PACIFIC POWER
A DIVISION OF PACIFICORP

825 NE Multnomah Street, Suite 2000
Portland, Oregon 97232

June 30, 2025

VIA ELECTRONIC FILING

Public Utility Commission of Oregon
Attn: Filing Center
201 High Street SE, Suite 100
Salem, OR 97301-3398

Re: LC 85—PacifiCorp's 2025 Clean Energy Plan

PacifiCorp d/b/a Pacific Power (PacifiCorp or Company) submits to the Public Utility Commission of Oregon (Commission) for filing its 2025 Oregon Clean Energy Plan (2025 CEP).

The company will provide a follow-up supplemental filing containing all public, confidential, and highly confidential workpapers as well as Staff's data template within 14 days of PacifiCorp's filed 2025 CEP. All formal correspondence and data requests regarding this filing should be addressed as follows:

By e-mail (preferred):	datarequest@pacificorp.com OregonCEP@PacifiCorp.com zachary.rogala@pacificorp.com
By regular mail:	Data Request Response Center PacifiCorp 825 NE Multnomah Street, Suite 2000 Portland, Oregon 97232

Informal inquiries may be directed to Amira Streeter, State Regulatory Affairs Manager, at (503) 260-4420.

Sincerely,

Rick Link
Senior Vice President, Resource Planning

Enclosures

OREGON 2025
Clean Energy Plan

June 30, 2025

TABLE OF CONTENTS

Appendices

List of Figures

List of Tables

ACRONYMS

CAIDI	Customer Average Interruption Duration Index
CBI	Community benefits indicator
CBIAG	Community Benefits Indicators Advisory Group
CBRE	Community based renewable energy
CEP	Clean energy plan
COD	Commercial operation date
CO_2	Carbon dioxide
CO_2e	Carbon dioxide-equivalent
CSP	Community solar program
DEQ	Department of Environmental Quality
DSM	Demand-side management
DSP	Distribution system planning
EJ	Environmental justice
ENS	Energy not served
ETO	Energy Trust of Oregon
EV	Electric Vehicle
GHG	Greenhouse gases
GW	Gigawatt
HB	House Bill
IRP	Integrated resource plan
LID	Low-income discount program
LMP	Locational marginal price
LT	Long-term (PLEXOS Model)
MW	Megawatt
NOx	Nitrogen oxides
ODOE	Oregon Department of Energy
ORS	Oregon Revised Statutes
PUC	Public Utility Commission
PVRR	Present value revenue requirement
REC	Renewable energy credit
RFP	Request for proposals
SAIDI	System Average Interruption Duration Index
SAIFI	System Average Interruption Frequency Index
SB	Senate Bill
SO_2	Sulfur dioxide
SSR	Small-scale renewables
ST	Short-term (PLEXOS Model)
WEIM	Western Energy Imbalance Market
WRAP	Western Resource Adequacy Program

I. INTRODUCTION

PacifiCorp, doing business as Pacific Power in Oregon, presents its 2025 Clean Energy Plan (CEP) for review by the Public Utility Commission of Oregon (Commission or OPUC), our stakeholders, and the communities we serve.

In 2021, Governor Kate Brown signed House Bill 2021 (HB 2021), which established greenhouse gas reduction requirements for electric providers, while also directing utilities to consider how to maximize additional benefits to communities. HB 2021 requires retail electricity providers to reduce greenhouse gas emissions associated with electricity sold to Oregon consumers by: 80% by 2030; 90% by 2035; and 100% by 2040.[1] For PacifiCorp, this requires the company to reduce baseline emissions of 8.99 million metric tons (MMT) of carbon dioxide equivalent emissions (CO_2e) to 1.79 MMT CO_2e by 2030, 0.89 MMT CO_2e by 2035, and zero by 2040.

HB 2021 lays the groundwork for the transition to a clean, reliable, and sustainable energy future, but also seeks to protect and support communities who are the most vulnerable and highly impacted by the energy transition.

In service to these emissions reduction requirements, an electric company must develop a clean energy plan for meeting relevant targets concurrent with the development of its integrated resource plan (IRP) every two years.[2] Over the past few years, the Commission and stakeholders have collaboratively considered important issues regarding clean energy planning generally, and the implementation of HB 2021 specifically, providing guidance for the company's first CEP filed in 2023.[3] Discussions continue regarding the implementation of key HB 2021 and clean energy planning issues.[4]

Fundamental to PacifiCorp's approach in building a bridge from the IRP to the CEP are utility and Oregon-specific generation and transmission resource selections, small-scale resource planning, distribution system planning, and community emphases. Community emphases includes community benefit indicators, community-based renewable energy, and engagement with community members through advisory groups. Consistent with Commission Order No. 25-090, PacifiCorp's 2025 CEP builds upon the modeling and results presented in the 2025 IRP, and presents an action plan towards compliance with HB 2021 emissions standards, while at the same time maintaining a reliable and resilient electric system.

This CEP includes a near-term set of action items, a plan to reach near-term greenhouse gas emission reductions targets, and a discussion of key considerations regarding the longer-term compliance trajectory. There are potentially significant operational and financial impacts and risks associated with compliance over the next two decades. With each planning cycle, the company will continue to evaluate the benefits and costs of specific compliance strategies, assessing the

[1] ORS 469A.410.
[2] ORS 469A.415.
[3] *In re PacifiCorp's 2023 Clean Energy Plan*, Docket LC 82 (May 31, 2023) (available online at https://apps.puc.state.or.us/edockets/edocs.asp?FileType=HAS&FileName=lc82has145438.pdf&DocketID=23647&numSequence=46).
[4] *E.g., In re Commission HB 2021 Investigation,* Docket UM 2273.

timing and pace of resource selections and greenhouse gas reductions. A discussion of these Key Findings and Challenges follows.

Key Findings

1. As of 2024, PacifiCorp has reduced emissions by 18.68 percent from HB 2021-defined baseline levels, an additional 6 percent reduction since filing the 2023 CEP.
2. PacifiCorp has brought 6.263 gigawatts (GW) of resources online since 2019 to support the company's greenhouse gas reductions (including less-emitting natural gas conversions of existing coal-fired units). And 4.005 GW of resources have come online or are expected to come online in the next year since the filing of PacifiCorp's 2023 CEP.
3. To further reduce emissions, the 2025 CEP preferred portfolio includes 11,837 megawatts (MW) of new proxy resources to serve Oregon over the 21-year planning period, including: 2,491 MW of wind; 2,152 MW of utility-scale solar; 1,032 MW of small-scale solar; 3,835 MW of storage resources; 2,045 MW of energy efficiency; and 153 MW of demand response.
4. In the near-term, Oregon will require 153 MW of new renewable resources and 186 MW of storage resources before 2030. Between 2030 and 2034, there is an additional need of 2,694 MW of new utility-scale renewable resources, 326 MW of new small-scale renewables and 757 MW of new storage resources. PacifiCorp's 2025 Oregon-situs request for proposals (2025 OR Situs RFP) and 2025 small-scale renewables (SSR) request for proposals (2025 OR SSR RFP) are the first steps to begin procuring these resources. PacifiCorp plans to evaluate opportunities to accelerate procurement of resources identified in the preferred portfolio in 2030 when evaluating proposals from both resource solicitations.
5. The CEP preferred portfolio forecasts Oregon-allocated greenhouse gas emissions to fall 84.6 percent from baseline levels by 2030, 90.2 percent by 2035 and 100 percent by 2040.

Key Challenges

1. In the absence of a clean energy market, by 2035 Oregon might require as much as 17.5 GW of new non-emitting and storage resources to meet HB 2021 decarbonization targets.
2. HB 2021 could require Oregon load to be served with non-emitting resources on an hourly as opposed to annual basis before 2040. Depending on whether compliance is measured annually or hourly, Oregon's HB 2021 greenhouse gas emissions reductions targets could, conservatively, cost between $14.63 and $45.59 billion over the next two decades. Over a 21-year period, this is equivalent to $135 million or $1.6 billion incremental costs each year.
3. If federal tax credits for renewable and storage resources are eliminated, the expected cost of compliance will increase by over $7 billion if compliance is measured on an annual basis, and $19 billion if measured on an hourly basis. If HB 2021 compliance-driven transmission upgrades are allocated entirely to Oregon customers, these costs increase by another $559 million when compliance is measured annually, and another $4 billion when compliance is measured hourly.
4. Based on forecasted resource additions, by 2030 PacifiCorp's SSR resource obligation amounts to an estimated 542 MW of SSR capacity, increasing to 735 MW by 2045. Based

on existing resources, PacifiCorp estimates it has 396 MW of SSR-compliant resources, leaving an additional forecasted need of 146 MW of SSRs by 2030, increasing to 339 MW by 2045. PacifiCorp will continue to reevaluate its SSR needs over time.

5. Even under conservative assumptions, these compliance strategies—depending on the pace, timing, and volume of resource procurements—could trigger HB 2021's cost cap. Annual impacts to revenue requirements, including generation and transmission costs, are forecasted to range from 10 percent under annual compliance, to 101 percent under hourly compliance, over a 21-year planning horizon. These costs increase materially if federal production or investment tax credits are repealed, or if Oregon customers are assigned the full transmission costs of HB 2021-driven resources.

The 2025 CEP begins with a discussion regarding PacifiCorp's continual progress towards compliance with HB 2021 clean energy targets in Chapter II. As of 2024, this includes an 18.68 percent reduction in emissions from baseline levels. These emission reductions are driven by the non-emitting and storage resources that PacifiCorp has procured or converted from coal-fired generation resources since 2019, amounting to over 6.6263 GW of HB 2021-compliant energy.

Chapter III includes a discussion on community engagement. Beyond the more typical utility investment decisions, HB 2021 re-envisions utility planning processes. The law requires utilities to broaden stakeholder engagement so that more communities can better participate in utility planning, which includes expanding access and opportunity for historically vulnerable populations and strengthening relationships with existing partners. Within these venues, information is better able to flow in both directions, where stakeholder feedback can inform PacifiCorp's strategic priorities, and provides opportunities to educate customers, stakeholders, and the company. This chapter describes the company's engagement channels, including the Oregon Community Benefits and Input Advisory Groups, newly created information hubs and activities, and details the company's vision and proposed processes for future engagement.

Chapter IV builds on engagement channels and discusses the company's current community benefit indicators (CBI) framework, and includes 14 CBIs and 18 proposed metrics. CBIs fall into four categories (resiliency, health and community wellbeing, environmental impacts, and economic impacts), and each support progress towards energy equity. Each CBI and metric can be compared against PacifiCorp-developed baseline metrics, that will allow the company to demonstrate, and stakeholders to track, the impact of PacifiCorp's proposed programs, actions, investments, and progress within each service region. The CBI framework continues to evolve over time after on-going discussions with stakeholders.

In Chapter V, PacifiCorp provides an overview of its resiliency analysis framework and how it can be leveraged to focus efforts to build resilience within the community and the electric grid. Additionally, the chapter includes an overview of current programs and grid investments the company continues to prioritize beyond the requirements of HB 2021 to foster a more resilient system.

Chapter VI discusses community based renewable energy (CBRE) challenges and opportunities, including an updated CBRE Inventory and Potential Study, and new CBRE-Resiliency Hub Pilot (CBRE-RH Pilot).

Chapter VII discusses PacifiCorp's 2025 CEP resource planning processes, and Chapter VIII includes the results from these processes, including analyses of Oregon-specific resource selections, compliance scenarios, greenhouse gas emissions, transmission, small-scale resource planning, CBRE valuation and cost impacts.

Chapter IX concludes with PacifiCorp's 2025 CEP Action Plan, and Key Issues for Further Consideration.

II. CONTINUAL PROGRESS

To ensure utilities are taking adequate steps to achieve HB 2021's significant emissions reductions, the law requires utility CEPs to demonstrate "continual progress within the planning period" towards meeting HB 2021's clean energy targets, including demonstration of "a projected reduction of annual greenhouse gas emissions."[5] The law also requires the Commission to ensure that utilities demonstrate "continual progress," and are "taking actions as soon as practicable that facilitate rapid reduction of greenhouse gas emissions at reasonable costs to retail electricity consumers."[6]

Applied here, PacifiCorp represents that the 2025 CEP demonstrates the company is making continual progress to achieve HB 2021's emissions reductions. This is based on actual and forecasted performance, where PacifiCorp has reduced HB 2021 emissions by 18.68 percent compared to baseline emissions in 2024, and PacifiCorp's CEP preferred portfolio is forecasted to reduce emissions by 84.6 percent by 2030, and 90.2 percent by 2035.

Table 1 summarizes non-HB 2021 related Oregon emissions that have been reported to the Oregon Department of Environmental Quality (DEQ) under longstanding emissions reporting requirements for years 2010-2023 (Non-HB 2021 Emissions). Table 1 also reports HB 2021-specific emissions under PacifiCorp's interpretation of what HB 2021 and Oregon DEQ methodologies require for years 2022-2023.[7] Emissions for both methods are also reported for 2024; however, these data are preliminary and subject to additional verification and review. Non-HB 2021 emissions are included to provide broader context to PacifiCorp's emissions trajectory than just the prior three-year period, even though these emissions differ from HB 2021 emissions. Under HB 2021, PacifiCorp, is required to reduce baseline emissions from 8.99 MMT CO_2e, as defined by the DEQ. Percent reductions from this baseline for HB 2021 covered emissions are presented in the final column.[8] Additional discussion regarding PacifiCorp's calculation of HB 2021-specific emissions can be found in subsequent chapters.

[5] ORS 469A.415(4)(e).
[6] ORS 469A.415(6).
[7] Non-HB 2021 emissions are calculated in accordance with DEQ's greenhouse gas reporting requirements in OAR 340, Division 215, and include emissions from qualifying facilities and net metering resources. HB 2021 emissions are calculated in the same manner, though emissions from qualifying facilities and net metering resources are excluded from HB 2021 Emissions in accordance with ORS 469A.435(2).
[8] Oregon Department of Environmental Quality HB 2021 Emissions Baseline Order (issued May 25, 2022) (available here: https://www.oregon.gov/deq/ghgp/Documents/HB2021Order.pdf).

Table 1 – Oregon-Allocated Emissions

Year	Non-HB 2021 Emissions (MTCO2e)[9]	HB 2021 Emissions (MTCO2e)	HB 2021 Emissions (% Reduction from Baseline)
2010	9,248,689		
2011	8,880,884		
2012	9,137,084		
2013	9,626,625		
2014	9,582,985		
2015	9,701,719		
2016	8,422,662		
2017	8,628,965		
2018	8,696,220		
2019	9,042,557		
2020	8,433,448		
2021	8,257,701		
2022	7,953,132	7,851,150	12.71
2023	7,653,943	7,570,127	15.84
2024[10]	7,318,603	7,314,573	18.68

PacifiCorp's trajectory of emission reductions are driven by the procurement of non-emitting generating resources (or the transition to less-emitting generation resources in the example of Jim Bridger conversions to natural gas) and storage resources summarized in Table 2 below.[11] These resources include those that have come online since 2019, and that are expected to come online before the end of 2026, and that will be fully or partially allocated to serve Oregon customers. In aggregate, PacifiCorp has brought 6.263 GW of HB 2021-supporting resources online since 2019. This list of resources includes over 4.005 GW from 45 resources that have come online since the filing of PacifiCorp's inaugural CEP in 2023, contributing to PacifiCorp's compliance with emissions reductions requirements.

Table 2 – PacifiCorp HB 2021 Contributing Resources (2019-2026)[12]

Name	Type	Capacity	Commercial Operation Date
Dominguez Grid	Battery Storage	200.0	6/1/2026
Enterprise Storage	Battery Storage	80.0	6/1/2026
Escalante I	Battery Storage	80.0	6/1/2026

[9] *E.g.,* PacifiCorp's Oregon Non-HB2021 Emissions (available here: https://www.oregon.gov/deq/ghgp/Pages/GHG-Emissions.aspx).
[10] Preliminary estimates, subject to additional verification and review during the annual agency emissions reporting and verification processes.
[11] While battery storage resources do not necessarily store or generate only clean energy, batteries are a key component to reliably bringing on significant variable energy resources to decarbonize the electric grid.
[12] Resources with an asterisk are Oregon Community Solar Program Resources under PacifiCorp's Oregon Schedule 126.

Name	Type	Capacity	Commercial Operation Date
Granite Mountain East	Battery Storage	80.0	6/1/2026
Iron Springs	Battery Storage	80.0	6/1/2026
Green River Solar I /II	Solar + Battery	400.0	5/31/2026
Canyonville Solar 1*	Solar	1.0	5/22/2026
Canyonville Solar 2*	Solar	1.5	5/22/2026
Buckaroo Solar 1*	Solar	2.400	9/30/2025
Buckaroo Solar 2*	Solar	2.990	9/30/2025
Pilot Rock Solar 2*	Solar	3.0	9/30/2025
Tutuilla Solar*	Solar	1.6	9/30/2025
Rock Creek II Wind	Wind	400.0	9/1/2025
Oregon Institute of Technology	Battery Storage	2.0	8/31/2025
Hornshadow Solar II	Solar	200.0	6/30/2025
Hornshadow Solar	Solar	100.0	6/30/2025
Rock Creek I Wind	Wind	12.2	6/30/2025
Goodling Community Solar*	Solar	1.0	6/30/2025
Sunset Ridge Solar*	Solar	2.3	6/1/2025
7 Mile Solar*	Solar	1.0	6/1/2025
Chapman Creek Solar*	Solar	3.0	5/5/2025
Pine Grove Solar*	Solar	1.4	2/3/2025
Cedar Springs Wind IV	Wind	350.4	1/31/2025
Orchard Knob Solar*	Solar	2.3	1/24/2025
Round Lake Solar*	Solar	1.0	1/24/2025
Marble Solar*	Solar	2.9	1/21/2025
Antelope Creek Solar*	Solar	2.3	1/10/2025
Blackwell Creek Solar*	Solar	1.4	1/8/2025
Wood River Solar*	Solar	0.4	1/8/2025
Mid-Columbia Hydro (Tacoma Power MP share)	Water	37.0	1/1/2025
Mid-Columbia Hydro (Cowlitz PUD MP share)	Water	21.6	1/1/2025
Boswell Wind	Wind	320.0	12/31/2024
Anticline Wind	Wind	100.5	12/31/2024
Rock Creek I Wind	Wind	183.0	12/30/2024
Rock River I	Wind	50.0	9/23/2024
Green Solar*	Solar	2.9	7/23/2024
Jim Bridger	Natural Gas	531.0	4/30/2024
Linkville Solar*	Solar	2.8	4/30/2024
Jim Bridger	Natural Gas	539.0	4/13/2024
Cedar Creek Wind	Wind	151.8	3/21/2024
Foote Creek III	Wind	24.8	11/21/2023
Foote Creek IV	Wind	16.8	11/21/2023
Wallowa County*	Solar	0.4	7/1/2022
Solarize Rogue*	Solar	0.1	3/14/2022
Sigurd Solar	Solar	80.0	5/3/2021
Foote Creek I	Wind	43.2	3/24/2021
Millican Solar	Solar	60.0	3/21/2021

Name	Type	Capacity	Commercial Operation Date
Hunter Solar	Solar	100.0	3/1/2021
TB Flats 1/2	Wind	500.0	12/31/2020
Pryor Mountain	Wind	239.8	12/31/2020
Prineville Solar	Solar	40.0	12/31/2020
Ekola Flats	Wind	250.0	12/30/2020
Cedar Springs III	Wind	133.3	12/15/2020
Cedar Springs II	Wind	198.9	12/8/2020
Cedar Springs I	Wind	199.4	12/7/2020
Milford Solar I	Solar	99.0	11/19/2020
Cove Mountain	Solar	58.0	11/1/2020
Naughton 3	Natural Gas	290.0	7/20/2020
Marengo 2	Wind	78.0	2/24/2020
Marengo 1	Wind	156.0	1/27/2020
Glenrock 1	Wind	100.0	12/31/2019

Regarding forecasted HB-2021 emissions reductions, PacifiCorp anticipates the need for 11,838 MW of new proxy resources to serve Oregon customers' energy and capacity needs, to meet the small-scale renewable standard, and to reach annual decarbonization goals on a least-cost basis. These resource selections include: 2,491 MW of wind; 2,152 MW of utility-scale solar; 1,032 MW of small-scale solar; and 3,835 MW of storage resources.[13] The portfolio also includes 2,045 MW of energy efficiency and 153 MW of demand response.

PacifiCorp's already-issued 2025 OR SSR RFP and planned 2025 OR Situs RFP are two strategies to allow the company to begin procuring these material resources to reduce PacifiCorp's Oregon-allocated emissions.

Regarding the 2025 OR SSR RFP,[14] based on then-current estimated projections from the 2025 IRP preferred portfolio, PacifiCorp was looking to procure as much as 320 MW of capacity from SSRs to meet Oregon's SSR requirement.[15] In the 2025 CEP, this projected need falls to 145 MW. This reduction in near-term SSR need is attributed to reduced near-term utility-scale resource additions (prior to 2030) in the CEP preferred portfolio, relative to the 2025 IRP preferred portfolio. However, the longer-term SSR need will continue to evolve based on all resource procurement and will be evaluated on an ongoing basis. PacifiCorp plans to evaluate opportunities to accelerate procurement of resources identified in the preferred portfolio in 2030 when evaluating

[13] The 2025 IRP preferred portfolio selections for all non-Oregon jurisdictions are considered locked for the CEP analysis presented below. However, portfolio results are re-optimized for Oregon's jurisdictional obligations under the various modeling assumptions and sensitivities. Unless otherwise noted, all portfolio resource selections and costs are described on an Oregon-allocated basis.

[14] The 2025 OR SSR RFP will accept and evaluate cost-competitive bids for resources with a nameplate capacity of 1 to 20 MW and a guaranteed commercial operation date on or before December 31, 2029. SSR-eligible resources must be certified by the Oregon Department of Energy as renewable portfolio standard (RPS)-eligible generation resources within 90 days of commercial operation date and will maintain RPS certification throughout the duration of any agreement with PacifiCorp. Selected bids must also demonstrate deliverability to PacifiCorp's Oregon load. The bid submittal due date is July 2, 2025, with the aim to execute contracts by mid-2026. More information can be found on the PacifiCorp website at https://www.pacificorp.com/suppliers/rfps/2025-oregon-small-scale-renewable-rfp.html.

[15] ORS 469A.210(2).

proposals from the 2025 OR SSR RFP. Consistent with the Commission's direction,[16] the SSR RFP has incorporated CBIs—specifically non-price scoring elements—to inform SSR resource procurement.[17]

Regarding the 2025 OR Situs RFP, PacifiCorp filed a draft RFP with the Commission in docket UM 2383 in April 2025. On May 28, 2025, the Commission moved forward with additional investigation on the RFP, with a schedule that contemplates stakeholder engagement and a Commission decision in Fall 2025. Once approved, PacifiCorp aims to issue the RFP to market and procure resources that are aligned with the near-term needs identified in the 2025 CEP, while evaluating opportunities to accelerate procurement of resources identified in the preferred portfolio in 2030 when reviewing bids. PacifiCorp is seeking proposals for resources that can achieve a COD by the end of December 2029, with a minimum nameplate capacity of 1 MW, that generate electricity from HB 2021-compliant resources or storage resources and must demonstrate deliverability to PacifiCorp's Oregon load. Based on current estimates, Oregon will require 153 MW of new renewable resources and 186 MW of storage resources prior to 2030. However, by the end of 2030, the CEP preferred portfolio includes over 2 GW of utility-scale wind and solar resources and over 700 MW of batteries. This capacity need is driven both by Oregon's exit from all coal-fired resources at the end of 2029 and 2030 HB 2021 decarbonization targets. While the underlying models exhibit a preference for "just-in-time" resource selections, PacifiCorp recognizes there are risks associated with this strategy. The 2025 OR Situs RFP will consider this resource need through 2030 in its review of projects.

Complementing these supply-side resource strategies are PacifiCorp's ambitious demand-side resource programs. Since the filing of the 2023 CEP, PacifiCorp has aggressively expanded its demand response portfolio. These include: launching of both the Irrigation Load Control and Wattsmart Business Demand Response (DR) programs in 2023, and the planned launch of three new programs in 2025, including the Wattsmart Battery, Cool Keeper, and Wattsmart Drive programs. Together, PacifiCorp anticipates its DR capacity to more than double in the next three years—from 27 MW of current DR capacity to 55 MW by 2027.

PacifiCorp's analysis of these resources and strategies to reduce emissions are discussed below.

III. CLEAN ENERGY PLANNING ENGAGEMENT

PacifiCorp's inaugural CEP was the company's first attempt at defining long-term strategies to meet Oregon's ambitious greenhouse gas reductions, while creating an initial framework to define key community benefits and impacts.

Building from these initial efforts, on December 30, 2024, PacifiCorp filed its Clean Energy Planning Engagement Report in Docket No. LC 82.[18] This engagement report addressed prior

[16] Order No. 24-073, App. B, at 3.
[17] SSR RFP, Appendix P Non-Price Scoring Questionnaire (available here: https://www.pacificorp.com/content/dam/pcorp/documents/en/pacificorp/suppliers/rfps/2025-orssr-rfp/2025ORSSR_RFP_Appx_P_Non-Price_Scoring_Questionnaire.xlsx).
[18] *In re PacifiCorp's Report on CEP Engagement*, Docket LC 82 (Dec. 30, 2024) (available online: https://apps.puc.state.or.us/edockets/edocs.asp?FileType=HAQ&FileName=lc82haq333830114.pdf&DocketID=23647&numSequence=208).

Commission recommendations,[19] while also implementing broader clean energy planning goals and objectives. The intent of the report was to describe PacifiCorp's clean energy planning engagement efforts, including an initial summary of the company's advisory group spaces, and goals and ongoing commitments to improvement.

These efforts have informed and contributed significantly to PacifiCorp's current CEP. Early learning has highlighted the dynamic nature of advisory group spaces, where each continues to shift with its participants over time. Offering information in an accessible way requires testing new approaches, co-designing, building psychological safety within each space, and emphasizing the importance of listening to and understanding each audience. Approaches may adapt over time as advisory group members share feedback and content is presented. As parties collectively participate in shared dialogue and interests continue to grow, attention to subjects and the menu of content offered will continue to shift to reflect the priorities expressed by engagement members and participants.

PacifiCorp's CBIAG, Tribal Nations Community Benefits and Impacts Advisory Group, CEP Engagement Series, and IRP Public Input Meetings series advise and inform the company on developing its IRP, CEP, and other related plans and programs. Each of these engagement channels are detailed below.

Community Benefits and Impacts Advisory Group

When PacifiCorp filed its initial engagement strategy with the Commission on April 21, 2022, the company proposed a hybrid stakeholder engagement model that leveraged existing IRP engagement processes while also developing new engagement pathways through the formation of an Oregon community benefits and impacts advisory group. At that time, the company envisioned a single, statewide engagement group to represent the lived experiences and perspectives of communities and customers within our service area, the Community Benefits and Impacts Advisory Group (CBIAG).

Since then, PacifiCorp has expanded its engagement framework to include two distinct Community Benefits and Impacts Advisory Groups: the original CBIAG, which continues to serve as a broad-based advisory body representing a diversity of stakeholders, and a dedicated Tribal Nations Community Benefits and Impacts Advisory Group. This evolution reflects the company's ongoing commitment to inclusive, equitable, and culturally respectful engagement that recognizes the unique relationships and responsibilities PacifiCorp holds with different communities across its service area.

Through the CBIAG PacifiCorp creates space for direct stakeholder feedback to build an inclusive and accessible process for consultation and collaboration. This includes increasing participation from communities that have not traditionally participated in utility planning processes; providing

[19] Order No. 24-073, App. B, Recommendation 8 ("Direct PacifiCorp to work collaboratively with Staff, stakeholders, peer utilities, environmental justice groups and the CBIAGs in a dedicated working group to develop clear, actionable improvements to community and stakeholder engagement in subsequent IRP/CEPs by December 31, 2024. If PacifiCorp cannot complete this effort by this timeline, PacifiCorp should provide a detailed status update and explanation of how it will ensure that remaining issues are resolved as soon as practicable, inclusive of the perspectives of peer utilities and the utilities' CBIAGs.").

the company with a better understanding of community needs and perspectives; identifying barriers to participation and providing input on how to address these barriers; acting as a conduit to exchange information and ideas between the company and stakeholder communities; and assisting with community outreach.

The CBIAG currently consists of 11 individuals and/or organizations representing the lived experiences, interests, and perspectives of the communities and customers within PacifiCorp's Oregon service area. Consistent with the definition of environmental justice communities within HB 2021, communities identified for inclusion/representation in PacifiCorp's CBIAG include "communities of color, communities experiencing lower incomes, tribal communities, rural communities, coastal communities, communities with limited infrastructure, and others traditionally underrepresented in public processes and adversely harmed by environmental and health hazards, including seniors, youth, and persons with disabilities."[20]

PacifiCorp is committed to advancing engagement, leveraging previous learnings, and deepening its community lens using data to understand unique community characteristics that impact planning and implementation of clean energy efforts and initiatives. PacifiCorp's stakeholder engagement spaces will continue to adapt to foster inclusion, accessibility, and collaboration for the diverse participating audiences. Through these efforts, stakeholders may connect to new tools, approaches, and resources. As a result, people and organizations can share best practices, support one another in reaching a shared understanding of critical concepts, and help inform solutions.

Matters of importance as expressed across PacifiCorp's CBIAG and Tribal Nations Community Benefits and Impacts Advisory Group engagement spaces and members include:

- Costs and potential increases in customer bills;
- The transition to cleaner energy and overcoming the associated challenges like the dependability of renewable resources and the potential impact of materials required for clean energy technology;
- Seeing input in the advisory space translate into action or meaningful community benefits;
- Partnerships with the community and stakeholders;
- Greater accessibility to energy program information and program opportunities.
- Information and transparency, and access to user-friendly tools that allow members to understand utility systems and intersections of the regulatory process;
- Funds to add capacity for participation in programs and offerings resulting from clean energy planning.

In addition to advancing stakeholder engagement, the PacifiCorp teams intend to further develop and integrate the conversations with the Oregon community benefit and advisory groups around energy resilience and planning, which support a community by ensuring that it can maintain reliable and sustainable access to energy, especially during disruptions. Energy resilience and planning are foundational for a community's ability to thrive under both normal and challenging conditions. The company looks forward to continuing to surface these issues in future CBIAG

[20] ORS 469A.400(5).

meetings. Resiliency and key considerations from advisory members are summarized in Chapter V.

Oregon Tribal Nations Community Benefits and Impacts Advisory Group

PacifiCorp developed a Tribal Nations Community Benefits and Impacts Advisory Group series, which supports and fosters collaboration, consultation, and shared understanding of federal, state, and local programs, policies, and grants. The engagement series was formatted through informed feedback from Oregon Tribal members and representatives of Tribal enterprises and partners that support Tribal communities.

Engaging Tribal nations in the advisory group discussions is crucial in planning and prioritizing future projects and recognizing Tribes' unique needs and perspectives as sovereign governments, including:

- The understanding and discussion of historical and cultural interests; and
- The ability to build strong, professional relationships and foster positive collaboration.

Tribal nations' engagement is a critical step toward collaborative, equitable, and effective planning. To facilitate these efforts, PacifiCorp has hired a Tribal Liaison, who offers internal guidance regarding relationships and trust-building between the company and Tribal nations. The liaison supports outreach to Oregon's nine federally recognized Tribes and provides essential context regarding Tribal sovereignty, self-determination and cultural differences.

PacifiCorp also engages Tribes with the assistance of Regional Business Managers, who play a key role in nurturing relationships with Tribes located in their geographic service areas and serve as the first point of contact when needs and issues arise. With the support of the Tribal Liaison, their local presence underscores the company's dedication to the community and Tribal outreach and engagement.

Clean Energy Plan Engagement Series

During the development of PacifiCorp's 2023 CEP, the company identified the need to initiate a complementary and educational CEP engagement series to support existing engagements, and to provide the time and space to dive into key clean energy planning topics. Although PacifiCorp has various dedicated engagement spaces that support integrated resource planning and clean energy planning engagement, the CEP engagement series was developed to focus on technical components of PacifiCorp's Oregon CEP filing and regulatory requirements.

PacifiCorp's CEP Engagement Series is designed for more technical audiences that are actively engaged in the company's clean energy planning and integrated resource planning processes. Oregon CEP Engagement Series meetings have drawn participation from different groups such as the Public Utility Commission of Oregon Staff (Staff), environmental and justice advocates, members of PacifiCorp's CBIAG and Tribal Nations Community Benefits and Impacts Advisory Group, community-based organization representatives and general members of the public. PacifiCorp's CEP Engagement Series meetings continue to be offered through 2025. Sessions are held once per quarter virtually to increase access and socialize PacifiCorp's developing CEP, providing additional opportunities for community and stakeholder input on elements of the plan. Unless communicated otherwise, CEP engagement series meetings are recorded for expanded accessibility and notes from each meeting are shared on Pacific Power's Oregon CEP webpage in both English and Spanish following each session.[21]

Integrated Resource Plan Public Input Meetings

The IRP is a long-term planning tool providing a 20-year view of significant system forecasts and PacifiCorp's response to a wide range of future conditions. The IRP is developed through a comprehensive analysis and public input process that incorporates opportunities for feedback across the company's six-state system through a series of public input meetings. These meetings review all major input categories and strategies contributing to the selection of a least-cost, least-risk preferred portfolio with the objective of meeting all system and regulatory requirements.

PacifiCorp's IRP public input meetings solicit feedback from the public on such topics as emerging resource costs and performance, data modeling of electricity load and market trends. These meetings and feedback inform the development of PacifiCorp's full IRP, filed every two years (odd-numbered years) and the development of narrower IRP updates filed in the off-years (even numbered years). This process provides the opportunity for substantive discussions during live meetings and via stakeholder feedback form submissions, which are available to the public as a reference point for a myriad of topics.[22] In addition to providing public access to ongoing comments and responses, PacifiCorp's IRP public input meetings are recorded for public access.[23] The IRP public input process and portfolio outcomes inform the CEP and ultimately, PacifiCorp's progress toward achieving the clean energy targets identified in House Bill 2021.

Looking ahead, future engagement tactics include:

- Beginning the IRP public input process earlier, with the next cycle tentatively scheduled to begin October 2025;
- Making an intentional effort to discuss topics early and often;
- Enhancing the quality and depth of discussion; and
- Increasing the transparency of how feedback is considered.

Updates made since the previous 2023 IRP cycle that are notable:

- In the 2025 IRP cycle, feedback is footnoted throughout the filed document for added transparency;
- An appendix devoted to feedback and responses has been added to the 2025 IRP, Volume II.

While the CEP development process features distinct engagement through PacifiCorp's CBIAG, Oregon Tribal Nations CBIAG, CEP Engagement Series and other efforts, the IRP public input meeting series is a forum that includes background and updates more specific to the underlying

[21] Available online at: https://www.pacificpower.net/community/oregon-clean-energy-plan.html.
[22] Available online at: https://www.pacificorp.com/energy/integrated-resource-plan/comments.html.
[23] Available online at: https://www.pacificorp.com/energy/integrated-resource-plan/public-input-process.html.

long-term resource modeling, input data details and assumptions, and high-level state specific policy updates.

Integration of Meeting Topics

Engagement spaces serve as collaborative environments where interested parties engage on topics such as utility strategies and priorities. Meetings are ideal for introducing and integrating key initiatives that reflect system needs and community interests. Engagement in this context is not a standalone activity; it is an integrated action that informs and enhances decision-making across planning, programs, and policy.

The following engagements are recent examples of this integration in action:

- **Distribution System Planning Engagement.** The Distribution System Planning (DSP) group hosted hybrid workshops, accessible both online and in person within local communities, to support transparency and informed stakeholder engagement. The workshops provide education on electrical grid functions, load growth forecasting methodologies, and the full range of solutions under consideration—both traditional infrastructure and non-wires alternatives. Stakeholder input was solicited on community-specific concerns, priorities, and the feasibility of nontraditional solutions. Feedback gathered during these sessions is incorporated into PacifiCorp's long-term planning process, ensuring that grid needs, investment priorities, and resilience planning reflect the perspectives of the communities we serve. This process provides stakeholders with greater visibility into utility decision-making, opportunities to shape future investments, and assurance that local needs and concerns are meaningfully considered in the development of system plans.

- **Transportation Electrification Engagement.** This engagement brings diverse voices into planning electric vehicle infrastructure and policy, supporting equitable access and effective deployment of the company's transportation electrification initiatives.

- **Demand Response Presentations.** Through these presentations, stakeholders explore opportunities to shape the company's demand response and grid flexibility programs that align with customer needs and grid reliability goals. These engagements feed directly into advisory group discussions, reinforcing the group's role as a bridge between utility planning and public interest. PacifiCorp uses presentations to educate CBIAG members on demand response concepts, review demand response planning including designs for new programs, and update members on program performance.

As PacifiCorp approaches its next clean energy plan cycle, it will continue to offer engagement opportunities to connect and provide feedback on key CEP topics and other related areas of interest. Additionally, engagement activities will continue to adapt in response to input and learnings to further inclusion, accessibility, and the collaboration of diverse participating audiences.

IV. COMMUNITY BENEFIT INDICATORS

CBIs are designed to demonstrate the impact of PacifiCorp's proposed programs, actions, and investments. The company defines CBIs as the desired outcome that utility actions could either incentive, influence, or cause. Each CBI identifies a desired outcome, while the companion metrics allow PacifiCorp to monitor progress toward achieving these outcomes.

In the development of PacifiCorp's inaugural 2023 CEP, the company worked with and received input from a range of stakeholders including Commission Staff, the Joint Advocates Group (the Northwest Energy Coalition, Coalition of Communities of Color, Verde, Rogue Climate, and the Columbia River Inter-Tribal Fish Commission) and CBIAG members to create an initial set of interim CBIs. This included 7 interim CBIs and 13 interim CBI metrics.[24] Consistent with Commission guidance at the time, these CBIs were broken into five distinct categories: resilience; health and community well-being; environmental impacts; economic impacts; and energy equity.[25]

Through refinement of understanding and objectives, PacifiCorp's current CBI framework includes 14 CBIs and 18 associated CBI metrics, across four distinct categories (as opposed to the prior five). Consistent with Commission guidance, many, though not all, of PacifiCorp's CBIs include baseline metrics that will allow for measured progress towards CBI goals or targets.[26]

As PacifiCorp's CBI framework has evolved, the company has begun to view energy equity as a parent CBI category under which the other four CBI categories should be grouped. The concept of energy equity encompasses the broader social, economic, and environmental impacts tied to each of the other categories. Below is a summary of how each of the four CBI categories fit under the umbrella of energy equity:

- **Resilience (System & Community)**: Energy equity aims to ensure that all communities, especially those that have been historically marginalized and underserved, have the infrastructure and support needed to withstand and recover from long duration outages.
- **Health and Community Well-Being**: Energy equity aims to ensure that all members of society can afford and have access to a necessary and basic supply of energy to be able to meet basic human needs.
- **Environmental Impacts**: Energy equity aims to ensure that the environmental benefits tied to reduced emissions and improved air quality are distributed fairly across all communities.
- **Economic Impacts**: Energy equity calls for local job creation, workforce development and increased spending on diverse businesses.

While the term "interim" is not used in this plan, PacifiCorp's CBI framework continues to evolve. As the company continues to engage with its advisory groups to better understand the impacts of these CBIs, how trackable these data are and how useful or actionable they can be, PacifiCorp will continue to update its framework to reflect that understanding and identify areas for improvement. A discussion on PacifiCorp's CBI framework, each of the four CBI categories, and proposed

[24] PacifiCorp's 2023 Oregon Clean Energy Plan, at 18.
[25] *In re Commission HB 2021 Investigation,* Docket UM 2225, Order No. 22-390, Attachment A.
[26] Order No. 24-073, App. B, at 3.

environmental justice community framework to be developed over the next CEP planning period, are detailed below.

CBI Framework

Table 3 depicts PacifiCorp's CBI framework, built upon the interim framework presented in the 2023 CEP, but with several important developments, including an update to the table for illustrative and clarity purposes and additional CBIs and metrics that the company proposes.

The current CBI framework proposes a few new CBIs and additional refinement of the previous interim CBIs. For example, the current framework proposes the addition of Low-Income Discount (LID) program participation as a metric to evaluate energy burden. This metric did not appear in the interim framework. The previously described CBI "increase community focused efforts and investments" under the banner of economic impacts, has been refined into several individual CBIs that offer more granularity and directionality. The company also added a new CBI, to reduce nitrogen oxides (NOx) and sulfur dioxide (SO_2) emissions. The company anticipates that the work on CBI development and metrics will continue over the coming years as more is learned about how best to measure the distribution of the benefits and burdens of the transition to clean energy.

Table 3 – PacifiCorp's Community Benefit Indicators Framework

No.	Category	CBI Type	CBI	Metric(s)
1a	Resilience	CBRE	Improve resilience of vulnerable communities during long duration outages	SAIDI at area level including major events
1b	Resilience	CBRE	Improve resilience of vulnerable communities during long duration outages	SAIFI including major events
1c	Resilience	CBRE	Improve resilience of vulnerable communities during long duration outages	CAIDI including major events
2	Resilience	Portfolio	Reduce frequency and duration of energy outages	Energy Not Served (ENS)
3	Environmental Impacts	Portfolio	Increase energy from non-emitting and renewable resources	Amount of Oregon-allocated renewable and non-emitting energy (MWh)
4	Environmental Impacts	Portfolio	Reduce CO2 equivalent emissions	Amount of Oregon CO2 equivalent emissions, MT CO2e
5	Environmental Impacts	Portfolio	Reduce NOx and SO_2 emissions	Amount of NOx and SO_2 emissions produced [20]
6	Health & Community Well-Being	Informational	Decrease residential disconnections	Number of residential disconnections and arrearages by census tract
7a	Health & Community Well-Being	Informational	Decrease proportion of households experiencing high energy burden	Average energy burden by census tract.
7b	Health & Community Well-Being	Informational	Decrease proportion of households experiencing high energy burden	Average energy burden for customers residing in census tracts identified as underserved or vulnerable.

No.	Category	CBI Type	CBI	Metric(s)
7c	Health & Community Well-Being	Informational	Decrease proportion of households experiencing high energy burden	Low-Income Discount (LID) program participation
8	Health & Community Well-Being	Informational	Increase residential and small business energy efficiency for vulnerable communities	Count of customer participation in business and residential incentive programs by census tract
9	Health & Community Well-Being	Informational	Reduce barriers to participation in energy efficiency programs for vulnerable communities	Low-income energy efficiency program participation
10	Economic Impacts	Informational	DSM program delivery staff and grants	Headcount of DSM program delivery staff and grants awarded
11	Economic Impacts	Informational	Public charging station installations	Count of public charging stations installed in PacifiCorp territory
12	Economic Impacts	Informational	Pre-apprenticeship and educational program participation	Headcount of participants in pre-apprenticeship programs
13	Economic Impacts	Informational	Local workforce development	Headcount of local and state workers during facility construction
14	Economic Impacts	Informational	Diverse business expenditures	Spend on Disadvantaged Business Enterprise (DBE), tribal, women, minority, and/or veteran-owned resources during facility construction

Most of PacifiCorp's CBIs are considered informational and are intended to be monitored over time, to identify trends and assess whether the company's collective, long-term efforts are positively impacting the communities it serves. It is not always clear how each of these informational CBIs will be impacted by resource actions described in the IRP or CEP.

Four of the CBIs identified are categorized as portfolio CBIs that address the impacts of a utility's portfolio of resources on communities. These, specifically, are CBIs that the company can model and forecast as part of its long-term resource planning efforts and are included as part of the overall portfolio results described in Chapter VIII. Some of the portfolio CBIs can also be tracked over time with actual data, like the emissions reductions and renewable energy metrics described in more detail below. Similarly, the portfolio CBI of "reduce frequency and duration of energy outages" that is measured as Energy Not Served (ENS) is a modeling-specific metric that is aligned with the resilience CBIs that are tracked in actuals.

The Community-Based Renewable Energy (CBRE) CBIs may be used to set goals and track progress on specific outcomes that the utility intends to achieve through its CBRE activities. All of them are centered on community resiliency. As discussed in Chapter V, resilience is a key component of community well-being and an intended long-term benefit of CBRE buildout

It is important to note that PacifiCorp has not set specific targets associated with any CBIs or metrics. While the CBIs identified in this framework provide the company with important information regarding the impact of its activities on communities served over time, there are always factors outside the company's control that can impact the outcome of its efforts. Nonetheless, CBIs can inform company planning and decision-making where appropriate and applicable. For example, PacifiCorp continues to make progress on its use of nonprice scoring methodologies for supply-side resources. To that end, and consistent with the Commission's direction to develop CBIs for use in procurement activities,[27] PacifiCorp has incorporated relevant CBIs into its bid evaluation and selection process for its 2025 OR SSR RFP and in its draft 2025 OR Situs RFP.

Each of the CBI categories and corresponding CBIs are discussed at length below.

Resilience

PacifiCorp has two resiliency CBIs: a CBRE-focused CBI to improve the resilience of vulnerable communities during long duration outages, measured by SAIDI (System Average Interruption Duration Index)[28], SAIFI (System Average Interruption Frequency Index)[29], and CAIDI (Customer Average Interruption Duration Index)[30] at area level including major events; and a portfolio CBI to reduce the frequency and duration of energy outages, measured in terms of ENS which is a resource planning portfolio-specific outcome, reported in the results in Chapter VIII.

Higher SAIDI, SAIFI, and CAIDI values can indicate that an area is more prone to outages. However, it is important to note that extreme weather, natural disasters, wildfire mitigation efforts, or other unforeseen events outside the control of the utility can result in higher values. SAIDI, SAIFI, and CAIDI metrics for the 10 census tracts that have the highest SAIDI, SAIFI, and CAIDI values in the company's service territory are presented in Table 4, Table 5, and Table 6, respectively, below.

The SAIDI, SAIFI, and CAIDI values presented below complement PacifiCorp's resilience analysis framework (see Chapter V), which assesses community vulnerability and the historical reliability of the electric grid serving those areas. The resiliency CBIs support the company's ongoing efforts to enhance grid resilience and reduce community exposure to long-duration power outages. However, it is important to note that the baseline values shown in the tables below reflect the impact of the company's policies regarding implementation of enhanced safety settings and emergency de-energization, both of which contributed to a marked increase in SAIDI, SAIFI, and CAIDI values. A detailed breakdown of SAIDI, SAIFI, and CAIDI values for all 2020 census tracts in PacifiCorp's Oregon service area with community demographic information is included in the supporting Resilience (2022-2024) workpaper described in Appendix A.

27 Order No. 24-073, App. B at 3.

28 SAIDI is a measure of the average cumulative duration (typically minutes) of outages for customers served in a given area (e.g. census tract) and time period.

29 SAIFI is a measure of how often customers in a given area and time period experience an outage.

30 CAIDI is a measurement of the average amount of time (typically minutes) it takes to restore power after an outage occurs for impacted customers.

Table 4 – SAIDI (minutes) by Year, 2022-2024

GEO_ID	NAME	SAIDI 2022	SAIDI 2023	SAIDI 2024	Baseline SAIDI
41043030300	Census Tract 303; Linn County; Oregon	3594.429	1125.408	6837.048	3852.295
41035970100	Census Tract 9701; Klamath County; Oregon	1224.850	5577.385	4120.762	3640.999
41057960102	Census Tract 9601.02; Tillamook County; Oregon	4333.550	961.777	4307.550	3200.959
41039001101	Census Tract 11.01; Lane County; Oregon	58.934	433.785	8324.540	2939.086
41039001201	Census Tract 12.01; Lane County; Oregon	145.570	668.359	7894.519	2902.816
41039001202	Census Tract 12.02; Lane County; Oregon	98.678	697.737	7902.918	2899.777
41039001302	Census Tract 13.02; Lane County; Oregon	67.542	726.669	7847.312	2880.508
41039001102	Census Tract 11.02; Lane County; Oregon	63.504	507.387	8040.062	2870.318
41039001301	Census Tract 13.01; Lane County; Oregon	111.496	727.498	7381.401	2740.132
41033361602	Census Tract 3616.02; Josephine County; Oregon	3113.784	1329.397	2931.657	2458.279

Table 5 – SAIFI (Average Customers Impacted) by Year, 2022-2024

GEO_ID	NAME	SAIFI 2022	SAIFI 2023	SAIFI 2024	Baseline SAIFI
41035970100	Census Tract 9701; Klamath County; Oregon	7.967	16.879	23.890	16.245
41057960102	Census Tract 9601.02; Tillamook County; Oregon	18.028	9.667	7.000	11.565
41047002400	Census Tract 24; Marion County; Oregon	6.111	18.926	5.148	10.062
41047002800	Census Tract 28; Marion County; Oregon	5.411	17.866	5.723	9.667
41063960100	Census Tract 9601; Wallowa County; Oregon	8.444	3.604	15.454	9.167
41033361602	Census Tract 3616.02; Josephine County; Oregon	9.810	6.804	10.757	9.124
41011000200	Census Tract 2; Coos County; Oregon	7.308	5.993	13.458	8.920
41029002600	Census Tract 26; Jackson County; Oregon	4.253	6.553	15.639	8.815
41019100000	Census Tract 1000; Douglas County; Oregon	4.386	6.351	14.479	8.405
41033361400	Census Tract 3614; Josephine County; Oregon	4.519	7.056	13.558	8.378

Table 6 – CAIDI (in Minutes) by Year, 2022-2024

GEO_ID	NAME	CAIDI 2022	CAIDI 2023	CAIDI 2024	Baseline CAIDI
41039001201	Census Tract 12.01; Lane County; Oregon	45.082	620.757	3408.595	1358.145
41039001301	Census Tract 13.01; Lane County; Oregon	36.665	536.265	2525.620	1032.850
41039001202	Census Tract 12.02; Lane County; Oregon	34.893	301.885	1592.083	642.954
41043030300	Census Tract 303; Linn County; Oregon	493.579	181.116	794.192	489.629
41039001302	Census Tract 13.02; Lane County; Oregon	29.804	191.673	1225.200	482.226
41039001101	Census Tract 11.01; Lane County; Oregon	27.617	85.600	1325.912	479.709
41011001002	Census Tract 10.02; Coos County; Oregon	1031.356	148.125	237.622	472.368
41039001102	Census Tract 11.02; Lane County; Oregon	30.586	97.917	1253.044	460.516
41043030401	Census Tract 304.01; Linn County; Oregon	479.445	177.167	634.679	430.430
41043030403	Census Tract 304.03; Linn County; Oregon	368.281	248.373	513.336	376.663

Environmental Impacts

HB 2021 mandates significant reductions in greenhouse gas emissions, though there are other air pollutants that are also byproducts of the electricity generation process. Greenhouse gas emissions are global pollutants that cause damage everywhere regardless of the point of emission. In contrast, local pollutants cause more damage closer to the source of emission. The regulation of global pollutants gains more attention; however, the reduction of greenhouse gas emissions is also thought to correlate with reductions in local pollutants.

Reducing emissions improves air quality, which not only has positive impacts on environmental outcomes but on health outcomes for communities by reducing respiratory illnesses and other diseases that can be related to pollution. Tracking emissions will help PacifiCorp meet HB 2021 targets and monitor the impact of its power generation activities on all communities served by the company. To this end, PacifiCorp has identified three portfolio CBIs to track the environmental impacts of its activities:

- Increase energy from non-emitting and renewable resources.
- Reduce CO_2 equivalent emissions.
- Reduce SO_2 and NOx emissions.

Emission reductions, including NOx and SO_2, in addition to CO_2e as required by HB 2021, are measured against an Oregon-allocated emissions baseline, defined as the average annual greenhouse gas emissions from electricity sold to Oregon retail customers during the years 2010, 2011, and 2012, as reported under ORS 468A.280. Results from these CBIs are shown in Table 7, while additional discussion regarding greenhouse gas emissions reductions can be found in Chapter VII.

Table 7 – PacifiCorp's Baseline, Current, and Percent of Reported Emissions from Baseline[31]

Emissions		MT CO2e	MT NOx	MT SO_2
Oregon Allocated Baseline		7,894,233	6,015	4,094
Emission Type	**2023 – lbs/ MWh**	**2023 MT**	**2022 – lbs/ MWh**	**2022 MT**
Total CO2e	0.5439	7,739,010	0.5760	8,049,455
Total NOx	0.8992	5,803	0.9823	6,227
Total SO_2	0.5943	3,835	0.6868	4,354

Health and Community Wellbeing

PacifiCorp has four informational health and community wellbeing CBIs: (1) decrease residential disconnections, measured by the number of disconnections by census tract; (2) decrease proportion of households experiencing high energy burden, measured by average energy burden by census tract for customers residing in underserved or vulnerable communities, and LID program

[31] Conversion factor for pounds to metric tons = 0.00045359.

participation; (3) increase residential and small business energy efficiency for vulnerable communities, measured by customer participation in business and residential incentive programs by census tract; and similarly, (4) reduce barriers to participation in energy efficiency programs for vulnerable communities, also measured by customer participation in business and residential incentive programs by census tract.

The first and second CBIs address energy burden and energy insecurity, which are intricately linked to other forms of material hardship. Research indicates that households with high energy burden are significantly more likely to experience housing or food insecurity, often facing difficult trade-offs between paying utility bills and meeting other essential needs. Furthermore, the financial stress associated with high energy costs and the threat of service disconnection can exacerbate existing mental health conditions, such as depression and anxiety. Although financial assistance programs for utility costs are available, limited public awareness and uncertainty regarding eligibility and benefits can create a barrier to access.

The third and fourth CBIs address access to energy efficiency programs. Climate change has led to increasingly frequent and impactful weather events, like the extreme heat wave in 2021 during which some communities in Oregon saw temperatures reach as high as 118 degrees Fahrenheit. These events necessitate community-level adaptation to safeguard public health and well-being, particularly for the most vulnerable communities. Moreover, poor indoor air quality has been shown to exacerbate respiratory conditions, including asthma and chronic obstructive pulmonary disease (COPD). These risks are especially pronounced in older buildings with substandard ventilation and filtration systems. Central to these adaptations is the ability to maintain safe indoor environments through mechanisms such as air conditioning (both window-mounted and central systems) and building weatherization. However, access to such adaptive measures is unequally distributed, with vulnerable communities often facing significant barriers. Tracking metrics like energy efficiency program accessibility with these CBIs can help the company develop support mechanisms for vulnerable customers, so that they can also adapt to a rapidly changing climate and the financial strain that can be imposed by the transition to clean energy.

The metrics for health and community wellbeing CBIs are discussed below.

Reduce Energy Burden

Energy burden is a standardized metric that tracks whether the energy individuals and households need to live safely and comfortably is affordable. Typically, households with low socio-economic status spend a much higher portion of their income on energy than higher-income households. For this reason, among others, individuals and households with high energy burden may forgo keeping their homes at safe temperatures to save money, which can lead to unsafe living conditions and negative health outcomes. This is especially true for children, the elderly, and people with disabilities. Finally, individuals and households with high energy burden are often precluded from participating in energy efficiency incentive programs, primarily because of the high upfront cost to do so.

To track energy burden, the company relies in part on data from the Low-Income Energy Affordability Data (LEAD) Tool,[32] which provides a five-year running average of energy burden at the census tract level. Table 8 provides a breakdown of energy burden for census tracts in PacifiCorp's Oregon service area that have the highest energy burden. A detailed breakdown of energy burden for all 2020 census tracts in PacifiCorp's Oregon service area with customer demographic information is included in the Burden (LEAD) workpaper described in Appendix A.

Table 8 – 5-Year Running Average Energy Burden (LEAD)

NAME	Customer Count	Energy Burden (% income)	Avg. Annual Energy Cost ($)
Census Tract 9601; Gilliam County; Oregon	601	5	$3,812
Census Tract 15; Lane County; Oregon	0	5	$2,268
Census Tract 9501; Sherman County; Oregon	991	5	$4,018
Census Tract 9506; Baker County; Oregon	0	4	$2,774
Census Tract 11.01; Coos County; Oregon	953	4	$2,021
Census Tract 9501; Curry County; Oregon	0	4	$1,968
Census Tract 3616.01; Josephine County; Oregon	2811	4	$2,030
Census Tract 9701; Klamath County; Oregon	91	4	$2,658
Census Tract 9702.01; Klamath County; Oregon	1307	4	$2,166
Census Tract 9702.02; Klamath County; Oregon	2021	4	$2,549

Monitoring disconnections and arrearages is also a powerful and practical way to evaluate energy burden. That is because understanding where disconnections and arrearages are higher can be an indicator of where, when, and for whom, energy affordability issues are more acute. This means that monitoring disconnects and arrearages in tandem with energy burden from the LEAD Tool can support more robust evaluation of low-income customer support programs. Table 9 and Table 10 provide a breakdown of disconnections and arrearages, respectively, for census tracts in PacifiCorp's Oregon service area that have the highest count of both. An average of disconnections and arrears over the course of three years was calculated to establish the baseline for each. A detailed breakdown of arrearages and disconnections for all 2020 census tracts in PacifiCorp's Oregon service territory with customer demographic information is included in the supporting Arrears and Disconnects (2022-2024) workpaper described in Appendix A.

Table 9 – Disconnections by Year, 2022-2024

NAME	2022 Disconnects	2023 Disconnects	2024 Disconnects	Baseline Disconnects
Census Tract 23.03; Multnomah County; Oregon	89	138	597	274
Census Tract 81; Multnomah County; Oregon	111	221	460	264
Census Tract 3; Jackson County; Oregon	35	100	284	139
Census Tract 5.02; Jackson County; Oregon	45	105	237	129
Census Tract 2.01; Jackson County; Oregon	56	107	195	119
Census Tract 3616.01; Josephine County; Oregon	35	84	233	117

[32] Available online at: https://lead.openei.org/.

NAME	2022 Disconnects	2023 Disconnects	2024 Disconnects	Baseline Disconnects
Census Tract 57.02; Multnomah County; Oregon	59	90	204	117
Census Tract 2.02; Jackson County; Oregon	53	97	187	112
Census Tract 22.03; Multnomah County; Oregon	63	94	181	112
Census Tract 304.01; Linn County; Oregon	43	76	209	109

Table 10 – Average Arrearages by Year 2022-2024

NAME	2022 Avg Arrears	2023 Avg Arrears	2024 Avg Arrears	Baseline Arrears
Census Tract 9701.01; Morrow County; Oregon	$1,602	$2,216	$2,026	$1,948
Census Tract 9504.01; Crook County; Oregon	$2,473	$1,901	$588	$1,654
Census Tract 103; Benton County; Oregon	$1,625	$1,472	$659	$1,252
Census Tract 22; Jackson County; Oregon	$1,373	$1,280	$697	$1,117
Census Tract 3616.02; Josephine County; Oregon	$1,002	$867	$498	$789
Census Tract 3601; Josephine County; Oregon	$645	$785	$585	$672
Census Tract 3615; Josephine County; Oregon	$883	$682	$440	$668
Census Tract 3614; Josephine County; Oregon	$775	$641	$510	$642
Census Tract 30.02; Jackson County; Oregon	$870	$672	$361	$634
Census Tract 18.01; Jackson County; Oregon	$1,117	$417	$366	$633

Finally, tracking customer participation in the Oregon Low-Income Discount (LID) program is another way the company can monitor energy burden. LID program participation provides concrete, measurable insight into how well energy affordability programs are supporting vulnerable communities, especially as energy costs continue to rise in tandem with the transition to clean energy. Further, taking the additional step of tracking LID program participation at the census tract level can help to identify whether vulnerable communities are receiving this critical support. For example, disparities in enrollment can point to systemic barriers like language gaps, digital access issues, or burdensome paperwork. It can also reveal ways that utilities can facilitate outreach regarding this critical program.

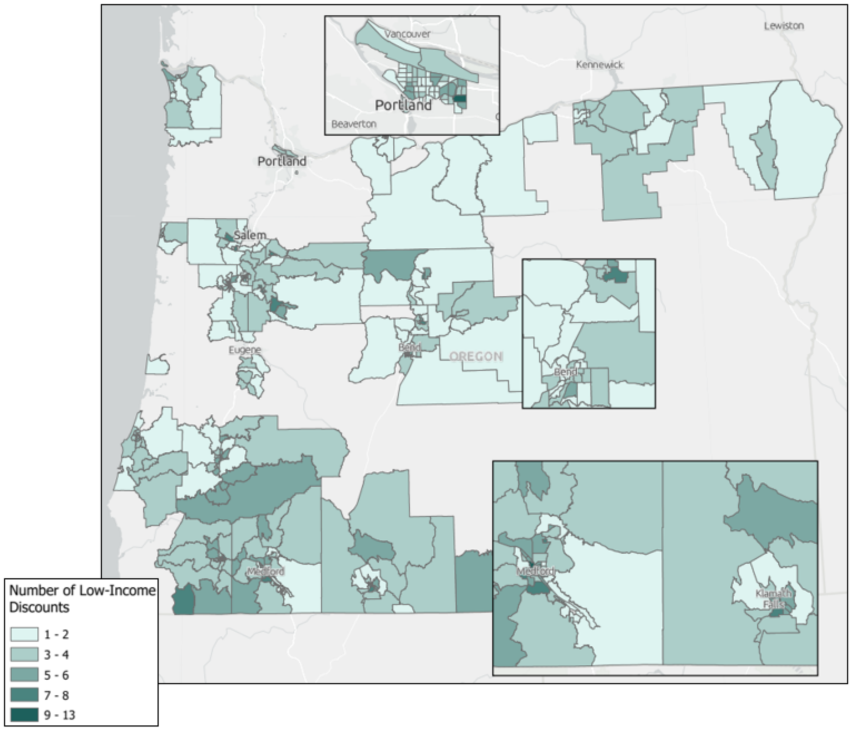
From 2022 through 2024, a total of 34,768 PacifiCorp customers were enrolled in the LID program. Table 11 provides a breakdown of customer participation in the LID program by census tract for the ten tracts with the highest energy burden as reported in the LEAD Tool. A detailed breakdown of energy burden and LID enrollment throughout the company's Oregon service area that includes demographic and socioeconomic information by census tract is included in the supporting LID Enrollments (2022-2024) workpaper described in Appendix A.

Table 11 – LID Enrollments by Year (2022-2024)

NAME	Customer Count	Energy Burden (% income)	2022 LID Enrollments	2023 LID Enrollments	2024 LID Enrollments	Baseline LID Enrollments
Census Tract 9601; Gilliam County; Oregon	601	5	8	4	13	8
Census Tract 9501; Sherman County; Oregon	991	5	16	14	11	13
Census Tract 11.01; Coos County; Oregon	953	4	18	23	17	19
Census Tract 3616.01; Josephine County; Oregon	2811	4	75	102	94	90
Census Tract 9701; Klamath County; Oregon	91	4	0	0	0	0
Census Tract 9702.01; Klamath County; Oregon	1307	4	13	18	35	22
Census Tract 9702.02; Klamath County; Oregon	2021	4	39	40	54	44
Census Tract 9716; Klamath County; Oregon	1773	4	79	115	83	92
Census Tract 9602; Wallowa County; Oregon	1209	4	13	11	9	11
Census Tract 9708; Wasco County; Oregon	78	4	1	9	4	4

Figure 1 provides a summary visualization of LID program participation in the company's Oregon service area.

Figure 1 – LID Program Participation



Increase Residential and Small Business Energy Efficiency in Vulnerable Communities, Reduce Barriers to Participation in Energy Efficiency Programs

Improving energy efficiency for vulnerable communities can help ensure that the benefits of the transition to clean energy are equitable. Energy efficiency upgrades, such as weatherization, insulation, efficient appliances, and other improvements, can offer significant long-term benefits, particularly to vulnerable customers.

For example, low-income individuals and families often live in substandard housing, such as older homes, multi-unit housing, or mobile homes. Substandard housing conditions often go hand-in-hand with poor energy efficiency. Energy efficiency upgrades not only lower energy use but can also result in safer, healthier homes. These improvements are particularly important for seniors, children, and individuals with disabilities. Additionally, energy efficiency upgrades can result in cost savings for customers that are able to take advantage of them.

Tracking energy efficiency incentive program participation by census tract can reveal what customers are benefiting from these important programs and support identification of structural or procedural problems that could be associated with access to them. These could include, for instance, language barriers or a general lack of customer awareness. Additionally, tracking at this level of granularity allows for the inclusion of publicly available demographic and socio-economic data from the American Community Survey (ACS), such as age, race or ethnicity, and disability status.

Table 12, Table 13, and Table 14 provide a breakdown of non-residential incentive program participation by census tract for tracts in the company's Oregon service area where program participation is the lowest. Baseline program participation was calculated using the average participation for 2023 and 2024. The company intends to work with the program administrator, Energy Trust of Oregon (ETO), to use this data to guide the development and implementation of program improvements. A more detailed analysis of incentive program participation is included in the supporting Incentives (2023-2024) workpaper described in Appendix A.

Table 12 – Commercial Incentives 2023-2024

NAME	2023 Commercial	2024 Commercial	Baseline Commercial
Census Tract 13.03; Jackson County; Oregon	No Data	1	1
Census Tract 17.02; Deschutes County; Oregon	No Data	1	1
Census Tract 5.02; Deschutes County; Oregon	No Data	1	1
Census Tract 202.04; Polk County; Oregon	No Data	1	1
Census Tract 9508; Umatilla County; Oregon	1	1	1
Census Tract 3609; Josephine County; Oregon	1	No Data	1
Census Tract 38.02; Multnomah County; Oregon	No Data	1	1
Census Tract 38.03; Multnomah County; Oregon	1	No Data	1
Census Tract 38.01; Multnomah County; Oregon	No Data	1	1
Census Tract 9706; Wasco County; Oregon	No Data	1	1

Table 13 – Industrial Incentives 2023-2024

NAME	2023 Industrial	2024 Industrial	Baseline Industrial
Census Tract 202.04; Polk County; Oregon	No Data	1	1
Census Tract 309.06; Linn County; Oregon	No Data	1	1
Census Tract 9601; Gilliam County; Oregon	1	No Data	1
Census Tract 6.01; Deschutes County; Oregon	1	No Data	1
Census Tract 9709.01; Klamath County; Oregon	No Data	1	1
Census Tract 25; Jackson County; Oregon	1	1	1
Census Tract 77; Multnomah County; Oregon	No Data	1	1
Census Tract 1.02; Benton County; Oregon	No Data	1	1
Census Tract 204; Polk County; Oregon	1	No Data	1
Census Tract 9400; Umatilla County; Oregon	1	1	1

Table 14 – Renewable Incentives 2023-2024

NAME	2023 Renewables	2024 Renewables	Baseline Renewables
Census Tract 309.06; Linn County; Oregon	1	1	1
Census Tract 77; Multnomah County; Oregon	1	No Data	1
Census Tract 5; Benton County; Oregon	1	1	1
Census Tract 9512; Clatsop County; Oregon	1	1	1

NAME	2023 Renewables	2024 Renewables	Baseline Renewables
Census Tract 6.02; Deschutes County; Oregon	1	1	1
Census Tract 303; Linn County; Oregon	1	No Data	1
Census Tract 53.02; Polk County; Oregon	No Data	1	1
Census Tract 9503; Clatsop County; Oregon	No Data	1	1
Census Tract 106.01; Benton County; Oregon	No Data	1	1
Census Tract 700; Douglas County; Oregon	No Data	1	1

Table 15 summarizes residential incentive program participation in census tracts with the highest energy burden, as identified by the LEAD Tool. Tracking residential program participation in this way can help to identify disparities in residential incentive program access and support more equitable delivery of residential energy efficiency resources. In this case, energy burden serves as a useful proxy for household vulnerability by highlighting communities that may face greater barriers to participation and benefit from more targeted support.

Table 15 – Residential Incentives 2023-2024

NAME	Energy Burden (% income)	2023 Residential	2024 Residential	Baseline Residential
Census Tract 9601; Gilliam County; Oregon	5	7	7	7
Census Tract 9501; Sherman County; Oregon	5	1	2	1.5
Census Tract 11.01; Coos County; Oregon	4	13	19	16
Census Tract 3616.01; Josephine County; Oregon	4	18	92	55
Census Tract 9716; Klamath County; Oregon	4	9	23	16
Census Tract 9702.02; Klamath County; Oregon	4	47	71	59
Census Tract 9702.01; Klamath County; Oregon	4	14	13	13.5
Census Tract 9602; Wallowa County; Oregon	4	24	31	27.5
Census Tract 9708; Wasco County; Oregon	4	4	1	2.5
Census Tract 9701; Klamath County; Oregon	4	No Data	No Data	No Data

Detailed information regarding customer participation in incentive programs is included in the supporting Incentives (2023-2024) workpaper described in Appendix A.

Economic Impacts

A clean energy transition that aligns with HB 2021 targets will have an economic impact on the communities served by PacifiCorp. To that end, PacifiCorp has five informational economic impact CBIs that track the number of: (1) demand side management program delivery staff and grants; (2) public charging stations installed in PacifiCorp territory; (3) participation in pre-apprenticeship programs; (4) headcounts of local and state workers during facility construction; and (5) spend on Disadvantaged Business Enterprise (DBE), tribal, women, minority, and/ or veteran-owned resources during facility construction.

Tracking the economic impact of its clean energy investments, like public electric vehicle (EV) charging station installations and local workforce development, can help to guide the company's efforts to ensure that it delivers the economic benefits of the transition to clean energy equitably throughout the communities it serves. These CBIs are discussed below.

Demand Side Management Program Delivery Staff and Grants

In its interim CBI framework, PacifiCorp proposed the CBI of Demand Side Management (DSM) Program Delivery Staff and Grants. This CBI is intended to track staffing for the company's portfolio of customer DSM programs and grants. However, effectively tracking program delivery staff and grants for all of the company's DSM programs has proven to be challenging. This is because most of the DSM programs are managed by the Energy Trust of Oregon, an external partner, and the company is unable to track or influence staffing and issuance of grants. Currently, the company is struggling to address these challenges and plans to engage the CBIAG in future discussions regarding this CBI.

Public Charging Station Installations

Oregon has established a robust policy framework to support the adoption of electric vehicles as part of its broader climate and equity goals. Key objectives include:

- Reducing carbon emissions by accelerating EV adoption.
- Expanding charging infrastructure to support a growing fleet of EVs.
- Ensuring equitable access to EV benefits, particularly for low- and moderate-income households.

The state has continued to evolve its electric transportation policies to meet these goals. One of the most significant regulatory drivers has been the Advanced Clean Cars II regulation, which requires automobile manufacturers to steadily increase sales of Zero-Emission Vehicles (ZEVs) from 35% of new vehicle sales in 2026 to 100% by 2035.

As outlined in its 2026–2028 Transportation Electrification (TE) Plan, to support the objective of 100% EV adoption by 2035, PacifiCorp committed to supporting EV access for underserved communities through the following strategies:

- Leveraging existing company resources to develop and construct new company-owned EV charging sites in underserved communities.
- Continuing to offer and expand grant programs that support community-led EV adoption.
- Targeting outreach and programming toward large-load customers and underserved populations to promote participation in utility programs and support income-eligible rates at publicly owned charging stations.
- Deploying flexible, customer-specific delivery strategies to ensure infrastructure deployment (e.g., multi-port installations) that facilitates broader participation across a variety of customer classes.

As of March 2025, there are 136 active charging ports, and 71 Electric Vehicle Supply Equipment (EVSE) ports funded through the company's programs at more than 40 public stations in Oregon.

Additionally, PacifiCorp owns five charging pods consisting of 25 ports. These stations are in five municipalities spread over four regions:

- Bend (Central region)
- Klamath Falls (Southern region)
- Madras (Central region)
- Mill City (Willamette Valley region)
- Otis (Southern Coast region).

The 2024 statistics for these charging stations are presented in Table 16 below.

Table 16 – PacifiCorp-Owned Charging Station Statistics (2024)

Station	Number of Transactions	Average Session Duration (hours)	Average Charging Time per Session (hours)	Number of Distinct User IDs
DCFC				
Bend	6,129	0.70	0.63	1,554
Klamath Falls	3,598	0.67	0.63	1,003
Madras	1,215	0.53	0.50	425
Mill City	1,742	0.43	0.42	589
Otis	2,440	0.50	0.47	913
Level 2				
Bend	1,284	2.25	1.80	351
Klamath Falls	469	2.30	1.97	105
Madras	59	1.47	1.23	157
Mill City	135	1.75	1.00	57
Otis	60	0.92	0.70	31

As identified in the company's 2025 Transportation Electrification Plan filing, more public EVSE ports are in underserved areas than in areas that are not considered underserved.

Pre-Apprenticeship and Educational Program Participation

PacifiCorp has one program that can be tracked with this CBI to measure progress. The Rural Electrical Pre-Apprenticeship program, an industry-led career and technical education course, is designed to develop the next generation of electrical workers by providing rural high school students with pre-apprenticeship training. Since early 2022, the Crater Lake Electrical Training Center, Pacific Power, and IBEW Local 659 have collaborated to bring this program to Southern Oregon's rural school districts. Initially launched at Glide High School in 2022, the program expanded to multiple schools throughout Douglas and Klamath counties. Through this program, students gain essential knowledge and skills, including the basics of DC Theory and expectations for on-the-job performance. Successful completion of the program also qualifies graduates for a registered electrical apprenticeship. Hands-on training covers critical tasks such as the installation of electrical conduits, boxes, devices, wire pulling, terminations, and basic control systems. These skills provide graduates with a strong foundation to excel in electrical apprenticeships and secure employment with electrical and utility contractors. Summary statistics for the 2023-2024 program year are summarized in Table 17 .

Table 17 - Number of Participants in the Rural Electrical Pre-Apprenticeship program

Program Year	# High School Students	# Adult Students	# Disabled Students	# Program Graduates
2023-2024	21	26	3	35

In the 2023-2024 academic year, the program delivered cohorts at three high schools—Glide High School, Riddle High School and Winston-Dillard High School—and two adult cohorts in Roseburg, Oregon. The high school cohorts enrolled a total of twenty-one students, with eleven successfully completing the pre-apprenticeship program. Two of these students identified themselves as having a disability, and accommodation was provided to ensure their success. The adult cohorts enrolled twenty-six participants, with twenty-four completing the program, including one student with a self-identified disability for whom accommodation was made.

For the 2024-2025 academic year, the program expanded to include three additional high school cohorts at Douglas High School, North Douglas High School, and Yoncalla High School. These cohorts, set to conclude in June 2025, have enrolled a total of thirty-six students. Of these, eighteen have completed or are on track to complete the program, including five students who identified themselves as having a disability and received accommodation.

In 2025, the introduction of a mobile training center allowed instructors to replicate the apprenticeship training center at any participating school, ensuring equitable learning experiences for every student. This initiative aims to reduce barriers to employment for underserved communities in rural Oregon, particularly where schools lack dedicated classroom space for hands-on learning.

Local Workforce Development

HB 2021 calls specific attention to ensuring that the benefits of the transition to clean energy reach all communities, particularly those that are rural, low-income, or historically marginalized. Integrating local workforce development, namely creation of local jobs, with the transition can support more equitable distribution of the resulting economic benefits, especially for these communities. As part of its resource procurement strategy for both the 2025 OR SSR RFP and 2025 OR Situs RFP, PacifiCorp introduced a non-price scoring methodology in which bidders' intent to create local jobs is a weighting factor in proposal evaluation. This is a new scoring methodology for the company, and the downstream impact it could have on the selection of projects of this size and duration will continue to be investigated for future procurement efforts.

At this time, PacifiCorp does not have an adequate metric to measure this impact by or to establish a baseline.

Diverse Business Expenditures

To strengthen partnerships with women-, minority-, disabled-, and veteran-owned suppliers and contractors, PacifiCorp established the Diverse Business Expenditures CBI. Through this CBI, the company has made a commitment to engage diverse suppliers where it is feasible to do so. For example, the company partnered with Pano AI, a certified Women Business Enterprise (WBE) by the Utility Supplier Diversity Program of the California Public Utilities Commission, for its wildfire camera installation project in Oregon. However, relative to this CBI, it is important to note that tracking diversity-related expenditures has become increasingly challenging. This is because the current political climate has made it more difficult for organizations to monitor commitments to diversity, equity, and inclusion in the workforce. To that end, the company is working on new ways to track diverse business expenditures that are aligned with national policy. At this time, PacifiCorp has not yet identified an adequate metric to measure this impact by or to establish a baseline.

Future Environmental Justice Community Framework

A key consideration within clean energy planning as directed by HB 2021, is understanding of the impacts of utility actions across the communities it serves and how the costs or benefits of such actions can be distributed in a way that ensures equitable outcomes. These considerations go beyond traditional cost and risk metrics and incorporate environmental justice considerations. [33] PacifiCorp's CBIs and related metrics offer tools to incorporate this work. If CBIs are designed and tracked at the census tract level in alignment with the concept of energy equity they can also help draw a clearer picture of the long-term impacts of utility planning and decision-making on PacifiCorp's "environmental justice communities". [34]

To improve these efforts, PacifiCorp has taken the initial steps to work towards development of a PacifiCorp-specific Environmental Justice Community Framework. This proposed framework is a methodological approach to geographically defining "environmental justice communities" at the census tract level, which can be used to identify the most at-risk, marginalized and vulnerable communities in the company's Oregon service territory. This identification of environmental justice communities can then be applied to PacifiCorp's CBI metrics to improve tracking and allow for a more nuanced understanding of the distribution of benefits and burdens from the clean energy transition.

For example, an environmental justice (EJ) community framework can support efforts to:

- *Address Historical Inequities*. Many low-income, Indigenous, and communities of color have experienced environmental harms (e.g., pollution, proximity to industrial facilities,

[33] ORS 469A.400(4) (defined as "equal protection from environmental and health hazards and meaningful public participation in decisions that affect the environment in which people live, work, learn, practice spirituality and play.").
[34] ORS 469A.400(5) (defined as "Communities of color, communities experiencing lower incomes, tribal communities, rural communities, coastal communities, communities with limited infrastructure and other communities traditionally underrepresented in public processes and adversely harmed by environmental and health hazards, including seniors, youth and persons with disabilities.").

and climate-related impacts) stemming from a long history of policy decisions that have not accounted for equity. An EJ community framework can help to identify systemic imbalances by supporting recognition and facilitating response.

- *Promote Fair Access to Benefits*. Having an established EJ community framework can support the company's effort to ensure that all communities have equitable access to clean energy, and climate resilience energy programs.
- *Strengthen Community Trust and Engagement*. Collaborating closely with external stakeholders to build a definition for what it means to be an EJ community can foster trust and a culture of engagement between utilities like PacifiCorp and the communities they serve.
- *Improve Program Effectiveness*. Building an EJ community framework can support the development of programs that are more targeted, efficient, and impactful. Additionally, having an EJ community framework can prevent unintended harm by recognizing intersecting social and environmental risks.
- *Meet Legal and Regulatory Requirements*. Building a definition for what it means to be an EJ community will support development of a framework that can support PacifiCorp's efforts to align its projects and programs with HB 2021.
- *Support Long-Term Resilience*. Environmental justice and energy equity are both closely tied to climate resilience, disaster preparedness, and sustainability. Building an EJ community framework can support efforts to ensure that no community is left behind in the transition to a cleaner, safer future.
- *Support Distribution and Transmission System Planning Activities.* Ensure that the Company's planning, siting, and development of distribution and transmission system planning efforts minimize impacts to PacifiCorp EJ Communities.

PacifiCorp is in the early stages of developing this framework and engaging with stakeholders and community members, with the overall objective of making its CBI framework more informative and actionable for PacifiCorp-specific environmental justice communities. The discussion below highlights several of the variables that PacifiCorp believes will inform this framework over the next biennium, including Socio-Economic Status, Health, Housing and Infrastructure, Demographics, and Weather and Climate.[35]

Socio-Economic Status

Socioeconomic status is a core dimension of any EJ community-driven approach because it shapes how individuals and communities experience environmental risks and benefits from the transition to clean energy. Low-income communities are more likely to live near sources of pollution, such as factories, highways, and hazardous waste sites, and face greater exposure to environmental hazards. Additionally, limited financial and social resources often make it harder for these communities to adapt to threats like extreme heat, flooding, or power outages. Individuals and households with lower Socioeconomic status are also more likely to have underlying health conditions and limited access to healthcare, which increases their vulnerability to environmental

[35] For additional discussion of these variables, please see the meeting slides from PacifiCorp's May 28, 2025 Oregon CEP Engagement Series meeting, available here: OR_CEP_Meeting_2025-05_May_Slides.pdf.

stressors. Further, these communities often have less political power and are underrepresented in decision-making processes, leading to inequities in planning and resource allocation. Barriers such as lack of information, limited internet access, or complex program requirements can also prevent lower-income households from participating in energy efficiency programs, relocating to safer areas, or preparing for emergencies.

Health

Health status also plays a critical role in building an EJ community framework as it helps determine how severely individuals may be affected by environmental hazards. People with chronic conditions, such as asthma, Chronic Obstructive Pulmonary Disease (COPD), heart disease, or diabetes, are especially vulnerable to the effects of pollution, extreme temperatures, and poor air quality. Children and older adults are also more susceptible to long-term impacts, including physical and cognitive setbacks caused by environmental harms. Poor health can limit a person's ability to cope with or recover from stressors like extreme weather events or extended power outages, like Public Safety Power Shutoffs (PSPS). Additionally, many vulnerable populations have limited access to healthcare, which can make it harder to manage chronic illnesses.

Housing and Infrastructure

Housing and infrastructure are essential components of an EJ community framework because they influence both exposure to risk and access to vital resources. Inadequate infrastructure, such as deteriorating roads, drainage, water, and energy systems, can intensify the impact of extreme weather events and slow or even stop recovery efforts. Older or poorly maintained homes often lack proper insulation, ventilation, or weatherproofing, making them especially vulnerable to extreme heat, cold, and moisture-related issues like mold. Outdated appliances and inefficient heating or cooling systems can raise energy costs and reduce indoor comfort, posing challenges for households with limited or fixed incomes. Renters and residents of mobile homes or multi-unit buildings frequently lack control over critical safety and energy improvements, such as weatherization. Additionally, limited access to internet, transportation, or emergency services can isolate vulnerable communities during crises, cutting them off from essential aid and information

Socio-Demographics

Demographics play a significant role in building an EJ community framework because they help identify which populations are disproportionately affected by environmental hazards and which communities have fewer resources to adapt or respond. Communities of color often face higher exposure to pollutants, live closer to industrial sites, and have less access to clean air, water, and green space due to a legacy of discriminatory policies. Children and older adults are more vulnerable to environmental risks such as extreme temperatures, air pollution, and natural disasters due to physiological and mobility-related factors. People with disabilities are more vulnerable during environmental events like extreme heatwaves or wildfire and may require specialized services that can be overlooked in emergency planning. Non-English speakers and recent immigrants may face barriers to receiving critical information or services, especially during emergencies or when applying for energy assistance and other support. Rural communities may lack access to public infrastructure like public transit, reliable broadband, and healthcare facilities, like hospitals. Finally, tribal lands and Indigenous communities require special acknowledgement because they face unique environmental justice challenges.

Weather and Climate

As previously discussed, low-income communities and communities of color are more frequently located in areas that are more vulnerable to flooding, extreme heat, wildfires, and other climate-related hazards. These populations may lack the resources to prepare for, respond to, or recover from severe weather events like heat waves, deep freezes, or wildfires. For example, they may not have access to air conditioning during extreme heat or reliable transportation to evacuate during emergencies like wildfire. Rising temperatures also drive up the need for cooling, which increases energy costs, disproportionately affecting individuals and households already experiencing high energy burden. Climate-related events such as heatwaves or poor outdoor air quality from wildfire smoke can have especially harmful effects on individuals with preexisting health conditions like asthma or COPD, as well as children, the elderly, and people with disabilities. These events can also lead to housing damage or loss, particularly in communities with substandard housing and limited or no access to an insurance safety net to fall back on. Moreover, aging infrastructure is more likely to fail during extreme weather, severely impacting the most vulnerable communities.

PacifiCorp will continue to develop this EJ Community Framework and include results from these efforts in the next CEP.

V. RESILIENCY

HB 2021 requires utility clean energy plans to include a "risk-based examination of resiliency opportunities that includes costs, consequences, outcomes and benefits based on reasonable and prudent industry resiliency standards and guidelines."[36] The Commission offered initial guidance on the consideration of resiliency and resiliency analysis in inaugural CEPs, and commissioned a report from the U.S. Department of Energy's Grid Modernization Lab Consortium (GMLC) to research various resiliency-related issues and guidelines, that continues to help inform the company's approach (GMLC Report).[37][38]

While reliability and resiliency might often be used interchangeably, reliability, which has long been one of the key drivers of prudent utility planning, refers to the ability of the electricity grid to provide power without interruptions. Resiliency, however, focuses on the ability of an electricity system to recover quickly from significant non-routine disruptions to that provision of power, driven by events like extreme weather or cyber-attacks. PacifiCorp defines resilience as the combined ability of a community and the electric grid to withstand, respond to, and recover from events that result in long-duration power disruptions.

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[36] ORS § 469A.415(4)(c).
[37] *In re Commission HB 2021 Investigation,* UM 2225, Order 22-390 (Oct. 25, 2022 (available online at: https://apps.puc.state.or.us/orders/2022ords/22-390.pdf).
[38] "Considerations for Resilience Guidelines for Clean Energy Plans," Homer, JS, et. al, at 1 (U.S. DOE GMLC; Sept. 2022) (available here: https://edocs.puc.state.or.us/efdocs/HAH/um2225hah113046.pdf).

PacifiCorp's CBIAG members expressed key examples of potential resiliency considerations:

- Energy resilience ensures that critical services—such as hospitals, emergency response, water supply, and communications—remain operational during power outages. This is vital for public safety, health, and security.
- A resilient energy system minimizes downtime for businesses and industries, protecting jobs and local economies. It reduces losses associated with blackouts and supply interruptions.
- By keeping heating, cooling, and lighting functional, energy resilience supports resident well-being, especially vulnerable populations like the elderly or those with medical needs.
- Communities with energy planning and backup systems (e.g., microgrids, solar plus battery storage) can bounce back more quickly after extreme events. This reduces reliance on external aid and speeds up recovery.
- Thoughtful energy planning can ensure all neighborhoods, including underserved or remote communities, have access to affordable and reliable energy. It can involve local stakeholders in decisions, promoting energy equity.
- Proactive energy planning helps a community anticipate risks, prioritize investments (e.g., hardening infrastructure, diversifying energy sources), and implement policies that reduce vulnerabilities over time.

In this chapter, the company builds upon its resiliency analysis framework introduced in the first CEP. Additionally, the company offers insight into how PacifiCorp continues to build a resilient system for its customers beyond the requirements of HB 2021, through customer programs and grid investments.

Resilience Analysis Framework

The literature offers a range of general definitions regarding resilience, as described in the GMLC report, but the common theme is the rapid recovery following non-routine disruptions. The report also emphasizes that while "reliability events are generally high-probability/low-consequence events, resilience events are singular, infrequent large-scale incidents, like hurricanes, earthquakes, and terrorist attacks, with more severe consequences."[39]

Consistent with the GMLC Report's proposed resiliency planning analysis process, and drawing from experience in Washington, the company proposed an initial process for developing resilience metrics, a resilience definition and a methodology for assessing electric system and community resilience for resilience-related programs in its 2023 CEP. In this subsection, the company presents its updated methodology, developed resilience scores, and current and proposed applications.

[39] GMLC Report, at 5.

Methodology

The company has developed a community-utility resilience scoring methodology, using measures from sources including the U.S. Census Bureau, Center for Disease Control (CDC), federal Emergency Management Agency (FEMA), and utility data. For the purposes of this methodology, a “community” is defined as a census block group, which is the smallest geographic area for which the Census Bureau publishes detailed demographic and socioeconomic data.

The score captures both the vulnerability of a community and the historical reliability of the electric grid serving it. It combines two key components:

- **Community Resilience** – measures of vulnerability related to health, outage preparedness, and evacuation challenges.
- **Utility Resilience** – total System Average Interruption Duration Index (SAIDI) at the community level over a five-year period.

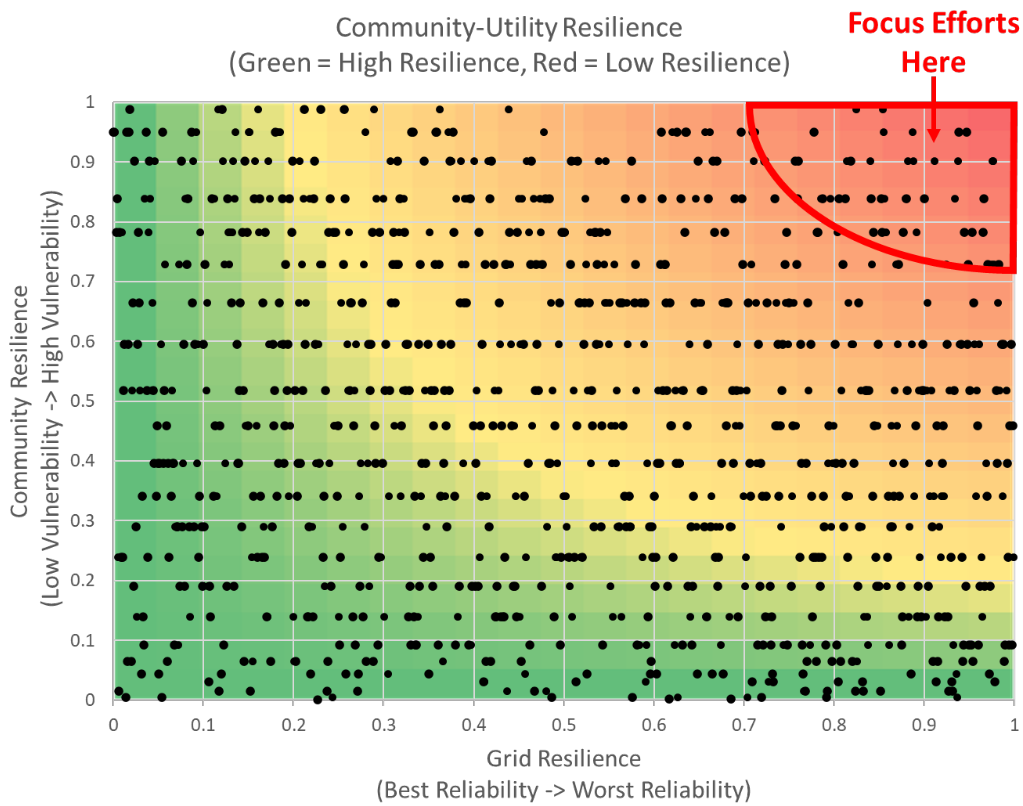
By incorporating both community needs and utility performance, the score enables the company to prioritize outreach, guide resilience investments, and support applications for grant opportunities where they may have the greatest (relative) impact.

Both resiliency components are independently calculated for each PacifiCorp Oregon community, and scored on a 0–1 percentile scale, with higher values indicating greater need. The final score is calculated by multiplying the two component percentiles, capturing both a community’s underlying vulnerability and the historical reliability of the grid serving that area. The framework is designed to be:

- **Scalable** – calculated at the census block group level, with flexibility to aggregate to larger geographies (e.g., census tracts, counties or utility service areas).
- **Actionable** – intended to guide outreach, investment planning, and support grant applications.
- **Adaptable –** allows incorporation of additional or alternative indicators of community vulnerability or grid reliability as new data availability, stakeholder input, and operational experience is gained.

To help visualize the relationship between the community-utility resilience score and the two components, Figure 2 shows a scatter plot of communities by their Community Resilience percentile (y-axis) and Utility Resilience percentile (x-axis). Each point represents an Oregon community within PacifiCorp’s service territory, with the background color indicating the combined resilience score, ranging from green (high community-utility resilience) to red (low community-utility resilience).

Figure 2 – Community-Utility Resilience Plot



A discussion of each resiliency component follows.

Community Resilience Component

The Community Resilience component is a composite metric intended to capture a community's relative vulnerability to long-duration power disruptions. Measures are used to calculate scores for three categories of vulnerabilities: Health, Outage Preparedness, and Evacuation. Measures are obtained from multiple sources, including the U.S. Census Bureau, CDC PLACES, historical weather data, and the company's customer information system.

Regarding Health Vulnerability, this category includes age and health-related sensitivities to long-duration outages. Measures include:

- Percent of the population under 5 and over 65 years of age
- Prevalence of chronic health conditions (e.g., coronary heart disease, diabetes, asthma)
- Households flagged as medically dependent in the company's customer database
- Environmental stressors that can worsen health outcomes during outages (e.g., high summer temperatures, low winter temperatures)

Regarding Outage Preparedness, this category includes socioeconomic and demographic factors that may present challenges for a household's ability to prepare for a prolonged outage. Measures include:

- Housing type and density (e.g., multi-unit structures & mobile homes)
- Language barriers
- Educational attainment
- Household income and SNAP participation
- Households with young children
- Elderly individuals living alone

Regarding Evacuation Challenges, this category includes factors that may influence evacuation intent or present barriers to evacuation. Measures include:

- Average household size
- Households with children under 18
- Households with at least one person with a disability
- Vehicle availability
- Proximity to FEMA ESF #6 shelters with backup generation
- Median household income

All measures are calculated in a way that allows for consistent comparison across communities and are used to generate individual scores for each of the three categories. The category scores are then combined into a single *Community Resilience* score, with higher values indicating greater overall vulnerability to long-duration power disruptions.

Utility Resilience Component

The Utility Resilience component reflects the reliability of electric service over time within each community. It is calculated using five years of outage data, aggregated to the community level.

The reliability metric used is the SAIDI which represents the total average outage duration experienced by customers within a community. With an emphasis on vulnerabilities to long-duration interruptions, this methodology includes all events without excluding major storms or other extreme events.

To calculate SAIDI at the community level:

- Customer outage data is spatially joined to Census block group geographies based on service locations.
- For each community, customer minutes of interruption and number of customers served are aggregated.
- SAIDI is computed as: $SAIDI = \frac{Customer\ Minutes\ of\ Interruption}{Number\ of\ Customers\ Served}$

Each community's SAIDI value is then converted to a percentile rank, which becomes the Utility Resilience score. Higher percentile values indicate relatively worse reliability and greater likelihood of long-duration outages.

Applications and Future Considerations

The Community-Utility Resilience Score is intended to support the company's ongoing efforts to improve grid resilience and reduce community vulnerability in areas of greatest need. By identifying communities with both high vulnerability and high exposure to long-duration outages, the score enables targeted, data-informed decision-making in several strategic areas:

- **Outreach and Engagement** – Prioritizing outreach for Company initiatives, including the Community-Based Renewable Energy Resilience Hub (CBRE-RH) Pilot.
- **Infrastructure Planning** – Supporting distribution system planning (DSP) by identifying areas where grid hardening or non-traditional solutions, such as distributed energy resources, may be most impactful.
- **Grant and Funding Strategy** – Strengthening applications for federal, state, and other external funding by demonstrating data-supported community needs.

The score can be aggregated to broader geographies, such as census tracts, counties or utility service areas, and can also be paired with other datasets to support planning, analysis, and reporting. The methodology will continue to evolve and improve as new data sources, stakeholder feedback, and operational experience is gained.

Focusing on one specific application, Community-Utility Resilience Scores have been leveraged to prioritize initial outreach efforts undertaken within the CBRE-RH Pilot. Three distinct pathways of CBRE project support, described in greater detail in Chapter VI: Community-Based Renewable Energy, are designed to advance projects in various stages of development. Ten communities with the highest Community-Utility Resilience Scores were targeted to receive the first round of prioritized outreach. The CBRE-RH Pilot implementation team worked with PacifiCorp regional business managers (RBMs) and emergency managers (EMs) to identify both planned and existing CBRE projects in and around these communities, as well as any projects currently in development. In addition, community leaders, known community-based organizations, first responders and county emergency managers were contacted to raise awareness about the support pathways in the CBRE-RH Pilot and to consult on any additional CBRE project opportunities. Additional information can be found in Chapter VI.

Programs and Grid Investments

Outside of the requirements and recommendations under HB 2021 and clean energy planning umbrella, PacifiCorp recognizes the importance of resilience for its customers and continues to invest in programs and grid updates that make a more resilient system. Below are a few highlights that capture these efforts.

PacifiCorp offers a battery rebate program for customers who may be vulnerable to the impacts of outages. This program is for customers who are enrolled in the Medical Certification Program or are in a licensed residential care home, facility, adult foster care home, or hospice. Local providers of support services to seniors and people with disabilities are also eligible for a rebate and can assist customers with rebate applications. The list of qualified products can be found on the company's website as well as more information about support for customers with Access and Functional Needs.[40]

Extreme weather events like winter storms or wildfires continue to rise in both frequency and intensity and improving early detection of events and the speed of reaction provide resiliency benefits. For example, in 2024, PacifiCorp installed five artificial intelligence (AI) enabled wildfire detection camera systems as part of a pilot project in its Southern Oregon service territory. The camera systems are outfitted with around the clock artificial intelligence software, near infrared, and nighttime detection capabilities and offer both pan-tilt-zoom and 360° continuously rotating capture. PacifiCorp sought input from state agencies such as the Oregon Department of Forestry in determining the final locations for camera station placement. Once installed, the company worked closely with the camera station supplier, Pano AI, to provide access to fire agencies, dispatch centers, and other public safety partners who could benefit from access to the technology. PacifiCorp has also worked extensively to increase the number of internally owned weather stations across the service territory. Over 200 weather stations have been installed across the service territory since 2022 for real-time situational awareness which increases the ability to monitor weather conditions across the service territory. All of the weather station data is available for the public to access in real-time.

PacifiCorp's most recently approved 2024 Wildfire Mitigation Plan (WMP) encompasses various strategies, programs and investments designed to reduce the risk of wildfire, which also provides several co-benefits to the utility and its customers.[41] Specifically, grid hardening and situational awareness improve resiliency of the grid. System hardening investments increase the level of localized weather conditions that can be tolerated without impact on utility operations. For example, installed covered conductors will increase the grid's resilience against wind-driven contacts. The mechanical properties of a covered conductor design physically prevent the initiation of a flash-over due to contact, mitigating wildfire risk. For this same reason, covered conductor also reduces the potential for outages, thereby providing significant reliability benefits.[42] Additionally, PacifiCorp's situational awareness capabilities play a key role in facilitation of PSPS protocols and decision-making and support the company's response to many types of emergency related events, such as winter storms.[43] PacifiCorps's recently submitted its 2025 WMP Update for review and approval by the Commission and details key updates on program implementations, grants that have been awarded for specific actions, and other investments that have significant benefits for resilience.[44]

[40] Available online at: https://www.pacificpower.net/outages-safety/access-and-functional-needs.html.
[41] *In re Pacific Power's 2024 Wildfire Mitigation Plan* (available online at: https://www.pacificorp.com/content/dam/pcorp/documents/en/pacificorp/wildfire-mitigation/PacifiCorp_2024_WMP_12-29-23.pdf).
[42] *Id*. at 179.
[43] *Id*. at 180.
[44] *In re Pacific Power's 2025 Oregon Wildfire Mitigation Plan Update* (available online at: https://www.pacificorp.com/content/dam/pcorp/documents/en/pacificorp/wildfire-mitigation/OR_WMP_UM_2207_Rev1.pdf).

VI. COMMUNITY-BASED RENEWABLE ENERGY

CBRE projects are energy systems that interconnect to utility distribution or transmission assets, and may be combined with microgrids, storage systems, demand response measures, or energy-related infrastructure that promotes climate resiliency.

Utility CEPs must examine both the costs and opportunities that CBRE projects can potentially provide when determining what mix of resources are most appropriate to offset energy generated from fossil fuels.[45] Additionally, CBRE projects must: (1) directly benefit particular communities through community-benefit agreements or direct ownership by local government, nonprofit entities, or federally recognized Indian tribes; or (2) increase resiliency or community stability, local jobs, economic development, or direct energy cost savings to families and small businesses.[46]

It is important to contrast CBRE projects from SSR projects. While similar in many respects, a Venn diagram of CBRE and SSR projects has the potential to overlap, but there are important differences. Net-metered projects may not count as SSRs, for example, and SSRs need to be certified by the Oregon Department of Energy (ODOE) as an eligible Oregon RPS generator, while CBREs do not need to adhere to either requirement. This results in little crossover between these resource types for PacifiCorp. In fact, out of 39 CBRE projects in PacifiCorp's service area that have been awarded funding within ODOE's Community Renewable Energy Project (C-REP) Grant Program, none contributes to the company's SSR requirement in ORS 469A.210. PacifiCorp has been careful to avoid conflating these two types of renewable energy projects, and this chapter focuses on CBRE resources.

As an initial matter, and consistent with the ODOE's 2022 Study on Small-Scale and Community-Based Renewable Energy (ODOE Study),[47] PacifiCorp remains cautiously optimistic of the potential benefits and costs of CBRE resources. While small-scale renewable and CBRE projects "can have unique benefits that are customized to meet local and community expectations and goals," the ODOE Study cautioned that the "individualized nature of these types of projects also make it difficult to provide an overarching assessment on the energy, environmental, economic, and social benefits and challenges of small-scale and community-based projects writ large."[48] This is because these types of projects "involve trade-offs, and for small-scale and community-based projects those trade-offs will vary significantly but will also be more flexible to address community or local concerns and needs."[49] As a result, the ODOE work group was not able to reach consensus on specific recommendations for the study.[50]

Instead, the ODOE Study acknowledged "the potential for increasing rate pressure on utility customers when discussing the costs of incentivizing small-scale and community-based renewable energy project development and agreed that future policy decisions should be based

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[45] ORS 469A.415(4)(d).
[46] ORS 469A.400(2).
[47] Available online at: https://www.oregon.gov/energy/Data-and-Reports/Documents/2022-Small-Scale-Community-Renewable-Projects-Study.pdf.
[48] ODOE Study, at 43.
[49] *Id.*
[50] *Id.* at 32.

on a principle of equitable distribution of costs and benefits."[51] This is because there were "differing perspectives on the appropriateness of using regulated utility rates to pay for benefits that do not necessarily contribute to delivery of safe and reliable service at just and reasonable rates for all electricity customers."[52] Accordingly, the ODOE Study concluded that "policymakers will need to consider the difference between economic and other societal and local benefits versus utility system benefits" when evaluating the overall value of small-scale renewable and CBRE projects in meeting the goals of HB 2021.[53]

Until those considerations are addressed, PacifiCorp has developed an ongoing strategy for CBREs that centers Oregon communities, advances projects in various stages of development, and is largely informed by stakeholder input, as exemplified by the CBRE-RH Pilot. This chapter includes the following sections:

> **Updated CBRE Inventory and Potential Study:** Provides an overview of existing and known potential CBRE projects, within established and new pathways, and summarizes communities within PacifiCorp's Oregon service area that have, or are developing, energy or sustainability plans. Outlines the approach and methodology used to develop the study, key assumptions, updated results, and takeaways.
>
> **CBRE-RH Pilot:** Summarizes the work towards a pilot program to support CBRE project development, including stakeholder engagement.
>
> **Updated CBRE Action Plan.** Addresses the ongoing assessment of community needs and project opportunities, as well as supporting activities and efforts to support implementation.

Updated CBRE Inventory

HB 2021's definition of CBREs created an umbrella term encompassing several types of renewable energy projects—and many of these resources predate the legislation. Like the company's previous CBRE Inventory,[54] PacifiCorp's current inventory provides an update on several established pathways and discusses potential CBRE resources that have been identified in collaboration with the ETO, as well as outreach undertaken within the CBRE-RH Pilot, Distribution System Planning group, and PacifiCorp regional business managers. The result of this exercise includes potential future projects with current programming, and projects proposed to the company as possible future opportunities within newly established channels.

The bulk of CBRE projects continues to be identified within the company's Oregon Community Solar Program, Blue Sky Usage, and Blue Sky Block programs. Externally, projects awarded ODOE C-REP grants and projects identified in collaboration with ETO may also qualify as CBRE

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[51] *Id.* at 43.
[52] *Id.*
[53] *Id.*
[53] *In re House Bill 2021 Investigation,* Docket No. UM 2225, Order 22-390 (Oct. 25, 2022).
[54] *In re PacifiCorp's 2023 CEP,* Docket LC 82, 2023 CEP, at 36 (May 31, 2023).

projects. The company's CBRE-RH Pilot provides support to communities both actively developing, and just beginning to consider, resilience hubs which would likely also count as CBRE projects.

Additionally, the company's community survey identified 17 communities that have (or are engaged in) some level of community-specific energy planning that could heighten interest in CBRE opportunities. Of the 17 communities that expressed interest, 12 have formally adopted plans, and the remaining 5 are developing plans or organizations to support energy planning. Of the 12 communities with adopted plans:

- Ten communities established targets or goals for energy supply (utility-scale) level changes including GHG emission reductions, fossil fuel reductions, and/or renewable targets;
- Eleven communities have established targets or goals for customer-scale renewables energy supply, or local resilience; and
- Four communities established targets or goals for electric vehicles and transportation adoption or infrastructure.

While this community survey provides insight into additional opportunities for engagement and development with communities that may be more inclined to move forward with CBRE projects in the future, to the best of the company's understanding, all 17 of these efforts remain unchanged since the 2023 Inventory.

Table 18 summarizes the channels of planned and future CBRE projects, amounting to a forecasted 95.59 megawatts of CBRE capacity by the end of 2029. Taken together, this inventory provides a snapshot of the relative momentum gained by CBRE projects in the time since the previous inventory was undertaken.

Table 18 – Summary of Current and Potential Future CBRE Projects

CBRE Pathway (Established or New)	Current Operational Capacity	Potential Future Capacity
Oregon Community Solar Program (Established)	15 projects, an increase in 13 since the prior CEP (19.6 megawatts (MW) capacity)	**45 MW** of additional capacity allowed in PAC territory. Included in "Group 1" Existing Program Potential
Oregon Blue Sky Usage and Block Programs (Established)	136 operational projects, an increase in 8 since the prior CEP (10.9 MW total capacity)	**0.87 MW** Total (Assumed capacity addition of 290 kW in 3 future grant cycles). Included in "Group 1" Existing Program Potential
Community-Based Renewable Energy – Resilience Hub Pilot (New)	N/A	Possible **1.4 MW** of capacity from Pilot. Included in "Group 2" of CBRE Potential Study

CBRE Pathway (Established or New)	Current Operational Capacity	Potential Future Capacity
Energy Trust of Oregon (Established)	ETO delivers all energy efficiency programs for PacifiCorp in Oregon and provides technical and financial assistance to development of renewable projects (thousands of megawatt hours of energy savings and generation capacity over two decades)	Continued management of energy efficiency programs and provision of financial incentives to customers installing solar systems and/or battery storage
Energy Trust of Oregon (Established)	Since the previous CEP, 3 new operational projects with a total 0.10 MW of CBRE capacity	Small, community-focused hydro: **17 MW** Total Small, community-focused solar: 65 identified opportunities – **8.14 MW** Total Included in "Group 1" Existing Program Potential
ODOE C-REP Grants (New)	No projects awarded funding are yet in operation	39 projects have been awarded funding in three application rounds (21 planning grants and 18 construction grants); projects total **~14.5 MW** **~6 MW** (Round 4 is anticipated to open in Q3 of 2025; additional funding cycles are currently uncertain) Included in "Group 2" CBRE Potential Study
PacifiCorp Opportunities from Input Received from Communities (New)	No projects receiving assistance are yet in operation	6 projects projected, with roughly **2 MW** total capacity Included in "Group 2" CBRE Potential Study

A discussion of the different pathways for CBRE resources follows. Note that the CBRE-RH Pilot is discussed in more detail in a later section.

Oregon Community Solar Program

In 2016, the Oregon Legislature established the Oregon Community Solar Program (CSP),[55] and the Commission adopted rules in 2017, resulting in administration of the CSP by Energy Solutions and the ETO, and funded by Oregon customers of Portland General Electric, PacifiCorp and Idaho Power Company, and CSP participants.[56]

The goal of the Oregon CSP is to expand access to solar energy for customers as an alternative to traditional solar rooftop systems, including but not limited to renters, people who live in

[55] 2016 OR Laws Ch. 28, § 22.
[56] *In re CSP Rulemaking,* Docket AR 603; *In re CSP Implementation,* Docket UM 1930.

multifamily buildings, low-income customers, and small businesses in rented or leased space. Participants purchase energy from a community solar project—such as a large solar system on a business, school or church—and receive credits on monthly utility bills for the electricity from their portion of the project.

The initial capacity for CSPs was limited to 2.5 percent of each utility's 2016 system peak load (64.6 MW for PacifiCorp).[57] Of that total capacity, 25 percent is reserved for projects that meet certain eligibility criteria, such as a greater focus on low-income participation, or association with a non-profit entity, public entity or renewable energy cooperative.

Currently, PacifiCorp's CSP queue is full, and includes a waitlist. Roughly 6 MW of carveout project capacity remains available in the special queue of 16.2 MW.[58] While the Commission is currently considering expanding the carveout project capacity of the CSP, as of the time of this writing, it is not clear how much capacity would be assigned to PacifiCorp's service area. This expansion is not included in PacifiCorp's updated inventory; however, the company continues to assume that the entire 64.6 MW of currently-approved CSP capacity will be operational by 2030.

Blue Sky Usage and Blue Sky Block Renewable Energy Programs

Blue Sky is a customer-powered, opt-in program offered by PacifiCorp that helps residents, small businesses, and municipalities support renewable energy and environmental stewardship in their communities. Blue Sky has ranked in National Renewable Energy Lab's (NREL) top 10 voluntary programs for more than 20 years based on participation and sales.[59] Blue Sky allows customers to purchase and support renewable energy, above and beyond what the company generates or acquires for its basic generation mix and offers customers the opportunity to support the delivery of newly developed renewable energy to the regional power pool now and help build a larger market for renewable energy. Blue Sky participants pay the incremental cost of acquiring the additional renewable energy, plus the costs associated with offering the program. Since 2000, Blue Sky participants have supported more than 12 million megawatt-hours of renewable energy. Based on typical residential customers that use approximately 826 kilowatt-hours per month, this is enough energy to power more than 1,210,653 homes for a year.

With the passage of Senate Bill (SB) 1149 in 1999, the Oregon State Legislature required investor-owned utilities in Oregon to provide all residential and small non-residential electric customers with a portfolio of voluntary options to support renewable energy. The restructuring law was designed to give consumers more options while at the same time encouraging the development of a competitive energy market. As a result of SB 1149, PacifiCorp offered two new green pricing options to Oregon residential and small non-residential customers – Blue Sky Usage and Blue Sky Habitat. These options are in addition to basic service, and allow participants to support a blend of renewable energy equivalent to their actual monthly usage. Both options allow participants to support a blend of wind and solar from the western region for an additional $0.0105 per kilowatt-hour. The Blue Sky Habitat option also adds a $2.50 monthly donation to help restore and preserve

[57] OAR 860-088-060(2).
[58] ORCSP Monthly Project Report – April 2025. Monthly Project Reports - Oregon Community Solar Program
[59] The National Renewable Energy Laboratory is a national laboratory of the U.S. Department of Energy, Office of Energy Efficiency and Renewable Energy.

habitats for native fish, including salmon, in Oregon. These funds are directed to a non-profit program administrator (currently The Freshwater Trust). More than 90 river miles have been improved through these funds.

The Blue Sky Block option, originally launched in 2000, allows customers to support renewable energy in 100 kilowatt-hour increments (called “blocks”). Blue Sky Block participants match a portion of their electricity use for a fixed price by purchasing blocks of western region wind and solar energy. In 2004, Blue Sky QS (quantity savings) was introduced to support large commercial and industrial customers by providing quantity-based savings for bulk purchases. In 2006 a provision was added to the Block tariffs that allowed funds not spent after covering program costs and matching renewable energy purchases to Block purchases to be used to fund Qualifying Initiatives. The intent of this process was to use the positive liability balances as a catalyst for reducing barriers to the construction of small and medium sized community-based renewable energy projects and increase the benefits extended to Blue Sky Block customers and the communities in which they live, while educating customers on renewable energy technologies. Since 2006 PacifiCorp has used these funds to provide grants for roughly 150 community-based renewable energy projects at schools, libraries, municipal buildings, and community groups in local communities. By reducing operating costs through renewable energy savings, more money can be used in other ways to support these vital organizations.

Blue Sky participants help drive demand for new renewable energy in the West while creating local jobs and supporting community-based renewable energy projects and native fish habitat restoration. Enrollment has grown steadily over time. Nearly 80,000 customers in PacifiCorp’s Oregon service area participate in one of the Blue Sky options—12 percent of PacifiCorp’s customer base.

ODOE Community Renewable Energy Project Grant Program

In 2021, the Oregon Legislature created a $50 million fund to provide C-REP grants and directed ODOE to establish guidelines for the program.[60] Subsequent legislation increased the fund to $70 million. ODOE established guidelines and rules for the C-REP grant program in 2022 that included:

- Program processes, including periodic opportunity announcements, information required in applications, completeness and competitive reviews, and performance agreements between the department and successful applicants;
- Eligibility requirements and criteria that the department must use to prioritize applications;
- Allocation and distribution of grant funds; and
- Compliance and recovery of grant funds.[61]

[60] 2021 OR Laws Ch. 508, §§ 29-32.
[61] 2022 OR Admin. Reg. Ch. 330, DOE 1-2022 (Feb. 28, 2022) (more information available here: https://www.oregon.gov/energy/Incentives/Pages/CREP.aspx).

The C-REP grant program is open to Oregon Tribal Nations, public bodies, and consumer-owned utilities. Public bodies include counties, municipalities, and special government bodies such as ports and irrigation districts. Grants are awarded on a competitive basis and priority is given to projects that support program equity goals, demonstrate community energy resilience, and include energy efficiency and/or demand response.

At least half of the grant funds will be awarded for projects that serve environmental justice communities, including communities of color, lower-income communities, rural communities, and others. Similarly, at least half of the grant funds will be awarded to projects that support community energy resilience. Of the $70 million allocated to the grant program, a minimum of $1 million is reserved for planning projects that qualify as community energy resilience projects, and an additional $1 million that do not.

In the first application for CREP grants in 2022, ODOE announced that 21 applicants would receive $12 million in total grants.[62] Of the 17 applications submitted by public entities in PacifiCorp's service regions, four were selected to receive funding. In the 2023 cycle, 39 of the 52 applicants received funding, for a $12 million total award. Twenty of those potential projects are located in PacifiCorp's service area. In the 2024 cycle, out of 75 project applications, 34 recipients were awarded nearly $18 million in project funding. Sixteen of these projects are located in the company's service area, although one is a "repeat" from the first application window.

In total, 39 projects have been awarded funding within territory that PacifiCorp serves, including 21 Planning grants and 18 construction grant awards. The generation proposed by these projects totals nearly 14.5 MW. Details about specific projects can be found on the Community Renewable Energy Grant Program website.[63]

Projects Identified by ETO

Part of the work of the ETO involves partnering with communities interested in identifying, planning and developing small-scale renewable and resilience-related projects. During this CBRE inventory, PacifiCorp engaged in a series of conversations to learn more about this work.

Relevant here, the ETO supports the advancement of irrigation modernization hydropower projects across the state and sees the possibility of more than 35 MW potential projects. However, ETO sees the likelihood of a much smaller number to have "near term" potential, and has recommended that the company continue to project approximately 17 MW of capacity through the remainder of the decade. Additionally, ETO identified approximately 65 public or community-related solar projects that are receiving feasibility assessments and/or are under ETO's consideration throughout the company's Oregon service area. While this adds 8.14 MW of project capacity to the Potential Study, it should be noted that seven of these projects do not yet have presumed capacity associated with them, so this capacity may increase slightly in the future.

[62] More information available here: https://energyinfo.oregon.gov/blog/2022/10/18/oregon-department-of-energy-grant-program-supports-renewable-energy-projects-from-ashland-to-ontario.

[63] https://www.oregon.gov/energy/Incentives/Pages/CREP.aspx

Additional Opportunities Identified by the Company

Three recent CBRE opportunities have been identified through coordination with PacifiCorp's regional business managers who serve as the company's primary points of contact with communities. The potential opportunities have been captured and reflected in Group 2 of the Initial CBRE Potential Study. The company believes it is likely that an additional three projects will be identified in the subsequent years of this Study window.

Updated CBRE Potential Study

This section provides the results of the company's updated CBRE Potential Study and outlines anticipated CBRE benefits and costs.

Potential project capacity outlined below is based on the company's CBRE Inventory, inclusive of Oregon CSP projects, Blue Sky Program grant awards, the PacifiCorp's CBRE-RH Pilot, ODOE C-REP grants, ETO-identified projects, opportunities identified by the company and through community survey. While it is possible that SSRs may benefit local communities (and therefore also be labeled as a CBRE project), the company is unclear about the amount of capacity these projects would represent and is therefore not including SSR project development as a pathway in the CBRE Inventory or as capacity in the Potential Study.

This study has been presented to Oregon stakeholders, including the CBIAG, the CBIAG for Oregon Tribal Nations, in the Oregon CEP engagement series. A 90-minute CBRE Special Session was held on March 11, 2025, to discuss details and approach, including the inventorying process that has led to this study of potential. It reflects the company's expected potential CBRE resources from known CBRE categories and includes high-level assumptions for inclusion in the company's IRP modeling. This Potential Study does not identify a "supply curve" of potential CBRE resources but instead focuses on characterization of potential capacity from CBREs. Because of the complexities associated with CBRE project development, as well as the firm belief that projects benefiting specific communities should be led by those communities, the company's approach continues to be the provision of support to communities in consideration of, or actively developing, CBRE projects.

The company's Initial CBRE Potential Study, analyzing existing and forecasted opportunities, identified approximately 95 MW of incremental CBRE capacity from 2023 through 2029. That included 92 MW from existing programs and roughly 3.5 MW from potential small-scale and community-focused renewable projects from 2025 through 2029.

This updated Potential Study illustrates the adjusted potential project capacity, including revised projections since the Initial Potential Study. This is largely a result of the inclusion of 35 additional CBRE projects that have received funding from ODOE's C-REP grant program since the time of the original calculations, as well as additional community-centered solar projects supported by the ETO in the past two years. It should also be noted that assumptions about future potential projects funded by the Blue Sky Grant Program have decreased, due to both a change in Renewable Energy Credit markets, as well as the expansion of the grant award to incorporate battery storage. Additionally, some projects identified in the previous inventory by the ETO have transitioned from presumptive to operational, decreasing the overall capacity in that channel. The same is true for 13 projects within the Community Solar Program.

Taken together, these changes have almost perfectly canceled themselves out: the estimated capacity of CBRE project capacity continues to be ~95 MW through the year 2029, although nearly 20 MW of project capacity has become operational since the previous inventory. Therefore, nearly 20 MW of *incremental* project capacity has been identified in the past two years to take its place. Ultimately, this Updated Potential Study underscores the increasing interest and momentum for CBRE projects in PacifiCorp's Oregon service area.

As before, presumed CBRE capacity falls into two distinct groups. The first group includes well-established programs, and projects identified by the ETO. The second group includes newer CBRE opportunities that will be identified in collaboration with individual communities, based on CBRE and resilience goals and priorities, both within and outside of the company's CBRE-RH Pilot. Projects in both groups will continue to be proactively sought after and supported by the company, but are grouped as such because they will require different forms and levels of backing.

Group 1: The estimated 71.69 MW of potential capacity from current CBRE programs includes:

- 45 MW of remaining capacity within OCSP through the year 2029. As of this writing, 19.6 MW of the allotted 64.6 MW of program capacity are operational. The company assumes that all available capacity will be operational by the end of the decade.
- 0.87 MW from Blue Sky Grant projects through 2029. This forecast assumes that all future program grants will support community projects that align with CBREs, and that annual capacity in the near future is in line with recent award cycles and reflective of recent program adjustments.
- 25.14 MW from two ETO-Identified Opportunities:
    - 17 MWs from ETO-identified potential small, community-focused hydro opportunities through 2029. This forecast assumes that each project consists entirely of small qualifying facilities in PacifiCorp's service area (in-conduit hydroelectric generation resources) and would be subject to standard Public Utility Policies Act (PURPA) qualifying facility (QF) contracting processes.
    - 8.14 MW from ETO-identified potential community-focused, non-residential solar opportunities that have entered or completed an initial feasibility assessment.

Group 2: The estimated 23.9 MW of project capacity coming from new pathways includes:

- 1.4 MW of potential capacity from projects supported from within the CBRE-RH Pilot. This amount assumes that seven 200 kW projects move forward with the help of feasibility studies provided by the utility. While the Pilot contains a pathway to support "in-flight", funded projects (i.e., C-REP), those projects are not included here to avoid double-counting.
- Roughly 20.5 MW of ODOE C-REP capacity will be added by 2030. Approximately 14.5 MW have received a grant award, and approximately 6 MW of additional projects are

anticipated to be awarded funding in the upcoming Round 4 of ODOE's C-REP grant program. This number assumes a similar award rate as the most recent grant cycles, for a comparable size and number of projects, in PacifiCorp's service area.

- An additional 2 MW of capacity from other projects identified by communities and/or brought forth by Company Regional Business Managers. Three projects have been identified in the past two years; it is conservatively projected that another three will be brought forward in the remainder of the decade.

These CBRE Potential Study results are a placeholder and in no way represent CBRE acquisition targets or goals. The company continues to uplift and "center" the priorities of individual communities in its approach to CBRE support and will leverage the CBRE-RH Pilot to work alongside the leaders advancing resilience-focused projects at facilities critical to their communities. Goals specific to Pilot outreach and support can be found in that section in this chapter.

It is also important to note that, when considering projects in the CBRE Potential Study, the company continues to prioritize enhancing community resilience over acquiring additional capacity. As has already been mentioned, when estimating the sizing of potential CBRE projects, decisions were made using the company's actual experience working with, and following the lead of, its Oregon communities. The experience to date indicates that community-centered projects intended to enhance specific aspects of local resilience (e.g.: solar plus storage at a critical facility, community center resilience hub, etc.) are typically very modest in capacity. This experience is also supported by the size and type of projects receiving support through ODOE's C-REP grant program in the company's Oregon service area.

A discussion of anticipated costs, benefits, and conclusions follows.

<u>Anticipated Costs</u>

CBREs can provide energy at a lower cost once installed by producing energy for a facility, thereby decreasing the amount of either grid-purchased energy or the direct purchase of fuel. It remains the case, however, that significant costs will be required to plan, purchase, install, configure, and maintain CBRE projects.

The types of CBRE costs that should be considered include, but are not limited to:

- Planning and Design Costs: electrical design and specifications, budget development, cost/benefit analysis, and implementation planning. It is anticipated that these costs would be lower for a simple solar installation on a single building and higher for more complex configurations (e.g., solar plus storage, multiple buildings, and microgrids).
- Contracting, Financing and Approvals: e.g., the time and effort required to establish the required contracts, financing, and receive any required regulatory approvals.
- Equipment Costs: solar panels, inverters, conductors, batteries, and controllers.
- Implementation, Installation and Configuration Costs: costs to install, configure and verify proper operation of the resource.
- On-going Operations and Maintenance Costs: resources have a certain level of on-going costs for operation and maintenance. Simple CBRE projects may have lower costs for

operations and maintenance, while more complex installations, for example solar plus storage, multiple building and micro-grid configurations, will likely have significantly higher annual O&M costs.
- Integration Costs: related to impacts that the local generation has on the utility grid.

The ODOE Study confirms that CBRE costs could be significantly more than other resources. For example, smaller renewable projects do not benefit from economies of scale of larger utility-scale projects, where certain fixed costs generally decrease as projects gets larger and can be "spread over more kilowatts, providing a volume discount."[64] Because of these realities, CBRE projects are often "only economically feasible at rates higher than the cost of the largely carbon-free electricity that can be purchased from [the Bonneville Power Administration]."[65] To the point, the ODOE Study determined that costs for small solar commercial installations are 30 to 105 percent higher than utility scale solar installations.[66]

The most recent NREL study (NREL Study) comes to the similar conclusion, and indicates that 3 MW "community solar" installation benchmarks approach twice the cost per watt direct current of a comparable 100 MW utility scale solar installation ($0.97/$W_{dc}$ for 100 MW utility-scale compared to $1.76/$W_{dc}$ for a "community solar" installation).[67] It should be noted that CBRE projects currently moving forward in Oregon are significantly smaller than NREL's 3 MW benchmark, presumably resulting in a larger contrast with utility-scale installations. Additionally, benchmarking of PV-plus-storage projects by NREL indicate an even larger disparity.

The Lawrence Berkeley National Laboratory's *Tracking the Sun* series reports that "the majority of non-residential systems installed in 2023 were well below 100 kW".[68] Their study is in line with the proposed projects awarded funding through the ODOE's C-REP grant program. The Berkeley Lab tracking tool averages the installation price of a 50-100 kW non-residential solar system to be $2.70/$Watt_{dc}$,[69] while "installed costs of [utility scale] PV have fallen by 8% since 2022, to $1.08/$W_{dc}$ in 2023."[70]

The company's analyses of anticipated costs, confirmed by the ODOE Study, NREL Study and Berkeley Lab Study, underscore the reality of CBRE costs—small-scale renewable resources and CBREs have the likelihood to be substantially more costly compared to utility-scale renewable resources. Additionally, current cost estimates are not based on recent market input. Actual costs may be significantly different, especially with continued supply chain disruptions, uncertain markets due to changing federal tariff policies and the continued high demand for electrical products and infrastructure.

Anticipated Benefits

[64] ODOE Study, at 23.
[65] *Id.* at 30.
[66] *Id.* at 24, Figure 6.
[67] "U.S. Solar Photovoltaic System and Energy Storage Cost Benchmarks, With Minimum Sustainable Price Analysis: Q1 2023," Ramasamy, V., et al (NREL Technical Report; Sept. 2023) (available here: U.S. Solar Photovoltaic System and Energy Storage Cost Benchmarks, With Minimum Sustainable Price Analysis: Q1 2023).
[68] Lawrence Berkeley National Laboratory. 2024. "Tracking the Sun Data Viewer." https://trackingthesun.lbl.gov.
[69] *Id.*
[70] Lawrence Berkeley National Laboratory. 2024. "Utility-Scale Solar". http://utilityscalesolar.lbl.gov.

As articulated in the company's inaugural Clean Energy Plan, there are several potential benefits related to renewable resources that may also result from CBRE projects. These include:

- Emissions reductions from renewable/non-emitting resources compared to the average emissions profile for system generated energy;
- Local installation of renewable resources have the potential to help to defer upgrades on local distribution and transmission infrastructure (depending on the type of renewable resource, grid conditions and grid needs);
- Reduced fuel costs from renewable/non-emitting resources compared to resources that have variable generation costs (e.g., natural gas, coal);
- Potential economic benefits for the renewable resource owner(s) from monthly energy bill offsets; and
- Potential workforce or employment opportunities in the areas where renewable projects are implemented.

There are additional benefits that can result if CBRE projects were to be paired with energy storage resources (e.g., battery storage). These benefits include the potential to:

- Provide backup power during system outages (value depends on end-use and community). For example, storage plus renewable resources can provide continued operation of critical facilities (water or wastewater facilities, health care facilities, emergency response facilities, etc.), or electrical stability for evacuation centers, community resilience hubs, or emergency operations centers;
- Shift load from peak to off-peak periods;
- Provide additional energy and capacity during peak load periods;
- Reduce demand during peak load periods; and
- Create potential value from price arbitrage, where energy stored during periods when electricity costs are lower can be discharged when electricity costs are higher.

The ODOE Study also considered the potential benefits associated with small-scale and CBRE projects. For example, the ODOE Study outlined the following:

> Some benefits of renewable energy projects are obvious: improving clean air and clean water, reducing greenhouse gas emissions, decreasing dependence on foreign energy sources, enhancing local economic development, increasing tax revenue for communities, and providing high-paying jobs in the state.
>
> The key question for this study is: "Which benefits are specifically unique to small-scale and community-based renewable energy projects?" *The key unique benefit for small-scale or community-based projects is local resilience*. Other benefits include an easier and potentially faster siting process, the opportunity to develop a skilled workforce with knowledge about developing and operating renewable energy projects, as well as a potential for local revenue.[71]

[71] ODOE Study, at 18–19, Figure 6 (emphasis added).

The ODOE Study highlighted several additional community resilience and economic benefits. For community resilience, workgroup members identified important services that investments in community energy resilience could support. These include providing power to: for cooling/warming centers; critical infrastructure; vehicle chargers; cell towers and phone chargers; refrigerators for food and medications; and water pumps.

For economic benefits, workgroup members identified benefits that may be associated with small-scale and community-based renewable energy projects, though most are common to all projects, regardless of size. These include: further reductions in solar energy costs, as increased demand for renewable energy systems brings down overall costs; deferred investment in grid infrastructure; reduced fossil fuel consumption; reduced customer energy costs; local economic development through local job creation, increased high-skilled labor, worker training, diversification of local economies, and increased local tax revenues; fully maximizing existing infrastructure by efficiently using existing excess capacity through smaller projects that can be integrated more readily than larger projects, and using existing skilled labor in areas sited near larger projects; and Potential gross revenues from power sales.[72]

PacifiCorp's agrees with the ODOE Study Workgroup's assessment regarding unique benefits of small-scale, CBRE projects, specifically that the majority of benefits from renewables are common to all projects, regardless of size, and that "*the key unique benefit for small-scale or community-based projects is local resilience*." [73]

<u>Conclusions</u>

Throughout HB 2021, Commission docket UM 2225, the ODOE Study and the NREL Study, there is broad recognition of the potential for localized benefits from certain CBRE projects. For example: "The benefits of renewable energy projects (notably, the value of replacing fossil fuels with emissions-free energy) for society are great, regardless of the size and ownership structure of the project."[74] Similarly, CBREs can provide uniquely local benefits: "While large-scale renewable energy projects produce clean power at economies of scale that greatly reduce greenhouse gas emissions and mitigate the effects of climate change for all, small-scale projects may have additional benefits of improving local energy resilience, local control over energy choices, and local job and infrastructure investments, among others. These unique benefits of small-scale and community-based projects accrue to the project owners."[75]

However, these unique local benefits are likely at least twice as expensive as utility scale renewable alternatives. This led the ODOE Study to conclude that: "Workgroup members held differing perspectives on the appropriateness of using regulated utility rates to pay for benefits that do not necessarily contribute to delivery of safe and reliable service at just and reasonable rates for all electricity customers."[76] In the end, the ODOE Study workgroup was unable to reach consensus on any specific recommendations, and instead offered guiding principles for future

[72] *Id.*
[73] *Id.* at 19.
[74] ODOE Study, at 13.
[75] *Id.* at ii.
[76] *Id.* at 32.

discussion.

The company restates those principles here, as PacifiCorp believes they are instructive and could help inform the Commission's future CBRE policies. The ODOE Study concluded that small-scale renewables and CBRE policies should:

- Assist Oregon in meeting state goals as defined in HB 2021;
- Promote equitable outcomes, including the state's environmental justice goals;
- Maintain affordable energy and rates;
- Promote an equitable distribution of costs and benefits, recognizing the difference between economic and other societal and local benefits versus utility system benefits;
- Support project transparency;
- Consider diverse stakeholder perspectives;
- Support economic development in Oregon; and
- Support unique contributions of small-scale projects, including local energy resilience; nimbleness due to smaller project size; community or local ownership; utilization and synergy of local available resources, including hydro and bioenergy; waste stream management when waste is used for bioenergy projects.[77]

General consensus among parties seems to be that while there are important community benefits from these projects, CBRE resources will be significantly more expensive than utility-scale resources. There is no consensus, however, on how to pay for these above-market costs. The company expects to continue discussions throughout its engagement channels to solicit input from communities, stakeholders and staff, and to explore productive opportunities to help resolve these issues and balance the perspectives various stakeholder groups and regulators.

The company intends, with its project support and collaboration efforts within the CBRE-RH Pilot, to add to the collective understanding of both the costs and benefits of CBRE projects in Oregon. This additional level of understanding of actual CBRE projects may inform important decisions that will need to be made regarding how such projects should advance in the future. PacifiCorp maintains that its current approach to CBREs addresses each of the principles in the ODOE Study's bulleted list above, and that it strikes a balance between prudent spending, new opportunities to better understand the nuances of CBREs and the meaningful advancement of community-based renewable energy.

CBRE-RH Pilot

CBRE-RH Pilot Rationale and Structure

The three components of the CBRE-RH Pilot address an opportunity identified in PacifiCorp's first CBRE Potential Study, where over 95 megawatts (MW) of possible future CBRE project capacity was identified through 2029, with roughly 92 MW of that capacity presumed to actualize within programs and channels already in existence.[78] The company's CBRE-RH Pilot represents

[77] *Id.* at 33.
[78] PacifiCorp 2023 CEP, at 37-39.

a much-needed pathway to support the development and implementation of local, community-led resilience opportunities and fills a critical niche in PacifiCorp CBRE programming. PacifiCorp had not, until this Pilot, had a distinct channel of support for this subset of CBRE projects, which is specific to resiliency enhancement at facilities critical to communities in emergency situations, as well as sites that address community need during both emergency and normal operations (e.g.: resilience hubs). Inclusion of "Resilience Hub" in the Pilot title underscores the specific focus on support for this particular type of community-led CBRE project. This CBRE-RH Pilot allows the company to leverage its experience and expertise to support projects, including many already "in flight" and with secured funding, to achieve the additional goal of increased grid value developed alongside enhanced community resilience. The company estimates that the support offered within the three components of the proposed CBRE-RH Pilot could result in the aid of advancement of as much as 3 MW of generation capacity of CBRE projects.

The CBRE-RH Pilot is the natural extension of PacifiCorp's previous Community Resiliency Pilot, and focuses specifically on community resilience hubs with three components:

1. Technical Feasibility Assessments: the continued provision of technical feasibility studies to communities interested in better understanding the costs, requirements and benefits of solar and battery energy storage systems at critical community facilities;
2. CBRE-RH Project Support/Custom Projects: the leveraging of both internal and external expertise and provision of supplemental funding to support the final design and installation of systems in planned and existing CBRE projects that will provide grid benefits as well as learning outcomes; and,
3. Grant Match Funding: a mechanism to provide matching funds for communities seeking external grant awards (which require supplemental grant matching) for solar + storage CBRE projects at critical facilities.

Stakeholder Participation and Feedback

Stakeholder engagement was an integral part of the development of the CBRE-RH Pilot. Table 19 includes only the formal engagement events hosted by PacifiCorp during which the CBRE-RH Pilot was presented to stakeholders. This table does not include presentations that have occurred since the filing for approval of the Pilot.

Table 19 – CBRE-RH Pilot Stakeholder Engagement Events

Date	Event
February 24, 2023	CEP Engagement Group meeting
March 16, 2023	CBIAG meeting
March 17, 2023	Clean Energy Planning Engagement Series for Oregon Tribal Nations meeting
April 20, 2023	CBIAG meeting
April 28, 2023	CEP Engagement Group meeting

June 15, 2023	CBIAG meeting
June 23, 2023	CEP Engagement Group meeting
June 20, 2023	CBIAG meeting
July 21, 2023	Clean Energy Planning Engagement Series for Oregon Tribal Nations meeting
August 17, 2023	CBIAG meeting
August 25, 2023	CEP Engagement Group meeting
September 22, 2023	Clean Energy Planning Engagement Series for Oregon Tribal Nations meeting
October 27, 2023	CEP Engagement Group meeting
February 23, 2024	Clean Energy Planning Engagement Series for Oregon Tribal Nations meeting
March 21, 2024	Commission Staff meeting
March 21, 2024	CBIAG meeting
April 18, 2024	CBIAG meeting

Stakeholder input provided to the company and the actions taken as a result of that input are summarized in Table 20.

Table 20 - Stakeholder Input and Resulting Action

Input Provided	Action Taken
Prioritize support of small resilience hubs at neighborhood-level community centers was suggested.	The CBRE-RH Pilot has targeted support for resiliency projects at critical community facilities.
Connect the "planners" of the community.	Outreach has been undertaken at the local and county levels.
Partner with local groups and the ETO.	PacifiCorp has worked closely with the ETO with the CBRE-RH Pilot. Regional business managers and the Pilot Manager lead ongoing outreach efforts.
"Pitch" projects in local communities.	The company will use resilience metrics to prioritize the early outreach to vulnerable communities, and will include the suggestion to consider the enhancement of resilience at Disaster Recovery Centers identified in a tracker made available by the Federal Emergency Management Agency. In addition, the Pilot will leverage local engagement during Distribution System Planning activities to outline CBRE-RH opportunities.

Input Provided	Action Taken
Explore opportunities to leverage public funding to advance CBRE projects.	The CBRE-RH Pilot will leverage public funding by providing matching grants to communities seeking state and federal funding. The Pilot will also focus its continued partnership on projects that have already been funded by other grant opportunities within Component 2.
PacifiCorp should engage with Tribes on applications for BIL formula grants.	PacifiCorp recently created a Tribal Liaison position. That role will include, upon approval of the Pilot, outreach to Oregon Tribes about the grant match opportunity.
Utilize media outlets to raise awareness and stimulate interest	The PacifiCorp communications team will use a variety of platforms to share the opportunities offered within the CBRE-RH Pilot.
Partner with schools and universities.	PacifiCorp is already in communication with several academic institutions about their development of CBRE projects.
Leverage energy fairs, cultural events and festivals.	PacifiCorp regional business managers will be equipped with information about the CBRE-RH Pilot as they engage with communities at public events across Oregon.
Generate online engagement platforms and gamification.	A webpage has been developed for the CBRE-RH Pilot.
Motivate engagement through a "sense of value."	PacifiCorp continues to engage communities and stakeholders, expanding upon the potential benefits that result from the CBRE-RH Pilot.
"Strengthen" the Pilot by increasing the amount of funding used to support projects.	The requested funding amount for the CBRE-RH Pilot increased from $2.75M to $4M over the course of its development.
A variety of potential metrics that might be used to track the way that CBRE projects help to advance the Community Benefit Indicator specific to resilience.	PacifiCorp will continue to work with the CBIAG, leveraging the suggestions provided, to determine the most effective and efficient methods of tracking progress.
A variety of methods of community engagement as it relates to sharing the opportunities for CBRE project advancement found in the CBRE-RH Pilot.	PacifiCorp will continue to assess the most effective and efficient methods of outreach. The intent will be not just to "advertise" the opportunities found within the CBRE-RH Pilot, but to share with communities the other pathways and forms of support that are available.

Initial CBRE-RH Pilot Progress

Consistent with the recommendation made by OPUC Staff, the CBRE-RH Pilot proposal was filed in mid-2024 and ultimately approved in late September 2024. The company took three months to formalize a Pilot Work Plan and officially "kicked off" the Pilot in January of 2025.

In the first months of 2025, the company has prioritized outreach to communities with the lowest composite scores in its internally-developed resilience metrics. These resilience metrics combine community vulnerability data, compiled from several sources, with utility reliability data, resulting in a composite score representative of a community's potential resilience. These metrics were discussed in detail in Chapter V: Resiliency.

After four months of Pilot activity and outreach efforts, the company has held 28 meetings, two projects have formally moved forward with a request for feasibility studies, and several other communities have expressed interest in the opportunity. PacifiCorp has interacted with the majority of projects that have received ODOE's C-REP grant awards, including 17 of the 19 recipients of construction grants. Additionally, the assurance of two years of grant match funding has been provided to an Oregon Tribal Nation as part of its efforts to secure available federal Infrastructure Investment and Jobs Act (IIJA) Formula Grant funding.

Anticipated outcomes

One of the core outcomes of this CBRE-RH Pilot is to establish a "fleet" of community-focused projects designed in such a way that battery storage components are installed to allow for participation in existing and future PacificCorp demand response programs. The three components in this proposal have been developed for eventual and successful grid dispatch, allowing for the study of test cases and scenarios meant to advance further demand response development.

The Pilot is designed to uncover the benefits that accrue to both ratepayers and host critical facilities when renewable generation and battery energy storage systems installed for resiliency purposes are also utilized to address a variety of grid needs. At the conclusion of the CBRE-RH Pilot program, PacifiCorp will partner with a third-party consultant to report on Pilot outcomes and learnings. The report may include items such as:

1. Examples of use cases and scenarios of battery storage systems dispatched for grid benefit;
2. An estimated value of resilience of a generation and energy storage system to a host customer, the wider immediate community as well as utility customers, in emergency situations;
3. An estimated value of a generation and energy storage system to both host customers and utility customers during periods of normal grid operation;
4. Preliminary cost benefit calculations of a variety of CBRE-RH project types;
5. Barriers to project advancement and ultimate success, as identified by CBRE-RH Pilot managers and other stakeholders;
6. A determination of whether broader system-funded support of local resilience hub

projects would result in inequitable cost shifting; and

7. The number of additional grid-connected, utility-dispatchable, non-residential behind-the-meter battery storage projects in Oregon.

The WattSmart Battery Program

The WattSmart Battery Program overlaps and operates in parallel with the CBRE-RH Pilot. It is the company's demand response program that autonomously dispatches eligible, customer-owned battery storage systems to address frequency irregularities on the grid. It has been in operation in other PacifiCorp states since 2020 and was approved to begin operation in Oregon in February of 2025.

The company sees an opportunity to supplement the support provided to CBRE projects through its pilot with incentives available via participation in the Wattsmart Battery Program. The "on-ramping" of CBRE projects taking advantage of Wattsmart Battery Program offerings will help to supplement the intended learning outcomes articulated in this section. The Wattsmart Battery Program does not yet have many critical community facilities participating; this will be an opportunity to work toward the quantification of grid benefits (of battery dispatch by the utility) stacked on top of local benefits (of facilities with enhanced resilience for local community members and/or emergency services).

VII. RESOURCE PLANNING

PacifiCorp's 2025 CEP focuses on resource selections optimized to meet Oregon customers' needs and state policy objectives. Consistent with Commission direction, this CEP is based on a unified portfolio that allows for the incorporation of system- and state-specific requirements.[79]

This chapter focuses on the processes behind PacifiCorp's CEP resource planning. Results from these analyses, in addition to cost considerations and compliance scenarios, are discussed in the next chapter. The subsections that follow describe these resource planning processes, including:

- Modeling Updates;
- Jurisdictional Definitions;
- Modeling and Portfolio Evaluation;
- 2025 IRP/CEP Portfolio Integration;
- HB 2021 Emissions Reporting and Assumptions; and
- Portfolio Sensitivities/Counterfactuals.

Additional details regarding PacifiCorp's approach to resource planning generally, and for system purposes specifically, can be found in the 2025 IRP.

[79] Order 24-073, App. B, Recommendation 15; *see also* PacifiCorp's 2025 IRP, Appendix B, for additional discussion on implementation of Commission recommendations.

Modeling Updates

While the 2025 IRP is the starting point for the 2025 CEP, PacifiCorp made several updates and modeling enhancements post-IRP filing for the 2025 CEP:

- Escalation rates for proxy resources were corrected to align with the commercial operation date assumed in the Supply-Side Resources Table in the 2025 IRP.
- The value of production tax credits (PTCs) was levelized over the life of the asset for proxy wind and solar resources, consistent with the way a power purchase agreement is typically structured.
- The Climate Commitment Act (CCA) Cap-And-Invest Price applicable to the Chehalis natural gas plant was updated to reflect the most recent auction price of $50/metric ton of greenhouse gas emissions.
- The March 2025 medium natural gas/no federal CO_2 price-policy scenario was used.
- Emissions factors for Oregon coal-to-natural gas converted units were updated to reflect the recently-approved Oregon DEQ factors.

Jurisdictional Definitions

PacifiCorp serves more than 2 million customers across six states. In the past, all portfolio decisions have been considered at a system-wide level to arrive at the best results for all customers, where customers share in the costs and benefits from system-wide planning. However, each jurisdiction now has distinct requirements, some of which conflict. Consequently, PacifiCorp's initial portfolio modeling is now separated into three jurisdictions reflecting these distinctions. In the 2025 IRP and the 2025 CEP, these jurisdictions are distinguished as follows:

- **Utah/Idaho/Wyoming/California (UIWC):** The four states included in this jurisdictional category in the 2025 IRP incorporate resource requirements driven by the Western Resource Adequacy Program (WRAP) for each jurisdiction. These requirements enforce the selection of sufficient firm capacity (including existing resources under the currently-approved cost-allocation protocol) to meet the UIWC load requirement, plus a WRAP planning reserve margin.

- **Washington:** In addition to WRAP compliance as described for UIWC above, jurisdictional selections for Washington include clean energy targets consistent with the Washington Clean Energy Transformation Act (CETA). As required, Washington resource selections were analyzed and optimized using the social cost of greenhouse gas (SCGHG) price-policy assumption. Emitting resources incur a dispatch cost adder under SCGHG, applying pressure to decrease emissions, and this is also part of regional dispatch in the development of market prices.

- **Oregon:** Jurisdictional modeling for Oregon includes compliance with WRAP, HB 2021 emissions reductions goals, SB 1547 coal-out-of-rates and RPS requirements, and the SSR standard. Like other jurisdictions, Oregon must be WRAP compliant. Oregon customers are assumed to participate in existing coal-fired resources only through 2029 (consistent with SB 1547) and existing gas-fired resources through 2039. Emissions allocated to Oregon from existing resources are calculated based on Oregon's allocated share of each resource and the applicable Oregon DEQ emissions factors, consistent with the methodology described in more detail later in this document. The SSR standard defines a target that small-scale renewable resources of 20 MW or less must represent at least 10 percent of the nameplate capacity of Oregon's resource supply.[80]

Compliance with HB 2021 is modeled as a requirement in both the long-term (LT) and short-term (ST) models. Oregon-allocated clean generation must equal or exceed Oregon load on an annual basis.[81] This ensures that the LT model will select enough clean proxy resources to avoid significant energy shortfalls. Additionally, in the ST model, the weekly generation of each Oregon-allocated gas plant is limited to avoid exceeding the annual emissions limits.

As in the 2025 IRP, all proxy batteries are assumed to meet WRAP compliance requirements for the state in which they are located and are situs allocated to that state. To represent the need to comply with Oregon's SSR standard, a constraint requires that for every 9 megawatts of utility-scale resources selected for Oregon compliance, at least one megawatt of a small-scale resource must be added.

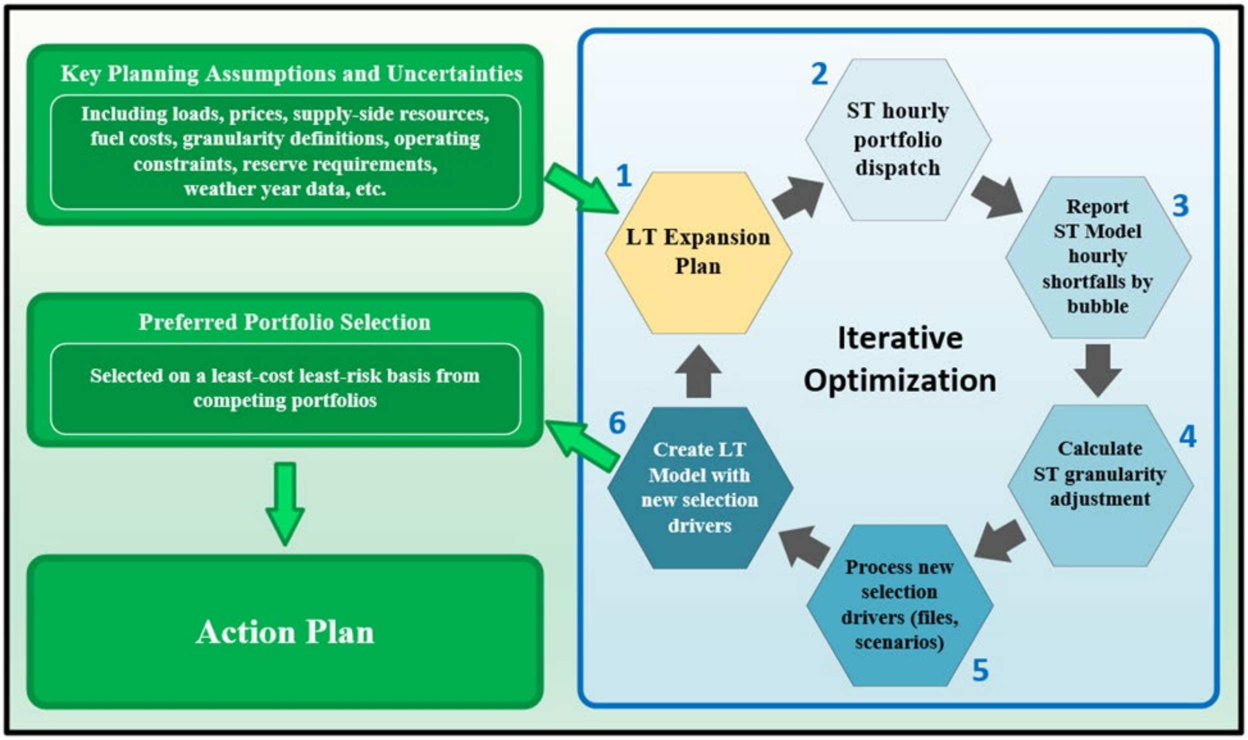
Every portfolio in the 2025 CEP includes the proxy resource selections for the other jurisdictions (UIWC and Washington) as determined in the 2025 IRP preferred portfolio, along with the newly optimized selections for Oregon. Thermal resource selections are determined by the UIWC jurisdiction and all thermal resource selections in the 2025 IRP are maintained in CEP portfolio development.

Modeling and Portfolio Evaluation

PacifiCorp's portfolio evaluation uses two models from the PLEXOS platform.[82] Resource expansion plan modeling, performed with the LT model, is used to produce resource portfolios with sufficient capacity to achieve reliability over the 21-year study horizon by evaluating groups of hours on an aggregated basis. Each resource portfolio is refined for reliability at an hourly granularity in the ST model. Each portfolio is uniquely characterized by the type, timing, location, and number of new resources in PacifiCorp's system over time. Figure 3 summarizes the modeling and evaluation steps for the 2025 IRP and CEP.

[80] ORS 469A.210(2).
[81] The ST and LT models are part of the PLEXOS platform and are described in more detail in the next section of this chapter.
[82] Additional information regarding the PLEXOS platform is available online here: https://www.energyexemplar.com/plexos.

Figure 3 – Portfolio Evaluation Steps within the IRP Process



Long-Term Capacity Expansion Model

The LT model is used to establish an initial portfolio under expected conditions (medium gas, zero CO_2), and then modified for each case based on study parameters to eliminate shortfalls and maintain reliability. The LT model operates by minimizing operating costs for existing and prospective new resources, subject to system load balance, reliability, and other constraints. Over the 21-year planning horizon, the model optimizes resource additions subject to resource costs and load constraints. These constraints include seasonal loads, operating reserves, and regulation reserves. Operating reserve requirements include contingency reserves, which are calculated as 3 percent of load and 3 percent of generation. Consistent with modeling in the 2025 IRP, the planning reserve margin is based on compliance with WRAP.

If early retirement of an existing generating resource is assumed or selected for a given planning scenario, the LT model will select additional resources as required to meet loads plus reliability requirements in each period and location. The LT model may also select additional resources that are more economic than an existing generating resource.

To accomplish these optimization objectives, the LT model performs a least-cost dispatch for existing and potential planned generation, while considering cost and performance of existing contracts and new DSM alternatives within PacifiCorp's transmission system. Resource dispatch is based on representative data blocks for each of the 12 months of every year. To enhance the ability of the LT model to differentiate key resource types and system conditions, for the 2025 CEP each month was split into four blocks of hours based on load and wind and solar generation profiles:

1. The top ten percent highest net load hours. 10 percent is approximately 70 hours per month, or an average of 2-3 per day, though some days may not have any hours in this group at all.
2. The top ten percent highest wind generation hours on a system basis.
3. The top ten percent highest solar generation hours on a system basis.
4. All other hours

The intent of this modeling is to indicate to the LT model that wind and solar have very high availability in some hours, and very low availability in others. This contributes to more reasonable selections of wind and solar, as they will saturate some periods where they would have lower value. This approach also leads to more reasonable selections of storage and peaking resources, targeted to cover periods in which wind and solar provide little generation supply.

PLEXOS LT model dispatch among blocks of hours in a month is not chronological, so it cannot constrain energy storage charging and discharging, except to ensure that over the course of a month, these remain balanced. But within that limitation, PLEXOS determines generation and storage dispatch, optimal electricity flows between zones, and optimal market transactions for system balancing. The model minimizes the system Present Value Revenue Requirement (PVRR), which includes the net present value of existing contract costs, market purchase costs, market sale revenues, generation costs (fuel, fixed and variable operation and maintenance, decommissioning, emissions, amortized capital costs for thermal resource upgrades and potential new resources), costs of DSM resources, costs for potential transmission upgrades, and costs for unserved energy and unmet capacity.

These LT results are then re-analyzed through ST modeling discussed below to provide more granular and accurate resource selections.

Short-Term Cost and Risk Analyses

To evaluate portfolio selections under the range of conditions experienced in actual operations, the portfolio selected in the LT is run through the ST phase of the model. This hourly view dispatches the entire system and provides critical data for evaluation. Relevant here, the ST model analyzes:

- *Reliability Assessment and System Cost*. The ST model begins with a portfolio from the LT model that has not yet been refined to reflect the reliability and compliance needs of a particular study (e.g., a particular sensitivity or price-policy scenario). The ST model is first run at an hourly level for 21 years to retrieve two critical pieces of data: 1) reliability shortfalls by hour, and 2) the value of every potential resource to the system that is specific to the portfolio itself, and the other input assumptions, such as the price-policy scenario. These data points are fed back into the LT model to prompt endogenous selections of resources that lead to a reliable portfolio.

- *Resource Value*. PLEXOS calculates a locational marginal price (LMP) specific to each area in each hour based on supply and demand and available imports and exports on transmission links to adjacent areas (a shadow price). PLEXOS then multiplies these prices by a resource's optimized energy and operating reserve provision for each hour and reports the total as a resource's estimated revenue. When variable costs (such as fuel, emissions, and variable operations and maintenance costs) are subtracted out, the result is a resource's "net revenue." Net revenue provides a clear model-optimized assessment of every resource's value to the system, which is then used to assess resource additions needed to preserve reliable operation of the system.

While the net revenue approach is demonstrably superior to past resource value measures, especially as it is evaluated simultaneously for all potential resources, net revenue has limitations that should be acknowledged. Net revenue represents the value of the last MW of capacity from a given resource – as resources grow larger, the average value from the first MW of capacity to the last MW of capacity will tend to be somewhat higher than the reported marginal value. Conversely, adding more of a particular resource will result in declining values. While marginal prices will be very high in hours with supply shortfalls, this only indirectly contributes to reliable operation by helping to identify beneficial replacement resources. Once sufficient resources are added, shortfalls will mostly be eliminated, and marginal prices will again reflect the variable cost of an available resource.

- *Portfolio Refinements.* While many resource options are evaluated, utility-scale generation resources are mostly restricted to two circumstances: surplus or replacement resources at generators that are eligible to retire, and new resources at locations with interconnection or transmission upgrade options. As in the 2025 IRP, small resources (those with a capacity of up to 20 megawatts) are eligible to be sited within any of the load regions and are unconstrained by new transmission requirements, as PacifiCorp's studies have shown that resources that are sufficiently small and sized consistent with the local grid can be integrated without large transmission investments. Like small resources, PacifiCorp has added a "local" battery option within each of the load areas which is available for selection at a higher cost than those co-located with other resources (per the supply-side resource table).

- *Portfolio Cost and CBIs*. Each run of the ST model produces an optimized dispatch of a portfolio to reflect least-cost operations while meeting all requirements and adhering to modeled constraints. The ST model's hourly granularity means that this system cost will take into account operational nuances that are obscured in the less granular LT model. This allows resource portfolios that are constructed in the LT model to be compared based on the system PVRR determined through the ST model. Beyond just the consideration of cost, four portfolio CBI metrics are reported for each portfolio: annual energy not served (ENS), annual greenhouse gas equivalent emissions, annual local pollutant emissions (SO_2 and NO_x) and Oregon-allocated renewable energy. The basis for inclusion of these metrics is described in more detail previously in Chapter IV – Community Benefit Indicators.

Together, these ST cost and risk analyses provide more accurate resource selections for PacifiCorp's six-state system.

2025 IRP/CEP Portfolio Integration

Portfolio integration involves combining resource selections from each of the jurisdictions. Every initial jurisdictional portfolio evaluates the entire system and all proxy resource options, plus the constraints specific to that jurisdiction. For proxy resources that can be allocated to any jurisdiction, the integration step adopts the largest quantity of each individual resource by year that was included in any of the jurisdictional studies (UIWC, OR, and WA). Because of interconnection limits, it is generally not possible to sum the selections across the various jurisdictions, and the overall quantity might not be economic. For resources that are specific to a single jurisdiction, including demand-side resources and existing thermal resources, the integration step adopts the quantity from that specific jurisdiction's initial portfolio result. Given concerns related to the availability of transmission on an hourly basis between the West and East sides of PacifiCorp's system, the selection of proxy resources on the West is determined jointly by the Oregon and Washington initial jurisdictional portfolios, and the selection of proxy resources on the East is determined by the initial jurisdictional UIWC portfolio. Accordingly, only the jurisdictional portfolios that determine the selection of a given resource are eligible to participate in that resource. For more details on the integration process, please refer to the 2025 IRP, Volume I, Chapters 8 and 9.

In this way, resource allocations are fixed based on jurisdictional selections in the year in which they are built and do not change over time. Where a proxy resource has additions in multiple years, only the quantity added in a given year is allocated, based on portfolio selections in that year in each jurisdictional run. This integration process is applied to every initial portfolio.

This initial integration step has the potential to result in compliance shortfalls, as a portion of the resources that were identified for compliance may have been allocated to other jurisdictions. Thus, the final step of the integration process is to identify and remedy any such shortfalls in energy and capacity compliance.

This means that the 2025 IRP preferred portfolio included optimized resource selections for Washington and the UIWC jurisdiction, including thermal resource decisions that were driven by the UIWC portfolio. These selections were locked in all CEP portfolios such that the thermal resource decisions and the proxy resource selections for Washington and UIWC did not change. Table 21 shows the Washington and Utah, Idah, Wyoming, and California (UIWC) proxy resource selection from the 2025 IRP preferred portfolio that were locked for the 2025 CEP. Resources which are not assumed to count towards Oregon compliance requirements (e.g. batteries in Washington or energy efficiency in Wyoming) were fully locked by using both the "minimum units built in year" and the "maximum units built in year" properties in PLEXOS. Generating proxy resources located in the West Balancing Authority Area (BAA) were only assigned the "minimum units built in year" property so that any selections made by Washinton would be preserved while also allowing Oregon to select more units of the resource. As a result, all incremental resource selections made in any portfolio developed within this CEP are situs-allocated to Oregon.

Finally, the Oregon-allocated costs reported in the CEP include the allocation of a share of system-wide costs to Oregon consistent with the currently approved 2020 PacifiCorp Interjurisdictional

Allocation Protocol (2020 Protocol).[83] Costs associated with existing resources and with incremental transmission additions are considered "system-allocated" and are allocated based on Oregon's forecasted load-share of the system. All new proxy resources are determined based on incremental needs of Oregon customers only, and are therefore situs-allocated, or allocated one hundred percent to the state.

Resources included in the 2025 IRP preferred portfolio for *non-Oregon* jurisdictions are reflected in Table 21. 2025 CEP proxy resource selections for Oregon are presented further below in the "2025 CEP Preferred Portfolio" subsection.

Table 21 – 2025 IRP Preferred Portfolio Resource Selections for Non-Oregon Jurisdictions

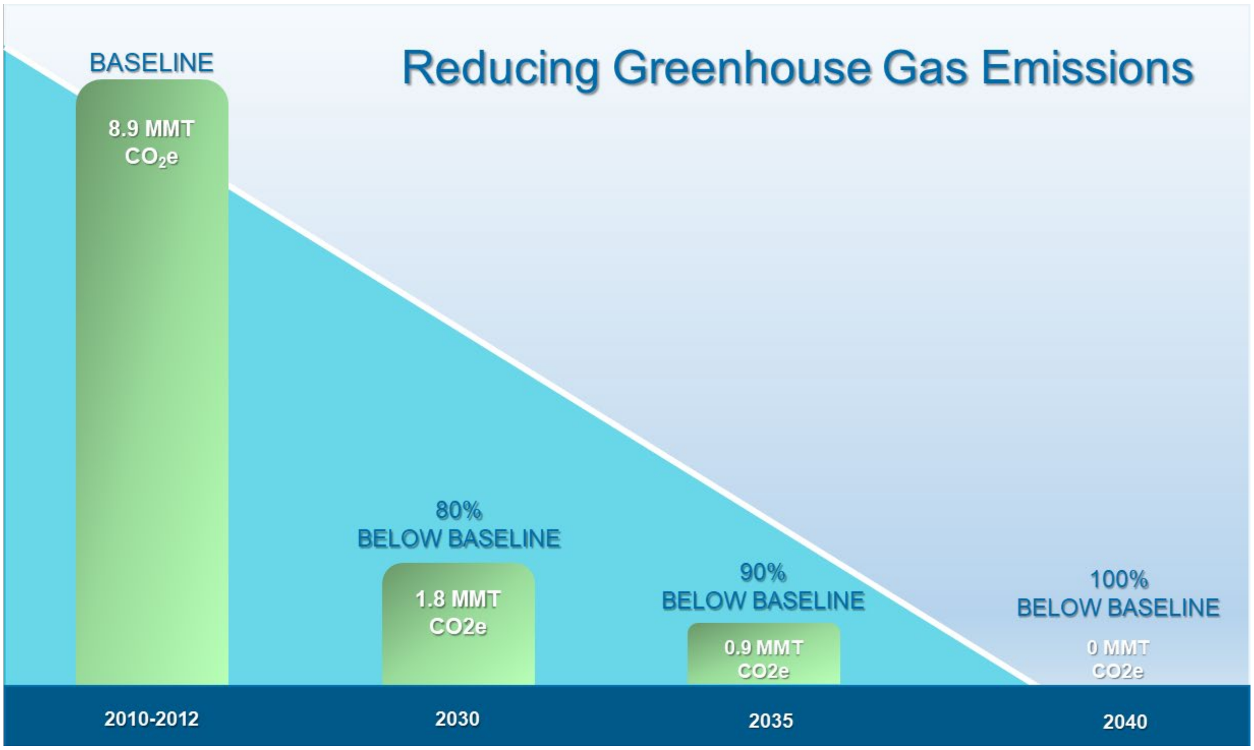
25 IRP WA + UIWC Shares by Resource Type and Year, Installed MW																						
	Installed Capacity, MW																					
Resource	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	Total
Nuclear	-	-	-	-	-	-	-	370	-	-	-	-	-	-	-	-	-	-	-	-	-	370
Renewable Peaking	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
DSM - Energy Efficiency	-	-	112	119	132	147	214	181	186	187	190	204	237	209	191	184	181	208	124	113	93	3,211
DSM - Demand Response	-	2	-	15	4	113	99	-	-	-	-	10	112	6	1	1	57	106	20	26	44	617
Renewable - Wind	-	-	-	5	348	992	344	-	-	7	87	10	44	9	-	94	12	-	5	-	24	1,982
Renewable - Utility Solar	-	-	-	56	45	423	713	60	101	56	3	-	1	-	139	26	3	-	-	49	19	1,693
Renewable - Small Scale Solar	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Renewable - Battery, < 8 hour	-	-	1	865	141	168	-	-	-	-	-	-	-	129	67	7	12	713	5	459	733	3,300
Renewable - Battery, 24+ hour	-	-	-	-	-	239	3	3	4	3	4	4	4	4	4	4	4	109	5	5	5	404

HB 2021 Emissions Reporting and Assumptions

HB 2021 directs the state's large investor-owned utilities to reduce greenhouse gas emissions associated with retail electricity sales relative to a baseline emissions level, defined as the average annual emissions of greenhouse gases associated with the electricity sold to retail electricity consumers for the years 2010, 2011, and 2012, as reported to the Oregon DEQ.[84] The DEQ's baseline emissions level determination for PacifiCorp, measured in MMT CO_2e, and corresponding emissions reductions for each clean energy target year, are reflected in Figure 4.[85]

[83] *In re PacifiCorp's 2020 Protocol,* Docket UM 1050, Order No. 20-024 (Jan. 23, 2020).
[84] ORS 469A.400(1)(a).
[85] Order Determining Baseline Emissions and Emissions Necessary to Reach Clean Energy Targets under 2021 Oregon Laws, Chapter 508 (May 25, 2022) (available online at: https://www.oregon.gov/deq/ghgp/Documents/HB2021Order.pdf).

Figure 4 – HB 2021 Emissions Targets for PacifiCorp



Oregon DEQ is responsible for measuring and verifying the greenhouse gas emissions that are included in a utility's CEP and reporting these findings to the Commission. Consistent with these responsibilities, Oregon DEQ published guidance for GHG emissions accounting for HB 2021 that incorporates the methodologies from the agency's longstanding Greenhouse Gas Reporting Program under OAR 340, Division 215.[86] In addition, Oregon DEQ has published guidance that directs the utilities to use unit and resource specific emission factors and default emission factors for the 2025 CEP,[87] as well as for multi-jurisdictional utility reporting, adjusting for netting wholesale sales or non-retail electricity, accounting for transmission losses, and accounting for electricity purchased from specified and unspecified sources.[88]

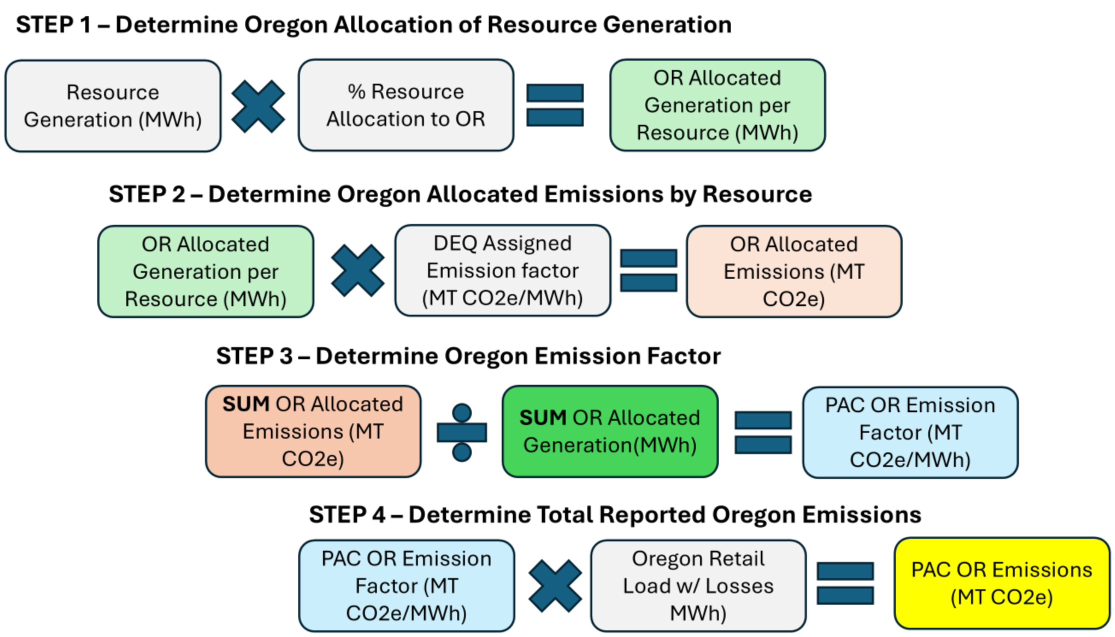
As a multi-jurisdictional utility, PacifiCorp's annual calculation of actual GHG follows a multi-step process.[89] First, the company determines the Oregon-allocated generation for each resource according to a cost allocation methodology approved by the Commission. Second, it applies the DEQ published facility or unit specific emission factor to the Oregon allocated generation for each resource to determine Oregon allocated emissions for each resource and then totals the emissions of each resource. Purchases of unspecified power to serve Oregon retail load receive an emission

[86] ODEQ GHG Emissions Accounting for House Bill 2021, Reporting and Projecting Emissions from Electricity Using DEQ Methodology, Updated December 2022.
[87] ODEQ Specified Source Emission Factor, Updated December 4, 2023. Available online at: https://www.oregon.gov/deq/aq/Documents/ghg-SpecifiedSourceEFmethods.pdf
[88] ODEQ Multijurisdictional Utilities Instructions for Reporting Greenhouse Gas Emissions, Updated December 4, 2023. Available online at: https://www.oregon.gov/deq/aq/Documents/GHGRP-MutlijurisdictionalProtocol.pdf
[89] OAR 340-215-0120.

factor of 0.428 MT CO2e/MWh, in accordance with DEQ's rule, and are included in the total of Oregon allocated emissions. Third, it divides the total Oregon-allocated emissions by the sum of Oregon-allocated generation to determine an Oregon-allocated system emission factor. Finally, the Oregon-allocated system emission factor is multiplied by the total amount of electricity delivered to retail customers.

A visualization of the annual GHG emissions calculation is included in Figure 5. This methodology forms the basis for the calculation of compliance with HB 2021's clean energy targets. However, HB 2021 provides for some specific exclusions that are not part of the company's annual GHG emissions calculation. Notably, under HB 2021, emissions associated with electricity acquired from net metering or qualifying facilities under the terms of the PURPA are excluded from the determination of Oregon-allocated emissions.[90]

Figure 5 – Visual Demonstration of DEQ GHG Emissions Calculation



Additionally, Table 22 provides detailed descriptions of the assumptions and authorities PacifiCorp relied on when determining total forecasted utility emissions for compliance with HB 2021.

Table 22 – GHG Accounting Assumptions

Category	Assumption and Authority
Baseline Emissions	In May 2022, Oregon DEQ established PacifiCorp's baseline emissions levels, and emissions reductions necessary to achieve PacifiCorp's emissions reduction requirements. However, Oregon DEQ may have established an incorrect baseline emissions level, contrary to the statutory definition. The

[90] ORS 469A.435(2).

Category	Assumption and Authority
	company relies on Oregon DEQ's determination in the 2025 IRP and this CEP, without conceding its accuracy.
General Calculation Methodology	PacifiCorp's initial calculation of projected emissions, before any exclusions or special treatment, is based on Oregon's long-standing Greenhouse Gas Reporting framework established in OAR 340-215 for annual actual emissions reporting. ORS 469A.420(1)(b), 468A.280.
Emission factor for existing specified resources	Oregon DEQ assigns emission factors to PacifiCorp's existing facilities by unit, based on historical data. The Oregon DEQ assigned emission factors are available online.
Emission Factors for future resources	In cases where a facility or unit-specific emission factor is either not available or applicable, DEQ directs utilities to use default emission factors by fuel type. When possible, these emission factors are based on U.S. Environmental Protection Agency's (EPA) 2022 Greenhouse Gas Emission Factors hub, which is available on the EPA's website. When not available, emission factors from EPA's 2020 Emissions & Generation Resources Integrated Database (eGRID) Technical Guide were used. Oregon DEQ's default emission factors are available online.
Emissions for planned coal-to-natural gas converted resources	In accordance with OAR 340-215-0040(4), a utility may petition Oregon DEQ to approve in writing an alternative calculation or method for determining an emission factor, providing an explanation and rationale for the alternative. On March 20, 2025, DEQ approved PacifiCorp's petition to use an alternative calculation method for determining the emission factor for planned coal-to-natural gas converted resource. PacifiCorp will use an emissions adjustment multiplier of 0.578, applied to the DEQ published unit-specific emissions rate for coal fired resources that are planned to convert to natural gas. PacifiCorp's alternative is more conservative than DEQ's published default emission factors for natural gas fired resources and estimates higher emissions from converted coal-to-gas units based on more accurate operational assumptions and lower efficiency of converted units relative to a combined cycle combustion turbine.
Emission factors for unspecified resources	The default emission factor is 0.428 $MTCO_2e$/megawatt-hour for energy originating from an unspecified source. This includes purchases from a centralized electricity market, such as the Western Energy Imbalance Market. OAR 340-215-120(2)(a).
Transmission Losses	Electricity suppliers must include a 2 percent transmission loss correction factor when calculating emissions from generation not measured at the busbar. OAR 340-215-120(1)(b)(B)(i).
Removal of non-retail sales	According to Oregon DEQ guidance, energy and emissions from the sale of wholesale power are not included in annual Oregon emissions totals. Rather, a utility must remove the energy and emissions associated with those non-retail sales from its calculations and reporting of emissions associated with the electricity the utility supplied to its Oregon retail customers. Utilities may account for non-retail sales with three approaches, based on the nature of each individual sale: 1) Sales of specific power: Non-retail sales of a specific resource or set of resources are accounted for by removing that power and any associated emissions from a utility's emissions reported to Oregon DEQ.

Category	Assumption and Authority
	2) Sales of unspecified power: Unspecified power purchased by a utility and then re-sold to non-retail customers is removed (both the power and emissions) from the amount of unspecified power included in a utility's emissions reported to Oregon DEQ. 3) Sales of the utilities' overall resource mix: Non-retail sales of a utility's power, without specification of any particular portion of the utility's portfolio, are removed by proportionately subtracting it across the utility's overall resource mix for that year. Oregon DEQ Guidance: GHG Emissions Accounting for House Bill 2021, Reporting and Projecting Emissions from Electricity Using DEQ Methodology.
Multi-state jurisdictional reporting	Oregon rules allow for multi-jurisdictional utilities like PacifiCorp to rely on a cost allocation methodology approved by the Oregon PUC for allocating emissions associated with the generation of electricity that serves Oregon customers. OAR 340-215-0120(6)(c). PacifiCorp's most current multi-jurisdictional cost allocation methodology approved by the Oregon commission is the 2020 Protocol. While the 2020 Protocol does not extend through the planning horizon of the 2025 CEP, the company relies on this allocation methodology for the planning horizon. Under the currently approved cost allocation methodology, the utility reports a percentage of its entire multi-state system emissions based on the share of the power served in Oregon. Under all cost allocation structures, it is assumed that no coal is allocated to Oregon starting in 2030 consistent with ORS § 457.518, and that no thermal resources or market purchases are allocated to Oregon starting in 2040. OAR 340-215-0120 and Oregon DEQ Guidance: Multijurisdictional Utilities, Instructions for Reporting Greenhouse Gas Emissions.
Exclusions	Emissions from qualified facilities under the terms of PURPA and net metering programs are not regulated under HB 2021, and emissions from these sources are excluded from Oregon DEQ's determination of relevant emissions. The energy associated with these resources remains as part of the calculation. ORS 469A.435(3).

Portfolio Sensitivities/Counterfactuals

The following sensitivities and counterfactuals were analyzed in this CEP to provide additional information regarding timing of resource procurement, costs, and other compliance paths. The sensitivities and counterfactuals focus on Oregon-allocated resource selections and impacts only. Unless otherwise indicated, all portfolios endogenously model compliance with the SSR standard, HB 2021 greenhouse gas emissions reductions goals, and resource adequacy requirements. These sensitivities and counterfactuals include:

1. *Hourly Clean.* This portfolio models compliance with HB 2021 under current rules, but assuming that Oregon-allocated generation must be sufficient to meet load on an hourly basis starting in 2035. This hourly requirement is modeled in PLEXOS as a constraint that balances Oregon-allocated generation net of energy need to charge batteries against Oregon retail load. Emitting generation is allowed until 2040 but is constrained on a weekly basis to avoid exceeding the annual emissions limits.

2. *HB 2021 Counterfactual.* This portfolio identifies the set of resource selections that would serve Oregon absent compliance with HB 2021 greenhouse gas emissions reductions standards.

3. *HB 2021 and Small-Scale Renewables Counterfactual.* This portfolio identifies resource selections that would serve Oregon absent compliance with HB 2021 greenhouse emissions reductions standards and the small-scale renewable standard.

4. *Community-based Renewable Energy Valuation Study.* This portfolio includes 20 MW of CBRE hydro and 80 MW of CBRE solar resources to examine the costs and benefits of adding CBRE resources to the system. It is assumed that CBRE resources offset proxy small-scale renewable resources as part of meeting the small-scale renewable standard. The roughly 95 MW of CBRE potential resources outlined in the CBRE Potential Study were aggregated into four 20 MW resource "blocks" of small solar projects and one 20 MW "block" of small hydro. The company analyzed the effect of adding this 100 MW of CBRE solar projects across Oregon locations in 2030. The CBRE solar projects were assumed to operate at the same capacity factor and receive the same average locational marginal price identified in the 2025 CEP preferred portfolio for small-scale solar in Central Oregon, Southern Oregon, Willamette Valley, and Walla Walla. The cost per kW of CBRE projects awarded grant funding by ODOE was used to develop the capital costs and the retail rate for the Oregon Community Solar Program was used as a marginal cost. The 20 MW "block" of small hydro was assigned the same marginal cost as the solar resource.

5. *Maximum Customer Benefits.* This portfolio includes double the technical potential of demand-side resources (DSM), 100 MW of CBRE resources, and no additional transmission intended to serve Oregon load.

6. *Oregon In-State Only.* This portfolio includes double the technical potential of demand-side resources (DSM) and only allows incremental proxy resource selections that are physically located in Oregon.

7. *Accelerated Resource Selection.* This portfolio was created by taking some of the wind and solar resource selections made in 2030 in the CEP portfolio and moving them into 2028 and 2029.

VIII. RESOURCES, COSTS, AND EMISSIONS REDUCTIONS

This chapter summarizes the near and long-term resources that are necessary to meet Oregon's state-specific planning requirements and emissions reductions, while continuing to serve customers reliably and with minimum-required cost impacts.

The 2025 CEP preferred portfolio selects 11,838 MW of new proxy resources to serve Oregon customers' energy and capacity needs, to meet the small-scale renewable standard, and to reach annual decarbonization goals on a least-cost basis. These resource selections include: 2,491 MW of wind; 2,152 MW of utility-scale solar; 1,032 MW of small-scale solar; and 3,835 MW of storage resources.[91] The portfolio also includes 2,045 MW of energy efficiency and 153 MW of demand response. These HB 2021-driven resources would be supported by multiple new transmission lines and related transmission upgrades.

These 2025 CEP preferred portfolio generation and transmission resources achieve Oregon's annual greenhouse gas reductions under current DEQ emissions reporting methodologies, resulting in annual emissions reductions of 84 percent by 2030, 90 percent by 2035 and 100 percent by 2040.

Importantly, these results assume that compliance with HB 2021 is possible with annual as opposed to hourly compliance. Given the Oregon DEQ's emissions accounting framework described in the prior subsection, PacifiCorp's multi-jurisdictional nature allows the company to meet emissions reduction goals on an annual basis, through an annual cost-allocation of generation resources and system balancing market purchases, while in reality, there may be several hours in which Oregon energy needs are actually being served by other resources, not necessarily cost-allocated to Oregon. One of the benefits of PacifiCorp's diverse system is the ability to balance across a wide range of loads and resources that peak at different times. However, this benefit becomes a potential cost if emissions accounting methodologies adapt to treat hourly system shortfalls met with system resources that are not allocated to Oregon as market purchases which, consequently, would get assigned an unspecified emissions rate. If the emissions accounting methodology evolves in this way, PacifiCorp will need to show that Oregon is "clean" on an hourly basis.

In 2035, when emission reduction requirements increase to 90 percent, it becomes increasingly difficult to meet HB 2021 targets using a system balancing approach on an annual basis if an emissions rate is assigned during hours where system resources not allocated to Oregon are needed to serve Oregon load. As a result, PacifiCorp analyzed hourly HB 2021 compliance scenarios. Under this scenario, an hourly clean portfolio selects 23,904 MW of new proxy resources to serve Oregon customers—over 12 GW more than in the annual compliance base case.

Results from both scenarios, annual and hourly, assume that federal tax policies for clean energy investment and production tax credits remain in place, and that HB 2021-driven transmission upgrades are allocated across PacifiCorp's system consistent with existing multi-state allocation

[91] The 2025 IRP preferred portfolio selections for all non-Oregon jurisdictions are considered locked for the CEP analysis presented below. However, portfolio results are re-optimized for Oregon's jurisdictional obligations under the various modeling assumptions and sensitivities. Unless otherwise noted, all portfolio resource selections and costs are described on an Oregon-allocated basis.

protocols. Given current federal legislation that could impact these tax policies, and that future cost allocation methodologies are uncertain, PacifiCorp examined how compliance with HB 2021 would be impacted without tax incentives and assuming full allocation of HB 2021-caused transmission costs are situs to Oregon.

Each scenario would materially impact PacifiCorp's forecasted costs to comply with HB 2021. These results are detailed below and summarized in Table 23. While specific cost cap implications would depend on the timing, pacing, and volume of resource procurement to analyze PacifiCorp revenue requirement impacts, as well as the Commission's additional guidance in UM 2273, the company provides this analyses as benchmarks of HB 2021 cost cap implications for Commission and stakeholder review.

Table 23 - Estimated HB 2021 Average Annual Compliance Costs 2025-2045 ($millions) and Percentage of 2025 Revenue Requirement (shown in parenthesis)

	Annual Cost with System Transmission	Annual Cost with Situs Transmission	Annual Cost with System Transmission (No PTC/ITCs)	Annual Cost with Situs Transmission (No PTCs/ITCs)
CEP Preferred Portfolio (Annual Clean)	$135 (10%)	$161 (11%)	$214 (12%)	$241 (14%)
Hourly Clean Portfolio	$1,609 (91%)	$1,800 (101%)	$2,287 (129%)	$2,479 (140%)

Resource Selections

This section discusses the non-emitting, storage, SSR, transmission, and demand-side actions that PacifiCorp forecasts are required to comply with HB 2021. This section also summarizes several portfolios and sensitivities. The results from each of these portfolios and counterfactuals are included in Table 24 below, including measurements from several of PacifiCorp's CBI's, including Oregon-allocated PVRR, ENS, CO2e, SO2, NOx, and renewable energy.

There a few conclusions to highlight. The PVRR from the hourly clean portfolio is almost three times more expensive on a PVRR basis compared to the CEP preferred portfolio, resulting in almost twice the amount of renewable resources. While the PVRR from the CEP portfolio is only about $1 billion more than the no HB 2021 counterfactual, there are significant costs from the No HB 2021 counterfactual—replacement resources that are required to offset generation once Oregon exits coal resources by 2030—that may be more appropriately included in the CEP portfolio and subject to HB 2021's cost cap. The no HB 2021-SSR counterfactual PVRR is almost $500 million less than the no HB 2021 counterfactual, while the CBRE valuation PVRR is $1.2 billion more. Meanwhile, accelerated resource procurement increases the PVRR by $118 million compared to the CEP preferred portfolio. Finally, differences in ENS among all portfolios are arguably insignificant. The sections below provide additional details on these results.

Table 24 - 2025 CEP Portfolio Results (Oregon Allocated)

Study	PVRR ($ millions)	ENS[92] 2025-2045 (%)	CO2e Emissions 2025-2045 (thousands metric tons)	SO2 Emissions 2025-2045 (thousands metric	NOx Emissions 2025-2045 (thousands metric	Renewable Energy 2025-2045 (GWh)
CEP Preferred Portfolio	5,440	0.000195%	39,270	5,989	26	255,545
Hourly Clean Portfolio	15,482	0.000195%	38,246	5,990	26	582,803
No HB 2021 Counterfactual	4,482	0.000170%	63,105	5,991	26	187,240
No HB 2021-SSR Counterfactual	4,016	0.000170%	67,572	5,991	26	171,506
CBRE Valuation Study	5,660	0.000195%	39,124	5,989	26	256,922
Max Customer Benefit	8,141	0.000195%	46,252	5,987	26	182,463
In-State Resources	7,749	0.000195%	35,021	5,985	26	353,045
Accelerated Resources	5,518	0.000195%	38,114	5,985	26	258,593

The sections below provide additional details on these results.

2025 CEP Preferred Portfolio

The 2025 CEP preferred portfolio selects 11,838 MW of new proxy resources to serve Oregon customers' energy and capacity needs, to meet the SSR standard, and to reach annual decarbonization goals on a least-cost basis. These resource selections include: 2,491 MW of wind; 2,152 MW of utility-scale solar; 1,032 MW of small-scale solar; and 3,835 MW of storage resources.[93] The portfolio also includes 2,045 MW of energy efficiency and 153 MW of demand response. These resources, by resource type and year of selection, are summarized in Table 25.

[92] Represents an allocated share of system ENS divided by Oregon load

[93] The 2025 IRP preferred portfolio selections for all non-Oregon jurisdictions are considered locked for the CEP analysis presented below. However, portfolio results are re-optimized for Oregon's jurisdictional obligations under the various modeling assumptions and sensitivities. Unless otherwise noted, all portfolio resource selections and costs are described on an Oregon-allocated basis.

Table 25 - 2025 CEP Preferred Portfolio OR Resource Selections

25 CEP Preferred Portfolio OR Shares by Resource Type and Year, Installed MW	Installed Capacity, MW																					
Resource	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	Total
Nuclear	-	-	-	-	-	-	-	130	-	-	-	-	-	-	-	-	-	-	-	-	-	130
Renewable Peaking	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
DSM - Energy Efficiency	-	-	97	101	107	114	115	110	114	108	109	111	110	105	102	117	122	107	114	92	89	2,045
DSM - Demand Response	-	-	-	48	15	7	-	5	1	3	3	11	-	12	4	23	4	-	9	-	8	153
Renewable - Wind	-	-	-	11	140	1,650	165	128	172	74	-	1	1	-	-	-	-	-	-	-	150	2,491
Renewable - Utility Solar	-	-	-	2	-	414	-	-	-	91	231	243	266	265	257	245	-	-	33	104	-	2,152
Renewable - Small Scale Solar	-	-	-	-	-	275	-	14	19	18	26	27	29	62	-	23	257	154	84	18	26	1,032
Renewable - Battery, < 8 hour	-	-	-	185	1	428	-	-	35	-	25	75	137	145	114	400	180	266	241	-	-	2,231
Renewable - Battery, 24+ hour	-	-	-	-	-	286	-	-	-	8	-	2	-	-	-	823	-	5	128	176	175	1,603

The 2025 CEP preferred portfolio differs from the 2025 IRP preferred portfolio for Oregon, driven by modeling updates and enhancements. In the near-term, the CEP preferred portfolio delays procurement of solar resources and some batteries, resulting in around 800 MW less of proxy resource selections before 2030. Between 2030 and 2034, both portfolios select similar levels of new renewable resources, though the CEP preferred portfolio includes significantly more proxy wind than solar, largely as a result of the delayed solar resources before 2030. Further out, between 2035 and 3045 the CEP preferred portfolio selects more proxy resources, having delayed some of the earlier procurement, resulting in over 400 MW of new resources, made up of additional utility-scale solar and shorter-duration batteries. In total, over the 21-year planning horizon the 2025 CEP preferred portfolio: selects 370 MW less proxy resources relative to the 2025 IRP; favors a greater amount of wind rather than solar; requires around 100 MW less of small-scale resources; and favors more shorter-duration battery resources over longer (24+ hour) batteries. A detailed comparison of Oregon proxy resource selections by type and year in the 2025 IRP preferred portfolio and 2025 CEP preferred portfolio is presented in Table 26 below.[94]

Table 26 - OR Resource Selections 2025 CEP Preferred Portfolio Less 2025 IRP Preferred Portfolio

2025 CEP Preferred Portfolio less 2025 IRP Preferred Portfolio	Installed Capacity, MW																					
Resource	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	Total
Expansion Options																						
Nuclear	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Renewable Peaking	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(19)	-	(4)	-	(18)	(41)
Renewable - Wind	-	-	-	(5)	(306)	712	165	127	172	51	(260)	(29)	(130)	(28)	-	(282)	(37)	-	(15)	-	79	214
Renewable - Utility Solar	-	-	-	(165)	(135)	(853)	(136)	(180)	(302)	(78)	221	243	266	265	(158)	166	(9)	-	33	(44)	(56)	(922)
Renewable - Small Scale Solar	-	-	-	-	-	(45)	(2)	(4)	(7)	(3)	(4)	(105)	29	(247)	-	23	147	154	84	(124)	(11)	(115)
Renewable - Battery (< 8 hour)	-	-	-	(96)	(100)	300	-	(119)	(4)	(210)	5	29	137	99	114	294	125	266	241	-	-	1,081
Renewable - Battery (24+ hour)	-	-	-	-	-	15	(88)	-	-	7	-	2	(7)	(79)	(33)	(112)	(102)	(205)	(269)	(16)	(178)	(1,065)

The three figures below, Figure 6, Figure 7, and Figure 8, compare the different utility-scale solar, wind, and storage resource selections respectively, between the 2025 CEP (green dashed line) and IRP (solid shading). Each table also includes selections from the hourly clean portfolio (purple dot-dashed line), and the no HB 2021 counterfactual (blue dotted line) for additional context. Resource selections are depicted in terms of cumulative MW of nameplate capacity of resources over the 21-year time horizon.

[94] Positive values indicate years in which the 2025 *CEP* Preferred Portfolio selected more MWs of a resource while a (negative) value indicates years in which the 2025 *IRP* Preferred Portfolio selected more MWs of a resource.

Figure 7 – 2025 CEP Preferred Portfolio Utility-Scale Solar Selections

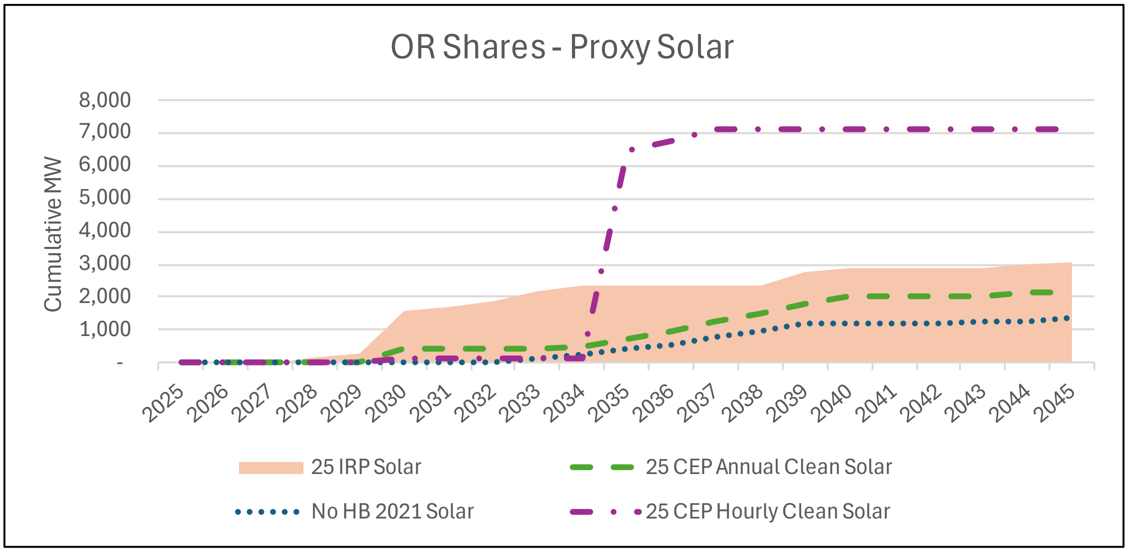


Figure 6 – 2025 CEP Preferred Portfolio Proxy Wind Selections

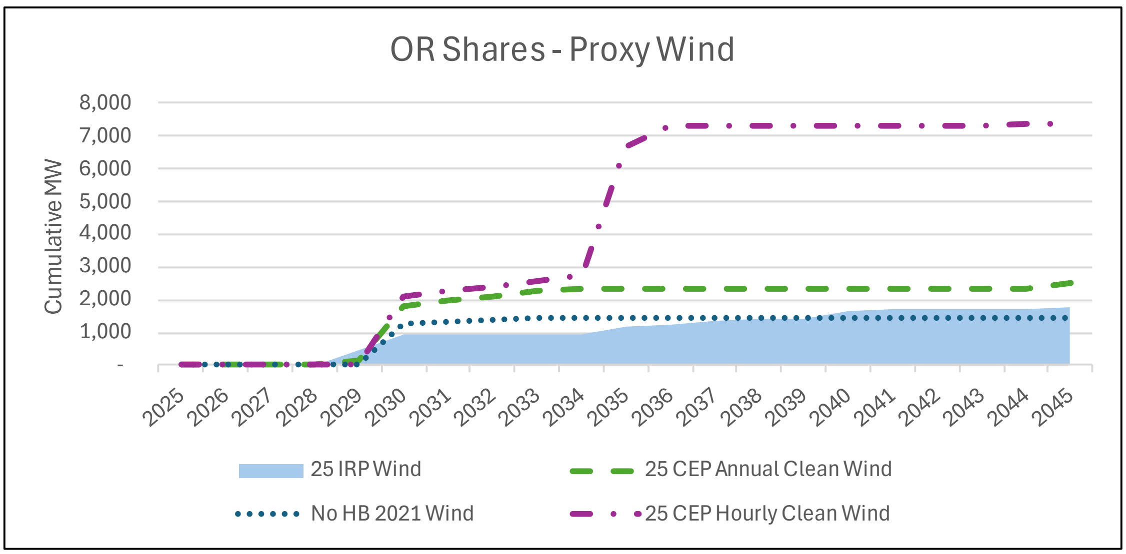


Figure 8 – 2025 CEP Preferred Portfolio Proxy Storage Selections

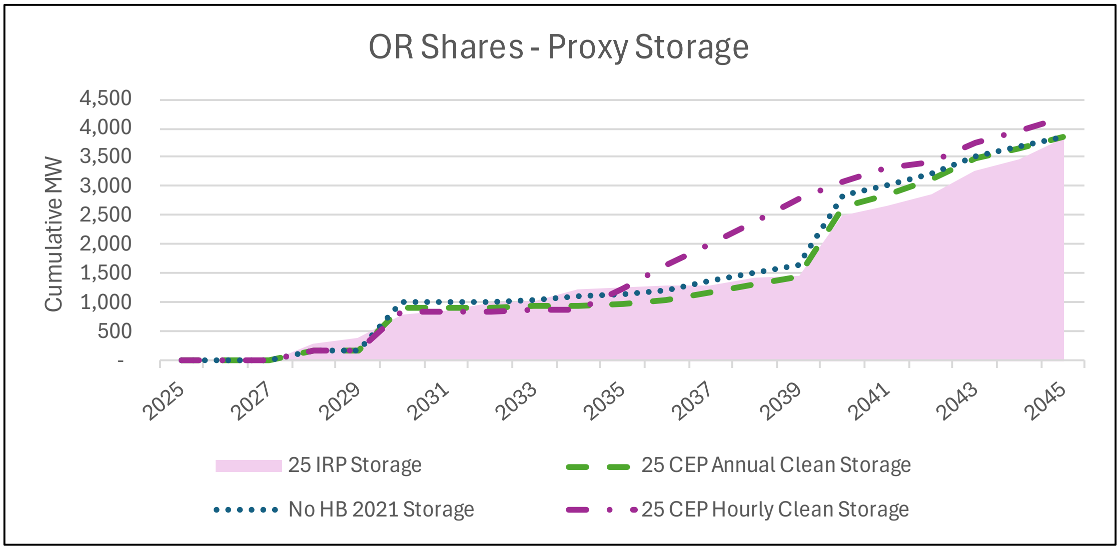
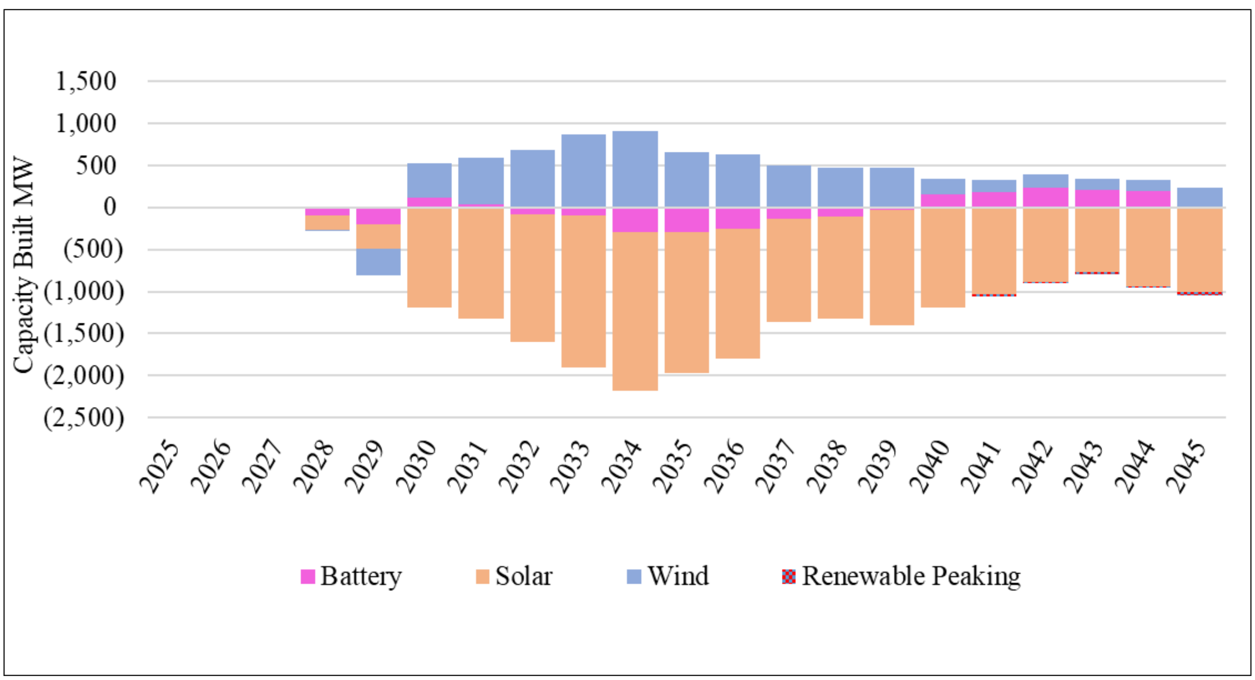


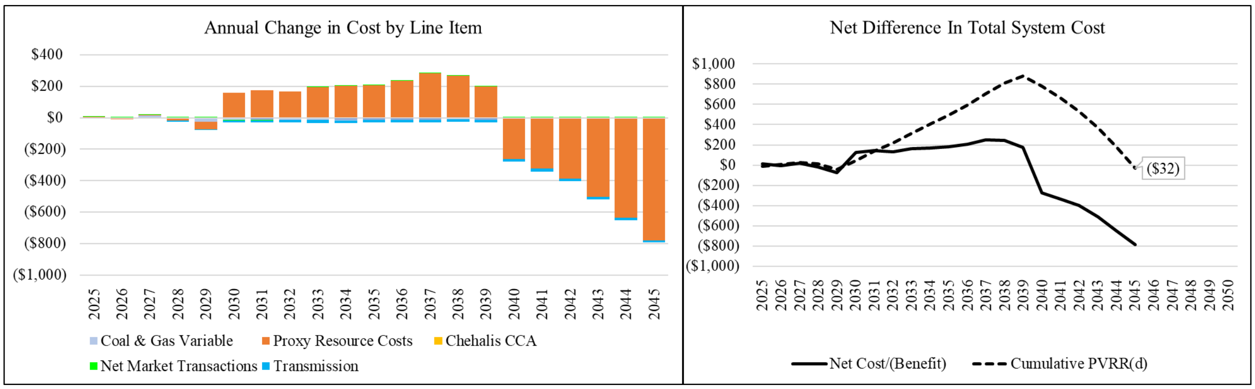
Figure 9 provides the overall comparative resource selections between the 2025 CEP and IRP preferred portfolios. Positive numbers indicate that more of a given resource was selected in the 2025 CEP preferred portfolio compared to the 2025 IRP, while negative numbers indicate that the 2025 IRP selected more resources compared to the CEP.

Figure 9 – 2025 CEP Preferred Portfolio Comparative Resource Selections (With the 2025 IRP Preferred Portfolio)



In terms of cost impacts, the net-present value of portfolio costs between the 2025 IRP and the 2025 CEP do not result in an apples-to-apples comparison, given it is not just the portfolio selections that differ, but the forward price curves and other assumptions that impact resource values and total benefits. Noting those caveats, the cost comparison of Oregon-allocated PVRR is depicted in Figure 10. Negative numbers indicate that the CEP preferred portfolio is less expensive than the IRP preferred portfolio. The 2025 CEP preferred portfolio is roughly $32 million cheaper on a PVRR basis, relative to the 2025 IRP preferred portfolio. This is the result of refinements and enhancements discussed above in the previous subsection "Modeling Updates".

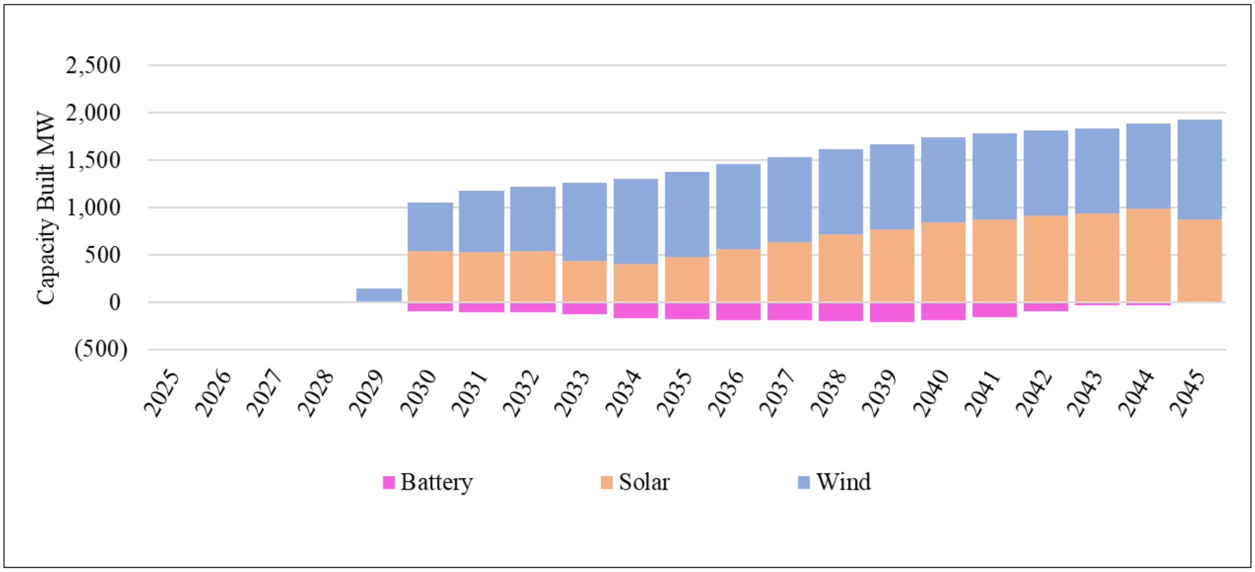
Figure 10 – CEP Preferred Portfolio and 2025 IRP Preferred Portfolio Cost Comparison



No HB 2021 Counterfactual

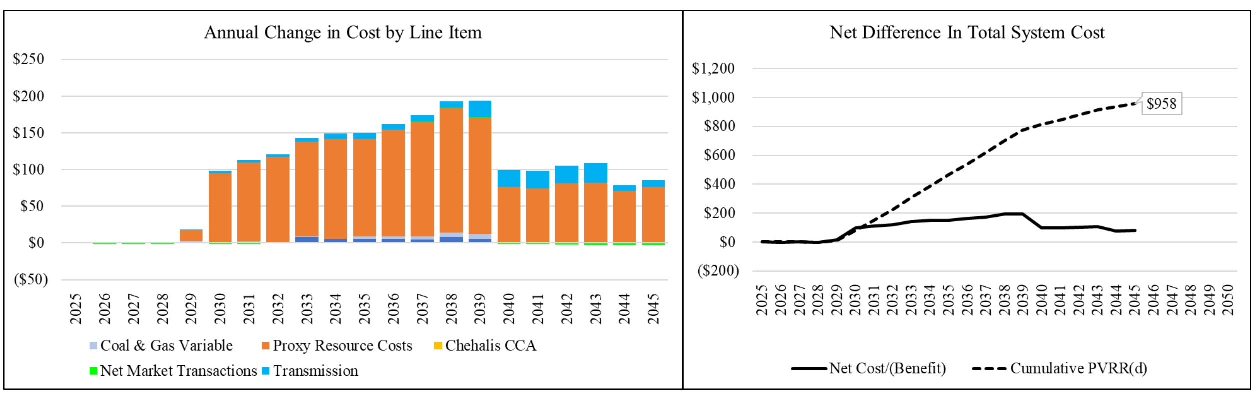
The No HB 2021 counterfactual portfolio reoptimizes Oregon's resource selections (keeping all of the jurisdictional selections from the 2025 IRP preferred portfolio constant) without modeling compliance with HB 2021 emissions reductions goals. This results in 1,914 fewer proxy resource selections over the planning horizon, and approximately $1 billion less cost in present value terms, relative to the CEP preferred portfolio. However, it bears repeating that the No HB 2021 counterfactual includes significant resource costs—replacement resources that are required to offset generation once Oregon exits coal resources by 2030—that may be more appropriately included in the HB 2021 cost cap. This is because only HB 2021-compliant resources (non-emitting proxy resources) can be used to replace the need previously met by coal. Figure 11 provides the cumulative resource selections between the two portfolios, with positive resource additions representing the resources needed to comply with HB 2021.

Figure 11 – Comparative Resource Selections between CEP Preferred Portfolio and No HB 2021 Counterfactual



The cumulative PVRR savings under the no HB 2021 counterfactual relative to the CEP preferred portfolio is $958 million. Positive numbers indicate that costs are higher in the preferred portfolio. The cost impacts from these resource selections, and related costs, are reflected in Figure 12 for each year.

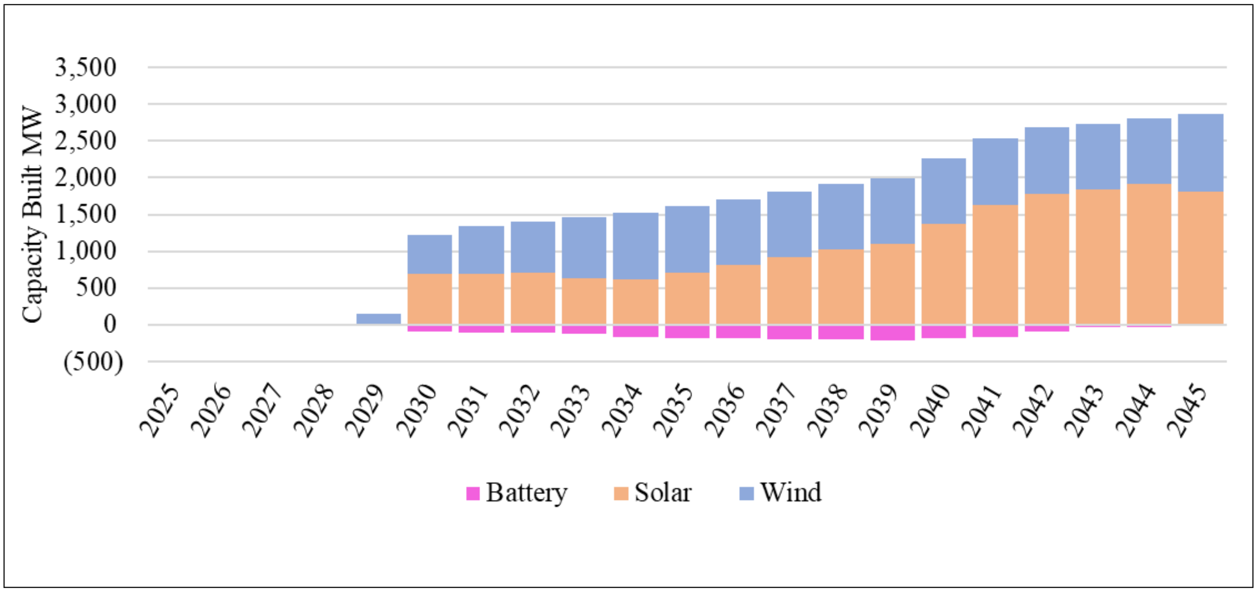
Figure 12 – CEP Preferred Portfolio and No HB 2021 Counterfactual Cost Comparison



No HB 2021-SSR Counterfactual

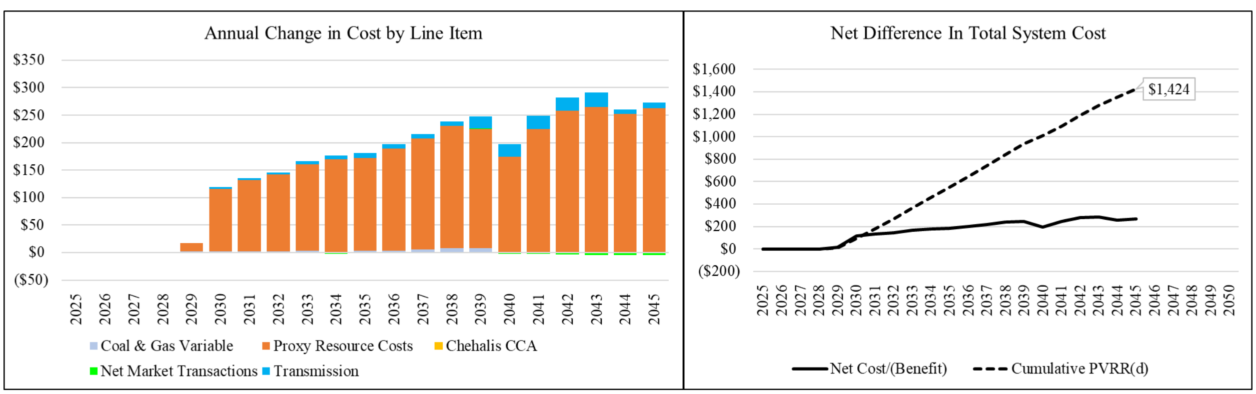
The No HB 2021-SSR counterfactual portfolio reflects Oregon's resource selections without including both the HB 2021 clean energy targets and resources necessary to meet the SSR standard. This results in over 3,000 MW fewer proxy resource selections over the planning horizon compared to the CEP preferred portfolio, and approximately $1.42 billion less cost in present value terms. Figure 13 provides the cumulative resource selections between the two portfolios, with positive resource additions representing the resources needed to comply with HB 2021 and Oregon's SSR mandate.

Figure 13 – Comparative Resource Selections between CEP Preferred Portfolio and No HB 2021-SSR Counterfactual



The cumulative PVRR savings from the no HB 2021-SSR relative to the CEP preferred portfolio is $1.424 billion. Positive numbers indicate that costs are higher in the preferred portfolio. The cost impacts from these resource selections, and related costs, are reflected in Figure 14 for each year.

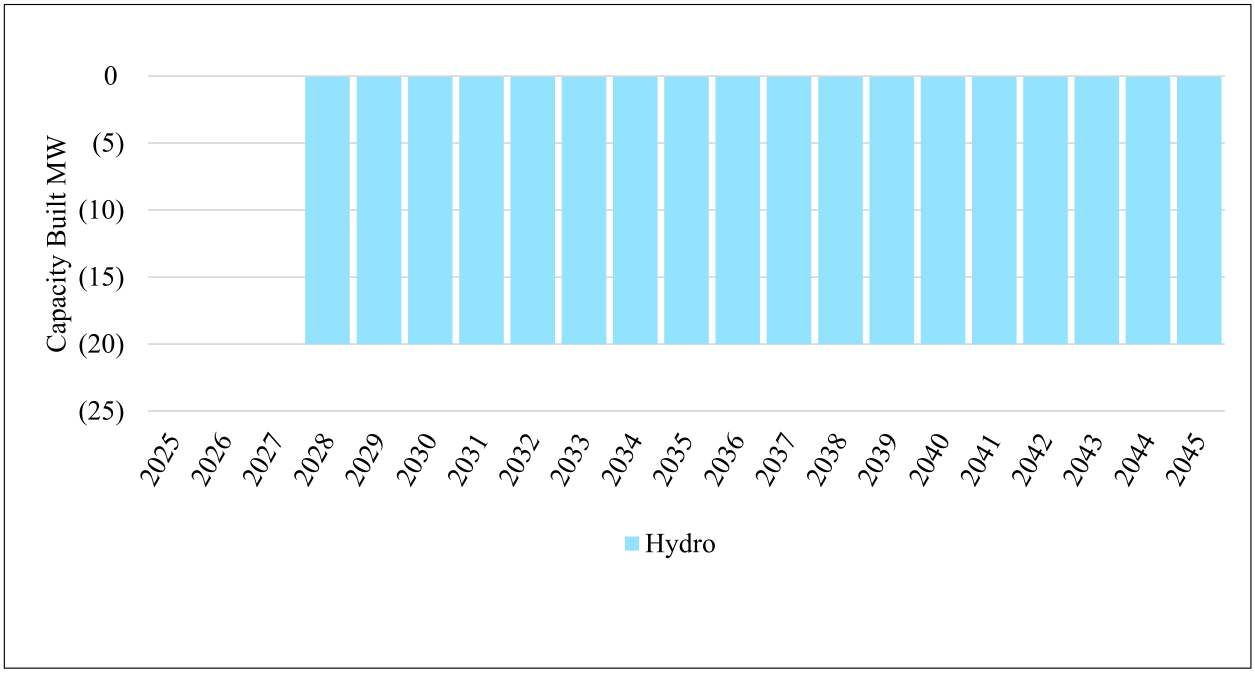
Figure 14 – CEP Preferred Portfolio and No HB 2021-SSR Counterfactual Cost Comparison



CBRE Valuation Study

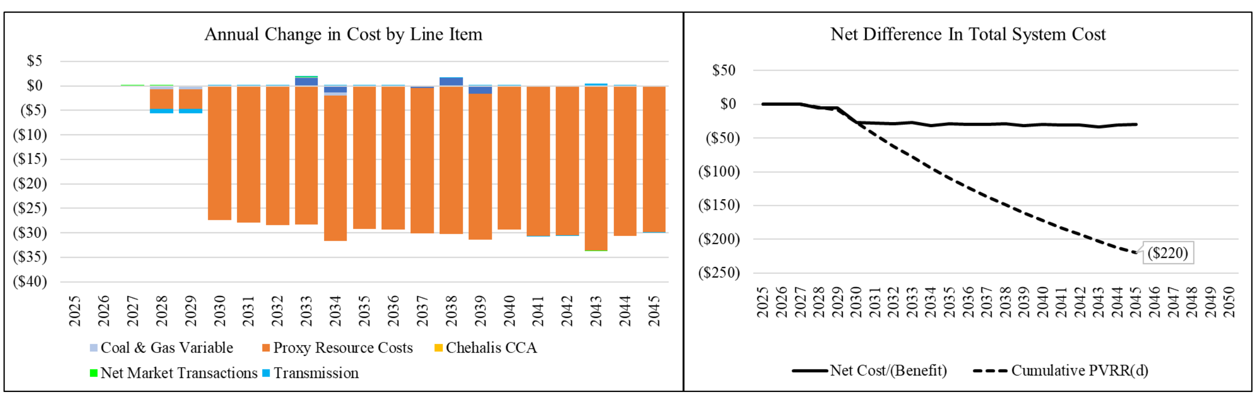
The CBRE valuation study analyzes resource selections between the substitution of CBREs for SSRs. While emissions and ENS are similar between the CEP preferred portfolio and CBRE portfolio, the substitution of CBREs for small-scale renewables incurs a steep cost increase of $220 million on a PVRR basis, compared to the CEP preferred portfolio. Figure 15 provides the cumulative resource selections between the two portfolios, with negative resource additions representing the additional CBRE hydro added to the portfolio.

Figure 15 – Comparative Resource Selections between CEP Preferred Portfolio and CBRE Valuation Study



The cumulative increase in PVRR costs from the CBRE valuation study relative to the CEP preferred portfolio is $220 million. Negative numbers indicate that costs are lower in the CEP preferred portfolio. The cost impacts from these resource selections, and related costs, are reflected in Figure 16 for each year.

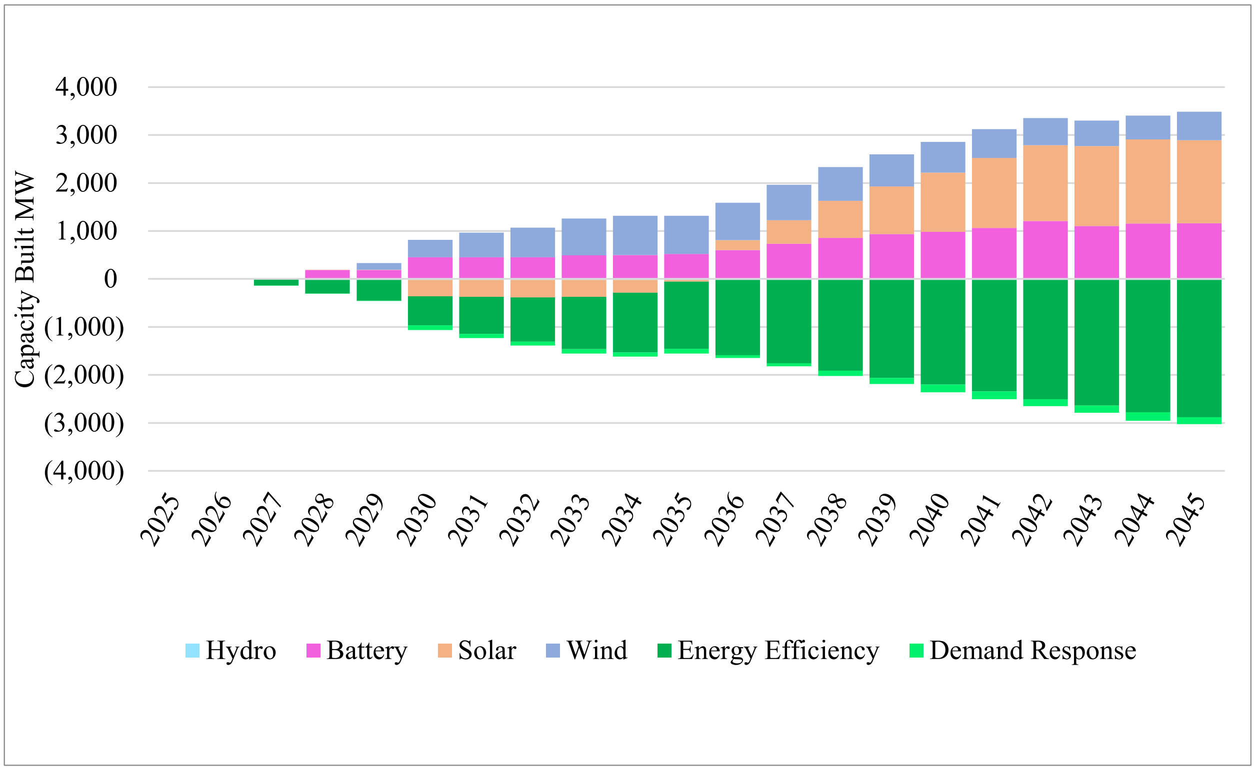
Figure 16 – CEP Preferred Portfolio and CBRE Valuation Study Cost Comparison



Maximum Customer Benefit

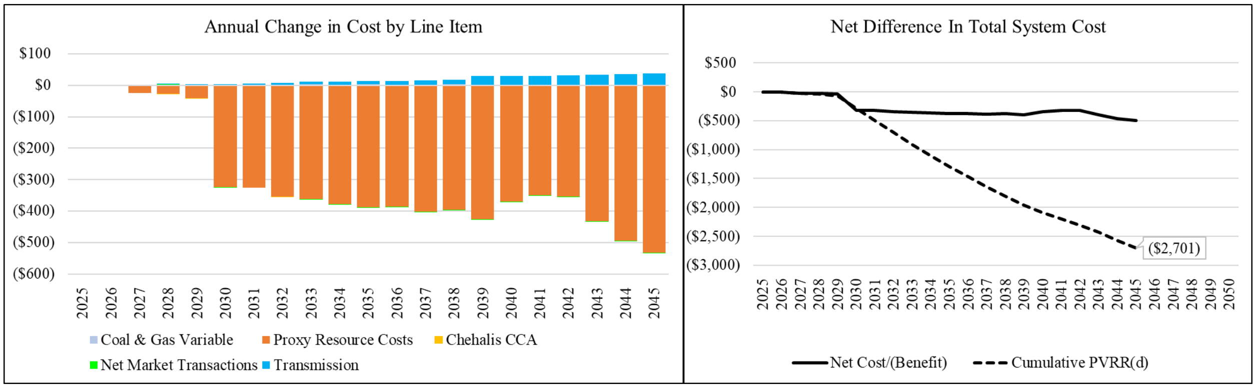
The maximum customer benefit sensitivity includes double the technical potential of DSM, 100 MW of CBRE resources, and no additional transmission intended to serve Oregon load. This results in 3,020 MW more proxy DSM resource selections and 2,272 MW fewer proxy generator selections over the planning horizon compared to the CEP preferred portfolio, and $2.7 billion more cost in present value terms. Because of the restriction on adding new utility-scale resources to serve Oregon customers in this sensitivity, there are not enough new resources built to reach emissions reductions goals. This sensitivity does achieve 84.6% emissions reductions in 2030, but only achieves 89.1% in 2035 and 92.6% in 2040, ultimately falling short of HB 2021's long-term decarbonization goals. Figure 17 provides the cumulative resource selections between the two portfolios, with positive resource additions representing the resources needed to comply with HB 2021 under a Maximum Customer Benefit scenario.

Figure 17 – Comparative Resource Selections between CEP Preferred Portfolio and Maximum Customer Benefit Study



The cumulative increase in PVRR costs from the maximum customer benefit study is $2.7 billion, relative to the CEP preferred portfolio. Negative numbers indicate that costs are lower in the CEP preferred portfolio. The cost impacts from these resource selections, and related costs, are reflected in Figure 18 for each year.

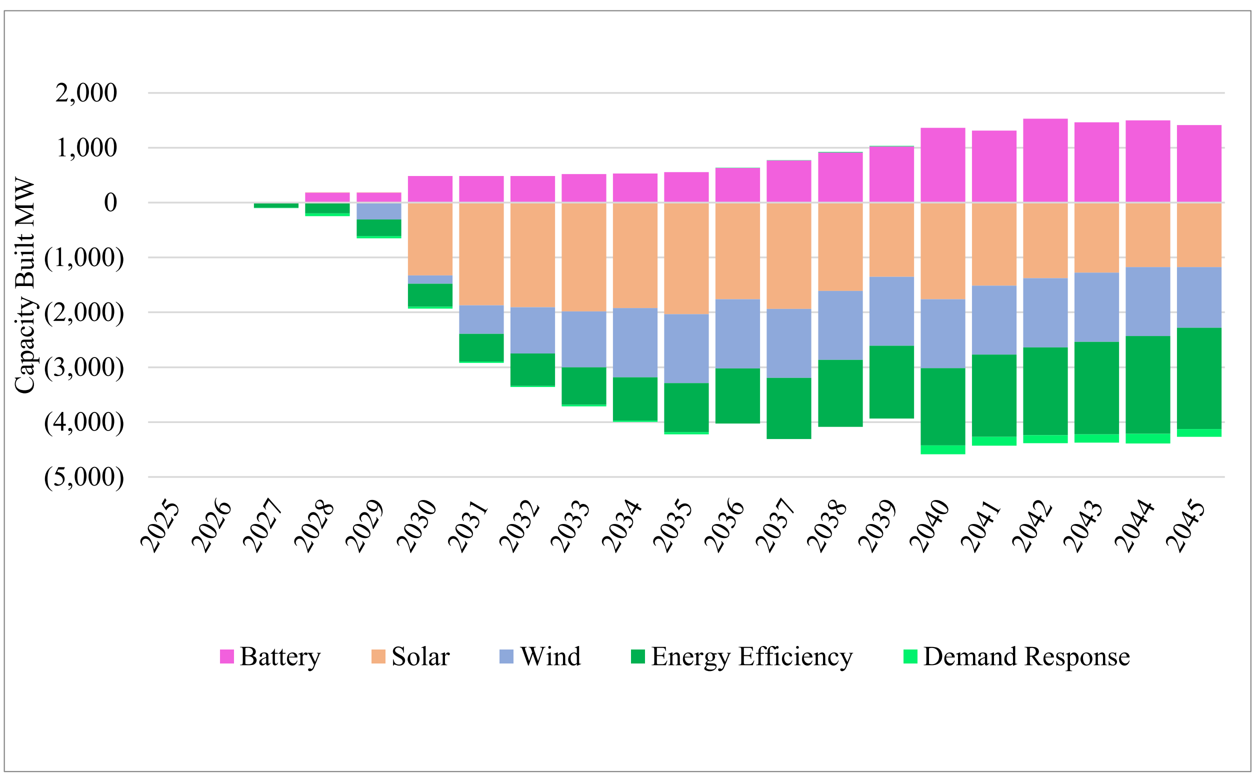
Figure 18 – CEP Preferred Portfolio and Maximum Customer Benefit Cost Comparison



In-State Resources

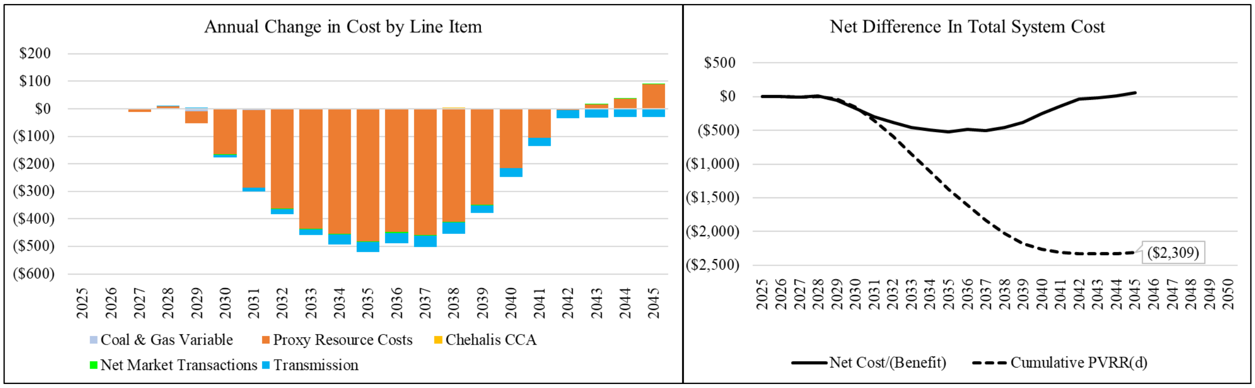
The in-state resources only sensitivity includes double the technical potential of DSM and only allows incremental proxy resource selections that are physically located in Oregon. This results in 2,914 MW more proxy generator selections over the planning horizon relative to the CEP preferred portfolio, and $2.3 billion more cost in present value terms. Figure 19 provides the cumulative resource selections between the two portfolios, with positive resource additions representing the resources needed to comply with HB 2021 under an in-state resources only scenario.

Figure 19 – Comparative Resource Selections between CEP Preferred Portfolio and In-State Resources



The cumulative increase in PVRR costs from the in-state resource is $2.3 billion, compared to the CEP preferred portfolio. Negative numbers indicate that costs are lower in the CEP preferred portfolio. The cost impacts from these resource selections, and related costs, are reflected in Figure 20 for each year.

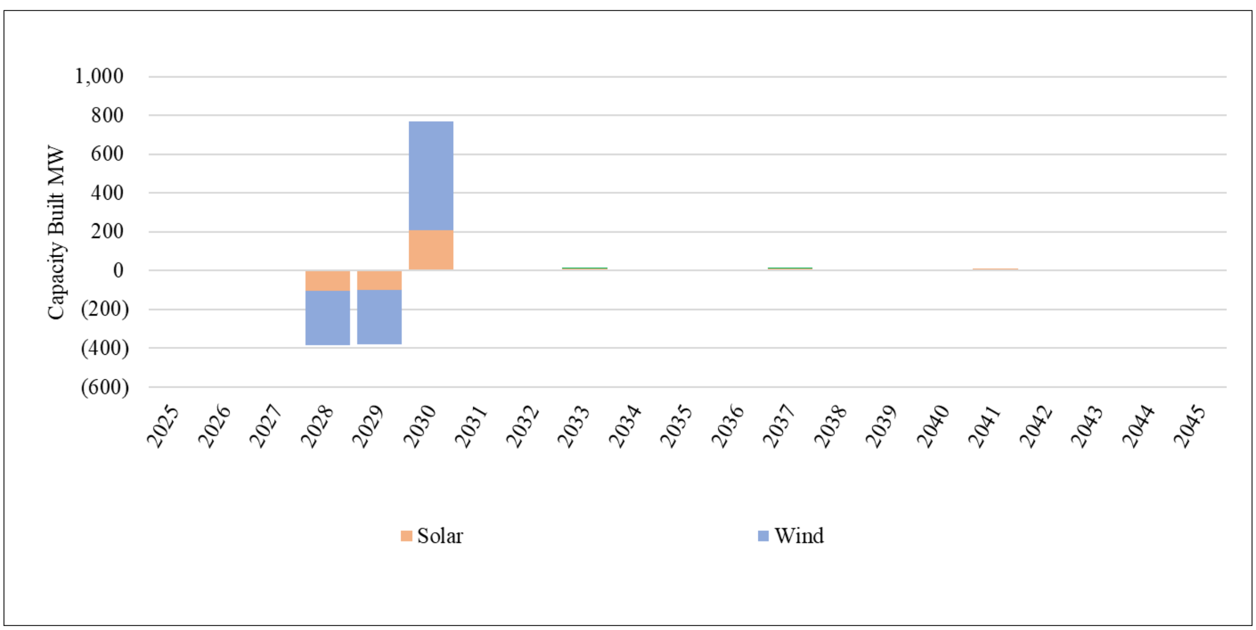
Figure 20 – CEP Preferred Portfolio and In-State Resources Cost Comparison



Accelerated Resources

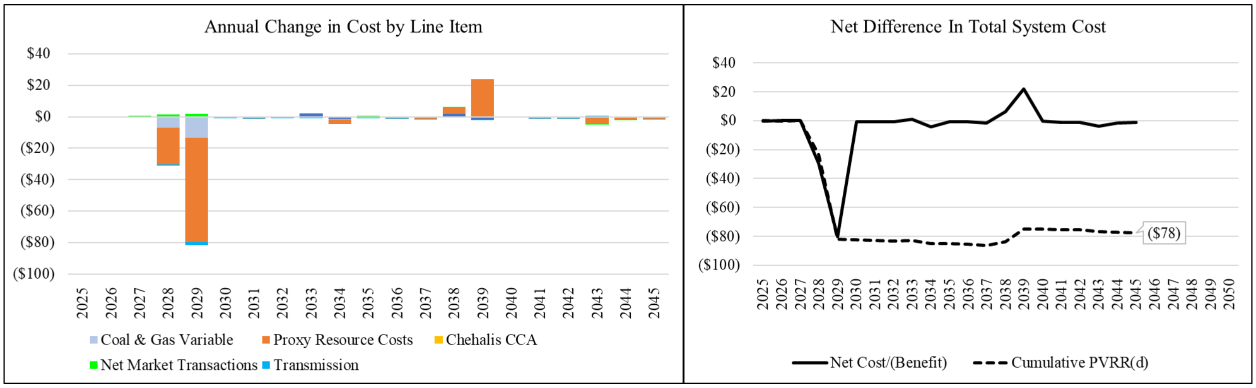
The accelerated resources sensitivity selects some of the wind and solar resources in 2030 from the CEP portfolio (560 and 207 MW, respectively), and includes them instead in 2028 and 2029. This results in the same total resource build as the CEP preferred portfolio, and $78 million more cost in present value terms. Figure 21 below provides the cumulative resource selections and timing of procurement between the two portfolios.

Figure 21 – Comparative Resource Selections between CEP Preferred Portfolio and Accelerated Resources



The cumulative increase in PVRR costs from the accelerated resource study is $78 million compared to the CEP preferred portfolio. Negative numbers indicate that costs are lower in the CEP preferred portfolio. The cost impacts from these resource selections, and related costs, are reflected in Figure 22 for each year.

Figure 22 – CEP Preferred Portfolio and Accelerated Resources Cost Comparison



Portfolio Costs

Total nominal costs incurred over the 21-year planning horizon and summarized across 2025-2029, 2030-2034, 2035-2039, and 2040-2045 for all portfolios is included in Table 27.

Table 27 – All Portfolio Costs (Nominal, $ millions) 2025-2045

Portfolio	2025-2029	2030-2034	2035-2039	2040-2045	**Total**	**Incremental Cost of HB 2021 Compliance**
CEP Preferred Portfolio	$153	$2,636	$4,466	$7,380	$14,634	$2,830
Hourly Clean Portfolio	$150	$2,730	$18,849	$23,862	$45,590	$33,786
No HB 2021 Counterfactual	$135	$1,918	$3,375	$6,378	$11,805	-
No HB 2021-SSR Counterfactual	$144	$1,801	$3,168	$5,403	$10,516	-
CBRE Valuation Study	$170	$2,777	$4,614	$7,563	$15,125	$3,320
Max Customer Benefit	$239	$4,208	$6,063	$8,972	$19,482	$7,677
In-State Resources	$202	$4,825	$7,529	$8,438	$20,995	$9,190
Accelerated Resources	$275	$2,641	$4,440	$7,386	$14,742	$2,937

These nominal cost results reveal that the CEP preferred portfolio, which applies an annual compliance approach consistent with the current DEQ emissions accounting methodology, is the least-cost portfolio that achieves HB 2021 compliance relative to the other sensitivities. However, the cost of HB 2021 compliance is significant across the various portfolios (as compared to the no HB 2021 counterfactual)—as much as $2.830 billion in the CEP preferred portfolio, going up to $33.786 billion in the hourly clean portfolio.

Small-Scale Renewables Target

In addition to establishing greenhouse gas emissions reduction requirements, HB 2021 amended Oregon's SSR mandate in ORS 469A.210, by postponing compliance with the law until 2030 and increasing the target to 10 percent (from 8 percent) of PacifiCorp's aggregate electrical capacity.

To determine PacifiCorp's SSR target, the company identified Oregon-allocated aggregate electrical capacity in each year from 2030 onwards and calculated a 10 percent SSR requirement based on that capacity. As shown in Table 28, the 10 percent SSR target in 2030 amounts to 542 MW, and increases to 735 MW by 2045. PacifiCorp estimates it has 396 MW of nameplate capacity from existing resources that are allocated to Oregon and SSR-compliant (assuming all SSR-eligible QFs that expire before 2030 renew at 100 percent nameplate capacity). This leaves an additional need for 146 MW of SSR proxy resources to meet the 2030 SSR target, increasing to 339 MW by 2045.

To address this annual target, the 2025 CEP preferred portfolio includes a slight compliance buffer of SSR capacity in each year. For example, in the year 2030 there are 209 MW of SSR additions, resulting in a 64 MW compliance buffer for that year. This compliance buffer increases through the planning period, resulting in a 189 MW buffer in 2045.

Table 28 - Small-Scale Renewables Target (2030-2045)

OR Small-Scale Position (MW)	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045
Small-Scale 10% Target	542	553	567	581	599	625	652	682	714	739	661	678	693	705	717	735
Existing Small-Scale	396	396	396	396	396	396	396	396	396	396	396	396	396	396	396	396
SSR Need	146	157	171	185	203	229	256	286	318	343	265	282	297	309	321	339
Portfolio Small-Scale Additions	209	226	240	259	277	303	330	360	393	418	445	471	486	498	510	528
Portfolio Small-Scale (Excess)	(64)	(69)	(69)	(74)	(74)	(74)	(74)	(74)	(75)	(75)	(181)	(189)	(189)	(189)	(189)	(189)

As discussed in Chapter II, to help meet these targets PacifiCorp issued its 2025 OR SSR RFP to the market in April 2025 and will contemplate rolling procurements.

Transmission

PacifiCorp's 2025 CEP uses the same 2025 IRP transmission topology that captures major load centers, generation resources, and market hubs interconnected along firm transmission paths. Transfer capabilities across transmission paths are based upon the firm transmission rights of PacifiCorp's merchant function, including transmission rights from PacifiCorp's transmission function and other regional transmission providers.

In support of the renewable resources identified for Oregon in the 2025 CEP preferred portfolio, PacifiCorp has identified transmission options that will reinforce existing transmission paths, allow for increased transfer capability, and will support the interconnection of new resources required for compliance with HB 2021 under both annual and hourly compliance scenarios. These transmission-related costs are incremental to system-related transmission costs or expenses that would otherwise be required absent HB 2021.

For annual compliance from the years 2028-2045, PacifiCorp identified multiple transmission lines and related transmission upgrades, ranging from 230 kV to 500 kV lines, that would be needed to increase transmission capacity. These system upgrades would result in 2,750 MW of incremental capacity between bubbles, allowing for 3,830 MW of capacity interconnecting resources to load, and would cost an estimated $3.374 billion. These costs represent PacifiCorp's estimates of the total upfront costs for PacifiCorp's system and are not an annualized figure of PVRR estimate.

This analysis includes: transmission infrastructure necessary to export or import electricity between transmission clusters (*e.g.,* Cluster 1 Area 14: Summer Lake 88 MW of import, export, and interconnection capacity); to interconnect resources (*e.g.,* Cluster 1 Area 11: Willamette Valley 26 MW of interconnection capacity, or Serial Queue: Central Oregon); and regional transmission lines (*e.g.,* Walla Walla-Yakima 230 kV line). This analysis also allows for fractional selection of transmission resources. For example, in each year 2033 through 2037, the model selected a share of a single 500 kV line from Walla Walla to Central Oregon (Cluster 2 Area 18). Each year, the model selects a portion of 500 kV line from Walla Walla to Central Oregon. This allows for a more granular review of transmission resource impacts from HB 2021 generation resource selections, even though fractional transmission resource selections do not align as well with transmission development practices. Table 29 summarizes total transmission resource selections in the CEP preferred portfolio.[95]

Table 29 - CEP Preferred Portfolio Transmission Selections

		Export (MW)	Import (MW)	Interconnect (MW)	Build Investment ($m)	Build (%)	From	To
2028	Cluster 1 Area 11: Willamette Valley	0	0	26	2	13%	n/a	n/a
2028	Cluster 1 Area 14: Summer Lake	88	88	88	25	22%	Summer Lake	Hemingway
2028	Cluster 2 Area 23: Willamette Valley	0	0	52	0	13%	n/a	n/a
2028	Serial queue: Central Oregon	0	0	14	0	9%	n/a	n/a
2029	Cluster 1 Area 11: Willamette Valley	0	0	70	5	35%	n/a	n/a
2029	Cluster 2 Area 23: Willamette Valley	0	0	138	1	35%	n/a	n/a
2030	Cluster 1 Area 11: Willamette Valley	0	0	103	7	52%	n/a	n/a
2030	Cluster 1 Area 14: Summer Lake	312	312	312	89	78%	Summer Lake	Hemingway
2030	Cluster 1/2/3: Walla Walla	0	0	378	318	96%	n/a	n/a
2030	Cluster 2 Area 23: Willamette Valley	0	0	203	1	52%	n/a	n/a
2030	Serial queue: Central Oregon	0	0	137	3	90%	n/a	n/a
2030	Walla Walla - Yakima 230 kV	400	400	400	142	100%	Walla Walla	Yakima
2031	Serial through Cluster 1 Area 13: Southern Oregon	0	0	163	30	71%	n/a	n/a
2032	Cluster 2/3: Willamette Valley - Central Oregon 230 kV	127	127	127	117	28%	Willamette Valley	Central OR
2033	Cluster 2 Area 18: Central Oregon 500 kV Substation	0	0	66	48	13%	n/a	n/a
2033	Cluster 2/3: Willamette Valley - Central Oregon 230 kV	170	170	170	157	38%	Willamette Valley	Central OR
2034	Cluster 2 Area 18: Central Oregon 500 kV Substation	0	0	145	105	28%	n/a	n/a
2034	Cluster 2/3: Willamette Valley - Central Oregon 230 kV	73	73	73	68	16%	Willamette Valley	Central OR
2035	Cluster 2 Area 18: Central Oregon 500 kV Substation	0	0	125	91	24%	n/a	n/a
2035	Serial through Cluster 1 Area 13: Southern Oregon	0	0	53	10	23%	n/a	n/a
2036	Cluster 2 Area 18: Central Oregon 500 kV Substation	0	0	44	32	8%	n/a	n/a
2037	Cluster 2 Area 18: Central Oregon 500 kV Substation	0	0	134	97	26%	n/a	n/a
2039	Walla Walla - Central Oregon 500 kV	1,500	1,500	396	1,342	100%	Walla Walla	Central OR
2040	Walla Walla - Central Oregon 500 kV	0	0	271	542	40%	Walla Walla	Central OR
2044	Cluster 1 Area 12: Southern Oregon	0	0	44	47	15%	n/a	n/a
2045	Cluster 1 Area 12: Southern Oregon	0	0	19	20	6%	n/a	n/a
2045	Cluster 2/3: Willamette Valley - Central Oregon 230 kV	80	80	80	73	18%	Willamette Valley	Central OR
Grand Total		**2,750**	**2,750**	**3,830**	**3,374**			

[95] Export and import values represent total transfer capability. Actual scope and costs will vary depending upon the interconnection queue, transmission service queue, specific location of generating resources and type of equipment for any given generating resource. Additionally, transmission upgrades frequently include primarily all-or-nothing components, though the cluster study process allows for project-specific timing and costs can be project-specific. Given its singular jurisdictional focus, modeling for the CEP did not require all-or-nothing upgrade selections.

Demand-Side Actions

The subsections below discuss demand-side actions and resources that, while not entirely driven by the 2025 IRP/CEP process, are nonetheless integral to the company's resource portfolio and system operations.

Energy Efficiency

The ETO is an independent nonprofit organization dedicated to promoting energy efficiency and renewable energy solutions for customers of participating utilities in Oregon. Since 2002, PacifiCorp has collaborated with ETO to implement energy efficiency programs within its Oregon service area.[96] These programs are funded through two tariffs: Oregon Schedule 291, which supports energy efficiency initiatives, and Oregon Schedule 292, which funds renewable energy efforts.

Looking ahead to the rest of 2025, PacifiCorp will continue working with ETO to review its proposed inaugural multi-year plan (MYP). This plan will establish ETO's energy efficiency targets and associated budgets for the five-year period from 2026 to 2030, ensuring alignment with statewide energy goals and utility resource planning efforts. Through this ongoing collaboration, PacifiCorp aims to support effective program delivery while ensuring cost-effective investments that benefit customers and contribute to broader energy policy objectives.

The CEP uses the Oregon energy efficiency selections from the 2025 IRP. Additionally, two of the sensitivities analyzed in the CEP relate to energy efficiency, including the "maximum customer benefit" and "in-state only" sensitivities.

Demand Response

PacifiCorp has been aggressively growing its demand response portfolio in Oregon for several years. PacifiCorp's DR programs are carefully designed to provide a range of grid management services, while meeting the needs of the customer segment and targeted end-use. As of December 2024, the company had the following programs in its portfolio:

- Irrigation Load Control, launched in 2023, which uses a program-provided load control switch for peak management during the summer season.
- Wattsmart Business Demand Response, launched in 2023, which enrolls loads at the customer meter to provide peak management, contingency reserves, or frequency response resources. Control mechanisms vary from manual control to full automation.

In 2025, PacifiCorp will focus on the launch of three new programs. All three will provide participation options for residential customers, though other customers can participate as well.

- Wattsmart Battery, which dispatches residential batteries for various demand response applications.

[96] *E.g.,* ORS 757.054, 757.612.

- Cool Keeper, which uses a load control switch to curtail the compressor on residential cooling equipment for peak load reduction, contingency reserve, and frequency response needs during the summer colling season.
- Wattsmart Drive, which uses EV telematics to curtail charging for demand response. This program was originally included as part of the Transportation Electrification Plan but is now managed as part of the DR portfolio.

In addition to these program offerings, the company offers time-of-use rates for all customer classes that contribute to PacifiCorp's strategy to manage loads effectively.

PacifiCorp files most demand response programs under its Tariff Schedule 106. Schedule 106 is an umbrella tariff created to allow streamlined creation of new demand response programs, while at the same time emphasizing the role of stakeholder engagement in program development and design. PacifiCorp reviews annual results and proposed with the CBIAG and OPUC staff at the end of each program year. For each program year, PacifiCorp files an annual report on program performance, including recommendations for program improvements, by March 31 of the following year. Programs such as Wattsmart Drive, created as part of PacifiCorp's 2023 Oregon Transportation Electrification Plan, are implemented with a similar level of stakeholder engagement and reporting.[97]

Key demand response milestones for 2025 are shown in Table 30 below.

Table 30 - 2025 Milestones for Demand Response

Timing	Milestone
Q2 2025	Launch Wattsmart Battery Launch Cool Keeper
Q3 2025	Launch Wattsmart Drive
Q4 2025	Review year-end results of individual programs to consider potential additional actions to continuously improve delivery of programs
Q1 2026 (March 31, 2026)	File annual report on 2025 demand response program performance

PacifiCorp expects to continue to grow the DR portfolio to keep pace with the projected increase in demand response resources forecast in the 2025 IRP through 2027. Table 31 presents an estimated forecast of total DR capacity, measured as available MW at generation. PacifiCorp will continue to maintain this three-year forecast in future CEPs, providing a rolling estimate of future demand response capacity.

[97] PacifiCorp, 2023 Oregon Transportation Electrification Plan. Microsoft Word - 0_UM 2056 PacifiCorp CLtr_Final 2023 TEP.docx

Table 31 - Estimated DR Capacity, 2024-2027

	2024 (Actual)	2025	2026	2027
Available MW at Generation	27	28	40	55

Compliance Scenarios

This subsection discusses three scenarios that could materially impact PacifiCorp's HB 2021 compliance strategies: (1) what resources would be needed to comply with HB 2021 on an hourly, as opposed to annual basis; (2) what are the potential cost implications to Oregon customers from the potential passage of currently proposed federal tax policies; and (3) implications from situs-assigned transmission resource costs needed to comply with state-specific policies. PacifiCorp includes these scenarios to inform the Commission and stakeholders on issues that could materially impact the company's compliance strategies.

Annual or Hourly Clean

The DEQ framework for calculating PacifiCorp's Oregon GHG emissions is used to model PacifiCorp's HB 2021 emission reductions goals. Because PacifiCorp operates a multijurisdictional system, this emissions calculation includes a resource allocation component—only emissions that are considered cost-allocated to Oregon customers are covered under HB 2021 obligations. Determining emissions for these resources is straightforward for existing and proxy supply-side resources: resource generation and associated emissions are allocated based on a system or a situs allocation factor as prescribed under the current cost allocation protocol.

For HB 2021 purposes, an issue arises with the calculation of emissions for market purchases and system balancing. Operationally, PacifiCorp makes market purchases and sales on a short-term basis to reliably and economically balance its load and resources. System balancing purchases usually have an "unspecified-source," i.e., they do not have specified generation resource, lack identifying environmental attributes, and as a result are assigned the unspecified market emissions rate under the DEQ methodology equal to 0.428 $MTCO_2e/MWh$.[98] Under PacifiCorp's current cost-allocation protocol, Oregon customers are assigned a system share of the costs of all market balancing purchases as part of net power costs, which are forecasted annually in Transition Adjustment Mechanism (TAM) filings and partially trued-up with actual results in Power Cost Adjustment Mechanism (PCAM) filings. This Oregon-allocated volume of system market purchases is reported to the DEQ under the unspecified market emissions rate as part of PacifiCorp's Oregon-relevant emissions.

In the 2025 IRP and CEP, annual greenhouse gas emissions under the DEQ methodology drives clean energy resource additions for Oregon in the capacity expansion model (the LT model). This results in resource selections for Oregon that generate enough energy on an annual basis to serve Oregon customers, under acceptable annual emissions limits. By 2040, total emissions must drop to zero, which requires that no emitting generation or unspecified market purchases be used to serve Oregon customers, since both have an emissions rate. Yet even prior to 2040, assigning

[98] OAR 340-215-0120(5)(a).

Oregon a share of system market purchases as optimized in PLEXOS could cause PacifiCorp to exceed HB 2021's emissions limits.

To accommodate this issue, the 2025 IRP and CEP preferred portfolios assume that Oregon no longer participates in system market balancing purchases starting in 2035. With this constraint, these portfolios show that on an annual basis, it is possible to meet the requirements under HB 2021 under existing cost-allocation protocol—though only until the end of 2034.[99]

Modeling for the 2025 CEP indicates that by 2035 it is unlikely that even annual clean energy targets can be met without significant developments in resources, markets, and/or allocations. One, or several, of the following developments must occur by 2035:

- Resources – Hourly Clean Portfolio: PacifiCorp would need to procure enough resources for Oregon that can generate enough energy to serve Oregon in all hours and be zero-emitting resources (or nearly zero-emitting, prior to 2040).

- Clean energy markets: PacifiCorp would need access to a short-term energy market that is considered "clean" or not unspecified, so purchases could be made to balance Oregon load without incurring emissions. There is certain to be an incremental cost for clean market purchases, relative to unspecified market purchases, and the potential supply is unknown.

- Multi-State Cost Allocation: The six states where PacifiCorp operates would need to approve successor cost-allocation protocols to better address state-specific policies (*e.g.,* HB 2021 and SSR mandate).

The only option that is wholly within PacifiCorp's control on behalf of Oregon customers is the procurement of incremental resources, as clean energy markets require participation from other utilities and allocation changes require the approval of other state commissions. There is not currently a short-term market that PacifiCorp can go to that offers entirely non-emitting energy, and if there were, it would likely come with a premium on top of regular market clearing prices. But without some form of "specification" noting that the market purchase is non-emitting, a market

[99] Even under the assumption that Oregon no longer "participates" in system market balancing purchases, it is not the case that Oregon-allocated resources are serving Oregon load in every hour. One of the benefits of PacifiCorp's diverse footprint and multijurisdictional allocation methodology is to the ability to balance the system using system resources where needed. Electrons are not individually dispatched to meet specific load, as the system is balanced as a whole at all points in time using all available generation. Cost-allocations are meant to fairly allocate those costs based on average system shares; but from hour to hour, the amount of resource capacity and energy needed to meet Oregon load varies widely from averages. This divergence between supply and demand increases in 2030 when Oregon exits coal-fired resources and reduces the dispatch of natural gas-fired resources, both of which help cover periods when the output of variable energy resources like wind and solar is low. Market purchases can also cover periods when load exceeds availably supply but incur emissions that are higher than the most efficient natural gas plants. While the sharing of costs and resources under existing multijurisdictional allocation methodology is fair when all of the jurisdictions include similar resources, this breaks down when Oregon exits or severely limits all of the flexible sources of supply. Ceasing the allocation of all emitting generation and system market purchases to Oregon does not change the need to serve Oregon load on an hour-to-hour basis, and there are necessarily non-Oregon resources serving Oregon load that are not reflected either in costs or emissions accounting. As a result, the premise of resource sharing that underlies PacifiCorp's current annual compliance requirements will be strained by the reduction of emitting generation and unspecified market purchases in Oregon rates.

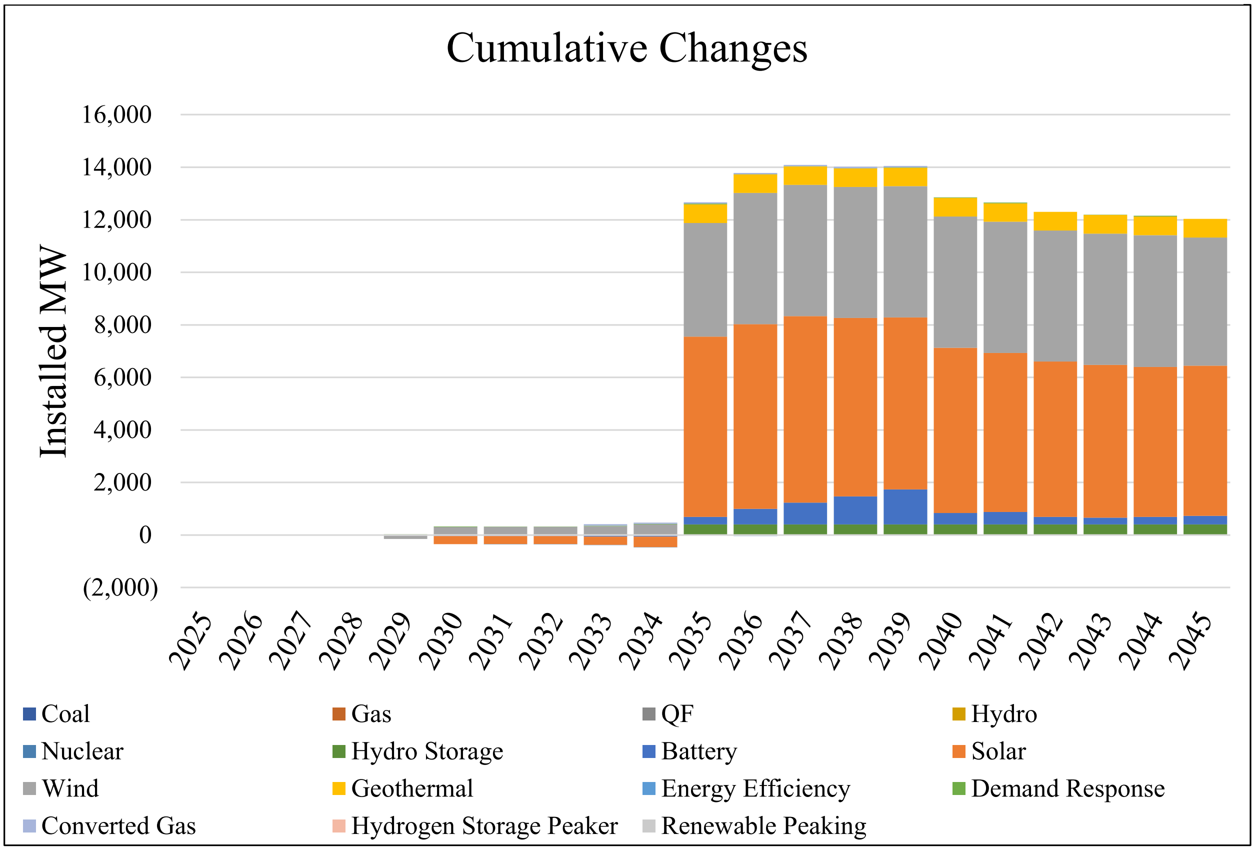
purchase will always contribute to the total emissions associated with serving Oregon electricity needs. Developing a clean energy specification and integrating it with existing market processes, such as the Enhanced Day-Ahead Market (EDAM) and Western Energy Imbalance Market (WEIM), will be a significant undertaking given the number of stakeholders involved and the difficulty of modifying already complex operational processes. Similar issues arise with cost-allocation proceedings. While allocations involve fewer stakeholders, the implications of resource sharing can impact planning, hedging, and operations in ways that are beyond the scope of EDAM and WEIM, such that finding mutually beneficial outcomes may be more difficult.

Moreover, under current emissions accounting methodologies, PacifiCorp's multi-jurisdictional nature allows the company to meet emissions reduction goals on an annual basis, through an annual cost-allocation of generation resources, while in reality, there may be several hours in which Oregon energy needs are actually being served by other resources on PacifiCorp's system that are not allocated to Oregon customers in rates. One of the benefits of PacifiCorp's diverse system is the ability to balance across a wide range of loads and resources that peak at different times. However, this benefit becomes a potential cost if emissions accounting methodologies adapt to treat hourly system shortfalls met with system resources that are not allocated to Oregon as market purchases which, consequently, would get assigned an unspecified emissions rate. If the emissions accounting methodology evolves in this way, PacifiCorp will need to show that Oregon is "clean" on an hourly basis.

Given these uncertainties and challenges, the next-best alternative is to build a portfolio of resources that can generate enough clean energy to serve Oregon in every hour of each year, with minimal reliance on emitting resources or market purchases prior to 2040, and none after 2040. PacifiCorp created an "hourly clean portfolio" sensitivity to evaluate this alternative. Beginning in 2035, the hourly clean portfolio must include enough Oregon-allocated resources to meet Oregon load in every hour without relying on unspecified market purchases (though a small amount of natural gas generation is allowed until 2039).

This hourly clean compliance scenario would incur significant extra costs. Figure 23 shows the additional resource selections included in the hourly clean portfolio relative to the CEP preferred portfolio. The hourly clean portfolio selects over 12 GW more of renewable and storage resources over the planning horizon compared to the annual clean scenario, the majority of which would occur after 2035. These additional resources are more than double what would otherwise be required under annual compliance scenarios.

Figure 23 – Cumulative differences in resource selections between the CEP Preferred Portfolio and Hourly Clean Portfolio



PacifiCorp's transmission needs would also materially increase under an hourly clean scenario. PacifiCorp's forecasted system transmission upgrades would result in 9,526 MW of export capacity, 9,733 MW of import capacity, 8,477 MW of interconnection capacity, and would cost a total of $11.859 billion. This represents an increase of 6,776 MW of export capacity, 7,023 MW of import capacity, 4,647 MW of interconnection capacity and $8.485 billion in cost when compared to annual clean compliance. Hourly clean transmission resources are included in Table 32.[100]

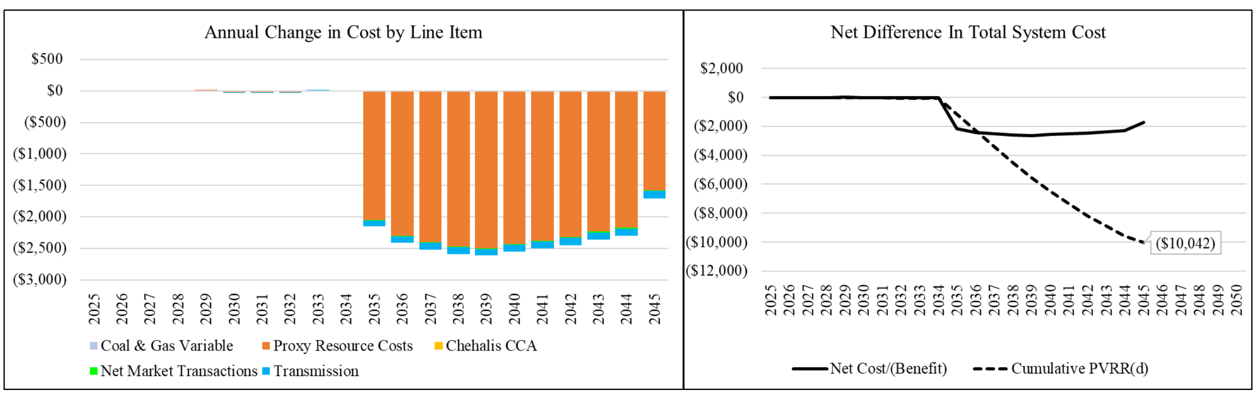
[100] Export and import values represent total transfer capability. Actual scope and costs will vary depending upon the interconnection queue, transmission service queue, specific location of any given generating resource and the type of equipment proposed for any given generating resource. Additionally, transmission upgrades frequently include primarily all-or-nothing components, though the cluster study process allows for project-specific timing and costs can be project-specific. Given its singular jurisdictional focus, modeling for the CEP did not require all-or-nothing upgrade selections.

Table 32 - Hourly Clean Portfolio Transmission Resources

		Export (MW)	Import (MW)	Interconnect (MW)	Build Investment ($m)	Build (%)	From	To
2028	Cluster 1 Area 14: Summer Lake	24	24	24	7	6%	Summer Lake	Hemingway
2029	Cluster 1 Area 11: Willamette Valley	0	0	49	3	25%	n/a	n/a
2029	Cluster 1 Area 14: Summer Lake	25	25	25	7	6%	Summer Lake	Hemingway
2029	Cluster 2 Area 23: Willamette Valley	0	0	97	1	25%	n/a	n/a
2029	Serial queue: Central Oregon	0	0	9	0	6%	n/a	n/a
2030	Cluster 1 Area 11: Willamette Valley	0	0	150	11	75%	n/a	n/a
2030	Cluster 1 Area 14: Summer Lake	351	351	351	101	88%	Summer Lake	Hemingway
2030	Cluster 2 Area 23: Willamette Valley	0	0	296	2	75%	n/a	n/a
2030	Serial queue: Central Oregon	0	0	143	4	94%	n/a	n/a
2030	Walla Walla - Yakima 230 kV	400	400	400	142	100%	Walla Walla	Yakima
2031	Serial through Cluster 1 Area 13: Southern Oregon	0	0	171	31	74%	n/a	n/a
2032	Cluster 2/3: Willamette Valley - Central Oregon 230 kV	129	129	129	119	29%	Willamette Valley	Central OR
2033	Cluster 2 Area 18: Central Oregon 500 kV Substation	0	0	66	48	13%	n/a	n/a
2033	Cluster 2/3: Willamette Valley - Central Oregon 230 kV	115	115	115	107	25%	Willamette Valley	Central OR
2034	Cluster 2 Area 18: Central Oregon 500 kV Substation	0	0	55	40	11%	n/a	n/a
2034	Cluster 2/3: Willamette Valley - Central Oregon 230 kV	94	94	94	90	21%	Willamette Valley	Central OR
2035	Cluster 1 Area 12: Southern Oregon	0	0	300	322	100%	n/a	n/a
2035	Cluster 2 Area 18: Central Oregon 500 kV Substation	0	0	225	168	43%	n/a	n/a
2035	Cluster 2 Area 19: Summer Lake to Central Oregon 500 kV	1500	1500	670	1428	100%	Summer Lake	Central OR
2035	Cluster 2 Area 20: Southern Oregon	0	0	450	2396	100%	n/a	n/a
2035	Cluster 2/3: Willamette Valley - Central Oregon 230 kV	112	112	112	110	25%	Willamette Valley	Central OR
2035	Serial through Cluster 1 Area 13: Southern Oregon	0	0	53	11	23%	n/a	n/a
2035	Southern Oregon - Central Oregon 500 kV	1500	1500	981	1715	100%	Southern OR	Central OR
2035	Walla Walla - Central Oregon 500 kV	1500	1500	670	1342	100%	Walla Walla	Central OR
2035	Yakima - Central Oregon 500 kV	1240	1240	554	1221	83%	Yakima	Central OR
2036	Willamette Valley - Southern Oregon 500 kV, 230 kV	1500	1500	665	1117	100%	Willamette Valley	Southern OR
2037	Cluster 2 Area 18: Central Oregon 500 kV Substation	0	0	43	33	8%	n/a	n/a
2037	Gateway West Segment E (Populus-Hemingway)	293	400	0	550	27%	BorahPop	Hemingway
2039	Cluster 2 Area 18: Central Oregon 500 kV Substation	0	0	87	71	17%	n/a	n/a
2040	Cluster 2 Area 18: Central Oregon 500 kV Substation	0	0	26	23	5%	n/a	n/a
Grand Total		9,526	9,733	8,477	11,859			

These additional generation and transmission resources under the hourly clean portfolio would increase Oregon-allocated PVRR by $10.042 billion, driven by the large increases in proxy resource costs and transmission costs. Figure 24 compares the annual costs between the CEP preferred portfolio and the hourly clean portfolio. Positive numbers indicate that a given cost is higher in the CEP preferred portfolio than in the hourly clean portfolio.

Figure 24 – Annual Cost Comparison of the CEP Preferred Portfolio and the Hourly Clean Portfolio



Federal Tax Policy Implications

The United States Congress is considering legislation that could materially impact the costs and benefits of renewable and storage resources needed to comply with HB 2021 emissions targets.[101]

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[101] "The One Big Beautiful Bill Act," House Resolution 1 (119th Congress, 2025-2026) (available here: https://www.congress.gov/bill/119th-congress/house-bill/1).

Under current law, generation facilities that do not produce greenhouse gas emissions are entitled to a production tax credit for each kilowatt hour of generated electricity,[102] and an investment credit for a percentage of each dollar invested in the resource.[103] There are similar production credits for clean hydrogen resources.[104]

H.R. 1 would phase out and repeal these tax credits for new resources.[105] If passed, all solar, wind, storage, and clean hydrogen facilities would no longer receive either production or investment tax credits if they are unable to achieve COD within the timelines being debated in Congress. This would have a material implication on the costs to comply with Oregon policies, including HB 2021 and the elimination of coal resources by 2030.[106]

For example, the company analyzed how resource selections from the 2025 CEP would be impacted by the loss of production and investment tax credits. As shown in Table 33, removal of these tax credits for new proxy resources would increase Oregon-allocated nominal portfolio costs across three separate scenarios: the current CEP preferred portfolio by $7.127 billion; the hourly clean portfolio by $19.699 billion; and the no-HB 2021 counterfactual by $5.460 billion. These additional costs, resulting from the loss of tax credit benefits, would be additional costs on top of the incremental costs identified to comply with HB 2021 greenhouse gas emissions reductions as described in the prior subsection summarized in Table 27. For the CEP preferred portfolio, this brings the total incremental cost of HB 2021 compliance from $2.83 billion to $4.497 billion on a nominal basis across the planning horizon; for the hourly clean portfolio the incremental cost without tax credits would increase from $33.786 billion to $48.035 billion. And importantly, these results do not reflect how resource selections in the 2025 CEP could be impacted by the passage of H.R. 1; they only reflect how the cost of resource selections under pre-H.R. 1 assumptions would be impacted.

Table 33 – Oregon-allocated Nominal Costs with and without Tax Credits ($millions)

Study	Costs with Tax Credits	Costs without Tax Credits	Increase in Costs
CEP Preferred Portfolio	$14,634	$21,762	$7,127
Hourly Clean Portfolio	$45,590	$65,290	$19,699
No HB 2021 Counterfactual	$11,805	$17,264	$5,460

Situs Transmission Costs

As stated previously, portfolio costs are allocated to Oregon customers consistent with the currently approved allocation methodology which includes system-allocated transmission costs. This means that the costs of PacifiCorp transmission assets are allocated to states based on a system

[102] 26 U.S.C. § 45Y(a)(1).
[103] 26 U.S.C. § 48E(a)(1).
[104] 26 U.S.C. § 45V(a).
[105] H.R. 1 § 112008 (repealing clean energy production credit after 2028), § 112009 (repealing clean energy investment credit after 2028); § 112013 (repealing clean hydrogen production credit after January 1, 2026).
[106] ORS 757.518.

transmission factor, which calculates demand and energy-related costs based on state-specific annual retail peak consumption and energy usage.[107] Similarly, each state receives a corresponding FERC revenue credit from PacifiCorp's wholesale revenue requirement under the same transmission factor.[108] This means that Oregon retail customers pay for a percentage of PacifiCorp's transmission system, accomplished by an offsetting credit from the use of this system by PacifiCorp's wholesale customers as determined by FERC.

PacifiCorp's 2025 CEP reflects this approach. All incremental transmission resources are system resources, regardless if that transmission resource was only selected to meet Oregon needs.

Considering that there is uncertainty in how transmission costs might be allocated among the states in the future, PacifiCorp analyzed an alternative cost-allocation scenario where the costs from incremental transmission resources that are needed to comply with Oregon policies are entirely situs-allocated to Oregon. Development of this sensitivity should not be interpreted as a PacifiCorp proposal for future allocation methodologies. Rather, this scenario is intended to highlight a potential bookend of how alternative allocation approaches for transmission might influence cost. As such, this scenario analyses the incremental costs resulting from situs-allocation of transmission resources across the CEP preferred portfolio (annual clean) and the hourly clean portfolio, relative to the no-HB 2021 counterfactual.

Under each scenario, the incremental cost to comply with HB 2021 and Oregon's no-coal mandate would be higher than with system-allocation of transmission resources. Table 34 summarizes the Oregon-allocated total nominal costs for the CEP preferred portfolio, the hourly clean portfolio and the no HB 2021 counterfactual (which is unchanged), with the additional costs that would be incurred if incremental transmission was situs cost-allocated to Oregon. Under the annual clean planning environment, the CEP preferred portfolio would incur an additional $559 million over the planning horizon, relative to the no HB 2021 counterfactual, whereas under the hourly clean planning environment the portfolio would incur an additional $4.024 billion to meet energy and capacity needs.

Table 34 – Oregon-allocated Nominal Costs with System and Situs Transmission Costs ($millions)

Study	Costs with System Transmission	Costs with Situs Transmission	Increase in Costs
CEP Preferred Portfolio	$14,634	$15,193	$559
Hourly Clean Portfolio	$45,590	$49,615	$4,024
No HB 2021 Counterfactual	$11,805	$11,805	-

Greenhouse Gas Emissions Reductions

As described above, PacifiCorp's integrated portfolio methodology incorporated HB 2021 emissions reduction targets as part of Oregon's compliance obligations, ensuring they are met through a least-cost, least-risk approach based on the endogenous selection of resources and

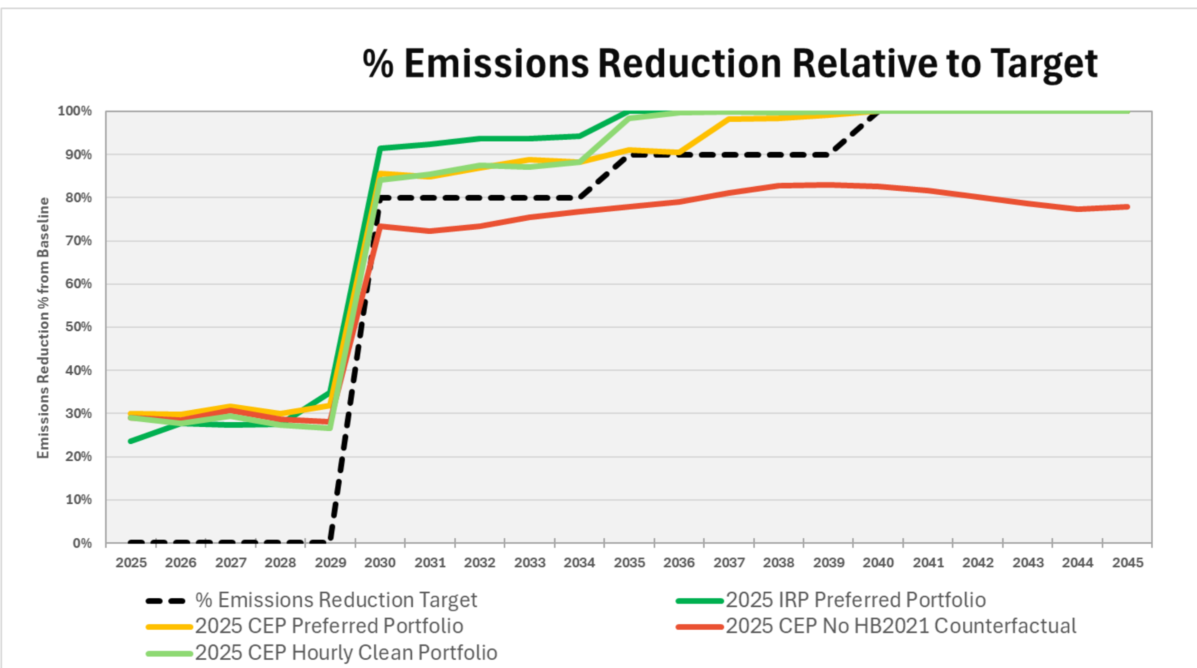
[107] *E.g.,* 2020 Multi-State Protocol, § 5.2.
[108] *Id.*

optimized dispatch of resources and market transactions. This results in a significant downward trend in Oregon-allocated greenhouse gas emissions, with a modest decline from 2025-2029, and a steeper reduction in 2030 onwards. These forecasted reductions are driven by the large addition of proxy renewable and storage resources and removal of coal resources from Oregon rates.

Achieving compliance with HB 2021 requires that (a) enough megawatt-hours of energy are allocated to Oregon to meet every megawatt-hour of Oregon load on an annual basis, and (b) that the emissions associated with those megawatt-hours do not exceed the emissions allowed under the emissions reduction target. Compliance with both requirements creates a need for significant new non-emitting generation. Additionally, Oregon's share of existing gas plants and some gas conversions are modeled as distinct units that dispatch separately from the portion allocated to other jurisdictions. Each Oregon jurisdictional portfolio required that the model add enough megawatt-hours of new non-emitting generation to meet a majority of Oregon load in each year after 2030, ensuring that the emissions associated with any load not met with non-emitting generation does not exceed the emissions reduction target.

Figure 25 illustrates PacifiCorp's Oregon-specific greenhouse gas emissions trajectory, relative to HB 2021 defined targets. The black dashed line represents HB 2021 emissions reduction targets, and emissions relative to the 2025 CEP preferred portfolio, 2025 hourly clean portfolio, 2025 IRP preferred portfolio, and no HB 2021 counterfactual are provided for reference.

Figure 25 – Oregon Greenhouse Gas Emissions elative to HB 2021 Targets

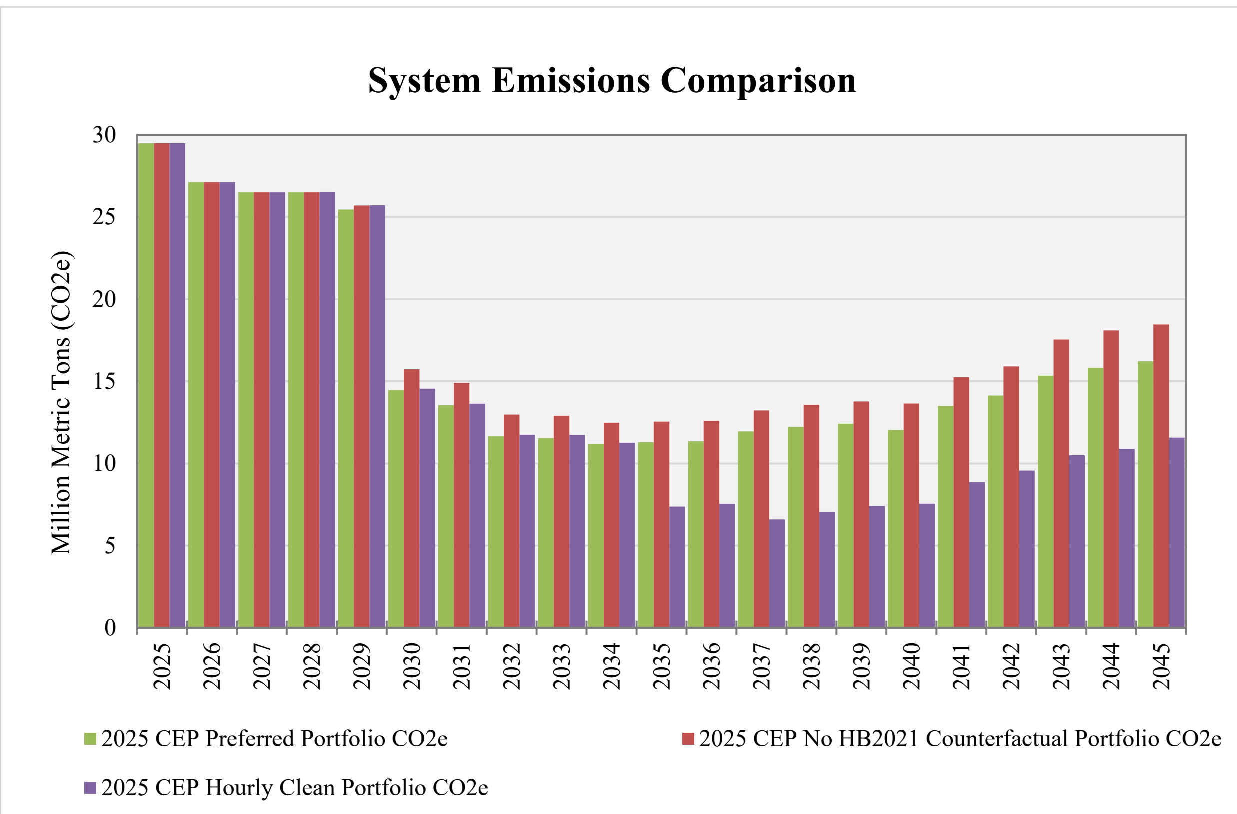


As discussed in prior sections PacifiCorp's Oregon-allocated emissions are materially impacted not only by HB 2021 requirements, but also by Oregon's no-coal mandate. The graph above indicates that beginning in 2030, HB 2021 requirements only require the reduction of Oregon-allocated emissions by an approximate 10 percent in 2030, 12 percent in 2035, and 20 percent in

2040 relative to the emissions profile associated with removing coal from Oregon rates (the no HB 2021 counterfactual).

There are also system emissions impacts from Oregon policies. While HB 2021 is an Oregon statute and its clean energy policies are designed to drive decarbonization efforts within the state, the additional clean energy resources necessary to meet this goal can impact the total PacifiCorp system emissions position. For example, where HB 2021 resources generate more electricity than what is required to meet Oregon retail load in a given hour, any excess energy can displace more expensive, potentially emitting, system resources. As shown in Figure 26, system emissions are expected to decrease over time, even when HB 2021 compliance is not contemplated—though this is driven in-part by Washington's own trajectory towards its CETA targets and that any resources added to meet Oregon's non-HB 2021 capacity needs are also non-emitting. The hourly clean portfolio, unsurprisingly, further drives system emission down over the planning horizon, particularly 2035 and beyond when 15 GW of new non-emitting resources are added to the system. The CEP preferred portfolio, relative to the no HB 2021 counterfactual, also reduces system emissions over the period, most notably from 2030 on.

Figure 26 – Total System Greenhouse Gas Emissions Across CEP Portfolios



Cost Cap Implications

To ensure an equitable energy transition and minimize customer costs, HB 2021 includes a cost cap, such that if a utility's costs to comply with the law exceed 6 percent of a utility's annual revenue requirement for a year, the Commission shall exempt the utility from compliance with Oregon's emissions reductions under certain conditions.[109]

Table 23 is reproduced here which summarizes the estimated average annual cost associated with resource selections that would be required to comply with HB 2021 greenhouse gas reductions targets through 2040. These include four different compliance scenarios where compliance costs for annual and hourly portfolios are calculated assuming Oregon only pays for a system-share of HB 2021 transmission costs (with and without production and investment tax credits), and with full Oregon-allocation of HB 2021 transmission costs (with and without production and investment tax credits).

Table 23 - Estimated HB 2021 Average Annual Compliance Costs 2025-2045 ($millions) and Percentage of 2025 Revenue Requirement (shown in parenthesis)

	Annual Cost with System Transmission	Annual Cost with Situs Transmission	Annual Cost with System Transmission (No PTC/ITCs)	Annual Cost with Situs Transmission (No PTCs/ITCs)
CEP Preferred Portfolio (Annual Clean)	$135 (10%)	$161 (11%)	$214 (12%)	$241 (14%)
Hourly Clean Portfolio	$1,609 (91%)	$1,800 (101%)	$2,287 (129%)	$2,479 (140%)

These analyses are based on: the 11,837 MW or 23,904 MW of resources from the annual and hourly clean CEP resource selections; nominal levelized resource and transmission costs (where resource cost assumptions are based in part on relevant NREL ATB cost assumptions); and PacifiCorp's revenue requirement as approved by the Commission in PacifiCorp's most recent rate case—$1.774 billion (without escalating this figure over time to account for non-HB 2021 cost increases).[110]

Importantly, these figures also include two untested assumptions: (1) that all resources otherwise necessary to comply with Oregon's no-coal mandate (which by definition must also be HB 2021-compliant), are not included in HB 2021's cost cap; and (2) that while HB 2021's cost cap does not apply to SSR resources, the SSR resources necessary to meet the incremental 10 percent SSR obligation for HB 2021 resources are included.

If the costs of replacement resources to comply with Oregon's no-coal mandate were included within HB 2021's cost cap, that would *significantly increase* the costs to comply with HB 2021, as the company estimates at least an additional 2 GW of resources are necessary to replace Oregon's share of coal resources. If the costs of incremental SSR resources are not included within HB 2021's cost cap, that would *slightly decrease* the costs to comply with HB 2021, as the company estimates approximately 123 MW and 901 MW of additional SSRs are included in the table above—1.04 and 4 percent of the total HB 2021-driven resources.

[109] ORS 469A.445.
[110] *E.g., In re PacifiCorp's 2024 Oregon Rate Case,* UE 433, Order No. 24-447 (Dec. 19, 2024).

While this summary is not intended to be a precise application of how the cost cap might be calculated under HB 2021, these data indicate that there is the potential for PacifiCorp to exceed the cost cap under most annual clean portfolios. The average annual cost to comply with HB 2021 under annual clean scenarios range from $135 million to $2 million each year on average, amounting to a 7-14% increase relative to current Oregon rate base. These compliance costs only increase under each hourly clean portfolio. The average annual cost to comply with HB 2021 in each hour starting in 2035 would range from $1.609 billion to $2.479 billion each year, amounting to a 91-140% increase relative to current Oregon rate base.

While specific cost cap implications depend on the timing, pacing, and volume of resource procurement to analyze PacifiCorp revenue requirement impacts, as well as the Commission's additional guidance in UM 2273, PacifiCorp provides this analysis as benchmarks of HB 2021 cost cap implications for Commission and stakeholder review.

IX. ACTION PLAN

PacifiCorp's 2025 CEP presents a near-term action plan identifying steps that it will take over the next two-to-four years to deliver resources in the CEP preferred portfolio for Oregon customers. This action plan includes action items for existing resources, new resources, transmission, DSM resources, short-term firm market purchases, and the purchase and sale of RECs.

The action matrix in Table 36 is an Oregon-specific view that expands upon the systemwide action plan included in the 2025 IRP to include other actions that broadly support the company's progress and fulfillment of HB 2021 goals, such as community and stakeholder engagement, activities related to CBIs, and forthcoming regulatory filings and actions.

Table 35 – Oregon Clean Energy Plan Action Matrix

Action Item	Existing Resource Actions
1a	**Natural Gas Emissions Compliance Strategies:** • The 2025 CEP indicates that changes in accounting and/or dispatch of existing natural gas resources may be beneficial for HB 2021 compliance strategies and to align with evolving state policies. PacifiCorp will continue investigating strategies with impacted parties, program administrators, and regulators on available options to prepare for implementation no later than 2030.
	New Resource Actions
2a	**Small-scale renewables RFP:** • On April 23, 2025, PacifiCorp issued an OR SSR RFP. • PacifiCorp will continue to investigate, develop, and pursue other strategies, as outlined in its SSR Acquisition Strategy filed concurrently with the 2025 IRP, to increase its small-scale and community-based resources.

	• PacifiCorp will evaluate opportunities to accelerate procurement of resources identified in the preferred portfolio in 2030 when evaluating proposals from the 2025 OR SSR.
2b	**<u>2025 Oregon-situs RFP:</u>** • On April 16, 2025 PacifiCorp filed the draft 2025 OR Situs RFP to procure Oregon situs resources that can achieve commercial operations by the end of December 2029. PacifiCorp expects a Commission decision regarding approval of the RFP by early October 2025. Following approval, PacifiCorp will issue the RFP to market. • PacifiCorp will evaluate opportunities to accelerate procurement of resources identified in the preferred portfolio in 2030 when evaluating proposals from the 2025 OR Situs RFP.
2c	**<u>Transmission:</u>** • Ensure that PacifiCorp's planning, siting, and development of Oregon-sited distribution and transmission resources minimizes impacts to PacifiCorp's Oregon EJ Communities.
	Demand-Side Management (Actions)
3a	**<u>Energy Efficiency</u>** • In 2025, PacifiCorp will continue collaborating with the ETO to review their proposed inaugural MYP that will establish their energy efficiency targets, corresponding budgets, and cross-organization support for the next five-year period (2026-2030).
3b	**<u>Demand Response</u>** • PacifiCorp will continue to expand its portfolio of DR programs by launching three new programs in 2025: Wattsmart Battery, Wattsmart Drive, and Cool Keeper. • In 2026 and beyond, the company will focus on sustaining a rapid pace of growth in existing programs, to double the total DR capacity by 2027.
	Community-Based Renewable Energy Actions
4a	• Provide an annual CBRE assessment and report, and continue to strengthen partnerships with ETO. • Consider a Blue Sky Grant Program "Go-Back" strategy.
	Community Engagement
5a	**<u>Advisory Groups</u>** • PacifiCorp will continue to include an update on various elements of the CEP in the CBIAG meetings (including Tribal Nations-focused meetings) through 2025.
5b	**<u>CEP Engagement Series</u>** • PacifiCorp will continue to offer Oregon CEP engagement series meetings, with four regular sessions scheduled in 2025, with opportunity

	for additional special meetings as requested or required, as an avenue for expanded learning and dialogue on key clean energy planning topics.
	Community Benefit Indicators
6a	• PacifiCorp has proposed two new CBI metrics: SO_2 and NOx, and will continue to solicit input and feedback from its advisory groups and interested parties and finalize the proposed metrics.
6b	• PacifiCorp will continue refining its CBI framework, evaluating current CBIs and proposed metrics to establish a clear baseline and transparent framework for use in resource procurement, planning, and other relevant business decisions.
6c	• PacifiCorp will work with advisory group members and other interested parties to develop a proposal to more fully define environmental justice communities within its service area over the one to two years.
	Regulatory Actions
7a	**<u>Agency Engagement</u>** • PacifiCorp will engage with Oregon DEQ in any upcoming relevant rulemakings to address changes to the methodology and calculations of greenhouse gas emissions for purposes of demonstrating progress towards clean energy targets. • PacifiCorp will continue to engage with the Commission and stakeholders in docket UM 2273 regarding the implementation of HB 2021's cost cap. • PacifiCorp will continue to work with the Commission and stakeholders regarding PacifiCorp's request for clarification on Oregon's SSR mandate. • PacifiCorp continues to engage with CAISO, regulators, and other stakeholders on developing a greenhouse gas accounting and reporting framework for market participation.

Key Issues for Further Consideration

PacifiCorp represents that there are several key issues that the Commission should consider in its review of this CEP.

- Cost Cap. Even under conservation assumptions, PacifiCorp's compliance strategies could trigger HB 2021's cost cap. Relative to current rate base, average annual impacts from HB 2021 are forecasted to range from 10 percent under annual compliance with system transmission costs, to 101 percent under annual cost for hourly compliance with system transmission. These costs increase materially if federal production or investment tax credits are repealed, or if Oregon customers are assigned the full transmission costs triggered by HB 2021 resources.

- Situs-Transmission. HB 2021 requires significant transmission upgrades, and if these costs are situs assigned to Oregon under a future cost allocation methodology, HB 2021 costs increase by an additional $559 million to $4.024 billion across the planning horizon.

- Load Growth. PacifiCorp's current CEP load forecast reflects a modest growth rate in Oregon retail sales over the next 10-year period (a compounded annual growth rate of 0.07 percent).[111] This is a material difference from the 2023 CEP, which forecasted a 4.39 percent 10-year compounded annual growth rate.[112] These forecasts can differ dramatically each CEP cycle based on the timing and siting of data center load. For example, the 2025 IRP includes a high data center load forecast scenario, which indicates an approximate 7.5 GW of additional system resources that could be needed to meet increased demand by 2045.[113] High data center load growth presents material compliance issues for HB 2021 purposes. As noted in PacifiCorp's 2023 CEP: "Gradual load growth can be accommodated through PacifiCorp procurement efforts addressing both utility and small-scale resources. Large, uncertain load growth can create immediate procurement needs."[114]

- Just-in-time Compliance. Least-cost, least-risk planning delays resource procurement until necessary to meet state-specific policy objectives. The accelerated resource sensitivity provides one scenario and additional context for how accelerated resource procurement could impact the timing and cost of resource procurement. As noted in the action plan, PacifiCorp will evaluate opportunities to accelerate procurement of resources identified in the preferred portfolio in 2030 when evaluating proposals from the 2025 OR Situs RFP and the 2025 OR SSR RFP.

- EDAM and Markets+ Implications. Based on current information, PacifiCorp's CEP does not account for impacts from market participation, but the company will continue to review how market participation impacts energy and compliance forecasts in future planning cycles.

- Continued DEQ Rulemaking Efforts. By 2030, resources allocated to Oregon to satisfy HB 2021 emission requirements are forecasted to exceed Oregon's annual energy requirements. Currently, DEQ regulations do not allow the company to specify sales on an Oregon-allocated basis or by fuel type; if PacifiCorp's generation exceeds load, specified sales must reflect a proportionate share of the system, not individual resources. If PacifiCorp were permitted to sell Oregon-allocated energy exceeding its annual requirements from specific emitting resources, the company could further reduce emissions, accelerate progress toward its HB 2021 targets, and lower costs for Oregon customers. In addition, Oregon DEQ's emission factor for an unspecified source of electricity, which is set in rule, may not accurately reflect current grid

[111] *In re PacifiCorp's 2025 IRP,* Volume II, Table A.10, at 14.
[112] The primary driver to changes in load growth are due to the exclusion of specific new large customers who are expected to provide or pay for the resources and transmission necessary to support their load.
[113] 2025 IRP, Vol. II, Figure A.5, at 18.
[114] *Id.*

conditions and should be revised to accurately reflect the current mix of regional resources.

- Renewable and Non-Emitting Market Development. PacifiCorp continues to engage with the California Independent System Operator (CAISO), regulators, and stakeholders on developing a GHG accounting and reporting framework for market participants. The framework aims to provide market participants with an approach to detail emissions associated with market transfers, which could significantly decrease the costs to comply with state-specific policies that require clean or non-emitting energy resources. Oregon DEQ may also use data generated by the CAISO to inform GHG rulemaking in Oregon.

APPENDIX A: SUPPORTING WORKPAPERS AND REFERENCES

Chapter IV – Community Benefit Indicators

File Name	Short Description	Tables	Figures
Resilience (2022-2024).xlsx	Detailed List of SAIDI, SAIFI and CAIDI Scores by Census Tract, ACS 2023 (5-year average)	4, 5, 6	
Burden (LEAD).xlsx	Complete List of Energy Burden Estimates by Census Tract, LEAD Tool (5-year average)	8	
Arrears & Disconnects (2022-2024).xlsx	Complete List of all Disconnections and Arrears by Census Tract, ACS 2023 (5-year average)	9, 10	
LID Enrollments (2022-2024).xlsx	Complete List of LID Enrollments from 2022-2024 by census tract, ACS 2023 (5-year average)	11	
LID Enrollments.xlsx	Visualization of all LID Enrollments by census tract		1
Incentives (2023-2024).xlsx	List of all Incentives by Type and Census Tract, ACS 2023 (5-year average)	12, 13, 14, 15	

Chapter VI – Community-Based Renewable Energy

File Name	Short Description	Tables	Figures
Inventory of CBRE Projects.xlsx	Detailed list and/or links to locations of projects identified within the CBRE inventory process and study of potential future projects within known channels	-	-

Chapter VIII – Resources, Costs, and Emissions Reductions[115]

File Name	Short Description	Tables	Figures
CEP Preferred Portfolio (LT. 187421 - 187467)_OR Emissions Workpaper_FINAL_06-25-2025.xlsx	Oregon Allocated Greenhouse Gas Emissions associated with the CEP Preferred Portfolio.	24	25
CEP No HB2021 Counterfactual Portfolio (LT. 187535 - 187814)_OR Emissions Workpaper_FINAL 06-25-2025.xlsx	Oregon Allocated Greenhouse Gas Emissions associated with the CEP No HB2021 Counterfactual Portfolio.	24	25
CEP No HB2021 No SSR Portfolio (LT. 191213 - 191304)_OR Emissions Workpaper_FINAL 06-25-2025.xlsx	Oregon Allocated Greenhouse Gas Emissions associated with the CEP No HB2021 SSR Portfolio.	24	
CEP Max Customer Benefit Portfolio (LT. 191484 - 191485)_OR Emissions Workpaper_FINAL 06-25-2025.xlsx	Oregon Allocated Greenhouse Gas Emissions associated with the CEP Max Customer Benefit Portfolio.	24	

[115] Some workpapers listed as supporting this chapter have prefixes not listed here that support their level of confidentiality. Public workpapers have the prefix "(P)_", confidential workpapers have the prefix "CONF_", and highly confidential workpapers have the prefix "HIGH CONF_"

File Name	Short Description	Tables	Figures
CEP In-State Resources Portfolio (LT. 191784 - 192354)_OR Emissions Workpaper_FINAL 06-25-2025.xlsx	Oregon Allocated Greenhouse Gas Emissions associated with the CEP In-State Resources Portfolio.	24	
CEP CBRE Valuation Study Portfolio (LT. 187941 - 190878)_OR Emissions Workpaper_FINAL 06-25-2025.xlsx	Oregon Allocated Greenhouse Gas Emissions associated with the CEP CBRE Valuation Portfolio.	24	
CEP Accelerated Resources Portfolio (LT. 191303 - 191623)_OR Emissions Workpaper_FINAL 06-25-2025.xlsx	Oregon Allocated Greenhouse Gas Emissions associated with the CEP CEP Accelerated Portfolio.	24	
CEP Hourly Clean Portfolio (LT. 191018 - 191065)_OR Emissions Workpaper_FINAL_06-25-2025.xlsx	Oregon Allocated Greenhouse Gas Emissions associated with the CEP Hourly Clean Portfolio.	24	25

File Name	Short Description	Tables	Figures
2025 CEP_OR Emissions Portfolio Comparison Chart_FINAL_06-12-2025.xlsx	Chart comparing progress to HB2021 targets from the 2025 IRP, CEP Preferred, No HB2021 Counterfactual, and Hourly Clean Portfolios.		25
CEP Preferred Portfolio (LT. 187421 - 187467)_System Emissions Workpaper_FINAL 06-25-2025.xlsx	System Greenhouse Gas Emissions associated with the CEP Preferred Portfolio.		26
CEP No HB2021 Counterfactual Portfolio (LT. 187535 - 187814)_System Emissions Workpaper_FINAL 06-25-2025.xlsx	System Greenhouse Gas Emissions associated with the CEP No HB2021 Counterfactual Portfolio.		26
CEP Hourly Clean Portfolio (LT. 191018 - 191065)_System Emissions Workpaper_FINAL_06-25-2025.xlsx	System Greenhouse Gas Emissions associated with the CEP Hourly Clean Portfolio.		26
2025 CEP_System Emissions Portfolio Comparison Chart_FINAL_06-12-2025.xlsx	Chart comparing system emissions between the CEP Preferred, No HB2021 Counterfactual, and Hourly Clean Portfolios.		26

File Name	Short Description	Tables	Figures
Tbl 23,Tbl 27-Avg Annual Compliance Costs.xlsx	Shows CEP resource selections by portfolio and type	23	
Tbl 25,26-25,Fig 6-8- CEP Resources by Type.xlsx	Shows CEP resource selections by portfolio and type	25	
Tbl 25,26-25,Fig 6-8- CEP Resources by Type.xlsx	Shows CEP resource selections by portfolio and type	26	
Tbl 25,26-25,Fig 6-8- CEP Resources by Type.xlsx	Shows CEP resource selections by portfolio and type		7
Tbl 25,26-25,Fig 6-8- CEP Resources by Type.xlsx	Shows CEP resource selections by portfolio and type		6
Tbl 25,26-25,Fig 6-8- CEP Resources by Type.xlsx	Resource selections compare		8
Fig 9-LT_OR.EP.2503MN.Clean110%AlwaysBind.Iterator (187421) less LT_Integrated.EP.2409MN.BaseIntTrans (155264).xlsb	Cost Comparison		9
Fig 10-_Compare - 25 CEP PP less 25 IRP PP.xlsx	Resource selections compare		10
Fig 11 LT Compare-CEP PP (187421) less No HB2021 Counterfactual (187535).xlsb	Cost Comparison		11
Fig 12-_Compare - 25 CEP PP less No HB2021 Compliance Counterfactual.xlsx	Resource selections compare		12
Fig 13-LT_OR.EP.2503MN.Clean110%AlwaysBind.Iterator (187421) less LT_Integrated-ORNoSSR.EP.2503MN.187535 (191213).xlsb	Cost Comparison		13

File Name	Short Description	Tables	Figures
Fig 14-_Compare - 25 CEP PP less No HB2021 NoSSR Compliance Counterfactual.xlsx	Resource selections compare		14
Fig 15-LT_OR.EP.2503MN.Clean110%AlwaysBind.Iterator (187421) less LT_Integrated-OR+CBRE.EP.2503MN.187421 (187941).xlsb	Cost Comparison		15
Fig 16-_Compare - 25 CEP PP less CBRE.xlsx	Resource selections compare		16
Fig 17-LT_OR.EP.2503MN.Clean110%AlwaysBind.Iterator (187421) less LT_OR.EP.2503MN.MaxBenefit (191484).xlsb	Cost Comparison		17
Fig 18-_Compare - 25 CEP PP less Max Customer Benefits.xlsx	Resource selections compare		18
Fig 19-LT_OR.EP.2503MN.Clean110%AlwaysBind.Iterator (187421) less LT_OR.EP.2503MN.OR InState (191784).xlsb	Cost Comparison		19
Fig 20-_Compare - 25 CEP PP less In State Resources.xlsx	Resource selections compare		20
Fig 21-LT_OR.EP.2503MN.Clean110%AlwaysBind.Iterator (187421) less LT_Integrated-OR+Accelerate.EP.2503MN.187421 (191303).xlsb	Cost Comparison		21

File Name	Short Description	Tables	Figures
Fig 22-_Compare - 25 CEP PP less Accelerated Resources.xlsx	Shows average annual compliance costs		22
Tbl 23,Tbl 27-Avg Annual Compliance Costs.xlsx	Shows SSR Target	27	
Tbl 29-OR CEP PP SSR Table.xlsb	Shows transmission tables	29	
Tbl 30, Tbl 33-TransmissionTables.xlsx	Resource selections compare	30	
Fig 23-Hourly Clean (191018) less Annual Clean PP (187421).xlsb	Shows transmission tables		23
Tbl 30, Tbl 33-TransmissionTables.xlsx	Cost Comparison	33	
Fig 24-_Compare - 25 CEP PP less Hourly Clean.xlsx			24
LT_25C.IR.iLT.21.Integrated-OR.EP.2503MN.189724 Geo1 - 191018 v14.8.xlsx	Resource selections report		
LT_25C.IR.iLT.21.Integrated-OR+Accelerate.EP.2503MN.187421 - 191303 v16.4.xlsx	Resource selections report		
LT_25C.IR.iLT.21.Integrated-OR+CBRE.EP.2503MN.187421 - 187941 v11.1.xlsx	Resource selections report		
LT_25C.IR.iLT.21.Integrated-ORNoSSR.EP.2503MN.187535 - 191213 v16.3.xlsx	Resource selections report		
LT_25C.IR.iLT.21.OR.EP.2503MN.MaxBenefit - 191484 v16.9.xlsx	Resource selections report		

File Name	Short Description	Tables	Figures
LT_25C.IR.iLT.21.OR-NoTaxCredits.EP.2503MN.187421 - 191141 v15.7.xlsx	Resource selections report		
LT_25C.IR.iLT.21.OR-NoTaxCredits.EP.2503MN.187535 - 191142 v15.7.xlsx	Resource selections report		
LT_25C.IR.iLT.21.OR-NoTaxCredits.EP.2503MN.191018 - 191143 v15.8.xlsx	Resource selections report		
LT_25C.IR.iLT.r21.Integrated-ORWithDJ1+2.EP.2503MN.187421 - 193231 v19.2.xlsx	Resource selections report		
LT_25C.IR.iLT.r21.OR.EP.2503MN.Clean90%AlwaysBind.Iterator - 187535 v.xlsx	Resource selections report		
LT_25C.IR.iLT.r21.OR.EP.2503MN.Clean110%AlwaysBind.Iterator - 187421 v.xlsx	Resource selections report		
LT_25C.IR.iLT.r21.OR.EP.2503MN.HourlyClean_200.Iterator - 189724 v.xlsx	Resource selections report		
LT_25C.IR.iLT.r21.OR.EP.2503MN.OR InState - 191784 v17.7.xlsx	Resource selections report		
OR Alloc ST Cost Summary - 25C.IR.ST.r21.OR.EP.2503MN.Accelerate.191303 (LT. 191303 - 191623) v17.1.xlsb	Cost Report		
OR Alloc ST Cost Summary - 25C.IR.ST.r21.OR.EP.2503MN.AnnualClean-	Cost Report		

File Name	Short Description	Tables	Figures
NoTaxCredits.191141 (LT. 191141 - 191145) v16.xlsb			
OR Alloc ST Cost Summary - 25C.IR.ST.r21.OR.EP.2503MN. Clean110%AlwaysBind.Iterator (LT. 187421 - 187467) v.xlsb	Cost Report		
OR Alloc ST Cost Summary - 25C.IR.ST.r21.OR.EP.2503MN. Clean110%AlwaysBind+CBRE. 187941 (LT. 187941 - 190878) v14.2.xlsb	Cost Report		
OR Alloc ST Cost Summary - 25C.IR.ST.r21.OR.EP.2503MN. HourlyClean_200.191018 (LT. 191018 - 191065) v15.1.xlsb	Cost Report		
OR Alloc ST Cost Summary - 25C.IR.ST.r21.OR.EP.2503MN. MaxBenefit.191484 (LT. 191484 - 191485) v17.xlsb	Cost Report		
OR Alloc ST Cost Summary - 25C.IR.ST.r21.OR.EP.2503MN. NonComp.187535 (LT. 187535 - 187814) v10.5.xlsb	Cost Report		
OR Alloc ST Cost Summary - 25C.IR.ST.r21.OR.EP.2503MN. NonCompNoSSR.191213 (LT. 191213 - 191304) v16.5.xlsb	Cost Report		
OR Alloc ST Cost Summary - 25C.IR.ST.r21.OR.EP.2503MN. OR InState (LT. 191784 - 192354) v17.9.xlsb	Cost Report		

File Name	Short Description	Tables	Figures
OR Alloc ST Cost Summary - 25C.IR.ST.r21.OR-NoTaxCredits.EP.2503MN.HourlyClean_200.191143 (LT. 191143 - 191189) v16.xlsb	Cost Report		
OR Alloc ST Cost Summary - 25C.IR.ST.r21.OR-NoTaxCredits.EP.2503MN.NonComp.191142 (LT. 191142 - 191167) v16.xlsb	Cost Report		

APPENDIX B – OREGON REGULATORY COMPLIANCE

Introduction

This appendix describes how PacifiCorp's 2025 CEP complies with the Oregon Commission's standards, guidelines, and specific analytical requirements.

The 2025 CEP, in alignment with compliance requirements, is fundamentally based on methods and data developed for the 2025 IRP, with updates as appropriate. Relevant IRP regulatory requirements are therefore included below. For a full presentation of IRP regulatory compliance, please refer to the publicly available 2025 IRP[116].

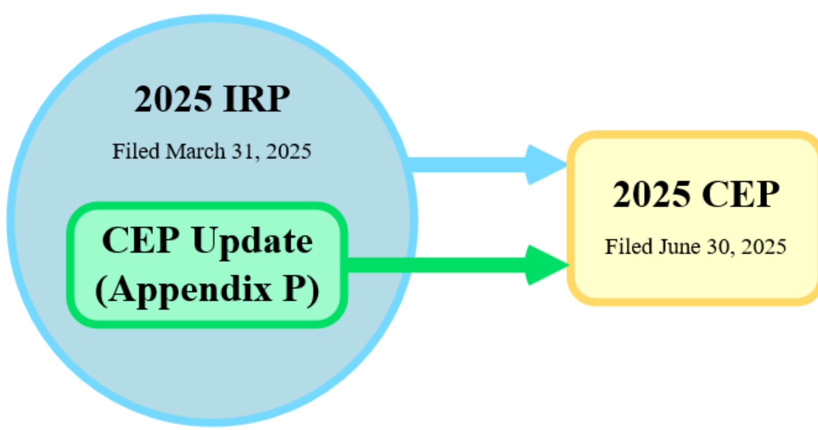
General Compliance

PacifiCorp prepares the IRP, which underlies the CEP, on a biennial basis. The preparation of the IRP is done in an open public process with consultation from all interested parties, including commissioners and commission staff, customers, and other stakeholders. This open process provides parties with a substantial opportunity to contribute information and ideas in the planning process and serves to inform all parties on the planning issues and approach.

The IRP provides a framework and plan for future actions to ensure PacifiCorp continues to provide reliable and least-cost electric service to its customers. The IRP evaluates, over a twenty-year planning period, the future load of PacifiCorp customers and the resources required to meet this load.

As illustrated in Figure B.1, the 2025 CEP is supported by the totality of the 2025 IRP, inclusive of the IRP's Appendix P (Oregon Clean Energy Plan Update).

Figure B.1 – 2025 IRP, CEP Update and 2025 CEP Relationship



[116] PacifiCorp's 2025 IRP is available online at https://www.pacificorp.com/energy/integrated-resource-plan.html.

Table B.1 – Integrated Resource Planning Standards and Guidelines Summary

IRP Guidelines - Source
Order No. 07-002, *Investigation into Integrated Resource Planning*, January 8, 2007, as amended by Order No. 07-047. Order No. 08-339, *Investigation into the Treatment of CO2 Risk in the Integrated Resource Planning Process*, June 30, 2008. Order No. 09-041, New Rule OAR 860-027-0400, implementing Guideline 3, "Plan Filing, Review, and Updates". Order No. 12-013, "Investigation of Matters related to Electric Vehicle Charging", January 19, 2012 Order No. 23-061, "Reconsideration of Order No. 22-390 Granted in Part; Reconsideration of Order Nos. 22-446 and 22-477 Denied, February 24, 2023.
IRP Guidelines – Source
Least-cost plans must be filed with the Oregon PUC, including a Clean Energy Plan.
IRP Guidelines - Frequency
Plans filed biennially, within two years of its previous IRP acknowledgment order. An annual update to the most recently acknowledged IRP is required to be filed on or before the one-year anniversary of the acknowledgment order date. While informational only, utilities may request acknowledgment of proposed changes to the action plan.
IRP Guidelines – Commission Response
Least-cost plan (LCP) *acknowledged* if found to comply with standards and guidelines. A decision made in the LCP process does not guarantee favorable rate-making treatment. The OPUC may direct the utility to revise the IRP or conduct additional analysis before an acknowledgment order is issued.
IRP Guidelines - Process
The public and other utilities are allowed significant involvement in the preparation of the plan, with opportunities to contribute and receive information. Order 07- 002 requires that the utility present IRP results to the Oregon PUC at a public meeting prior to the deadline for written public comments. Commission staff and parties should complete their comments and recommendations within six months after IRP filing. Competitive secrets must be protected.
IRP Guidelines - Focus
20-year plan, with end- effects, and a short-term (two-year) action plan. The IRP process should result in the selection of that mix of options which yields, for society over the long run, the best combination of expected costs and variance of costs.

IRP Guidelines - Elements
Basic elements include: • Consistent and comparable resource evaluation. • Risk and uncertainty must be considered. • Least cost planning, consistent with the long-run public interest. • Consistent with Oregon and federal energy policy. • External costs must be considered, and quantified where possible. OPUC specifies environmental adders (Order No. 93-695, Docket UM 424). • Multi-state utilities should plan their generation and transmission systems on an integrated-system basis. • Construction of resource portfolios over the range of identified risks and uncertainties. • Portfolio analysis shall include fuel transportation and transmission requirements. • Plan includes conservation potential study, demand response resources, environmental costs, and distributed generation technologies. • Avoided cost filing required within 30 days of acknowledgment. • IRP includes a description of the electric company's plan for meeting the requirements of the renewable portfolio standard.

Table B.2 –IRP/CEP Requirements and Handling

Reference	Requirement or Recommendation	2025 IRP/CEP Approach
ORS 469A.415	(1) An electric company shall develop a clean energy plan for meeting the clean energy targets set forth in ORS 469A.410 (Clean energy targets) concurrent with the development of each integrated resource plan.	This 2025 CEP is submitted in fulfillment of this requirement.
ORS 469A.415	(2) The electric company shall submit the clean energy plan to the Public Utility Commission and the Department of Environmental Quality.	This 2025 CEP is submitted in fulfillment of this requirement.
ORS 469A.415	(3) (a) A clean energy plan must be based on or included in an integrated resource plan filing made no earlier than January 1, 2022, and filed no later than 180 days after the integrated resource plan is filed, or developed within an integrated resource planning process and incorporated into the integrated resource plan filed with the commission.	The 2025 CEP is submitted 90 days after the filing of the 2025 IRP in fulfillment of this requirement.
ORS 469A.415	(3) (b) Notwithstanding paragraph (a) of this subsection, a clean energy plan developed by a multistate jurisdictional electric company must be based on or contained in other information developed consistent with a cost-allocation methodology approved by the commission.	All cost-allocation assumptions used to develop this clean energy plan are based on currently approved methodologies.
ORS 469A.415	(4) A clean energy plan must: (a) Incorporate the clean energy targets set forth in ORS 469A.410 (Clean energy targets);	The 2025 CEP incorporates and is developed to meet the clean energy targets.
ORS 469A.415	(b) Include annual goals set by the electric company for actions that make progress towards meeting the clean energy targets set forth in ORS 469A.410 (Clean energy targets), including acquisition of nonemitting generation resources, energy efficiency	The 2025 CEP includes annual outcomes and goals that contribute towards the clean energy targets.

Reference	Requirement or Recommendation	2025 IRP/CEP Approach
	measures and acquisition and use of demand response resources;	
ORS 469A.415	(c) Include a risk-based examination of resiliency opportunities that includes costs, consequences, outcomes and benefits based on reasonable and prudent industry resiliency standards and guidelines established by the Public Utility Commission;	The 2025 CEP Chapter V: Resiliency fulfills this requirement.
ORS 469A.415	(d) Examine the costs and opportunities of offsetting energy generated from fossil fuels with community-based renewable energy;	The 2025 CEP Chapter VI: Community-Based Renewable Energy describes how PacifiCorp is examining the costs and opportunities of CBRE projects.
ORS 469A.415	(e) Demonstrate the electric company is making continual progress within the planning period towards meeting the clean energy targets set forth in ORS 469A.410 (Clean energy targets), including demonstrating a projected reduction of annual greenhouse gas emissions; **and**	The 2025 CEP Chapter II: Continual Progress describes how PacifiCorp is demonstrating continual progress with the long-term clean energy goals.
ORS 469A.415	(f) Result in an affordable, reliable and clean electric system	The 2025 IRP and CEP process are designed to result in a long-term plan is affordable and reliable while meeting the clean energy obligations.
ORS 469A.415	(5) Actions and investments proposed in a clean energy plan may include the development or acquisition of clean energy resources, acquisition of energy efficiency and demand response, including an acquisition required by ORS 757.054 (Cost-effective energy efficiency resources and demand	The 2025 IRP and CEP include a comprehensive plan that contemplated cost-effective demand-side management resources, transmission resources, supply-side resources and any necessary changes to operations of the system.

Reference	Requirement or Recommendation	2025 IRP/CEP Approach
	response resources), development of new transmission and other supporting infrastructure, retirement of existing generating facilities, changes in system operation and any other necessary action.	
Order No. 24-073	#5: Direct PacifiCorp to develop proposals for the use of CBIs in scoring in the SSR RFP, in the design of the CBRE pilot, and in scoring for the next all-source RFP.	PacifiCorp has included CBIs for the use of scoring in the 2025 OR SSR RFP that was issued to market on April 23, 2025 and in the draft 2025 OR Situs RFP filed with the Commission on April 16, 2025 PacifiCorp utilized both Resilience CBIs in its design of the CBRE-RH Pilot and will track the associated metrics as part of the progress reporting within the Pilot.
Order No. 24-073	#6: Direct PacifiCorp to provide specific baseline metrics in the 2025 IRP/CEP to allow for measured progress towards CBI goals.	PacifiCorp has included baseline metrics for its current CBI framework in Chapter IV of the 2025 CEP.
Order No. 24-073	# 7: Direct PacifiCorp to proceed with the CBRE Grant Pilot, contingent on the Company seeking feedback from the CBIAG and environmental justice groups	This has been completed. Please refer to PacifiCorp's CBRE Resiliency Hub Pilot filing with the Commission and Chapter VI of the 2025 CEP.
Order No. 24-073	#8: Direct PacifiCorp to work collaboratively with Staff, stakeholders, peer utilities, environmental justice groups, and the CBIAGs in a dedicated working group to develop clear, actionable improvements to community and stakeholder engagement in subsequent IRP/CEPs by December 31, 2024. If PacifiCorp cannot complete this effort by this timeline, PacifiCorp should provide a detailed status update and explanation of how it will ensure that remaining issues are resolved as soon as practicable, inclusive of the perspectives of peer utilities and the utilities.	This has been completed. PacifiCorp filed a Report on CEP Engagement with the Commission on December 30, 2024, in docket LC 82.
Order No. 24-073	#9: The SSR RFP incorporates into project selection criteria appropriate elements of the current Resiliency Analysis Framework and	The 2025 OR SSR RFP includes demonstrated capability of a resource to deliver to PacifiCorp's Oregon load as an eligibility requirement. The CBRE RH-Pilot was designed with the Resiliency Analysis Framework in mind, specifically leveraging the

Reference	Requirement or Recommendation	2025 IRP/CEP Approach
	the CBRE Pilot be designed to promote resiliency-related factors.	Community-Utility Resilience Scores.
Order No. 24-073	#10: In the 2025 IRP/CEP, direct PacifiCorp to update Natrium assumptions to reflect actual events.	For the 2025 IRP and CEP, Natrium assumptions have been updated to the extent possible as described in 2025 IRP, Chapter 7 (Resource Options), and 2025 CEP, Chapter VIII.
Order No. 24-073	#12: Acknowledge updated avoided costs from the 2023 IRP planning and direct PacifiCorp to work with Staff and Stakeholders to update avoided costs for use in UM 1893 considering HB 2021 constraints.	PacifiCorp's November 2024 energy efficiency avoided cost submittal in docket UM 1893 included incremental value associated with the need for clean energy resources for compliance with HB 2021. PacifiCorp's submittal in response to Staff's proposal for qualifying facility avoided costs in docket UM 2000 also includes incremental value related to HB 2021. PacifiCorp expects this concept to be further developed in its 2025 CEP, and to continue to evolve as it applied in specific programs and rates.
Order No. 24-073	#15: In the 2025 IRP/CEP model, PacifiCorp must: (1) demonstrate that simultaneous compliance with all state-level policies is feasible with the least-cost, least-risk Preferred Portfolio and with the Preferred Portfolio variants tested in the IRP under multiple allocations.	In the 2025 IRP, each jurisdiction's resources are optimally selected in compliance with its unique requirements and then integrated into the preferred portfolio. Existing resources are assumed to be allocated consistent with what is currently approved in each states' rates for cost-allocations. Proxy resource selections, as they are driven by a jurisdictions' specific need and obligations, are generally assumed to be situs cost allocated. Allocation strategies were not used to demonstrate compliance with HB 2021 greenhouse gas emissions reductions. In the 2025 CEP, all jurisdictional selections as developed optimally for the 2025 IRP preferred portfolio, are locked and only Oregon's resource selections are re-optimized. Each portfolio is simultaneously compliant with all state-level policies.
Order No. 24-073	#16: In the 2025 IRP/CEP, PacifiCorp shall include an analysis of forecasted costs and annual emissions of the Preferred Portfolio using only actual carbon prices in effect in 2025 through the 20-year planning horizon.	In the 2025 IRP and CEP, this requirement is met through the base assumptions of the medium gas price / no carbon price (MN) scenario. PacifiCorp also models other price-policy scenarios considering alternative carbon price futures in the 2025 IRP.
Order No. 24-073	#17: In the 2025 IRP/CEP, PacifiCorp shall calculate and report the costs and GHG emissions associated with each portfolio assuming that GHG prices are not reflected in dispatch decisions but still included in investment and retirement decisions.	The base or 'expected' case assumption in the 2025 IRP for the preferred portfolio and all variants has no GHG cost adder for Oregon (and system) resource selections or dispatch. Other jurisdictions' modeling requirements include GHG emissions as a cost-adder for the selection of their resources. Other price policies (as indicated by their names) may have GHG emissions costs which impact dispatch, but these portfolios are for analytics and not selectable as the preferred portfolio. The 2025 CEP portfolio analysis does not include additional GHG cost adders.

Reference	Requirement or Recommendation	2025 IRP/CEP Approach
Order No. 24-073	#18: In the 2025 IRP/CEP PacifiCorp shall provide an explanation of renewable cost assumptions and a comparison to recent pricing information from such organizations as National Renewable Energy Lab and Lazard.	The 2025 IRP provided an expanded explanation of resource cost determinations and data sourcing. See Chapter 7 (Resource Options). These same resource cost assumptions are reflected in the 2025 CEP.
Order No. 24-073	#19: In the 2025 IRP/CEP, PacifiCorp shall confirm that coal generator cost assumptions reasonably reflect the structure and terms of any associated fuel supply agreements or fuel supply plans. Categorize variable costs that affect dispatch as variable costs in the model with as much accuracy as reasonably possible.	PacifiCorp updated coal costs and assumptions in September 2024 for the 2025 IRP leveraging the most current future cost and performance estimates available to the company. Any items which are based on generation (fuel, emissions, variable O&M etc.) have been confirmed with subject matter experts for accuracy. The 2025 CEP relies on these same assumptions.
Order No. 24-073	#20: In the 2025 IRP/CEP PacifiCorp shall report on steps that the Company took to reduce the magnitude of reliability and granularity adjustments, how the Company engaged with stakeholders on adjustments, and describe the methodology and report the resulting reliability and granularity adjustments by resource. Include any supporting work papers demonstrating the granularity/reliability adjustments in the Data Disk.	As in the 2023 IRP and 2023 IRP Update, all workpapers for granularity/reliability adjustments are included in the 2025 IRP workpaper filing.[117] PacifiCorp engaged with stakeholders regarding granularity/reliability adjustments in five public input meetings spanning January 25, 2024 through September 25, 2024. PacifiCorp also provided additional detail in response to stakeholder feedback forms.[118] The enhancements of the iterative approach to modeling have led to more efficient model outcomes. All resources included in jurisdictional portfolios were endogenously selected by the model, and the integrated portfolios only include resources selected in the best of the compliant jurisdictional portfolios.
Order No. 24-073	#21: In the 2025 IRP/CEP PacifiCorp shall provide an update on PacifiCorp's efforts to secure Energy Infrastructure Reinvestment (EIR) financing from the DOE Loan Program Office. Assume EIR financing through the DOE Loan Program Office in the Preferred Portfolio or include a variant portfolio that optimizes resource additions and retirements under the assumption of EIR financing.	PacifiCorp has been selected for a $3.52 billion conditional DOE federal loan through Project WIRE to support multiple transmission projects across four states, benefiting customers in California, Idaho, Oregon and Utah.[119] The High IRA adoption sensitivity included in the 2025 IRP fulfills the study request in this order.

[117] Note that 'data disk' is a carry-over from the days of providing physical media, and Pacific is transitioning to refer to public, confidential and highly confidential 'workpapers'.
[118] Refer to Appendix M, stakeholder feedback form #17 (OPUC) and stakeholder feedback form #36 (Sierra Club).
[119] PacifiCorp Lands $3.5B Federal Loan for Transmission Projects in Four States | Clearing Up | newsdata.com

Reference	Requirement or Recommendation	2025 IRP/CEP Approach
Order No. 24-297	PacifiCorp's next Clean Energy Plan filing must contain an executable action plan.	The 2025 CEP includes a near-term action plan in Chapter IX.
Order No. 24-297	PacifiCorp is directed to file a small-scale resource acquisition strategy that includes timelines by April 2025.	PacifiCorp filed a small-scale resource acquisition strategy with the Commission on April 18, 2025, in docket LC 82.
HB 3162, ORS 469A.075	IRP includes a description of the electric company's plan for meeting the requirements of the renewable portfolio standard.	See PacifiCorp's 2025 IRP, Appendix R (Renewable Portfolio Implementation Plan).