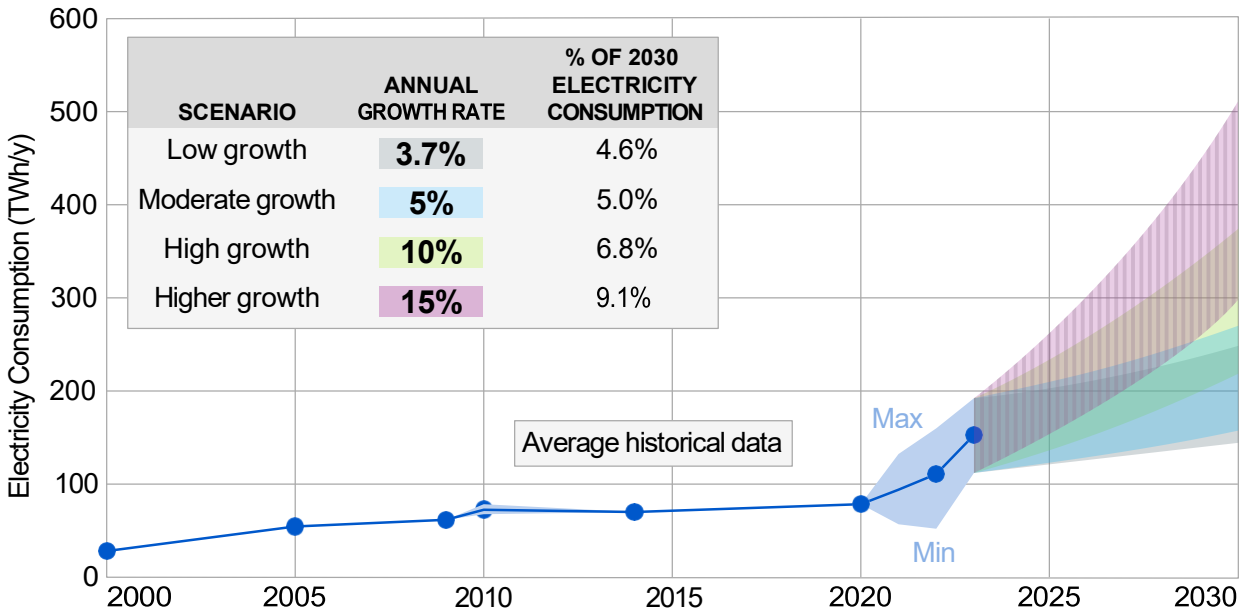


Figure ES-1. *Projections of potential electricity consumption by U.S. data centers: 2023–2030 . % of 2030 electricity consumption projections assume that all other (non-data center) load increases at 1% annually.*

- ***Moderate growth**—5% annual load growth based on an expert assessment commissioned by EPRI.*
- ***High growth**—10% annual load growth consistent with both a McKinsey estimate and another expert assessment commissioned by EPRI in summer 2023.*
- ***Higher growth**—15% annual growth based upon a commissioned expert assessment consistent with rapid expansion of AI applications and limited efficiency gains.*

The estimates of data centers' share of total U.S. electricity consumption in 2030—9.1%, 6.8%, 5.0%, and 4.6%—assume that all other loads increase at 1% per year. Data centers accounted for about 4% of the total load in 2023 (average estimate).

Data Center Power Demands Are Concentrated in a Few Regions

Fifteen states accounted for an estimated 80% of the national data center load in 2023. Ranked from highest to lowest, they are Virginia, Texas, California, Illinois, Oregon, Arizona, Iowa, Georgia, Washington, Pennsylvania, New York, New Jersey, Nebraska, North Dakota, and Nevada. Concentration of demand is also evident globally, with the International Energy Agency recently projecting that data centers in Ireland could account for almost one-third of Ireland's total electricity demand by 2026.

The map in **Figure ES-2** shows the effect in 2030 of applying the annual U.S. data center growth rates (averaged across the four scenarios) to project state-level loads against a backdrop of 1% annual growth in other loads. With evenly spread growth, the data center share of load in Virginia increases to almost 50% in the higher growth scenario and to 36% when averaged across the four scenarios. The shares in other states vary widely with five other states projected to approach 20% or more of electricity demand under these simplified assumptions. In reality, load growth is unlikely to be spread evenly. Data centers favor sites where internet connections are strong; where electricity prices, land costs, and disruptive events are low; where skilled labor is available; near population centers and users; and where the centers can develop backup power to ensure power supply (usually natural gas or diesel generators). The additional

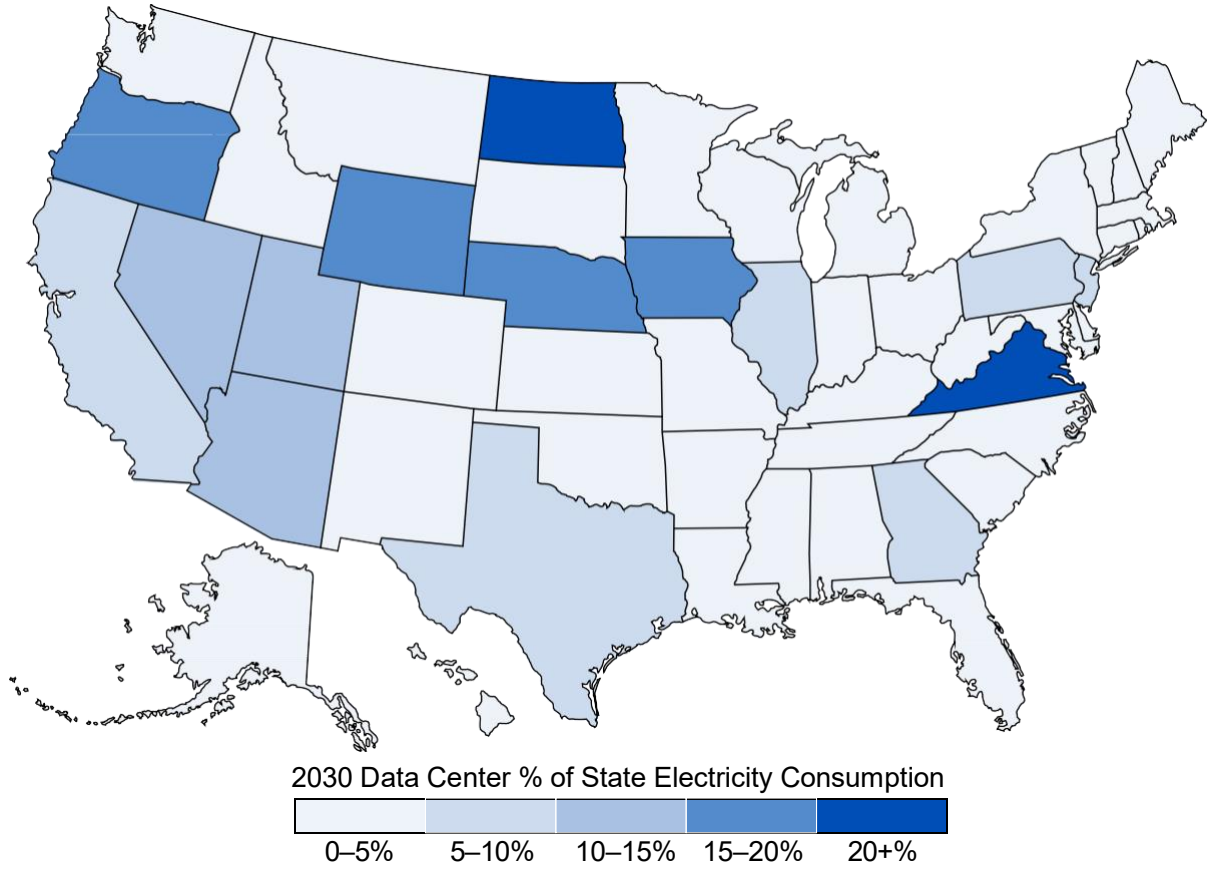


***Figure ES-2.** 2030 projected data center share of electricity consumption (assumes average of the four growth scenarios and that non-data center loads grow at 1% annually) [4, 8, 9]*

requirement of some developers for new, clean electricity generation sources adds to the challenge of developing and delivering this new generation.

A Roadmap to Support Rapid Data Center Expansion

The most serious challenges to data center expansion are local and regional and result from the scale of the centers themselves and mismatches in infrastructure timing. A typical new data center of 100 to 1000 megawatts represents a load equal to that of a new neighborhood of 80,000 to 800,000 average homes. While neighborhoods require many years to plan and build, data centers can be developed and connected to the internet in one to two years. New transmission, in contrast, takes four or more years to plan, permit, and construct. And developing and connecting new generation can also take years.

EPRI highlights three essential strategies to support rapid data center expansion. These strategies emphasize increased collaboration between data center developers and electric companies.

1. ***Improve data center operational efficiency and flexibility***. Although gains in data center operational efficiency have plateaued in recent years, there are clear opportunities for further improvement, including more efficient IT hardware; lower electricity use for cooling, lighting, and security; and more efficient AI development and deployment strategies. Efforts to increase both temporal and spatial (i.e., spreading compute geographically) flexibility are critical to helping accommodate these new loads.
2. ***Increase collaboration between data center developers and electric companies***. Developing a deeper understanding of data center power needs, timing, and potential flexibilities—while assessing how they match available electric supplies and delivery constraints—can create workable solutions for all. Enabled by technology and supporting policies, data center backup generators, powered by clean fuels, could support a more reliable grid while reducing the cost of data center operation. Shifting the data center-grid relationship from the current "passive load" model to a collaborative "shared energy economy"—with grid resources powering data centers and data center backup resources contributing to grid reliability and flexibility—could not only help electric companies contend with the explosive growth of AI but also contribute to affordability and reliability for all electricity users.
3. ***Improve point load forecasting to better anticipate future point load growth and modeling of transient system behavior to maintain reliability***. Forecasts need to make better projections describing new point load locations, magnitudes, and timing alongside better techniques for making decisions—to build or not build long lead-time infrastructure—while facing the economic, regulatory, and political uncertainty associated with siting these large point loads. Also, real-time modeling of data center operational characteristics in an increasingly inverter-based grid is needed to maintain reliability.

INTRODUCTION

Research Questions

As the number and size of data centers expand to support continued growth in data processing, internet traffic, and rapid expansion in artificial intelligence (AI) applications, some critical questions emerge:

- How rapidly can we expect data centers to expand, and how does the rapid growth in AI change their power demands?
- What is the impact of these developments on electric load and resource adequacy?
- What implications do these trends have for future electricity infrastructure planning?
- How can the data center and electric utility industries work together to support rapid data center expansion?

Data Centers in the United States

As of March 2024, there were approximately 10,655 data centers globally; half of them, 5,381, were in the United States. Just over three years ago, in January 2021, there were approximately 8,000 data centers, with about one-third of them in the United States [1].

The construction of new data centers is accelerating at a rapid pace, largely driven by demand for AI-powered tasks such as speech recognition, tailored diagnostics, logistics, internet of things (IoT), and generative AI. The expansion of interest in generative AI is particularly notable due to the overnight popularity of ChatGPT, released on November 30, 2022, marking the public-facing start of a technology race.

Data centers vary significantly in design and purpose and are generally grouped into two categories, small or large scale. *Small-scale data centers*, representing about 10% of U.S. data center load [2], typically cater to localized operations and service small businesses, government facilities, or specific departmental needs within larger corporations. They include server rooms/closets embedded in buildings and "edge data centers," which are strategically located on the outer edges of networks to bring computing capabilities closer to users who are geographically distant from large cloud data centers [3]. Though the electricity demands of each installation are relatively modest—500 kilowatts (kW) to 2 megawatts (MW)—they account for roughly half of all servers [3]. Market research analysts have projected the global edge data center market to grow at a compound annual growth rate (CAGR) of 22.1% to 2030 [4], highlighting the rising importance of small-scale and edge data centers in digital infrastructure.

Large-scale commercial data centers are designed to serve extensive operations and often serve multiple businesses or even entire industries. These data centers seek proximity to customers and a skilled workforce and can benefit from lower land costs, property taxes, labor rates, energy prices, and risk of severe weather or seismic activity [5]. **Figures 1–3** show maps of various large-scale facility types, which include:

- Enterprise data centers, which are owned and operated by single companies for their exclusive computing and networking use. These account for about 20–30% of total load [2, 6].
- Co-location centers, where several businesses may rent space to house their servers and other hardware with shared energy and cooling infrastructure.
- Hyperscale data centers, which are capable of rapidly scaling up their operations to meet the vast computing needs of cloud giants like Amazon AWS, Google Cloud, and Microsoft Azure. Given their large scale and recent emergence, they are often at the forefront of electricity consumption and efficiency innovations. Hyperscale and co-location centers together account for the lion's share of U.S. data center load—about 60%–70% [7].

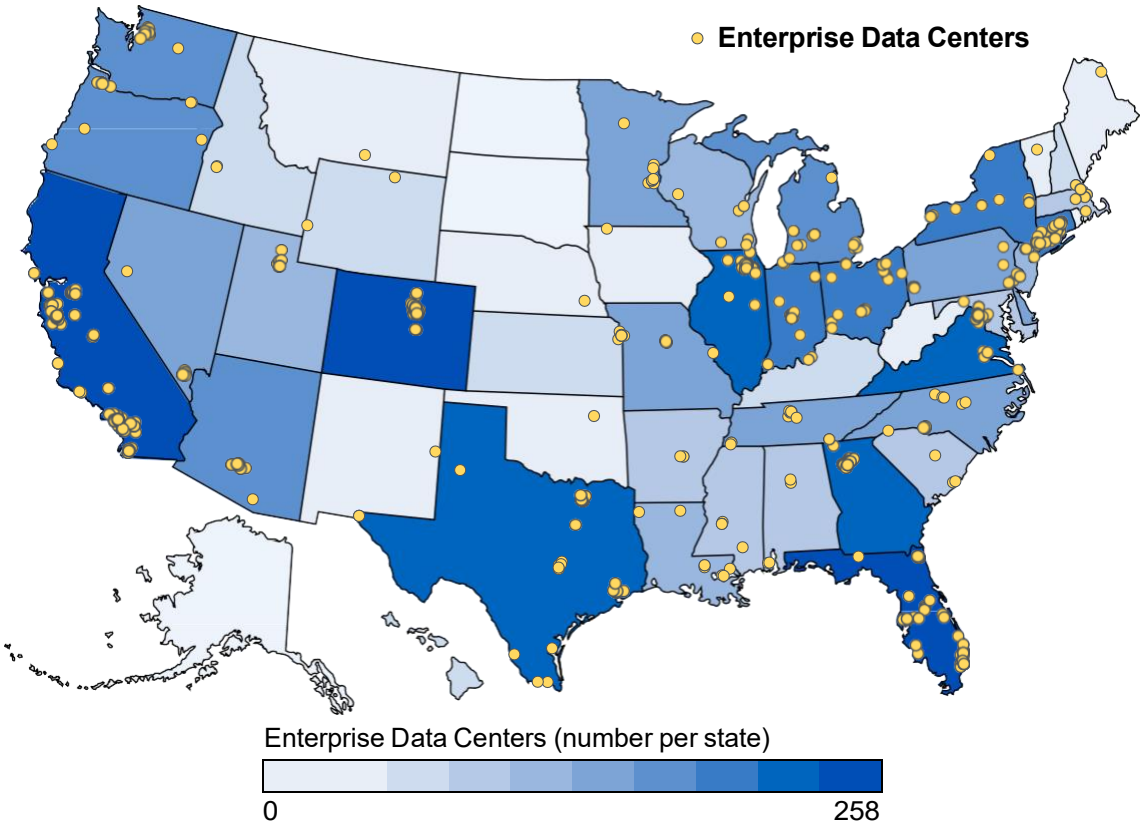


Figure 1. U.S. enterprise data center distribution as of 2022 [4, 8, 9]

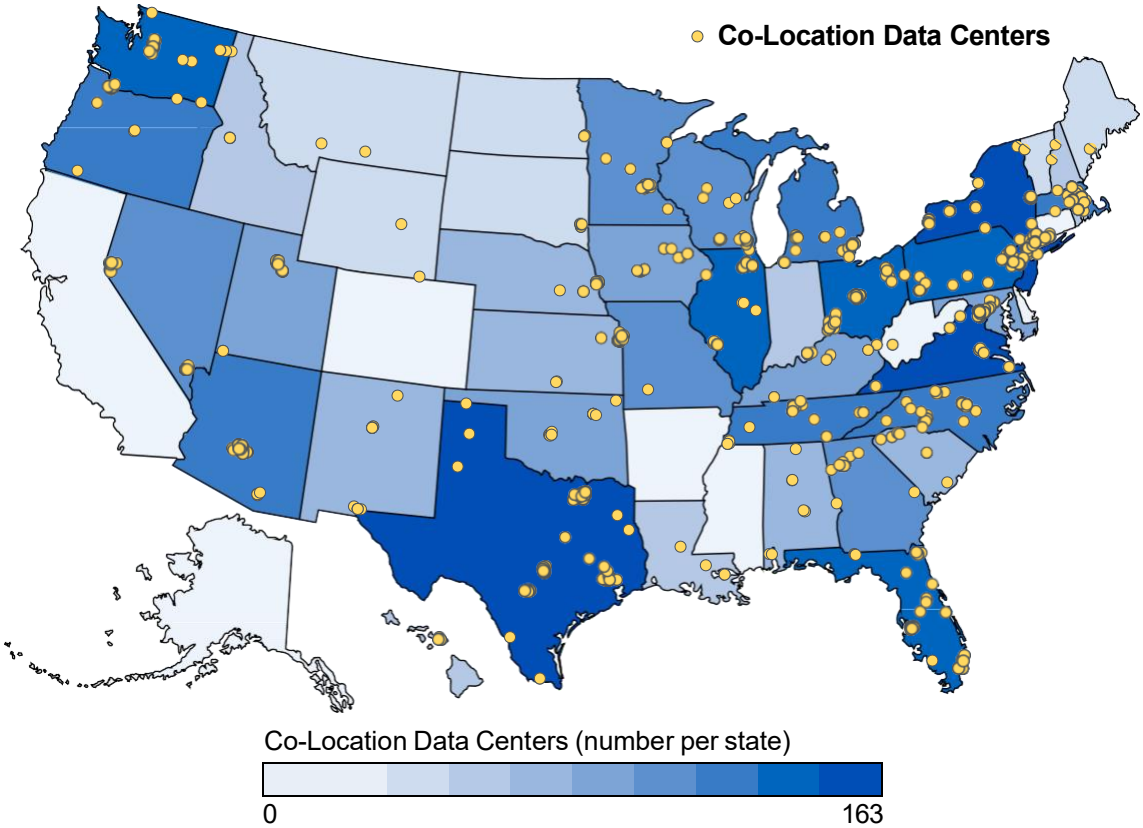


Figure 2. U.S. co-location data center distribution as of 2022 [4, 8, 9]

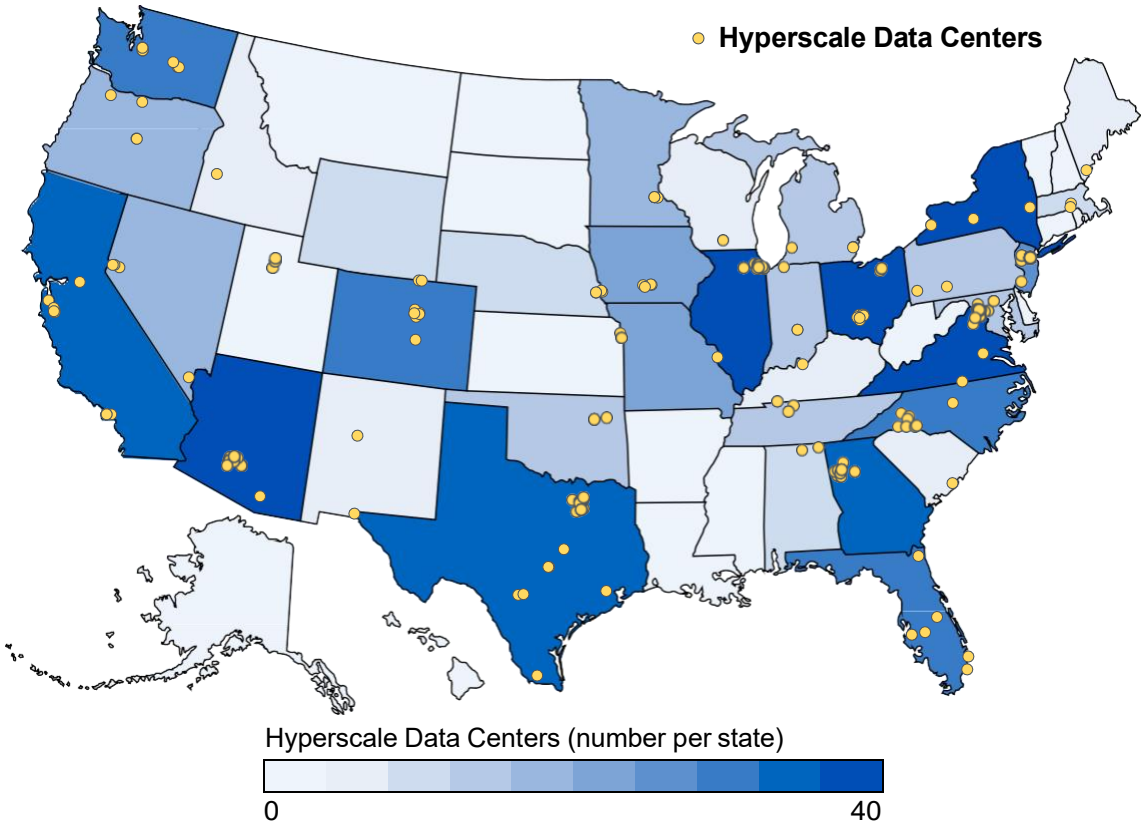


Figure 3. U.S. hyperscale data center distribution as of 2022 [4, 8, 9]

Data Centers' Primary Electricity-Consuming Hardware and Equipment

The electricity needs of data centers are determined primarily by the three constituent hardware categories. Each category's proportion of energy consumption can vary depending on the data center's age, configuration, type, and function [10, 11, 12, 13]. The three main categories and their energy consumption [2, 13, 14] are:

- IT equipment, typically composing 40%–50% of data center energy consumption, encompasses the following foundational hardware units:
  - Servers, which are the workhorses, responsible for data processing and computational tasks
  - Storage systems, which include both traditional hard disk drives (HDDs) and the faster, more energy-efficient solid-state drives (SSDs), crucial for data retention
  - Network infrastructure, which comprises switches, routers, and other components, ensuring seamless data transfer and connectivity
- Cooling systems, typically composing 30%–40% of data center energy consumption, are critical to maintaining an optimal temperature within data centers to prevent hardware malfunction and ensure longevity. While data centers historically used traditional HVAC, advanced cooling technologies in data centers have transitioned towards systems that are specialized for data center use. Please refer to the section **Energy Efficiency and Load Management** below for more details.
- Auxiliary components, typically composing 10%–30% of data center energy consumption, are used for various operational needs and include uninterruptible power supplies, security systems, and lighting.

Assessing data center energy efficiency is crucial to gauging how effectively they use electricity. These assessments help to identify trends, drive improvements, and set benchmarks for electricity usage; and play a key role in operational strategy [15, 16].

AI AND DATA CENTER POWER CONSUMPTION INSIGHTS

Immense Volumes of Data are Being Processed Daily

Data centers' worldwide electricity use in 2022 totaled 300 million megawatt-hours (MMWh), or 1.2% of all load, a 45% increase from 2015 [17]. In the United States in 2023, data centers accounted for about 4% of total electricity consumption or 150 MMWh, equivalent to the average annual consumption of 14 million households [9, 18].

Since 2017, *annual* data volumes have soared, tripling to around 4,750 exabytes (an exabyte being a billion gigabytes) by 2022, showcasing the immense volume of information being processed and transmitted globally every day [19]. In 2022, the *daily* generation of data—including captured, copied, or consumed—reached approximately 13 exabytes, a surge partly attributable to the burgeoning impact of AI models [17]. Concurrently, in 2022, global data transmission network energy use was reported to be around 260–360 MMWh, roughly equal to data center power use [17, 20]. **Figure 4** illustrates the dramatic rise in global consumer IP traffic.

Data centers are facing a significant challenge with internet traffic growing nearly 12-fold in the past decade, a trend paralleled by increasing AI-related workload demands [19]. The historical precedent is showcased in **Figure 5**, which contrasts the U.S. data storage supply versus estimated demand from 2009 to 2020, underscoring a growing deficit and the need to address these trends [22].

Despite the immense growth in network traffic and data generation, load growth has been much slower due to efficiency gains and consolidation.

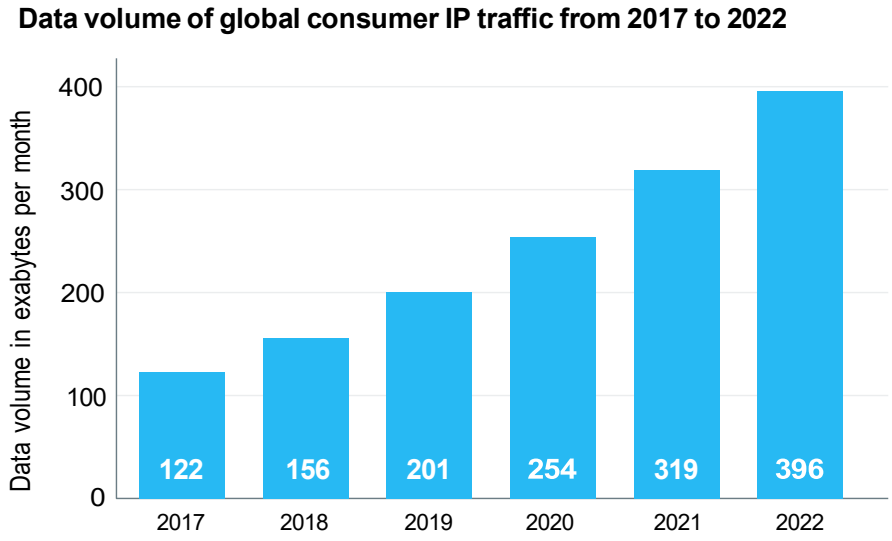


Figure 4. Trends in global consumer IP traffic, 2017–2022 [21]

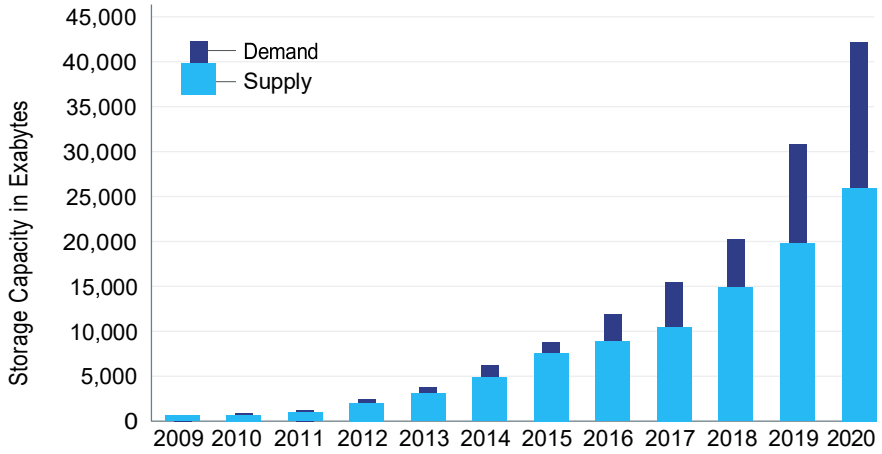


Figure 5. U.S. data storage supply vs. demand, 2009–2020 [22, 23]

History of Energy Efficiency in the Data Center Industry

Over the last 25 years, U.S. data center load growth, as shown in **Figure 6**, has experienced three phases:

1. Energy consumption grew in the early 2000s driven by the rapid expansion of internet infrastructure and the dot-com boom [24].
2. From 2010–2020, electricity consumption stabilized as data center expansion was offset by equally rapid improvements in energy efficiency achieved both through improvements at individual facilities and through the transition from small data centers to more efficient cloud facilities [25, 26].
3. Recent load growth in data centers is driven mainly by the expanding demand for cloud services, big data analytics, and AI technologies—which require significant computational resources—and a slowing of efficiency gains [27].

Efficiency gains in individual data centers have been led by advancements in server efficiency, which have been significant, leading to reduced power consumption per unit of computing power [28]. Power and cooling equipment, required to operate the IT components, has also improved its efficiency. Power Usage Effectiveness (PUE) and Data Center Infrastructure Efficiency (DCIE), key efficiency metrics in the data center industry, are defined in the box on the next page. **Figure 7** shows the U.S. PUE declined from 2007 to 2022, illustrating notable efficiency gains in

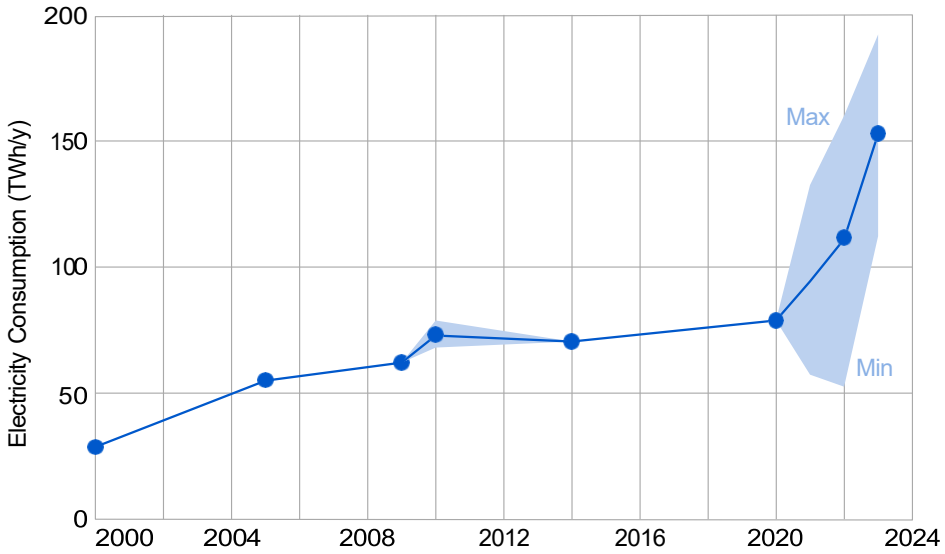


Figure 6. U.S. data center load growth from 2000 to 2023. The graph's light blue area indicates the uncertainty range based on two datasets estimating recent-to-current data center loads [4, 8, 9]

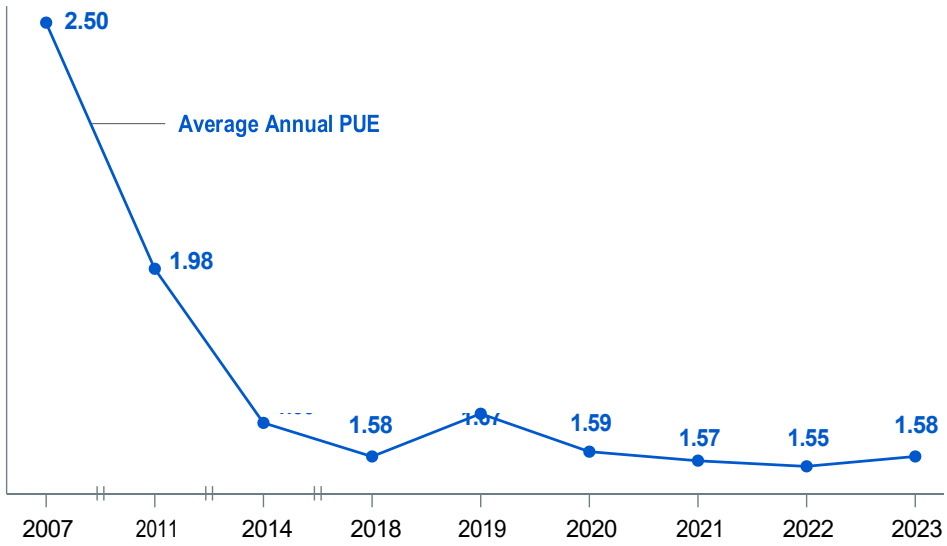


Figure 7. Average annual PUE in data centers, 2007–2023 [26, 29]

non-compute power demands [26, 29]. The recent stabilization at an average PUE of 1.6 suggests slowed progress in energy-saving strategies amidst the recent, rapid buildout [29]. With increased cooling needs of GPUs, advanced technologies (as discussed later in the report) could restart the downward drive in cooling and ancillary equipment power needs, with projected PUEs in advanced facilities potentially approaching 1.2.

DEFINITIONS OF KEY EFFICIENCY METRICS FOR DATA CENTERS

Power Usage Effectiveness (PUE)—A metric that quantifies a data center's energy efficiency by dividing the total energy usage by the energy consumed by the IT equipment alone. A lower PUE indicates higher efficiency, with 1.0 implying that all energy use is for computation.

Data Center Infrastructure Efficiency (DCIE)—A measure of a data center's energy efficiency calculated as the percentage of energy used directly by IT equipment out of the total energy consumption. Higher DCIE values signify greater efficiency in non-computational functions.

Uneven Geographic Distribution Creates Imbalance in Data Center Load

The geographic distribution of data centers is notably uneven, creating economic opportunity but also localized grid stress. For example, in 2022, data centers accounted for 1.2% of worldwide electricity, but 20% of electricity consumption in Ireland [30]. Similarly, the United States shows uneven growth in data center investments, reflecting a diverse landscape of regional opportunities and challenges. Data centers consume more power in Virginia, for instance, than in any other state. [9, 17]

Fifteen states accounted in 2023 for 80% of the national data center load. Ranked from highest to lowest in estimated load, each presents both opportunities and challenges as shown in **Table 1**.

Table 1. Opportunities and challenges for states ranked in the Top 15 for data center growth [29, 31, 32, 33, 34, 35, 36, 37]

STATE	OPPORTUNITIES	CHALLENGES
Virginia	Unparalleled network infrastructure; proximity to federal government agencies	Community pushback; regulatory scrutiny, particularly concerning environmental impact; transmission
Texas	Business-friendly; ample land availability	Electric grid reliability and pace of expansion
California	Robust technological ecosystem	High real estate and power costs; stringent environmental regulations
Illinois	Strategic location; significant tax incentives; nuclear generation and increasing renewable energy investments to address sustainability	Transmission constraints and rapidity of development
Oregon	Low electricity rates, low carbon emissions, moderate climate, tax incentives, and skilled workforce	Complex environmental regulations; demand for green energy solutions, and pace of growth
Arizona	Solar electricity, low risk of natural disasters; recent market growth	Water scarcity; need for sustainable cooling solutions
Iowa	Low electric rates; renewable energy availability	Geographic limitation (distant from major U.S. data hubs)
Georgia	Availability of land and power; friendly business environment	Balancing rapid expansion with local resource impacts
Washington	Abundant renewable energy resources	High energy costs; strict regulatory measures
Pennsylvania	Strategic location near major East Coast markets; relatively low energy costs	Aging infrastructure
New York	Hub for financial services; high connectivity demand	Space limitations; high energy costs
New Jersey	Close to major metropolitan areas; robust fiber-optic infrastructure ; transmission capacity from recent build out	High property and energy costs
Nebraska	Low energy costs; generous tax incentives	Remote location might limit connectivity options
North Dakota	Significant tax incentives; low cost of operations	Limited connectivity; need for more robust infrastructure
Nevada	Tax abatements; low electricity prices	Water scarcity; need for sustainable cooling solutions

Table 2 presents estimates of data center consumption in 2023, 2030, and the projected consumption as a percentage of state electricity demand (%EC) for the 15 states. For detailed graphs of each state's projections as well as a table showing 44 states that are pertinent to the U.S. data center market, see **Appendix A**.

Table 2. Current and projected load growth in Top 15 states [4, 8, 9]

FORECASTED SCENARIOS: PROJECTIONS OF DATA CENTER ELECTRICITY CONSUMPTION IN TOP 15 STATES (2023—2030)										
	2023 Load		Low-growth □cenario (3.71%)		Moderate-growth □cenario (5%)		High-growth □cenario (10%)		Higher-growth □cenario (15%)	
STATE	MWh/y	% of Total State Electricity Consumed (%EC)	MWh/y	% of Total State Electricity Consumed (%EC)	MWh/y	% of Total State Electricity Consumed (%EC)	MWh/y	% of Total State Electricity Consumed (%EC)	MWh/y	% of Total State Electricity Consumed (%EC)
Virginia	33,851,122	25.59%	43,683,508	29.28%	47,631,928	31.10%	65,966,260	38.47%	89,880,357	46.00%
Texas	21,813,159	4.59%	28,149,002	5.47%	30,693,306	5.94%	42,507,676	8.04%	57,917,564	10.64%
California	9,331,619	3.70%	12,042,078	4.43%	13,130,525	4.81%	18,184,686	6.54%	24,777,000	8.70%
Illinois	7,450,176	5.48%	9,614,151	6.53%	10,483,145	7.08%	14,518,285	9.54%	19,781,455	12.56%
Oregon	6,413,663	11.39%	8,276,574	13.39%	9,024,668	14.43%	12,498,415	18.93%	17,029,342	24.14%
Arizona	6,253,268	7.43%	8,069,590	8.81%	8,798,975	9.53%	12,185,850	12.73%	16,603,465	16.58%
Iowa	6,193,320	11.43%	7,992,230	13.44%	8,714,623	14.48%	12,069,029	18.99%	16,444,294	24.21%
Georgia	6,175,391	4.26%	7,969,093	5.08%	8,689,396	5.51%	12,034,090	7.48%	16,396,690	9.92%
Washington	5,171,612	5.69%	6,673,757	6.77%	7,276,977	7.34%	10,078,009	9.88%	13,731,490	13.00%
Pennsylvania	4,590,240	3.16%	5,923,520	3.78%	6,458,929	4.11%	8,945,079	5.61%	12,187,850	7.49%
New York	4,067,385	2.84%	5,248,796	3.40%	5,723,219	3.69%	7,926,182	5.05%	10,799,583	6.75%
New Jersey	4,038,360	5.42%	5,211,341	6.46%	5,682,378	7.00%	7,869,621	9.44%	10,722,517	12.44%
Nebraska	3,959,520	11.70%	5,109,601	13.75%	5,571,442	14.81%	7,715,984	19.41%	10,513,184	24.71%
North Dakota	3,915,720	15.42%	5,053,079	18.00%	5,509,811	19.31%	7,630,631	24.89%	10,396,888	31.11%
Nevada	3,416,707	8.69%	4,409,122	10.28%	4,807,649	11.10%	6,658,195	14.75%	9,071,924	19.07%

The four load growth projection scenarios reflect national-level estimates of data center growth applied to state-level estimates of current demand. This analytical approach is explained in more detail in the section **Forecasting Data Center Load Growth to 2030.*

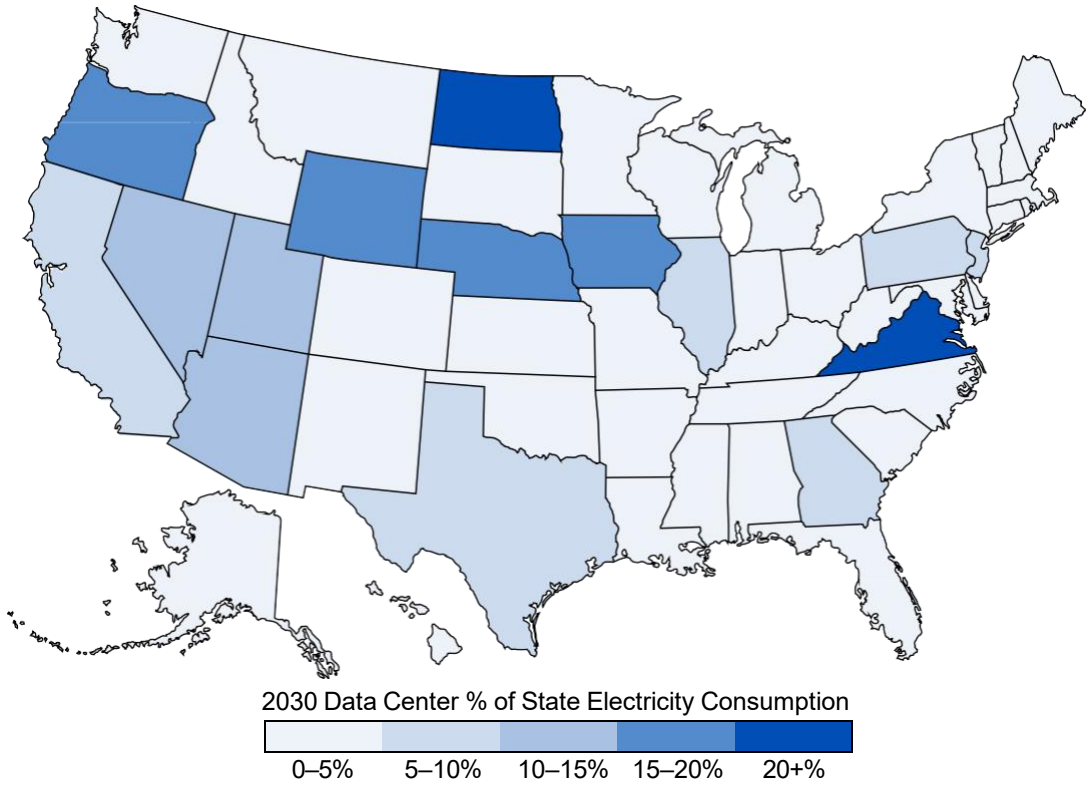


Figure 8. 2030 projected data center share of electricity consumption (assumes average of the four growth scenarios and that non-data center loads grow at 1% annually) [4, 8, 9]

The map in **Figure 8** depicts the projected data center share of state electricity demand in 2030, calculated by applying the annual U.S. data center growth rates (averaged across the four scenarios) to project state-level data center loads and assuming other loads grow at 1% annually. (The scenarios are explained in the section **Forecasting Data Center Load Growth to 2030**.) The potential for a rapidly rising share of data center power demand in many states accentuates the need for customized energy strategies that align with the specific demands and infrastructure capabilities of each state's grid. State-level projections also underscore the critical need for innovation in energy management and the optimization of localized infrastructure to accommodate the rising energy demands associated with expanding data center workloads.

AI Implications for Power Consumption

In the latter half of the 20th century, AI applications typically involved rule-based strategies and small machine-learning models that used very little electricity. However, as the 21st century unfolded, AI systems witnessed exponential growth in their complexity and computational requirements [38, 39]. On a global level, the United States has been leading in the development of prominent AI systems, with the creation of 16 such systems since 2022, compared to the United Kingdom's eight and China's three [39].

Key AI-related technological drivers contributing to escalating data center electricity demands include:[1]

- The exponential growth of data generation: The dramatic rise in global consumer IP traffic represents a reflection of the "big data" wave, part of which has resulted from feeding AI models with diverse and large datasets [9, 10, 40, 41]. The surge in data availability not only fuels the sophistication and accuracy of AI algorithms but also underscores the symbiotic relationship between increasing internet usage and AI advancement. Of course, this has required expanded storage, increased processing capabilities, and escalating electricity demands [21].
- The increasing complexity of AI models: Initially constituted as rule-based entities functioning through coded

1 While cryptocurrency mining, with its distinct computational processes and energy patterns for blockchain transaction verification and cryptocurrency generation, also impacts energy loads, it is excluded from this study to maintain focus on traditional data center operations and AI-driven computations. In 2022, global crypto mining was estimated to have consumed around 110 million MWh, accounting for 0.4% of annual global electricity demand, around one-third the usage of traditional data centers [17]. A separate assessment is warranted to understand the potential power needs and flexibility of cryptocurrency power demands.

instructions, AI models have undergone a monumental transformation, becoming increasingly complex and capable over time [42], in turn increasing their computational demands. As an illustration of the staggering increase in computation demand, note that in 1957, the Perceptron Mark I, the first real-world implementation of a one-layer neural network that could classify images, utilized 695,000 floating-point operations per second (FLOPS)—an assessment of AI complexity and computation intensity. In 2020, however, GPT-3 required a staggering $3.14x10^{23}$ FLOPS, an increase of 18 orders of magnitude, and at present each subsequent AI model is requiring even greater amounts.

- The continuous operational demands of a digital ecosystem: In the modern era, data centers function ceaselessly to uphold the demands of a globalized society that thrives on connectivity. Data centers facilitate uninterrupted services, ensuring 24/7 availability in various sectors including business, e-commerce, and entertainment. Maintaining constant uptime requires robust backup power solutions.

Energy contributions of AI annual workloads are categorized into three major areas [7, 18, 39, 43, 44]:

- Model development (10% of the energy footprint): Models are developed and fine-tuned before training.
- Model training (30% of the energy footprint): Algorithms learn by processing a vast array of data to make predictions or decisions without exact input-response relations preprogrammed, which requires substantial computation efforts and high energy expenditure for extended periods.
- Use/inference (60% of the energy footprint): Includes the deployment and utilization of developed AI models in real-world applications and requires computational resources for interpreting new data and generating outcomes or predictions based on pre-trained models.

For detailed information on AI model types, specific models and their descriptions, and the electricity consumption of each, see **Appendix B**.

Chat GPT and Other Large Language Models (LLMs)

Over the last year, the surge in popularity of generative AI sparked by the public release of Open AI's ChatGPT has created new concerns about AI's potential impact on future computing energy needs. **Figure 9** shows the increase in web traffic—starting from zero—for prominent generative AI platforms including ChatGPT, which is illustrated by the dark blue line [45].

ChatGPT garnered 100 million global users in only two months, which was rapidly followed by tech giants like Microsoft, Alphabet, Meta, and Bing launching their own large-language model chatbots. From a power usage perspective, these LLMs create a new frontier with ultimate impact to be determined, in part, by how widely the 5.3 billion internet users adopt the new features being rolled out. [46, 47].

For example, Google plans to implement LLMs to boost its search engine's ability to recognize and respond to user queries in a more conversational and natural style [48]. At

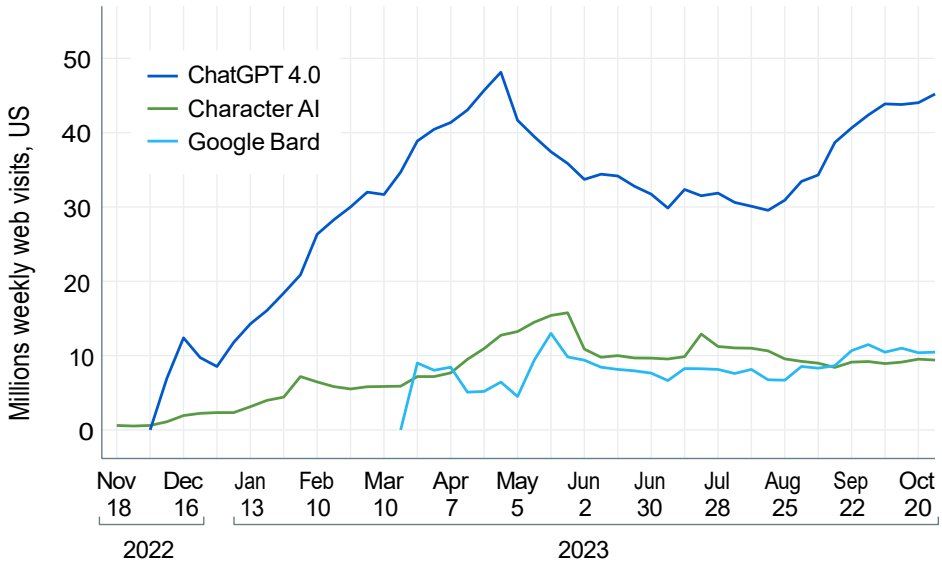


Figure 9. U.S. web traffic trends to AI platforms, 2022–2023 [45]

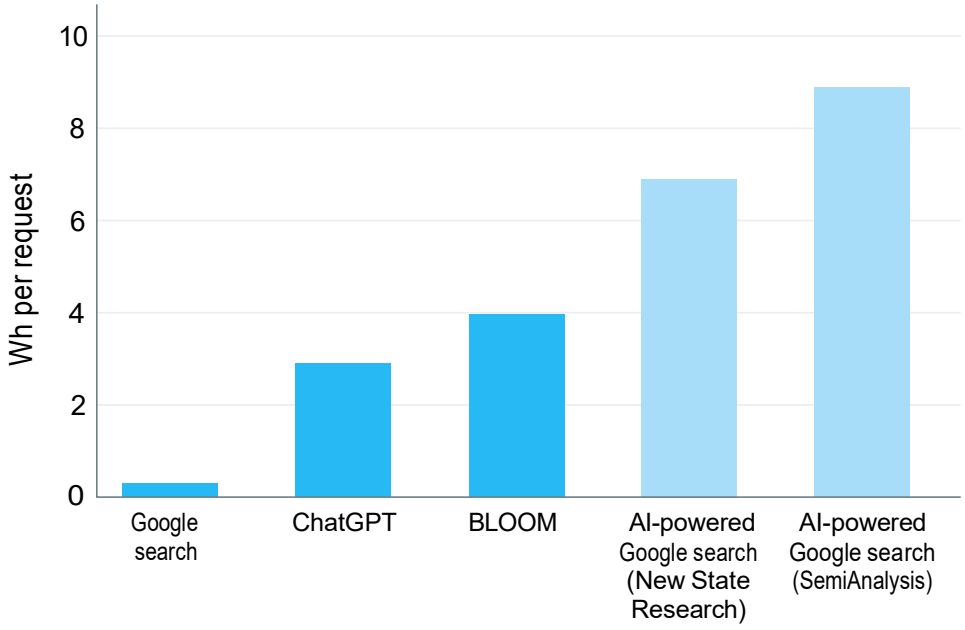


Figure 10. Electricity consumption per request [47]

2.9 watt-hours (Wh) per ChatGPT request, AI queries are estimated to require 10 times the electricity of traditional Google queries, which use about 0.3 Wh each [47]. Implementing LLMs in every Google search could necessitate 80 gigawatt-hours (GWh) daily or 29.2 terawatt-hours (TWh) yearly electricity consumption, according to SemiAnalysis [34]. New Street Research's similar analysis suggests the need for around 400,000 servers, consuming 62.4 GWh daily or 22.8 TWh yearly [47]. As shown in **Figure 10**, the BLOOM model's electricity usage averages 3.96 Wh per request, while ChatGPT's is slightly lower at 2.9 Wh per request; however, if Google integrated similar AI into its searches, the electricity per search could increase to between 6.9–8.9 Wh [47].

The explosive growth in investments aimed at building and deploying new AI capabilities are raising concerns over the overall electricity consumption and environmental impact of AI and data centers and the ability of the United States to maintain its leadership position.

FORECASTING DATA CENTER LOAD GROWTH TO 2030

Four Scenarios Based on Historical Data, Expert Insights, and Current Trends

Drawing on public information about existing data centers, public estimates of industry growth, and recent electricity demand forecasts by industry experts, EPRI prepared four projections—using low (3.7%), moderate (5%), high (10%), and higher (15%) growth scenarios described in **Table 3** below—of potential electricity consumption in U.S. data centers from 2023 to 2030. See **Figure 11** for a graph of the projections. These projections are based on a bounding analysis of various data sources surveyed as of November 2023 [1, 2, 4, 8, 14]. The analysis reflects historical trends for the AI industry, internet traffic, demand for storage, coupled with the computational intensity and prevalence of AI models. All of these factors are uncertain, including the development of business models and updates for LLMs, rate of increase in mature applications, and efficiency gains in computational and non-computational aspects of data centers.

The graph's blue line depicts average historical data center electricity consumption. The light blue area indicates the uncertainty in recent historical projections of data center power use, and the colored swaths show the four projection scenarios [4, 8].

Under the 15% higher growth scenario, EPRI's projections show data center electricity usage rising to an average of 403.9 TWh/year. Under the 10% high growth scenario, data center energy usage rises to a mid-range of 296.4 TWh/yr. Using the moderate growth 5% scenario, the projection predicts a mid-range of 214.0 TWh/yr. Under the 3.7% low growth scenario, the graph shows the projection at a mid-range of 196.3 TWh/yr. The mid-range estimates of data centers' share of total U.S. electricity consumption in 2030—9.1%, 6.8%, 5.0%, and 4.6%—assume that other loads grow at 1% annually. An examination of regional variations is found in **Appendix A**.

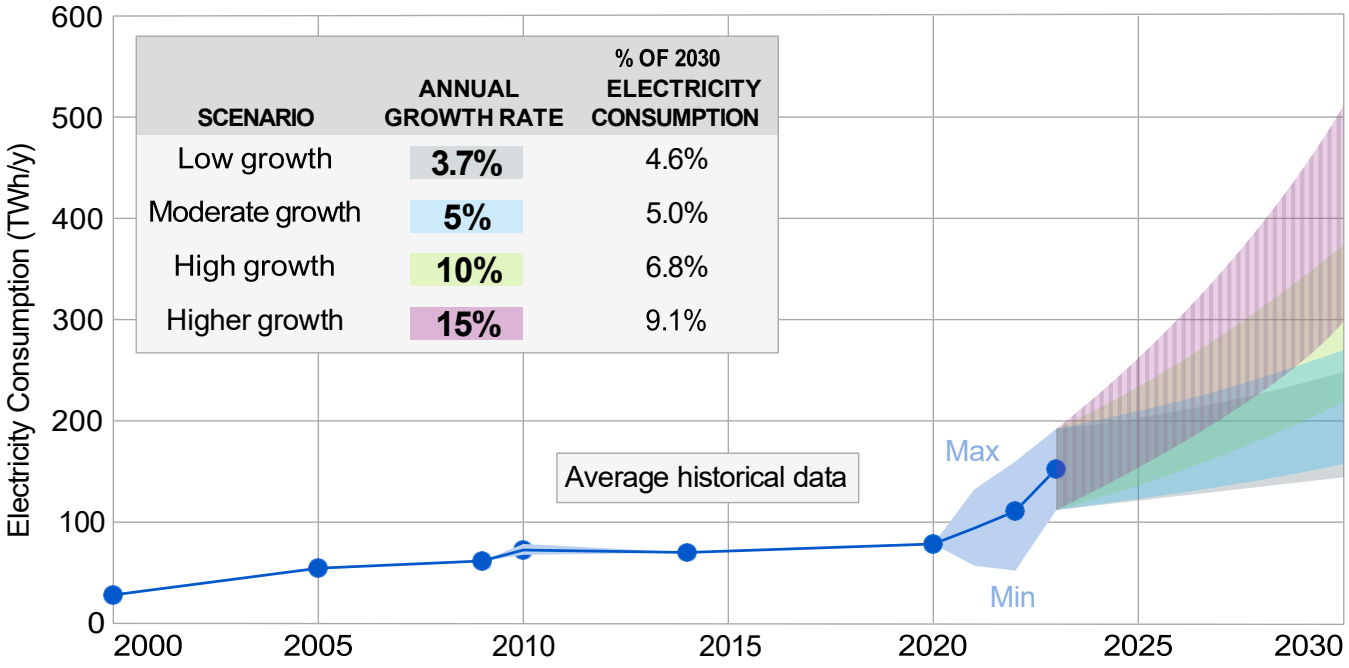


Figure 11. Projections of potential power consumption in U.S. data centers scenarios, 2023–2030 [1, 2, 4, 8, 14]

Table 3. Forecasted load projections: Parameters of power consumption in each of the four U.S. data center scenarios, 2022-2030 [4, 8, 9]

COMPOSITION OF GROWTH SCENARIOS (2023—2030)				
GROWTH SCENARIO	CAGR (%)	AVERAGE 2023 DATA CENTER LOAD (MWH)	AVERAGE PROJECTED LOAD, 2030 (MWH)	CHANGE IN GROWTH (Δ)
Higher Growth	15%	152,120,846	403,906,136	166%
High Growth	10%	152,120,846	296,440,493	95%
Moderate Growth	5%	152,120,846	214,049,306	41%
Low Growth	3.7%	152,120,846	196,305,818	29%

Each growth scenario's characteristics are described in **Table 3**. The load projections combine estimates of today's data center power usage with assessments of potential future technological advances and computational demands. It is essential to understand that while these scenarios are based upon the latest available data and subject-matter expert (SME) insights, the factors affecting them—such as consumer demand, technological advancements, operational efficiencies, and evolving industry standards—are changing almost daily.

ENERGY EFFICIENCY, LOAD MANAGEMENT AND CLEAN ELECTRICITY SUPPLY

With the escalating demands of AI and data center operations, there is a critical need for new, innovative strategies that leverage advances in hardware, system monitoring, computational algorithms, clean electricity procurement, and operational flexibility [49]. Key considerations include:

- Energy efficiency: Adopt advanced cooling solutions, power management systems, and leverage efficiency advances in computational and supporting hardware to reduce overall electricity consumption.
- Scalability: Implement modular designs and virtualization techniques to ensure that infrastructure can handle future demands without disproportionate increases in energy use.
- Carbon-free energy (CFE) use: Transition to carbon-free electricity sources for data center operations and low-carbon technologies for backup power to support data center expansion without increasing carbon emissions and make energy costs more certain.
- Monitoring and analytics: Utilize real-time monitoring tools to track electricity consumption, detect inefficiencies, and optimize operations.
- Research and development (R&D): Invest in innovations that drive both performance and sustainability, such as green energy sources or AI-driven optimization of work load to meet latency, grid, environmental, and other objectives.

The remainder of this section discusses in more detail strategies that cover energy-efficient algorithms, hardware, and cooling technologies; scalability and renewable energy use; and monitoring, analytics, and R&D.

Energy-Efficient Training Algorithms

The initial phases of AI algorithm development have been heavily focused on enhancing accuracy and augmenting performance capabilities. However, as the performance of the algorithms has increased and recognizing the exponential growth in computational demands, the paradigm is beginning to shift to also value the efficiency of model development. Recent studies document applications where a slight compromise on model accuracy has yielded substantial reductions in electricity consumption [7, 18, 43, 50]. The techniques utilized include:

- Pruning: This technique aims to reduce or eliminate unnecessary elements in neural networks, thereby maintaining robust performance while reducing computational complexity [43, 51].
- Quantization: This method reduces the numerical precision of computations, effectively conserving electricity without compromising significantly on accuracy [14, 51].
- Knowledge distillation: This approach involves developing a smaller, more manageable model that mirrors the functionalities of a larger, more intricate structure, reducing computational requirements [14, 51].

Energy-Efficient Hardware

Computational hardware is becoming more efficient, venturing beyond general-purpose central processing units (CPUs) to embrace an array of specialized hardware. These hardware variants are customized for specific tasks, streamlining power usage, and enhancing overall efficiency. This specialized hardware includes:

- Tensor processing units (TPUs): Specifically designed to expedite machine learning (ML) tasks, these units provide pronounced performance and energy efficiency enhancements [11, 18]. For example, Google's Cloud TPUv4 showed not only a 10-times leap forward in ML system performance over TPUv3, but it also boosted energy efficiency by 2–3% compared to contemporary ML data structures and algorithms [52].
- Field-programmable gate arrays (FPGAs): Recognized for their versatility as non-hard etched processors, FPGAs can be reprogrammed for specific tasks, providing improved performance and lower per-unit energy consumption [11, 28]. Though savings are task-dependent, FPGAs have shown reductions in memory and bandwidth usage as much as 75% when compared to traditional CPUs and graphics processing units (GPUs) [28, 53, 54].
- Power capping: Some processing chips, such as GPUs, can operate at reduced power levels. For example they can reduce direct power consumption by 10% while also reducing cooling needs.

Energy-Efficient Cooling Technologies

Heat is a byproduct of computation, and traditional cooling methods are energy-intensive, composing around 35% of data center electricity use. However, innovative solutions are emerging, some of which include:

- Liquid cooling: Utilizing liquids to absorb and dissipate heat can use less electricity than traditional air-cooling systems [18, 50]. A recent study, which examined the shift from 100% air cooling to a combination of 25% air cooling and 75% liquid cooling, highlighted the efficiency gains—leading to a notable decrease in PUE—from transitioning to hybrid cooling systems in data centers. The study observed a 27% reduction in facility power consumption and a 15.5% decrease in overall energy usage across the data center site [55]. **Table 4** shows an overview of various innovative cooling ttechnologies currently being adopted or considered in data centers, highlighting vendor-reported technology-readiness level (TRL) and energy-saving estimates [56, 57, 58, 59, 60, 61].
- Economizer use: An economizer can evaluate outside temperature and humidity, and use exterior air to help cool data center infrastructure when appropriate, minimizing reliance on mechanical cooling methods and leading to significant electricity savings [18, 62]. A 2015 study found that air-side economizers yielded cooling coil load savings of 76–99% in comparison to conventional cooling systems in data centers; and the total cooling energy savings of the economizers ranged from 47.5%–67.2% [62].

Table 4. Emerging cooling technologies with vendor-reported TRLs and energy savings [56, 57, 58, 59, 60, 61]

EMERGING COOLING TECHNOLOGIES		
TECHNOLOGY	TECHNOLOGY-READINESS LEVEL (TRL)	CLAIMED EFFICIENCY DIFFERENTIAL (%)
Air-Assisted Liquid Cooling	9	This technology offers up to a 50% reduction in energy usage compared to traditional air cooling, with the potential to reach a PUE of less than 1.1 [56].
Immersion Cooling	8	Immersion cooling promises substantial energy savings from 50–95% compared to traditional air-cooling methods [57, 58].
Microconvective Liquid Cooling	6	This emerging technology proposes an 18% energy saving and a PUE of 1.02, alongside a 90% reduction in water usage compared to other liquid systems, indicating its potential for more sustainable operation [59].
Radiative Cooling	6	This solution offers 50–70% energy savings, with the benefits of zero water use and low maintenance [60].
Two-Phase Liquid Immersion Cooling	7	This technology claims a 41% energy saving compared to air cooling, noting its water conservation and space-saving benefits [61].

- Heat reuse: Heat generated by computation can be used for various applications such as heating adjacent buildings, particularly in cold climates, thereby reducing overall energy usage [18, 42, 63]. Since 2016, Amazon's 1.1 million-square-foot Doppler building has been estimated to recover 3200 MWh of excess heat from a nearby data center; this is projected to continue over the next 25 years. This heat, which would otherwise have been wasted and would have required cooling equipment, is redirected through the district's energy system, demonstrating an energy-efficient approach to energy reutilization [25].

Scalable Clean Energy Use

As digital services proliferate and demand for computational power intensifies, scalable clean energy supplies are important to avoid increases in greenhouse gas emissions [64]. Corporate commitments to acquire carbon-free electricity on an annual or hourly-matched basis are emerging and can play a significant role in reducing data center emissions impacts. These include:

- Clean electricity procurement from the grid and clean onsite generation: Data center owners have been instrumental in driving the corporate shift towards contracting for renewable energy to provide their power needs. In 2021, Apple, Google, Meta, and Microsoft matched their operational electricity consumption, predominantly from data centers, on an annual basis with the purchase or generation of renewable electricity—2800 MWh, 18,300 MWh, 9400 MWh, and 13,000 MWh respectively [55, 56, 57, 58]. Meanwhile, Amazon's operations consumed 30,900 MWh, 85% of which was matched on an annual basis by generation from renewable sources, and the company aims to reach 100% renewable energy by 2025 [25, 16, 41]. Moreover, a growing number of organizations are working towards 24/7 CFE, which entails matching their electricity demand with carbon-free sources in the same region on an hourly basis. This hourly matching will require flexible technologies such as batteries that can shift solar or wind output to times when they are needed as well as firm clean capacity such as nuclear, fossil plants with carbon capture and storage, or geothermal, that typically operate around the clock. Spurring deployment of flexible and clean firm assets can help speed the path to a net-zero power sector [42, 44].
- Cleaner onsite backup power systems: Backup power systems at most existing data centers typically operate for less than 100 hours annually when the grid or primary power supply are unavailable. Accordingly, they constitute only a small portion of a data center's environmental footprint. Shifting from the most common backup technology, diesel generators, to lower-emitting alternatives, like battery energy storage systems (BESS) or cleaner fuels—such as renewable natural gas, biodiesel, or clean hydrogen or ammonia, especially when the latter are integrated with fuel cells—can reduce backup GHG emissions and, in some instances, allow more frequent operation of these resources, creating the potential for them to serve as a grid resource when/if needed [9, 42].
- Clean onsite or nearby technologies such as nuclear generation or renewable generation coupled with long-duration energy storage that can match the growing size of data centers: With currently proposed data centers reaching 1 GW or more at a single site, the scale of power demand is escalating rapidly. In the near term, uprating, relicensing, or restarting existing nuclear plants near data centers could provide one solution. Amazon's purchase of a data center in Pennsylvania co-located with a Talen nuclear power plant provides one example of utilizing existing nuclear. Looking forward, small modular reactors (SMRs) offer a scalable power solution that can grow with the demands of a data center. Companies such as NuScale are exploring scalable capacities of 250–600MW for SMRs [9, 42]. Standard Power has chosen NuScale's SMR technology to power two facilities it plans to develop, one in Ohio and the other in Pennsylvania [69].

Monitoring and Analytics

Advances in monitoring and analytics of power consumption play a crucial role in realizing operational savings in data centers. These processes enable precise tracking of energy usage, identification of inefficiencies, and implementation of advanced technologies, thus driving cost reduction and enhancing overall efficiency:

- Efficient server management: Traditionally, data centers have grappled with up to 30% server underutilization, where servers consume energy but don't fully utilize their computational capabilities. However, with the adoption of innovations like advanced scheduling and dynamic resource allocation, some companies are aiming to reduce underutilization rates to below 10% within the next five years [18, 40, 63, 70]. In addition, the implementation of virtualization and containeriza-

tion can enhance server efficiency significantly, potentially increasing server capacity utilization by 45% by having a single physical server handle more workloads through virtual or containerized environments. If successful, this is estimated to reduce the number of physical servers needed, leading to about 20% less energy consumption per unit of computation over the next decade [15, 33, 42].

- Flexible computation strategies: Optimizing data center computation and geographic location to respond to electricity supply conditions, electricity carbon intensity, and other factors in addition to minimizing latency enables data centers to actively adjust their electricity consumption [71]. For example, some could achieve significant cost savings—as much as 15%—by optimizing computation to capitalize on lower electric rates during off-peak hours, reducing strain on the grid during high-demand periods [38, 72]. With technological and regulatory advances, these strategies could evolve to incorporate real-time energy market dynamics enabling data centers to not only adjust their operations based on grid demands but also actively participate in energy markets to optimize their benefits and support grid stability.

Reducing Data Centers' Environmental Footprint

The previous sections focus on actions that data center owners and operators are actively pursuing to diminish their carbon footprint, focusing primarily on onsite direct emissions such as from onsite generation (Scope 1 emissions) and emissions associated with the purchase of electricity (Scope 2 emissions) [64]. These strategies involve reducing their electricity needs through the adoption of advanced computation, cooling, and operational technologies, shifting toward cleaner onsite backup power, and moving towards various strategies for matching their hourly loads with carbon-free electricity [73]. Several of the hyperscale companies have fully matched their annual power purchases with carbon-free electricity on an annual basis and are moving forward on hourly matching. Progress is slower on shifting to cleaner backup power (although this, as noted earlier, represents only a small fraction of their environmental footprint).

In recent years, some companies have taken the additional step of quantifying and setting reduction targets for their (Scope 3) indirect emissions, which include emissions associated with supply chains and end-user services [7, 44, 66]. Key actions include sourcing materials from environmentally responsible vendors, minimizing the carbon footprint associated with transportation and logistics, and ensuring that the lifecycle of data center components is managed sustainably, from manufacturing to end-of-life disposal and recycling [42, 74, 75].

ACTIONS TO SUPPORT RAPID DATA CENTER EXPANSION

Data centers are one of the fastest growing industries worldwide. These facilities—and advanced cloud computing and AI technologies that are proliferating and driving further growth—represent large point loads and are at the leading edge of an anticipated global rise in electricity demand driven by efficient electrification and production of low-carbon fuels.

In the United States, data center power demand growth, coupled with increasing electricity demands from EVs, heat pumps, electrification in industry, and the onshoring of manufacturing incentivized by the CHIPS Act, Inflation Reduction Act (IRA), and Infrastructure Investment and Jobs Act (IIJA), is placing both immediate and sustained pressure on the electric grid to accommodate new loads.

Clusters of new, large point loads create several challenges. Data centers' speed from breaking ground to operation—often within two or three years—requirements for highly reliable power, and requests for power generated by new, non-emitting generation sources can create local and regional electric supply challenges and test the ability of electric companies to keep pace. The most serious challenges to data center expansion are local and result from the scale of the centers themselves and mismatches in infrastructure timing.

EPRI highlights three essential strategies to support rapid data center expansion. These strategies, each of which is explained below, emphasize increased collaboration between data center developers and electric companies and are:

- Improve data center operational efficiency and flexibility
- Increase collaboration through a shared energy economy model for sustainable data centers
- Better anticipate future point load growth through improved forecasting and modeling

Improve Data Center Operational Efficiency and Flexibility

Over the past decade, economy-wide electricity demand in the United States has remained relatively flat in large part due to enhanced energy efficiency, which has offset potential increases driven by economic expansion and population growth. Specific to data centers, power demands from rapid expansion in computation, communication, and data storage were largely offset by efficiency gains for over a decade. This is largely due to technological advancements in computation, improved cooling systems, sophisticated energy management strategies, and the replacement of many small data centers with more efficient cloud data centers. However, since around 2018, efficiency gains have slowed, data center expansion accelerated (in part due to lifestyle changes caused by the pandemic), and AI has proliferated, leading to an increase in data center power consumption.

Meeting the increasing electricity demands of AI and data centers while limiting the growth of CO_2 emissions necessitates a comprehensive strategy that intertwines technological advancements that improve efficiency with power purchase and production strategies that favor low-carbon resources and that increase both temporal and spatial flexibility to link intense operation periods to the availability of low-cost, low-carbon generation.

Computational efficiency gains require investing in the next generation of energy-efficient processors and server architectures and enhancing AI training algorithms for greater computational efficiency. From an architectural viewpoint, virtualization stands out, with its capability to run multiple virtual machines on one physical server, potentially cutting hardware needs by 30–40% with consequent electricity savings [9, 75]. Implementations like software-defined infrastructure (SDI) offer dynamic resource allocation in real time, potentially increasing allocation efficiency by 30%, potentially increasing spatial flexibility in computation loads. Hybrid cloud solutions provide a balance between on-premises infrastructure and shared cloud services, potentially providing locational flexibility by reducing onsite requirements by 25% during peak periods.

In addition, continued gains in data center infrastructure efficiency can be achieved through more effective cooling technologies, adopting energy management systems that leverage AI for optimized power usage, and setting stringent industry targets for energy consumption. Continuous monitoring and analytics can help data centers better anticipate and react to dynamic energy needs, ensuring optimal operational efficiency and rapid adaptability [42, 50, 78]. Embedding real-time monitoring tools within AI and data center ecosystems can facilitate immediate insights into fluctuations in electricity usage. Pilot projects to explore and validate novel energy conservation methods, which document and disseminate findings broadly, can accelerate adoption of proven sustainable strategies [10, 70].

Increase Collaboration through a Shared Energy Economy Model for Sustainable Data Centers

Electric companies are challenged as they must meet the increasing and uncertain load from data centers while also ensuring reliability, affordability, and sustainability for all customers. Developing a deeper understanding of data center power needs, timing, and potential flexibilities—while assessing how they match available electric supplies and delivery constraints—can create workable solutions for all.

EPRI, in collaboration with major data center builders/operators/owners and the electric companies that power these facilities, is exploring sustainable approaches to powering the growing wave of AI data centers. Enabled by technology and supporting policies, data center backup generators, powered by clean fuels, could support a more reliable grid while reducing the cost of data center operation. Shifting the data center-grid relationship from the current “passive load” model to a collaborative “shared energy economy”—with grid resources powering data centers and data center backup resources contributing to grid reliability and flexibility—could not only help electric companies contend with the explosive growth of AI but also contribute to affordability and reliability for all electricity users.

This new paradigm of collaboration between data centers and electric companies, which transforms data centers from passive consumers to active participants in maintaining the grid, is crucial for ensuring electric companies are prepared for the explosive growth of AI. Under this model, data centers move from being a burden on the grid—acting as passive loads demanding specific power levels within defined timeframes and at affordable rates—to becoming partners in a sustainable future, serving as a grid reliability resource. The goal is the complete integration of grid and data center power resources. Clean power generators co-located with data centers act as both grid and data center power sources. During grid outages, these resources can seamlessly form a microgrid to provide uninterrupted power to data

centers, eliminating the need and cost of standard diesel backup generators.

More research is needed into how data centers and electric grids can collaborate in a shared energy economy model, as well as the benefits and challenges of doing so. Focusing on U.S. AI training data centers using backup generators powered by clean fuels, EPRI suggests a study of the economic, environmental, social, and technological implications of this shared energy economy model compared to other, more traditional models. The results of this study could provide suggestions and guidelines for data centers and electric grids to adopt and implement the shared energy economy model, or parts of it, in their operations and planning.

Better Anticipate Future Point Load Growth through Improved Forecasting and Modeling

The lead time for constructing and bringing a large data center online is around two to three years, while adding new electric infrastructure (generation, transmission, substations) can take four or many more years. This highlights the need for better forecasting and decision tools to anticipate where and when data center connection requests may appear and characterizing the operational characteristics of that load, especially as the size of interconnection requests grow from hundreds of MW to thousands of MW.

In the current environment, electricity companies are often receiving multiple requests for the same project from the owner and from developers trying to support the owner. Also, a single data center project may seek interconnection information in multiple locations. And the ramp up to full power demand and operational characteristics on the data centers can vary widely, depending upon their function (e.g., cloud, AI training, AI inference). Therefore, new approaches are needed not only to project where load will grow, but also its operational characteristics and opportunities for flexible operation.

EPRI's Load Forecasting Initiative (https://msites.epri.com/lfi), initiated in late 2023, has research activities underway to help address some of these key uncertainties.

APPENDIX A: STATE-SPECIFIC SCENARIOS

Projected Data Center Load Scenarios for Top 15 States

Figures A1 through A15 apply the projected U.S. load growth rates under EPRI's higher-, high-, moderate-, and low-growth scenarios to 2023 estimated state-level data center loads. The figures show projections for the 15 states with the highest data center demands in 2023, comprising around 80% of U.S. data center load in that year. As noted above, the projections utilize the projected national growth rate and do not reflect the deferential regional growth rates implied by Integrated Resource Plan analyses that have emerged recently.

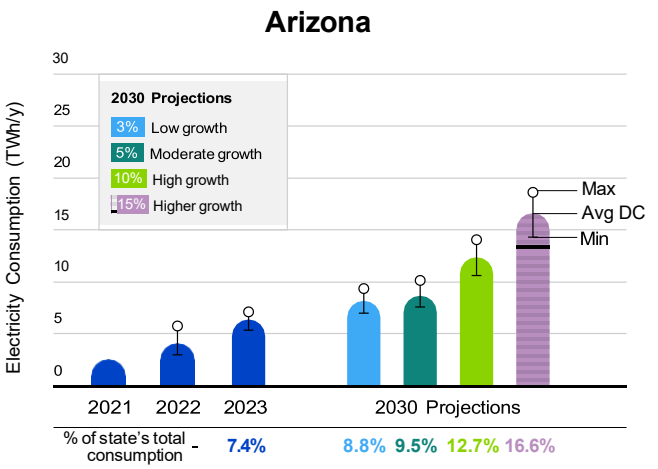


Figure A1.
Projected electricity consumption in Arizona data centers

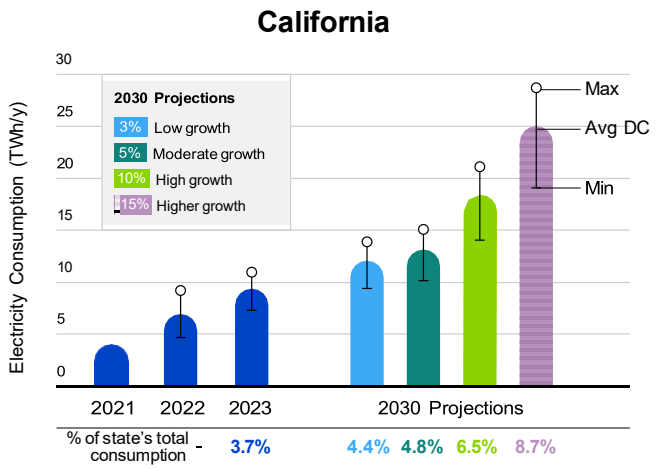


Figure A2.
Projected electricity consumption in California data centers

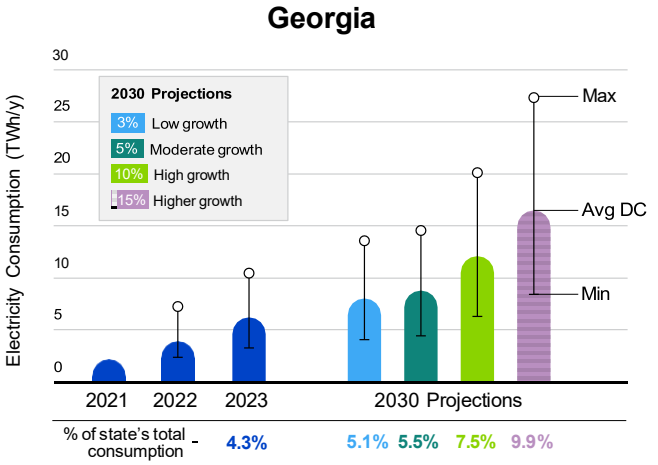


Figure A3.
Projected electricity consumption in Georgia data centers

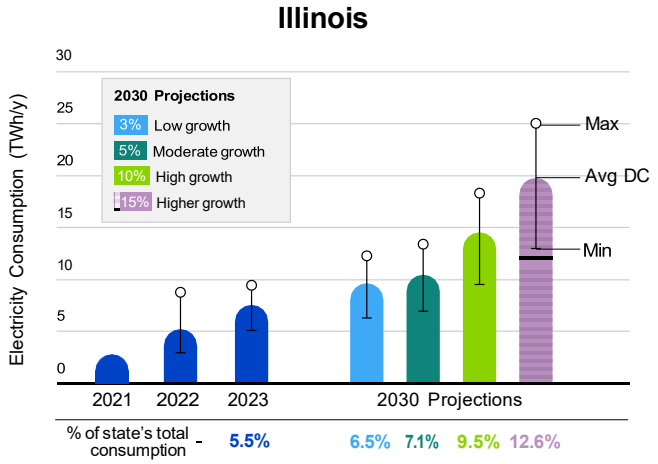


Figure A4.
Projected electricity consumption in Illinois data centers

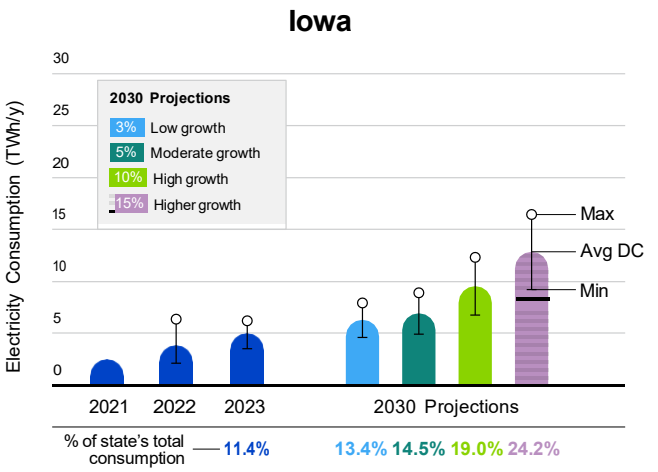


Figure A5.
Projected electricity consumption in Iowa data centers

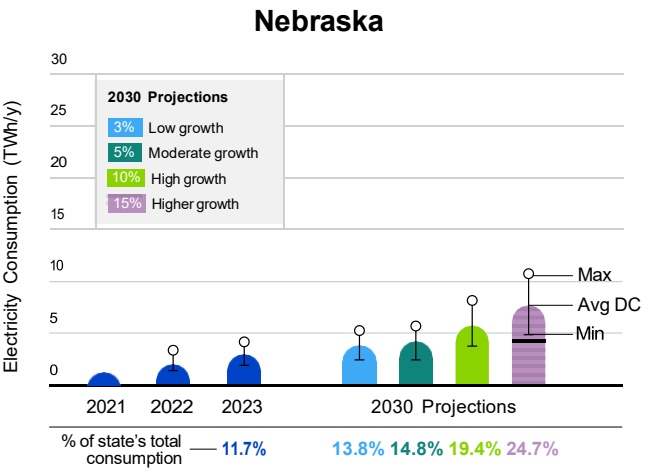


Figure A6.
Projected electricity consumption in Nebraska data centers

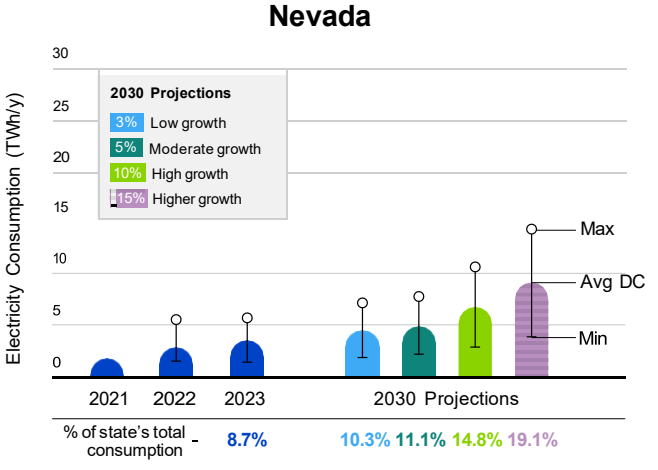


Figure A7.
Projected electricity consumption in Nevada data centers

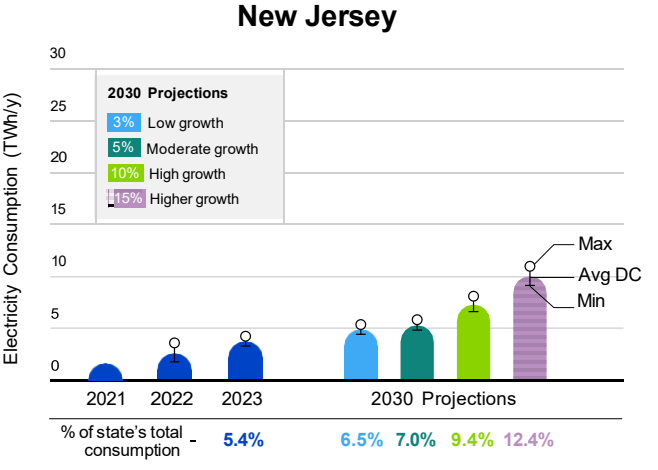


Figure A8.
Projected electricity consumption in New Jersey data centers

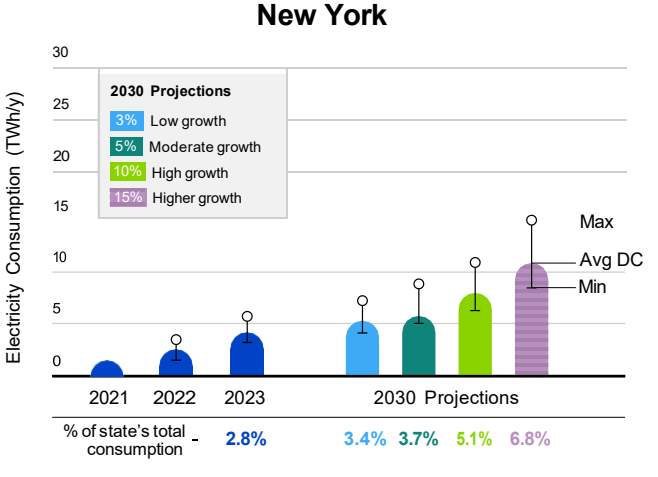


Figure A9.
Projected electricity consumption in New York data centers

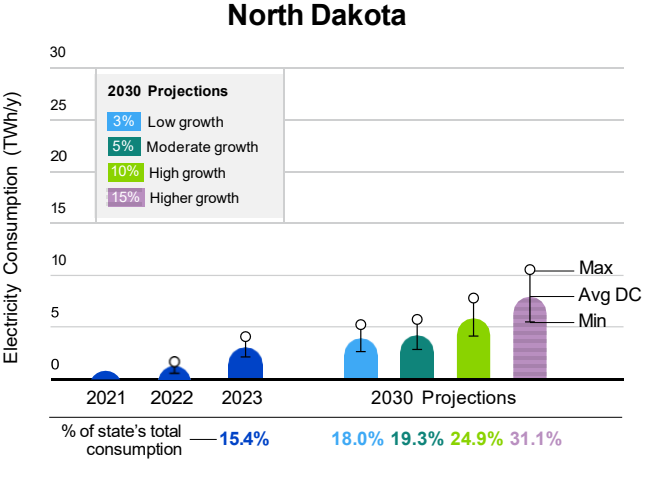


Figure A10.
Projected electricity consumption in North Dakota data centers

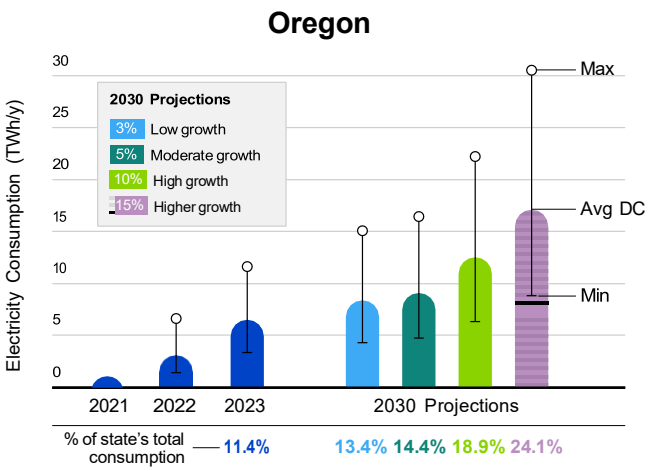


Figure A11.
Projected electricity consumption in Oregon data centers

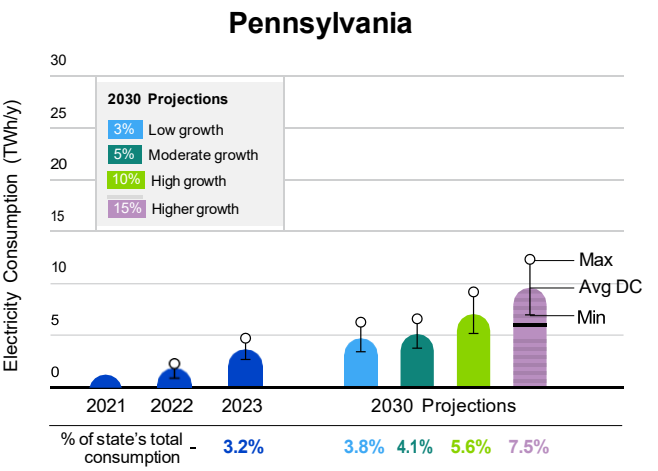


Figure A12.
Projected electricity consumption in Pennsylvania data centers

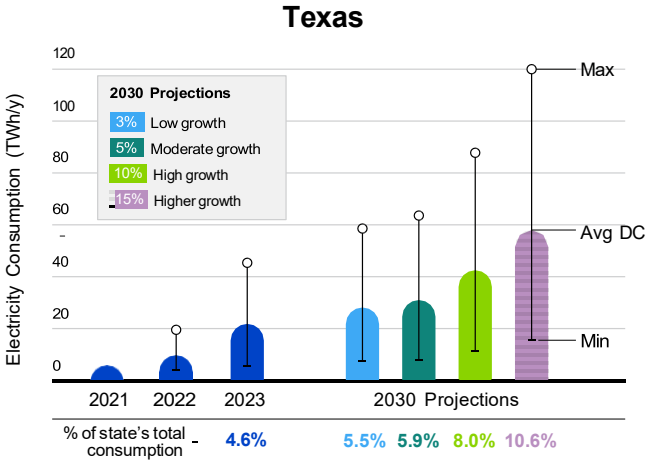


Figure A13.
Projected electricity consumption in Texas data centers

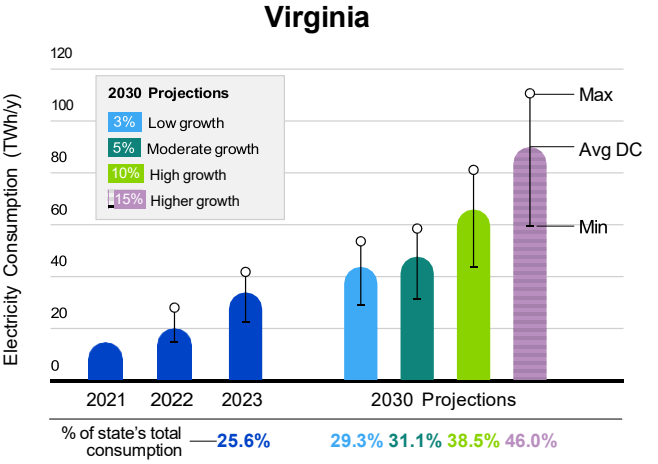


Figure A14.
Projected electricity consumption in Virginia data centers

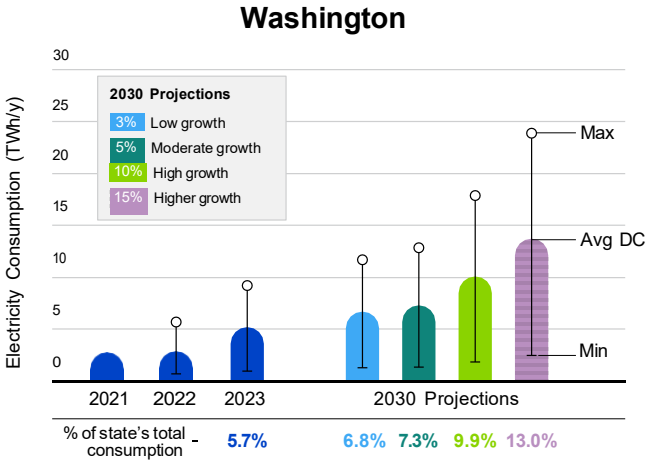


Figure A15.
Projected electricity consumption in Washington data centers

Regional Differences in Data Center Capacities by Metropolitan Area

Data center development is heavily clustered in a few counties/cities across the country rather than evenly spread within states, exacerbating power delivery challenges. **Figure A16** provides a snapshot for leading metropolitan areas of current data center capacity (measured in MW); additional capacity under development; absorption rates, reflecting the percentage of capacity leased by customers over a specific period of time; and vacancy rates, indicating unutilized space within these data centers.

Northern Virginia is the clear leader in terms of current capacity and current construction. Other regions, such as Dallas-Ft. Worth, Silicon Valley, Chicago, New York Tri-State, and Atlanta, highlight current construction activity that is projected to lead to a 50% or more increase in power demands. [29].

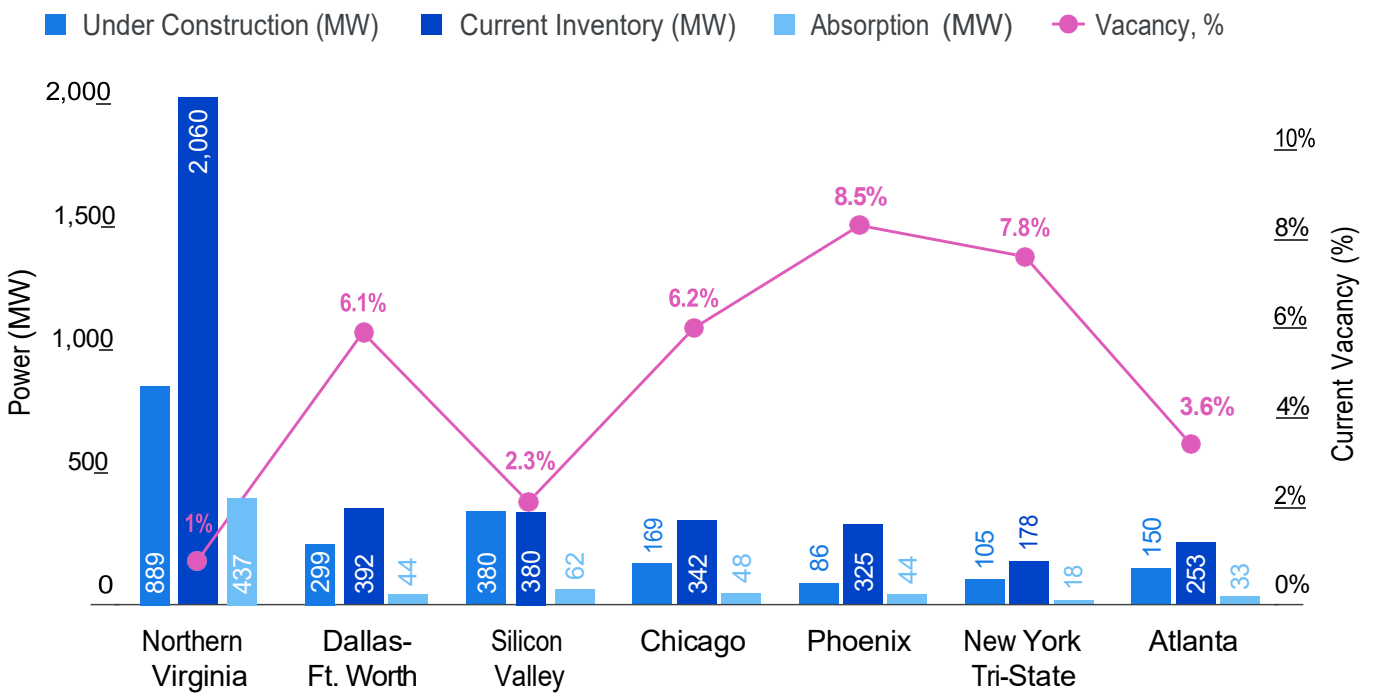


Figure A16. Data center development: Key U.S. regions (2022)

Projections of Potential Power Consumption for 44 States

Table A1 presents a detailed view of the energy consumption from data centers in each of the 44 states that had significant data center load in 2023 and contrasts it with projections for 2030. These projections are categorized into three scenarios: low growth, moderate growth, high growth, and higher growth [1, 2, 4, 8, 14].

Table A1. Projections to 2030 of potential power consumption for states with significant data center load in 2023 [4, 8, 9]

FORECASTED SCENARIOS: PROJECTIONS OF POTENTIAL POWER CONSUMPTION BY STATE (2023–2030)										
	2023 Load		Low-growth Scenario (3.71%)		Moderate-growth Scenario (5%)		High-growth Scenario (10%)		Higher-growth Scenario (15%)	
STATE	MWh/y	% of Total State Electricity Consumed (%EC)	MWh/y	% of Total State Electricity Consumed (%EC)	MWh/y	% of Total State Electricity Consumed (%EC)	MWh/y	% of Total State Electricity Consumed (%EC)	MWh/y	% of Total State Electricity Consumed (%EC)
Alabama	1,489,200	1.71%	1,921,753	2.05%	2,095,454	2.23%	2,902,030	3.07%	3,954,074	4.13%
Arizona	6,253,268	7.43%	8,069,590	8.81%	8,798,975	9.53%	12,185,850	12.73%	16,603,465	16.58%
California	9,331,619	3.70%	12,042,078	4.43%	13,130,525	4.81%	18,184,686	6.54%	24,777,000	8.70%
Colorado	1,509,640	2.66%	1,948,130	3.18%	2,124,215	3.46%	2,941,861	4.73%	4,008,345	6.34%
Connecticut	262,800	0.95%	339,133	1.14%	369,786	1.24%	512,123	1.71%	697,778	2.31%
Florida	1,384,080	0.56%	1,786,099	0.67%	1,947,540	0.73%	2,697,180	1.01%	3,674,963	1.37%
Georgia	6,175,391	4.26%	7,969,093	5.08%	8,689,396	5.51%	12,034,090	7.48%	16,396,690	9.92%
Hawaii	8,760	0.10%	11,304	0.12%	12,326	0.13%	17,071	0.18%	23,259	0.24%
Idaho	148,920	0.57%	192,175	0.68%	209,545	0.74%	290,203	1.03%	395,407	1.40%
Illinois	7,450,176	5.48%	9,614,151	6.53%	10,483,145	7.08%	14,518,285	9.54%	19,781,455	12.56%
Indiana	192,720	0.19%	248,697	0.23%	271,176	0.25%	375,557	0.35%	511,704	0.48%
Iowa	6,193,320	11.43%	7,992,230	13.44%	8,714,623	14.48%	12,069,029	18.99%	16,444,294	24.21%
Kansas	8,760	0.02%	11,304	0.03%	12,326	0.03%	17,071	0.04%	23,259	0.05%
Kentucky	1,620,600	2.15%	2,091,319	2.58%	2,280,347	2.80%	3,158,091	3.84%	4,302,962	5.16%
Louisiana	78,840	0.08%	101,740	0.10%	110,936	0.11%	153,637	0.15%	209,333	0.20%
Maine	26,280	0.22%	33,913	0.27%	36,979	0.29%	51,212	0.40%	69,778	0.55%
Maryland	96,360	0.16%	124,349	0.19%	135,588	0.21%	187,778	0.29%	255,852	0.40%
Massachusetts	1,062,369	2.08%	1,370,944	2.50%	1,494,860	2.72%	2,070,257	3.72%	2,820,766	5.01%
Michigan	525,600	0.52%	678,266	0.63%	739,572	0.68%	1,024,246	0.95%	1,395,555	1.28%
Minnesota	824,316	1.24%	1,063,747	1.49%	1,159,895	1.62%	1,606,359	2.23%	2,188,696	3.01%
Missouri	972,360	1.21%	1,254,791	1.45%	1,368,208	1.58%	1,894,855	2.18%	2,581,777	2.95%
Montana	578,160	3.71%	746,092	4.43%	813,529	4.81%	1,126,670	6.54%	1,535,111	8.71%
Nebraska	3,959,520	11.70%	5,109,601	13.75%	5,571,442	14.81%	7,715,984	19.41%	10,513,184	24.71%
Nevada	3,416,707	8.69%	4,409,122	10.28%	4,807,649	11.10%	6,658,195	14.75%	9,071,924	19.07%
New Hampshire	17,520	0.16%	22,609	0.19%	24,652	0.21%	34,142	0.29%	46,519	0.40%
New Jersey	4,038,360	5.42%	5,211,341	6.46%	5,682,378	7.00%	7,869,621	9.44%	10,722,517	12.44%
New Mexico	402,960	1.48%	520,004	1.78%	567,005	1.94%	785,255	2.66%	1,069,926	3.60%
New York	4,067,385	2.84%	5,248,796	3.40%	5,723,219	3.69%	7,926,182	5.05%	10,799,583	6.75%
North Carolina	2,672,676	1.92%	3,448,981	2.30%	3,760,724	2.50%	5,208,289	3.44%	7,096,399	4.62%
North Dakota	3,915,720	15.42%	5,053,079	18.00%	5,509,811	19.31%	7,630,631	24.89%	10,396,888	31.11%
Ohio	2,363,886	1.58%	3,050,500	1.90%	3,326,225	2.07%	4,606,545	2.84%	6,276,510	3.83%
Oklahoma	1,226,400	1.76%	1,582,620	2.12%	1,725,668	2.30%	2,389,907	3.16%	3,256,296	4.26%

FORECASTED SCENARIOS: PROJECTIONS OF POTENTIAL POWER CONSUMPTION BY STATE (2023–2030)										
	2023 Load		Low-growth Scenario (3.71%)		Moderate-growth Scenario (5%)		High-growth Scenario (10%)		Higher-growth Scenario (15%)	
STATE	MWh/y	% of Total State Electricity Consumed (%EC)	MWh/y	% of Total State Electricity Consumed (%EC)	MWh/y	% of Total State Electricity Consumed (%EC)	MWh/y	% of Total State Electricity Consumed (%EC)	MWh/y	% of Total State Electricity Consumed (%EC)
Oregon	6,413,663	11.39%	8,276,574	13.39%	9,024,668	14.43%	12,498,415	18.93%	17,029,342	24.14%
Pennsylvania	4,590,240	3.16%	5,923,520	3.78%	6,458,929	4.11%	8,945,079	5.61%	12,187,850	7.49%
Rhode Island	17,520	0.23%	22,609	0.28%	24,652	0.30%	34,142	0.42%	46,519	0.57%
South Carolina	2,023,560	2.45%	2,611,323	2.93%	2,847,352	3.18%	3,943,346	4.36%	5,372,888	5.84%
South Dakota	70,080	0.52%	90,435	0.63%	98,610	0.68%	136,566	0.94%	186,074	1.28%
Tennessee	1,327,140	1.30%	1,712,621	1.56%	1,867,419	1.70%	2,586,220	2.34%	3,523,777	3.16%
Texas	21,813,159	4.59%	28,149,002	5.47%	30,693,306	5.94%	42,507,676	8.04%	57,917,564	10.64%
Utah	2,562,037	7.68%	3,306,206	9.10%	3,605,044	9.84%	4,992,686	13.13%	6,802,635	17.08%
Virginia	33,851,122	25.59%	43,683,508	29.28%	47,631,928	31.10%	65,966,260	38.47%	89,880,357	46.00%
Washington	5,171,612	5.69%	6,673,757	6.77%	7,276,977	7.34%	10,078,009	9.88%	13,731,490	13.00%
Wisconsin	148,920	0.21%	192,175	0.26%	209,545	0.28%	290,203	0.39%	395,407	0.53%
Wyoming	1,857,120	11.26%	2,396,538	13.24%	2,613,154	14.27%	3,619,002	18.73%	4,930,962	23.90%

APPENDIX B: INSIGHTS INTO THE ENERGY USE OF AI MODELS

To better appreciate how AI uses such enormous amounts of electricity, it can be useful to understand more about AI models and how they work. AI models are typically divided into three types:

- Process automation and optimization (PAO), which focuses on streamlining and enhancing operations
- Predictive analytics (PA), which deals with forecasting trends and patterns
- Natural language processing (NLP), which interprets and generates human language

Moreover, machine learning (ML), a subset of AI, employs statistical methods to enable machines to improve at tasks with experience. Deep learning (DL), a further subset of ML, involves neural networks with multiple layers that autonomously learn from vast amounts of data. ML and DL have evolved significantly, with industrial applications overtaking academic contributions in recent years. Industry's edge stems from its vast data access, advanced computing capacities, and robust financial backing, positioning it above academia and nonprofit sectors in this subset of the AI domain. ML's broad capabilities enable advancements in PAO, PA, and NLP models, while DL's complex neural networks further refine these applications [81, 82].

Each AI model type has distinct energy implications due to its unique computational requirements. Understanding these distinctions is essential for assessing the broader energy impact of AI's spread. **Table B1** provides a comparative analysis of various AI models' energy consumption and key characteristics, offering a view of their energy footprints and their computational complexity [44, 51, 57, 63, 84, 85, 86, 87, 88].

Table B1. Comparative analysis of AI model load consumption and characteristics [44, 51, 57, 63, 84, 85, 86, 87, 88]

LOAD CONSUMPTION: BY SPECIFIC AI MODEL					
MODEL NAME	AI TYPE	YEAR	TRAINING (DAYS)	CONSUMPTION (MWH)	MODEL DESCRIPTION
T5	PA	2019	~20	85.7	A versatile model trained to convert text inputs into text outputs, suitable for various tasks like translation and summarization.
Meena	NLP	2019	~30	232	A chatbot model developed by Google designed to engage in conversations and understand context more naturally.
Evolved Transformer	PAO	2019	~7	7.5	A machine learning model designed using neural architecture search for improved performance on tasks.
Switch Transformer	PAO	2020	~27	179	A variant of the Transformer model designed to handle a large number of parameters more efficiently by dynamically routing activations to a subset of experts.
GShard-600B	PAO	2020	~3	24.1	Google's model optimized for large-scale multitask training, aiding in handling vast amounts of parameters.
ChatGPT-3	NLP	2021	~34	1,287	A state-of-the-art language model by OpenAI known for generating coherent and contextually relevant sentences over long passages.
BERT	PA	2021	~6	2.8	A model that understands the context of words in a sentence by analyzing them in both directions (left-to-right and right-to-left), widely used in sentiment analysis and other prediction tasks.
Gopher	NLP	2022	~23	1,066	Large language models on many tasks, particularly answering questions about specialized subjects like science and the humanities, such as logical reasoning and mathematics.
BLOOM	PA	2022	~117	433	Multilingual and open source, the Bloom model, which has emerged from the BigScience participatory project, aims to help advance research work on large language models
ChatGPT-4	NLP	2023	~100	62,318.8	An advanced version of OpenAI's ChatGPT series, designed for more nuanced and context-aware language generation.
OPT-175B	NLP	2023	~33	324	A state-of-the-art language model by Meta known for generating coherent and contextually relevant sentences over long passages.

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ENERGYWIRE

Q&A: Portland General Electric's leader on data centers, renewables and Trump

Maria Pope said that a growth in electricity demand is an "opportunity" to increase both reliability and clean energy development.



BY: **JASON PLAUTZ** | 03/24/2025 07:04 AM EDT



Maria Pope, the CEO of Portland General Electric in Oregon, speaks earlier this month at the CERAWeek energy conference in Houston.| CERAWeek by S&P Global

ENERGYWIRE | Utility executives are increasingly anxious about how they can both meet booming electricity demand and the emissions reductions goals that matter to customers and shareholders.

But not Maria Pope, who leads Oregon's Portland General Electric. With more than 900,000 customers — including not only households, but a thriving tech industry and 15 percent of the country's semiconductor manufacturing — PGE sees balancing the various demands in its service area as an "opportunity," Pope said.

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Pope — who is currently chair of the utility trade group Edison Electric Institute — first joined PGE in 2009 and took over as president in 2017. In that time, she said, the utility industry has dealt with a "pace of change we haven't seen in decades," especially with a changing generation mix and load growth.

Add to that PGE's decision to join a day-ahead Western market organized by the California Independent System Operator, and Pope finds herself at the center of a once-sleepy industry in flux.

The day-ahead market, which aims to enable the buying and selling of energy across Western states, is a "real opportunity to accelerate savings and also to create greater reliability and stability for the grid," Pope said. But it also carries with it significant operational changes for the 137-year-old utility.

Pope spoke to POLITICO's E&E News at the CERAWeek conference in Houston about working under the Trump administration and balancing load growth with affordability and sustainability.

We're hearing a lot about load growth and demand growth. Does PGE view this as a challenge or an opportunity?

We very much look at it as an opportunity. The customers that are growing the fastest in our area are very focused on clean energy and represent really the value of all of the customers that we serve.

PGE has a goal to achieve net-zero energy production by 2040. Is that goal in conflict with the demand growth you're seeing?

We actually see them as very complementary, and we have grown our clean energy portfolio on a compounded annual growth rate of 7 percent since 2020. The large growth that we've seen from data centers and semiconductors has very much been a driver in our ability to grow clean energy at that level.

When you look out to 2040, what does the grid look like?

It's going to look like a myriad of interconnections and connectivity, optimizing clean energy while recognizing the intermittency. It's going to be optimizing new technologies, whether they be hardware like battery storage or software like integration tools. It's going to be customers and the utility, understanding each other's needs and creating synergies between our operations for the benefit of the entire grid.

You've got 500 megawatts of batteries coming online. How are you integrating that kind of balance into the system?

We're part of the entire West-wide market today through the energy imbalance market [operated by the California ISO] and tomorrow through the day-ahead market. We've seen tremendous opportunity from the batteries in California and the Desert Southwest.

The batteries that we're bringing along will only enhance what we're seeing in terms of price stability and increased renewable energy, but we're also seeing the ability to maintain customer reliability at a more micro level, not just a macro level. So very specific customers and areas of constraint within our system can be managed better at lower costs with battery storage.

In his CERAWeek remarks, Federal Energy Regulatory Commission Chair Mark Christie said that gas was the answer to stabilizing the grid and meeting new demand. How do you view the role of thermal resources?

At Portland General, we've always relied upon our legacy thermal assets, in particular our natural gas plants, to balance the grid and ensure reliability when the sun is not shining or the wind is not blowing. Today, we're using our gas plants less as we're getting better at integrating renewable resources, given the West-wide markets that we're able to tap, as well as the new technologies in terms of battery storage. Gas has been important, is important today and will be important in the future.

When you join the Western market, do you anticipate operations changing?

Absolutely, we'll change much of what we do. And it's, quite frankly, a lot of work, but it is the next evolution to keep customer prices affordable and to keep the grid reliable.

Five or six years ago, we had a strategy, not only of integrating into West-wide markets, but ensuring that our integration reached to our customers as well. So in addition to our West-wide goals of the energy day-ahead market, we expect to have 25 percent of our capacity come from the distribution system — with some of these largest customers that bring backup generation, both gen sets [portable generators] as well as battery storage. We see this as actually accelerating and being able to hit some of these goals sooner than we otherwise would have.

How do you work with large load customers to bring them online without negatively influencing residential customers?

We've been able to incorporate the best of what can come in Oregon to the grid that we've been developing over decades, and the practices of really working closely with our customers. So ensuring that we understand their needs, and they understand our needs, and that we're able to create synergies. Because there's a speed-to-market concern as well as a reliability concern and an affordability concern.

We certainly have been an area that has accelerated with technology, not only because of the data centers that have located in our region, but the Pacific Northwest is known for being home to some of the most innovative and progressive technology companies. So as part of the ethos of our region, we've been leaning into technology for more than a decade, and it's critical to how we operate our system, keep costs affordable and continue the evolution to cleaner and cleaner energy.

Do you have any sense of how customers' bills will be impacted?

What we're looking at is how we keep residential customer prices as affordable as possible, and in the neighborhood of inflation is really our target. Over time, we generally have been below inflation, most recently above, and we will be hopefully returning to a trajectory that is affordable and sustainable for all of our customers.

How does your utility's vision align with federal policy?

We see them very consistent, and we look forward to working with the administration on permitting, on accelerating development, particularly of transmission and many of the operations that we run. Many of our investments have taken place over 10 or 20 different administrations. We've worked with all sides of the aisle, and we look forward to working with this one.

Have you been affected by the funding freeze?

We have not at this point in time. We're very fortunate that our grants have contracts behind them, and we have continued to receive payments for that work that we have done to enhance the reliability and the capacity of the overall grid.

Some Canadian provinces have threatened tariffs on electricity or even shutting off exports. Do you anticipate any trouble with tariffs?

We have not seen anything with regards to electricity at this point in time. We are impacted by potential tariffs on natural gas.

How different does your job look today than when you started?

It looks totally different today, given the level of technology that we're using and the pace of change that the industry is going through. I would expect that only to accelerate, and for the pace to increase and the results to materialize faster and in ways that we probably wouldn't have expected just a few years ago.

This interview has been edited for clarity and length.

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BEFORE THE PUBLIC UTILITY COMMISSION
OF OREGON

UM 2377

In the Matter of

PUBLIC UTILITY COMMISSION OF OREGON

Investigation into Marginal Cost Study Treatment and Costs for Large Customers and Further Modifications to Portland General Electric Company's Rule C and Rule I

OPENING TESTIMONY

OF ANDY EIDEN

ON BEHALF OF CLIMATE SOLUTIONS, COLUMBIA RIVERKEEPER, COMMUNITY ENERGY PROJECT, GREEN ENERGY INSTITUTE, AND OREGON ENVIRONMENTAL COUNCIL

(Non-Confidential)

August 11, 2025

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I. Introduction

Q. Please state your name and business address.

A. My Name is Andy Eiden. My business address is 2900 E Broadway Blvd., Suite 100 #780, Tucson, AZ 85716

Q. By whom are you employed and in what capacity?

A. I am employed by Current Energy Group LLC ("CEG") as a Senior Manager of Distribution System Planning and Distributed Energy Resource("DER") Integration. CEG specializes in providing clients regulatory services in the areas of cost-of-service modeling, regulatory innovation, performance-based regulation, DER, rate design, renewable program development, grid modernization, new grid technologies, integrated resource planning, and electric vehicles ("EVs").

During my time at CEG I have worked with numerous consumer advocates and non-governmental organizations around many of the issues central to this docket, including large load forecasting, planning challenges associated with large load growth coupled with state emission reduction goals, cost of service studies and rate design to enhance ratepayer protections from new large loads, and more. I am also a member of the Energy Systems Integration Group's Large Load Taskforce.

Q. On whose behalf are you submitting testimony?

A. I am submitting testimony on behalf of Climate Solutions, Columbia Riverkeeper, Community Energy Project, Green Energy Institute at Lewis & Clark Law School, and Oregon Environmental Council (collectively, the "Coalition").

Q. Please summarize your professional and education experience.

A. Please see my resume and witness statement attached as Coalition/201, Eiden/1, and Coalition/202, Eiden/1. I have more than a decade of experience on a range of utility issues, described in part in my previous answer. Before joining CEG, I was a Senior Principal Planning & Strategy Analyst in Portland General Electric Company's ("PGE's") Distributed Resource Planning team, where I led company-wide DER forecasting and planning efforts, including for EVs, distributed solar photovoltaic ("PV") and battery energy storage systems ("BESS"), building electrification, and demand response ("DR"). As part of these job duties, I worked closely with Corporate Load Forecasting, Integrated Resource Planning, Transmission and Distribution Planning, and Power Operations teams surrounding all facets of DER integration into typical utility operations. In addition, while at PGE, I was a workstream lead to advance bottom-up load and DER forecasting into PGE's Transmission and Distribution ("T&D") planning efforts. Part of my duties as a workstream lead included participating in internal working groups regarding the establishment of new policies and practices surrounding large load forecasting and planning. I have also conducted studies on solar PV forecasting with Pacific Northwest National Laboratory and served on Stanford University's technical advisory group for their Deep Solar project.

Prior to joining PGE, I worked for five years at Energy Trust of Oregon ("Energy Trust"), where I evaluated numerous EE and renewable energy programs. I was the lead Planning Analyst for multiple targeted demand side management ("DSM") pilots to defer T&D capacity needs with Pacific Power. Prior to Energy Trust, I was a consultant with Cadmus Group focusing on third-party evaluations of utility EE programs.

I have a Bachelor of Science dual degree from Portland State University in Economics and Environmental Studies, and have taught graduate-level courses related to Smart Grid topics at both Oregon State University and Portland State University.

Q. What have you reviewed in preparing this testimony?

A. I have reviewed the filings in UE 430, the docket that preceded this UM 2377 docket, as well as many of the Company's discovery responses.

Q. Have you previously testified before the Oregon Public Utility Commission?

A. No. This is my first time testifying before the Oregon Public Utility Commission.

Q. Have you participated in any other proceedings before the Oregon Public Utility Commission?

A. No.

Q. Have you testified before any other state regulatory bodies?

A. Yes. I have testified in the following states: Colorado (Proceeding No. 24A-0442E) covering issues of DER forecasting within an IRP context, large load growth forecasting and ratepayer risks, and transmission and distribution line extension policies; Kentucky (Case No. 2025-00045) regarding EE and DER potential, including how VPPs and storage can be used to meet new capacity needs associated with large load growth; and Massachusetts regarding DER integration and T&D capital investment projects (D.P.U 25-31), as well as EV time of use rates and rate design (D.P.U. 23-84/D.P.U. 23-85).

Q. How is your testimony organized?

A. My testimony is organized by the following sections:

- Section I: Introduction
- Section II: Evolving the Marginal Cost of Service Study

- Section III: Data Centers Will Present New System Challenges for Maintaining Flexibility Adequacy that Must be Accounted for in Cost Allocation
- Section IV: Assessing Innovative Opportunities to Promote Energy Efficiency, Flexibility, and Clean Firm Generation Options with Data Centers

II. Evolving the Marginal Cost of Service Study

Q. What is the purpose of this section of your testimony?

A. In this section I provide a general overview of Marginal Cost of Service Studies (MCOSS) and discuss the importance of updating the methodology to match the changing needs of the power system. I also summarize and critique PGE's MCOSS from its most recent general rate case and recommend improvements with respect to how future MCOSS studies should evolve with consideration of large loads and data centers.

Q. What is the purpose of a Marginal Cost of Service Study (MCOSS)?

A. The purpose of an MCOSS is to categorize costs into bundled cost categories and to decipher, with as much detail and accuracy as possible, which customer class caused the utility's various embedded costs to inform class revenue allocation and rate design.

Q. How is a traditional COSS performed?

A. A COSS has three steps: 1) Functionalize costs into various categories, 2) Classify costs related to energy/commodity, demand/capacity, or customers, and 3) Allocate costs to the various customer classes using allocators related to energy, demand, or customer characteristics.

The principles of cost causation and beneficiary pays are used throughout the COSS to determine the most appropriate functionalization, classification, and allocation of costs. "Cost causation" dictates that the user(s) who incurred, or caused, a cost must pay for it.

Conversely, "beneficiary pays" dictates that all of those who benefit from an investment must pay for its costs – in other words, "costs follow benefits."[1] Incorporating the beneficiary pays principle at the retail level is a more modern concept but is reflected in some traditional cost classification and allocation approaches.

Q. Please describe PGE's most recent Generation MCOSS methodology at a high level.

A. In its most recent Generation MCOSS, PGE calculated long-run marginal energy and marginal generation capacity costs assuming a combination of non-emitting resources and market purchases.[2] For energy, the proxy resources were Montana wind and Nevada (Mead) solar, and capacity was modeled as a non-emitting 4-hr battery energy storage system (BESS).[3]

Q. How does PGE assign generation costs of service to individual rate classes?

A. After calculating the marginal (i.e., per kW or per kWh) energy and capacity values identified above, PGE estimates each rate schedule's marginal costs by multiplying each rate schedule's forecasted monthly coincident peak (for capacity) and monthly on- and off-peak load forecast (for energy) by the corresponding energy and capacity cost values.[4] Finally, PGE shapes the annual long-run marginal energy cost based on Mid-C forward prices using

[1] *See* Transmission Planning and Cost Allocation by Transmission Owning and Operating Public Utilities, FERC Order 1000, Docket No. RM10-23-000, at 358 (July 21, 2011), available at https://www.ferc.gov/whats-new/comm-meet/2011/072111/E-6.pdf. *See a lso* Lazar, J., Chernick, P., Marcus, W., and LeBel, M. *Electric cost allocation for a new era: A manual,* Regulatory Assistance Project, at 18 (Jan. 2020).
[2] In the Matter of PORTLAND GENERAL ELECTRIC COMPANY, Request for a General Rate Revision, Docket No. UE 435, PGE's Direct Testimony and Exhibits, PGE/800, Macfarlane-Manley/3.
[3] *Id*., Macfarlane-Manley/5.
[4] *Id*., Macfarlane-Manley/6.

its variable power cost model, Multi-area Optimization Network Energy Transaction (MONET).[5]

Q. Is this method consistent with the methodology used in previous rate cases?

A. No. PGE made several incremental changes to this MCOSS from that employed in UE 416, including assuming a weighted average of wind, solar, and market purchases for the marginal energy supply mix, as opposed to only wind; embedded transmission and renewable integration costs; and new transmission costs associated with proxy renewables located off-system where the renewable resource is more optimal.[6]

Q. Does PGE's generation MCOSS methodology adequately capture the evolving system needs associated with meeting the State's emissions policy reflected in HB 2021 and continuing to serve new large loads such as data centers?

A. No. The Company admits as much when it says, "[b]y considering these proxy resources the complexity caused by a transitioning generation and capacity landscape is avoided while also providing results that reasonably approximate those from legacy generation marginal cost studies."[7] The Company further states this method allows greater relative consistency with past methods and therefore maintains price stability among customer classes.[8] These principles of price stability and avoiding abrupt changes are indeed historic norms with their own merits; however, given the challenges posed by transitioning to a decarbonized power system coupled with unprecedented load growth from new large loads such as data centers, Oregon needs to advance its ability to understand the complexity

[5] *Id*., Macfarlane-Manley/6-7.
[6] *Id*., Macfarlane-Manley/4.
[7] *Id*., Macfarlane-Manley/3.
[8] *Id*.

inherent in these transitions. Moreover, it must find a way to translate the complexity and layered assumptions used during the Integrated Resource Planning ("IRP") modeling process into clear and transparent frameworks that fairly allocate network expansion costs to the customers driving those network expansions.

Q. Can you elaborate on what you mean by translating the complexity of the IRP modeling process into the cost allocation framework?

A. Yes. In its IRP, PGE conducts resource adequacy modeling to determine the amount of new capacity needed, as well as how many of each type of resource will be required to meet this need.[9] Using Sequoia, PGE assesses likely loss-of-load-hours ("LOLH") [10] and determines the effective load carrying capability ("ELCC") of new resources.[11] Crucially, the thousands of random simulations of load that are factored into Sequoia are incorporated at an aggregate system level for both the current state and after forecasts are added. By not separating historical or forecasted load into customer class breakdowns, it is impossible to tell how a given customer class's historical load dynamics and future growth patterns contribute to system capacity needs.

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[9] In this example I focus on generation network capacity expansion because that is the focus of my testimony, however, these principles are equally applicable to transmission network expansion modeling.

[10] *See* In the Matter of PORTLAND GENERAL ELECTRIC COMPANY, 2023 Clean Energy Plan and Integrated Resource Plan, Docket No. LC 80, PGE 2023 CEP/IRP, at 123, App H.3 (Mar. 31, 2023), available at https://edocs.puc.state.or.us/efdocs/HAA/lc80haa8431.pdf (discussion of Sequioa). To determine the LOLH under current and future scenarios, Sequoia models 50,000 "synthetic weeks" per season (summer/winter) comprised of differing water years, loads, temperatures, renewable output, and thermal output, and more.

[11] *Id*., at 526-527. PGE calculates the ELCC of a resource by first running a base model to determine a starting point capacity need, and then adding new candidate resources one at a time to evaluate the change in capacity needed, which is the "effective capacity" and is divided by the nameplate resource capacity to determine the ELCC.

Q. Why is it important to connect this methodology of capacity expansion to an evolved rate allocation framework?

A. Given that larger data center load requests can range from 100 MW up to 2,500 MW for a single site, we are now facing realistic near-term scenarios where substantial network capacity expansion may be driven by a small group of customers, or even a single customer. Currently, the generation cost allocator used by PGE simply takes the revenue requirement—based on marginal generation capacity costs as described above—and allocates cost according to each customer class based on a simplified assumption of class-level contribution to the 4-CP during the forecast test year.

This simplification may have been justified in the past based on the relative makeup of the power system, but advancing toward an emissions-free system will yield times when there are relative surpluses of available energy and capacity given the need to overbuild renewable energy supply. Therefore, a single- or even 4-CP method may not align well with cost causation. The residential customer class has a significantly greater share of the capacity versus energy cost allocations compared to other sectors, but it is not clear that the simple breakdown of contribution to 4-CP is well aligned with true cost causation principles as born out in the Company's IRP modeling. Figure 1 shows the relative proportion of capacity versus energy costs under each rate schedule's generation cost allocation.

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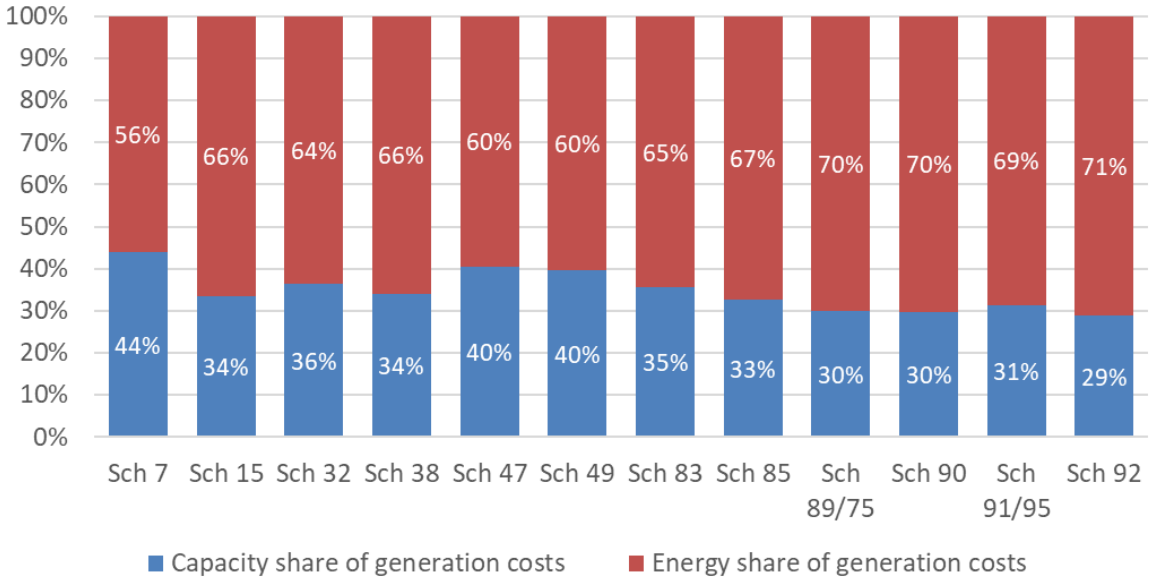
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Figure 1. Capacity Versus Energy Share of Generation Cost Allocations, by Rate Schedule



Q. Do you have any other concerns regarding the Company's generation MCOSS methodology as it relates to the scope of the current UM 2377 investigation?

A. Another major concern is that the MCOSS study used during general rate cases to underpin customer cost allocation does not have a direct linkage to the Company's annual Power Cost Adjustment methodology. This disconnect will be important to investigate when it comes to future allocations of energy and capacity costs since the Net Variable Power Cost adjustment comprises approximately 62% of the total revenue requirement functionalized to generation costs.[12] In its most recent general rate case, the Commission noted that this practice of separately accounting for market power cost adjustments and general rate case expenses has made it ever more challenging to find suitable ways to discipline costs across these activities.[13]

[12] Coalition/203, Eiden/2 (see cells C8 to C10).
[13] In the Matter of PORTLAND GENERAL ELECTRIC COMPANY, Request for a General Rate Revision, Docket No. UE 435, Order 24-454, at 122 (Dec 20. 2024), available at https://apps.puc.state.or.us/orders/2024ords/24-454.pdf.

Q. Can you elaborate on your concerns regarding the disconnect of the MCOSS methodology as utilized in the Company's general rate case and that of the annual Power Cost Adjustment filing?

A. Yes. My first concern relates to how significant the rate impacts to customers are from the recent annual power cost adjustments, and the fact that it happens outside of the rate case thus making it harder for stakeholders to identify and assess costs and risks holistically. Second, it may be worth revisiting the Company's use of a purely long-run marginal cost basis for allocating generation capacity costs to new loads. The reason for this is that there are short-run market changes reflecting an increasing scarcity of dispatchable resources and associated market price volatility that are impacting the Company's planning.[14] Further, the Company indicates that it may account for such divergences, in terms of how MONET typically captures capacity planning versus market realities, by potentially entering structured capacity products in 2025.[15] Therefore, it will be important to ensure that any new capacity procurements sought by the Company to cover their load obligations in the short-term are accurately captured in the MCOSS methodology and ultimately in rates based on which customer class is driving the need for those contracts. Based on the Company's load growth estimates, it appears that industrial customers are a significant portion of expected load growth, even before accounting for additional data center loads.[16]

[14] In the Matter of PORTLAND GENERAL ELECTRIC COMPANY, 2025 Annual Power Cost Update Tariff, Docket No. UE 436, PGE/100, Schwartz-Outama-Cristea/19-20, (Feb. 29, 2024), available at https://edocs.puc.state.or.us/efdocs/HAA/ue436haa327011023.pdf.
[15] *Id.,* at Schwartz-Outama-Cristea/20.
[16] In the Matter of PORTLAND GENERAL ELECTRIC COMPANY, Request for a General Rate Revision, Docket No. UE 435, PGE/700, Greene-Riter/3.

III. Data Centers Will Present New System Challenges for Maintaining Flexibility Adequacy that Must be Accounted For in Cost Allocation

A. Flexibility Adequacy and Variable Energy Resources Integration Costs

Q. Please describe the concepts of flexibility adequacy, flexibility value, and renewable integration cost.

A. To determine the flexibility requirements of the portfolio, which is one component of PGE's resource adequacy construct, PGE models the system operational needs for fast-acting dispatchable resources to balance the growing amount of variable energy resources ("VERs").[17] Flexibility value is then the value attributable to resources that can respond to meet these operational needs, based on modeling conducted in Grid Path by Blue Marble Analytics.[18] Finally, integration costs are developed to reflect the additional need for flexibility that is attributable to VERs like wind and solar.[19]

Q. Do you have any concerns with the flexibility value or integration costs modeled by PGE?

A. Yes, I have two concerns. First, regarding the flexibility value, the Company currently attributes both an energy arbitrage value of leveraging the BESS as a market-dispatchable resource, as captured in its AURORA production cost model, and the flexibility value as determined using Grid Path. This presents the potential for double-counting given that the modeling is being carried out under two different models that are at what at least appear to be cross-purposes. Namely, the modeling in AURORA assumes perfect foresight of

[17] In the Matter of PORTLAND GENERAL ELECTRIC COMPANY, 2023 Clean Energy Plan and Integrated Resource Plan, Docket No. LC 80, PGE 2023 CEP/IRP, at 128 (Mar. 30, 2023), available at https://edocs.puc.state.or.us/efdocs/HAA/lc80haa8431.pdf.
[18] *Id.*
[19] *Id.*

future market prices for a 2-day ahead period,[20] while the flexibility value in Grid Path is primarily attributed to using BESS for intra-day balancing needs stemming from day-ahead forecast error.[21] These two propositions of a BESS potential value (perfect foresight and market dispatch commitments, and reserving capacity to enable same-day balancing for forecast errors) are seemingly incongruent.

My second concern is that the integration cost for solar is two to three times the wind integration cost.[22] This increased integration cost for solar versus wind does not line up well with industry norms regarding wind and solar forecast error, and in fact wind might have higher integration costs.

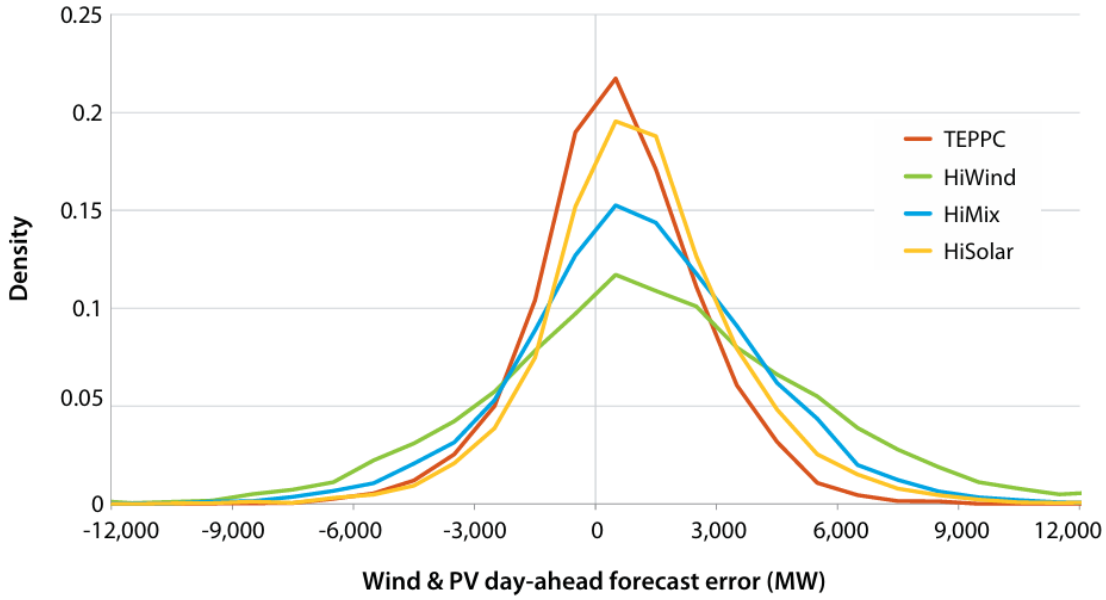
Q. Why do you say that the integration cost assigned to solar is too high compared to wind?

A. The flexibility adequacy study from the 2023 IRP/CEP that PGE states is the source of the integration cost—being the inverse of the flexibility value[23]—found that unserved energy due to system flexibility inadequacies were mostly the result of day ahead forecast error and not due to ramping constraints.[24] Although solar production is highly variable due to its heavy diurnal patterns, these are known and predictable variations. With wind energy,

[20] Coalition/204, Eiden/2.
[21] PGE 2023 IRP/CEP, External Study IV: Flexibility Study, at 12, available at https://assets.ctfassets.net/416ywc1laqmd/35EOAGYH4823pDrjzURp6F/ee3b94846ab455395ea6171c3f036329/PGE_Flexibility_Studies_.pdf; *see* In the Matter of PORTLAND GENERAL ELECTRIC COMPANY, 2023 Clean Energy Plan and Integrated Resource Plan, Docket No. LC 80, PGE 2023 CEP/IRP, at 696.
[22] *See,* In the Matter of PORTLAND GENERAL ELECTRIC COMPANY, 2023 Clean Energy Plan and Integrated Resource Plan, Docket No. LC 80, PGE 2023 CEP/IRP, at 237.
[23] Coalition/205, Eiden/2.
[24] PGE 2023 IRP/CEP, External Study IV Flexibility Study, at 12, available at https://assets.ctfassets.net/416ywc1laqmd/35EOAGYH4823pDrjzURp6F/ee3b94846ab455395ea6171c3f036329/PGE_Flexibility_Studies_.pdf.

there is greater uncertainty, especially on the day ahead forecast horizon.[25] Figure 2 shows the results of a large-scale study on wind and solar integration into the Western interconnection.[26] The solar forecast error density curve in the figure below (the yellow curve labeled "HiSolar") is more concentrated around zero, indicating lesser day ahead forecast error, compared to wind (green curve labeled "HiWind") which has fatter tails, indicating greater chance and magnitude of day ahead forecast error.

Figure 2. Day ahead wind and solar PV forecast error in high wind and high solar scenarios



Q. What is the relevance of these findings with respect to customer class cost allocation and the new large load tariff?

A. PGE's present method for assigning integration costs to VERs within its IRP, and subsequently in the MCOSS, is insufficient and does not capture the complexities inherent in balancing loads and resources under an increasingly VER dominant system. The current

[25] D. Lew et al., "The Western Wind and Solar Integration Study Phase 2," Nat. Renewable Energy Lab., at xxxiii (Sep. 2013), available at https://docs.nrel.gov/docs/fy13osti/55588.pdf
[26] *Id*.

methodology used by the Company analyzes the total system cost difference over a single model year from adding 100 MWa of wind or solar with that of a baseline model.[27] However, looking at only a single load year (as opposed to multiple stochastic load years, as is done with Sequoia for resource adequacy) may mask interrelationships between net load patterns and wind and solar output. For instance, studies have shown how load is generally positively correlated with solar generation, whereas load tends to exhibit a negative correlation with wind output, especially in the summer.[28] As I discuss above, the flexibility value from PGE's study is mostly related to day-ahead forecast error. The dynamics relating changes in net load with corresponding VER output must be considered fully in the modeling. As significant new data center loads come online with uncertain energization timelines and site usage forecasts, it will be important to improve the modeling of specific load types and their relationship to both load and VER forecast error.

B. The Logic of PGE's Load Following Credit Should Not be Applied to New Large Loads without Further Justification

Q. What logic does the Company provide for the Load Following Credit?

A. The Company states that the Load Following Credit was introduced as a result of a partial stipulation in the 2014 General Rate Case, and is meant to reflect the benefit that

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[27] PGE 2023 IRP/CEP, External Study IV Flexibility Study, at 14, available at https://assets.ctfassets.net/416ywc1laqmd/35EOAGYH4823pDrjzURp6F/ee3b94846ab455395ea6171c3f036329/PGE_Flexibility_Studies_.pdf.

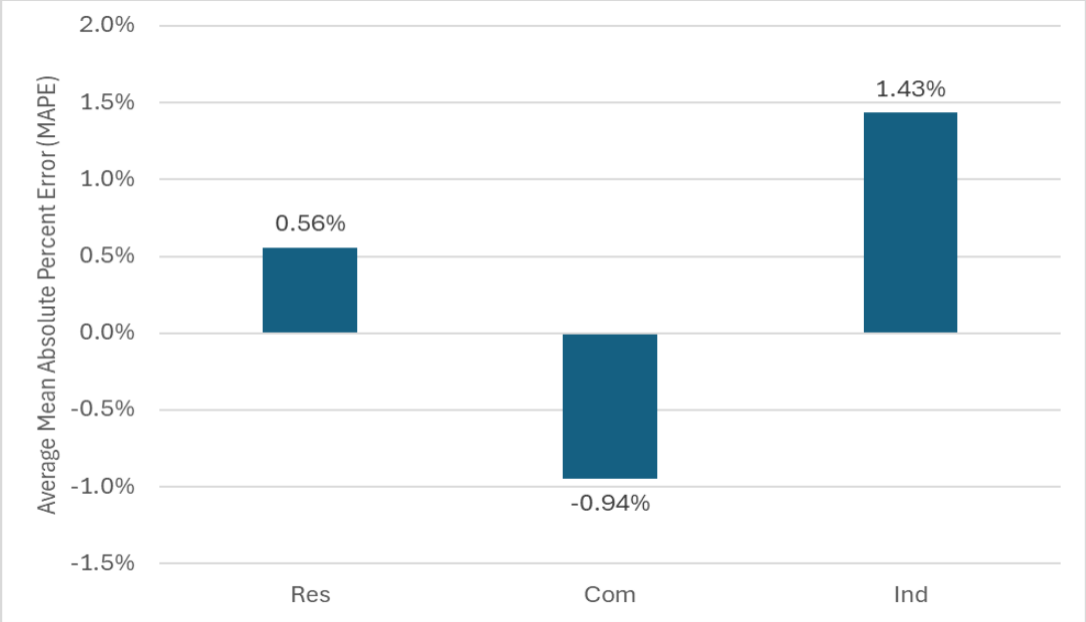
[28] Matthew Lave and Abraham Eliis, "Comparison of Solar and Wind Power Generation Impact on Net Load across a Utility Balancing Area" Sandia Nat. Lab., at 2, (2016), available at https://www.osti.gov/servlets/purl/1368867; Han Wang, et al., "A comprehensive review for wind, solar, and electrical load forecasting methods," *Global Energy Interconnection,* at 10–11, (Feb. 25, 2022), available at https://www.gei-journal.com/en/upload/files/2022/1/A%20comprehensive%20review%20for%20wind,%20solar,%20and%20electrical.pdf; Mark Z. Jacobsen, "On the correlation between building heat demand and wind energy supply and how it helps to avoid blackouts," *Smart Energy*, at 9, (Mar. 5, 2021), available at https://web.stanford.edu/group/efmh/jacobson/Articles/Others/21-Wind-Heat.pdf.

customers with greater than 250 MWa bring to the system in terms of consistency in their load that is easier for PGE to plan and forecast for.[29] The Company further states that due to this consistent load, it can avoid procuring flexible capacity in the short-term energy market or triggering a Peaker plant resource.[30]

Q. Do you have any concerns with the Company's stated logic?

A. Yes. PGE's forecast trends by customer class demonstrate that the industrial customer segment has greater forecast uncertainty than both the residential and commercial class, thereby undermining the claim that it is easier to forecast and plan for large loads. In fact, the Industrial customer segment has over two and a half times the average forecast error than the residential class.[31] Figure 3 shows the forecast error for each sector averaged over the 2016-2024 period.

Figure 3. Average forecast error by customer class 2016-2024



[29] Coalition/206, Eiden/2.
[30] *Id.*
[31] In the Matter of PORTLAND GENERAL ELECTRIC COMPANY, Request for a General Rate Revision, Docket No. UE 435, PGE/700, Riter-Greene/14.

Q. Can you describe the sources of uncertainty regarding forecasting future data center load?

A. Yes. There are two key areas of uncertainty with respect to data centers that impact their contribution to forecast error and associated cost increases.[32] The first uncertainty is timing associated with ramping to full facility demand levels. The second is uncertainty around hourly and seasonal usage patterns. I discuss each of these areas of uncertainty in more detail below.

Q. Can you elaborate on your first point regarding uncertainty in data center ramping?

A. Ramping faces a dual uncertainty of: 1) whether or not a project will continue all the way from interconnection request through to energization and 2) the risk associated with timing to ramp up its computing load once connected. The risk associated with projects getting all the way to energization stems in part from the fact that data center developers commonly "shop around" to different locations seeking the best terms, as well as the economic, financial, and other setbacks that could derail a project.[33] PGE recognized this increased risk in its most recent IRP/CEP, where the Company stated, "[t]he realization and timing of large projects present heightened uncertainty around PGEs load forecast."[34]

[32] "Characteristics and Risks of Emerging Large Loads: Large Loads Task Force Whitepaper," N. Am. Elec. Reliability Corp, at 16, (Jul. 2025). https://www.nerc.com/comm/RSTC_Reliability_Guidelines/Whitepaper%20Characteristics%20and%20Risks%20of%20Emerging%20Large%20Loads.pdf#page48
[33] *Id*., at 16.
[34] In the Matter of PORTLAND GENERAL ELECTRIC COMPANY, 2023 Clean Energy Plan and Integrated Resource Plan, Docket No. LC 80, PGE 2023 IRP/CEP, at 105; *see also*, Coalition Intervenors/103, Souder/48.

The risk associated with timing of compute load within a single facility will differ based on the nature and type of data center. Inherently, co-located data centers where the business model is to rent out space will face greater uncertainty because their business model depends on third parties to enter into contracts, compared to hyperscalers where a single company can scale up their demands internally without the added risk of contracting third parties. However, hyperscalers are also typically much larger, and so changes to their development plans can have an outsized effect on the development pipeline of a utility. Recent examples, such as Microsoft's paused plans in Ohio for $1 billion of investments in new data center capacity,[35] indicate there is still substantial risk surrounding the long-term planning for these customer types.

Q. Can you elaborate on your second point regarding uncertainty in data center usage patterns?

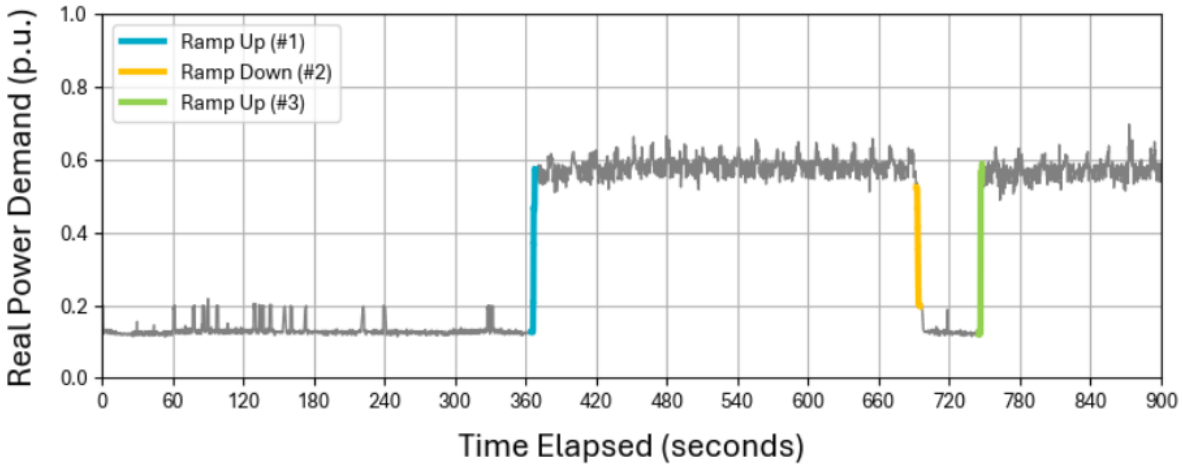
A. Yes. An additional and compounding source of uncertainty relates to the ultimate hourly load profiles of data center customers. Despite the common presumption that these facilities operate with nearly constant usage (i.e., load factor > 90%) there are nevertheless meaningful differences in diurnal swings, as well as seasonal usage, that when viewed at the scale of the new loads coming online can have dramatic impacts on peak power demand. In fact, PGE's existing data center customers have an average of 79% load factor.[36]

According to the North American Electric Reliability Corporation (NERC), high-load factors typically correspond to data centers providing cloud computing and digital services,

[35] Matt O'Brien, "Microsoft says it's 'slowing or pausing' some AI data center projects, including $1B plan for Ohio", *AP News,* (Apr. 9, 2025), available at https://apnews.com/article/microsoft-ai-data-center-pause-ohio-4d987fe8446fc9e6cda31d919f938911.
[36] Coalition/207, Eiden/1.

whereas AI facilities can ramp up and down in a manner of seconds depending on the phase of the AI model training needs, potentially swinging hundreds of MWs over very short time scales.[37] Figure 4 below shows the changes in usage for an example AI data center from moment to moment based on different data center processing needs.

Figure 4. AI Training Data Center (50 MW) Demand Curve (EdgeTunePower, during training run)[38]



In addition to the sudden and dramatic ramping associated with AI training use cases, the impact of cooling technology choice on the resultant facility load profile is also critical. Therefore, methods to improve cooling efficiency and integrate flexible load design into data centers should be considered as a means of mitigating adverse system impacts. I discuss energy efficiency considerations for data centers in more detail in Section IV of my testimony.

Q. Aren't data center loads supposed to be flat, and running all the time?

[37] "Characteristics and Risks of Emerging Large Loads: Large Loads Task Force Whitepaper," N. Am. Elec. Reliability Corp. at 14, (Jul. 2025), available at https://www.nerc.com/comm/RSTC_Reliability_Guidelines/Whitepaper%20Characteristics%20and%20Risks%20of%20Emerging%20Large%20Loads.pdf#page48.
[38] *Id.*, at 6.

A. No. This is a common misconception when evaluating data center loads. In fact, data center servers are not operated near full capacity of the chips in order to extend the lifespan of their most important and valuable asset. Furthermore, given that the average lifecycle of server equipment is approximately 3 years, for a large-scale facility this translates into a significant portion of the installed server capacity being down for regular maintenance at any given time.

These changes in server load "uptime" can be especially pronounced with emergence of new AI data center compute loads, which are split between model training periods and the more prevalent inference period.[39] Figure 5 shows estimates from a recent Lawrence Berkeley National Laboratory ("LBNL") report on data center energy usage that range from just around 20% server time operational up to 80% for AI training use cases.[40] The figure shows historical trends (left of the vertical dotted line) compared to future projections (right of the dotted line) with a range of uncertainty for the newer AI training and inference use cases based on the study author's assumptions.

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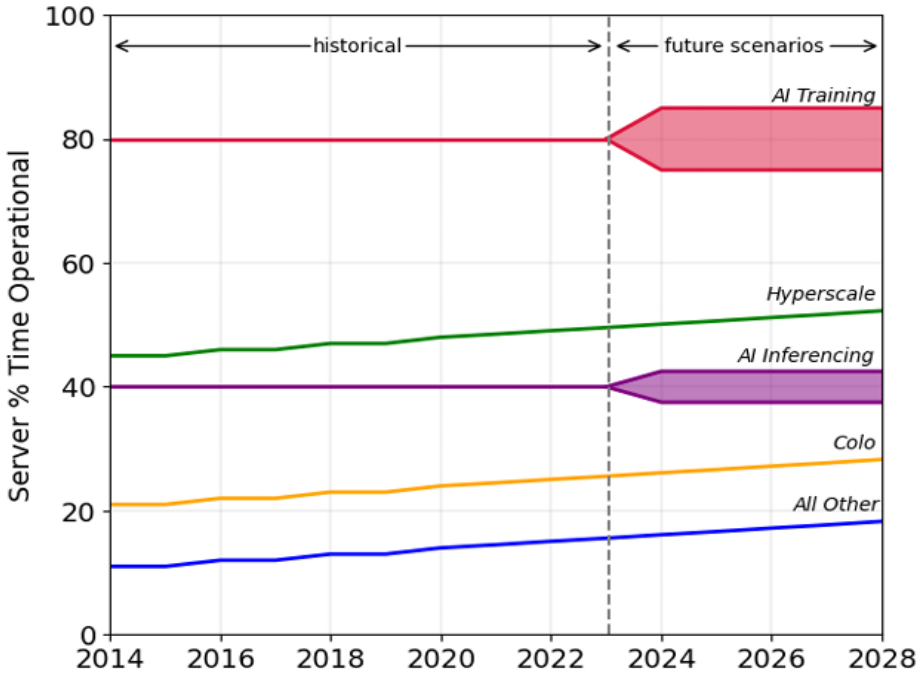
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[39] Arman Shehabi, et al., "2024 United States Data Center Energy Usage Report" Lawrence Berkeley Nat. Lab., at 27, (Dec. 2024), available at https://eta-publications.lbl.gov/sites/default/files/2024-12/lbnl-2024-united-states-data-center-energy-usage-report_1.pdf.
[40] *Id.*

Figure 5. Operational Time for Servers Given Data Center Type



Q. Is it possible that individual large customers, such as those on Schedule 90, exhibit less extreme forecast error?

A. It is possible, yes. The Company's forecast error metrics that I discuss above, and presented in UE 435, only describes the forecast error at a sector level, though the Company states that it does conduct individual load forecasts for its largest customers.[41] However, no recent statements or analysis have been provided by the Company sufficient to support the claim to increase the Load Following credit.[42]

Q. In your opinion, should this Load Following credit be applied to other new large loads, such as data centers?

A. No. Without further analysis and justification by the Company as to how this credit is determined, and under which conditions it would apply, the Commission should not adopt

[41] UE 435, PGE/700, Riter-Greene/7-8.
[42] UE 435, Order 24-454, at 75.

this value for new large loads being considered under this investigation. For example, PGE has not clearly distinguished initial customer load requests into total connected load amounts, total expected max utilization levels, and forecasted average and peak loads.[43] These concepts, as I discuss above, are closely related to the evolving understanding of server operational time for different data center use cases, and the consequent impacts on temporal power demand levels. Therefore, it is not possible to evaluate whether forecasting and planning for these data center loads will be any more accurate than other customer classes.

Q. Is there evidence to suggest that data center load may present more uncertainty and therefore risk in terms of impact on grid operations and the cost to meet flexibility needs?

A. Yes. A recent event where 1,500 MW of data center load suddenly tripped offline highlights the uncertainty presented by these new large loads which, if not addressed, could pose substantial challenges for grid operators. The Eastern Interconnection experienced a sudden drop of 1,500 MW of data center load on July 10, 2024, with no warning to the grid operator, when a lightning strike caused a transmission-level fault.[44] The sudden drop in load was a result of the data centers switching to on-site backup power to avoid damage to their sensitive IT equipment.[45] It was later determined that the location of the 1,500 MW load drop

[43] Coalition/208, Eiden/2.
[44] Incident Review: Considering Simultaneous Voltage-Sensitive Load Reductions, N. Am. Elec. Reliability Corp, at 2-3, available at https://www.nerc.com/pa/rrm/ea/Documents/Incident_Review_Large_Load_Loss.pdf.
[45] *Id.*

was in Dominion's territory in northern Virginia, but similar scares have been experienced in ERCOT in Texas, which also has substantial data center load.[46]

Q. What kind of visibility into data center operation and load forecasting is necessary in order to effectively plan and operate the system?

A. NERC stated that it is critical to have visibility into how loads were going to operate, including peak demand, interconnection timelines, dynamic load models, and control and protection settings.[47] Without visibility into these load dynamics, planners and operators cannot assess the full impact of these new loads on the bulk power system and could result in poor planning decisions.[48]

Q. Is PGE collecting this type of information today?

A. It does not appear so. Based on my review of the information the Company has provided, they do not require this type of detailed information from interconnecting customers during the application phase.[49]

[46] Tim McLaughlin, "Big Tech's data center boom poses new risk to US grid operators," *Reuters,* (Mar. 19, 2025), available at https://www.reuters.com/technology/big-techs-data-center-boom-poses-new-risk-us-grid-operators-2025-03-19/.
[47] "Characteristics and Risks of Emerging Large Loads: Large Loads Task Force Whitepaper," N. Am. Elec. Reliability Corp. at 15, (Jul. 2025), available at https://www.nerc.com/comm/RSTC_Reliability_Guidelines/Whitepaper%20Characteristics%20and%20Risks%20of%20Emerging%20Large%20Loads.pdf#page48.
[48] *Id.*
[49] *See* Coalition/208, Eiden/2. Although the response by PGE indicates they do not require detailed operational data, such as capacity utilization factors, during the load request phase, it is possible the Company plans to collect more detailed operational data to inform later stages of the study process. I encourage the Company to discuss these considerations and what kind of steps it plans to take to account for the type of load disturbances witnessed by Dominion/PJM and ERCOT.

Q. What do you recommend based on your assessment of the flexibility adequacy needs and potential application of the Load Following credit for large data center loads?

A. PGE has not demonstrated that the new large load customers taking service under a prospective future large load tariff will use consistent, easy to forecast power levels that will reduce the need for system flexibility. In fact, data centers will likely create substantial challenges in terms of forecasting both short- and long-term energy and capacity needs, as well as increasing system reliability risks and associated need for additional flexibility to deal with potentially large load swings like those that happened in Virginia and Texas. For these reasons, the Commission should not allow the Load Following Credit to apply to new data center loads until further studies are performed to justify potential benefits. Further, I recommend that the Commission direct the Company as follows:

- Conduct a transmission planning study accounting for N-1 sudden loss of large loads, in addition to loss of the single largest generator or transmission line. Report on these outcomes before the next rate case and include discussion of how the added costs of accommodating this loss of load potential will be allocated to customers.
- Develop a proposal for interconnection standards that require data center customers to demonstrate the ability to ride-through voltage and frequency disturbances and provide the Company with sufficient detail about the planned protection schemes for equipment and backup sources used.
- Require customers entering an interconnection study to provide sufficient details about system operations, such as server operational time, max server utilization

capacity, and other relevant site-level detail needed to construct a dynamic load model of data center operations that can be applied to forecasts.

IV. Assessing Innovative Opportunities to Promote Energy Efficiency, Flexibility, and Clean Firm Generation Options with Data Centers

Q. What is the purpose of this section of your testimony?

A. In this section I describe the energy usage patterns of data centers and survey the landscape of energy efficiency trends and opportunities, as well as emerging load flexibility opportunities. I also highlight the importance of developing new and innovative approaches to accelerating procurement of new clean energy resources through the concepts of Clean Transition Tariffs and energy parks. Finally, I recommend steps that the Commission can take to encourage and incentivize data center market development in ways that do not threaten the GHG goals of the state and limit the impacts on near-term resource adequacy challenges.

Q. How is this section of your testimony organized?

A. Section A provides an overview of data center energy usage patterns, with a focus on load pattern differences based on data center facility type and use case and opportunities for end use energy efficiency. Section B reviews the opportunity for data centers to provide load flexibility during system critical peak periods. Section C introduces the concept of Clean Transition Tariffs and situates these mechanisms within the Oregon planning context.

A. Reviewing data center usage patterns and efficiency opportunities

Q. What are the key drivers of electricity use within a data center?

A. Energy usage within a data center is commonly reported based on IT and non-IT usage, with further delineation among non-IT uses between mechanical losses (such as energy going to mechanical space cooling, plug loads, lighting, etc.) and electrical losses

(such as losses from the onsite transformer and site power distribution).[50] Given the high temperatures of chips and servers, data centers require significant amounts of cooling. For the hyperscaler data centers, which are among the fastest growing data center facility type, over 80 percent of spaces are cooled with air- and water-cooled chillers.[51] According to a recent study of energy efficient cooling opportunities within data centers across the Northwest region, adoption of best practices for chiller system design could reduce peak power demand by an average of 1,000 MW in total.[52] The study is limited to exploring design options among just a single cooling design choice within data centers, highlighting the importance of evaluating efficiency impacts on peak power demand, and not just annual energy savings as is commonly done.[53] The study also highlighted the tradeoff of higher water usage to achieve energy savings from the evaporative cooling techniques studied, a consideration that needs to be considered in combination with the water consumption of the specific energy generation source that would likely have powered the additional energy demand at the data center in the baseline scenario of less energy efficient cooling strategies.[54]

Q. What additional options are there for energy efficiency within data centers?

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[50] "The Energy & Water Use Impacts of Building Systems Design for Data Centers: Design Considerations for Oregon & Washington," PAE, at 5, (Feb. 14, 2025), available at https://critfc.org/wp-content/uploads/2025/03/data-center-report.pdf. *See also* Coalition/100, Souder/31–32.

[51] Arman Shehabi, et al., "2024 United States Data Center Energy Usage Report" Lawrence Berkeley Nat. Lab., (Dec. 2024), available at https://eta-publications.lbl.gov/sites/default/files/2024-12/lbnl-2024-united-states-data-center-energy-usage-report_1.pdf.

[52] The Energy & Water Use Impacts of Building Systems Design for Data Centers: Design Considerations for Oregon & Washington," PAE, at 10, (Feb. 14, 2025), available at https://critfc.org/wp-content/uploads/2025/03/data-center-report.pdf

[53] *Id.*

[54] *Id.,* at 12-13.

A. In addition to the more efficient cooling strategies discussed above, new AI data centers can achieve greater efficiency through developing energy efficient algorithms and adopting efficient hardware such as tensor processing units ("TPU") and field programmable gate arrays ("FPGA").[55]

Q. What emerging technologies are most promising?

A. There are many efforts underway at the National Laboratories, universities, and industry groups such as the Electric Power Research Institute (EPRI) to accelerate data center efficiency. These technologies include:

District heating approaches can utilize waste heat from data centers to provide heating needs of nearby communities, such as the example partnership between Amazon and Ireland.[56] More recently, approaches to integrate thermal waste heat recovery along with realistic data center and electric system operations have been proposed, highlighting that this strategy can benefit not only the larger integrated electric and heating system but also the individual facility efficiency.[57]

Geothermal underground thermal energy storage (UTES) is a new technology being developed by researchers at the National Renewable Energy Lab ("NREL"). It differs from traditional geothermal electricity production by using underground reservoirs to actively

[55] Coalition/209, Eiden/2.
[56] Tallaght District Heating Scheme, Sustainable Energy Auth. of Ireland, (last visited Aug. 7, 2025), available at https://www.seai.ie/case-studies/tallaght-district-heating?utm_source=chatgpt.com
[57] Xunhu Yin, et al., "Exploiting Internet Data Centers as Energy Prosumers in Integrated Electricity-Heat System," in *IEEE Transactions on Smart Grid*, at 167-182 (Jan. 2023), available at https://ieeexplore.ieee.org/document/9852739.

store cold energy, allowing for active charge and discharge management to meet a data center's cooling demand year-round.[58]

Cold thermal energy storage (CTES) offers a useful means to shift data center peak cooling load to nighttime hours, thereby improving the efficiency of the chiller which can operate more at lower ambient temperatures (thus reducing overall equipment strain and increasing performance).[59] Additionally, CTES provides additional redundancy to grid power outages since chilled water from CTES systems can begin circulating faster upon switching to the backup generator, compared to standard chillers.[60]

Liquid immersion cooling is widely perceived to be a significant evolution in server cooling technology, being much more efficient than air-cooled strategies due to the large reductions in thermal resistance of liquid cooling mediums (such as water, but including other mediums) compared to air.[61] Industry observers note that with the increasing power processing demands on data center servers, this move to liquid immersion cooling, or air-to-liquid hybrid systems, may be inevitable in order to maintain competitiveness in the industry.[62]

Q. How is PGE forecasting for EE opportunities within the data center segment?

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[58] "Advanced Manufacturing Research, Nat. Renewable Energy Lab., (last visited Aug. 6, 2025), available at https://www.nrel.gov/manufacturing/news/program/2025/reducing-data-center-peak-cooling-demand-and-energy-costs-with-underground-thermal-energy-storage

[59] "Data Center Master List of Energy Efficiency Measures," U.S. Dept. of Energy, at 57–58 (Sep. 2020), available at https://datacenters.lbl.gov/sites/default/files/2024-04/DCEE%20Actions%20Master%20List_090920_final.pdf.

[60] *Id.*

[61] "Emergence and Expansion of Liquid Cooling in Mainstream Data Centers," ASHRAE, at 5, (2021), available at https://www.ashrae.org/file%20library/technical%20resources/bookstore/emergence-and-expansion-of-liquid-cooling-in-mainstream-data-centers_wp.pdf.

[62] *Id.*

A. PGE includes EE in its IRP based on forecasts developed by Energy Trust of Oregon ("Energy Trust"). Currently, Energy Trust models a flat 542 kWh per square foot usage assumption for data centers to capture all facility usage inclusive of HVAC pumps and chillers, lighting, computing loads, and on-site power supply.[63] For project-specific savings calculations, Energy Trust has moved to adopt an ASHRAE 90.4 code baseline, and currently only offers measures related to the non-IT energy usage within a data center.[64] Critically, within the IRP forecasting process, this means that there is no differentiation between the HVAC, on-site power delivery load, and IT equipment load of forecasted data center customers. As I discussed above, these different end uses can have significantly different impacts on peak power demand depending on the cooling design choices, and each choice will present different EE opportunities. Data collection efforts are needed to establish more reliable means to validate forecast models with actual real-world data regarding these energy usage characteristics, especially in context of IT characteristics such as compute capacities, average system configurations, and workload types.[65] Though these types of data are typically considered proprietary, novel data sharing agreements that collect and publish anonymized and aggregated information could be developed similar to approaches in other industries.[66]

Q. What are your recommendations regarding EE opportunities in data centers?

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[63] PGE IRP Roundtable, at 14 (Mar. 8, 2023), available at https://assets.ctfassets.net/416ywc1laqmd/1jJplZrDEgY8NqWede8SzN/13e98519b52e24306a12ca2c68896ae4/IRP_Roundtable_March_8.pdf#page=5

[64] *Id.*, at 17.

[65] Arman Shehabi, et al., "2024 United States Data Center Energy Usage Report" Lawrence Berkeley Nat. Lab., at 68 (Dec. 2024), available at https://eta-publications.lbl.gov/sites/default/files/2024-12/lbnl-2024-united-states-data-center-energy-usage-report_1.pdf.

[66] *Id.*

A. I recommend that the Commission direct PGE to do the following:

- Work with Energy Trust to provide data center specific growth forecasts, in terms of number of customers, location, and MW demand, that can be incorporated into a direct estimate of Data Center EE savings opportunities. The Commission should separately direct Energy Trust to develop specific energy use models for data center energy consumption that account for the distinct attributes specified in the LBNL and PAE reports, as opposed to relying on simplified and average square footage usage equivalents currently used for assessing C&I savings potential.
- Given the lack of specificity currently being collected as part of PGE's application intake process, the Commission should direct PGE to update its interconnection application process for data centers to include collection of sufficient operational detail needed to assess facility load profile dynamics and potential impact on BPS reliability and power quality, as well as identify EE opportunities earlier in the design process. This data collection should be designed in conformance with Energy Trust's updated EE end-use savings model to facilitate greater alignment between forecasting data center demand at multiple junctures throughout the planning and program design phases, as well as reduce timelines required to conduct future EE site-specific studies because the required data would already be collected and available.
- Develop standardized language for use in application that distinguishes connected load from anticipated average and peak load, including collecting relevant details regarding rated computing power, expected operational power, planned utilization levels (e.g., percent of maximum for chip usage, scheduled maintenance plans, etc.),

and finally load factor. All of these are important in terms of increasing the accuracy of the forecasts for these new large loads.

B. Flexible connections can maximize use of existing assets and interconnect data centers more speedily than waiting for grid upgrades.

Q. What are flexible connections?

A. Flexible connections are options for connecting or expanding customer importing facilities (i.e., load or consumption) and exporting facilities (i.e., generation pushed onto the distribution or transmission system) that permit actively managed facilities to interconnect under the presumption that they will operate within the established limits in lieu of, or prior to, grid upgrades being completed. These limits can be managed through setting import/export schedules that are more static in nature or can be more actively adjusted based on more real-time grid constraints.

Q. What is a firm connection?

A. Firm connection means that an importing/exporting facility (e.g., customer and customer with solar, respectively) is energized based on its connected capacity and that the connected capacity does not violate any system constraints under any feasible operation.

Q. How can flexible connections improve upon traditional connection limitations?

A. Flexible connections are an integration strategy used to defer or avoid system upgrades and/or increase distribution system utilization generally by limiting (i.e., curtailing) active power imports/exports from customers when they have the potential to create grid congestion.[67] The approach increases grid utilization, defers current and future generation, transmission, and distribution system upgrades, and supports greater energy exports from

[67] Coalition/210, Eiden/3.

DERs utilizing current infrastructure.[68] The amount of import/export that can be accommodated on the system is inherently time varying because the underlying load, generation, temperature, control settings, circuit configuration, and other system parameters of the utility's system fluctuate over time.[69] Flexible connection approaches permit customers to connect to systems with capacity that exceed local and system peaks with the expectation that their import/export capacity may be curtailed when necessary. This service option makes more efficient use of existing system capacity.[70]

Q. Why are flexible connection options relevant to discussions around data center load?

A. Flexible connections can create non-firm capacity that enables utility operational flexibility and reduces transmission and generation requirements including for data center load. Ramped connections are an example. One form of a ramped connection, a static ramped connection, is to allow incremental customer load up to the system constraints, and no more, then later allowing additional load onto the system once system capacity is fully built out. However, ramped connections can also be actively managed.[71] An actively managed ramped connection would allow large customer load to be energized even though it violates system planning criteria for a few hours of the year. The active management of the load can allow for customers to integrate behind-the-meter resources to fill in periods when the system is stressed or the customer's load can be curtailed down to a firm load limit. These ramped

[68] *Id.*
[69] *Id.*
[70] *Id.*
[71] Steven Brisley, "What is Flexible Interconnection—And How Does it Help?" Camus, (Mar. 24, 2025), available at https://www.camus.energy/blog/what-is-flexible-interconnection--and-how-does-it-help.

connections can be used to bring on data centers in a way that better utilizes the existing system in a phased way that may avoid stranded assets.

Q. How significant is the potential to address data center interconnection challenges with flexible connections?

A. Very significant. According to a recent study by Duke University, existing headroom at the balancing area (BA) level for PGE's BA is 54 percent on an annual average basis, reaching approximately 65 percent in the winter season.[72] The study finds that curtailing data center load during the top 0.25 percent to 1 percent of high load hours in PGE's BA could allow between 800 MW and 1,100 MW of additional load to interconnect to the system, based on analysis of new large load additions compared to historical net load over the last eight years (2016-2024).[73] This significant finding underscores the need for further study as to how best these new large loads can be incorporated using flexible arrangements.

Q. Would data center customers accept this risk?

A. There is reason to believe that data centers could be encouraged to implement load flexibility or leverage their on-site backup power to reduce demand on the grid during the critical curtailment periods identified in the Duke study, and perhaps even beyond those limits.[74] For instance, the example I discussed earlier in my testimony of 1,500 MW of data

[72] Tyler H. Norris, et al., "Rethinking Load Growth: Assessing the Potential for Integration of Large Flexible Loads in US Power Systems," Nicholas Institute for Energy, Environment & Sustainability, at 18, (2025), available at https://nicholasinstitute.duke.edu/publications/rethinking-load-growth.
[73] *Id.*, at 4.
[74] I acknowledge that the Duke study is highlighting existing headroom at the BA level, and that before implementing this type of strategy a more detailed study would need to be conducted that accounted for specific transmission deliverability and related hourly constraints on a location-specific basis. But the findings still encourage deeper study for how to unlock this significant potential.

center load tripping offline proves that these facilities are capable of quickly transitioning from grid power to self-supply via backup power. In the case of the incident in Virginia, however, most of the 1,500 MW stayed disconnected from the grid for hours, despite the transmission fault being cleared much sooner.[75] The reason for the large lag is due to the particular backup power characteristics employed at the sites, and how they interacted with the transmission system protection schemes.[76] Further, systems utilizing battery backup systems could re-connect immediately following transient disturbances such as the one under review, while systems utilizing diesel backup had to be re-connected manually and used the temporary short-duration power source primarily as a means of transitioning to a diesel backup system.[77]

Q. Are there examples of commercially-available products that are designed to meet data center needs and perform the type of seamless switching from grid power to backup power as you describe?

A. Yes. Verrus, in partnership with NREL, has successfully demonstrated in a simulation and lab-controlled setting how its novel microgrid setup coupled with grid aware onsite power flow management software can coordinate BESS dispatch for utility demand response, as well as provide response time in under 10 seconds from a grid operator command or disturbance in power quality.[78] This type of standardized data center design and

[75] Incident Review: Considering Simultaneous Voltage-Sensitive Load Reductions, N. Am. Elec. Reliability Corp, at 8, available at https://www.nerc.com/pa/rrm/ea/Documents/Incident_Review_Large_Load_Loss.pdf.
[76] *Id.*
[77] *Id.,* at 6.
[78] Deepthi Vaidhynathan., et al. "Vulcan Test Platform: Demonstrating the Data Center as a Flexible Grid Asset," Nat. Renewable Energy Lab., at 22, (Jun. 2025), available at https://docs.nrel.gov/docs/fy25osti/94844.pdf

infrastructure can help shift data centers away from diesel backup. In fact, by contracting for reliable use of this on-site backup or self-supply that is harmonized with the grid, Oregon can leverage the scale and resources of the data center industry to drive an acceleration of the energy transition with respect to development of innovative clean firm technologies, versus a scenario where un-managed large loads significantly contribute to delaying progress to meet the State's clean energy goals. I discuss this more in the next subsection.

C. Clean Transition Tariff

Q. Why is a clean energy tariff relevant to this docket?

A. Clean energy tariffs offer a solution to mitigate the costs and risks of serving inflexible electricity demand with increasingly clean energy, while providing large customers opportunities to meet their own sustainability goals. Significant large load growth exerts additional risk and costs to meet Oregon's clean energy goals. Without clean energy tariff options for large load customers, other customers also take on large load customers' costs and risks for meeting Oregon's energy needs with clean energy.

Q. What do you mean by a Clean Energy Tariff for large load customers?

A. A clean energy tariff is an optional provision for large load customers to contract with third party independent power producers to build new clean resources to serve some or all of their energy needs.[79] Alternatively, a large customers could fund and enable new demand-side management resources, such as energy efficiency, demand response, or a virtual power plant, to make reductions in other customers' demand that would otherwise be unrealized potential. This contractual clean energy arrangement would remove risk from utilities and other customers for building increasing clean and dispatchable energy resources to serve

[79] See Ben Hertz-Shargel, *Large Load Tariffs Have a Problem, Clean Transition Tariffs are the Solution*, Utility Dive (Jun. 5, 2025), available at http://bit.ly/4nigkem.

rapidly growing large customers and displace investments in new gas generation that would otherwise be necessary to meet the current pace of load growth. Therefore, a clean energy tariff can benefit all electricity consumers in Oregon and accelerate the transition to an emission-free system.

Q. Are there examples of Clean Energy Tariffs for large load customers implemented by other utilities?

A. Yes. Most notably, the Nevada Public Utilities Commission recently approved a clean transition tariff (CTT) proposed by Nevada Energy (NVE).[80] The CTT enables a large customer, Google, to have a portion of its load served directly by a new renewable resource identified in the utility's integrated resource plan.[81] The customer pays a surcharge for all energy from this renewable resource, equal to the difference between the cost of the chosen resource and the utility's cost of energy. That is, any additional costs of the new renewable resource are paid directly by the large customer. The customer is also obligated to take this service for the lifetime of the new resource, ensuring these costs are not stranded. This arrangement aligns the costs and contract period for the large customer, with the cost and lifetime of the renewable resource, which removes the risk or costs of this asset from other customers, while providing the large customer with 100 percent clean energy.

Q. Why are these clean energy tariffs different or advantageous compared to utility renewable resource procurement?

A. A benefit of these clean energy tariffs over other renewable subscription programs delivered by a utility procurement process is that customer subscription could be provided to

[80] Coalition/211, Eiden/1.
[81] Coalition/212, Eiden/34.

any clean energy resource, not only those which can win an RFP for renewable generation. This means that large customers may specifically fund technologies that are less mature, more expensive, or unable to win an RFP but may specifically meet large customers' needs for dispatchable reliable energy, such as long duration energy storage or advanced geothermal energy. This could be an invaluable benefit to technology development that can spur growth in more clean firm resources that will enable Oregon to get to 100% emissions-free energy by 2040. Indeed, PGE identified the need for quickened market development of such resources in order to meet its energy and capacity needs at a reasonable cost beginning with the 90 percent emissions reduction milestone from HB2021 starting in 2035.[82]

Q. Can demand side resources also be supported through clean energy tariffs?

A. Yes. Large customers have also expressed interest in supporting demand-side resources that offset their demand and energy use. In Nevada, Google proposed a Large Customer Offsite Demand Side Management ("DSM") Program that could reasonably enable a large data center customer to fund additional demand-side reductions through the utility's energy efficiency or demand response programs.[83] In return, the large customer would receive the value of the incremental capacity benefits unlocked by their contribution. The contributions to the Large Customer DSM funding pool would be voluntary and additional to existing programs, meaning they would not necessarily be subject to the same cost effectiveness rules governing traditional programs and may therefore fund critical pre-weatherization health and safety retrofits needed for many low- and moderate-income

[82] In the Matter of PORTLAND GENERAL ELECTRIC COMPANY, 2023 Clean Energy Plan and Integrated Resource Plan, Docket No. LC 80, PGE 2023 CEP/IRP, at 36 (Mar. 31, 2023), available at https://edocs.puc.state.or.us/efdocs/HAA/lc80haa8431.pdf.
[83] Coalition/213, Eiden/4.

weatherization programs.[84] Barriers to weatherization such as health and safety upgrades are widespread, often lead to deferred efficiency upgrades, and disproportionately impact low income customers.[85]

Q. Does this conclude your testimony?

A. Yes.

[84] *Id.*, Eiden/5–6.
[85] Elizabeth Bourguet and Richard Faesy, "Overcoming Weatherization Barriers: A Survey of Resources to Address Barriers to Weatherization in Homes," Energy Futures Group, at 2, (Dec. 23, 2020), available at https://e4thefuture.org/wp-content/uploads/2021/01/Weatherization-Barriers-White-Paper-1-6-21.pdf.

CURRENT ENERGY GROUP

Andy Eiden

Sr. Manager, (971) 244-2063, aeiden@currentenergy.group

Education

Bachelor of Science, *magna cum laude*, Economics and Environmental Studies
Portland State University – Portland, OR (2011)

Master's Certificate in Energy Policy and Management
Portland State University – Portland, OR (expected fall 2025)

Work Experience

Sr. Manager, Current Energy Group, (January 2025 – Present)

- Subject matter expert in Distribution System Planning (DSP), electrification and DER forecasting, DSM potential studies, DER integration, advanced rate design, cost-effectiveness modeling, and locational value frameworks.
- Designing strategies to advance DSP processes and practices, DER adoption, and other decarbonization strategies before state public utility commissions.

Sr. Principal Planning & Strategy Analyst, Portland General Electric (2023-2024)
Principal Planning & Strategy Analyst (2022-2023)
Sr. Planning & Strategy Analyst (2020-2022)
Planning & Strategy Analyst (2019-2020)

- Led company-wide DER forecasting efforts to support DSP, IRP, finance, programs, and transmission planning. Responsible for all aspects of analysis and final reports.
- Represented PGE in regulatory proceedings, including DSP and TE dockets and related technical working groups.
- Designed Python-based DER forecasting tools for circuit-level DER adoption modeling.
- Led team of analysts to deliver sound planning studies to internal clients
- Managed multiple R&D partnerships with government, industry, and academia.
- Led valuation efforts and non-wire alternative evaluations for grid optimization.

Planning Project Manager, Energy Trust of Oregon (2015-2019)

- Managed electric avoided-cost dockets and targeted non-wire alternative pilots.
- Oversaw cost-effectiveness reporting for a $200M energy efficiency portfolio.
- Maintained TRM database and managed solar and multifamily program evaluations.

Research Analyst, The Cadmus Group (2012-2013)

- Conducted process and impact evaluations for utility clients across the U.S.
- Developed survey instruments to evaluate utility efficiency program offerings
- Delivered actionable recommendations through data-driven insights for client projects.

CURRENT ENERGY GROUP

Publications

"Distribution Capacity Expansion: Current Practice, Opportunities, and Decision Support" (2022)

Co-authored a report looking at the future evolution of Distribution Planning to evolve toward a more holistic approach encompassing scenario planning, DER penetration, and economic optimization. Worked closely with lead authors to validate existing utility planning practices and identify areas for improvement.
Report

"KPF-AE-LSTM: A Deep Probabilistic Model for Net-Load Forecasting in High Solar Scenarios" (np., March 2022)

Co-authored a paper on net-load forecasting at the distribution level of aggregation that identified statistically-determined upper- and lower-error bounds for PV production while considering typical end use load patterns. Also presented on the paper topic at 2022 IEEE IGST conference in New Orleans regarding utility load forecasting from a system operations perspective.
Article

Industry Technical Advisory Committees

ESIG DER and Electrification Impacts Task Force Member (2023-current)

Invited to serve as Task Force member for Energy Systems Integration Group (ESIG) distribution impacts working group. Primary focus was identifying best practices in utility system planning and necessary regulatory evolution related to EV and DER growth.

NEEA End Use Load Research Steering Committee (2021-2024)

Utility representative for regional end-use metering study to update end use load profiles. Assisted steering committee with guidance around key study objectives and desired outcomes, guided workgroup with feedback about relevant research and analysis, and participated in quarterly meetings.

NREL Technical Advisory Group, Grid-Scale Metrics for GEBs (2022-2023)

Provided technical assistance to the NREL NOVA team related to development of metrics for assessing value of grid-interactive efficient buildings (GEBs) as part of DOE grant work. Participated in TAG meetings to review NREL staff concepts about possible metrics and advised on industry feasibility and usefulness. Reviewed draft study materials about TOU rate designs related to solar and storage, as well as provided data and input for a case study of buildings in the Pacific Northwest.

CURRENT ENERGY GROUP

Industry Presentations

"Planning EV Impacts on the Grid" Presentation at ESIG Spring Technical Workshop (2023)

Presented on utility planning practices to accommodate EV load growth on the grid to conference of international attendees.

EV Load Forecasting and Planning, Western Energy Institute Fall conference (2022)

Gave presentation related to utility practices for forecasting EV load and integration of EV load forecasts with planning studies, with a particular focus on secondary distribution networks and common infrastructure sizing practices.

Expert Testimony

1. Petition of Massachusetts Electric Company and Nantucket Electric Company, each d/b/a National Grid, for approval of the Capital Investment Project (CIP) for the Monson-Palmer-Longmeadow (Northwest) DG Group Interconnection Study (D.P.U. 25-31). On Behalf of the Massachusetts AGO (with Ron Nelson and Tim Cook).
   DG Interconnection and cost allocation
   Direct
2. In the Matter of Electronic Application of Kentucky Utilities Company and Louisville Gas & Electric Company for Certificates of Public Convenience and Necessity and Site Certificates. Case No. 2025-00045. On behalf of Joint Intervenors Kentuckians for the Commonwealth, Kentucky Solar Energy Society, Metropolitan Housing Association, and Mountain Association.
   DSM potential, S+S resource modeling, VPP design
   Direct
3. In the Matter of the Application of Public Service Company of Colorado for Approval of its 2024 Just Transition Solicitation. On Behalf of Western Resource Advocates and Southwest Energy Efficiency Partnership.
   Load and DER forecasting, Large Load forecasting, Interconnection policy
   Direct
4. Petition of NSTAR Electric Company d/b/a Eversource Energy for Approval to Offer Optional Electric Vehicle Time-of-Use Rates (D.P.U. 23-84). Petition of Massachusetts Electric Company and Nantucket Electric Company each d/b/a National Grid for Approval to offer Optional Electric Vehicle Time-of-Use Rates (D.P.U. 23-85). On Behalf of the Massachusetts AGO (with Ron Nelson).
   EV TOU Rate Design, Submetering
   Direct, Surrebuttal

Other Industry Engagement

Smart Grid Graduate Policy Course, Portland State University, adjunct instructor (Spring 2024)

Taught graduate-level Smart Grid course covering policy trends in Smart Grid topics for public administration and policy students, as well as professional development for industry practitioners.

Smart Grid Graduate Course in Electrical Engineering, Oregon State University, adjunct instructor (Spring 2023)

Taught graduate-level Smart Grid course in electrical engineering covering distribution system basics, smart controls, demand-side technologies, transmission and market integration issues.

WITNESS QUALIFICATION STATEMENT

NAME: Andy Eiden

EMPLOYER: Current Energy Group LLC

TITLE: Senior Manager, Distribution System Planning and DER Integration

ADDRESS: 2900 E Broadway Blvd., Suite 100 #780, Tucson, AZ 85716

EDUCATION: Bachelor of Science, Economics and Environmental Studies

Portland State University, Portland, OR

EXPERIENCE:

Provided testimony in the following states: Colorado (Proceeding No. 24A-0442E) covering issues of distributed energy resource (DER) forecasting, large load growth forecasting and addressing associated ratepayer risks, and transmission and distribution line extension policies; Kentucky (Case No. 2025-00045) regarding energy efficiency and DER potential, including how virtual power plants and storage can be used to meet new capacity needs associated with large load growth; and Massachusetts regarding DER integration and transmission and distribution capital investment projects (D.P.U 25-31), as well as electric vehicle time of use rates and rate design (D.P.U. 23-84/D.P.U. 23-85). During my time at CEG I have worked with numerous consumer advocates and non-governmental organizations around many of the issues central to this docket, including large load forecasting, planning challenges associated with large load growth coupled with state emission reduction goals, cost of service studies and rate design to enhance ratepayer protections from new large loads, among others. I am a member of the Large Load Taskforce led by Energy Systems Integration Group (ESIG), a leading industry membership group. From 2019 to 2024 worked with PGE as a resource planning analyst in the Distributed Resource Planning team. From 2014 to 2019 worked as a planning analyst with Energy Trust of Oregon focused on cost benefit analysis and electric system avoided costs, as well as planning targeted EE and renewable programs to defer utility grid upgrades.

BEFORE THE

PUBLIC UTILITY COMMISSION OF OREGON

UM 2377

Coalition

Exhibit of Andy Eiden

EXHIBIT 203

Notes on Exhibit:

Native Excel spreadsheet: UM 2377_NONC_PGEtoGEI_DR10R_Attachment A_07152025
Tab: Ratespread

	A	B	C	D	E	F
1						
2		PORTLAND GENERAL ELECTRIC				
3		UNBUNDLED 2025 COSTS ($000)				
4						
5			Unbundled		Adjusted	
6			Costs		to Cycle	
7						
8	**Fixed Generation Revenue Requirement**		$624,821		$623,391	
9	**Net Variable Power Costs**		$1,031,483		$1,029,123	
10	**Production Costs**		$1,656,305		$1,652,514	
11						
12	**Ancillary Services**		$7,831		$7,813	
13						
14	**Transmission**					
15		Transmission	$134,860			
16		Partial Requirements Daily Demand	$0			
17	Transmission Costs		$134,860		$134,547	
18						
19	**Distribution Services**		$908,557			
20		Franchise	($74,194)			
21		Uncollectibles	($11,570)			
22		Trojan Decommissioning	($1,896)			
23		Partial Requirements Daily Demand	$0			
24		Employee Discount	$1,071		$1,071	
25		Distribution Costs	$821,969		$819,931	
26						
27	**Consumer Services**					
28		**Metering Services**	$2,301		$2,296	
29		**Billing Services**	$46,000		$45,886	
30		**Other Consumer Services**	$132,122		$131,794	
31						
32	**Franchise Fees**		$74,194		$74,010	
33						
34	**Uncollectibles**		$11,570		$11,541	
35						
36	**Trojan Decommissioning**		$1,896		$1,891	
37						
38	**Schedule 129**		$1,824		$1,824	
39	**Schedule 139**		$0		$0	
40						
41	**Totals**		$2,890,871		$2,884,047	
42						
43		Net of employee discount	$2,889,800		$2,882,976	
44						
45		Net of Sch 129 and Sch 139	$2,887,976		$2,881,152	
46						
47						
48		Calendar MWH (COS & ESS)	22,499,683			
49		Cycle MWH (COS & ESS)	22,443,910			
50		Cycle/Cal Ratio	99.75%			
51						
52						
53		COS Calendar Energy MWH	20,010,920			
54		COS Cycle MWH	19,964,492			
55		Cycle/Cal Ratio	99.77%			

July 15, 2025

To: Cole Souder
Green Energy Institute

From: Jaki Ferchland
Senior Manager, Rates & Regulatory Affairs

Portland General Electric Company
UM 2377
PGE Response to OPUC Data Request 008
Dated July 1, 2025

Request:

Refer to UE 435 Exhibit 800, at 5:3-9, describing the energy and flexibility value of the proxy battery resource.

a. Please explain how the Company's system flexibility adequacy target is determined.
b. Please provide the adequacy target for the test year and each year of the 20-year forecast period.
c. Does PGE assume perfect foresight in optimizing the battery charge/discharge for energy value arbitrage?
d. Can the battery provide energy arbitrage and flexibility services simultaneously? Explain whether there are market or operational limitations to this, and how the MCOSS study treats any identified limits.

Response:

a. As defined in Section 6.8 of PGE's 2023 Integrated Resource Plan (IRP), 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). Unserved energy from operating reserves, operational constraints of power plants and errors in supply forecasts and commitments can be attributed to a deficit in the system's operational flexibility. Accordingly, flexibility adequacy is an element of resource adequacy that highlights the deficit in a system's operational capabilities hourly and is denoted by a MW flexible adequacy target.
b. PGE objects to this request on the basis that the information it seeks is not relevant or reasonably calculated to lead to the discovery of admissible evidence in the current proceeding. Without waiving this objection, PGE responds as follows:

Table 17 of PGE's 2023 IRP shows that in 2026, PGE's system will require an additional 80 MW and 158 MWh of flexible resources to meet the needs of the system, which occur about 0.1 percent of the time. This inadequacy grows to 122 MW and 501 MWh by 2030, with the frequency increasing to 0.3 percent of the time.

Flexibility value and integration costs were included in PGE's UE 435 generation marginal cost study, but not in the form of the adequacy target for the test year and each year of the 20-year forecast period.

c. The Aurora PGE Zone Model (PZM) is the source of the battery energy values. The model assumes perfect foresight in optimizing battery charge/discharge on a 2-day horizon for determining battery energy values. The PZM is used to simulate the economic dispatch of existing PGE and candidate new resources. Aurora simulates PGE existing dispatchable generation resources, contracts, and new resources using economic dispatch based on electricity prices and associated risk variable inputs consistent with each price future. When economically dispatched, resources will generate when resource dispatch cost is lower than the electricity market price and will not generate when market purchases are cheaper. See Appendix H of PGE's 2023 IRP for more information.

d. PGE objects to this request on the basis that it is vague and ambiguous. GEI's use of "MCOSS" is unclear. Notwithstanding its objection, PGE responds as follows: No. PGE cannot sell and use the energy from batteries at the same time.

July 15, 2025

To: Cole Souder
Green Energy Institute

From: Jaki Ferchland
Senior Manager, Rates & Regulatory Affairs

Portland General Electric Company
UM 2377
PGE Response to GEI Data Request 006
Dated July 1, 2025

Request:

Refer to UE 435 Exhibit 800, at 4:7-18, which describes the Company's updated approach to estimating long-run marginal costs.

a. Please explain PGE's application of transmission deferral under the Generation cost of service study.
b. In what circumstances was the transmission deferral applied? For instance, does the transmission deferral get applied to only distribution-connected wind or solar, or to transmission-connected?
c. Explain the difference between the transmission deferral value and the transmission costs described at 14-15.
d. Define integration costs. Provide workpapers for this calculation for each proxy generation resource type used in the MCOSS of generation study.
e. Which ancillary services (AS) are included in the integration costs described in this section?
f. Please provide the hourly breakdown of AS in $/MWh, for each hour of the forecast period, in an Excel spreadsheet.

Response:

a. While PGE referred to these costs as deferred in testimony, they are embedded transmission costs and PGE will refer to them as such through this response for clarity. Both embedded and new build transmission values referenced in UE 435 Exhibit 800, at 4:7-18 are included in the revenue requirement calculation of the wind and solar proxy resources included in PGE's UE 435 generation marginal cost study.
b. See response to part a.
c. Two different transmission costs are included in the revenue requirement calculation of the wind and solar proxy resources. First, transmission upgrade costs, or embedded costs, are included in the overnight capital costs. The source of the

overnight capital costs of the wind and solar proxy resources is the National Renewable Energy Laboratory's (NREL) publicly available 2023 Annual Technology Baseline (ATB) data. Sheet, 'Financial Definitions', states that overnight capital costs include "a nominal-distance spur line (<1 mi), and necessary upgrades at a transmission substation."

Second, the transmission costs described in UE 435 Exhibit 800, at 4:14-15 refer to the cost to procure transmission to reach these proxy resources. PGE selected Montana wind and Mead solar as the proxy resources in the UE 435 generation marginal cost study. This is a 20 year long-run marginal cost study, which underlined the need to include diverse proxy resources and additional transmission. PGE's 2023 Integrated Resource Plan (IRP) on page 227 includes estimates of the cost to procure transmission to reach these proxy resources. These transmission values were applied to proxy resources that would require extra-regional transmission.

d. PGE objects to this request on the basis that it is vague and ambiguous. GEI's use of "MCOSS" is unclear. Subject to and without waiving this objection, PGE responds as follows:

PGE defines flexibility and integration on page 236 of its 2023 IRP, "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."

UM 2377_CONF_PGEtoGEI_DR6R_Attachment A ("Attachment A") provides PGE's UE 435 generation marginal cost study workbook. Sheets "Wind" and "Solar" contain the revenue requirement calculations for both proxy generation resources. Attachment A contains confidential information and is protected under General Protective Order 23-132.

e. See response to part d. Integration costs are included to account for ancillary services.

f. PGE objects to this request on the grounds that it is overly burdensome, requires new analysis, and that the information it seeks is not relevant or reasonably calculated to lead to the discovery of admissible evidence in the current proceeding. Subject to and without waiving its objection, PGE responds as follows:

PGE's 2023 IRP Flexibility Adequacy Study, available at https://portlandgeneral.com/flexibility-studies, is the source of the flexibility and integration values on page 237 of PGE's 2023 IRP. UM 2377_NONC_PGEtoGEI_DR6R_Attachment B provides the workpapers supporting PGE's 2023 IRP Flexibility Adequacy Study.

May 30, 2025

To: Scott Gibbens
Oregon Public Utility Commission

From: Jaki Ferchland
Senior Manager, Rates & Regulatory Affairs

Portland General Electric Company
UM 2377
PGE Response to OPUC Data Request 060
Dated May 16, 2025

Request:

Please provide PGE responses to OPUC DRs 457-459, and 732-736 from Docket No. UE 435.

Response:

UM 2377_NONC_PGEtoOPUC_DR60R_Attachment A provides the requested responses.

May 29, 2024

To: Bryan Conway
Public Utility Commission of Oregon

From: Jaki Ferchland
Senior Manager, Revenue Requirement

Portland General Electric Company
UE 435
PGE Response to OPUC Data Request 457
Dated May 15, 2024

Request:

Please expand on the reasoning used to determine the Load Following price. In particular, please discuss where the hard coded numbers in cells C30:C32 in tab "Load Follow" in the workpaper "2025 Ratespread -January Prices FINAL". In your response please also provide a brief history of the Load Following Credit.

Response:

The Load Following Credit was introduced in a Partial Stipulation in PGE's 2014 GRC (UE 262), and the methodology used to calculate the credit has not fundamentally changed since that time. In UE 262, parties agreed to a load following credit of 1.13 per mills/kWh for 100MW. In PGE's 2018 GRC (UE 319), Parties entered into another Partial Stipulation and agreed to update the load following credit to 1.13 mill/kWh + 0.25mills/kWh. Parties also agreed the surcharge for Schedule 89 would not exceed 0.57 mills/kWh and the load following credit would be reduced accordingly if the Schedule 89 surcharge otherwise exceeds 0.57mills/kWh.

The Load Following Credit is applicable to Schedule 90 customers greater than 250 MWa, which are many multiples in size larger than other PGE customers. The purpose of the Load Following Credit recognizes the benefits of volume and load factor associated with customers of this magnitude. Since their load is consistent, PGE can factor their consistent load into our planning and resource mix for how PGE operates its bulk electrical system. Because PGE can plan for this load, PGE does not have to procure flexible capacity for this unexpectedly in the short energy market or trigger a Peaker plant resource. This is a significant benefit for the remainder of PGE's customer base.

The hard coded number in cell C30 is the flexibility value of a four-hour battery in Docket LC 80, PGE's most recently acknowledged IRP. The 2026, 4-hour battery value expressed in 2023 dollars comes from Table 47 on page 237. PGE converted the 2026, 4-hour battery value of $9.77 in Table 47 from kW to MWh. Attachment 457 A provides the calculation.

The hard coded number in in cell C31 is the previous Load Following Credit price from the UE 319 settlement.

The hard coded number in cell C32 is the previous Schedule 89 Load following price which is described above.

July 28, 2025

To: Cole Souder
Green Energy Institute

From: Jaki Ferchland
Senior Manager, Rates & Regulatory Affairs

Portland General Electric Company
UM 2377
PGE Response to GEI Data Request 001
Dated July 1, 2025

Request:

Provide a table, in Microsoft Excel format, providing the following details for each data center the Company has interconnected onto its system. The Company can anonymize each customer (e.g., Customer A, Customer B), etc.

a. Initial interconnection request service level, aka "connected load" level, (MW)
b. Forecasted load ramp (MW in service each year)
c. Actual load factor (average usage to peak usage ratio) by year
d. Average capacity utilization factor (average usage to connected load) by year

Response:

PGE objects to this data request on the grounds that it calls for speculation, as PGE does not distinguish "data centers" as a customer class and seeks information that is not reasonably calculated to lead to the discovery of admissible evidence. Without waiving and subject to the foregoing objections, PGE responds as follows.

For the purpose of responding to this data request, PGE interprets this request as seeking the energized customers known to PGE to be operating as data centers on Schedules 89 or 90 as of the time of this request. To facilitate the provision of this information, customer data has been aggregated into two categories: those with demand greater than 20 megawatts (MW) and those with demand less than or equal to 20 MW.

a. The aggregated load of customers greater than 20MW = 543 MW, and the aggregated load of requests less than 20MW = 34.5MW.
b. PGE doesn't provide customer-specific forecasted load ramps as this is highly confidential information and may be covered by NDAs.
c. Overall actual load factor for data center customers is 79%.
d. Connected capacity does not always reflect the requested capacity and is a function of utility equipment sizing.

July 15, 2025

To: Cole Souder
Green Energy Institute

From: Jaki Ferchland
Senior Manager, Rates & Regulatory Affairs

Portland General Electric Company
UM 2377
PGE Response to OPUC Data Request 002
Dated July 1, 2025

Request:

Provide a table, in Microsoft Excel format, providing the following details for each new data center load request that the Company has received:

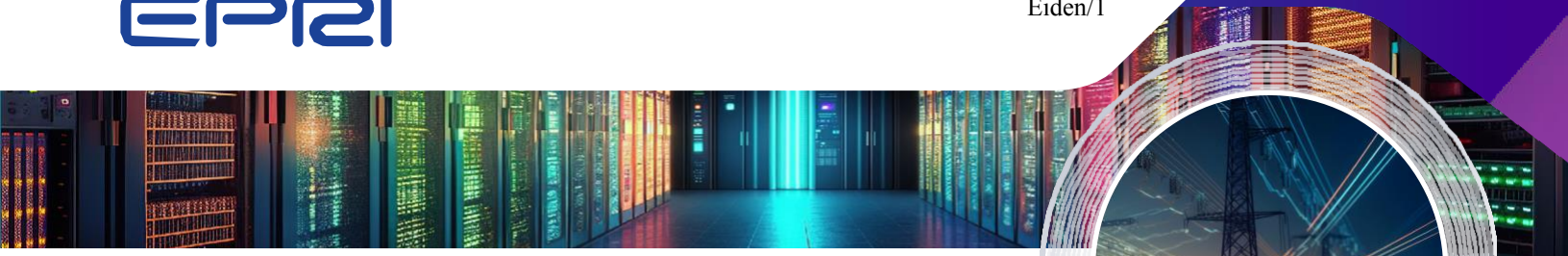
a. Forecast probability
b. Interconnection start year
c. Initial interconnection request service level, aka "connected load" level, (MW)
d. Forecasted load ramp (MW in service each year)
e. Forecasted load factor (average usage to peak usage ratio) by year
f. Forecasted peak capacity utilization factor (peak usage to connected load) by year
g. Forecasted average capacity utilization factor (peak usage to connected load) by year

Response:

PGE objects to this data request on the grounds that it is vague and ambiguous, unduly burdensome, and calls for speculation. The data request is unclear in terms of what is a "data center," what is a "request" and what time period is covered. PGE's response below concerns submissions to the current cluster study process. Without waiving its objection, PGE responds as follows:

a. It is unclear what is meant by the phrase "forecast probability," as such PGE cannot respond to this request.
b. PGE does not have interconnection start years for new data center customers. The interconnection start year is contingent on available system capacity, which is being determined as a part of a load study PGE is conducting for new data center customers.

c. UM 2377_CONF_PGEtoGEI_DR02R_Attachment A ("Attachment A") column C provides the initial service request. Attachment A contains confidential information and is protected under General Protective Order 23-132
d. Attachment A columns D-M provide the requested load ramp over ten years. Available system capacity, including load ramp, will being determined as a part of a load study PGE is conducting for new data center customers.
e. Attachment A column O provides the forecasted load factor.
f. PGE does not require customers to provide their peak capacity utilization factor, and PGE does not forecast that information at this stage of the study process.
g. PGE does not require customers to provide their average capacity utilization factor, and PGE does not forecast that information at this stage of the study process.





Power Consumption Trends from Increased AI and Data Center Utilization

Jordan Aljbour | Technology Innovation – Strategic Research August 2023

Introduction

Artificial intelligence (AI) and data centers, the engines of the worldwide digital economy, are driving innovative solutions and novel business models across the transforming energy industry. However, their increased utility poses a set of significant challenges that EPRI is diligently assessing—most importantly the current energy consumption trends, contributing factors, and management strategies.

Research Question

"How do emerging trends in AI and data center usage impact US electricity infrastructure, and what insights can we gain from these trends?"

This subject explores the nexus of digital transformation, energy use, and environmental sustainability. It seeks to examine the implications of escalating AI and data center usage on US energy systems.

Power Consumption Insights

AI usage broadly, particularly large-scale enterprise models, are commonly tasked with Process Automation & Optimization (PAO), Predictive Analytics (PA), and Natural Language Processing (NLP), demanding intensive resources for training and operation. For instance, in 2020, ChatGPT-3, a prevalent generative NLP AI required ~10.57 GWh for both initial training and annual search request operation. A 2019 study indicated a single NLP AI model's carbon footprint equaling five average American cars' full lifecycle, emitting ~280 tons of CO_2e. Despite these figures, potential for more efficient and sustainable AI implementation exists with broad adoption and technological advancements.

Data centers, supporting digital services like cloud computing and AI, are a significant energy consumer, though they constitute only a fraction of the market. From small-scale to large-scale commercial data centers, which include enterprise centers (*private*), colocation centers (*shared tenancy*), and hyperscalers (*global-scale facilities*). In 2020, US data centers accounted for 1.8% of total electricity consumption, akin to Wisconsin's annual usage. Globally, data centers represented 1% of worldwide electricity use, expected to rise with increasing digital reliance.

Factors Driving Increased Power Consumption

There are several key drivers behind increasing power consumption of AI and data centers:

1. **Explosion of Data:** The 'big data' surge necessitates substantial storage and processing in data centers, escalating their energy demands. Global IP traffic is set to triple by 2022, reaching 396 exabytes monthly or ~1.98e6 GWh; resulting in providing AI models with a valuable resource—diverse and vast datasets.
2. **Model Complexity:** With AI models becoming more intricate and data-intensive, they demand increased computational power, resulting in higher energy consumption. Resources needed for large AI training runs amplified by 300,000 times from 2012-2018.
3. **24/7 Operation:** Data centers' continuous operation for an "always-on" digital economy ensures relentless energy consumption. In 2020, US data centers used about 69 billion kWh, equivalent to the annual consumption of 6.4 million homes.

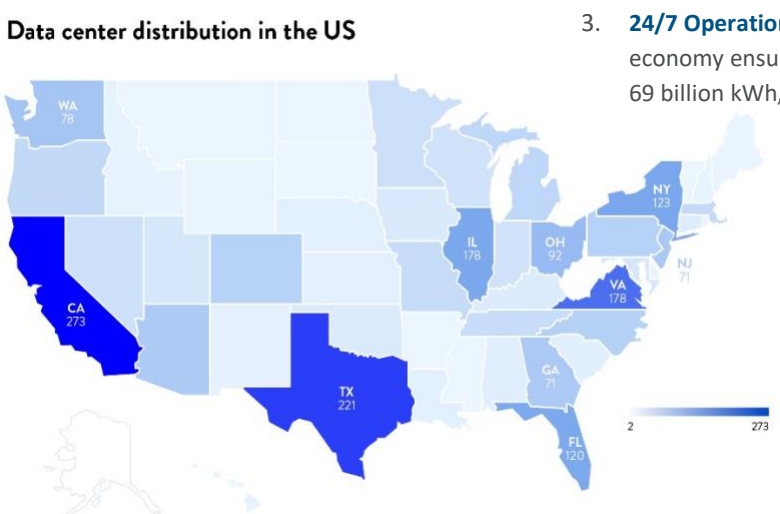


***Figure 1**. US Data Center distribution aggregated together by general classifications of commercial, co-location, and hyperscaler. As of 2022, approximately 2,701 data centers were operational in the U.S.—with the geographic concentration following the sequential distribution of: California, Texas, Virginia, and New York. Illustrating the socio-economic determinants of population density and grid infrastructure on data center location.*

Strategies to Manage Efficiency, Usage, and Environmental Impact:

1. **Efficient Algorithms:** Developing energy-efficient AI algorithms, such as pruning, quantization, and knowledge distillation, can offer high performance with lower power use, reducing AI models' computational demands.
2. **Hardware Enhancements/Optimization:** Adoption of energy-efficient hardware like TPUs and FPGAs can notably cut power usage. Plus, advanced cooling methods could reduce energy use by 40%, and server utilization optimization can counter energy waste.
3. **Greener Data Centers:** The use of renewable energy sources can help decrease ecological footprints. Tech companies, like Google, are increasingly investing in renewables for their data centers, targeting 100% carbon-free energy use by 2030.

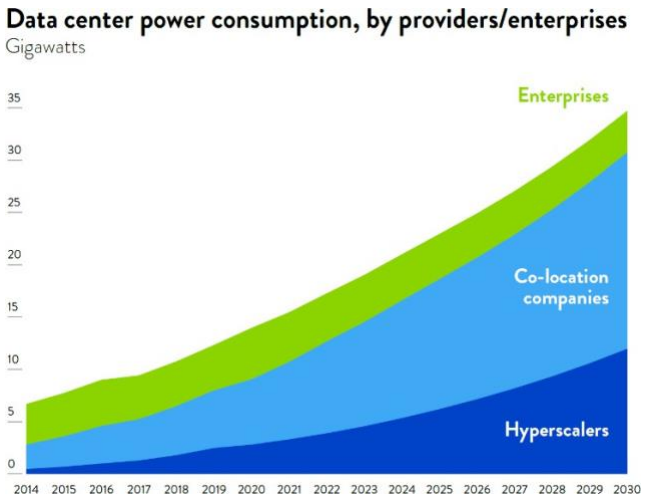


Figure 2. *According to some industry sources, U.S. data center marketsize demand is forecasted to grow by an average of 7.1% annually until 2030. Suggesting that the current value of 148,920 GWh (2022) is estimated to increase to ~233,500 GWh by 2030. These estimates are posited from real-estate growth forecasting, wherein corresponding energy consumption ratios were applied to each data center type to gain a more accurate mosiac of how forecasted changes in US data center marketsize could impact power consumption.*

Future Scenarios – Improved Efficiency, "Business as Usual", and Depreciated Efficiency:

1. **Optimistic Scenario:** Successful research leading to highly energy-efficient algorithms, hardware, and widespread green data centers could cut AI and data center energy use by 50% in a decade.
2. **Neutral Scenario:** With moderate adoption of energy-efficient technologies and data center design improvements, the energy consumption could remain stable over the next decade, despite expected growth.
3. **Pessimistic Scenario:** Without significant energy-efficient tech advances and adoption of green data center practices, escalating demand for digital services and data explosion could double AI and data centers' energy use in a decade.

KEY TAKEAWAYS

AI and data center systems, despite their transformative impact, pose substantial environmental challenges due to high energy consumption. This growing energy demand underscores a critical trade-off between digital innovation and environmental sustainability. However, advances in software and hardware efficiency present promising strategies to mitigate this energy footprint, paving the way towards a more sustainable future.

The future leans towards greener AI and data centers, but this direction hinges on relentless research and collaboration between tech companies and policymakers to establish best practices and regulations. In doing so, we can continue to leverage the transformative benefits of AI and databases while remaining cognizant of our environmental responsibilities.

NEXT STEPS

EPRI's ongoing research investigates the historical and projected trends for AI, ML, and data center load consumption, analyzing their impacts on regional demand growth and infrastructure planning. The study also examines load consumption during the AI & ML learning and user phase to provide comprehensive insights.

For more information, contact:

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3002027934 August 2023

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EPRI ELECTRIC POWER RESEARCH INSTITUTE

PRINCIPLES OF ACCESS FOR FLEXIBLE INTERCONNECTION SOLUTIONS

RULES OF CURTAILMENT







Technical White Paper, July 2020

ABSTRACT

Rising penetrations of distributed photovoltaic (PV) systems and other types of distributed energy resources (DERs) are driving increasing interest in using flexible interconnection solutions in lieu of traditional infrastructure upgrades to integrate these resources onto the grid. Based on the experiences of early-adopter utilities, this white paper provides an overview of the curtailment logic schemes that govern the order and extent of curtailed DER output to manage grid constraints. Insights are intended to inform and simplify the complexities of flexible interconnection solutions for utilities, DER developers, regulators, policy makers, and other stakeholders considering using these approaches in the future. This paper specifically discusses:

- The drivers behind flexible interconnection solutions and the benefits they can bring to different stakeholders, and
- The curtailment logic schemes being used by early adopters of flexible interconnection solutions.

This white paper is the first of a two-paper series covering the principles of access for flexible interconnection solutions. A companion piece[1] addresses cost allocation mechanisms and other aspects related to financial risk management (see 3002019635)

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This white paper was prepared by Tanguy Hubert and Steven Coley of the Electric Power Research Institute. Content is based on research supported by the New York State Energy Research and Development Authority (NYSERDA) Agreement #137950 – Quantifying the Value of DERMS for NY Distribution Grid Services. The opinions expressed in this white paper do not necessarily reflect those of NYSERDA or the State of New York.

[1] *Principles of Access for Flexible Interconnection Solutions: Cost Allocation Mechanisms and Financial Risk Management.* EPRI. Palo Alto, CA: 2020. 3002019635.

INTRODUCTION

WHAT IS FLEXIBLE INTERCONNECTION?

Flexible interconnection is a DER control strategy used to defer or avoid system upgrades and/or increase distribution system utilization. In general, this may involve defining operating constraints on the DER active and/or reactive power at key times when transmission and/or distribution system constraints are binding. In practice, most early-adopter utilities have focused on using flexible interconnection to limit (i.e. curtail) active power exports from DER units in order to avoid grid congestions.

The amount of DER power export that can be accommodated on the distribution system is inherently time varying because the underlying load, generation, temperature, control settings, circuit configuration and other system parameters fluctuate over time. Traditionally, DER customers are connected under a fixed capacity agreement; this fixed export capacity is granted based on "worst case" grid conditions, such that the grid can absorb the full power generated by the DERs whenever it appears while ensuring grid reliability and power quality. By contrast, the flexible interconnection approach aims to grant higher export capacity to DER units, provided that their operation c an be reliability managed if grid congestions appear. The approach aims to increase grid utilization, supporting greater energy exports from DER units and larger DER sizes in more locations (see Figure 1).

ADOPTION DRIVERS

While it is common practice for transmission system operators (TSOs) to manage transmission constraints by re-dispatching generation in the presence of transmission system congestion, it is a relatively new practice for distribution system operators (DSOs) to do so. To date, early adopters of flexible interconnection solutions are predominately located in Europe and Australia, while interest appears to be growing in the U.S.[2]. Table 1 summarizes potential benefits of flexible interconnection solutions, drawing on early-adopter experiences.

Although there are many potential benefits, not every situation is suitable for flexible interconnection arrangements. For example, some areas may not have sufficient variability in net loads to yield enough flexibility in a feeder's time-varying hosting capacity to limit the expected amount of curtailment in a flexible interconnection arrangement. Insights from early-adopter utilities[3] also reveal several key factors denoting an area's suitability for flexible interconnection, including:

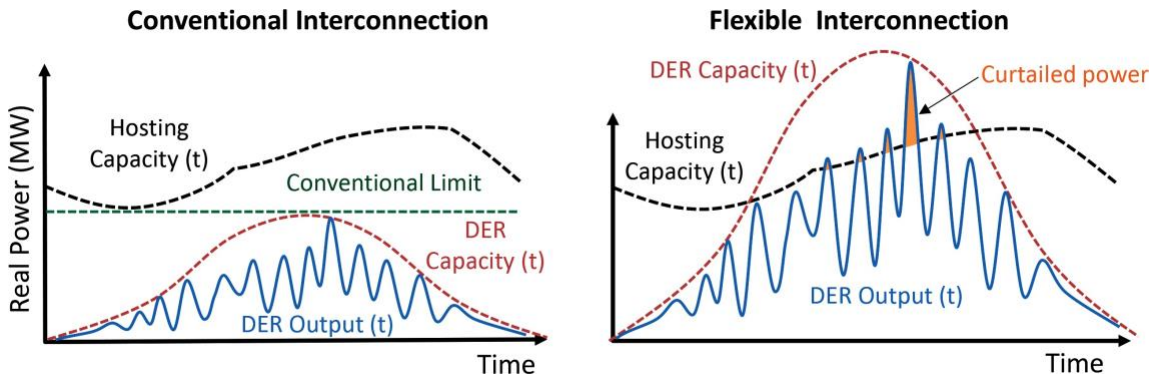


Figure 1. *Conventional (fixed capacity) vs. flexible interconnection*

[2] In Europe, flexible interconnection solutions are more commonly referred to as *Active Network Management* (ANM); in the U.S., the term *Flexible Interconnection Capacity Solution* (FICS) is sometimes used.

[3] *Flexible Interconnection for Distributed Energy Resources: Emerging Practices at Early-Adopter Utilities*. EPRI. Palo Alto, CA: 2018. 3002012964.

Table 1. *Potential benefits of flexible interconnection solutions*

Benefit	Description
Lower interconnection costs	Adding controls and curtailing available generation can be cheaper than conventional network reinforcements. In many cases, conventional upgrades may be prohibitively expensive, constraining DER project development. Flexible interconnection may provide a less costly interconnection option by instituting limited curtailment in lieu of grid upgrades.
Faster interconnection times	Adding controls can be a faster solution than many conventional upgrades (e.g. constructing a dedicated feeder). Flexible interconnection can also be used as a temporary solution for customers who want a firm connection; it allows them to grid connect while they wait for the network reinforcement to occur.
Increased network utilization	Flexible interconnection allows for more DER generation per unit of delivery capacity available, maximizing use of existing grid assets.
Facilitated renewable generation growth	Flexible interconnection can expand renewable generation and meet renewable portfolio standards by using existing network infrastructure, as opposed to building out additional network capacity.

- Areas where conventional reinforcements would be slow or cost prohibitive;
- Areas with enough DER penetration to approach the grid's existing DER accommodation limits; and
- Areas with DER growth (i.e. cheap and available land, good resource potential, and favorable economic conditions).

"PRINCIPLES OF ACCESS" – AN UMBRELLA TERM

Areas that can benefit from flexible interconnection arrangements may attract a growing number of participating DER customers over time. However, the presence of many DER customers, contributing to perhaps multiple constraints on the system, can create complexities with respect to the rules that govern the order and degree of DER curtailment.

Because subsequent DER customers connecting to an area can impact the extent of potential grid violations and thus the required amounts of DER curtailment, there are financial implications that must be addressed to create a commercial environment amenable to flexible interconnection solutions. To adequately provide for this commercial environment, it is important to establish clear principles of access. This umbrella term is used to refer to several principles and rules, associated with different topics, that need to be established when deploying flexible interconnection solutions, including:

- *High-level guiding principles*, which may include objectives such as:
  - *Network efficiency* – maximizing the amount of generation and load that can be economically connected to the grid and driving the efficient buildout of network capacity over time;
  - *Fairness* – creating an environment perceived as equitable with respect to the allocation of curtailment costs and future upgrade costs between flexible DER customers;
  - *Simplicity* – developing a solution that is easy to implement and understand;
  - *Visibility* – providing appropriate levels of transparency in curtailment estimates and curtailment logs to build trust among stakeholders;
  - *Certainty* – providing each flexible DER customer with adequate levels of certainty about long-term curtailment estimates.
- *Rules for DER customer eligibility*, which define requirements associated with items such as:
  - A specific geographic area in which flexible interconnection is an available option;
  - Qualification requirements related to certain customer characteristics (e.g. size thresholds, DER technology);
  - Stipulations for transitioning in or out of a flexible interconnection arrangement over time.

- *Rules of curtailment*, which establish the control logic governing the order and degree to which participating DER customers are curtailed to alleviate grid constraints on the network.
- *Principles defining how future upgrades affect flexible DER customers*. With enough interconnected capacity, it may become economic to make network reinforcements given the large amount of curtailment. Rules that establish how flexible DER customers are to contribute towards the cost of future reinforcements are important for commercial viability of flexible interconnection solutions.
- *Principles supporting sound financial risk management*. Flexible interconnection arrangements increase the uncertainty of future revenues to DER customers, thus impacting the ability to finance their projects. Establishing appropriate transparency, stakeholder education about rules and uncertainties, and any applicable methods (if desired) to mitigate financial risk can help enable commercial implementation of flexible interconnection solutions.
- *Technical requirements* for communications and interoperability of eligible DER customers to enable adequate monitoring of network constraint(s), and control of the distributed energy resources.

While it is important to address all of the above areas when creating the principles of access, this paper offers specific guidance for establishing the rules governing curtailment. This includes considerations of the factors triggering curtailment, curtailment logic options, and a comparative analysis of leading curtailment options. An accompanying paper[1] addresses other areas covered under the principles of access, including the principles defining how future upgrades affect DER customers connected under flexible interconnection agreements, as well as other aspects related to financial risk management.

RULES OF CURTAILMENT

Each flexible interconnection agreement explicitly defines (1) the *grid conditions* that may trigger curtailment, and (2) the *curtailment logic* used to calculate the active power export limit applicable to each participating DER when such grid conditions occur. Since curtailing power exports results in reduced revenues for DER customers, curtailment rules must be clearly defined upfront so that each DER project can adequately compare the flexible interconnection alternative against traditional fixed-capacity arrangements.

CONDITIONS TRIGGERING CURTAILMENT

Grid conditions triggering curtailment are characterized by one or several specific network constraints defined by a binding limit. Curtailment may be triggered when at least one of these constraints gets "too close" to its binding limit in order to avoid violations that compromise reliability or power quality. Network constraints can be of several types (e.g. thermal, voltage), and of various levels of complexity, as illustrated in Figure 2.

Simple scenarios may involve a single network constraint either localized close to a DER site or at a distance. Examples of single constraints include thermal operating limits constraining the operation of a specific distribution line or substation transformer. In more complex scenarios, multiple network constraints, possibly intertwined, may simultaneously trigger active power curtailment at multiple,

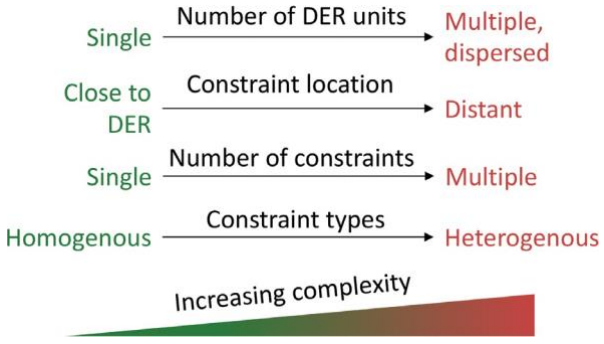


Figure 2. *Network constraint complexity factors*

geographically-dispersed DER sites owned by different customers. In all cases, constraint status is monitored and logged in real-time so that customers involved can verify grid conditions when curtailment was triggered.

CURTAILMENT LOGIC: EMERGING APPROACHES

Flexible interconnection agreements must specify the curtailment logic which defines how curtailment requests are calculated when triggering conditions occur. The logic considered can have various levels of complexity. A basic approach may consist of time-differentiated maximum export schedules, based on historical local network conditions. This approach can be implemented through a local controller and may not require any real-time communications. Infrequent manual schedule updates, for example seasonal, may be considered. Another relatively simple approach may consider a binary logic where a "no-export" command is issued in real time to one or several DER units, based on actual grid conditions.

Many early-adopter utilities have considered more advanced curtailment approaches that seek to minimize curtailment in complex scenarios when simple approaches may lead to levels of curtailment that are not economically viable. These more refined strategies can distribute curtailment requests across multiple participating DERs in a given area, based on actual grid conditions and other factors specific to each DER. A summary of some these emerging approaches is provided in Table 2. The remainder of this paper focuses primarily on the last-in-first-out (LIFO) and pro-rata strategies, which have, to date, been the most commonly implemented approaches by early-adopter utilities.

Understanding Sensitivity Factors

While curtailment strategies aim to distribute curtailment requests across multiple DERs, some DERs in a given area may have a greater capability to alleviate grid congestions than others. Sensitivity factors represent the degree to which a DER unit can influence a particular network constraint under a particular set of grid conditions. For simplicity, examples provided in this paper assume unity sensitivity factors for all DERs (i.e. DERs affect the network constraint at hand equally when curtailing by the same amount). However, in practice, different DER customers may have different sensitivity factors:

- In radial networks, DERs located upstream of a thermal constraint typically have no effective influence on that constraint (sensitivity factor = 0); DERs located *downstream* of that constraint have a sensitivity factor close to 1;
- In meshed networks, the influence of DER units on each particular thermal network constraint is more complex to estimate and depends on several factors, including the point of connection of each DER and the circuit conditions (particularly the nodal voltages).
- In general, sensitivity factors for voltage constraints are more complex to estimate compared to thermal constraints;
- For any given constraint, only DER units with a non-zero sensitivity factor should be considered for curtailment to minimize individual active power curtailment.

Sensitivity factors may be one of the input parameters considered when defining the curtailment logic scheme. Sensitivity factor values can change over time, based on circuit conditions and network reconfigurations.

Table 2. Examples of curtailment strategies	
Curtailment Logic	**Description**
Last-in-first-out	DER units are curtailed in the reverse order in which they applied for network connection..
Pro-rata	DER units are equally curtailed in proportion to their contribution to network constraints.
Competitive bidding	DER units with the lowest bids to use network capacity are required to curtail.
Emissions-based priority	DER units with the highest emissions are curtailed first.

CURTAILMENT STRATEGY: LAST-IN-FIRST-OUT

The LIFO approach curtails DER customers contributing to a specified constraint in the reverse order in which they applied for network connection. The term "LIFO stack" is sometimes used to refer to this ordered list of flexible DER customers. An example of curtailment under LIFO is shown in Figure 3 (at left) for a group of five DER units. Under LIFO, DER-5, the DER customer most recently connected ("last in"), gets curtailed first ("first out"). For this example, grid conditions triggered a full curtailment of DER units 5, 4, and 3, while DER unit 2 was only partially curtailed. DER unit 1, the first to connect, was permitted to continue to fully export (100% of active power available for export).

Grid conditions are intrinsically dynamic, as both load and DER power production constantly change over time. Evolving grid conditions require to regularly adjust the curtailment levels[4]. Figure 3 (at right) illustrates, for the same group of five DER units, a curtailment update requiring additional active power curtailment on DER-2. Grid conditions eventually return to a state where curtailment of DER power exports can be progressively relaxed thanks to increased load demand and/or decreased DER power production.

Curtailment as depicted in Figure 3 may occur multiple times a year, with different levels of severity based on grid conditions. Some grid conditions may require all flexible DER units to be fully curtailed, while less severe grid conditions may only require a single DER unit to be partially curtailed.

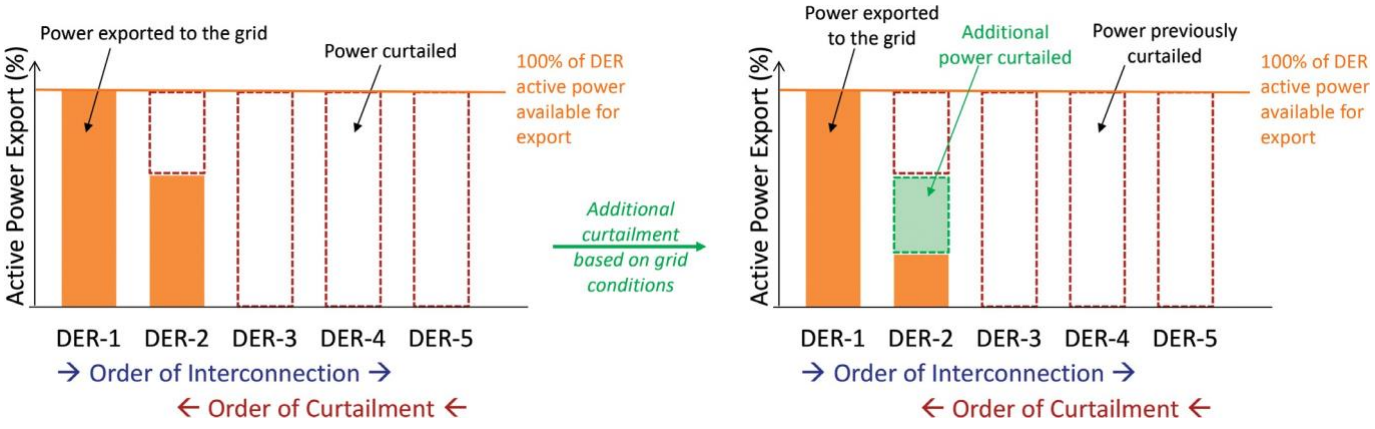


Figure 3. *Curtailment under LIFO*

[4] The frequency at which curtailment levels are updated depends on the type of the control and communication technology used, among other factors.

LIFO: First Connected, Lowest Curtailment? Not Always.

The amount of power curtailed by a given DER unit depends on its position in the LIFO stack, but that's not the only factor in play. Differences in underlying DER technologies and production schedules can also influence curtailment. Consider an example with two DER units of similar power nameplates, one harnessing wind and the other solar irradiance. Assume the wind energy unit was connected first, and is therefore curtailed last under LIFO. These two units have different production patterns—while the solar unit may only export during the day, the wind unit generates power based on wind conditions, which evolve over time. At night, power production may be in excess due to lower load demand, while congestions may occur more rarely during the day. Since the solar unit never produces at night, the wind unit may frequently get curtailed, despite its prime position in the LIFO stack. This simple example illustrates that while a DER unit's position in the LIFO stack matters, congestion timing and DER export schedule also play an important role.

CURTAILMENT STRATEGY: PRO-RATA

Under the pro-rata approach, active power curtailment is shared across DER customers contributing to a specified constraint in proportion to a reference parameter, or "allocation key". Specifically, when grid conditions requiring curtailment occur, the amount of power curtailed for each DER is the product of a proportion factor α, which is the same across all DERs, and an allocation key value, which is specific to each DER.

$$\text{DER Active Power Curtailed} = \text{Proportion Factor } \alpha \text{ (same for all DERs)} \times \text{Allocation Key Value (specific to each DER)}$$

For a given group of DERs:

- The proportion factor α is the same across all DER units[5]. The system operator re-selects the value of α as grid conditions evolve over time, such that the total amount of power curtailed across all DERs matches the total export reduction needed to address the underlying grid conditions;
- All DERs in the group use the same allocation key, although the "value" of that allocation key is specific to each DER. For example, if *DER nameplate* is the reference parameter used as the allocation key, each DER will have its own nameplate value.

Figure 4 provides a simplified overview of the various steps used to calculate the amount of active power curtailed for each DER, for a given set of grid conditions.

A basic example of a curtailment under pro-rata is shown in Figure 5 (at left) for a group of three DER units located in the same geographical area and contributing to the

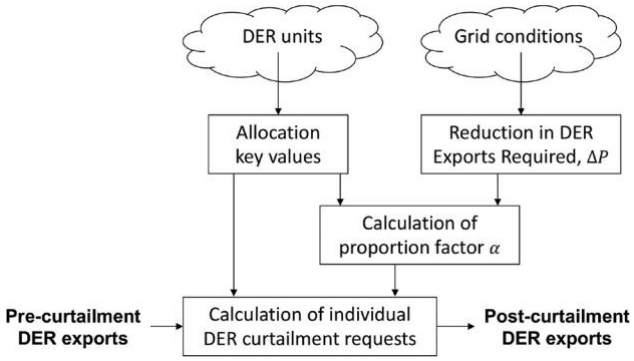


Figure 4. *Simplified overview of the curtailment process under pro-rata*

[5] When addressing a *single* network constraint, the proportion factor α is in principle the same across all DER units. Exceptions may occur when some DER units have maxed out their curtailment capacity while other units belonging to the same group are still able to curtail further. Such exceptions are further discussed below. Further, scenarios with multiple DERs contributing to *multiple* constraints may also lead to the assignment of different proportion factor values across a group of DER units.

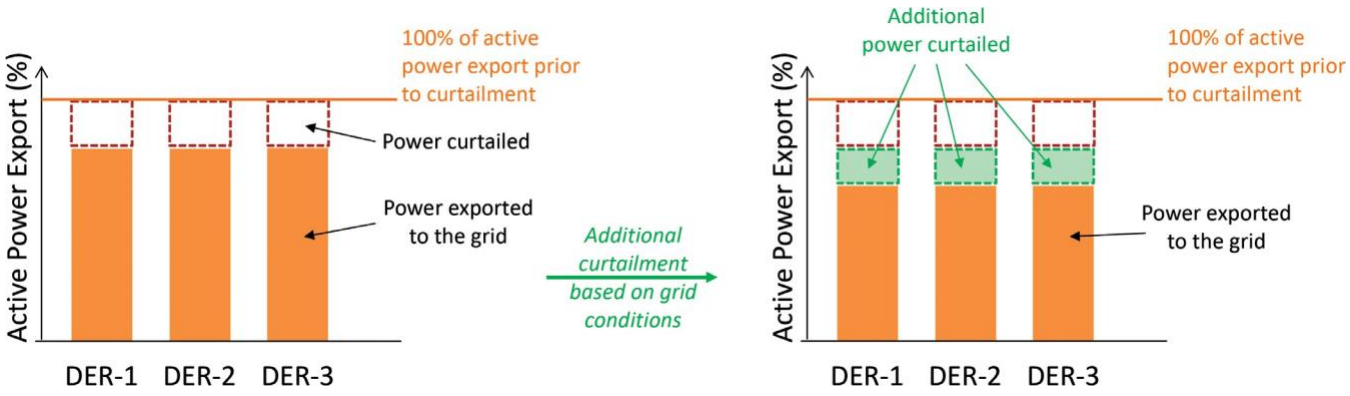


Figure 5. *Curtailment under pro-rata using "DER active power available for export" as allocation key.*

same constraint. In this example, *DER active power available for export* is used as the allocation key. It is assumed that all DER units were exporting 100% of their active power available for export prior to curtailment. As a result of evolving grid conditions, active power exports are reduced across all DERs by the same proportion factor α.

Evolving grid conditions, reflecting changes in generation and/or demand, may trigger updates in curtailment levels as illustrated in Figure 5 (at right). Such updates may involve an increase or decrease of the total amount of DER power exports curtailed in a given geographical area. Of course, each DER unit can only curtail up to its amount of active power available for export (then equivalent to a "no-export" command). Therefore, while Figure 4 provides a simplified overview of the curtailment process, the actual process may be much more involved in practice to ensure that DER units are never asked to curtail *more* than their active power available for export.

SELECTING AN ALLOCATION KEY

The allocation key selected for a given group of DERs is defined upfront as part of the flexible interconnection agreement. A variety of reference parameters – or even a combination of multiple parameters – can be used as the allocation key. It is important to carefully consider the tradeoffs of selecting a particular allocation key given that it will directly influence the way curtailment requests are distributed across individual DER units. Table 3 provides two examples of allocation keys: 1) present active power export, and 2) maximum active power *available*[6] for export.

Table 3: *Allocation key examples for pro-rata curtailment (formulas provided for three DERs)*

Allocation key	Curtailment allocation method	Proportion factor α =	Curtailed power for DER k	Total power curtailed
Present active power export	Each DER k is requested to curtail active power export in proportion to its present power export P_k.	$\frac{\Delta P}{(P_1 + P_2 + P_3)}$	$\alpha \times P_k$	$\alpha P_1 + \alpha P_2 + \alpha P_3 = \Delta P$
Maximum active power *available* for export	Each DER k is requested to curtail active power export in proportion to its active power available for export A_k.	$\frac{\Delta P}{(A_1 + A_2 + A_3)}$	$\alpha \times A_k$	$\alpha A_1 + \alpha A_2 + \alpha A_3 = \Delta P$

Notes: the calculation of the proportional factor α for a group of three DERs, assuming that the system operator is aiming for a total export reduction ΔP across the three DERs; ΔP is defined based on grid conditions

[6] The maximum active power "available" for export may be defined differently depending on the DER technology considered. For PV, the maximum active power available for export is likely to be the maximum solar power available in excess (i.e. after subtracting any local consumption). For storage, the maximum active power available for export may depend on several factors, including the storage power capacity, the current state of charge, and the stack of services pursued, each associated with specific operating constraints.

For a given DER unit, the active power *available* for export is either larger than (if curtailment has been active) or equal to (if curtailment has been inactive) the active power effectively exported. (See sidebar, *"Active Power Available for Export: An Important Parameter for Management of Flexible DERs"*)

Consider a numerical example with three solar PV customers with system nameplates of 2MW, 1MW, and 3MW, respectively. *Present active power export* is used as the allocation key. Prior to curtailment, DER-1 is exporting 1.2 MW, DER-2 is exporting 0.9 MW, and DER-3 is exporting 2.8 MW. Due to changing grid conditions, ΔP=1 MW must get curtailed across the three solar PV customers. Figure 6 illustrates the adjusted active power exports for each DER unit after execution of the curtailment commands[7].

Active Power Available for Export: A Strategic Parameter for Advanced Management of Flexible DERs

Monitoring and telemetry requirements, as defined in the flexible interconnection agreement, enable the system operator to remotely collect measurements or other data from participating DER units, including *present* active power export levels. When curtailment is active, present export levels are, by definition, *lower* than the maximum active power available for export. For PV units specifically, the active power available for export is likely to be the maximum net solar power available (i.e. after subtracting any local consumption). The ability of DER units to calculate and report their active power available for export, which changes over time, can be beneficial for managing flexible DERs in that it enables the use of *active power available for export* as the allocation key, as illustrated in Table 3. While approaches leveraging the *active power available for export* parameter are currently being evaluated, most of today's commercial PV systems are not yet capable of calculating and reporting their maximum solar power available to an upstream DER managing entity, when executing curtailment commands. This topic is an active area of research at EPRI.

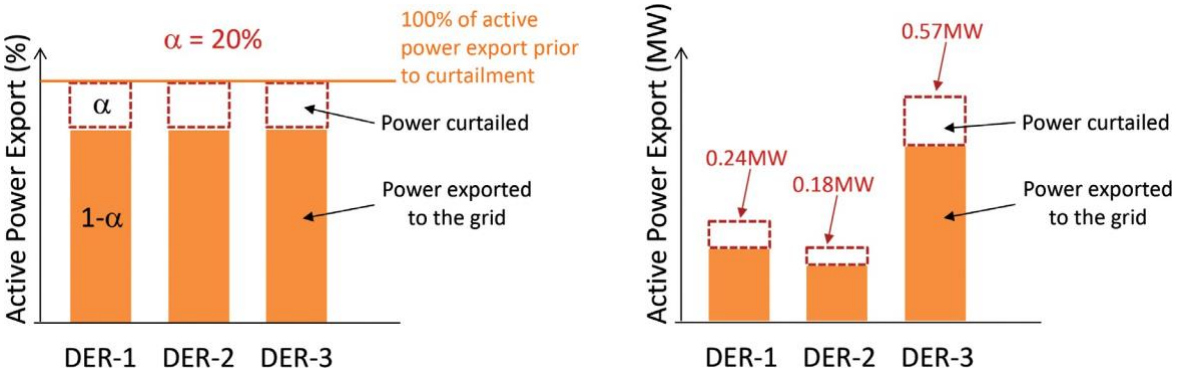


Figure 6. *Active power export curtailment under Pro-rata (left: reduction in %; right: reduction in absolute value)*

[7] Different levels of individual curtailment may be obtained for this illustrative example if selecting a different allocation key. Further, the type of control signal sent to the DER units may vary based on the technology used. For example, the control signal could represent the amount of power to be curtailed (as compared to the last export level measured); alternatively, the control signal could represent the new maximum export limit allowed (adjusted based on the amount of power to be curtailed).

COMPARATIVE ANALYSIS: LIFO VS. PRO-RATA

What follows is a comparison of the LIFO and pro-rata approaches from several perspectives.

CAPACITY FACTORS AND NETWORK UTILIZATION

DER customers who connect early under LIFO tend to get curtailed less often[8], while the pro-rata approach aims to spread curtailment more evenly across participating DER units. For this reason, a greater number of DER units may be able to reach a capacity factor above the minimum economic capacity factor under pro-rata (Figure 7). This may result in more DER projects being financially viable, and therefore more projects connecting to the grid. A greater number of interconnected DER units can potentially enable better network utilization, especially with a diverse DER technology mix.

EFFECT OF ADDITIONAL FLEXIBLE DERS ON INDIVIDUAL DER CURTAILMENT

Under LIFO, additional DER customers connecting under a flexible agreement do not impact DER customers previously connected from a curtailment standpoint, since customers connecting last get curtailed first[10]. However, under pro-rata, additional DER customers may lead already-connected DER customers to experience increased curtailment: as new DER customers connect, the total active power export capacity increase, potentially leading to more frequent network congestions, in turn leading to more frequent curtailment which increasingly affect all DER customers under pro-rata. Consequently, pro-rata may fail to provide DER customers with sufficient confidence that curtailment levels will remain sufficiently low in the long term to ensure financial viability of their DER projects. Backstop measures may include a quota on connected DER capacity, or a maximum curtailment threshold beyond which new DER customers are not allowed to connect under a flexible agreement. For both LIFO and pro-rata, all DER customers may experience increased curtailment as a result of decreasing load in the area.

INCENTIVES TO UPGRADE TO FIXED CAPACITY AGREEMENTS

The number of DER customers connected under a flexible agreement in a specific area may reach a critical mass beyond which the total cost of curtailed active power across the group of DER customers may exceed the cost

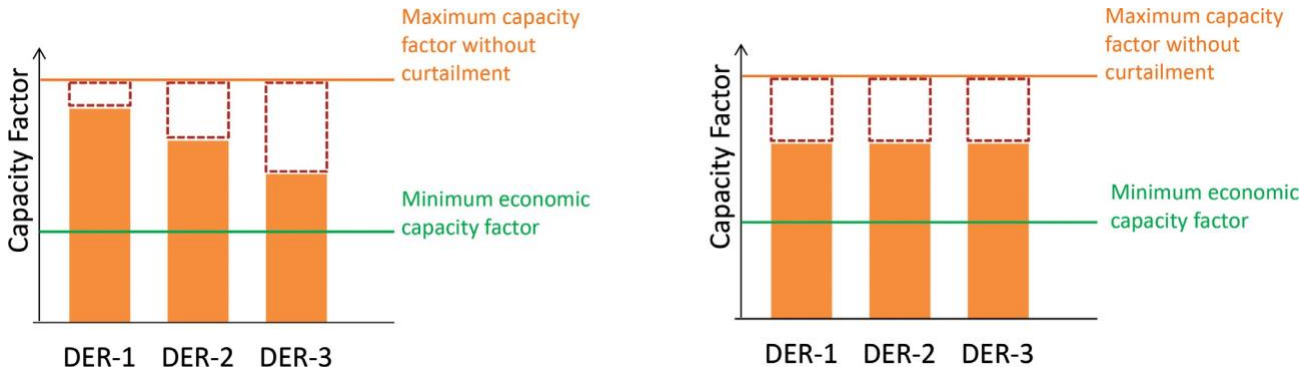


Figure 7. *Illustrative annual capacity factors[9] under LIFO (left) and pro-rata (right)*

[8] See also side bar *"LIFO: First connected, lowest curtailment? Not always"* in this paper for further discussion on this topic.

[9] This illustrative example assumes that all three DERs have similar technology and production potential.

[10] This assumes that all additional customers can get *fully* curtailed.

of implementing network reinforcements required to upgrade all DER customers to traditional, fixed capacity interconnection agreements. LIFO and pro-rata rules allocate curtailment requests differently across DER customers, leading to differences in customers' willingness to pay (WTP) for network reinforcements. Under pro-rata, all DER customers are affected by curtailment requests similarly (proportionally to the allocation key used): when DER technologies are similar (e.g. solar PV), all DER customers connected under a flexible agreement have similar incentives to co-finance upgrades when a certain critical mass of DER customers is reached. However, under LIFO, the customers' WTP for upgrades is dependent on their position in the LIFO stack. In general, last-in customers experience more curtailment, and thus would receive greater benefit from network upgrades. This asymmetry in curtailment allocation may require an arrangement where upgrade costs are also allocated asymmetrically[1].

GAMING OF PRIORITY RULES

Since LIFO curtails DERs in the reverse order in which they applied for network connection, some customers may be tempted to apply early to "hold a spot" in the LIFO stack, with no intention to actually connect a DER asset in the short term. Such customers could eventually re-enter the LIFO stack in the mid- to long-term to the detriment of customers who applied at a later date, but effectively connected their DER systems earlier. Backstop measures may include setting a maximum period of time between the interconnection application and effective connection, beyond which the application expires; or using the effective connection date as the reference to establish the priority order in the LIFO stack.

CONCLUSIONS

Flexible interconnection solutions are emerging as an alternative to traditional infrastructure upgrades for integrating more DER resources onto the grid. Establishing clear rules governing DER export curtailment is a key requirement to creating a commercial environment amenable to flexible interconnection solutions. While basic curtailment strategies are possible (e.g. time-differentiated maximum export schedules), many early-adopter utilities have considered more advanced curtailment approaches, including LIFO and pro-rata, which each have pros and cons.

LIFO provides higher financial certainty for developers, but proper safeguards must be established to prevent potential gaming of LIFO priority rules. Pro-rata can potentially lead to higher network utilization, and also provides similar incentives for DER customers to co-finance network enforcements and upgrade to fixed capacity interconnection agreements. However, additional DER customers may cause previously connected DER customers to experience increased curtailments, potentially leading to insufficient financial certainty for developers. Comparing and contrasting curtailment strategies for flexible interconnection solutions is an area of ongoing EPRI research.

RECOMMENDED READING

1. *Active Network Management: Good Practice Guide*. Baringa Partners and Energy Networks Association. 2015.
2. *Employing Active Power Curtailment of Distribution-Connected Solar Photovoltaics: Economic and Regulatory Considerations*. EPRI. Palo Alto, CA: 2017. 3002010289
3. *Flexible Interconnection for DER: Emerging Practices at Early-Adopter Utilities*. EPRI. Palo Alto, CA: 2018. 3002012964
4. *Flexible Plug and Play: Principles of Access Report*. Baringa Partners and UK Power Networks. December 2012.
5. *Principles of Access for Flexible Interconnection Solutions: Cost Allocation Mechanisms and Financial Risk Management*. EPRI. Palo Alto, CA: 2020. 3002019635.
6. *Understanding Flexible Interconnection*. EPRI. Palo Alto, CA: 2018. 3002014475

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BEFORE THE PUBLIC UTILITIES COMMISSION OF NEVADA

Joint Application of Sierra Pacific Power Company d/b/a NV Energy and Callisto Enterprises LLC for approval of an Energy Supply Agreement.	))))	Docket No. 24-06014

At a general session of the Public Utilities Commission of Nevada, held at its offices on May 13, 2025.

PRESENT: Chair Hayley Williamson
Commissioner Tammy Cordova
Commissioner Randy J. Brown
Assistant Commission Secretary Trisha Osborne

ORDER

The Public Utilities Commission of Nevada ("Commission") makes the following findings of fact and conclusions of law:

I. INTRODUCTION

On June 10, 2024, Sierra Pacific Power Company d/b/a NV Energy ("Sierra") and Callisto Enterprises LLC ("Google" together with Sierra, "Joint Applicants") filed with the Commission a joint application, designated as Docket No. 24-06014 ("Joint Application"), for approval of an Energy Supply Agreement ("ESA").

On April 28, 2025, Joint Applicants, the Bureau of Consumer Protection ("BCP"), and the Regulatory Operations Staff of the Commission ("Staff" and together with Joint Applicants and BCP, the "Parties") filed a Stipulation, attached hereto as Attachment A, resolving all issues in the docket.

II. SUMMARY

The Commission accepts the Stipulation and grants the Application as modified by the Stipulation.

III. PROCEDURAL HISTORY

• On June 10, 2024, Joint Applicants filed the Joint Application pursuant to the Nevada Revised Statutes ("NRS") and the Nevada Administrative Code ("NAC"), Chapters 703 and 704, including but not limited to NAC 703.535 and the Clean Transition Tariff ("CTT") that is pending approval in Docket No. 24-05023. Pursuant to NRS 703.190 and NAC 703.527 *et seq.*,

Joint Applicants request that certain material in the Joint Application receive confidential treatment.

- On June 17, 2024, the Commission issued a Notice of Application for Approval of an Energy Supply Agreement and a Notice of Prehearing Conference.

- Staff participates as a matter of right pursuant to NRS 703.301.

- On June 20, 2024, BCP filed a Notice of Intent to Intervene, pursuant to NRS 228.360.

- On July 12, 2024, the Presiding Officer held a prehearing conference attended by the Parties, wherein two potential procedural schedules were discussed, depending on the procedural schedule adopted in Consolidated Docket Nos. 24-05022 and 24-05023.

- On July 23, 2024, the Commission issued Procedural Order No. 1, setting a Continued Prehearing Conference for December 3, 2024, and Notice of Hearing.

- On August 12, 2024, Joint Applicants filed an Amendment to the Joint Application.

- On December 3, 2024, the Presiding Officer held a Continued Prehearing Conference attended by the Parties, wherein the procedural schedule was discussed.

- On December 4, 2024, the Commission issued Procedural Order No. 2, setting the procedural schedule, and a Notice of Hearing.

- On March 11, 2025, the CTT was approved by the Commission in consolidated Docket Nos. 24-05022 and 24-05023.

- On March 13, 2025, the Commission issued a notice for a Continued Prehearing Conference.

- On April 1, 2025, the Presiding Officer held a Prehearing Conference attended by the Parties, setting a Continued Prehearing Conference for April 9, 2025.

- On April 4, 2025, Joint Applicants filed a supplement to the Joint Application.

- On April 7, 2025, Joint Applicants filed the confidential portion of the Supplement of the Joint Application.

- On April 9, 2025, the Presiding Officer held a Continued Prehearing Conference attended by the Parties, setting a Continued Prehearing Conference for April 29, 2025.

- On April 28, 2025, the Parties filed the Stipulation.

- On April 29, 2025, the Presiding Officer held a Continued Prehearing Conference attended by the Parties, wherein the Stipulation was discussed.

IV. PARTY POSITIONS

The Parties' Position

1. The Parties agree and recommend that the Commission grant the Joint Application in Docket 24-06014, as modified by the Stipulation. (Attachment A at 3.)

2. Joint Applicants agree to amend the ESA and adopt the model methodologies the Commission approved for the base Large Customer Market Price Energy ("LCMPE") model presented in Docket No. 24-05041 and the updated requirements from the CTT presented in Consolidated Docket Nos. 24-05022 and 24-05023, as outlined in the Supplemental Direct Testimony of Hank Will and Exhibit Will Supplement 1, filed with the Commission on April 4, 2025. (*Id.*)

3. Joint Applicants agree to file an amended ESA, as a compliance filing, after the Commission files an Order accepting the Stipulation, the amended ESA will clearly state the Base Tariff General Rate ("BTGR") and Base Tariff Energy Rate ("BTER") rate components of the overall ESA rate. (*Id.* at 4.)

4. Sierra agrees that it will not request a Regulatory Asset or Liability for any revenue differential between the start of the ESA and the filing of the first General Rate Case ("GRC") in which rates are re-set. (*Id.*)

5. Sierra agrees to provide detailed spreadsheets and testimony in its subsequent three (3) GRCs detailing the accounting between the ESA rate, the existing BTGR, the existing BTER, and its proposed BTGR; further, Sierra agrees to provide testimony detailing whether the BTGR portion of the ESA rate has offset the generation credits in Statement O from the ESA, and if a differential exists between the BTGR credits and the BTGR portion of the ESA rate, the Parties may argue for differential cost allocations for any shortfall or excess from the ESA. (*Id.*)

6. The Parties agree that in entering this Stipulation, no Party is endorsing any particular input or concepts that may apply to future ESAs pending or proposed under the CTT, and the Parties fully reserve their ability to propose modifications to CTT model inputs and concepts in all other pending and future CTT ESAs. (*Id.*)

Commission Discussion and Findings

7. The Commission accepts the Stipulation and grants the Joint Application as modified by the Stipulation.

8. The Commission finds that the Stipulation complies with the requirements of NAC 703.845 in that it settles only issues relating to the instant proceedings and does not seek relief the Commission is not otherwise empowered to grant. The Stipulation is a consensus resolution of the issues pursuant to the Parties' negotiations and is a reasonable recommendation and resolution of the issues in these proceedings.

9. All arguments of the Parties raised in these proceedings not expressly addressed herein have been considered and either rejected or found to be non-essential for further discussion in this Order. Any agreements and recommendations contained in the Stipulation but not expressly addressed herein are either agreements by the Parties regarding matters non-essential to the disposition of this Docket or are recommendations for specific findings that do not require delineation given the Commission's acceptance of the Stipulation and corresponding approval of the Joint Application as modified by the Stipulation.

THEREFORE, it is ORDERED:

1. The Stipulation filed by Sierra Pacific Power Company d/b/a NV Energy, Callisto Enterprises LLC, the Bureau of Consumer Protection, and the Regulatory Operations Staff of the Public Utilities Commission of Nevada, attached hereto as Attachment A, is accepted.

2. The Joint Application of Sierra Pacific Power Company d/b/a NV Energy and Callisto Enterprises LLC for approval of an Energy Supply Agreement is granted as modified by the Stipulation and this Order.

3. The Public Utilities Commission of Nevada's acceptance of the Stipulation does not constitute precedent regarding any legal or factual issue.

Compliance

4. Sierra Pacific Power Company d/b/a NV Energy and Callisto Enterprises LLC shall, within forty-five (45) days of the issuance of the present Order, file an amended Energy Supply Agreement, which clearly states the Base Tariff General Rate and Base Tariff Energy Rate components of the overall Energy Supply Agreement rate.

Directives

5. Sierra Pacific Power Company d/b/a NV Energy shall not request a Regulatory Asset or Regulatory Liability for any revenue differential between the start of the term of the Energy Supply Agreement as amended pursuant to ordering paragraph 4 above, and the filing of the first General Rate Case in which rates are re-set.

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6. Sierra Pacific Power Company d/b/a NV Energy shall provide detailed spreadsheets and testimony in its subsequent three (3) General Rate Cases detailing the accounting between the Energy Supply Agreement rate, the existing Base Tariff General Rate, the existing Base Tariff Energy Rate, and its proposed Base Tariff General Rate, and detailing whether the Base Tariff General Rate portion of the Energy Supply Agreement rate has offset the generation credits in Statement O from the Energy Supply Agreement.

By the Commission,

HAYLEY WILLIAMSON, Chair

TAMMY CORDOVA, Commissioner

RANDY J. BROWN, Commissioner

Attest:
TRISHA OSBORNE,
Assistant Commission Secretary

Dated: Carson City, Nevada

5/14/25

(SEAL)

PUBLIC UTILITIES COMMISSION OF NEVADA PUC

ATTACHMENT A

BEFORE THE PUBLIC UTILITIES COMMISSION OF NEVADA

Joint Application of Sierra Pacific Power Company d/b/a NV Energy and Callisto Enterprises LLC for Approval of an Energy Supply Agreement.	Docket No. 24-06014

STIPULATION

Pursuant to Nevada Administrative Code ("NAC") § 703.845, Sierra Pacific Power Company d/b/a NV Energy ("NV Energy"), Callisto Enterprises, LLC, ("Google") the Regulatory Operations Staff ("Staff") of the Public Utilities Commission of Nevada ("Commission"), the Office of the Attorney General's Bureau of Consumer Protection ("BCP"), each individually a "Signatory" and together the "Signatories," enter into this Stipulation to resolve all issues related to the Joint Application for approval of an Energy Supply Agreement ("ESA") between NV Energy and Google under Clean Transition Tariff ("CTT") Schedule No. CTT ("Joint Application").

SUMMARY OF STIPULATION

The Signatories agree this Stipulation provides a reasonable resolution of issues raised in the Joint Application.

The Stipulation only settles issues related to the underlying docket.

The Stipulation only seeks relief that the Commission is empowered to grant.

Accordingly, the Signatories recommend that the Commission accept the Stipulation and grant certain requests for relief made by NV Energy and Google in its Joint Application to approve an ESA between NV Energy and Google as modified by this Stipulation.

RECITALS

1. On June 10, 2024, Sierra and Google filed a joint application with the Commission, designated as Docket No. 24-06014 for approval of an ESA under the CTT.

2. NV Energy and Google filed the Joint Application pursuant to the Nevada Revised Statutes ("NRS") and the Nevada Administrative Code ("NAC") Chapters 703 and 704, including, but not limited to, NRS 703.535 and the CTT. NV Energy and Google also

requested that certain material in the Joint Application receive confidential treatment pursuant to NRS 703.190 and NAC 703.527 et seq.

3. On June 17, 2024, the Commission issued a Notice of Application for Approval of an Energy Supply Agreement and notice of Prehearing conference.

4. Staff participates as a matter of right pursuant to NRS 703.301.

5. On June 20, 2024, BCP filed a Notice of Intent to Intervene pursuant to NRS 228.360 and participates as a matter of right.

6. On July 12, 2024, the Commission held a prehearing conference attended by the NV Energy, Google, Staff and BCP, wherein two potential procedural schedules were discussed, depending on the procedural schedule adopted in consolidated Docket Nos. 24-05022 and 24-05023.

7. On July 23, 2024, the Commission issued Procedural Order No. 1, setting a Continued Prehearing Conference for December 3, 2024.

8. On August 12, 2024, NV Energy and Google filed an Amendment to the Application.

9. On December 3, 2024, the Presiding Officer held a prehearing conference attended by NV Energy, Google, Staff and BCP, wherein the procedural schedule was discussed.

10. On December 4, 2024, the Presiding Officer issued Procedural Order No. 2 setting the procedural schedule.

11. On March 11, 2025, the CTT was approved by the Commission in consolidated Docket Nos. 24-05022 and 24-05023.

12. On March 13, 2025, the Presiding Officer issued a notice for a continued pre-hearing conference.

13. On April 1, 2025, the Presiding Officer held a prehearing conference attended by NV Energy, Google, Staff and BCP, setting a continued prehearing conference for April 9, 2025.

14. On April 4, 2025, NV Energy and Google filed a supplement to the filing.

15. Staff, BCP, Google, and NV Energy agree to enter into the Stipulation.

16. As a result of Staff's investigation into this Application, Staff has determined that, through this ESA, Google is providing significant financial support, which facilitates a new technology, Fervo Energy's next generation geothermal project ("Fervo Project") to move forward with a resource that could be vital to both NV Energy and its customers going forward. The construction and operation of the Fervo Project would provide an incremental opportunity to contract with renewable energy resources that are not intermittent and which may help avoid the potential increased costs and operational difficulties associated with meeting the growing renewable portfolio standard requirement with prevalent existing resource types.

17. This Stipulation resolves all issues related to NV Energy and Google's Joint Application in the above reference docket.

NOW THEREFORE, in light of the foregoing considerations, the Signatories agree and recommend the following:

AGREEMENT OF THE SIGNATORIES

NOW THEREFORE, considering the foregoing considerations, the Signatories agree and recommend that the Commission:

1. Grant NV Energy and Google's Joint Application in Docket No. 24-06014, as modified by this Stipulation.

2. NV Energy and Google agree to amend the ESA and adopt the model methodologies that were approved by the Commission for the base Large Customer Market Price Energy ("LCMPE") model presented in Docket No. 24-05041, and the updated requirements from the CTT presented in consolidated Docket Nos. 24-05022 and 24-05023. The changes are set forth in the Supplemental Direct Testimony of Hank Will and Exhibit Will Supplement 1, filed with the Commission on April 4, 2025.

3. NV Energy and Google agree to file an amended ESA as a compliance filing with the Commission after an Order granting this Stipulation has been filed in the undersigned docket. This ESA will clearly state the Base Tariff General Rate ("BTGR") and Base Tariff Energy Rate ("BTER") rate component of the overall ESA rate.

4. NV Energy will not request a Regulatory Asset or Liability for any revenue differential between the start of the ESA and the filing of the first General Rate Case in which rates are re-set.

5. NV Energy will provide detailed spreadsheets and testimony in the subsequent three (3) General Rate Cases detailing the accounting between the ESA rate, the existing BTGR, the existing BTER, and its proposed BTGR. NV Energy will provide testimony detailing whether the generation credits in Statement O from the ESA have been offset by the BTGR portion of the ESA rate. If there is a differential between the BTGR credits and the BTGR portion of the ESA rate, the Parties may argue for differential cost allocations for any shortfall or excess from the ESA.

6. In entering into this Stipulation, no Party is endorsing any particular model inputs or concepts that may be applicable to any future ESAs pending or proposed under the CTT. The Parties fully reserve their ability to propose modifications to CTT model inputs and concepts in all other pending and future CTT ESAs.

GENERAL PROVISIONS.

A. This Stipulation shall not serve as precedent for the resolution of any issue in the future by the Commission, with the exception of the matters enumerated herein and the findings that follow.

B. In accordance with NAC § 703.845, this Stipulation settles only issues relating to the present proceeding and seeks relief that the Commission is empowered to grant.

C. This Stipulation is entered into for the purpose of resolving all the issues in this Docket by and among the Signatories as set forth above. This Stipulation is made upon the

express understanding that it constitutes a negotiated settlement. The provisions of this Stipulation are not severable.

D. This Stipulation represents a compromise of the positions of the Signatories. As such, conduct, statements and documents disclosed in the negotiation of this stipulation shall not be admissible as evidence in this Docket or any other proceeding. Except as set forth herein, neither this Stipulation, nor its terms, nor the Commission's acceptance or rejection of the terms contained in this Stipulation shall have any precedential effect in future proceedings.

E. If the Commission does not accept the Stipulation in whole, then the Stipulation shall be withdrawn, without prejudice to any claims or contentions that may have been made or are made in this Docket; no part of the Stipulation shall be admissible in evidence; and no Signatory shall be bound by any of the provisions of the withdrawn Stipulation.

F. This Stipulation may be executed in one or more counterparts, all of which together shall constitute the original executed document. This Stipulation may be executed by Signatories by electronic transmission, which signatures shall be as binding and effective as original signatures.

This Stipulation is entered into by each Signatory as of the date entered below.

SIERRA PACIFIC POWER COMPANY D/B/A NV ENERGY By: */s/ Deborah Bone* Date: April 28, 2025 Name: Deborah Bone Title: Deputy General Counsel	REGULATORY OPERATIONS STAFF By: */s/ Donald Lomoljo* Date: April 28, 2025 Name: Donald Lomoljo Title: Staff Counsel
OFFICE OF ATTORNEY GENERAL, BUREAU OF CONSUMER PROTECTION By: */s/ Michael Saunders* Date: April 28, 2025 Name: Michael Saunders Title: Senior Deputy Attorney General	PARSONS BEHLE & LATIMER By: */s/ Justina Caviglia* Date: April 28, 2025 Name: Justina A. Caviglia, Esq. Attorney for Callisto Enterprises, LLC

Original Filing

Public Utilities Commission of Nevada

Electronic Filing

Submitted: 6/7/2024 3:37:16 PM

PAYMENT PENDING VERIFICATION: $200.00

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Payment Reference: 91-9f68-a3b0a7a24d61

Filed For: SPPC

In accordance with NRS Chapter 719,
this filing has been electronically signed and filed
by: /s Erin Moore

By electronically filing the document(s),
the filer attests to the authenticity of the electronic signature(s) contained therein.

This filing has been electronically filed and deemed to be signed by an authorized agent or
representative of the signer(s) and
SPPC

NVEnergy

FILED WITH THE PUBLIC UTILITIES COMMISSION OF NEVADA - 6/7/2024

June 7, 2024

Ms. Trisha Osborne
Assistant Commission Secretary
Public Utilities Commission of Nevada
1150 East William Street
Carson City, Nevada 89701-3109

RE: Docket No. 24-06___ Application of Sierra Pacific Power Company d/b/a NV Energy for Approval of an Energy Supply Agreement with Callisto Enterprises, LLC

Dear Ms. Osborne:

Enclosed for filing please find Sierra Pacific Power Company d/b/a NV Energy's (the "Company") and Callisto Enterprises, LLC's ("Callisto") Joint Application for approval of an energy supply agreement ("ESA") between the Company and Callisto pursuant to the Clean Transition Tariff pending approval in Docket No. 24-05023. Consistent with NAC § 703.535, the filing is made up of this Application, the ESA, a draft notice, testimony of Company witnesses Janet Wells and Hank Will and Callisto witnesses Briana Kobor and Carolyn Berry.

Portions of the filing accompanying this transmittal letter are to be kept under seal pursuant to NAC § 703.527 *et seq.* This information is contained in a sealed envelope, appropriately marked, and contains the unredacted pages from of the ESA, testimony of Janet Wells, testimony of Hank Will and certain workpapers supporting the testimony of Hank Will, which includes confidential customer-specific information as well as confidential commercially sensitive and/or trade secret information of the Company that derives independent economic value from not being generally known. This information is not known outside the Company and its distribution is limited within the Company. Publication of this information would also unfairly advantage competing suppliers and impair the Company's ability to achieve the most favorable pricing and terms and conditions from suppliers on behalf of its customers. The Company and Callisto requests that this confidential information remain under seal for a period of at least five years following the expiration or earlier termination of the attached energy supply agreement.

Should you have any questions regarding this filing, please contact me at (775) 834-5696 or deborah.bone@nvenergy.com.

Respectfully submitted,

/s/Deborah Bone
Deborah Bone
Deputy General Counsel

BEFORE THE PUBLIC UTILITIES COMMISSION OF NEVADA

Joint Application of Sierra Pacific Power Company d/b/a NV Energy and Callisto Enterprises, LLC for Approval of an Energy Supply Agreement	)) /	Docket No. 24-06___

JOINT APPLICATION OF SIERRA PACIFIC POWER COMPANY D/B/A NV ENERGY AND CALLISTO ENTERPRISES, LLC FOR APPROVAL OF AN ENERGY SUPPLY AGREEMENT

Sierra Power Company, d/b/a NV Energy ("Sierra" or "Company") and Callisto Enterprises, LLC ("Google" or "Customer" and together with Sierra "Joint Applicants"), hereby makes this Application pursuant to Nevada Administrative Code ("NAC") NAC § 703.535 for approval of an energy supply agreement ("ESA") between Sierra and Google for purposes of providing electric service to Customer's data center facilities, located in Storey County, Nevada (the "Facilities"). The ESA will provide a mechanism that allows Google's facilities to take service under the Clean Transition tariff ("CTT") that is pending approval in Docket No. 24-05023. The Joint Applicants seek approval of a long-term energy supply period within the ESA to meet Customer's corporate goals regarding carbon-free energy ("CFE") supply on an hourly load matching basis, which requires access to dedicated clean generation sources to supply its Facilities in a manner that complies with the CTT requirements and does not result in any increased costs or forgone benefits for non-participating customers.

I.

THE APPLICANTS

SIERRA PACIFIC POWER COMPANY

Sierra is a Nevada corporation and wholly-owned subsidiary of NV Energy, Inc., a Nevada corporation, an exempt utility holding company. Sierra is engaged in providing electric service to the public in portions of Washoe, Pershing, Humboldt, Lander, Elko, Mineral, Churchill, Nye, Esmeralda, Douglas, Storey, and Lyon counties, Nevada, pursuant to a

certificate of public convenience and necessity issued by this Commission. Sierra is a "public utility" as that term is defined and used pursuant to Chapter 704 of the NRS.

Sierra's primary business office is located at 6100 Neil Road, Reno, Nevada. All correspondence related to this Application should be transmitted to Sierra's counsel *and* to Sierra's Manager of Regulatory Services, as set forth below:

Deborah Bone Deputy General Counsel 6100 Neil Road Reno, NV 89511 775-834-5696 deborah.bone@nvenergy.com	Sandra Blain Director, Regulatory Services 6100 Neil Road Reno, NV 89511 775-834-5823 regulatory@nvenergy.com

CALLISTO ENTERPRISES LLC

Callisto Enterprises is a subsidiary of Google LLC, which is a subsidiary of Alphabet Inc. Google owns and operates two data centers in Nevada, one in Storey County, and one in Clark County. All correspondence related to this Application should be transmitted to Google's counsel *and* to Briana Kobor, Head of Energy Market Innovation for Google, as set forth below:

Justina Caviglia, Esq. Parsons Behle & Latimer 50 W. Liberty Street, Suite 750 Reno, NV 89502 775-323-1601 jcaviglia@parsonsbehle.com	Briana Kobor Head of Energy Market Innovation Google 1021 S 400 W Salt Lake City, UT 84101 bkobor@google.com

II.

OVERVIEW

The ESA provides Google with a vehicle to receive electric service under the CTT. The term of Google's long-term ESA is expected to commence once the dedicated renewable energy resource, the Corsac Station Enhanced Geothermal Project in development by Fervo Energy,

reaches commercial operation.[1] Non-participating customers of the utility will not experience increased costs for electric service or forgo the benefit of a reduction of costs for electric service. Prior to commercial operation of the underlying geothermal project, Google will be served at its otherwise applicable rate.

Additional information regarding the ESA is included in the attached testimony of Company witnesses Janet Wells and Hank Will and Customer witnesses Briana Kobor and Carolyn Berry.

III.

THE FILING

Consistent with NAC § 703.535, the filing is made up of the transmittal letter, this Application, the ESA, the ESA pricing model, a draft notice, testimony of Janet Wells, Hank Will, Briana Kobor and Carolyn Berry.

The ESA (Exhibit A). The ESA provides a means for Google to purchase and receive electric service using clean energy resources, while not shifting costs to other customer classes.

Draft Notice (Exhibit B). Accompanying this filing is a Draft Notice satisfying the requirements of NAC § 703.162.

Direct Testimony of Janet Wells. The direct testimony of Janet Wells supports the terms and conditions in the ESA and describes how the ESA is in the public interest.

Direct Testimony of Hank Will. The direct testimony of Hank Will describes the ESA's fixed long-term energy price and the underlying pricing model.

Direct Testimony of Briana Kobor. The direct testimony of Briana Kobor reviews Google's footprint in Nevada, describes Google's corporate clean energy objectives and addresses how the ESA meets Google's corporate clean energy objectives while protecting the interest of all Nevada ratepayers.

[1] The Company's power purchase agreement for this resource is presented to the Commission contemporaneous with this Application, in Docket No. 24-05041.

Direct Testimony of Carolyn Berry. The direct testimony of Carolyn Berry provides an overview of the importance of the ESA for Google, the resource that supports the Google ESA and the impact of the ESA on non-participating customers.

IV.

THE ESA IS IN THE PUBLIC INTEREST

The ESA is in the public interest. Approval of the ESA does not subject Sierra's other customers to increased costs, nor does it cause them to forego the benefit of a reduction in cost. As further described in the supporting testimony, Sierra's other customers and all Nevadans receive benefits from the approval of this ESA. Specifically, the testimony of Janet Wells explains that the ESA's terms and its underlying pricing model incorporates certain protections such that the Google pays for the entire output of the underlying resource and its effective rate under the ESA and is higher than the effective rate of its otherwise applicable rate class.

V.

TIMELINE

The CTT is currently pending approval in Docket No. 24-05023. Joint Applicants are filing this Application prior to the approval of the CTT to provide the ESA contemporaneous with the request for approval of the underlying project in the pending triennial Integrated Resource Plan filing, as contemplated in the proposed CTT. Given that the processing of this Application is not subject to any statutory deadline, the Joint Applicants respectfully request that the Commission set a procedural schedule for this docket that allows time for the Commission to first approve the CTT prior to any hearings or rulings on the ESA.

VI.

CONFIDENTIAL INFORMATION

Portions of the testimony and excerpts of the ESA and the ESA pricing model are to be

kept under seal pursuant to NRS § 703.196 and NAC § 703.527 *et seq.* This information is contained in a sealed envelope, appropriately marked, and contains the unredacted versions of portions of the ESA and the testimony of Ms. Janet Wells and Mr. Hank Will and supporting exhibits. These materials contain customer specific information of Google, as well as commercially confidential information of Google and Sierra, which includes commercially sensitive and/or trade secret information that derives independent economic value from not being generally known. This information is not known outside Google or Sierra and its distribution is limited within the Company. Publication of this information would also unfairly advantage competing suppliers and impair the Company's ability to achieve the most favorable pricing and terms and conditions from suppliers on behalf of its customers.

To maintain the confidentiality of Google's information and the commercially sensitive information, the Joint Applicants have designated this information as confidential pursuant to NRS § 703.196 and NAC § 703.5274. The public version of the filing will include redactions of this confidential information. Pursuant to NAC § 703.5274(2), Joint Applicants request that the above-described information not be disclosed to the public and that this information remain confidential for a period of five years following the expiration or earlier termination of the ESA, after which the Commission may return or destroy these materials, whichever is most convenient. Protective agreements with the Regulatory Operations Staff ("Staff") and the Bureau of Consumer Protection ("BCP") will be provided and, once executed, Staff and BCP will be served with confidential unredacted versions of the above-described material.

VII.

PRAYER FOR RELIEF

WHEREFORE, Sierra and Google requests that the Commission:

(1) Approve the ESA between Sierra and Google;

(2) Approve Sierra's request to maintain customer specific information and the commercially sensitive information confidential for a period of five years; and

(3) Grant such additional other relief as the Commission may deem appropriate and necessary.

Dated this 7th day of June, 2024.

Respectfully submitted,

SIERRA PACIFIC POWER COMPANY D/B/A NV ENERGY

/s/Deborah Bone
Deborah Bone
Deputy General Counsel
Sierra Pacific Power Company
6100 Neil Road
Reno, NV 89511
775-834-5696
deborah.bone@nvenergy.com

CALLISTO ENTERPRISES LLC

PARSONS BEHLE & LATIMER

/s/ Justina A. Caviglia
Justina A. Caviglia
Nevada Bar No. 9999
50 West Liberty Street, Suite 750
Reno, Nevada 89501
775-323-1601
jcaviglia@parsonsbehle.com

Attorneys for Callisto Enterprises LLC

EXHIBIT A

DocuSign Envelope ID: 357C8D7D-F352-4873-BF0D-A0169FC162CA

SCHEDULE NO. CTT

ENERGY SUPPLY AGREEMENT

AMONG

SIERRA PACIFIC POWER COMPANY d/b/a NV ENERGY,

AND

CALLISTO ENTERPRISES, LLC.

dated May 13, 2024

DocuSign Envelope ID: 357C8D7D-F352-4873-BF0D-A0169FC162CA

This **SCHEDULE NO. CTT ENERGY SUPPLY AGREEMENT** (this "Agreement"), dated as of May 13, 2024 (the "Execution Date"), is made by and between SIERRA PACIFIC POWER COMPANY, a Nevada corporation doing business as NV Energy ("NV Energy"), and Callisto Enterprises, LLC, a Delaware limited liability company ("Customer"). NV Energy and Customer also may be referred to as a "Party" and collectively as the "Parties".

RECITALS

WHEREAS, NV Energy is an electric service provider in Nevada, as defined in NRS Chapter 704;

WHEREAS, Customer is a current customer receiving electric service from NV Energy for its data centers in Storey County, Nevada (the "Facilities");

WHEREAS, Customer desires that NV Energy provide the Facilities with certain electric service to support Customer's corporate goals regarding cost-effective carbon-free energy ("CFE") supply on an hourly load matching basis, which requires access to dedicated clean generation sources to supply its Facilities;

NOW THEREFORE, in consideration of the mutual promises set forth herein, and for other good and valuable consideration, the receipt and sufficiency of which are hereby acknowledged, the Parties, intending to be legally bound, do hereby agree as follows:

AGREEMENT

1. CERTAIN DEFINITIONS.

1.1 "**Action**" means any claim, action, cause of action, demand, lawsuit, arbitration, inquiry, audit, notice of violation, proceeding, litigation, citation, summons, subpoena or investigation of any nature, civil, criminal, administrative, regulatory or otherwise, whether at law or in equity.

1.2 "**Affiliate**" means, with respect to NV Energy, Berkshire Hathaway Energy Company and its direct and indirect wholly-owned subsidiaries and, with respect to Customer, any Person who, directly or indirectly, through one or more intermediaries, controls, is controlled by, or is under common control of, a Person.

1.3 "**Agreement**" has the meaning set forth in the preamble hereto.

1.4 "**BTGR Credits**" means rate credits for generation capacity and energy supply in the Base Tariff General Rate ("BTGR") that are applied to Schedule No. CTT for CTT Load.

1.5 "**Business Day**" means any day, other than a Saturday, Sunday or legal holiday, on which commercial banks in Clark County, Nevada, are generally open for the transaction of business.

1.6 "**Carbon Free Energy**" means energy generated from carbon free sources, including but not limited to, wind, solar, geothermal or as the Parties may otherwise agree.

1.7 "**CTT Energy Supply Commencement Date**" means the date that the Generating Facility has achieved commercial operation, as determined by NV Energy.

1.8 "**CTT Generating Facility Rate**" means the fixed rate of [redacted] to provide Customer with energy from the Generating Facility in the Resource Procurement Agreement.

1.9 "**CTT Energy Rate**" means a fixed rate of [redacted] for the energy delivered from the Generating Facility to the Customer under Schedule No. CTT.

1.10 "**CTT Load**" has the meaning set forth in Section 5.1.1.

1.11 "**CTT Effective Rate**" means an overall rate calculated by NV Energy for the Generating Facility Products that includes (a) the CTT Energy Rate pursuant to Section 1.9; (b) transmission and distribution usage costs based on the otherwise applicable rate class; (c) Base Tariff Energy Rate and Deferred Energy Accounting Adjustment rate for load not served from the Generating Facility (d) a franchise fee as set by Storey County; and (e) any applicable public program charges or fees, as determined by the PUCN, in each case, without duplication.

1.12 "**Customer**" has the meaning set forth in the preamble.

1.13 "**Effective Date**" has the meaning set forth in Section 2.2.

1.14 "**Environmental Attributes**" means any and all existing and future credits, benefits, emissions reductions, offsets, and allowances, attributable to the generation from the Generating Facility. This includes Portfolio Energy Credits as defined in Section 1.34.

1.15 "**Event of Default**" has the meaning set forth in Section 9.1.

1.16 "**Execution Date**" has the meaning set forth in the preamble above.

1.17 "**Excess Energy**" is defined as energy generated by the Generating Facility minus the energy served to Customer's Facilities.

1.18 "**Facilities**" has the meaning set forth in the Recitals above.

1.19 "**Facilities Load**" means the total energy load of the Facilities.

1.20 "**Generating Facility**" means one or more carbon-free energy generating facilities approved by the PUCN from which NV Energy will procure or generate energy for Customer pursuant to Schedule No. CTT specified under Exhibit A.

1.21 "**Generating Facility Products**" means all products associated with the Generating Facility specified under Exhibit A, including but not limited to energy, capacity, environmental attributes and ancillary capacity.

1.22 "**Governmental Entity**" means any federal, state, or local government or political subdivision thereof, or any agency or instrumentality of such government or political subdivision, or any self-regulated organization or other non-governmental regulatory authority or quasi-governmental authority (to the extent that the rules, regulations or orders of such organization or authority have the force of law), or any arbitrator, court or tribunal of competent jurisdiction.

1.23 "**kPC**" means one thousand (1,000) PCs.

1.24 "**kW**" means kilowatt.

1.25 "**kWh**" means kilowatt-hour.

1.26 "**MW**" means megawatt.

1.27 "**MWh**" means megawatt-hour.

1.28 "**NAC**" means the Nevada Administrative Code, as amended.

1.29 "**NRS**" means the Nevada Revised Statutes, as amended.

1.30 "**NV Energy**" has the meaning set forth in the preamble hereto.

1.31 "**Party**" and "**Parties**" have the meanings set forth in the preamble.

1.32 "**PC Administrator**" means the Person appointed by the PUCN to administer the system of Portfolio Energy Credits established pursuant to the Renewable Energy Law or a successor law if the Renewable Energy Law is replaced, superseded or preempted by another law or regulatory regime tasked with enforcement of renewable energy quotas by users or utility providers in Nevada.

1.33 "**Person**" means an individual, corporation, partnership, limited liability company, trust, business trust, association, joint stock company, joint venture, sole proprietorship, unincorporated organization, Governmental Entity, or other entity.

1.34 "**Portfolio Energy Credit**" or "**PC**" means a unit of credit which equals one kilowatt-hour of electricity generated, acquired or saved (or deemed so), all as calculated by the PUCN Regulatory Operations Staff and certified by the PC Administrator pursuant to the Renewable Energy Law (or by a successor Governmental Entity pursuant to a successor law if the Renewable Energy Law is replaced, superseded or preempted by another law or regulatory regime tasked with enforcement of renewable energy quotas by utility providers in Nevada), and certified by WREGIS.

1.35 "**PUCN**" means the Public Utilities Commission of Nevada and any successor entity thereto.

1.36 "**PUCN Schedule No. CTT Approval**" means a final order issued by the PUCN that (a) approves the Schedule No. CTT, in form and substance satisfactory to NV Energy

and Customer, and (b) is not the subject of (i) a petition for reconsideration or rehearing, (ii) a petition for judicial review, or (iii) a petition for a preliminary injunction. For clarity and avoidance of doubt, and without limitation of the foregoing, if the Schedule No. CTT is approved by a final order of the PUCN, but such approval includes terms or conditions unacceptable to NV Energy or Customer, it shall be deemed that "PUCN Schedule No. CTT Approval" has not been obtained for purposes of this section.

1.37 "**PUCN ESA Approval**" means a final order issued by the PUCN that (a) approves this Agreement, in form and substance satisfactory to NV Energy and Customer, and (b) is not the subject of (i) a petition for reconsideration or rehearing, (ii) a petition for judicial review, or (iii) a petition for a preliminary injunction. For clarity and avoidance of doubt, and without limitation of the foregoing, if the Agreement is approved by a final order of the PUCN, but such approval includes terms or conditions unacceptable to NV Energy or Customer, it shall be deemed that "PUCN ESA Approval" has not been obtained for purposes of this section.

1.38 "**PUCN Resource Approval**" means a final order issued by the PUCN that (a) approves the Resource Procurement Agreement or new Generating Facility from which NV Energy will procure or generate energy for Customer, in form and substance satisfactory to NV Energy, and (b) is not the subject of (i) a petition for reconsideration or rehearing, (ii) a petition for judicial review, or (iii) a petition for a preliminary injunction. For clarity and avoidance of doubt, and without limitation of the foregoing, the Resource Procurement Agreement or Generating Facility is approved by a final order of the PUCN, but such approval includes terms or conditions unacceptable to NV Energy, it shall be deemed that "PUCN Resource Approval" has not been obtained for purposes of this section.

1.39 "**Renewable Energy Law**" means an act of the Nevada legislature relating to energy, or law that affects Customer's renewable energy consumption or that requires certain electric service providers to comply with the portfolio standard for renewable energy, and providing for other matters relating thereto, codified as NRS 704.7801 through 704.7828, inclusive, and NAC 704.8831 through 704.8937, inclusive, and the rules and regulations of WREGIS, and the regulations, guidance and other requirements promulgated thereunder, in each case as such laws, regulations, guidance and requirements may be amended, preempted or superseded.

1.40 "**Resource Procurement Agreement**" means one or more agreements entered into by NV Energy and pursuant to which NV Energy shall obtain the right to provide energy, capacity, Environmental Attributes and ancillary services from the applicable Generating Facility and its associated facilities to serve all of the CTT Load.

1.41 "**Resource Procurement Agreement Rate**" means the rate paid by NV Energy for energy, capacity, Environmental Attributes and ancillary services from the Generating Facility as provided in the Resource Procurement Agreement.

1.42 "**RPS**" means the State of Nevada's Renewable Portfolio Standard.

1.43 "**Schedule No. CTT**" means Nevada Power's Clean Transition Tariff, Schedule No. CTT, to be filed for approval with the PUCN.

1.44 "**Short Term Avoided Cost**" means the long term avoided costs for the applicable period filed with the PUCN pursuant to NV Energy's most recently approved Integrated Resource Plan filing minus the capacity costs.

1.45 "**Tariff Rules**" means the terms and conditions applicable to Schedule No. CTT that have been approved by the PUCN.

1.46 "**Tax**" or "**Taxes**" means the applicable federal, state, local or foreign income, gross receipts, license, payroll, employment, excise, severance, stamp, occupation, premium, windfall profits, environmental, customs duties, capital stock, franchise, profits, withholding, social security (or similar), unemployment, disability, real property (including assessments, fees or other charges based on the use or ownership of real property), personal property, transactional, sales, use, transfer, registration, value added, alternative or add-on minimum, estimated tax, or other tax of any kind whatsoever, or any liability for unclaimed property or escheatment under common law principles, including any interest, penalty or addition thereto, whether disputed or not, including any item for which liability arises as a transferee or successor-in-interest.

1.47 "**Term**" has the meaning set forth in Section 3.

1.48 "**Termination Payment**" means the compensation due to Company, if any, in the event Customer terminates pursuant to Section 4 of the Agreement. For purposes of calculating the Termination Payment, the price per kWh will be the difference between the Resource Procurement Agreement Rate and the weighted average of the per kWh levelized cost of energy for NV Energy's most recent PUCN-approved renewable energy facilities for comparable periods taking into account all energy reasonably expected to be produced by the Generating Facility from the termination date through the expiration of the Resource Procurement Agreement term. In the event that such per kWh levelized cost of energy for NV Energy's most recent PUCN-approved renewable energy facilities for comparable periods is greater than the Resource Procurement Agreement Rate, no Termination Payment shall be payable by Customer. As described in Section 4 below, the Termination Payment is only applicable if Customer elects to terminate this Agreement after the CTT Energy Supply Commencement Date.

1.49 "**Transferee**" has the meaning set forth in Section 10.2.

1.50 "**WREGIS**" means the Western Renewable Energy Generation Information System, or a successor organization or system.

2. CONDITIONS TO EFFECTIVENESS; EFFECTIVE DATE.

2.1 Conditions to Effectiveness. The effectiveness of this Agreement, including the Parties' rights and obligations under this Agreement, is expressly subject to the fulfillment of each of the following conditions:

2.1.1 PUCN ESA Approval (a) shall have been obtained by June 1, 2025, provided that if by such date the PUCN ESA Approval is still pending a final decision by the PUCN, then such date shall be automatically extended for successive thirty (30)-day periods; and (b) shall be in full force and effect.

2.1.2 PUCN Resource Approval (a) shall have been obtained by June 1, 2025, provided that if by such date the PUCN Resource is still pending a final decision by the PUCN, then such date shall be automatically extended for successive thirty (30)-day periods; and (b) shall be in full force and effect.

2.1.3 PUCN Schedule No. CTT Approval (a) shall have been obtained by June 1, 2025, provided that if by such date the PUCN Resource is still pending a final decision by the PUCN, then such date shall be automatically extended for successive thirty (30)-day periods; and (b) shall be in full force and effect.

For the avoidance of doubt, no aspect of this Agreement, other than this Section 2.1, shall have any effect unless and until each of the foregoing conditions have been fulfilled. If any of the foregoing conditions have not been fulfilled, this Agreement (including this Section 2.1) shall become void and of no force or effect as if it had not been entered into. Notwithstanding, the above, the rights and obligations of the Parties with respect to Section 6.3 Confidentiality shall remain in effect.

2.2 Effective Date. For purposes of this Agreement, the "Effective Date" is the date as of which each of the conditions set forth in Section 2.1 has been fulfilled.

3. TERM. The term of this Agreement shall commence on the Execution Date and shall continue until the expiration date of the Resource Procurement Agreements specified in Exhibit A, (the "Term"), subject to earlier termination of this Agreement pursuant to Section 4.1 or Section 9.2.

4. ELECTIVE TERMINATION BY CUSTOMER.

4.1 Customer may elect to terminate this Agreement at any time after the CTT Energy Supply Commencement Date and prior to the end of the Term, for any reason and at Customer's sole discretion, upon written notice of such election to NV Energy at least thirty-six (36) months prior to the effective date of the termination.

4.2 If Customer validly terminates this Agreement pursuant to Section 4.1, Customer shall be liable for payment to NV Energy of the Termination Payment, if any, to mitigate any potential cost to NV Energy associated with such termination.

4.3 Customer does not have the right to terminate this Agreement prior to the CTT Energy Supply Commencement Date.

5. ENERGY SUPPLY.

5.1 Facilities Load; CTT Load.

5.1.1 Facilities Load and CTT Load. Customer and NV Energy acknowledge that this Agreement is executed to supply a portion of Customer's Facilities Load. That load portion's anticipated peak load is [redacted] (the "CTT Load"). Under no circumstance will the CTT Energy Rate apply to energy other than the energy generated by the Generating Facility. If the peak load of the Facilities is less than [redacted] as measured by the maximum peak billing demand reached

as of the date that is two years after the CTT Energy Supply Commencement Date, an additional charge of [redacted] will be added to the CTT Energy Rate. The additional charge will cease to be applied upon next billing period following the peak billing demand of the Facilities reaching [redacted].

5.1.2 Facilities Load Exceeding CTT Load. If the Facilities Load exceeds the CTT Load, NV Energy shall provide the Facilities electric service. Facilities Load that exceeds the CTT Load will be subject to the applicable rates, charges and fees of the Customer's otherwise applicable rate class, as a fully-bundled NV Energy customer unless agreed upon otherwise between NV Energy and Customer and approved by the PUCN. For the avoidance of doubt, charges assessed on Facilities Load in excess of CTT Load will not receive BTGR Credits as applicable under Schedule No. CTT.

5.2 CTT Energy Supply.

5.2.1 Procurement and Payment. Commencing on the CTT Energy Supply Commencement Date and continuing through the Term, NV Energy shall deliver to Customer Generating Facilities Products to serve Customer's CTT Load, and Customer shall pay to NV Energy the CTT Effective Rate with respect to the CTT Load. Invoices shall be provided to Customer monthly by the method or methods authorized by the Tariff Rules and shall be paid by Customer in accordance with payment terms set forth therein.

5.2.2 Forecast. Within thirty (30) days after the Effective Date, Customer shall provide NV Energy with a non-binding, forward-looking, five (5)-year monthly forecast (the "Forecast"). Customer shall update the Forecast annually and deliver such updated Forecast to NV Energy no later than six (6) months prior to the end of the period covered by the then-existing Forecast; provided that, in the event that Customer becomes aware of any material changes to the then-existing Forecast, Customer shall update such Forecast and deliver such updated Forecast to NV Energy as soon as is reasonably practicable. If Customer fails to deliver an updated Forecast to NV Energy as provided in this Section 5.3.2, Customer agrees that NV Energy shall use and be entitled to rely on the last Forecast received from Customer.

5.2.3 CTT Energy Rate Adjustment. If the developer of the Generating Facility requests a higher price under its Resource Procurement Agreement with NV Energy, NV Energy will notify Customer within five (5) Business Days of such request and its impact on CTT Energy Rate (the "CTT Energy Rate Adjustment"). Within thirty (30) Business Days of the notice, Customer shall inform NV Energy whether it agrees to or disagrees to the CTT Energy Rate Adjustment. If Customer agrees to the CTT Energy Rate Adjustment, then NV Energy will reflect such cost increase in the CTT Effective Rate beginning on the date such price increase takes effect under the contract between NV Energy and the developer and will continue for the remainder of the Term. If Customer does not agree to the CTT Energy Rate Adjustment, NV Energy may either (a) request the developer to continue under the existing contract, (b) terminate the contract with the developer and this Agreement, or (c) agree to the price increase under the contract with the developer, however, such increase will not be reflected in the CTT Energy Rate.

5.2.4 Generating Facility Products, Excess Energy and Portfolio Energy Credits.

(a) Generating Facility Products. Commencing on the CTT Energy Supply Commencement Date and continuing through the Term, Customer shall receive all products, including but not limited to energy, capacity, ancillary services and Environmental Attributes produced by the Generating Facility. Customer shall pay the CTT Effective Rate for all energy served to Customer's CTT Load, as specified in Section 5.2.1, above, and Customer shall pay the CTT Generating Facility Rate for all Excess Energy.

(b) Excess Energy and Associated Portfolio Energy Credits. NV Energy will purchase Excess Energy from Customer at a rate equivalent to its Short Term Avoided Cost. Alternatively, NV Energy may, at its election, purchase from Customer both Excess Energy and the PCs associated with the Excess Energy, at a rate equivalent to the higher of (i) [redacted] of its weighted average of the per kWh levelized cost of energy for NV Energy's most recent PUCN-approved renewable energy facilities for comparable periods, or (ii) its Short Term Avoided Costs. The settlement for such Excess Energy purchase or Excess Energy and PCs purchase will take place monthly as part of the next regularly scheduled invoice. The Short-Term Avoided Cost used for monthly settlement will be equal to the annual average of the hourly Short-Term Avoided Cost. During the first billing cycle of a calendar year an adjustment payment will be calculated to true-up Short-Term Avoided Cost reflecting the hourly granularity for each instance when Excess Energy or Excess Energy and PC purchase occurred.

(c) Certification of Portfolio Energy Credits. NV Energy will take such commercially reasonable actions as may be necessary and appropriate to cause WREGIS and the PC Administrator to certify or otherwise validate in a timely manner all PCs with respect to energy generated by the Generating Facility to which Customer is entitled. NV Energy shall make commercially reasonable efforts to deliver to Customer proof of certification of the PCs no later than the third Business Day of April for the preceding year. The Parties acknowledge and agree that the certification of PCs is WREGIS-dependent, and that the timing of certification is solely at WREGIS' discretion. NV Energy shall not be liable for certification delays or denials beyond its control.

(d) Retirement of Portfolio Energy Credits. NV Energy will take such commercially reasonable actions as may be necessary and appropriate to retire PCs, on behalf of Customer, with respect to energy generated by the Generating Facility, less any PCs purchased by NV Energy pursuant to Section 5.2.4(b) and to provide an annual report of such retirement which meets applicable certification and reporting requirements.

(e) Optional Transfer of Portfolio Energy Credits. If Customer elects to take ownership of the PCs to which it is entitled rather than have NV Energy retire them on behalf of Customer pursuant to Section 5.2.4(d), NV Energy shall not be required to incur any additional costs or expense for the transfer of such PCs to Customer. As such, any expense incurred for such transfer shall be borne by Customer, and invoiced as part of the next regularly scheduled invoice.

5.3 Effect of Termination of Resource Procurement Agreement or Failure of Generating Facility to Deliver Energy and Capacity.

5.3.1 If (a) the Resource Procurement Agreement is terminated for any reason other than a material breach or default by NV Energy prior to the date that the Generating Facility

has achieved commercial operation or (b) after the Generating Facility has achieved commercial operation, the Generating Facility is not delivering sufficient Generating Facility Products, NV Energy will be excused from obligations under this Agreement and will continue serving Customer under its otherwise applicable rate.

6. COVENANTS OF THE PARTIES.

6.1 Covenants of NV Energy.

6.1.1 PUCN ESA Approval. Following the Execution Date, NV Energy shall use commercially reasonable efforts to obtain the PUCN ESA Approval in a timely manner; provided that, in the event a final order is issued by the PUCN that (a) denies transactions contemplated by this Agreement, or (b) approves the transactions contemplated by this Agreement but such order imposes conditions not acceptable to NV Energy or Customer, NV Energy may, but shall not be obligated to, undertake further efforts to obtain the PUCN ESA Approval.

6.1.2 PUCN Resource Approval. Following the Execution Date, NV Energy shall use commercially reasonable efforts to obtain the PUCN Resource Approval in order to meet the CTT Energy Supply Commencement Date; provided that, in the event a final order is issued by the PUCN that (a) denies the Resource Procurement Agreement or Generating Facility, or (b) approves the Resource Procurement Agreement or Generating Facility but such order imposes conditions not acceptable to NV Energy or Customer, NV Energy may, but shall not be obligated to, undertake further efforts to obtain the PUCN Resource Approval.

6.2 Covenants of Customer.

6.2.1 No Alternative Provider. After the Effective Date and during the Term of this Agreement, NV Energy shall be the sole and exclusive provider of electricity to meet Customer's electricity requirements for the Facilities. However, this provision does not preclude Customer from installing any back-up generation or storage equipment on its site that is either (a) owned by Customer, or (b) leased by Customer, under an agreement that makes Customer the sole owner of the electrical output.

6.3 Confidentiality.

6.3.1 Disclosure. Neither Party shall disclose the content of this Agreement, or disclose any information exchanged between the Parties related to this Agreement, except to its Affiliates and advisors, without the prior written consent of the other Party except as required by applicable law, by any court or other Governmental Entity, but only to the extent, that, based upon reasonable advice of counsel, a Party is required to do so and prior to making such disclosure, the Party shall, to the extent legally permitted, provide the other Party with prompt notice of such disclosure. Notwithstanding the above, NV Energy may disclose this Agreement and information exchanged related to the content of this Agreement to the PUCN and its staff for purposes of obtaining approval of this Agreement or to otherwise advance the purposes of this Agreement.

6.3.2 Public Announcements. Except as permitted in this Section 6.3.2 neither Party may release, distribute, or disseminate any information to the public concerning this Agreement or issue or make any public announcement, press release, or similar public statement

concerning this Agreement (each, an "Announcement") unless the Announcement is issued jointly by the Parties or, prior to the release of the Announcement, the Party furnishes the other Party with a copy of the proposed Announcement and obtains the approval of the other Party, which approval may not be unreasonably withheld, conditioned, or delayed. After any Announcement is issued in accordance with this Section 6.3.2, either Party may issue subsequent Announcements with the same content and wording of the originally issued Announcement, until otherwise notified by the other Party.

7. NOTICES.

7.1 Method of Delivery; Contacts. Except for the monthly invoices referenced in Section 5.2, each notice, consent, request, or other communication required or permitted under this Agreement must be in writing and delivered personally, transmitted by electronic mail, or sent by certified mail (postage prepaid, return receipt requested) or by a recognized international courier or overnight delivery service provider, and addressed to a Party as follows:

Customer:
Callisto Enterprises, LLC
a Delaware limited liability company

Email addresses: [redacted]

NV Energy:

NV Energy
7155 S. Lindell Road, MS B13RE
Las Vegas, NV 89118
Attention: Manager, Energy Supply Contract Management
Email: ContractManagement@nvenergy.com

With a copy to:

NV Energy
6226 W. Sahara Ave., M/S 2
Las Vegas, NV 89146
Attention: General Counsel
Email: legal@nvenergy.com

7.2 Receipt of Notice; Change of Information. Each notice, consent, request, or other communication is deemed to have been received by the Party to whom it was addressed (a) when delivered if delivered personally; (b) upon acknowledgement of receipt, if delivered by telecopier or electronic mail, (c) on the third (3rd) Business Day after the date of mailing if mailed by certified mail; or (d) on the date officially recorded as delivered according to the record of delivery if delivered by courier or overnight delivery. Each Party may change its contact information for purposes of the Agreement by giving written notice to the other Party in the manner set forth above.

8. REPRESENTATIONS AND WARRANTIES OF THE PARTIES.

8.1 Representations and Warranties of Customer.

8.1.1 Customer's Standing. Customer represents that it is (a) a duly organized and validly existing limited liability company which is in good standing under the laws of the State of Nevada, and (b) licensed to do business in the State of Nevada.

8.1.2 Customer's Authority; Enforceability. Customer has the full limited liability power and authority to execute and deliver this Agreement and the other transaction documents to which it will be a party in connection with the transactions contemplated hereby, to perform its obligations hereunder and thereunder and to consummate the transactions contemplated hereby and thereby. The execution and delivery by Customer of this Agreement and the other transaction documents to which it will be a party in connection with the transactions contemplated hereby, and the performance by Customer of its obligations hereunder and thereunder, have been duly and validly authorized by all necessary entity action, and assuming due and valid authorization, execution and delivery thereof by the other Party, will be when delivered, valid and binding obligations of Customer, enforceable against Customer in accordance with their terms.

8.1.3 No Pending Actions, Suits or Proceedings against Customer. Customer represents that, to its knowledge, there are no Actions pending or threatened against Customer in any court or before any administrative agency that would prevent its performance under this Agreement.

8.2 Representations and Warranties of NV Energy.

8.2.1 NV Energy's Standing. NV Energy represents that it (a) is duly organized, validly existing and in good standing under the laws of the State of Nevada, and (b) is licensed to do business in the State of Nevada.

8.2.2 NV Energy's Authority; Enforceability. NV Energy has the full corporate power and authority to execute and deliver this Agreement and the other transaction documents to which it will be a party in connection with the transactions contemplated hereby, to perform its obligations hereunder and thereunder and to consummate the transactions contemplated hereby and thereby. The execution and delivery by NV Energy of this Agreement and the other transaction documents to which it will be a party in connection with the transactions contemplated hereby, and the performance by NV Energy of its obligations hereunder and thereunder, have been duly and validly authorized by all necessary entity action, and assuming due and valid authorization, execution and delivery thereof by the other Party, will be when delivered, valid and binding obligations of NV Energy enforceable against NV Energy in accordance with their terms.

8.2.3 No Pending Actions, Suits or Proceedings against NV Energy. NV Energy represents that, to its knowledge, there are no Actions pending or threatened against NV Energy in any court or before any administrative agency that would prevent its performance under this Agreement.

9. DEFAULT; REMEDIES.

9.1 Each of the following shall be an "Event of Default" under this Agreement:

9.1.1 If NV Energy fails to deliver the CTT Energy pursuant to the terms of this Agreement; provided, however, that such failure shall not be considered an Event of Default in the event of a resource or transmission outage that requires curtailment of service in order to maintain reliability, system integrity or safety;

9.1.2 If Customer fails to pay any amount when due in accordance with Schedule No. CTT, or any other amount due pursuant to this Agreement within the period specified in Schedule No. CTT (or within forty-five (45) days after such amount is due when no other period is specified in Schedule No. CTT), provided that NV Energy shall provide written notice of such non-payment to Customer and Customer shall have fifteen (15) days in which to cure such non-payment;

9.1.3 If either Party is in material breach of any representation or warranty set forth herein or fails to perform any covenant, agreement or other material obligation set forth in this Agreement, including the covenants of the Parties set forth in Section 6 (other than failure to pay referenced in Section 9.1.2), and such breach or failure is not cured within thirty (30) days after written notice of the default is provided to the defaulting Party from the non-defaulting Party; provided, however, that the cure period shall be extended by an additional thirty (30) days if (a) the defaulting Party is unable to cure such breach, (b) failure is not cured within such thirty (30) day period but such Party is diligently pursuing a cure, and (c) the material breach cannot reasonably be cured within such thirty (30) day period; or

9.1.4 If either Party files any voluntary petition in bankruptcy, or any of such Party's creditors files an involuntary petition, which involuntary petition remains undischarged for a period of thirty (30) days.

9.2 Termination. Upon the occurrence of an Event of Default, the non-defaulting Party shall provide notice of the default to the defaulting Party and shall specify in such notice the basis for the Event of Default. In addition to the cure periods specified in Section 9.1.3, unless another cure period is specified in this Agreement, the defaulting Party shall have thirty (30) days from the date the defaulting Party receives written notice of an Event of Default to cure the Event of Default. If the Event of Default is not cured within such thirty (30)-day period, or another cure period specified in this Agreement, the non-defaulting Party may provide notice to the defaulting Party that the Agreement has been terminated. The termination shall be effective in accordance with the notice provisions of this Agreement. The defaulting Party shall remain liable for any obligations that the defaulting Party had pursuant to the Agreement prior to the date of termination, in addition to any other surviving obligations specified herein or remedies available pursuant to Section 9.3.

9.3 Remedies.

9.3.1 In General. Subject to Sections 9.1 and 9.2, upon an Event of Default by a Party, the other Party shall have, in addition to any other remedies available to such Party at law or in equity, the right, but not the obligation, to terminate or suspend this Agreement with respect

to all obligations arising after the effective date of such termination or suspension (other than payment obligations relating to obligations arising prior to such termination or suspension).

9.3.2 Termination Payment. In the event this Agreement is validly terminated by NV Energy in connection with an Event of Default of Customer pursuant to Section 9.2, in addition to Customer remaining liable for its obligations prior to the date of termination, Customer shall be liable for payment to NV Energy of the Termination Payment, if any, to mitigate any potential cost to NV Energy associated with such termination.

10. MISCELLANEOUS PROVISIONS.

10.1 Limitation of Liability. Notwithstanding anything to the contrary contained in this Agreement, neither Party shall be liable to the other Party or a third party for any consequential, punitive, indirect, exemplary, expectation or incidental damages, including, but not limited to, damages based on lost revenues or profits. This Section 10.1 shall survive the expiration or earlier termination of, or any default or excuse of performance under, this Agreement.

10.2 Assignment; Binding Effect. Without the prior written consent of the other Party, which shall not be unreasonably withheld, delayed or conditioned, neither Party may assign, delegate or otherwise transfer to any third party (a "Transferee"), whether by contract, operation of law or otherwise, including in connection with any reorganization, merger or consolidation in which the other Party is not the surviving entity, this Agreement or any of a Party's rights or obligations under this Agreement. Any assignment, delegation or other transfer in breach of this Section 10.2 will be void and of no effect. As a condition to any granting of a Party's written consent, the Transferee must agree to assume all obligations of such Party under this Agreement pursuant to a written agreement in form and substance reasonably satisfactory to the other Party. This Agreement is binding upon, inures to the benefit of, and is enforceable by the Parties and their respective successors and permitted assigns. Notwithstanding the foregoing, either Party may assign, delegate or otherwise transfer this Agreement or any of a Party's rights or obligations under this Agreement to its Affiliate(s), so long as such Affiliate(s) agree to assume all obligations of such Party under this Agreement pursuant to a written agreement in form and substance reasonably satisfactory to the other Party.

10.3 Taxes, Fees or Charges from Governmental Entities. Customer is responsible for any Taxes, fees or charges including, but not limited to, those from Governmental Entities imposed on or associated with the Portfolio Energy Credits or their transfer to Customer. Either Party, upon written request of the other Party, shall provide a certificate of exemption or other reasonably satisfactory evidence of exemption if such Party is exempt from Taxes, and shall use reasonable efforts to obtain and cooperate with the other Party in obtaining any exemption from or reduction of any Tax, fee or charges including, but not limited to, those from Governmental Entities.

10.4 Expenses. Except as otherwise expressly provided in this Agreement, each Party shall pay its own costs and expenses incurred in connection with the negotiation, execution, performance and enforcement of its rights and obligations under this Agreement and the transactions contemplated hereby.

10.5 No Waiver. The failure of either Party to enforce any of the provisions of this Agreement at any time, or to require performance by either Party of any of the provisions of this Agreement at any time, will not be a waiver of any provisions, nor in any way affect the validity of the Agreement, or either Party's right to enforce each and every provision hereof.

10.6 Remedies. All rights and remedies of either Party provided for in this Agreement are cumulative and in addition to, and not in lieu of, any other remedies available to either Party at law, in equity, or otherwise, except as provided in Section 10.1.

10.7 Governing Law; Venue. This Agreement is governed by and construed in accordance with the laws of the State of Nevada, without giving effect to any conflict of law principles that would apply the laws of another jurisdiction. In the event the PUCN has jurisdiction over a civil action or remedy brought under this Agreement, the Parties agree that they will first seek to initiate such action before the PUCN. In the event the PUCN lacks jurisdiction over such a dispute, the Parties agree the dispute will be brought in the U.S. District Court for the District of Nevada. In the event the federal court lacks jurisdiction over such a dispute, the Parties agree the dispute will be brought in the state district court in Clark County, Nevada. The Parties agree not to initiate any legal action against the other Party except in the jurisdictions as provided in this Section 10.7.

10.8 Waiver of Jury Trial. TO THE FULLEST EXTENT PERMITTED BY LAW, EACH OF THE PARTIES HERETO WAIVES ANY RIGHT IT MAY HAVE TO A TRIAL BY JURY IN RESPECT OF LITIGATION DIRECTLY OR INDIRECTLY ARISING OUT OF, UNDER OR IN CONNECTION WITH THIS AGREEMENT. EACH PARTY FURTHER WAIVES ANY RIGHT TO CONSOLIDATE ANY ACTION IN WHICH A JURY TRIAL HAS BEEN WAIVED WITH ANY OTHER ACTION IN WHICH A JURY TRIAL CANNOT BE OR HAS NOT BEEN WAIVED.

10.9 Integration. This Agreement represents the entire and integrated agreement between NV Energy and Customer and supersedes all prior and contemporaneous oral and written communications, representations, and agreements relating to the subject matter of the transaction, except as otherwise expressly stated herein.

10.10 Amendments. Any change, modification, or amendment to this Agreement is not enforceable unless consented to in writing by the Parties and executed with the same formality as this Agreement. The Parties acknowledge that any change, modification or amendment to this Agreement may require approval of the PUCN.

10.11 Severability. If any portion or provision of this Agreement is deemed invalid, illegal, or unenforceable, or any event occurs that renders any portion or provision of the Agreement void, including but not limited to a final order by the PUCN, the other portions or provisions of this Agreement will remain valid and enforceable. Any voided portion or provision will be deemed severed from this Agreement, and the balance of this Agreement will be construed and enforced as if this Agreement did not contain the particular portion or provision held to be void. The Parties further agree to amend this Agreement to replace any stricken portion or provision with a valid provision that comes as close as possible to the intent of the stricken portion

or provision. Nothing in this Section 10.11 shall be construed to waive the conditions in Section 2.1.

10.12 No Third-Party Beneficiaries. Nothing expressed or implied in this Agreement is intended, or should be construed, to confer upon or give any person or entity not a party to this Agreement any third-party beneficiary rights, interests, or remedies under or by reason of any term, provision, condition, undertaking, warranty, representation, or agreement contained in this Agreement.

10.13 Headings; Exhibits; Cross References. The headings or section titles contained in this Agreement are used solely for convenience and do not constitute a part of this Agreement, nor should they be used to aid in any manner in the construction of this Agreement. All exhibits and schedules attached to this Agreement are incorporated into this Agreement by reference. All references in this Agreement to Sections, Subsections, Exhibits, and Schedules are to Sections, Subsections, Exhibits, and Schedules of or to this Agreement, unless otherwise specified. Unless the context otherwise requires, the singular includes the plural and the plural includes the singular and the neuter includes feminine and masculine.

10.14 Performance of Acts on Business Days. Any reference in this Agreement to time of day refers to local time in Clark County, Nevada. All references to days in this Agreement refer to calendar days, unless stated otherwise. If the final date for payment of any amount or performance of any act required by this Agreement falls on a day other than a Business Day, that payment is required to be made or act is required to be performed on the next Business Day.

10.15 No Construction Against Drafting Party. The language used in this Agreement is the product of both Parties' efforts and each Party hereby irrevocably waives the benefits of any rule of contract construction that disfavors the drafter of a contract or the drafter of specific words in a contract.

10.16 Business Formation. Nothing in this Agreement creates a partnership, joint venture or other similar business construct between the Parties.

10.17 Counterparts. This Agreement may be executed in any number of counterparts, each of which will be deemed an original, but all of which together will constitute one and the same instrument.

10.18 Time of Essence. Time is of the essence with respect to all obligations of the Parties hereunder.

[Signature page follows]

DocuSign Envelope ID: 357C8D7D-F352-4873-BF0D-A0169FC162CA

IN WITNESS WHEREOF, this Agreement has been duly executed by the Parties as of the Execution Date.

SIERRA PACIFIC POWER COMPANY, a Nevada corporation d/b/a NV ENERGY

DocuSigned by:

By: _____ 14-May-2024
A4D1AF8A949443C...

Name: Douglas A. Cannon

Title: President & CEO

Callisto Enterprises, a Delaware limited liability company

DocuSigned by:

By: Gary Demasi 15-May-2024
FDA14D740D9A4BE...

Name: Gary Demasi

Title: Authorized Signatory

Confidential Exhibit A

Generating Facility(s)

Generating Facility	[redacted]
Generating Facility Developer	[redacted]
Term (as defined in the PPA):	[redacted]
Expected Commercial Operation Date (as defined in the PPA):	[redacted]
Expected Generating Facility Output in the first Contract Year (as those terms are defined in the PPA):	[redacted]
Percentage of Generating Facility capacity dedicated to Customer:	[redacted]
PPA Execution Date:	[redacted]

EXHIBIT B

PUBLIC UTILITIES COMMISSION OF NEVADA DRAFT NOTICE
(Applications, Tariff Filings, Complaints, and Petitions)

The Commission requires a draft notice be included with all applications, petitions and complaints. See Nevada Administrative Code 703.162. Please include one copy of this form with all the above filings.

I. A title that generally describes the relief requested (see NAC 703.160(5)(a)):

Application of Sierra Pacific Power Company d/b/a NV Energy and Callisto Enterprises, LLC for Approval of an Energy Supply Agreement.

II. The name of the applicant, complainant, petitioner or the name of the agent for the applicant, complainant or petitioner (see NAC 703.160(5)(b)):

Sierra Pacific Power Company d/b/a NV Energy and Callisto Enterprises, LLC

III. A brief description of the purpose of the filing or proceeding, including, without limitation, a clear and concise introductory statement that summarizes the relief requested or the type of proceeding scheduled **AND** the effect of the relief or proceeding upon consumers (see NAC 703.160(5)(c)):

Sierra Pacific Power Company and Callisto Enterprises, LLC are requesting the Public Utilities Commission of Nevada issue an Order approving an energy supply agreement to provide electric service to with Callisto Enterprises, LLC's facilities, located in Storey County, Nevada. The ESA will provide a mechanism to allow Callisto Enterprises LLC's facility to take service under the Clean Transition tariff ("CTT"), pending approval of the CTT in Docket No. 24-05023.

IV. A statement indicating whether a consumer session is required to be held pursuant to Nevada Revised Statute ("NRS") 704.069(1):[1]

No. A consumer session is not required pursuant to NRS 704.069.

V. If the draft notice pertains to a tariff filing, please include the tariff number **AND** the section number(s) or schedule number(s) being revised.

Not Applicable

---

[1] **NRS 704.069 Commission required to conduct consumer session for certain rate cases; Commission required to conduct general consumer session annually in certain counties.**

1. The Commission shall conduct a consumer session to solicit comments from the public in any matter pending before the Commission pursuant to NRS 704.061 to 704.110, inclusive, in which:

(a) A public utility has filed a general rate application, an application to recover the increased cost of purchased fuel, purchased power, or natural gas purchased for resale or an application to clear its deferred accounts; and

(b) The changes proposed in the application will result in an increase in annual gross operating revenue, as certified by the applicant, in an amount that will exceed $50,000 or 10 percent of the applicant's annual gross operating revenue, whichever is less.

2. In addition to the case-specific consumer sessions required by subsection 1, the Commission shall, during each calendar year, conduct at least one general consumer session in the county with the largest population in this state and at least one general consumer session in the county with the second largest population in this state. At each general consumer session, the Commission shall solicit comments from the public on issues concerning public utilities. Not later than 60 days after each general consumer session, the Commission shall submit the record from the general consumer session to the Legislative Commission.

JANET WELLS

BEFORE THE PUBLIC UTILITIES COMMISSION OF NEVADA

Sierra Pacific Power Company d/b/a NV Energy
Docket No. 24-06___
Energy Supply Agreement with Callisto Enterprises, LLC

Prepared Direct Testimony of

Janet Wells

1. Q. PLEASE STATE YOUR NAME, OCCUPATION, BUSINESS ADDRESS AND PARTY FOR WHOM YOU ARE FILING TESTIMONY.

A. My name is Janet Wells. My current position is Vice President of Regulatory for Nevada Power Company d/b/a NV Energy ("Nevada Power" or the "Company") and Sierra Pacific Power Company d/b/a NV Energy ("Sierra," and together with Nevada Power, the "Companies"). My primary business address is 6100 Neil Road, Reno, Nevada. I am filing testimony on behalf of Sierra.

2. Q. PLEASE DESCRIBE YOUR BACKGROUND AND EXPERIENCE IN THE UTILITY INDUSTRY.

A. I hold a Bachelor of Arts Degree in Geography and a Master of Science Degree in Applied Economics and Statistics. I have more than 15 years of utility experience within the Rates and Regulatory Affairs department. Prior to joining the Companies, and during an absence from the Companies, I worked in economic consulting and research. The details of my background and experience are provided in **Exhibit Wells-Direct-1.**

3. Q. PLEASE DESCRIBE YOUR RESPONSIBILITIES AS VICE PRESIDENT OF REGULATORY.

A. As Vice President of Regulatory, my responsibilities include overseeing the preparation of regulatory filings before the Public Utilities Commission of Nevada ("Commission"), and specifically, the work performed by the Load Research and Forecasting, Pricing, and Regulatory Affairs technical teams.

4. Q. HAVE YOU PREVIOUSLY TESTIFIED BEFORE THE COMMISSION?

A. Yes, most recently in Docket No. 24-05041 the 2024 Joint Triennial Integrated Resource Plan. **Exhibit Wells-Direct-1** provides a full list of proceedings in which I have testified before the Commission.

5. Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. The purpose of my testimony is to provide support for Sierra's request for approval of the Energy Supply Agreement ("ESA") with Callisto Enterprises, LLC, a subsidiary of Google ("Google"). Google is eligible to apply for an ESA through the pending Clean Transition Tariff ("CTT").[1] Google is an existing fully-bundled retail customer of Sierra and will remain a fully-bundled retail customer until transitioning to the long-term energy supply period of the ESA. Specifically, I will provide an overview of the framework of the ESA and explain how it provides a unique opportunity to meet the sustainability objectives of Google, while also providing value to the Company's non-participating customers. In addition, I will explain why the ESA is in the public interest. In summary, my testimony shows that the ESA between Sierra and Google is in the public interest, advances Nevada's

[1] Docket No. 24-05023.

sustainability and economic policies and objectives, and benefits all Sierra customers. Hank Will provides testimony in support of the calculation of the long-term energy supply rate for the ESA.

6. Q. ARE YOU SPONSORING ANY EXHIBITS?

A. Yes. I am sponsoring the following Exhibits:

Exhibit Wells-Direct-1 Statement of Qualifications

7. Q. IS SIERRA REQUESTING CONFIDENTIAL TREATMENT OF CERTAIN INFORMATION CONTAINED IN YOUR TESTIMONY?

A. Yes. Confidential information is redacted in my testimony and the ESA.

8. Q. PLEASE DESCRIBE THE CONFIDENTIAL MATERIAL.

A. Portions of my testimony and the ESA contain customer specific information of Google, as well as confidential information of Sierra which is commercially sensitive and/or trade secret information that derives independent economic value from not being generally known. This information is not known outside Sierra and its distribution is limited within the Company.

9. Q. FOR HOW LONG DOES SIERRA REQUEST CONFIDENTIAL TREATMENT?

A. The requested period for confidential treatment is for no less than five years.

10. Q. WILL CONFIDENTIAL TREATMENT IMPAIR THE ABILITY OF THE COMMISSION'S REGULATORY OPERATIONS STAFF ("STAFF") OR THE BUREAU OF CONSUMER PROTECTION ("BCP") TO PARTICIPATE IN THIS DOCKET.

A. No. In accordance with the accepted practice in Commission proceedings, the confidential material will be provided to Staff and the BCP under standardized protective agreements with them.

11. Q. PLEASE PROVIDE AN OVERVIEW OF THE ESA BETWEEN SIERRA AND GOOGLE.

A. The ESA between Sierra and Google (collectively the "Parties") is an agreement that requires Sierra to serve a portion of Google's load corresponding to a peak load of [redacted] megawatts at its data center in Sierra's territory with a new renewable resource. Google meets the eligibility requirement of the pending CTT, which provides a path for existing customers with an average hourly load greater than 5 megawatts to have their energy needs served by Sierra through an ESA. Google's ESA represents a 15-year contract that aligns with the life of a new renewable resource currently requested for approval in the 2024 Joint Integrated Resource Plan, Docket No. 24-05041. Google's ESA provides for a fixed price for all energy provided by the resource while using the variable base tariff energy rate ("BTER") and deferred energy accounting adjustment rate ("DEAA") to apply to all other provision of energy.[2] The long-term energy supply period of Google's ESA begins when the resource is commercially operable and lasts for 15 years from that date,

[2] If Google's load exceeds that of the new renewable resource, Google will pay the otherwise applicable fully bundled rate.

after which Google will return to the fully-bundled retail rate or could pursue a new ESA.

12. Q. DESCRIBE HOW GOOGLE'S ESA FULFILLS THE KEY COMPONENTS OF THE PENDING CTT.

A. The CTT is intended to provide eligible customers the option to receive retail electric service from the Company, reflecting a price within an ESA for energy associated with a new clean energy resource(s) proposed concurrently in an Integrated Resource Plan. Google meets the eligibility requirements as an existing fully-bundled customer of Sierra with an average hourly load that exceeds 5 megawatts. The long-term energy supply rate within Google's ESA reflects a new renewable resource currently requested for approval in the 2024 Joint Integrated Resource Plan. The long-term energy supply period of Google's ESA aligns with the contract terms of the new renewable resource and also fits the customers' needs for a long-term solution to reach their clean energy goals. The ESA model provides a comparison to the otherwise applicable effective rate to demonstrate that Google's ESA price results in an overall effective rate that is no less than the overall effective rate of the otherwise applicable schedule, which can be considered when evaluating whether the public interest standard is met.[3] The mechanics of implementing that calculation are provided in the testimony of Mr. Will.

[3] Other considerations may influence the assessment of the public interest standard.

13. Q. PLEASE EXPLAIN THE PRICE GOOGLE PAYS FOR ENERGY UNDER THE LONG-TERM ENERGY SUPPLY PERIOD.

A. During the long-term energy supply period, Google will pay a fixed price of $[redacted]/MWh for energy consumed by Google's facilities for any output generated by the ESA resource. The price per MWh for the ESA resource, an enhanced geothermal system, includes the rate provided in the purchased power agreement ("PPA") currently requested for approval in the 2024 IRP.[4] A description of how the fixed price was calculated is provided in the testimony of Mr. Will and detailed in the confidential workpaper provided with Mr. Will's testimony.

14. Q. DOES GOOGLE HAVE A RIGHT TO TERMINATE THE ESA? IF SO, WHEN AND UNDER WHAT CONDITIONS?

A. Yes. The ESA provides Google the right to terminate once the long-term energy supply period commences. However, Google must provide timely notice of such intent per the terms of the ESA. In the event it elects to terminate the ESA, the ESA also includes a provision requiring an early termination payment that is meant to hold non-participating customers harmless for the period encompassing the effective date of termination until the expiry of the ESA term.

15. Q. WILL THE ENTIRE OUTPUT OF THE RENEWABLE ENERGY FACILITIES SERVE GOOGLE EXCLUSIVELY?

A. Yes. The output of the renewable energy facility will be provided to and paid for by Google. In the event excess energy is generated, excess energy from the resource is purchased by Sierra after Google first pays the price premium that exceeds the

[4] The PPA presented to the Commission contemporaneous with this Application, in Docket No. 24-05041, is the Fervo project designated to be sleeved to Google.

comparable short term avoided costs. The ESA also provides an option for Sierra to purchase renewable credits associated with any excess energy at the terms provided in the ESA. The nameplate capacity of the resource is 115 MW. Google will pay a fixed long-term energy rate for every MWh of energy produced by the resource.

16. Q. IS THE ESA BETWEEN SIERRA AND GOOGLE IN THE PUBLIC INTEREST?

A. Yes, the ESA is in the public interest for the reasons stated below.

First, this agreement retains an existing customer that is eligible to seek an alternative provider within the Company's systems, which leads to more efficient planning, procurement, and utilization of utility-controlled assets. This stability and efficiency tends to drive down the costs of many of the activities Sierra undertakes on behalf of all customers.[5]

Second, the model informing the long-term price in the energy supply agreement uses the same cost of the resource being requested in the 2024 IRP for all output from the resource to be paid by Google. That cost is applied to all output from the resource and adds in the cost of grid supplied capacity and planning reserve margin for Google. This results in no additional cost being spread to existing customers. The resource serving Google's load brings the diversity of geothermal to Sierra's system and also presents potential future benefit to Nevada if the technology expands to additional projects. Without the ESA and the CTT with

[5] Currently in Sierra's territory there is no import capacity that prevents customers from seeking an alternative provider. However, soon after the anticipated commercial operation date of the new renewable resources, import capacity is anticipated to become available.

Google, Sierra would not have brought the geothermal resource for approval given the price premium.

Third, for energy provided to Google in hours where the resource output is insufficient to meet Google's load, Google will pay the variable BTER and DEAA rates. By paying this variable rate, Google is contributing to the fuel and purchased power costs, including a portion of the existing renewables contracts identified in the R-BTER rate component. There is a benefit to existing customers from Google's contribution to fuel and purchased power costs because the hours where Google will be relying on the grid to serve its load are lower cost hours, yet Google will pay the flat BTER and DEAA rate, calculated as the average of all hours. For the energy provided to Google where the output from the resource is insufficient, Google is also contributing to system capacity costs based on the 25-year average of the capacity portion of the long-term avoided costs presented for approval in the 2024 IRP. This results in ensuring no additional cost to existing customers and provides a benefit in the difference between the average fuel and purchased power costs paid versus the cost of fuel and purchased power when serving Google under this rate.

Fourth, in addition to the planning reserve margin and capacity costs described above, Google will pay the fully bundled otherwise applicable rate once the load at its facility exceeds the full capacity of the resource. No capacity protection cost is needed due to the fact the overall effective rate under Google's ESA exceeds the overall effective rate under the otherwise applicable fully-bundled rate.

Fifth, approximately [redacted] percent of Google's load will be served by renewable energy from the ESA resource. This proportion exceeds the current state mandated renewable portfolio standard and therefore increases the overall renewable proportion for Sierra as a total, furthering the state's sustainability goals.

Sixth, the ESA is conditioned on both the approval of the CTT and the resource, providing a path to remain as a fully-bundled retail customer of Sierra thereby protecting existing customers.

Finally, the ESA will continue to serve as a template for other existing large customers to replicate, which will result in the further development of new clean energy resources located throughout the state.

17. Q. DOES RETIRING THE PORTFOLIO ENERGY CREDITS ON GOOGLE'S BEHALF OR TRANSFERRING THE PORTFOLIO ENERGY CREDITS TO GOOGLE UNDER THE ESA ADVERSELY AFFECT SIERRA OR ITS' CUSTOMERS?

A. No. The renewable energy facility proposed is concurrently being considered by the Commission for approval in the 2024 IRP and is designated entirely to serve Google's load. Sierra's position relative to compliance with Nevada's RPS will not be adversely impacted.

18. Q. PLEASE SUMMARIZE YOUR RECOMMENDATION.

A. I recommend that the Commission approve the ESA between Google and Sierra.

19. Q. DOES THIS CONCLUDE YOUR PREPARED DIRECT TESTIMONY?

A. Yes.

EXHIBIT WELLS-DIRECT-1

Janet C. Wells
Vice President of Regulatory
Rates and Regulatory Affairs
NV Energy
6100 Neil Road
Reno, Nevada 89511-1137
(775) 834-4135

Mrs. Wells has been an employee of NV Energy for more than fifteen years and her time at the company includes her previous positions as Regulatory Policy Director, Manager of Load Research, Senior Economist and Staff Economist in the Rates and Regulatory Affairs department and her current position as Vice President of Regulatory. Her current responsibilities are focused on the analytical and strategic approaches to regulatory issues and filings.

Prior to joining NV Energy, Mrs. Wells had experience in economic consulting and research in both corporate and academic environments, detailed below, as well as other non-profit business experience not specifically detailed below.

Employment History

NV Energy
October 2011 to Present
December 2000 to August 2005

Vice President of Regulatory
May 2022 to Present

- Oversee the preparation of regulatory filings before the Public Utilities Commission of Nevada and specifically the Load Research, Pricing, and Regulatory Affairs technical teams.

Regulatory Policy Director, Rates and Regulatory Affairs
March 2020 to April 2022

- Direct analytical and strategic approaches to regulatory issues and filings as well as corporate deliverables. Conduct research and analysis in support of new regulatory initiatives. Collaborate with regulatory groups in developing analysis and strategic approaches to integrating regulatory, load research, load forecasting, and pricing.
- Continue to support the management and technical production of class loads and other regulatory filings employing load data analyses.

Manager, Load Research, Rates and Regulatory Affairs
April 2017 to February 2020

Supervisor, Load Research, Rates and Regulatory Affairs
July 2012 to March 2017

- Manage all data and analysis related to producing hourly class loads for all Nevada Power and Sierra Pacific customer classes. Specifically, this process includes verification and estimation of interval data from multiple systems, population identification and validation, statistical sampling from populations, expansion of sample classes to produce class level total loads, and verification of final class loads to historical loads.

- Support all regulatory filings and data requests with load data and analysis ranging from: providing actual data, drafting responses, providing feedback to responses, and documenting completed analysis. Write and support testimony as needed.
- Provide validated load data and analysis to numerous areas within the company including Major Accounts, Load Forecasting, Energy Efficiency, Billing, Contracts, and to specific projects within the company such as the Energy Imbalance Market and Advanced Metering Infrastructure. In addition, provide validated load data where appropriate for external requests.
- Provide expertise and support to other major projects related to load data management and analysis including all work from raw data integrations and management, customer specific deliverables, original programming to produce needed calculations, and both data and statistical support of final analyses and report writing for projects such as the Nevada Dynamic Pricing Trial (NDPT)

Senior Economist, Advanced Service Delivery Project
October 2011 to July 2012

- Managed statistical sampling for U.S. Department of Energy reporting on metrics and recruitment
- Contributed to development of statistical design for analysis
- Managed data integrations needed for implementation of project

Staff Economist, Rates and Regulatory Affairs
October 2001 to August 2005

- Updated the Nevada Power Cost of Service Study as an input to rate cases
- Updated Customer Weighting Factor Study for Nevada Power and Sierra Pacific as an input to rate cases
- Supported all regulatory filings with testimony review and responses to data requests

Senior Economist, Rates and Regulatory Affairs
December 2000 to October 2001

- Developed Nevada Power Cost of Service Study as an input to rate cases
- Developed automated system for completing Customer Weighting Factor Studies

Other Related Employment
University of Nevada, Reno
May 2005 to August 2006

Research Associate

- Developed statistical programs for data management and analysis of 20 years of data to assess the Economic Value of Hiking for publication in a book chapter
- Developed survey instrument, data management from the survey, and econometric analysis related to wild horse adoption

Triangle Economic Research, Durham, NC
July 1997 to December 2000

Senior Economist, March 2000-December 2000
Economist, July 1997-March 2000

- Prepared preliminary estimate of recreational fishing damages from hazardous substance release using revealed preference data in a random utility model
- Estimated random utility models to determine expected catch using multiple methods, including non-parametric estimation and a multinomial logit estimation of catch (presented at American Agricultural Economics Association annual meeting)
- Developed and administered survey of recreational boaters; acquired survey research firm and validated data. Developed analysis plan for probit model of probability of site choice and conditional logit model of recreational benefits from restoration projects. Results were published with estimates of recreational benefits from proposed restoration projects using benefit transfer from other cases in Arizona Law Review
- Completed data collection, data management, econometric modeling and analysis, and report writing to estimate aggregate values of recreational activities using a nested price index, published in Environmental and Resource Economics

Prior Testimony Before Public Utilities Commissions

PUCN Docket Nos.: 15-07041, 15-07042, 16-06006, 17-06003, 17-06014, 17-06015, 18-08007, 18-10034, 19-02002, 19-04002, 19-06002, 20-06003, 21-09031, 21-09032, 22-06014, 22-09002, 22-09006, 22-11032, 23-02010, 23-02011, 23-06007, 23-08019, 24-02026, 24-02027, 24-05022, 24-05023, and 24-05041.

Education

University of Nevada, Reno
Master of Applied Economics and Statistics, August 1996

University of Manitoba, Winnipeg, Manitoba
Bachelor of Arts in Geography, June 1992

Continuing Education
NERA Marginal Cost Methodology for Electric Utilities
SAS Programming I and II
CORE Leadership Training
Six Sigma Green Belt Certification

AFFIRMATION

Pursuant to the requirements of NRS 53.045 and NAC 703.710, JANET WELLS, states that she is the person identified in the foregoing prepared testimony and/or exhibits; that such testimony and/or exhibits were prepared by or under the direction of said person; that the answers and/or information appearing therein are true to the best of her knowledge and belief; and that if asked the questions appearing therein, her answers thereto would, under oath, be the same.

I declare under penalty of perjury that the foregoing is true and correct.

Date: June 7, 2024

JANET WELLS

EXHIBIT
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24-05041

Public Utilities Commission of Nevada
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This filing has been electronically filed and deemed to be signed by an authorized agent or
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GOOGLE
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BEFORE THE PUBLIC UTILITIES COMMISSION OF NEVADA

Nevada Power Company d/b/a NV Energy and
Sierra Pacific Power Company d/b/a NV Energy
2025-2044 Integrated Resource Plan
Docket No. 24-05041

Phase II

Demand Side Management Plan

Prepared Direct Testimony of

Carolyn A. Berry

on behalf of

Google LLC

A. INTRODUCTION

1. Q. PLEASE STATE YOUR NAME, TITLE, AND BUSINESS ADDRESS.

My name is Carolyn A. Berry. I am a Principal with Bates White, LLC. My business address is 2001 K Street NW, North Building, Suite 500, Washington DC 20006.

2. Q. PLEASE DESCRIBE YOUR EDUCATIONAL BACKGROUND.

A. I received a B.S. in economics and a B.A. in Spanish from the University of Minnesota in Minneapolis, Minnesota, in 1986, and a Ph.D. in economics from Northwestern University in Evanston, Illinois, in 1995. The details of my background and experience are provided in **Exhibit-Berry-Direct-1.**

3. Q. PLEASE SUMMARIZE YOUR PROFESSIONAL BACKGROUND.

A. I am a Principal with the economic consulting firm of Bates White, LLC. I specialize in regulatory issues, market design and analysis, and policy formation in the energy industry, including advising on electric and gas market initiatives and strategy. I have worked for over 25 years on electric utility issues, including cost recovery, transmission access, market power, and resource optimization. I have prepared economic analyses for regulatory commissions and state agencies analyzing the effects of energy policy on incentives and market outcomes. I recently filed testimony on behalf of the Massachusetts Attorney General's Office providing analysis of Electric Sector Modernization Plans filed by the electric distribution companies in Massachusetts. I am currently working on a fuel audit for an investor-owned utility evaluating utility operations and optimization, and a newly implemented tariff. I have testified at hearing before the Federal Energy Regulatory Commission ("FERC"), state and provincial regulatory commissions in California, Utah, Massachusetts, Nova Scotia, and the U.S. District Court for the District of South Carolina. Through my career, I have gained an appreciation of a variety of industry perspectives through my work at a regulatory agency – FERC – at an investor-owned utility – Pacific Gas & Electric Company – and as an economic consultant for both regulators and regulated entities. Attached to this testimony is a copy of my curriculum vitae that includes a complete list of my testimony.

4. Q. HAVE YOU PREVIOUSLY TESTIFIED BEFORE THE PUBLIC UTILITIES COMMISSION OF NEVADA ("PUCN" OR "COMMISSION")?

A. Yes. I have testified in the cost of capital and rate design phases of Docket No. 22-06014, Sierra Pacific Power Company's ("Sierra") General Rate Case ("GRC"); in Docket No. 22-09006, NV Energy's Third Amendment to the 2021 Joint Integrated Resource Plan; in the first and second phases of Docket No. 22-11032, NV Energy's Fourth Amendment to the 2021 Joint Integrated Resource Plan; in Consolidated Docket Nos. 23-02010/23-02011, the Large Customer Market Price Energy ("LCMPE") docket; in the Cost of Capital and Rated Design phases of Docket No. 23-06007, Nevada Power Company's ("Nevada Power") GRC; in the Cost of Capital phase of Docket No. 24-02026, Sierra's GRC; and in Docket No. 24-06014, the Energy Supply Agreement between Sierra and Callisto Enterprises, LLC under the Clean Transition Tarriff.

5. Q. ON WHOSE BEHALF ARE YOU SUBMITTING THIS TESTIMONY?

A. I am submitting this testimony on Google LLC, which is a subsidiary of Alphabet Inc. ("Google").

6. Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. I support the creation of a Large Customer Offsite Demand Side Management ("DSM") Program.

7. Q. WHAT IS A LARGE CUSTOMER OFFSITE DSM PROGRAM?

A. A Large Customer Offsite DSM program would allow large fully-bundled customers of either Nevada Power or Sierra (collectively the "Companies"), who have a minimum peak demand of 5 megawatts or greater ("MW") to make voluntary contributions to the Companies' energy efficiency and demand response portfolio budgets as part of their Demand Side Management Plan. These contributions would be above and beyond their existing financial support of current programs, thereby providing additional funding to enhance DSM initiatives beyond business as usual. In return, the customer would receive credit for the value of the generation capacity benefits that result from their contributions.

8. Q. HOW WILL CREDITS WORK AS PART OF THE LARGE CUSTOMER DSM PROGRAM?

A. Contributing customers will receive a credit on their bill in an amount equal to the capacity savings from supported measures multiplied by the generation capacity cost portion of the base tariff generation rate, over the life of the supported energy efficiency or demand response measure.

9. Q. HOW WILL CAPACITY SAVINGS BE MEASURED?

A. Capacity savings would be measured as part of the Companies' normal Evaluation, Measurement, and Verification ("EM&V") process. Initial credits

should be based on the projected capacity savings from supported energy efficiency or demand response measures, subject to true-up based on the results of EM&V. In this way the program ensures large customers are not being over-compensated for their voluntary contributions.

10. Q. HOW WOULD PARTICIPATING LARGE CUSTOMERS CONVEY VOLUNTARY CONTRIBUTIONS TO THE COMPANIES?

A. Google plans to discuss this with the Companies and stakeholders, but ideally contributions would be conveyed in a rider whose amount is specific to each participating customer. The rider would collect the voluntary contribution over the course of the year, based on that customer's expected usage.

11. Q. WHAT PROGRAMS WOULD THE VOLUNTARY CONTRIBUTIONS SUPPORT?

A. Funding should *add* to existing program budgets, rather than offset existing customer contributions. Google would work with the Companies and stakeholders to identify where contributions would be most impactful. For example, they could support pre-weatherization activities to broaden the pool of customers who would otherwise be ineligible for low-income weatherization due to health, safety, or structural issues in their homes; or mid-stream incentives delivered to equipment distributors. As these would be voluntary contributions, the funding would not necessarily need to demonstrate standard cost-effectiveness requirements, allowing for greater flexibility in how it is allocated.

This approach would enable the Companies and stakeholders to invest in innovative solutions and targeted initiatives that may not fit traditional cost-benefit analyses but can still deliver significant value and support to underserved communities.

12. Q. DOES GOOGLE HAVE EXPERIENCE WITH SIMILAR INITIATIVES?

A. Yes, Google has significant experience with similar initiatives. Google has established successful partnerships in the Carolinas, collaborating with organizations such as Sol Systems, Roanoke Electric Cooperative in North Carolina, Santee Electric Cooperative, Aiken Electric Cooperative, and the Sustainability Institute of South Carolina to reduce energy burdens by funding critical home pre-weatherization and safety upgrades for low- and moderate-income households.

13. Q. WILL A LARGE CUSTOMER DSM PROGRAM ADVERSELY IMPACT THE COMPANIES' OTHER CUSTOMERS?

A. No, it will not. The purpose of this program is to allow large customers to voluntarily provide additional financial support for the companies' energy efficiency and demand response programs, beyond their existing contributions. This will enhance the overall benefits of the DSM portfolio, potentially enabling more customers to participate and/or allowing participants to achieve greater energy and capacity savings, thereby benefiting the overall system and all ratepayers.

14. Q. WHAT ARE YOU REQUESTING THE COMMISSION DO IN THIS PROCEEDING WITH RESPECT TO THE LARGE CUSTOMER OFFSITE DSM PROGRAM?

A. I request that the Commission direct the Companies to work with stakeholders to develop the details of the Large Customer Offsite DSM Program to be included in the Companies' next Demand Side Management Plan Amendment or Update.

15. Q. DOES THIS CONCLUDE YOUR PREPARED DIRECT TESTIMONY?

A. Yes.

AFFIRMATION

I, Carolyn A. Berry, pursuant to NAC 703.710 hereby affirm that the foregoing prepared direct testimony was prepared by me or under my direction and is correct to the best of my knowledge.

Dated: October 8, 2024.

/s/ Carolyn A. Berry
CAROLYN A. BERRY