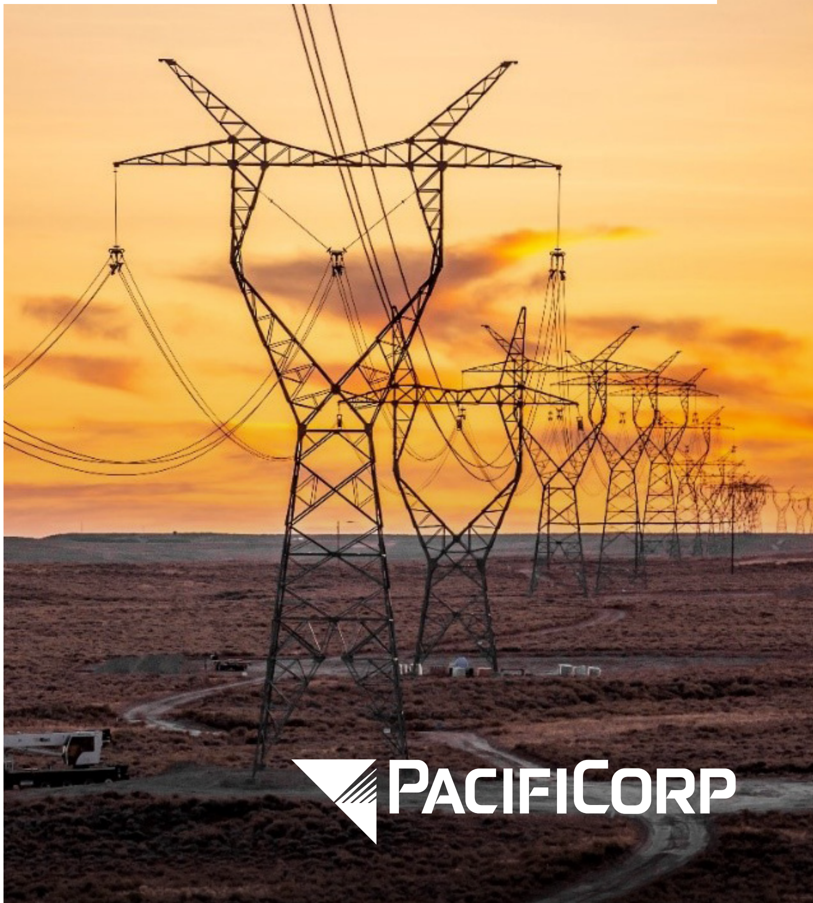
2021 Integrated Resource Plan Update

MARCH 31, 2022



PACIFICORP

This 2021 Integrated Resource Plan Update is based upon the best available information at the time of preparation. The IRP action plan will be implemented as described herein, but is subject to change as new information becomes available or as circumstances change. It is PacifiCorp's intention to revisit and refresh the IRP action plan no less frequently than annually. Any refreshed IRP action plan will be submitted to the State Commissions for their information.

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Cover Photos (Top to Bottom):
Pavant III Solar Plant
Marengo Wind Project
Transmission Line - Wyoming
Panguitch Solar & Battery Storage

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CHAPTER 1 – EXECUTIVE SUMMARY

PacifiCorp submitted its 2021 Integrated Resource Plan (IRP) to state regulatory commissions on September 1, 2021. That plan provides a framework for future actions that PacifiCorp will take to provide reliable and reasonably priced service for its customers through the least-cost, least-risk resource portfolio. The 2021 IRP Update reflects resource planning and procurement activities that have occurred since the 2021 IRP and presents an updated load-and-resource balance and an updated resource portfolio consistent with changes in the planning environment. The 2021 IRP Update also provides a status update for the action plan filed with the 2021 IRP. In presenting the updated load-and-resource balance and updated resource portfolio, PacifiCorp highlights changes in the 2021 IRP Update preferred portfolio relative to the 2021 IRP preferred portfolio which covers the 2021 to 2040 planning horizon. Consistent with the 2021 IRP, the 2021 IRP Update preferred portfolio demonstrates reliable service will be maintained with investment in transmission infrastructure, the conversion of two coal units to natural gas peaking units, growth in demand response programs, the addition of advanced nuclear resources, the addition of energy storage resources, and over the long term, the addition of non-emitting peaking resources.

PacifiCorp's Vision

The time is now

At PacifiCorp, we share a vision with our customers and communities in which clean energy from across the West powers jobs and innovation. This bold vision has guided our work for years. Most recently, it took shape in our 2017, 2019 and 2021 IRPs, in which we outlined an ambitious path to substantially increase our renewable energy capacity, evolving our existing portfolio and connecting supply with demand through an expanded, modernized transmission system.

Delivering on our promise

The power of the West lies in its diversity: windswept plains and high deserts, the sun-soaked Great Basin, and rivers fed by rain and mountain snow. Taken together, these reserves of wind, solar and hydro power can help meet the growing and changing needs of homes and businesses throughout the West, cleanly, reliably and affordably.

Yet, capturing this power alone is not enough. To unlock the full promise of these abundant resources, we must add transmission and storage capacity, unlock customer demand response resources with a modernized grid, and replace retiring thermal resources with non-emitting resources like advanced nuclear, to connect the West to its energy future—built on a resilient, hardened, adaptable grid that safely delivers power when and where it's needed.

PacifiCorp's 2021 IRP Update remains a roadmap for action and reinforces the significant progress toward the goals laid out in the 2017, 2019 and 2021 IRPs. The 2021 IRP Update also confirms the benefits of critical investments in expanded and modernized transmission, renewable energy, storage, demand response and advanced nuclear resources.

Our integrated system connects and brings new opportunities to the West, building on a foundation of infrastructure designed to handle extreme weather and enhance the energy resilience of communities from the Pacific Coast to the Rocky Mountains, all while continuing to deliver energy solutions for our customers at prices that are below national and regional averages.

As our 2021 IRP Update shows, this expanded, modernized transmission system will connect supply with demand from east to west and from north to south, serving as the backbone of the West for the hundreds of energy providers that serve our region alongside PacifiCorp.

Putting our customers at the center of everything we do

At PacifiCorp, we're committed to meeting the demands of our customers and communities throughout the West to deliver safe, affordable, clean energy and a resilient, modern grid.

Together with the communities we serve and our regional partners, it is time to act, with targeted, strategic investments that will position us to continue delivering affordable, reliable power.

Our customer-centered vision embodies four core themes:

Reliable Power: We strive to deliver energy safely during all hours, and plan extensively to ensure that we have sufficient supply and ability to deliver to the communities we serve. We understand that electricity is an essential service, and work around the clock to ensure that we are dependable, and communities can rely on us.

Resilient Infrastructure: We live in times of rapid change, with more extreme weather and challenging conditions. We are working to minimize disruptions, implement strategies to recover quickly when they occur, and deploy upgrades that will strengthen our critical infrastructure.

Affordable Prices: PacifiCorp is proud to be one of the lowest-cost electricity providers in the nation and the region. As we plan for our next generation of resources, we are prioritizing resources that add value and keep customer prices low.

Clean Energy: Through strategic, customer-focused investments in diverse resources, PacifiCorp remains committed to reducing carbon emissions, system-wide, by 74 percent from 2005 levels by 2030. Although a higher load forecast has driven an increase in emissions based on this IRP Update, primarily in the last 10 years of the 20-year study period, the 2021 IRP Update resource plan includes continued significant new renewable additions among other diverse, advanced technologies to keep us on that path and achieve even deeper decarbonization beyond 2030. The higher load forecast can be viewed as a less extreme version of the S01 High Load sensitivity from the 2021 IRP, driving a similar trajectory. However, PacifiCorp fully anticipates that additional transmission and resource options explored in the 2023 IRP will counter the immediate appearance on an uptick in emissions outcomes.

2021 IRP Update Roadmap

The 2021 IRP Update continues to fulfill on PacifiCorp's bold vision for the West between now and 2040 and stays on course to achieve a clean, resilient and affordable energy future that leverages the abundant, diverse, clean energy resources that the West can offer through a modernized and expanded grid.

- **Continue our growth into a grid powered by clean energy**:
    - 4,685 MW from energy efficiency programs
    - 5,297 MW of new solar resources (most paired with storage)
    - 4,160 MW of new wind resources
    - 5,546 MW of storage resources, including battery storage co-located with solar, standalone battery storage and pumped hydro storage resources
    - 978 MW of direct load control programs
    - 500 MW of advanced nuclear (the Natrium ™ reactor demonstration project) in 2028, with an additional 1,000 MW of advanced nuclear over the long-term
    - 1,237 MW of non-emitting peaker resources

- **Connect and optimize these diverse, clean resources across the West with a strengthened and modernized transmission network that ensures resilient service, reduces costs and creates maximum opportunities for our communities to thrive (incremental to projects already online)**:
    - 416 miles of new transmission from the new Aeolus substation near Medicine Bow, Wyoming, to the Clover substation near Mona, Utah (Energy Gateway South)
    - 59 miles of new transmission from the Shirley Basin substation in southeastern Wyoming to the Windstar substation near Glenrock, Wyoming (Energy Gateway West Sub-Segment D.1)
    - 290 miles of new transmission from the Boardman substation in north central Oregon to the Hemingway substation in south central Idaho

PacifiCorp's Integrated Resource Plan Approach

PacifiCorp has been making progress in its efforts to bring the best of the West to its customers. In September 2021, the 2021 IRP set forth a clear path to provide reliable and reasonably priced service to its customers. The analysis supporting this plan helps PacifiCorp, its customers, and its regulators understand the effect of both near-term and long-term resource decisions on customer bills, the reliability of electric service PacifiCorp customers receive, and changes to emissions from the generation sources used to serve customers. In the 2021 IRP Update, PacifiCorp presents a preferred portfolio that continues to build on its vision to deliver energy affordably, reliably and responsibly through near-term investments in transmission infrastructure that will facilitate continued growth in new renewable resource capacity while maintaining substantial investment in energy efficiency and demand response programs. All of this can be achieved by maintaining reliable service with incremental investments in transmission infrastructure and other non-emitting flexible resources capable of shaping and responding to changes in energy from an increasing supply of wind and solar resources.

The primary objective of an IRP is to identify the best mix of resources to serve customers in the future. The best mix of resources is identified through analysis that measures cost and risk. The least-cost, least-risk resource portfolio—defined as the "preferred portfolio"—is the portfolio that can be delivered through specific action items at a reasonable cost and with manageable risks, while considering customer demand for clean energy and ensuring compliance with state and federal regulatory obligations.

The 2021 IRP Update serves as a checkpoint to the recent IRP roadmap to ensure that changes in the planning environment are considered in between the full IRP planning process that is completed every two years, thus providing guidance as to constantly evolving trends and events which may ultimately impact our customers.

As depicted in Figure 1.1, PacifiCorp's 2021 IRP and this 2021 IRP Update were developed by working through five fundamental planning steps that began with development of key inputs and assumptions to inform the modeling and portfolio evaluation process. The optimization of the updated preferred portfolio allows for a new endogenous selection of retirements, transmission and resources to meet projected gaps in the updated load and resource balance, characterized by the type, timing, and location of new resources in PacifiCorp's system. Options for the 2021 IRP Update considered a wide range of potential coal retirement dates, options to convert to gas or to retrofit for carbon capture utilization and sequestration for certain coal units, and other planning uncertainties.

PacifiCorp then developed key variants of the updated preferred portfolio, focusing on three variant studies from the 2021 IRP which address large transmission projects and significant volumes of associated resources. In the resource portfolio analysis step, PacifiCorp conducted targeted reliability analysis to ensure portfolios had sufficient flexible capacity resources to meet reliability requirements. PacifiCorp then analyzed these different resource portfolios to measure the comparative cost, risk, reliability, and emission levels. This resource portfolio analysis ultimately informed selection of the least-cost and least-risk portfolio and the 2021 IRP Update preferred portfolio.

Figure 1.1 – Key Elements of PacifiCorp's 2021 IRP Approach

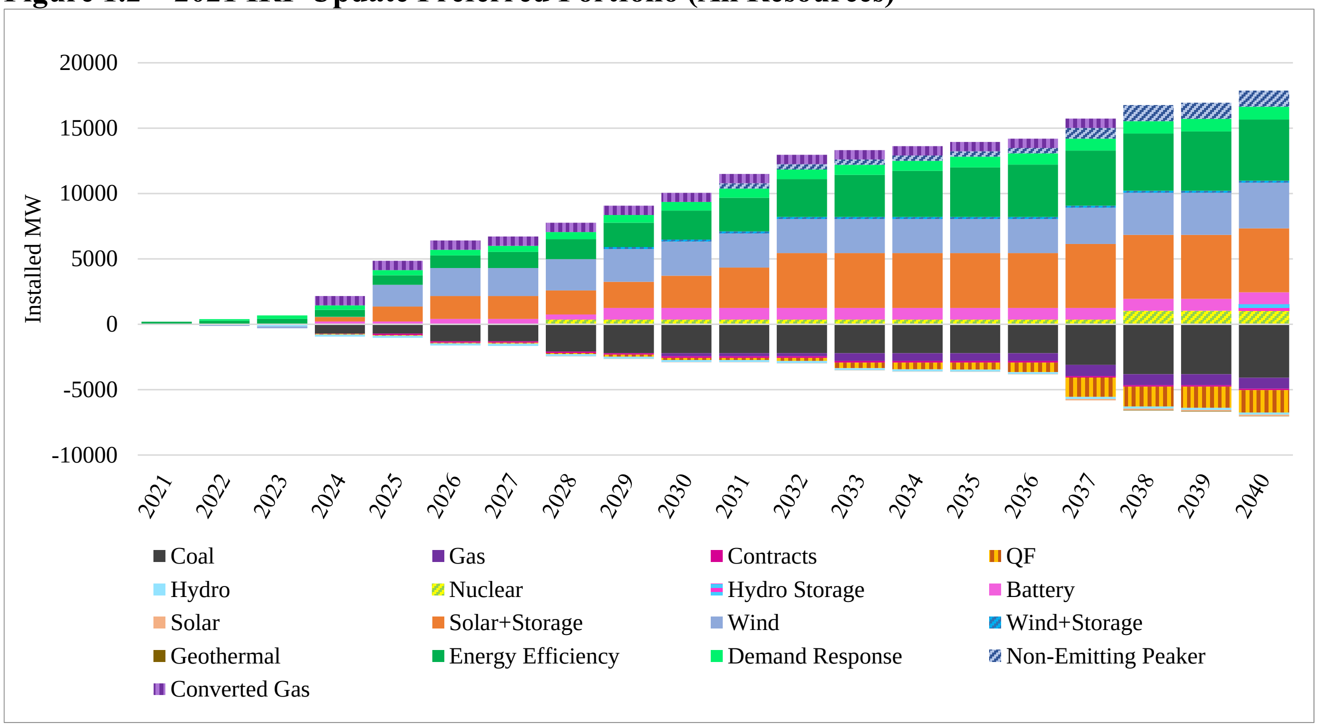
2021 IRP Update Preferred Portfolio Highlights

Figure 1.2 shows that PacifiCorp's 2021 Update preferred portfolio continues to include substantial new renewables, facilitated by incremental transmission investments, demand-side management (DSM) resources, significant storage resources, and continues to show support for advanced nuclear and non-emitting peaker resources.

By the end of 2024, the 2021 IRP Update preferred portfolio includes the 2020 All-Source Request for Proposals (RFP) final shortlist resources. These projects include 1,792 MW of wind, 1,150 MW of solar additions, and 639 MW of battery storage capacity—439 MW paired with solar and a 200 MW standalone battery.[1] During this time, the Update preferred portfolio also includes the acquisition and repowering of Rock River I (49 MW) and Foote Creek II-IV (43 MW) wind projects located in Wyoming. Through the end of 2026, the 2021 IRP Update preferred portfolio includes an additional 597 MW of wind and an additional 600 MW solar co-located with storage. The 2021 IRP Update preferred portfolio includes the 500 MW advanced nuclear Natrium™ demonstration project, which will come online by summer 2028. Through 2040, the 2021 IRP Update preferred portfolio includes 1,000 MW of additional advanced nuclear resources and 1,237 MW of non-emitting peaking resources.

Over the 20-year planning horizon, the 2021 IRP Update preferred portfolio includes 4,160 MW[2] of new wind and 5,297 MW of new solar co-located with storage.

Figure 1.2 – 2021 IRP Update Preferred Portfolio (All Resources)



To facilitate the delivery of new renewable energy resources to PacifiCorp customers across the West, the updated preferred portfolio includes necessary transmission investments. Specifically, the portfolio includes the Energy Gateway South transmission line - a new 416-mile high-voltage 500-kilovolt transmission line and associated infrastructure running from the new Aeolus substation near Medicine Bow, Wyoming, to the Clover substation near Mona, Utah. The 2021 Update preferred portfolio also includes the Energy Gateway West Subsegment D.1 project - a new 59-mile, high-voltage (230-kilovolt) transmission line from the Shirley Basin substation in southeastern Wyoming to the Windstar substation near Glenrock, Wyoming. Both transmission lines will come online by the end of 2024.

[1] The reported capacity for RFP solar resources reflects their expected maximum output after degradation in their first full year of operation.
[2] This figure includes 160 MW of hybrid wind located in Yakima Washington as part of CETA compliance

The 2021 IRP Update preferred portfolio also includes a 290-mile high-voltage 500-kilovolt transmission line known as Boardman-to-Hemingway, which connects those respective substations in Oregon and Idaho, which will come online in 2026. Further, the portfolio includes near-term and long-term transmission upgrades across the system that will facilitate continued and long-term growth in new resources needed to serve our customers.

A higher load forecast drives new and accelerated transmission in the updated preferred portfolio. Table 1.1 reports changes in transmission selections relative to the 2021 IRP. Four transmission paths are accelerated and two new paths are selected, adding 300 MW of interconnection capability to the system. One transmission upgrade, Portland North coast to Willamette Valley, is delayed in the back 10 years of the model horizon. Finally, one transmission path, Portland North Coast to Southern Oregon, is removed, partly offset by the accelerations, particularly of the Central Oregon to Willamette Valley transmission line, as well as the additional transmission options.

Table 1.1 – Transmission Upgrade Changes in the 2021 IRP Update Preferred Portfolio Compared to the 2021 IRP Preferred Portfolio[1]

Upgrade	Export Capacity	2021 Update Year	2021 IRP Year	Change
CON Central OR > TxCON 2027	100	2030	2037	-7
CON Yakima > TxCON 2027a	180	2029	2030	-1
CON Yakima > TxCON 2027b	100	2029	-	New
INC Central OR > Willamette Valley 2037	1500	2037	2040	-3
INC Portland North Coast > Southern Oregon 2037	1500	-	2040	Removed
INC Portland North Coast > Willamette Valley 2032	450	2038	2032	6
INC Utah South > Utah North 2032	800	2032	2033	-1
INC Walla Walla - WA > Yakima 2030	200	2030	-	New

1 – Negative values in the "Change" column indicates the number of years of acceleration compared to the 2021 IRP Preferred Portfolio.

Table 1.2 summarizes the incremental transmission projects in the 2021 IRP Update preferred portfolio.

Table 1.2 – Transmission Projects Included in the 2021 IRP Update Preferred Portfolio[1,2,*]

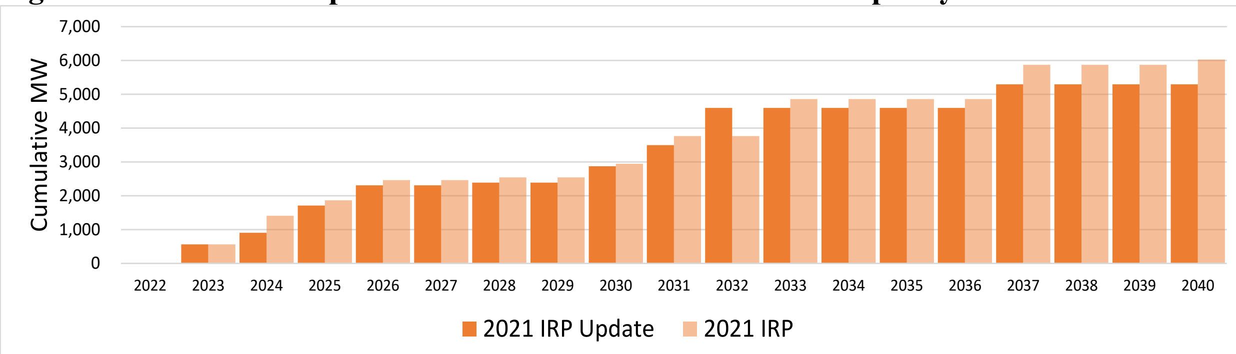
Year	Resource(s)	From	To	Description
2025	1,641 MW RFP Wind (2025)	Aeolus WY	Clover	Enables 1,930 MW of interconnection with 1700 MW of TTC: Energy Gateway South
2026	415 MW Wind (2026) 200 MW Standalone Battery (2026)	Within Willamette Valley OR Transmission Area		Enables 615 MW of interconnection: Albany OR area reinforcement
2026	130 MW Wind (2026) 450 MW Wind (2032)	Portland North Coast	Willamette Valley	Enables 450 MW of interconnection with 450 MW TTC; Portland Coast area reinforcement and Willamette Valley
2026	600 MW Solar+Storage (2026)	Borah-Populous	Hemingway	Enables 600 MW of interconnection with 600 MW of TTC: B2H Boardman-Hemingway
2028	83 MW Solar+Storage (2028) 377 MW Solar+Storage (2030)	Within Southern OR Transmission Area		Enables 460 MW of interconnection: Medford area reinforcement
2029	160 MW Solar+Wind+Storage (2030) 120 MW Solar+Storage (2030)	Yakima WA Transmission Area		Enables 280 MW of interconnection: Yakima local area reinforcement
2030	100 MW Wind (2030)	Walla Walla	Yakima	Enables 100 MW of interconnection
2030	100 MW Solar+Storage (2030)	Central OR Transmission Area		Enables 100 MW of interconnection
2031	626 MW Solar+Storage (2031) 412 MW Non-Emitting Peaker (2033)	Northern UT Transmission Area		Enables 1040 MW of interconnection: Northern UT 345 kV reinforcement
2032	1100 MW Solar+Storage (2032)	Southern UT	Northern UT	Enables 1500 MW of interconnection with 800 MW TTC: Spanish Fork - Mercer 345 kV; New Emery – Clover 345 kV
2037	155 MW Wind (2037) 500 MW Pumped Storage (2040)	Central OR	Willamette Valley	Enables 980 MW of interconnection with 1500 MW of TTC
2028*	500 MW Adv Nuclear (2028)	Southwest Wyoming Transmission Area		Reclaimed transmission upon retirement of Naughton 1 & 2
2029*	500 MW Battery (2029) 330 MW Wind (2028 & 2029)	Eastern Wyoming Transmission Area		Reclaimed transmission upon retirement of Dave Johnston Plant
2037	702 MW Solar+Storage (2037) 206 MW Non-Emitting Peaker (2037)	Southern Utah Transmission Area		Reclaimed transmission upon retirement of Huntington 1 & 2
2038	412 MW Non-Emitting Peaker (2038) 1000 MW Adv Nuclear (2038)	Bridger WY Transmission Area		Reclaimed transmission upon retirement of Jim Bridger Plant
2040	268 MW Wind (2040)	Eastern Wyoming Transmission Area		Reclaimed transmission upon retirement of Wyodak

1 - TTC = total transfer capability. The scope and cost of transmission upgrades are planning estimates. Actual scope and costs will vary depending upon the interconnection queue, the transmission service queue, the specific location of any given generating resource and the type of equipment proposed for any given generating resource.
2 - Energy Gateway South is modeled in the 2021 IRP Update as a contingent option with bids in the 2020 All-Source Request for Proposals. Other transmission options prior to 2026 are not modeled as transmission requirements and costs are accounted for in the 2020 All-Source Request for Proposals transmission cluster study for all other resource bids.
* - Reclaimed transmission is committed with resources with a commercial operation date later than the date of retirement.

New Solar Resources

As reported in Figure 1.3, the 2021 IRP Update preferred portfolio includes 1,709 MW of new solar by the end of 2024 and 2,309 MW by the end of 2026, with additions of 5,297 MW through 2040. Accounting for a 153 MW reduction in resources associated with the 2020 AS RFP, the 2021 IRP Update includes 833 MW more new solar capacity by the end of 2031 compared to the 2021 IRP preferred portfolio. After 2031, driven by more efficient higher cost transmission and energy efficiency gains, solar additions are ultimately reduced 730 MW by 2040.

Figure 1.3 – 2021 IRP Update Preferred Portfolio New Solar Capacity*

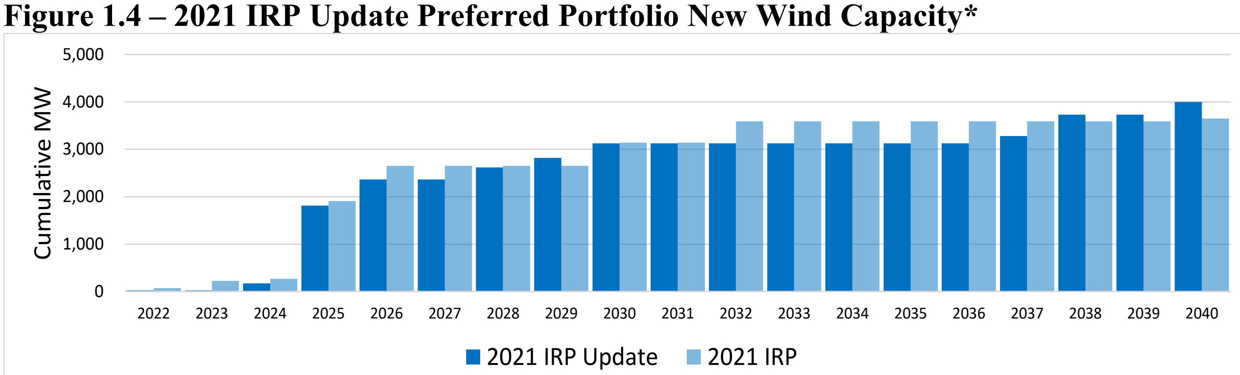


* 2021 IRP Update solar capacity shown in the figure includes solar resources coming via the 2020 All-Source Request for Proposals by the end of 2024. Resources are shown in the first full year of operation (the year after the year-online dates). The reported capacity for the 2020 All-Source Request for Proposals solar resources reflects their expected maximum output after degradation in their first full year of operation.

New Wind Resources

As shown in Figure 1.4, by the end of 2024, PacifiCorp's 2021 IRP Update preferred portfolio includes 1,815 MW of new wind generation resulting from the 2020 All-Source RFP and the acquisition and repowering of Rock River I (49 MW) and Foote Creek II-IV (43 MW). Through the end of 2026, the 2021 IRP Update preferred portfolio includes an additional 2,363 MW of new wind and more than 4,000 MW of new wind by 2040. Relative to the 2021 IRP, 2021 IRP Update wind additions are mostly reduced or flat through 2037, and ultimately increase by 348 MW of new wind by the end of 2040.

Figure 1.4 – 2021 IRP Update Preferred Portfolio New Wind Capacity*

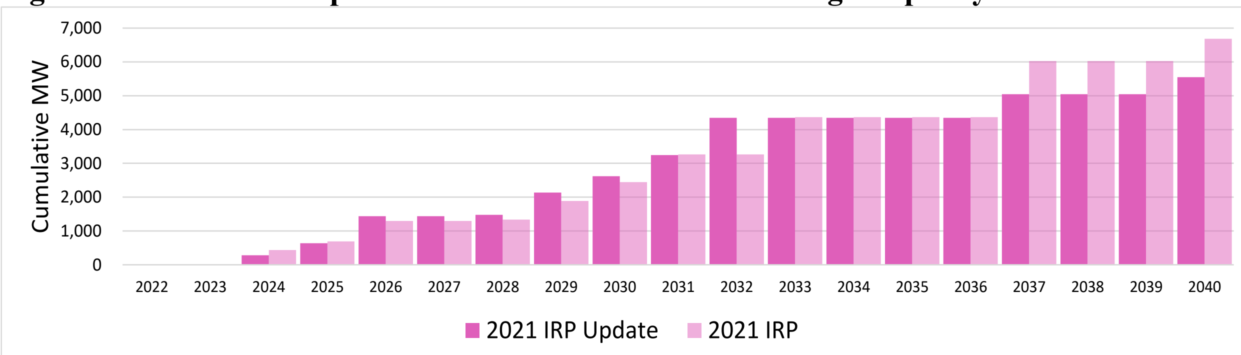


*Note: Wind additions shown are incremental to Energy Vision 2020 and other projects that have come online over the past few years. Resources are shown in the first full year of operation (the year after year-end online dates).

New Storage Resources

New storage resources in the 2021 IRP Update preferred portfolio are summarized in Figure 1.5. The updated portfolio includes nearly 639 MW of battery storage by the end of 2024 – 200 MW of which is a standalone battery and the remaining portion paired with solar resources resulting from the 2020 All-Source RFP. Through 2040, the 2021 IRP includes 4,146 MW of storage co-located with solar resources, 900 MW of standalone battery, and 500 MW of pumped hydro.

Figure 1.5 – 2021 IRP Update Preferred Portfolio New Storage Capacity*

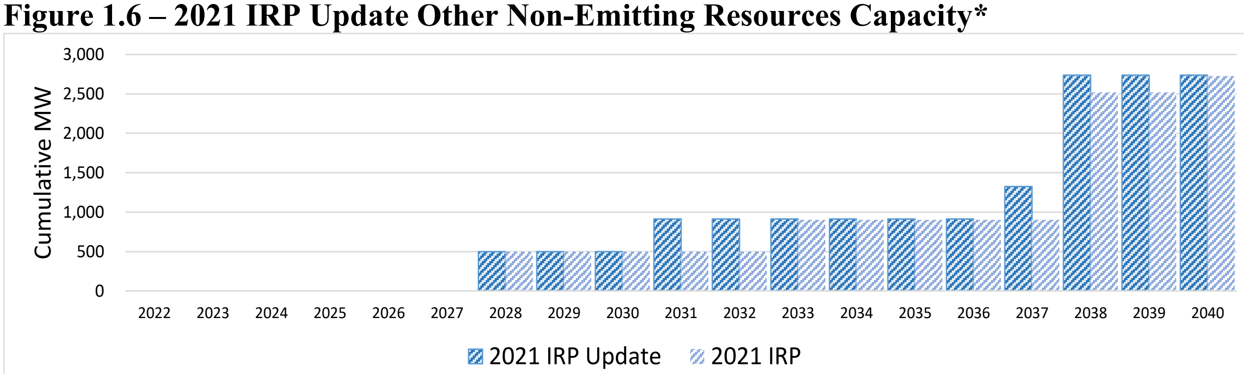


*Note: Resources are shown in the first full year of operation (the year after the year-end online dates).

Other Non-Emitting Resources

The 2021 IRP was the first to include new advanced nuclear and non-emitting peaking resources as part of its least-cost, least-risk preferred portfolio. The 2021 IRP Update continues to select these resources. As shown in Figure 1.6, the 500 MW advanced nuclear Natrium^{TM} demonstration project is projected to come online by summer 2028. Through 2040, the 2021 IRP Update preferred portfolio includes 1,500 MW of advanced nuclear resources and 1,237 MW of non-emitting peaking resources.

Figure 1.6 – 2021 IRP Update Other Non-Emitting Resources Capacity*



*Note: Resources are shown in the first full year of operation (the year after the year-end online dates).

Demand-Side Management

PacifiCorp evaluates new DSM opportunities, which includes both energy efficiency and direct load control programs, as a resource that competes with traditional new generation and wholesale power market purchases when developing the IRP Update preferred portfolio. Figure 1.7 shows that PacifiCorp's load forecast before incremental energy efficiency savings has increased relative to projected loads used in the 2021 IRP. On average, forecasted system load is up 1.9 percent and forecasted coincident system peak is up 2.1 percent when compared to the 2021 IRP. Over the planning horizon, the average annual growth rate, before accounting for incremental energy efficiency improvements, is 1.28 percent for load and 0.85 percent for peak. Changes to PacifiCorp's load forecast are driven by higher projected demand from data centers driving up the commercial forecast.

Figure 1.7 – Forecasted Annual Load (GWh) (Before Incremental Energy Efficiency Savings)

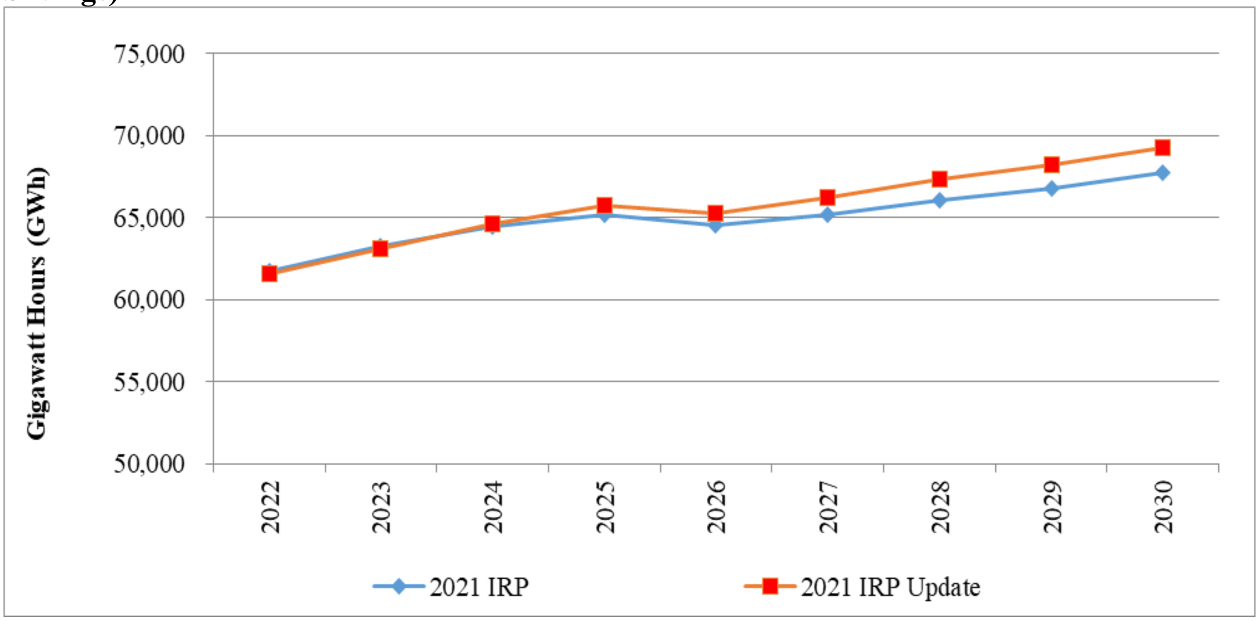
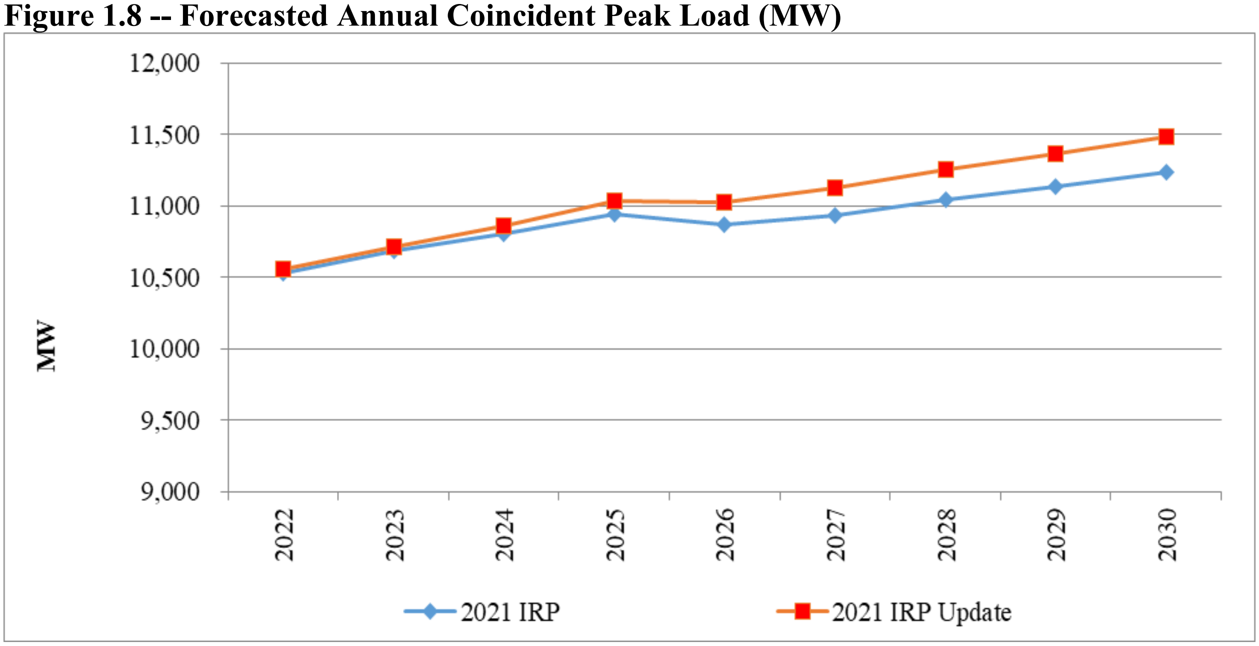
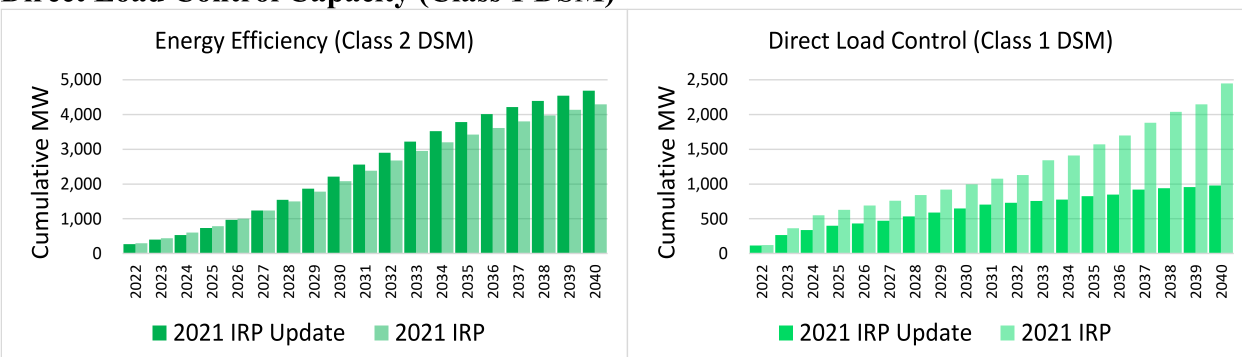


Figure 1.8 -- Forecasted Annual Coincident Peak Load (MW)



DSM resources continue to play a key role in PacifiCorp's resource mix. The chart to the left in Figure 1.9 compares total energy efficiency capacity savings in the 2021 IRP Update preferred portfolio relative to the 2021 IRP preferred portfolio and includes 4,685 MW by the end of the planning period. This increase is attributed to the reductions in demand response, combined with the alignment of energy efficiency to load, both described in Chapter 5 – Modeling Updates. For the 2021 IRP Update, selections of demand response have been scaled back to realistic targets, which is responsible for decreases shown on the right-hand side of Figure 1.9. Demand response selections in the 2021 IRP Update total nearly 1,000 MW over the 20-year horizon. By the end of 2040 and relative to the 2021 IRP preferred portfolio, energy efficiency selection increases by nearly 400 MW, whereas demand response selections are reduced by more than 1,400 MW.

Figure 1.9 – 2021 IRP Update Preferred Portfolio Energy Efficiency (Class 2 DSM) and Direct Load Control Capacity (Class 1 DSM)



Wholesale Power Market Prices and Purchases

Figure 1.10 summarizes the three wholesale electricity price forecasts and three natural gas price forecasts used in the Base and scenario cases for the 2021 IRP Update. As shown, low and medium power and gas prices are higher in the near term. All three power price scenarios trend higher beginning in 2024, but generally escalate at different increasing rates. Additional detail regarding power and gas prices is provided in Chapter 5 – Modeling and Assumptions Update.

Figure 1.10 – Comparison of Power Prices and Natural Gas Prices in Recent IRPs

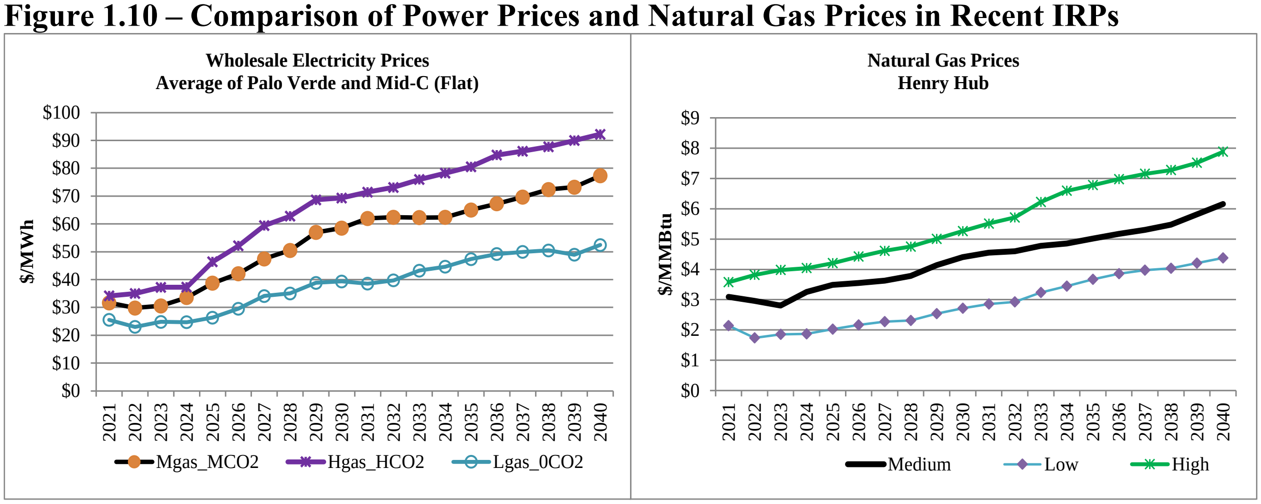
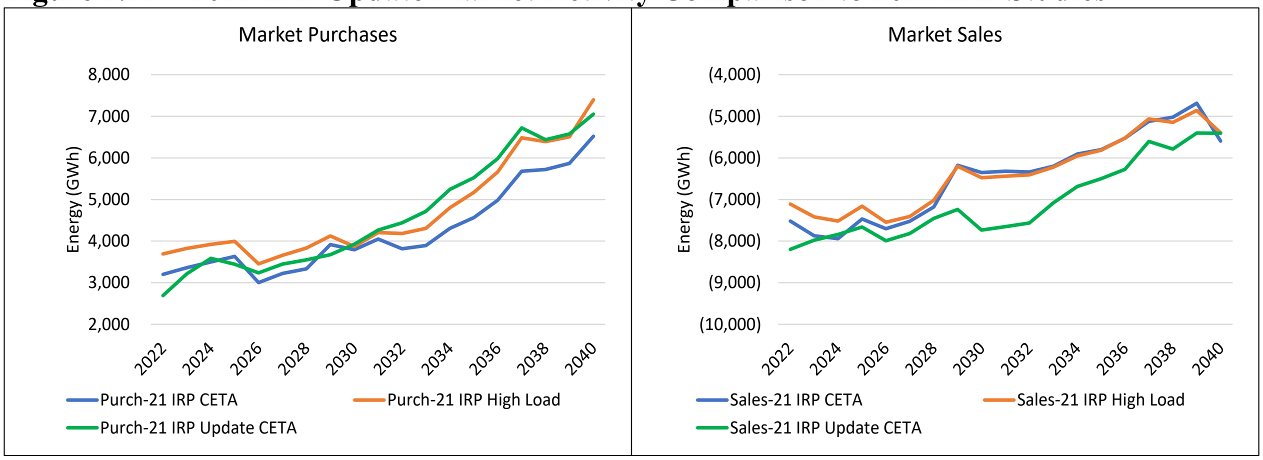


Figure 1.11 compares market purchases and sales among the 2021 IRP preferred portfolio, the 2021 IRP S01 High Load sensitivity and the 2021 IRP Update. While the 2021 IRP Update averages approximately 500 GWh additional sales annually compared to the 2021 IRP preferred portfolio or the 2021 IRP High Load scenario, offsetting purchases are higher in some years, particularly 2032 to 2037. On average, 2021 IRP Update purchase increase by an average of 200 MW annually on a purely volumetric basis. Given near-term concerns over resource adequacy, generally lower market purchases in 2021 IRP Update portfolio in the first 5 years are viewed favorably.

Figure 1.11 – 2021 IRP Update Market Activity Comparison to 2021 IRP Studies



Coal and Gas Retirements/Gas Conversions

Coal resources have been an important resource in PacifiCorp's resource portfolio for many years. PacifiCorp's coal resources will continue to play a pivotal role in following fluctuations in renewable energy as the remaining coal units approach retirement dates. The 2021 IRP Update yields the same retirement timing as seen in the 2021 IRP. Driven in part by ongoing cost pressures on existing coal-fired facilities and cost-effective new resource alternatives, of the 22 coal units currently serving PacifiCorp customers, the preferred portfolio includes retirement of 14 of the units by 2030 and 19 of the 22 units by the end of the planning period in 2040.

Coal unit retirements scheduled under the preferred portfolio include:

- 2023 = Jim Bridger Units 1-2, converted to natural gas peakers
- 2025 = Naughton Units 1-2
- 2025 = Craig Unit 1
- 2025 = Colstrip Units 3-4
- 2027 = Dave Johnston Units 1-4
- 2027 = Hayden Unit 2
- 2028 = Craig Unit 2
- 2028 = Hayden Unit 1
- 2036 = Huntington Units 1-2
- 2037 = Jim Bridger Units 3-4
- 2039 = Wyodak

In addition to the coal unit retirements outlined above, the preferred portfolio reflects 1,554 MW natural gas retirements through 2040. This includes Naughton Unit 3 at the end of 2029, Gadsby at the end of 2032, Hermiston at the end of 2036, and Jim Bridger Units 1 and 2 at the end of 2037.

Carbon Dioxide Emissions

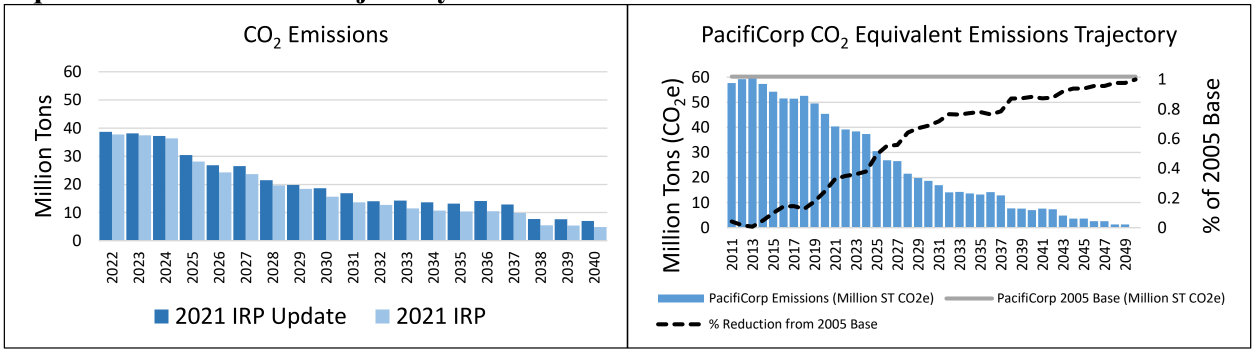
While the 2021 IRP Update preferred portfolio reflects PacifiCorp's on-going efforts to provide cost-effective clean-energy solutions for our customers, increased load has driven thermal dispatch and therefore emissions higher based on currently modeled resource options and assumptions. Portfolio emissions and costs due to the higher load forecast present a less extreme version of the S01 High Load sensitivity from the 2021 IRP.

PacifiCorp's emissions have been declining and are expected to continue to decline related to several factors including PacifiCorp's participation in the energy imbalance market, which reduces customer costs and maximizes use of clean energy; PacifiCorp's on-going transition to clean-energy resources including new renewable resources, new advanced nuclear resources, new non-emitting resources, storage, transmission, and Regional Haze compliance that capitalizes on flexibility. Input updates and additional transmission and resource options in the 2023 IRP are expected to allow economic emissions reductions not available to the 2021 IRP Update and in the absence of a full IRP cycle.

The chart on the left in Figure 1.12 compares projected annual CO_2 emissions between the 2021 IRP update and 2021 IRP preferred portfolios. In this graph, emissions are not assigned to market purchases or sales.

The chart on the right in Figure 1.12 includes historical data, assigns emissions at a rate of 0.4708 tons CO_2 equivalent per MWh to market purchases (with no credit to market sales), includes emissions associated with specified purchases, and extrapolates projections out through 2050. This graph demonstrates that relative to a 2005 baseline, 2021 IRP Update preferred portfolio system CO_2 equivalent emissions are down 49 percent in 2025, 69 percent in 2030, 78 percent in 2035, 88 percent in 2040, 94 percent in 2045, and 100 percent in 2050.

Figure 1.12 – 2021 IRP Update Preferred Portfolio CO_2 Emissions and PacifiCorp CO_2 Equivalent Emissions Trajectory*



*Note: PacifiCorp CO_2 equivalent emissions trajectory reflects actual emissions through 2020 from owned facilities, specified sources and unspecified sources. From 2022 through the end of the twenty-year planning period in 2040, emissions reflect those from the 2021 IRP Update preferred portfolio with emissions from specified sources reported in CO_2 equivalent. Beyond 2040, emissions reflect the rolling average emissions of each resource from the 2021 IRP update preferred portfolio through the life of the resource. The emissions trajectory does not incorporate clean energy targets set forth in Oregon House Bill 2021 or any other state-specific emissions trajectories. PacifiCorp expects these targets, and an Oregon-specific emissions trajectory, to be incorporated following the 2023 integrated resource plan when PacifiCorp is required under the bill to file a Clean Energy Plan.

Renewable Portfolio Standards

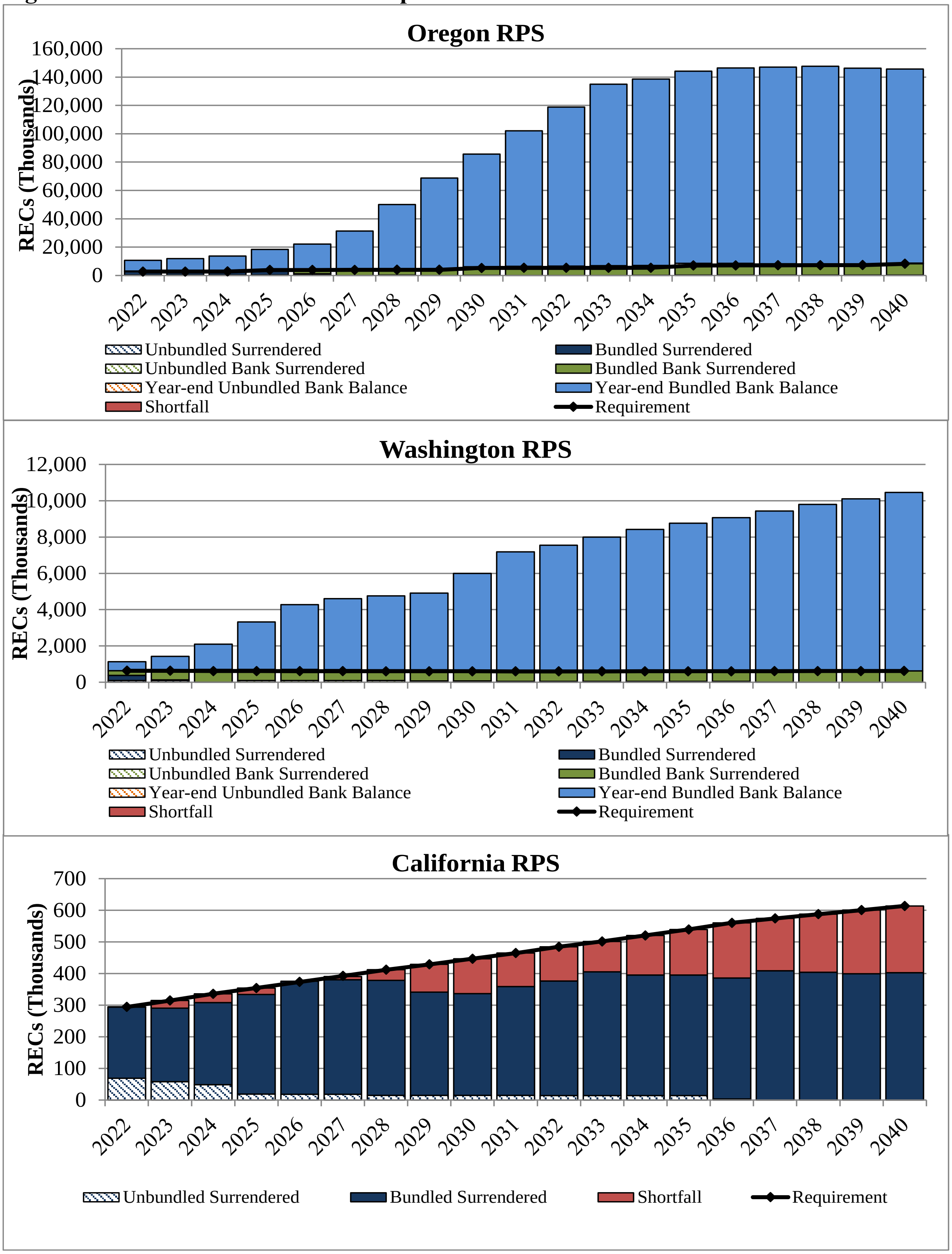
Figure 1.13 shows PacifiCorp's renewable portfolio standard (RPS) compliance forecast for California, Oregon, and Washington after accounting for new renewable resources in the preferred portfolio. While these resources are included in the preferred portfolio as cost-effective system resources and are not included to specifically meet RPS targets, they nonetheless contribute to meeting RPS targets in PacifiCorp's western states.

Oregon RPS compliance is achieved through 2040 with the addition of new renewable resources and transmission in the 2021 IRP Update preferred portfolio. Consistent with the 2021 IRP, in the 2021 IRP Update, Washington RPS compliance is achieved with the benefit of increased system renewable resources beginning 2022 as well as additional resources procured that meet the state's Clean Energy Transformation Act. Under PacifiCorp's 2020 Protocol, and the Washington Interjurisdictional Allocation Methodology, Washington's RPS position is improved by receiving a system share of renewable resources across the PacifiCorp's system.

The California RPS compliance position will be met with owned and contracted renewable resources, as well as REC purchases throughout the study period. The ramping RPS requirement results in an increased need for unbundled REC purchases to meet the annual and compliance period targets in 2021-2040. New renewable resources and transmission in the 2021 IRP update preferred portfolio mitigate that shortfall, but the company has made a 120,000 REC purchase towards compliance period 4, years 2021-2024, and will continue to evaluate the need for unbundled RECs and issue RFPs to meet its state RPS compliance requirements as needed.

While not shown in Figure 1.13, PacifiCorp meets the Utah 2025 state target to supply 20 percent of adjusted retail sales with eligible renewable resources with existing owned and contracted resources and new renewable resources and transmission in the 2021 IRP Update preferred portfolio.

Figure 1.13 – Annual State RPS Compliance Forecast



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CHAPTER 2 – INTRODUCTION

This 2021 IRP Update describes resource planning activities following the filing of the 2021 IRP on September 1, 2021 and presents an updated load-and-resource balance, an updated preferred portfolio consistent with changes in the planning environment and provides a status update on the action plan filed with the 2021 IRP. In presenting the updated load and resource balance assessment and updated preferred portfolio, PacifiCorp describes changes relative to the 2021 IRP.

PacifiCorp's 2021 IRP Update preferred portfolio reflects updates to load, existing resources, signed contracts and modeling improvements. The 2021 IRP Update also includes an update to certain variant analysis conducted in the 2021 IRP related to portfolio analysis of major transmission projects and related resources including Energy Gateway South and D.1, Boardman-to-Hemingway and the 2020 All Source Request for Proposals final shortlist projects.

Chapter 1 of the 2021 IRP Update provides an executive summary focused on the updated preferred portfolio. Chapter 3 describes the current planning environment, load updates, resource updates, state and federal policy updates, transmission upgrades and recent changes in the Western Resource Adequacy Program. Chapter 4 provides updated load-and-resource balance information. Chapter 5 describes changes to key inputs and assumptions relative to those used for the 2021 IRP. Chapter 6 presents the updated preferred portfolio, variant studies, a regional haze study and additional bookend price-policy studies for information. A status update on the 2021 IRP Action Plan is provided in Chapter 7. The Appendix provides additional load forecast details.

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CHAPTER 3 – THE PLANNING ENVIRONMENT

Federal Policy Update

Federal Climate Change Legislation

To date, no federal legislative climate change proposal has been passed by the U.S. Congress. Federal climate change legislation is not anticipated in the near term but remains possible in the mid- to long-term.

New Source Performance Standards for Carbon Emissions – Clean Air Act § 111(b)

New Source Performance Standards (NSPS) are established under the Clean Air Act for certain industrial sources of emissions determined to endanger public health and welfare. On October 23, 2015, the U.S. Environmental Protection Agency (EPA) finalized a rule limiting carbon emissions from coal-fueled and natural-gas-fueled power plants. New natural-gas-fueled power plants can emit no more than 1,000 pounds of carbon dioxide (CO_2) per megawatt-hour (MWh). New coal-fueled power plants can emit no more than 1,400 pounds of CO_2/MWh. The final rule largely exempts simple cycle combustion turbines from meeting the standards. On December 6, 2018, the EPA proposed to revise the NSPS for greenhouse gas emissions from new, modified, and reconstructed fossil fuel-fired power plants. EPA's proposal would replace EPA's 2015 determination that carbon capture and storage technology was the best system of emissions reduction for new coal units. The comment period for the proposed revisions closed in March 2019. In January 2021, the EPA issued the final rule. However, in April 2021, at the request of the EPA as directed by the Biden Administration, the D.C. Circuit vacated and remanded the January 2021 final rule.

Carbon Emission Guidelines for Existing Sources – Clean Air Act § 111(d)

On August 3, 2015, EPA issued a final rule, referred to as the Clean Power Plan (CPP), regulating CO_2 emissions from existing power plants.

On February 9, 2016, the U.S. Supreme Court issued a stay of the CPP suspending implementation of the rule pending the outcome of the merits of litigation before the D.C. Circuit Court of Appeals. On October 10, 2017, EPA proposed to repeal the CPP and on August 21, 2018, proposed the Affordable Clean Energy (ACE) rule to replace the CPP. The ACE rule sets forth a list of "candidate technologies" that states can use to reduce greenhouse gas emissions at coal-fueled power plants. The ACE rule was finalized June 19, 2019, replacing the CPP. On January 19, 2021, the D.C. Circuit vacated the ACE rule and directed the EPA to proceed with new rulemaking for the control of carbon emissions from electric utility coal-fired boilers.

Credit for Carbon Oxide Sequestration – Internal Revenue Service (IRS) § 45Q

In 2008, the Internal Revenue Service issued a tax credit for carbon oxide sequestration under section 45Q to incentivize carbon capture and sequestration (CCS) investments. The tax credit is computed per metric ton (tonne) of qualified carbon oxide captured and sequestered.[1] Carbon oxide can either be permanently disposed of in secure geological storage or the carbon oxide can be utilized – typically as a tertiary injectant in enhanced oil recovery (EOR).

The Bipartisan Budget Act of 2018 reformed 45Q for carbon capture equipment that is placed in service on or after February 9, 2018, increasing the credit amount from $10/tonne to $35/tonne for utilization and from $20/tonne to $50/tonne for storage.[2] This Act also removed the limit on the amount of tax credits that could be awarded for CCS, and, instead, requires a minimum amount of carbon oxide to be captured annually and is available for 12 years from the date the carbon capture equipment is originally placed into service.[3]

Clean Air Act Criteria Pollutants – National Ambient Air Quality Standards

The Clean Air Act requires EPA to set National Ambient Air Quality Standards (NAAQS) for six criteria pollutants that have the potential of harming human health or the environment. The NAAQS are rigorously vetted by the scientific community, industry, public interest groups, and the general public, and establish the maximum allowable concentration allowed for each "criteria" pollutant in outdoor air. The six pollutants are carbon monoxide, lead, ground-level ozone, nitrogen dioxide (NO_X), particulate matter (PM), and sulfur dioxide (SO_2). The standards are set at a level that protects public health with an adequate margin of safety. All states are required to develop a state implementation plan (SIP) to implement the NAAQS, and that plan must be approved by EPA. The plan must provide for implementation, maintenance, and enforcement of the NAAQS for each pollutant, with more specific requirements and limits imposed on states that fail to achieve the NAAQS for a particular pollutant. SIPs must also contain adequate provisions to prevent emissions that significantly contribute to nonattainment of the NAAQS in any other state.

In October 2015, EPA issued a final rule modifying the standards for ground-level ozone from 75 parts per billion (ppb) to 70 ppb. On November 16, 2017, the EPA designated all counties where PacifiCorp's coal facilities are located (Lincoln, Sweetwater, Converse and Campbell Counties in Wyoming; and Emery County in Utah) as attainment/unclassifiable. On June 4, 2018, the EPA designated two areas in Utah as Marginal Nonattainment: Salt Lake County and three neighboring counties (Northern Wasatch Front) where the PacifiCorp Gadsby facility is located, and part of Utah County (Southern Wasatch Front) where the PacifiCorp Lake Side facility is located. A marginal designation is the least stringent classification for an ozone nonattainment area and does not require a formal nonattainment SIP. Utah submitted its strategy for meeting the standard to EPA in May of 2021. The Wasatch Front was required to attain the ozone standard by August 3, 2021. Recent monitoring data indicates that the Southern Wasatch Front nonattainment area has attained the standard, and Utah has initiated the process for redesignation to attainment for this area. However, recent monitoring data indicates that the Northern Wasatch Front nonattainment area will not attain the ozone standard by that date and will be bumped up to moderate classification in 2022.

[1] Before February 9, 2018, the tax credit was strictly for CO_2.
[2] The tax credit reaches $35/tonne and $50/tonne in 2026.
[3] For an electric generating facility, a minimum of 500,000 tonnes of qualified carbon oxide must be captured per year to receive the 45Q tax credit. Construction of the qualified facility must begin before January 1, 2026.

On March 11, 2022, the Environmental Protection Agency released a pre-publication version of its "Ozone Transport Rule" (also called Good Neighbor Rule or Cross-State Air Pollution Rule), which contains proposed revisions intended to address ozone transport between states. The rule is focused on reductions of nitrogen oxides, precursors to ozone formation, and covers 26 states. Four states, including Wyoming and Utah, are included in the cross-state program for the first time.

Under the proposed rule, beginning in 2023, trading allowances and emissions budgets would be set to achieve reductions from current emissions through immediately available measures. Starting in May of 2026, emissions budgets would be set for coal-fired units at levels achievable by the installation of selective catalytic reduction (SCR) controls. Daily emission “backstop” limits for units with SCR will become effective in 2027.

PacifiCorp is evaluating the pre-publication version of the proposed rule and its potentially significant impacts on coal-fired power plants in both Utah and Wyoming as first-time participants in the trading program. PacifiCorp anticipates submitting comments as part of the public comment process. The public comment process will commence when the proposed rule is published in the Federal Register and run for 60-days. Further review of the lengthy and complex OTR is needed to determine how it will impact specific Utah and Wyoming facilities. However, on initial review, it appears that emissions levels for coal-fired units without SCR could be significantly impacted starting in 2026, while existing natural gas units will not experience significant reduction requirements from 2021 levels. The rule has yet to be formally proposed and could change before its expected finalization in late 2022 or early 2023.

In April 2017, the EPA Administrator signed a final action to reclassify the Salt Lake City and Provo PM2.5 nonattainment area from moderate to serious. PacifiCorp’s Lake Side and Gadsby facilities were identified as major sources subject to Utah’s serious nonattainment area SIP for PM2.5 and PM2.5 precursors. On April 27, 2017, PacifiCorp submitted a best-available control measure technology analysis for Lake Side and Gadsby to the Utah Division of Air Quality for review. PacifiCorp proposed ammonia limits for the Gadsby and Lake Side facilities. On January 2, 2019, the Utah Air Quality Board adopted source specific emission limits and operating practices in the SIP which incorporated the current emission and operating limits for the Lake Side and Gadsby facilities. On November 6, 2020, EPA proposed approval to redesignate the Salt Lake City and Provo nonattainment areas for PM2.5 as attainment. The rulemaking was delayed by corrections issued in May of 2021 and has not yet been finalized.

On January 9, 2018, EPA published the results for the air quality designations for the 2010 SO_2 primary NAAQS-Round three in the *Federal Register*. The Utah county of Emery, where PacifiCorp’s Hunter and Huntington Generation Stations are located, was classified as attainment/unclassifiable. The Wyoming counties of Campbell and Lincoln, where PacifiCorp’s Wyodak and Naughton generation stations are located, were classified as attainment/unclassifiable. The eastern portion of Sweetwater County, where PacifiCorp’s Jim Bridger generation station is located, was classified as attainment/unclassifiable. PacifiCorp’s Jim Bridger facility has conducted on-site ambient SO_2 monitoring to demonstrate compliance and is currently working with the state and federal agencies to terminate the monitoring site. On March 26, 2021, the EPA issued the last of its final designations for the 2010 primary SO_2 standard. Included in this round was designation of Converse County, Wyoming as an attainment/unclassifiable area. PacifiCorp's Dave Johnston generating facility is located in Converse County. PacifiCorp facilities located in areas classified as attainment/unclassifiable will be required to demonstrate ongoing compliance by performing modeling every three years using actual facility emission data.

Regional Haze

EPA's regional haze rule, finalized in 1999, requires states to develop and implement plans to improve visibility in certain national park and wilderness areas. On June 15, 2005, EPA issued final amendments to its regional haze rule to require emission controls known as the Best Available Retrofit Technology (BART) for industrial facilities meeting certain regulatory criteria with emissions that have the potential to affect visibility. The regulated pollutants include PM, NO_X, SO_2, certain volatile organic compounds, and ammonia. The 2005 amendments included final guidelines, known as BART guidelines, for states to use in determining which facilities must install controls and the type of controls the facilities must use. States were given until December 2007 to develop their implementation plans, in which states were responsible for identifying the facilities that would have to reduce emissions under BART guidelines, as well as establishing BART emissions limits for those facilities. States are also required to periodically update or revise their implementation plans to reflect current visibility data and an effective long-term strategy for achieving reasonable progress toward visibility goals. In January 2017, EPA issued a final rule updating requirements for the first periodic update to the SIP. EPA required states to submit their second periodic SIP update by July 31, 2021, unless granted an extension.

The regional haze rule is intended to achieve natural visibility conditions by 2064 in specific National Parks and Wilderness Areas, many of which are in the western United States where PacifiCorp owns and operates several coal-fired generating units (Utah, Wyoming, Colorado and Montana as well as Arizona, where a PacifiCorp-owned coal unit ceased operating in 2020).

On August 20, 2019, EPA issued a final guidance document on the technical aspects of developing regional haze SIPs for the second implementation period of the Regional Haze Program. EPA issued additional guidance through a memorandum on July 8, 2021, that emphasizes the 4-factor reasonable progress analysis for the second planning period and the reduced weight of visibility as a factor in the second planning period.

Utah Regional Haze

In May 2011, the state of Utah issued a regional haze SIP requiring the installation of SO_2, NO_X and PM controls on Hunter Units 1 and 2 and Huntington Units 1 and 2. In December 2012, the EPA approved the SO_2 portion of the Utah regional haze SIP and disapproved the NO_X and PM portions. EPA's approval of the SO_2 SIP was appealed by environmental advocacy groups to the Tenth Circuit Court of Appeals ("Tenth Circuit" or "Court"). In addition, PacifiCorp and the state of Utah appealed EPA's disapproval of the NO_X and PM SIP. PacifiCorp and the state's appeals were dismissed, and EPA's approval of the SO_2 SIP was upheld by the Tenth Circuit. In June 2015, the state of Utah submitted a revised SIP to EPA for approval with an alternative BART NO_X analysis incorporating a requirement for PacifiCorp to retire Carbon Units 1 and 2, crediting NO_X controls previously installed on Hunter Unit 3, and concluding that no incremental controls (beyond those included in the May 2011 SIP and already installed) were required at the Hunter and Huntington units. On June 1, 2016, EPA issued a final rule to partially approve and partially disapprove Utah's regional haze BART NO_X SIP and propose a federal implementation plan (FIP). The FIP required the installation of selective catalytic reduction (SCR) controls by August 4, 2021, at four of PacifiCorp's units in Utah: Hunter Units 1 and 2 and Huntington Units 1 and 2. On

September 2, 2016, the state of Utah and PacifiCorp filed petitions for administrative and judicial review of EPA's final rule, followed by a motion to stay the effective date of the final rule.

On June 30, 2017, Utah and PacifiCorp provided new information to EPA, again requesting reconsideration. EPA responded on July 14, 2017, indicating its intent to reconsider its FIP. EPA also filed a motion with the Tenth Circuit to stay EPA's FIP and hold the litigation in abeyance pending the rule's reconsideration. On September 11, 2017, the Tenth Circuit granted the petition for stay and the request for abatement. The compliance deadline of the FIP and the litigation were stayed pending EPA's reconsideration, and EPA was required to file periodic status reports with the Court.

Utah and PacifiCorp worked with EPA to develop a revised Utah Regional Haze SIP, based on the new Comprehensive Air Quality Model with Extensions (CAMx) modeling. The Utah Air Quality Board approved the revised SIP on June 24, 2019, and the SIP Revision was submitted to EPA for review on July 3, 2019. On December 3, 2019, Utah submitted a supplement to EPA with a minor SIP revision relating to PM 2.5.

On January 10, 2020, the EPA published its proposed approval of the Utah SIP Revision and withdrawal of the FIP requirements for the installation of SCR on Hunter Units 1 and 2 and Huntington Units 1 and 2. After receiving public comments and holding a public hearing in the Price area on February 12, 2020, EPA issued final approval of the Utah SIP Revision and FIP withdrawal on November 27, 2020. The final rule credits existing NO_X emission controls at the Hunter and Huntington plants as well as NO_X and PM emission reductions provided by the closure of the Carbon plant in 2015. Based on the newly approved plan, EPA also withdrew the 2016 FIP requirements to install selective catalytic reduction (SCR) control technology on Hunter Units 1 and 2 and Huntington Units 1 and 2. On January 11, 2021, the Tenth Circuit granted Utah, PacifiCorp, and EPA's motion to dismiss the Utah regional haze petitions.

Environmental advocacy groups filed a petition for review, objecting to the revised Utah regional haze SIP on January 19, 2021, in the Tenth Circuit. At EPA's request, the Tenth Circuit abated the petition on February 4, 2021, while EPA considered the petition under the new Biden administration's guidelines. The state of Utah, PacifiCorp and co-owners of the Hunter plant filed motions to intervene. EPA notified the court that it would defend the revised Utah regional haze SIP, and the court granted intervention to Utah and PacifiCorp in December of 2021. The parties scheduled briefing, and HEAL Utah submitted its opening brief on February 8, 2022, challenging the legitimacy of the states' modeling as well as crediting emissions from the Carbon plant retirement and requesting reinstatement of the FIP and the SCR requirement at Hunter Units 1 and 2 and Huntington Units 1 and 2. EPA's response brief is due April 5, 2022, with briefs from Utah and PacifiCorp to follow on May 3, 2022.

The Western Regional Air Partnership (WRAP) developed modeling for the state's use for the implementation of the second planning period. Utah used a 'Q/d' screening level of 10 to determine which sources to evaluate for reasonable progress controls under the rule. On April 21, 2020, PacifiCorp submitted a Regional Haze Reasonable Progress Analysis for the second planning period to the Utah Department of Environmental Quality (Utah DEQ) for PacifiCorp's Huntington and Hunter plants. The analysis was requested by the State as part of its second planning period SIP (2PP SIP) development process. PacifiCorp's analysis included a proposal to implement reasonable progress emission limits for NOx and SO_2 on the Hunter and Huntington units to meet second planning period requirements. On October 20, 2020, PacifiCorp submitted a follow-up letter in response to questions from the Utah DEQ about proposed emission reductions and costs for control technology.

The state is on track to submit a final implementation plan to the state air quality board in March or April 2022 and plans to submit the final state-approved implementation plan to the Environmental Protection Agency late summer/early fall of 2022.

Wyoming Regional Haze

On January 30, 2014, EPA issued a final rule partially approving and partially disapproving the Wyoming SIP. The final rule required installation of the following NO_X and PM controls at PacifiCorp facilities for regional haze first planning period:

- Naughton Units 1 and 2: low-NO_X burners (LNB)/over-fired air (OFA) as BART
- Naughton Unit 3 by December 31, 2014: SCR equipment and a baghouse, BART
- Jim Bridger Units 1 – 4: LNB/separated over-fired air (SOFA), BART
- Jim Bridger Unit 3 by December 31, 2015: SCR equipment, long-term strategy (LTS)
- Jim Bridger Unit 4 by December 31, 2016: SCR equipment, LTS
- Jim Bridger Unit 2 by December 31, 2021: SCR equipment, LTS
- Jim Bridger Unit 1 by December 31, 2022: SCR equipment, LTS
- Dave Johnston Unit 3: SCR within five years or a commitment to shut down in 2027, BART
- Dave Johnston Unit 4: LNB/OFA, BART
- Wyodak: SCR equipment within five years, BART

Wyodak – PacifiCorp and the state of Wyoming petitioned EPA's final action on Wyodak, which required SCR. PacifiCorp and the state of Wyoming successfully requested a stay of EPA's final rule relating to the Wyoming SIP, pending resolution of the petition. PacifiCorp subsequently submitted a request for reconsideration to EPA and is currently engaged in a settlement process with EPA and Wyoming. The EPA, state of Wyoming and PacifiCorp signed a Settlement Agreement for Wyodak on December 16, 2020, removing the requirement to install SCR in lieu of monthly and annual NO_X emission limits. EPA published the Settlement Agreement in the *Federal Register* requesting public comment on January 4, 2021. PacifiCorp submitted formal comments to the EPA on March 5, 2021, in support of the Wyodak Settlement Agreement. The public comment period was extended through July 6, 2021. EPA did not proceed with final approval of the Settlement Agreement and is currently engaged with Wyoming and PacifiCorp regarding alternative paths for resolution.

Naughton – In its 2014 rule, EPA approved Wyoming's determination that BART for Units 1 and 2 was LNB/OFA. EPA also indicated support for the conversion of Naughton Unit 3 to natural gas in lieu of retrofitting the unit with SCR and stated that it would expedite consideration of the gas conversion once the state of Wyoming submitted the requisite SIP amendment. Wyoming submitted its regional haze SIP amendment regarding Naughton Unit 3 to EPA on November 28, 2017. On March 7, 2017, Wyoming issued PacifiCorp a permit for Naughton Unit 3's conversion to natural gas, extending the requirement to cease coal firing to no later than January 30, 2019. PacifiCorp ceased coal operation on Naughton Unit 3 on January 30, 2019. EPA's final rule approval of Wyoming's SIP revision for Naughton Unit 3 gas conversion was published in the *Federal Register* on March 21, 2019, with an effective date of April 22, 2019. Naughton Unit 3 currently operates on natural gas. Environmental groups petitioned EPA's approval of LNB/OFA as BART for Units 1 and 2 in the Tenth Circuit. The petition was stayed by the Court and remains stayed. The environmental groups have participated in on-going mediation with Wyoming, PacifiCorp and EPA to settle the Naughton claims.

Jim Bridger – PacifiCorp installed SCR on Jim Bridger Units 3 and 4 by 2015 and 2016, the dates required by Wyoming state law as well as the 2014 SIP. On February 5, 2019, PacifiCorp submitted to Wyoming an application and proposed SIP revision instituting plant-wide variable average monthly-block pound per hour NO_X and SO_2 emission limits, in addition to an annual combined NO_X and SO_2 limit, on all four Jim Bridger units in lieu of the requirement to install SCR on Units 1 and 2. The proposed SIP revision demonstrates that the proposed limits are more cost effective while leading to better modeled visibility than the SCR installation on Units 1 and 2 required in the federally approved SIP.

Wyoming's proposed approval of the SIP revision was published for public comment July 20, 2019, through August 23, 2019. On May 5, 2020, the Wyoming Department of Environmental Quality issued permit P0025809 with PacifiCorp's proposed monthly and annual NO_X and SO_2 emission limits. Under the permit, the new emissions limits become effective January 1, 2022. Wyoming submitted a corresponding regional haze SIP revision to EPA on May 14, 2020. After initially signaling that the SIP revision had been approved by EPA Region 8 in November of 2020, EPA did not finalize the approval by publication in the *Federal Register* after an administration change. EPA failed to act upon the SIP revision by November 14, 2021, as required by law. EPA, PacifiCorp and Wyoming worked to find a solution for the unresolved SIP revision and the pending January 1, 2022, SCR requirement.

Using authority granted by the Clean Air Act, the Governor of Wyoming issued a temporary emergency order on December 27, 2021, suspending the current state implementation plan requirement for Jim Bridger Unit 2 to install SCR by December 31, 2021. The suspension was issued for the full four months allowed by the act due to EPA's failure to act on the SIP revision submitted by Wyoming in 2020, by November 14, 2021. EPA published a proposed disapproval of Wyoming's SIP revision on January 18, 2022, commencing a 30-day public comment period. Discussions between EPA, Wyoming, and PacifiCorp regarding the SIP revision and regional haze compliance at Jim Bridger are ongoing. The Wyoming district court approved a consent decree between PacifiCorp and Wyoming on February 14, 2022, to resolve regional haze compliance issues for the Jim Bridger plant. The consent decree enables PacifiCorp to continue operation of Jim Bridger units 1 and 2 until they are converted to natural gas in 2024. The consent decree commits Wyoming to processing a state implementation plan revision with post-conversion emission limits in a timely manner.

WRAP performed modeling for the state to use for the implementation of the second planning period. On March 31, 2020, PacifiCorp submitted a four-factor reasonable progress analysis to Wyoming which analyzed PacifiCorp's Naughton, Jim Bridger, Dave Johnston, and Wyodak plants. The four-factor analysis was used by the state in its development of the SIP for the regional haze second planning period (2PP SIP). The state of Wyoming issued its proposed 2PP SIP for public comment on February 18, 2022, and held a public hearing on March 23, 2022 to receive comments on their proposed plan. PacifiCorp participated in the hearing and provided verbal and written comments. It is estimated that the state will submit a final state-approved implementation plan to the U.S. Environmental Protection Agency in April 2022. In February of 2022 environmental groups submitted a 60-day notice of intent to sue EPA to take action against states that have missed the deadline to submit their second planning period SIPs.

Arizona Regional Haze

The state of Arizona issued a regional haze SIP requiring, among other things, the installation of SO_2, NO_X and PM controls on Cholla Unit 4, which is owned by PacifiCorp and operated by Arizona Public Service. EPA approved, in part, and disapproved, in part, the Arizona SIP and issued a FIP requiring the installation of SCR equipment on Cholla Unit 4. PacifiCorp filed an appeal regarding the FIP as it relates to Cholla Unit 4, and the Arizona Department of Environmental Quality and other affected Arizona utilities filed separate appeals of the FIP as related to their interests. For the Cholla FIP requirements, the Ninth Circuit Court of Appeals stayed the appeals while parties attempted to agree on an alternative compliance approach.

In July 2016, the EPA issued a proposed rule to approve an alternative Arizona SIP, which included the option to convert Cholla 4 to a natural gas-fired unit or retire the unit by in 2025. EPA approved the revised SIP on March 27, 2017. The final action allowed Cholla Unit 4 to utilize coal until April 30, 2025, with an option to convert to gas by July 31, 2025. Cholla Unit 4 was retired in December 2020.

Colorado Regional Haze

The Colorado regional haze SIP required SCR controls at Craig Unit 2 and Hayden Units 1 and 2, which were installed by the required dates, and the installation of selective non-catalytic reduction (SNCR) technology at Craig Unit 1. Environmental groups appealed EPA's action, and PacifiCorp intervened in support of EPA. In July 2014, parties to the litigation, other than PacifiCorp, entered into a settlement agreement that required installation of SCR equipment at Craig Unit 1 in 2021. This was incorporated into a regional haze SIP revision that was approved by EPA in 2015. EPA approved a modified SIP on July 5, 2018, that requires Craig Unit 1 to retire by December 31, 2025, or, to convert the unit to natural gas by August 31, 2023.

Colorado's regional haze SIP for the second planning period were adopted in phases in 2020 and 2021 by the Colorado Air Quality Control Commission. The SIP includes retirements of Craig Units 1 and 2 by 2025 and 2028, respectively, and Hayden Units 1 and 2 by 2028 and 2027, respectively.

Mercury and Hazardous Air Pollutants

The Mercury and Air Toxics Standards (MATS) became effective April 16, 2012. The MATS rule requires that new and existing coal-fueled facilities achieve emission standards for mercury, acid gases and other non-mercury hazardous air pollutants. Existing sources were required to comply with the new standards by April 16, 2015. However, individual sources may have been granted up to one additional year, at the discretion of the Title V permitting authority, to complete installation of controls or for transmission system reliability reasons. By April 2015, PacifiCorp had taken the required actions to comply with MATS across its generation facilities. On April 25, 2016, the EPA published a Supplemental Finding that determined that it is appropriate and necessary to regulate under the MATS rule which addressed the Supreme Court decision.

On February 7, 2019, the EPA published a reconsideration of the Supplemental Finding in which it proposed to find that it is not appropriate and necessary to regulate hazardous air pollutants, reversing the Agency's prior determination. In May 2020, the EPA published its decision to repeal the appropriate and necessary findings in the MATS rule regarding regulation of electric utility steam generating units, and to retain the rule's current emission standards. The rule took effect in July 2020. Several petitions for review were filed in the D.C. Circuit by parties challenging and supporting the EPA's decision to rescind the appropriate and necessary finding. On February 9, 2022, the EPA proposed to revoke the May 2020, decision that is not appropriate and necessary to regulate under Section 112 and reaffirm the April 2016 finding.

Coal Combustion Residuals

In May 2010, the EPA released a proposed rule to regulate the management and disposal of coal combustion byproducts under the Resource Conservation and Recovery Act (RCRA). The final rule became effective October 19, 2015. The final rule regulates coal combustion byproducts as non-hazardous waste under RCRA Subtitle D and establishes minimum nationwide standards for the disposal of coal combustion residuals (CCR). Under the final rule, surface impoundments and landfills utilized for coal combustion byproducts may need to be closed unless they can meet the more stringent regulatory requirements. The final rule requires regulated entities to post annual groundwater monitoring and corrective action reports. The first of these reports was posted to PacifiCorp's coal combustion rule compliance data and information websites in March 2018. Based on the results in those reports, additional action was required under the rule. At the time the rule became effective in October 2015, nine surface impoundments and four landfills were in operation and subject to the final rule. Since that time, three surface impoundments have been closed under the CCR rules and two are in the process of closure.

Multiple parties filed challenges over various aspects of the final rule in 2015, resulting in settlement of some of the issues and subsequent regulatory action by the EPA, including subjecting inactive surface impoundments to regulation. In response to legal challenges and court actions, EPA, in March 2018, issued a proposal to address provisions of the final CCR rule that were remanded back to the agency. The proposal included provisions that establish alternative performance standards for owners and operators of CCR units located in states that have approved permit programs or are otherwise subject to oversight through a permit program administered by the EPA. The first phase of the CCR rule amendments was made effective in August 2018 (the "Phase 1, Part 1 rule"). In addition to adopting alternative performance standards and revising groundwater performance standards for certain constituents, the EPA extended the deadline by which facilities must initiate closure of unlined ash ponds exceeding a groundwater protection standard and impoundments that do not meet the rule's aquifer location restrictions to October 2020.

Following the March 2019 submittal of competing motions from environmental groups, EPA finalized its Holistic Approach to Closure: Part A rule ("Part A rule") in September 2020. The rule reclassified compacted-soil lined surface impoundments from "lined" to "unlined," established a deadline of April 11, 2021, by which all unlined surface impoundments must initiate closure, and revised the alternative closure provisions to grant facilities additional time to initiate closure in order to manage CCR and non-CCR waste streams either due to a lack of alternative capacity or due to a commitment to close the coal-fueled operating unit and complete closure of unlined impoundments by a date certain. The Part A rule also revised certain requirements regarding annual groundwater monitoring and corrective action reports and publicly accessible CCR internet sites. A provision in Part A allows demonstrations to be submitted to the EPA allowing for operation of unlined CCR ponds beyond the April 11, 2021, deadline for initiation of closure. The demonstrations were allowed to be submitted for: (1) a site-specific extension to develop alternate disposal capacity and initiate closure by October 15, 2023; and (2) a site-specific extension for facilities that agree to shut down the coal-fueled unit and complete ash pond closure activities by October 17, 2028. PacifiCorp has submitted alternative closure demonstrations for the Naughton South Ash Pond and the Jim Bridger FGD Pond 2, submitted in November 2020. Approval of these demonstrations was anticipated in first quarter 2021 prior to the April 11, 2021, cease receipt of waste date, but has not been granted as of February 2022. On January 11, 2022, PacifiCorp received notice from the EPA that the Jim Bridger and Naughton demonstrations have been determined to be complete and the April 11, 2021, cease receipt of waste deadline is tolled until the EPA issues a final decision.

On October 16, 2020, the EPA released the pre-publication version of the final Holistic Approach to Closure: Part B rule ("Part B rule"). The Part B rule finalizes a two-step process, as set forth in the March 2020 proposal, allowing facilities to request approval to continue operating an existing unlined CCR surface impoundment with an alternate liner system. The other provisions that were contained in the Part B proposal, including (1) options to use CCR during closure of a CCR unit, (2) an additional closure-by-removal option and (3) new requirements for annual closure progress reports, were not finalized with the Part B rule. These options will be addressed by the EPA in a subsequent rulemaking action. In addition to the Part A and Part B rules, the EPA has proposed the Phase II rule, the federal CCR permit program rule, and the advanced notice of proposed rulemaking for legacy impoundments. Until the proposals are finalized and fully litigated, PacifiCorp cannot determine whether additional action may be required.

Separately, on August 10, 2017, the EPA issued proposed permitting guidance on how states' CCR permit programs should comply with the requirements of the final rule as authorized under the December 2016 Water Infrastructure Improvements for the Nation Act. To date, none of the states in which PacifiCorp operates has submitted an application to the EPA for approval of state permitting authority. The state of Utah adopted the federal final rule in September 2016, which required PacifiCorp to submit permit applications for two of its landfills by March 2017. It is anticipated that the state of Utah will submit an application to EPA for approval of CCR permit program prior to the end of 2022. In 2019, the state of Wyoming proposed to adopt state rules which incorporate the final federal rule by reference. Wyoming finalized its rule in late 2020 and is waiting on legislative approval, likely in 2022, before submitting an application to the EPA to implement a state permit program.

Water Quality Standards

Cooling Water Intake Structures

The federal Water Pollution Control Act ("Clean Water Act") establishes the framework for maintaining and improving water quality in the U.S. through a program that regulates, among other things, discharges to and withdrawals from waterways. The Clean Water Act requires that cooling-water-intake structures reflect the "best technology available for minimizing adverse environmental impact" to aquatic organisms. In May 2014, EPA issued a final rule, effective October 2014, under § 316(b) of the Clean Water Act to regulate cooling-water intakes at existing facilities. The final rule established requirements for electric-generating facilities that withdraw more than two million gallons per day, based on total design intake capacity, of water from waters of the U.S. and use at least 25 percent of the withdrawn water exclusively for cooling purposes. PacifiCorp's Dave Johnston generating facility withdraws more than two million gallons per day of water from waters of the U.S. for once-through cooling applications. Jim Bridger, Naughton, Gadsby, Hunter, and Huntington generating facilities currently use closed-cycle cooling towers but withdraw more than two million gallons of water per day. The rule includes impingement (*i.e.*, when fish and other aquatic organisms are trapped against screens when water is drawn into a facility's cooling system) mortality standards and entrainment (*i.e.*, when organisms are drawn into the facility) standards. The standards will be set on a case-by-case basis to be determined through site-specific studies and will be incorporated into each facility's discharge permit.

Rule-required permit application requirements (PARs) have been submitted to the appropriate permitting authorities for the Jim Bridger, Naughton, Gadsby, Hunter and Huntington plants. As the five facilities utilize closed-cycle recirculating cooling water systems (cooling towers) exclusively for equipment cooling, it is expected that state agencies will require no further action from PacifiCorp to comply with the rule-required standards.

Because Dave Johnston utilizes once-through cooling with withdrawal rates greater than 125 million gallons per day, the facility has been required to conduct more rigorous permit application requirements. The Dave Johnston permit application requirements were submitted to the Wyoming Water Quality Division on May 31, 2019. The application proposed that no modifications to the intake structure were required; however, upon review of the submittal and subsequent issuance of a draft permit for public notice, the Water Quality Division has indicated that PacifiCorp may be required to select and implement an approved 316(b) impingement mortality compliance option by December 31, 2023. As the final Dave Johnston Wyoming Pollutant Discharge Elimination System permit has yet to be issued which is expected to include 316(b) impingement mortality (IM) compliance requirements, it is anticipated that the December 31, 2023, IM technology implementation date will be adjusted to compensate for the actual permit issuance date.

As of March 2022, the Wyoming and Utah regulatory agencies have yet to make 316(b) compliance determinations for the site-specific permit application requirements which were provided to the agencies for each PacifiCorp rule-affected facility.

Effluent Limit Guidelines

In November 2015, the EPA published final effluent limitation guidelines and standards for the steam electric power generating sector which, among other things, regulate the discharge of bottom ash transport water, fly ash transport water, combustion residual leachate and non-chemical metal cleaning wastes. These guidelines, which had not been revised since 1982, were revised in response to the EPA's concerns that the addition of controls for air emissions has changed the effluent discharged from coal- and natural gas-fueled generating facilities. Under the originally promulgated guidelines, permitting authorities were required to include the new limits in each impacted facility's National Pollutant Discharge Elimination System permit upon renewal with the new limits to be met as soon as possible, beginning November 1, 2018, and fully implemented by December 31, 2023.

On April 5, 2017, a request for reconsideration and administrative stay of the guidelines was filed with the EPA. EPA granted the request for reconsideration and extended certain compliance dates for flue gas desulfurization wastewater and bottom ash transport water limits until November 1, 2020.

On November 22, 2019, EPA proposed updates to the 2015 rule, specifically addressing flue gas desulfurization wastewater and bottom ash transport water. Those proposals were formalized in rule when the EPA administrator signed the Reconsideration Rule, and it was published in the Federal Register on October 13, 2020. The rule eases selenium limits on flue gas desulfurization wastewater, eases the zero-discharge requirements on bottom ash transport water associated with blowdown of ash handling systems, allows a two-year time extension to meet flue gas desulfurization wastewater requirements, and includes additional subcategories to both wastewater categories.

Most of the issues raised by this rule are already being addressed at PacifiCorp facilities through compliance with the coal combustion residuals rule and are not expected to impose significant additional requirements on the facilities. The Dave Johnston plant anticipates achieving compliance with the rule by issuing a notice of planned participation for subcategorization, or by installation and operation of a bottom ash recycle system that would enable long-term compliance with the Reconsideration Rule.

Tax Extender Legislation

On Dec. 27, 2020, President Trump signed into law the Taxpayer Certainty and Disaster Relief Act of 2020. Among other things, the bill extended and expanded certain alternative energy tax credits. Notable as relating to the 2021 IRP, the renewable electricity production tax credit (PTC) was extended by one year for certain qualifying facilities; for wind facilities that begin construction during 2021, the credit continues to be equal to 60% of the full value of the PTC. The energy tax credit (ITC) was extended by two years for certain qualifying facilities; the bill extends the 26% ITC for solar energy property that begins construction during 2021 and 2022, before being phased down further.

The energy tax credit was expanded to cover offshore wind facilities; generally, any offshore wind project that on which construction after December 31, 2017, and before January 1, 2026, will qualify for a 30% ITC. And, finally, the credit for carbon dioxide sequestration was extended to cover facilities that begin construction by the end of 2025. Additional schedules detailing the phase-out of the wind PTC and solar ITC are provided as follows:

Table 3.1 – Tax Extender Legislation and Phaseout of PTC and ITC

Phaseout of Wind PTC		
Date Construction Begins	**In-Service Date***	**% of Full PTC Rate**
Before 12/31/2015	Before 01/01/2020	100%
01/01/2016 - 12/31/2016	Before 01/01/2022	100%
01/01/2017 - 12/31/2017	Before 01/01/2023	80%
01/01/2018 - 12/31/2018	Before 01/01/2023	60%
01/01/2019 - 12/31/2019	Before 01/01/2024	40%
01/01/2020 - 12/31/2020	Before 01/01/2025	60%
01/01/2021 - 12/31/2021	Before 01/01/2026	60%
On or After 01/01/2022	Any	0%

* In-Service date assumes the use of the Continuity Safe Harbor which is 4 years after the calendar year during which construction, 5 years for projects beginning construction in 2016 and 2017.

Phaseout of Solar ITC		
Date Construction Begins	**In-Service Date**	**ITC Rate**
Before 01/01/2020	Before 01/01/2026	30%
01/01/2020 - 12/31/2020	Before 01/01/2026	26%
01/01/2021 - 12/31/2021	Before 01/01/2026	26%
01/01/2022 - 12/31/2022	Before 01/01/2026	26%
01/01/2023 - 12/31/2023	Before 01/01/2026	22%
Before 01/01/2024	On or After 01/01/2026	10%
On or After 01/01/2024	Any	10%

These schedules remain then same as referenced in the 2021 IRP.

State Policy Update

California

Under the authority of the Global Warming Solutions Act, the California Air Resources Board (CARB) adopted a greenhouse gas cap-and-trade program in October 2011, with an effective date of January 1, 2012; compliance obligations were imposed on regulated entities beginning in 2013. The first auction of greenhouse gas allowances was held in California in November 2012, and the second auction in February 2013. PacifiCorp is required to sell, through the auction process, its directly allocated allowances and purchase the required amount of allowances necessary to meet its compliance obligations.

In May 2014, CARB approved the first update to the Assembly Bill (AB) 32 Climate Change scoping plan, which defined California's climate change priorities for the next five years and set the groundwork for post-2020 climate goals. In April 2015, Governor Brown issued an executive order to establish a mid-term reduction target for California of 40 percent below 1990 levels by 2030. CARB was subsequently directed to update the AB 32 scoping plan to reflect the new interim 2030 target and previously established 2050 target. In July 2017, California Governor Jerry Brown signed AB 398, extending the state's California Cap and Trade program from January 1, 2021, through December 31, 2030. In 2022, CARB is expected to issue a revised scoping plan establishing emissions reduction targets post-2030. The 2022 scoping plan may also reduce target prior to 2030.

In 2002, California established a renewable portfolio standard (RPS) requiring investor-owned utilities to increase procurement from eligible renewable energy resources. California's RPS requirements have been accelerated and expanded a number of times since its inception. Most recently, in September 2018, Governor Jerry Brown signed into law the 100 Percent Clean Energy Act of 2018, Senate Bill (SB) 100, which requires utilities to procure 60 percent of their electricity from renewables by 2030 and enabled all the state's agencies to work toward a longer-term planning target for 100 percent of California's electricity to come from renewable and zero-carbon resources by December 31, 2045.

Oregon

In 2007, Oregon enacted SB 838 establishing an RPS requirement in Oregon. Under SB 838, utilities are required to deliver 25 percent of their electricity from renewable resources by 2025. On March 8, 2016, Governor Kate Brown signed SB 1547-B, the Clean Electricity and Coal Transition Plan, into law. SB 1547-B extends and expands the Oregon RPS requirement to 50 percent of electricity from renewable resources by 2040 and requires that coal-fueled resources are eliminated from Oregon's allocation of electricity by January 1, 2030. The increase in the RPS requirements under SB 1547-B is staged—27 percent by 2025, 35 percent by 2030, 45 percent by 2035, and 50 percent by 2040. The bill changes the renewable energy certificate (REC) life to five years, while allowing RECs generated from the effective date of the bill passage until the end of 2022 from new long-term renewable projects to have unlimited life. The bill also includes provisions to create a community-solar program in Oregon and encourage greater reliance on electricity for transportation.

On March 10, 2020, Oregon Governor Kate Brown issued Executive Order 20-04 (EO 20-04), which directs state agencies to take actions to reduce and regulate greenhouse gas emissions.

EO 20-04 establishes emissions reduction goals for Oregon and directs certain state agencies to take specific actions to reduce emissions and mitigate the impacts of climate change. EO 20-04 also provides overarching direction to state agencies to exercise their statutory authority to help achieve Oregon's climate goals.

In 2021, Oregon passed House Bill (HB) 2021, which directs utilities to reduce emissions levels below 2010-2012 baseline levels by 80% by 2030, 90% by 2035, and 100% by 2040. Utilities will also convene a Community Benefits and Impacts Advisory Group. PacifiCorp's 2023 IRP will include modeling as appropriate to support HB 2021. HB 2021 also increases state goals for small-scale renewable energy projects, to ten percent of aggregate electrical capacity by 2030. HB 2021 is complementary to – but does not modify – Oregon's longstanding RPS requirements.

Washington

In November 2006, Washington voters approved Initiative 937 (I-937), the Washington Energy Independence Act, which imposes targets for energy conservation and the use of eligible renewable resources on electric utilities. Under I-937, utilities must supply 15 percent of their energy from renewable resources by 2020. Utilities must also set and meet energy conservation targets starting in 2010.

In 2008, the Washington Legislature approved the Climate Change Framework E2SHB 2815, which establishes the following state greenhouse gas emissions reduction limits: (1) reduce emissions to 1990 levels by 2020; (2) reduce emissions to 25 percent below 1990 levels by 2035; and (3) by 2050, reduce emissions to 50 percent below 1990 levels or 70 percent below Washington's forecasted emissions in 2050.

In July 2015, Governor Inslee released an executive order that directed the Washington Department of Ecology to develop new rules to reduce carbon emissions in the state. In December 2017, Washington's Superior Court concluded that the Department of Ecology did not have the authority to impose the Clean Air Rule without legislative approval. As a result, the Department of Ecology has suspended the rule's compliance requirements.

In 2019, the Washington Legislature approved the Clean Energy Transformation Act (CETA) which requires utilities to eliminate coal-fired resources from Washington rates by December 31, 2025, be carbon neutral by January 1, 2030, and establishes a target of 100 percent of its electricity from renewable and non-emitting resources by 2045.

Finally, in 2021, Washington passed the Climate Commitment Act, which establishes a cap-and-trade program to be implemented by no later than January 1, 2023, through the regulatory rulemaking process. The Climate Commitment Act does not modify any of PacifiCorp's obligations under CETA, and utility allowances within the cap-and-trade program are aligned with the CETA renewable energy requirements. The legislation allows – but does not require – linkage with cap-and-trade programs in jurisdictions outside of Washington state. Utilities are provided allowances at no cost to "mitigate the cost burden" of the program on customers,

Utah

In March 2008, Utah enacted the Energy Resource and Carbon Emission Reduction Initiative, which includes provisions to require utilities to pursue renewable energy to the extent that it is cost effective. It sets out a goal for utilities to use eligible renewable resources to account for 20 percent of their 2025 adjusted retail electric sales.

On March 10, 2016, the Utah legislature passed SB 115–The Sustainable Transportation and Energy Plan (STEP). The bill supports plans for electric vehicle infrastructure and clean coal research in Utah and authorizes the development of a renewable energy tariff for new Utah customer loads. The legislation establishes a five-year pilot program to provide mandated funding for electric vehicle infrastructure and clean coal research, and discretionary funding for solar development, utility-scale battery storage, and other innovative technology and air quality initiatives. The legislation also allows PacifiCorp to recover its variable power supply costs through an energy balancing account and establishes a regulatory accounting mechanism to manage risks and provide planning flexibility associated with environmental compliance or other economic impairments that may affect PacifiCorp's coal-fueled resources in the future. The deferrals of variable power supply costs went into effect in June 2016, and implementation and approval of the other programs was completed by January 1, 2017.

On March 11, 2020, the Utah Legislature passed HB 396, Electric Vehicle Charging Infrastructure Amendments, that enables PacifiCorp to create an Electrical Vehicle Infrastructure Program, with a maximum funding from customers of $50 million for all costs and expenses. The legislation allows PacifiCorp to own and operate electric vehicle charging stations and to provide investments in make-ready infrastructure to interested customers.

Wyoming

On March 8, 2019, Wyoming Senate File 0159 (SF 159) was passed into law. SF 159 limits the recovery costs for the retirement of coal fired electric generation facilities, provides a process for the sale of an otherwise retiring coal fired electric generation facility, exempts a person purchasing an otherwise retiring coal fired electric generation facility from regulation as a public utility; requires purchase of electricity generated from purchased retiring coal fired electric generation facility (as specified in final bill); and provides an effective date.

Cost recovery associated with electric generation built to replace a retiring coal fired generation facility shall not be allowed by the Wyoming Public Service Commission unless the Commission has determined that the public utility made a good faith effort to sell the facility to another person prior to its retirement and that the public utility did not refuse a reasonable offer to purchase the facility or the Commission determines that, if a reasonable offer was received, the sale was not completed for a reason beyond the reasonable control of the public utility.

Under SF 159 electric public utilities, other than cooperative electric utilities, shall be obligated to purchase electricity generated from a coal fired electric generation facility purchased under agreement approved by the Commission, provided the otherwise retiring coal fired electric generation facility offers to sell some or all of the electricity from the facility to an electric public utility, the electricity is sold at a price that is no greater than the purchasing electric utility's avoided cost, the electricity is sold under a power purchase agreement, and the Commission approves a 100 percent cost recovery in rates for the cost of the power purchase agreement and the agreement is 100 percent allocated to the public utility's Wyoming customers unless otherwise agreed to by the public utility.

In March 2020, the Wyoming legislature passed House Bill 200 (HB 200), Reliable and Dispatchable Low-Carbon Energy Standards. HB 200 requires the Wyoming Public Service Commission to put in place a standard for each public utility specifying a percentage of electricity to be generated from coal-fired generation utilizing carbon capture technology by 2030. The requirement would only apply to generation allocated to Wyoming customers. HB 200 will require each public utility to demonstrate in its IRP the steps taken to achieve the electricity generation standard established by the Commission and will allow rate recovery of costs incurred by a public utility that utilizes coal-fired generation with carbon capture technology installed. The Commission finalized administrative rules to implement HB 200, which became effective January 7, 2022. The administrative rules require public utilities to file an initial application to establish intermediate standards for compliance by March 31, 2022, and an application to establish the final plan for compliance by March 31, 2023. PacifiCorp filed the initial application with the Commission on March 31, 2022, as required.

During the 2022 legislative session, the Wyoming Legislature passed HB 131, nuclear power plant and storage amendments, that will help facilitate development of the Natrium nuclear demonstration project. The bill modifies existing laws to clarify the authority of the United States Nuclear Regulatory Commission. The bill also requires the operator of the facility, at least 30 days prior to construction, to submit a report identifying the number of jobs expected to be created by the project, the amount of local and state taxes estimated to be generated by the project, and the anticipated benefits and impacts that will accrue to the state and local community from the project. With respect to SF 159, the bill provides that the requirements of that law shall not apply to a public utility that replaces a coal-fired generation facility with an advanced nuclear reactor. Finally, the bill exempts tax payments, but provides that, beginning July 1, 2035, the exemption only applies if not less than 80 percent of the uranium is sourced in the United States.

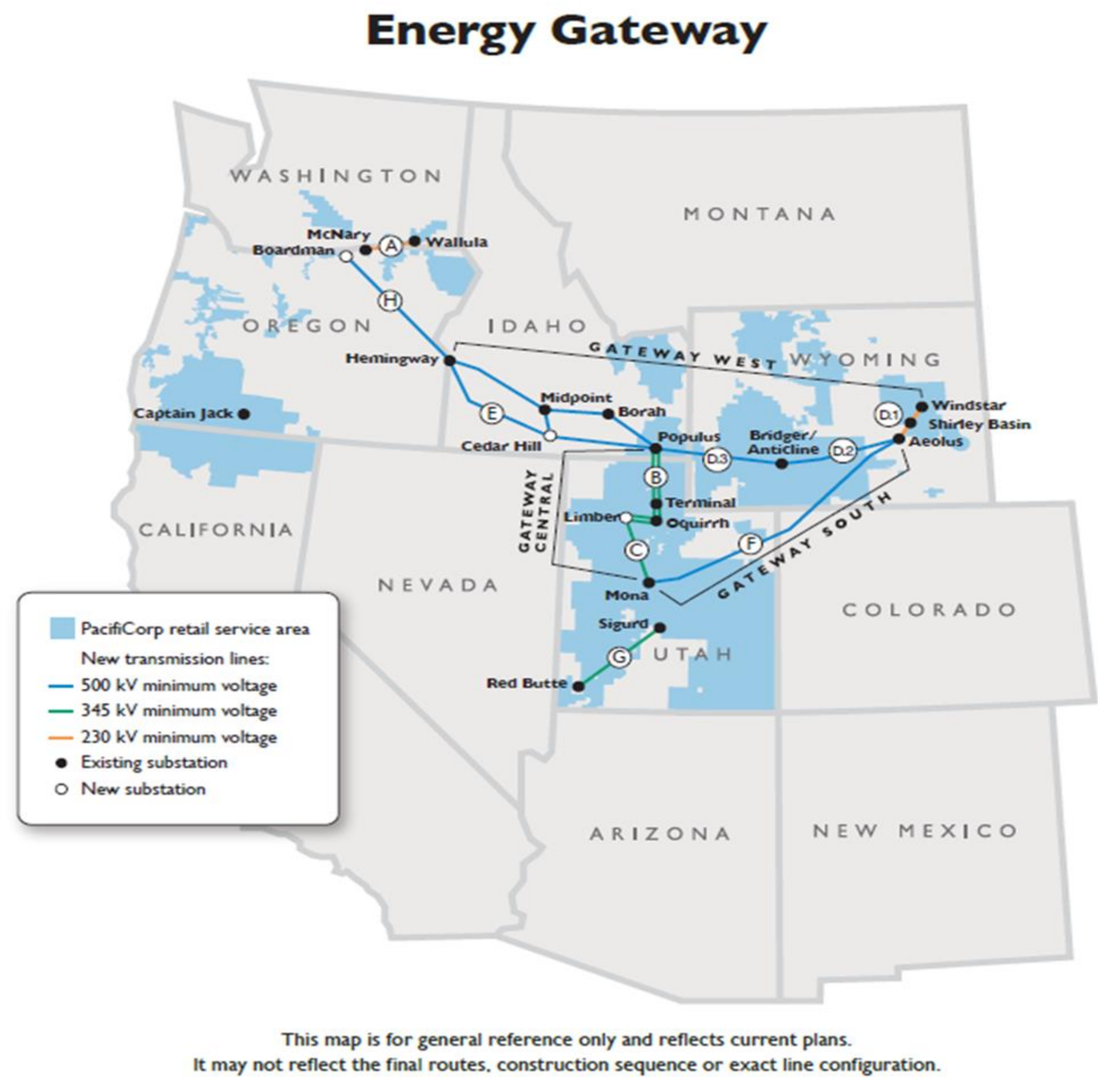
Greenhouse Gas Emission Performance Standards

California, Oregon and Washington have greenhouse gas emission performance standards applicable to all electricity generated in the state or delivered from outside the state that is no higher than the greenhouse gas emission levels of a state-of-the-art combined cycle natural gas generation facility. The standards for Oregon and California are currently set at 1,100 lb. CO_2/MWh, which is defined as a metric measure used to compare the emissions from various greenhouse gases based on their global warming potential. In September 2018, the Washington Department of Commerce issued a new rule lowering the emissions performance standard to 925 lb. CO_2/MWh.

Energy Gateway Transmission Program Planning

As discussed in 2021 IRP, the Energy Gateway transmission project continues to play an important role in PacifiCorp's commitment to provide safe, reliable, reasonably priced electricity to meet the needs of our customers. Energy Gateway's design and extensive footprint provides needed system reliability improvements and supports the development of a diverse range of cost-effective resources required for meeting customers' energy needs. The IRP has incorporated Energy Gateway as part of a solution for delivering the least cost resource portfolio for multiple IRP planning cycles. PacifiCorp continues to develop methods, in parallel with current industry best practices and regional transmission planning requirements, to better quantify all the benefits of transmission that are essential to serve customers. For example, Energy Gateway is designed to relieve operating limitations, increase capacity, and improve operations and reliability in the existing electric transmission grid. Figure 3.1 shows a high-level geography of the Energy Gateway transmission project.

Figure 3.1 – Energy Gateway Map



This map is for general reference only and reflects current plans. It may not reflect the final routes, construction sequence or exact line configuration.

Energy Gateway Transmission Project Updates

Wallula to McNary (Segment A)
This project was placed in service in January 2019.

Gateway West (Segments D and E)

Under the National Environmental Policy Act (NEPA), the U.S. Bureau of Land Management (BLM) has completed the environmental impact statement (EIS) for the Gateway West project. The BLM released its final EIS on April 26, 2013, followed by the record of decision (ROD) on November 14, 2013, providing a right-of-way grant for all of Segment D and for all but two segments of Segment E, followed with a record of decision on these two segments of the line on April 19, 2018:

- Gateway West (Segment D1): A single-circuit 230-kV line that will run approximately 59 miles between the existing Windstar substation in eastern Wyoming and the Aeolus substation near Medicine Bow, Wyoming, which includes a loop-in to the existing Shirley Basin 230-kV substation. The Aeolus – Shirley Basin 230-kV line section was energized in November 2020. This project was included in the 2021 IRP for acknowledgement with an in-service date of 2024.

- Gateway West (Segment D2): This single-circuit 500-kV segment was placed in service November 2020.

- Gateway West (Segment D3): A single-circuit 500-kV line running approximately 200 miles between the new Anticline substation which was placed in-service in November 2020 with the energization of Gateway West Segment D.2 and the Populus substation in southeast Idaho.

Gateway West (Segment E)

The Populus-to-Hemingway transmission project consists of two single-circuit 500-kV lines that run approximately 500 miles between the Populus substation in eastern Idaho to the Hemingway substation in western Idaho.

Gateway South (Segment F)

The 2021 PacifiCorp IRP preferred portfolio includes the Aeolus-to-Mona (Clover substation) transmission segment (Energy Gateway South or Segment F).

To facilitate the delivery of new renewable energy resources to PacifiCorp customers across the West, the preferred portfolio includes significant transmission investment. Specifically, the 2021 IRP preferred portfolio includes the Energy Gateway South transmission line - a new 416-mile, high-voltage 500-kilovolt transmission line and associated infrastructure running from the new Aeolus substation near Medicine Bow, Wyoming, to the Clover substation near Mona, Utah. The 2021 preferred portfolio also includes the Energy Gateway West Subsegment D.1 project - a new 59 mile high-voltage 230-kilovolt transmission line from the Shirley Basin substation in southeastern Wyoming to the Windstar substation near Glenrock, Wyoming. Both transmission lines come online by the end of 2024.

Timing of construction is driven by the phase-out schedule of federal production tax credits (PTCs), particularly the 2024 in-service requirements for 60 percent PTC eligibility, and potential risk associated with the termination of the BLM permit for non-use. In addition to supporting renewable resource additions in PacifiCorp's generation portfolio, qualifying them for PTCs, the new transmission segment will increase transfer capability out of eastern Wyoming.

Boardman to Hemingway (Segment H)

The Boardman to Hemingway project was included in the 2021 IRP request for acknowledgement and represents a significant improvement in the connection between PacifiCorp's east and west control areas and will help deliver more diverse resources to serve its customers in Oregon, Washington, and California. Idaho Power leads the permitting efforts on this project and PacifiCorp continues to support the permitting efforts under the conditions of the Boardman to Hemingway Transmission Project Joint Permit Funding Agreement. The Bureau of Land Management's Record of Decision was issued in November of 2017, followed by the U.S. Forest Service ROD issued on November 9, 2018. The Oregon Energy Facilities Siting Council's final order on the Site Certificate is currently under process. In January 2020, the three parties signatory to the permitting agreement entered a non-binding term sheet that addresses the terms required to move the project to the next step of construction.

In-Service Dates

Table 3.2 summarizes the in-service dates for segments of the Energy Gateway transmission project.

Table 3.2 - Energy Gateway Segment In-Service Dates

Segment & Name	Description	Approximate Mileage	Status and Scheduled In-Service
(A) Wallula-McNary	230 kV, single circuit	30 mi	• Status: completed • Placed in-service: January 2019
(B) Populus-Terminal	345 kV, double circuit	135 mi	• Status: completed • Placed in-service: November 2010
(C) Mona-Oquirrh	500 kV single circuit 345 kV double circuit	100 mi	• Status: completed • Placed in-service: May 2013
Oquirrh-Terminal	345 kV double circuit	14 mi	• Status: rights-of-way acquisition underway • Scheduled in-service: 2026
(D1) Windstar-Aeolus	New 230 kV single circuit Re-built 230 kV single circuit	59 mi	• Status: permitting underway • Scheduled in-service: 2024
(D2) Aeolus-Bridger/Anticline	500 kV single circuit	140 mi	• Status: completed • Placed in-service: November 2020
(D3) Bridger/Anticline-Populus	500 kV single circuit	200 mi	• Status: permitting underway • Scheduled in-service: 2027 earliest
(E) Populus-Hemingway	500 kV single circuit	500 mi	• Status: permitting underway • Scheduled in service: 2030 earliest
(F) Aeolus-Mona	500 kV single circuit	416 mi	• Status: permitting underway • Scheduled in-service: 2024
(G) Sigurd-Red Butte	345 kV single circuit	170 mi	• Status: completed • Placed in-service: May 2015
(H) Boardman-Hemingway	500 kV single circuit	290 mi	• Status: pursuing joint-development and/or firm capacity opportunities with project sponsors • Scheduled in-service: 2026

Regional Markets

Increased renewable generation has contributed to the need for balancing sub-hourly demand and supply across a broader and more diverse market. For balancing purposes, PacifiCorp combined its resources with those of the CAISO through the creation of the EIM. The EIM became operational November 1, 2014, and as of March 2022 has 17 utilities participating. Tucson Electric Power and Bonneville Power Administration plan to join in 2022, while Avangrid, El Paso Electric and WAPA Desert Southwest plan to join in 2023.[4] The multi-service area footprint brings greater resource and geographical diversity allowing for increased reliability and cost savings in balancing generation with demand using 15-minute interchange scheduling and five-minute dispatch. CAISO's role is limited to the sub-hourly scheduling and dispatching of participating EIM generators. CAISO does not have any other grid operator responsibilities for PacifiCorp's service areas. As part of other EIM participant entities, PacifiCorp is also participating in the CAISO stakeholder process to establish an Expanded Day-Ahead Market (EDAM).

[4] https://www.westerneim.com/Pages/About/default.aspx

In December 2021, it was announced that the Western Resource Adequacy Program (WRAP), administered by the Western Power Pool (WPP), formerly known as the Northwest Power Pool, had entered the first stage of implementation. The WRAP consists of 26 participants, including PacifiCorp, who are working on the remaining program design questions and outstanding issues. Additionally, the WPP has partnered with the Southwest Power Pool (SPP) to provide program operation services, including facilitating the collection of participants data to perform modeling for the upcoming seasons.[5] This program includes two components, a forward showing (FS) planning mechanism and an operational program (Ops Program) to help participants that are experiencing extreme events meet customer demand. The program is intended to be a starting point and does not solve every issue facing the region, but is an incremental step toward increased regional coordination, which could better position the region to continue to tackle these big issues. The WRAP will create a capacity RA program with a demonstration of deliverability. The region may also benefit from other forms of coordination, and while the structure and process associated with the program may serve as foundational building blocks to additional regional coordination, the WPP and the WRAP participants are only working to implement the capacity RA program at this time. The WRAP does not replace or supplant the resource planning processes used by states or provinces or the regulatory requirements of the Federal Energy Regulatory Commission (FERC), North America Electric Reliability Corporation (NERC) or Western Electricity Coordinating Council (WECC). The program is designed to be supplemental and complementary to those processes and requirements. Full implementation is expected to occur in 2024.

[5] https://www.westernpowerpool.org/news/wrap-announces-full-participation-of-phase-3a

CHAPTER 4 – LOAD-AND-RESOURCE BALANCE UPDATE

Introduction

This chapter presents an update to PacifiCorp's load-and-resource balance. Updates to PacifiCorp's long-term load forecasts (both energy and coincident peak load) for each state and the system as a whole are summarized in the Appendix. Updates to PacifiCorp's load forecast, resources, and capacity position are presented and summarized in this chapter.

System Coincident Peak Load Forecast

The 2021 IRP Update relies on PacifiCorp's May 2021 load forecast. Figure 4.1 compares PacifiCorp's most recent load forecast to the forecast used for the 2021 IRP. Figure 4.2 compares PacifiCorp's most recent coincident system peak load forecast to the forecast used for the 2021 IRP. Considering that PacifiCorp analyzes incremental energy efficiency and direct-load control programs as demand-side resource options in its IRP, both figures exclude incremental energy efficiency savings and direct-load control capacity included in the updated resource portfolio. The compounded average annual growth rate (CAGR) for system load is 1.46 percent over the period 2022 through 2031. The CAGR for system coincident peak is 1.04 percent over the period 2022 through 2031.

Figure 4.1 - Forecasted Annual Load (GWh)

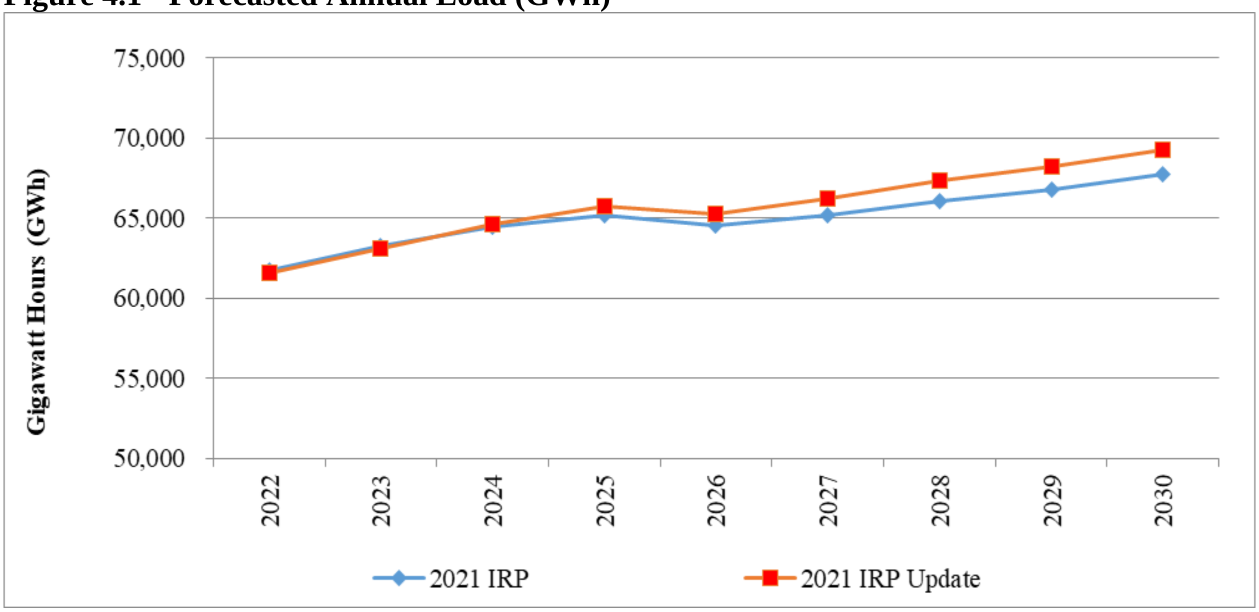
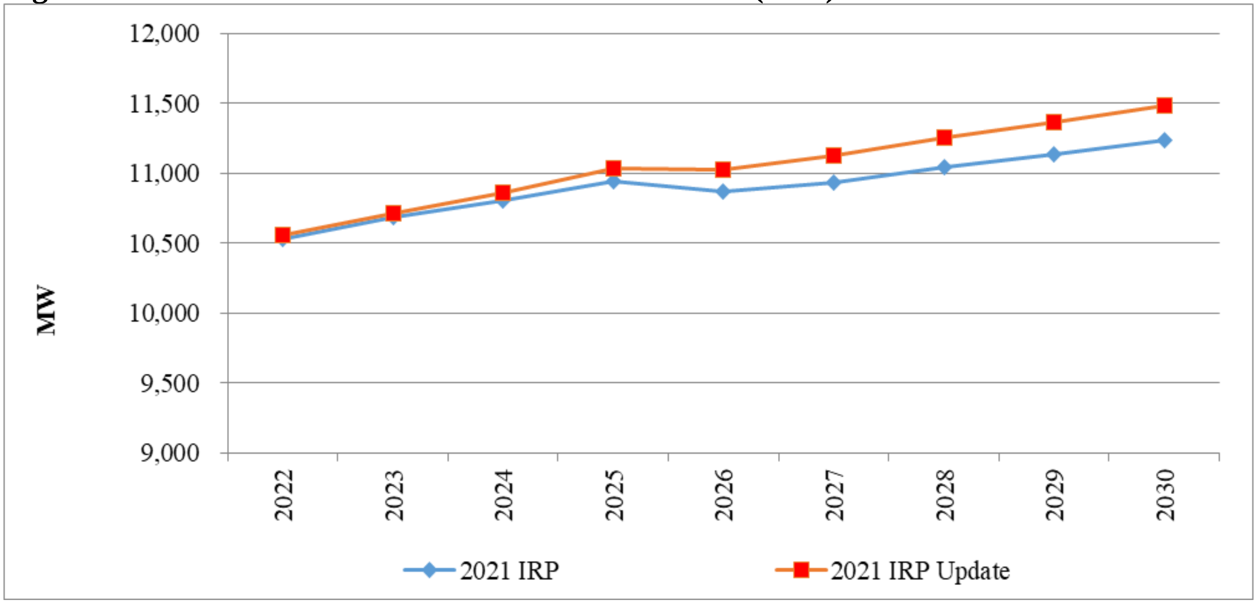


Figure 4.2 – Forecasted Annual Coincident Peak Load (MW)



Wind and Solar Qualifying Facility Resource Updates

Table 4.1 summarizes updates to the capacity from solar and geothermal power-purchase agreements (PPAs) with qualifying facilities (QFs) that have occurred since the September 1, 2021 IRP filing.

Table 4.1 – New Power Purchase Agreements

Power Purchase Agreements	Resource Type	PPA or QF	State	Capacity (MW)	COD Year
Amor IX, LLC Soda Lake	Geothermal	QF	Utah	20	2021
Castle Solar (Intermountain Health Care)	Solar	PPA	Utah	20	2021
Solarize Rogue	Solar	QF	Oregon	0.1296	2021
Wallowa County (Community Solar Project)	Solar	QF	Oregon	0.36	2021
Sunnyside Solar	Solar	QF	Washington	4.99	2023

Updated Capacity Load-and-Resource Balance

Load-and-Resource Balance Components

Capacity and energy balances make use of the same load-and-resource components in their calculations. The main component categories consist of the following: resources, obligation, reserves, system position, and available front-office transactions (FOTs).

The resource categories include resources by type—thermal, hydroelectric, renewable, QFs, purchases, and sales. Categories in the obligation section include load, private generation, existing demand response (includes interruptible contracts), and new energy efficiency from the updated resource portfolio. Both resources and obligations can be represented as either a positive or negative value, which is consistent with how these elements are represented in portfolio modeling.

A description of each of the resource categories is provided below.

Existing Resources

Capacity contribution is a measure of the ability for a resource to reliably meet demand. There are many possible ways to attribute capacity to specific resources and the portfolio modeling in the 2021 IRP Update doesn't rely on a specific capacity contribution for each resource during portfolio development, in part because the reliability benefits of the next resource of a given type may not be the same as the reliability benefits from resources of that type already included in a portfolio. For the purpose of calculating capacity contribution, resources which are dispatchable for a limited duration (measured in hours) are distinguished from resources which are dispatchable for long durations (i.e., thermal) or whose output must be used as it is delivered, such as wind, solar and other non-dispatchable generators.

Thermal

This category includes all thermal plants that are wholly owned or partially owned by PacifiCorp. The capacity balance counts these plants at their expected availability (after derating for forced outages and maintenance), as discussed below. The energy balance also counts them at expected availability but includes all hours in the year. This includes the existing fleet of coal-fueled units, and seven natural-gas-fueled plants. Presently, these thermal resources account for roughly two thirds of the firm capacity available in the PacifiCorp system.

Resources without duration limits

For the purpose of reporting the capacity contribution resources without duration limits, including thermal, wind, solar, and other small generators, PacifiCorp first calculated the availability of each resource type during the top five percent of net load hours in each season (calculated as PacifiCorp's load less the wind and solar generation in its portfolio).[1] For the purpose of reporting load in the load and resource balance, the single highest load hour is used, and a planning reserve margin of 13% is added. Resources whose is output higher in the top five percent load hours than in the top give percent net load hours are allocated additional capacity value for their role in meeting peak requirements. It should be noted that while allocation of capacity among resources as described in this section is helpful for presenting a load and resource balance, the allocation to specific resources has no bearing on the reliability or economics of the preferred portfolio, which reflects the coordinated dispatch of all available resources in every hour of the year. The economics of resource additions are more closely aligned with marginal or "last-in" capacity contribution estimates, which are generally lower for resources whose output is positively correlated with other resources already present in the portfolio. For estimates of marginal capacity contribution values, please refer to PacifiCorp's 2021 IRP, specifically Volume II, Appendix K (Capacity Contribution).

[1] The Western Resource Adequacy Program (WRAP) has proposed a capacity contribution methodology that is based in part on the top five percent of net load hours. The WRAP proposal includes an effective load carrying capability (ELCC) analysis for a number of resource types. ELCC is very computationally intensive. For details, please refer to: https://www.westernpowerpool.org/private-media/documents/2021-12-21_RAPC_Minutes.pdf

Resources with duration limits

Certain resource types have duration limits, such that while they could be called upon in any given hour, they cannot be called upon continuously for more than specified duration. Such resources include energy storage, such as batteries or pumped hydro, as well as demand response programs and contracts, which generally have limits on consecutive hours, hours per day, and/or hours per year. As a result, while these resources are available in every hour, they are limited in how often they can be called upon for energy. However, reliable system operation also requires resources that can be deployed at short notice to address unexpected events that occur relatively infrequently, such as a generator outage, increase in load, or decrease in wind and solar output. These operating reserve requirements are part of the load and resource balance, and because they do not require frequent energy dispatch, duration-limited resources are assumed to be able to provide operating reserves continuously. Once operating reserve needs are fulfilled in a given hour, energy limited resources would need to deploy energy to make additional contributions to serving load. This incremental energy is assumed to be deployed in the hours with the highest shortfalls, but is capped for each day at the lesser of the total duration of energy-limited resources (in MWh) and available excess generation capacity in hours where resources exceed the capacity requirement. This represents the need to charge batteries, for example, which represent the vast majority of the energy-limited resources through the study horizon. After summing the operating reserve and energy contributions of duration-limited resources, their capacity contribution as a class is calculated based on the net output in the top five percent net load hours, as described above. This total contribution is then allocated back to individual resources based on their duration capability, with shorter duration resources receiving a lower contribution.

Sales

Contracts for the sale of firm capacity and energy are treated the same as all other resources, except that they have a negative capacity value. The energy balance counts them by expected model dispatch.

Obligation

The obligation is the total electricity demand that PacifiCorp must serve, consisting of forecasted retail load, private generation, new energy efficiency from the preferred portfolio, existing demand response (including interruptible contracts). The following are descriptions of each of these components:

Load and Private Generation

The largest component of the obligation is retail load. In the 2021 IRP Update, the hourly retail load at a location is first reduced by hourly private generation at the same location. The system coincident peak is determined by summing the net loads for all locations (topology bubbles with loads) and then finding the highest hourly system load by year and season. Loads reported by east and west BAAs thus reflect loads at the time of PacifiCorp's coincident system summer and winter peaks. The energy balance counts the average load on a monthly basis. For simplicity, load net of private generation is referred to as load in the following sections.

Energy Efficiency (Class 2 DSM)

An adjustment is made to load to remove the projected embedded energy efficiency as a reduction to load. Due to timing issues with the vintage of the load forecast, there was a level of 2020 energy efficiency that was not incorporated in the forecast for the 2021 IRP. The 2020 energy efficiency forecast of 73 MW was accounted for by adding an existing energy efficiency resource in the load-and-resource balance; this adjustment was not required for the 2021 IRP Update because the 2020 projected embedded energy efficiency is included in the load forecast. The energy efficiency line includes the selected energy efficiency from the 2021 IRP Update preferred portfolio.

Demand Response (Class 1 DSM)

Existing demand response program capacity is categorized as a reduction to peak load. Also included in the demand response category are existing interruptible contracts. PacifiCorp has had interruptible contracts for approximately 177 MW of load interruption capability for many years. These contracts are a key aspect of the retail service provided to the associated customers, and absent these contracts their demand would likely be different from that included in the load forecast. To maintain an alignment with the load forecast, these contracts are assumed to continue indefinitely under their current structure.

Planning Reserve Margin

Planning reserve margin (PRM) represents an incremental capacity requirement, applied as an increase to the obligation to ensure that there will be sufficient capacity available on the system to manage uncertain events (i.e., weather, outages) and known requirements (i.e., operating reserves).

System Position

The system position is the resource surplus or deficit after subtracting obligation plus required reserves from total resources. While similar, the position calculation is slightly different for the capacity and energy views of the load and resource balance. Thus, the position calculation for each of the views will be presented in their respective sections.

Capacity Balance Determination and Results

Methodology

The capacity balance is developed by first determining the system coincident peak load for each of the first ten years of the planning horizon. Then the annual firm-capacity availability of the existing resources is determined for each of these annual system summer and winter peak periods, as applicable, and summed as follows:

Existing Resources = Coal + Gas + Hydro + Renewables + Contracts – Firm Sales

The peak load, private generation, existing demand response, and new energy efficiency from the preferred portfolio are netted together for each of the annual system summer and winter peaks, as applicable, to compute the annual peak obligation:

Obligation = Load – Private Generation – Demand Response – New Energy Efficiency

The amount of reserves to be added to the obligation is then calculated. This is accomplished by the net system obligation calculated above multiplied by the 13 percent PRM adopted for the 2021 IRP Update. The formula for this calculation is:

Planning Reserves = Obligation x PRM

Finally, the annual system position is derived by adding the computed reserves to the obligation, and then subtracting this amount from existing resources, as shown in the following formula:

System Position = (Existing Resources) – (Obligation + Planning Reserves)

Capacity Balance Results

Table 4.2 and Table 4.3 show the annual capacity balances and component line items for the summer peak and winter peak, respectively, using a target PRM of 13 percent to calculate the planning reserve amount. Balances for PacifiCorp's system as well as the east and west control areas are shown. While east and west control area balances are broken out separately, the PacifiCorp system is planned for and dispatched on a system basis.

Table 4.2 – Summer Peak - System Capacity Load and Resource Balance without Resource Additions, 2021 IRP Update (2022-2031) (Megawatts)[2]

East	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
Coal	3,536	3,474	3,505	3,513	3,076	3,067	2,343	2,245	2,199	2,198
Gas	1,942	1,964	1,922	1,947	1,968	1,933	1,950	1,942	1,753	1,748
Hydroelectric	108	108	88	88	88	88	88	87	87	87
Solar	377	521	197	424	341	320	352	316	291	161
Wind	337	405	262	452	445	424	422	491	490	395
Geothermal	49	50	51	50	50	52	51	50	51	50
Contracts	185	182	122	35	31	30	31	24	22	17
Sales and Ancillary Services	(267)	(267)	(243)	(243)	(239)	(236)	(235)	(234)	(233)	(233)
East Existing Resources	**6,268**	**6,438**	**5,905**	**6,265**	**5,760**	**5,678**	**5,003**	**4,922**	**4,660**	**4,423**
Load	7,274	7,421	7,543	7,685	7,654	7,732	7,843	7,944	8,052	8,162
Private Generation	(57)	(66)	(69)	(71)	(75)	(81)	(90)	(103)	(120)	(144)
Existing - Demand Response	(594)	(585)	(594)	(593)	(520)	(496)	(460)	(255)	(220)	(196)
New Energy Efficiency	(134)	(210)	(242)	(379)	(500)	(810)	(801)	(1,051)	(1,026)	(1,252)
East Total obligation	**6,489**	**6,561**	**6,638**	**6,642**	**6,559**	**6,345**	**6,493**	**6,535**	**6,686**	**6,570**
Planning Reserve Margin (13%)	844	853	863	863	853	825	844	850	869	854
East Obligation + Reserves	7,332	7,413	7,501	7,505	7,412	7,170	7,337	7,385	7,555	7,424
East Position	(1,065)	(976)	(1,596)	(1,240)	(1,653)	(1,492)	(2,334)	(2,463)	(2,895)	(3,001)
Available Front Office Transactions	0	0	0	0	0	0	0	0	0	0
West										
Coal	1,500	1,495	1,487	1,488	1,354	1,352	1,348	1,370	1,356	1,356
Gas	663	673	660	664	663	664	664	664	675	665
Hydroelectric	955	796	790	799	795	798	798	794	792	797
Solar	7	27	10	20	16	15	16	14	13	6
Wind	89	83	50	87	82	89	77	84	91	85
Geothermal	0	0	0	0	0	0	0	0	0	0
Contracts	171	168	131	146	132	97	102	72	63	47
Sales and Ancillary Services	(209)	(207)	(182)	(182)	(179)	(177)	(177)	(168)	(168)	(169)
West Existing Resources	**3,177**	**3,034**	**2,945**	**3,022**	**2,863**	**2,838**	**2,828**	**2,831**	**2,822**	**2,787**
Load	3,372	3,402	3,434	3,471	3,501	3,534	3,569	3,604	3,640	3,679
Private Generation	(28)	(40)	(45)	(49)	(54)	(60)	(67)	(75)	(85)	(106)
Existing - Demand Response	0	0	0	0	0	0	0	0	0	0
New Energy Efficiency	(73)	(120)	(147)	(192)	(242)	(157)	(354)	(264)	(442)	(321)
West Total obligation	**3,271**	**3,242**	**3,243**	**3,229**	**3,205**	**3,318**	**3,148**	**3,264**	**3,113**	**3,251**
Planning Reserve Margin (13%)	425	421	422	420	417	431	409	424	405	423
West Obligation + Reserves	3,696	3,664	3,664	3,649	3,622	3,749	3,557	3,688	3,518	3,674
West Position	(520)	(629)	(719)	(627)	(758)	(911)	(729)	(857)	(695)	(887)
Available Front Office Transactions	500	500	500	500	500	500	500	500	500	500
System										
Total Resources	9,445	9,472	8,850	9,287	8,623	8,516	7,831	7,753	7,482	7,210
Obligation	9,760	9,803	9,880	9,871	9,764	9,663	9,641	9,799	9,799	9,821
Planning Reserves (13%)	1,269	1,274	1,284	1,283	1,269	1,256	1,253	1,274	1,274	1,277
Obligation + Reserves	11,029	11,077	11,165	11,155	11,034	10,919	10,894	11,073	11,073	11,098
System Position	(1,584)	(1,605)	(2,315)	(1,867)	(2,411)	(2,403)	(3,063)	(3,320)	(3,591)	(3,888)
Available Front Office Transactions	500	500	500	500	500	500	500	500	500	500
Uncommitted FOTs to meet remaining Need	1,584	1,605	2,315	1,867	500	500	500	500	500	500
Net Surplus/(Deficit)	0	0	0	0	(1,911)	(1,903)	(2,563)	(2,820)	(3,091)	(3,388)

[2] The DSM line includes selected Class 2 DSM from the 2021 IRP Update resource portfolio.

Table 4.2 (cont.) – Summer Peak - System Capacity Load and Resource Balance without Resource Additions, 2021IRP Update (2032-2040) (Megawatts)[3]

East	2032	2033	2034	2035	2036	2037	2038	2039	2040
Coal	2,212	2,219	2,207	2,219	2,218	1,359	1,362	1,357	1,100
Gas	1,743	1,412	1,401	1,397	1,398	1,403	1,403	1,399	1,410
Hydroelectric	86	87	87	86	87	86	86	87	87
Solar	30	136	124	132	125	137	144	142	83
Wind	252	355	359	353	333	475	502	480	457
Geothermal	51	50	51	51	52	50	20	20	20
Contracts	10	15	14	12	9	8	0	0	0
Sales and Ancillary Services	(226)	(230)	(229)	(228)	(228)	(233)	(233)	(234)	(227)
East Existing Resources	**4,159**	**4,043**	**4,013**	**4,022**	**3,993**	**3,287**	**3,285**	**3,251**	**2,931**
Load	8,266	8,370	8,473	8,444	8,585	8,679	8,793	8,655	8,759
Private Generation	(173)	(203)	(236)	(150)	(173)	(196)	(221)	(116)	(128)
Existing - Demand Response	(176)	(163)	(161)	(161)	(160)	(148)	(144)	(148)	(142)
New Energy Efficiency	(1,489)	(1,442)	(1,522)	(1,590)	(1,607)	(1,702)	(1,753)	(1,702)	(1,844)
East Total obligation	**6,428**	**6,563**	**6,555**	**6,543**	**6,644**	**6,633**	**6,674**	**6,689**	**6,644**
Planning Reserve Margin (13%)	836	853	852	851	864	862	868	870	864
East Obligation + Reserves	7,264	7,416	7,407	7,394	7,508	7,495	7,542	7,559	7,508
East Position	(3,105)	(3,372)	(3,394)	(3,372)	(3,515)	(4,208)	(4,257)	(4,308)	(4,577)
Available Front Office Transactions	0	0	0	0	0	0	0	0	0
West									
Coal	1,356	1,358	1,355	1,354	1,353	1,351	0	0	0
Gas	667	665	665	663	677	449	448	446	446
Hydroelectric	793	794	796	792	793	795	795	798	798
Solar	1	5	4	5	5	9	10	10	7
Wind	56	88	77	73	83	97	114	117	84
Geothermal	0	0	0	0	0	0	0	0	0
Contracts	24	35	31	30	32	23	19	10	10
Sales and Ancillary Services	(162)	(169)	(167)	(160)	(155)	(161)	(157)	(156)	(144)
West Existing Resources	**2,735**	**2,776**	**2,760**	**2,757**	**2,787**	**2,563**	**1,229**	**1,224**	**1,200**
Load	3,711	3,747	3,785	3,775	3,809	3,854	3,892	3,861	3,896
Private Generation	(147)	(193)	(247)	(217)	(254)	(296)	(341)	(190)	(221)
Existing - Demand Response	0	0	0	0	0	0	0	0	0
New Energy Efficiency	(432)	(382)	(412)	(450)	(561)	(327)	(344)	(455)	(685)
West Total obligation	**3,133**	**3,172**	**3,126**	**3,108**	**2,994**	**3,231**	**3,207**	**3,216**	**2,990**
Planning Reserve Margin (13%)	407	412	406	404	389	420	417	418	389
East Obligation + Reserves	(24)	30	(5)	(46)	(172)	93	73	(37)	(296)
East Position	2,760	2,746	2,766	2,803	2,959	2,470	1,156	1,262	1,496
Available Front Office Transactions	500	500	500	500	500	500	500	500	500
System									
Total Resources	6,894	6,819	6,773	6,779	6,780	5,850	4,514	4,475	4,131
Obligation	9,561	9,735	9,681	9,651	9,638	9,863	9,882	9,905	9,634
Planning Reserves (13%)	1,243	1,265	1,259	1,255	1,253	1,282	1,285	1,288	1,252
Obligation + Reserves	10,804	11,000	10,940	10,906	10,891	11,146	11,166	11,192	10,886
System Position	(3,910)	(4,181)	(4,166)	(4,127)	(4,111)	(5,295)	(6,652)	(6,717)	(6,755)
Available Front Office Transactions	500	500	500	500	500	500	500	500	500
Uncommitted FOTs to meet remaining Need	500	500	500	500	500	500	500	500	500
Net Surplus/(Deficit)	(3,410)	(3,681)	(3,666)	(3,627)	(3,611)	(4,795)	(6,152)	(6,217)	(6,255)

[3] The DSM line includes selected Class 2 DSM from the 2021 IRP Update resource portfolio.

Table 4.3 – Winter Peak – System Capacity Load and Resource Balance without Resource Additions, 2021 IRP Update (2022-2031) (Megawatts) [4]

East	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
Coal	3,443	3,491	3,470	3,477	2,931	2,941	2,249	2,224	2,148	2,090
Gas	1,938	2,045	2,043	1,995	1,913	1,969	2,042	2,012	1,817	1,700
Hydroelectric	80	80	70	70	68	67	70	69	69	67
Solar	48	72	40	22	14	16	16	24	39	11
Wind	268	383	250	278	280	263	256	355	418	306
Geothermal	52	52	52	51	51	46	52	52	52	50
Contracts	164	137	66	16	15	15	15	9	9	8
Sales and Ancillary Services	(212)	(215)	(189)	(192)	(190)	(189)	(191)	(193)	(194)	(194)
East Existing Resources	**5,781**	**6,045**	**5,801**	**5,716**	**5,081**	**5,127**	**4,509**	**4,552**	**4,360**	**4,038**
Load	5,691	5,868	5,936	6,050	5,977	6,033	6,138	6,220	6,297	6,374
Private Generation	(1)	(2)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
Existing - Demand Response	(322)	(309)	(335)	(408)	(330)	(324)	(336)	(229)	(204)	(180)
New Energy Efficiency	(108)	(148)	(198)	(221)	(275)	(725)	(400)	(842)	(880)	(520)
East Total obligation	**5,260**	**5,410**	**5,401**	**5,418**	**5,368**	**4,980**	**5,396**	**5,142**	**5,205**	**5,665**
Planning Reserve Margin (13%)	684	703	702	704	698	647	701	668	677	736
East Obligation + Reserves	5,944	6,114	6,103	6,122	6,066	5,627	6,097	5,810	5,882	6,401
East Position	(163)	(69)	(302)	(406)	(984)	(500)	(1,588)	(1,258)	(1,522)	(2,363)
Available Front Office Transactions	300	300	300	300	300	300	300	300	300	300
West										
Coal	1,488	1,488	1,319	1,468	1,321	1,314	1,338	1,335	1,360	1,313
Gas	718	718	711	713	697	693	717	715	630	695
Hydroelectric	1,038	858	865	861	847	843	869	866	869	843
Solar	0	1	1	1	0	0	0	1	1	0
Wind	39	52	33	50	39	33	34	44	52	50
Geothermal	0	0	0	0	0	0	0	0	0	0
Contracts	78	73	70	68	58	31	33	21	17	15
Sales and Ancillary Services	(192)	(174)	(149)	(146)	(145)	(142)	(142)	(147)	(147)	(146)
West Existing Resources	**3,168**	**3,016**	**2,850**	**3,014**	**2,818**	**2,772**	**2,849**	**2,834**	**2,782**	**2,771**
Load	3,330	3,373	3,408	3,446	3,487	3,534	3,580	3,628	3,673	3,710
Private Generation	(0)	(1)	(1)	(1)	(1)	(2)	(2)	(3)	(3)	(4)
Existing - Demand Response	0	0	0	0	0	0	0	0	0	0
New Energy Efficiency	(76)	(110)	(165)	(160)	(191)	150	(271)	172	114	(339)
West Total obligation	**3,253**	**3,262**	**3,243**	**3,285**	**3,295**	**3,682**	**3,308**	**3,798**	**3,784**	**3,368**
Planning Reserve Margin (13%)	423	424	422	427	428	479	430	494	492	438
West Obligation + Reserves	3,676	3,686	3,664	3,712	3,723	4,161	3,738	4,291	4,276	3,806
West Position	(508)	(670)	(815)	(698)	(905)	(1,389)	(889)	(1,458)	(1,494)	(1,035)
Available Front Office Transactions	700	700	700	700	700	700	700	700	700	700
System										
Total Resources	8,950	9,061	8,651	8,730	7,899	7,900	7,358	7,386	7,142	6,809
Obligation	8,513	8,672	8,644	8,703	8,663	8,662	8,703	8,939	8,989	9,033
Planning Reserves (13%)	1,107	1,127	1,124	1,131	1,126	1,126	1,131	1,162	1,169	1,174
Obligation + Reserves	9,620	9,800	9,767	9,834	9,789	9,788	9,835	10,101	10,157	10,207
System Position	(670)	(739)	(1,117)	(1,104)	(1,890)	(1,889)	(2,477)	(2,716)	(3,016)	(3,398)
Available Front Office Transactions	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000
Uncommitted FOTs to meet remaining Need	670	739	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000
Net Surplus/(Deficit)	0	0	(117)	(104)	(890)	(889)	(1,477)	(1,716)	(2,016)	(2,398)

[4] The DSM line includes selected Class 2 DSM from the 2021 IRP Update resource portfolio.

Table 4.3 (cont.) – Winter Peak – System Capacity Load and Resource Balance without Resource Additions, 2021IRP Update (2032-2040) (Megawatts)[5]

East	2032	2033	2034	2035	2036	2037	2038	2039	2040
Coal	2,051	2,203	2,178	2,212	2,188	1,353	1,332	1,338	1,178
Gas	1,736	1,444	1,473	1,485	1,353	1,482	1,479	1,487	1,466
Hydroelectric	66	69	69	69	69	70	69	69	69
Solar	7	6	9	23	33	31	37	36	24
Wind	220	271	274	389	454	578	701	744	561
Geothermal	49	52	49	52	52	52	20	20	20
Contracts	7	7	7	6	6	3	0	0	7
Sales and Ancillary Services	(194)	(196)	(198)	(203)	(205)	(202)	(203)	(205)	(208)
East Existing Resources	**3,942**	**3,857**	**3,861**	**4,034**	**3,949**	**3,367**	**3,436**	**3,490**	**3,116**
Load	6,459	6,542	6,645	6,724	6,801	6,890	6,992	7,083	7,190
Private Generation	(10)	(12)	(13)	(14)	(16)	(18)	(19)	(21)	(23)
Existing - Demand Response	(166)	(155)	(155)	(155)	(162)	(141)	(137)	(139)	(135)
New Energy Efficiency	(905)	(920)	(1,185)	(1,051)	(1,057)	(343)	(1,143)	(443)	(1,458)
East Total obligation	**5,378**	**5,456**	**5,291**	**5,504**	**5,566**	**6,389**	**5,691**	**6,481**	**5,575**
Planning Reserve Margin (13%)	699	709	688	715	724	831	740	842	725
East Obligation + Reserves	6,077	6,165	5,979	6,219	6,289	7,219	6,431	7,323	6,299
East Position	(2,135)	(2,308)	(2,118)	(2,185)	(2,340)	(3,852)	(2,996)	(3,833)	(3,183)
Available Front Office Transactions	300	300	300	300	300	300	300	300	300
West									
Coal	1,285	1,323	1,361	1,362	1,360	1,360	0	0	27
Gas	680	710	718	718	683	490	489	490	495
Hydroelectric	828	865	874	875	874	877	878	880	879
Solar	0	0	0	0	0	1	1	1	0
Wind	31	41	46	52	60	79	83	82	68
Geothermal	0	0	0	0	0	0	0	0	0
Contracts	14	13	13	14	13	13	12	11	14
Sales and Ancillary Services	(144)	(141)	(144)	(145)	(146)	(143)	(142)	(142)	(148)
West Existing Resources	**2,695**	**2,812**	**2,867**	**2,877**	**2,846**	**2,675**	**1,322**	**1,321**	**1,336**
Load	3,756	3,805	3,854	3,902	3,946	3,994	4,048	4,102	4,156
Private Generation	(4)	(5)	(6)	(7)	(8)	(9)	(11)	(12)	(13)
Existing - Demand Response	0	0	0	0	0	0	0	0	0
New Energy Efficiency	(80)	(134)	73	89	40	(934)	(237)	(1,013)	(3)
West Total obligation	**3,672**	**3,666**	**3,921**	**3,985**	**3,978**	**3,051**	**3,801**	**3,076**	**4,139**
Planning Reserve Margin (13%)	477	477	510	518	517	397	494	400	538
East Obligation + Reserves	398	343	582	607	558	(537)	257	(613)	535
East Position	2,298	2,470	2,285	2,270	2,289	3,212	1,065	1,935	801
Available Front Office Transactions	700	700	700	700	700	700	700	700	700
System									
Total Resources	6,637	6,669	6,728	6,911	6,796	6,042	4,757	4,811	4,452
Obligation	9,050	9,121	9,212	9,488	9,544	9,440	9,492	9,557	9,714
Planning Reserves (13%)	1,176	1,186	1,198	1,233	1,241	1,227	1,234	1,242	1,263
Obligation + Reserves	10,226	10,307	10,409	10,722	10,784	10,667	10,726	10,799	10,976
System Position	(3,589)	(3,638)	(3,681)	(3,810)	(3,989)	(4,625)	(5,968)	(5,988)	(6,524)
Available Front Office Transactions	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000
Uncommitted FOTs to meet remaining Need	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000
Net Surplus/(Deficit)	(2,589)	(2,638)	(2,681)	(2,810)	(2,989)	(3,625)	(4,968)	(4,988)	(5,524)

[5] The DSM line includes selected Class 2 DSM from the 2021 IRP Update resource portfolio.

Figure 4.3 and Figure 4.4 are graphic representations of the above tables for the 2021 IRP Update annual capacity position for the summer system, winter system respectively. Also shown in the system capacity position graphs are the capacity contribution from uncommitted FOTs, which as discussed above, are provided for informational purposes.

Figure 4.3 – Summer System Capacity Position Trend

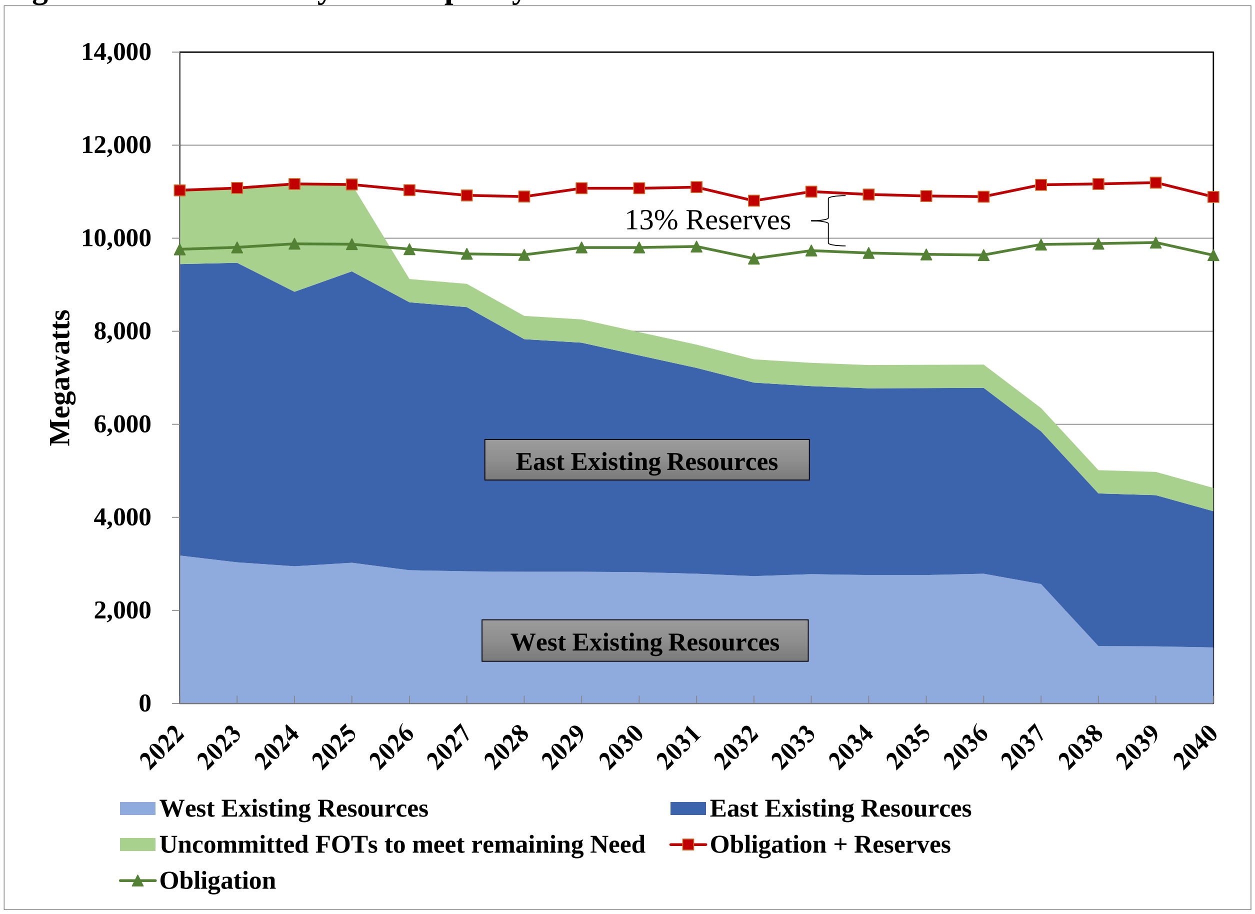
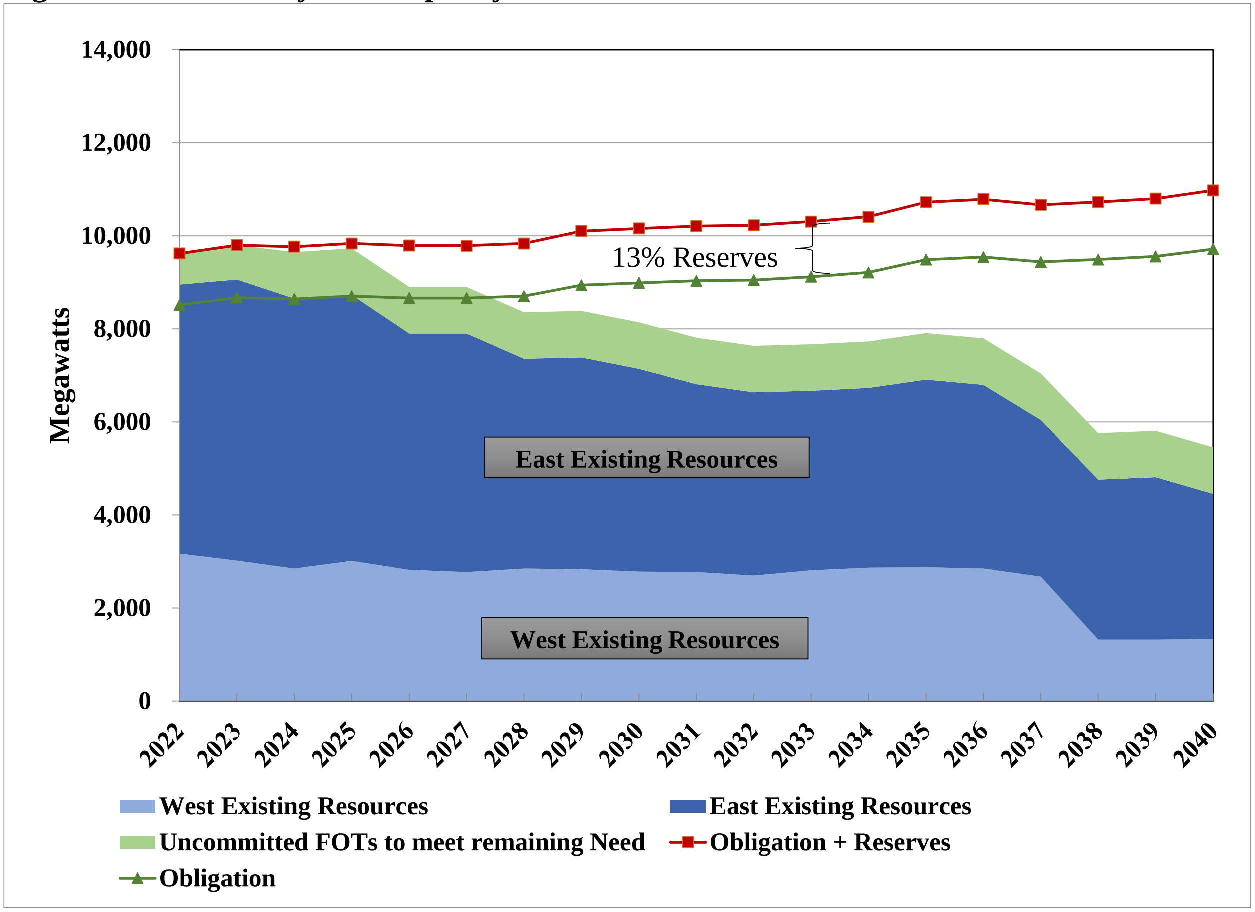


Figure 4.4 – Winter System Capacity Position Trend



Energy Balance Determination

Methodology

The energy balance shows the monthly surplus or (deficit) of energy. Please refer to the section on load and resource balance components for details on how energy for each component is counted.

Existing Resources = Thermal + Hydro + Renewable + Firm Purchases + QF – Sales

The average obligation is computed using the following formula:

Obligation = Load + Firm Sales

The energy position by month is then computed as follows:

Energy Position = Existing Resources – Obligation – Operating Reserve Requirements

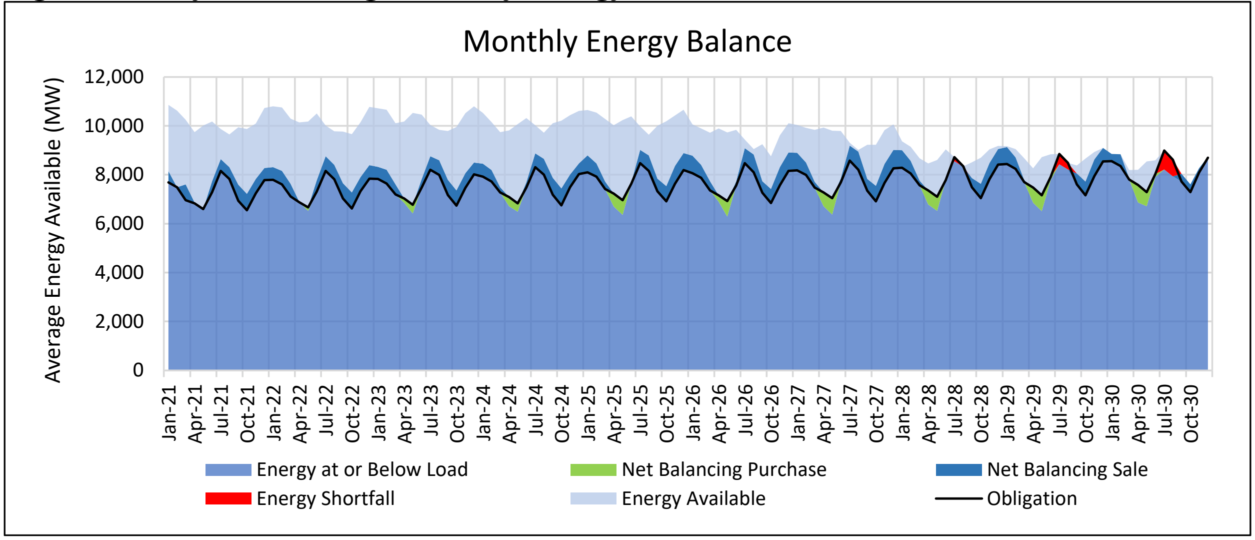
Operating Reserve Requirements include spinning and non-spinning reserves, but not regulation reserves, which are expected to be close to energy neutral over time. As duration-limited resources such as batteries become a larger portion of the Company's portfolio, less of the potential output of thermal resources is likely to be needed to meet Operating Reserve requirements. In addition, energy storage resources represent a net load, due to their roundtrip efficiency. For the 2021 IRP Update, storage resources are not included in the energy balance.

Energy Balance Results

The capacity position shows how existing resources and loads, accounting for coal unit retirements and incremental energy efficiency savings from the preferred portfolio, balance during the coincident peak summer and winter. Outside of these peak periods, PacifiCorp economically dispatches its resources to meet changing load conditions taking into consideration prevailing market conditions. In those periods when variable costs of the system resources are less than the prevailing market price for power, PacifiCorp can dispatch resources that in aggregate exceed then-current load obligations facilitating off system sales that reduce customer costs. Conversely, at times when system resource costs fall below prevailing market prices, system balancing market purchases can be used to meet then-current system load obligations to reduce customer costs. The economic dispatch of system resources is critical to how PacifiCorp manages net power costs.

Figure 4.5 provides a snapshot of how existing system resources could be used to meet forecasted load across on-peak and off-peak periods given the assumptions about resource availability and wholesale power and natural gas prices. At times, resources are economically dispatched above load levels facilitating net system balancing sales. At other times, economic conditions result in net system balancing purchases, which occur more often during on-peak periods. Figure 4.5 also shows how much energy is available from existing resources at any given point in time. Those periods where all available resource energy falls below forecasted loads are highlighted in red and indicate short energy positions without the addition of incremental resources to the portfolio.

Figure 4.5 – System Average Monthly Energy Positions



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CHAPTER 5 – MODELING AND ASSUMPTIONS UPDATE

General Assumptions

Consistent with the 2021 IRP, the study period for the 2021 IRP Update is 2021-2040, with a focus on the 2022-2027 planning horizon.

PacifiCorp has updated certain general assumptions in the 2021 IRP Update from the 2021 IRP as discussed below.

Inflation Rates

The 2021 IRP Update model simulations and cost data reflect PacifiCorp's corporate inflation rate schedule unless otherwise noted. A single annual escalation rate value of 2.155 percent is assumed, consistent with the 2021 IRP. The annual escalation rate reflects the average of annual inflation rate projections for the period 2021 through 2040, using PacifiCorp's September 2020 inflation curve. PacifiCorp's inflation curve is a straight average of forecasts for Gross Domestic Product inflator and Consumer Price Index.

Discount Factor

The discount rate used in present-value calculations is based on PacifiCorp's after-tax weighted average cost of capital (WACC). The value used for the 2021 IRP Update is 6.88 percent, consistent with the 2021 IRP. The use of the after-tax WACC complies with the Public Utility Commission of Oregon's IRP guideline 1a, which requires that the after-tax WACC be used to discount all future resource costs.[1] Present-value revenue requirement values reported in the 2021 IRP Update are reported in 2021 dollars.

Front Office Transactions (FOTs)

FOT modeling assumptions in the 2021 IRP Update are consistent with the FOT modeling assumptions from the 2021 IRP. Table 5.1 reports the available FOT modeling assumptions for reference; identifying the market hub, product type, annual capacity limit, and availability associated with the product. PacifiCorp develops its FOT planning limits based upon its active participation in wholesale power markets, its view of physical delivery constraints, market liquidity and depth, and with consideration of regional resource supply.

[1] Public Utility Commission of Oregon, Order No. 07-002, Docket No. UM 1056, January 8, 2007.

Table 5.1 - Maximum Available Front Office Transaction Quantity by Market Hub

Market Hub/Proxy FOT Product Type Available over Study Period	Megawatt Limit and Availability (MW)	
	Summer (July)	Winter (December)
Mid-Columbia (Mid-C)		
Flat Annual or Heavy Load Hour	350	350
Heavy Load Hour	150	0
California Oregon Border (COB)		
Flat Annual or Heavy Load Hour	0	250
Nevada Oregon Border (NOB)		
Heavy Load Hour	0	100
Mona		
Heavy Load Hour	0	300

Stochastic Parameters

Stochastic parameters assumed in the 2021 IRP Update are consistent with those applied in the 2021 IRP. PacifiCorp provided a detailed description of its stochastic parameters and their development in Volume II, Appendix H of the 2021 IRP.

Flexible Reserve Study

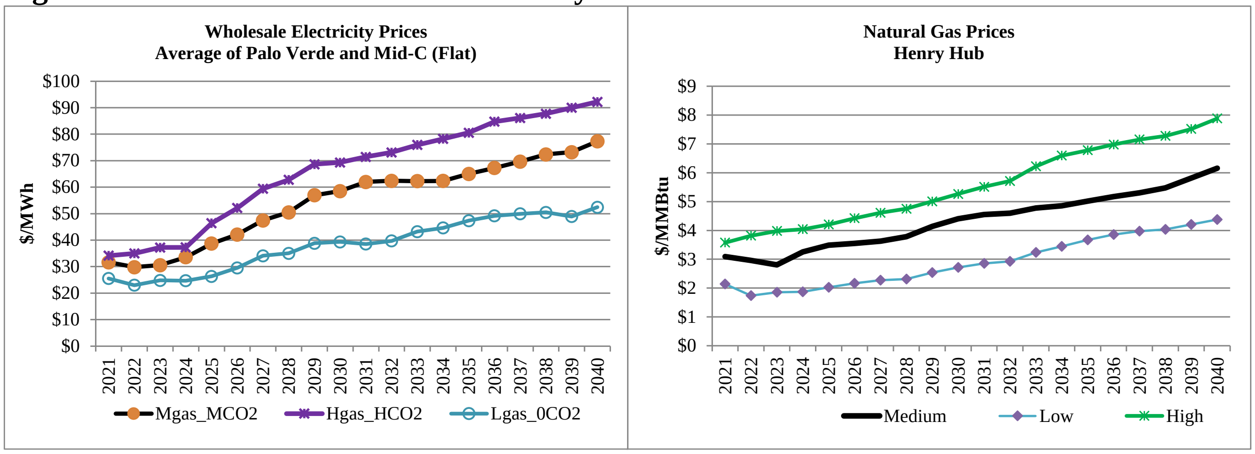
PacifiCorp applied its Flexible Reserve Study methodology from the 2021 IRP in its 2021 IRP Update. PacifiCorp provided a detailed description of its Flexible Reserve Study in Volume II, Appendix F of the 2021 IRP.

Natural Gas and Power Market Price Updates

Portfolio modeling for the 2021 IRP Update was prepared using three market price forecasts that have not changed from the 2021 IRP, in part due to the short period of time that has transpired since the September 1, 2021, filing. PacifiCorp is also transitioning to a new third-party vendor for its price curves and a full set of updated prices are not yet available.

Figure 5.1 summarizes the three wholesale electricity price forecasts and three natural gas price forecasts used in the base and scenario cases for the 2021 IRP Update. As shown, low and medium power and gas prices are higher in the near term. All three power price scenarios trend higher beginning in 2024, but generally escalate at different increasing rates.

Figure 5.1 – Nominal Wholesale Electricity and Natural Gas Price Scenarios



PacifiCorp's March 31, 2021, official forward price curve (OFPC) is used to represent medium natural gas price assumptions with no CO_2 prices for the "MN" price-policy scenario. OFPCs are produced for both natural gas and power prices by point of delivery. For both gas and electricity, starting with the prompt month, the front 36 months of the OFPC reflects market forwards at the close of a given trading day.[2] As such, these 36 months are market forwards as of March 2021. The blending period (months 37 through 48) is calculated by averaging the month-on-month market forward from the prior year with the month-on-month fundamentals-based price from the subsequent year. The fundamentals portion of the natural gas and electricity OFPCs reflect expert third-party price forecasts. PacifiCorp updates its natural gas price forecasts each quarter for the OFPC and, as a corollary, the electricity OFPC is also updated.

Supply and demand for electricity and natural gas are related, and changes in some assumptions that directly impact one can result in prices changes that indirectly impact the other. Other assumptions may impact both markets directly. For example, greenhouse gas prices can impact demand for natural gas for electricity generation, but they can also impact demand for natural gas for other purposes. The combined impact of the change in demand will in turn change natural gas prices, which can in turn further impact demand in the electric sector. By using a single vendor for both electric and gas price forecasting, more of the interaction between these markets as a result of other assumptions can be captured in the price forecast. PacifiCorp previously prepared the fundamentals portion of the electricity forecast in house and could not capture these interactions, which are increasing in importance with the rising penetration of renewable resources and evolving policies that impact CO_2-emitting generation resources.

To improve its forecasts within this changing landscape, PacifiCorp is transitioning to third-party forecasts of both gas and electricity prices. PacifiCorp executed a two-year contract in February 2022 that will provide quarterly OFPC updates for both gas and electricity, starting with the March 2022 OFPC, as well as the price-policy sensitivities used in IRP modeling going forward.

[2] The March 2021 OFPC prompt month is May 2021; April 2021 would be traded as "balance of month" when the OFPC is released.

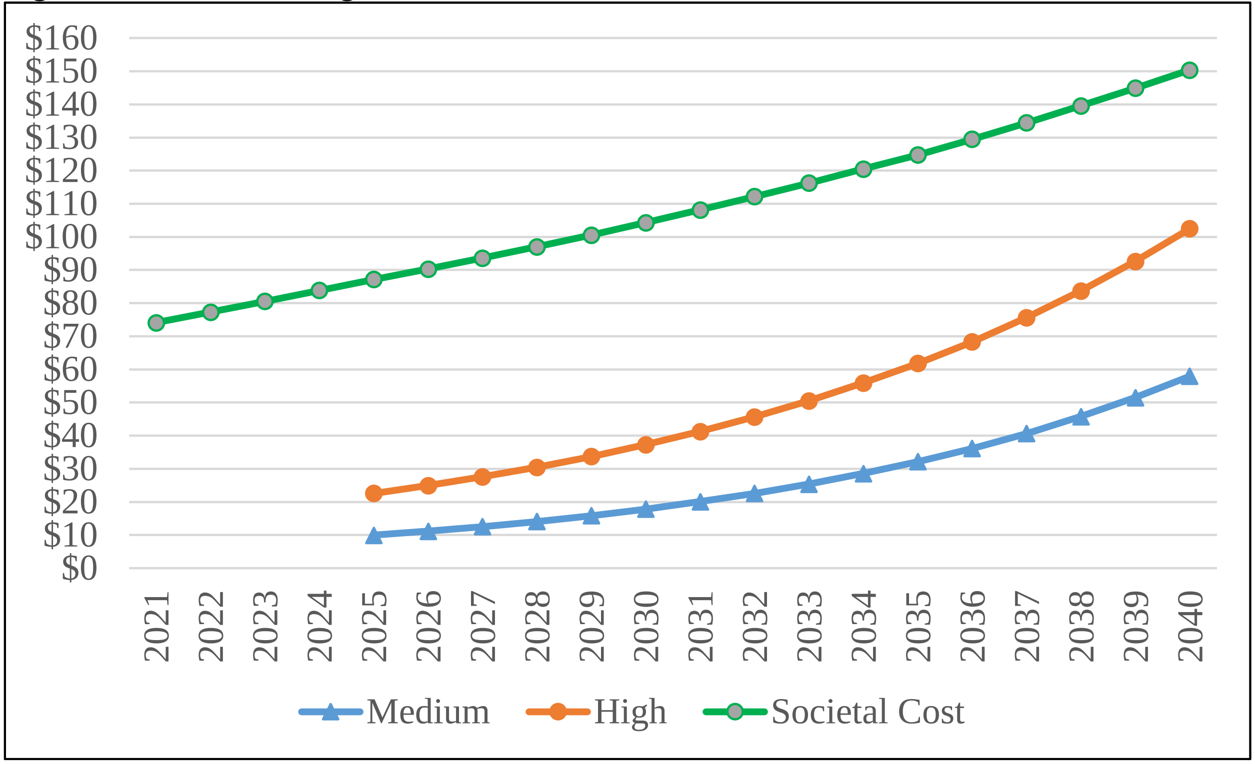
Carbon Dioxide Emission Policy

Consistent with the 2021 IRP, PacifiCorp used three different CO_2 price scenarios in the 2021 IRP Update—zero, medium, high. The medium and high scenario are derived from expert third-party multi-client "off-the-shelf" subscription services. Both scenarios apply a CO_2 price as a tax beginning 2025.

A fourth CO_2 price scenario, social cost of greenhouse gas (SC-GHG), was used in the 2021 IRP but has not been incorporated into the 2021 IRP Update. This is primarily because the 2021 IRP Update is not an update to CETA or the CEIP, and updates such as the CETA Progress Report are addressed through other specified requirements. For informational purposes, the SC-GHG price curve is nonetheless discussed here for comparison to the medium and high price curves. In PacifiCorp's 2021 IRP and future IRPs, the SC-GHG price curve will be incorporated in compliance with RCW 19.280.030. The social cost of greenhouse gases is applied such that the price for the SC-GHG is reflected in market prices and dispatch costs for the purposes of developing each portfolio (i.e., incorporated into capacity expansion optimization modeling). Aligned with Washington staff suggested treatment, system operations in a full IRP also include the SC-GHG once the portfolios are determined, presenting the risk that this operational assumption will not be aligned with actual market forces (i.e., market transactions at the Mid-Columbia market do not reflect the social cost of greenhouse gases and PacifiCorp does not directly incur emission costs at the price assumed for the social cost of greenhouse gases).

For the purposes of the 2021 IRP Update, the zero and high CO_2 price assumptions serve as bookends for future market environment analysis. As described further in Chapter 6, CETA-driven resource assumptions that consider the SC-GHG CO_2 price are incorporated into the 2021 IRP Update preferred portfolio so that updated CETA interim targets could be evaluated.

Figure 5.2 – Medium, High and Social Cost of Greenhouse Gas CO_2 Prices



Supply-Side Resources

Proxy resource costs and operating characteristics are generally unchanged from assumptions used in the 2021 IRP. The supply-side table in the 2021 IRP showed proxy costs for combined solar and storage resources based on storage capacity equal to 50% of solar nameplate, with four-hour duration. As part of the Reliability Assessment in the 2021 IRP, the storage capacity was set at 100% of solar nameplate, with four-hour duration. As part of the development of the 2021 IRP preferred portfolio, costs and operating characteristics for a hybrid wind-solar-storage resource were developed. Since these resource configurations were not included in the supply-side table for the 2021 IRP, they have been provided in the tables below.

All costs remain in real levelized 2020 dollars. Cost (de)escalation curves are applied in the portfolio modeling process to the solar, wind, and/or storage components of a resource. The cost (de)escalation curves are unchanged from the 2021 IRP.

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Table 5.2 - 2021 IRP Update Supply Side Resources

Supply Side Resource Options Mid-Calendar Year 2020 Dollars ($)	Resource Characteristics				Costs				Operating Characteristics				Environmental			
Resource Description	Elevation (AFSL)	Net Capacity (MW)	Commercial Operation Year	Design Life (yrs)	Base Capital ($/KW)	Demolition Cost ($/kW)	Var O&M ($/MWh)	Fixed O&M ($/KW-yr)	Average Full Load Heat Rate (HHV Btu/KWh)/ Efficiency	EFOR (%)	POR (%)	Water Consumed (Gal/MWh)	SO2 (lbs/MMBtu)	NOx (lbs/MMBtu)	Hg (lbs/TBTu)	CO2 (lbs/MMBtu)
Idah Falls, ID, 200 MW, Solar, CF: 26.1% + BESS: 100% pwr, 4 hours	4,700	200	2023	25	$ 3,020	$ 475	$ -	$ 41.80	85%	(a)	(a)	n/a	n/a	n/a	n/a	n/a
Lakeview, OR, 200 MW, Solar, CF: 27.6% + BESS: 100% pwr, 4 hours	4,800	200	2023	25	$ 2,977	$ 475	$ -	$ 41.80	85%	(a)	(a)	n/a	n/a	n/a	n/a	n/a
Milford, UT, 200 MW, Solar, CF: 30.2% + BESS: 100% pwr, 4 hours	5,000	200	2023	25	$ 2,907	$ 475	$ -	$ 43.30	85%	(a)	(a)	n/a	n/a	n/a	n/a	n/a
Rock Springs, WY, 100 MW, Solar, CF: 27.9% + BESS: 100% pwr, 4 hours	6,400	100	2023	25	$ 3,201	$ 475	$ -	$ 45.20	85%	(a)	(a)	n/a	n/a	n/a	n/a	n/a
Rock Springs, WY, 200 MW, Solar, CF: 27.9% + BESS: 100% pwr, 4 hours	6,400	200	2023	25	$ 2,960	$ 475	$ -	$ 43.30	85%	(a)	(a)	n/a	n/a	n/a	n/a	n/a
Yakima, WA, 100 MW, Solar, CF: 24.2% + BESS: 100% pwr, 4 hours	1,000	100	2023	25	$ 3,323	$ 475	$ -	$ 45.20	85%	(a)	(a)	n/a	n/a	n/a	n/a	n/a
Yakima, WA, 200 MW, Solar, CF: 24.2% + BESS: 100% pwr, 4 hours	1,000	200	2023	25	$ 3,077	$ 475	$ -	$ 43.30	85%	(a)	(a)	n/a	n/a	n/a	n/a	n/a
Idah Falls, ID, 200 MW, Solar & Wind, CF: 26.1% + BESS: 100% pwr, 4 hours + 200 MW Wind	4,700	200	2023	25	$ 3,395	$ 488	$ -	$ 82.95	85%	(a)	(a)	n/a	n/a	n/a	n/a	n/a
Lakeview, OR, 200 MW, Solar & Wind,CF: 27.6% + BESS: 100% pwr, 4 hours + 200 MW Wind	4,800	200	2023	25	$ 3,424	$ 488	$ -	$ 82.95	85%	(a)	(a)	n/a	n/a	n/a	n/a	n/a
Milford, UT, 200 MW, Solar & Wind,CF: 30.2% + BESS: 100% pwr, 4 hours + 200 MW Wind	5,000	200	2023	25	$ 3,364	$ 488	$ -	$ 81.45	85%	(a)	(a)	n/a	n/a	n/a	n/a	n/a
Rock Springs, WY, 200 MW, Solar & Wind,CF: 27.9% + BESS: 100% pwr, 4 hours + 200 MW Wind	6,400	200	2023	25	$ 3,364	$ 488	$ -	$ 81.45	85%	(a)	(a)	n/a	n/a	n/a	n/a	n/a
Yakima, WA, 200 MW, Solar & Wind, CF: 24.2% + BESS: 100% pwr, 4 hours + 200 MW Wind	1,000	200	2023	25	$ 3,424	$ 488	$ -	$ 81.45	85%	(a)	(a)	n/a	n/a	n/a	n/a	n/a

Information Presented is Illustrative

Table 5.3 – 2021 IRP Update Supply Side Resources

Supply Side Resource Options Mid-Calendar Year 2020 Dollars ($)	Modeled IRP	Elevation (AFSL)	Capital Cost $/kW				Fixed Cost						
							Fixed O&M $/kW-Yr						Total Fixed ($/kW-Yr)
Resource Description			Total Capital Cost	Demolition Cost	Payment Factor	Annual Payment ($/kW-Yr)	O&M	Capitalized Premium	O&M Capitalized	Gas Transportation	Total		
Idah Falls, ID, 200 MW, Solar, CF: 26.1% + BESS: 100% pwr, 4 hours	Yes	4,700	$3,020	$475	6.839%	$239.06	$41.80	1.379%	$0.58	$0.00	$42.38		$281.44
Lakeview, OR, 200 MW, Solar, CF: 27.6% + BESS: 100% pwr, 4 hours	Yes	4,800	$2,977	$475	6.839%	$236.10	$41.80	1.379%	$0.58	$0.00	$42.38		$278.48
Milford, UT, 200 MW, Solar, CF: 30.2% + BESS: 100% pwr, 4 hours	Yes	5,000	$2,907	$475	6.839%	$231.30	$43.30	1.379%	$0.60	$0.00	$43.90		$275.20
Rock Springs, WY, 200 MW, Solar, CF: 27.9% + BESS: 100% pwr, 4 hours	Yes	6,400	$2,960	$475	6.839%	$234.95	$43.30	1.379%	$0.60	$0.00	$43.90		$278.85
Yakima, WA, 200 MW, Solar, CF: 24.2% + BESS: 100% pwr, 4 hours	Yes	1,000	$3,077	$475	6.839%	$242.90	$43.30	1.379%	$0.60	$0.00	$43.90		$286.79
Idah Falls, ID, 200 MW, Solar, CF: 26.1% + BESS: 100% pwr, 4 hours	Yes	4,700	$3,020	$475	6.839%	$239.06	$41.80	1.379%	$0.58	$0.00	$42.38		$281.44
Lakeview, OR, 200 MW, Solar, CF: 27.6% + BESS: 100% pwr, 4 hours	Yes	4,800	$2,977	$475	6.839%	$236.10	$41.80	1.379%	$0.58	$0.00	$42.38		$278.48
Milford, UT, 200 MW, Solar, CF: 30.2% + BESS: 100% pwr, 4 hours	Yes	5,000	$2,907	$475	6.839%	$231.30	$43.30	1.379%	$0.60	$0.00	$43.90		$275.20
Rock Springs, WY, 200 MW, Solar, CF: 27.9% + BESS: 100% pwr, 4 hours	Yes	6,400	$2,960	$475	6.839%	$234.95	$43.30	1.379%	$0.60	$0.00	$43.90		$278.85
Yakima, WA, 200 MW, Solar, CF: 24.2% + BESS: 100% pwr, 4 hours	Yes	1,000	$3,077	$475	6.839%	$242.90	$43.30	1.379%	$0.60	$0.00	$43.90		$286.79
Idah Falls, ID, 200 MW, Solar & Wind, CF: 26.1% + BESS: 100% pwr, 4 hours + 200 MW Wind	No	4,700	$3,395	$488	6.839%	$265.55	$82.95	1.379%	$1.14	$0.00	$84.09		$349.64
Lakeview, OR, 200 MW, Solar & Wind,CF: 27.6% + BESS: 100% pwr, 4 hours + 200 MW Wind	No	4,800	$3,424	$488	6.839%	$267.48	$82.95	1.379%	$1.14	$0.00	$84.09		$351.58
Milford, UT, 200 MW, Solar & Wind,CF: 30.2% + BESS: 100% pwr, 4 hours + 200 MW Wind	No	5,000	$3,364	$488	6.839%	$263.42	$81.45	1.379%	$1.12	$0.00	$82.57		$345.99
Rock Springs, WY, 200 MW, Solar & Wind,CF: 27.9% + BESS: 100% pwr, 4 hours + 200 MW Wind	No	6,400	$3,364	$488	6.839%	$263.38	$81.45	1.379%	$1.12	$0.00	$82.57		$345.95
Yakima, WA, 200 MW, Solar & Wind, CF: 24.2% + BESS: 100% pwr, 4 hours + 200 MW Wind	No	1,000	$3,424	$488	6.839%	$267.51	$81.45	1.379%	$1.12	$0.00	$82.57		$350.08

Information Presented is Illustrative

Table 5.4 – 2021 IRP Update Supply Side Resources

Supply Side Resource Options Mid-Calendar Year 2020 Dollars ($)		Convert to $/MWh			Variable Costs($/MWh)								
					Levelized Fuel							Credits	
Resource Description	Elevation (AFSL)	Capacity Factor	Total Fixed ($/MWh)	Storage Efficiency	$/MMBtu	$/MWh	O&M	Capitalized Premium	O&M Capitalized	Integration Cost	Total Resource Cost	PTC Tax Credits / ITC (Solar Only) / 45Q Tax Credits (CCUS Only)	Total Resource Cost - with PTC / ITC / 45Q Credits
Idah Falls, ID, 200 MW, Solar, CF: 26.1% + BESS: 100% pwr, 4 hours	4,700	26%	$123.09	85%	$ -	$ -	$ -	0.00%	$ -	$ 0.70	$123.80	$ (23.18)	$100.62
Lakeview, OR, 200 MW, Solar, CF: 27.6% + BESS: 100% pwr, 4 hours	4,800	28%	$115.18	85%	$ -	$ -	$ -	0.00%	$ -	$ 0.70	$115.88	$ (21.61)	$94.28
Milford, UT, 200 MW, Solar, CF: 30.2% + BESS: 100% pwr, 4 hours	5,000	30%	$104.02	85%	$ -	$ -	$ -	0.00%	$ -	$ 0.70	$104.73	$ (19.28)	$85.45
Rock Springs, WY, 200 MW, Solar, CF: 27.9% + BESS: 100% pwr, 4 hours	6,400	28%	$114.09	85%	$ -	$ -	$ -	0.00%	$ -	$ 0.70	$114.80	$ (21.25)	$93.54
Yakima, WA, 200 MW, Solar, CF: 24.2% + BESS: 100% pwr, 4 hours	1,000	24%	$135.29	85%	$ -	$ -	$ -	0.00%	$ -	$ 0.70	$135.99	$ (25.46)	$110.52
Idah Falls, ID, 200 MW, Solar, CF: 26.1% + BESS: 100% pwr, 4 hours	4,700	26%	$123.09	85%	$ -	$ -	$ -	0.00%	$ -	$ 0.70	$123.80	$ (1.10)	$122.70
Lakeview, OR, 200 MW, Solar, CF: 27.6% + BESS: 100% pwr, 4 hours	4,800	28%	$115.18	85%	$ -	$ -	$ -	0.00%	$ -	$ 0.70	$115.88	$ (1.03)	$114.86
Milford, UT, 200 MW, Solar, CF: 30.2% + BESS: 100% pwr, 4 hours	5,000	30%	$104.02	85%	$ -	$ -	$ -	0.00%	$ -	$ 0.70	$104.73	$ (0.91)	$103.81
Rock Springs, WY, 200 MW, Solar, CF: 27.9% + BESS: 100% pwr, 4 hours	6,400	28%	$114.09	85%	$ -	$ -	$ -	0.00%	$ -	$ 0.70	$114.80	$ (1.01)	$113.79
Yakima, WA, 200 MW, Solar, CF: 24.2% + BESS: 100% pwr, 4 hours	1,000	24%	$135.29	85%	$ -	$ -	$ -	0.00%	$ -	$ 0.70	$135.99	$ (1.21)	$134.78
Idah Falls, ID, 200 MW, Solar & Wind, CF: 26.1% + BESS: 100% pwr, 4 hours + 200 MW Wind	4,700	26%	$152.92	85%	$ -	$ -	$ -	0.00%	$ -	$ 0.70	$153.63	$ -	$153.63
Lakeview, OR, 200 MW, Solar & Wind,CF: 27.6% + BESS: 100% pwr, 4 hours + 200 MW Wind	4,800	28%	$145.41	85%	$ -	$ -	$ -	0.00%	$ -	$ 0.70	$146.12	$ -	$146.12
Milford, UT, 200 MW, Solar & Wind,CF: 30.2% + BESS: 100% pwr, 4 hours + 200 MW Wind	5,000	30%	$130.78	85%	$ -	$ -	$ -	0.00%	$ -	$ 0.70	$131.49	$ -	$131.49
Rock Springs, WY, 200 MW, Solar & Wind,CF: 27.9% + BESS: 100% pwr, 4 hours + 200 MW	6,400	28%	$141.55	85%	$ -	$ -	$ -	0.00%	$ -	$ 0.70	$142.25	$ -	$142.25
Yakima, WA, 200 MW, Solar & Wind, CF: 24.2% + BESS: 100% pwr, 4 hours + 200 MW Wind	1,000	24%	$165.14	85%	$ -	$ -	$ -	0.00%	$ -	$ 0.70	$165.84	$ -	$165.84

Information Presented is Illustrative

Modeling Enhancements and Resource Updates

Demand Side Management

PacifiCorp evaluates new DSM opportunities, which includes both energy efficiency and demand response programs, as a resource that competes with traditional new generation and wholesale power market purchases when developing the IRP Update preferred portfolio. Upon additional review of demand response availability, demand response targets have been scaled back to obtainable levels, decreasing potential selections in this update. Also in the 2021 IRP Update, energy efficiency shapes are now aligned to load, better representing the relative effectiveness of bundles to meet system need.

2020 All-source Request for Proposals Resources (2020AS RFP)

Since September 1, 2021, two 2020AS RFP resources withdrew from further contract negotiations and have been removed from assumed development. These solar resources were planned to contribute 153 MW of nameplate capacity and 58 MW of storage capacity in the 2024-2025 timeframe. At this time no replacement has been identified for these solar projects.

Other Contracts

Five contracts have been signed since September 2021, comprising 45 MW of nameplate solar and geothermal capacity, partially offsetting losses due to changes in the 2020AS RFP. As an original purchaser of the output of the Priest Rapids and Wanapum hydro projects, PacifiCorp has an annual option to purchase approximately 100 MW of the output from these plants at market-based rates. For this IRP Update, it has been assumed that PacifiCorp elects to purchase this hydro output in each year of the study horizon.

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CHAPTER 6 – PORTFOLIO DEVELOPMENT

Introduction

PacifiCorp used Plexos' three optimization models to develop an updated preferred portfolio based on inputs and assumptions that have changed since the 2021 Integrated Resource Plan (IRP) was filed September 1, 2021. This updated resource portfolio is consistent with PacifiCorp's most recent load-and-resource balance as described in Chapter 4. This chapter presents the 2021 IRP Update preferred portfolio and a comparison of changes relative to the 2021 IRP preferred portfolio. This chapter also includes three key variants studied in the 2021 IRP regarding significant transmission projects and related resources, and one regional haze sensitivity evaluating compliance strategy for Hunter and Huntington coal.

2021 IRP Update Preferred Portfolio

Key Updates

As discussed in Chapter 5 – Modeling and Assumptions Updates, key updates driving preferred portfolio outcomes include higher load (approaching the 2021 IRP high-load sensitivity), DSM alignment with achievable objectives and improved alignment to load, and resource changes due to 2020AS RFP activity and newly signed contracts.

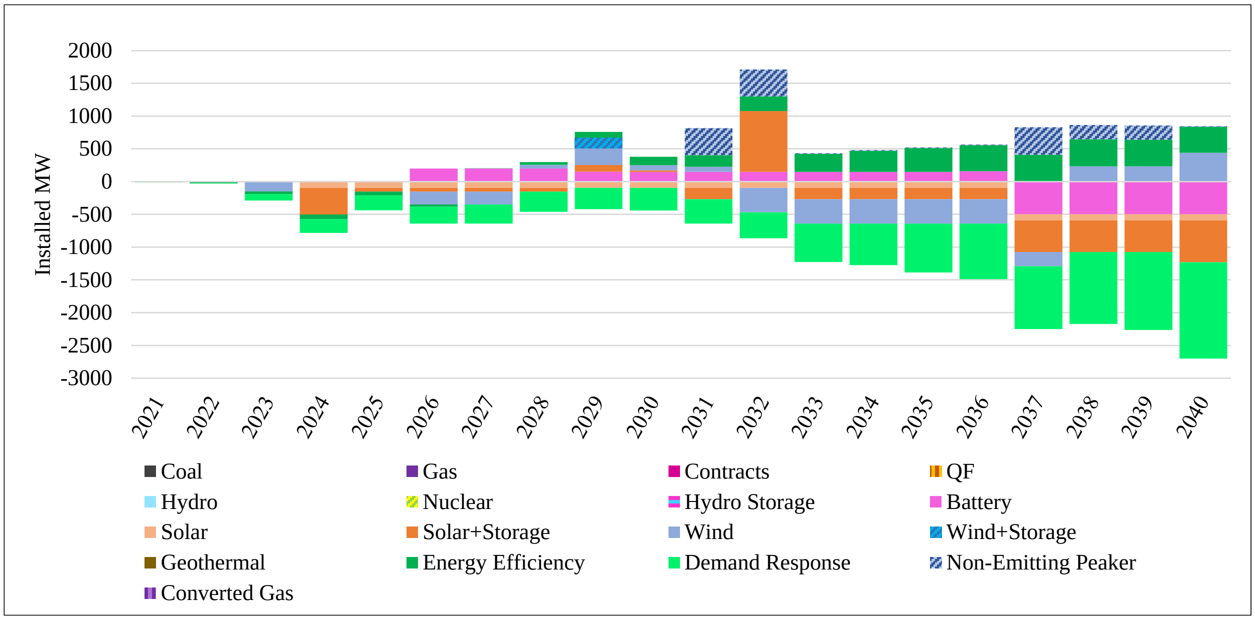
Also of note is the March 11, 2022 release of the Environmental Protection Agency's pre-publication version of its "Ozone Transport Rule" (also called Good Neighbor Rule or Cross-State Air Pollution Rule). The rule, discussed in Chapter 3 – Planning Environment, could not be modeled in the 2021 IRP Update at this early juncture, but is expected to be considered in the 2023 IRP development cycle.

Portfolio Outcomes

The 2021 IRP Update focuses on updates following PacifiCorp's filed 2021 IRP. These include updates to load forecast, changes in existing resources and PacifiCorp's contracts with other entities.

Figure 6.1 summarizes the annual nameplate capacity in the 2021 IRP Update relative to the 2021 IRP preferred portfolio for the 20-year period 2021 through 2040. Consistent with the change in PacifiCorp's load-and-resource balance, the increase in loads accelerates transmission projects and related resources into earlier timeframes and re-balances the resource mix as a result.

Figure 6.1 – Cumulative Increase/(Decrease) in 2021 IRP Update and 2021 IRP Preferred Portfolio



As in the 2021 IRP, the 2021 IRP Update preferred portfolio does not include any new natural gas proxy resources through the 20-year planning horizon. Table 6.5 (summer) and (winter) summarize the 2021 IRP Update load and resource balance, inclusive of incremental resources, for 2021-2040.

Present Value Revenue Requirement (PVRR)

In Table 6.1, the 2021 IRP Update reports a PVRR differential (PVRR(d)) increase in system cost of $946m compared to the 2021 IRP preferred portfolio. Increased load is the primary driver for differences between the two studies, and therefore the High Load sensitivity (S01) analyzed in the 2021 IRP is also compared for reference. The 2021 IRP Update portfolio's increase in cost falls intuitively between the cost of the 2021 IRP preferred portfolio and the High Load sensitivity. The increased load trends notably higher but does not exceed the high load forecast, as seen in Figure 6.3, below. Emissions and energy not served are also marginally higher, but the 2021 IRP Update portfolio avoids the extremes anticipated in the S01 High Load sensitivity.

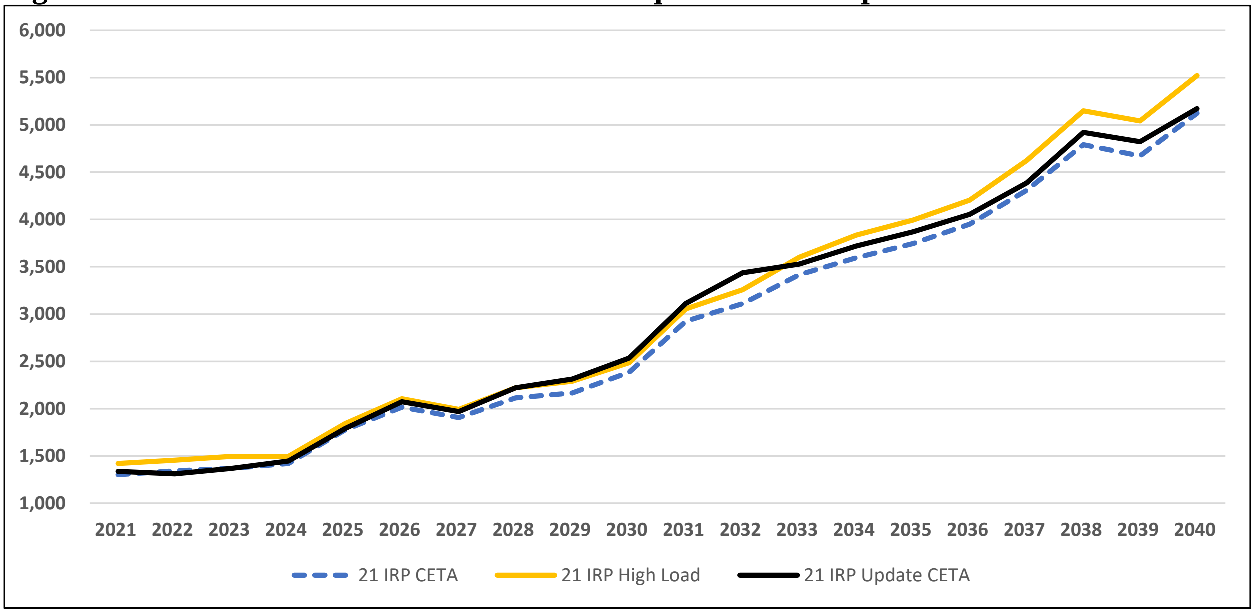
Table 6.1 – Cost and Risk Portfolio Summary

	2021 to 2040							
Vintage	Study Name	ST PVRR ($million)	ST PVRR plus 5% of 95th Stochastic ($million)	Risk Adjusted PVRR(d) Compared to 2021 Preferred Portfolio ($million)	CO2 emissions (Mtons)	CO2 emissions cost ($million)	Avg Annual Energy Not Served plus Reserve Deficiency (GWh)	Energy Not Served as a Percentage of Load (%)
21 IRP Update	Preferred Portfolio Update (MM-CETA)	26,866	27,289	122	419	$2,587	3.9	0.005647%
21 IRP	Preferred Portfolio (P02-MM-CETA)	26,740	27,167	-	420	$2,594	3.9	0.005647%
21 IRP	High Load (S01)	27,606	28,436	1,269	409	$2,446	8.9	0.012619%

Figure 6.2 reports the relative annual PVRR of three portfolios, indicating the magnitude of the load change in the 2021 IRP Update compared to the 2021 IRP and also to the S01 High Load sensitivity. The results show that the annual PVRR of the updated portfolio is higher than in the

2021 IRP, generally lower than in the High Load sensitivity, but rises above the High Load sensitivity in some years (2029-2032). The trend comports with expected changes in PVRR under higher load conditions and intuitively tracks with the load trajectory over the course of the 20-year study period.

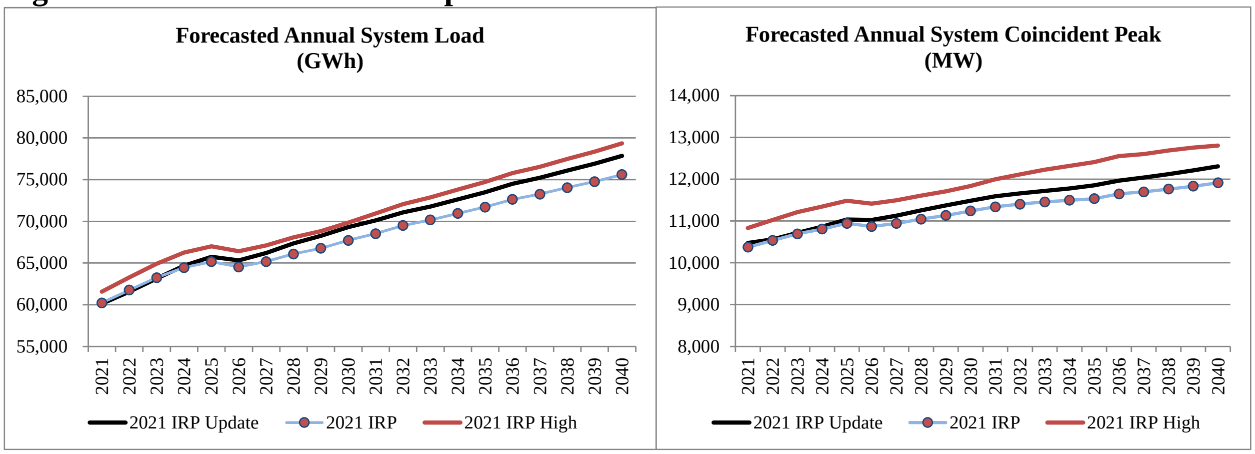
Figure 6.2 – Annual Present Value Revenue Requirement Comparison



Load Increase

The 2021 IRP Update load forecast is significantly higher than the forecast at the time of the 2021 IRP, and is discussed in more detail in Chapter 4 – Load and Resource Balance. Figure 6.3 shows the load comparison among the 2021 IRP, 2021 IRP Update and the S01 High Load sensitivity from the 2021 IRP in support of the PVRR comparison discussed above.

Figure 6.3 – Load Forecast Comparison



Transmission Acceleration

Load increase drives new and accelerated transmission in the updated preferred portfolio. While more expensive, accelerated transmission is necessary to meet the higher load. By the end of the study period, accumulated efficiencies including load-aligned DSM and improved resource locations allows the model to avoid a major transmission upgrade in year 2040, and to avoid approximately 400 MW of accompanying additional resources, net of the demand response decrease discussed in Chapter 5 – Modeling Updates.

Table 6.2 reports changes in transmission selections relative the 2021 IRP. Four transmission paths are accelerated by a total of 12 years in combination and two new paths are selected, adding 30 MW of interconnection capability to the system. One transmission upgrade, Portland North coast to Willamette Valley, is delayed in the back 10 years of the model horizon. Finally, one transmission path, Portland North Coast to Southern Oregon, is removed, partly offset by the accelerations, particularly of the Central Oregon to Willamette Valley transmission line, as well as the additional transmission selected.

Table 6.2 – Transmission Upgrade Changes in the 2021 IRP Update Preferred Portfolio Compared to the 2021 IRP Preferred Portfolio[1]

Upgrade	Export Capacity	2021 Update Year	2020 IRP Year	Change
CON Central OR > TxCON 2027	100	2030	2037	-7
CON Yakima > TxCON 2027a	180	2029	2030	-1
CON Yakima > TxCON 2027b	100	2029	-	New
INC Central OR > Willamette Valley 2037	1500	2037	2040	-3
INC Portland North Coast > Southern Oregon 2037	1500	-	2040	Removed
INC Portland North Coast > Willamette Valley 2032	450	2038	2032	6
INC Utah South > Utah North 2032	800	2032	2033	-1
INC Walla Walla - WA > Yakima 2030	200	2030	-	New

1 – Negative values in the "Change" column indicates the number of years of acceleration compared to the 2021 IRP Preferred Portfolio.

Table 6.3 reports all of the transmission projects selected for the 2021 IRP Update.

Table 6.3 – Transmission Projects Included in the 2021 IRP Update Preferred Portfolio[1, 2]

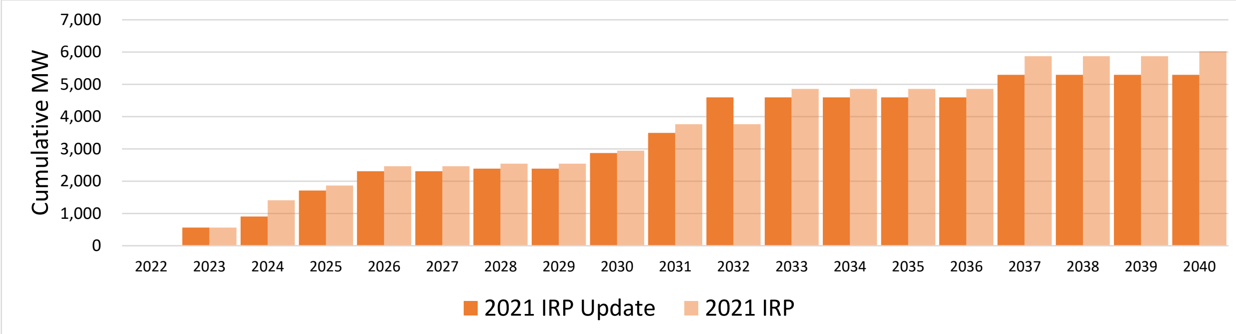
Year	Resource(s)	From	To	Description
2025	1,641 MW RFP Wind (2025)	Aeolus WY	Clover	Enables 1,930 MW of interconnection with 1700 MW of TTC: Energy Gateway South
2026	415 MW Wind (2026) 200 MW Standalone Battery (2026)	Within Willamette Valley OR Transmission Area		Enables 615 MW of interconnection: Albany OR area reinforcement
2026	130 MW Wind (2026) 450 MW Wind (2032)	Portland North Coast	Willamette Valley	Enables 450 MW of interconnection with 450 MW TTC; Portland Coast area reinforcement and Willamette Valley
2026	600 MW Solar+Storage (2026)	Borah-Populous	Hemingway	Enables 600 MW of interconnection with 600 MW of TTC: B2H Boardman-Hemingway
2028	83 MW Solar+Storage (2028) 377 MW Solar+Storage (2030)	Within Southern OR Transmission Area		Enables 460 MW of interconnection: Medford area reinforcement
2029	160 MW Solar+Wind+Storage (2030) 120 MW Solar+Storage (2030)	Yakima WA Transmission Area		Enables 280 MW of interconnection: Yakima local area reinforcement
2030	100 MW Wind (2030)	Walla Walla	Yakima	Enables 100 MW of interconnection
2030	100 MW Solar+Storage (2030)	Central OR Transmission Area		Enables 100 MW of interconnection
2031	626 MW Solar+Storage (2031) 412 MW Non-Emitting Peaker (2033)	Northern UT Transmission Area		Enables 1040 MW of interconnection: Northern UT 345 kV reinforcement
2032	1100 MW Solar+Storage (2032)	Southern UT	Northern UT	Enables 1500 MW of interconnection with 800 MW TTC: Spanish Fork - Mercer 345 kV; New Emery – Clover 345 kV
2037	155 MW Wind (2037) 500 MW Pumped Storage (2040)	Central OR	Willamette Valley	Enables 980 MW of interconnection with 1500 MW of TTC
2028*	500 MW Adv Nuclear (2028)	Southwest Wyoming Transmission Area		Reclaimed transmission upon retirement of Naughton 1 & 2
2029*	500 MW Battery (2029) 330 MW Wind (2028 & 2029)	Eastern Wyoming Transmission Area		Reclaimed transmission upon retirement of Dave Johnston Plant
2037	702 MW Solar+Storage (2037) 206 MW Non-Emitting Peaker (2037)	Southern Utah Transmission Area		Reclaimed transmission upon retirement of Huntington 1 & 2
2038	412 MW Non-Emitting Peaker (2038) 1000 MW Adv Nuclear (2038)	Bridger WY Transmission Area		Reclaimed transmission upon retirement of Jim Bridger Plant
2040	268 MW Wind (2040)	Eastern Wyoming Transmission Area		Reclaimed transmission upon retirement of Wyodak

1 - TTC = total transfer capability. The scope and cost of transmission upgrades are planning estimates. Actual scope and costs will vary depending upon the interconnection queue, the transmission service queue, the specific location of any given generating resource and the type of equipment proposed for any given generating resource.
2 - Energy Gateway South is modeled in the 2021 IRP as a contingent option with bids in the 2020 All Source RFP. Other transmission options prior to 2026 are not modeled as transmission requirements and costs are accounted for in the 2020 All Source RFP cluster study for all other resource bids.
* Reclaimed transmission is committed with resources with COD later than the date of retirement.

New Solar Resources

The 2021 IRP Update preferred portfolio includes 1,709 MW of new solar by the end of 2024 and 2,309 MW by the end of 2026, with additions of 5,297 MW through 2040. Accounting for a 153 MW reduction in resources associated with the 2020 AS RFP, the 2021 IRP Update includes 833 MW more new solar capacity by the end of 2031 compared to the 2021 IRP preferred portfolio. After 2031, driven by more efficient higher cost transmission and energy efficiency gains, solar additions are ultimately reduced 730 MW by 2040.

Figure 6.4 – 2021 IRP Update Preferred Portfolio New Solar Capacity*

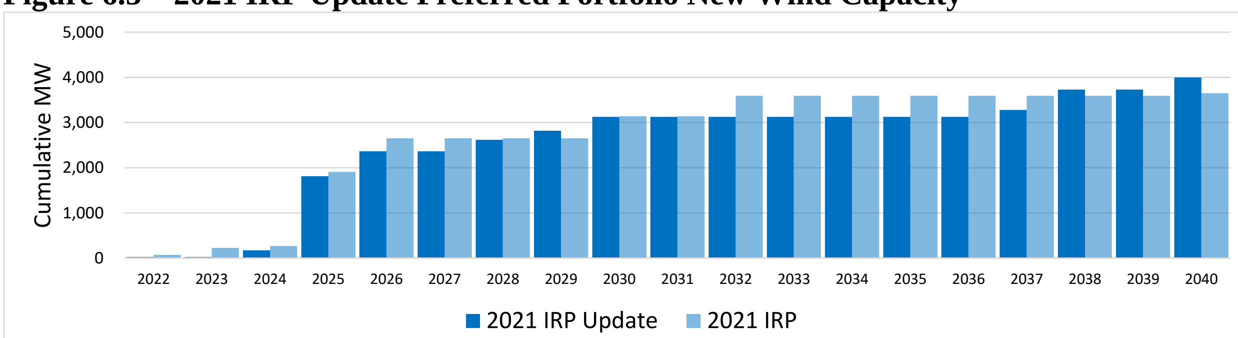


* 2021 IRP Update solar capacity shown in the figure includes solar resources coming via the 2020 All-Source Request for Proposals by the end of 2024. Resources are shown in the first full year of operation (the year after the year-online dates). The reported capacity for the 2020 All-Source Request for Proposals solar resources reflects their expected maximum output after degradation in their first full year of operation.

New Wind Resources

As shown in Figure 6.5, by the end of 2024, PacifiCorp's 2021 IRP Update preferred portfolio includes 1,815 MW of new wind generation resulting from the 2020 All-Source RFP and the acquisition and repowering of Rock River I (49 MW) and Foote Creek II-IV (43 MW). Through the end of 2026, the 2021 IRP Update preferred portfolio includes an additional 2,363 MW of new wind and more than 4,000 MW of new wind by 2040. Relative to the 2021 IRP, 2021 IRP Update wind additions are mostly reduced or flat through 2037, and ultimately increase by 348 MW of new wind by the end of 2040.

Figure 6.5 – 2021 IRP Update Preferred Portfolio New Wind Capacity*

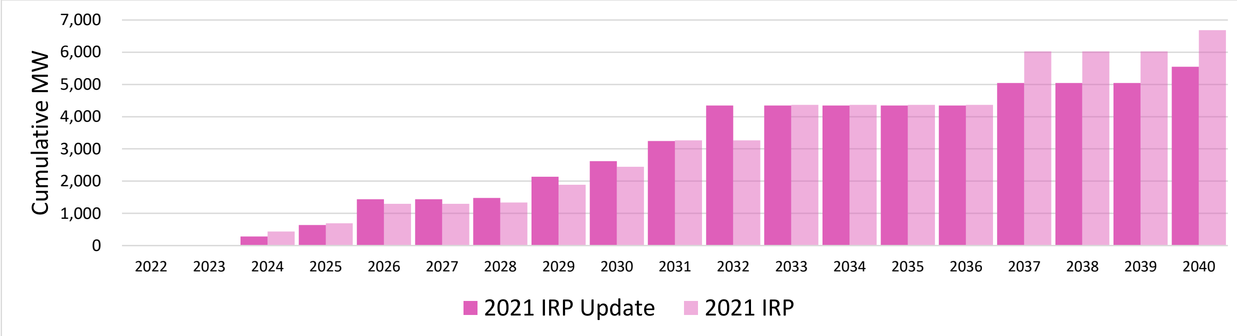


*Note: Wind additions shown are incremental to Energy Vision 2020 and other projects that have come online over the past few years. Resources are shown in the first full year of operation (the year after year-end online dates).

New Storage Resources

New storage resources in the 2021 IRP Update preferred portfolio are summarized in Figure 6.6. The updated portfolio includes nearly 639 MW of battery storage by the end of 2024 – 200 MW of which is a standalone battery and the remaining portion paired with solar resources resulting from the 2020 All-Source RFP. Through 2040, the 2021 IRP includes 4,146 MW of storage co-located with solar resources, 900 MW of standalone battery, and 500 MW of pumped hydro.

Figure 6.6 – 2021 IRP Update Preferred Portfolio New Storage Capacity*

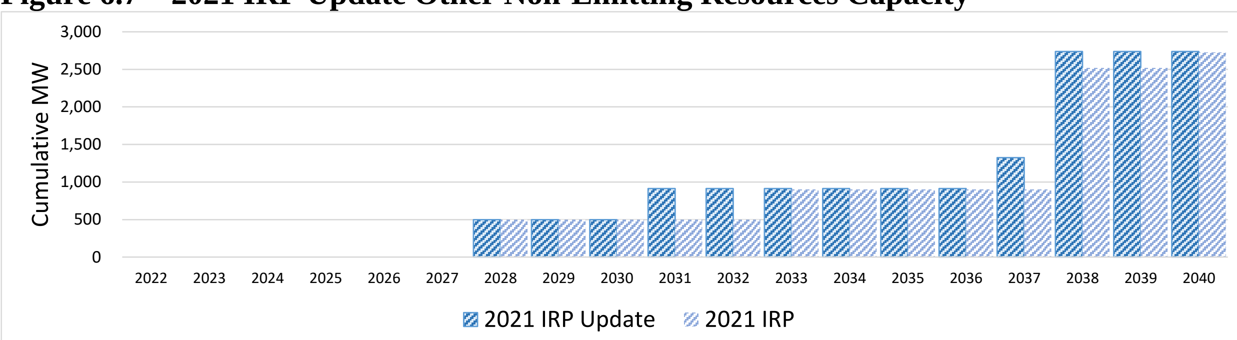


*Note: Resources are shown in the first full year of operation (the year after the year-end online dates).

Other Non-Emitting Resources

The 2021 IRP was the first to include new advanced nuclear and non-emitting peaking resources as part of its least-cost, least-risk preferred portfolio. The 2021 IRP Update continues to select these resources. As shown in Figure 6.7, the 500 MW advanced nuclear Natrium™ demonstration project is projected to come online by summer 2028. Through 2040, the 2021 IRP Update preferred portfolio includes 1,500 MW of advanced nuclear resources and 1,237 MW of non-emitting peaking resources to support meeting requirements. Compared to the 2021 IRP, non-emitting peaker additions increase by 11 MW due to capacity sizing differences of the selected locations.

Figure 6.7 – 2021 IRP Update Other Non-Emitting Resources Capacity

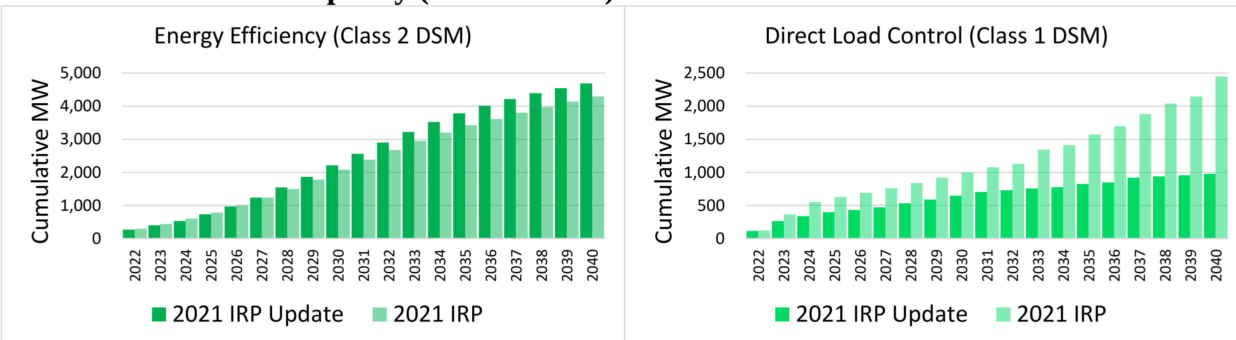


*Note: Resources are shown in the first full year of operation (the year after the year-end online dates).

Demand-Side Management

DSM resources continue to play a key role in PacifiCorp's resource mix. The chart to the left in Figure 6.8 compares total energy efficiency capacity savings in the 2021 IRP Update preferred portfolio relative to the 2021 IRP preferred portfolio and includes 4,685 MW by the end of the planning period. This increase is attributed to the reductions in demand response, combined with the alignment of energy efficiency to load, both described in Chapter 5 – Modeling Updates. For the 2021 IRP Update, selections of demand response have been scaled back to realistic targets, which is responsible for decreases shown on the right-hand side of Figure 6.8. Demand response selections in the 2021 IRP Update total nearly 1,000 MW over the 20-year horizon. By the end of 2040 and relative to the 2021 IRP preferred portfolio, energy efficiency selection increases by nearly 400 MW, whereas demand response selections are reduced by more than 1,400 MW.

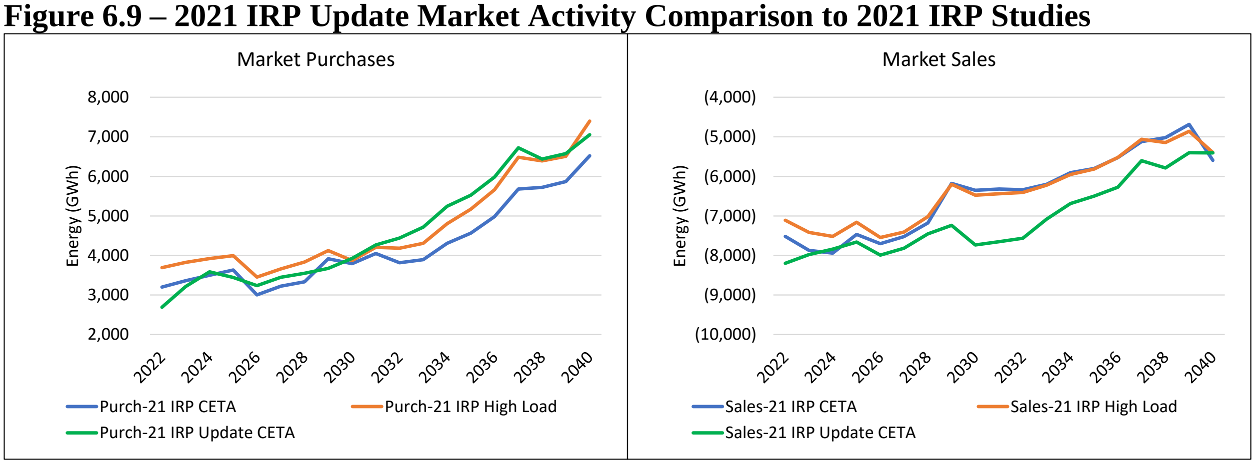
Figure 6.8 – 2021 IRP Update Preferred Portfolio Energy Efficiency (Class 2 DSM) and Direct Load Control Capacity (Class 1 DSM)



Market Activity

Figure 6.9 compares market purchases and sales among the 2021 IRP preferred portfolio, the 2021 IRP S01 High Load sensitivity and the 2021 IRP Update. While the 2021 IRP Update averages approximately 500 GWh of additional sales annually compared to both the 2021 IRP preferred portfolio and the 2021 IRP High Load scenario, offsetting purchases are higher in some years, particularly 2032 to 2037. On average, 2021 IRP Update purchases increase by an average of 200 MW annually on a purely volumetric basis. Given near-term concerns over resource adequacy, generally lower market purchases in 2021 IRP Update portfolio in the first 5 years are viewed favorably.

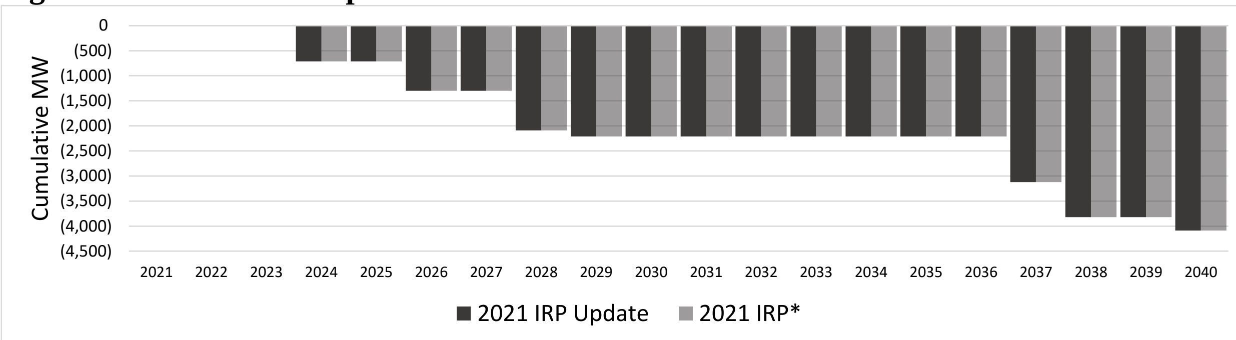
Figure 6.9 – 2021 IRP Update Market Activity Comparison to 2021 IRP Studies



Coal and Gas Retirements/Gas Conversions

The 2021 IRP Update did not trigger any changes to the retirement or conversion assumptions selected in the 2021 IRP. Driven in part by ongoing cost pressures on existing coal-fired facilities and dropping costs for new resource alternatives, of the 22 coal units currently serving PacifiCorp customers, the updated preferred portfolio continues to include retirement of 14 of the units by 2030 and 19 of the units by the end of the planning period in 2040. As shown in , coal unit retirements/gas peaker conversions in the 2021 IRP Update preferred portfolio will reduce coal-fueled generation capacity by 1,300 MW by the end of 2025, over 2,200 MW by 2030, and over 4,000 MW by 2040.

Figure 6.10 – 2021 IRP Update Preferred Portfolio Coal Retirements/Gas Conversions*



* Note: Coal retirements are assumed to occur by the end of the year before the year shown in the graph. The graph shows the year in which the capacity will not be available for meeting summer peak load. All figures represent PacifiCorp's ownership share of jointly owned facilities.

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Table 6.4 – Comparison of 2021 IRP Update with 2021 IRP Preferred Portfolio (Megawatts)

2021 IRP Update

	Capacity (MW)																				10- year Total
Resource	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**	**2036**	**2037**	**2038**	**2039**	**2040**	**2021-2040**
Expansion Options																					
Gas - CCCT	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Gas- Peaking	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
NonEmitting Peaking	-	-	-	-	-	-	-	-	-	-	412	-	-	-	-	-	412	412	-	-	**1,237**
DSM - Energy Efficiency	146	124	131	132	199	237	270	304	323	347	348	339	322	296	262	230	201	176	155	143	**4,685**
DSM - Demand Response	-	117	148	74	61	35	37	62	58	58	54	28	24	22	47	24	72	20	17	20	**978**
Renewable - Wind	49	-	-	194	1,641	547	-	255	202	308	-	-	-	-	-	-	156	450	-	268	**4,069**
Renewable - Wind+Storage	-	-	-	-	-	-	-	-	160	-	-	-	-	-	-	-	-	-	-	-	**160**
Renewable - Utility Solar	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Renewable - Utility Solar + Storage	-	-	-	345	805	600	-	83	160	477	626	1,100	-	-	-	-	702	-	-	-	**4,898**
Renewable - Geothermal	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Renewable - Battery (Wind+Storage)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Renewable - Battery (Solar+Storage)	-	-	-	88	352	600	-	42	160	477	626	1,100	-	-	-	-	702	-	-	-	**4,146**
Battery - Stand Alone	-	-	-	200	-	200	-	-	500	-	-	-	-	-	-	-	-	-	-	-	**900**
Storage - CAES	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Storage - Pumped Hydro	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	500	**500**
Nuclear	-	-	-	-	-	-	-	345	-	-	-	-	-	-	-	-	-	690	-	-	**1,035**
Nuclear + Storage	-	-	-	-	-	-	-	155	-	-	-	-	-	-	-	-	-	310	-	-	**465**
Front Office Transactions - Summer *	125	59	108	132	171	113	129	141	188	172	163	164	251	253	301	251	255	309	348	351	**199**
Front Office Transactions - Winter *	164	60	121	143	133	1	1	1	1	-	-	-	-	89	103	138	366	607	670	714	**166**
Existing Unit Changes																					
Thermal Plant End-of-life Retirements	-	-	-	-	-	(230)	-	(788)	(123)	-	-	-	-	-	-	-	(909)	(699)	-	(268)	**(3,018)**
Coal Early Retirement	-	-	-	-	-	(357)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	**(357)**
Coal Plant Gas Conversion	-	-	-	713	-	-	-	-	-	-	-	-	-	-	-	-	-	(713)	-	-	-
Coal Plant ceases running as Coal	-	-	-	(713)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	**(713)**
Gas Plant End-of-life Retirements	-	-	-	-	-	-	-	-	-	(247)	-	-	(356)	-	-	-	(237)	-	-	-	**(840)**
Total	**484**	**360**	**509**	**1,306**	**3,361**	**1,746**	**437**	**600**	**1,630**	**1,592**	**2,228**	**2,730**	**240**	**661**	**713**	**644**	**1,720**	**1,561**	**1,191**	**1,728**	

*** FOT in resource total are 20-year averages**

2021 IRP Update less 2021 IRP Preferred Portfolio

	Capacity (MW)																				10- year Total
Resource	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**	**2036**	**2037**	**2038**	**2039**	**2040**	**2021-2040**
Expansion Options																					
Gas - CCCT	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Gas- Peaking	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
NonEmitting Peaking	-	-	-	-	-	-	-	-	-	-	412	-	(402)	-	-	-	412	(206)	-	(206)	**11**
DSM - Energy Efficiency	(11)	(14)	(13)	(33)	14	26	32	41	44	43	47	46	50	47	41	36	12	6	(5)	(13)	**395**
DSM - Demand Response	-	(7)	(94)	(110)	(18)	(29)	(32)	(18)	(19)	(19)	(29)	(22)	(189)	(48)	(113)	(101)	(111)	(139)	(90)	(281)	**(1,471)**
Renewable - Wind	-	-	(151)	151	-	(198)	-	255	202	(182)	-	(450)	-	-	-	-	156	450	-	208	**441**
Renewable - Wind+Storage	-	-	-	-	-	-	-	-	160	(160)	-	-	-	-	-	-	-	-	-	-	-
Renewable - Utility Solar	-	-	-	(95)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	**(95)**
Renewable - Utility Solar + Storage	-	-	-	(407)	349	-	-	-	160	(81)	(194)	1,100	(1,100)	-	-	-	(307)	-	-	(156)	**(635)**
Renewable - Geothermal	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Renewable - Battery (Wind+Storage)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Renewable - Battery (Solar+Storage)	-	-	-	(152)	94	-	-	-	160	(81)	(194)	1,100	(1,100)	-	-	-	(307)	-	-	(156)	**(635)**
Battery - Stand Alone	-	-	-	-	-	200	-	-	(49)	(1)	-	-	-	-	-	-	(650)	-	-	-	**(500)**
Storage - CAES	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Storage - Pumped Hydro	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Nuclear	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Nuclear + Storage	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Front Office Transactions - Summer *	(90)	(180)	(119)	(71)	(138)	(94)	(117)	(114)	(145)	(193)	(210)	(209)	(122)	(247)	(72)	(192)	(179)	(191)	(152)	(149)	**(149)**
Front Office Transactions - Winter *	(6)	(113)	(78)	(38)	(56)	(22)	(40)	(29)	(29)	(30)	(22)	(86)	(165)	(114)	(102)	(165)	(64)	82	118	38	**(46)**
Existing Unit Changes																					
Thermal Plant End-of-life Retirements	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Coal Early Retirement	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Coal Plant Gas Conversion	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Coal Plant ceases running as Coal	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Gas Plant End-of-life Retirements	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Total	**(107)**	**(314)**	**(456)**	**(754)**	**244**	**(116)**	**(158)**	**135**	**483**	**(703)**	**(190)**	**1,479**	**(3,028)**	**(361)**	**(246)**	**(423)**	**(1,037)**	**1**	**(129)**	**(714)**	

*** FOT in resource total are 20-year averages**

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Table 6.5 – 2021 IRP Update Summer Capacity Load and Resource Balance (Megawatts)

East	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
Coal	3,536	3,474	3,505	3,513	3,076	3,067	2,343	2,245	2,199	2,198
Gas	1,942	1,964	1,922	1,947	1,968	1,933	1,950	1,942	1,753	1,748
Hydroelectric	108	108	88	88	88	88	88	87	87	87
Solar	377	521	197	424	341	320	352	316	291	161
Wind	337	405	262	452	445	424	422	491	490	395
Geothermal	49	50	51	50	50	52	51	50	51	50
Contracts	185	182	122	35	31	30	31	24	22	17
Sales and Ancillary Services	(267)	(267)	(243)	(243)	(239)	(236)	(235)	(234)	(233)	(233)
East Existing Resources	**6,268**	**6,438**	**5,905**	**6,265**	**5,760**	**5,678**	**5,003**	**4,922**	**4,660**	**4,423**
Front Office Transactions	300	300	300	124	0	0	0	0	0	0
NonEmitting Peaker	0	0	0	0	0	0	0	0	0	367
Wind	0	0	14	300	293	291	352	397	449	392
Solar	0	0	30	169	143	133	165	148	129	117
Storage	1	1	284	583	553	535	669	923	817	1,125
Nuclear	0	0	0	0	0	0	324	322	334	318
East Planned Resources	**301**	**301**	**628**	**1,177**	**990**	**959**	**1,510**	**1,790**	**1,729**	**2,319**
East Total Resources	**6,569**	**6,739**	**6,533**	**7,442**	**6,749**	**6,637**	**6,513**	**6,712**	**6,388**	**6,742**
Load	7,274	7,421	7,543	7,685	7,654	7,732	7,843	7,944	8,052	8,162
Private Generation	(57)	(66)	(69)	(71)	(75)	(81)	(90)	(103)	(120)	(144)
Existing - Demand Response	(594)	(585)	(594)	(593)	(520)	(496)	(460)	(255)	(220)	(196)
New Demand Response	(74)	(146)	(169)	(192)	(182)	(187)	(202)	(158)	(141)	(130)
New Energy Efficiency	(134)	(210)	(242)	(379)	(500)	(810)	(801)	(1,051)	(1,026)	(1,252)
East Total obligation	**6,415**	**6,414**	**6,468**	**6,450**	**6,377**	**6,158**	**6,291**	**6,378**	**6,545**	**6,440**
East Reserve Margin	2%	5%	1%	15%	6%	8%	4%	5%	-2%	5%
West										
Coal	1,500	1,495	1,487	1,488	1,354	1,352	1,348	1,370	1,356	1,356
Gas	663	673	660	664	663	664	664	664	675	665
Hydroelectric	955	796	790	799	795	798	798	794	792	797
Solar	7	27	10	20	16	15	16	14	13	6
Wind	89	83	50	87	82	89	77	84	91	85
Geothermal	0	0	0	0	0	0	0	0	0	0
Contracts	171	168	131	146	132	97	102	72	63	47
Sales and Ancillary Services	(209)	(207)	(182)	(182)	(179)	(177)	(177)	(168)	(168)	(169)
West Existing Resources	**3,177**	**3,034**	**2,945**	**3,022**	**2,863**	**2,838**	**2,828**	**2,831**	**2,822**	**2,787**
Front Office Transactions	1,245	1,128	1,445	290	0	0	0	0	0	0
NonEmitting Peaker	0	0	0	0	0	0	0	0	0	0
Wind	0	0	0	0	141	153	162	223	273	239
Solar	0	0	0	59	157	154	190	196	274	151
Storage	0	0	0	53	844	844	886	868	1,092	971
Nuclear	0	0	0	0	0	0	0	0	0	0
West Planned Resources	**1,245**	**1,128**	**1,445**	**402**	**1,142**	**1,151**	**1,238**	**1,286**	**1,640**	**1,361**
West Total Resources	**4,421**	**4,162**	**4,390**	**3,424**	**4,006**	**3,989**	**4,066**	**4,118**	**4,462**	**4,148**
Load	3,372	3,402	3,434	3,471	3,501	3,534	3,569	3,604	3,640	3,679
Private Generation	(28)	(40)	(45)	(49)	(54)	(60)	(67)	(75)	(85)	(106)
Existing - Demand Response	0	0	0	0	0	0	0	0	0	0
New Demand Response	(42)	(107)	(149)	(174)	(164)	(170)	(174)	(119)	(110)	(103)
New Energy Efficiency	(73)	(120)	(147)	(192)	(242)	(157)	(354)	(264)	(442)	(321)
West Total obligation	**3,229**	**3,136**	**3,094**	**3,055**	**3,041**	**3,147**	**2,975**	**3,145**	**3,003**	**3,148**
West Reserve Margin	37%	33%	42%	12%	32%	27%	37%	31%	49%	32%
System										
Total Resources	10,990	10,900	10,924	10,866	10,755	10,626	10,578	10,830	10,850	10,890
Obligation	9,644	9,550	9,562	9,505	9,418	9,305	9,265	9,523	9,548	9,588
Capacity Reserve Margin (13%)	1,254	1,242	1,243	1,236	1,224	1,210	1,204	1,238	1,241	1,246
Obligation + Reserves	10,898	10,792	10,805	10,741	10,643	10,515	10,470	10,761	10,789	10,834
System Position	92	109	119	125	113	111	109	69	61	56
Reserve Margin	**14%**	**14%**	**14%**	**14%**	**14%**	**14%**	**14%**	**14%**	**14%**	**14%**

Table 6.5 (Cont.) – 2021 IRP Update Summer Capacity Load and Resource Balance (Megawatts)

East	2032	2033	2034	2035	2036	2037	2038	2039	2040
Thermal	2,212	2,219	2,207	2,219	2,218	1,359	1,362	1,357	1,100
Hydroelectric	1,743	1,412	1,401	1,397	1,398	1,403	1,403	1,399	1,410
Hydroelectric	86	87	87	86	87	86	86	87	87
Solar	30	136	124	132	125	137	144	142	83
Wind	252	355	359	353	333	475	502	480	457
Geothermal	51	50	51	51	52	50	20	20	20
Contracts	10	15	14	12	9	8	0	0	0
Sales and Ancillary Services	(226)	(230)	(229)	(228)	(228)	(233)	(233)	(234)	(227)
East Existing Resources	**4,159**	**4,043**	**4,013**	**4,022**	**3,993**	**3,287**	**3,285**	**3,251**	**2,931**
Front Office Transactions	0	0	0	0	0	0	0	0	0
NonEmitting Peaker	398	380	386	385	398	581	580	585	576
Wind	253	394	413	400	372	490	483	526	568
Solar	40	200	187	191	172	474	520	525	324
Storage	1,642	1,521	1,497	1,497	1,496	1,720	1,675	1,626	1,558
Nuclear	322	314	326	322	335	319	932	925	939
East Planned Resources	**2,655**	**2,809**	**2,809**	**2,795**	**2,773**	**3,584**	**4,190**	**4,187**	**3,965**
East Total Resources	**6,813**	**6,853**	**6,822**	**6,817**	**6,766**	**6,871**	**7,475**	**7,438**	**6,896**
Load	8,266	8,370	8,473	8,444	8,585	8,679	8,793	8,655	8,759
Private Generation	(173)	(203)	(236)	(150)	(173)	(196)	(221)	(116)	(128)
Existing - Demand Response	(176)	(163)	(161)	(161)	(160)	(148)	(144)	(148)	(142)
New Demand Response	(119)	(113)	(113)	(120)	(122)	(123)	(121)	(126)	(122)
New Energy Efficiency	(1,489)	(1,442)	(1,522)	(1,590)	(1,607)	(1,702)	(1,753)	(1,702)	(1,844)
East Total obligation	**6,309**	**6,450**	**6,442**	**6,423**	**6,522**	**6,510**	**6,553**	**6,563**	**6,522**
East Reserve Margin	8%	6%	6%	6%	4%	6%	14%	13%	6%

West									
Coal	1,356	1,358	1,355	1,354	1,353	1,351	0	0	0
Gas	667	665	665	663	677	449	448	446	446
Hydroelectric	793	794	796	792	793	795	795	798	798
Solar	1	5	4	5	5	9	10	10	7
Wind	56	88	77	73	83	97	114	117	84
Geothermal	0	0	0	0	0	0	0	0	0
Contracts	24	35	31	30	32	23	19	10	10
Sales and Ancillary Services	(162)	(169)	(167)	(160)	(155)	(161)	(157)	(156)	(144)
West Existing Resources	**2,735**	**2,776**	**2,760**	**2,757**	**2,787**	**2,563**	**1,229**	**1,224**	**1,200**
Front Office Transactions	0	0	0	0	0	0	0	0	0
NonEmitting Peaker	0	0	0	0	0	196	566	575	586
Wind	157	246	256	220	220	343	522	543	470
Solar	35	137	126	127	130	249	272	278	183
Storage	873	809	796	796	796	735	915	940	1,364
Nuclear	0	0	0	0	0	0	0	0	0
West Planned Resources	**1,065**	**1,192**	**1,177**	**1,143**	**1,145**	**1,522**	**2,276**	**2,337**	**2,603**
West Total Resources	**3,801**	**3,968**	**3,938**	**3,900**	**3,932**	**4,086**	**3,505**	**3,561**	**3,803**
Load	3,711	3,747	3,785	3,775	3,809	3,854	3,892	3,861	3,896
Private Generation	(147)	(193)	(247)	(217)	(254)	(296)	(341)	(190)	(221)
Existing - Demand Response	0	0	0	0	0	0	0	0	0
New Demand Response	(94)	(88)	(88)	(90)	(91)	(85)	(84)	(87)	(84)
New Energy Efficiency	(432)	(382)	(412)	(450)	(561)	(327)	(344)	(455)	(685)
West Total obligation	**3,040**	**3,084**	**3,038**	**3,018**	**2,902**	**3,145**	**3,124**	**3,129**	**2,906**
West Reserve Margin	25%	29%	30%	29%	35%	30%	12%	14%	31%

System									
Total Resources	10,614	10,820	10,760	10,716	10,699	10,957	10,980	10,999	10,698
Obligation	9,348	9,534	9,481	9,441	9,425	9,655	9,677	9,692	9,428
Capacity Reserve Margin (13%)	1,215	1,239	1,232	1,227	1,225	1,255	1,258	1,260	1,226
Obligation + Reserves	10,563	10,773	10,713	10,668	10,650	10,911	10,935	10,952	10,653
System Position	51	47	47	48	49	46	45	47	45
Reserve Margin	**14%**	**13%**	**13%**	**14%**	**14%**	**13%**	**13%**	**13%**	**13%**

Table 6.6 – 2021 IRP Update Winter Capacity Load and Resource Balance (Megawatts)

East	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
Coal	3,443	3,491	3,470	3,477	2,931	2,941	2,249	2,224	2,148	2,090
Gas	1,938	2,045	2,043	1,995	1,913	1,969	2,042	2,012	1,817	1,700
Hydroelectric	80	80	70	70	68	67	70	69	69	67
Solar	48	72	40	22	14	16	16	24	39	11
Wind	268	383	250	278	280	263	256	355	418	306
Geothermal	52	52	52	51	51	46	52	52	52	50
Contracts	164	137	66	16	15	15	15	9	9	8
Sales and Ancillary Services	(212)	(215)	(189)	(192)	(190)	(189)	(191)	(193)	(194)	(194)
East Existing Resources	**5,781**	**6,045**	**5,801**	**5,716**	**5,081**	**5,127**	**4,509**	**4,552**	**4,360**	**4,038**
Front Office Transactions	181	167	187	0	0	0	0	0	0	0
NonEmitting Peaker	0	0	0	0	0	0	0	0	11	375
Wind	0	0	20	293	255	247	309	424	539	460
Solar	0	0	7	14	10	11	8	14	24	13
Storage	1	1	250	491	456	453	614	847	758	1,037
Nuclear	0	0	0	0	0	3	308	309	308	297
East Planned Resources	**182**	**168**	**464**	**797**	**722**	**715**	**1,240**	**1,594**	**1,640**	**2,182**
East Total Resources	**5,963**	**6,213**	**6,265**	**6,514**	**5,803**	**5,842**	**5,749**	**6,146**	**6,000**	**6,220**
Load	5,691	5,868	5,936	6,050	5,977	6,033	6,138	6,220	6,297	6,374
Private Generation	(1)	(2)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
Existing - Demand Response	(322)	(309)	(335)	(408)	(330)	(324)	(336)	(229)	(204)	(180)
New Demand Response	(73)	(138)	(150)	(166)	(163)	(167)	(182)	(142)	(131)	(120)
New Energy Efficiency	(108)	(148)	(198)	(221)	(275)	(725)	(400)	(842)	(880)	(520)
East Total obligation	**5,186**	**5,273**	**5,251**	**5,252**	**5,205**	**4,813**	**5,213**	**5,000**	**5,074**	**5,545**
East Reserve Margin	15%	18%	19%	24%	11%	21%	10%	23%	18%	12%
West										
Coal	1,488	1,488	1,319	1,468	1,321	1,314	1,338	1,335	1,360	1,313
Gas	718	718	711	713	697	693	717	715	630	695
Hydroelectric	1,038	858	865	861	847	843	869	866	869	843
Solar	0	1	1	1	0	0	0	1	1	0
Wind	39	52	33	50	39	33	34	44	52	50
Geothermal	0	0	0	0	0	0	0	0	0	0
Contracts	78	73	70	68	58	31	33	21	17	15
Sales and Ancillary Services	(192)	(174)	(149)	(146)	(145)	(142)	(142)	(147)	(147)	(146)
West Existing Resources	**3,168**	**3,016**	**2,850**	**3,014**	**2,818**	**2,772**	**2,849**	**2,834**	**2,782**	**2,771**
Front Office Transactions	422	390	437	0	0	0	0	0	0	0
NonEmitting Peaker	0	0	0	0	0	0	0	0	0	0
Wind	0	0	0	2	67	63	60	109	135	123
Solar	0	0	0	3	7	7	8	11	21	8
Storage	0	0	0	53	844	844	886	782	1,013	894
Nuclear	0	0	0	0	0	0	0	0	0	0
West Planned Resources	**422**	**390**	**437**	**58**	**918**	**915**	**954**	**902**	**1,169**	**1,025**
West Total Resources	**3,590**	**3,407**	**3,287**	**3,072**	**3,737**	**3,687**	**3,803**	**3,736**	**3,951**	**3,796**
Load	3,330	3,373	3,408	3,446	3,487	3,534	3,580	3,628	3,673	3,710
Private Generation	(0)	(1)	(1)	(1)	(1)	(2)	(2)	(3)	(3)	(4)
Existing - Demand Response	0	0	0	0	0	0	0	0	0	0
New Demand Response	(35)	(82)	(108)	(136)	(129)	(134)	(144)	(107)	(102)	(95)
New Energy Efficiency	(76)	(110)	(165)	(160)	(191)	150	(271)	172	114	(339)
West Total obligation	**3,218**	**3,179**	**3,135**	**3,148**	**3,166**	**3,548**	**3,164**	**3,690**	**3,682**	**3,273**
West Reserve Margin	12%	7%	5%	-2%	18%	4%	20%	1%	7%	16%
System										
Total Resources	9,553	9,620	9,553	9,585	9,540	9,529	9,552	9,882	9,951	10,016
Obligation	8,405	8,452	8,385	8,401	8,371	8,361	8,377	8,690	8,756	8,818
Capacity Reserve Margin (13%)	1,093	1,099	1,090	1,092	1,088	1,087	1,089	1,130	1,138	1,146
Obligation + Reserves	9,497	9,551	9,475	9,493	9,459	9,448	9,466	9,820	9,894	9,965
System Position	56	69	77	92	81	81	86	62	57	51
Reserve Margin	**14%**	**14%**	**14%**	**14%**	**14%**	**14%**	**14%**	**14%**	**14%**	**14%**

Table 6.6 (Cont.) - 2021 IRP Update Winter Capacity Load and Resource Balance (Megawatts)

East	2032	2033	2034	2035	2036	2037	2038	2039	2040
Coal	2,051	2,203	2,178	2,212	2,188	1,353	1,332	1,338	1,178
Gas	1,736	1,444	1,473	1,485	1,353	1,482	1,479	1,487	1,466
Hydroelectric	66	69	69	69	69	70	69	69	69
Solar	7	6	9	23	33	31	37	36	24
Wind	220	271	274	389	454	578	701	744	561
Geothermal	49	52	49	52	52	52	20	20	20
Contracts	7	7	7	6	6	3	0	0	7
Sales and Ancillary Services	(194)	(196)	(198)	(203)	(205)	(202)	(203)	(205)	(208)
East Existing Resources	**3,942**	**3,857**	**3,861**	**4,034**	**3,949**	**3,367**	**3,436**	**3,490**	**3,116**
Front Office Transactions	0	0	0	0	0	0	0	0	126
NonEmitting Peaker	360	382	387	385	386	577	579	581	569
Wind	300	424	460	535	581	676	790	852	792
Solar	11	13	16	39	59	100	112	114	84
Storage	1,549	1,449	1,445	1,447	1,509	1,634	1,596	1,523	1,478
Nuclear	278	312	314	310	305	342	945	955	906
East Planned Resources	**2,498**	**2,581**	**2,622**	**2,715**	**2,841**	**3,328**	**4,022**	**4,024**	**3,955**
East Total Resources	**6,440**	**6,437**	**6,483**	**6,749**	**6,790**	**6,695**	**7,457**	**7,514**	**7,071**
Load	6,459	6,542	6,645	6,724	6,801	6,890	6,992	7,083	7,190
Private Generation	(10)	(12)	(13)	(14)	(16)	(18)	(19)	(21)	(23)
Existing - Demand Response	(166)	(155)	(155)	(155)	(162)	(141)	(137)	(139)	(135)
New Demand Response	(113)	(107)	(109)	(116)	(123)	(117)	(115)	(118)	(116)
New Energy Efficiency	(905)	(920)	(1,185)	(1,051)	(1,057)	(343)	(1,143)	(443)	(1,458)
East Total obligation	**5,265**	**5,348**	**5,183**	**5,387**	**5,443**	**6,272**	**5,576**	**6,363**	**5,459**
East Reserve Margin	22%	20%	25%	25%	25%	7%	34%	18%	30%

West									
Coal	1,285	1,323	1,361	1,362	1,360	1,360	0	0	27
Gas	680	710	718	718	683	490	489	490	495
Hydroelectric	828	865	874	875	874	877	878	880	879
Solar	0	0	0	0	0	1	1	1	0
Wind	31	41	46	52	60	79	83	82	68
Geothermal	0	0	0	0	0	0	0	0	0
Contracts	14	13	13	14	13	13	12	11	14
Sales and Ancillary Services	(144)	(141)	(144)	(145)	(146)	(143)	(142)	(142)	(148)
West Existing Resources	**2,695**	**2,812**	**2,867**	**2,877**	**2,846**	**2,675**	**1,322**	**1,321**	**1,336**
Front Office Transactions	0	0	0	0	0	0	0	0	293
NonEmitting Peaker	0	0	0	0	7	212	577	579	540
Wind	84	111	112	131	127	189	290	294	242
Solar	4	5	5	13	18	24	30	37	22
Storage	823	770	768	769	803	698	872	881	1,294
Nuclear	0	0	0	0	0	0	0	0	0
West Planned Resources	**911**	**886**	**886**	**913**	**954**	**1,123**	**1,769**	**1,791**	**2,392**
West Total Resources	**3,606**	**3,699**	**3,753**	**3,790**	**3,801**	**3,798**	**3,091**	**3,112**	**3,727**
Load	3,756	3,805	3,854	3,902	3,946	3,994	4,048	4,102	4,156
Private Generation	(4)	(5)	(6)	(7)	(8)	(9)	(11)	(12)	(13)
Existing - Demand Response	0	0	0	0	0	0	0	0	0
New Demand Response	(88)	(84)	(85)	(87)	(92)	(81)	(80)	(81)	(80)
New Energy Efficiency	(80)	(134)	73	89	40	(934)	(237)	(1,013)	(3)
West Total obligation	**3,584**	**3,582**	**3,836**	**3,898**	**3,886**	**2,970**	**3,721**	**2,995**	**4,059**
West Reserve Margin	1%	3%	-2%	-3%	-2%	28%	-17%	4%	-8%

System									
Total Resources	10,047	10,136	10,236	10,539	10,591	10,493	10,548	10,625	10,798
Obligation	8,848	8,930	9,018	9,285	9,329	9,243	9,297	9,358	9,518
Capacity Reserve Margin (13%)	1,150	1,161	1,172	1,207	1,213	1,202	1,209	1,217	1,237
Obligation + Reserves	9,999	10,091	10,191	10,492	10,542	10,444	10,505	10,574	10,755
System Position	48	45	45	47	49	49	43	51	43
Reserve Margin	**14%**	**14%**	**14%**	**14%**	**14%**	**14%**	**13%**	**14%**	**13%**

Carbon Dioxide Emissions

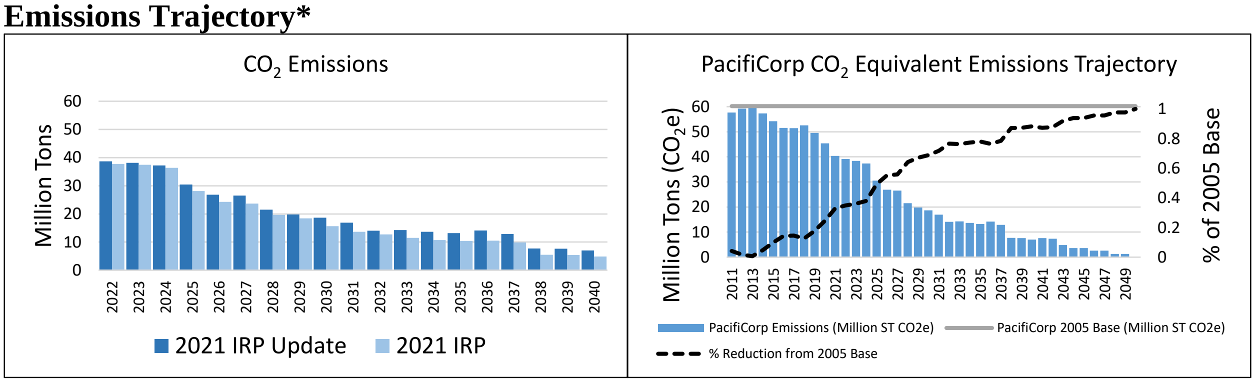
While the 2021 IRP Update preferred portfolio reflects PacifiCorp's on-going efforts to provide cost-effective clean-energy solutions for our customers, increased load has driven thermal dispatch and therefore emissions higher based on currently modeled resource options and assumptions. Portfolio emissions and costs due to the higher load forecast present a less extreme version of the S01 High Load sensitivity from the 2021 IRP.

PacifiCorp's emissions have been declining and are expected to continue to decline related to several factors including PacifiCorp's participation in the EIM, which reduces customer costs and maximizes use of clean energy; PacifiCorp's on-going transition to clean-energy resources including new renewable resources, new advanced nuclear resources, new non-emitting resources, storage, and associated transmission; and Regional Haze compliance. Input updates and additional transmission and resource options in the 2023 IRP are expected to allow economic emissions reductions not available to the 2021 IRP Update and in the absence of a full IRP cycle.

The chart on the left in Figure 6.11 compares projected annual CO_2 emissions between the 2021 IRP update and 2021 IRP preferred portfolios. In this graph, emissions are not assigned to market purchases or sales.

The chart on the right in Figure 6.11 includes historical data, assigns emissions at a rate of 0.4708 tons CO_2 equivalent per MWh to market purchases (with no credit to market sales), includes emissions associated with specified purchases, and extrapolates projections out through 2050. This graph demonstrates that relative to a 2005 baseline, 2021 IRP Update preferred portfolio system CO_2 equivalent emissions are down 49 percent in 2025, 69 percent in 2030, 78 percent in 2035, 88 percent in 2040, 94 percent in 2045, and 100 percent in 2050.

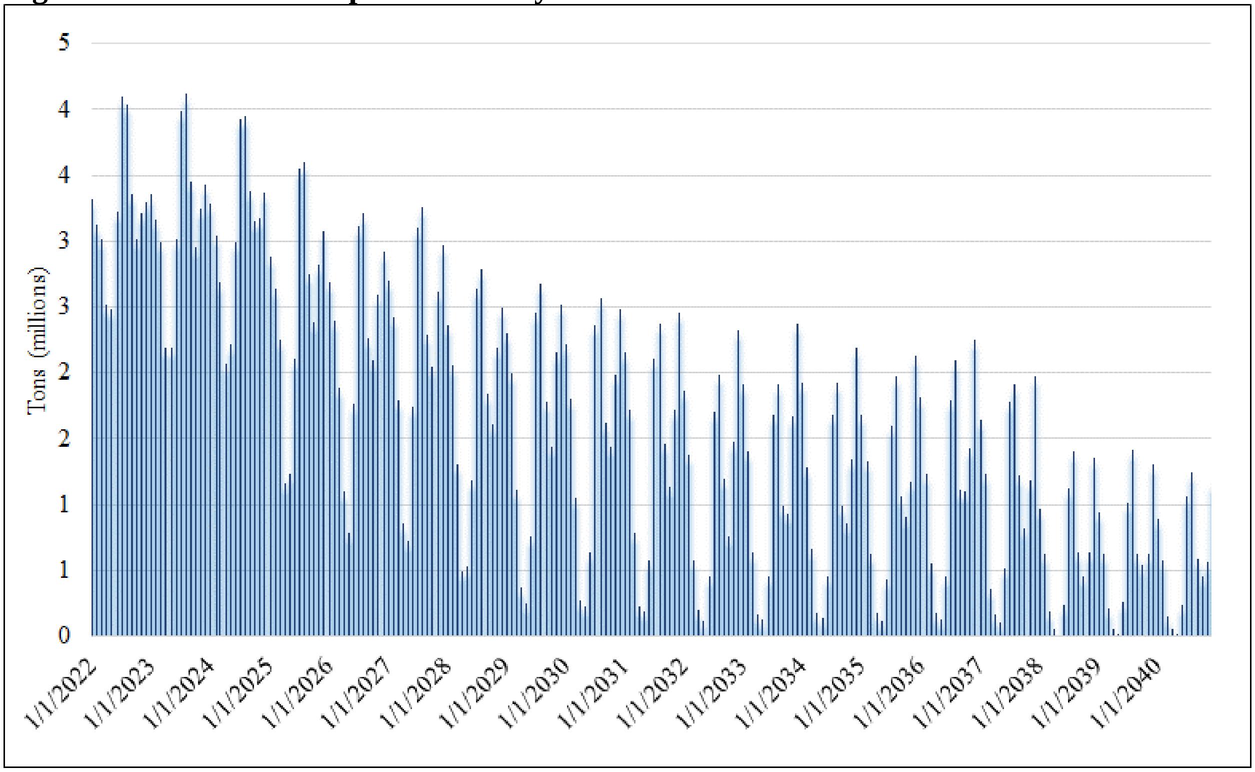
Figure 6.11 – 2021 IRP Preferred Portfolio CO_2 Emissions and PacifiCorp CO_2 Equivalent Emissions Trajectory*



*Note: PacifiCorp CO_2 equivalent emissions trajectory reflects actual emissions through 2020 from owned facilities, specified sources and unspecified sources. From 2021 through the end of the twenty-year planning period in 2040, emissions reflect those from the 2021 IRP Update preferred portfolio with emissions from specified sources reported in CO_2 equivalent. Market purchases are assigned a default emission factor (0.4708 short tons CO_2e/MWh) – emissions from sales are not removed. Beyond 2040, emissions reflect the rolling average emissions of each resource from the 2021 IRP update preferred portfolio through the life of the resource. The emissions trajectory does not incorporate clean energy targets set forth in Oregon House Bill 2021 or any other state-specific emissions trajectories. PacifiCorp expects these targets, and an Oregon-specific emissions trajectory, to be incorporated following the 2023 integrated resource plan when PacifiCorp is required under the bill to file a Clean Energy Plan.

Monthly CO_2 emissions are available for the preferred portfolio as shown in Figure 6.12 below.

Figure 6.12 – 2021 IRP Update Monthly CO_2



Renewable Portfolio Standards

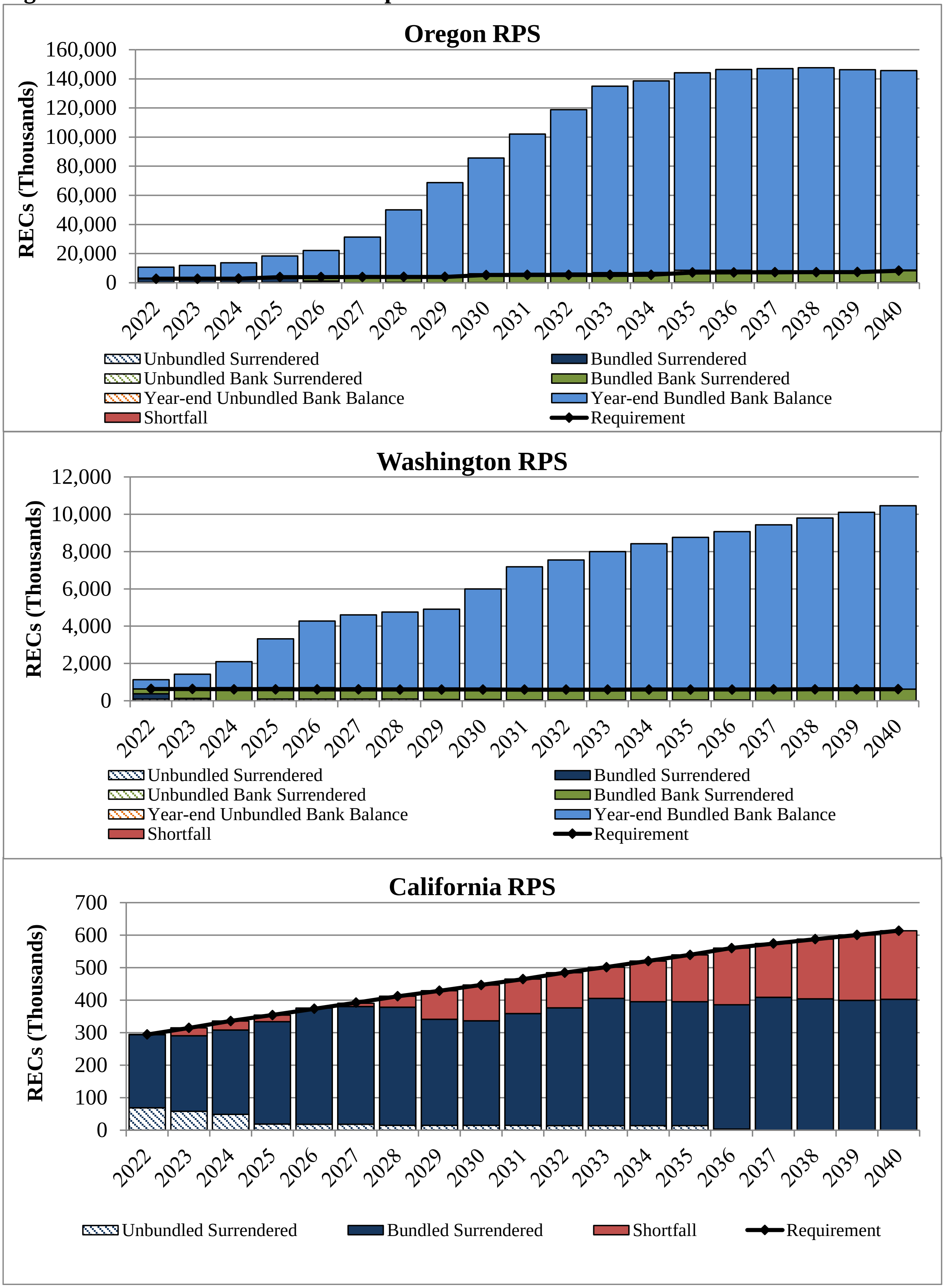
Figure 6.13 shows PacifiCorp's renewable portfolio standard (RPS) compliance forecast for California, Oregon, and Washington after accounting for new renewable resources in the preferred portfolio. While these resources are included in the preferred portfolio as cost-effective system resources and are not included to specifically meet RPS targets, they nonetheless contribute to meeting RPS targets in PacifiCorp's western states.

Oregon RPS compliance is achieved through 2040 with the addition of new renewable resources and transmission in the 2021 IRP Update preferred portfolio. Consistent with the 2021 IRP, in the 2021 IRP Update, Washington RPS compliance is achieved with the benefit of increased system renewable resources as well as additional resources procured that meet the state's Clean Energy Transformation Act. Under PacifiCorp's 2020 Protocol, and the Washington Interjurisdictional Allocation Methodology, Washington's RPS position is improved by receiving a system share of renewable resources across the PacifiCorp's system.

The California RPS compliance position will be met with owned and contracted renewable resources, as well as REC purchases throughout the study period. The ramping RPS requirement results in an increased need for unbundled REC purchases to meet the annual and compliance period targets in 2021-2040. New renewable resources and transmission in the 2021 IRP update preferred portfolio mitigate that shortfall, but the company has made a 120,000 REC purchase towards compliance period 4, years 2021-2024, and will continue to evaluate the need for unbundled RECs and issue RFPs to meet its state RPS compliance requirements as needed.

While not shown in Figure 6.13, PacifiCorp meets the Utah 2025 state target to supply 20 percent of adjusted retail sales with eligible renewable resources with existing owned and contracted resources and new renewable resources and transmission in the 2021 IRP Update preferred portfolio.

Figure 6.13 – Annual State RPS Compliance Forecast



Washington Clean Energy Transformation Act

Washington's Clean Energy Transformation Act (CETA) legislation establishes specific targets for utilities serving customers in Washington including:

- By 2025, utilities remove coal-fueled generation from Washington's allocation of electricity;[1]
- By 2030, Washington retail sales are carbon-neutral;
- By 2045, Washington's retail sales are 100 percent renewable and non-carbon-emitting.

In the 2021 IRP, resources required to achieve compliance and meet targets in 2030 and 2045 were identified. These resource additions are not re-evaluated in the 2021 IRP Update, which is not a Clean Energy Implementation Plan Update (CEIP) and is not a Washington requirement. Instead, the same CETA resource considerations made in the 2021 IRP are included in the 2021 IRP Update, with adjustments made only to the extent necessary to align with changes in the updated portfolio. The two changes layered into the 2021 IRP Update portfolio are 1) the inclusion of incremental demand-side management resources specific to Washington identified from the P02-SCGHG portfolio in the 2021 IRP, and 2) in 2029, the creation of a hybrid Washington-situs assigned 160 MW Yakima resource that includes wind collocated with the solar and storage resource. This Washington-situs assigned resource maximizes usage of transmission interconnection availability at this location, and as a result is added in 2029 rather than 2030, to align with the one-year acceleration of Yakima transmission included as part of the least-cost least-risk selection of transmission upgrades.

As previously noted, in the 2021 IRP Update preferred portfolio, increased system load drives the acceleration of 300 MW of new transmission interconnection into the front 10 years, as well as increased energy efficiency and other portfolio shifts when compared to the 2021 IRP preferred portfolio. The added renewables and system dispatch in the ST model, partly offset by the loss of two 2020AS RFP resources, contributes to reducing the cost of the previously identified CETA portfolio additions relative to the updated base portfolio. Although higher load increases PVRR across all cases, relative to the base case, CETA portfolio costs are reduced from $164 million to $122 million on a risk adjusted PVRR(d) basis. Bearing in mind that PVRR(d) is not the measure of CETA incremental costs, the CETA portfolio in the 2021 RP Update is $42 million less costly than in the 2021 IRP on a risk-adjusted PVRR(d) basis.

Table 6.7 summarizes the PVRR(d) of the 2021 IRP Update preferred portfolio, including CETA resource, relative to the Base portfolio under a range of different price-policy scenarios.

[1] RCW 19.405.030(1)(a)

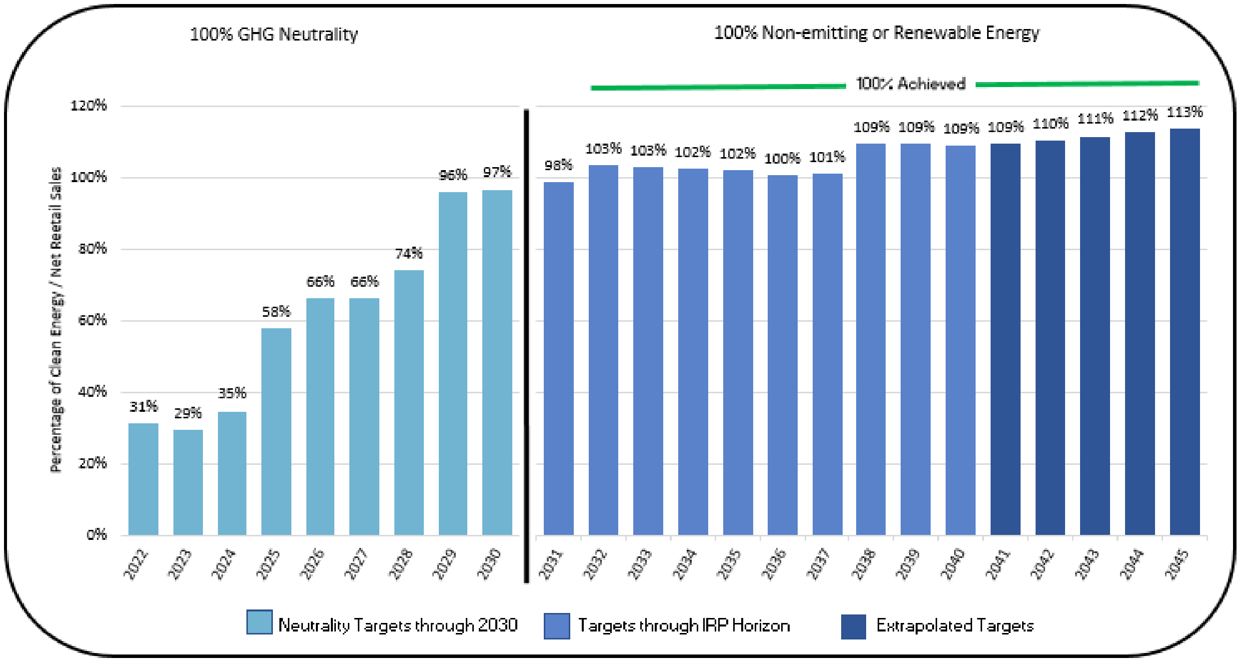
Table 6.7 – PVRR(d) of the 2021 IRP Update Portfolio Relative to the Base Portfolio Under Varying Price-Policy Scenarios

	ST PVRR ($million)	ST PVRR plus 5% of 95th Stochastic ($million)	Energy Not Served as a Percentage of Load (%)	CO2 emissions (Mtons)
Base MM	$26,740	$27,167	0.0056%	420
Base LN	$23,367	$23,732	0.0059%	460
Base HH	$29,946	$30,311	0.0056%	386
2021 IRP Update CETA MM	$26,866	$27,289	0.0056%	419
2021 IRP Update CETA LN	$23,533	$23,899	0.0059%	460
2021 IRP Update CETA HH	$30,045	$30,410	0.0056%	385
Change from P02-MM-MM	$126	$122	0.0000%	(1)
Change from P02-MM-LN	$167	$167	0.0000%	(0)
Change from P02-MM-HH	$99	$99	0.0000%	(1)

While a full assessment of incremental costs as calculated in the Washington Clean Energy Implementation Plan is not contemplated here, this comparison is informative as PacifiCorp's CETA Progress Report is developed to be filed January 1, 2023, ahead of the March 31, 2023, filing of the 2023 IRP.

Figure 6.14 reports updated CETA interim targets assuming the same compliance resources assumed in both the 2021 IRP and the CEIP, prior to alternative compliance via unbundled REC purchases. In the 2021 IRP Update, PacifiCorp achieves 100 percent compliance with the 2030 and 2045 CETA standard with lower reliance on alternative compliance through the purchase of unbundled RECs. While CO_2 emissions are higher by roughly 3 percent over the planning period, Washington has no coal generation in its energy portfolio from 2025 forward, and therefore the projection to meeting CETA requirements is largely unaffected.

Figure 6.14 - 2021 IRP Update Interim Targets



Oregon Clean Energy Plan

The 2021 IRP Update preferred portfolio of resources, similar to the 2021 IRP preferred portfolio, anticipates the high-level environmental objectives of Oregon's Clean Energy Plan (CEP), which was passed by the Oregon legislature in 2021 in House Bill 2021, through the procurement of renewable and non-emitting resources. CEP provisions are not modeled in the 2021 IRP Update; however, PacifiCorp is actively engaged with the Public Utility Commission of Oregon's rulemaking efforts in this regard and is in the process of developing its public engagement and planning. The CEP will be further considered and discussed in the 2023 IRP development cycle.

Additional information regarding the CEP is included in Chapter 3 – Planning Environment.

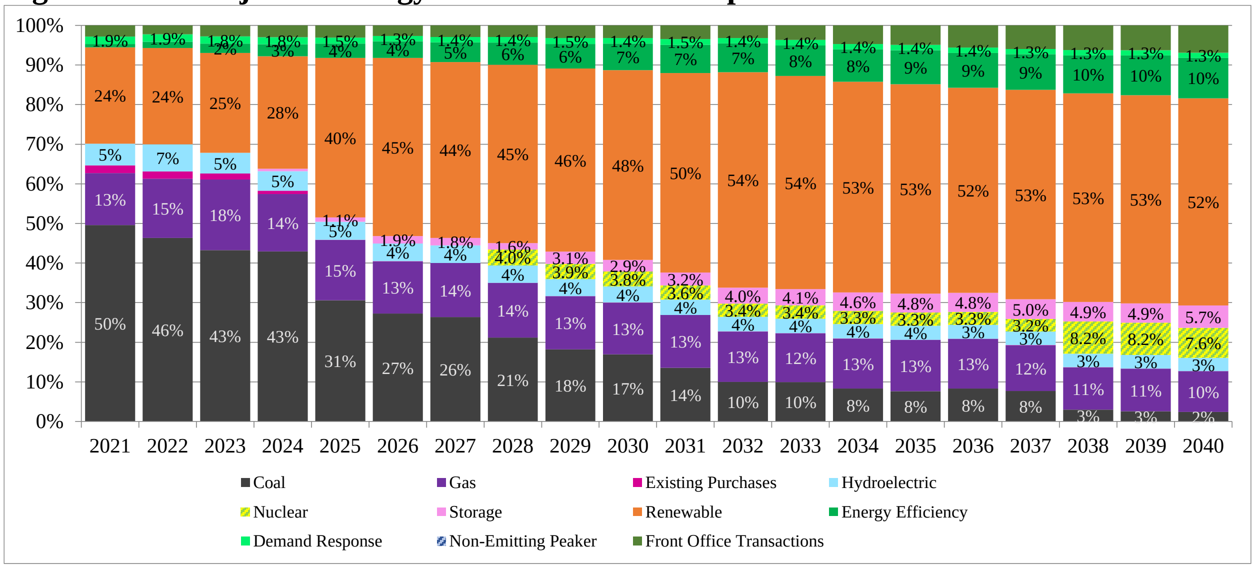
Projected Energy Mix

Figure 6.15 how PacifiCorp's system energy mix is projected to change over time. In developing these figures, purchased power is reported in identifiable resource categories where possible. Energy mix figures are based upon preferred portfolio outcomes in the long-term (LT) model. Renewable capacity and generation reflect categorization by technology type and not disposition of renewable energy attributes for regulatory compliance requirements.[2] On an energy basis, coal

[2]The projected PacifiCorp 2021 IRP preferred portfolio "energy mix" is based on energy production and not resource capability, capacity or delivered energy. All or some of the renewable energy attributes associated with wind, biomass, geothermal and qualifying hydro facilities in PacifiCorp's energy mix may be: (a) used in future

generation drops to 25 percent by 2028, falls to 10 percent by 2032, and declines to only 2 percent by the end of the planning period. Reduced energy from coal is offset primarily by increased energy from renewable and storage resources, nuclear resources, DSM resources, and to a smaller extent later in the plan, non-emitting peaker resources.

Figure 6.15 – Projected Energy Mix with 2021 IRP Update Preferred Portfolio Resources



Additional Studies

In addition to the 2021 IRP Update preferred portfolio, PacifiCorp developed key variants of the updated preferred portfolio, focusing on three variant studies from the 2021 IRP which address large transmission projects and significant volumes of associated resources. The economics of these studies further supports their value in the 2021 IRP Update preferred portfolio as the least-cost, least-risk portfolio. In addition, PacifiCorp examined one regional haze sensitivity.

The variant portfolios are summarized in the Table 6.8. Each variant portfolio is aligned with a P02-MM variant portfolio from the 2021 IRP, updated here to assess the impacts of assumption updates since the filing of the 2021 IRP.

years to comply with renewable portfolio standards or other regulatory requirements; (b) sold to third parties in the form of renewable energy credits or other environmental commodities; or (c) excluded from energy purchased. PacifiCorp's 2021 IRP preferred portfolio energy mix includes owned resources and purchases from third parties.

Table 6.8 – Base Case Variant Portfolios[1, 2]

Case	Description
No B2H	Excludes Boardman-to-Hemingway transmission segment
No GWS	Excludes the Energy Gateway South transmission segment
No RFP	Excludes 2020 All-Source Request for Proposals Final Shortlist and the Energy Gateway South transmission segment

1 – The Base case in the 2021 IRP Update is equivalent the P02-MM case from the 2021 IRP in that it is the least-cost least-risk portfolio for the entire system prior to small additions made for Washington CETA compliance.
2- In the 2021 IRP, the No B2H case equivalent was referred to as P02b – No B2H; the No GWS case equivalent was referred to as P02c – No GWS; the No RFP case equivalent was referred to as P02c – No RFP

Table 6.9 provides a cost and risk summary of the variant portfolios compared to the Base case, which is the least-cost least-risk portfolio before the addition of CETA-compliant Washington demand response and the Yakima 160 MW hybrid renewable resource.

Table 6.9 – Cost and Risk Summary of Variant Portfolios

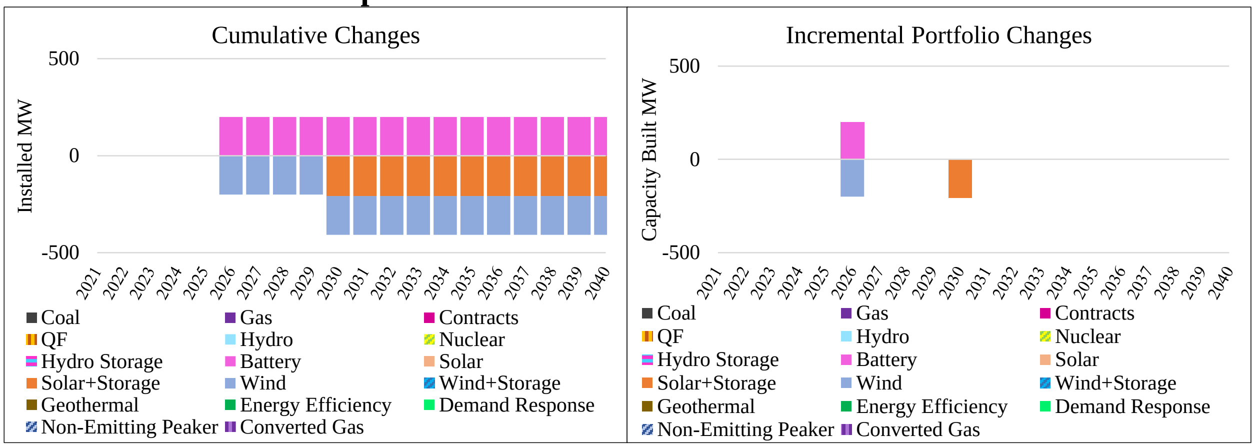
	2021 to 2040							
Vintage	Study Name	ST PVRR ($million)	ST PVRR plus 5% of 95th Stochastic ($million)	Risk Adjusted PVRR(d) ($million)	CO2 emissions (Mtons)	CO2 emissions cost ($million)	Avg Annual Energy Not Served plus Reserve Deficiency (GWh)	Energy Not Served as a Percentage of Load (%)
21 IRP Update	Base	26,740	27,167	-	420	$2,594	3.9	0.005647%
21 IRP Update	No B2H	27,154	27,607	439	423	$2,625	3.9	0.005648%
21 IRP Update	No GWS	27,010	27,562	395	451	$3,000	4.3	0.006117%
21 IRP Update	No RFP	28,415	29,084	1,916	499	$3,404	35.6	0.051194%

Boardman-to-Hemingway Variant (No B2H)

The B2H transmission line provides more flexibility and increased load-serving capability on the 500-kV transmission system into the central Oregon load pocket. In the case where the Boardman to Hemingway (B2H) transmission line and associated renewable resources is excluded from consideration, the portfolio responds by replacing 200 MW of wind in the Willamette Valley area with 200 MW of standalone storage in 2026. The 2026 removal of wind in favor of storage is accompanied by a 41 aMW increase in front office transactions. In 2030, 207 MW of Solar plus Storage is removed relative to the Base portfolio, offset by an additional 87 aMW increase in front office transactions.

Figure 6.16 shows the cumulative (at left) and incremental (at right) portfolio changes when the B2H transmission line is eliminated from the Base portfolio. A positive value indicates an increase in resources and a negative value indicates a decrease in resources when the transmission line is eliminated.

Figure 6.16 – Increase/(Decrease) in Proxy Resources when the B2H Transmission Line is Eliminated from the Base portfolio



Through 2040, the risk-adjusted PVRR(d) of the portfolio without the B2H transmission line is \$439 million higher cost than the Base portfolio. This substantial outcome is comparable to the \$453 million higher cost PVRR(d) seen in the 2021 IRP. Relative to the Base case, the No B2H case is also slightly less reliable as measured by the energy not served as a percentage of load and reports 2.7 million tons of higher CO_2 emissions. This analysis assumes that 725 MW of incremental 4-hour battery resources and other transmission upgrades would also be needed in southern Oregon if the B2H transmission line is not built. Transmission cost savings reflect the fact that these investments would be avoided if B2H is built.

Figure 6.17 - Increase/(Decrease) in System Costs when the B2H Transmission Line is Eliminated from the Base Portfolio

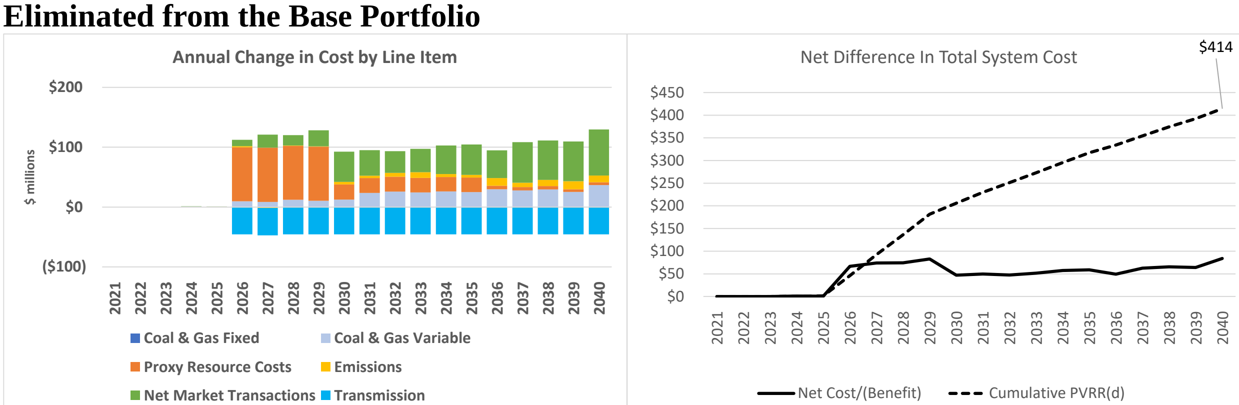


Table 6.10 summarizes the PVRR(d) of the No B2H portfolio relative to the Base portfolio under a range of different price-policy scenarios. Eliminating the B2H transmission line increases the ST PVRR and the risk-adjusted PVRR for all price-policy scenarios, Removal of B2H also results in higher emissions. Note, that both portfolios, as measured by ENS results, are very reliable among all price-policy scenarios. While the cost increase from B2H in the LN price-policy scenario is low relative to other price-policy scenarios, it is more likely than not that there will be some form of policy that will impute a cost on greenhouse gas emissions. It is also unlikely that gas prices will

remain low for decades to come. In aggregate, these results support the inclusion of the B2H transmission line in the 2021 IRP Update preferred portfolio.

Table 6.10 – PVRR(d) of the No B2H Portfolio Relative to the Base Portfolio Under Varying Price-Policy Scenarios

	PVRR ($m)	ST PVRR + 5% of 95th Stochastic ($m)	ENS Average % of Load	CO2 Emissions 2021-2040 (Million Tons)
Base MM	$26,740	$27,167	0.0056%	420
Base LN	$23,367	$23,732	0.0059%	460
Base HH	$29,946	$30,311	0.0056%	386
No B2H MM	$27,154	$27,607	0.0056%	423
No B2H LN	$23,514	$23,797	0.0059%	462
No B2H HH	$30,394	$31,007	0.0056%	392
Change from Base MM	$414	$439	0.0000%	3
Change from Base LN	$148	$65	0.0000%	2
Change from Base HH	$448	$696	0.0000%	6

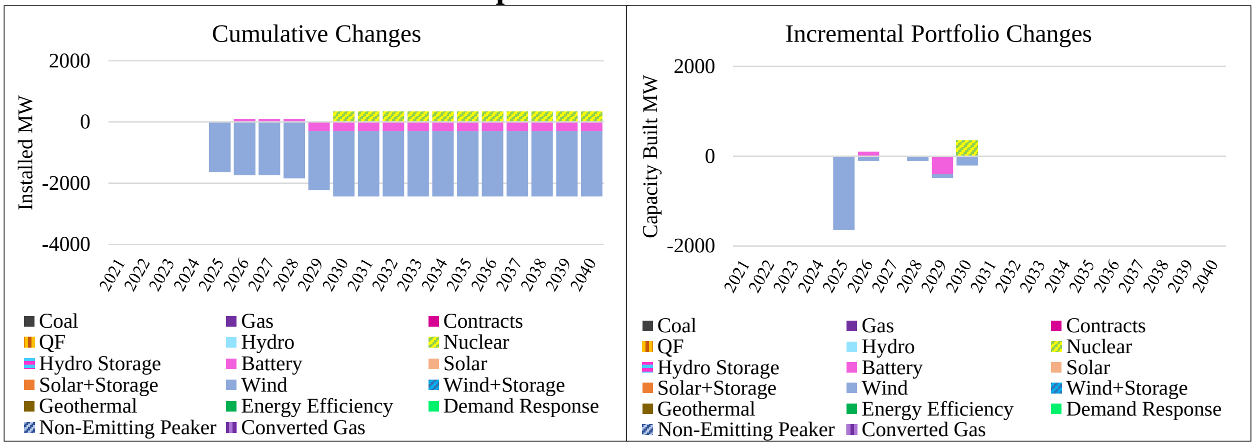
Energy Gateway South and Sub-Segment D.1 Variant (No GWS)

The No GWS portfolio is a variant of the Base portfolio that eliminates the Energy Gateway South and D.1 transmission lines. Because wind bids selected to the 2020AS RFP final shortlist that are located in eastern Wyoming cannot interconnect without these two transmission lines,[3] these resources are also eliminated from the No GWS portfolio. When GWS and D.1 transmission upgrades are excluded from consideration in the modeling, resource shifts are more significant than in the Boardman to Hemingway exclusion, as Energy Gateway South supports 1,641 MW of renewable resources which are no longer eligible to come online in 2025. An additional 289 MW of Wyoming East wind relying on GWS interconnection will no longer be built in years 2029 and 2030. To meet reliability, the model replaces 100 MW of Willamette Valley wind with 100 MW of standalone battery in 2026. Additionally, 500 MW of wind and standalone battery is removed from the Dave Johnson brownfield site to allow for the inclusion of a 500 MW advanced nuclear project in 2030.

Figure 6.18 shows the cumulative (at left) and incremental (at right) portfolio changes when the GWS and D.1 transmission line are eliminated from the Base portfolio. A positive value indicates an increase in resources and a negative value indicates a decrease in resources when the transmission lines are eliminated.

[3] Examination of this variant focuses on the estimated impacts to resource procurement, market purchases, and system costs, but ignores the elimination of GWS and D.1 transmission lines would interfere with PacifiCorp transmission's ability to provide nearly 2,500 MW of requests for transmission and interconnection service governed by multiple FERC-jurisdictional executed contracts.

Figure 6.18 – Increase/(Decrease) in Proxy Resources when the GWS and D.1 Transmission Lines are Eliminated from the Base portfolio



The removal of GWS and associated RFP wind resources results in a cost increase to the system of $395 million on a risk-adjusted PVRR(d) basis. This is $135 million more in relative costs than measured in the 2021 IRP variant P02c. The relative increase in the value of GWS compared to the 2021 IRP is primarily driven by higher load, increasing the value of the renewables enabled by GWS transmission. Cost increases without GWS stem from higher thermal generation and emission costs, and market purchases, which are more expensive than transmission plus low cost renewables. Market purchases increase by 134 aMW. Without GWS and D.1, emissions from PacifiCorp's fossil-fueled resources increase by 7 percent, and energy not served increase by more than 8 percent. These factors further substantiate the benefits of GWS and D.1, which lower portfolio emissions and provide system reliability.

Figure 6.19 – Increase/(Decrease) in System Costs when the GWS and D.1 Transmission Lines are Eliminated from the Base Portfolio

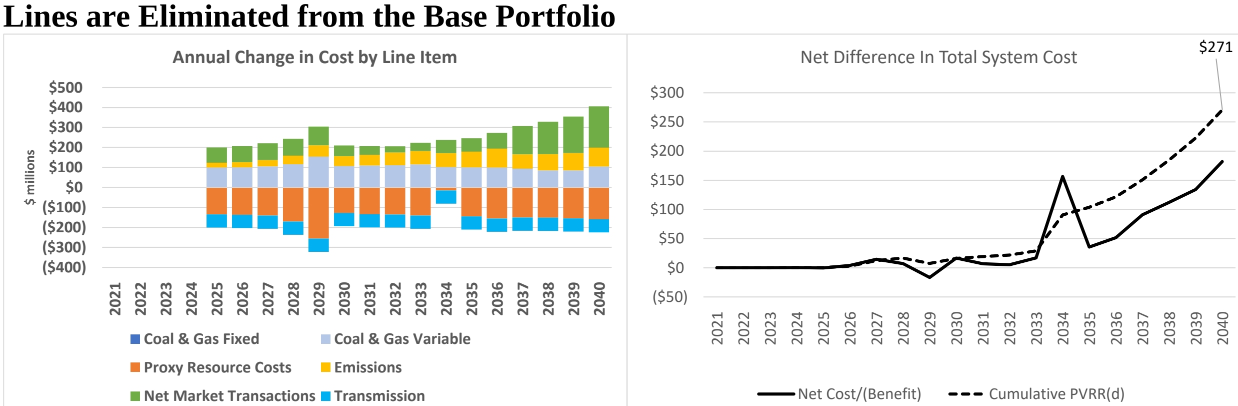


Table 6.11 summarizes the PVRR(d) of the No GWS portfolio relative to the Base portfolio under a range of different price-policy scenarios. System costs increase when GWS and D.1 are removed from the portfolio in MM, and HH price-policy scenarios. Conversely, costs decrease in the LN price-policy scenario. Without GWS and D.1, emissions from PacifiCorp's fossil-fueled resources increase considerably—ranging from 6.9% in the MM price-policy scenario to 9.7% in the HH price-policy scenario. As discussed earlier, it is more likely than not that there will be some form of policy action taken to impute a cost or penalty on greenhouse gas emissions. It is also unlikely gas prices will be suppressed for many decades to come, as assumed in the LN price-policy

scenario. Further, cost-and-risk results indicate that there is a tremendous opportunity cost of not building these transmission lines should policies develop that impose costs on greenhouse gas emissions. This is seen with the disproportionate increase in costs under MM and HH price-policy scenarios relative to the size of cost reductions in the unlikely LN price-policy scenario. Considering the removal of GWS and D.1 increases system costs in the MM and HH price-policy scenarios, increases emissions and associated costs and risks, and significantly increases market-reliance risk, this analysis supports including GWS, D.1, and the associated 2020AS RFP wind resources in the 2021 IRP Update preferred portfolio.

Table 6.11 – PVRR(d) of the No GWS Portfolio Relative to the Base Portfolio Under Varying Price-Policy Scenarios

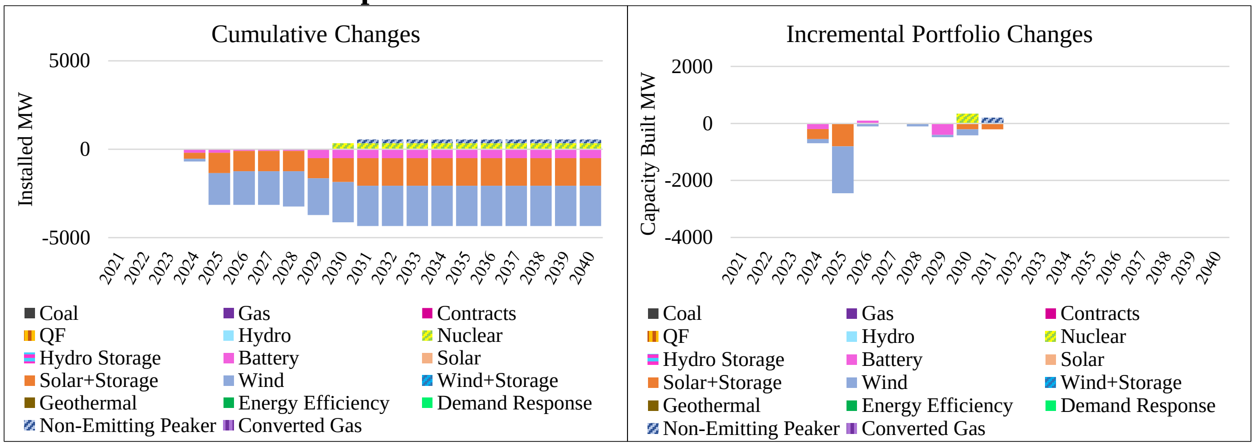
	ST PVRR ($million)	ST PVRR plus 5% of 95th Stochastic ($million)	Energy Not Served as a Percentage of Load (%)	CO2 emissions (Mtons)
Base MM	$26,740	$27,167	0.0056%	420
Base LN	$23,367	$23,732	0.0059%	460
Base HH	$29,946	$30,311	0.0056%	386
No GWS MM	$27,010	$27,562	0.0061%	451
No GWS LN	$22,814	$23,162	0.0063%	498
No GWS HH	$30,945	$31,687	0.0060%	427
Change from Base MM	$271	$395	0.0005%	31
Change from Base LN	($553)	($570)	0.0003%	38
Change from Base HH	$999	$1,375	0.0004%	41

2020AS RFP Variant (No RFP)

The No RFP portfolio is a variant of the Base portfolio that eliminates all 2020AS RFP resources, including the GWS and D.1 transmission lines. Compared to either the No B2H or No GWS variants, resource changes are more drastic with the removal of all RFP-related transmission and resources, where more than 3,400 MW of RFP renewable resources are excluded. As a result, 100 MW of Willamette Valley wind is replaced by 100 MW of standalone battery in 2026. At Dave Johnson, 500 MW of advanced Nuclear in 2030 replaces 100 MW of wind and 400 MW of standalone battery. In Utah, 207 MW of Solar plus Storage is replaced with 207 MW of non-emitting peaker.

Figure 6.20 shows the cumulative (at left) and incremental (at right) portfolio changes when the 2020AS RFP resources are eliminated from the Base portfolio. A positive value indicates an increase in resources and a negative value indicates a decrease in resources when the 2020AS RFP resources and the GWS and D.1 transmission lines are eliminated.

Figure 6.20 – Increase/(Decrease) in Proxy Resources when 2020AS RFP Resources are Eliminated from the Base portfolio



The removal of all RFP renewables increases costs to the system by $1.9 billion on a risk-adjusted PVRR(d) basis. This is $651 million more in relative costs than measured in the 2021 IRP variant P02d. The relative increase in the value of the RFP resources including GWS and D.1 is primarily driven by higher load, which increases the value of the additional renewables. This cost increase is primarily comprised of higher thermal generation and emission costs and heavy market reliance. Market purchases increase by 282 aMW. Without RFP bids and the GWS and D.1 projects, emissions from PacifiCorp's fossil-fueled resources increase by nearly 19 percent, and energy not served increases by more than eight-fold.

Figure 6.21 – Increase/(Decrease) in System Costs when RFP Projects and GWS and D.1 Transmission Lines are Eliminated from the Base Portfolio

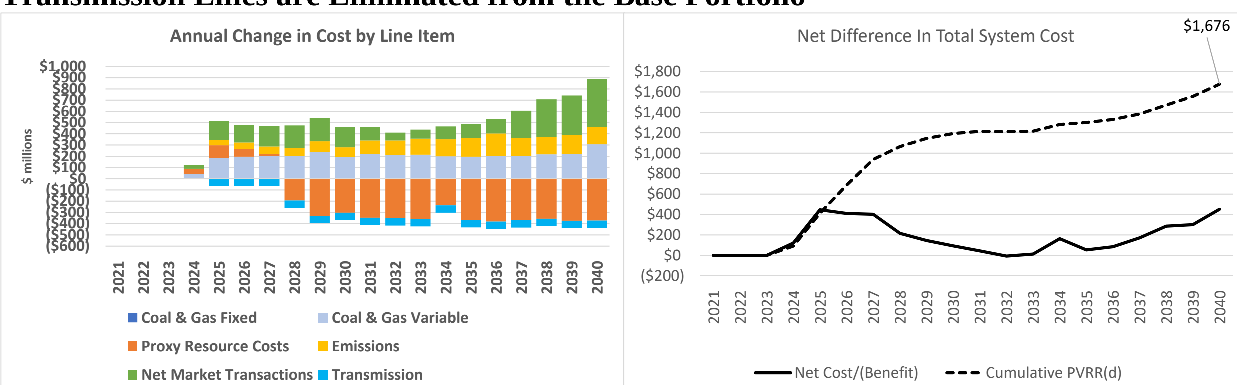


Table 6.12 summarizes the PVRR(d) of the No RFP portfolio relative to the Base portfolio under a range of different price-policy scenarios. System costs increase significantly when 2020AS RFP resources are removed from the portfolio in all three price-policy scenarios. Without the RFP resources, emissions from PacifiCorp's fossil-fueled resources increase considerably—ranging from 15.8% in the MM price-policy scenario to 17.4% in the HH price-policy scenario. As discussed earlier, it is more likely than not that there will be policy actions taken to impute a cost or penalty on greenhouse gas emissions. It is also unlikely that gas prices will be suppressed for many decades to come, as assumed in the LN price-policy scenario. Further, cost-and-risk results indicate that there is a tremendous opportunity cost of not pursuing the RFP resources along with the associated investments in the GWS and D.1 transmission lines should policies develop that

impose costs on greenhouse gas emissions. This is seen with the disproportionate increase in costs under MM and HH price-policy scenarios relative to the size of cost increase in the unlikely LN price-policy scenario. Further, each of cases that remove 2020AS RFP resources show a more notable decline in reliability, as measured by the ENS metric. Considering the removal of 2020AS RFP bids and the associated investment in the GWS and D.1 transmission lines increases system costs among all price-policy scenarios, significantly increases emissions and associated costs, and significantly increases market-reliance risk, this analysis supports including 2020AS RFP resources in the 2021 IRP Update preferred portfolio.

Table 6.12 – PVRR(d) of the No RFP Portfolio Relative to the Base Portfolio Under Varying Price-Policy Scenarios

	ST PVRR ($million)	ST PVRR plus 5% of 95th Stochastic ($million)	Energy Not Served as a Percentage of Load (%)	CO2 emissions (Mtons)
Base MM	$26,740	$27,167	0.0056%	420
Base LN	$23,367	$23,732	0.0059%	460
Base HH	$29,946	$30,311	0.0056%	386
No RFP MM	$28,415	$29,084	0.0512%	499
No RFP LN	$23,530	$23,958	0.0589%	535
No RFP HH	$33,056	$33,946	0.0542%	467
Change from Base MM	$1,676	$1,916	0.0455%	79
Change from Base LN	$164	$226	0.0529%	75
Change from Base HH	$3,110	$3,634	0.0486%	81

Regional Haze Hunter-Huntington Sensitivity

Table 6.13 reports the cost and risk outcome of the regional haze sensitivity. Additional discussion of Regional Haze under the EPA's rule finalized in 1999 is presented in Chapter 3 – The Planning Environment. The study is designed to look at reducing nitrogen oxide starting in 2022 under the State of Utah's proposed state implementation plan for the second planning period for the Hunter and Huntington coal plants. Decreasing nitrogen oxide emission limits are implemented using a "reasonable progress emission limits" (RPEL) approach that will require changes to how these coal plants operate but avoids installation of costly emission control equipment.

Table 6.13 – Cost and Risk Summary of Regional Haze Hunter-Huntington Sensitivity

	2021 to 2040							
Vintage	Study Name	ST PVRR ($million)	ST PVRR plus 5% of 95th Stochastic ($million)	Risk Adjusted PVRR(d) ($million)	CO2 emissions (Mtons)	CO2 emissions cost ($million)	Avg Annual Energy Not Served plus Reserve Deficiency (GWh)	Energy Not Served as a Percentage of Load (%)
21 IRP Update	Base	26,740	27,167	-	420	$2,594	3.9	0.005647%
21 IRP Update	Regional Haze Hunter-Huntington	26,756	27,184	16	418	$2,597	3.9	0.005663%

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CHAPTER 7 – ACTION PLAN STATUS UPDATE

This chapter provides an update to the action items listed in the Action Plan of PacifiCorp's 2021 IRP. The status for all action items is provided in Table 7.1 below.

Table 7.1 – 2021 IRP Action Plan Status Update

Action Item	1. Existing Resource Actions	Status
1a	**Colstrip Units 3 and 4:** • PacifiCorp will continue to work closely with co-owners to seek the most cost-effective path forward toward the 2021 IRP preferred portfolio target exit date of December 31, 2025.	• The Company continues to work with co-owners to develop the most cost-effective path toward an exit from the project.
1b	**Craig Unit 1:** • PacifiCorp will continue to work closely with co-owners to seek the most cost-effective path forward toward the 2021 IRP preferred portfolio target exit date of December 31, 2025.	• The Company continues to work with co-owners to develop the most cost-effective path toward an exit from the project.
1b	**Naughton Units 1 and 2:** • PacifiCorp will initiate the process of retiring Naughton Units 1-2 by the end of December 2025, including completion of all required regulatory notices and filings. • By the end of Q2 2023, PacifiCorp will confirm transmission system reliability assessment and year-end 2025 retirement economics in 2023 IRP filing. • By the end of Q4 2023, PacifiCorp will initiate the process with the Wyoming Public Service Commission for approval of a reverse request for	• PacifiCorp is on track to complete required regulatory notices and filings to process the retirements of Naughton units 1 and 2. • PacifiCorp's Integrate Resource Planning group has initiated gathering updated assumptions and stakeholder feedback for the 2023 IRP. • PacifiCorp is on track to initiate the approval process of a reverse request for proposals for a potential sale of Naughton Units 1 and 2.

(1b)	proposals for a potential sale of Naughton Units 1 and 2. • By the end of Q4 2023, PacifiCorp will administer termination, amendment, or close-out of existing permits, contracts, and other agreements.	• PacifiCorp is on track to close-out existing environmental permits and coal agreements for Naughton Units 1 and 2.
1c	**<u>Jim Bridger Units 1 and 2 Gas Conversion:</u>** • PacifiCorp will initiate the process of ending coal-fueled operations and seeking permitting for a natural-gas conversion by 2024, including completion of all required regulatory notices and filings. • By the end of Q2 2022, PacifiCorp will finalize an employee transition plan. • By the end of Q2 2022, PacifiCorp will develop a community action plan in coordination with community leaders. • By the end of Q4 2023, PacifiCorp will administer termination, amendment, or close-out of existing permits, contracts, and other agreements. • By the end of Q4, 2023, PacifiCorp will remove units 1 and 2 from Washington's allocation of electricity.	• PacifiCorp plans to submit a permit application to the Wyoming Department of Environmental Quality in Q2 2022 for the conversion of JB Units 1 &2 to natural gas by 2024 and is on track to complete required regulatory notices and filings. • An Impacted Employee Transition Plan was created and finalized in 2020 and will be updated as needed. • In 2020, PacifiCorp assigned a Certified Economic Developer (CEcD) to work with impacted communities, state and federal agencies and state associations to identify economic diversification funding and resources. In May 2021, the Company provided an update to the WPSC and will provide another in April 2022. • PacifiCorp is on track to remove units 1 and 2 from Washington's allocation of electricity.
1d	**<u>Carbon Capture, Utilization, and Sequestration/Wyoming House Bill 200 Compliance:</u>** • PacifiCorp issued a carbon capture, utilization, and sequestration (CCUS) request for expression of interest (REOI) on June 29, 2021. PacifiCorp will complete the 2021 CCUS REOI process and utilize any new relevant information. Additional model sensitivities will be run accordingly.	• PacifiCorp issued a carbon capture, utilization, and sequestration (CCUS) request for expression of interest (REOI) on June 29, 2021. PacifiCorp completed the 2021 CCUS REOI process and a third party evaluated the responses. • PacifiCorp will issue two CCUS Requests for Proposals (RFP) in 2022. • A completed CCUS Front End Engineering & Design Study (FEED Study) based on a new CCUS technology was submitted to PacifiCorp in July 2021

(1d)	• PacifiCorp will issue a CCUS Request for Proposals (RFP) in 2022. The 2021 CCUS REOI responses will inform the scope of the CCUS RFP. • A completed CCUS Front End Engineering & Design Study (FEED Study) based on a new CCUS technology was submitted to PacifiCorp in July 2021 for Dave Johnston Unit 2. Third-party review of the FEED Study will be completed by Q1 2022, and model sensitivities will subsequently be run as needed, with FEED Study assumptions and inputs as appropriate. • Subject to finalization of rules by the Wyoming Public Service Commission (WPSC) to implement House Bill 200 (HB 200), the Wyoming Low Carbon Energy Standard (anticipated by Q4 2021), by March 31, 2022, PacifiCorp will file with the WPSC an initial CCUS application to establish intermediate CCUS standards and requirements. • Subject to finalization of rules by the WPSC to implement HB 200, the Wyoming Low Carbon Energy Standard (anticipated by Q4 2021), PacifiCorp will submit for WPSC approval a final plan with its proposed energy portfolio standard for dispatchable and reliable low-carbon electricity, its plan for achieving the standard, and a target date of no later than July 1, 2030.	for Dave Johnston Unit 2. Third-party review of the FEED Study was completed in February 2022. Model sensitivities will be run in the 2023 IRP with the FEED Study assumptions and inputs as appropriate. • PacifiCorp filed with the Wyoming Public Service Commission (WPSC), an initial application to establish intermediate CCUS standards and requirements on March 31, 2022, as required under Wyoming House Bill 200. • PacifiCorp will submit a final plan with its proposed energy portfolio standard for dispatchable and reliable low-carbon electricity by March 31, 2023. The final plan will be submitted for WPSC approval and will detail the Company's plan for achieving the standard, by July 1, 2030.
1e	**Regional Haze Compliance:** • Following the resolution of first planning period regional haze compliance disputes, and the submission of second planning period regional haze state implementation plans, PacifiCorp will evaluate and model any emission control retrofits, emission	• PacifiCorp is working with parties to resolve regional haze first planning period disputes, and has engaged with states and commented on proposed second planning period implementation plans. No second planning periods requirements have been finalized to date.

(1e)	limitations, or utilization reductions that are required for coal units. • PacifiCorp will continue to engage with the Environmental Protection Agency, state agencies, and stakeholders to achieve second planning period regional haze compliance outcomes that improve Class I visibility, provide environmental benefits, and are cost effective.	• PacifiCorp is on track in engaging with the Environmental Protection Agency, state agencies, and stakeholders relating to second planning period regional haze compliance.
Action Item	**2. New Resource Actions**	**Status**
2a	**<u>Customer Preference Request for Proposals:</u>** • Consistent with Utah Community Renewable Energy Act, PacifiCorp continues to work with eligible communities to develop program to achieve goal of being net 100 percent renewable by 2030; PacifiCorp anticipates filing an application for approval of the program with the Utah Public Service Commission in 2022, which may necessitate issuance of a request for proposals to procure resources within the action plan window.	• The Company and the eligible communities are meeting monthly to discuss program design. Subject to finalization of the program details, PacifiCorp anticipates filing an application for approval of the program with the Utah Public Service Commission in 2022.
2b	• Acquisition and Repowering of Foote Creek II-IV and Rock River I: • In Q3 2021, PacifiCorp will pursue necessary regulatory approvals to authorize the acquisition and repowering of Foote Creek II-IV in order to issue repowering contracts in Q1 2022 in support of a late 2023 in-service date. • In Q1 2022, PacifiCorp will pursue necessary regulatory approvals to authorize the acquisition and repowering of Rock River I following the expiration of	• PacifiCorp is pursuing necessary regulatory approvals to authorize the acquisition and repowering of Foote Creek II-IV in order to commence construction in late Q2 2022 in support of a late 2023 in-service date. PacifiCorp filed a certificate of public convenience and necessity (CPCN) application with the WPSC for Foote Creek II-IV in October 2021. A decision from the WPSC is expected sometime in Q2 2022. • In Q1 2022, PacifiCorp initiated necessary regulatory approvals to authorize the acquisition and repowering

(2b)	the existing power purchase agreement in order to issue repowering contracts in Q3 2022 to support a late 2024 in-service date.	of Rock River I in order to issue repowering contracts in Q3 2022 to support a late 2024 in-service date. PacifiCorp filed a CPCN application with the WPSC for Rock River I in March 2022 and requested a decision in Q3 2022.
2c	**<u>Natrium™ Demonstration Project:</u>** • PacifiCorp will continue to monitor key TerraPower milestones for development and will make regulatory filings, as applicable. • By the end of 2022, PacifiCorp will finalize commercial agreements for the Natrium™ project. • Q1 2022, PacifiCorp will develop a community action plan in coordination with community leaders. • By 2025, PacifiCorp will begin training operators. • PacifiCorp will continue to monitor key TerraPower milestones for development and will make regulatory filings, as applicable, including, but not limited to, a request for the Oregon Public Utility Commission to explicitly acknowledge an alternative acquisition method consistent with OAR 860-089-0100(3)(c), and a request for a waiver of a solicitation for a significant energy resource decision consistent with Utah statute 54-17-501.	• The Company continues to monitor TerraPower's development of the Natrium™ project. The Company and TerraPower are discussing potential commercial agreement structures. The agreement is expected to contain numerous conditions precedent, including the Company obtaining required regulatory approvals and/or waivers, project offramps and performance related metrics which must be met for the PacifiCorp to move forward with acquisition of the Natrium™ project to provide protections to customers. • PacifiCorp will supplement TerraPower in stakeholder outreach and coordination with community leaders in PacifiCorp's service territory. • PacifiCorp is evaluating training schedules, positions, and requirements for the Natrium™ project. • See response to 2c bullet 1. No regulatory filings are required at this time.

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<td>2d</td>
<td><u>2022 All-Source Request for Proposals:</u>

PacifiCorp will issue an all-source Request for Proposals (RFP) to procure resources that can achieve commercial operations by the end of December 2026.
In September 2021, PacifiCorp will notify the Public Utility Commission of Oregon, the Public Service Commission of Utah, and the Washington Utilities and Transportation Commission, of PacifiCorp’s need for an independent evaluator.
In October 2021, PacifiCorp will file a draft all-source RFP with applicable state utility commissions.
In January 2022, PacifiCorp expects to receive approval of the all-source RFP from applicable state utility commissions and issue the RFP to the market.
In Q2 2022, PacifiCorp will identify an initial shortlist in advance of annual Cluster Request Window.
In Q1 2023, PacifiCorp will identify a final shortlist from the all-source RFP, and file for approval of the final shortlist in Oregon, file, certificate of public convenience and necessity (CPCN) applications, as applicable.
By Q2 2023 PacifiCorp will execute definitive agreements with winning bids from the all-source RFP.
By Q4 2025-2026, winning bids from the all-source RFP are expected to achieve commercial operation. Resources must have commercial operation date of December 31, 2026, or earlier.
</td>
<td>
PacifiCorp will issue an all-source Request for Proposals (RFP) to procure resources that can achieve commercial operations by the end of December 2027.
In Q4 2021, PacifiCorp notified the Public Utility Commission of Oregon, the Public Service Commission of Utah, and the Washington Utilities and Transportation Commission, of PacifiCorp’s need for an independent evaluator.
In December 2021 and January 2022, PacifiCorp filed a draft all-source RFP with applicable state utility commissions.
In March 2022, PacifiCorp received approval from the Washington Utilities and Transportation Commission and in April, PacifiCorp expects to receive approval of the all-source RFP from the Public Utility Commission of Oregon, the Public Service Commission of Utah and issue the RFP to the market.
In Q2 2023, PacifiCorp will identify a final shortlist from the all-source RFP, and in Q3 2023 file for approval of the final shortlist in Oregon, file, certificate of public convenience and necessity (CPCN) applications, as applicable.
By Q1 2024 PacifiCorp will execute definitive agreements with winning bids from the all-source RFP.
By Q4 2027, winning bids from the all-source RFP are expected to achieve commercial operation. Resources must have commercial operation date of December 31, 2027, or earlier.
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2e	**<u>2020 All-Source Request for Proposals:</u>** • PacifiCorp filed for approval of the final shortlist in Oregon in June 2021. • In September 2021, PacifiCorp will file CPCN applications in Wyoming, as applicable, for final shortlist. • In Q4 2021, PacifiCorp will make a filing in Utah for significant energy resources on final shortlist.	• In September 2021, PacifiCorp filed CPCN applications for the Gateway South Transmission project in Wyoming, as applicable, in support of the 2020AS RFP final shortlist. • In January 2022, Rocky Mountain Power (RMP) filed an Application for Waiver to the Utah Public Service Commission (PUC) to waive the requirement that RMP obtain certain significant energy resource decisions representing five bids in the 2020AS RFP. On February 2022, the waiver, subject to certain conditions, was granted by the Utah PUC (see Docket No. 22-035-03 for further details).
Action Item	**3. Transmission Action Items**	**Status**
3a	**<u>Energy Gateway South Segment F (Aeolus-Clover 500 kV transmission line):</u>** • By Q2 2022, obtain Utah and Wyoming Certificates of Public Convenance and Necessity. • By the end of Q1 2022, Bureau of Land Management notice to proceed to construct Energy Gateway South. • In Q3 2024, construction of Energy Gateway South is expected to be completed and placed in service.	• Regulatory approval processes for certificates of public convenience and necessity in Utah and Wyoming are on track. In Utah an unopposed stipulation for the CPCN was filed February 22, 2022 and a commission order is pending. In Wyoming, hearings were completed March 2, 2022 and briefs due April 1, 2022; a decision is expected in early Q2 2022. Wyoming approval will be conditioned on obtaining all right-of-way, which is on track to be completed by the end of Q2 2022.

3b	**<u>Energy Gateway West, Segment D.1 (Windstar-Shirley Basin 230 kV transmission line):</u>** • By Q2 2022, obtain conditional Wyoming Certificate of Public Convenance and Necessity • By Q3 2022 complete ROW easement acquisition and option full Wyoming CPCN • In Q3 2024, construction of Energy Gateway West segment D.1 to be completed and placed in service.	• The Wyoming approval process for the certificate of public convenience and necessity is on track; hearings were completed March 2, 2022 and briefs due April 1, 2022, with a decision expected in early Q2 2022. Approval will be conditioned on obtaining all right-of-way, which is on track to be completed by Q3 2022.
3c	**<u>Boardman-to-Hemingway (500 kV transmission line):</u>** • Continue to support the project under the conditions of the Boardman-to-Hemingway Transmission Project (B2H) Joint Permit Funding Agreement. • Continue to participate in the development and negotiations of the construction agreement. • Continue to participate in "pre-construction" activities in support of the 2026 in-service date. • Continue negotiations for plan of service post B2H for parties to the permitting agreement.	• PacifiCorp has continued to participate in the support, negotiations, planning and permitting of the Boardman-to-Hemingway 500 kV transmission line, which remains targeted for a 2026 in-service date.
3d	Initiate Local Reinforcement Projects as identified with the addition of new resources per the preferred portfolio, and follow-on requests for proposal successful bids	• Reinforcements have been identified. A final assessment of upgrades is pending signed agreements.
3e	Continue permitting support for Gateway West segments D.3 and E.	• PacifiCorp continues permitting efforts on both segments D.3 and E, maintaining the record of decision on each segment.

<table>
<tr><th>Action Item</th><th>4. Demand-Side Management (DSM) Actions</th><th>Status</th></tr>
<tr><td>4a</td><td>

Energy Efficiency Targets:

- PacifiCorp will acquire cost-effective Class 2 DSM (energy efficiency) resources targeting annual system energy and capacity selections from the preferred portfolio as summarized below. PacifiCorp's state-specific processes for planning for DSM acquisitions is provided in Appendix D in Volume II of the 2021 IRP.
- PacifiCorp will pursue cost-effective energy efficiency resources as summarized in the table below:

<table>
<tr><th>Year</th><th>Annual 1st Year Energy (GWh)</th><th>Annual Incremental Capacity (MW)</th></tr>
<tr><td>2021</td><td>510</td><td>157</td></tr>
<tr><td>2022</td><td>492</td><td>138</td></tr>
<tr><td>2023</td><td>486</td><td>144</td></tr>
<tr><td>2024</td><td>529</td><td>164</td></tr>
</table>

- PacifiCorp will pursue cost-effective Class 1 (demand response) resources targeting annual system capacity[1] selections from the preferred portfolio[2] as summarized in the table below:

<table>
<tr><th>Year</th><th>Annual Incremental Capacity (MW)</th></tr>
<tr><td>2021</td><td>0</td></tr>
<tr><td>2022</td><td>123</td></tr>
<tr><td>2023</td><td>242</td></tr>
<tr><td>2024</td><td>184</td></tr>
</table>

[1] Capacity impacts for demand response include both summer and winter impacts within a year.
[2] A portion of cost-effective demand response resources identified in the 2021 preferred portfolio are expected to be

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- PacifiCorp achieved the Action Plan target of 510 GWh in 2021 and the Company is on track to achieve its 2022 Class 2 DSM target.

- PacifiCorp is actively working to pursue demand response resources in multiple states. The Company is currently expanding its existing programs and contracting for new demand response resources identified in the 2021 demand response RFP. In the event additional demand response resource need is identified, PacifiCorp may issue a voluntary targeted RFP outlining the specific remaining incremental resource needs, including type, location and timing.

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(4a)	acquired through a previously issued demand response RFP soliciting resources identified in the 2019 IRP. PacifiCorp will pursue all cost-effective demand response resources identified as incremental to resources subsequently procured under the previously issued RFP in compliance with state level procurement requirements.	
Action Item	**5. Market Purchases**	**Status**
5a	**<u>Market Purchases:</u>** • Acquire short-term firm market purchases for on-peak delivery from 2021-2023 consistent with the Risk Management Policy and Energy Supply Management Front Office Procedures and Practices. These short-term firm market purchases will be acquired through multiple means: Balance of month and day-ahead brokered transactions in which the broker provides a competitive price. • Balance of month, day-ahead, and hour-ahead transactions executed through an exchange, such as the Intercontinental Exchange, in which the exchange provides a competitive price. • Prompt-month, balance-of-month, day-ahead, and hour-ahead non-brokered bi-lateral transactions.	• Since the publication of the 2021 IRP action plan, PacifiCorp has continued to engage in financially beneficial transactions to support customers' interests. Such transactions include seeking competitive pricing to acquire short-term firm purchases, execute balance of month, day-ahead and hour-ahead transactions through exchanges, and engage in prompt-month, balance-of-month, day-ahead and hour-ahead non-brokered bi-lateral transactions.

Action Item	6. Renewable Energy Credit (REC) Actions	Status
6a	**Renewable Portfolio Standards (RPS):** • PacifiCorp will pursue unbundled REC RFPs and purchases to meet its state RPS compliance requirements. • As needed, issue RFPs seeking then current-year or forward-year vintage unbundled RECs that will qualify in meeting California RPS targets through 2024.	• Since October 1, 2021, PacifiCorp has purchased unbundled RECs to meet its California RPS targets through 2024. PacifiCorp will continue to evaluate the need for unbundled RECs and issue RFPs to meet its state RPS compliance requirements as needed.
6b	**Renewable Energy Credit Sales:** • Maximize the sale of RECs that are not required to meet state RPS compliance obligations.	• On October 27, 2021, PacifiCorp issued a reverse RFPs to sell RECs and completed several bilateral transactions. PacifiCorp will continue to issue reverse RFPs to maximize the sale of RECs that are not required to meet state RPS compliance obligations

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APPENDIX A – ADDITIONAL LOAD FORECAST DETAILS

The load forecast presented in Chapter 4 represents the data used for capacity expansion modeling and excludes load reductions from incremental energy efficiency resources (Class 2 DSM). The load forecast used in the 2021 IRP Update was produced in May 2021. The average annual energy growth rate for the 10-year period (2022 through 2031) is 1.46 percent. Relative to the load forecast prepared for the 2021 IRP, PacifiCorp's 2031 forecasted energy requirement decreased in all jurisdictions other than Oregon and Utah, while PacifiCorp system energy requirement increased approximately 2.3 percent. Table A.1 and Table A.2 illustrate the annual load and coincident peak load forecast when not reducing load projections to account for new energy efficiency measures (Class 2 DSM).[1]

Table A.1 – Forecasted Annual Load Growth, 2022 through 2031 (Megawatt-hours), at Generation, pre-DSM

Year	Total	OR	WA	CA	UT	WY	ID
2022	61,564,330	15,225,790	4,605,340	870,230	27,635,390	9,281,340	3,946,240
2023	63,153,010	15,542,160	4,643,520	871,480	28,603,020	9,538,990	3,953,840
2024	64,661,770	16,080,310	4,681,580	874,560	29,438,980	9,627,450	3,958,890
2025	65,743,100	16,349,100	4,691,870	873,570	29,989,480	9,867,530	3,971,550
2026	65,308,270	16,677,410	4,720,470	876,030	29,123,740	9,920,230	3,990,390
2027	66,210,480	17,013,040	4,755,770	879,110	29,600,710	9,953,650	4,008,200
2028	67,345,980	17,408,920	4,810,220	884,040	30,182,810	10,027,440	4,032,550
2029	68,250,270	17,742,390	4,843,960	884,190	30,679,530	10,052,470	4,047,730
2030	69,298,260	18,122,940	4,890,370	886,080	31,248,620	10,091,160	4,059,090
2031	70,122,890	18,357,130	4,938,900	887,880	31,741,320	10,128,710	4,068,950
Compound Annual Growth Rate							
2022-31	**1.46%**	**2.10%**	**0.78%**	**0.22%**	**1.55%**	**0.98%**	**0.34%**

[1] Class 2 DSM load reductions are included as resources in the System Optimizer model.

Table A.2 - Forecasted Annual Coincident Peak Load (Megawatts) at Generation, pre-DSM

Year	Total	OR	WA	CA	UT	WY	ID
2022	10,561	2,429	775	140	5,201	1,231	786
2023	10,717	2,442	779	142	5,320	1,250	785
2024	10,864	2,468	782	140	5,423	1,265	786
2025	11,035	2,494	787	141	5,524	1,293	796
2026	11,027	2,516	790	141	5,481	1,298	801
2027	11,126	2,538	795	142	5,545	1,302	805
2028	11,255	2,560	799	143	5,636	1,309	808
2029	11,370	2,582	805	142	5,717	1,312	812
2030	11,487	2,603	810	142	5,800	1,317	815
2031	11,590	2,613	818	142	5,875	1,321	821
Compound Annual Growth Rate							
2022-31	**1.04%**	**0.81%**	**0.60%**	**0.10%**	**1.36%**	**0.79%**	**0.49%**

Table A.3 and Table A.4 show the forecast changes relative to the 2021 IRP load forecast for loads and coincident system peak, respectively.

Table A.3 – Annual Load Growth Change: 2021 IRP Update Forecast less 2021 IRP Forecast (Megawatt-hours) at Generation, pre-DSM

Year	Total	OR	WA	CA	UT	WY	ID
2022	(196,580)	(180,480)	14,320	(9,030)	191,300	(186,600)	(26,090)
2023	(89,980)	(216,520)	(12,510)	(11,020)	392,640	(217,480)	(25,090)
2024	210,460	(25,810)	(29,060)	(13,610)	646,800	(335,810)	(32,050)
2025	580,840	109,590	(38,370)	(15,320)	648,450	(89,470)	(34,040)
2026	781,240	258,590	(40,420)	(15,100)	770,820	(159,280)	(33,370)
2027	1,032,080	403,790	(40,420)	(13,300)	899,780	(186,400)	(31,370)
2028	1,262,560	552,280	(40,180)	(12,240)	989,950	(200,380)	(26,870)
2029	1,481,610	705,290	(35,940)	(11,180)	1,069,680	(225,750)	(20,490)
2030	1,575,050	854,900	(32,730)	(12,530)	1,092,870	(302,510)	(24,950)
2031	1,594,240	877,130	(19,280)	(11,680)	1,107,530	(336,960)	(22,500)

Table A.4 – Annual Coincident Peak Growth Change: 2021 IRP Update Forecast less 2017 IRP Forecast (Megawatts) at Generation, pre-DSM

Year	Total	OR	WA	CA	UT	WY	ID
2022	26	(13)	(4)	(0)	42	(17)	18
2023	26	(20)	(10)	(0)	65	(29)	20
2024	56	(13)	(14)	(1)	97	(35)	21
2025	93	(6)	(17)	(1)	105	(9)	21
2026	160	3	(20)	(1)	173	(16)	22
2027	186	11	(22)	(1)	194	(19)	23
2028	212	20	(24)	(0)	211	(20)	25
2029	237	30	(26)	(0)	227	(23)	28
2030	248	41	(27)	(0)	237	(31)	29
2031	252	42	(28)	(0)	244	(35)	29

This section provides total system and state-level forecasted retail sales summaries measured at the customer meter by customer class including load reduction projections from new energy efficiency measures from the 2021 IRP Update preferred portfolio. The average annual retail sales growth rate for the 10-year period (2022 through 2031) is 0.58 percent.

Table A.5 – System Annual Retail Sales Forecast 2022 through 2031 (Megawatt-hours), post-DSM

System Retail Sales – Megawatt-hours (MWh)						
Year	Residential	Commercial	Industrial	Irrigation	Lighting	Total
2022	16,883,025	19,430,835	18,304,202	1,483,507	107,925	56,209,495
2023	16,880,836	20,126,970	18,576,997	1,482,501	102,792	57,170,096
2024	17,023,491	20,766,719	18,657,118	1,482,555	99,255	58,029,138
2025	17,101,849	21,036,255	18,773,837	1,482,228	96,195	58,490,363
2026	17,296,271	21,299,464	17,330,721	1,481,509	94,166	57,502,131
2027	17,526,492	21,499,322	17,278,284	1,479,999	92,587	57,876,684
2028	17,861,288	21,747,665	17,257,346	1,478,048	91,497	58,435,844
2029	18,081,010	21,871,791	17,160,525	1,475,700	89,955	58,678,981
2030	18,305,130	22,031,321	17,120,319	1,473,386	88,706	59,018,862
2031	18,546,830	22,014,167	17,088,099	1,470,631	87,515	59,207,242
Compound Annual Growth Rate						
2022-31	1.05%	1.40%	-0.76%	-0.10%	-2.30%	0.58%

Table A.6– Forecasted Retail Sales Growth in Oregon, post-DSM

Oregon Retail Sales – Megawatt-hours (MWh)						
Year	Residential	Commercial	Industrial	Irrigation	Lighting	**Total**
2022	5,787,079	5,887,735	1,480,507	333,775	36,859	**13,525,955**
2023	5,762,694	6,066,118	1,437,047	333,504	35,996	**13,635,359**
2024	5,785,881	6,372,669	1,408,680	333,517	35,350	**13,936,096**
2025	5,796,057	6,501,134	1,401,833	333,409	34,630	**14,067,063**
2026	5,838,292	6,640,891	1,397,397	333,326	34,138	**14,244,045**
2027	5,887,806	6,778,086	1,393,803	333,013	33,759	**14,426,467**
2028	5,972,311	6,925,882	1,392,590	332,569	33,571	**14,656,922**
2029	6,036,711	7,051,309	1,389,902	332,002	33,263	**14,843,186**
2030	6,121,032	7,189,924	1,388,345	331,520	33,109	**15,063,930**
2031	6,203,383	7,201,637	1,389,462	331,062	32,998	**15,158,541**
Compound Annual Growth Rate						
2022-31	**0.77%**	**2.26%**	**-0.70%**	**-0.09%**	**-1.22%**	**1.27%**

Table A.7 – Forecasted Retail Sales Growth in Washington, post-DSM

Washington Retail Sales – Megawatt-hours (MWh)						
Year	Residential	Commercial	Industrial	Irrigation	Lighting	**Total**
2022	1,529,078	1,563,728	854,633	160,251	3,514	**4,111,204**
2023	1,510,337	1,581,369	842,930	159,721	3,283	**4,097,639**
2024	1,504,658	1,586,702	831,049	159,603	3,220	**4,085,232**
2025	1,491,410	1,582,136	817,469	159,602	3,188	**4,053,805**
2026	1,484,929	1,577,641	809,322	159,577	3,181	**4,034,651**
2027	1,480,508	1,571,996	803,278	159,531	3,179	**4,018,493**
2028	1,483,834	1,569,934	799,933	159,466	3,189	**4,016,356**
2029	1,479,846	1,560,954	793,073	159,322	3,179	**3,996,373**
2030	1,479,029	1,559,549	789,220	159,096	3,179	**3,990,074**
2031	1,480,155	1,559,370	787,489	158,885	3,179	**3,989,077**
Compound Annual Growth Rate						
2022-31	**-0.36%**	**-0.03%**	**-0.91%**	**-0.10%**	**-1.11%**	**-0.33%**

Table A.8 – Forecasted Retail Sales Growth in California, post-DSM

California Retail Sales – Megawatt-hours (MWh)						
Year	Residential	Commercial	Industrial	Irrigation	Lighting	**Total**
2022	382,297	235,420	53,687	91,103	1,421	**763,928**
2023	381,755	235,971	52,872	90,973	1,323	**762,893**
2024	383,221	236,685	51,010	90,920	1,246	**763,081**
2025	382,098	235,693	49,105	90,846	1,178	**758,920**
2026	382,238	235,144	47,575	90,647	1,128	**756,731**
2027	382,478	234,065	46,454	90,367	1,091	**754,454**
2028	384,043	233,155	45,038	90,051	1,066	**753,353**
2029	383,329	230,679	43,237	89,700	1,043	**747,988**
2030	383,712	228,952	41,414	89,361	1,029	**744,469**
2031	384,512	227,073	39,790	88,986	1,018	**741,380**
Compound Annual Growth Rate						
2022-31	**0.06%**	**-0.40%**	**-3.27%**	**-0.26%**	**-3.63%**	**-0.33%**

Table A.9 – Forecasted Retail Sales Growth in Utah, post-DSM

Utah Retail Sales – Megawatt-hours (MWh)						
Year	Residential	Commercial	Industrial	Irrigation	Lighting	**Total**
2022	7,486,721	9,885,130	7,826,692	232,649	51,617	**25,482,810**
2023	7,563,353	10,386,939	7,921,202	232,571	47,781	**26,151,846**
2024	7,698,651	10,706,741	8,005,055	232,586	45,136	**26,688,169**
2025	7,807,461	10,869,905	7,962,311	232,495	43,154	**26,915,326**
2026	7,977,241	11,013,101	6,544,182	232,429	41,986	**25,808,940**
2027	8,170,602	11,104,346	6,536,315	232,339	41,275	**26,084,877**
2028	8,414,703	11,226,321	6,529,252	232,207	40,969	**26,443,452**
2029	8,584,013	11,261,726	6,485,280	231,928	40,603	**26,603,549**
2030	8,749,010	11,302,572	6,480,594	231,603	40,457	**26,804,237**
2031	8,933,960	11,288,665	6,468,866	231,292	40,373	**26,963,156**
Compound Annual Growth Rate						
2022-31	**1.98%**	**1.49%**	**-2.09%**	**-0.06%**	**-2.69%**	**0.63%**

Table A.10 – Forecasted Retail Sales Growth in Idaho, post-DSM

Idaho Retail Sales – Megawatt-hours (MWh)						
Year	Residential	Commercial	Industrial	Irrigation	Lighting	**Total**
2022	731,411	536,502	1,740,182	638,729	2,607	**3,649,432**
2023	720,703	536,531	1,746,769	638,753	2,574	**3,645,330**
2024	723,863	540,050	1,732,842	638,946	2,547	**3,638,247**
2025	720,853	540,125	1,732,104	638,909	2,504	**3,634,496**
2026	723,428	539,778	1,730,168	638,580	2,469	**3,634,423**
2027	726,455	537,494	1,726,496	637,829	2,434	**3,630,709**
2028	733,689	536,026	1,722,956	636,869	2,407	**3,631,947**
2029	736,108	531,204	1,717,517	635,903	2,367	**3,623,099**
2030	731,214	528,740	1,713,034	634,996	2,335	**3,610,320**
2031	724,653	527,341	1,709,501	633,630	2,304	**3,597,428**
Compound Annual Growth Rate						
2022-31	**-0.10%**	**-0.19%**	**-0.20%**	**-0.09%**	**-1.36%**	**-0.16%**

Table A.11 – Forecasted Retail Sales Growth in Wyoming, post-DSM

Wyoming Retail Sales – Megawatt-hours (MWh)						
Year	Residential	Commercial	Industrial	Irrigation	Lighting	**Total**
2022	966,439	1,322,319	6,348,502	26,999	11,907	**8,676,165**
2023	941,994	1,320,042	6,576,179	26,979	11,836	**8,877,030**
2024	927,218	1,323,873	6,628,483	26,983	11,757	**8,918,313**
2025	903,969	1,307,262	6,811,014	26,967	11,542	**9,060,753**
2026	890,143	1,292,909	6,802,077	26,950	11,263	**9,023,341**
2027	878,643	1,273,335	6,771,939	26,920	10,848	**8,961,685**
2028	872,709	1,256,347	6,767,577	26,885	10,295	**8,933,814**
2029	861,004	1,235,919	6,731,517	26,845	9,501	**8,864,786**
2030	841,131	1,221,583	6,707,712	26,809	8,598	**8,805,833**
2031	820,168	1,210,082	6,692,991	26,776	7,643	**8,757,660**
Compound Annual Growth Rate						
2022-31	**-1.81%**	**-0.98%**	**0.59%**	**-0.09%**	**-4.81%**	**0.10%**