2019 Integrated resource plan

VOLUME I

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This 2019 Integrated Resource Plan Report 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):
Marengo Wind Project
Transmission Line
Electric Meter
Pavant III Solar Plant

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CHAPTER 1 – EXECUTIVE SUMMARY

PacifiCorp's 2019 Integrated Resource Plan (IRP) was developed through comprehensive analysis and a public-input process spanning nearly a year and a half resulting in the selection of a least-cost, least-risk preferred portfolio. The 2019 IRP preferred portfolio includes accelerated coal retirements and investment in transmission infrastructure that will facilitate adding over 6,400 megawatt (MW) of new renewable resources by the end of 2023, with nearly 11,000 MW of new renewable resources over the 20-year planning period through 2038.[1] The 2019 IRP preferred portfolio advances PacifiCorp's long-term vision as described in the following section.

PacifiCorp's Vision

PacifiCorp shares a bold vision with our customers for a future where energy is delivered affordably, reliably and without greenhouse gas emissions. A future where our vast, modern energy grid connects local communities to the low-cost and reliable energy they need to innovate and achieve their goals. PacifiCorp believes that affordability and sustainability go hand in hand and together, they form the foundation for a reliable, resilient energy future—where regional and state economies benefit from investments in energy resources and infrastructure that help them pioneer new growth opportunities. It is an ambitious vision, but it is absolutely achievable. By connecting the West's diverse resources to the vast reach of our transmission system and by investing in technology, partnerships and markets, PacifiCorp is positioned to create the future our customers and communities seek.

Reimagining the Future Based on a Century of Innovation

When PacifiCorp joined Berkshire Hathaway Energy in 2006, the company set out to be the best energy company in terms of service to its customers while delivering sustainable energy solutions. The path forward was viewed as an invitation to reimagine not just how energy is produced but how it is dispatched and delivered. It was clear that PacifiCorp's greatest opportunity would be discovered in understanding the needs and aspirations of its customers and communities. The company saw the West itself, with its abundance of diverse natural resources, as a way to deliver greater value. And believed that the greatest gains could be realized by building upon the more than 100 years of innovation that helped create PacifiCorp's ten-state energy grid. By drawing on its track record of partnership and technology-driven innovation, PacifiCorp could transform its expansive grid into an industry-leading, interconnected energy system—a system uniquely equipped to access the best energy resources the West has to offer and efficiently deliver those resources to customers and communities across the region.

PacifiCorp has made significant progress over the past 13 years, becoming the largest regulated utility owner of wind power in the West. From 2018 to 2020, PacifiCorp will have increased the percentage of zero-carbon energy resources in its portfolio by 70 percent. The company made sure to do it all while capturing and returning savings to its customers.[2]

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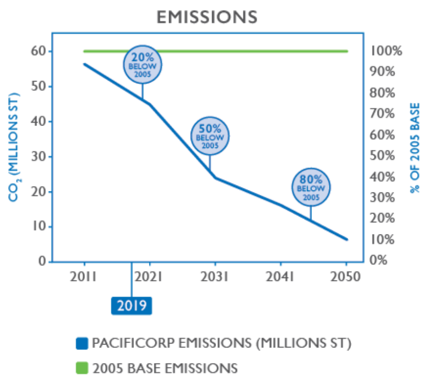
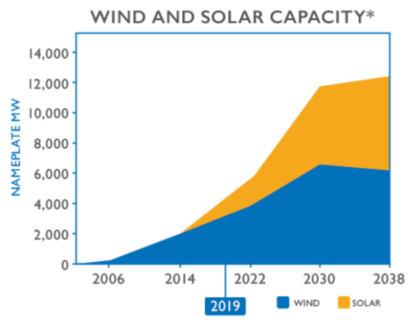
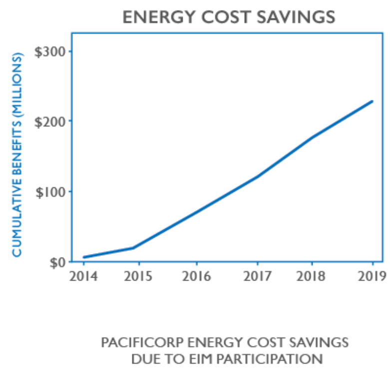
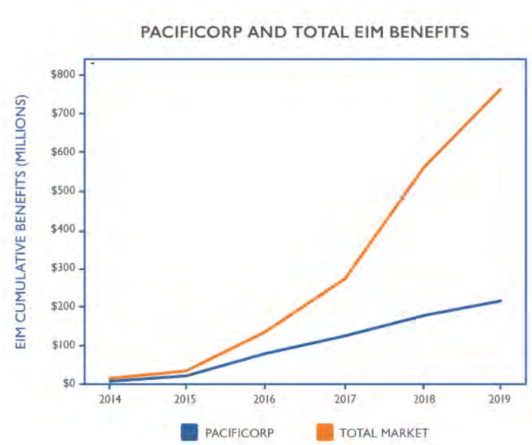
[1] Resources acquired through customer partnerships, used for renewable portfolio standard compliance, or for third-party sales of renewable attributes are included in the total capacity figures quoted.
[2] *Id.*







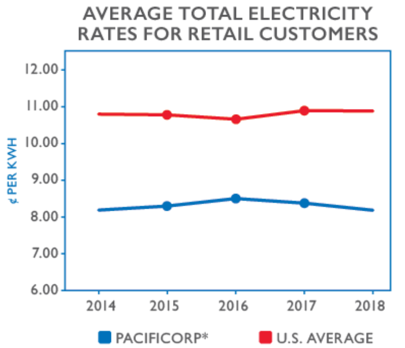
Reinventing the Future through Collaboration



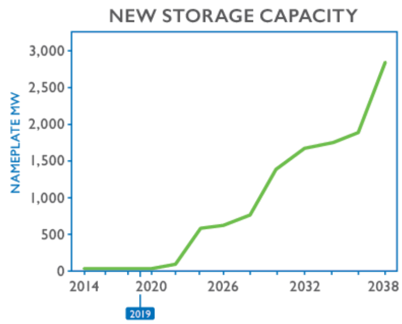
Over the past 13 years, PacifiCorp has successfully reduced its carbon emissions and improved reliability while simultaneously delivering energy cost savings to its customers. These results have been achieved by collaborating with others to create a more open and connected Western grid and through the visionary and collaborative efforts of PacifiCorp's own generation, transmission, information technology and energy supply management teams. In 2014, PacifiCorp pioneered the Western Energy Imbalance Market (EIM) in partnership with the California Independent System Operator. This innovative market allows utilities across the West to access the lowest-cost energy available in near real time, making it easy for zero fuel-cost renewable energy to go where it is needed. If excess solar energy in California, excess wind from Wyoming or hydropower from Washington and Oregon is available, PacifiCorp will harness it and transport it instantly across the company's 16,500-mile grid.

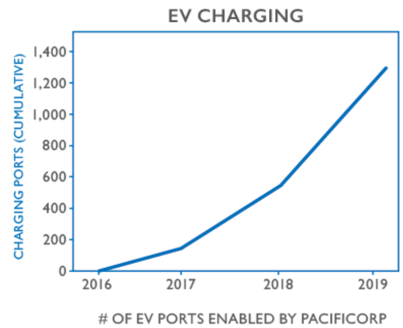
Through participation in the EIM, PacifiCorp has saved its customers over $200 million so far. The savings get bigger every year, and the company has reduced its portfolio carbon emissions over 15 million tons—the equivalent of taking 3 million cars off the road for a year.

Since its inception, nine utilities have joined the EIM and 11 more have committed to join by 2022, altogether representing almost 70 percent of the West's total electricity demand. As more participants join the EIM, the benefits increase. To date, participating utilities across the West have saved customers over $730 million while simultaneously decarbonizing the Western grid. PacifiCorp continues to engage new partners in evolving the real-time EIM to include a day-ahead market for even bigger future benefits.



Source: Edison Electric Institute Sales and Revenue Data for the 12 months ending December of each year





Rethinking the Future by Investing in the Diversity of the West

PacifiCorp continues to offer its customers some of the lowest energy prices in the country—well below the national average—while simultaneously expanding the depth and breadth of its energy portfolio and solutions.

- **Energy Vision 2020**: In 2017, PacifiCorp announced its largest historical investment in the development of renewable energy and infrastructure—Energy Vision 2020. This $3 billion project to be completed in 2020 embodies the company's commitment to a future that benefits its customers, its communities and the environment. It will dramatically increase PacifiCorp's renewable energy portfolio with new and repowered wind resources and new transmission while leveraging federal production tax incentives to provide hundreds of millions of dollars in savings to its customers over the life of the projects. Energy Vision 2020 also benefits rural communities across the West by creating hundreds of construction jobs and adding millions of dollars in construction tax revenue and ongoing annual state and local tax revenue.

- **Proposed New Resource Investments**: PacifiCorp's 2019 IRP sets forth a plan to expand its resource portfolio with new low-cost wind generation, solar generation and storage to meet changing customer needs.[3]

Resource	Through 2023	Through 2038
Wind (ID, UT, WA, WY)	Over 3,500 MW	Over 4,600 MW
Solar (ID, OR, UT, WA, WY)	Nearly 3,000 MW	Over 6,300 MW
Storage (ID, OR, UT, WA, WY)	Nearly 600 MW	Over 2,800 MW

Innovating Solutions to Build the Future

- **Demand Response**: PacifiCorp is championing technical innovations that use fast-acting residential demand response resources to support the bulk power system. PacifiCorp's approach moves beyond peak-load management to create a grid-scale solution that turns demand response resources into frequency-responsive operating reserves. With over 92,000 customers participating in this program, more than 200 MW of operating reserve is available every day and can be dispatched in a matter of seconds. This reduces PacifiCorp's

[3] *Id.*

need to supply operating reserves with higher cost alternatives, and it is only used in emergencies, minimizing inconvenience to customers.

PacifiCorp is also partnering with The Wasatch Group to develop and manage a first-of-its-kind residential battery demand response solution. This new all-electric apartment building in Utah features on-site energy storage for each of its 600 units, totaling 12.6 MWh of solar-powered battery storage. This innovative all-electric design provides emergency back-up power to residents, helps address air quality issues in the area and benefits overall electric grid operation.

- **Customized Renewable Energy Solutions**: PacifiCorp is partnering with communities and customers across the West to champion customized energy solutions to achieve their renewable energy goals. For example, the company's work with Facebook is resulting in the construction of 677 MW of new solar and wind capacity, all in service by the end of 2020. These projects support Facebook's operations in Oregon, enabling it to achieve its 100% renewable goal while simultaneously lowering energy supply costs for all PacifiCorp customers. In addition, PacifiCorp secured 122 MW of new solar energy capacity on behalf of Facebook's data center in Eagle Mountain, Utah.

- **Electrification**: The electric transportation market is in an emerging state that represents a potential driver for future load growth, improved air quality, reduced greenhouse gas emissions, improved public health and safety, and creation of financial benefits for drivers, particularly for low and moderate-income populations. PacifiCorp is investing over $26 million to support electric vehicle (EV) fast chargers along key corridors, develop robust workplace charging programs, implement smart mobility programs and develop opportunities for customers in its rural communities. The company's investments include a $4 million partnership award from the U.S. Department of Energy to research and develop electric transportation primarily in Utah and $3 million as part of the Oregon Clean Fuels Program.

Bringing the Best of the West to PacifiCorp's Customers

PacifiCorp's 2019 IRP includes investments in diverse new resources like, renewables, storage and modern grid technology among them. It outlines new transmission infrastructure investments across our territory that are needed to remove existing transmission constraints and improve grid resilience so the lowest-cost renewable resources can flow freely to customers across the West.

PacifiCorp's IRP also provides the roadmap by which it will dramatically reduce its greenhouse gas emissions over the next 20 years. The IRP shows that, by 2030, PacifiCorp will have reduced greenhouse emissions by nearly 60 percent from 2005 levels. Along with adding renewables and leveraging new technology, emissions reductions will be achieved by the phased transition of its coal fleet.

PacifiCorp's thermal assets and operations teams have played an essential role in enabling the progress made to date, and the company recognizes the vital part that these resources play in their communities too. PacifiCorp is committed to open and transparent communication about our coal transition, and equally committed to working with our employees and communities to develop plans that help them through this time of change.

Connecting the West to More Value

PacifiCorp believes a path to reduced carbon emissions must be substantiated with a prescriptive and thoughtful plan. The company's plan revolves around three interrelated strategies to reimagine an energy future that serves all of its communities.

PacifiCorp sees the energy diversity of the West as a catalyst. The company's plans to meet the energy needs of its customers and communities across the West will continue to evolve, but PacifiCorp's commitment to making the West stronger and better is unwavering. PacifiCorp will achieve this by continuing to find answers in new partnerships, advanced technologies and expanded energy markets, and by pursuing energy solutions that harness and bring the best energy resources the West has to offer to its customers' door.

PacifiCorp's Integrated Resource Plan Approach

PacifiCorp has been making progress in its efforts to bring the best of the West to its customers, and PacifiCorp's 2019 IRP presents the company's plans to make significant advancements in this vision. The 2019 IRP sets 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 2019 IRP, PacifiCorp presents a preferred portfolio that builds 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 programs.

The primary objective of the 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 full planning process is completed every two years, with a review and update completed in the off years. Consequently, these plans, particularly the longer-range elements, can and do change over time. PacifiCorp's 2019 IRP was developed through an open and extensive public process, with input from an active and diverse group of stakeholders, including customer advocacy groups, community members, regulatory staff, and other interested parties. The public-input process began with the first public-input meeting in June 2018. Over the subsequent year and a half, PacifiCorp met with stakeholders in five states and hosted eighteen public-input meetings. Throughout this effort, PacifiCorp received valuable input from stakeholders and presented findings from a broad range of studies and technical analyses that shaped and informed the 2019 IRP.

As depicted in Figure 1.1, PacifiCorp's 2019 IRP was developed by working through five fundamental planning steps that began with a comprehensive and robust analysis of its coal units. The narrow scope of the coal study, which focused on unit-by-unit analyses with prescriptive retirement timing assumptions, was never intended to inform retirement decisions, but rather to inform the more in-depth and refined analysis in the subsequent portfolio-development process. The portfolio-development process is where PacifiCorp produced a range of different resource portfolios that meet projected gaps in the load and resource balance, each uniquely characterized by the type, timing, and location of new resources in PacifiCorp's system that considers a wide range of potential coal retirement dates and other planning uncertainties. 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 informed selection of a preferred portfolio and development of the associated near-term resource action plan. Throughout this process, PacifiCorp considered a wide range of factors to develop key planning assumptions and to identify key planning uncertainties, with input from its stakeholder group. Supplemental studies were are also done to produce specific modeling assumptions.

Figure 1.1 – Key Elements of PacifiCorp's 2019 IRP Approach

Preferred Portfolio Highlights

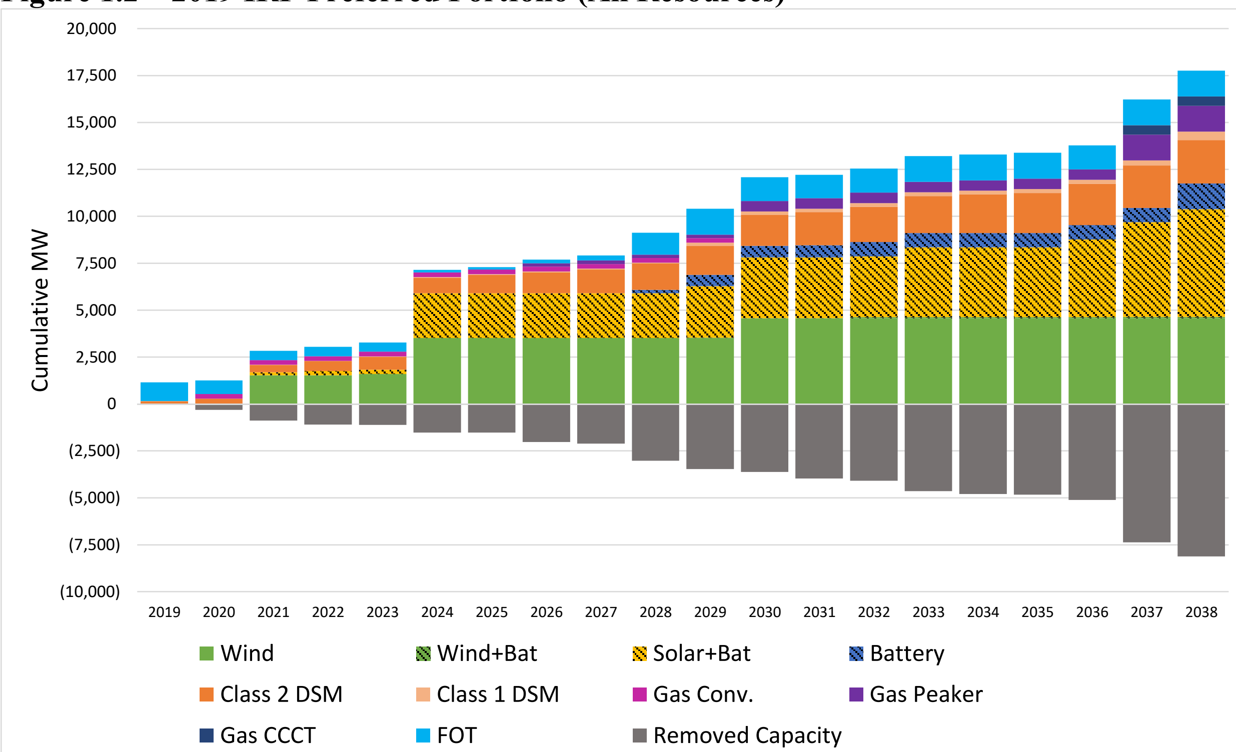
PacifiCorp's selection of the 2019 IRP preferred portfolio is supported by comprehensive data analysis and an extensive stakeholder input process, described in the chapters that follow. Figure 1.2 shows that PacifiCorp's preferred portfolio continues to include new renewables, facilitated by incremental transmission investments, demand-side management (DSM) resources, and for the first time, significant battery storage resources. By the end of 2023, the preferred portfolio includes nearly 3,000 MW of new solar resources and more than 3,500 MW of new wind resources, inclusive of resources that will come online by the end of 2020 that were not in the 2017 IRP.[4] The preferred portfolio also includes nearly 600 MW of battery storage capacity (all collocated with

[4] *Id*.

new solar resources), and over 700 MW of incremental energy efficiency and new direct load control resources.

Over the 20-year planning horizon, the preferred portfolio includes more than 4,600 MW of new wind resources, more than 6,300 MW of new solar resources, more than 2,800 MW of battery storage (nearly 1,400 MW of which are stand-alone storage resources starting in 2028), and more than 2,700 MW of incremental energy efficiency and new direct load control resources.[5] While the preferred portfolio includes new natural gas peaking capacity beginning 2026, this falls outside of the 2019 IRP action plan window, which provides time for PacifiCorp to continue to evaluate whether non-emitting capacity resources can be used to supply the flexibility necessary to maintain long-term system reliability.

Figure 1.2 – 2019 IRP Preferred Portfolio (All Resources)



To facilitate the delivery of new renewable energy resources to PacifiCorp customers across the West, the preferred portfolio includes a 400-mile transmission line known as Gateway South, planned to come online by the end of 2023, that will connect southeastern Wyoming and northern Utah. The new transmission line is in addition to the 140-mile Gateway West transmission line in Wyoming currently under construction as part of PacifiCorp's Energy Vision 2020 initiative. The preferred portfolio further includes near-term transmission upgrades in Utah and Washington. Ongoing investment in transmission infrastructure in Idaho, Oregon, Utah, Washington, and Wyoming will facilitate continued and long-term growth in new renewable resources. Table 1.1 summarizes the incremental transmission projects included in the 2019 IRP preferred portfolio, and Table 1.2 summarizes the total amount of initial capital investment required to deliver incremental transmission and resource investments through the 20-year planning period of the 2019 IRP.

[5] *Id.*

Table 1.1 – Transmission Projects Included in the 2019 IRP Preferred Portfolio*

Year	Resource(s)	From	To	Description
2023	69 MW Wind (2023) 231 MW Solar (2024)	Within Southern UT Transmission Area		Enables 300 MW of interconnection: UT Valley 345-138 kV + 138 kV reinforcement ($8m)
2024	354 MW Solar (2024)	Within Bridger WY Transmission Area		Reclaimed transmission upon retirement of Jim Bridger 1 ($0)
2024	674 MW Solar (2024)	Within Northern UT Transmission Area		Enables 600 MW of interconnection: Northern UT 345 kV reinforcement ($30m)
2024	1,920 MW Wind (2024)	Aeolus WY	UT North	Enables 1,920 MW of interconnection with 1,700 MW of TTC: Energy Gateway South ($1,752m)
2024	395 MW Solar (2024) 10 MW Wind (2029)	Within Yakima WA Transmission Area		Enables 405 MW of interconnection: local reinforcement ($3m)
2024	359 MW Solar (2024)	Within Bridger WY Transmission Area		Reclaimed transmission upon retirement of Jim Bridger 2 ($0)
2030	1,040 MW Wind (2030) 60 MW Wind (2032)	Goshen ID	UT North	Enables 1,100 MW of interconnection with 800 MW of TTC ($254m)
2030	500 MW Solar (2030)	Within Southern UT Transmission Area		Enables 500 MW of interconnection: UT Valley local area reinforcement ($206m)
2033	475 MW Solar (2033)	Within Southern OR Transmission Area		Enables 475 MW of interconnection: Medford area 500 kV-230 kV reinforcement ($102m)
2036	419 MW Solar (2036)	Yakima WA	Southern OR	Enables 430 MW of interconnection with 450 MW of TTC: Yakima WA to Bend OR 230 kV ($255m)
2037	909 MW Solar (2037)	Southern UT	Northern UT	Reclaimed transmission upon retirement of Huntington 1-2 ($0)
2037	443 MW Gas (2037)	Within Willamette Valley OR Transmission Area		Enables 615 MW of interconnection: Albany OR area reinforcement ($40m)
2037	370 MW Gas (2037)	Within Southwest WY Transmission Area		Enables 500 MW of interconnection: separation of double circuit 230 kV lines ($39m)
2038	702 MW Solar (2038)	Within Bridger WY Transmission Area		Reclaimed transmission upon retirement of Jim Bridger 3-4 ($0)

*Note: 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.

Table 1.2 – Total Initial Capital to Deliver Preferred Portfolio Transmission and Resource Investments ($ million)

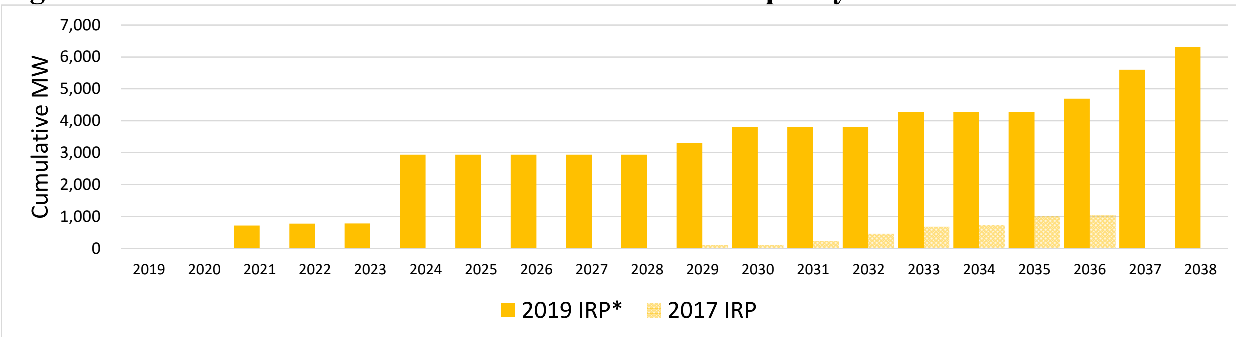
State	Transmission	Resources	Total
Idaho	$254	$1,659	$1,912
Oregon	$264	$2,540	$2,804
Utah	$1,004	$3,466	$4,470
Washington	$136	$1,509	$1,644
Wyoming	$765	$5,376	$6,141
Colorado	$370	$0	$370
Total	$2,792	$14,550	$17,342

New Solar Resources

The 2019 IRP preferred portfolio includes more than 3,000 MW of new solar by the end of 2023, which accounts for resources that will be online by the end of 2020 but not in the 2017 IRP, and more than 6,300 MW of new solar by 2038 as shown in Figure 1.3.[6]

[6] *Id.*

Figure 1.3 – 2019 IRP Preferred Portfolio New Solar Capacity*

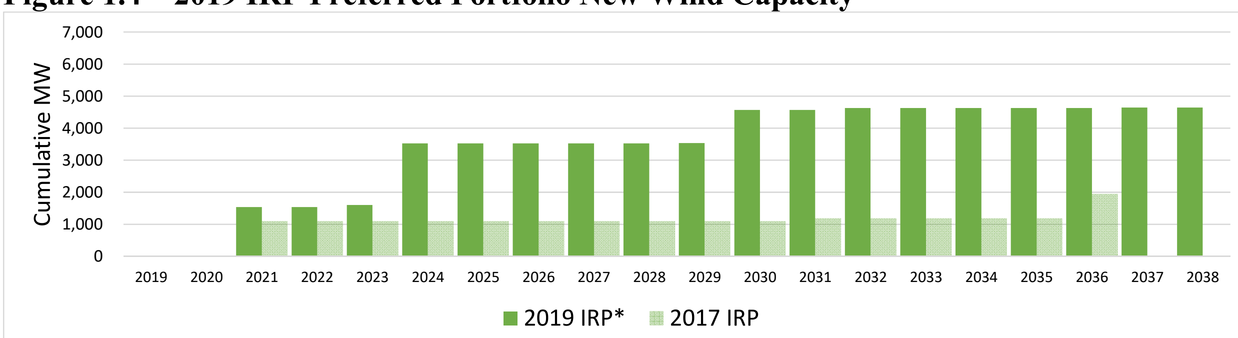


*Note: 2019 IRP solar capacity shown in the figure includes 559 MW of contracted new solar (all power-purchase agreements) that was not identified in the 2017 IRP. These resources will be online by the end of 2020 and are shown in the first full year of operation (the year after year-online dates). Resources acquired through customer partnerships, used for renewable portfolio standard compliance, or for third-party sales of renewable attributes are included in the total capacity figures quoted.

New Wind Resources

As shown in Figure 1.4, PacifiCorp's 2019 IRP preferred portfolio includes more than 3,500 MW of new wind generation by the end of 2023, which accounts for new resources that will come online by the end of 2020 but not in the 2017 IRP, and more than 4,600 MW of new wind by 2038.[7]

Figure 1.4 – 2019 IRP Preferred Portfolio New Wind Capacity*



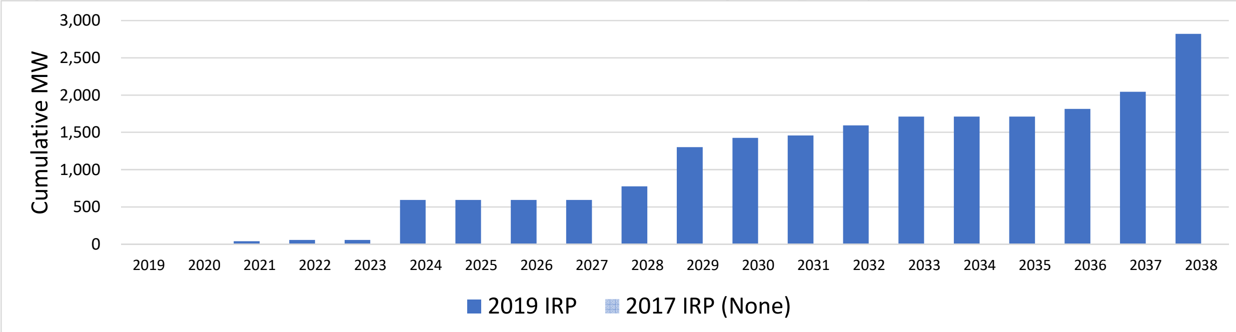
*Note: 2019 IRP wind capacity shown in the figure includes 1,533 MW of contracted new wind (21 percent power-purchase agreements) that was either identified in the 2017 IRP and is under construction or that was not identified in the 2017 IRP and is under contract. These resources will come on-line by the end of 2020. These resources are shown in the first full year of operation (the year after year-end online dates). Resources acquired through customer partnerships, used for renewable portfolio standard compliance, or for third-party sales of renewable attributes are included in the total capacity figures quoted.

New Storage Resources

This is the first PacifiCorp IRP that identifies new battery storage resources as part of its least-cost, least-risk portfolio. As shown in Figure 1.5, PacifiCorp's 2019 IRP preferred portfolio includes nearly 600 MW of battery storage by the end of 2023. All of the storage resources planned through this period are paired with new solar generation. The plan also adds nearly 1,400 MW of stand-alone storage resources starting in 2028.

[7] *Id*.

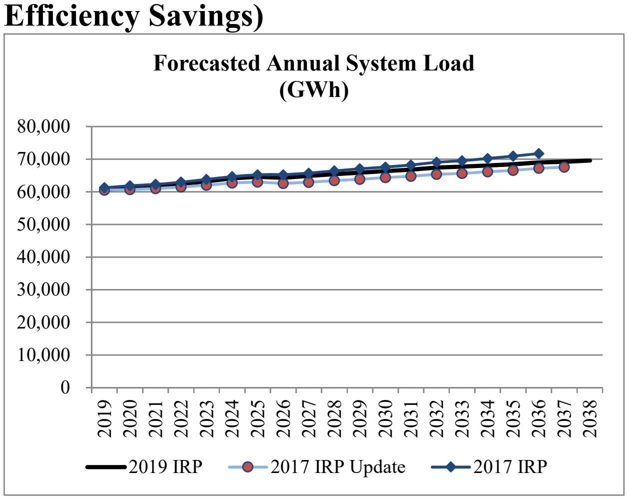
Figure 1.5 – 2019 IRP Preferred Portfolio New Storage Capacity

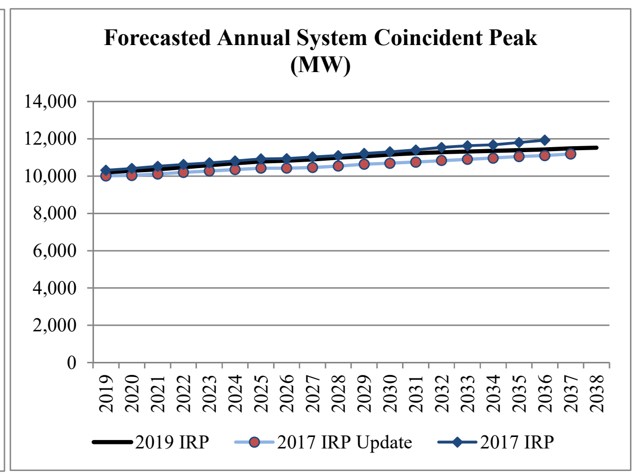


Demand-Side Management

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 resource portfolios for the IRP. Consequently, the load forecast used as an input to the IRP does not reflect any incremental investment in new energy efficiency programs; rather, the load forecast is reduced by the selected additions of energy efficiency resources in the IRP. Figure 1.6 shows that PacifiCorp's load forecast before incremental energy efficiency savings has increased relative to projected loads used in the 2017 IRP and 2017 IRP Update. On average, forecasted system load is up 2.4 percent and forecasted coincident system peak is up 3.4 percent when compared to the 2017 IRP Update. Over the planning horizon, the average annual growth rate, before accounting for incremental energy efficiency improvements, is 0.73 percent for load and 0.64 percent for peak. Changes to PacifiCorp's load forecast are driven by higher projected demand from data centers driving up the commercial forecast and an increase the residential forecast.

Figure 1.6 – Load Forecast Comparison between Recent IRPs (Before Incremental Energy Efficiency Savings)

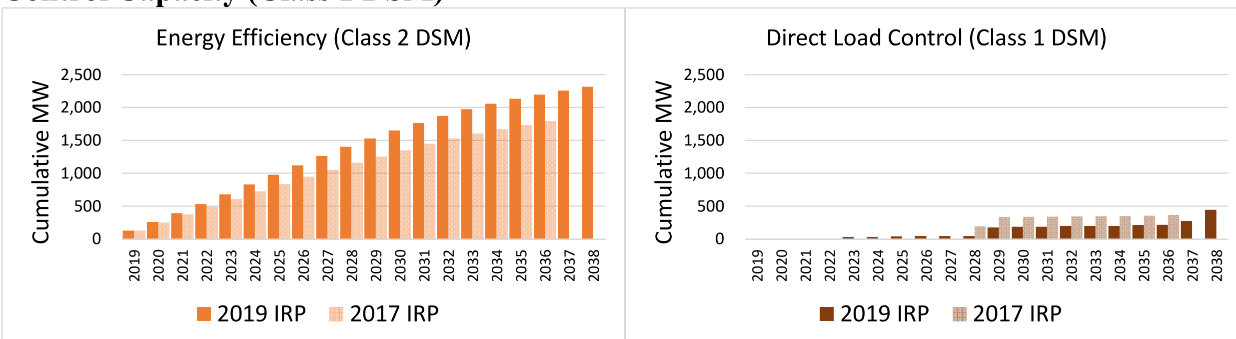




DSM resources continue to play a key role in PacifiCorp's resource mix. The chart to the left in Figure 1.7 compares total energy efficiency savings in the 2019 IRP preferred portfolio relative to the 2017 IRP preferred portfolio.

In addition to continued investment in energy efficiency programs, the preferred portfolio continues to show a role for incremental direct load control programs with total capacity reaching 444 MW by the end of the planning period. The chart to the right in Figure 1.7 compares total incremental capacity of direct load control program capacity in the 2019 IRP preferred portfolio relative to the 2017 IRP preferred portfolio and does not include capacity from existing programs.

Figure 1.7 – 2019 IRP Preferred Portfolio Energy Efficiency (Class 2 DSM) and Direct Load Control Capacity (Class 1 DSM)



Wholesale Power Market Prices and Purchases

Figure 1.8 shows that the 2019 IRP's base case forecast for natural gas and power prices has increased from those in the 2017 IRP and 2017 IRP Update. These forecasts are based on prices observed in the forward market and on projections from third-party experts. The higher power prices observed in the 2019 IRP are primarily driven by the assumption of a carbon price that is higher and starts earlier (2025) than what was assumed in the 2017 IRP Update (2030).[8] Moreover, the 2019 IRP assumed higher natural gas prices than either the 2017 IRP or 2017 IRP Update as Henry Hub, in particular, is boosted by increasing LNG exports. While not shown in the figure below, the 2019 IRP also evaluated low and high price scenarios when evaluating the cost and risk of different resource portfolios.

Figure 1.8 – Comparison of Power Prices and Natural Gas Prices in Recent IRPs

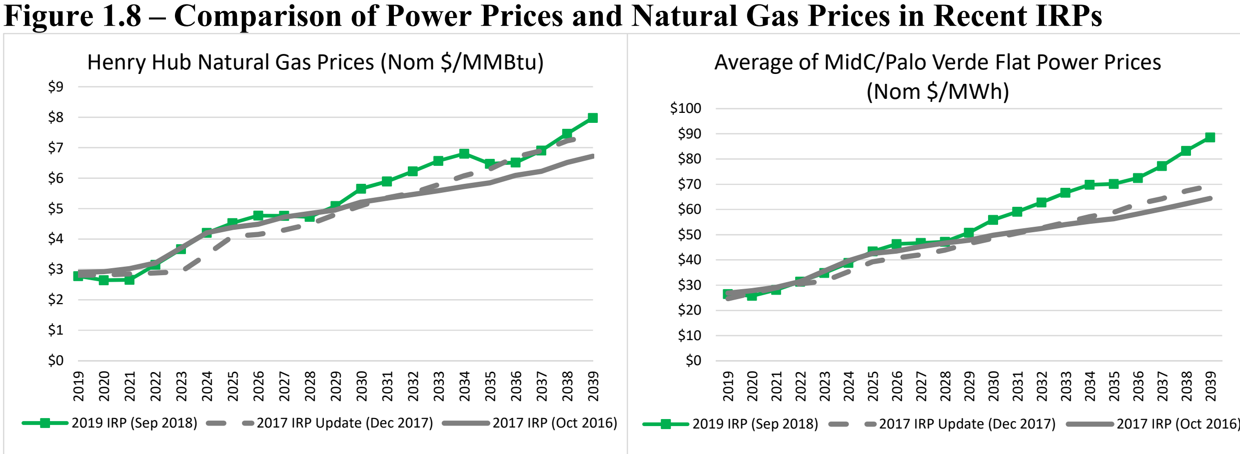
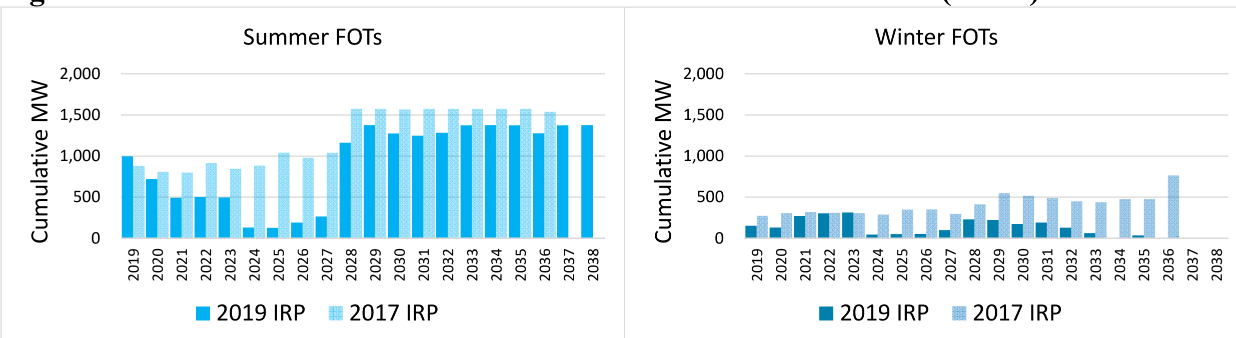


Figure 1.9 shows an overall decline in reliance on wholesale market firm purchases in the 2019 IRP preferred portfolio relative to the market purchases included in the 2017 IRP preferred portfolio. In particular, reliance on market purchases during summer peak periods averages 366

[8] The 2017 IRP did not assume a carbon price but, instead, reflected implementation of the Clean Power Plan.

MW per year over the 2020-2027 timeframe—down 60 percent from market purchases identified in the 2017 IRP preferred portfolio. This reduction in market purchases coincides with the period over which there are resource adequacy concerns in the region. While market purchases increase beyond 2027, PacifiCorp is actively participating in regional efforts to develop day-ahead markets and a resource adequacy program that will help unlock regional diversity and facilitate market transactions over the long term.

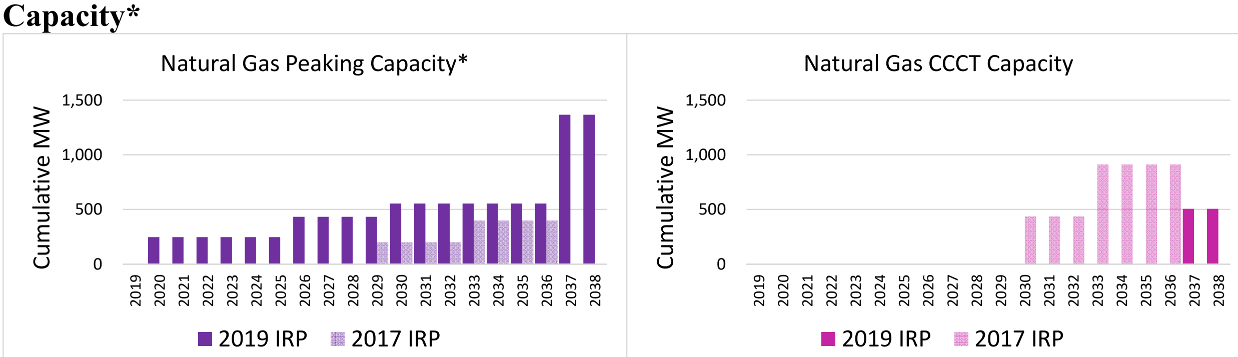
Figure 1.9 – 2019 IRP Preferred Portfolio Front Office Transactions (FOTs)



Natural Gas Resources

In the 2019 IRP preferred portfolio, Naughton Unit 3 is converted to natural gas in 2020, providing a low-cost resource to reliably serve our customers during peak-load periods. New natural gas peaking resources appear in the preferred portfolio starting in 2026, which is outside the action-plan window. This provides time for PacifiCorp to continue to evaluate whether non-emitting capacity resources can be used to supply the flexibility necessary to maintain system reliability long into the future.

Figure 1.10 – 2019 IRP Preferred Portfolio Natural Gas Peaking and Combined Cycle Capacity*



* Note: 2019 IRP natural gas peaking capacity includes the conversion of Naughton Unit 3 to natural gas in 2020 (247 MW).

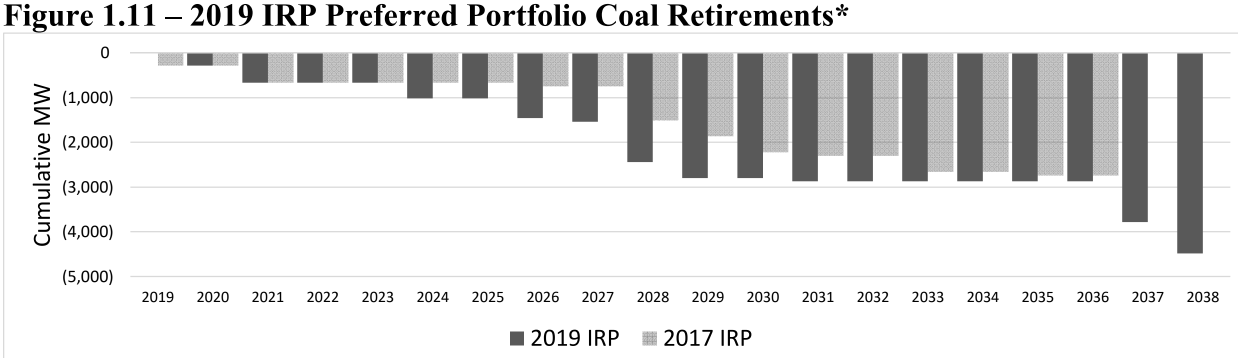
Coal Retirements

Coal resources have been an important resource in PacifiCorp's resource portfolio. Changes in how PacifiCorp has been operating these assets (i.e., by lowering operating minimums) has allowed the company to buy increasingly low-cost, zero-emissions renewable energy from market participants, which is accessed by our expansive transmission grid. PacifiCorp's coal resources will continue to play a pivotal role in following fluctuations in renewable energy as those units approach retirement dates. Driven in part by ongoing cost pressures on existing coal-fired facilities and dropping costs for new resource alternatives, of the 24 coal units currently serving PacifiCorp customers, the preferred portfolio includes retirement of 16 of the units by 2030 and 20 of the units by the end of the planning period in 2038. As shown in Figure 1.11, coal unit retirements in the 2019 IRP preferred portfolio will reduce coal-fueled generation capacity by over 1,000 MW by the end of 2023, nearly 1,500 MW by the end of 2025, nearly 2,800 MW by 2030, and nearly 4,500 MW by 2038.

Coal unit retirements scheduled under the preferred portfolio include:

- 2019 = Naughton Unit 3 (same as 2017 IRP), converted to natural gas in 2020
- 2020-2023 = Cholla Unit 4 (same as 2017 IRP)
- 2023 = Jim Bridger Unit 1 (instead of 2028 in the 2017 IRP)
- 2025 = Naughton Units 1-2 (instead of 2029 in the 2017 IRP)
- 2025 = Craig Unit 1 (same as 2017 IRP)
- 2026 = Craig Unit 2 (instead of 2034 in the 2017 IRP)
- 2027 = Dave Johnston Units 1-4 (same as 2017 IRP)
- 2027 = Colstrip Units 3-4 (instead of 2046 in the 2017 IRP)
- 2028 = Jim Bridger Unit 2 (instead of 2032 in the 2017 IRP)
- 2030 = Hayden Units 1-2 (same as 2017 IRP)
- 2036 = Huntington Units 1-2 (same as 2017 IRP)
- 2037 = Jim Bridger Units 3-4 (same as 2017 IRP)

Figure 1.11 – 2019 IRP Preferred Portfolio Coal Retirements*



* 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.

Carbon Dioxide Emissions

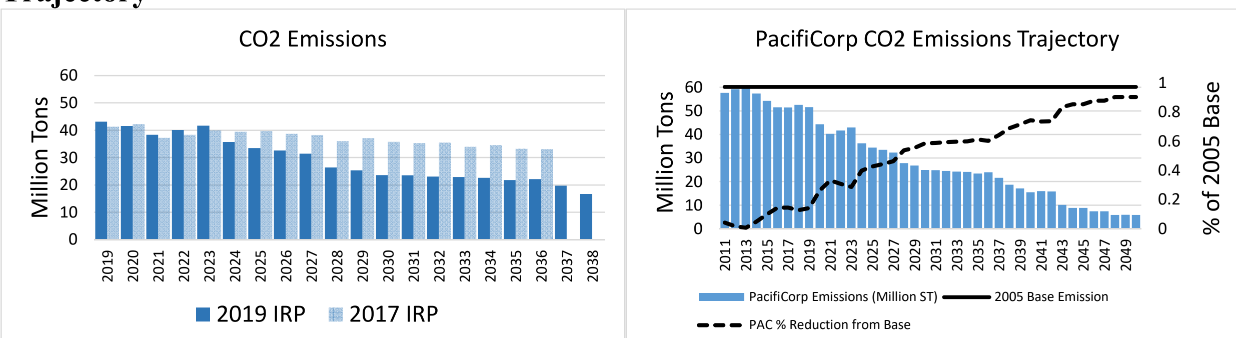
The 2019 IRP preferred portfolio reflects PacifiCorp's on-going efforts to provide cost-effective clean-energy solutions for our customers and accordingly reflects a continued trajectory of declining carbon dioxide (CO_2) emissions. PacifiCorp's emissions have been declining and continue to decline as a result of a number of factors, including PacifiCorp's participation in the Energy Imbalance Market (EIM), which reduces customer costs and maximizes use of clean energy; PacifiCorp's on-going expansion of renewable resources and transmission; and Regional Haze compliance that capitalizes on flexibility.

The chart on the left in Figure 1.12 compares projected annual CO_2 emissions between the 2019 IRP and 2017 IRP preferred portfolios. In this graph, emissions are not assigned to market purchases or sales, and in 2025, annual CO_2 emissions are down sixteen percent relative to the

2017 IRP preferred portfolio. By 2030, average annual CO_2 emissions are down 34 percent relative to the 2017 IRP preferred portfolio, and down 35 percent in 2035. By the end of the planning horizon, system CO_2 emissions are projected to fall from 43.1 million tons in 2019 to 16.7 million tons in 2038—a 61.3 percent reduction.

The chart on the right in Figure 1.12 includes historical data, assigns emissions at a rate of 0.4708 tons/MWh to market purchases (with no credit to market sales), and extrapolates projections out through 2050. This graph demonstrates that relative to a 2005 baseline (a ubiquitous baseline year in the industry), system CO_2 emissions are down 43 percent in 2025, 59 percent in 2030, 61 percent in 2035, 74 percent in 2040, 85 percent in 2045, and 90 percent in 2050.

Figure 1.12 – 2019 IRP Preferred Portfolio CO_2 Emissions and PacifiCorp CO_2 Emissions Trajectory*



*Note: PacifiCorp CO_2 Emissions Trajectory reflects actual emissions through 2018 from owned facilities, specified sources and unspecified sources. From 2019 through the end of the twenty-year planning period in 2038, emissions reflect those from the 2019 IRP preferred portfolio with market purchases assigned the California Air Resources Board default emission factor (0.4708 tons/MWh) – emissions from sales are not removed. Beyond 2038, emissions reflect the rolling average emissions of each resource from the 2019 IRP preferred portfolio through the life of the resource.

Renewable Portfolio Standards

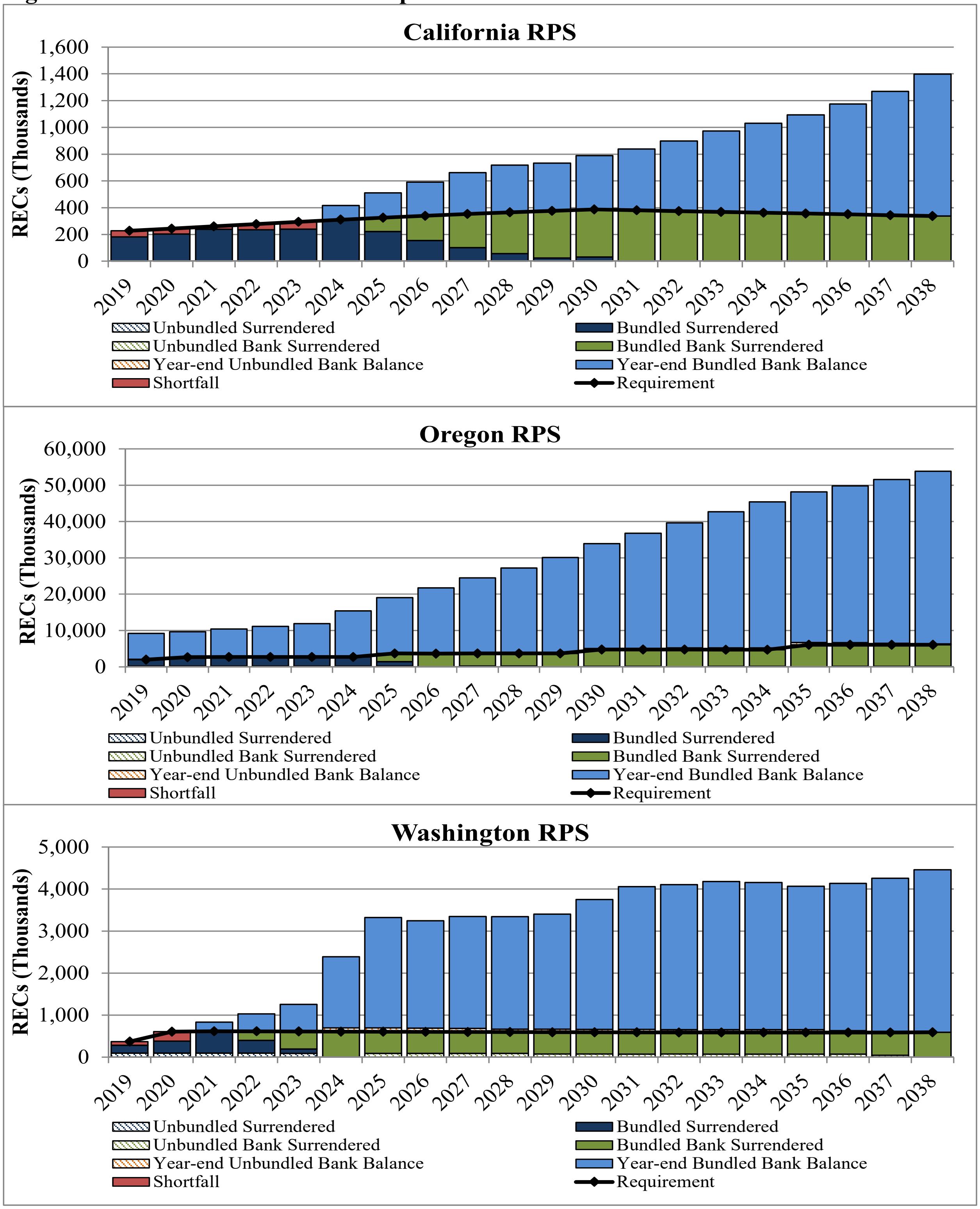
Figure 1.13 shows PacifiCorp's renewable portfolio standard (RPS) compliance forecast for California, Oregon, and Washington after accounting for new renewable resources in the preferred portfolio. While these resources are included in the preferred portfolio as cost-effective system resources and are 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 2038 with the addition of new renewable resources and transmission in the 2019 IRP preferred portfolio. The California RPS compliance position is also improved by the addition of new renewable resources and transmission in the 2019 IRP preferred portfolio but requires a small amount of unbundled renewable energy credit (REC) purchases under 150 thousand RECs per year to achieve compliance through the near term. Washington RPS compliance is achieved with the benefit of repowered wind assets located in the west side, Marengo, Leaning Juniper and Goodnoe Hills, increased system renewable resources contributing to the west side beginning 2021[9], and unbundled REC purchases under 300 thousand

[9] PacifiCorp will propose the Multi-State Protocol allocation methodology in a December 13, 2019 Washington general rate case (GRC) filing. The methodology would allocate a system generation share of all non-emitting system resources to Washington. The 2019 IRP Annual State RPS Compliance Forecast reflected in Figure 1.13 reflects PacifiCorp's proposal to be filed in the rate case starting in 2021. Upon approval, the effective date of the new allocation methodology would be January 1, 2021.

RECs per year through 2021. Under current allocation mechanisms, Washington customers do not benefit from the new renewable resources added to the east side of PacifiCorp's system. 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 2019 IRP preferred portfolio.

Figure 1.13 – Annual State RPS Compliance Forecast



Load and Resource Balance

A key element of PacifiCorp's IRP process is to assess its load and resource balance over the 20-year planning horizon. The load and resource balance relies on the ability for specific types of resources to meet our forecasted coincident system peak load while accounting for reserve requirements, which ensures reliable electric service for PacifiCorp customers. In developing the resource plan, PacifiCorp applies a 13 percent planning reserve margin to account for near-term and longer-term planning uncertainties.

Capacity Balance

Table 1.3 shows PacifiCorp's summer capacity position from 2020 through 2029, with coal unit retirement assumptions and incremental energy efficiency savings from the 2019 IRP preferred portfolio before adding any incremental new generating resources. Before accounting for uncommitted market purchases that are assumed to be available when developing resource portfolios, PacifiCorp is capacity deficit over the summer peak through the planning horizon. When accounting for uncommitted market purchases, PacifiCorp is capacity deficient beginning 2028. With continued load growth and assumed coal unit retirements, the summer capacity position deteriorates over time.

Table 1.3 – PacifiCorp 10-Year Summer Capacity Position Forecast (MW)

System (Summer)	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
Existing Resource Capacity Contribution	10,437	10,671	10,638	10,641	10,347	10,290	9,953	9,899	8,999	8,494
Available FOT Capacity Contribution	1,468	1,468	1,468	1,468	1,468	1,468	1,468	1,468	1,468	1,468
Total Existing Resource + FOTs	11,905	12,138	12,106	12,108	11,815	11,758	11,421	11,367	10,467	9,962
Obligation Net of Incremental DSM	9,876	9,882	9,918	9,953	9,982	10,005	9,962	9,966	9,985	9,998
13% Planning Reserve Margin	1,307	1,308	1,312	1,317	1,321	1,324	1,318	1,319	1,321	1,323
Obligation + 13% Planning Reserves	11,183	11,190	11,231	11,270	11,303	11,328	11,281	11,284	11,306	11,321
System Position without Uncommitted Market Purchases	(746)	(519)	(592)	(630)	(956)	(1,038)	(1,328)	(1,385)	(2,307)	(2,827)
Reserve Margin without Available FOTs	6%	8%	7%	7%	4%	3%	0%	-1%	-10%	-15%
System Position with Uncommitted Market Purchases Required to Meet Need	0	0	0	0	0	0	0	0	(839)	(1,359)
Reserve Margin with Available FOTs	13%	13%	13%	13%	13%	13%	13%	13%	5%	0%

Table 1.4 reflects a winter load and resource balance for the 2019 IRP and shows PacifiCorp's annual winter capacity position from 2020 through 2029, with coal unit retirement assumptions and incremental energy efficiency savings from the 2019 IRP preferred portfolio before adding any incremental new generating resources. Before accounting for uncommitted market purchases that are assumed to be available when developing resource portfolios, PacifiCorp is capacity deficient over the winter peak beginning 2024. When accounting for uncommitted market purchases, PacifiCorp is capacity deficient beginning 2029. As in the summer, with continued load growth and assumed coal unit retirements, the winter capacity position deteriorates over time.

Table 1.4 – PacifiCorp 10-Year Winter Capacity Position Forecast (MW)

System (Winter)	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
Existing Resource Capacity Contribution	11,627	10,770	10,746	10,671	9,560	9,558	9,212	9,124	8,382	7,949
Available FOT Capacity Contribution	1,468	1,468	1,468	1,468	1,468	1,468	1,468	1,468	1,468	1,468
Total Existing Resource + FOTs	13,095	12,238	12,214	12,139	11,027	11,026	10,680	10,592	9,850	9,416
Obligation Net of Incremental DSM	8,671	8,695	8,725	8,743	8,734	8,751	8,631	8,634	8,645	8,666
13% Planning Reserve Margin	1,150	1,153	1,157	1,160	1,158	1,161	1,145	1,145	1,147	1,150
Obligation + 13% Planning Reserves	9,821	9,848	9,883	9,902	9,892	9,912	9,776	9,779	9,792	9,815
System Position without Uncommitted Market Purchases	1,806	922	864	769	(333)	(354)	(564)	(655)	(1,410)	(1,867)
Reserve Margin without Available FOTs	34%	24%	23%	22%	9%	9%	7%	6%	-3%	-8%
System Position with Uncommitted Market Purchases Required to Meet Need	1,806	922	864	769	0	0	0	0	0	(399)
Reserve Margin with Available FOTs	34%	24%	23%	22%	13%	13%	13%	13%	13%	9%

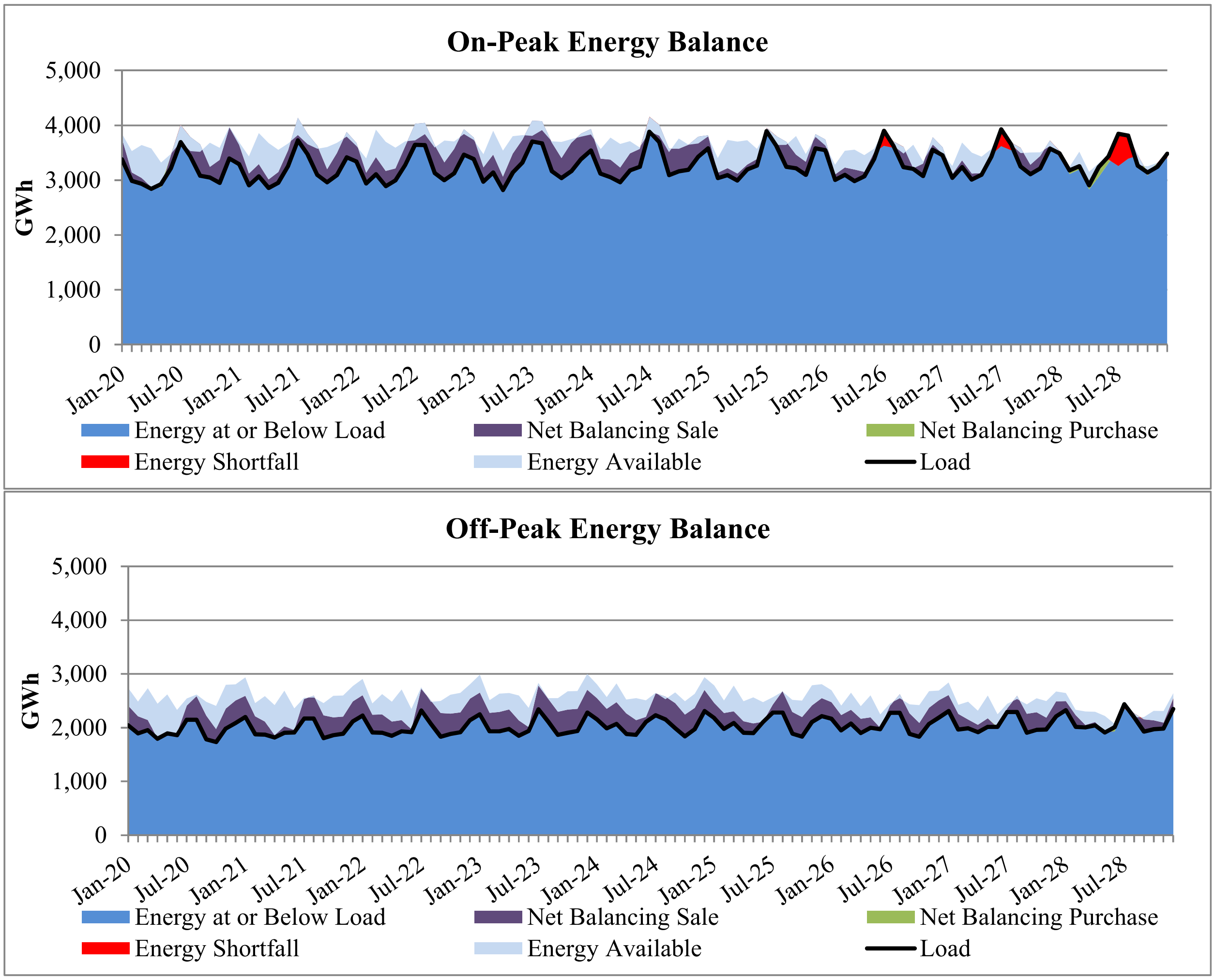
Energy Balance

The capacity position shows how existing resources and loads balance during the coincident peak summer and winter periods, accounting for assumed coal unit retirements and incremental energy efficiency savings from the 2019 IRP preferred portfolio. Outside of these peak periods, PacifiCorp economically dispatches its resources to meet changes in load while taking into consideration prevailing market conditions. In those periods when system resource costs are less than the prevailing market price for power, PacifiCorp can dispatch resources that, in aggregate, exceed then-current PacifiCorp customer load obligations, facilitating off-system wholesale market power sales that reduce costs for PacifiCorp customers. Conversely, at times when system resource costs are greater than prevailing market prices, system balancing wholesale market power 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 on behalf of its customers.

Figure 1.14 provides a snapshot of how existing system resources could be used to meet forecasted load across on-peak and off-peak periods given current planning assumptions and recent wholesale power and natural gas prices.[10] The figure shows expected monthly energy production from system resources during on-peak and off-peak periods in relation to load, reflecting coal unit retirement assumptions and incremental energy efficiency savings from the 2019 IRP preferred portfolio before adding any new generating resources. At times, system resources are economically dispatched above load levels facilitating net system balancing sales. This occurs more often in off-peak periods than in on-peak periods. At other times, economic conditions result in net system balancing purchases, which occur more often during on-peak periods. Figure 1.14 also shows how much system 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 addition of any new generating resources to the portfolio. During on-peak periods, the first notable energy shortfall appears in summer 2026. There are no energy shortfalls during off-peak periods over this timeframe.

[10] On-peak hours are defined as hour ending 7 AM through 10 PM, Monday through Saturday. Off-peak periods are all other hours.

Figure 1.14 – Economic System Dispatch of Existing Resources in Relation to Monthly Load



2019 IRP Advancements and Supplemental Studies

IRP Advancements

During each IRP planning cycle, PacifiCorp identifies and implements advancements to continuously improve the IRP for its customers, other stakeholders, and regulatory commissions. Some of the key advancements implemented in the 2019 IRP include:

- Coal Studies
  PacifiCorp built upon prior IRP coal unit analysis with a robust and comprehensive analysis of its coal fleet. Results of this analysis, described in more detail in the 2019 IRP Volume II, Appendix R, Coal Studies, informed the portfolio-development phase of the 2019 IRP.

- Endogenous Modeling of Transmission Upgrades
  As part of it 2019 IRP, PacifiCorp was successfully able to provide its System Optimizer (SO) model with the ability to endogenously view costs and transmission capability associated with certain transmission upgrades that allowed for selection of specific transmission investments that coincide with new resource additions. This is an improvement from prior IRPs, where transmission upgrades and associated costs could only be coarsely evaluated in SO model

resource selections that required post-modeling assessment of upgrade costs after resource portfolios were developed. New transmission modeling capabilities include the endogenous consideration of 1) new incremental transmission options tied to resource selections, 2) existing transmission rights tied to the use of post-retirement brownfield sites, and 3) incorporation of costs associated with these transmission options. Limitations of this approach include transmission options that interact with multiple or complex elements of the IRP transmission topology. These transmission options were therefore studied as sensitivity cases in the 2019 IRP.

- Targeted Portfolio Reliability Analysis
  PacifiCorp developed in its 2019 IRP an approach for assessing the reliability of its portfolios and the ability of each unique resource portfolio to meet reliability requirements. With significant levels of economic renewable resource being selected in every resource portfolio, PacifiCorp found that subsequent modeling of these resource portfolios using the Planning and Risk model (PaR), which considers more granularity and an explicit accounting of operating reserve requirements, consistently identified capacity shortfalls needed to maintain reliable operation of the system. PacifiCorp developed a process by producing hourly deterministic PaR runs for select years to identify the incremental need for reliability resources that could then be added to a resource portfolio to ensure there is sufficient flexible capacity to meet reliability requirements.

- Improved Storage Modeling
  As PacifiCorp observed an increased presence of battery storage resources in many resource portfolios, it developed a modeling tool to optimize charge and discharge cycles against a “net load” profile (load net of wind and solar generation) to better represent battery storage resources in a resource portfolio that has increasing levels of incremental renewable resources.

- Improvements in Modeling Assumptions
  In the 2019 IRP, PacifiCorp improved granularity of its analysis of reserve requirements from monthly to hourly. PacifiCorp also incorporated into its modeling capacity contribution values that decline with increasing penetration of wind and solar resources.

- Stakeholder Feedback Forms
  In its 2019 IRP, PacifiCorp expanded upon its stakeholder feedback form process by posting not only the forms received from stakeholders but also PacifiCorp’s response throughout the public-input process. PacifiCorp received and responded to over 133 stakeholder feedback forms in the 2019 IRP up from 19 in the 2017 IRP.

- Stakeholder Requests
  PacifiCorp was able to accommodate numerous stakeholder requests to develop additional stakeholder-driven studies during the public-input process. PacifiCorp and stakeholders identified and requested alternative modeling scenarios, including proposed changes to methodology such as an alternate DSM-bundling methodology, which was informed by discussion during the public-input process. Further, and as informed by PacifiCorp’s analysis during the coal studies, initial portfolios were developed with the ability for stakeholder input to request other variations of coal retirement cases. Results from some of these studies led PacifiCorp to consider additional scenarios.

- Public-Input Meetings
  PacifiCorp continued to coordinate with stakeholders to include video conference connections with locations in Cheyenne, Wyoming, and Denver, Colorado, to supplement the existing video conference connection between Portland, Oregon, and Salt Lake City, Utah, in addition to the phone conference capability. PacifiCorp responded to stakeholder requests to schedule shorter lunch breaks and start earlier on the second day of two-day public-input meetings.

Supplemental Studies

PacifiCorp's 2019 IRP relies on numerous supplemental studies that support the derivation of specific modeling assumptions critical to its long-term resource plan. A description of these studies, discussed in more detail in appendices filed with the 2019 IRP, is provided below.

- Conservation Potential Assessment
  An updated conservation potential assessment (CPA), prepared by Applied Energy Group (commissioned by PacifiCorp) and the Energy Trust of Oregon was prepared to develop DSM resource potential and cost assumptions specific to PacifiCorp's service territory. The CPA supports the cost and DSM savings data used during the portfolio-development process.

- Private Generation Resource Assessment
  This supplemental study, prepared by Navigant Consulting, Inc., was refreshed for the 2019 IRP to produce updated private generation penetration forecasts for solar photovoltaic, small-scale wind, small-scale hydro, combined heat and power reciprocating engines, and combined heat and power micro-turbines specific to PacifiCorp's service territory. The private generation penetration forecasts from this study are applied as a reduction to forecasted load throughout the IRP modeling process and used in developing assumptions for the low private generation sensitivity and high generation sensitivity cases.

- Western Resource Adequacy Evaluation
  PacifiCorp updated its analysis of regional resource adequacy to support its assumptions for wholesale power market purchase limits adopted for the 2019 IRP. The western resource adequacy evaluation presents data from the Western Electricity Coordinating Council's Power Supply Assessment, reviews recent resource adequacy studies performed for the Pacific Northwest region, and summarizes PacifiCorp's historical peak period market purchase data.

- Planning Reserve Margin Study
  The 2019 IRP was developed targeting a 13 percent planning reserve margin, which influences the need for new resources and is applied during the portfolio development process. In the 2019 IRP planning reserve margin study, PacifiCorp analyzes the relationship between cost and reliability among ten different planning reserve margin levels, accounting for variability and uncertainty in load and generation resources.

- Capacity Contribution Study
  PacifiCorp made significant enhancements to the capacity contribution values applied to certain resources for the 2019 IRP. At the start of the IRP process, PacifiCorp developed resource-specific capacity contribution values for wind, solar, storage, energy efficiency, and load control programs, starting with the capacity factor approximation method ("CF Method") used in previous IRPs. For wind and solar, capacity contribution values were modified to account for resource penetration levels based on equivalent conventional power studies. For storage and load control programs, the capacity factor approximation calculation was refined

to account for outage durations in each iteration, to better assess the capability of these energy-limited resources. These initial values were used in the portfolio development process. As capacity contribution is dependent on all components in a portfolio, PacifiCorp assessed the reliability of every portfolio. For the preferred portfolio, the effective capacity contribution for each resource was reassessed based on an updated CF Method to inform development of the load and resource balance.

- Flexible Reserve Study
  This study evaluates the need for flexible resources as a result of the variability and uncertainty in load, wind, solar, and other generation resources. The study produces an estimate of flexible reserve needs for each hour that accounts for the specific load, wind, and solar resources being evaluated in the PaR model. Reserve costs estimated in the study are also applied during the portfolio development process in the SO model.

- Stochastic Parameter Update
  PacifiCorp's preferred portfolio-selection process relies, in part, on stochastic risk analysis using Monte Carlo random sampling of stochastic variables. Stochastic variables include natural gas and wholesale electricity prices, load, hydro generation, and unplanned thermal outages. For the 2019 IRP, PacifiCorp updated its stochastic parameter input assumptions with more current historical data.

- Smart Grid
  PacifiCorp has included an update on its Smart Grid efforts with a focus on transmission and distribution systems and customer information.

- Renewable Resources Assessment
  Commissioned by PacifiCorp for its 2019 IRP, Burns and McDonnell Engineering Company (BMcD) evaluated various renewable energy resources in support of the development of PacifiCorp's IRP. The Renewable Resources Assessment is screening-level in nature and includes a comparison of technical capabilities, capital costs, and operations and maintenance costs that are representative of renewable energy and storage technologies.

- Energy Storage Potential Evaluation
  Energy storage resources can provide a variety of grid services since they are highly flexible, with the ability to respond to dispatch signals and act as both a load and a resource. This study provides details on these grid services and on how energy storage resources can be configured and sited to maximize the benefits they provide.

Action Plan

The 2019 IRP action plan identifies specific resource actions PacifiCorp will take over the next two to four years to deliver resources included in the preferred portfolio. Action items are based on the type and timing of resources in the preferred portfolio, findings from analysis completed during the development of the 2019 IRP, and other resource activities described in the 2019 IRP. Table 1.5Table 1.5 details specific 2019 IRP action items by category.

Table 1.5 – 2019 IRP Action Plan

Action Item	1. Existing Resource Actions
1a	**<u>Naughton Unit 3:</u>** • PacifiCorp will complete the gas conversion of Naughton Unit 3, including completion of all required regulatory notices and filings, in 2020. Initiate procurement of materials in Q4 2019. Conversion completed in 2020.
1b	**<u>Cholla Unit 4:</u>** • PacifiCorp will initiate the process of retiring Cholla Unit 4, including all required regulatory notices and filings, as soon as practicable, but will remove Cholla Unit 4 from service no later than January 2023 and earlier if possible. • PacifiCorp will continue to coordinate with the plant operator to transition employees, develop plans to cease plant operations, safely remove the unit from service, finalize decommissioning plans and confirm joint-ownership obligations; complete required regulatory notices and filings; administer termination, amendment, or close-out of existing permits, contracts and other agreements; and coordinate with state and local stakeholders as appropriate. • By the end of Q1 2020, the plant operator will be requested to develop plans to cease plant operations, safely remove the unit from service, finalize decommissioning plans, and confirm joint-ownership obligations. • By the end of Q2 2020, the plant operator will be requested to file required transmission interconnection and transmission services unit retirement notices/request for study. • By the end of Q4 2020, PacifiCorp will finalize an employee transition agreement with the plant operator.
1c	**<u>Jim Bridger Unit 1:</u>** • PacifiCorp will initiate the process of retiring Jim Bridger Unit 1 by the end of December 2023, including completion of all required regulatory notices and filings. By the end of Q2 2020, file a request with PacifiCorp transmission to study the year-end 2023 retirement of Jim Bridger Unit 1. By the end of Q2 2021, confirm transmission system reliability assessment and year-end 2023 retirement economics in 2021 IRP filing. • By the end of Q2 2021, finalize an employee transition plan.

	• By the end of Q2 2021, develop a community action plan in coordination with community leaders. • By the end of Q4 2021, initiate the process with the Wyoming Public Service Commission for approval of a reverse request for proposals for a potential sale of Jim Bridger Unit 1. • By the end of Q4 2023, administer termination, amendment, or close-out of existing permits, contracts, and other agreements.
1d	**Naughton Units 1-2:** • 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 2022, file a request with PacifiCorp transmission to study the year-end 2025 retirement of Naughton Units 1 and 2. • By the end of Q2 2022, finalize an employee transition plan. • By the end of Q2 2022, develop a community action plan in coordination with community leaders. • By the end of Q2 2023, confirm transmission system reliability assessment and year-end 2025 retirement economics in 2023 IRP filing. • By the end of Q4 2023, initiate the process with the Wyoming Public Service Commission for approval of a reverse request for proposals for a potential sale of Naughton Units 1 and 2. • By the end of Q4 2023, administer termination, amendment, or close-out of existing permits, contracts, and other agreements.
1e	**Craig Unit 1:** • The plant operator will be requested to administer termination, amendment, or close-out of existing permits, contracts, and other agreements to support retiring Craig Unit 1, including completion of all required regulatory notices and filings, by the end of December 2025.
Action Item	**2. New Resource Actions**
2a	**Customer Preference Request for Proposals:** • PacifiCorp will work with customers to achieve their respective resource preference requirements. By the end of Q4 2019, sign a fifteen year 80 MW Power Purchase Agreement (PPA) for Utah solar for six Utah Schedule 34 customers. By the end of Q4 2019, sign two 20-year PPAs of approximately 80 MW for a large Utah Schedule 34 customer. Monitor the finalization of rules by the Public Service Commission of Utah for HB 411 (anticipated by the end of Q1 2020), that provides a path forward for development of a program for participating communities to begin procuring renewable resources.

2b	**<u>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 2023. • By the end of Q4 2019, file a request for interconnection queue reform with the Federal Energy Regulatory Commission (FERC) and make state filings to initiate the process of identifying an independent evaluator. • In Q1 2020, file a draft all-source RFP with the Public Utility Commission of Oregon, the Public Service Commission of Utah, and the Washington Utilities and Transportation Commission, as applicable. • In Q2 2020, receive approval from FERC to reform the interconnection queue. • In Q2 2020, receive approval of the all-source RFP from applicable state regulatory commissions and issue the RFP to the market. • In Q3 2020, identify a preliminary final shortlist from the all-source RFP and initiate transmission interconnection studies consistent with queue reform as approved by FERC. • In Q2 2021, 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 2022 execute definitive agreements with winning bids from the all-source RFP. • By Q4 2023, winning bids from the all-source RFP achieve commercial operation.
Action Item	**3. Transmission Action Items**
3a	**<u>Energy Gateway South:</u>** • By December 31, 2023, PacifiCorp will seek to build the approximately 400-mile, 500-kilovolt (kV) transmission line from the Aeolus substation near Medicine Bow, Wyoming to the Clover substation near Mona, Utah. • By Q2 2021, receive the final CPCN from the Wyoming Public Service Commission and the Public Service Commission of Utah (initial filing dates for the CPCN to be determined after stakeholder engagement). • By the end of Q4 2021, issue full notice to proceed to construct Energy Gateway South. • In Q4 2023, construction of Energy Gateway South is completed and placed in service.
3b	**<u>Utah Valley Reinforcements:</u>** • Utah Valley Reinforcements: As necessary to facilitate interconnection of customer-preference resources, PacifiCorp will proceed with system reinforcements in the Utah Valley. • In Q2 2020, complete the Spanish Fork 345 kV/138 kV transformer upgrade. • In Q4 2020, complete rebuild of approximately five miles of the Spanish Fork-Timp138 kV line in the Utah Valley.

3c	**<u>Northern Utah Reinforcements:</u>** • Rebuild two miles of the Morton Court –Fifth West 138 kV line. • Loop existing Populus–Terminal 345 kV line into both Bridgerland and Ben Lomond; build 345 kV yard with 345/138 transformer and 138 kV yard buildout at Bridger plus ancillary 345 kV and 230 kV circuit breakers at Ben Lomond. • Complete identified plan of service in support of 2019 IRP preferred portfolio for resource additions in the northern Utah.
3d	**<u>Utah South Reinforcements:</u>** • Develop plan of service in support of 2019 IRP preferred portfolio for resource additions in southern Utah. • Complete rebuild of the Mona –Clover #1 & #2 345 kV lines. • Identify route and terminals for new approximately 70-mile 345 kV line in southern/central Utah. • Yakima Washington Reinforcements: To facilitate interconnection of preferred portfolio resources in the Yakima area, PacifiCorp will proceed with protection system and remedial action scheme upgrades to local 230 kV and 115 kV substations not otherwise included in network upgrade requirements for generator interconnection requests. • In Q2 2020, complete the Vantage-Pomona Heights 230 kV line (in process). • By Q2 2022, establish the type and location of new resources and finalize project scope, as necessary.
3e	**<u>Yakima Washington Reinforcements:</u>** • To facilitate interconnection of preferred portfolio resources in the Yakima area, PacifiCorp will proceed with protection system and remedial action scheme upgrades to local 230 kV and 115 kV substations not otherwise included in network upgrade requirements for generator interconnection requests. • In Q2 2020, complete the Vantage-Pomona Heights 230 kV line (in process). • By Q2 2022, establish the type and location of new resources and finalize project scope, as necessary.
3f	**<u>Boardman to Hemmingway (B2H):</u>** • Continue to support the project under the conditions of the Boardman to Hemingway Transmission Project Joint Permit Funding Agreement. • Continue to participate in the development and negotiations of the construction agreement. • Continue analysis in efforts to identify customer benefits that may include contributions to reliability, interconnection of additional resources, geographical diversity of intermittent resources, Energy Imbalance Market, and resource adequacy. • Continue negotiations for plan of service post B2H for parties to the permitting agreement.

<table>
<tr><td>3g</td><td><u>Energy Gateway West:</u>
Energy Gateway West Segment D.2, continue construction with target in-service date of 12/31/2020.
Continue permitting for the Energy Gateway transmission plan, with near term targets as follows:
For Segments D.3, and E, continue funding of the required federal agency permitting environmental consultant actions required as part of the federal permits. Also, continue to support the projects by providing information and participating in public outreach.</td></tr>
<tr><td>Action Item</td><td>4. Demand Side Management (DSM) Actions</td></tr>
<tr><td>4a</td><td><u>Energy Efficiency Targets:</u>
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 will be provided in Appendix D in Volume II of the 2019 IRP.
<table>
<tr><th>Year</th><th>Annual Incremental Energy (GWh)</th><th>Annual Incremental Capacity (MW)</th></tr>
<tr><td>2019</td><td>562</td><td>126</td></tr>
<tr><td>2020</td><td>536</td><td>132</td></tr>
<tr><td>2021</td><td>538</td><td>133</td></tr>
<tr><td>2022</td><td>571</td><td>143</td></tr>
</table>
* Note, Class 2 DSM capacity figures reflect projected maximum annual hourly energy savings, which is similar to a nameplate rating for a supply-side resource.
Energy Efficiency Bundling: PacifiCorp will continue to evaluate alternate bundling methodologies of Class 2 DSM in the 2019 IRP.
Direct-Load Control: PacifiCorp will acquire cost-effective Class 1 DSM (i.e., demand response) in Utah targeting approximately 29 MW of incremental capacity from 2020 through 2023.</td></tr>
<tr><td>Action Item</td><td>5. Front Office Transactions</td></tr>
<tr><td>5a</td><td><u>Market Purchases:</u>
Acquire short-term firm market purchases for on-peak delivery from 2019-2021 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.</td></tr>
</table>

Action Item	6. Renewable Energy Credit Actions
6a	**Renewable Portfolio Standards:** • PacifiCorp will pursue unbundled RFPs to meet its state renewable portfolio standard (RPS) compliance requirements. • As needed, issue RFPs seeking then current-year vintage unbundled RECs that will qualify in meeting California RPS targets through 2020. As needed, issue RFPs seeking then current-year or forward-year vintage unbundled RECs that will qualify in meeting Washington RPS targets.
6b	**Renewable Energy Credit Sales:** • Maximize the sale of RECs that are not required to meet state RPS compliance obligations.

CHAPTER 2 – INTRODUCTION

PacifiCorp files an Integrated Resource Plan (IRP) on a biennial basis with the state utility commissions of Utah, Oregon, Washington, Wyoming, Idaho, and California. This IRP fulfills the company's commitment to develop a long-term resource plan that considers cost, risk, uncertainty, and the long-run public interest. It was developed through a collaborative public-input process with involvement from regulatory staff, advocacy groups, and other interested parties. As the owner of the IRP and its action plan, all policy judgments and decisions concerning the IRP are ultimately made by PacifiCorp in light of its obligations to its customers, regulators, and shareholders.

PacifiCorp's selection of the 2019 IRP preferred portfolio is supported by comprehensive data analysis and an extensive stakeholder input-process, described in the chapters that follow. PacifiCorp's preferred portfolio continues investments in new wind, transmission, and demand-side management (DSM), while adding significant solar and battery. By 2025, the preferred portfolio includes nearly 3,000 megawatt (MW) of new solar resources, more than 3,500 MW of new wind resources, nearly 600 MW of battery storage capacity (all of which is combined with new solar resources), 860 MW of incremental energy efficiency resources and new direct load control capacity.

Over the 20-year planning horizon, the preferred portfolio includes more than 4,600 MW of new wind resources, more than 6,300 MW of new solar resources, more than 2,800 MW of battery storage by 2038 (nearly 1,400 MW of which are stand-alone storage resources starting in 2028), and more than 1,890 MW of incremental energy efficiency resources and new direct load control capacity.

To facilitate the delivery of new renewable energy resources to PacifiCorp customers across the West, the preferred portfolio includes the construction of a 400-mile transmission line known as Gateway South connecting southeastern Wyoming and northern Utah.

Other significant studies conducted to support analysis in the 2019 IRP include:

- An updated demand-side management resource conservation potential assessment;
- A private generation study for PacifiCorp's service territory;
- A renewable resources assessment;
- A planning reserve margin study;
- A western region resource adequacy assessment;
- A capacity contribution study;
- A flexible reserve study developed in coordination with a technical review committee;
- Updated stochastic parameters; and
- An updated load and resource balance.

Finally, the 2019 IRP reflects continued alignment efforts with PacifiCorp's annual ten-year business planning process. The purpose of the alignment, initiated in 2008, is to:

- Provide corporate benefits in the form of consistent planning assumptions;

- Ensure that business planning is informed by the IRP portfolio analysis, and, likewise, that the IRP accounts for near-term resource affordability concerns as they relate to capital budgeting; and
- Improve the overall transparency of PacifiCorp's resource planning processes to public stakeholders.

This chapter outlines the components of the 2019 IRP, summarizes the role of the IRP, and provides an overview of the public process.

2019 Integrated Resource Plan Components

The basic components of PacifiCorp's 2019 IRP include:

- Set of IRP principles and objectives adopted for the IRP effort (this chapter).
- Assessment of the planning environment, market trends and fundamentals, legislative and regulatory developments, and current procurement activities (Chapter 3).
- Description of PacifiCorp's transmission planning efforts and activities (Chapter 4).
- Load and resource balance on a capacity and energy basis based on the preferred portfolio and determination of the load and energy positions for the front ten years of the twenty year planning horizon (Chapter 5).
- Profile of resource options considered for addressing future capacity and energy needs (Chapter 6).
- Description of the IRP modeling, including a description of the resource portfolio development process, cost and risk analysis, and preferred portfolio selection process (Chapter 7).
- Presentation of IRP modeling results, and selection of top-performing resource portfolios and PacifiCorp's preferred portfolio including sensitivities (Chapter 8).
- Presentation of PacifiCorp's 2019 IRP action plan linking the company's preferred portfolio with specific implementation actions, including an accompanying resource acquisition path analysis and discussion of resource procurement risks (Chapter 9).

The IRP appendices, included as a Volume II, contain the items listed below.

- Load Forecast Details (Volume II, Appendix A),
- IRP Regulatory Compliance (Volume II, Appendix B),
- Public Input Process (Volume II, Appendix C),
- Demand Side Management Resources (Volume II, Appendix D),
- Smart Grid discussion (Volume II, Appendix E),
- Flexible Reserve Study (Volume II, Appendix F),
- Plant Water Consumption data (Volume II, Appendix G),
- Stochastic Parameters (Volume II, Appendix H),
- Planning Reserve Margin Study (Volume II, Appendix I),
- Western Resource Adequacy Evaluation (Volume II, Appendix J),
- Capacity Expansion Results Detail (Volume II, Appendix K),
- Stochastic Simulation Results (Volume II, Appendix L),
- Case Study Fact Sheets (Volume II, Appendix M),
- Capacity Contribution Study (Volume II, Appendix N),

- Private Generation Study (Volume II, Appendix O),
- Renewable Resources Assessment (Volume II, Appendix P),
- Energy Storage Potential Evaluation (Volume II, Appendix Q) , and
- Coal Studies (Volume II, Appendix R).

In an effort to improve transparency PacifiCorp is also providing data discs for the 2019 IRP. These discs support and provide additional details for the analysis described within the document. Discs containing confidential information are provided separately under non-disclosure agreements, or specific protective orders in docketed proceedings.

The Role of PacifiCorp's Integrated Resource Planning

PacifiCorp's IRP mandate is to assure, on a long-term basis, an adequate and reliable electricity supply at a reasonable cost and in a manner "consistent with the long-run public interest."[1] The main role of the IRP is to serve as a roadmap for determining and implementing PacifiCorp's long-term resource strategy according to this IRP mandate. In doing so, it accounts for state commission IRP requirements, the current view of the planning environment, corporate business goals, and uncertainty. As a business planning tool, it supports informed decision-making on resource procurement by providing an analytical framework for assessing resource investment tradeoffs, including supporting Request for Proposal (RFP) bid evaluation efforts. As an external communications tool, the IRP engages numerous stakeholders in the planning process and guides them through the key decision points leading to PacifiCorp's preferred portfolio of generation, demand-side, and transmission resources.

While PacifiCorp continues to plan on a system-wide basis, the company recognizes that new state resource acquisition mandates and policies add complexity to the planning process and present challenges to conducting resource planning on this basis.

Public-Input Process

The IRP standards and guidelines for certain states require PacifiCorp to have a public input process allowing stakeholder involvement in all phases of plan development. PacifiCorp organized six state meetings and held 18 public-input meetings, some of which spanning two days to facilitate information sharing, collaboration, and expectations for the 2019 IRP. The topics covered all facets of the IRP process, ranging from specific input assumptions to the portfolio modeling and risk analysis strategies employed. Table 2.1 lists the public input meetings/conferences and highlights major agenda items covered. Volume II, Appendix C (Public Input Process) provides more details concerning the public-input process.

Table 2.1 – 2019 IRP Public Input Meetings

Meeting Type	Date	Main Agenda Items
State Meeting	6/11/2018	Oregon state stakeholder comments

[1] The Public Utility Commission of Oregon and Public Service Commission of Utah cite "long-run public interest" as part of their definition of integrated resource planning. Public interest pertains to adequately quantifying and capturing for resource evaluation any resource costs external to the utility and its ratepayers. For example, the Public Service Commission of Utah cites the risk of future internalization of environmental costs as a public interest issue that should be factored into the resource portfolio decision-making process.

Meeting Type	Date	Main Agenda Items
State Meeting	6/12/18	Washington state stakeholder comments
State Meeting	6/18/18	Idaho state stakeholder comments
State Meeting	6/19/18	Wyoming state stakeholder comments
State Meeting	6/20/18	Utah state stakeholder comments
State Meeting	8/9/18	Utah State Stakeholder Meeting on IRP Process
General Meeting (2-Day)	6/28/18	2019 IRP Kick-off Meeting, Model Overview, Unit-by-Unit Coal Study Results
	6/29/18	Demand-Side Management Workshop
General Meeting (2-Day)	7/26/18	Energy Storage Workshop, Renewable Resource Schedules and Load Forecast, Distribution System Planning, Supply-Side Resource Study
	7/27/18	Environmental Policy, Renewable Portfolio Standards, Modeling Assumptions and Study Updates
General Meeting (2-Day)	8/30/18	Private Generation Study, Conservation Potential Assessment and Energy Efficiency Credits, Portfolio Development Process and Initial Sensitivity Studies, Flexible Reserve Study
	8/31/18	Market Reliance Assessment, Planning Reserve Margin Study, Capacity Contribution Study
General Meeting (2-Day)	9/26/18	Draft Supply-Side Resource Table, Intra-Hour Flexible Resource Credit, Environmental Policy, Price-Policy Scenarios, Transmission Overview and Updates
	9/27/18	Flexible Reserve Study Cost Results, Planning Reserve Margin Study and Capacity Contribution Study Results, Portfolios Discussion/Coal Studies Next Steps, Demand-Side Management Credits and Conservation Potential Assessment
General Meeting (phone conference)	10/9/18	Supply-Side Resource Table, Intra-Hour Flexible Resource Credits, Updated CO_2 Assumptions
General Meeting	11/1/18	Supply-Side Resource Table, Modeling Improvements and Updates, Update on Coal Studies
General Meeting (2-Day)	12/3/18	Coal Studies Discussion
	12/4/18	Coal Studies Discussion
General Meeting	1/24/19	Capacity Contribution Values for Energy-Limited Resources, Coal Studies Discussion
General Meeting (phone conference)	2/21/19	General Updates, Summary of Oregon Energy Efficiency Analysis Results
General Meeting	3/21/19	Coal Studies Discussion
General Meeting	4/25/19	Coal Studies Discussion
General Meeting (2-Day)	5/20/19	Conservation Potential Assessment, DSM Bundling Methodology, Updated Portfolio Matrix and Analysis
	5/21/19	Portfolio Analysis Discussion
General Meeting (2-Day)	6/20/19	Modeling Updates, Portfolio Analysis Results
	6/21/19	Portfolio Analysis Results
DSM Workshop	7/12/19	Conservation Potential Assessment, Demand-Side Management Portfolio Methodology
General Meeting (phone conference)	7/18/19	General Updates
General Meeting	9/5/19	Portfolio Analysis Results
General Meeting (2-Day)	10/3/19	Preferred Portfolio and Action Plan, Portfolio Development and Selection
	10/4/19	Portfolio Development and Selection, Sensitivities

In addition to the public-input meetings, PacifiCorp used other channels to facilitate resource planning-related information sharing and stakeholder input throughout the IRP process. The company maintains a public website: (www.pacificorp.com/energy/integrated-resource-plan.html), an e-mail "mailbox" (irp@pacificorp.com), and a dedicated IRP phone line (503-813-5245) to support communications and inquiries among participants. Additionally, a Stakeholder Feedback Form was used to provide opportunities for stakeholders to submit additional input and ask questions throughout the 2019 IRP public input process. The submitted forms, as well as PacifiCorp's responses to these feedback forms are located on the PacifiCorp's IRP website: www.pacificorp.com/energy/integrated-resource-plan/comments.html. A summary of stakeholder feedback forms received and company response was provided during the public-input meetings.

CHAPTER 3 – PLANNING ENVIRONMENT

CHAPTER HIGHLIGHTS

- In 2009 Appalachia (mostly Pennsylvania and West Virginia), produced almost no natural gas; by late 2013 it was producing almost 12 billion cubic feet per day (BCF/D) and by end-of-year 2018, Appalachia was producing over 28 BCF/D. In short, supply from Appalachia continues to grow as volumes and costs prove to be, respectively, higher and lower than anticipated. Today, Appalachia accounts for 34 percent of the nation's gas supply, and by 2040 is expected to account for 44 percent, spurred by increased drilling efficiencies and rising demand. Day-ahead 2018 Henry Hub prices averaged $3.15/Million British thermal units (MMBtu), down 64 percent from 2008 prices.
- Federal and state tax credits, declining capital costs, and improved technology performance have put wind and solar "in the money" in areas of high potential. As such, wind and solar will dominate U.S. capacity additions for the next decade. To better integrate these resources into the larger grid requires more flexible generation, transmission, new storage technologies, and market design changes.
- In 2019, the Washington Legislature approved the Clean Energy Transformation Act (CETA) that will require the state to power 100 percent of its electricity from carbon-free resources by 2045. Rulemaking by state agencies, including the Washington Utilities and Transportation Commission (WUTC) and the Washington Department of Commerce commenced in July 2019. PacifiCorp is participating in rulemaking proceedings and will perform an analysis of the portfolio effects of the new requirements under CETA in a Supplement to the 2019 Integrated Resource Plan (IRP) on or before December 31, 2019.
- On March 8, 2019, Wyoming Senate File (SF) 0159 was passed into law. SF 0159 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.
- PacifiCorp and the California Independent System Operator Corporation (CAISO) launched the voluntary energy imbalance market (EIM) November 1, 2014, the first western energy market outside of California. The EIM has produced significant monetary benefits ($736 million total footprint-wide benefits as of July 31, 2019). A significant contributor to EIM benefits are transfers across balancing authority areas, providing access to lower-cost supply, while factoring in the cost of compliance with greenhouse gas emissions regulations when energy is transferred into the CAISO balancing authority area.
- Near-term procurement activities focused on three areas—the purchase and sale of renewable energy credits, the purchase of new or repowered wind energy, firm power for western balancing authority, and Oregon solar resources.

Introduction

Chapter 3 profiles the major external influences that affect PacifiCorp's long-term resource planning and recent procurement activities. External influences include events and trends affecting the economy, wholesale power and natural gas prices, and public policy and regulatory initiatives that influence the environment in which PacifiCorp operates.

Major issues in the power industry market include capacity resource adequacy and associated standards for the Western Electricity Coordinating Council (WECC). As discussed elsewhere in this IRP, future natural gas prices, the role of gas-fired generation and the falling costs and increasing efficiencies of renewables are some of the critical factors affecting the selection of the portfolio that best achieves least-cost, least-risk planning objectives.

On the government policy and regulatory front, a significant issue facing PacifiCorp continues to be planning for an eventual, but highly uncertain, climate change regulatory regime. This chapter focuses on climate change regulatory initiatives. A high-level summary of PacifiCorp's greenhouse gas emissions mitigation strategy is included as well as a review of significant policy developments for currently regulated pollutants.

Other topics covered in this chapter include regulatory updates on the Environmental Protection Agency (EPA), regional and state climate change regulation, the status of renewable portfolio standards, and resource procurement activities.

Wholesale Electricity Markets

PacifiCorp's system does not operate in an isolated market. Operations and costs are tied to a larger electric system known as the Western Interconnection which functions, on a day-to-day basis, as a geographically dispersed marketplace. Each month, millions of megawatt-hours of energy are traded in the wholesale electricity market. These transactions yield economic efficiency by assuring that resources with the lowest operating cost are serving demand in a region and by providing reliability benefits that arise from a larger portfolio of resources.

PacifiCorp actively participates in the wholesale market by making purchases and sales to keep its supply portfolio in balance with customers' constantly varying needs. This interaction with the market takes place on time scales ranging from sub-hourly to years in advance. Without the wholesale market, PacifiCorp or any other load serving entity would need to construct or own an unnecessarily large margin of supplies that would go unutilized in all but the most unusual circumstances and would substantially diminish its capability to cost effectively match delivery patterns to the profile of customer demand.

The benefits of access to an integrated wholesale market have grown with the increased penetration of intermittent generation such as solar and wind. Intermittent generation tends to come online and go offline abruptly in congruence with changing weather conditions. Federal and state (where applicable) tax credits, declining capital costs, and improved technology performance have put wind and solar "in the money" in areas of high potential. As such, wind and solar will dominate U.S. capacity additions for the next decade. To better integrate these resources into the larger grid requires more flexible generation, transmission, new storage technologies, and market design changes.

With regard to transmission, there are long-haul renewable-driven transmission projects, in advanced development in the U.S. WECC. These lines ultimately connect areas of high renewable potential and low population density to areas of high population density with less renewable potential. This includes PacifiCorp's proposed 400-mile 1,500 megawatt (MW) Gateway South project, with an online date of 2024, to transport Wyoming wind to central Utah. Similarly, Gateway West, a jointly proposed 1,000-mile project by PacifiCorp and Idaho Power would transport Wyoming wind to western Idaho to be picked up for westward delivery with a 2024 online date. In the eastern interconnect, the Grain Belt Express, a 780 mile 4,000 MW direct-current line is in advanced development to go live in 2023 to transport Kansas wind to Missouri, Illinois, and Indiana. Moreover, the eastern seaboard is seeing a rising acceptance of off-shore wind. After years of resistance, local opposition has softened as technology improvements allow wind turbines to be located further from shore. To date, eastern states have sanctioned over 17,000 MWs of offshore wind power and the Bureau of Ocean Energy Management has seen record prices paid for leases in federal waters. Regardless, offshore wind remains expensive and requires government policy support and subsidization.

The intermittency of renewable generation has also given rise to a greater need for fast-responding storage – essential for grid stability and resiliency. Pumped storage has been the traditional storage option but expansion is extremely limited due to topography limitations, with the best resources already harnessed. Of remaining mechanical, thermal, and chemical storage options, Lithium-ion (Li-ion) batteries have shown the most promise in terms of cost and performance improvement. In 2013, the California Public Utility Commission (CPUC) required investor-owned utilities to procure 1,325 MW of storage by 2020; that requirement is now close to being met. Utility-scale four-hour battery storage modules have fallen in price to $1500/kilowatt (kW); costs are expected to continue to decline as electric vehicle manufacturing drives further innovation. To date, five states have implemented energy storage targets or mandates, with another two states seriously considering implementation.[1] In California, the world's largest Li-ion battery, 300 MW, is scheduled to go online at Pacific Gas & Electric (PG&E)'s Moss Landing Power Plant in 2021. Hybrid co-located solar photo voltaic (SPV) and battery systems are now in Hawaii, Arizona, Nevada, California, and Texas. In February 2019, Arizona Public Service announced it would pair existing solar with 200 MWs of battery storage while Nevada Energy has contracted for 100 MW of battery storage to be paired with solar. But, perhaps most importantly, in 2018, the Federal Energy Regulatory Commission (FERC) directed regional transmission organizations (RTO) and independent system operators (ISO) to develop market rules for the participation of energy storage in wholesale energy, capacity, and ancillary services markets[2]. The FERC gave operators nine months to file tariffs and another year to implement – essentially opening wholesale markets to energy storage. Operators' proposed tariffs have varied substantially among regions with PJM requiring a 10-hour continuous discharge capability while New England requires a continuous 2-hour capability. As part of its 2019 IRP, PacifiCorp is evaluating the cost effectiveness of several energy storage systems, including pumped storage, stand-alone li-on batteries, as well as co-located solar and co-located wind.[3]

[1] California, New Jersey, New York, Massachusetts, and Oregon have either mandated or set energy storage targets while Nevada and Arizona are seriously studying the implementation of targets.
[2] 162 FERC ¶ 61,127 United States of American Federal Energy Regulatory Commission, 18 CFR Part 35 [Docket Nos. RM16-23-000; AD16-20-000; Order No. 841] *Electric Storage Participation in Markets Operated by Regional Transmission Organizations and Independent System Operator* (Issued February 15, 2018)
[3] Solar or wind resources coupled with battery storage.

Increased renewable generation has also 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. The resulting EIM became operational November 1, 2014. By December 2015, Nevada Energy had joined as did Puget Sound Energy and Arizona Public Service in 2016. Portland General Electric joined in 2017, followed by Powerex and Idaho Power in 2018, and Balancing Authority of Northern California in 2019. Today, Salt River Project and Seattle City Light are slated to join in 2020; Los Angeles Water & Power, Northwestern Energy, and Public Service Company of New Mexico in 2021, followed by Avista and Tucson Electric Power in 2022. 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 with all markets, electricity markets are faced with a wide range of uncertainties. However, some uncertainties are easier to evaluate than others. Market participants are routinely studying demand uncertainties driven by weather and overall economic conditions. Similarly, there is a reasonable amount of data available to gauge resource supply developments. The North American Electric Reliability Corporation (NERC) publishes an annual assessment of regional power reliability and any number of data services are available that track the status of new resource additions[4]. In its latest assessment, published December 2018, the NERC indicates that WECC as a whole, has adequate resources through 2026. However, WECC's Northwest Power Pool (NWPP), Rockies, and southwest reserve sharing group (SRSG) sub-regions fall short starting 2027[5]. The NERC's probabilistic studies indicate that WECC's CA/MX sub region's resource adequacy is at risk during off peak hours, starting as early as 2020.

There are other uncertainties that are more difficult to analyze that can heavily influence the direction of future prices. One such uncertainty is the evolution of natural gas prices over the course of the IRP planning horizon. Given the increased role of natural gas-fired generation, gas prices are a critical determinant of western electricity prices, and this trend is expected to continue over the term of this plan's decision horizon. Another critical uncertainty that weighs heavily on the 2019 IRP, as in past IRPs, is the uncertainty surrounding future greenhouse gas policies, both federal and/or state. PacifiCorp's official forward price curve (OFPC) does not assume a federal carbon dioxide (CO_2) policy, but other price scenarios developed for the IRP consider impacts of potential future federal CO_2 emission policies. However, PacifiCorp's OFPC does include enforceable state climate programs that have been signed into law[6].

Natural Gas Uncertainty

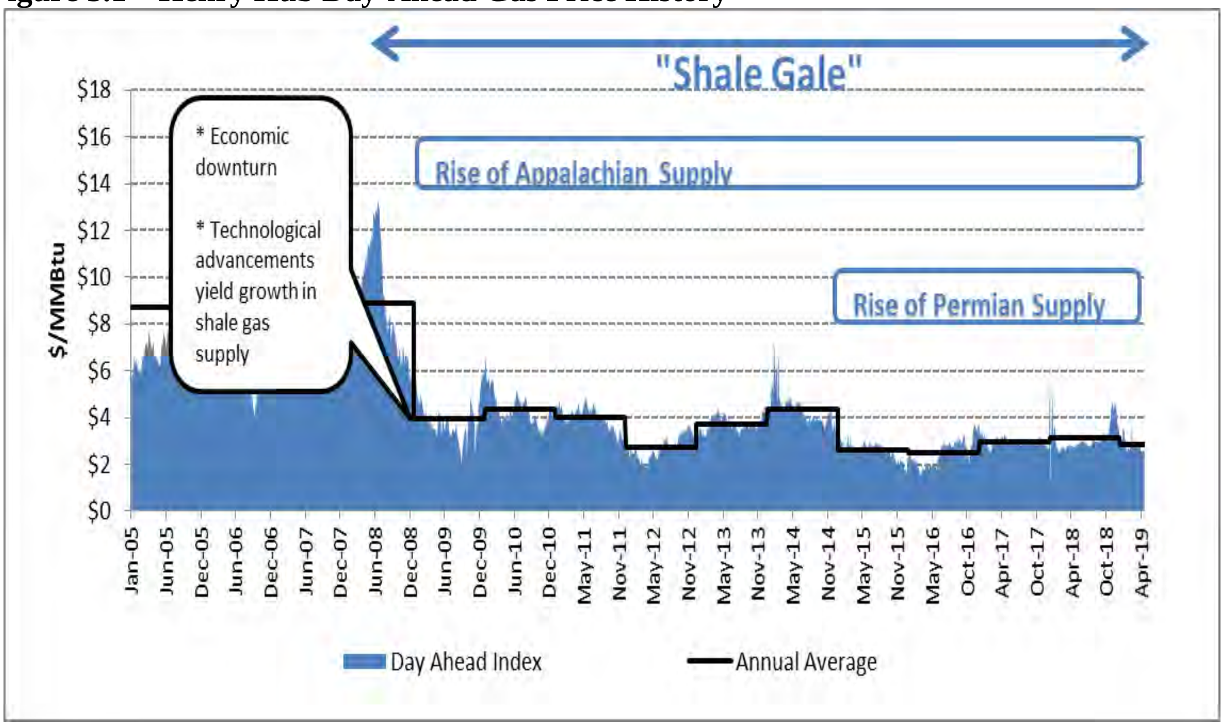
Since 2008, North American natural gas markets have undergone a remarkable paradigm shift. As shown in Figure 3.1, Henry Hub day-ahead gas prices hit a high of $13.31/MMBtu on July 2, 2008 and a low of $1.49/MMBtu on March 4, 2016. Day-ahead prices averaged $8.86/MMBtu in 2008, dropped to $3.94 in 2009, and have averaged $2.82 since 2015. Day-ahead 2018 Henry Hub prices

[4] 2018 Long-term Reliability Assessment, December 2018, North American Electric Reliability Assessment
[5] SRSG: Southwest Reserve Sharing Group; NWPP: Northwest Power Pool.
[6] A forecast of California carbon allowance prices is used as a proxy for future cap-and-trade allowance auction prices. Oregon's House Bill 2020, establishing a Climate Policy Office and directing it to adopt an Oregon Climate Action Program by rule is still in Committee and has not yet been signed into law.

averaged $3.15/MMBtu, down 64 percent from 2008 prices. The relative price placidity since 2009, labeled the "Shale Gale", reflects a story of supply – mostly that of Appalachian and, later, Permian supply[7].

In 2009 Appalachia (mostly Pennsylvania and West Virginia), produced almost no natural gas; by late 2013 it was producing almost 12 BCF/D and by end-of-year 2018, Appalachia was producing over 28 BCF/D. In short, supply from Appalachia continues to grow as volumes and costs prove to be, respectively, higher and lower than anticipated. Today, Appalachia accounts for 34 percent of the nation's gas supply, and by 2040 is expected to account for 44 percent, spurred by increased drilling efficiencies and rising demand.

Figure 3.1 – Henry Hub Day-Ahead Gas Price History



Source: Thomson Reuters as cited by the Energy Information Administration at: www.eia.gov/dnav/ng/hist/rngwhhdD.htm.

Historically, depletion of conventional mature resources largely offset unconventional resource growth, but as shale gas "came into its own," production gains outpaced depletion. Figure 3.2 through Figure 3.4 shows natural gas by source and location.

[7] Other significant shale gas plays include: Eagle Ford (TX); Haynesville (LA/TX); Niobrara (CO/WY); and the Bakken (ND/MT).

Figure 3.2 – U.S. Dry Natural Gas Production (Trillion Cubic Feet)

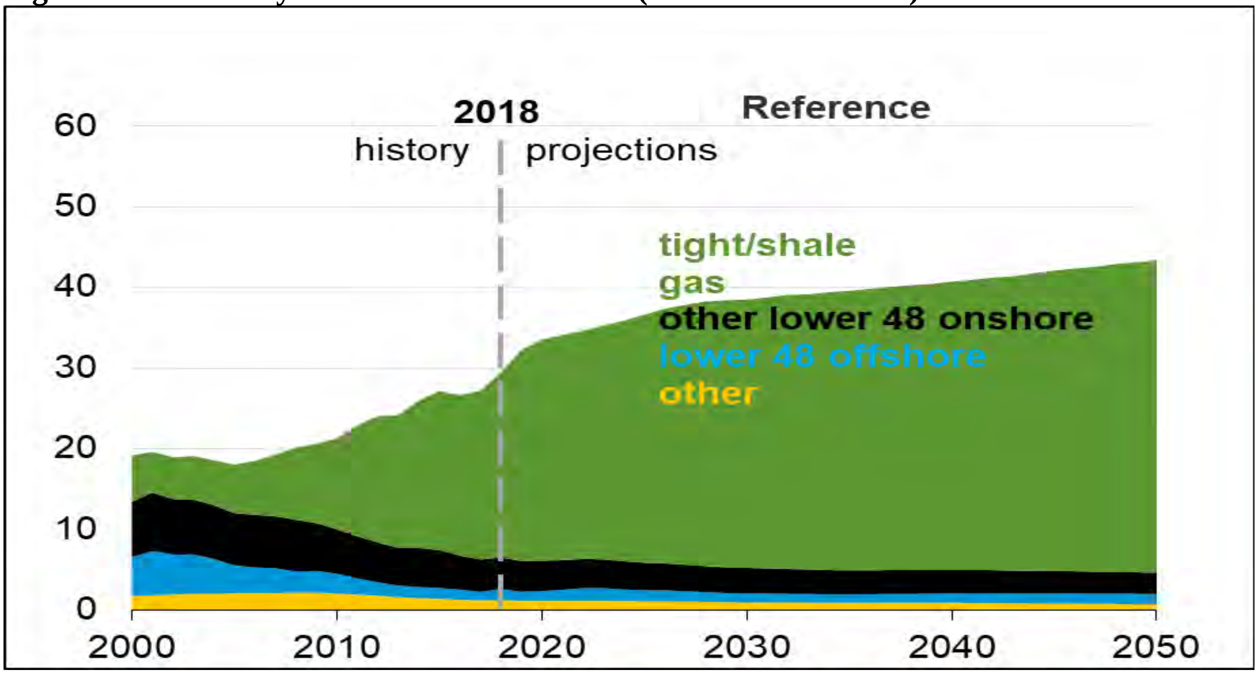
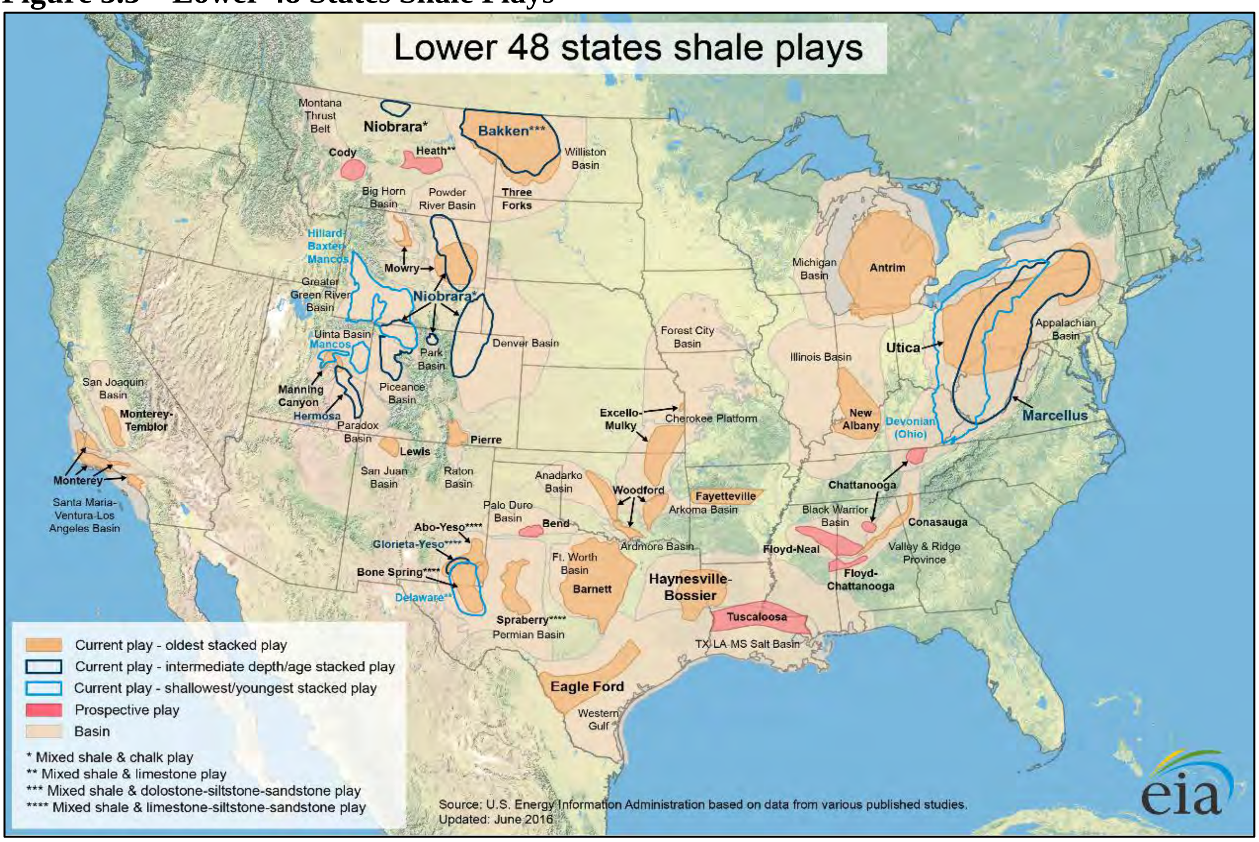
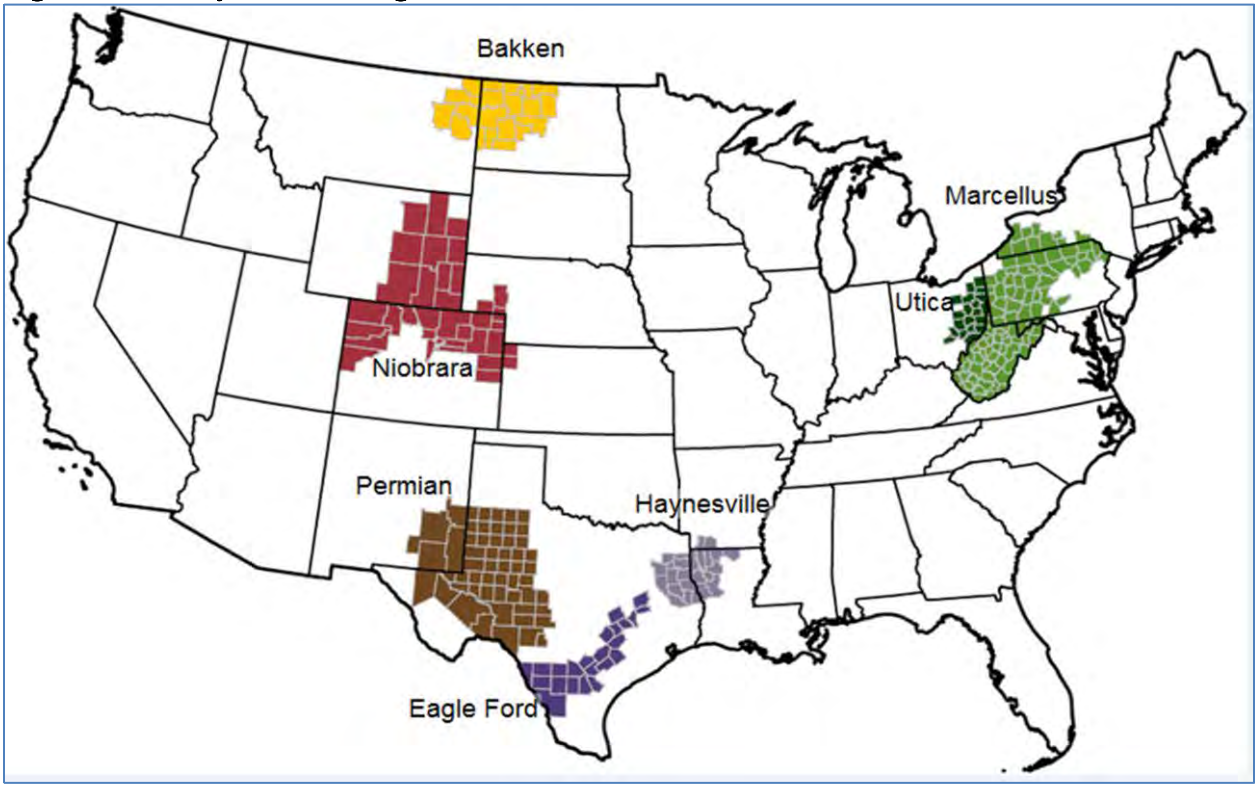


Figure 3.3 – Lower 48 States Shale Plays



Source: U.S. Department of Energy, Energy Information Administration

Figure 3.4 – Plays Accounting for All Natural Gas Production Growth 2011 -2018



Source: *Drilling Productivity Report*, May 13, 2019, U.S. Department of Energy, Energy Information Administration

Figure 3.5 shows Henry Hub NYMEX futures, as of May 28, 2019. While futures are rising it would appear that price expectations offer little "signal-to-drill" after all, annual futures don't even crack $4.00 per MMBtu. But as producers chase production efficiencies the "signal-to-drill" price becomes lower. Producers have discovered the economies of scale of deeper wells, super laterals, clustered well spacing, and repetitive fracking. The Utica's 'Purple Hayes" well, drilled in 2017, is over 27,000 feet deep with a lateral extension of 20, 803 feet.[8] As such, it has one of the longest onshore laterals ever drilled. The developer estimated that supersizing the well yielded an incremental internal rate of return of 130 percent and 215 percent, for condensate and natural gas, respectively.

But, for the next decade ultra-cheap natural gas will come from oil-targeted plays, especially in the Permian Basin. West Texas Intermediate two-year futures are currently hovering around $58/barrel -- more than enough to spur oil-targeted drilling in western Canada, the Permian, and Bakken. In the Bakken break even costs are below $50/barrel, while in the Permian, break-even costs range from $26/barrel to $50/barrel. Moreover, producers are "front-loading" oil production which releases a disproportionately large amount of associated gas. Front-loading involves drilling closely spaced "child" wells to quickly boost initial oil production but the resulting decrease in well pressure also releases inordinate quantities of associated gas.[9] This is especially true of Permian Basin oil wells, whose output naturally contains 20 to 50 percent natural gas. Currently, there is not enough Permian take-away capacity to accommodate this surge of natural gas. As such, there's been heavy flaring and pricing dislocation in the Permian as evidenced by Waha cash prices which averaged a negative $3.75/MMBtu on April 3, 2019. New take-away capacity coming

[8] *Super Laterals: Going Really, Really Long in Appalachia*, Larry Prado, Hart Energy.
[9] Note that while front-loading increases initial production it often shortens productive well life.

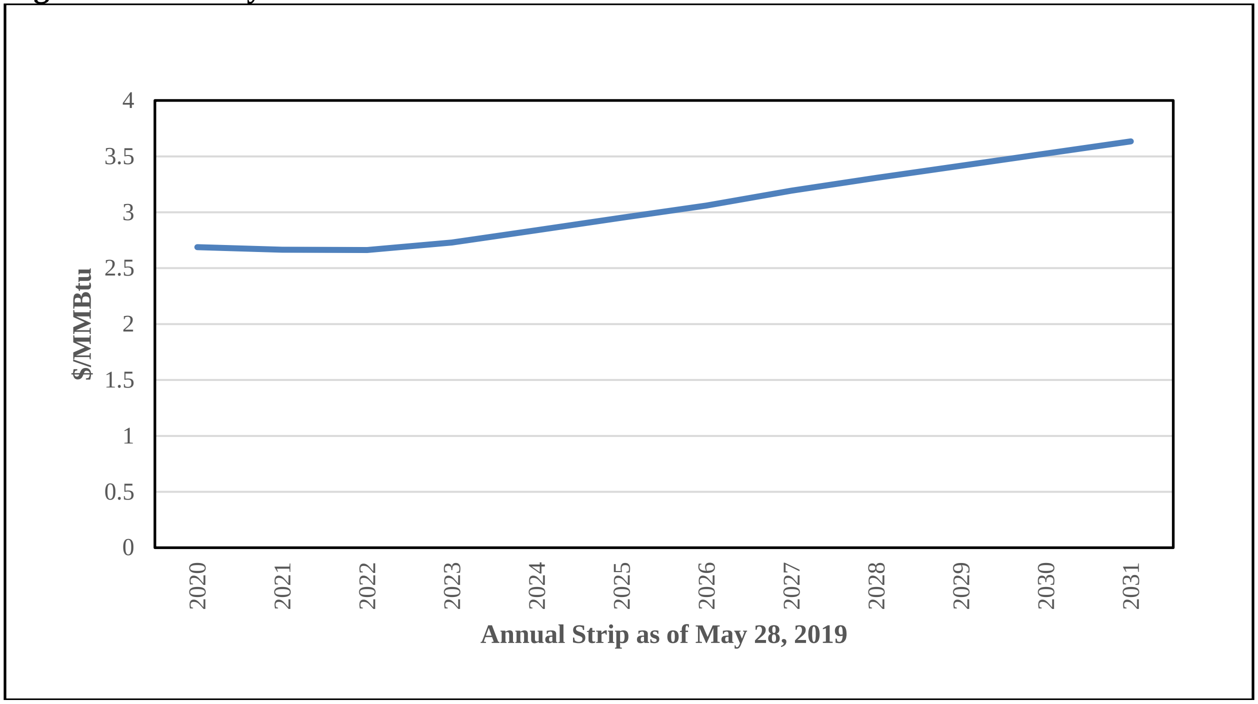
online in 2019 – 2020 will help alleviate the glut but natural gas prices are expected to remain depressed through 2020.

In 2016, following crude's price collapse, U.S. production finally fell to 8.8 million barrels of oil per day (MMbpd[10]) from a high of 9.6 MMbpd in 2015. In 2018, U.S. production averaged 10.9 MMbpd, hitting an all-time high of 11.97 MMBpd in December 2018. Moreover, the EIA estimated that as of April 2019, 8,390 wells remain drilled but uncompleted; these wells can be put into production quickly and represent a significant source of supply[11]. U.S. production can ramp up very quickly.

This resiliency of supply coupled with the flexibility to quickly ramp up production will shorten the length of asynchronous supply and demand cycles. Unexpected weather-induced demand spikes or supply disruptions will still whipsaw prices for short periods of time. But, Liquefied Natural Gas (LNG) startups, outages or dial backs could swing prices for longer periods given the magnitude of volumes coupled with locational concentration[12]. The global LNG market is expected to be in oversupply through 2022, especially during summer months. Summer feed gas normally bound for liquefaction would then be diverted onto the U.S. market, depressing prices. This summer dial back will act to also moderate winter prices by increasing storage and the likelihood of entering winter with an overhang. Although U.S. LNG tends to be the marginal global supplier, buyers are interested in U.S. LNG due to its low-cost natural gas supply and contract flexibility. Of note, even oil-rich Saudi Arabia has entered into a 20-year supply agreement for U.S. LNG. The imported LNG is expected to be used to replace Saudi Arabia's oil-fired power generation, thereby freeing up oil for export. To summarize, the key drivers of U.S. demand are: 1) LNG exports, 2) Mexican exports, and 3) power generation. Of the three, power generation is by far the largest but exports (especially LNG) are the fastest growing.

[10] MMbpd: Million barrels per day.
[11] EIA does not distinguish between oil and gas wells since over 50 percent of wells produce both.
[12] Current and expected facilities are mostly concentrated in the Gulf Coast.

Figure 3.5 – Henry Hub NYMEX Futures



Appalachian gas production will slow in the 2020s as associated gas, from oil-targeted plays, displaces it. However, Appalachian production and take-away capacity will pick up in the 2030's as associated gas volumes begin to dwindle. Rocky Mountain production gets squeezed by western Canadian, lower-48 associated gas, and Appalachian volumes. In the Northwest, where natural gas markets are influenced by production and imports from Canada, prices at Sumas have traded at a premium relative to AECO. This is likely to continue as AECO loses market share to Appalachia in serving AECO's Ontario and Midwest markets. In short, the challenge in gauging the uncertainty in natural gas markets will be one of timing. The North American natural gas supply curve continues to flatten as production efficiencies expose an ever-increasing resilient, flexible, and low-cost resource base. In such a world, managing long-term boom and bust cycles is not as crucial as managing shorter-term market perturbations.

The Future of Federal Environmental Regulation and Legislation

PacifiCorp faces continuously changing electricity plant emission regulations. Although the exact nature of these changes is uncertain, they are expected to impact the cost of future resource alternatives and the cost of existing resources in PacifiCorp's generation portfolio. PacifiCorp monitors these regulations to determine the potential impact on its generating assets. PacifiCorp also participates in rulemaking processes by filing comments on various proposals, participating in scheduled hearings, and providing assessments of proposals.

Federal Climate Change Legislation

To date, no federal legislative climate change proposal has been passed by the U.S. Congress. The election of Donald Trump as U.S. President reduces the likelihood of federal climate change legislation in the near term.

Federal Renewable Portfolio Standards

Since 2010, there has been no significant activity in the development of a federal renewable portfolio standard (RPS). Accordingly, PacifiCorp's 2019 IRP assumes no federal RPS requirement over the course of the planning horizon.

Federal Policy Update

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 August 3, 2015, the United States Environmental Protection Agency (EPA) issued a final rule limiting CO_2 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 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.

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

On August 3, 2015, the 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, the EPA proposed to repeal the Clean Power Plan and on August 21, 2018, proposed the Affordable Clean Energy (ACE) rule to replace the Clean Power Plan. 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 Clean Power Plan.

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. If an area is determined to be out of compliance with an established NAAQS standard, the state is required to develop a state implementation plan for that area. And that plan must be approved by EPA. The plan is developed so that once implemented, the NAAQS for the particular pollutant of concern will be achieved.

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." On June 4, 2018, the EPA designated Salt Lake County and part of Utah County where the PacifiCorp Lake Side and Gadsby facilities are located as "Marginal Nonattainment." A Marginal designation is the least stringent classification for a nonattainment area and does not require a formal State Implementation Plan (SIP), however Utah has until 2021 to develop ways to meet the standard.

In April 2017, the EPA Administrator signed a final action to reclassify the Salt Lake City and Provo $PM_{2.5}$ 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 $PM_{2.5}$ and $PM_{2.5}$ 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. On January 2, 2019, the Utah Air Quality Board adopted source specific emission limits and operating practices in the SIP in which incorporated the current emission and operating limits for the Lake Side and Gadsby facilities.

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. These amendments apply to the provisions of the regional haze rule that 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. These pollutants include fine 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 the effectiveness of the state's long-term strategy for achieving reasonable progress toward visibility goals. On December 14, 2016, EPA issued a final rule setting forth revised and clarifying requirements for periodic updates in state implementation plans. States are currently required to submit the next periodic update by July 31, 2021.

The regional haze rule is intended to achieve natural visibility conditions by 2064 in specific National Parks and Wilderness Areas, many of which are located in Utah and Wyoming where PacifiCorp operates generating units, as well as Arizona where PacifiCorp owns but does not operate a coal unit, and in Colorado and Montana where PacifiCorp has partial ownership in generating units operated by others, but are nonetheless subject to the regional haze rule.

On December 20, 2018, the EPA prepared a final guidance document to support states with the technical aspects of developing reginal haze state implementation plans for the second implementation period of the Reginal Haze Program.

Utah Regional Haze

In May 2011, the state of Utah issued a regional haze state implementation plan (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 to federal circuit 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. In June 2015, the state of Utah submitted a revised SIP to EPA for approval with an updated BART analysis incorporating a requirement for PacifiCorp to retire Carbon Units 1 and 2, recognizing 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 the Utah's regional haze SIP and propose a federal implementation plan (FIP). The final rule requires the installation of selective catalytic reduction (SCR) controls at four of PacifiCorp's units in Utah: Hunter Units 1 and 2, and Huntington Units 1 and 2. On September 2, 2016, PacifiCorp filed petitions for administrative and judicial review of EPA's final rule and requested a stay of the effective date of the final rule. Unless the EPA's FIP is stayed or reversed, the controls are required to be installed by August 4, 2021.

On October 28, 2016, PacifiCorp filed a motion for stay with the 10th Circuit Court. EPA sent letters to Utah and PacifiCorp on July 14, 2017, indicating its intent to reconsider its FIP. EPA also filed a motion with the 10th Circuit Court of Appeals to hold the litigation in abeyance pending the rule's reconsideration. On September 11, 2017, the 10th Circuit Court granted the petition for stay and the request for abatement. The compliance deadline of the FIP and the litigation were stayed indefinitely pending EPA's reconsideration, and EPA was required to file status reports with the Court.

The EPA filed its first status report on December 13, 2017. The report stated that EPA was working with Utah to develop additional information in support of its reconsideration. The report stated that once the technical analyses (CAMx air quality modeling) had been fully developed, the EPA would proceed with rulemaking. Final CAMx modeling reports were delivered by PacifiCorp to Utah on September 21, 2018. On March 6, 2019, Utah Division of Air Quality staff presented a revised Utah Regional Haze SIP, based on the new modeling, to the Utah Air Quality Board. The Utah Air Quality Board voted in favor of sending the revised SIP out for public comment. On March 11, 2019 EPA filed its latest status report wherein EPA indicated that it was working with Utah to incorporate the results of the analysis. On April 1, 2019, the SIP revision was released for a 45-day public comment period, which closed on May 15, 2019.

On June 24, 2019, the Utah Air Quality Board unanimously voted to approve the Utah Regional Haze SIP Revision which incorporates and adopts the BART Alternative into Utah's Regional Haze SIP. The BART Alternative makes the shutdown of PacifiCorp's Carbon Plant enforceable under the SIP and removes the requirement to install SCR on Hunter Units 1 & 2, and Huntington Units 1 & 2. The state's final rule was published in the Utah Bulletin on July 15, 2019 and had an effective date of August 15, 2019. The Utah Division of Air Quality submitted the SIP Revision to the EPA for review on July 3, 2019. On September 9, 2019, the EPA provided a status report on Utah Regional Haze to the U.S. 10th Circuit Court of Appeals. The update stated that EPA is reviewing Utah's proposed SIP Revision, which was submitted by the state on July 3, 2019.

However, the EPA also stated that it was waiting on Utah to submit an additional minor revision to the SIP to address certain recordkeeping and reporting requirements. The additional modification relates to particulate matter (PM) emissions and exceedance reporting, which was a conditional requirement from EPA's 2016 partial approval of the SIP. The minor revision was proposed to the Utah Air Quality Board on September 4, 2019 and was issued for public comment on October 1, 2019. A draft of the revision was sent to EPA for concurrent review on October 2, 2019. The state anticipates getting final approval from the Utah Air Quality Board during its November board meeting and formally submitting the minor revision to EPA in December 2019.

The Western Regional Air Partnership (WRAP) is currently developing the modeling that the state will use for the implementation of the second planning period. Utah will use a 'Q/d' screening of 10 to determine which sources will be subject to the rule. The state is expecting to notify the effected sources soon and will require the sources to conduct a four-factor analysis. It is expected that the Hunter and Huntington facilities will be subject to the rule.

Wyoming Regional Haze

On January 10, 2014, EPA issued a final action in Wyoming requiring installation of the following NO_X and PM controls at PacifiCorp facilities:

- Naughton Unit 3 by December 31, 2014: SCR equipment and a baghouse
- Jim Bridger Unit 3 by December 31, 2015: SCR equipment
- Jim Bridger Unit 4 by December 31, 2016: SCR equipment
- Jim Bridger Unit 2 by December 31, 2021: SCR equipment
- Jim Bridger Unit 1 by December 31, 2022: SCR equipment
- Dave Johnston Unit 3: SCR within five years or a commitment to shut down in 2027
- Wyodak: SCR equipment within five years

Wyodak - Different aspects of EPA's final action were appealed by a number of entities. PacifiCorp appealed EPA's action requiring SCR at Wyodak. PacifiCorp successfully requested a stay of EPA's action as it pertains to Wyodak pending resolution of the appeals.

Naughton - In its 2014 rule, EPA indicated support for the conversion of the Naughton Unit 3 to natural gas 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 revision regarding Naughton Unit 3 to EPA on November 28, 2017. On March 7, 2017, Wyoming issued PacifiCorp a permit which allowed for adjusted emission limits upon Unit 3's conversion to natural gas; and allowed for operation of Unit 3 on coal through January 30, 2019. PacifiCorp ceased coal operation on Unit 3 on January 30, 2019 as required by the permit. EPA's final rule approving 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, On May 24, 2019, PacifiCorp provided Wyoming with a notice of commencement of construction for upgrades supporting Unit 3's conversion to natural gas, along with a notice of initial startup on natural gas firing in accordance with state permits and EPA's approval of the Wyoming SIP.

Jim Bridger - SCR was installed on Jim Bridger Units 3 and 4 by the dates required in the 2014 final rule. On February 5, 2019, PacifiCorp submitted to Wyoming an application and proposed SIP revision which would institute 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 boilers in lieu of the requirement to install SCR on Units 1 and 2. The application demonstrates that the proposed limits are more cost effective, results in less overall environmental impacts, and leads to better modeled visibility that SCR installation on Units 1 and 2. Wyoming is reviewing the application in coordination with EPA.

WRAP is currently developing the modeling that the state will use for the implementation of the second planning period. Wyoming has not determined which sources will be subject to the rule.

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 but 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 it relates to their interests. For the Cholla FIP requirements, the court stayed the appeals while parties attempt to agree on an alternative compliance approach.

In July 2016, the EPA issued a proposed rule to approve an alternative Arizona SIP, which includes converting Cholla 4 to a natural gas-fired unit or shutting the unit down in 2025. EPA approved the revised SIP on March 27, 2017.

WRAP is currently developing the modeling that the state will use for the implementation of the second planning period. Arizona will use a 'Q/d' screening of 20 to determine which sources will be subject to the rule. The state has notified the effected facilities has is requiring the facility to conduct a four-factor analysis by end of 2019.

Colorado Regional Haze

The Colorado regional haze SIP required SCR controls at Craig Unit 2 and Hayden Units 1 and 2. In addition, the SIP required the installation of selective non-catalytic reduction (SNCR) technology at Craig Unit 1 by 2018. 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 requires installation of SCR equipment at Craig Unit 1 in 2021.

In February 2015, the State of Colorado submitted a revised SIP to EPA for approval. As part of a further agreement between the owners of Craig Unit 1, state and federal agencies, and parties to previous settlements, the owners of Craig agreed to retire Unit 1 by December 31, 2025, or convert the unit to natural gas by August 31, 2023. The Colorado Air Quality Board approved the agreement on December 15, 2016. Colorado submitted the corresponding SIP amendment to EPA Region 8 on May 17, 2017. EPA approved the SIP on July 5, 2018.

WRAP is currently developing the modeling that the state will use for the implementation of the second planning period. Colorado will use a 'Q/d' screening of 10 to determine which sources will be subject to the rule. The state is expecting to notify the effected facility soon and will require the facility to conduct a four-factor analysis by end of 2019.

Mercury and Hazardous Air Pollutants

The Mercury and Air Toxics Standards (MATS) became effective April 16, 2012. The MATS rule required 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. The comment period on the proposed rule closed on April 17, 2019. PacifiCorp is awaiting EPA's final action.

Coal Combustion Residuals

Coal Combustion Residuals (CCRs), including coal ash, are the byproducts from the combustion of coal in power plants. CCRs have historically been considered exempt wastes under an amendment to the Resource Conservation and Recovery Act (RCRA); however, EPA issued a final rule in December 2014 to regulate CCRs for the first time. Under the final rule, EPA will regulate CCRs as non-hazardous waste under Subtitle D of RCRA and establish minimum nationwide standards for the disposal of CCRs. The final CCR Rule became effective October 19, 2015. Under the final rule, surface impoundments utilized for CCRs may need to close unless they can meet more stringent regulatory requirements. At the time the rule was published in April 2015, PacifiCorp operated 18 surface impoundments and seven landfills that contained CCRs. Before the effective date in October 2015, nine surface impoundments and three landfills were either closed or repurposed to no longer receive CCRs and hence are not subject to the final rule.

The final CCR regulation was set up to be enforced by citizen suits; however, in September 2016, the Senate passed, and in December 2016 President Obama signed, the Coal Combustion Residuals Regulatory Improvement Act, which sets forth the process and standards for EPA approval (and withdrawal) of a state's permitting program for coal combustion residual units. A state may incorporate either the requirements of the EPA rule into its permit program or other state requirements that, based on site-specific conditions, are at least as protective as the EPA rule.

The legislation:

- Authorizes the EPA to operate permit programs in states that have not been authorized.
- Clarifies that a coal ash residual unit is subject to the EPA rule until a permit is issued by either a state or EPA.
- Provides the EPA with inspection and enforcement authorities. Before EPA can take enforcement action in an authorized state, EPA must consider any other actions against the facility and determine if an enforcement action by EPA "is likely to be necessary" to ensure the facility is operating in accordance with its permit requirements.
- Authorizes EPA to operate a permit program in Indian country.
- Provides a permit shield for facilities that are operating in accordance with a state- or EPA-issued permit.

- Preserves other legal authorities or regulatory determinations in effect before enactment.

CCR Litigation

On August 21, 2018 the U.S. Court of Appeals for the District of Columbia issued a decision in the *Utility Solid Waste Activities Group, et al., vs. Environmental Protection Agency* case over the 2015 CCR Rule. Specifically, the Court vacated and remanded 40 CFR § 257.101(a) to EPA for additional consideration "consistent" with the Court's opinion. The 101(a) provision relates to the timing of closure for unlined CCR impoundments. PacifiCorp is awaiting EPA's final action.

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 United States 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 United States 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 and withdraw more than two million but less than 125 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 the Water Quality Division may require the facility to conduct an impingement characterization study. If an impingement characterization study is required, the final disposition of the Dave Johnston cooling water intake structure will not occur until the Water Quality Division has reviewed the study results.

Effluent Limit Guidelines

EPA first issued effluent guidelines for the Steam Electric Power Generating Point Source Category (i.e., the Steam Electric effluent guidelines or "ELG") in 1974, with subsequent revisions in 1977 and 1982. On November 3, 2015, the agency issued a final rule entitled *Effluent Limitations Guidelines and Standards for the Steam Electric Power Generating Point Source Category*. The revised rule addressed the following wastestreams produced by steam-generation power plants: (1) flue gas desulfurization ("FGD") wastewater; (2) fly ash transport wastewater; (3) bottom ash transport wastewater; (4) flue gas mercury control ("FGMC") wastewater ("Hg control waste"); (5) combustion residual leachate (or "Leachate"); and (6) gasification wastewater.

Compliance with the revised ELG is required by dates determined by the permitting authority, which must be as soon as possible beginning November 1, 2018, but no later than December 31, 2023 (compliance deadlines are generally expected to be set at NPDES permit renewal dates).

On September 18, 2017, EPA announced that it intends to conduct a rulemaking to revise the definitions of Best Available Technology Economically Available ("BAT") effluent limitations, and Pretreatment Standards for Existing Sources ("PSES") for existing sources for bottom ash transport water and flue gas desulfurization wastewater. EPA is postponing the earliest compliance dates for the new, more stringent, BAT effluent limitations and PSES for both waste streams for a period of two years to November 1, 2020. BAT effluent limitations and pretreatment standards for all other wastestreams, or any of the other requirements in the 2015 Rule will not be revised during this reconsideration. EPA's action to postpone compliance dates in the 2015 Rule is intended to preserve the status quo for FGD wastewater and bottom ash transport water until EPA completes its next rulemaking.

On April 12, 2019, the Fifth Circuit Court of Appeals vacated the portions of the rule that set BAT for combustion residual leachate and legacy wastewater, and remanded those sections to the EPA for reconsideration. PacifiCorp is awaiting EPA's final action.

2015 Tax Extender Legislation

On December 18, 2015, President Obama signed tax extender legislation (H.R. 2029) that retroactively and prospectively extended certain expired and expiring federal income tax deductions and credits.

Bonus Depreciation

Fifty percent bonus depreciation was extended for property acquired and placed in service during 2015, 2016, and 2017. For property acquired and placed in service during 2018, 40 percent of the eligible cost of the property qualifies for bonus depreciation. For property acquired and placed in service during 2019, 30 percent of the eligible cost of the property qualifies for bonus depreciation. For property placed in service after December 31, 2019, there will be no bonus depreciation.[13]

Production Tax Credit (Wind)

[13] There is an exception for long-production-period property (generally property with a construction period longer than one year and a cost exceeding $1 million). Costs incurred on long-production-period property may qualify for bonus depreciation if physical construction has begun before the placed-in-service date of the bonus phase-out.

The production tax credit (PTC), currently 2.3 cents per kilowatt-hour (inflation adjusted), has been extended and phased out for wind property for which construction begins before January 1, 2020, as follows:

- 2015 – 100% retroactive
- 2016 – 100% (construction begins before January 1, 2017)
- 2017 – 80% (construction begins before January 1, 2018)
- 2018 – 60% (construction begins before January 1, 2019)
- 2019 – 40% (construction begins before January 1, 2020)

Production Tax Credit (Geothermal and Hydro)
The PTC for geothermal and hydro were granted a two-year extension as follows (no phase-out period was adopted):

- 2015 – 100% retroactive
- 2016 – 100% (construction begins before January 1, 2017)

30% Energy Investment Tax Credit (Wind)
The investment tax credit (ITC) has been extended and phased out for wind property for which construction begins before January 1, 2020, as follows:

- 2015 – 30% retroactive
- 2016 – 30% (construction begins before January 1, 2017)
- 2017 – 24% (construction begins before January 1, 2018)
- 2018 – 18% (construction begins before January 1, 2019)
- 2019 – 12% (construction begins before January 1, 2020)

30% Energy Investment Tax Credit (Solar)
The ITC has been extended and steps down for solar property for which construction begins before January 1, 2022, as follows:

- 2015 – 30% retroactive
- 2016 – 30% (construction begins before January 1, 2017)
- 2017 – 30% (construction begins before January 1, 2018)
- 2018 – 30% (construction begins before January 1, 2019)
- 2019 – 30% (construction begins before January 1, 2020)
- 2020 – 26% (construction begins before January 1, 2021)
- 2021 – 22% (construction begins before January 1, 2022)
- 2022 – 10% (construction begins on or after January 1, 2022)

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 has subsequently been directed to update the AB 32 scoping plan to reflect the new interim 2030 target and previously established 2050 target.

In 2002, California established a 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, the Oregon Legislature passed House Bill (HB) 3543 – Global Warming Actions, which establishes greenhouse gas reduction goals for the state that: (1) end the growth of Oregon greenhouse gas emissions by 2010; (2) reduce greenhouse gas levels to ten percent below 1990 levels by 2020; and (3) reduce greenhouse gas levels to at least 75 percent below 1990 levels by 2050. In 2009, the legislature passed SB 101, which requires the Public Utility Commission of Oregon (OPUC) to submit a report to the legislature before November 1 of each even-numbered year regarding the estimated rate impacts for Oregon's regulated electric and natural gas companies of meeting the greenhouse gas reduction goals of ten percent below 1990 levels by 2020 and 15 percent below 2005 levels by 2020. The OPUC submitted its most recent report November 1, 2014.

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.

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 conversation 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. Rulemaking by state agencies, including the WUTC and the Washington Department of Commerce commenced in July 2019. PacifiCorp is participating in rulemaking proceedings and will perform an analysis of the portfolio effects of the new requirements under CETA in a Supplement to the 2019 IRP on or before March 31, 2019.

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.

Wyoming

On March 8, 2019, Wyoming Senate File 0159 was passed into law. SF 0159 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 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 0159 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 one hundred percent cost recovery in rates for the cost of the power purchase agreement and the agreement is one hundred percent allocated to the public utility's Wyoming customers unless otherwise agreed to by the public utility.

Greenhouse Gas Emission Performance Standards

California, Oregon and Washington have all adopted 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.

Renewable Portfolio Standards

An RPS requires a retail seller of electricity to include in its resource portfolio a certain amount of electricity from renewable energy resources, such as wind, geothermal and solar energy. The retailer can satisfy this obligation by using renewable energy from its own facilities, purchasing renewable energy from another supplier's facilities, using Renewable Energy Credits (RECs) that certify renewable energy has been generated, or a combination of all of these.

RPS policies are currently implemented at the state level and vary considerably in their renewable targets (percentages), target dates, resource/technology eligibility, applicability of existing plants and contracts, arrangements for enforcement and penalties, and use of RECs.

In PacifiCorp's service territory, California, Oregon, and Washington have each adopted a mandatory RPS, and Utah has adopted a RPS goal. Each of these states' legislation and requirements are summarized in Table 3.1, with additional discussion below.

Table 3.1 – State RPS Requirements

	California	Oregon	Washington	Utah
Legislation	• Senate Bill 1078 (2002) • Assembly Bill 200 (2005) • Senate Bill 107 (2006) • Senate Bill 2 First Extraordinary Session (2011) • Senate Bill 350 (2015) • Senate Bill 100 (2018)	• Senate Bill 838 Oregon Renewable Energy Act (2007) • House Bill 3039 (2009) • House Bill 1547-B (2016)	• Initiative Measure No. 937 (2006) • SB 5400 (2013) • SB 5116 (2019)	• Senate Bill 202 (2008)
Requirement or Goal	• 20% by December 31, 2013 • 25% by December 31, 2016 • 33% by December 31, 2020 • 44% by December 31, 2024 • 52% by December 31, 2027 • 60% by December 31, 2030 and beyond • Planning target of 100% renewable and carbon-free by 2045 * Based on the retail load for a three-year compliance period	• 5% by December 31, 2011 • 15% by December 31, 2015 • 20% by December 31, 2020 • 27% by December 31, 2025 • 35% by December 31, 2030 • 45% by December 31, 2035 • 50% by December 31, 2040 * Based on the retail load for that year	• 3% by January 1, 2012 • 9% by January 1, 2016 • 15% by January 1, 2020 and beyond • 100% carbon neutral by 2030 • planning target of 100% renewable and non-emitting by 2045 * Annual targets are based on the average of the utility's load for the previous two years	• Goal of 20% by 2025 (must be cost effective • Annual targets are based on the adjusted[14] retail sales for the calendar year 36 months before the target year

California

California originally established its RPS program with passage of SB 1078 in 2002. Several bills that have since been passed into law to amend the program. In the 2011 First Extraordinary Special Session, the California Legislature passed SB 2 (1X) to increase California's RPS to 33 percent by 2020.[15] SB 2 (1X) also expanded the RPS requirements to all retail sellers of electricity and publicly owned utilities. In October 2015, SB 350, the Clean Energy and Pollution Reduction Act, was signed into law.[16] SB 350 established a greenhouse gas reduction target of 40 percent below 1990 levels by 2030 and 80 percent below 1990 levels by 2050 and expanded the state's renewables portfolio standard to 50 percent by 2030. In September 2018, the signing of SB 100, the Clean Energy Act of 2018, further expanded and accelerated the California RPS to 60 percent by 2030 and directed the state's agencies to plan for a longer-term goal of 100 percent of total retail sales of electricity in California to come from eligible renewable and zero-carbon resources by December 31, 2045.

SB 2 (1X) created multi-year RPS compliance periods, which were expanded by SB 100. The California Public Utilities Commission approved compliance periods and corresponding RPS procurement requirements, which are shown in Table 3.2.

Table 3.2 – California Compliance Period Requirements

Compliance Period	Procurement Quantity Requirement Calculation
Compliance Period 1 (2011-2013)	(20% * 2011 Retail Sales) + (20% * 2012 Retail Sales) + (20% * 2013 Retail Sales)
Compliance Period 2 (2014-2016)	(21.7% * 2014 Retail Sales) + (23.3% * 2015 Retail Sales) + (25% * 2016 Retail Sales)

[14] Adjustments for generated or purchased from qualifying zero carbon emissions and carbon capture sequestration and DSM.
[15] www.leginfo.ca.gov/pub/11-12/bill/sen/sb_0001-0050/sbx1_2_bill_20110412_chaptered.pdf
[16] leginfo.legislature.ca.gov/faces/billNavClient.xhtml?bill_id=201520160SB350

Compliance Period 3 (2017-2020)	(27% * 2017 Retail Sales) + (29% * 2018 Retail Sales) + (31% * 2019 Retail Sales) + (33% * 2020 Retail Sales)
Compliance Period 4 (2021-2024)	(35.8% * 2021 Retail Sales) + (38.5% * 2022 Retail Sales) + (41.3% * 2023 Retail Sales) + (44% * 2024 Retail Sales)
Compliance Period 5 (2025-2027)	(47% * 2025 Retail Sales) + (50% * 2026 Retail Sales) + (52% * 2027 Retail Sales)
Compliance Period 6 (2028-2030)	(54.7% * 2028 Retail Sales) + (57.3% * 2029 Retail Sales) + (60% * 2030 Retail Sales)

SB 2 (1X) established new “portfolio content categories” for RPS procurement, which delineated the type of renewable product that may be used for compliance and also set minimum and maximum limits on certain procurement content categories that can be used for compliance.

Portfolio Content Category 1 includes eligible renewable energy and RECs that meet either of the following criteria:

- Have a first point of interconnection with a California balancing authority, have a first point of interconnection with distribution facilities used to serve end users within a California balancing authority area, or are scheduled from the eligible renewable energy resource into a California balancing authority without substituting electricity from another source;[17] or
- Have an agreement to dynamically transfer electricity to a California balancing authority.

Portfolio Content Category 2 includes firmed and shaped eligible renewable energy resource electricity products providing incremental electricity and scheduled into a California balancing authority.

Portfolio Content Category 3 includes eligible renewable energy resource electricity products, or any fraction of the electricity, including unbundled renewable energy credits that do not qualify under the criteria of Portfolio Content Category 1 or Portfolio Content Category 2.[18]

Additionally, the California Public Utilities Commission established the balanced portfolio requirements for contracts executed after June 1, 2010. The balanced portfolio requirements set minimum and maximum levels for the Procurement Content Category products that may be used in each compliance period as shown in Table 3.3.

[17] The use of another source to provide real-time ancillary services required to maintain an hourly or sub-hourly import schedule into a California balancing authority is permitted, but only the fraction of the schedule actually generated by the eligible renewable energy resource will count toward this portfolio content category.
[18] A REC can be sold either “bundled” with the underlying energy or “unbundled” as a separate commodity from the energy itself into a separate REC trading market.

Table 3.3 – California Balanced Portfolio Requirements

California RPS Compliance Period	Balanced Portfolio Requirement
Compliance Period 1 (2011-2013)	Category 1 – Minimum of 50% of Requirement Category 3 – Maximum of 25% of Requirement
Compliance Period 2 (2014-2016)	Category 1 – Minimum of 65% of Requirement Category 3 – Maximum of 15% of Requirement
Compliance Period 3 (2017-2020) Compliance Period 4 (2021-2024) Compliance Period 5 (2025-2027) Compliance Period 6 (2028-2030)	Category 1 – Minimum of 75% of Requirement Category 3 – Maximum of 10% of Requirement

In December 2011, the California Public Utilities Commission (CPUC) confirmed that multi-jurisdictional utilities, such as PacifiCorp, are not subject to the percentage limits in the three portfolio content categories. PacifiCorp is required to file annual compliance reports with the CPUC and annual procurement reports with the California Energy Commission (CEC). Neither SB 350 nor SB 100 changed the portfolio content categories for eligible renewable energy resources or the portfolio balancing requirements exemption provided to PacifiCorp. For utilities subject to the portfolio balancing requirements, the CPUC extended the compliance period 3 requirements through 2030.

The full California RPS statute is listed under Public Utilities Code Section 399.11-399.32. Additional information on the California RPS can be found on the CPUC and CEC websites.

Qualifying renewable resources include solar thermal electric, photovoltaic, landfill gas, wind, biomass, geothermal, municipal solid waste, energy storage, anaerobic digestion, small hydroelectric, tidal energy, wave energy, ocean thermal, biodiesel, and fuel cells using renewable fuels. Renewable resources must be certified as eligible for the California RPS by the CEC and tracked in the Western Renewable Energy Generation Information System (WREGIS).

Oregon

Oregon established the Oregon RPS with passage of SB 838 in 2007. The law, called the Oregon Renewable Energy Act, was adopted in June 2007 and provides a comprehensive renewable energy policy for the state.[19] Subject to certain exemptions and cost limitations established in the Oregon Renewable Energy Act, PacifiCorp and other qualifying electric utilities must meet a target of at least 25 percent renewable energy by 2025. In March 2016, the Legislature passed SB 1547,[20] also referred to as Oregon's Clean Electricity and Coal Transition Act. In addition to requiring Oregon to transition off coal by 2030, the new law doubled Oregon's RPS requirements, which are to be staged at 27 percent by 2025, 35 percent by 2030, 45 percent by 2035, and 50 percent by 2040 and beyond. Other components of SB 1547 include:

- Development of a community solar program with at least 10 percent of the program capacity reserved for low-income customers.

[19] www.leg.state.or.us/07reg/measpdf/sb0800.dir/sb0838.en.pdf
[20] olis.leg.state.or.us/liz/2016R1/Downloads/MeasureDocument/SB1547/Enrolled

- A requirement that by 2025, at least eight percent of the aggregate electric capacity of the state's investor-owned utilities must come from small-scale renewable projects under 20 megawatts.
- Creates new eligibility for pre-1995 biomass plants and associated thermal co-generation. Under the previous law, pre-1995 biomass was not eligible until 2026.
- Direction to the state's investor-owned utilities to propose plans encouraging greater reliance on electricity in all modes of transportation, in order to reduce carbon emissions.
- Removal of the Oregon Solar Initiative mandate.[21]

SB 1547 also modified the Oregon REC banking rules as follows:

- RECs generated before March 8, 2016, have an unlimited life.
- RECs generated during the first five years for long-term projects coming online between March 8, 2016, and December 31, 2022, have an unlimited life.
- RECs generated on or after March 8, 2016, from resources that came online before March 8, 2016, expire five years beyond the year the REC was generated.
- RECs generated beyond the first five years for long-term projects coming online between March 8, 2016, and December 31, 2022, expire five years beyond the year the REC is generated.
- RECs generated from projects coming online after December 31, 2022, expire five years beyond the year the REC is generated.
- Banked RECs can be surrendered in any compliance year regardless of vintage (eliminates the "first-in, first-out" provision under SB 838).

To qualify as eligible, the RECs must be from a resource certified as Oregon RPS eligible by the Oregon Department of Energy and tracked in WREGIS.

Qualifying renewable energy sources can be located anywhere in the United States portion of the Western Electricity Coordinating Council geographic area, and a limited amount of unbundled renewable energy credits can be used toward the annual compliance obligation. Eligible renewable resources include electricity generated from wind, solar photovoltaic, solar thermal, wave, tidal, ocean thermal, geothermal, certain types of biomass and biogas, municipal solid waste, and hydrogen power stations using anhydrous ammonia.

Electricity generated by a hydroelectric facility is eligible if the facility is not located in any federally protected areas designated by the Pacific Northwest Electric Power and Conservation Planning Council as of July 23, 1999, or any area protected under the federal Wild and Scenic Rivers Act, P.L. 90-542, or the Oregon Scenic Waterways Act, ORS 390.805 to 390.925; or if the electricity is attributable to efficiency upgrades made to the facility on or after January 1, 1995, and up to 50 average megawatts of electricity per year generated by a certified low-impact hydroelectric facility owned by an electric utility and up to 40 average megawatts of electricity per year generated by certified low-impact hydroelectric facilities not owned by electric utilities.

[21] In 2009, Oregon passed House Bill 3039, also called the Oregon Solar Initiative, requiring that on or before January 1, 2020, the total solar photovoltaic generating nameplate capacity must be at least 20 megawatts from all electric companies in the state. The Public Utility Commission of Oregon determined that PacifiCorp's share of the Oregon Solar Initiative was 8.7 megawatts.

PacifiCorp files an annual RPS compliance report by June 1 of every year and a renewable implementation plan on or before January 1 of even-numbered years, unless otherwise directed by the Public Utility Commission of Oregon. These compliance reports and implementation plans are available on PacifiCorp's website.[22]

The full Oregon RPS statute is listed in Oregon Revised Statutes (ORS) Chapter 469A and the solar capacity standard is listed in ORS Chapter 757. The Public Utility Commission of Oregon rules are in Oregon Administrative Rules (OAR) Chapter 860 Division 083 for the RPS and OAR Chapter 860 Division 084 for the solar photovoltaic program. The Oregon Department of Energy rules are under OAR Chapter 330 Division 160.

Utah

In March 2008, Utah's governor signed Utah SB 202, the Energy Resource and Carbon Emission Reduction Initiative.[23] The Energy Resource and Carbon Emission Reduction Initiative is codified in Utah Code Title 54 Chapter 17. Among other things, this law provides that, beginning in the year 2025, 20 percent of adjusted retail electric sales of all Utah utilities be supplied by renewable energy if it is cost effective. Retail electric sales will be adjusted by deducting the amount of generation from sources that produce zero or reduced carbon emissions and for sales avoided as a result of energy efficiency and demand side management programs. Qualifying renewable energy sources can be located anywhere in the Western Electricity Coordinating Council areas, and unbundled renewable energy credits can be used for up to 20 percent of the annual qualifying electricity target.

Eligible renewable resources include electricity from a facility or upgrade that becomes operational on or after January 1, 1995, that derives its energy from wind, solar photovoltaic, solar thermal electric, wave, tidal or ocean thermal, certain types of biomass and biomass products, landfill gas or municipal solid waste, geothermal, waste gas and waste heat capture or recovery, and efficiency upgrades to hydroelectric facilities if the upgrade occurred after January 1, 1995. Up to 50 average megawatts from a certified low-impact hydro facility and in-state geothermal and hydro generation without regard to operational online date may also be used toward the target. To assist solar development in Utah, solar facilities located in Utah receive credit for 2.4 kilowatt-hours of qualifying electricity for each kWh of generation.

Under the Carbon Reduction Initiative, PacifiCorp is required to file a progress report by January 1 of each of the years 2010, 2015, 2020 and 2024. Following PacifiCorp's December 31, 2009 progress report, the Utah Division of Public Utilities' report to the Legislature stated: "Given PacifiCorp's projections of its loads and qualifying electricity for 2025, PacifiCorp is well positioned to meet a target of 20 percent renewable energy by 2025."

PacifiCorp filed its most recent progress report on December 31, 2014. This report showed that the company is positioned to meet its 20 percent target requirement of approximately 5.2 million megawatt-hours of renewable energy in 2025 from existing company-owned and contracted renewable energy sources.

[22] www.pacificpower.net/ORrps
[23] le.utah.gov/~2008/bills/sbillenr/sb0202.pdf

In 2027, the legislation requires a commission report to the Utah Legislature, which may contain any recommendation for penalties or other action for failure to meet the 2025 target. The legislation requires that any recommendation for a penalty must provide that the penalty funds be used for demand side management programs for the customers of the utility paying the penalty.

Washington

In November 2006, Washington voters approved I-937, a ballot measure establishing the Energy Independence Act, which is an RPS and energy efficiency requirement applied to qualifying electric utilities, including PacifiCorp.[24] The law requires that qualifying utilities procure at least three percent of retail sales from eligible renewable resources or RECs by January 1, 2012 through 2015; nine percent of retail sales by January 1, 2016 through 2019; and 15 percent of retail sales by January 1, 2020, and every year thereafter.

Eligible renewable resources include electricity produced from water, wind, solar energy, geothermal energy, landfill gas, wave, ocean, or tidal power, gas from sewage treatment facilities, biodiesel fuel with limitation, and biomass energy based on organic byproducts of the pulp and wood manufacturing process, animal waste, solid organic fuels from wood, forest, or field residues, or dedicated energy crops. Qualifying renewable energy sources must be located in the Pacific Northwest or delivered into Washington on a real-time basis without shaping, storage, or integration services. The only hydroelectric resource eligible for compliance is electricity associated with efficiency upgrades to hydroelectric facilities. Utilities may use eligible renewable resources, RECs, or a combination of both to meet the RPS requirement.

PacifiCorp is required to file an annual RPS compliance report by June 1 of every year with the WUTC demonstrating compliance with the Energy Independence Act. PacifiCorp's compliance reports are available on PacifiCorp's website.[25]

The WUTC adopted final rules to implement the initiative; the rules are listed in the Revised Code of Washington (RCW) 19.285 and the Washington Administrative Code (WAC) 480-109.

Under SB 5116, passed in 2019, Washington utilities are required to be carbon neutral by January 1, 2030 and institute a planning target of one hundred percent clean electricity by 2045. The bill establishes four-year compliance periods beginning January 1, 2030 and requires utilities to use electricity from renewable resources and non-emitting electric generation in an amount equal to 100 percent of the retail electric load over each compliance period. Through December 31, 2044, an electric utility may satisfy up to 20 percent of its compliance obligation with an alternative compliance option such as the purchase of unbundled RECs.

Transportation Electrification

The electric transportation market is in an emerging state,[26] and plug-in electric vehicles currently comprise a negligible share of PacifiCorp's load. This rapidly evolving market represents a potential driver of future load growth and those impacts managed proactively, provide an opportunity to increase the efficiency of the electrical system and provide benefits for all

[24] www.secstate.wa.gov/elections/initiatives/text/I937.pdf
[25] www.pacificpower.net/report
[26] As of June 2019, the market share of plug-in electric vehicles was two percent: www.nada.org/WorkArea/DownloadAsset.aspx?id=21474858563

PacifiCorp customers. In addition, increased adoption of electric transportation has the ability to improve air quality, reduce greenhouse gas emissions, improve public health and safety, and create financial benefits for drivers, which can be a particular benefit for low and moderate income populations.

To help manage and understand the potential future load growth impacts of electric transportation PacifiCorp is investing $26 million to support EV fast chargers along key corridors, develop workplace charging programs, research new rate designs and implement time-of-use pricing pilots, create partnerships for smart mobility programs and develop opportunities for customers in our rural communities. Our investments include a $4 million partnership award from the U.S. Department of Energy to research and develop electric transportation and $3 million as part of the Oregon Clean Fuels Program.

Given the emerging state of electric transportation a forecast explicitly identifying the load associated with electric transportation on PacifiCorp's system is currently unavailable. Electric vehicle load is, however, reflected in the Company's load forecast. PacifiCorp continues to actively engage with local, regional, and national stakeholders and participate in state regulatory processes that can inform future planning and load forecasting efforts.

Hydroelectric Relicensing

The issues involved in relicensing hydroelectric facilities are multifaceted. They involve numerous federal and state environmental laws and regulations, and the participation of numerous stakeholders including agencies, Native American tribes, non-governmental organizations, and local communities and governments.

The value of relicensing hydroelectric facilities is continued availability of energy, capacity, and ancillary services associated with hydroelectric generation. Hydroelectric projects can often provide unique operational flexibility because they can be called upon to meet peak customer demands almost instantaneously and back up intermittent renewable resources such as wind. In addition to operational flexibility, hydroelectric generation does not have the emissions concerns of thermal generation and can also often provide important ancillary services, such as spinning reserve and voltage support, to enhance the reliability of the transmission system.

On September 27, 2019, the FERC issued a new license order for the Prospect No. 3 Hydroelectric Project, a 7.2 MW project located in southern Oregon. The license period is 40 years. Conditions of the license are consistent with the Commission's previous environmental analysis. Pursuant to the new license, PacifiCorp will implement increased minimum flows downstream of the diversion dam, replace the project's wood-stave flowline and sag-pipe, upgrade and construct new wildlife crossings over the waterway, and prepare and implement various monitoring and management plans.

With the exception of the Klamath River and Weber hydroelectric projects, all of PacifiCorp's applicable generating facilities now operate under contemporary licenses from the FERC. In 2019, PacifiCorp initiated the FERC relicensing process for the Cutler Hydroelectric Project. This 30 MW project is located in Utah and has a 30-year license period that ends March 2024. Under a 2010 settlement agreement, amended in 2016, the 169 MW Klamath Hydroelectric Project is anticipated to operate under its existing license until project operations cease in 2021 with the decommissioning of the project. The assumed date of Klamath project removal in the IRP is January 1, 2021. The 3.85 MW Weber project is currently in the FERC relicensing process.

The FERC hydroelectric relicensing process can be extremely political and often controversial. The process itself requires that the project's impacts on the surrounding environment and natural resources, such as fish and wildlife, be scientifically evaluated, followed by development of proposals and alternatives to mitigate those impacts. Stakeholder consultation is conducted throughout the process. If resolution of issues cannot be reached in this process, litigation often ensues, which can be costly and time-consuming. The usual alternative to relicensing is decommissioning. Both choices, however, can involve significant costs.

FERC has sole jurisdiction under the Federal Power Act to issue new operating licenses for non-federal hydroelectric projects on navigable waterways, federal lands, and under other criteria. FERC must find that the project is in the broad public interest. This requires weighing, with "equal consideration," the impacts of the project on fish and wildlife, cultural resources, recreation, land use, and aesthetics against the project's energy production benefits. Because some of the responsible state and federal agencies have the ability to place mandatory conditions in the license, FERC is not always in a position to balance the energy and environmental equation. For example, the National Oceanic and Atmospheric Administration Fisheries agency and the U.S. Fish and Wildlife Service have the authority in the relicensing process to require installation of fish passage facilities (fish ladders and screens) and to specify their design. This is often the largest single capital investment that will be considered in relicensing and can significantly impact project economics. Also, because a myriad of other state and federal laws come into play in relicensing, most notably the Endangered Species Act and the Clean Water Act, agencies' interests may compete or conflict with each other, leading to potentially contrary or additive licensing requirements. PacifiCorp has generally taken a proactive approach towards achieving the best possible relicensing outcome for its customers by engaging in negotiations with stakeholders to resolve complex relicensing issues. In some cases settlement agreements are achieved which are submitted to FERC for incorporation into a new license. FERC welcomes license applications that reflect broad stakeholder involvement or that incorporate measures agreed upon through multi-party settlement agreements. History demonstrates that with such support, FERC generally accepts proposed new license terms and conditions reflected in settlement agreements.

Potential Impact

Relicensing hydroelectric facilities involves significant process costs. The FERC relicensing process takes a minimum of five years and may take longer, depending on the characteristics of the project, the number of stakeholders, and issues that arise during the process. As of December 31, 2016, PacifiCorp had incurred approximately $16 million in costs for license implementation and ongoing hydroelectric relicensing, which are included in construction work-in-progress on PacifiCorp's Consolidated Balance Sheet. As current or upcoming relicensing and settlement efforts continue for the Weber, Cutler and other hydroelectric projects, additional process costs are being or will be incurred that will need to be recovered from customers. Hydroelectric relicensing costs have and will continue to have a significant impact on overall hydroelectric generation cost. Such costs include capital investments and related operations and maintenance costs associated with fish passage facilities, recreational facilities, wildlife protection, water quality, cultural and flood management measures. Project operational and flow-related changes, such as increased in-stream flow requirements to protect aquatic resources, can also directly result in lost generation. The majority of these relicensing and settlement costs relate to PacifiCorp's three largest hydroelectric projects: Lewis River, Klamath River, and North Umpqua.

Treatment in the IRP

The known or expected operational impacts related to FERC orders and settlement commitments are incorporated in the projection of existing hydroelectric resources discussed in Chapter 5.

PacifiCorp's Approach to Hydroelectric Relicensing

PacifiCorp continues to manage the hydroelectric relicensing process by pursuing interest-based resolutions or negotiated settlements as part of relicensing. PacifiCorp believes this proactive approach, which involves meeting agency and others' interests through creative solutions, is the best way to achieve environmental improvement while balancing customer costs and risks. PacifiCorp also has reached agreements with licensing stakeholders to decommission projects where that has been the most cost-effective outcome for customers.

Utah Rate Design Information

Current rate designs in Utah have evolved over time based on orders and direction from the Public Service Commission of Utah and settlement agreements between parties during general rate cases. Most recently, current rates and rate design changes were adopted in Docket No. 13-035-184. The goals for rate design are (generally) to reflect the cost to serve customers and to provide price signals to encourage economically efficient usage. This is consistent with resource planning goals that balance consideration of costs, risk, and long-run public policy goals. PacifiCorp currently has a number of rate design elements that take into consideration these objectives, in particular, rate designs that reflect cost differences for energy or demand during different time periods and that support the goals of acquiring cost-effective energy efficiency.

Residential Rate Design

Residential rates in Utah are comprised of a customer charge and energy charges. The customer charge is a monthly charge that provides limited recovery of customer-related costs incurred to serve customers regardless of usage. All other remaining costs are recovered through volumetric-based energy charges. Energy charges for residential customers are designed with an inclining-tier rate structure so high usage during a billing month is charged a higher rate. This gives customers a price signal to encourage reduced consumption. Additionally, energy charges are differentiated by season with higher rates in the summer when the costs to serve are higher. Residential customers also have an option for time-of-day rates. Time-of-day rates have a surcharge for usage during the on-peak periods and a credit for usage during the off-peak periods. This rate structure provides an additional price signal to encourage customers to use less energy during the daily on-peak periods when energy costs are higher. Currently, less than one percent of customers have opted to participate in the time-of-day rate option.

Changes in residential rate design that might facilitate IRP objectives include a critical peak pricing program or an expansion of time-of-use rates. These types of rate designs are discussed in more detail in Volume I, Chapter 6 (Resource Options). As part of the STEP legislation enacted in SB 115, the company developed a pilot time-of-use program to encourage off-peak charging of electric vehicles for residential customers. The results of this pilot may inform future rate design offerings. Any changes in standard residential rate design or institution of optional rate options to support energy efficiency or time-differentiated usage should be balanced with the recovery of fixed costs to ensure price signals are economically efficient and do not unduly shift costs to other customers.

With the growth in the number of customers adopting private distributed generation, rates have begun to evolve to address the change in usage requirements and ensure appropriate cost recovery from these customers. A deeper consideration of the implications of current rates and rate designs is necessary to address growing issues with private generation and ensure the appropriate price signals are set for the changing circumstances. As a result of a settlement in Docket No. 14-035-114, new customer generators in Utah receive export credits that are valued at a different rate than retail rates as part of a transition program.

Commercial and Industrial Rate Design

Commercial and industrial rates in Utah include customer charges, facilities charges, power charges (for usage over 15 kW) and energy charges. As with residential rates, customer charges and facilities charges are generally intended to recover costs that do not vary with energy usage. Power charges are applied to a customer's monthly demand on a kW basis and are intended to recover the costs associated with demand or capacity needs. Energy charges are applied to the customer's metered usage on a kWh basis. All commercial and industrial rates employ seasonal variations in power and/or energy charges with higher rates in the summer months to reflect the higher costs to serve during the summer peak period. Additionally, for customers with load 1,000 kW or more, rates are further differentiated by on-peak and off-peak periods for both power and energy charges. For commercial and industrial customers with load less than 1,000 kW, the company offers two optional time-of-day rates—one that differentiates energy rates for on- and off-peak usage, and one that differentiates power charges by on- and off-peak usage. Currently, about 19 percent of the eligible customers are on the energy time-of-day option and less than one percent are on the power time-of-day option.

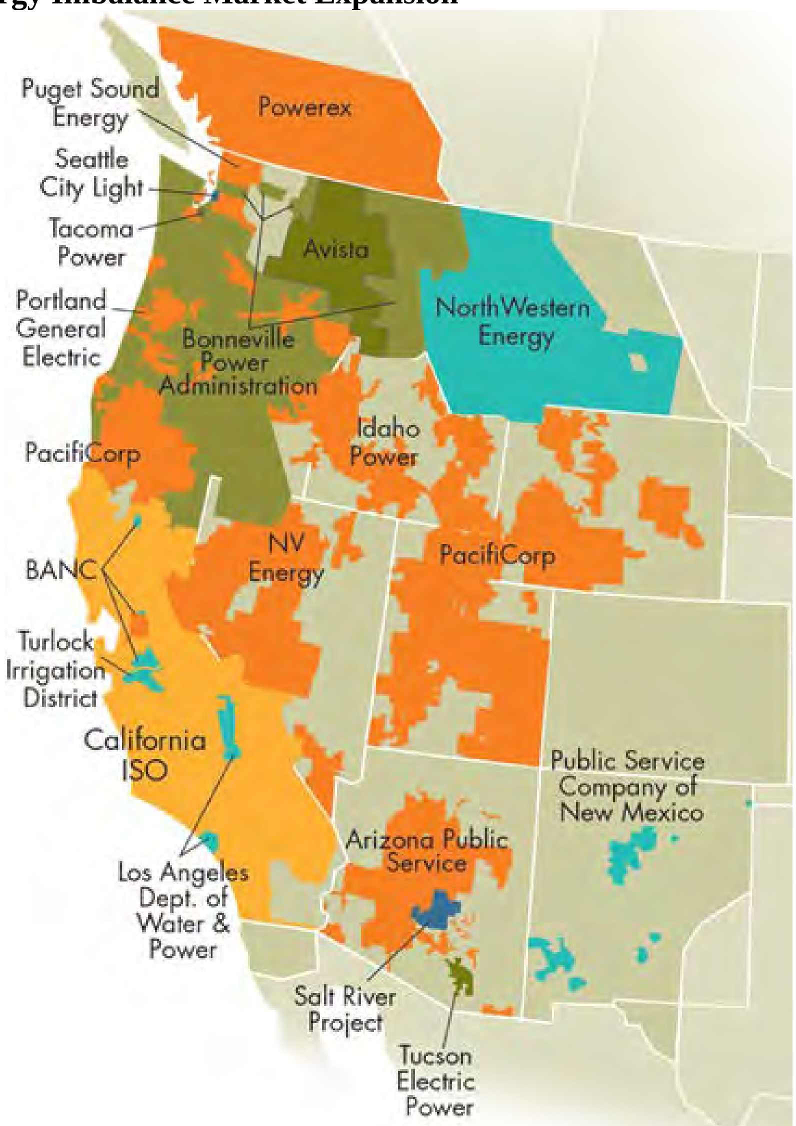
Irrigation Rate Design

Irrigation rates in Utah are comprised of an annual customer charge, a monthly customer charge, a seasonal power charge, and energy charges. The annual and monthly customer charges provide some recovery of customer-related costs incurred to serve customers regardless of usage. All other remaining costs are recovered through a seasonal power charge and energy charges. The power charge is for the irrigation season only and is designed to recover demand-related costs and to encourage irrigation customers to control and reduce power consumption. Energy charges for irrigation customers are designed with two options. One is a time-of-day program with higher rates for on-peak consumption than for off-peak consumption. Irrigation customers also have an option to participate in a third-party operated Irrigation Load Control Program. Customers are offered a financial incentive to participate in the program and give the company the right to interrupt service to the participating customers when energy costs are higher.

Energy Imbalance Market

PacifiCorp and the CAISO launched the EIM November 1, 2014. The EIM is a voluntary market and the first western energy market outside of California. The EIM covers eight states in the United States of America and one province in Canada—British Columbia, California, Nevada, Arizona, Idaho, Oregon, Utah, Washington, and Wyoming—and uses CAISO advanced market systems to dispatch the least-cost resources every five minutes. Since the launch of the EIM, NV Energy joined the market December 1, 2015; Puget Sound Energy and Arizona Public Service joined October 1, 2016; Portland General Electric joined October 1, 2017; Idaho Power and Powerex joined April 4, 2018; Balancing Authority of Northern California/Sacramento Municipal Utility District Phase 1 joined April 3, 2018. Entities scheduled to join the EIM include Salt River Project and Seattle City Light in April 2020; and Los Angeles Department of Power and Water, NorthWestern Energy, Turlock Irrigation District, BANC Phase 2 and Public Service Company of New Mexico in 2021; and Tucson Electric Power, Avista, Tacoma Power and Bonneville Power Administration in 2022. PacifiCorp continues to work with the CAISO, existing and prospective EIM entities, and stakeholders to enhance market functionality and support market growth.

Figure 3.6 – Energy Imbalance Market Expansion



The EIM has produced significant monetary benefits ($736 million total footprint-wide benefits as of July 31, 2019), quantified in the following categories: (1) more efficient dispatch, both inter- and intra-regional, by automating dispatch every 15 minutes and every five minutes within and across the EIM footprint; (2) reduced renewable energy curtailment by allowing balancing authority areas to export or reduce imports of renewable generation that would otherwise need to be curtailed; and (3) reduced need for flexibility reserves in all EIM balancing authority areas, also referred to as diversity benefits, which reduces cost by aggregating load, wind, and solar variability and forecast errors of the EIM footprint.

A significant contributor to EIM benefits are transfers across balancing authority areas, providing access to lower-cost supply, while factoring in the cost of compliance with greenhouse gas emissions regulations when energy is transferred into the CAISO balancing authority area to serve California load. The transfer volumes are therefore a good indicator of a portion of the benefits attributed to the EIM. Transfers can take place in both the five and 15-minute market dispatch intervals.

After development and expansion of the EIM in the west, a natural next question is – are there continued opportunities to increase economic efficiency and renewable integration beyond the scope of EIM but short of a fully regional independent system operator? PacifiCorp believes the answer may be yes, but several items that are critical to its success will need creative solutions; resource sufficiency, transmission utilization, voluntary nature and governance. Currently, the benefits of an extended day-ahead market (EDAM) in the west have not been assessed and the market design has not yet been developed. The concept of extending day-ahead market services are included in the CAISO's 2019 Draft Policy Initiatives Roadmap, which has an EDAM stakeholder initiative which entered the first stage of policy development October 10, 2019, with the issuance of an Issue Paper by the CAISO. The EDAM stakeholder initiative will tackle questions such as transmission utilization, grid management charges, governance and regulatory considerations in an open forum to reach consensus on a viable EDAM concept.

Recent Resource Procurement Activities

PacifiCorp issued and will issue multiple requests for proposals (RFP) to secure resources or transact on various energy and environmental attribute products. Table 3.4 summarizes recent RFP activities.

Table 3.4 – PacifiCorp's Request for Proposal Activities

RFP	RFP Objective	Status	Issued	Completed
2017 Renewable Energy Credits RFP	Purchase renewable energy credits for Oregon Schedule 272 participation	Closed	August 2017	September 2017
2017 Renewable RFP	Purchase new or repowered wind renewable energy	Closed	September 2017	November 2018
2017 Solar RFP	Purchase solar renewable energy	Closed	November 2017	March 2018
2017 Market Resource RFP	Purchase firm power for PacifiCorp's western balancing authority	Closed	November 2017	November 2017
2018 Oregon Community Solar RFP	Purchase solar energy or Oregon Community Solar	Ongoing	July 2018	On hold pending final program rules
2018 Renewable Energy Credits RFP	Purchase renewable energy credits for Oregon Schedule 272 participation	Closed	August 2018	September 2018

RFP	RFP Objective	Status	Issued	Completed
2019R Utah RFP	Purchase new renewable energy for specific customers under Utah Schedule 32 or 34	Ongoing	March 2019	Ongoing
Renewable energy credits (Sale)	Excess system RECs	Ongoing	Based on specific need	Ongoing
2019 Capacity and Energy Supply RFP	Purchase capacity and energy supply	Ongoing	June 4, 2019	Ongoing
Renewable energy credits (Purchase)	Oregon compliance needs	Ongoing	Based on specific need	Ongoing
Renewable energy credits (Purchase)	Washington compliance needs	Ongoing	Based on specific need	Ongoing
Renewable energy credits (Purchase)	California compliance needs	Ongoing	Based on specific need	Ongoing
Short-term Market (Sales)	System balancing	Ongoing	Based on specific need	Ongoing

Demand Side Management (DSM) Resources

In 2018, through competitive procurement processes, the company selected vendors to continue and adaptively manage the successful, cost-effective delivery of its two largest Energy Efficiency programs: wattsmart Homes and wattsmart Business. PacifiCorp also competitively procured for Demand Response programs: Oregon Irrigation Load Control and Home Energy Reports. These delivery contracts support the delivery designs of existing programs.[27]

2017 Renewable Energy Credits RFP

PacifiCorp issued a 2017 Oregon Schedule 272 REC RFP in August 2017 seeking cost-competitive bids under Oregon Schedule 272 for individually negotiated arrangements for unbundled RECs from facilities in Oregon and Utah. As a result of discussions with customers, no transactions were completed pursuant to this RFP.

2017 Renewable RFP

PacifiCorp issued a Renewable RFP in September 2017 seeking cost-competitive bids for up to 1,270 MW of wind energy interconnecting with or delivering to PacifiCorp's Wyoming system and any additional wind energy located outside of Wyoming that will reduce system costs and provide net benefits for customers. As a result of the RFP, PacifiCorp has contracted to construct and/or procure three new wind projects – TB Flats I and II, Ekola Flats, and Cedar Springs – totaling 1,150 MW.

2017 Solar RFP

PacifiCorp issued a 2017 Solar Resource RFP in November 2017 seeking cost-competitive bids for solar energy interconnecting with or delivering to PacifiCorp's system that will reduce system

[27] Program information for Rocky Mountain Power can be found at energyvision2020.com/and programs for Pacific Power can be found at www.pacificpower.net/about/innovation-environment/energy-vision-2020.html.

costs and provide net benefits for customers. At the conclusion of the final shortlist evaluation process, PacifiCorp decided not to select any of the bids under this RFP.

2017 Market Resource RFP

PacifiCorp issued a 2017 Market Resource RFP in November 2017 seeking firm physical power delivered to PacifiCorp's western balancing authority area for the time period 2018 through 2020. No transactions were completed as a result of this RFP.

2018 Oregon Community Solar RFP

PacifiCorp issued a 2018 Oregon Community Solar RFP in July 2018 seeking cost-competitive bids for individual projects up to 3.0 MW of new greenfield, alternating current (AC) solar photovoltaic resources directly interconnecting with PacifiCorp's distribution or transmission system and located in PacifiCorp's Oregon service territory. The RFP is currently on hold while Oregon Community Solar Program rules, guidelines and timelines are furthered clarified and established within Public Utility Commission of Oregon proceedings.[28]

2018 Renewable Energy Credits RFP

PacifiCorp issued a 2017 Oregon Schedule 272 REC RFP in August 2018 seeking cost-competitive bids under Oregon Schedule 272 for individually negotiated arrangements for unbundled RECs from facilities within Pacific Power and Rocky Mountain Power service territories. As a result of discussions with customers, no transactions were completed as a result of this RFP.

2019 Renewable RFP - Utah

PacifiCorp issued a Renewable RFP in March 2019 on behalf of a select group of customers seeking cost-competitive bids for renewable projects constructed in Utah meeting the criteria established by the participating customers to meet their annual energy requirements. Projects must interconnect or be capable of delivery to PacifiCorp's system. Customers will contract for the project output through Utah's Schedule 32 or 34.[29] RFP is in progress with a target completion date in December 2019.

Renewable Energy Credits RFP (Sale)

On an ongoing basis, and based on availability, PacifiCorp issues short-term RFPs to sell RECs that are not required to be held and/or retired for meeting regulatory requirements, such as state RPS compliance obligations.

Renewable Energy Credits RFP (Purchase)

On an ongoing basis, and based on availability, PacifiCorp issues short-term RFPs to purchase RECs for PacifiCorp's Oregon, Washington and/or California state renewable portfolio standard compliance obligations.

[28] See Public Utility Commission of Oregon, Community Solar Program Implementation, Docket No. UM 1930, for more information.
[29] This Utah schedule information for Rocky Mountain Power can be found at: www.rockymountainpower.net/about/rates-regulation/utah-rates-tariffs.html

CHAPTER 4 – TRANSMISSION

CHAPTER HIGHLIGHTS

- PacifiCorp's planned transmission projects will facilitate a transitioning resource portfolio and will comply with reliability requirements, while providing sufficient flexibility necessary to ensure existing and future resources can meet customer demand cost effectively and reliably.
- Given the long lead time needed to site, permit and construct major new transmission lines, these projects need to be planned in advance.
- PacifiCorp's transmission planning and benefits evaluation efforts adhere to regulatory and compliance requirements and respond to commission and stakeholder requests for a robust evaluation process and clear criteria for evaluating transmission additions.
- PacifiCorp requests acknowledgement of its plan to construct the Aeolus to Mona (Clover substation) Gateway South 500 kilovolt (kV) transmission line based on customer benefits and the inclusion of this segment in the 2019 PacifiCorp Integrated Resource Plan (IRP) preferred portfolio.
- While construction of the balance of future Energy Gateway segments (i.e., Gateway West, and Boardman to Hemingway) is beyond the scope of acknowledgement for this IRP, these segments are expected to deliver future benefits for our customers and for the region. Thus, continued permitting of these segments is warranted to ensure that PacifiCorp is well positioned to advance these projects at the appropriate time.

Introduction

PacifiCorp's bulk transmission network is designed to reliably transport electric energy from a broad array of generation resources (owned or contracted generation including market purchases) to load centers. There are many benefits associated with a robust transmission network, some of which are set forth below:

1. Reliable delivery of diverse energy supply to continuously changing customer demands under a wide variety of system operating conditions.
2. Ability to meet aggregate electrical demand and customers' energy requirements at all times, taking into account scheduled outages and the ability to maintain reliability during unscheduled outages.
3. Economic dispatch of resources within PacifiCorp's diverse system.
4. Economic transfer of electric power to and from other systems as facilitated by the company's participation in the market, which reduces net power costs and provides opportunities to maintain resource adequacy at a reasonable cost.
5. Access to some of the nation's best wind and solar resources, which provides opportunities to develop geographically diverse low-cost renewable assets.
6. Protection against market disruptions where limited transmission can otherwise constrain energy supply.
7. Ability to meet obligations and requirements of PacifiCorp's Open Access Transmission Tariff (OATT).

PacifiCorp's transmission network is highly integrated with other transmission systems in the west and provides the critical infrastructure needed to serve our customers cost effectively and reliably. Consequently, PacifiCorp's transmission network is a critical component of the IRP process.

PacifiCorp has a long history of providing reliable service in meeting the bulk transmission needs of the region. This valued asset will become even more critical as the regional resource mix transitions to accommodate increasing levels of variable generation from renewable resources that will be used to serve growing energy needs of PacifiCorp's customers.

Regulatory Requirements

Open Access Transmission Tariff

PacifiCorp provides open access transmission and interconnection service in accordance with its OATT, as approved by the Federal Energy Regulatory Commission (FERC). Under the OATT, PacifiCorp plans and builds its transmission system to meet the needs of two different types of transmission customers: network customers and point-to-point customers. The OATT also obligates PacifiCorp to expand its system as needed to grant requests for generator interconnection service.

For network customers, PacifiCorp uses ten-year load-and-resource (L&R) forecasts supplied by the customer, as well as network transmission service requests to facilitate development of transmission plans. Each year, PacifiCorp solicits L&R data from each of its network customers to determine future L&R requirements for all transmission network customers. The bulk of PacifiCorp's network customer needs comes from the company's Energy Supply Management (ESM) function, which supplies energy and capacity for PacifiCorp's retail customers. Other network customers include Utah Associated Municipal Power Systems, Utah Municipal Power Agency, Deseret Power Electric Cooperative (including Moon Lake Electric Association), Bonneville Power Administration (BPA), Basin Electric Power Cooperative, Black Hills Power, Tri-State Generation & Transmission, the United States Department of the Interior Bureau of Reclamation, and the Western Area Power Administration.

PacifiCorp uses its customers' L&R forecasts and best available information, including transmission service requests, as one factor to determine the need and timing for investments in the transmission system. If customer L&R forecasts change significantly, PacifiCorp may consider alternative deployment scenarios or schedules for transmission system investments, as appropriate. In accordance with FERC guidelines, PacifiCorp is able to reserve transmission network capacity based on these data. PacifiCorp's experience, however, is that the lengthy planning, permitting and construction timeline required to deliver significant transmission investments, as well as the typical useful life of these facilities, is well beyond the 10-year timeframe of L&R forecasts.[1] A 20-year planning horizon and ability to reserve transmission capacity to meet existing and forecasted need over that timeframe is more consistent with the time required to plan for and build large-scale transmission projects, and PacifiCorp supports clear regulatory acknowledgement of this reality and corresponding policy guidance.

For point-to-point transmission service, the OATT requires PacifiCorp to grant service on existing transmission infrastructure using existing capacity or to build transmission system infrastructure as required to provide the requested service. The required action is determined with each point-to-

[1] For example, PacifiCorp's application to begin the Environmental Impact Statement (EIS) process for the Gateway West segment of its Energy Gateway Transmission Expansion Project was filed with the Bureau of Land Management (BLM) in 2007. A partial Record of Decision (ROD) was received in late April 2013, and a supplemental ROD was received in January 2017.

point transmission service request through FERC-approved study processes that identify the transmission facilities needed to grant the request.

Requests for generator interconnection service can also drive the need for transmission network upgrades. Similar to the process for point-to-point requests, the OATT contains study procedures to determine the facilities needed to grant a request for new generator interconnection service.

Reliability Standards

PacifiCorp is required to meet mandatory FERC, North American Electric Reliability Corporation (NERC), and Western Electricity Coordinating Council (WECC) reliability standards and planning requirements. The operation of PacifiCorp's transmission system also responds to requests issued by Peak Reliability as the NERC Reliability Coordinator. Beginning in 2020, Peak Reliability will be disbanded and the California Independent System Operator (CAISO) will provide the Reliability Coordinator function for PacifiCorp. The company conducts annual system assessments to confirm minimum levels of system performance during a wide range of operating conditions, from serving loads with all system elements in service to extreme conditions where portions of the system are out of service. Factored into these assessments are load growth forecasts, operating history, seasonal performance, resource additions or removals, new transmission asset additions, and the largest transmission and generation contingencies. Based on these analyses, PacifiCorp identifies any potential system deficiencies and determines the infrastructure improvements needed to reliably meet customer loads. NERC planning standards define reliability of the interconnected bulk electric system in terms of adequacy and security. Adequacy is the electric system's ability to meet aggregate electrical demand for customers at all times. Security is the electric system's ability to withstand sudden disturbances or unanticipated loss of system elements. Increasing transmission capacity often requires redundant facilities in order to meet NERC reliability criteria.

This chapter provides:

- Justification supporting acknowledgement of PacifiCorp's plan to construct Gateway South.
- Support for PacifiCorp's plan to continue permitting the balance of Gateway West and Boardman to Hemmingway;
- Key background information on the evolution of the Energy Gateway Transmission Expansion Plan; and
- An overview of PacifiCorp's investments in recent short-term system improvements that have improved reliability, helped to maximize efficient use of the existing system, and enabled the company to defer the need to invest in larger-scale transmission infrastructure.

Wallula to McNary Update

The Wallula to McNary transmission project was energized at the end of January 2019 and the transmission customer began taking transmission service February 1, 2019. The project meets the requirement to provide the requested transmission service in accordance with the OATT and improves reliability of load served from the Wallula substation.

Aeolus to Bridger/Anticline Update

In 2018 PacifiCorp received the necessary state regulatory approvals, state and local permits, and private rights-of-way to construct the Aeolus-to-Bridger/Anticline sub-segment D.2 of Gateway West. Construction began in April 2019 and will be completed and placed in service by the end of 2020.

Request for Acknowledgement of Aeolus to Mona

The 2019 PacifiCorp IRP preferred portfolio includes the Aeolus-to-Mona (Clover substation) transmission segment (Energy Gateway South or Segment F). This segment is included in the preferred portfolio as a component of the least-cost, least-risk plan.

The 500 kV transmission segment extends 416 miles between the planned (as part of Gateway West sub-segment D.2) Aeolus substation near Medicine Bow, Wyoming, and the existing Clover substation located near Mona, Utah. PacifiCorp, with stakeholder involvement, has pursued permitting of the Energy Gateway South transmission project since 2008. In May 2016 the Bureau of Land Management (BLM) released its final Environmental Impact Statement (EIS) and issued their Record of Decision (ROD) in December of the same year. In May 2018 the U.S. Forest Service issued its ROD, completing the permitting on federal lands and providing a right-of-way grant for federal properties.

Leveraging transmission modeling improvements implemented in the 2019 IRP, the Aeolus-to-Mona transmission segment was made available as a transmission upgrade that could be endogenously selected by the System Optimizer (SO) model—the modeling tool used to develop a broad spectrum of resource portfolios during the portfolio-development phase of the IRP. In the initial phase of the portfolio-development process, PacifiCorp produced 35 unique resource portfolios to evaluate how the type, timing, location, and volume of new resources and transmission upgrades changed in response to different planning assumptions (i.e., coal retirements, market prices, carbon dioxide (CO_2) prices). The Aeolus-to-Mona transmission segment was endogenously selected by the SO model to come online by the end of 2023 in 34 out of these 35 resource portfolios, and was selected to come online by the end of 2023 in all subsequent resource portfolios developed to refine cost-and-risk analysis for top-performing cases. Based on the IRP analysis, the Aeolus-to-Mona transmission segment will be placed into service by the end of 2023, subject to completion of local permitting and private rights-of-way acquisitions. To align development of the Aeolus-to-Mona transmission segment with additional renewable generation projects that will further decarbonize PacifiCorp's portfolio and to provide full line rating capacity on Gateway West and South, the company requests the Aeolus-to-Mona transmission segment be acknowledged in this IRP.

Factors Supporting Acknowledgement

Acknowledgment of the Aeolus-to-Mona transmission segment is supported by the extensive analysis that led to the inclusion of the transmission line in the 2019 IRP preferred portfolio. This transmission segment will allow PacifiCorp to implement system improvements, supports the full capacity rating for Gateway South and West and enables the addition of incremental Wyoming wind resources to support customer needs and deliver value for customers in the most cost-effective way. Timing of construction is driven by the phase-out schedule of federal production tax credits (PTCs), particularly the 2023 in-service requirements for 40 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.

The addition of the Aeolus-to-Mona transmission segment further improves the reliability of PacifiCorp's transmission system in the following ways:

- Provides a parallel path to the Gateway West – Sub-segment D.2 Project (Aeolus-to-Bridger/Anticline 500 kV line) improving the reliability of the 230 kV transmission system in Wyoming for the loss of either 500 kV line.
- Strengthens the PacifiCorp transmission system (increased fault duty) by interconnecting the geographically diverse areas of eastern Wyoming and southern Utah together, allowing additional generation resources to be connected.
- Improves grid reliability by providing better operational control of the backbone transmission system by interconnecting two areas of the PacifiCorp transmission system that are abundant in two different forms of renewable resources, specifically wind rich eastern Wyoming with the solar rich area of southern Utah.
- Provides anticipated improvements in eastern Utah reliability by providing a potential future high voltage source and power delivery option to meet the projected oil expansion and corresponding load growth (Ashley, Vernal).
- Improves the southern Utah transmission system reliability by providing congestion relief on the 345 kV lines during outage conditions.
- Supports PacifiCorp's NERC TPL-001-4 transmission system reliability efforts, which are necessary to improve grid reliability performance.
- Assists PacifiCorp in meeting its OATT obligations to interconnect new generation.

Completion of the new transmission segment realizes the full 1,700 MW rating of Gateway South allowing the addition of up to 1,920 MW of renewable resources added to the system. Connecting into the Mona/Clover market hub provides additional flexibility in the use of least-cost resources from eastern Wyoming or southern Utah to serve customer load.

PacifiCorp's preferred portfolio includes nearly 11,000 MW of new wind and solar resources expected to come online in the 2020-2038 timeframe, which reflects a least-cost, least-risk mix of resources that requires incremental infrastructure investment to serve PacifiCorp's customers cost effectively and reliably.

Gateway West – Continued Permitting

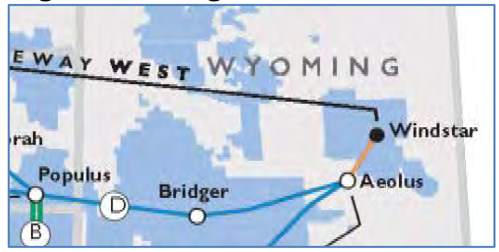
In addition to the Windstar-to-Populus line (Energy Gateway Segment D), the Gateway West transmission project also includes the Populus-to-Hemingway transmission segment (Energy Gateway Segment E). In a future IRP, PacifiCorp will support a request for acknowledgement to construct the balance of Gateway West. While PacifiCorp is not requesting acknowledgement of a plan to construct these segments in this IRP, the company will continue to permit the projects.

Windstar to Populus (Segment D)

The Windstar-to-Populus transmission project consists of three key sub-segments:

- D1—A single-circuit 230-kV line that will run approximately 75 miles between the existing Windstar substation in eastern Wyoming and the Aeolus substation that is currently under construction near Medicine Bow, Wyoming, which includes a loop-in to the existing Shirley Basin 230-kV substation;

Figure 4.1 - Segment D



- D2—A single-circuit 500-kV line that is currently under construction running approximately 140 miles from the Aeolus substation (under construction) to a new annex substation (Anticline, also currently under construction) near the existing Bridger substation in western Wyoming; and

- D3—A single-circuit 500-kV line running approximately 200 miles between the new annex substation (Anticline, under construction) and the Populus substation in southeast Idaho.

Populus to Hemingway (Segment E)

Figure 4.2 - 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.

The Gateway West project would enable PacifiCorp to more efficiently dispatch system resources, improve performance of the transmission system (i.e., reduce line losses), improve reliability, and enable access to a diverse range of new resource alternatives over the long term.

Under the National Environmental Policy Act, the BLM has completed the EIS for the Gateway West project. The BLM released its final EIS on April 26, 2013, followed by the ROD on November 14, 2013, providing a right-of-way grant for all of Segment D and most of Segment E of the project. The BLM chose to defer its decision on the western-most portion of Segment E of the project located in Idaho in order to perform additional review of the Morley Nelson Snake River Birds of Prey Conservation Area. Specifically, the sections of Gateway West that were deferred for a later ROD include the sections of Segment E from Midpoint to Hemingway and Cedar Hill to Hemingway. A ROD for these final sections of Segment E was issued on January 19, 2017 and a right-of-way grant was issued on August 8, 2018.

Plan to Continue Permitting – Gateway West

The Gateway West transmission projects continue to offer benefits under multiple, future resource scenarios. To ensure that PacifiCorp is well positioned to advance the projects, it is prudent for PacifiCorp to continue to permit the balance of Gateway West transmission projects. The Records of Decision and rights-of-way grants contain many conditions and stipulations that must be met and accepted before a project can move to construction. PacifiCorp will continue the work necessary to meet these requirements and will continue to meet regularly with the Bureau of Land Management to review progress.

Plan to Continue Permitting – Boardman to Hemingway

PacifiCorp continues to participate in the project under the Joint Funding Permitting Agreement with Idaho Power and BPA. In accordance with this agreement, PacifiCorp is responsible for its share of the costs associated with federal and state permitting activities.

Idaho Power's 2019 IRP identifies the Boardman-to-Hemingway transmission line (B2H) as a preferred resource to meet its capacity needs, reflecting a need for the project in 2026 to avoid a deficit in load-serving capability in peak-load periods. Given the status of ongoing permitting activities and the construction period, Idaho Power expects the in-service date for the transmission line to be in 2026 or beyond.

Permitting Update

The BLM released its ROD for B2H on November 17, 2017. The ROD allows BLM to grant right-of-way to Idaho Power for the construction, operation, and maintenance of the B2H Project on BLM-administered land. The approved route is the agency-preferred alternative identified in the final EIS and proposed land-use plan amendments.

For all lands crossed in Oregon, Idaho Power must receive a site certificate from the Energy Facility Siting Council (EFSC) prior to constructing and operating the proposed transmission line. The Oregon Department of Energy (ODOE) serve as staff members to EFSC facilitating the review of the site certificate application process. ODOE and EFSC both review Idaho Power's application to ensure compliance with state energy facility siting standards

The U.S. Forest Service (USFS) issued a separate ROD on November 9, 2018 for lands administered by the USFS based on the analysis in the final EIS. The USFS ROD approves the issuance of a special-use authorization for a portion of the project that crosses the Wallowa-Whitman National Forest. The U.S. Department of the Navy issued a ROD on September 25, 2019 in support of construction of a portion of the B2H project on 7.1 miles of the Naval Weapons Systems Training Facility in Boardman, Oregon.

Benefits

The existing transmission path between the Pacific Northwest and Intermountain West regions is fully used during key operating periods, including winter peak periods in the Pacific Northwest and summer peak in the Intermountain West. PacifiCorp has invested in the permitting of the B2H project because of the strategic value of connecting the two regions. As a potential owner in the project, PacifiCorp would be able to use its bidirectional capacity to increase reliability and to enable more efficient use of existing and future resources for its customers. The following lists additional B2H benefits:

- **Customers**: PacifiCorp continues to invest to meet customers' needs, making only critical investments now to ensure future reliability, security, and safety. The B2H project will bolster reliability, security, and safety for PacifiCorp customers as the regional supply mix transitions.
- **Renewables**: The B2H project has been identified as a strategic project that can facilitate the transfer of geographically diverse renewable resources, in addition to other resources, across PacifiCorp's two balancing authority areas. Transmission line infrastructure, like

B2H, is needed to maintain a robust electrical grid while integrating clean, renewable energy resources across the Pacific Northwest and Mountain West states.

- **Regional Benefit**: PacifiCorp, as a member of the regional planning entity Northern Tier Transmission Group (NTTG), supports the inclusion of B2H in the NTTG regional plan. From a regional perspective, the B2H project is a cost-effective investment that will provide regional solutions to identified regional needs.
- **Balancing Area Operating Efficiencies**: PacifiCorp operates and controls two balancing areas. After the addition of B2H and portions of Gateway West, more transmission capacity will exist between PacifiCorp's two balancing areas, providing the ability to increase operating efficiencies. B2H will provide PacifiCorp 300 MW of additional west-to-east capability and 600 MW of east-to-west capability to move resources between PacifiCorp's two balancing authority areas.
- **Regional Resource Adequacy**: PacifiCorp is participating in the ongoing effort to evaluate and develop a regional resource adequacy program with other utilities that are members of the Northwest Power Pool. The B2H project is anticipated to provide incremental transmission infrastructure that will broaden access to a more diverse resource base, which will provide opportunities to reduce the cost of maintaining adequate resource supplies in the region.
- **Grid Reliability and Resiliency**: The Midpoint-to-Summer Lake 500-kV transmission line is the only line connecting PacifiCorp's east and west control areas. The loss of this line has the potential to reduce transfers by 1,090 MW. When B2H is built, the new transmission line will provide redundancy by adding an additional 1,000 MW of capacity between the Hemingway substation and the Pacific Northwest. This additional asset would mitigate the impact when the existing line is lost.
- **Oregon and Washington Renewable Portfolio Standards and Other State Legislation**: New legislation and rules for recently passed legislation are being developed to meet state-specific policy objectives that are expected to drive the need for additional renewable resources. As these laws are enacted and rules are developed, PacifiCorp will evaluate how the B2H transmission line can help facilitate meeting state policy objectives by providing incremental access to geographically diverse renewable resources and other flexible capacity resources that will be needed to maintain reliability. PacifiCorp believes that investment in transmission infrastructure projects, like B2H and other Energy Gateway segments, are necessary to integrate and balance intermittent renewable resources cost effectively and reliably.
- **EIM**: PacifiCorp was a leader in implementing the western energy imbalance market (EIM). The real-time market helps optimize the electric grid, which lowers costs, enhances reliability, and more effectively integrates resources. PacifiCorp believes the B2H project could help advance the objectives of the EIM and has the potential of benefitting PacifiCorp customers and the broader region.

Next Steps

Given the extensive list of benefits noted above, PacifiCorp is committed to participating in the B2H project in accordance with the terms of the Joint Funding Permitting Agreement through the final Oregon Department of Energy Facilities Siting Council's permitting process and will continue to evaluate the benefits to PacifiCorp's customers prior to commitment of entering into a project construction agreement. Additionally, PacifiCorp will continue to review possible benefits of the project as it continues to participate in project development activities, including moving forward with preliminary construction and construction agreement negotiations.

Energy Gateway Transmission Expansion Plan

Introduction

Given the long–lead time required to successfully site, permit and construct major new transmission lines, these projects need to be planned well in advance. The Energy Gateway Transmission Expansion Plan is the result of several robust local and regional transmission planning efforts that are ongoing and have been conducted multiple times over a period of several years. The purpose of this section is to provide important background information on the transmission planning efforts that led to PacifiCorp's proposal of the Energy Gateway Transmission Expansion Plan.

Background

Until PacifiCorp's announcement of Energy Gateway in 2007, its transmission planning efforts traditionally centered on new resource additions identified in the IRP. With timelines of seven to ten years or more required to site, permit, and build transmission, this traditional planning approach was proving to be problematic, leading to a perpetual state of transmission planning and new transmission capacity not being available in time to be viable for meeting customer needs. The existing transmission system has been at capacity for several years, and new capability is necessary to enable new resource development.

The Energy Gateway Transmission Expansion Plan, formally announced in May 2007, has origins in numerous local and regional transmission planning efforts discussed further below. Energy Gateway was designed to ensure a reliable, adequate system capable of meeting current and future customer needs. Importantly, given the changing resource picture, its design supports multiple future resource scenarios by connecting resource-rich areas and major load centers across PacifiCorp's multi-state service area. In addition, the ability to use these resource-rich areas helps position PacifiCorp to meet current state renewable portfolio requirements. Please refer to the regional maps of wind, solar, biomass, and geothermal potential available on PacifiCorp's Energy Gateway project website to see an overlay of the Energy Gateway project and renewable resource potential.[2] Energy Gateway has since been included in all relevant local, regional and interconnection-wide transmission studies.

Planning Initiatives

Energy Gateway is the result of robust local and regional transmission planning efforts. PacifiCorp has participated in numerous transmission planning initiatives, both leading up to and since Energy Gateway's announcement. Stakeholder involvement has played an important role in each of these initiatives, including participation from state and federal regulators, government agencies, private and public energy providers, independent developers, consumer advocates, renewable energy groups, policy think tanks, environmental groups, and elected officials. These studies have shown a critical need to alleviate transmission congestion and move constrained energy resources to regional load centers throughout the west, and include:

[2] www.pacificorp.com/transmission/transmission-projects/energy-gateway.html

- ***Northwest Transmission Assessment Committee (NTAC)***
  The NTAC was the sub-regional transmission planning group representing the northwest region, preceding Northern Tier Transmission Group and ColumbiaGrid. The NTAC developed long-term transmission options for resources located within the provinces of British Columbia and Alberta, and the states of Montana, Washington, and Oregon to serve Pacific Northwest loads and northern California.

- ***Rocky Mountain Area Transmission Study***
  Recommended transmission expansions overlap significantly with Energy Gateway configuration, including:
    - Bridger system expansion similar to Gateway West.
    - Southeast Idaho to southwest Utah expansion akin to Gateway Central and Sigurd to Red Butte.
    - Improved east-west connectivity similar to Energy Gateway Segment H alternatives.

“The analyses presented in this Report suggest that well-considered transmission upgrades, capable of giving LSEs greater access to lower cost generation and enhancing fuel diversity, are cost-effective for consumers under a variety of reasonable assumptions about natural gas prices.”

- ***Western Governors’ Association Transmission Task Force Report***
  Examined the transmission needed to deliver the largely remote generation resources contemplated by the Clean and Diversified Energy Advisory Committee. This effort built upon the transmission previously modeled by the Seams Steering Group-Western Interconnection, and included transmission necessary to support a range of resource scenarios, including high efficiency, high renewables and high coal scenarios. Again, for PacifiCorp’s system, the transmission expansion that supported these scenarios closely resembled Energy Gateway’s configuration.

“The Task Force observes that transmission investments typically continue to provide value even as network conditions change. For example, transmission originally built to the site of a now obsolete power plant continues to be used since a new power plant is often constructed at the same location.”

- ***Western Regional Transmission Expansion Partnership (WRTEP)***
  The WRTEP was a group of six utilities working with four western governors’ offices to evaluate the proposed Frontier Transmission Line. The Frontier Line was proposed to connect California and Nevada to Wyoming’s Powder River Basin through Utah. The utilities involved were PacifiCorp, Nevada Power, Pacific Gas & Electric, San Diego Gas & Electric, Southern California Edison, and Sierra Pacific Power.

- ***Northern Tier Transmission Group Transmission Planning Reports***

In the 2016-2017 NTTG Draft Regional Transmission Plan, sub segments of Energy Gateway (both Gateway West and Gateway South) were listed as necessary to provide acceptable system performance. The study also established that the amount of new Wyoming wind generation that is added over time can impact the transmission system reliability west of Wyoming. Additionally three interregional projects were included in the study Southwest Inter-tie Project (SWIP North, Cross Tie and TransWest Express), which showed that all three projects relied on Energy Gateway to attain their full transfer capability rating.

"After analyzing the steady-state performance of stressed conditioned cases, a rigorous contingency analysis commenced… then, NTTG's Technical Committee determined additional facilities would be needed to meet the reliability criteria…."

- ***WECC/Reliability Assessment Committee (RAC) Annual Reports* and *Western Interconnection Transmission Path Utilization Studies***
  These analyses measure the historical use of transmission paths in the west to provide insight into where congestion is occurring and assess the cost of that congestion. The Energy Gateway segments were included in the analyses that support these studies, alleviating several points of significant congestion on the system, including Path 19 (Bridger West) and Path 20 (Path C).

"Path 19 [Bridger] is the most heavily loaded WECC path in the study…. Usage on this path is currently of interest due to the high number of requests for transmission service to move renewable power to the West from the Wyoming area."

Energy Gateway Configuration

To address constraints identified on PacifiCorp's transmission system, as well as meeting system reliability requirements discussed further below, the recommended bulk electric transmission additions took on a consistent footprint, which is now known as Energy Gateway. This expansion plan establishes a triangle of reliability that spans Utah, Idaho and Wyoming with paths extending into Oregon and Washington, and contemplates geographically diverse resource locations based on environmental constraints, economic generation resources, and federal and state energy policies.

Since Energy Gateway's initial announcement in 2007, this series of projects has continued to be vetted through multiple public transmission planning forums at the local, regional and Western Interconnection level. In accordance with the local planning requirements in PacifiCorp's OATT, Attachment K, PacifiCorp has conducted numerous public meetings on Energy Gateway and transmission planning in general. Meeting notices and materials are posted publicly on PacifiCorp's Attachment K Open Access Same-time Information System (OASIS) site. PacifiCorp is also a member of NTTG and WECC's RAC.

These groups continually evaluate PacifiCorp's transmission plan in their efforts to develop and refine the optimal regional and interconnection-wide plans. Please refer to PacifiCorp's OASIS site for information and materials related to these public processes.[3]

[3] www.oatioasis.com/ppw/index.html

Additionally, an extensive 18-month stakeholder process on Gateway West and Gateway South was conducted. This stakeholder process was conducted in accordance with WECC Regional Planning Project Review guidelines and FERC OATT planning principles, and was used to establish need, assess benefits to the region, vet alternatives, and eliminate duplication of projects. Meeting materials and related reports can be found on PacifiCorp's Energy Gateway OASIS site.

Energy Gateway's Continued Evolution

The Energy Gateway Transmission Expansion Plan is the product of years of ongoing local and regional transmission planning efforts with significant customer and stakeholder involvement. Since its announcement in May 2007, Energy Gateway's scope and scale have continued to evolve to meet the future needs of PacifiCorp customers and the requirements of mandatory transmission planning standards and criteria. Additionally, PacifiCorp has improved its ability to meet near-term customer needs through a limited number of smaller-scale investments that maximize efficient use of the current system and help defer, to some degree, the need for larger capital investments like Energy Gateway (see the following section titled "Efforts to Maximize Existing System Capability"). The IRP process, as compared to transmission planning, can result in frequent changes in the least-cost, least-risk resource plan driven by changes in the planning environment (i.e., market conditions, cost and performance of new resource technologies, etc.). Near-term fluctuations in the resource plan do not always support the longer-term development needs of transmission infrastructure, or the ability to invest in transmission assets in time to meet customer needs. Together, however, the IRP and transmission planning processes complement each other by helping PacifiCorp optimize the timing of its transmission and resource investments to deliver cost-effective and reliable energy to our customers.

While the core tenets for Energy Gateway's design have not changed, the project configuration and timing continue to be reviewed and modified to coincide with the latest mandatory transmission system reliability standards and performance requirements, annual system reliability assessments, input from several years of federal and state permitting processes, and changes in generation resource planning and our customers' forecasted demand for energy.

As originally announced in May 2007, Energy Gateway consisted of a combination of single- and double-circuit 230-kV, 345-kV and 500-kV lines connecting Wyoming, Idaho, Utah, Oregon and Nevada. In response to regulatory and industry input regarding potential regional benefits of "upsizing" the project capacity (for example, maximized use of energy corridors, reduced environmental impacts and improved economies of scale), PacifiCorp included in its original plan the potential for doubling the project's capacity to accommodate third-party and equity partnership interests. During late 2007 and early 2008, PacifiCorp received in excess of 6,000 MW of requests for incremental transmission service across the Energy Gateway footprint, which supported the upsized configuration. PacifiCorp identified the costs required for this upsized system and offered transmission service contracts to queue customers. These queue customers, however, were unable to commit due to the upfront costs and lack of firm contracts with end-use customers to take delivery of future generation, and withdrew their requests. In parallel, PacifiCorp pursued several potential partnerships with other transmission developers and entities with transmission proposals in the Intermountain Region. Due to the significant upfront costs inherent in transmission investments, firm partnership commitments also failed to materialize, leading PacifiCorp to pursue the current configuration with the intent of only developing system capacity sufficient to meet the long-term needs of its customers.

In 2010, PacifiCorp entered into memorandums of understanding to explore potential joint-development opportunities with Idaho Power Company on its Boardman-to-Hemingway project and with Portland General Electric Company (PGE) on its Cascade Crossing project. One of the key purposes of Energy Gateway is to better integrate PacifiCorp's east and west balancing authority areas, and Gateway Segment H from western Idaho into southern Oregon was originally proposed to satisfy this need. However, recognizing the potential mutual benefits and value for customers of jointly developing transmission, PacifiCorp has pursued these potential partnership opportunities as a potential lower-cost alternative.

In 2011, PacifiCorp announced the indefinite postponement of the Gateway South 500-kV segment between the Mona substation in central Utah and Crystal substation in Nevada. This extension of Gateway South, like the double-circuit configuration discussed above, was a component of the upsized system to address regional needs if supported by queue customers or partnerships. However, despite significant third-party interest in the Gateway South segment to Nevada, there was a lack of financial commitment needed to support the upsized configuration.

In 2012, PacifiCorp determined that one new 230-kV line between the Windstar and Aeolus substations and a rebuild of the existing 230-kV line were feasible, and that the second new proposed 230-kV line and proposed 500-kV line planned between Windstar and Aeolus would be eliminated. This decision resulted from PacifiCorp's ongoing focus on meeting customer needs, taking stakeholder feedback and land-use limitations into consideration, and finding the best balance between cost and risk for customers. In January 2012, PacifiCorp signed the Boardman to Hemingway Permitting Agreement with Idaho Power Company and BPA that provides for the PacifiCorp's participation through the permitting phase of the project. The Boardman-to-Hemingway project was pursued as an alternative to PacifiCorp's originally proposed transmission segment from eastern Idaho into southern Oregon (Hemingway to Captain Jack). Idaho Power leads the permitting efforts on the Boardman-to-Hemingway project, and PacifiCorp continues to support these activities under the conditions of the Boardman to Hemingway Transmission Project Joint Permit Funding Agreement. The proposed line provides additional connectivity between PacifiCorp's west and east balancing authority areas and supports the full projected line rating for the Gateway projects at full build out. PacifiCorp plans to continue to support the project under the Permit Funding Agreement and will assess next steps post-permitting based on customer need and possible benefits.

In January 2013, PacifiCorp began discussions with PGE regarding changes to its Cascade Crossing transmission project and potential opportunities for joint development or firm capacity rights on PacifiCorp's Oregon system. PacifiCorp further notes that it had a memorandum of understanding with PGE for the development of Cascade Crossing that was terminated by its own terms. PacifiCorp had continued to evaluate potential partnership opportunities with PGE once it announced its intention to pursue Cascade Crossing with BPA. However, because PGE decided to end discussions with BPA and instead pursue other options, PacifiCorp is not actively pursuing this opportunity. PacifiCorp continues to look to partner with third parties on transmission development as opportunities arise.

In May 2013, PacifiCorp completed the Mona-to-Oquirrh project. In November 2013, the B LM issued a partial ROD providing a right-of-way grant for all of Segment D and most of Segment E of Energy Gateway. The agency chose to defer its decision on the western-most portion of Segment E of the project located in Idaho in order to perform additional review of the Morley Nelson Snake River Birds of Prey Conservation Area. Specifically, the sections of Gateway West that were deferred for a later ROD include the sections of Segment E from Midpoint to Hemingway and Cedar Hill to Hemingway.

In May 2015, the Sigurd-to-Red Butte project was completed and placed in service.

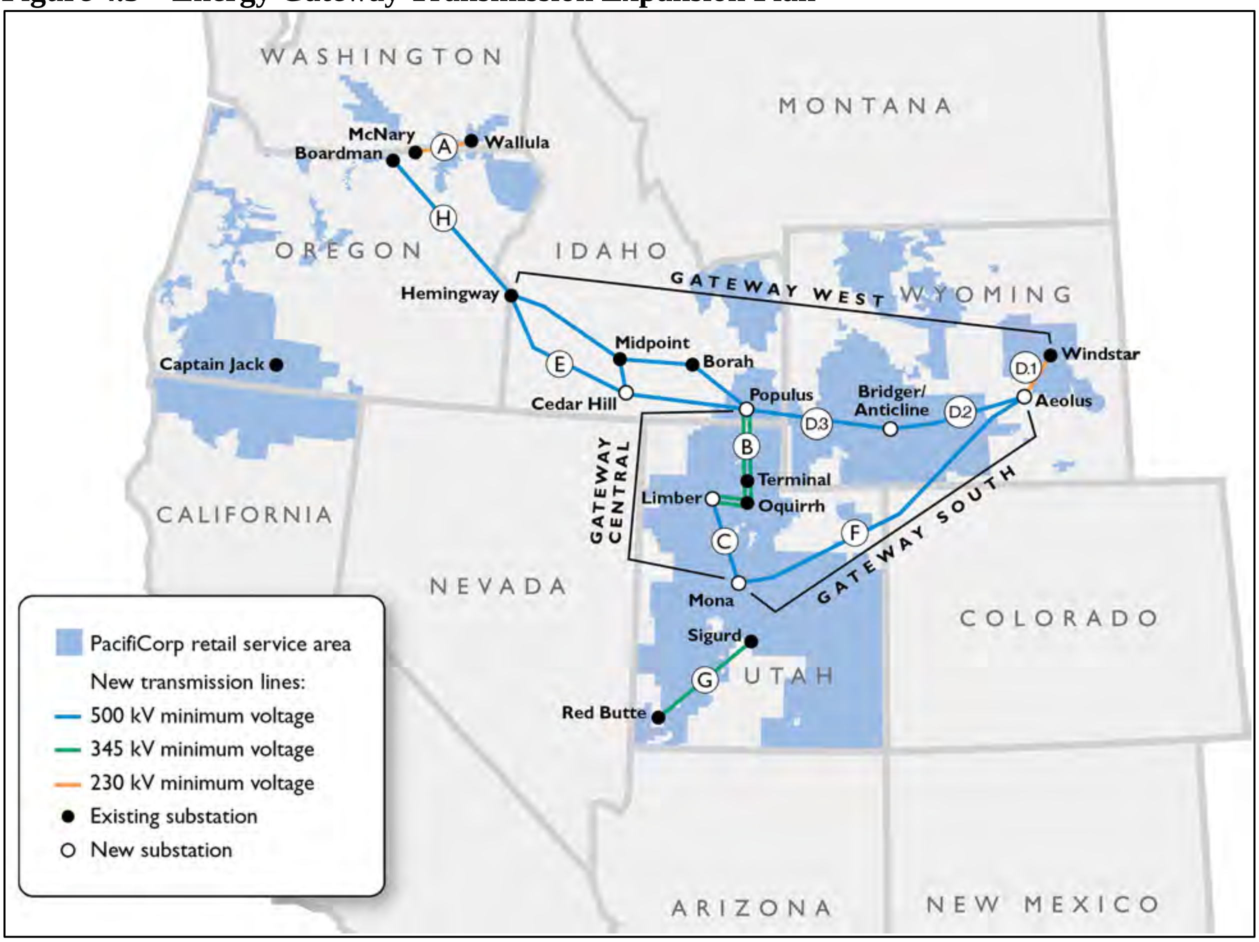
In December 2016, the BLM issued its ROD and right-of-way grant for the Gateway South project.

In January 2017, the BLM issued its ROD and right-of-way grant, previously deferred as part of the November 2013 partial ROD, for the sections of Segment E from Midpoint to Hemingway and Cedar Hill to Hemingway.

Finally, the timing of Energy Gateway segments is regularly assessed and adjusted. While permitting delays have played a significant role in the adjusted timing of some segments (e.g., Gateway West, Gateway South, and Boardman to Hemingway), PacifiCorp has been proactive in deferring in-service dates as needed due to permitting schedules, moderated load growth, changing customer needs, and system reliability improvements.

PacifiCorp will continue to adjust the timing and configuration of its proposed transmission investments based on its ongoing assessment of the system's ability to meet customer needs, its compliance with mandatory reliability standards, and the stipulations in its project permits.

Figure 4.3 – Energy Gateway Transmission Expansion Plan



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

Segment & Name	Description	Approximate Mileage	Status and Scheduled In-Service
(A) Wallula-McNary	230 kV, single circuit	30 mi	• Status: Construction complete • 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: 2024
(D1) Windstar-Aeolus	New 230 kV single circuit Re-built 230 kV single circuit	75 mi	• Status: permitting underway • Scheduled in service: 2023 earliest
(D2) Aeolus-Bridger/Anticline	500 kV single circuit	140 mi	• Status: under construction • Scheduled in service: 2020
(D3) Bridger/Anticline-Populus	500 kV single circuit	200 mi	• Status: permitting underway • Scheduled in service: 2024 earliest
(E) Populus-Hemingway	500 kV single circuit	500 mi	• Status: permitting underway • Scheduled in service: 2024 earliest
(F) Aeolus-Mona	500 kV single circuit	400 mi	• Status: permitting underway • Scheduled in service: 2023
(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: sponsor driven

Efforts to Maximize Existing System Capability

In addition to investing in the Energy Gateway transmission projects, PacifiCorp continues to make other system improvements that have helped maximize efficient use of the existing transmission system and defer the need for larger-scale, longer-term infrastructure investment. Despite limited new transmission capacity being added to the system over the last 20 to 30 years, PacifiCorp has maintained system reliability and maximized system efficiency through other smaller-scale, incremental projects.

System-wide, PacifiCorp has instituted more than 155 grid operating procedures and 17 special protection schemes to maximize the existing system capability while managing system risk. In addition, PacifiCorp has been an active participant in the EIM since November 2014. The EIM provides for more efficient dispatch of participating resources in real-time through an automated system that dispatches generation across the EIM footprint (collectively, EIM Area), which currently includes:

- PacifiCorp east and west balancing authority areas
- NV Energy
- Puget Sound Energy
- Arizona Public Service
- Portland General Electric

- Idaho Power Company
- Powerex Corporation in the BC Hydro balancing authority area
- Balancing Authority of Northern California with its member the Sacramento Municipal Utility District
- CAISO balancing authority area (collectively, EIM Area)

Entities scheduled to join the EIM include Seattle City Light, Los Angeles Department of Water and Power, and Salt River Project (April 2020), NorthWestern Energy (April 2021), and Public Service of New Mexico (April 2021 pending state commission approval).

By broadening the pool of lower-cost resources that can be accessed to balance load system requirements, reliability is enhanced and system costs are reduced across the entire EIM Area. In addition, the automated system is able to identify and use available transmission capacity to transfer the dispatched resources, enabling more efficient use of the available transmission system.

Transmission System Improvements Placed In-Service Since the 2017 IRP

PacifiCorp East (PACE) Control Area

1. Central Wyoming Area
    - Installed backup 345-kV bus differential relays at Jim Bridger substation located in Wyoming
        - Project driver was to correct NERC Standard TPL-001-4 Category P5 deficiency identified in PacifiCorp's 2015 NERC TPL Assessment resulting from a fault plus relay failure to operate event.
        - Benefits include mitigating the risk of thermal overloads and voltage issues in the surrounding area resulting from the failure of the primary 345-kV bus differential relay protection to operate, and the resolution of the NERC Standard TPL-001-4 Category P5 deficiency.
2. Goshen Idaho Area
    - Reconstructed the Goshen-Jefferson 161-kV line located in Idaho
        - Project driver was projected load growth at Jefferson substation that required increasing the capacity of the 161-kV line and eliminating existing clearance issues on the 161-kV line from Goshen-to-Jefferson substation.
        - Benefits include supporting projected load growth in the area by increasing the capacity of the 161-kV transmission line and eliminating line clearance issues which allows operation of the line at full capacity.
    - Installed a new remedial action scheme (RAS) in the Goshen/Rigby area of Idaho
        - Project driver was the risk of losing the 345-kV source at Goshen Substation that would result in thermal overload and severe low voltage conditions on other underlying transmission lines in the Goshen/Rigby area. The previous protection scheme would have tripped all load and generation in the area which was anticipated to be up to 700 MW and 650 MW, respectively.
        - Benefits include shedding less load and generation than the previous RAS (load up to 450 MW and generation up to 80 MW) to prevent multiple thermal overload and low voltage conditions and improved the restoration process by

making it less complicated than the previous protection scheme which dropped all load and generation in the area.

- Purchased a spare 345-161 kV transformer for Goshen substation in Idaho
    - Primary driver is to protect against experiencing a single contingency event (N-1) for the failure of one of the 700 megavolt-ampere (MVA), 345-161 kV transformers at Goshen substation that would cause thermal overload on the remaining transformer during heavy summer load periods and could result in the load shedding of up to 250 MW of load in the area for extended periods of time since there were no system spare transformers at this voltage class and capacity.
    - Benefits include mitigating the risk of thermal overload on the remaining 700 MVA, 345-161 kV transformer and not having to shed up to 250 MW of load for extended periods of time during heavy summer loading conditions.
- Installed shunt capacitors at Rigby and Sugarmill substations located in Idaho
    - Primary driver was to correct NERC Standard TPL-001-4 Category P1-2 deficiency identified in PacifiCorp's 2016 NERC TPL Assessment and the 2016 Goshen Area Study resulting in low voltage issues caused by the loss of a 161-kV line (N-1).
    - Benefits include improving the voltage profile under normal and outage conditions, resolving low voltage and voltage deviation issues, reducing load shedding risk under normal operating conditions, mitigating consequential load loss of up to 150 MW, improving reliability to the Rigby-Sugarmill area customers, and resolution of NERC TPL-001-4 Category P1-2 deficiency.

3. Southeast Idaho Area
    - Replaced an existing bus tie oil breaker with a SF6 breaker and added a circuit switcher in series with the breaker at the Treasureton 138-kV substation located in Idaho
        - Project driver was to correct NERC Standard TPL-001-4 Category P2-4 deficiency identified in PacifiCorp's 2015 NERC TPL Assessment resulting from a potential stuck breaker event that prevents the bus tie to operate to clear a fault. The P2-4 contingency event that would result in thermal overloads beyond the emergency rating of several 138 kV lines in that area.
        - Benefits include mitigating the risk of thermal overloads and voltage issues, eliminating the potential loss of load at the Treasureton substation of up to 465 MW, and resolution of the NERC TPL-001-4 Category P2-4 deficiency.
4. Ogden Utah Area
    - Energized one circuit of the 230-kV Ben Lomond-to-Parrish line as a three-terminal 138-kV line from Ben Lomond to Syracuse and Parrish located in Utah
        - Project driver was to correct the NERC Standard TPL-003 Category C3 deficiency that was identified in PacifiCorp's 2013 NERC TPL Assessment that caused by the loss of any two bulk transmission elements under peak load conditions.

    - Benefits include mitigating the risk of thermal overloads and voltage issues, mitigating the potential load shedding of up to 180 MW in the Ogden area, and the resolution of the NERC TPL-003 Category C3 deficiency.

- Installed a second 700 MVA 345/138 kV transformer at Syracuse substation located in Utah
    - Project driver was to correct NERC Standard TPL-001-4 Category P1, P6 and P7 deficiencies identified in PacifiCorp's 2015 NERC TPL Assessments resulting in a single contingency event (N-1) and multiple contingency events (P6 and P7).
    - Benefits include mitigating the risk of thermal overloads and low voltage issues, eliminating the risk of preemptive load shedding up to 30 MW, improving transmission reliability for customers in the Ogden area, and resolution of the NERC TPL-001-4 Category P1 deficiencies and resolves nearly half the number of identified NERC TPL-001-4 Category P6 and P7 deficiencies (Operating procedures are in place to address the non-resolved P6 and P7 deficiencies that were not corrected by the implementation of this project).
- Installed a new RAS at El Monte substation and line closing for Riverdale–Gordon Avenue–Parrish 138-kV lines in Utah
    - Project driver was to correct NERC Standard TPL-001-4 Category P2, P6 and P7 deficiencies identified in PacifiCorp's 2016 NERC TPL Assessment that could cause thermal overload issues on multiple 138-kV lines in the Ogden area.
    - Benefits include mitigating the risk of thermal overloads, improving reliability to the 138-kV system, optimizing the load shed levels of the new RAS, and resolving NERC TPL-001-4 Category P2, P6 and P7 deficiencies.

5. Salt Lake Valley Area
    - Replaced breakers identified as over-dutied with higher-capability breakers at MidValley substation in Utah
        - Project driver was to correct NERC Standard TPL-001-4 Requirement R2.3 deficiencies identified in PacifiCorp's 2015 NERC TPL Assessment resulting in the identification of three 138-kV over-dutied breakers at MidValley substation.
        - Benefits include eliminating the risk of over-dutied breakers failing under fault interruption conditions that pose safety and reliability risks, and the resolution of the NERC TPL-001-4 Requirement R2.3 deficiencies.
6. Park City Utah Area
    - Constructed a 138-kV line from Croydon substation to Silver Creek substation located in Utah
        - Project drivers were projected load growth and reliability improvements which required an additional 138-kV source into the Park City area.
        - Benefits are the additional a 138-kV source into the area, additional capacity to address projected load growth, and improved transmission reliability.
7. Utah Valley Area

- Installed backup bus differential relays at Camp Williams substation located in Utah
    - Project driver was to correct NERC Standard TPL-001-4 Category P5 deficiency identified in PacifiCorp's 2015 NERC TPL Assessment resulting from a fault plus relay failure to operate event.
    - Benefits include mitigating the risk of thermal overloads and voltage issues in the surrounding area resulting from the failure of the primary 345-kV bus differential relay protection to operate and the resolution of the NERC Standard TPL-001-4 Category P5 deficiency.
- Installed a new bay with a breaker and half scheme at Spanish Fork substation located in Utah
    - Project driver was to correct NERC Standard TPL-003 Category C2 deficiency identified in PacifiCorp's 2013 NERC TPL Assessment for a potential stuck breaker event that prevents the bus-tie breaker to operate to clear a fault.
    - Benefits include mitigating the risk of thermal overloads and voltage issues, and eliminating the potential loss of the entire Spanish 138-kV substation load of up to 270 MW, and resolution of the NERC TPL-003 Category C2 deficiency.

8. Southwest Utah Area

- Energized the Red Butte-St. George 345-kV line at 138 kV located in Utah
    - Project driver was to correct NERC Standard TPL-001-4 Category P6 and P7 deficiencies identified in PacifiCorp's 2015 NERC TPL Assessment resulting in multiple contingency events (N-1-1 and N-2) that would impact 138-kV lines between Red Butte/Central and St. George substations during heavy summer load conditions.
    - Benefits include adding a fourth Central/Red Butte to St. George 138-kV line that increased capacity into St. George substation, improved 138-kV reliability in the area, eliminated the need for preemptive loading shedding under an N-1-1 outage condition up to 170 MW, and resolved the NERC Standard TPL-001-4 Category P6 and P7 deficiencies.

9. East Utah Area

- Installed 3.6 megavolt-ampere-reactive (MVAr) capacitor banks at Maeser and Vernal substations located in Utah
    - Project driver was to correct NERC Standard TPL-001-4 Category P1 and P2 deficiencies identified in PacifiCorp's 2016 NERC TPL Assessment resulting for the loss of a 138-kV line (P1) and for circuit break/bus faults (P2) that result in low voltage in the Vernal area.
    - Benefits include mitigating the risk of low voltage issues and resolution of the NERC Standard TPL-001-4 Category P1 and P2 deficiencies.

PacifiCorp West (PACW) Control Area

1. Yakima Washington Area

- Rebuilt the 115-kV main and transfer bus into a breaker and half scheme at the Union Gap substation in Washington

   - Project driver was to correct NERC Standard TPL-003 Category C deficiencies identified in PacifiCorp's 2013 NERC TPL Assessment for a 115 kV bus section fault or breaker failure with protection system failure.
   - Benefits include mitigating the risk of thermal overloads and voltage issues, eliminating the risk of shedding up to 500 MW of load, and resolution of the NERC TPL-003 Category C deficiencies.
 - Replaced conductor on the Moxee-Hopland section of the Moxee-Union Gap 115-kV line located in Washington
   - Project driver was to correct NERC Standard TPL-001-4 Category P1 deficiency identified in PacifiCorp's 2015 NERC TPL Assessment resulting from a single contingency event (N-1) for the loss of a 230-kV transmission line.
   - Benefits include mitigating the risk of thermal overloads, increasing capacity of the 115-kV line, improving transmission reliability, and resolution of the NERC TPL-001-4 Category P1 deficiency.

2. Portland Oregon Area
   - Rebuilt the 230-kV portion of the Troutdale substation, located in Oregon, into a six breaker ring bus configuration
     - Project driver was to correct NERC Standard TPL-002 deficiency for the loss of a single 230 kV line and NERC Standard TPL-003 for multiple contingency (N-1-1 and N-2) outages to 230-kV lines that were identified in the PacifiCorp's 2011 NERC TPL Assessment.
     - Benefits include mitigating the risk of thermal overloads, eliminating the risk of shedding load in preparation of the second contingency for an N-1-1 outage, and resolution of the NERC TPL-002 and TPL-003 deficiencies.
   - Converted portions of Portland, Oregon area transmission network to 115 kV from 57 kV and 69 kV
     - Project drivers are projected load growth, needed additional capacity, and transmission reliability improvement needs in the Portland area.
     - Benefits include the elimination of portions of the old 57-kV and 69-kV systems, increasing the 115-kV network, adding additional capacity to address projected load growth and reliability improvement to the transmission network.
3. Grant Pass Oregon Area
   - Replaced three 230-115 kV 125 MVA transformers with two 230-115 kV 250 MVA transformers at Grants Pass substation in Oregon
     - Project driver was to correct NERC Standard TPL-002 deficiency for the loss of a single 230-kV line and NERC Standard TPL-003 deficiencies for multiple contingency (N-1-1 and N-2) outages to 230-kV lines that were identified in PacifiCorp's 2013 NERC TPL Assessment.
     - Benefits include mitigating the risk of thermal overloads, eliminating the risk of shedding load in preparation of the second contingency for an N-1-1 outage, and resolution of the NERC TPL-002 and TPL-003 deficiencies.
4. Klamath Falls Oregon Area

- Constructed the new Snow Goose 500-230 kV substation located in Oregon
    - o Project driver was to correct NERC Standard TPL-001-1 Category B deficiency for the single contingency of the loss of the existing 500-230 kV transformer and TPL-003 Category C deficiencies for multiple N-1-1 and N-2 outages that were identified in PacifiCorp's 2012 NERC TPL Assessment.
    - o Benefits include mitigating the risk of thermal overloads and voltage issues, eliminates the risk of shedding load in preparation of the second contingency for an N-1-1 outage, and resolves the NERC TPL-001-1 Category B and TPL-003 Category C deficiencies.

5. Yreka California Area

- Replaced the existing 115-69 kV transformer at Weed substation with a 50 MVA load tap changer (LTC) unit located in California
    - o Project driver was to improve 69-kV voltage regulation by changing out an old 115-69 kV transformer at Weed Junction substation that had its no-load tap changer locked in place due to the high risk of causing internal transformer fault if operated. The new replacement 115-69 kV LTC transformer was installed at the nearby Weed substation.
    - o Benefits include improved voltage control of the local 69-kV system, improved transformer reliability, and ability to use load drop compensation to improve transmission voltage profile.

Planned Transmission System Improvements

PacifiCorp East (PACE) Control Area

1. Central Wyoming Area

- Upgrade the 345-230 #2 transformer at Jim Bridger substation in Wyoming
    - o Project driver is to correct NERC Standard TPL-001-4 Category P1 and P3 deficiencies identified in PacifiCorp's 2017 NERC TPL Assessment resulting for a 345-kV or 230-kV bus fault (P1) and for the loss of a generator and both Jim Bridger 345-230 kV transformers #1 and #3 (P3) that will results in thermal overload of existing Jim Bridger 345-230 kV #2 transformer.
    - o Benefits include mitigating the risk of thermal overloads and resolution of the NERC TPL-001-4 Category P1 and P3 deficiencies.

2. Goshen Idaho Area

- Install a third 345-161 kV transformer at Goshen substation located in Idaho
    - o Project driver is to correct NERC Standard TPL-001-4 Category P1 (N-1) deficiency identified in PacifiCorp's 2016 Goshen Area Study resulting in thermal overload of the remaining 345-161 kV transformer at Goshen substation.
    - o Benefits include mitigating the risk of thermal overloads and resolution of the NERC Standard TPL-001-4 Category P1 deficiency.
- Install a new 161-kV line from Goshen to Sugarmill and then from Sugarmill to Rigby substations located in Idaho

  - Project driver is to address the single contingency (N-1) and multiple contingency (N-1-1) issues present in the Sugarmill-Rigby area and the large amount of load shedding risk identified in the 2016 Goshen Area Planning Study that proposed adding a new 161-kV line from Goshen to Sugarmill and then from Sugarmill to Rigby substation to allow a looped configuration during heavy summer load conditions.
  - Benefits include mitigating the risk of thermal overloads and voltage issues, and eliminating the loss of up to 150 MW of load for N-1 outages and up to 300 MW for N-1-1 outages.
- Rebuild and convert an existing 69-kV line to 161-kV to establish a new 161-kV source at Rexburg substation in Idaho
  - Project driver is to improve 69-kV capacity and voltage regulation served from Rigby substation by converting an existing 69-kV line to 161 kV to create a 161-kV source at Rexburg substation through a new 161-69 kV transformer installation. The project also will include a new six breaker 69-kV ring bus at Rexburg substation that includes terminating two existing 69-kV lines and one new 69-kV line.
  - Benefits include establishing a new 161-kV source in the area, providing additional 69-kV capacity, improving 69-kV voltage regulation and reliability to customers served from the 69-kV system.

3. Salt Lake Valley Area

- Install a new circuit switcher in series with the bus-tie circuit breaker at 90th South substation located in Utah
  - Project driver is to correct NERC Standard TPL-001-4 Category P2-4 deficiency identified in PacifiCorp's 2017 NERC TPL Assessment for a bus tie breaker internal fault event that results in the loss of the entire 90th South 138-kV substation.
  - Benefits include mitigating the risk of thermal overloads and voltage issues, and eliminating the potential loss of load at the entire 90th South 138-kV South substation for a bus tie failure event, and resolution of the NERC TPL-001-4 Category P2-4 deficiency.

4. Park City Utah Area

- Install a 9-mile, 138-kV transmission line between Midway and Jordanelle substations in Utah
  - Project drivers are projected load growth and reliability improvements which required of extension of the 138-kV line from Jordanelle-to-Midway substation.
  - Benefits are the established new 138-kV loop, additional capacity to address projected load growth and improved transmission reliability.

5. Utah Valley Area

- Upgrade the 345-138 kV transformer at Spanish Fork substation located in Utah
  - Project driver is to correct NERC Standard TPL-001-4 Category P1 and P3 deficiencies identified in PacifiCorp's 2017 NERC TPL Assessment resulting from an outage of Spanish Fork 345-138 kV transformer #4 (N-1) and multiple

double contingency outages (N-1-1) that result in thermal overloads on numerous substation transformers and transmission lines.

 - Benefits include mitigating the risk of thermal overloads and low voltage issues, additional capacity to address projected load growth, improved transmission reliability and resolution of the NERC TPL-001-4 Category P1 and P3 deficiencies.

6. East Utah Area

 - Construct the new Naples 138-12.5 kV substation located in Utah
    - Project driver is to correct NERC Standard TPL-001-4 Category P6 deficiencies identified in PacifiCorp's 2016 NERC TPL Assessment resulting in multiple double contingencies causing low 138-kV system voltages in the Vernal area.
    - Benefits include mitigating the risk of low voltage issues and resolution of the NERC Standard TPL-001-4 Category P6 deficiencies.

7. Utah & Idaho – Upgrade Program – Backup Bus Differential Relays

 - Install backup bus differential relays at various substations located in Utah and Idaho
    - Project driver is to correct the NERC Standard TPL-001-4 Category P5-5 deficiencies identified in PacifiCorp's 2015 NERC TPL Assessments resulting in multiple contingencies for faults plus bus differential relays failure to operate that cause delayed fault clearing due to the failure of a non-redundant relay installation.
    - Benefits include mitigating the risk of delayed clearing of all transmission line connected to specific buses that would lead to thermal overloads and voltage issues, ensuring that critical differential bus protection has the required relay redundancy, improving reliability to the impacted substations and their connected transmission lines, and resolution of the NERC TPL-001-4 Category P5-5 deficiencies.

8. Utah, Idaho & Wyoming - Upgrade Program – Replace Over-dutied Circuit Breakers

 - Replace breakers identified as over-dutied with higher-capability breakers in various substations located in Idaho, Utah, and Wyoming
    - Project driver is to correct NERC Standard TPL-001-4 Requirement R2.3 deficiencies identified in PacifiCorp's 2015-2018 NERC TPL Assessment resulting in the identification of 13 over-dutied breakers.
    - Benefits include eliminating the risk of over-dutied breakers failing under fault interruption conditions that pose safety and reliability risks, and the resolution of the NERC TPL-001-4 Requirement R2.3 deficiencies

PacifiCorp West (PACW) Control Area

1. Yakima Washington Area

 - Construct a new 230-kV transmission line from BPA's Vantage substation to PacifiCorp's Pomona Heights substation located in Washington
    - Project driver is to correct the NERC Standard TPL-002 deficiency identified in PacifiCorp's 2011 TPL Assessment for the loss of a single 230-kV line.

    - Benefits include mitigating the risk of thermal overloads and low voltage issues, adding additional capacity to address projected load growth, improving transmission reliability and resolution of the NERC TPL-002 deficiencies.

- Construct a new 115-kV transmission line from Outlook substation to Punkin Center substation located in Washington
    - Project driver is to correct NERC Standard TPL-001-4 Category P1 deficiencies identified in the 2016 NERC TPL Assessment for single contingency (N-1) outages on the 230-kV system serving the Yakima Upper Valley.
    - Benefits include mitigating the risk of thermal overloads, resolving an existing capacity limitation on the 115-kV line, improving transfer capability between the Upper Valley and the Lower Valley system, and resolution of the NERC TPL-001-4 Category P1 deficiency.

2. Walla Walla Washington Area
    - Replace the existing 115-69 kV, 20 MVA transformer with a 115-69 kV, 50 MVA transformer at Dry Gulch substation located in Washington
        - Project driver is to correct NERC Standard TPL-001-4 Category P2 deficiency identified in PacifiCorp's 2015 NERC TPL Assessment for a 115-kV bus fault at Dry Gulch substation.
        - Benefits include having 69-kV capacity and voltage regulation capability to operate in a normal open configuration to eliminate thermal overloads and low voltage conditions, eliminating the 69-kV loop in parallel with the 230-kV and 500-kV main grid system that impacted the 69-kV system for outages on the main grid system, removing the Tucannon 69-kV line from the WECC Path 6 definition, and resolving the NERC TPL-001-4 P2 deficiency.
3. Albany/Corvallis Oregon Area
    - Replace conductor on the 115-kV line between Hazelwood substation and BPA's Albany substation and construct a new 115-kV ring bus at Hazelwood substation all located in Oregon
        - Project driver is to correct NERC Standard TPL-001-4 Category P6 deficiencies for an outage on the transformers at Fry substation and reduce load loss exposure from various other N-1-1 contingencies.
        - Benefits include mitigating the risk of thermal overloads and voltage issues, improving transmission reliability, reducing the complexity of operating procedures for remaining N-1-1 contingencies and resolution of a number of NERC TPL-001-4 Category P6 deficiencies.
4. Medford Oregon Area
    - Construct one new 500-230 kV substation called Sams Valley located in Oregon
        - Project driver is to correct NERC Standard TPL-002 for the loss of a single 230-kV line and NERC Standard TPL-003 for the N-1-1 and N-2 outages to 230-kV lines that were identified in PacifiCorp's 2010 NERC TPL Assessment, and to provide a second 500-kV source to address load growth in the Southern Oregon region.

  - Benefits include adding a second source of 500-kV capacity, adding a new 230-kV line, improving reliability of the 230-kV network, mitigates the risk of thermal overloads and low voltage, mitigates the risk of shedding load in preparation of the second contingency for N-1-1 outages, and resolves the NERC TPL-002 and TPL-003 deficiencies.

- Expand the RAS at Meridian substation located in Oregon
  - Project driver is to expand the existing RAS to cover three additional N-1-1 contingencies on the southern Oregon 500-kV system and trip additional load as identified in the 2015 Meridian Area Load Tripping Assessment and the 2017 NERC TPL Assessment.
  - Benefit of expanding the RAS will be to avoid relying on the Southern Oregon Under-Voltage Load Shedding scheme as the primary mitigation for double contingencies on the 500-kV system.

5. Yreka California Area
   - Install an additional 115-69 kV transformer at Yreka substation located in California
     - Project driver is to correct low voltage conditions under normal operating conditions during heavy summer loading periods due to inadequate voltage regulation on the 69-kV system served from Yreka substation, as identified in the 2013 Yreka-Mt Shasta Area Study.
     - Benefits include the ability to provide 69-kV voltage regulation by the new 115-69 kV transformers load tap changer , allows the use of load drop compensation feature to further improve the transmission voltage profile over the long term, and making the exiting non-LTC transformer available as an installed spare for immediate service restoration when needed.
6. Oregon – Upgrade Program – Replace Over-dutied Circuit Breakers
   - Replace breakers identified as over-dutied with higher-capability breakers at Lone Pine Substation in Oregon
     - Project driver is to correct NERC Standard TPL-001-4 Requirement R2.3 deficiencies identified in PacifiCorp's 2015-2018 NERC TPL Assessment resulting in the identification of three over-dutied 115-kV breakers.
     - Benefits include eliminating the risk of over-dutied 115-kV breakers failing under fault interruption conditions that pose safety and reliability risks, and the resolution of the NERC TPL-001-4 Requirement R2.3 deficiencies.

These investments help maximize the existing system's capability, improve PacifiCorp's ability to serve growing customer loads, improve reliability, increase transfer capacity across WECC Paths, reduce the risk of voltage collapse and maintain compliance with NERC and WECC reliability standards.

CHAPTER 5 – LOAD AND RESOURCE BALANCE

CHAPTER HIGHLIGHTS

- On both a capacity and energy basis, PacifiCorp calculates load and resource balances from existing resources, forecasted loads and sales, and reserve requirements. The capacity balance compares existing resource capability at the time of the coincident system summer and winter peak periods.
- For capacity expansion planning, PacifiCorp uses a 13 percent target planning reserve margin (PRM) applied to the company's obligation, which is calculated as projected load less private generation, less energy efficiency savings (Class 2 demand-side management (DSM)), and less interruptible load.
- A 2018 Private Generation Long-Term Resource Assessment (2019-2038) study prepared by Navigant Consulting, Inc. produced estimates on private generation penetration levels specific to PacifiCorp's six-state territory. The study provided expected penetration levels by resource type, along with high and low penetration sensitivities. PacifiCorp's 2019 IRP load and resource balance treats base case private generation penetration levels as a reduction in load.
- After accounting for load reductions from private generation and energy efficiency savings from the preferred portfolio, PacifiCorp's system coincident peak load is forecasted to grow at a compound annual growth rate of 0.10 percent over the period 2019 through 2038 (0.64 percent without incremental energy efficiency from the preferred portfolio). On an energy basis, PacifiCorp expects system-wide average load growth of 0.06 percent per year from 2019 through 2038 (0.73 percent without incremental energy efficiency savings from the preferred portfolio).
- After accounting for the 13 percent target PRM, load growth, coal unit retirements from the preferred portfolio, and after incorporating future energy efficiency savings from the preferred portfolio, PacifiCorp's system is capacity deficient over the summer peak throughout the twenty-year planning period and is capacity deficient over the winter peak beginning 2024.
- When accounting for these same factors and the level of potential market purchases, front office transactions (FOTs), assumed in the 2019 Integrated Resource Plan (IRP), PacifiCorp's system is capacity deficient over the summer peak beginning 2028 and is capacity deficient over the winter peak beginning 2029.

Introduction

This chapter presents PacifiCorp's assessment of its load and resource balance. PacifiCorp's long-term load forecasts (both energy and coincident peak load) for each state and the system as a whole are summarized in Volume II, Appendix A (Load Forecast Details). The summary-level system coincident peak is presented first, followed by a profile of PacifiCorp's existing resources. Finally, load and resource balances for capacity and energy are presented. These balances are composed of a year-by-year comparison of projected loads against the existing resource base, with and without available FOTs, assumed coal unit retirements and incremental new energy efficiency savings from the 2019 IRP preferred portfolio, before adding new generating resources.

System Coincident Peak Load Forecast

The system coincident peak load is the annual maximum hourly load on the system. The 2019 IRP relies on PacifiCorp's September 2018 load forecast. Table 5.1 shows the annual summer coincident peak load stated in megawatts (MW) as reported in the capacity load and resource balance, before any load reductions from energy efficiency and private generation. The system summer peak load grows at a compound growth rate (CAGR) of 0.90 percent over the period 2019 through 2038.

Table 5.1 – Forecasted System Summer Coincident Peak Load in Megawatts, Before Energy Efficiency and Private Generation (MW)

	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
System	10,284	10,425	10,549	10,671	10,788	10,934	11,012	11,057	11,149	11,261
	2029	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**	**2036**	**2037**	**2038**
System	11,362	11,469	11,575	11,696	11,809	11,723	11,834	11,946	12,078	12,193

Existing Resources

On a system coincident basis, PacifiCorp is a summer-peaking utility. For the forecasted 2019 summer coincident peak, PacifiCorp owns or contracts for resources to meet expected system summer peak capacity. Note that capacity ratings in the following tables provide resource capacity value at nameplate, rounded to the nearest megawatt.

Thermal Plants

Table 5.2 lists PacifiCorp's existing coal-fueled plants and Table 5.3 lists existing natural-gas-fueled plants. End of life year dates reflect those assumed in the preferred portfolio.

Table 5.2 – Coal-Fueled Plants

Plant	PacifiCorp Percentage Share (%)	State	End of Life Year	Nameplate Capacity (MW)
Cholla 4	100	Arizona	2020	387
Colstrip 3	10	Montana	2027	74
Colstrip 4	10	Montana	2027	74
Craig 1	19	Colorado	2025	82
Craig 2	19	Colorado	2026	82
Dave Johnston 1	100	Wyoming	2027	99
Dave Johnston 2	100	Wyoming	2027	106
Dave Johnston 3	100	Wyoming	2027	220
Dave Johnston 4	100	Wyoming	2027	330
Hayden 1	24	Colorado	2030	44
Hayden 2	13	Colorado	2030	33
Hunter 1	94	Utah	2042	418

Hunter 2	60	Utah	2042	269
Hunter 3	100	Utah	2042	471
Huntington 1	100	Utah	2036	459
Huntington 2	100	Utah	2036	450
Jim Bridger 1	67	Wyoming	2023	354
Jim Bridger 2	67	Wyoming	2028	359
Jim Bridger 3	67	Wyoming	2037	349
Jim Bridger 4	67	Wyoming	2037	353
Naughton 1	100	Wyoming	2025	156
Naughton 2	100	Wyoming	2025	201
Naughton 3*	100	Wyoming	2019	0
Wyodak	80	Wyoming	2039	268
TOTAL – Coal				**5,638**

* Naughton 3 coal generation ended January 30, 2019. The preferred portfolio converts Naughton 3 to gas in 2020 through 2029.

Table 5.3 – Natural-Gas-Fueled Plants

Natural Gas -fueled	PacifiCorp Percentage Share (%)	State	Assumed End of Life Year	Nameplate Capacity (MW)
Chehalis	100	Washington	2043	491
Currant Creek	100	Utah	2045	545
Gadsby 1	100	Utah	2032	64
Gadsby 2	100	Utah	2032	69
Gadsby 3	100	Utah	2032	105
Gadsby 4	100	Utah	2032	40
Gadsby 5	100	Utah	2032	40
Gadsby 6	100	Utah	2032	40
Hermiston	100	Oregon	2036	234
Lake Side	100	Utah	2047	551
Lake Side 2	100	Utah	2054	644
TOTAL – Natural Gas				**2,821**

Renewable Resources

Wind

PacifiCorp either owns or purchases under contract 3,908 MW of wind resources. Table 5.4 shows existing wind facilities owned by PacifiCorp, while Table 5.5 shows existing wind power purchase agreements.

Table 5.4 – Owned Wind Resources

Utility-Owned Wind Projects	State	Capacity (MW)
Foote Creek I *	WY	32
Leaning Juniper	OR	101
Goodnoe Hills East Wind	WA	94
Marengo	WA	140
Marengo II	WA	70
Glenrock Wind I	WY	99
Glenrock Wind III	WY	39
Rolling Hills Wind	WY	99
Seven Mile Hill Wind	WY	99
Seven Mile Hill Wind II	WY	20
High Plains	WY	99
McFadden Ridge 1	WY	29
Dunlap 1	WY	111
Pryor Mountain **	MT	240
Cedar Springs II***	WY	200
Ekola Flats ***	WY	250
TB Flats ***	WY	500
TOTAL – Owned Wind		**2,222**

* Net total capacity for Foote Creek 1 is 40 MW.

** Wind facility not part of EV 2020. In service December 31, 2020.

*** EV 2020 in service by December 31, 2020.

Table 5.5 – Non-Owned Wind Resources

Power Purchase Agreements / Exchanges	State	PPA or QF	Capacity (MW)
Cedar Springs Wind ***	WY	PPA	200
Cedar Springs III *	WY	PPA	120
Combine Hills	OR	PPA	41
Foote Creek IV	WY	PPA	17
Rock River I	WY	PPA	50
Stateline Wind	OR / WA	PPA	175
Three Buttes Wind Power (Duke)	WY	PPA	99.0
Top of the World	WY	PPA	200
Wolverine Creek	ID	PPA	65
Chopin	WA	QF	10
Foote Creek II	WY	QF	2
Foote Creek III	WY	QF	25
Latigo Wind	UT	QF	60
Mariah Wind	OR	QF	10
Meadow Creek Project – Five Pine	ID	QF	40.0
Meadow Creek Project – North Point	ID	QF	80
Monticello Wind	UT	QF	79
Mountain Wind Power I	WY	QF	61
Mountain Wind Power II	WY	QF	80
Orchard Wind	WA	QF	40
Oregon Wind Farms I & II	OR	QF	65
Orem Family Wind	OR	QF	10.0
Pioneer Wind Park I	WY	QF	80
Power County Wind Park North	ID	QF	23

Power County Wind Park South	ID	QF	23
Spanish Fork Wind Park 2	UT	QF	19
Three Mile Canyon	WA	QF	10
Toole Army Depot	UT	QF	3
Small QF	WY	QF	0.2
TOTAL – Purchased Wind			**1,686**

* Wind facility not part of EV 2020. New since 2017 IRP Update.
** EV 2020 in service by December 31, 2020.

Solar

PacifiCorp has a total of 61 solar projects under contract representing 1,759 MW of nameplate capacity. Of these, seven projects totaling 559 MW are new since the 2017 IRP Update.

Table 5.6 – Non-Owned Solar Resources

Power Purchase Agreements / Exchanges	PPA or QF	State	Capacity (MW)
Black Cap	PPA	OR	2
Utah Solar PV Program	PPA	UT	2
Old Mill	PPA	OR	5
Oregon Solar Incentive Projects (OSIP)	PPA	OR	10
Milford *	PPA	UT	99
Hunter *	PPA	UT	100
Sigurd *	PPA	UT	80
Cove Mountain *	PPA	UT	58
Cove Mountain II *	PPA	UT	122
Prineville *	PPA	OR	40
Millican *	PPA	OR	60
Small Solar	QF	UT	0.5
Adams Solar Center	QF	OR	10
Bear Creek Solar Center	QF	OR	10
Beryl Solar	QF	UT	3
Black Cap Solar II	QF	OR	8
Bly Solar Center	QF	OR	9
Buckhorn Solar	QF	UT	3
Cedar Valley Solar	QF	UT	3
Chiloquin Solar	QF	OR	10
Collier Solar	QF	OR	10
Elbe Solar Center	QF	OR	10
Enterprise Solar	QF	UT	80
Escalante Solar I	QF	UT	80
Escalante Solar II	QF	UT	80
Escalante Solar III	QF	UT	80
Ewauna Solar	QF	OR	1
Ewauna Solar 2	QF	OR	3
SunF Solar XVII Project 1-3	QF	UT	9
Granite Mountain - East	QF	UT	80
Granite Mountain - West	QF	UT	50
Granite Peak Solar	QF	UT	3
Greenville Solar	QF	UT	2
Iron Springs	QF	UT	80
Laho Solar	QF	UT	3

Merrill Solar	QF	OR	10
Milford Flat Solar	QF	UT	3
Milford Solar 2	QF	UT	3
Norwest Energy 2 (Neff)	QF	OR	10
Norwest Energy 4 (Bonanza)	QF	OR	6
Norwest Energy 7 (Eagle Point)	QF	OR	10
Norwest Energy 9 Pendleton	QF	OR	6
OR Solar 2, LLC (Agate Bay)	QF	OR	10
OR Solar 3, LLC (Turkey Hill)	QF	OR	10
OR Solar 5, LLC (Merrill)	QF	OR	8
OR Solar 6, LLC (Lakeview)	QF	OR	10
OR Solar 7, LLC (Jacksonville)	QF	OR	10
OR Solar 8, LLC (Dairy)	QF	OR	10
Pavant Solar	QF	UT	50
Pavant Solar II LLC	QF	UT	50
Pavant Solar III LLC	QF	UT	20
Quichapa Solar 1- 3	QF	UT	9
Sage I Solar	QF	WY	20
Sage Il Solar	QF	WY	20
Sage Ill Solar	QF	WY	18
South Milford Solar	QF	UT	3
Sweetwater Solar	QF	WY	80
Three Peaks Solar	QF	UT	80
Tumbleweed Solar	QF	OR	10
Utah Red Hills Renewable Park	QF	UT	80
Woodline Solar	QF	OR	8
TOTAL – Purchased Solar			**1,759**

* New since 2017 IRP Update.

Geothermal

PacifiCorp owns and operates the Blundell geothermal plant in Utah, which uses naturally created steam to generate electricity. The plant has a net generation capacity of 34 MW. Blundell is a fully renewable, zero-discharge facility. The bottoming cycle, which increased the output by 11 MW, was completed at the end of 2007. The Oregon Institute of Technology added a new small qualifying facility (QF) using geothermal technologies to produce renewable power for the campus that is rated at 0.28 MW. PacifiCorp has a six-year power purchase agreement with a 3.65 MW QF geothermal project near Lakeview, Oregon, which became operational September 2016.

Biomass/Biogas

PacifiCorp has biomass/biogas agreements with 19 projects totaling approximately 100 MW of nameplate capacity. At least one project is located in each state in PacifiCorp's service territory.

Renewables Net Metering

Installation rates for net metering facilities have been relatively consistent for the last few years in the Pacific Power States. While in the Rocky Mountain Power states the net metering installation rates have declined approximately 40 percent from the peak installed in 2017. Table 5.7 provides a breakdown of net metered capacity and customer counts from data collected on September 30, 2019.

Table 5.7 – Net Metering Customers and Capacities

Fuel	Solar	Wind	Gas[1/]	Hydro	Mixed[2/]
Nameplate (kW)	401,718	873	884	899	1,157
Capacity (percentage of total)	99.06%	0.22%	0.22%	0.22%	0.28%
Number of customers	47,161	198	4	20	58
Customer (percentage of total)	99.41%	0.42%	0.01%	0.04%	0.12%

[1/] Gas includes: biofuel, waste gas, and fuel cells
[2/] Mixed includes projects with multiple technologies, one project is solar and biogas and the others are solar and wind

Hydroelectric Generation

PacifiCorp owns 1,135 MW of hydroelectric generation capacity and purchases the output from 89 MW of other hydroelectric resources.[1] These resources provide operational benefits such as flexible generation, spinning reserves and voltage control. PacifiCorp-owned hydroelectric plants are located in California, Idaho, Montana, Oregon, Washington, Wyoming, and Utah.

The amount of electricity PacifiCorp is able to generate or purchase from hydroelectric plants is dependent upon a number of factors, including the water content of snow pack accumulations in the mountains upstream of its hydroelectric facilities and the amount of precipitation that falls in its watershed. Operational limitations of the hydroelectric facilities are affected by varying water levels, licensing requirements for fish and aquatic habitat, and flood control, which lead to load and resource balance capacity values that are different from net facility capacity ratings.

Hydroelectric purchases are categorized into two groups, as shown in Table 5.8, which shows 2019 capacity.

Table 5.8 – Hydroelectric Contracts

Hydroelectric Contracts by Load and Resource Balance Category	Nameplate Capacity (MW)
Hydroelectric	192
Qualifying Facilities—Hydroelectric	88
Total Contracted Hydroelectric Resources	**280**

Table 5.9 provides the capacity for each of PacifiCorp's owned hydroelectric generation facilities in 2019.

[1]PacifiCorp's 2018 10-K shows 1,135 MW of Net Facility Capacity.

Table 5.9 – PacifiCorp Owned Hydroelectric Generation Facilities –Capacities

Plant	State(s)	Capacity (MW)
West		
Big Fork	MT	4
Klamath – Dispatch	CA	56
Klamath – Flat	CA	11
Klamath – Shape	OR	86
Lewis – Dispatch	WA	425
Lewis – Shape[1/]	WA	94
Rogue	OR	31
Small West Hydro[2/]	CA/OR/WA	2
Umpqua – Flat	OR	25
Umpqua – Shape	OR	89
East		
Bear River – Dispatch	ID/UT	60
Bear River – Shape	ID/UT	20
Small East Hydro[3/]	ID/UT/WY	14
TOTAL – Hydroelectric before Contracts		**916**
Plus Hydroelectric Contracts		**280**
TOTAL – Hydroelectric with Contracts		**1,204**

[1/] Cowlitz County PUD owns Swift No. 2, and is operated in coordination with the other projects by PacifiCorp

[2/] Includes Bend, Fall Creek, and Wallowa Falls

[3/] Includes Ashton, Paris, Pioneer, Weber, Stairs, Granite, Snake Creek, Olmstead, Fountain Green, Veyo, Sand Cove, Viva Naughton, and Gunlock

Hydroelectric Relicensing Impacts on Generation

Table 5.10 lists the estimated impacts to average annual hydro generation from expected Federal Energy Regulatory Commission (FERC) orders and relicensing settlement commitments. PacifiCorp assumes that the Klamath hydroelectric facilities will be decommissioned in accordance with the Klamath Hydroelectric Settlement Agreement in the year 2022 and that other projects currently in relicensing will receive new operating licenses, but that additional operating restrictions will be imposed in new licenses, such as higher bypass flow requirements, that will reduce generation available from these facilities.

Table 5.10 – Estimated Impact of FERC License Renewals and Relicensing Settlement Commitments on Hydroelectric Generation

Years	Incremental Lost Generation (MWh)	Cumulative Lost Generation (MWh)
2019-2020	9,485	11,116
2021-2036	628,000	639,116

Demand-Side Management

For resource planning purposes, PacifiCorp classifies DSM resources into four categories, differentiated by two primary characteristics: reliability and customer choice. These resources are captured through programmatic efforts that promote efficient electricity use through various intervention strategies, aimed at changing energy use during peak periods (load control), timing (price response and load shifting), intensity (energy efficiency), or behaviors (education and information). The four categories include:

- **Class 1 DSM (Demand Response) —Resources from fully dispatchable or scheduled firm capacity product offerings/programs:** Demand Response programs are those for which capacity savings occur as a result of active company control or advanced scheduling. Once customers agree to participate in these programs, the timing and persistence of the load reduction is involuntary on their part within the agreed upon limits and parameters of the program. Program examples include residential and small commercial central air conditioner load control programs that are dispatchable, and irrigation load management and interruptible or curtailment programs (which may be dispatchable or scheduled firm, depending on the particular program design or event noticing requirements). Savings are typically only sustained for the duration of the event and there may also be return energy associated with the program.

- **Class 2 DSM (Energy Efficiency) —Resources from non-dispatchable, firm energy and capacity product offerings/programs:** Energy Efficiency programs are energy and related capacity savings which are achieved through facilitation of technological advancements in equipment, appliances, structures, or repeatable and predictable voluntary actions on a customer's part to manage the energy use at their business or home. These programs generally provide financial incentives or services to customers to improve the efficiency of existing or new residential or commercial buildings through: (1) the installation of more efficient equipment, such as lighting, motors, air conditioners, or appliances; (2) increasing building efficiency, such as improved insulation levels or windows; or (3) behavioral modifications, such as strategic energy management efforts at business or home energy reports for residential customers. The savings are considered firm over the life of the improvement or customer action.

- **Class 3 DSM (Price Response and Load Shifting) —Resources from price-responsive energy and capacity product offerings/programs:** Price response and load shifting programs seek to achieve short-duration (hour by hour) energy and capacity savings from actions taken by customers voluntarily, based on a financial incentive or signal. As a result of their voluntary nature, participation tends to be low and savings are less predictable, making these resources less suitable to incorporate into resource planning, at least until their size and customer behavior profile provide sufficient information needed to model and plan for a reliable and predictable impact. The impacts of these resources may not be explicitly considered in the resource planning process; however, they are captured naturally in long-term load growth patterns and forecasts. Program examples include time-of-use pricing plans, critical peak pricing plans, and inverted block tariff designs. Savings are typically only sustained for the duration of the incentive offering and, in many cases, loads tend to be shifted rather than being avoided.

- **Class 4 DSM (Education and Information) —Non-incented behavioral-based savings achieved through broad energy education and communication efforts:** Education and Information programs promote reductions in energy or capacity usage through broad-based energy education and communication efforts. The program objectives are to help customers better understand how to manage their energy usage through no-cost actions such as conservative thermostat settings and turning off appliances, equipment and lights when not in use. These programs are also used to increase customer awareness of additional actions they might take to save energy and the service and financial tools available to assist them. These programs help foster an understanding and appreciation of why utilities seek customer participation in other programs. Similar to price response and load shifting resources, the impacts of these programs may not be explicitly considered in the resource planning process; however, they are captured naturally in long-term load growth patterns and forecasts. Program examples include company brochures with energy savings tips, customer newsletters focusing on energy efficiency, case studies of customer energy efficiency projects, and public education and awareness programs.

PacifiCorp has been operating successful DSM programs since the late 1970s. While the company's DSM focus has remained strong over this time, since the 2001 western energy crisis, PacifiCorp's DSM pursuits have expanded to new heights in terms of investment level, state presence, breadth of DSM resources pursued and resource planning considerations. Work continues on the expansion of cost-effective program portfolios and savings opportunities in all states while at the same time adapting programs and measure baselines to reflect the impacts of advancing state and federal energy codes and standards. In Oregon, PacifiCorp continues to work closely with the Energy Trust of Oregon to help identify additional resource opportunities, improve delivery and communication coordination, ensure adequate funding, and provide company support in pursuit of DSM resource targets.

Table 5.11 summarizes PacifiCorp's existing DSM programs, their assumed impact, and how they are treated for purposes of incremental resource planning. Note that since incremental energy efficiency is determined as an outcome of resource portfolio modeling and is characterized as a new resource in the preferred portfolio, existing energy efficiency in Table 5.11 is shown as having zero MW.[2] For a summary of current DSM program offerings in each state, refer to Volume II, Appendix D (Demand-Side Management Resources).

[2] The historical effects of previous Class 2 DSM savings are backed out of the load forecast before the modeling for new Class 2 DSM.

Table 5.11 – Existing DSM Resource Summary

Program Class	Description	Energy Savings or Capacity at Generator	Included as Existing Resources for 2019-2038 Period
1	Residential/small commercial air conditioner load control	122 MW summer peak	Yes.
	Irrigation load management	205 MW summer peak[1/]	Yes.
	Interruptible contracts	177 MW Year-round availability	Yes.
2	PacifiCorp and Energy Trust of Oregon programs	0 MW[2/]	No. Class 2 DSM programs are modeled as resource options in the portfolio development process and included in the preferred portfolio.
3	Time-based pricing	98 MW summer peak	No. Historical savings from customer responses to pricing signals are reflected in the load forecast.
	Inverted rate pricing	55-149 GWh (capacity impacts are unavailable due to lack of information on end use loads being saved	No. Historical savings from customer response to pricing structure is reflected in load forecast.
4	Energy education	Energy and capacity impacts are not available/measured	No. Historical savings from customer participation are reflected in the load forecast.

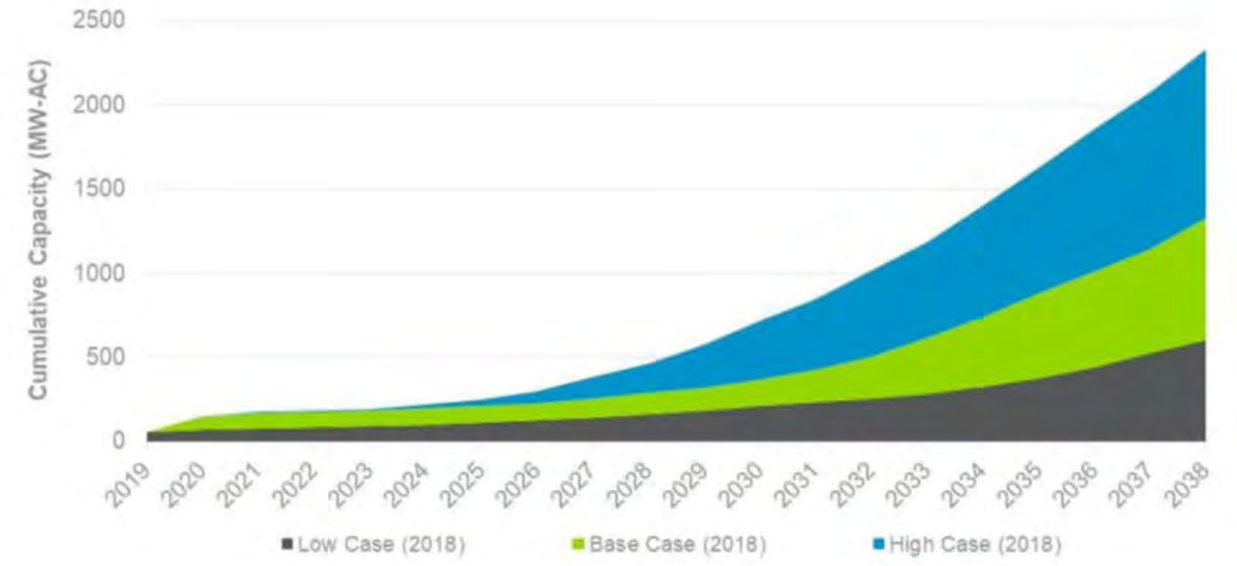
[1/] Assumes six percent for planning reserves in addition to realized irrigation load curtailment in Idaho and Utah of 170 MW and 20 MW, respectively, with an additional 3 MW from the Oregon pilot through 2020.
[2/] Due to the timing of the 2019 IRP load forecast, there is a small amount (81 MW) of existing Class 2 DSM in Table 5.14 (System Capacity Loads and Resources without Resource Additions).

Private Generation

For the 2019 IRP, PacifiCorp contracted with Navigant Consulting Inc. (Navigant) to update the assessment of private generation (PG) penetration performed for the 2017 IRP with new market and incentive developments. The study provided a forecast of adoption for each private generation resource in each of the six states served by PacifiCorp. Specific technologies studied included solar photovoltaic, small-scale wind, small-scale hydro, and combined heat and power (CHP) for both reciprocating engines and micro-turbines.

Navigant estimates approximately 1.3 gigawatts (GW) of PG capacity will be installed in PacifiCorp's territory from 2019-2038 in the base case scenario. As shown in Figure 5.1, the low and high scenarios project a cumulative installed capacity of 0.60 GW and 2.3 GW by 2038, respectively. The main drivers between the different scenarios include variation in technology costs, system performance, and electricity rate assumptions. As in the 2017 IRP, the Navigant study identifies expected levels of customer-sited private generation, which is applied as a reduction to PacifiCorp's forecasted load for IRP modeling purposes.

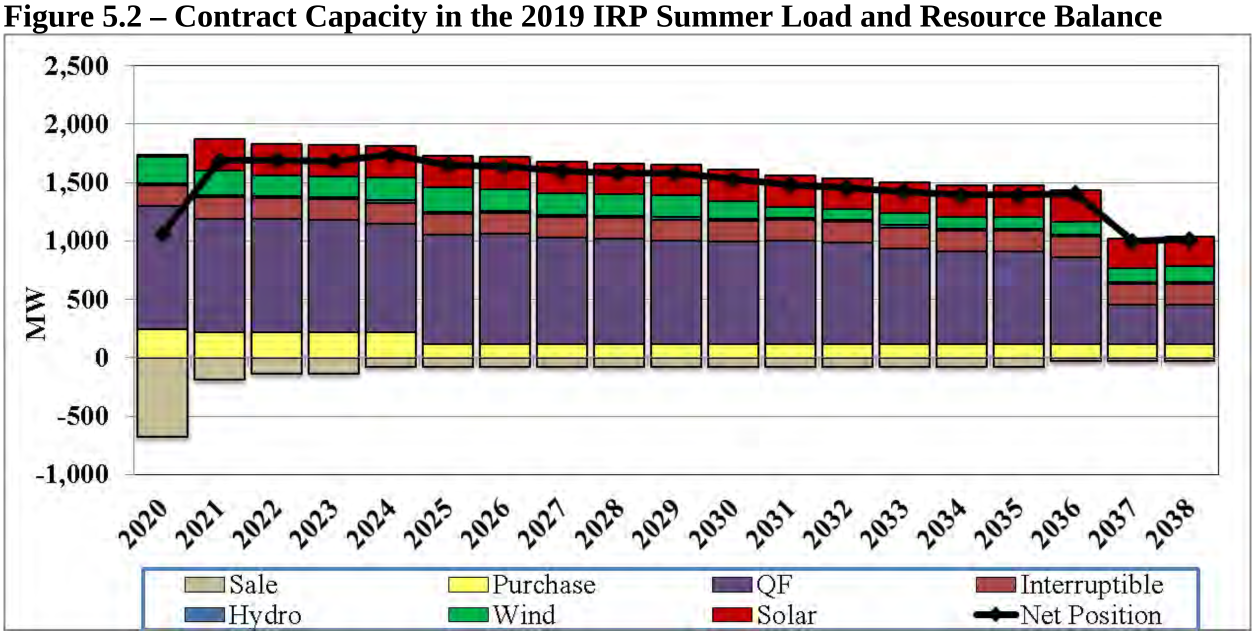
Figure 5.1 – Private Generation Market Penetration (MW_{AC}), 2019-2038



Power Purchase Contracts

PacifiCorp obtains the remainder of its capacity and energy requirements through long-term firm contracts, short-term firm contracts, and spot market purchases. Figure 5.2 presents the contract capacity in place for 2020 through 2038. As shown, major capacity reductions in wind purchases and QF contracts occur. For planning purposes, PacifiCorp assumes interruptible load contracts are extended through the end of the IRP study period. The renewable wind contracts are shown at their capacity contribution levels.

Figure 5.2 – Contract Capacity in the 2019 IRP Summer Load and Resource Balance



Load and Resource Balance

Capacity and Energy Balance Overview

The purpose of the load and resource balance is to compare annual obligations with the annual capability of PacifiCorp's existing resources, without new generating resource additions. This is done with two views of the system, the capacity balance and energy balance.

The capacity balance compares generating capability at time of system summer peak load hours. It is a key part of the load and resource balance because it helps guide the timing and severity of potential future resource need. The capacity balance is inherently captured in the IRP models for any give scenario. For reporting purposes, the capacity balance summarized in this chapter is developed by first reducing the hourly system load by hourly private generation projections to determine the net system coincident peak load for each of the first ten years (2019-2028) of the planning horizon. Interruptible load programs, existing load reduction DSM programs, and new load reduction DSM programs from the preferred portfolio at the time of the net system coincident peak are further netted from the peak load forecast to compute the annual peak-hour obligation. Then the annual firm capacity availability of the existing resources, reflecting assumed coal unit retirements from the preferred portfolio, is determined. The annual resource deficit or surplus is then computed by multiplying the obligation by the target PRM and then subtracting the result from existing resources. This view is presented with an account without and with uncommitted FOTs.

The energy balance shows the average monthly on-peak and off-peak surplus or deficit of energy over the first ten years of the planning horizon (2019-2028). The average obligation (load less existing DSM programs, new DSM programs from the preferred portfolio, and projected private generation) is computed and subtracted from the average existing resource availability for each month and time-of-day period. The usefulness of the energy balance is limited because it does not address the cost of the available energy. The economics of adding resources to the system to meet both capacity and energy needs are addressed during the resource portfolio development process described in Chapter 7 (Modeling and Portfolio Evaluation Approach).

Load and Resource Balance Components

The 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, position, and available FOTs.

Under the calculations, there are negative values in the table in both the resource and obligation sections. This is consistent with how resource categories are represented in portfolio modeling. The resource categories include resources by type—thermal, hydroelectric, renewable, QFs, purchases, existing demand response, sales, and non-owned reserves. Categories in the obligation section include load (net of private generation), interruptible contracts, existing energy efficiency, and new energy efficiency from the preferred portfolio.

Existing Resources

A description of each of the resource categories follows:

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) during summer or winter hours with loss of load events in the final capacity factor methodology analysis.[3] 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 six natural-gas-fueled plants. These thermal resources account for roughly two thirds of the firm capacity available in the PacifiCorp system.

Hydroelectric

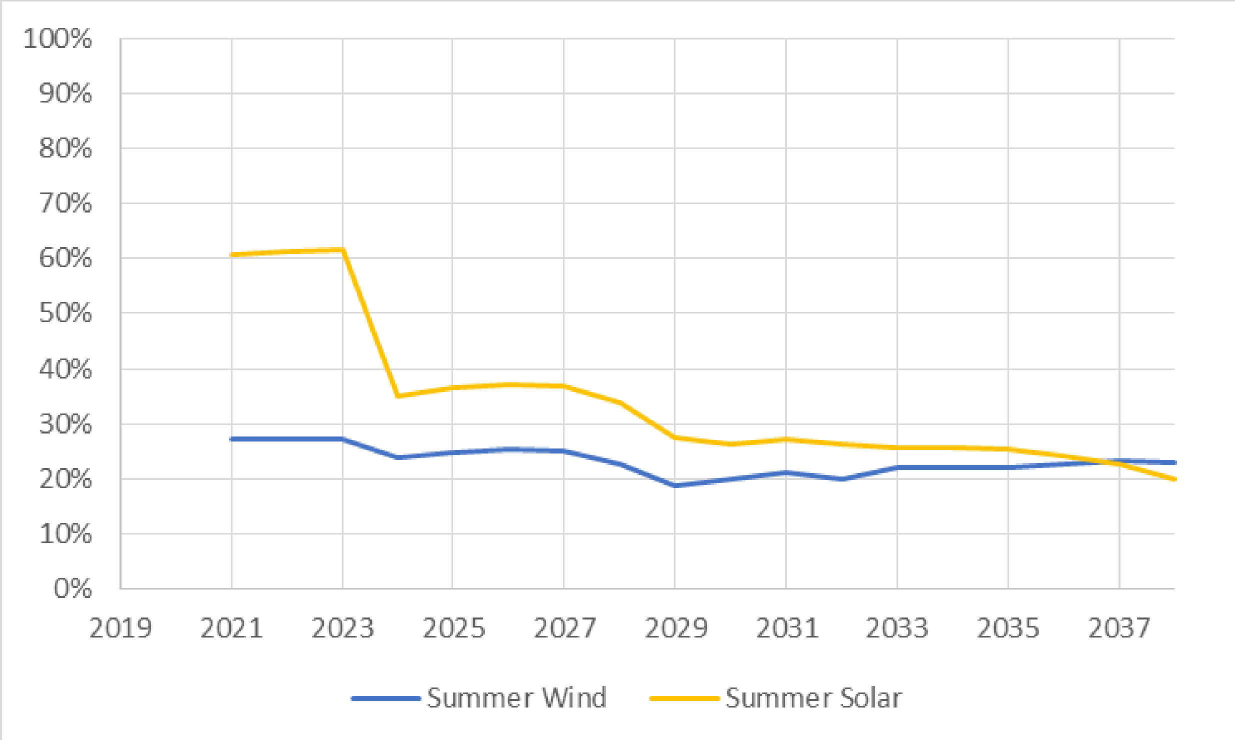
This category includes all hydroelectric generation resources operated in the PacifiCorp system, as well as a number of contracts providing capacity and energy from various counterparties. The capacity balance counts these resources at their expected availability (after derating for forced outages and maintenance) during summer or winter hours with loss of load events in the final capacity factor methodology analysis. The energy associated with stream flow is estimated and shaped by the hydroelectric dispatch from the Vista Decision Support System model. Also accounted for are energy impacts of hydro relicensing requirements, such as higher bypass flows that reduce generation. Over 90 percent of the hydroelectric capacity is on the west side of the PacifiCorp system.

Renewable

This category is comprised of geothermal and variable (wind and solar) renewable energy capacity. The capacity balance counts the geothermal plant using the same methodology applied to thermal resources. The capacity contribution of wind and solar resources, represented as a percentage of resource capacity, is a measure of the ability for these resources to reliably meet demand. During the 2019 IRP, PacifiCorp identified that capacity contribution values for wind and solar would vary based on the penetration levels of these resources, as well as the composition of the rest of a portfolio. To account for these effects, PacifiCorp performed a reliability analysis on every portfolio that was developed to ensure that the combination of resources achieved a targeted level of reliability. For the purpose of reporting the capacity contribution of wind and solar resources in the load and resource balance, PacifiCorp first calculated the contribution of all other resources in the portfolio, using the methodologies described in this section. The remaining capacity in the load and resource balance, up to PacifiCorp's thirteen percent planning reserve margin, is attributable to wind and solar. This remaining capacity was allocated to each wind and solar resource based on the wind and solar penetration analysis and the final capacity factor methodology analysis, as discussed in Volume II, Appendix N (Capacity Contribution Study). The resulting capacity contribution values for wind and solar for the purpose of the load and resource balance are shown in Figure 5.3 (summer) and Figure 5.4 (winter) below.

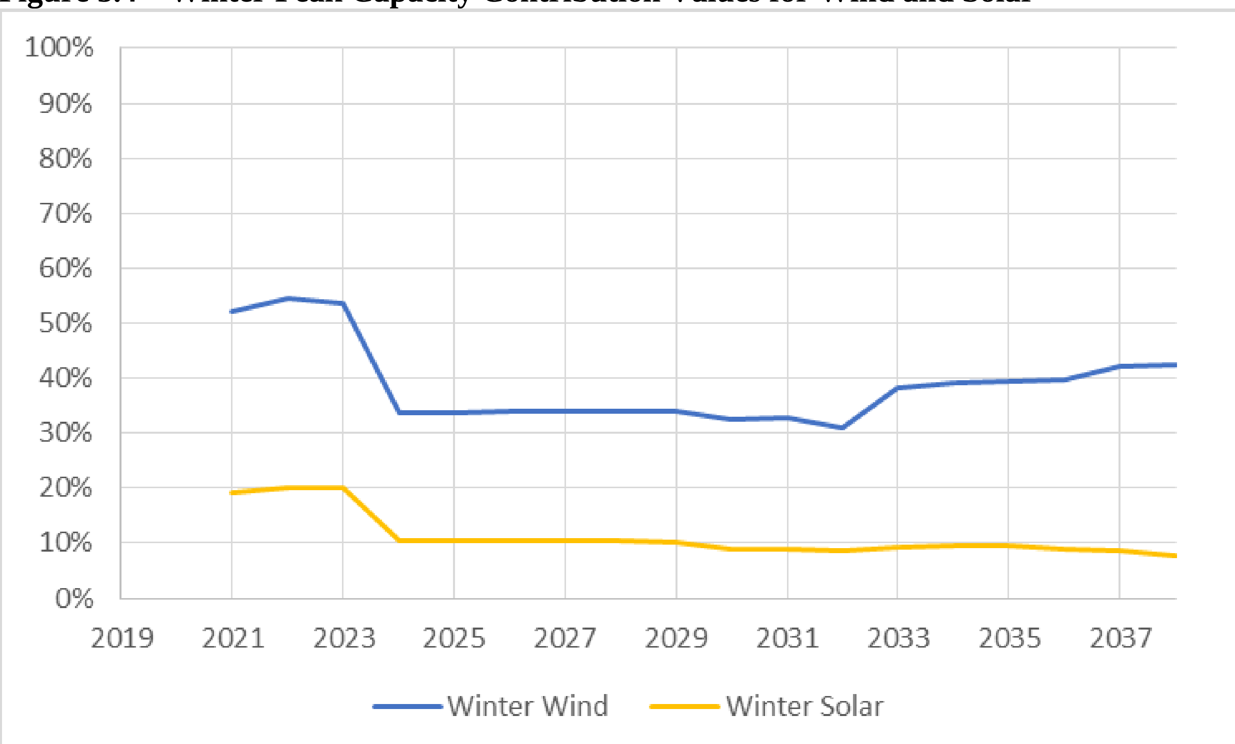
[3] Please refer to Volume II, Appendix N (Capacity Contribution Study)

Figure 5.3 – Summer Peak Capacity Contribution Values for Wind and Solar



Note: Marginal benefits are lower than shown; refer to Volume II, Appendix N (Capacity Contribution Study).

Figure 5.4 – Winter Peak Capacity Contribution Values for Wind and Solar



Note: Marginal benefits are lower than shown; refer to Volume II, Appendix N (Capacity Contribution Study).

Purchase

This includes all major purchase contracts for firm capacity and energy in the PacifiCorp system.[4] The capacity balance counts these by the maximum contract availability at time of system summer peak. The energy balance counts contracts at optimal economic model dispatch. Purchases are considered firm and thus planning reserves are not held for them.

Qualifying Facilities

All QFs that provide capacity and energy are included in this category. Wind and solar QFs are handled in the same manner as non-QF renewable resources, as described above. Other QFs are handled in the same manner as other power purchases, the capacity balance counts them at maximum system summer peak availability and the energy balance counts them at optimal economic model dispatch.

Demand Response (Class 1 DSM)

Existing demand response program capacity is categorized as an increase to resource capacity. This is in line with the treatment of DSM capacity in the latest version of the System Optimizer model that PacifiCorp uses to select resources.

Sales

This includes all contracts for the sale of firm capacity and energy. The capacity balance counts these contracts by the maximum obligation at time of system summer peak and the energy balance counts them by expected model dispatch. All sales contracts are firm and thus planning reserves are held for them in the capacity view.

Non-owned Reserves

Non-owned reserve capacity is categorized as a decrease to resource capacity to represent the capacity required to provide reserves for load and generation that are in PacifiCorp's balancing authority area (BAA) but not used to serve the company's retail load. There are a number of wholesale customers that operate in the PacifiCorp control areas that purchase operating reserves. The annual reserve obligation is about three MW in the west BAA and 38 MW in the east BAA. The non-owned reserves do not contribute to the energy obligation because the requirement is for capacity only.

Obligation

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

Load Net of Private Generation

The largest component of the obligation is retail load. In the 2019 IRP, 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. Loads reported by east and west BAAs thus reflect loads at the time of PacifiCorp's coincident system summer peak. The energy balance

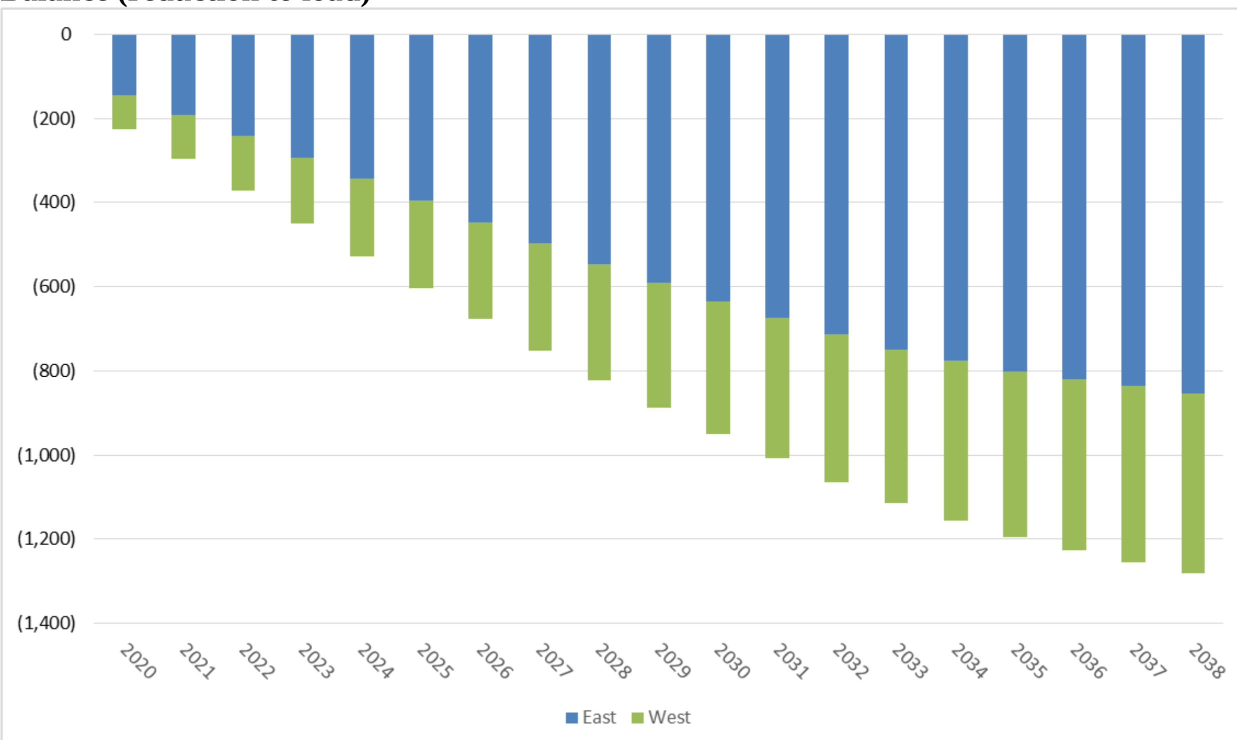
[4] PacifiCorp has curtailment contracts for approximately 172 MW on peak capacity that are treated as firm purchases. PacifiCorp has the right to curtail the customer's load as needed for economic purposes. The customer in turn may or may not pay market-based rates for energy used during a curtailment period.

counts the load on monthly basis by on-peak and off-peak hours. The net load is simply referred to as load in the context of load and resources balances and portfolio selection and evaluation.

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 is a level of 2018 Energy Efficiency that is not incorporated in the forecast. The 2018 energy efficiency forecast (81 MW) has been accounted for by adding an existing energy efficiency resource in the load and resource balance. The energy efficiency line also includes the selected energy efficiency from the 2019 IRP preferred portfolio. Figure 5.5 shows the energy efficiency for the east and west control areas in the 2019 IRP preferred portfolio.

Figure 5.5 – Energy Efficiency Peak Contribution in Summer Capacity Load and Resource Balance (reduction to load)



Interruptible Contracts

PacifiCorp has interruptible contracts for approximately 177 MW of load interruption capability beginning in 2019. These contracts allow the use of 177 MW of capacity for meeting reserve requirements. Both the capacity balance and energy balance count these resources at the level of full load interruption on the executed hours. Interruptible resources directly curtail load and thus full planning reserves are not held for the load that may be curtailed. As with demand response, this resource is categorized as a decrease to the peak load.

Planning Reserves

Planning reserves represent an incremental planning 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).

Position
The 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

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** = Thermal + Hydro + Renewable + Firm Purchases + Qualifying Facilities + Existing Demand Response – Firm Sales – Non-owned Reserves

The peak load, interruptible contracts, existing Energy Efficiency, 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 – Interruptible Contracts – New and Existing 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 target PRM adopted for the 2019 IRP. The formula for this calculation is:

> **Planning Reserves** = Obligation x PRM

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

> **Capacity Position** = (Existing Resources + Available FOTs) – (Obligation + Reserves)

Capacity Balance Results
Table 5.12 and Table 5.13 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. Also note that new QF wind and solar projects listed earlier in the chapter are reported under the QF line item rather than the renewables line item.

Table 5.12 -- Summer Peak – System Capacity Loads and Resources without Resource Additions[1/]

Calendar Year	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
East										
Thermal	5,963	5,634	5,634	5,634	5,634	5,634	5,217	5,140	4,481	4,481
Hydroelectric	74	74	74	74	74	74	74	74	74	74
Renewable	406	843	859	866	876	906	898	891	827	718
Purchases	242	215	215	215	215	115	115	115	115	115
Qualifying Facilities	891	666	665	665	617	619	621	620	610	590
Class 1 DSM	323	323	323	323	323	323	323	323	323	323
Sales	(655)	(175)	(175)	(175)	(148)	(148)	(66)	0	0	0
Non-Owned Reserves	(35)	(35)	(35)	(35)	(35)	(35)	(35)	(35)	(35)	(35)
East Existing Resources	**7,210**	**7,545**	**7,560**	**7,567**	**7,555**	**7,488**	**7,148**	**7,128**	**6,395**	**6,267**
Load	7,039	7,108	7,185	7,276	7,405	7,442	7,460	7,523	7,604	7,678
Private Generation	(125)	(166)	(173)	(176)	(202)	(188)	(195)	(204)	(218)	(233)
Interruptible	(177)	(177)	(177)	(177)	(177)	(177)	(177)	(177)	(177)	(177)
Energy Efficiency	(144)	(192)	(241)	(293)	(345)	(396)	(446)	(497)	(546)	(591)
East obligation	**6,592**	**6,572**	**6,593**	**6,629**	**6,681**	**6,682**	**6,641**	**6,644**	**6,663**	**6,677**
Planning Reserves (13%)	880	877	880	885	892	892	886	887	889	891
East Obligation + Reserves	**7,471**	**7,450**	**7,474**	**7,514**	**7,573**	**7,574**	**7,528**	**7,531**	**7,552**	**7,568**
East Position	**0**	**95**	**86**	**53**	**(17)**	**(85)**	**(380)**	**(403)**	**(1,156)**	**(1,300)**
Available Front Office Transactions	**309**	**309**	**309**	**309**	**309**	**309**	**309**	**309**	**309**	**309**
West										
Thermal	2,048	2,048	2,048	2,048	1,736	1,736	1,736	1,736	1,598	1,265
Hydroelectric	570	570	570	570	570	570	570	570	570	570
Renewable	383	379	287	289	289	298	302	300	273	240
Purchases	1	1	1	1	1	1	1	1	1	1
Qualifying Facilities	390	292	285	278	278	279	278	246	243	231
Class 1 DSM	3	0	0	0	0	0	0	0	0	0
Sales	(165)	(161)	(110)	(110)	(80)	(80)	(80)	(80)	(80)	(78)
Non-Owned Reserves	(3)	(3)	(3)	(3)	(3)	(3)	(3)	(3)	(3)	(3)
West Existing Resources	**3,227**	**3,126**	**3,078**	**3,074**	**2,792**	**2,802**	**2,805**	**2,771**	**2,604**	**2,227**
Load	3,387	3,441	3,486	3,513	3,529	3,570	3,597	3,626	3,657	3,684
Private Generation	(21)	(26)	(29)	(32)	(45)	(39)	(44)	(51)	(58)	(66)
Interruptible	0	0	0	0	0	0	0	0	0	0
Energy Efficiency	(81)	(106)	(131)	(157)	(183)	(208)	(232)	(255)	(276)	(296)
West obligation	**3,285**	**3,310**	**3,325**	**3,324**	**3,301**	**3,323**	**3,321**	**3,321**	**3,323**	**3,321**
Planning Reserves (13%)	427	430	432	432	429	432	432	432	432	432
West Obligation + Reserves	**3,712**	**3,740**	**3,757**	**3,756**	**3,730**	**3,755**	**3,753**	**3,753**	**3,755**	**3,753**
West Position	**(484)**	**(614)**	**(679)**	**(683)**	**(938)**	**(953)**	**(948)**	**(982)**	**(1,151)**	**(1,527)**
Available Front Office Transactions	**1,159**	**1,159**	**1,159**	**1,159**	**1,159**	**1,159**	**1,159**	**1,159**	**1,159**	**1,159**
System										
Total Resources	10,437	10,671	10,638	10,641	10,347	10,290	9,953	9,899	8,999	8,494
Obligation	9,876	9,882	9,918	9,953	9,982	10,005	9,962	9,966	9,985	9,998
Reserves	1,307	1,308	1,312	1,317	1,321	1,324	1,318	1,319	1,321	1,323
Obligation + Reserves	11,183	11,190	11,231	11,270	11,303	11,328	11,281	11,284	11,306	11,321
System Position	(746)	(519)	(592)	(630)	(956)	(1,038)	(1,328)	(1,385)	(2,307)	(2,827)
Available Front Office Transactions	**1,468**	**1,468**	**1,468**	**1,468**	**1,468**	**1,468**	**1,468**	**1,468**	**1,468**	**1,468**
Uncommitted FOTs to meet remaining Need	746	519	592	630	956	1,038	1,328	1,385	1,468	1,468
Net Surplus (Deficit)	0	0	0	0	0	0	0	0	(839)	(1,359)

1/ The Energy Efficiency line includes selected Energy Efficiency from the 2019 IRP preferred portfolio.

Table 5.12 (cont.) – Summer Peak System Capacity Loads and Resources without Resource Additions[1/]

Calendar Year	2030	2031	2032	2033	2034	2035	2036	2037	2038
East									
Thermal	4,242	4,169	4,169	3,838	3,838	3,838	3,838	2,984	2,984
Hydroelectric	74	74	74	74	74	74	74	74	74
Renewable	723	706	675	725	726	724	737	740	697
Purchases	115	115	115	115	115	115	115	115	115
Qualifying Facilities	595	599	587	555	536	536	503	125	120
Class 1 DSM	323	323	323	323	323	323	323	323	323
Sales	0	0	0	0	0	0	0	0	0
Non-Owned Reserves	(35)	(35)	(35)	(35)	(35)	(35)	(35)	(35)	(35)
East Existing Resources	**6,036**	**5,952**	**5,908**	**5,596**	**5,577**	**5,575**	**5,556**	**4,326**	**4,279**
Load	7,760	7,830	7,923	8,007	7,935	8,019	8,104	8,196	8,280
Private Generation	(249)	(264)	(281)	(316)	(227)	(261)	(295)	(330)	(374)
Interruptible	(177)	(177)	(177)	(177)	(177)	(177)	(177)	(177)	(177)
Energy Efficiency	(634)	(674)	(713)	(750)	(777)	(801)	(820)	(836)	(854)
East obligation	**6,700**	**6,713**	**6,751**	**6,763**	**6,754**	**6,780**	**6,811**	**6,853**	**6,876**
Planning Reserves (13%)	894	896	901	902	901	904	909	914	917
East Obligation + Reserves	**7,594**	**7,609**	**7,652**	**7,665**	**7,655**	**7,684**	**7,720**	**7,767**	**7,793**
East Position	**(1,557)**	**(1,657)**	**(1,744)**	**(2,070)**	**(2,078)**	**(2,109)**	**(2,164)**	**(3,440)**	**(3,514)**
Available Front Office Transactions	**309**	**309**	**309**	**309**	**309**	**309**	**309**	**309**	**309**
West									
Thermal	1,265	1,265	1,265	1,265	1,265	1,265	1,265	1,053	411
Hydroelectric	570	570	570	570	570	570	570	570	570
Renewable	249	259	248	266	266	265	270	275	270
Purchases	1	1	1	1	1	1	1	1	1
Qualifying Facilities	228	229	222	223	223	223	217	201	201
Class 1 DSM	0	0	0	0	0	0	0	0	0
Sales	(78)	(78)	(78)	(78)	(78)	(78)	(24)	(24)	(24)
Non-Owned Reserves	(3)	(3)	(3)	(3)	(3)	(3)	(3)	(3)	(3)
West Existing Resources	**2,233**	**2,244**	**2,226**	**2,245**	**2,245**	**2,244**	**2,297**	**2,073**	**1,427**
Load	3,709	3,745	3,773	3,803	3,788	3,814	3,842	3,881	3,912
Private Generation	(79)	(102)	(134)	(173)	(155)	(191)	(226)	(260)	(300)
Interruptible	0	0	0	0	0	0	0	0	0
Energy Efficiency	(315)	(333)	(350)	(365)	(379)	(393)	(406)	(417)	(428)
West obligation	**3,314**	**3,310**	**3,289**	**3,265**	**3,254**	**3,231**	**3,210**	**3,204**	**3,184**
Planning Reserves (13%)	431	430	428	424	423	420	417	417	414
West Obligation + Reserves	**3,745**	**3,740**	**3,717**	**3,689**	**3,677**	**3,651**	**3,627**	**3,621**	**3,598**
West Position	**(1,512)**	**(1,497)**	**(1,491)**	**(1,444)**	**(1,431)**	**(1,406)**	**(1,330)**	**(1,548)**	**(2,171)**
Available Front Office Transactions	**1,159**	**1,159**	**1,159**	**1,159**	**1,159**	**1,159**	**1,159**	**1,159**	**1,159**
System									
Total Resources	8,270	8,196	8,134	7,841	7,822	7,819	7,853	6,399	5,706
Obligation	10,014	10,024	10,040	10,028	10,008	10,011	10,021	10,057	10,060
Reserves	1,325	1,326	1,328	1,327	1,324	1,324	1,326	1,330	1,331
Obligation + Reserves	11,339	11,350	11,368	11,355	11,332	11,335	11,347	11,387	11,391
System Position	(3,070)	(3,154)	(3,234)	(3,514)	(3,510)	(3,516)	(3,495)	(4,988)	(5,685)
Available Front Office Transactions	**1,468**	**1,468**	**1,468**	**1,468**	**1,468**	**1,468**	**1,468**	**1,468**	**1,468**
Uncommitted FOTs to meet remaining Need	1,468	1,468	1,468	1,468	1,468	1,468	1,468	1,468	1,468
Net Surplus (Deficit)	(1,602)	(1,686)	(1,766)	(2,046)	(2,042)	(2,048)	(2,027)	(3,520)	(4,217)

1/ The Energy Efficiency line includes selected Energy Efficiency from the 2019 IRP preferred portfolio.

Table 5.13 – Winter Peak System Capacity Loads and Resources without Resource Additions[1/]

Calendar Year	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
East										
Thermal	6,020	5,692	5,692	5,692	5,692	5,692	5,275	5,199	4,545	4,545
Hydroelectric	54	54	54	54	54	54	54	54	54	54
Renewable	992	1,536	1,594	1,579	1,020	1,020	1,010	1,009	1,010	1,001
Purchases	727	228	228	228	115	115	115	115	115	115
Qualifying Facilities	672	460	465	413	335	333	334	334	333	326
Class 1 DSM	0	0	0	0	0	0	0	0	0	0
Sales	(173)	(173)	(173)	(173)	(148)	(148)	(66)	(52)	0	(77)
Non-Owned Reserves	(35)	(35)	(35)	(35)	(35)	(35)	(35)	(35)	(35)	(35)
East Existing Resources	**8,258**	**7,762**	**7,825**	**7,758**	**7,032**	**7,031**	**6,687**	**6,625**	**6,022**	**5,931**
Load	5,629	5,680	5,743	5,807	5,855	5,921	5,847	5,889	5,939	5,993
Private Generation	(1)	(1)	(1)	(2)	(2)	(3)	(3)	(4)	(5)	(5)
Interruptible	(177)	(177)	(177)	(177)	(177)	(177)	(177)	(177)	(177)	(177)
Energy Efficiency	(107)	(147)	(189)	(233)	(277)	(321)	(365)	(409)	(452)	(492)
East obligation	**5,344**	**5,355**	**5,376**	**5,396**	**5,399**	**5,420**	**5,301**	**5,298**	**5,305**	**5,319**
Planning Reserves (13%)	718	719	722	724	725	728	712	712	713	714
East Obligation + Reserves	**6,062**	**6,074**	**6,098**	**6,120**	**6,123**	**6,148**	**6,014**	**6,010**	**6,018**	**6,033**
East Position	**0**	**1,688**	**1,727**	**1,638**	**909**	**883**	**673**	**615**	**4**	**(102)**
Available Front Office Transactions	**309**	**309**	**309**	**309**	**309**	**309**	**309**	**309**	**309**	**309**
West										
Thermal	2,040	2,040	2,040	2,040	1,728	1,728	1,728	1,728	1,590	1,258
Hydroelectric	670	670	670	670	670	670	670	670	670	670
Renewable	672	351	232	230	137	137	138	138	137	136
Purchases	1	1	1	1	1	1	1	1	1	1
Qualifying Facilities	142	102	93	88	75	75	72	45	45	33
Class 1 DSM	0	0	0	0	0	0	0	0	0	0
Sales	(154)	(154)	(113)	(113)	(81)	(81)	(81)	(81)	(81)	(78)
Non-Owned Reserves	(3)	(3)	(3)	(3)	(3)	(3)	(3)	(3)	(3)	(3)
West Existing Resources	**3,369**	**3,008**	**2,921**	**2,913**	**2,527**	**2,527**	**2,525**	**2,499**	**2,360**	**2,018**
Load	3,416	3,458	3,499	3,529	3,550	3,576	3,605	3,640	3,672	3,706
Private Generation	(0)	(0)	(0)	(0)	(1)	(1)	(1)	(1)	(2)	(2)
Interruptible	0	0	0	0	0	0	0	0	0	0
Energy Efficiency	(89)	(118)	(150)	(181)	(214)	(244)	(274)	(303)	(331)	(356)
West obligation	**3,327**	**3,340**	**3,350**	**3,347**	**3,335**	**3,331**	**3,329**	**3,335**	**3,340**	**3,347**
Planning Reserves (13%)	432	434	435	435	434	433	433	434	434	435
West Obligation + Reserves	**3,759**	**3,774**	**3,785**	**3,782**	**3,769**	**3,764**	**3,762**	**3,769**	**3,774**	**3,783**
West Position	**(390)**	**(766)**	**(864)**	**(869)**	**(1,242)**	**(1,237)**	**(1,237)**	**(1,270)**	**(1,414)**	**(1,765)**
Available Front Office Transactions	**1,159**	**1,159**	**1,159**	**1,159**	**1,159**	**1,159**	**1,159**	**1,159**	**1,159**	**1,159**
System										
Total Resources	11,627	10,770	10,746	10,671	9,560	9,558	9,212	9,124	8,382	7,949
Obligation	8,671	8,695	8,725	8,743	8,734	8,751	8,631	8,634	8,645	8,666
Reserves	1,150	1,153	1,157	1,160	1,158	1,161	1,145	1,145	1,147	1,150
Obligation + Reserves	9,821	9,848	9,883	9,902	9,892	9,912	9,776	9,779	9,792	9,815
System Position	1,806	922	864	769	(333)	(354)	(564)	(655)	(1,410)	(1,867)
Available Front Office Transactions	**1,468**	**1,468**	**1,468**	**1,468**	**1,468**	**1,468**	**1,468**	**1,468**	**1,468**	**1,468**
Uncommitted FOTs to meet remaining Need	0	0	0	0	333	354	564	655	1,410	1,468
Net Surplus (Deficit)	1,806	922	864	769	0	0	0	0	0	(399)

1/ The Energy Efficiency line includes selected Energy Efficiency from the 2019 IRP preferred portfolio.

Table 5.13 (cont.) – Winter Peak System Capacity Loads and Resources without Resource Additions[1/]

Calendar Year	2030	2031	2032	2033	2034	2035	2036	2037	2038
East									
Thermal	4,311	4,239	4,239	3,908	3,908	3,908	3,908	3,054	3,054
Hydroelectric	54	54	54	54	54	54	54	54	54
Renewable	942	891	846	1,015	1,036	1,039	1,045	1,099	1,073
Purchases	115	115	115	115	115	115	115	115	115
Qualifying Facilities	325	326	310	284	251	251	222	26	26
Class 1 DSM	0	0	0	0	0	0	0	0	0
Sales	(77)	0	0	0	0	0	0	0	0
Non-Owned Reserves	(35)	(35)	(35)	(35)	(35)	(35)	(35)	(35)	(35)
East Existing Resources	**5,636**	**5,590**	**5,529**	**5,341**	**5,330**	**5,333**	**5,309**	**4,313**	**4,287**
Load	6,023	6,074	6,113	6,180	6,232	6,287	6,320	6,380	6,431
Private Generation	(6)	(7)	(8)	(9)	(10)	(12)	(14)	(15)	(17)
Interruptible	(177)	(177)	(177)	(177)	(177)	(177)	(177)	(177)	(177)
Energy Efficiency	(530)	(565)	(600)	(632)	(656)	(678)	(696)	(711)	(726)
East obligation	**5,310**	**5,324**	**5,328**	**5,362**	**5,389**	**5,420**	**5,434**	**5,477**	**5,510**
Planning Reserves (13%)	713	715	716	720	724	728	729	735	739
East Obligation + Reserves	**6,023**	**6,040**	**6,044**	**6,083**	**6,113**	**6,147**	**6,163**	**6,212**	**6,249**
East Position	**(387)**	**(450)**	**(515)**	**(741)**	**(783)**	**(815)**	**(854)**	**(1,899)**	**(1,962)**
Available Front Office Transactions	**309**	**309**	**309**	**309**	**309**	**309**	**309**	**309**	**309**
West									
Thermal	1,258	1,258	1,258	1,258	1,258	1,258	1,258	1,034	392
Hydroelectric	670	670	670	670	670	670	670	670	670
Renewable	135	135	128	155	159	159	160	169	170
Purchases	1	1	1	1	1	1	1	1	1
Qualifying Facilities	33	33	27	29	29	29	25	24	24
Class 1 DSM	0	0	0	0	0	0	0	0	0
Sales	(78)	(78)	(78)	(78)	(78)	(78)	(78)	(78)	(78)
Non-Owned Reserves	(3)	(3)	(3)	(3)	(3)	(3)	(3)	(3)	(3)
West Existing Resources	**2,016**	**2,017**	**2,003**	**2,032**	**2,036**	**2,036**	**2,034**	**1,818**	**1,177**
Load	3,727	3,751	3,782	3,816	3,849	3,880	3,902	3,933	3,967
Private Generation	(2)	(3)	(3)	(4)	(4)	(5)	(7)	(8)	(11)
Interruptible	0	0	0	0	0	0	0	0	0
Energy Efficiency	(380)	(403)	(424)	(443)	(461)	(479)	(495)	(510)	(525)
West obligation	**3,345**	**3,346**	**3,355**	**3,369**	**3,384**	**3,396**	**3,400**	**3,415**	**3,431**
Planning Reserves (13%)	435	435	436	438	440	441	442	444	446
West Obligation + Reserves	**3,780**	**3,781**	**3,791**	**3,808**	**3,824**	**3,838**	**3,842**	**3,859**	**3,877**
West Position	**(1,763)**	**(1,764)**	**(1,787)**	**(1,775)**	**(1,788)**	**(1,801)**	**(1,808)**	**(2,041)**	**(2,700)**
Available Front Office Transactions	**1,159**	**1,159**	**1,159**	**1,159**	**1,159**	**1,159**	**1,159**	**1,159**	**1,159**
System									
Total Resources	7,653	7,607	7,532	7,373	7,365	7,369	7,343	6,131	5,464
Obligation	8,655	8,670	8,683	8,732	8,773	8,816	8,834	8,892	8,941
Reserves	1,148	1,150	1,152	1,158	1,163	1,169	1,171	1,179	1,185
Obligation + Reserves	9,803	9,820	9,835	9,890	9,936	9,985	10,005	10,071	10,126
System Position	(2,150)	(2,214)	(2,302)	(2,517)	(2,571)	(2,616)	(2,662)	(3,940)	(4,662)
Available Front Office Transactions	**1,468**	**1,468**	**1,468**	**1,468**	**1,468**	**1,468**	**1,468**	**1,468**	**1,468**
Uncommitted FOTs to meet remaining Need	1,468	1,468	1,468	1,468	1,468	1,468	1,468	1,468	1,468
Net Surplus (Deficit)	(682)	(746)	(835)	(1,049)	(1,103)	(1,148)	(1,194)	(2,472)	(3,194)

1/ The Energy Efficiency line includes selected Energy Efficiency from the 2019 IRP preferred portfolio.

Figure 5.6 through Figure 5.9 are graphic representations of the above tables for annual capacity position for the summer system, winter system, east control area, and west control area. Also shown in the system capacity position graph are available FOTs, which can be used to meet capacity needs. The market availability assumptions used for portfolio modeling are discussed further in Chapter 6 (Resource Options) and Volume II, Appendix J (Western Resource Adequacy Evaluation).

Figure 5.6 – Summer System Capacity Position Trend

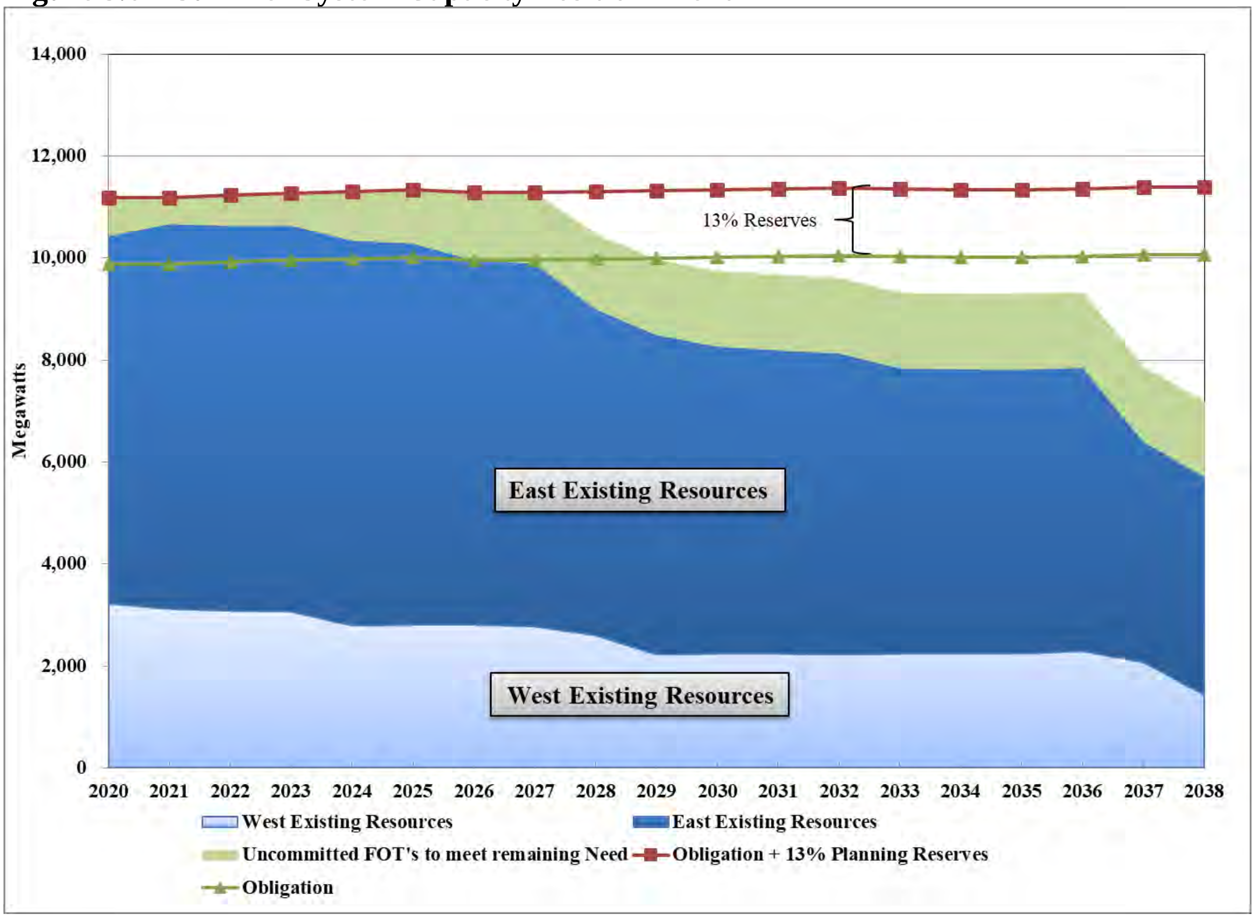


Figure 5.7 – Winter System Capacity Position Trend

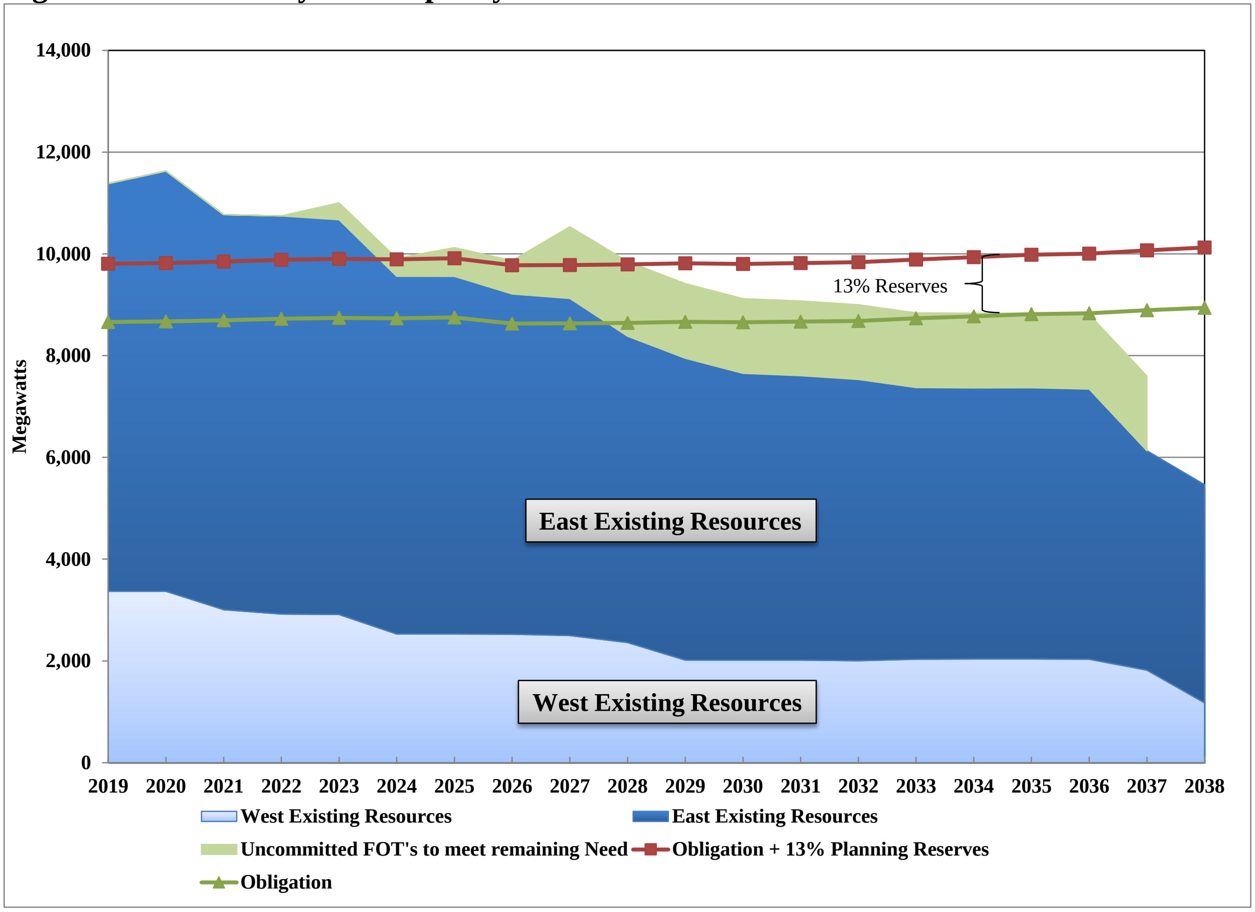


Figure 5.8 – East Summer Capacity Position Trend

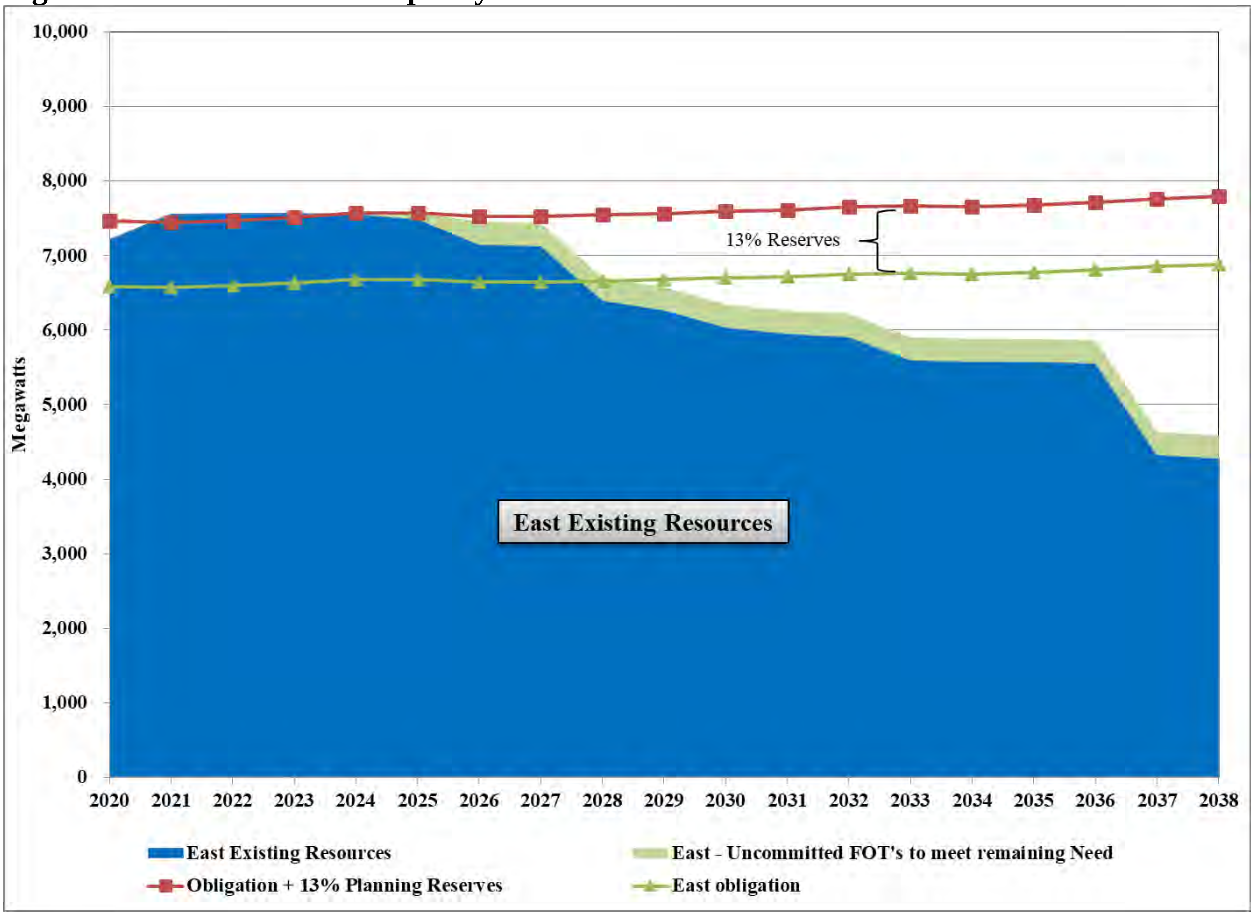
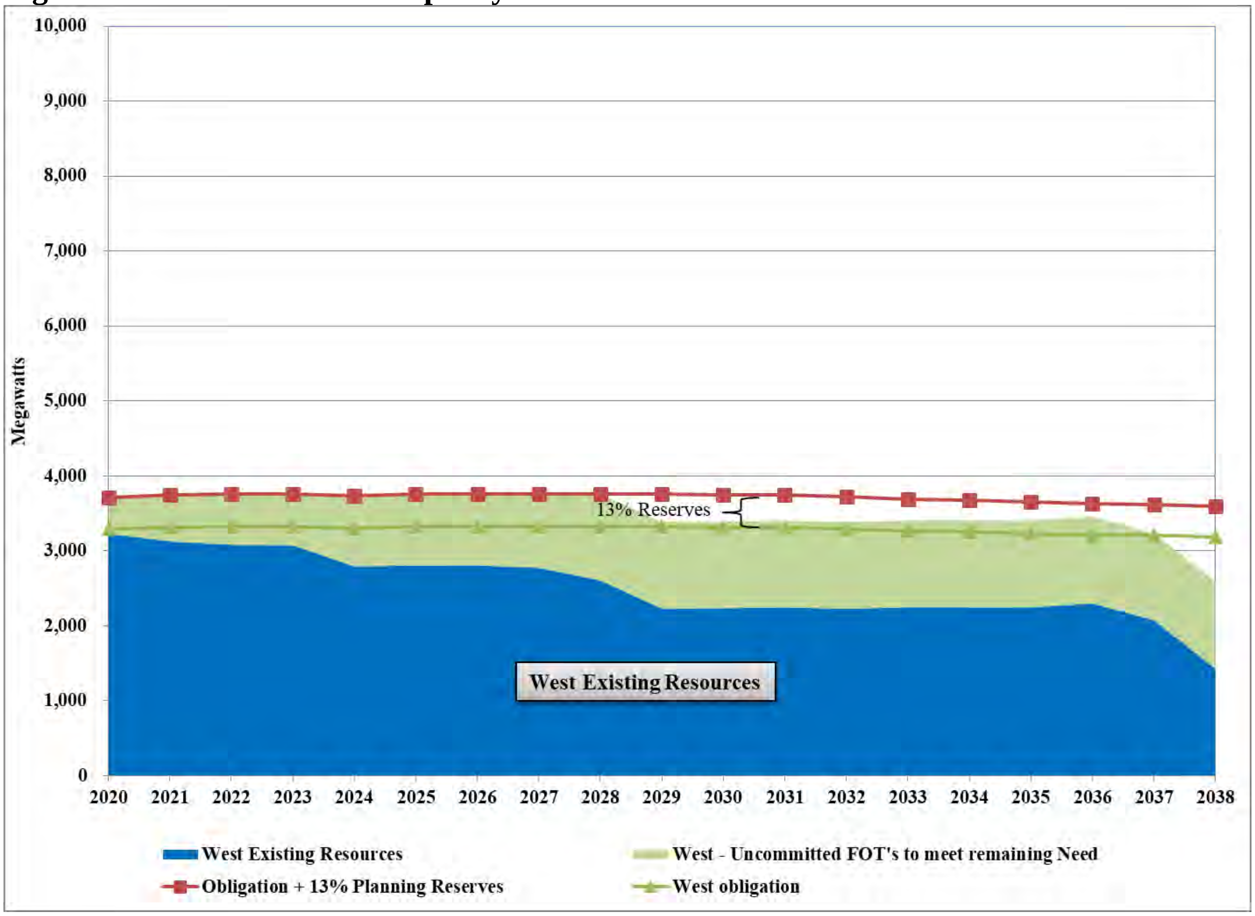


Figure 5.9 – West Summer Capacity Position Trend



Energy Balance Determination

Methodology

The energy balance shows the monthly on-peak and off-peak surplus (deficit) of energy. The on-peak hours are weekdays and Saturdays from hour-ending 7:00 am to 10:00 pm; off-peak hours are all other hours. This is calculated using the formulas that follow. 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 + Existing Class 1 DSM + Renewable + Firm Purchases + QF + Interruptible Contracts – Sales

The average obligation is computed using the following formula:

> **Obligation** = Load + Firm Sales

The energy position by month and time block is then computed as follows:

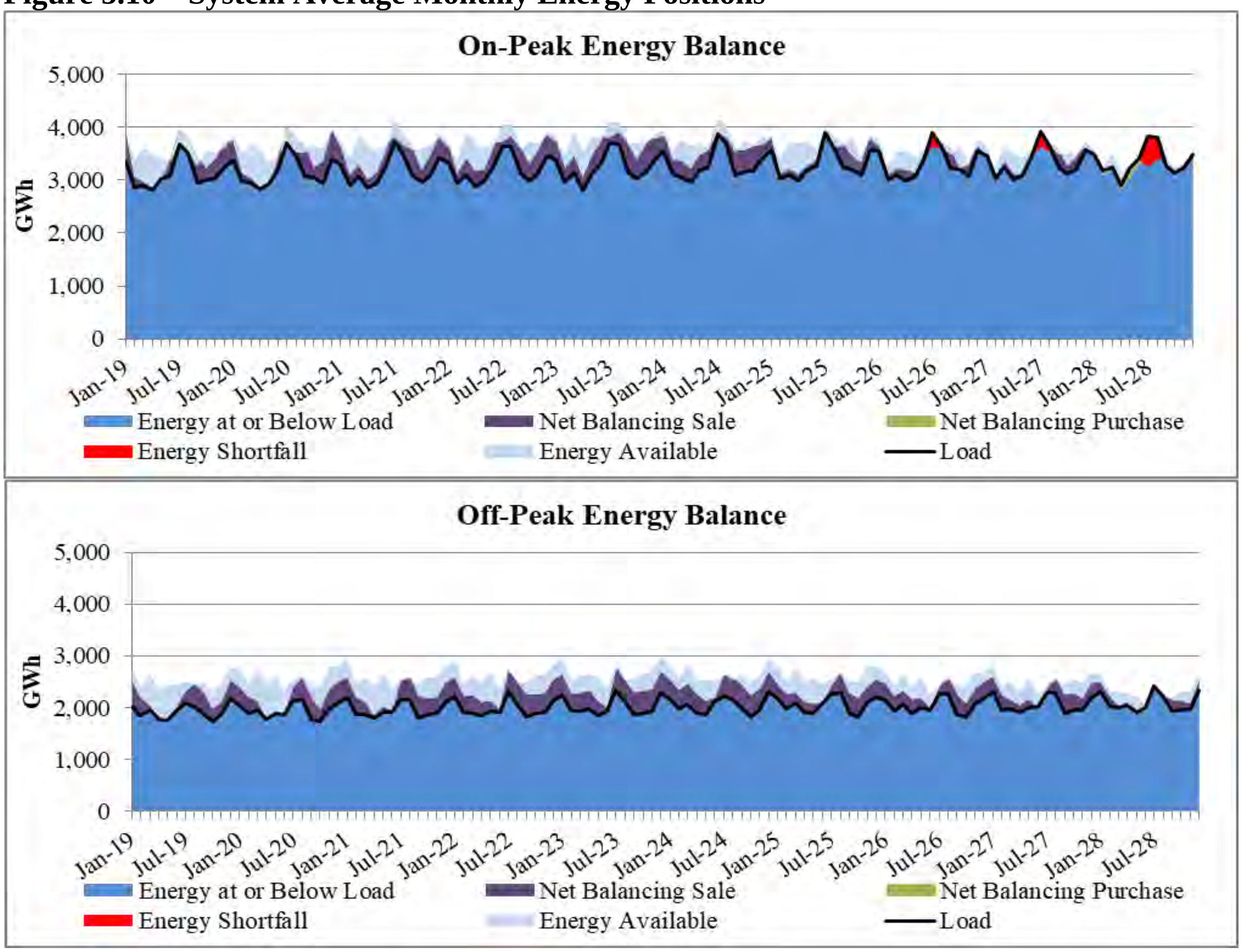
> **Energy Position** = Existing Resources – Obligation – Operating Reserve Requirements

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 5.10 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 5.10 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 5.10 – System Average Monthly Energy Positions



CHAPTER 6 – RESOURCE OPTIONS

CHAPTER HIGHLIGHTS

- PacifiCorp developed resource attributes and costs for expansion resources that reflect updated information from project experience, industry vendors, public meeting comments and studies.
- Resource costs have been generally stable since the previous integrated resource plan (IRP) and cost increases have been modest to declining. The cost of solar photovoltaic modules and balance of plant equipment decreased in 2018, continuing the downward cost trend of the past several years. Likewise, costs of wind turbines and batteries, and associated balance of plant costs, have shown a decline.
- Geothermal power purchase agreements (PPAs) are included as supply-side options in this IRP and updated to reflect current conditions.
- The combustion turbine types, configurations, and siting locations are identified in the supply-side resource options table. Performance and costs have been updated.
- Energy storage systems continue to be of interest to PacifiCorp, its stakeholders, and the industry at large. Options for advanced large batteries (15 megawatts (MW) and larger), renewable (wind and solar) plus storage, pumped hydro and compressed air energy storage are included in this IRP.
- For this IRP, PacifiCorp developed the capability for the System Optimizer (SO) model to endogenously model transmission upgrades.
- A 2018 Long Term Generation Resource Assessment study that was conducted by Navigant Consulting, Inc. served as the basis for updated resource characterizations covering private generation. The demand-side resource information was converted into supply curves grouped into cost bundles by measure or product type and competed against other resource alternatives in IRP modeling.
- PacifiCorp continued to apply cost reduction credits to energy efficiency, reflecting risk mitigation benefits, transmission and distribution investment deferral benefits, and a ten percent market price credit for Washington and Oregon as allowed by the Northwest Power Act.

Introduction

This chapter provides background information on the various resources considered in the IRP for meeting future capacity and energy needs. Organized by major category, these resources consist of utility-scale supply-side generation, demand-side management (DSM) programs, transmission resources and market purchases. For each resource category, the chapter discusses the criteria for resource selection, presents the options and associated attributes, and describes the various technologies. In addition, for supply-side resources, the chapter describes how PacifiCorp addressed long-term cost trends and uncertainty in deriving cost figures.

Supply-side Resources

The list of supply-side resource options reflect the realities evidenced through permitting, internally generated studies and externally commissioned studies undertaken to better understand details of available generation resources. Capital costs for some resource options have declined while others have remained stable compared to the 2017 IRP. New wind resources were given particular attention after the 2017 IRP selected a combination of wind and transmission resources for investment that would provide value for PacifiCorp's customers. Energy storage options of at least one MW continue to be of interest to PacifiCorp, its stakeholders, and the industry at large. PacifiCorp analyzed options for large pumped hydro projects and utility scale batteries. In response to stakeholder requests and utility industry trends, PacifiCorp studied multiple different battery energy storage configurations and combined battery configurations collocated with wind and solar projects. Solar resource options examined 200 MW single axis tracking facilities to reflect the industry trend of larger utility-size photovoltaic (PV) systems. A variety of gas-fueled generating resources were identified after consultation with major suppliers, large engineering-consulting firm and stakeholders. The combustion turbine types and configurations identified for consideration in the 2019 IRP are the same as those used in the 2017 IRP. Combustion turbine types and configurations remained the same because the market continued to improve the ability of existing technology to provide firming for variable energy resources. The capital and operating costs of simple and combined-cycle gas turbine plants have remained relatively low in recent years, with a flat to slightly decreasing cost trend. New coal-fueled and nuclear resources received minimal focus during this cycle due to ongoing environmental, economic, permitting and sociopolitical obstacles.

Derivation of Resource Attributes

The supply-side resource options were developed from a combination of resources. The process began with the list of major generating resources from the 2017 IRP. This resource list was reviewed and modified to reflect stakeholder input, new technology developments, environmental factors, cost dynamics and anticipated permitting requirements. Once the basic list of resources was determined, the cost-and-performance attributes for each resource were estimated. The information sources used are listed below, followed by a brief description on how they were used in the development of the supply-side resource table (SSR), which is used to develop inputs for IRP modeling:

- Recent (2018) third-party, cost-and-performance estimates;
- Publicly available cost and performance estimates;
- Actual PacifiCorp or electric utility industry installations, providing current construction/maintenance costs and performance data with similar resource attributes;
- Projected PacifiCorp or electric utility industry installations, providing projected construction/maintenance costs and performance data of similar or identical resource options; and
- Recent requests for proposals (RFP) and requests for information (RFI).

Recent third-party engineering information from original equipment manufacturers were used to develop capital, operating and maintenance costs, performance and operating characteristics and planned outage cycle estimates. Engineering-consultants or government agencies have access to this data based on prior research studies, academia, actual installations, and direct information exchanges with original equipment manufacturers. Examples of this type of effort include the 2018 Black & Veatch estimates prepared for simple cycle and combined cycle options. For this IRP cycle, the energy storage effort was performed by Burns & McDonnell and covers solar and wind resources. The Burns & McDonnell study builds upon prior energy storage studies, updates cost and technical information, and adds combined renewables plus energy storage resource options.

PacifiCorp or industry installations provide a solid basis for capital/maintenance costs and operating histories. Performance characteristics were adjusted to site-specific conditions identified in the SSR. For instance, the capacity of combustion turbine based resources varies with elevation and ambient temperature and, to a lesser extent, relative humidity. Adjustments were made for site-specific elevations of actual plants to more generic, regional elevations for future resources. Examples of actual PacifiCorp installations used to develop the cost-and-performance information provided in the SSR include operation and maintenance (O&M) costs for PacifiCorp's Gadsby GE LM6000PC peaking units and the Lake Side 2 combined cycle plant.

Recent RFIs and RFPs also provide a useful source of cost-and-performance data. In these cases, original equipment manufacturers provided technology specific information. Examples of RFIs informing the SSR include obtaining updated equipment pricing for wind turbine equipment from original equipment suppliers and reviews of capital costs prepared by engineering firms by engineer-procure-construct firms.

Handling of Technology Improvement Trends and Cost Uncertainties

The capital cost uncertainty for some generation technologies is relatively high. Various factors contribute to this uncertainty, including the relatively small number of facilities that have been built, especially for new and emerging technologies, as well as prolonged economic uncertainty. Despite this uncertainty, the cost profile between the 2017 IRP and the 2019 IRP has not changed significantly. For example, Figure 6.1 shows the trend in North American carbon steel sheet prices over the period from October 2015 through June 2018. The 2017 IRP included the historic carbon steel pricing shown in Figure 6.2. These figures illustrate near-term changes in capital costs of generation resources.

Figure 6.1 – World Carbon Steel Pricing by Type

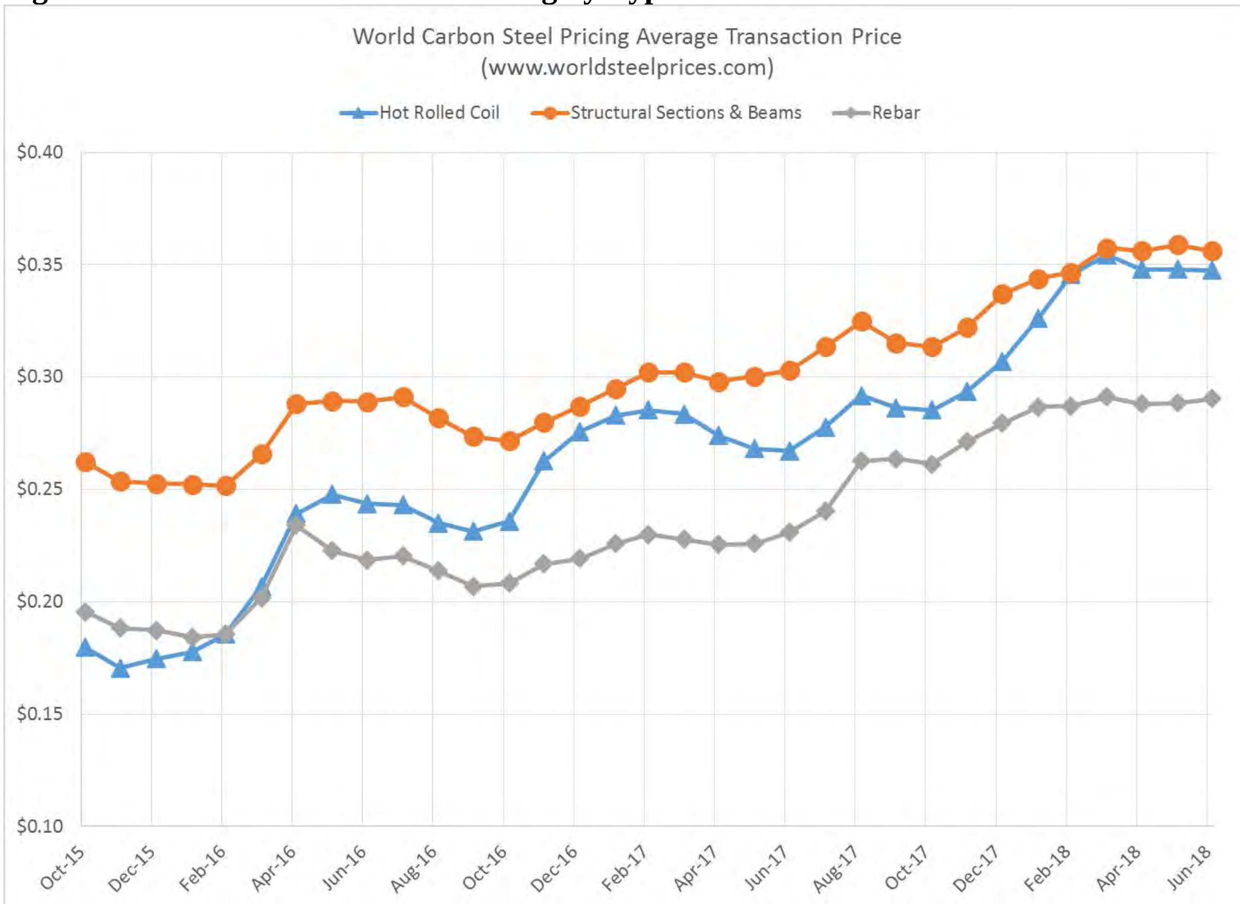
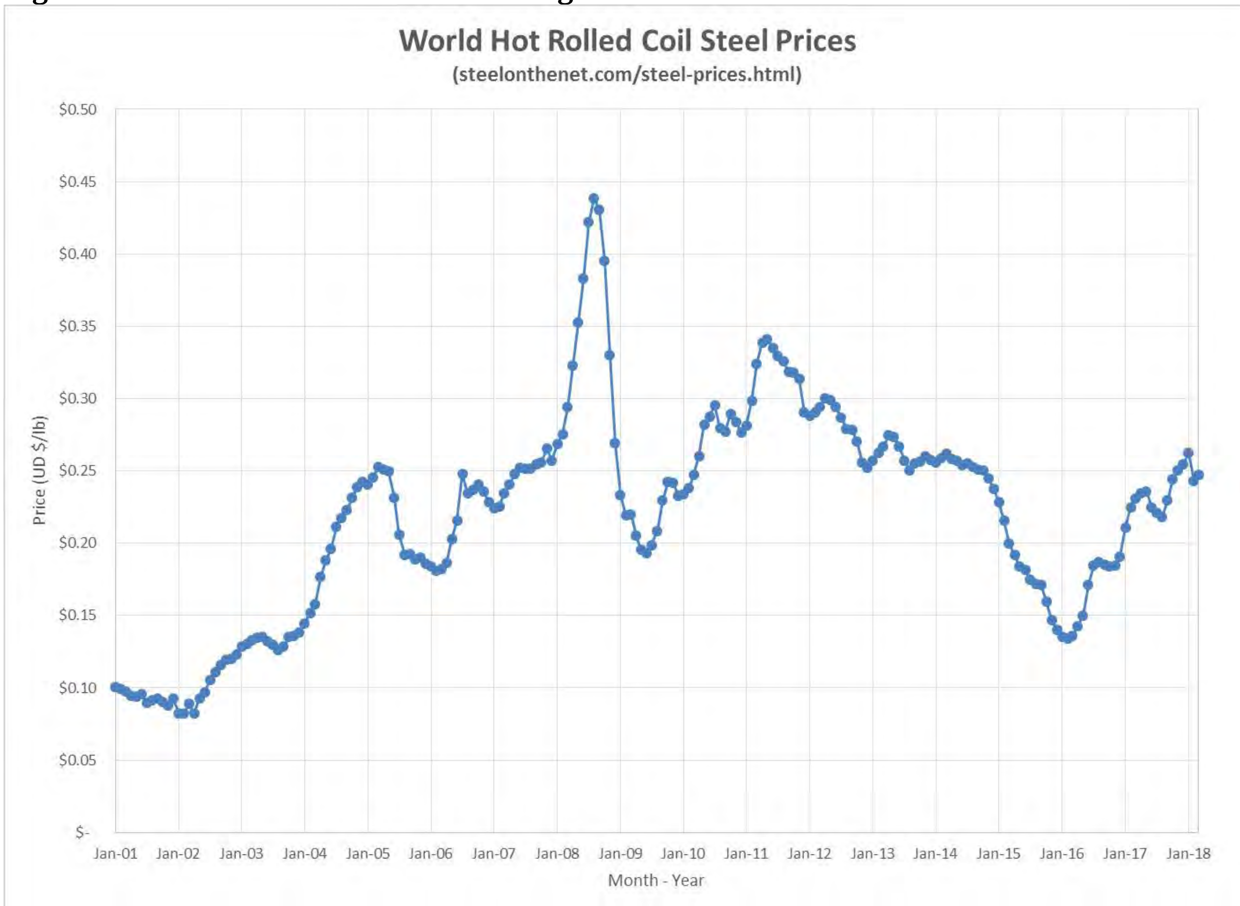


Figure 6.2 - Historic Carbon Steel Pricing



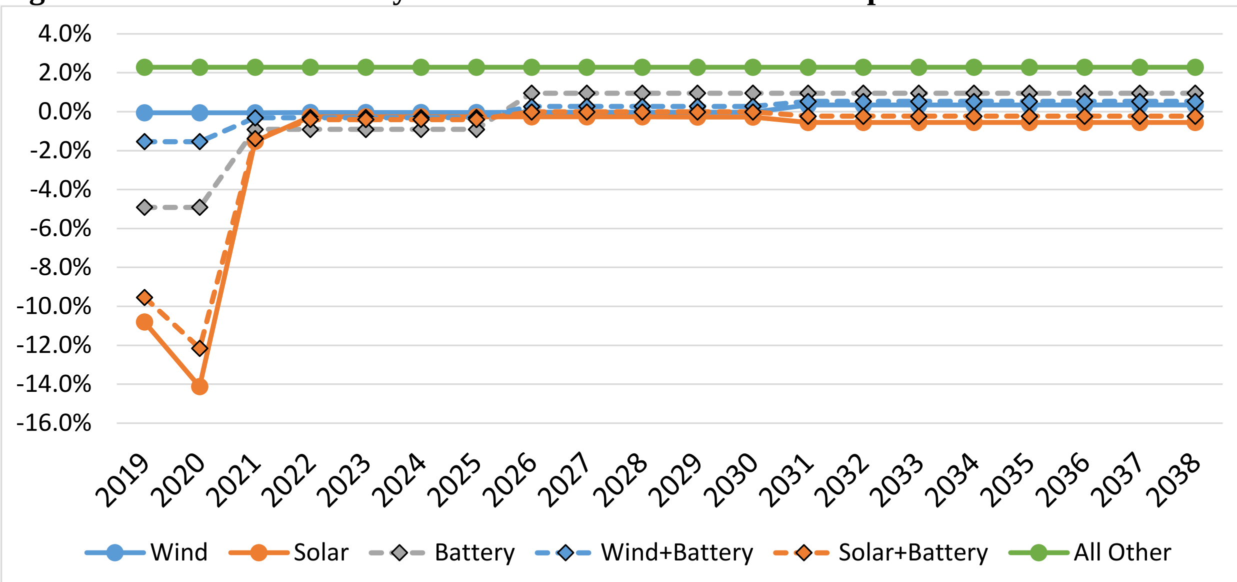
Prices for solar PV modules and balance of plant costs have come down since the 2017 IRP. Real prices are projected to continue to decline based upon technological and manufacturing improvements, but tariffs on Chinese imports and high demand for PV modules ahead of the phase out of the federal investment tax credits (ITC) for solar projects creates some degree of uncertainty in the solar market. The 2019 IRP anticipates the cost of new solar projects to decline approximately five percent per year during next three years and then to decline at a rate of approximately one percent per year beginning in year four.

Some generation technologies, such as integrated gasification combined cycle (IGCC), have shown significant cost uncertainty because only a few units have been built and operated. Recent experience with the significant cost overruns on IGCC projects such as Southern Company’s Kemper County IGCC plant illustrate the difficulty in accurately estimating capital costs of these resource options. As these technologies mature and more plants are constructed, the costs of such new technologies may decrease relative to more mature options such as pulverized coal and natural gas-fueled plants.

The SSR does not include the potential for such capital cost reductions since the benefits are not expected to be realized until the next generation of new plants are built and operated. For example, construction and operating “experience curve” benefits for IGCC plants are not expected to be available until after their commercial operation dates. As such, future IRPs will be better able to incorporate the potential benefits of future cost reductions. Given the current emphasis on construction and operating experience associated with renewable generation, PacifiCorp anticipates the cost benefits for these technologies to be available sooner. The estimated capital costs are displayed in the SSR along with expected availability of each technology for commercial utilization.

Figure 6.3 shows nominal year-by-year capital cost escalation rates for wind, solar, battery, wind+battery, solar+battery, and all other resources.

Figure 6.3 – Nominal Year-by-Year Escalation for Resource Capital Costs



Solar annual capital cost escalation rates are based on unweighted median scenarios from General Electric Renewable Energy, the U.S. Energy Administration, and Burns and McDonnell—note, rates for 2019 and 2020 are adjusted to calibrate levelized costs to be consistent with pricing received in the 2017S RFP.

Wind annual capital cost escalation rates are based on unweighted median scenarios from Energy+Environmental Economics, General Electric Renewable Energy, Berkley Labs, ArcTechnica, the Office of Energy Efficiency & Renewable Energy Administration, and Burns and McDonnell—note, rates for 2019 and 2020 are adjusted to calibrate levelized costs consistent with pricing received in the 2017R RFP. Annual capital cost escalation rates for batteries are based on data from Burns and McDonnell. All other resources are assumed to escalate at 2.28 percent per year.

Resource Options and Attributes

Table 6.1 lists the cost-and-performance attributes for supply-side resource options designated by generic, elevation-specific regions where resources could potentially be located:

- International organization for standardization (ISO) conditions (sea level and 59 degrees F); this is used as a reference for certain modeling purposes.
- 1,500 feet elevation: eastern Oregon/Washington.
- 3,000 feet elevation: southern/central Oregon.
- 4,500 feet elevation: northern Utah, specifically Salt Lake/Utah/Tooele/Box Elder counties.

- 5,050 feet elevation: central Utah, southern Idaho, central Wyoming.
- 6,500 feet elevation: southwestern Wyoming.

Table 6.2 and Table 6.3 present the total resource cost attributes for supply-side resource options, and are based on estimates of the first-year, real-levelized costs for resources, stated in June 2018 dollars. Similar to the approach taken in previous IRPs, it is not currently envisioned that new combined cycle resources could be economically permitted in northern Utah, specifically Salt Lake/Utah/Davis/Box Elder counties due to state implementation plans for these counties regarding particulate matter of 2.5 microns and less ($PM_{2.5}$).

A Glossary of Terms and a Glossary of Acronyms from the SSR is summarized in Table 6.4 and Table 6.5.

Table 6.1 – 2019 Supply-Side Resource Table (2018$)

Description		Resource Characteristics				Costs			Operating Characteristics				Environmental			
Fuel	Resource	Elevation (AFSL)	Net Capacity (MW)	Commercial Operation Year	Design Life (yrs)	Base Capital ($/KW)	Var O&M ($/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)
Natural Gas	SCCT Aero x3, ISO	0	142	2023	30	1,570	7.54	27.14	9279	2.6	3.9	58	0.0006	0.009	0.255	117
Natural Gas	Intercooled SCCT Aero x2, ISO	0	231	2023	30	1,092	5.05	18.78	8725	2.9	3.9	80	0.0006	0.009	0.255	117
Natural Gas	SCCT Frame "F" x1, ISO	0	233	2023	35	704	5.50	13.28	9811	2.7	3.9	20	0.0006	0.009	0.255	117
Natural Gas	IC Recips x 6, ISO	0	111	2023	35	1,810	7.45	29.82	8272	2.5	5.0	5	0.0006	0.0288	0.255	117
Natural Gas	CCCT Dry "G/H", 1x1, ISO	0	419	2024	40	1,469	1.76	20.52	6847	2.5	3.8	11	0.0006	0.0072	0.255	117
Natural Gas	CCCT Dry "G/H", DF, 1x1, ISO	0	51	2024	40	478	0.15	5.39	6847	0.8	3.8	11	0.0006	0.0072	0.255	117
Natural Gas	CCCT Dry "G/H", 2x1, ISO	0	840	2025	40	1,060	1.67	13.79	6861	2.5	3.8	11	0.0006	0.0072	0.255	117
Natural Gas	CCCT Dry "G/H", DF, 2x1, ISO	0	102	2025	40	365	0.16	4.44	6861	0.8	3.8	11	0.0006	0.0072	0.255	117
Natural Gas	CCCT Dry "J/HA.02", 1x1, ISO	0	539	2024	40	1,218	1.70	17.66	6787	2.5	3.8	0	0.0006	0.0072	0.255	117
Natural Gas	CCCT Dry "J/HA.02", DF, 1x1, ISO	0	63	2024	40	407	0.16	4.86	6787	0.8	3.8	0	0.0006	0.0072	0.255	117
Natural Gas	CCCT Dry, "J/HA.02" 2X1, ISO	0	1,083	2025	40	881	1.62	12.00	6787	2.5	3.8	0	0.0006	0.0072	0.255	117
Natural Gas	CCCT Dry "J/HA.02", DF, 2X1, ISO	0	126	2025	40	316	0.16	4.05	6787	0.8	3.8	0	0.0006	0.0072	0.255	117
Natural Gas	SCCT Aero x3	1,500	138	2023	30	1,612	7.76	27.96	9228	2.6	3.9	58	0.0006	0.009	0.255	117
Natural Gas	Intercooled SCCT Aero x2	1,500	221	2023	30	1,143	5.35	19.88	8689	2.9	3.9	80	0.0006	0.009	0.255	117
Natural Gas	SCCT Frame "F" x1	1,500	221	2023	35	741	5.81	14.02	9792	2.7	3.9	20	0.0006	0.009	0.255	117
Natural Gas	IC Recips x 6	1,500	111	2023	35	1,810	7.45	29.82	8272	2.5	5.0	5	0.0006	0.0288	0.255	117
Natural Gas	CCCT Dry "G/H", 1x1	1,500	396	2024	40	1,552	1.86	21.68	6788	2.5	3.8	11	0.0006	0.0072	0.255	117
Natural Gas	CCCT Dry "G/H", DF, 1x1	1,500	51	2024	40	478	0.15	5.39	6788	0.8	3.8	11	0.0006	0.0072	0.255	117
Natural Gas	CCCT Dry "G/H", 2x1	1,500	795	2025	40	1,120	1.77	14.57	6800	2.5	3.8	11	0.0006	0.0072	0.255	117
Natural Gas	CCCT Dry "G/H", DF, 2x1	1,500	102	2025	40	365	0.16	4.44	6800	0.8	3.8	11	0.0006	0.0072	0.255	117
Natural Gas	CCCT Dry "J/HA.02", 1x1	1,500	510	2024	40	1,288	1.80	18.67	6732	2.5	3.8	11	0.0006	0.0072	0.255	117
Natural Gas	CCCT Dry "J/HA.02", DF, 1x1	1,500	63	2024	40	407	0.16	4.86	6732	0.8	3.8	11	0.0006	0.0072	0.255	117
Natural Gas	CCCT Dry, "J/HA.02" 2X1	1,500	1,023	2025	40	932	1.71	12.69	6732	2.5	3.8	11	0.0006	0.0072	0.255	117
Natural Gas	CCCT Dry "J/HA.02", DF, 2X1	1,500	126	2025	40	316	0.16	4.05	6732	0.8	3.8	11	0.0006	0.0072	0.255	117
Natural Gas	SCCT Aero x3	3,000	131	2023	30	1,704	8.21	29.58	9232	2.6	3.9	58	0.0006	0.009	0.255	117
Natural Gas	Intercooled SCCT Aero x2	3,000	209	2023	30	1,209	5.67	21.10	8687	2.9	3.9	80	0.0006	0.009	0.255	117
Natural Gas	SCCT Frame "F" x1	3,000	210	2023	35	782	6.13	14.81	9799	2.7	3.9	20	0.0006	0.009	0.255	117
Natural Gas	IC Recips x 6	3,000	111	2023	35	1,810	7.45	29.82	8273	2.5	5.0	5	0.0006	0.0288	0.255	117
Natural Gas	CCCT Dry "G/H", 1x1	3,000	375	2024	40	1,641	1.97	22.92	6762	2.5	3.8	11	0.0006	0.0072	0.255	117
Natural Gas	CCCT Dry "G/H", DF, 1x1	3,000	51	2024	40	478	0.15	5.39	6762	0.8	3.8	11	0.0006	0.0072	0.255	117
Natural Gas	CCCT Dry "G/H", 2x1	3,000	752	2025	40	1,184	1.86	15.39	6775	2.5	3.8	11	0.0006	0.0072	0.255	117
Natural Gas	CCCT Dry "G/H", DF, 2x1	3,000	102	2025	40	365	0.16	4.44	6775	0.8	3.8	11	0.0006	0.0072	0.255	117
Natural Gas	CCCT Dry "J/HA.02", 1x1	3,000	482	2024	40	1,363	1.90	19.73	6690	2.5	3.8	11	0.0006	0.0072	0.255	117
Natural Gas	CCCT Dry "J/HA.02", DF, 1x1	3,000	63	2024	40	407	0.16	4.86	6690	0.8	3.8	11	0.0006	0.0072	0.255	117
Natural Gas	CCCT Dry, "J/HA.02" 2X1	3,000	967	2025	40	986	1.81	13.41	6692	2.5	3.8	11	0.0006	0.0072	0.255	117
Natural Gas	CCCT Dry "J/HA.02", DF, 2X1	3,000	126	2025	40	316	0.16	4.05	6692	0.8	3.8	11	0.0006	0.0072	0.255	117
Natural Gas	SCCT Aero x3	5,050	122	2023	30	1,829	8.85	31.86	9229	2.6	3.9	58	0.0006	0.009	0.255	117
Natural Gas	Intercooled SCCT Aero x2	5,050	194	2023	30	1,305	6.14	22.82	8680	2.9	3.9	80	0.0006	0.009	0.255	117
Natural Gas	SCCT Frame "F" x1	5,050	194	2023	35	843	6.61	15.97	9805	2.7	3.9	20	0.0006	0.009	0.255	117
Natural Gas	IC Recips x 6	5,050	111	2023	35	1,810	7.45	29.82	8280	2.5	5.0	5	0.0006	0.0288	0.255	117
Natural Gas	CCCT Dry "G/H", 1x1	5,050	344	2024	40	1,788	2.12	24.74	6510	2.5	3.8	11	0.0006	0.0072	0.255	117
Natural Gas	CCCT Dry "G/H", DF, 1x1	5,050	51	2024	40	478	0.15	5.39	6510	0.8	3.8	11	0.0006	0.0072	0.255	117
Natural Gas	CCCT Dry "G/H", 2x1	5,050	687	2025	40	1,297	2.01	16.63	6520	2.5	3.8	11	0.0006	0.0072	0.255	117
Natural Gas	CCCT Dry "G/H", DF, 2x1	5,050	102	2025	40	365	0.16	4.44	6520	0.8	3.8	11	0.0006	0.0072	0.255	117
Natural Gas	CCCT Dry "J/HA.02", 1x1	5,050	442	2024	40	1,485	2.05	21.26	6464	2.5	3.8	11	0.0006	0.0072	0.255	117
Natural Gas	CCCT Dry "J/HA.02", DF, 1x1	5,050	63	2024	40	407	0.16	4.86	6464	0.8	3.8	11	0.0006	0.0072	0.255	117
Natural Gas	CCCT Dry, "J/HA.02" 2X1	5,050	884	2025	40	1,079	1.95	14.45	6469	2.5	3.8	11	0.0006	0.0072	0.255	117
Natural Gas	CCCT Dry "J/HA.02", DF, 2X1	5,050	126	2025	40	316	0.16	4.05	6469	0.8	3.8	11	0.0006	0.0072	0.255	117
Natural Gas	SCCT Aero x3	6,500	113	2023	30	1,975	9.60	34.56	9209	2.6	3.9	58	0.0006	0.009	0.255	117
Natural Gas	Intercooled SCCT Aero x2	6,500	181	2023	30	1,394	6.45	24.00	8694	2.9	3.9	80	0.0006	0.009	0.255	117
Natural Gas	SCCT Frame "F" x1	6,500	185	2023	35	887	6.96	16.81	9786	2.7	3.9	20	0.0006	0.009	0.255	117
Natural Gas	IC Recips x 6	6,500	111	2023	35	1,810	7.75	31.04	8320	2.5	5.0	5	0.0006	0.0288	0.255	117
Natural Gas	CCCT Dry "G/H", 1x1	6,500	333	2024	40	1,843	2.25	26.20	6757	2.5	3.8	11	0.0006	0.0072	0.255	117
Natural Gas	CCCT Dry "G/H", DF, 1x1	6,500	51	2024	40	478	0.15	5.39	6757	0.8	3.8	11	0.0006	0.0072	0.255	117
Natural Gas	CCCT Dry "G/H", 2x1	6,500	669	2025	40	1,330	2.13	17.61	6772	2.5	3.8	11	0.0006	0.0072	0.255	117
Natural Gas	CCCT Dry "G/H", DF, 2x1	6,500	102	2025	40	365	0.16	4.44	6772	0.8	3.8	11	0.0006	0.0072	0.255	117
Natural Gas	CCCT Dry "J/HA.02", 1x1	6,500	424	2024	40	1,549	2.15	22.33	6681	2.5	3.8	11	0.0006	0.0072	0.255	117
Natural Gas	CCCT Dry "J/HA.02", DF, 1x1	6,500	63	2024	40	407	0.16	4.86	6681	0.8	3.8	11	0.0006	0.0072	0.255	117
Natural Gas	CCCT Dry, "J/HA.02" 2X1	6,500	851	2025	40	1,120	2.05	15.18	6681	2.5	3.8	11	0.0006	0.0072	0.255	117
Natural Gas	CCCT Dry "J/HA.02", DF, 2X1	6,500	126	2025	40	316	0.16	4.06	6681	0.8	3.8	11	0.0006	0.0072	0.255	117

Table 6.1 – 2019 Supply-Side Resource Table (2018$) (Continued)

Description		Resource Characteristics				Costs			Operating Characteristics				Environmental			
Fuel	Resource	Elevation (AFSL)	Net Capacity (MW)	Commercial Operation Year	Design Life (yrs)	Base Capital ($/KW)	Var O&M ($/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)
Coal	SCPC with CCS	4,500	526	2036	40	6,462	7.00	72.22	13087	5.0	5.0	1,004	0.009	0.070	0.022	20.5
Coal	IGCC with CCS	4,500	466	2036	40	6,257	11.77	58.20	10823	8.0	7.0	394	0.009	0.050	0.333	20.5
Coal	PC CCS retrofit @ 500 MW	4,500	-139	2033	20	1,419	6.47	77.76	14372	5.0	5.0	1,004	0.005	0.070	1.200	20.5
Coal	SCPC with CCS	6,500	692	2036	40	7,318	7.58	67.09	13242	5.0	5.0	1,004	0.009	0.070	0.022	20.5
Coal	IGCC with CCS	6,500	456	2036	40	7,085	14.11	63.40	11047	8.0	7.0	394	0.009	0.050	0.333	20.5
Coal	PC CCS retrofit @ 500 MW	6,500	-139	2031	20	1,607	7.00	72.22	14372	5.0	5.0	1,004	0.005	0.070	1.200	20.5
Geothermal	Blundell Dual Flash 90% CF	4,500	35	2021	40	5,708	1.16	103.85	n/a	5.0	5.0	10	n/a	n/a	n/a	n/a
Geothermal	Greenfield Binary 90% CF	4,500	43	2023	40	5,973	1.16	103.85	n/a	5.0	5.0	270	n/a	n/a	n/a	n/a
Geothermal	Generic Geothermal PPA 90% CF	4,500	30	2021	20	0	77.34	0.00	n/a	5.0	5.0	270	n/a	n/a	n/a	n/a
Wind	3.6 MW Wind turbine 37.1% CF WA, 2020	4,500	200	2020	30	1,354	0.00	27.99	n/a	Included with CF	0	n/a	n/a	n/a	n/a	n/a
Wind	3.6 MW Wind turbine 37.1% CF OR, 2020	1,500	200	2020	30	1,334	0.00	27.99	n/a	Included with CF	0	n/a	n/a	n/a	n/a	n/a
Wind	3.6 MW Wind turbine 37.1% CF ID, 2020	4,500	200	2020	30	1,358	0.00	27.99	n/a	Included with CF	0	n/a	n/a	n/a	n/a	n/a
Wind	3.6 MW Wind turbine 29.5% CF UT, 2020	6,500	200	2020	30	1,301	0.00	27.99	n/a	Included with CF	0	n/a	n/a	n/a	n/a	n/a
Wind	3.6 MW Wind turbine 43.6% CF WY, 2020	1,500	240	2020	30	1,301	0.65	27.99	n/a	Included with CF	0	n/a	n/a	n/a	n/a	n/a
Wind + Storag	Wind + Stor, Pocatello, ID, 200 MW+ 50 MW | 100 MWh	4,500	200	2023	30	1,738	0.00	29.18	1	Included with CF	0	n/a	n/a	n/a	n/a	n/a
Wind + Storag	Wind + Stor, Arlington, OR, 200 MW+ 50 MW | 100 MWh	1,500	200	2023	30	1,765	0.00	29.18	1	Included with CF	0	n/a	n/a	n/a	n/a	n/a
Wind + Storag	Wind + Stor, Monticello, UT, 200 MW+ 50 MW | 100 MWh	4,500	200	2023	30	1,735	0.00	29.18	1	Included with CF	0	n/a	n/a	n/a	n/a	n/a
Wind + Storag	Wind + Stor, Medicine Bow, WY, 200 MW+ 50 MW | 100 MWh	6,500	200	2023	30	1,730	0.65	29.18	1	Included with CF	0	n/a	n/a	n/a	n/a	n/a
Wind + Storag	Wind + Stor, Goldendale, WA, 200 MW+ 50 MW | 100 MWh	1,500	200	2023	30	1,772	0.00	29.18	1	Included with CF	0	n/a	n/a	n/a	n/a	n/a
Wind + Storag	Wind + Stor, Pocatello, ID, 200 MW+ 50 MW | 200 MWh	4,500	200	2023	30	1,880	0.00	29.88	1	Included with CF	0	n/a	n/a	n/a	n/a	n/a
Wind + Storag	Wind + Stor, Arlington, OR, 200 MW+ 50 MW | 200 MWh	1,500	200	2023	30	1,917	0.00	29.88	1	Included with CF	0	n/a	n/a	n/a	n/a	n/a
Wind + Storag	Wind + Stor, Monticello, UT, 200 MW+ 50 MW | 200 MWh	4,500	200	2023	30	1,877	0.00	29.88	1	Included with CF	0	n/a	n/a	n/a	n/a	n/a
Wind + Storag	Wind + Stor, Medicine Bow, WY, 200 MW+ 50 MW | 200 MWh	6,500	200	2023	30	1,872	0.65	29.88	1	Included with CF	0	n/a	n/a	n/a	n/a	n/a
Wind + Storag	Wind + Stor, Goldendale, WA, 200 MW+ 50 MW | 200 MWh	1,500	200	2023	30	1,924	0.00	29.88	1	Included with CF	0	n/a	n/a	n/a	n/a	n/a
Wind + Storag	Wind + Stor, Pocatello, ID, 200 MW+ 50 MW | 400 MWh	4,500	200	2023	30	2,158	0.00	31.03	1	Included with CF	0	n/a	n/a	n/a	n/a	n/a
Wind + Storag	Wind + Stor, Arlington, OR, 200 MW+ 50 MW | 400 MWh	1,500	200	2023	30	2,214	0.00	31.03	1	Included with CF	0	n/a	n/a	n/a	n/a	n/a
Wind + Storag	Wind + Stor, Monticello, UT, 200 MW+ 50 MW | 400 MWh	4,500	200	2023	30	2,155	0.00	31.03	1	Included with CF	0	n/a	n/a	n/a	n/a	n/a
Wind + Storag	Wind + Stor, Medicine Bow, WY, 200 MW+ 50 MW | 400 MWh	6,500	200	2023	30	2,150	0.65	31.03	1	Included with CF	0	n/a	n/a	n/a	n/a	n/a
Wind + Storag	Wind + Stor, Goldendale, WA, 200 MW+ 50 MW | 400 MWh	1,500	200	2023	30	2,221	0.00	31.03	1	Included with CF	0	n/a	n/a	n/a	n/a	n/a
Solar	PV Idaho Falls, ID, 50 MW, 28.1% CF	4,700	50	2021	25	1,366	0.00	21.72	n/a	Included with CF	0	n/a	n/a	n/a	n/a	n/a
Solar	PV Idaho Falls, ID, 200 MW, 2021, 28.1% CF	4,700	200	2021	25	1,271	0.00	21.72	n/a	Included with CF	0	n/a	n/a	n/a	n/a	n/a
Solar	PV Lakeview, OR, 50 MW, 2021, 29.7% CF	4,800	50	2021	25	1,424	0.00	22.35	n/a	Included with CF	0	n/a	n/a	n/a	n/a	n/a
Solar	PV Lakeview, OR, 200 MW, 2021, 29.7% CF	4,800	200	2021	25	1,329	0.00	22.35	n/a	Included with CF	0	n/a	n/a	n/a	n/a	n/a
Solar	PV Milford, UT, 50 MW, 2021, 32.5% CF	5,000	50	2021	25	1,363	0.00	22.32	n/a	Included with CF	0	n/a	n/a	n/a	n/a	n/a
Solar	PV Milford, UT, 200 MW, 2021, 32.5% CF	5,000	200	2021	25	1,268	0.00	22.32	n/a	Included with CF	0	n/a	n/a	n/a	n/a	n/a
Solar	PV Utah North, 200 MW, 2021, 30.1% CF	5,000	200	2021	25	1,266	0.00	21.13	n/a	Included with CF	0	n/a	n/a	n/a	n/a	n/a
Solar	PV Rock Springs, WY, 50 MW, 2021, 30.1% CF	6,400	50	2021	25	1,360	0.00	21.13	n/a	Included with CF	0	n/a	n/a	n/a	n/a	n/a
Solar	PV Rock Springs, WY, 200 MW, 2021, 30.1% CF	6,400	200	2021	25	1,266	0.00	21.13	n/a	Included with CF	0	n/a	n/a	n/a	n/a	n/a
Solar	PV Yakima, WA, 50 MW, 2021, 26% CF	1,000	50	2021	25	1,422	0.00	22.35	n/a	Included with CF	0	n/a	n/a	n/a	n/a	n/a
Solar	PV Yakima, WA, 200 MW, 2021, 26% CF	1,000	200	2021	25	1,327	0.00	22.35	n/a	Included with CF	0	n/a	n/a	n/a	n/a	n/a
Solar + Storag	PV + Stor, Idaho Falls, ID, 50 MW + 10 MW X 20 MWh	4,700	50	2021	25	1,628	0.00	23.48	1	Included with CF	0	n/a	n/a	n/a	n/a	n/a
Solar + Storag	PV + Stor, Idaho Falls, ID, 200 MW + 50 MW X 100 MWh	4,700	200	2021	25	1,470	0.00	22.91	1	Included with CF	0	n/a	n/a	n/a	n/a	n/a
Solar + Storag	PV + Stor,, Idaho Falls, ID, 50 MW + 10 MW X 40 MWh	4,700	50	2021	25	1,756	0.00	25.03	1	Included with CF	0	n/a	n/a	n/a	n/a	n/a
Solar + Storag	PV + Stor, Idaho Falls, ID, 200 MW + 50 MW X 200 MWh	4,700	200	2021	25	1,614	0.00	24.24	1	Included with CF	0	n/a	n/a	n/a	n/a	n/a
Solar + Storag	PV + Stor, Idaho Falls, ID, 50 MW + 10 MW X 80 MWh	4,700	50	2021	25	1,992	0.00	26.46	1	Included with CF	0	n/a	n/a	n/a	n/a	n/a
Solar + Storag	PV + Stor, Idaho Falls, ID, 200 MW + 50 MW X 400 MWh	4,700	200	2021	25	1,897	0.00	25.36	1	Included with CF	0	n/a	n/a	n/a	n/a	n/a
Solar + Storag	PV + Stor, Lakeview, OR, 50 MW + 10 MW X 20 MWh	4,800	50	2021	25	1,706	0.00	23.48	1	Included with CF	0	n/a	n/a	n/a	n/a	n/a
Solar + Storag	PV + Stor, Lakeview, OR, 200 MW + 50 MW X 100 MWh	4,800	200	2021	25	1,543	0.00	22.91	1	Included with CF	0	n/a	n/a	n/a	n/a	n/a
Solar + Storag	PV + Stor, Lakeview, OR, 50 MW + 10 MW X 40 MWh	4,800	50	2021	25	1,844	0.00	25.03	1	Included with CF	0	n/a	n/a	n/a	n/a	n/a
Solar + Storag	PV + Stor, Lakeview, OR, 200 MW + 50 MW X 200 MWh	4,800	200	2021	25	1,699	0.00	24.24	1	Included with CF	0	n/a	n/a	n/a	n/a	n/a
Solar + Storag	PV + Stor, Lakeview, OR, 50 MW + 10 MW X 80 MWh	4,800	50	2021	25	2,098	0.00	26.46	1	Included with CF	0	n/a	n/a	n/a	n/a	n/a
Solar + Storag	PV + Stor,, Lakeview, OR, 200 MW + 50 MW X 400 MWh	4,800	200	2021	25	2,004	0.00	25.36	1	Included with CF	0	n/a	n/a	n/a	n/a	n/a
Solar + Storag	PV + Stor,, Milford, UT, 50 MW + 10 MW X 20 MWh	5,000	50	2021	25	1,626	0.00	23.48	1	Included with CF	0	n/a	n/a	n/a	n/a	n/a
Solar + Storag	PV + Stor,, Milford, UT, 200 MW + 50 MW X 100 MWh	5,000	200	2021	25	1,467	0.00	22.91	1	Included with CF	0	n/a	n/a	n/a	n/a	n/a
Solar + Storag	PV + Stor,, Milford, UT 50 MW + 10 MW X 40 MWh	5,000	50	2021	25	1,754	0.00	25.03	1	Included with CF	0	n/a	n/a	n/a	n/a	n/a
Solar + Storag	PV + Stor,, Milford, UT, 200 MW + 50 MW X 200 MWh	5,000	200	2021	25	1,612	0.00	24.24	1	Included with CF	0	n/a	n/a	n/a	n/a	n/a
Solar + Storag	PV + Stor,, Milford, UT, 50 MW + 10 MW X 80 MWh	5,000	50	2021	25	1,990	0.00	26.46	1	Included with CF	0	n/a	n/a	n/a	n/a	n/a
Solar + Storag	PV + Stor,, Milford, UT, 200 MW + 50 MW X 400 MWh	5,000	200	2021	25	1,895	0.00	25.36	1	Included with CF	0	n/a	n/a	n/a	n/a	n/a
Solar + Storag	PV + Stor, Utah North, 200 MW + 50 MW X 200 MWh	5,000	200	2021	25	1,609	0.00	24.24	1	Included with CF	0	n/a	n/a	n/a	n/a	n/a
Solar + Storag	PV + Stor,, Rock Springs, WY, 50 MW + 10 MW X 20 MWh	6,400	50	2021	25	1,623	0.00	23.48	1	Included with CF	0	n/a	n/a	n/a	n/a	n/a
Solar + Storag	PV + Stor,, Rock Springs, WY, 200 MW + 50 MW X 100 MWh	6,400	200	2021	25	1,464	0.00	22.91	1	Included with CF	0	n/a	n/a	n/a	n/a	n/a
Solar + Storag	PV + Stor,, Rock Springs, WY, 50 MW + 10 MW X 40 MWh	6,400	50	2021	25	1,751	0.00	25.03	1	Included with CF	0	n/a	n/a	n/a	n/a	n/a
Solar + Storag	PV + Stor,, Rock Springs, WY, 200 MW + 50 MW X 200 MWh	6,400	200	2021	25	1,609	0.00	24.24	1	Included with CF	0	n/a	n/a	n/a	n/a	n/a
Solar + Storag	PV + Stor,, Rock Springs, WY, 50 MW + 10 MW X 80 MWh	6,400	50	2021	25	1,987	0.00	26.46	1	Included with CF	0	n/a	n/a	n/a	n/a	n/a
Solar + Storag	PV + Stor,, Rock Springs, WY, 200 MW + 50 MW X 400 MWh	6,400	200	2021	25	1,892	0.00	25.36	1	Included with CF	0	n/a	n/a	n/a	n/a	n/a
Solar + Storag	PV + Stor,, Yakima, WA, 50 MW + 10 MW X 20 MWh	1,000	50	2021	25	1,704	0.00	23.48	1	Included with CF	0	n/a	n/a	n/a	n/a	n/a
Solar + Storag	PV + Stor, Yakima, WA, 200 MW + 50 MW X 100 MWh	1,000	200	2021	25	1,541	0.00	22.91	1	Included with CF	0	n/a	n/a	n/a	n/a	n/a
Solar + Storag	PV + Stor, Yakima, WA, 50 MW + 10 MW X 40 MWh	1,000	50	2021	25	1,842	0.00	25.03	1	Included with CF	0	n/a	n/a	n/a	n/a	n/a
Solar + Storag	PV + Stor, Yakima, WA, 200 MW + 50 MW X 200 MWh	1,000	200	2021	25	1,697	0.00	24.24	1	Included with CF	0	n/a	n/a	n/a	n/a	n/a
Solar + Storag	PV + Stor, Yakima, WA, 50 MW + 10 MW X 80 MWh	1,000	50	2021	25	2,097	0.00	26.46	1	Included with CF	0	n/a	n/a	n/a	n/a	n/a
Solar + Storag	PV + Stor, Yakima, WA, 200 MW + 50 MW X 400 MWh	1,000	200	2021	25	2,002	0.00	25.36	1	Included with CF	0	n/a	n/a	n/a	n/a	n/a

Table 6.1 – 2019 Supply-Side Resource Table (2018$) (Continued)

Description		Resource Characteristics				Costs			Operating Characteristics				Environmental			
Fuel	Resource	Elevation (AFSL)	Net Capacity (MW)	Commercial Operation Year	Design Life (yrs)	Base Capital ($/KW)	Var O&M ($/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)
Storage	Oregon PS, 400 MW X 3,800 MWh	4,457	400	2025	60	3,095	0.00	16.76	79%	3	7	0	0	0	0	0
Storage	Oregon PS joint ownership, 100 MW X 950 MWh	4,457	100	2025	60	3,099	0.00	16.76	79%	3	7	0	0	0	0	0
Storage	Washington PS, 1,200 MW X 16,800 MWh	500	1,200	2029	60	2,719	0.00	12.50	79%	3	7	0	0	0	0	0
Storage	Wyoming PS, 700 MW X 7,000 MWh	580	700	2027	60	3,255	0.00	17.00	79%	3	7	0	0	0	0	0
Storage	Wyoming PS, 400 MW X 3,400 MWh	6,000	400	2028	60	2,348	0.00	17.00	79%	3	7	0	0	0	0	0
Storage	Utah PS, 300 MW X 1,800 MWh	6,359	300	2025	60	2,991	0.00	17.00	79%	3	7	0	0	0	0	0
Storage	Idaho PS, 360 MW X 2,880 MWh	5,000	360	2031	60	2,680	0.00	17.00	79%	3	7	0	0	0	0	0
Storage	Idaho PS, 360 MW X 2,880 MWh	5,000	360	2031	60	2,680	0.00	17.00	79%	3	7	0	0	0	0	0
Storage	CAES, 320 MW X 15,360 MWh	4,600	320	2022	30	1,625	0.00	7.01	4230 / 55%	1	3	0	0	0	0	117
Storage	Li-Ion 1 MW X 250 kWh	0	1	2020	15	1,473	11.42	8.29	88%	1	3	0	0	0	0	0
Storage	Li-Ion 1 MW X 2 MWh	0	1	2020	15	2,615	15.70	23.56	88%	1	3	0	0	0	0	0
Storage	Li-Ion 1 MW X 4 MWh	0	1	2020	15	3,412	14.98	35.23	88%	1	3	0	0	0	0	0
Storage	Li-Ion 1 MW X 8 MWh	0	1	2020	15	5,455	14.98	52.09	88%	1	3	0	0	0	0	0
Storage	Li-Ion 15 MW X 60 MWh	0	15	2020	15	1,766	15.07	11.50	88%	1	3	0	0	0	0	0
Storage	Flow 1 MW X 6 MWh	0	1	2021	15	3,996	0.00	32.00	65%	2	3	0	0	0	0	0
Nuclear	Advanced Fission	5,000	2,234	2030	40	6,765	11.75	101.62	10,710	7.7	7.3	96	0	0	0	0
Nuclear	Small Modular Reactor x 12	5,000	570	2028	40	6,028	15.50	173.35	10,710	7.7	7.3	65	0	0	0	0

Table 6.2 - Total Resource Cost for Supply-Side Resource Options

Supply Side Resource Options Mid-Calendar Year 2018 Dollars ($)		Capital Cost $/kW			Fixed Cost					
					Fixed O&M $/kW-Yr					
Resource Description	Elevation (AFSL)	Total Capital Cost 1/	Payment Factor 1/	Annual Payment ($/kW-Yr)	O&M 1/	Capitalized Premium	O&M Capitalized 1/	Gas Transportation 1/	Total	Total Fixed ($/kW-Yr)
SCCT Aero x3, ISO	0	$1,570	7.411%	$116.34	27.14	1.262%	0.34	31.94	59.42	$175.76
Intercooled SCCT Aero x2, ISO	0	$1,092	7.411%	$80.97	18.78	0.273%	0.05	30.03	48.87	$129.84
SCCT Frame "F" x1, ISO	0	$704	6.959%	$48.96	13.28	1.135%	0.15	33.77	47.21	$96.17
IC Recips x 6, ISO	0	$1,810	6.959%	$125.94	29.82	0.136%	0.04	28.47	58.33	$184.27
CCCT Dry "G/H", 1x1, ISO	0	$1,469	6.790%	$99.72	20.52	0.146%	0.03	23.57	44.12	$143.84
CCCT Dry "G/H", DF, 1x1, ISO	0	$478	6.790%	$32.45	5.39	0.000%	0.00	23.57	28.96	$61.42
CCCT Dry "G/H", 2x1, ISO	0	$1,060	6.790%	$71.98	13.79	0.146%	0.02	23.62	37.43	$109.41
CCCT Dry "G/H", DF, 2x1, ISO	0	$365	6.790%	$24.75	4.44	0.000%	0.00	23.62	28.05	$52.81
CCCT Dry "J/HA.02", 1x1, ISO	0	$1,218	6.790%	$82.69	17.66	0.000%	0.00	23.36	41.02	$123.70
CCCT Dry "J/HA.02", DF, 1x1, ISO	0	$407	6.790%	$27.67	4.86	0.000%	0.00	23.36	28.22	$55.89
CCCT Dry, "J/HA.02" 2X1, ISO	0	$881	6.790%	$59.80	12.00	0.146%	0.02	23.36	35.38	$95.18
CCCT Dry "J/HA.02", DF, 2X1, ISO	0	$316	6.790%	$21.45	4.05	0.000%	0.00	23.36	27.42	$48.86
SCCT Aero x3	1,500	$1,612	7.411%	$119.50	27.96	1.262%	0.35	31.76	60.07	$179.57
Intercooled SCCT Aero x2	1,500	$1,143	7.411%	$84.71	19.88	0.273%	0.05	29.91	49.85	$134.56
SCCT Frame "F" x1	1,500	$741	6.959%	$51.54	14.02	1.135%	0.16	33.71	47.89	$99.43
IC Recips x 6	1,500	$1,810	6.959%	$125.94	29.82	0.136%	0.04	28.47	58.33	$184.27
CCCT Dry "G/H", 1x1	1,500	$1,552	6.790%	$105.38	21.68	0.146%	0.03	23.37	45.08	$150.46
CCCT Dry "G/H", DF, 1x1	1,500	$478	6.790%	$32.45	5.39	0.000%	0.00	23.37	28.76	$61.21
CCCT Dry "G/H", 2x1	1,500	$1,120	6.790%	$76.07	14.57	0.146%	0.02	23.41	38.00	$114.07
CCCT Dry "G/H", DF, 2x1	1,500	$365	6.790%	$24.75	4.44	0.000%	0.00	23.41	27.84	$52.60
CCCT Dry "J/HA.02", 1x1	1,500	$1,288	6.790%	$87.46	18.67	0.000%	0.00	23.17	41.84	$129.30
CCCT Dry "J/HA.02", DF, 1x1	1,500	$407	6.790%	$27.67	4.86	0.000%	0.00	23.17	28.03	$55.70
CCCT Dry, "J/HA.02" 2X1	1,500	$932	6.790%	$63.30	12.69	0.146%	0.02	23.17	35.88	$99.17
CCCT Dry "J/HA.02", DF, 2X1	1,500	$316	6.790%	$21.45	4.05	0.000%	0.00	23.17	27.23	$48.67
SCCT Aero x3	3,000	$1,704	7.411%	$126.26	29.58	1.262%	0.37	16.94	46.89	$173.15
Intercooled SCCT Aero x2	3,000	$1,209	7.411%	$89.58	21.10	0.273%	0.06	15.94	37.10	$126.68
SCCT Frame "F" x1	3,000	$782	6.959%	$54.43	14.81	1.135%	0.17	17.98	32.95	$87.38
IC Recips x 6	3,000	$1,810	6.959%	$125.94	29.82	0.136%	0.04	15.18	45.03	$170.97
CCCT Dry "G/H", 1x1	3,000	$1,641	6.790%	$111.41	22.92	0.146%	0.03	23.28	46.23	$157.64
CCCT Dry "G/H", DF, 1x1	3,000	$478	6.790%	$32.45	5.39	0.000%	0.00	23.28	28.67	$61.12
CCCT Dry "G/H", 2x1	3,000	$1,184	6.790%	$80.42	15.39	0.146%	0.02	12.43	27.85	$108.27
CCCT Dry "G/H", DF, 2x1	3,000	$365	6.790%	$24.75	4.44	0.000%	0.00	12.43	16.87	$41.62
CCCT Dry "J/HA.02", 1x1	3,000	$1,363	6.790%	$92.58	19.73	0.000%	0.00	12.27	32.01	$124.58
CCCT Dry "J/HA.02", DF, 1x1	3,000	$407	6.790%	$27.67	4.86	0.000%	0.00	12.27	17.13	$44.80
CCCT Dry, "J/HA.02" 2X1	3,000	$986	6.790%	$66.98	13.41	0.146%	0.02	12.28	25.71	$92.69
CCCT Dry "J/HA.02", DF, 2X1	3,000	$316	6.790%	$21.45	4.05	0.000%	0.00	12.28	16.33	$37.78

Table 6.2 – Total Resource Cost for Supply-Side Resource Options (Continued)

Supply Side Resource Options Mid-Calendar Year 2018 Dollars ($)		Capital Cost $/kW			Fixed Cost					
					Fixed O&M $/kW-Yr					
Resource Description	Elevation (AFSL)	Total Capital Cost 1/	Payment Factor 1/	Annual Payment ($/kW-Yr)	O&M 1/	Capitalized Premium	O&M Capitalized 1/	Gas Transportation 1/	Total	Total Fixed ($/kW-Yr)
SCCT Aero x3	5,050	$1,829	7.411%	$135.58	31.86	1.262%	0.40	14.06	46.32	$181.90
Intercooled SCCT Aero x2	5,050	$1,305	7.411%	$96.74	22.82	0.273%	0.06	13.22	36.10	$132.84
SCCT Frame "F" x1	5,050	$843	6.959%	$58.69	15.97	1.135%	0.18	14.93	31.08	$89.77
IC Recips x 6	5,050	$1,810	6.959%	$125.94	29.82	0.136%	0.04	12.61	42.47	$168.41
CCCT Dry "G/H", 1x1	5,050	$1,788	6.790%	$121.40	24.74	0.146%	0.04	9.91	34.69	$156.09
CCCT Dry "G/H", DF, 1x1	5,050	$478	6.790%	$32.45	5.39	0.000%	0.00	9.91	15.30	$47.76
CCCT Dry "G/H", 2x1	5,050	$1,297	6.790%	$88.06	16.63	0.146%	0.02	9.93	26.58	$114.64
CCCT Dry "G/H", DF, 2x1	5,050	$365	6.790%	$24.75	4.44	0.000%	0.00	9.93	14.37	$39.12
CCCT Dry "J/HA.02", 1x1	5,050	$1,485	6.790%	$100.84	21.26	0.000%	0.00	9.84	31.10	$131.95
CCCT Dry "J/HA.02", DF, 1x1	5,050	$407	6.790%	$27.67	4.86	0.000%	0.00	9.84	14.70	$42.37
CCCT Dry, "J/HA.02" 2X1	5,050	$1,079	6.790%	$73.29	14.45	0.146%	0.02	9.85	24.33	$97.61
CCCT Dry "J/HA.02", DF, 2X1	5,050	$316	6.790%	$21.45	4.05	0.000%	0.00	9.85	13.91	$35.35
SCCT Aero x3	6,500	$1,975	7.411%	$146.35	34.56	1.262%	0.44	9.13	44.13	$190.47
Intercooled SCCT Aero x2	6,500	$1,394	7.411%	$103.31	24.00	0.273%	0.07	8.62	32.68	$136.00
SCCT Frame "F" x1	6,500	$887	6.959%	$61.71	16.81	1.135%	0.19	9.70	26.70	$88.42
IC Recips x 6	6,500	$1,810	6.959%	$125.94	31.04	0.136%	0.04	8.24	39.33	$165.27
CCCT Dry "G/H", 1x1	6,500	$1,843	6.790%	$125.17	26.20	0.146%	0.04	20.66	46.90	$172.07
CCCT Dry "G/H", DF, 1x1	6,500	$478	6.790%	$32.45	5.39	0.000%	0.00	20.66	26.05	$58.50
CCCT Dry "G/H", 2x1	6,500	$1,330	6.790%	$90.33	17.61	0.146%	0.03	6.71	24.34	$114.67
CCCT Dry "G/H", DF, 2x1	6,500	$365	6.790%	$24.75	4.44	0.000%	0.00	6.71	11.15	$35.90
CCCT Dry "J/HA.02", 1x1	6,500	$1,549	6.790%	$105.16	22.33	0.000%	0.00	6.62	28.95	$134.11
CCCT Dry "J/HA.02", DF, 1x1	6,500	$407	6.790%	$27.67	4.86	0.000%	0.00	6.62	11.48	$39.15
CCCT Dry, "J/HA.02" 2X1	6,500	$1,120	6.790%	$76.08	15.18	0.146%	0.02	6.62	21.82	$97.90
CCCT Dry "J/HA.02", DF, 2X1	6,500	$316	6.790%	$21.45	4.06	0.000%	0.00	6.62	10.68	$32.12
Blundell Dual Flash 90% CF	4,500	$5,708	6.185%	$0.00	103.85	0.918%	0.95	0.00	104.80	$104.80
Generic Geothermal PPA 90% CF	4,500	$0	6.185%	$0.00	0.00	0.000%	0.00	0.00	0.00	$0.00
3.6 MW Wind turbine 37.1% CF WA, 2020 (100% PTC)	4,500	$1,354	6.899%	$93.42	27.99	2.902%	0.81	0.00	28.80	$122.22
3.6 MW Wind turbine 37.1% CF OR, 2020 (100% PTC)	1,500	$1,334	6.899%	$92.01	27.99	2.902%	0.81	0.00	28.80	$120.81
3.6 MW Wind turbine 37.1% CF ID, 2020 (100% PTC)	4,500	$1,358	6.899%	$93.71	27.99	2.902%	0.81	0.00	28.80	$122.52
3.6 MW Wind turbine 29.5% CF UT, 2020 (100% PTC)	6,500	$1,301	6.899%	$89.79	27.99	2.902%	0.81	0.00	28.80	$118.59
3.6 MW Wind turbine 43.6% CF WY, 2020 (100% PTC)	1,500	$1,301	6.899%	$89.79	27.99	2.902%	0.81	0.00	28.80	$118.59
3.6 MW Wind turbine 37.1% CF WA,2023 (40% PTC)	4,500	$1,354	6.899%	$93.42	27.99	2.902%	0.81	0.00	28.80	$122.22
3.6 MW Wind turbine 37.1% CF OR, 2023 (40% PTC)	1,500	$1,334	6.899%	$92.01	27.99	2.902%	0.81	0.00	28.80	$120.81
3.6 MW Wind turbine 37.1% CF ID, 2023 (40% PTC)	4,500	$1,358	6.899%	$93.71	27.99	2.902%	0.81	0.00	28.80	$122.52
3.6 MW Wind turbine 29.5% CF UT, 2023 (40% PTC)	6,500	$1,301	6.899%	$89.79	27.99	2.902%	0.81	0.00	28.80	$118.59

Table 6.2 – Total Resource Cost for Supply-Side Resource Options (Continued)

Supply Side Resource Options Mid-Calendar Year 2018 Dollars ($)		Capital Cost $/kW			Fixed Cost					
					Fixed O&M $/kW-Yr					
Resource Description	Elevation (AFSL)	Total Capital Cost 1/	Payment Factor 1/	Annual Payment ($/kW-Yr)	O&M 1/	Capitalized Premium	O&M Capitalized 1/	Gas Transportation 1/	Total	Total Fixed ($/kW-Yr)
Wind + Stor, Pocatello, ID, 200 MW+ 50 MW | 200 MWh	4,500	$1,880	6.899%	$129.66	29.88	2.902%	0.87	0.00	30.74	$160.41
Wind + Stor, Arlington, OR, 200 MW+ 50 MW | 200 MWh	1,500	$1,917	6.899%	$132.26	29.88	2.902%	0.87	0.00	30.74	$163.00
Wind + Stor, Monticello, UT, 200 MW+ 50 MW | 200 MWh	4,500	$1,877	6.899%	$129.51	29.88	2.902%	0.87	0.00	30.74	$160.25
Wind + Stor, Medicine Bow, WY, 200 MW+ 50 MW | 200 MWh	6,500	$1,872	6.899%	$129.12	29.88	2.902%	0.87	0.00	30.74	$159.86
Wind + Stor, Goldendale, WA, 200 MW+ 50 MW | 200 MWh	1,500	$1,924	6.899%	$132.71	29.88	2.902%	0.87	0.00	30.74	$163.45
PV Idaho Falls, ID, 200 MW, 2021, 28.1% CF (30% ITC)	4,500	$1,271	7.712%	$98.02	21.72	1.379%	0.30	0.00	22.02	$120.04
PV Lakeview, OR, 200 MW, 2021, 29.7% CF (30% ITC)	4,800	$1,329	7.712%	$102.53	22.35	1.379%	0.31	0.00	22.66	$125.19
PV Milford, UT, 200 MW, 2021, 32.5% CF (30% ITC)	4,500	$1,268	7.712%	$97.83	22.32	1.379%	0.31	0.00	22.63	$120.46
PV Utah North, 200 MW, 2021, 30.1% CF (30% ITC)	4,501	$1,266	7.712%	$97.62	21.13	1.379%	0.29	0.00	21.42	$119.04
PV Rock Springs, WY, 200 MW, 2021, 30.1% CF (30% ITC)	4,800	$1,266	7.712%	$97.62	21.13	1.379%	0.29	0.00	21.42	$119.04
PV Yakima, WA, 200 MW, 2021, 26% CF (30% ITC)	4,802	$1,327	7.712%	$102.36	22.35	1.379%	0.31	0.00	22.66	$125.02
PV Idaho Falls, ID, 200 MW, 2026, 28.1% CF (10% ITC)	4,802	$1,271	7.712%	$98.02	21.72	1.379%	0.30	0.00	22.02	$120.04
PV Lakeview, OR, 200 MW, 2026, 29.7% CF (10% ITC)	4,802	$1,329	7.712%	$102.53	22.35	1.379%	0.31	0.00	22.66	$125.19
PV Milford, UT, 200 MW, 2026, 32.5% CF (10% ITC)	4,802	$1,268	7.712%	$97.83	22.32	1.379%	0.31	0.00	22.63	$120.46
PV Utah North, 200 MW, 2021, 30.1% CF (10% ITC)	4,803	$1,266	7.712%	$97.62	21.13	1.379%	0.29	0.00	21.42	$119.04
PV Rock Springs, WY, 200 MW, 2026, 30.1% CF (10% ITC)	4,802	$1,266	7.712%	$97.62	21.13	1.379%	0.29	0.00	21.42	$119.04
PV Yakima, WA, 200 MW, 2026, 26% CF (10% ITC)	4,802	$1,327	7.712%	$102.36	22.35	1.379%	0.31	0.00	22.66	$125.02
PV + Stor, Idaho Falls, ID, 200 MW + 50 MW X 200 MWh (30% ITC)	4,802	$1,614	7.712%	$124.48	24.24	1.379%	0.33	0.00	24.57	$149.05
PV + Stor, Lakeview, OR, 200 MW + 50 MW X 200 MWh (30% ITC)	4,802	$1,699	7.712%	$131.01	24.24	1.379%	0.33	0.00	24.57	$155.58
PV + Stor,, Milford, UT, 200 MW + 50 MW X 200 MWh (30% ITC)	4,802	$1,612	7.712%	$124.29	24.24	1.379%	0.33	0.00	24.57	$148.86
PV + Stor, Utah North, 200 MW + 50 MW X 200 MWh (30% ITC)	4,803	$1,609	7.712%	$124.08	24.24	1.379%	0.33	0.00	24.57	$148.65
PV + Stor,, Rock Springs, WY, 200 MW + 50 MW X 200 MWh (30% ITC)	4,802	$1,609	7.712%	$124.08	24.24	1.379%	0.33	0.00	24.57	$148.65
PV + Stor, Yakima, WA, 200 MW + 50 MW X 200 MWh (30% ITC)	4,802	$1,697	7.712%	$130.86	24.24	1.379%	0.33	0.00	24.57	$155.43
PV + Stor, Idaho Falls, ID, 200 MW + 50 MW X 200 MWh (10% ITC)	4,802	$1,614	7.712%	$124.48	24.24	1.379%	0.33	0.00	24.57	$149.05
PV + Stor, Lakeview, OR, 200 MW + 50 MW X 200 MWh (10% ITC)	4,802	$1,699	7.712%	$131.01	24.24	1.379%	0.33	0.00	24.57	$155.58
PV + Stor,, Milford, UT, 200 MW + 50 MW X 200 MWh (10% ITC)	4,802	$1,612	7.712%	$124.29	24.24	1.379%	0.33	0.00	24.57	$148.86
PV + Stor, Utah North, 200 MW + 50 MW X 200 MWh (10% ITC)	4,803	$1,609	7.712%	$124.08	24.24	1.379%	0.33	0.00	24.57	$148.65
PV + Stor,, Rock Springs, WY, 200 MW + 50 MW X 200 MWh (10% ITC)	4,802	$1,609	7.712%	$124.08	24.24	1.379%	0.33	0.00	24.57	$148.65
PV + Stor, Yakima, WA, 200 MW + 50 MW X 200 MWh (10% ITC)	4,802	$1,697	7.712%	$130.86	24.24	1.379%	0.33	0.00	24.57	$155.43
Oregon PS, 400 MW X 3,800 MWh	4,457	$3,095	6.142%	$190.09	16.76	0.000%	0.00	0.00	16.76	$206.85
Oregon PS joint ownership, 100 MW X 950 MWh	580	$3,099	6.142%	$190.38	16.76	0.000%	0.00	0.00	16.76	$207.14
Washington PS, 1,200 MW X 16,800 MWh	580	$2,719	6.142%	$166.98	12.50	0.000%	0.00	0.00	12.50	$179.48
Wyoming PS, 700 MW X 7,000 MWh	6,359	$3,255	6.142%	$199.94	17.00	0.000%	0.00	0.00	17.00	$216.94
Wyoming PS, 400 MW X 3,400 MWh	6,360	$2,348	6.142%	$144.20	17.00	0.000%	0.00	0.00	17.00	$161.20
Utah PS, 300 MW X 1,800 MWh	6,360	$2,991	6.142%	$183.72	17.00	0.000%	0.00	0.00	17.00	$200.72
Idaho PS, 360 MW X 2,880 MWh	6,361	$2,680	6.142%	$164.61	17.00	0.000%	0.00	0.00	17.00	$181.61
CAES, 320 MW X 15,360 MWh	4,640	$1,625	7.411%	$120.41	7.01	0.000%	0.00	0.00	7.01	$127.41
Li-Ion 15 MW X 60 MWh	6,359	$1,766	11.126%	$196.44	11.50	0.000%	0.00	0.00	11.50	$207.93

Table 6.2 – Total Resource Cost for Supply-Side Resource Options (Continued)

Supply Side Resource Options Mid-Calendar Year 2018 Dollars ($)		Capital Cost $/kW			Fixed Cost					
					Fixed O&M $/kW-Yr					
Resource Description	Elevation (AFSL)	Total Capital Cost 1/	Payment Factor 1/	Annual Payment ($/kW-Yr)	O&M 1/	Capitalized Premium	O&M Capitalized 1/	Gas Transportation 1/	Total	Total Fixed ($/kW-Yr)
Brownfield Site										
Dave Johnston										
SCCT Frame "F" x1	5,050	$709	6.959%	$49.31	15.97	1.135%	0.18	14.93	31.08	$80.39
3.6 MW Wind turbine 43,6% CF WY, 2023 (40% PTC)	6,400	$1,301	6.899%	$89.79	27.99	2.902%	0.81	0.00	28.80	$118.59
CCCT Dry "J/HA.02", 1x1	5,050	$1,342	6.790%	$91.12	21.26	0.000%	0.00	19.76	41.02	$132.14
CCCT Dry "J/HA.02", DF, 1x1	5,050	$368	6.790%	$25.00	4.86	0.000%	0.00	19.76	24.62	$49.62
Hunter										
SCCT Frame "F" x1	5,050	$709	6.959%	$49.31	15.97	1.135%	0.18	14.93	31.08	$80.39
PV, 200 MW, 2026, 32.5% CF (10% ITC)	5,000	$1,268	7.712%	$97.83	22.32	1.379%	0.31	0.00	22.63	$120.46
PV + Stor, 200 MW + 50 MW X 200 MWh (10% ITC)	5,000	$1,612	7.712%	$124.29	24.24	1.379%	0.33	0.00	24.57	$148.86
CCCT Dry "J/HA.02", 1x1	5,050	$1,342	6.790%	$91.12	21.26	0.000%	0.00	9.84	31.10	$122.22
CCCT Dry "J/HA.02", DF, 1x1	5,050	$368	6.790%	$25.00	4.86	0.000%	0.00	9.84	14.70	$39.70
Huntington										
SCCT Frame "F" x1	5,050	$709	6.959%	$49.31	15.97	1.135%	0.18	14.93	31.08	$80.39
PV, 200 MW, 2026, 32.5% CF (10% ITC)	5,000	$1,268	7.712%	$97.83	22.32	1.379%	0.31	0.00	22.63	$120.46
PV + Stor, 200 MW + 50 MW X 200 MWh (10% ITC)	5,000	$1,612	7.712%	$124.29	24.24	1.379%	0.33	0.00	24.57	$148.86
CCCT Dry "J/HA.02", 1x1	5,050	$1,342	6.790%	$91.12	21.26	0.000%	0.00	9.84	31.10	$122.22
CCCT Dry "J/HA.02", DF, 1x1	5,050	$368	6.790%	$25.00	4.86	0.000%	0.00	9.84	14.70	$39.70
Jim Bridger										
3.6 MW Wind turbine 43,6% CF WY, 2023 (40% PTC)	6,400	$1,301	6.899%	$89.79	27.99	2.902%	0.81	0.00	28.80	$118.59
Wind + Stor, 200 MW+ 50 MW | 400 MWh	6,500	$2,150	6.899%	$148.30	31.03	2.902%	0.90	0.00	31.93	$180.23
SCCT Frame "F" x1	6,500	$745	6.959%	$51.85	16.81	1.135%	0.19	9.70	26.70	$78.56
PV, 200 MW, 2026, 32.5% CF (10% ITC)	6,400	$1,266	7.712%	$97.62	21.13	1.379%	0.29	0.00	21.42	$119.04
PV + Stor, 200 MW + 50 MW X 200 MWh (10% ITC)	6,400	$1,609	7.712%	$124.08	24.24	1.379%	0.33	0.00	24.57	$148.65
CCCT Dry "J/HA.02", 1x1	6,500	$1,399	6.790%	$95.01	22.33	0.000%	0.00	6.62	28.95	$123.97
CCCT Dry "J/HA.02", DF, 1x1	6,500	$368	6.790%	$25.00	4.86	0.000%	0.00	6.62	11.48	$36.48
Naughton										
SCCT Frame "F" x1	6,500	$745	6.959%	$51.85	16.81	1.135%	0.19	14.90	31.91	$83.76
PV 200 MW, 2026, 30.1% CF (10% ITC)	6,400	$1,266	7.712%	$97.62	21.13	1.379%	0.29	0.00	21.42	$119.04
CCCT Dry "J/HA.02", 1x1	6,500	$1,399	6.790%	$95.01	22.33	0.000%	0.00	10.17	32.51	$127.52
CCCT Dry "J/HA.02", DF, 1x1	6,500	$368	6.790%	$25.00	4.86	0.000%	0.00	10.17	15.03	$40.03
Wyodak										
SCCT Frame "F" x1	6,500	$745	6.959%	$51.85	16.81	1.135%	0.19	29.92	46.92	$98.78

1/ Input into IRP SO and PAR Model
Results presented without credits
Information Presented is Illustrative

Table 6.2 – Total Resource Cost for Supply-Side Resource Options (Continued)

Resources not Modeled in 2019 IRP

Supply Side Resource Options Mid-Calendar Year 2018 Dollars ($)		Capital Cost $/kW			Fixed Cost					
					Fixed O&M $/kW-Yr					
Resource Description	Elevation (AFSL)	Total Capital Cost	Payment Factor	Annual Payment ($/kW-Yr)	O&M	Capitalized Premium	O&M Capitalized	Gas Transportation	Total	Total Fixed ($/kW-Yr)
SCPC with CCS	4,500	$6,462	6.726%	$434.61	72.22	5.541%	4.00	0.00	76.23	$510.84
IGCC with CCS	4,500	$6,257	6.533%	$408.75	58.20	0.000%	0.00	0.00	58.20	$466.95
PC CCS retrofit @ 500 MW	4,500	$1,419	6.726%	$95.42	77.76	0.000%	0.00	0.00	77.76	$173.17
SCPC with CCS	6,500	$7,318	6.726%	$492.18	67.09	5.541%	0.00	0.00	67.09	$559.27
IGCC with CCS	6,500	$7,085	6.533%	$462.83	63.40	0.000%	0.00	0.00	63.40	$526.23
PC CCS retrofit @ 500 MW	6,500	$1,607	6.712%	$107.84	72.22	0.000%	0.00	0.00	72.22	$180.07
Greenfield Binary 90% CF	4,500	$5,973	6.185%	$369.45	103.85	0.918%	0.95	0.00	104.80	$474.26
Wind + Stor, Pocatello, ID, 200 MW+ 50 MW | 100 MWh	4,500	$1,738	6.899%	$119.87	29.18	2.902%	0.85	0.00	30.03	$149.90
Wind + Stor, Arlington, OR, 200 MW+ 50 MW | 100 MWh	1,500	$1,765	6.899%	$121.79	29.18	2.902%	0.85	0.00	30.03	$151.83
Wind + Stor, Monticello, UT, 200 MW+ 50 MW | 100 MWh	4,500	$1,735	6.899%	$119.71	29.18	2.902%	0.85	0.00	30.03	$149.74
Wind + Stor, Medicine Bow, WY, 200 MW+ 50 MW | 100 MWh	6,500	$1,730	6.899%	$119.32	29.18	2.902%	0.85	0.00	30.03	$149.35
Wind + Stor, Goldendale, WA, 200 MW+ 50 MW | 100 MWh	1,500	$1,772	6.899%	$122.24	29.18	2.902%	0.85	0.00	30.03	$152.27
Wind + Stor, Pocatello, ID, 200 MW+ 50 MW | 400 MWh	4,500	$2,158	6.899%	$148.85	31.03	2.902%	0.90	0.00	31.93	$180.78
Wind + Stor, Arlington, OR, 200 MW+ 50 MW | 400 MWh	1,500	$2,214	6.899%	$152.75	31.03	2.902%	0.90	0.00	31.93	$184.68
Wind + Stor, Monticello, UT, 200 MW+ 50 MW | 400 MWh	4,500	$2,155	6.899%	$148.69	31.03	2.902%	0.90	0.00	31.93	$180.62
Wind + Stor, Medicine Bow, WY, 200 MW+ 50 MW | 400 MWh	6,500	$2,150	6.899%	$148.30	31.03	2.902%	0.90	0.00	31.93	$180.23
Wind + Stor, Goldendale, WA, 200 MW+ 50 MW | 400 MWh	1,500	$2,221	6.899%	$153.22	31.03	2.902%	0.90	0.00	31.93	$185.15
PV Idaho Falls, ID, 50 MW, 28.1% CF (30% ITC)	4,500	$1,366	7.712%	$105.31	21.72	1.379%	0.30	0.00	22.02	$127.33
PV Lakeview, OR, 50 MW, 2021, 29.7% CF (30% ITC)	4,800	$1,424	7.712%	$109.83	22.35	1.379%	0.31	0.00	22.66	$132.48
PV Milford, UT, 50 MW, 2021, 32.5% CF (30% ITC)	4,500	$1,363	7.712%	$105.12	22.32	1.379%	0.31	0.00	22.63	$127.75
PV Rock Springs, WY, 50 MW, 2021, 30.1% CF (30% ITC)	4,800	$1,360	7.712%	$104.91	21.13	1.379%	0.29	0.00	21.42	$126.34
PV Yakima, WA, 50 MW, 2021, 26% CF (30% ITC)	4,801	$1,422	7.712%	$109.66	22.35	1.379%	0.31	0.00	22.66	$132.31
PV Idaho Falls, ID, 50 MW, 2026, 28.1% CF (10% ITC)	4,802	$1,366	7.712%	$105.31	21.72	1.379%	0.30	0.00	22.02	$127.33
PV Lakeview, OR, 50 MW, 2026, 29.7% CF (10% ITC)	4,802	$1,424	7.712%	$109.83	22.35	1.379%	0.31	0.00	22.66	$132.48
PV Milford, UT, 50 MW, 2026, 32.5% CF (10% ITC)	4,802	$1,363	7.712%	$105.12	22.32	1.379%	0.31	0.00	22.63	$127.75
PV Rock Springs, WY, 50 MW, 2026, 30.1% CF (10% ITC)	4,802	$1,360	7.712%	$104.91	21.13	1.379%	0.29	0.00	21.42	$126.34
PV Yakima, WA, 50 MW, 2026, 26% CF (10% ITC)	4,802	$1,422	7.712%	$109.66	22.35	1.379%	0.31	0.00	22.66	$132.31
PV + Stor, Idaho Falls, ID, 50 MW + 10 MW X 20 MWh (30% ITC)	4,802	$1,628	7.712%	$125.57	23.48	1.379%	0.32	0.00	23.81	$149.37
PV + Stor, Idaho Falls, ID, 200 MW + 50 MW X 100 MWh (30% ITC)	4,802	$1,470	7.712%	$113.34	22.91	1.379%	0.32	0.00	23.23	$136.57
PV + Stor,, Idaho Falls, ID, 50 MW + 10 MW X 40 MWh (30% ITC)	4,802	$1,756	7.712%	$135.46	25.03	1.379%	0.35	0.00	25.38	$160.83
PV + Stor, Idaho Falls, ID, 50 MW + 10 MW X 80 MWh (30% ITC)	4,802	$1,992	7.712%	$153.67	26.46	1.379%	0.36	0.00	26.82	$180.49
PV + Stor, Idaho Falls, ID, 200 MW + 50 MW X 400 MWh (30% ITC)	4,802	$1,897	7.712%	$146.31	25.36	1.379%	0.35	0.00	25.71	$172.01
PV + Stor, Lakeview, OR, 50 MW + 10 MW X 20 MWh (30% ITC)	4,802	$1,706	7.712%	$131.56	23.48	1.379%	0.32	0.00	23.81	$155.37
PV + Stor, Lakeview, OR, 200 MW + 50 MW X 100 MWh (30% ITC)	4,802	$1,543	7.712%	$119.00	22.91	1.379%	0.32	0.00	23.23	$142.23
PV + Stor, Lakeview, OR, 50 MW + 10 MW X 40 MWh (30% ITC)	4,802	$1,844	7.712%	$142.22	25.03	1.379%	0.35	0.00	25.38	$167.59
PV + Stor, Lakeview, OR, 50 MW + 10 MW X 80 MWh (30% ITC)	4,802	$2,098	7.712%	$161.83	26.46	1.379%	0.36	0.00	26.82	$188.66
PV + Stor,, Lakeview, OR, 200 MW + 50 MW X 400 MWh (30% ITC)	4,802	$2,004	7.712%	$154.52	25.36	1.379%	0.35	0.00	25.71	$180.23
PV + Stor,, Milford, UT, 50 MW + 10 MW X 20 MWh (30% ITC)	4,802	$1,626	7.712%	$125.37	23.48	1.379%	0.32	0.00	23.81	$149.18
PV + Stor,, Milford, UT, 200 MW + 50 MW X 100 MWh (30% ITC)	4,802	$1,467	7.712%	$113.14	22.91	1.379%	0.32	0.00	23.23	$136.37
PV + Stor,, Milford, UT 50 MW + 10 MW X 40 MWh (30% ITC)	4,802	$1,754	7.712%	$135.27	25.03	1.379%	0.35	0.00	25.38	$160.64
PV + Stor,, Milford, UT, 50 MW + 10 MW X 80 MWh (30% ITC)	4,802	$1,990	7.712%	$153.48	26.46	1.379%	0.36	0.00	26.82	$180.30
PV + Stor,, Milford, UT, 200 MW + 50 MW X 400 MWh (30% ITC)	4,802	$1,895	7.712%	$146.11	25.36	1.379%	0.35	0.00	25.71	$171.82
PV + Stor,, Rock Springs, WY, 50 MW + 10 MW X 20 MWh (30% ITC)	4,802	$1,623	7.712%	$125.17	23.48	1.379%	0.32	0.00	23.81	$148.97
PV + Stor,, Rock Springs, WY, 200 MW + 50 MW X 100 MWh (30% ITC)	4,802	$1,464	7.712%	$112.94	22.91	1.379%	0.32	0.00	23.23	$136.17
PV + Stor,, Rock Springs, WY, 50 MW + 10 MW X 40 MWh (30% ITC)	4,802	$1,751	7.712%	$135.06	25.03	1.379%	0.35	0.00	25.38	$160.43
PV + Stor,, Rock Springs, WY, 50 MW + 10 MW X 80 MWh (30% ITC)	4,802	$1,987	7.712%	$153.27	26.46	1.379%	0.36	0.00	26.82	$180.09
PV + Stor,, Rock Springs, WY, 200 MW + 50 MW X 400 MWh (30% ITC)	4,802	$1,892	7.712%	$145.91	25.36	1.379%	0.35	0.00	25.71	$171.61
PV + Stor,, Yakima, WA, 50 MW + 10 MW X 20 MWh (30% ITC)	4,802	$1,704	7.712%	$131.40	23.48	1.379%	0.32	0.00	23.81	$155.21
PV + Stor, Yakima, WA, 200 MW + 50 MW X 100 MWh (30% ITC)	4,802	$1,541	7.712%	$118.85	22.91	1.379%	0.32	0.00	23.23	$142.08
PV + Stor, Yakima, WA, 50 MW + 10 MW X 40 MWh (30% ITC)	4,802	$1,842	7.712%	$142.07	25.03	1.379%	0.35	0.00	25.38	$167.45
PV + Stor, Yakima, WA, 50 MW + 10 MW X 80 MWh (30% ITC)	4,802	$2,097	7.712%	$161.70	26.46	1.379%	0.36	0.00	26.82	$188.53
PV + Stor, Yakima, WA, 200 MW + 50 MW X 400 MWh (30% ITC)	4,802	$2,002	7.712%	$154.39	25.36	1.379%	0.35	0.00	25.71	$180.10
Li-Ion 1 MW X 250 kWh	6,359	$1,473	11.126%	$163.90	8.29	0.000%	0.00	0.00	8.29	$172.19
Li-Ion 1 MW X 2 MWh	6,359	$2,615	11.126%	$290.96	23.56	0.000%	0.00	0.00	23.56	$314.52
Li-Ion 1 MW X 4 MWh	6,359	$3,412	11.126%	$379.58	35.23	0.000%	0.00	0.00	35.23	$414.82
Li-Ion 1 MW X 8 MWh	6,359	$5,455	11.126%	$606.91	52.09	0.000%	0.00	0.00	52.09	$659.00
Flow 1 MW X 6 MWh	6,360	$3,996	11.126%	$444.59	32.00	0.000%	0.00	0.00	32.00	$476.59
Advanced Fission	5,000	$6,765	6.639%	$449.13	101.62	5.687%	5.78	0.00	107.40	$556.53
Small Modular Reactor x 12	5,000	$6,028	6.639%	$400.24	173.35	11.228%	19.46	0.00	192.82	$593.06

Table 6.2 – Total Resource Cost for Supply-Side Resource Options (Continued)

Supply Side Resource Options Mid-Calendar Year 2018 Dollars ($)		Convert to $/MWh					Variable Costs ($/MWh)					Total Costs and Credits ($/MWh)		
					Levelized Fuel								Credits	
Resource Description	Elevation (AFSL)	Capacity Factor 2/	Total Fixed ($/MWh)	Storage Efficiency	¢/mmBtu	$/MWh	O&M 1/	Capitalized Premium	O&M Capitalized 1/	Integration Cost 1/	Environmental	Total Resource Cost	PTC Tax Credits / ITC (Solar Only)	Total Resource Cost - with PTC / ITC Credits
SCCT Aero x3, ISO	0	33%	60.80	na	320	29.73	7.54	11.48%	0.87	-	-	98.93	-	98.93
Intercooled SCCT Aero x2, ISO	0	33%	44.91	na	320	27.96	5.05	13.23%	0.67	-	-	78.59	-	78.59
SCCT Frame "F" x1, ISO	0	33%	33.27	na	320	31.44	5.50	11.48%	0.63	-	-	70.84	-	70.84
IC Recips x 6, ISO	0	33%	63.74	na	320	26.51	7.45	8.73%	0.65	-	-	98.35	-	98.35
CCCT Dry "G/H", 1x1, ISO	0	78%	21.05	na	320	21.94	1.76	10.21%	0.18	-	-	44.93	-	44.93
CCCT Dry "G/H", DF, 1x1, ISO	0	12%	58.42	na	320	21.94	0.15	0.00%	0.00	-	-	80.52	-	80.52
CCCT Dry "G/H", 2x1, ISO	0	78%	16.01	na	320	21.99	1.67	10.79%	0.18	-	-	39.85	-	39.85
CCCT Dry "G/H", DF, 2x1, ISO	0	12%	50.24	na	320	21.99	0.16	0.00%	0.00	-	-	72.38	-	72.38
CCCT Dry "J/HA.02", 1x1, ISO	0	78%	18.10	na	320	21.75	1.70	10.21%	0.17	-	-	41.72	-	41.72
CCCT Dry "J/HA.02", DF, 1x1, ISO	0	12%	53.17	na	320	21.75	0.16	0.00%	0.00	-	-	75.07	-	75.07
CCCT Dry, "J/HA.02" 2X1, ISO	0	78%	13.93	na	320	21.75	1.62	10.79%	0.17	-	-	37.47	-	37.47
CCCT Dry "J/HA.02", DF, 2X1, ISO	0	12%	46.48	na	320	21.75	0.16	0.00%	0.00	-	-	68.39	-	68.39
SCCT Aero x3	1500	33%	62.12	na	320	29.57	7.76	11.48%	0.89	-	-	100.34	-	100.34
Intercooled SCCT Aero x2	1500	33%	46.55	na	320	27.84	5.35	13.23%	0.71	-	-	80.45	-	80.45
SCCT Frame "F" x1	1500	33%	34.40	na	320	31.38	5.81	11.48%	0.67	-	-	72.25	-	72.25
IC Recips x 6	1500	33%	63.74	na	320	26.51	7.45	8.73%	0.65	-	-	98.35	-	98.35
CCCT Dry "G/H", 1x1	1500	78%	22.02	na	320	21.75	1.86	10.21%	0.19	-	-	45.82	-	45.82
CCCT Dry "G/H", DF, 1x1	1500	12%	58.23	na	320	21.75	0.15	0.00%	0.00	-	-	80.14	-	80.14
CCCT Dry "G/H", 2x1	1500	78%	16.69	na	320	21.79	1.77	10.79%	0.19	-	-	40.44	-	40.44
CCCT Dry "G/H", DF, 2x1	1500	12%	50.04	na	320	21.79	0.16	0.00%	0.00	-	-	71.98	-	71.98
CCCT Dry "J/HA.02", 1x1	1500	78%	18.92	na	320	21.57	1.80	10.21%	0.18	-	-	42.48	-	42.48
CCCT Dry "J/HA.02", DF, 1x1	1500	12%	52.99	na	320	21.57	0.16	0.00%	0.00	-	-	74.71	-	74.71
CCCT Dry, "J/HA.02" 2X1	1500	78%	14.51	na	320	21.57	1.71	10.79%	0.18	-	-	37.98	-	37.98
CCCT Dry "J/HA.02", DF, 2X1	1500	12%	46.30	na	320	21.57	0.16	0.00%	0.00	-	-	68.03	-	68.03
SCCT Aero x3	3000	33%	59.90	na	324	29.90	8.21	11.48%	0.94	-	-	98.95	-	98.95
Intercooled SCCT Aero x2	3000	33%	43.82	na	324	28.14	5.67	13.23%	0.75	-	-	78.38	-	78.38
SCCT Frame "F" x1	3000	33%	30.23	na	324	31.74	6.13	11.48%	0.70	-	-	68.80	-	68.80
IC Recips x 6	3000	33%	59.14	na	324	26.80	7.45	8.73%	0.65	-	-	94.04	-	94.04
CCCT Dry "G/H", 1x1	3000	78%	23.07	na	324	21.90	1.97	10.21%	0.20	-	-	47.14	-	47.14
CCCT Dry "G/H", DF, 1x1	3000	12%	58.15	na	324	21.90	0.15	0.00%	0.00	-	-	80.20	-	80.20
CCCT Dry "G/H", 2x1	3000	78%	15.85	na	324	21.94	1.86	10.79%	0.20	-	-	39.86	-	39.86
CCCT Dry "G/H", DF, 2x1	3000	12%	39.60	na	324	21.94	0.16	0.00%	0.00	-	-	61.70	-	61.70
CCCT Dry "J/HA.02", 1x1	3000	78%	18.23	na	324	21.67	1.90	10.21%	0.19	-	-	42.00	-	42.00
CCCT Dry "J/HA.02", DF, 1x1	3000	12%	42.62	na	324	21.67	0.16	0.00%	0.00	-	-	64.44	-	64.44
CCCT Dry, "J/HA.02" 2X1	3000	78%	13.56	na	324	21.67	1.81	10.79%	0.19	-	-	37.24	-	37.24
CCCT Dry "J/HA.02", DF, 2X1	3000	12%	35.94	na	324	21.67	0.16	0.00%	0.00	-	-	57.77	-	57.77

Table 6.2 – Total Resource Cost for Supply-Side Resource Options (Continued)

Supply Side Resource Options Mid-Calendar Year 2018 Dollars ($)		Convert to $/MWh					Variable Costs ($/MWh)					Total Costs and Credits ($/MWh)		
					Levelized Fuel								Credits	
Resource Description	Elevation (AFSL)	Capacity Factor 3/	Total Fixed ($/MWh)	Storage Efficiency	¢/mmBtu	$/MWh	O&M 1/	Capitalized Premium	O&M Capitalized 1/	Integration Cost 1/	Environmental	Total Resource Cost	PTC Tax Credits / ITC (Solar Only)	Total Resource Cost - with PTC / ITC Credits
SCCT Aero x3	5050	33%	62.92	na	327	30.14	8.85	11.48%	1.02	-	-	102.93	-	102.93
Intercooled SCCT Aero x2	5050	33%	45.95	na	327	28.35	6.14	13.23%	0.81	-	-	81.25	-	81.25
SCCT Frame "F" x1	5050	33%	31.05	na	327	32.02	6.61	11.48%	0.76	-	-	70.45	-	70.45
IC Recips x 6	5050	33%	58.26	na	327	27.04	7.45	8.73%	0.65	-	-	93.40	-	93.40
CCCT Dry "G/H", 1x1	5050	78%	22.84	na	327	21.26	2.12	10.21%	0.22	-	-	46.45	-	46.45
CCCT Dry "G/H", DF, 1x1	5050	12%	45.43	na	327	21.26	0.15	0.00%	0.00	-	-	66.85	-	66.85
CCCT Dry "G/H", 2x1	5050	78%	16.78	na	327	21.29	2.01	10.79%	0.22	-	-	40.30	-	40.30
CCCT Dry "G/H", DF, 2x1	5050	12%	37.21	na	327	21.29	0.16	0.00%	0.00	-	-	58.66	-	58.66
CCCT Dry "J/HA.02", 1x1	5050	78%	19.31	na	327	21.11	2.05	10.21%	0.21	-	-	42.68	-	42.68
CCCT Dry "J/HA.02", DF, 1x1	5050	12%	40.31	na	327	21.11	0.16	0.00%	0.00	-	-	61.57	-	61.57
CCCT Dry, "J/HA.02" 2X1	5050	78%	14.29	na	327	21.13	1.95	10.79%	0.21	-	-	37.57	-	37.57
CCCT Dry "J/HA.02", DF, 2X1	5050	12%	33.63	na	327	21.13	0.16	0.00%	0.00	-	-	54.91	-	54.91
SCCT Aero x3	6500	33%	65.89	na	320	29.50	9.60	11.48%	1.10	-	-	106.09	-	106.09
Intercooled SCCT Aero x2	6500	33%	47.04	na	320	27.85	6.45	13.23%	0.85	-	-	82.20	-	82.20
SCCT Frame "F" x1	6500	33%	30.59	na	320	31.35	6.96	11.48%	0.80	-	-	69.69	-	69.69
IC Recips x 6	6500	33%	57.17	na	320	26.65	7.75	8.73%	0.68	-	-	92.25	-	92.25
CCCT Dry "G/H", 1x1	6500	78%	25.18	na	320	21.64	2.25	10.21%	0.23	-	-	49.31	-	49.31
CCCT Dry "G/H", DF, 1x1	6500	12%	55.65	na	320	21.64	0.15	0.00%	0.00	-	-	77.45	-	77.45
CCCT Dry "G/H", 2x1	6500	78%	16.78	na	320	21.69	2.13	10.79%	0.23	-	-	40.84	-	40.84
CCCT Dry "G/H", DF, 2x1	6500	12%	34.15	na	320	21.69	0.16	0.00%	0.00	-	-	56.00	-	56.00
CCCT Dry "J/HA.02", 1x1	6500	78%	19.63	na	320	21.40	2.15	10.21%	0.22	-	-	43.39	-	43.39
CCCT Dry "J/HA.02", DF, 1x1	6500	12%	37.24	na	320	21.40	0.16	0.00%	0.00	-	-	58.80	-	58.80
CCCT Dry, "J/HA.02" 2X1	6500	78%	14.33	na	320	21.40	2.05	10.79%	0.22	-	-	38.00	-	38.00
CCCT Dry "J/HA.02", DF, 2X1	6500	12%	30.56	na	320	21.40	0.16	0.00%	0.00	-	-	52.12	-	52.12
Blundell Dual Flash 90% CF	4500	90%	13.26	na	0	-	1.16	0.00%	0.00	-	-	14.42	(15.55)	(1.14)
Generic Geothermal PPA 90% CF	4500	90%	-	na	0	-	77.34	0.00%	0.00	-	-	77.34	-	77.34
3.6 MW Wind turbine 37.1% CF WA, 2020 (100% PTC)	4500	37%	37.61	na	0	-	10.00	0.00%	0.00	0.93	-	48.54	(15.55)	32.98
3.6 MW Wind turbine 37.1% CF OR, 2020 (100% PTC)	1500	37%	37.17	na	0	-	10.00	0.00%	0.00	0.93	-	48.10	(15.55)	32.55
3.6 MW Wind turbine 37.1% CF ID, 2020 (100% PTC)	4500	37%	37.70	na	0	-	0.00	0.00%	0.00	0.93	-	38.63	(15.55)	23.07
3.6 MW Wind turbine 29.5% CF UT, 2020 (100% PTC)	6500	30%	45.89	na	0	-	0.00	0.00%	0.00	0.93	-	46.82	(15.55)	31.27
3.6 MW Wind turbine 43.6% CF WY, 2020 (100% PTC)	1500	44%	31.05	na	0	-	0.65	0.00%	0.00	0.93	-	32.63	(15.55)	17.08
3.6 MW Wind turbine 37.1% CF WA,2023 (40% PTC)	4500	37%	37.61	na	0	-	10.00	0.00%	0.00	0.93	-	48.54	(6.22)	42.31
3.6 MW Wind turbine 37.1% CF OR, 2023 (40% PTC)	1500	37%	37.17	na	0	-	10.00	0.00%	0.00	0.93	-	48.10	(6.22)	41.88
3.6 MW Wind turbine 37.1% CF ID, 2023 (40% PTC)	4500	37%	37.70	na	0	-	0.00	0.00%	0.00	0.93	-	38.63	(6.22)	32.41
3.6 MW Wind turbine 29.5% CF UT, 2023 (40% PTC)	6500	30%	45.89	na	0	-	0.00	0.00%	0.00	0.93	-	46.82	(6.22)	40.60
3.6 MW Wind turbine 43,6% CF WY, 2023 (40% PTC)	1500	44%	31.05	na	0	-	0.65	0.00%	0.00	0.93	-	32.63	(6.22)	26.41

Table 6.2 – Total Resource Cost for Supply-Side Resource Options (Continued)*

Supply Side Resource Options Mid-Calendar Year 2018 Dollars ($)		Convert to $/MWh					Variable Costs ($/MWh)					Total Costs and Credits ($/MWh)		
					Levelized Fuel								Credits	
Resource Description	Elevation (AFSL)	Capacity Factor 3/	Total Fixed ($/MWh)	Storage Efficiency	¢/mmBtu	$/MWh	O&M 1/	Capitalized Premium	O&M Capitalized 1/	Integration Cost 1/	Environmental	Total Resource Cost	PTC Tax Credits / ITC (Solar Only)	Total Resource Cost - with PTC / ITC Credits
Wind + Stor, Arlington, OR, 200 MW+ 50 MW | 200 MWh	1500	37%	50.15	88%	0	-	10.00	0.00%	0.00	0.93	-	61.08	(6.22)	54.86
Wind + Stor, Monticello, UT, 200 MW+ 50 MW | 200 MWh	4500	30%	62.01	88%	0	-	0.00	0.00%	0.00	0.93	-	62.94	(6.22)	56.72
Wind + Stor, Medicine Bow, WY, 200 MW+ 50 MW | 200 MWh	6500	44%	41.86	88%	0	-	0.65	0.00%	0.00	0.93	-	43.43	(6.22)	37.21
Wind + Stor, Goldendale, WA, 200 MW+ 50 MW | 200 MWh	1500	37%	50.29	88%	0	-	10.00	0.00%	0.00	0.93	-	61.22	(6.22)	55.00
PV Idaho Falls, ID, 200 MW, 2021, 28.1% CF (30% ITC)	4700	28%	48.77	na	0	-	0.00	0.00%	0.00	0.70	-	49.47	(13.57)	35.90
PV Lakeview, OR, 200 MW, 2021, 29.7% CF (30% ITC)	4800	30%	48.12	na	0	-	0.00	0.00%	0.00	0.70	-	48.82	(13.43)	35.40
PV Milford, UT, 200 MW, 2021, 32.5% CF (30% ITC)	5000	33%	42.31	na	0	-	0.00	0.00%	0.00	0.70	-	43.01	(11.71)	31.31
PV Utah North, 200 MW, 2021, 30.1% CF (30% ITC)	5000	30%	45.15	na	0	-	0.00	0.00%	0.00	0.70	-	45.85	(12.61)	33.24
PV Rock Springs, WY, 200 MW, 2021, 30.1% CF (30% ITC)	6400	30%	45.15	na	0	-	0.00	0.00%	0.00	0.70	-	45.85	(12.61)	33.24
PV Yakima, WA, 200 MW, 2021, 26% CF (30% ITC)	1000	26%	54.89	na	0	-	0.00	0.00%	0.00	0.70	-	55.60	(15.31)	40.28
PV Idaho Falls, ID, 200 MW, 2026, 28.1% CF (10% ITC)	4700	28%	48.77	na	0	-	0.00	0.00%	0.00	0.70	-	49.47	(4.97)	44.50
PV Lakeview, OR, 200 MW, 2026, 29.7% CF (10% ITC)	4800	30%	48.12	na	0	-	0.00	0.00%	0.00	0.70	-	48.82	(4.92)	43.91
PV Milford, UT, 200 MW, 2026, 32.5% CF (10% ITC)	5000	33%	42.31	na	0	-	0.00	0.00%	0.00	0.70	-	43.01	(4.29)	38.73
PV Utah North, 200 MW, 2021, 30.1% CF (10% ITC)	5000	30%	45.15	na	0	-	0.00	0.00%	0.00	0.70	-	45.85	(4.62)	41.23
PV Rock Springs, WY, 200 MW, 2026, 30.1% CF (10% ITC)	6400	30%	45.15	na	0	-	0.00	0.00%	0.00	0.70	-	45.85	(4.62)	41.23
PV Yakima, WA, 200 MW, 2026, 26% CF (10% ITC)	1000	26%	54.89	na	0	-	0.00	0.00%	0.00	0.70	-	55.60	(5.61)	49.99
PV + Stor, Idaho Falls, ID, 200 MW + 50 MW X 200 MWh (30% ITC)	4700	28%	60.55	88%	0	-	0.00	0.00%	0.00	0.70	-	61.25	(17.25)	44.01
PV + Stor, Lakeview, OR, 200 MW + 50 MW X 200 MWh (30% ITC)	4800	30%	59.80	88%	0	-	0.00	0.00%	0.00	0.70	-	60.50	(17.07)	43.43
PV + Stor,, Milford, UT, 200 MW + 50 MW X 200 MWh (30% ITC)	5000	33%	52.29	88%	0	-	0.00	0.00%	0.00	0.70	-	52.99	(14.88)	38.11
PV + Stor, Utah North, 200 MW + 50 MW X 200 MWh (30% ITC)	5000	30%	56.38	88%	0	-	0.00	0.00%	0.00	0.70	-	57.08	(16.04)	41.04
PV + Stor,, Rock Springs, WY, 200 MW + 50 MW X 200 MWh (30% ITC)	6400	30%	56.38	88%	0	-	0.00	0.00%	0.00	0.70	-	57.08	(16.04)	41.04
PV + Stor, Yakima, WA, 200 MW + 50 MW X 200 MWh (30% ITC)	1000	26%	68.24	88%	0	-	0.00	0.00%	0.00	0.70	-	68.95	(19.47)	49.48
PV + Stor, Idaho Falls, ID, 200 MW + 50 MW X 200 MWh (10% ITC)	4700	28%	60.55	88%	0	-	0.00	0.00%	0.00	0.70	-	61.25	(6.32)	54.94
PV + Stor, Lakeview, OR, 200 MW + 50 MW X 200 MWh (10% ITC)	4800	30%	59.80	88%	0	-	0.00	0.00%	0.00	0.70	-	60.50	(6.25)	54.25
PV + Stor,, Milford, UT, 200 MW + 50 MW X 200 MWh (10% ITC)	5000	33%	52.29	88%	0	-	0.00	0.00%	0.00	0.70	-	52.99	(5.45)	47.54
PV + Stor, Utah North, 200 MW + 50 MW X 200 MWh (10% ITC)	5000	30%	56.38	88%	0	-	0.00	0.00%	0.00	0.70	-	57.08	(5.87)	51.21
PV + Stor,, Rock Springs, WY, 200 MW + 50 MW X 200 MWh (10% ITC)	6400	30%	56.38	88%	0	-	0.00	0.00%	0.00	0.70	-	57.08	(5.87)	51.21
PV + Stor, Yakima, WA, 200 MW + 50 MW X 200 MWh (10% ITC)	1000	26%	68.24	88%	0	-	0.00	0.00%	0.00	0.70	-	68.95	(7.13)	61.82
Oregon PS, 400 MW X 3,800 MWh	4457	36%	65.59	79%	*324*	27.44	0.00	0.00%	0.00	-	-	93.03	-	93.03
Oregon PS joint ownership, 100 MW X 950 MWh	4457	36%	65.68	79%	*324*	27.44	0.00	0.00%	0.00	-	-	93.12	-	93.12
Washington PS, 1,200 MW X 16,800 MWh	500	36%	56.91	79%	*320*	27.14	0.00	0.00%	0.00	-	-	84.06	-	84.06
Wyoming PS, 700 MW X 7,000 MWh	580	36%	68.79	79%	*320*	27.13	0.00	0.00%	0.00	-	-	95.92	-	95.92
Wyoming PS, 400 MW X 3,400 MWh	6000	36%	51.12	79%	*320*	27.13	0.00	0.00%	0.00	-	-	78.25	-	78.25
Utah PS, 300 MW X 1,800 MWh	6359	36%	63.65	79%	*327*	27.67	0.00	0.00%	0.00	-	-	91.31	-	91.31
Idaho PS, 360 MW X 2,880 MWh	5000	36%	57.59	79%	*327*	27.67	0.00	0.00%	0.00	-	-	85.25	-	85.25
CAES, 320 MW X 15,360 MWh	4600	72%	20.20	55%	*327*	39.74	0.00	0.00%	0.00	-	-	59.94	-	59.94
Li-Ion 15 MW X 60 MWh	0	17%	142.42	88%	*327*	24.84	15.07	0.00%	0.00	-	-	182.32	-	182.32

Table 6.2 – Total Resource Cost for Supply-Side Resource Options (Continued)

Supply Side Resource Options Mid-Calendar Year 2018 Dollars ($)		Convert to $/MWh					Variable Costs ($/MWh)					Total Costs and Credits ($/MWh)		
					Levelized Fuel								Credits	
Resource Description	Elevation (AFSL)	Capacity Factor 3/	Total Fixed ($/MWh)	Storage Efficiency	¢/mmBtu	$/MWh	O&M 1/	Capitalized Premium	O&M Capitalized 1/	Integration Cost 1/	Environmental	Total Resource Cost	PTC Tax Credits / ITC (Solar Only)	Total Resource Cost - with PTC / ITC Credits
Brownfield Site														
Dave Johnston														
SCCT Frame "F" x1	5050	33%	27.81	na	327	32.11	6.61	11.48%	0.76	-	-	67.29	-	67.29
3.6 MW Wind turbine 43,6% CF WY, 2023 (40% PTC)	6400	44%	31.05	na	0	-	0.65	0.00%	0.00	0.93	-	32.63	(6.22)	26.41
CCCT Dry "J/HA.02", 1x1	5050	78%	19.34	na	320	20.66	2.05	10.21%	0.21	-	-	42.25	-	42.25
CCCT Dry "J/HA.02", DF, 1x1	5050	12%	47.20	na	320	20.66	0.16	0.00%	0.00	-	-	68.02	-	68.02
Hunter														
SCCT Frame "F" x1	5050	33%	27.81	na	327	32.11	6.61	11.48%	0.76	-	-	67.29	-	67.29
PV, 200 MW, 2026, 32.5% CF (10% ITC)	5000	33%	42.31	na	0	-	0.00	0.00%	0.00	0.70	-	43.01	(4.29)	38.73
PV + Stor, 200 MW + 50 MW X 200 MWh (10% ITC)	5000	33%	52.29	88%	0	-	0.00	0.00%	0.00	0.70	-	52.99	(5.45)	47.54
CCCT Dry "J/HA.02", 1x1	5050	78%	17.89	na	327	21.17	2.05	10.21%	0.21	-	-	41.31	-	41.31
CCCT Dry "J/HA.02", DF, 1x1	5050	12%	37.77	na	327	21.17	0.16	0.00%	0.00	-	-	59.09	-	59.09
Huntington														
SCCT Frame "F" x1	5050	33%	27.81	na	327	32.11	6.61	11.48%	0.76	-	-	67.29	-	67.29
PV, 200 MW, 2026, 32.5% CF (10% ITC)	5000	33%	42.31	na	0	-	0.00	0.00%	0.00	0.70	-	43.01	(4.29)	38.73
PV + Stor, 200 MW + 50 MW X 200 MWh (10% ITC)	5000	33%	52.29	88%	0	-	0.00	0.00%	0.00	0.70	-	52.99	(5.45)	47.54
CCCT Dry "J/HA.02", 1x1	5050	78%	17.89	na	327	21.17	2.05	10.21%	0.21	-	-	41.31	-	41.31
CCCT Dry "J/HA.02", DF, 1x1	5050	12%	37.77	na	327	21.17	0.16	0.00%	0.00	-	-	59.09	-	59.09
Jim Bridger														
3.6 MW Wind turbine 43,6% CF WY, 2023 (40% PTC)	6400	44%	31.05	na	0	-	0.65	0.00%	0.00	0.93	-	32.63	(6.22)	26.41
Wind + Stor, 200 MW+ 50 MW | 400 MWh	6500	44%	47.19	88%	0	-	0.65	0.00%	0.00	0.93	-	48.77	(6.22)	42.55
SCCT Frame "F" x1	6500	33%	27.17	na	321	31.43	6.96	11.48%	0.80	-	-	66.36	-	66.36
PV, 200 MW, 2026, 32.5% CF (10% ITC)	6400	30%	45.15	na	0	-	0.00	0.00%	0.00	0.70	-	45.85	(4.62)	41.23
PV + Stor, 200 MW + 50 MW X 200 MWh (10% ITC)	6400	30%	56.38	88%	0	-	0.00	0.00%	0.00	0.70	-	57.08	(5.87)	51.21
CCCT Dry "J/HA.02", 1x1	6500	78%	18.14	na	321	21.45	2.15	10.21%	0.22	-	-	41.97	-	41.97
CCCT Dry "J/HA.02", DF, 1x1	6500	12%	34.70	na	321	21.45	0.16	0.00%	0.00	-	-	56.31	-	56.31
Naughton														
SCCT Frame "F" x1	6500	33%	28.98	na	327	32.05	6.96	11.48%	0.80	-	-	68.78	-	68.78
PV 200 MW, 2026, 30.1% CF (10% ITC)	6400	30%	45.15	na	0	-	0.00	0.00%	0.00	0.70	-	45.85	(4.62)	41.23
CCCT Dry "J/HA.02", 1x1	6500	78%	18.66	na	327	21.88	2.15	10.21%	0.22	-	-	42.91	-	42.91
CCCT Dry "J/HA.02", DF, 1x1	6500	12%	38.08	na	327	21.88	0.16	0.00%	0.00	-	-	60.11	-	60.11
Wyodak														
SCCT Frame "F" x1	6500	33%	34.17	na	323	31.58	6.96	11.48%	0.80	-	-	73.51	-	73.51

1/ Input into IRP SO and PAR Model
2/ Wind and solar shapes are input into IRP SO and PAR Model
NC = Not Calculated
Results presented without credits
Information Presented is Illustrative

Table 6.2 – Total Resource Cost for Supply-Side Resource Options (Continued)

Resources not Modeled in 2019 IRP

Supply Side Resource Options Mid-Calendar Year 2018 Dollars ($)		Convert to $/MWh					Variable Costs ($/MWh)					Total Costs and Credits ($/MWh)		
					Levelized Fuel								Credits	
Resource Description	Elevation (AFSL)	Capacity Factor	Total Fixed ($/MWh)	Storage Efficiency	¢/mmBtu	$/MWh	O&M	Capitalized Premium	O&M Capitalized	Integration Cost	Environmental	Total Resource Cost	PTC Tax Credits / ITC (Solar Only)	Total Resource Cost - with PTC / ITC Credits
SCPC with CCS	4500	90%	64.62	na	178	23.30	7.00	0.00%	0.00	-	-	94.91	-	94.91
IGCC with CCS	4500	86%	62.30	na	178	19.27	11.77	11.52%	1.36	-	-	94.69	-	94.69
PC CCS retrofit @ 500 MW	4500	90%	21.90	na	178	25.58	6.47	0.00%	0.00	-	-	53.96	-	53.96
SCPC with CCS	6500	90%	70.74	na	178	23.57	7.58	0.00%	0.00	-	-	101.89	-	101.89
IGCC with CCS	6500	86%	70.21	na	178	19.66	14.11	0.00%	0.00	-	-	103.98	-	103.98
PC CCS retrofit @ 500 MW	6500	90%	22.78	na	178	25.58	7.00	0.00%	0.00	-	-	55.36	-	55.36
Greenfield Binary 90% CF	4500	90%	59.99	na	0	-	1.16	0.00%	0.00	-	-	61.15	(15.55)	45.60
Wind + Stor, Pocatello, ID, 200 MW+ 50 MW | 100 MWh	4500	37%	46.12	88%	0	-	0.00	0.00%	0.00	0.93	-	47.05	(6.22)	40.83
Wind + Stor, Arlington, OR, 200 MW+ 50 MW | 100 MWh	1500	37%	46.72	88%	0	-	10.00	0.00%	0.00	0.93	-	57.65	(6.22)	51.42
Wind + Stor, Monticello, UT, 200 MW+ 50 MW | 100 MWh	4500	30%	57.95	88%	0	-	0.00	0.00%	0.00	0.93	-	58.87	(6.22)	52.65
Wind + Stor, Medicine Bow, WY, 200 MW+ 50 MW | 100 MWh	6500	44%	39.10	88%	0	-	0.65	0.00%	0.00	0.93	-	40.68	(6.22)	34.46
Wind + Stor, Goldendale, WA, 200 MW+ 50 MW | 100 MWh	1500	37%	46.85	88%	0	-	10.00	0.00%	0.00	0.93	-	57.78	(6.22)	51.56
Wind + Stor, Pocatello, ID, 200 MW+ 50 MW | 400 MWh	4500	37%	55.62	88%	0	-	0.00	0.00%	0.00	0.93	-	56.55	(6.22)	50.33
Wind + Stor, Arlington, OR, 200 MW+ 50 MW | 400 MWh	1500	37%	56.82	88%	0	-	10.00	0.00%	0.00	0.93	-	67.75	(6.22)	61.53
Wind + Stor, Monticello, UT, 200 MW+ 50 MW | 400 MWh	4500	30%	69.89	88%	0	-	0.00	0.00%	0.00	0.93	-	70.82	(6.22)	64.60
Wind + Stor, Medicine Bow, WY, 200 MW+ 50 MW | 400 MWh	6500	44%	47.19	88%	0	-	0.65	0.00%	0.00	0.93	-	48.77	(6.22)	42.55
Wind + Stor, Goldendale, WA, 200 MW+ 50 MW | 400 MWh	1500	37%	56.97	88%	0	-	10.00	0.00%	0.00	0.93	-	67.90	(6.22)	61.68
PV Idaho Falls, ID, 50 MW, 28.1% CF (30% ITC)	4700	28%	51.73	na	0	-	0.00	0.00%	0.00	0.70	-	52.43	(14.58)	37.86
PV Lakeview, OR, 50 MW, 2021, 29.7% CF (30% ITC)	4800	30%	50.92	na	0	-	0.00	0.00%	0.00	0.70	-	51.63	(14.38)	37.24
PV Milford, UT, 50 MW, 2021, 32.5% CF (30% ITC)	5000	33%	44.87	na	0	-	0.00	0.00%	0.00	0.70	-	45.58	(12.58)	32.99
PV Rock Springs, WY, 50 MW, 2021, 30.1% CF (30% ITC)	6400	30%	47.91	na	0	-	0.00	0.00%	0.00	0.70	-	48.62	(13.56)	35.06
PV Yakima, WA, 50 MW, 2021, 26% CF (30% ITC)	1000	26%	58.09	na	0	-	0.00	0.00%	0.00	0.70	-	58.80	(16.40)	42.39
PV Idaho Falls, ID, 50 MW, 2026, 28.1% CF (10% ITC)	4700	28%	51.73	na	0	-	0.00	0.00%	0.00	0.70	-	52.43	(5.34)	47.09
PV Lakeview, OR, 50 MW, 2026, 29.7% CF (10% ITC)	4800	30%	50.92	na	0	-	0.00	0.00%	0.00	0.70	-	51.63	(5.27)	46.36
PV Milford, UT, 50 MW, 2026, 32.5% CF (10% ITC)	5000	33%	44.87	na	0	-	0.00	0.00%	0.00	0.70	-	45.58	(4.61)	40.97
PV Rock Springs, WY, 50 MW, 2026, 30.1% CF (10% ITC)	6400	30%	47.91	na	0	-	0.00	0.00%	0.00	0.70	-	48.62	(4.96)	43.65
PV Yakima, WA, 50 MW, 2026, 26% CF (10% ITC)	1000	26%	58.09	na	0	-	0.00	0.00%	0.00	0.70	-	58.80	(6.01)	52.79
PV + Stor, Idaho Falls, ID, 50 MW + 10 MW X 20 MWh (30% ITC)	4700	28%	60.68	88%	0	-	0.00	0.00%	0.00	0.70	-	61.39	(18.53)	42.85
PV + Stor, Idaho Falls, ID, 200 MW + 50 MW X 100 MWh (30% ITC)	4700	28%	55.48	88%	0	-	0.00	0.00%	0.00	0.70	-	56.18	(17.25)	38.93
PV + Stor,, Idaho Falls, ID, 50 MW + 10 MW X 40 MWh (30% ITC)	4700	28%	65.34	88%	0	-	0.00	0.00%	0.00	0.70	-	66.04	(18.53)	47.51
PV + Stor, Idaho Falls, ID, 50 MW + 10 MW X 80 MWh (30% ITC)	4700	28%	73.32	88%	0	-	0.00	0.00%	0.00	0.70	-	74.03	(18.53)	55.50
PV + Stor, Idaho Falls, ID, 200 MW + 50 MW X 400 MWh (30% ITC)	4700	28%	69.88	88%	0	-	0.00	0.00%	0.00	0.70	-	70.58	(17.25)	53.34
PV + Stor, Lakeview, OR, 50 MW + 10 MW X 20 MWh (30% ITC)	4800	30%	59.72	88%	0	-	0.00	0.00%	0.00	0.70	-	60.42	(18.28)	42.14
PV + Stor, Lakeview, OR, 200 MW + 50 MW X 100 MWh (30% ITC)	4800	30%	54.67	88%	0	-	0.00	0.00%	0.00	0.70	-	55.37	(17.07)	38.30
PV + Stor, Lakeview, OR, 50 MW + 10 MW X 40 MWh (30% ITC)	4800	30%	64.42	88%	0	-	0.00	0.00%	0.00	0.70	-	65.12	(18.28)	46.84
PV + Stor, Lakeview, OR, 50 MW + 10 MW X 80 MWh (30% ITC)	4800	30%	72.51	88%	0	-	0.00	0.00%	0.00	0.70	-	73.22	(18.28)	54.93
PV + Stor,, Lakeview, OR, 200 MW + 50 MW X 400 MWh (30% ITC)	4800	30%	69.27	88%	0	-	0.00	0.00%	0.00	0.70	-	69.98	(17.07)	52.91
PV + Stor,, Milford, UT, 50 MW + 10 MW X 20 MWh (30% ITC)	5000	33%	52.40	88%	0	-	0.00	0.00%	0.00	0.70	-	53.10	(15.99)	37.11
PV + Stor,, Milford, UT, 200 MW + 50 MW X 100 MWh (30% ITC)	5000	33%	47.90	88%	0	-	0.00	0.00%	0.00	0.70	-	48.60	(14.88)	33.72
PV + Stor,, Milford, UT 50 MW + 10 MW X 40 MWh (30% ITC)	5000	33%	56.43	88%	0	-	0.00	0.00%	0.00	0.70	-	57.13	(15.99)	41.14
PV + Stor,, Milford, UT, 50 MW + 10 MW X 80 MWh (30% ITC)	5000	33%	63.33	88%	0	-	0.00	0.00%	0.00	0.70	-	64.03	(15.99)	48.04
PV + Stor,, Milford, UT, 200 MW + 50 MW X 400 MWh (30% ITC)	5000	33%	60.35	88%	0	-	0.00	0.00%	0.00	0.70	-	61.06	(14.88)	46.17
PV + Stor,, Rock Springs, WY, 50 MW + 10 MW X 20 MWh (30% ITC)	6400	30%	56.50	88%	0	-	0.00	0.00%	0.00	0.70	-	57.20	(17.23)	39.97
PV + Stor,, Rock Springs, WY, 200 MW + 50 MW X 100 MWh (30% ITC)	6400	30%	51.64	88%	0	-	0.00	0.00%	0.00	0.70	-	52.34	(16.04)	36.31
PV + Stor,, Rock Springs, WY, 50 MW + 10 MW X 40 MWh (30% ITC)	6400	30%	60.85	88%	0	-	0.00	0.00%	0.00	0.70	-	61.55	(17.23)	44.31
PV + Stor,, Rock Springs, WY, 50 MW + 10 MW X 80 MWh (30% ITC)	6400	30%	68.30	88%	0	-	0.00	0.00%	0.00	0.70	-	69.00	(17.23)	51.77
PV + Stor,, Rock Springs, WY, 200 MW + 50 MW X 400 MWh (30% ITC)	6400	30%	65.09	88%	0	-	0.00	0.00%	0.00	0.70	-	65.79	(16.04)	49.75
PV + Stor,, Yakima, WA, 50 MW + 10 MW X 20 MWh (30% ITC)	1000	26%	68.15	88%	0	-	0.00	0.00%	0.00	0.70	-	68.85	(20.85)	48.00
PV + Stor, Yakima, WA, 200 MW + 50 MW X 100 MWh (30% ITC)	1000	26%	62.38	88%	0	-	0.00	0.00%	0.00	0.70	-	63.08	(19.47)	43.62
PV + Stor, Yakima, WA, 50 MW + 10 MW X 40 MWh (30% ITC)	1000	26%	73.52	88%	0	-	0.00	0.00%	0.00	0.70	-	74.22	(20.85)	53.37
PV + Stor, Yakima, WA, 50 MW + 10 MW X 80 MWh (30% ITC)	1000	26%	82.77	88%	0	-	0.00	0.00%	0.00	0.70	-	83.48	(20.85)	62.62
PV + Stor, Yakima, WA, 200 MW + 50 MW X 400 MWh (30% ITC)	1000	26%	79.07	88%	0	-	0.00	0.00%	0.00	0.70	-	79.78	(19.47)	60.31
Li-Ion 1 MW X 250 kWh	0	1%	1,886.99	88%	327	24.84	11.42	0.00%	0.00	-	-	1,923.24	-	1,923.24
Li-Ion 1 MW X 2 MWh	0	8%	430.85	88%	327	24.84	15.70	0.00%	0.00	-	-	471.38	-	471.38
Li-Ion 1 MW X 4 MWh	0	17%	284.12	88%	327	24.84	14.98	0.00%	0.00	-	-	323.94	-	323.94
Li-Ion 1 MW X 8 MWh	0	33%	225.69	88%	327	24.84	14.98	0.00%	0.00	-	-	265.50	-	265.50
Flow 1 MW X 6 MWh	0	25%	217.62	65%	327	33.62	0.00	0.00%	0.00	-	-	251.24	-	251.24
Advanced Fission	5000	86%	74.25	na	0	-	11.75	0.00%	0.00	-	-	86.00	-	86.00
Small Modular Reactor x 12	5000	86%	79.12	na	0	-	15.50	0.00%	0.00	-	-	94.62	-	94.62

Additionally, total resource costs were prepared for three natural gas-fired combined cycle combustion turbine resource options at an elevation of 5,050 feet at varying capacity factors to show how these costs are affected by dispatch. Table 6.3 shows the total resource cost results for this analysis.

Table 6.3 - Total Resource Cost, for various Capacity Factors ($/MWh, 2018$)

Total Resource Cost ($/MWh)			
Capacity Factor CCCT	**40%**	**78%**	**94%**
Capacity Factor Duct Fire	**10%**	**12%**	**22%**
CCCT Dry "G/H", 1x1	$68.15	$46.45	$42.56
CCCT Dry "G/H", DF, 1x1	$75.94	$66.85	$46.20
CCCT Dry "G/H", 2x1	$56.24	$40.30	$37.45
CCCT Dry "G/H", DF, 2x1	$66.11	$58.66	$41.75
CCCT Dry "J/HA.02", 1x1	$61.02	$42.68	$39.39
CCCT Dry "J/HA.02", DF, 1x1	$69.63	$61.57	$43.25
CCCT Dry, "J/HA.02" 2X1	$51.14	$37.57	$35.14
CCCT Dry "J/HA.02", DF, 2X1	$61.64	$54.91	$39.63

Table 6.4 - Glossary of Terms from the SSR

Term	Description
Fuel	Primary fuel used for electricity generation or storage.
Resource	Primary technology used for electricity generation or storage.
Elevation (afsl)	Average feet above sea level for the proxy site for the given resource.
Net Capacity (MW)	For natural gas-fired generation resources, the Net Capacity is the net dependable capacity (net electrical output) for a given technology, at the given elevation, at the annual average ambient temperature in a "new and clean" condition.
Commercial Operation Year	The resource availability year is the earliest year the technology associated with the given generating resource is commercially available for procurement and installation. The total implementation time is the number of years necessary to implement all phases of resource development and construction: site selection, permitting, maintenance contracts, IRP approval, RFP process, owner's engineering, construction, commissioning and grid interconnection.
Design Life (years)	Average number of years the resource is expected to be "used and useful," based on various factors such as manufacturer's guarantees, fuel availability and environmental regulations.
Base Capital ($/kW)	Total capital expenditure in dollars per kilowatt-hour ($/kW) for the development and construction of a resource including: direct costs (equipment, buildings, installation/overnight construction, commissioning, contractor fees/profit and contingency), owner's costs (land, water rights, permitting, rights-of-way, design engineering, spare parts, project management, legal/financial support, grid interconnection costs, owner's contingency), and financial costs (allowance for funds used during construction (AFUDC), capital surcharge, property taxes and escalation during construction, if applicable).

Term	Description
Var O&M ($/MWh)	Includes real levelized variable operating costs such as combustion turbine maintenance, water costs, boiler water/circulating water treatment chemicals, pollution control reagents, equipment maintenance and fired hour fees in dollars per megawatt hour ($/MWh).
Fixed O&M ($/kW-year)	Includes labor costs, combustion turbine fixed maintenance fees, contracted services fees, office equipment and training.
Full Load Heat Rate HHV (Btu/kWh)	Net efficiency of the resource to generate electricity for a given heat input in a "new and clean" condition on a higher heating value basis.
EFOR (%)	Estimated Equivalent Forced Outage Rate, which includes forced outages and derates for a given resource at the given site.
POR (%)	Estimated Planned Outage Rate for a given resource at the given site.
Water Consumed (gal/MWh)	Average amount of water consumed by a resource for make-up, cooling water make-up, inlet conditioning and pollution control.
SO_2 (lbs/MMBtu)	Expected permitted level of sulfur dioxide (SO_2) emissions in pounds of sulfur dioxide per million Btu of heat input.
NOx (lbs/MMBtu)	Expected permitted level of nitrogen oxides (NO_x) (expressed as NO_2) in pounds of NOx per million Btu of heat input.
Hg (lbs/TBtu)	Expected permitted level of mercury emissions in pounds per trillion Btu of heat input.
CO_2 (lbs/MMBtu)	Pounds of carbon dioxide (CO_2) emitted per million Btu of heat input.

Table 6.5 - Glossary of Acronyms Used in the Supply-Side Resources

Acronyms	Description
AFSL	Average Feet (Above) Sea Level
CAES	Compressed Air Energy Storage
CCCT	Combined Cycle Combustion Turbine
CCS	Carbon Capture and Sequestration
CF	Capacity Factor
CSP	Concentrated Solar Power
DF	Duct Firing
IC	Internal Combustion
IGCC	Integrated Gasification Combined Cycle
ISO	International Organization for Standardization (Temp = 59 F/15 C, Pressure = 14.7 psia/1.013 bar)
Li-Ion	Lithium Ion
NCM	Nickel Cobalt Manganese (sub-chemistry of Li-Ion)
PPA	Power Purchase Agreement
PC CCS	Pulverized Coal equipped with Carbon Capture and Sequestration
PHES	Pumped Hydro Energy Storage
PV Poly-Si	Photovoltaic modules constructed from poly-crystalline silicon semiconductor wafers
Recip	Reciprocating Engine
SCCT	Simple Cycle Combustion Turbine
SCPC	Super-Critical Pulverized Coal

Resource Option Descriptions

The following are brief descriptions of each of the resources listed in Table 6.1.

Natural Gas, Simple Combined Cycle Turbine (SCCT) Aero x 3 – a resource based on three General Electric LM6000PF-Sprint simple cycle aero-derivative combustion turbines fueled on natural gas. The scope would include selective catalytic reduction systems and oxidation catalysts to reduce NOx and carbon monoxide/volatile organic compounds (VOC) emissions.

Natural Gas, Intercooled SCCT Aero x 2 – a resource based on two General Electric LMS100PA+ simple cycle aero-derivative intercooled combustion turbine fueled on natural gas. Scope would include selective catalytic reduction systems and oxidation catalysts to reduce NOx and carbon monoxide/VOC emissions. An air-cooled intercooler is assumed.

Natural Gas, SCCT Frame "F" x 1 – a resource based on one General Electric 7FA.05 simple cycle frame type combustion turbine fueled on natural gas. Scope would include selective catalytic reduction systems and oxidation catalysts to reduce NOx and carbon monoxide/VOC emissions.

Natural Gas, Internal Combustion (IC) Recips x 6 – a resource based on six Wartsila 18V50SG reciprocating engines fueled on natural gas. Scope would include selective catalytic reduction systems and oxidation catalysts to reduce NOx and carbon monoxide/VOC emissions.

Natural Gas, Combined Cycle Combustion Turbine (CCCT) Dry "G/H", 1x1 – a combined cycle resource based on one frame-type General Electric 7HA.01 combustion turbine, one 3-pressure heat recovery steam generator and one steam turbine. Scope would include selective catalytic reduction systems and oxidation catalysts to reduce NOx and carbon monoxide/VOC emissions. Steam from the steam turbine is condensed in an air cooled condenser.

Natural Gas, CCCT Dry "G/H", DF, 1x1 – an option that can be added to a combined cycle plant to increase its capacity by the addition of duct burners in the heat recovery steam generator. This increases the amount of steam generated in the heat recovery steam generator. The amount of duct firing is up to the owner. Depending on the amount of duct firing added, the size of the steam turbine, steam turbine generator and associated feed water, steam condensing and cooling systems may need to be increased. This description also applies to the following technologies that are listed on Table 6.1: CCCT Dry "G/H", DF, 2x1; CCCT Dry "J/HA.02", DF, 1x1; CCCT Dry "J/HA.02", DF, 2x1.

Natural Gas, CCCT Dry "G/H", 2x1 - a combined cycle resource based on two frame-type General Electric 7HA.01 combustion turbines, two 3-pressure heat recovery steam generators and one steam turbine. Scope would include selective catalytic reduction systems and oxidation catalysts to reduce NOx and carbon monoxide/VOC emissions. Steam from the steam turbine is condensed in an air cooled condenser.

Natural Gas, CCCT Dry "J/HA.02", 1x1 - a combined cycle resource based on one frame-type General Electric 7HA.02 combustion turbine (air-cooled), one 3-pressure heat recovery steam generator and one steam turbine. Scope would include selective catalytic reduction systems and oxidation catalysts to reduce NOx and carbon monoxide/VOC emissions. Steam from the steam turbine is condensed in an air cooled condenser.

Natural Gas, CCCT Dry "J/HA.02", 2x1 - a combined cycle resource based on two frame-type Mitsubishi M501GAC combustion turbines (air-cooled), two 3-pressure heat recovery steam generators and one steam turbine. Scope would include selective catalytic reduction systems and oxidation catalysts to reduce NOx and carbon monoxide/VOC emissions. Steam from the steam turbine is condensed in an air cooled condenser.

Coal, Super-critical Pulverized Coal (SCPC) with Carbon Capture and Sequestration (CCS) – conventional coal-fired generation resource including a supercritical boiler (up to 4000 psig) using pulverized coal with all emission controls including scrubber, fabric filters (baghouse), mercury control, selective catalytic reduction (SCR) and CCS to reduce carbon dioxide emissions by 90 percent.

Coal, PC CCS retrofit at 500 MW – a retrofit of an existing conventional coal-fired boiler and steam turbine resource. Costs include the reduction in plant output due to higher auxiliary power requirements and reduced steam turbine output and would remove carbon dioxide by 90 percent and provide a marginal improvement in other emissions.

Coal, IGCC with CCS – an advanced IGCC resource to facilitate lower cost carbon capture and sequestration costs. An IGCC plant produces a synthetic fuel gas from coal using an advanced oxygen blown gasifier and burning the synthetic fuel gas in a conventional combustion turbine combined cycle power facility. The IGCC would utilize the latest advanced combustion turbine technology and provide fuel gas cleanup to achieve ultra-low emissions of sulfur dioxide, nitrogen oxides using selective catalytic reduction systems, mercury and particulate. Carbon dioxide would be removed from the synthetic fuel gas before combustion thereby reducing carbon dioxide emissions by more than 90 percent.

Wind, 3.6 MW turbine 37 percent NCF WA/OR/ID – a wind resource based on 3.6 MW wind turbines located in Washington, Oregon or Idaho with an estimated annual net capacity factor of 37 percent. The scope would include developing, permitting, engineering, procuring equipment and constructing a wind farm.

Wind, 3.6 MW turbine 29 percent Net Capacity Factor (NCF) UT – a wind resource based on 3.6 MW wind turbines located in Utah with an estimated annual net capacity factor of 29 percent. The scope would include developing, permitting, engineering, procuring equipment and constructing a wind farm.

Wind, 3.6 MW turbine 43 percent NCF WY – a wind resource based on 3.6 MW wind turbines located in Wyoming with an estimated annual net capacity factor of 43 percent. The scope would include developing, permitting, engineering, procuring equipment and constructing a wind farm.

Solar, PV Single Axis Tracking in ID, OR, UT, WA, and WY with NCF between 26.0 and 32.5 percent depending upon location (1.46 MWdc/MWac) – a large utility scale (50 MW or 200 MW) solar photovoltaic resource using crystalline silica solar panels in a single axis tracking system located in southwestern Utah.

Storage, Pumped Hydro Storage – a range (400 - 1,200 MW) of pumped storage systems using a combination of natural and constructed water storage combined with elevation difference to enable a system capable of discharging the rated capacity for eight hours combined with recharging that capacity over 16 hours. Total development time is estimated at six-to-12 years due to various progress on permitting. The recharge ratio for this resource is 79 percent. Actual pumped hydro storage projects within PacifiCorp's territory were analyzed.

Storage, Lithium Ion Battery – a battery technology of lithium ion batteries located close to the load center. Based on current commercial options such a system is modeled with an acquisition and implementation schedule of one year. The recharge ratio for this storage resource is 88 percent.

Storage, Flow Battery – a battery technology based vanadium ReDOx or other flow battery types. Based on current commercial options such a system is modeled with an acquisition and implementation schedule of one year. The recharge ratio for this storage resource is 65 percent.

Storage, CAES – compressed air energy storage (CAES) system consists of air storage reservoir replacing the compressor on a conventional gas turbine. The gas turbine exhaust powers a power turbine providing a simple cycle gas turbine energy at lower costs than a conventional gas turbine. Off-peak energy is used to compress air into the storage reservoir. A system size of 320 MW is assumed. The air storage reservoir is assumed to be solution mined to size. Natural gas is required to generate power. Although the recharge ratio is difficult to separate from the fuel combustion a recharge ratio assumed for this storage resource is 55 percent which includes the fuel required during the power generation cycle.

Nuclear, Advanced Fission – a large 2,234 MW nuclear resource reflects the current state-of-the-art advanced nuclear plant and is modeled after the Westinghouse AP1000 technology. The assumed location for this resource is the proposed Blue Castle site near Green River, Utah which is in development. It is expected that the resource would not be available earlier than 2025.

Nuclear, Small Modular Reactor – such systems hold the promise of being built off-site and transported to a location at lower cost than traditional nuclear facilities. A nominal 570 MW concept is included. It is recognized that this concept is still in the design and licensing stage and is not commercially available requiring approximately 10 years for availability.

Resource Types

Renewables

PacifiCorp retained Burns & McDonnell Engineering Company (BMcD) to evaluate various renewable energy resources in support of the development of the 2019 IRP and associated resource acquisition portfolios and/or products. The 2018 Renewable Resources Assessment and Summary Tables (Assessment) (See Volume II, Appendix P) is screening-level in nature and includes a comparison of technical capabilities, capital costs, and O&M costs that are representative of renewable energy and storage technologies listed below. The Assessment contains preliminary information in support of the long-term power supply planning process. Any technologies of interest to PacifiCorp shall be followed by additional detailed studies to further investigate each technology and its direct application within the owner's long-term plans.

- Single Axis Tracking Solar
- Onshore Wind
- Energy Storage
    - Pumped hydro energy storage (PHES)

  - CAES
  - Li-Ion Battery
  - Flow Battery
- Solar + Energy Storage
- Wind + Energy Storage

Each renewable resource is defined within the Assessment. General assumptions, technology specific assumptions and cost inclusions and exclusions are described within the Assessment. The following paragraphs discuss highlights from the Assessment, a comparison to previous IRP data and additional assessment performed by PacifiCorp.

Costs
The following costs which were excluded from the renewables costs estimates were added by the PacifiCorp:

- AFUDC
- Escalation
- Sales tax
- Property taxes and insurance
- Utility demand costs

Solar
The BMcD Assessment includes 5 MW, 50 MW, and 200 MW single axis tracking (SAT), PV options evaluated at five locations within the PacifiCorp services area. The 2019 differs from previous IRP's in the following ways:

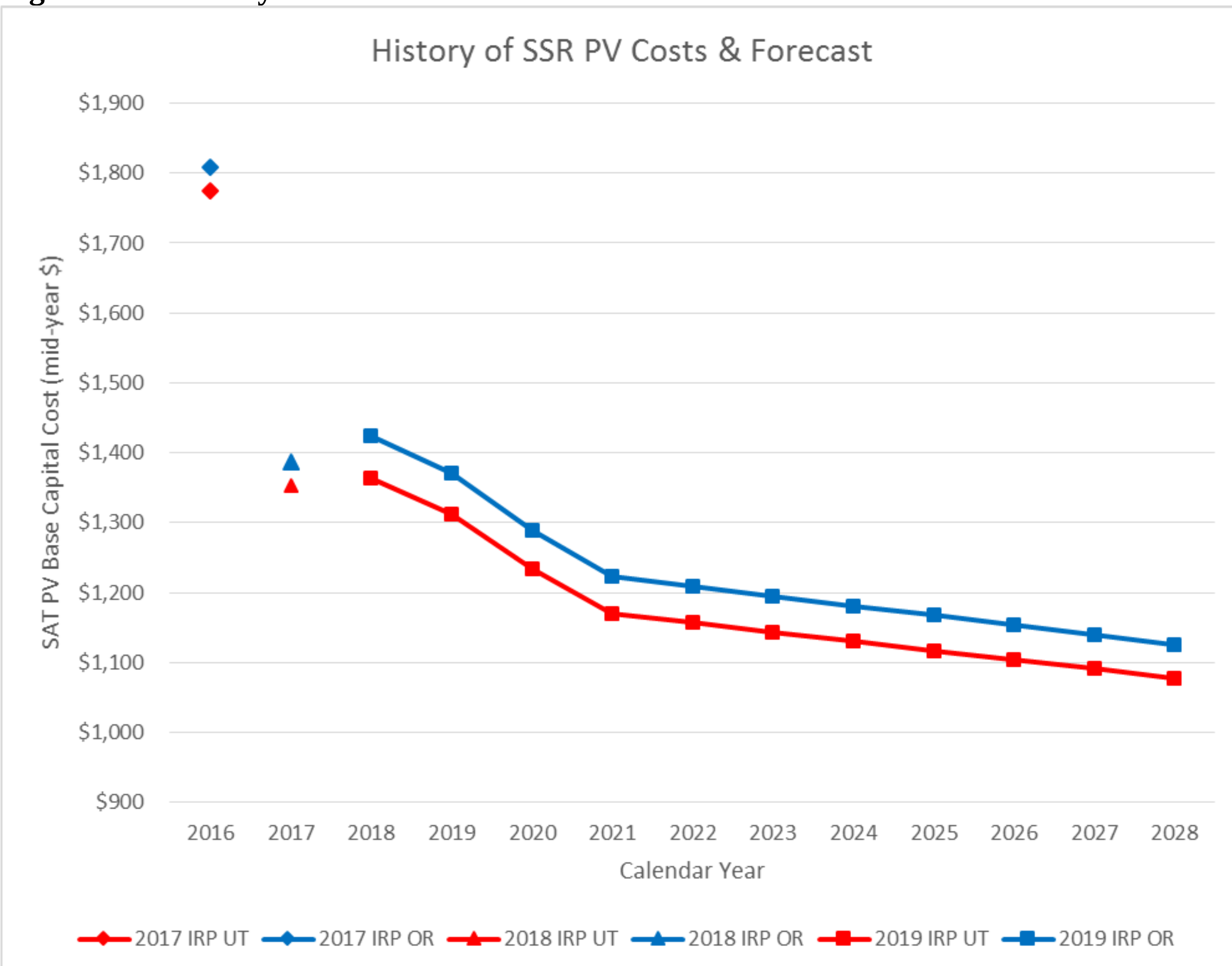
- The number of locations for solar development were expanded from two states (OR & UT) to five states (ID, OR, UT, WA, and WY) to reflect expanding solar development activity within PacifiCorp's service territory.
- A 200 MW option was added for each of the five locations based upon industry trends of building larger solar facilities.
- Fixed tilt PV and concentrated solar are not included based to findings in the 2017 IRP that SAT PV resources have lower costs and are better suited to PacifiCorp's service territory than fixed tilt PV or concentrated solar systems for the system sizes considered.

Solar costs (including forecasted costs) used for the 2019 IRP are higher than those used in the 2017 IRP Update, but are significantly lower than those used in the 2017 IRP. The increase from the 2017 IRP Update is partially due to a different assumed design. The inverter loading ratio results in a higher base capital cost, but a lower levelized cost of energy (LCOE). In addition to the different design basis two significant events have occurred with respect to solar costs since the 2017 IRP.

In late September 2017 the International Trade Commission passed a finding of injury to US solar manufacturers. A significant increase in solar prices in the US occurred following the ITC ruling. Solar costs have since resumed a declining trend, though at a reduced rate of decline. On January 22, 2018, the United States levied a 30 percent tariff on solar imports. The tariff covers both imported solar cells and solar modules. The tariff is expected to last for four years falling by five percent annually, dropping to a 15 percent tariff in 2021. At the time the tariff was levied solar prices briefly halted their decline from the peak price which occurred after the ITC ruling. Figure

6.4 shows a history of capital costs and a forecast used in the SSR for PV resources in Utah and Oregon. The forecast data for the solar 2019 IRP PV costs were provided via NREL data on an annual basis. The decreasing slope starting in 2021 shows that NREL is expecting storage pricing to drop more over the next three years than the years after that.

Figure 6.4 – History of SSR PV Cost & Forecast



There was significant solar development activity in PacifiCorp's service territory between 2012 and 2018. Over the course of those seven years, 332 solar projects with nameplates of 10 MW or greater have initiated generation interconnection requests with PacifiCorp. The total nameplate capacity of those 330 projects is over 27,500 MW. There were 66 new renewable generation projects greater than 10 MW that entered PacifiCorp's generation interconnection queue during 2018; of these 67 new projects, 51 are solar, six are solar & battery storage, seven are wind, one is battery energy storage, and one is nuclear. The nameplate capacity of the 57 solar projects added in 2018 alone is over 7,300 MW. While many projects that have initiated generation interconnection studies over the past 17 years have not been built, the number and size of the 2018 interconnection solar projects is testament to the tremendous solar development activity that is underway within PacifiCorp's service territory.

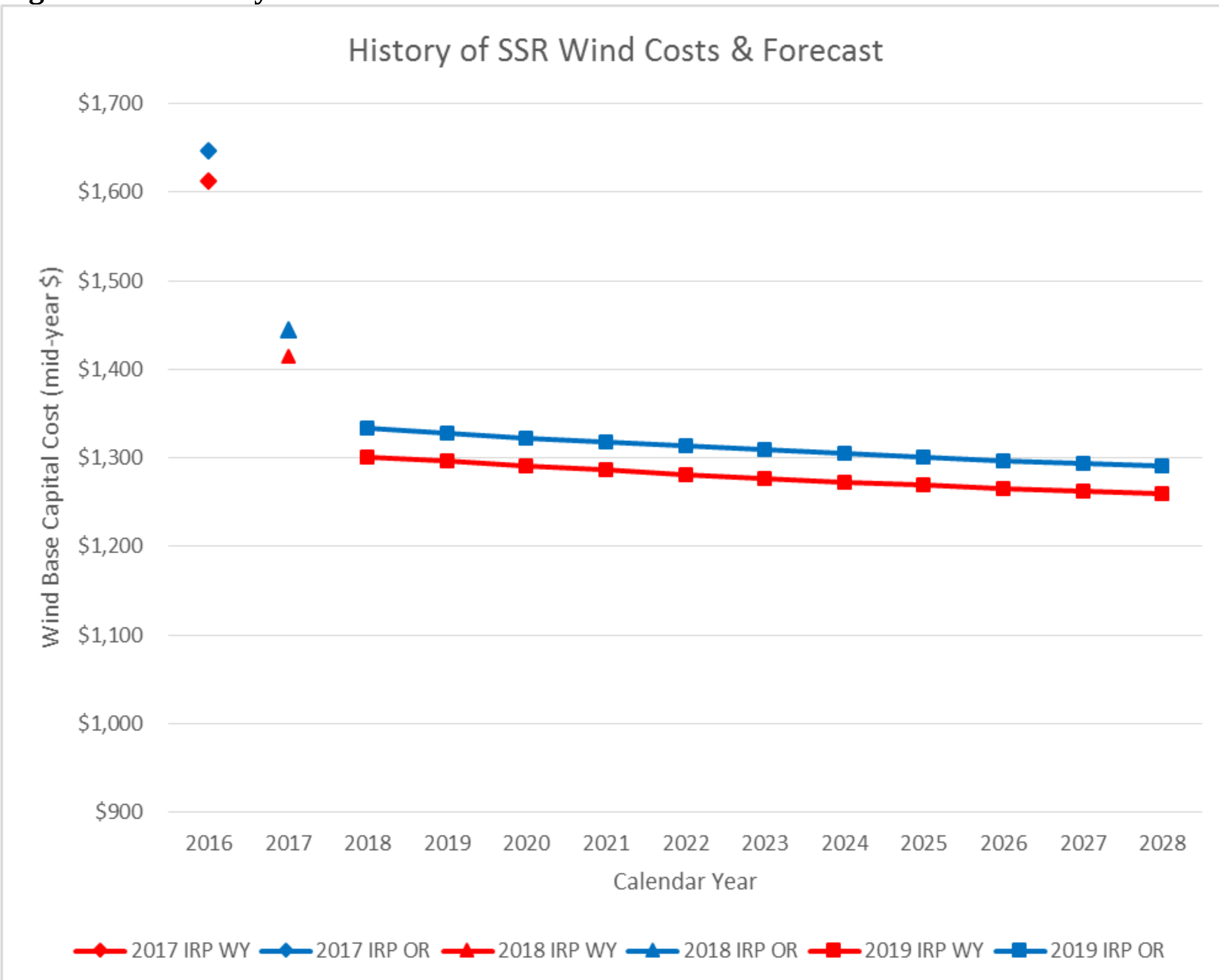
Wind

The 2017 IRP found wind energy to be one of the most cost effective new generation resources for PacifiCorp's customers and led to PacifiCorp's Energy Vision 2020 initiative. Energy Vision 2020 includes three new wind projects, a new 500-kV transmission line, and upgrades to existing infrastructure to deliver the new wind generation to PacifiCorp's customers. The three new wind projects will add 1,150 MW of new wind power to PacifiCorp's generation resources. Wind capital costs in the 2019 IRP are lower than the cost estimates in the 2017 IRP and will push the LCOE for new projects lower. However, reductions in federal production tax credits (PTCs) will push the LCOE for new wind projects built after 2020 higher, assuming there are no changes to PTC policy.

The BMcD Assessment includes 200 MW onshore wind generating facilities in the states of Idaho, Oregon, Utah, Washington, and Wyoming to reflect strong wind resources available within or near PacifiCorp's service areas. BMcD relied on publicly available data and proprietary computational programs to complete the net capacity factor characterization. Generic project locations were selected by the company based on viable wind project locations where there are favorable wind profiles. Figure 6.5 shows a history of capital costs and a forecast used in the SSR for wind resources in Wyoming and Oregon. Utility scale wind farm costs have declined significantly in recent years on a per MW nameplate basis due in large part to substantial increases in the MW size of wind turbines on the market.

Federal PTCs were extended in December 2015 and included a graduated phase out structure that reduces the value of the credits for projects completed after 2021 and eliminates PTCs completely for projects completed after 2023. The PTC extension has led to increasing demand for safe harbor and follow-on wind turbine generators (WTGs) in the United States since 2016 as developers and owners have chosen to purchase safe harbor equipment between 2016 and 2019 to qualify projects that will be commercially operational no later than 2020 to 2023. Burns & McDonnell estimates the cost of wind projects will remain mostly flat with cost decreases of less than five percent over the next ten years, while other estimates indicate the LCOE for wind production could decline as much as 20 percent over the next ten years. While the wind industry has faced PTC cliffs in the past, it is difficult to predict how the scheduled phase out of PTC benefits will impact the cost of future wind projects in the market over the next five to ten years.

Figure 6.5 – History of SSR Wind Costs & Forecast



Capital Costs

Capital cost estimates for wind resources in the IRP are based upon a combination of the Burns & McDonnell study, communications with wind equipment and construction companies, and PacifiCorp's active wind construction projects. All wind resources are specified in 200 MW blocks, but the model can choose multiple blocks or a fractional amount of a block.

Wind Resource Capacity Factors and Energy Shapes

Resource options in the topology bubbles are assigned capacity factors based upon historic or expected project performance. Assigned capacity factor values for wind resources are 43 percent in Wyoming, 37 percent in Washington, Oregon and Idaho, and 29 percent in Utah. Capacity factor is a separate modeled parameter from the capital cost, and is used to scale wind energy shapes used by both the SO model and the Planning and Risk model (PaR). The hourly generation shape reflects average hourly wind variability. The hourly generation shape is repeated for each year of the simulation.

Wind Integration Costs

To capture the costs of integrating wind into the system, PacifiCorp applied a value of $1.11/MWh (in 2018 dollars) for resource selection. To capture the costs of integrating solar into the system, PacifiCorp applied a value of $0.85/MWh (in 2018 dollars). Additional detailed information can be found in PacifiCorp's 2019 flexible reserve study (Volume II, Appendix F). Integration costs were incorporated into wind capital costs based on a 30-year project life expectancy and generation performance, and into solar capital costs based on a 25-year life expectancy and generation performance.

Geothermal

Geothermal resources can produce base-load energy and have high reliability and availability. However, geothermal resources have significantly higher development costs and exploration risks than other renewable technologies such as wind and solar. PacifiCorp has commissioned several studies of geothermal options during the past ten years to determine if additional sources of production can be added to the company's generation portfolio in a cost effective manner. A 2010 study commissioned by PacifiCorp and completed by Black & Veatch focused on geothermal projects near to PacifiCorp's service territory that were in advanced phases of development and could demonstrate commercial viability. PacifiCorp commissioned Black & Veatch to perform additional analysis of geothermal projects in the early stages of development and a report was issued in 2012. An evaluation of the PacifiCorp's Roosevelt Hot Springs geothermal resource was commissioned in 2013. The geothermal capital costs in the 2019 supply side resource option are built on the understanding gained from these earlier reports, publically available capital costs from the Geothermal Resources Council and publicly available prices for energy supplied under power purchase agreements.

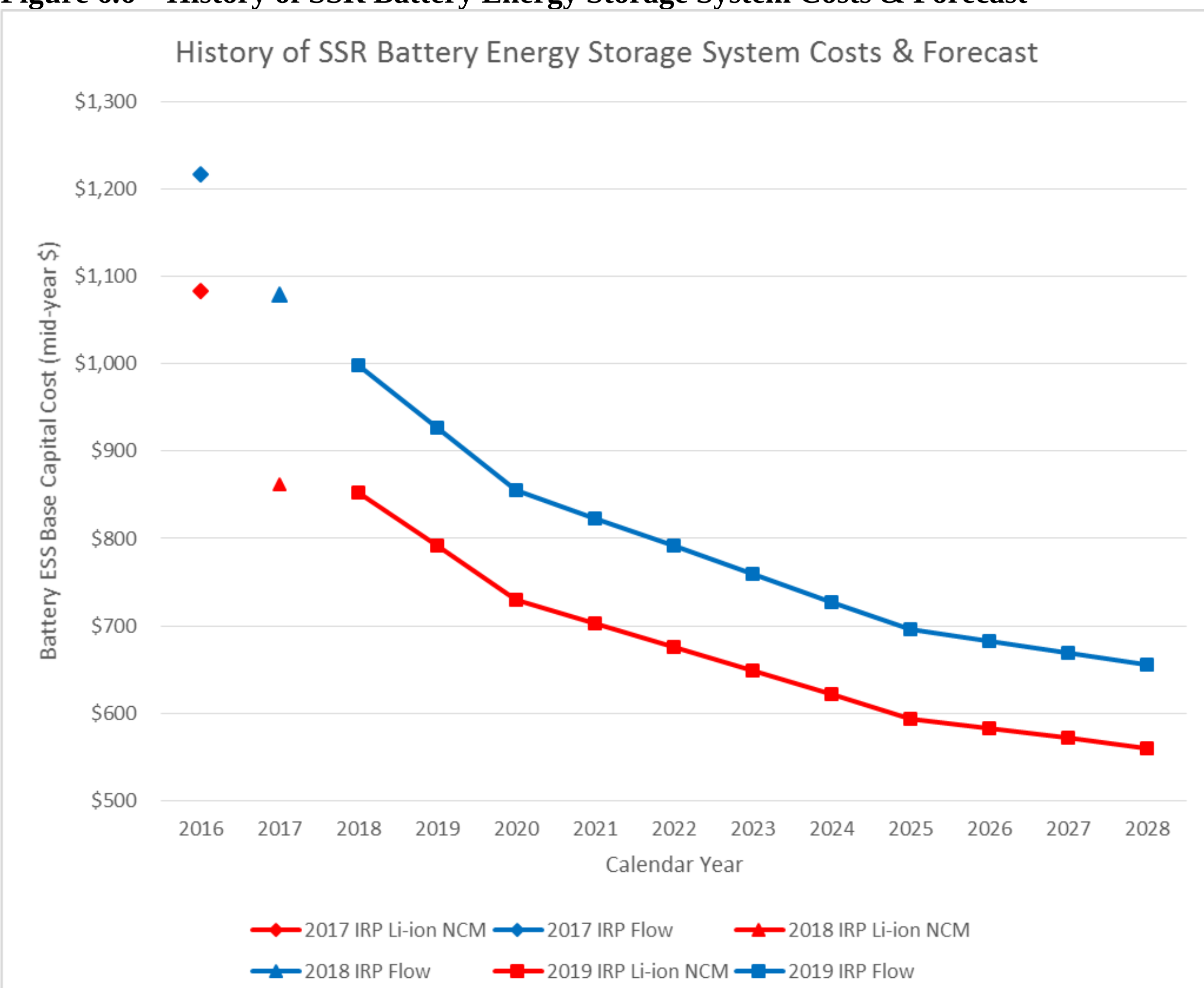
The cost recovery mechanisms currently available to PacifiCorp as a regulated electric utility are not compatible with the inherent risks associated with the development of geothermal resources for power generation. The primary risks of geothermal development are dry holes, well integrity and insufficient resource adequacy (flow, temperature and pressure). These risks cannot be fully quantified until wells are drilled and completed. The cost to validate total production capability of a geothermal resource can be as high as 35 percent of total project costs. Exploration test wells typically cost between $500,000 and $1.5 million per well. Full production and injection wells cost between $4-5 million per well. Variations in the permeability of subsurface materials can determine whether wells in close proximity are commercially viable, lacking in pressure or temperature, or completely dry with no interconnectivity to a geothermal resource. As a regulated utility subject to the public utility commissions of six states, PacifiCorp is not compensated nor incentivized to engage in these inherently risky development efforts.

To mitigate the financial risks of geothermal development, PacifiCorp would use an RFP process to obtain market proposals for geothermal power purchase agreements or build-own-transfer project agreement structures. Geothermal developers, external to PacifiCorp, have the flexibility to structure project pricing to include all development risks. Through an RFP process, PacifiCorp could choose the geothermal project with the lowest cost offered by the market and avoid considerable risk for the company and its customers. Several geothermal projects submitted proposals in response to the 2016 Oregon Renewables RFP, but none of the geothermal projects were selected as a new PacifiCorp generation source. In the event PacifiCorp identifies a geothermal asset that appears to be economically attractive but also determines that there is a significant possibility of development risk that the market will not economically absorb, PacifiCorp may approach state regulators with estimates of resource development costs and risks associated to obtain approval for a mechanism to address risks such as dry holes. Because public utility commissions typically do not allow recovery of expenditures which do not result in a direct benefit to customers, and at least one state has a statute that precludes cost recovery of any asset that is not considered to be "used and useful," obtaining a mechanism to recover geothermal development costs may be difficult.

Energy Storage

The BMcD Assessment discusses three energy storage resource options: 1) PHES), 2) CAES, and 3) battery storage. Battery storage was also considered in combination with solar and wind. The addition of wind plus storage and solar plus storage created a large number of new resource options in the SSR. To mitigate the impact of the additional information less emphasis was placed on the various battery chemistries. Two of the three pumped hydro projects included in both the 2017 and 2019 IRP's showed modest capital cost declines while one showed a modest cost increase. The capital cost for CAES showed a 24 percent cost decrease. No forecasts have been used for pumped hydro and CAES. Both technologies are expected to have a flat forecast despite the recent movement in costs. Figure 6.6 shows a history of capital costs and a forecast used in the SSR for Li-Ion and flow battery resources. Battery costs are expected to continue to decline for the next ten years. Due to the complexity and maturity of the battery market, O&M costs continue to be an area of some uncertainty. PacifiCorp currently has two battery projects under development, one in Utah and one in Oregon, which will provide real market data to validate or indicate if an adjustment is needed for O&M costs.

Figure 6.6 – History of SSR Battery Energy Storage System Costs & Forecast



Natural Gas

Natural gas-fueled generating resources offer several important services that support the safe and reliable operation of the energy grid in an economic manner. They include technologies that are capable of providing peaking, intermediate and base generation.

A variety of natural gas-fueled generating resources that are and will continue to be available for a several years are included in the SSR. The variety of natural gas resources were selected to provide for generating performance and services essential to safe and reliable operation of the energy grid. Natural gas resources generate cost competitive power while producing low air emissions. Natural gas-fueled resources are proven to be highly reliable and safe. Performance, cost and operating characteristics for each resource were provided at elevations of 1,500, 3,000, 5,050 and 6,500 feet above mean sea level, representative of geographic areas in which the resource could be located. Performance, cost and operating characteristics were also provided at ISO conditions (zero feet above mean sea level and 59 °F) as a reference. The essential services provided by the resource are peaking, intermediate and base generation.

Three simple cycle combustion turbine options and one reciprocating engine option were offered to provide peaking generating services. Peaking generating services require the ability to start and reach near full output in less than ten minutes. Peaking generating services also require the ability in increase (ramp up) and decrease (ramp down) very quickly in response to sudden changes in power demand as well as increases and decreases in production from intermittent power sources. Peaking generation provide the ability to meet peak power demand that exceed the capacity of intermediate and base generation. Peak generation also provide reserves to meet system upsets.

Options for peaking resources included in the supply side resources are: 1) three each General Electric (GE) LM6000 PF aero-derivative simple cycle combustion turbines, 2) two each GE LMS 100PA+ aero-derivative simple cycle combustion turbines, 3) one each GE 7F frame simple cycle combustion turbine, and 4) six each Wasilla 18V50SG reciprocating internal combustion engines. All of these options are highly flexible and efficient. Higher heating value heat rates for the resource ranged from 9,204 Btu/kW-hr for the LM6000 PF to 8,279 Btu/kW-hr for the 18V50SG engines. Installation of high temperature oxidation catalysts for carbon monoxide (CO) control and an SCR system for NOx control would be available for these resources.

Eight combined cycle combustion turbine options were provided for intermediate and base generating service. Intermediate generating service requires resources that are able to efficiently operate at production rates well below full production in compliance with air emissions regulations for long periods of time. Intermediate generating service also require the ability to change production rates quickly. Intermediate generation services provide cost effective means of providing power demand that is greater than base load and lower than peak demands. Base generating service requires a highly cost effective that is capable of operating at full production for long periods of time. Base generation provides for the minimum level of power demand over a day or longer period of time at a very low cost.

Options for intermediate and base generation were based on two size classes of engines. The “G/H” size was represented by a GE HA.01. The “J/HA.02” was represented by the GE HA.02. Each engine was arranged in a one combustion turbine to one steam turbine (1x1) and a two combustion turbine to one steam turbine (2x1) configuration to obtain four resource options. The combined cycle resources offered high heating value heat rates from 6,317 to 6,374 Btu/kW-hr. Installation of oxidation catalysts for carbon monoxide (CO) control and SCR systems for nitrogen oxides

(NOx) control is expected. All of the combined cycle options included dry cooling allowing them to be located in areas with water resource concerns.

Duct Firing (DF) of the combined cycle is shown in the Supply Side Resource table. Duct firing is not a stand-alone resource option, but is considered to be an available option for any combined cycle configuration and represents a low cost option to add peaking capability at relatively high efficiency and also a mechanism to recover lost power generation capability at high ambient temperatures. Duct firing is shown in the Supply Side Resource table as a fixed value for each combined cycle combination. In practice the amount of duct firing is a design consideration which is selected during the development of combined cycle generating facilities.

While equipment provided by specific manufacturers were used to for cost and performance information in the supply side resource table, more than one manufacturer produces these type of equipment. The costs and performance used here is representative of the cost and performance that would be expected from any of the manufacturers. Final selection of a manufacturer’s equipment would be made based on a bid process.

New natural gas resources were assumed to be installed at green-field sites on either the east or west side of PacifiCorp’s system. Greenfield development includes the costs of high pressure natural gas laterals, electrical power transmission lines, ambient air monitoring, permitting, real estate, rights of way and water rights. Resources additions a brownfield site, such as an existing coal-fueled generating facility, are reduced to reflect the decreases costs.

Coal

Potential coal resources are shown in the SSR as supercritical pulverized coal (PC) boilers and IGCC, located in both Utah and Wyoming. Both resource types include carbon dioxide capture and compression needed for sequestration.

Supercritical technology is considered the standard design technology compared to subcritical technology for pulverized coal. Increasing coal costs make the added efficiency of the supercritical technology more cost-effective. Additionally, there is a greater competitive marketplace for large supercritical boilers than for large subcritical boilers. Increasingly, large boiler manufacturers only offer supercritical boilers in the 500-plus MW sizes. Due to the increased efficiency of supercritical boilers, overall emission intensity rates are smaller than for similarly sized subcritical units. Compared to subcritical boilers, supercritical boilers also have better load following capability, faster ramp rates, use less water and require less steel for construction. The costs shown in the SSR for a supercritical PC facility reflect the cost of adding a new unit at an existing site.

Carbon Capture

The requirement for CO_2 CCS represents a significant cost for both new and existing coal resources. In order for a coal-fueled generating facility to meet the Federal New Source Performance Standards for Greenhouse Gases (NSPS-GHG) carbon dioxide emissions limit of 1,100 lbs per megawatt-hour would require CO_2 capture and permanent sequestration.[1] Capital

[1] This limit is still in effect and applies as it relates carbon capture analysis for the 2019 IRP. It should also be noted that on December 2018, EPA proposed revisions to the NSPS for GHG. Under the proposed rule, newly constructed plant CO_2 limits will be based on the most efficient demonstrated steam cycle in combination with the best operating practices. For large units, the BSER is proposed to be super-critical steam conditions, and if revised the emission rate would be 1,900 pounds of CO_2 per megawatt-hour on a gross output basis. For large units, the BSER

costs do not include the 45Q tax credit for carbon dioxide sequestration or enhanced oil recovery. Based on this requirement, only coal resource options that include carbon capture are included in the SSR.

Two major utility-scale CCS retrofit projects have been recently constructed and have entered commercial operation on pulverized coal plants in North America. SaskPower's 115 MW (net) $1.24 billion Boundary Dam project entered commercial operation in October 2014. In July 2016, the plant reached a major milestone when it demonstrated that over 1,100,000 tons of CO_2 had been captured. In January 2017, NRG's Petra Nova project went into commercial operation. Both of these projects have CO_2 capture rates in excess of 90 percent; sequestration is accomplished through enhanced oil recovery (EOR). Both of these projects utilize amine-based systems for carbon dioxide capture.

The Petra Nova project is especially meaningful in that the project entailed a retrofit of an existing coal-fueled plant using amine based system and captures approximately 5,000 tons per day from the 240 MWh equivalent flue gas slipstream from NRG's W.A. Parish unit 8. Captured CO_2 is transported through an 81-mile pipeline and used for EOR at the West Ranch Oilfield, located on the Gulf Coast of Texas. It is the largest retrofit of a carbon capture technology of a pulverized coal plant in the world. Petra Nova is 50-50 joint venture by NRG and JX Nippon. The United States DOE is provided up to $190 million in grants as part of the Clean Coal Power Initiative Program (CCPI), a cost-shared collaboration between the federal government and private industry. The amine-based capture system utilizes Mitsubishi's proprietary KM CDR Process® and uses its KS-1™ amine solvent.

PacifiCorp continues to monitor CO_2 capture technologies for possible retrofit application on its existing coal-fired resources, as well as their applicability for future fossil fueled plants that could serve as cost-effective alternatives to IGCC plants. An option to capture CO_2 at an existing coal-fired unit has been included in the SSR. Currently there are only a limited number of large-scale sequestration projects in operation around the world; most of these have been installed in conjunction with enhanced oil recovery. Given the high capital cost of implementing CCS on coal fired generation (either on a retrofit basis or for new resources) CCS is not considered a viable option before 2025. Factors contributing to this position include capital cost risk uncertainty, the availability of commercial sequestration (non-EOR) sites, uncertainty regarding long term liabilities for underground sequestration, and the availability of federal funding to support such projects.

To address the availability of commercial sequestration, three PacifiCorp power plants participated in federally funded research to conduct a Phase I pre-feasibility study of carbon capture and storage. A grant from the U.S. DOE to the University of Wyoming was used to assess the storage of carbon dioxide in the Rock Springs Uplift, a geologic formation located adjacent to the Jim Bridger Plant in southwest Wyoming. Similar funding was allocated to the University of Utah to study the feasibility of long-term carbon dioxide storage in the San Rafael Swell near the Hunter and Huntington plants in central Utah. Both of projects showed that geological formations exist near the plants that may support carbon sequestration, though further study would be required. Neither site was selected by the U.S. DOE for advance study in the Phase II of the grant program.

is proposed to be subcritical conditions, and if revised the emission rate would be 2,200 pounds of CO_2 per megawatt-hour regardless of the size of the unit.

PacifiCorp issued a request for expression of interest to potential carbon capture, utilization, and storage (CCUS) counterparties on September 7, 2018. The request focused on possible deployment of CCUS technologies at PacifiCorp's Dave Johnston generating facility for potential enhanced oil recovery (EOR). On February 28, 2019, a phase I feasibility study was received by each of the three interested parties selected to participate (Jupiter Oxygen, ION Clean Energy [previously Eco2Source], and Glenrock Energy). On April 23, 2019, the participants were notified they may progress to phase II engagement of front-end engineering design (FEED) study at their discretion. None of the participants received DOE grant funds to support their FEED studies. PacifiCorp remains open to a CCUS project with the three parties if they secure funding in their own efforts.

An alternative to supercritical pulverized-coal technology for coal-based generation is the application of IGCC technology. A significant advantage for IGCC when compared to pulverized coal with amine-based carbon capture, is the reduced cost of capturing CO_2 from the process. Only a limited number of IGCC plants have been built and operated around the world. In the United States, these facilities have been demonstration projects, resulting in capital and operating costs that are significantly greater than those costs for conventional coal plants. These projects have been constructed with significant federal funding. One large, utility-scale IGCC plant with carbon capture capability recently went into service. Southern Company's 582 MW (net) $6.8 billion Kemper County project includes carbon capture (65 percent capture) and sequestration (for EOR). The plant produced electric power using syngas in October of 2016. Leaks caused the plant to miss the scheduled March 2017 completion date. Kemper power plant suspended coal gasification in June 2017.

The costs presented in the SSR for new IGCC resources are based on 2007 studies of IGCC costs associated with efforts to partner PacifiCorp with the Wyoming Infrastructure Authority (WIA) to investigate the acquisition of federal grant money to demonstrate western IGCC projects.

A consortium of Japanese firms received orders on December 1, 2016 for two 540 MW IGCC plants to be constructed in Japan based on Mitsubishi's IGCC technology that was tested at the Nakoso Power Station from 2007 through 2013. A number of countries, including China, Turkey, Dubai, India, Kenya, Philippines, South Korea, Japan, and Malaysia have also announced plans to construct new conventional coal-fueled electric generating resources which will be monitored from a cost and technology deployment perspective.

No new cost studies were performed for coal-fueled generation options in 2018. Updated capital and O&M costs for coal-fuel generation options were based on escalating costs used in the 2017 IRP.

Coal Plant Efficiency Improvements

Fuel efficiency gains for existing coal plants, which are manifested as lower plant heat rates, are realized by: (1) continuous operations improvement, (2) monitoring the quality of the fuel supply, and (3) upgrading components if economically justified. Efficiency improvements can result in a smaller emissions footprint for a given level of plant capacity, or the same footprint when plant capacity is increased.

The efficiency of generating units, primarily measured by the heat rate (the ratio of heat input to energy output) degrades gradually as components wear over time. During operation, controllable process parameters are adjusted to optimize the unit's power output compared to its heat input. Typical overhaul work that contributes to improved efficiency includes (1) major equipment overhauls of the steam generating equipment and combustion/steam turbine generators, (2) overhauls of the cooling systems and (3) overhauls of the pollution control equipment.

When economically justified, efficiency improvements are obtained through major component upgrades of the electricity generating equipment. The most notable examples of upgrades resulting in greater generating capacity are steam turbine upgrades. Turbine upgrades can consist of adding additional rows of blades to the rearward section of the turbine shaft (generically known as a "dense pack" configuration), but can also include replacing existing blades, replacing end seals, and enhancing seal packing media. Currently PacifiCorp has no plans to make any major steam turbine or generator upgrades over the next 10 years.

Nuclear

PacifiCorp revisited two of the nuclear options presented in the 2017 for the 2019 IRP: 1) the AP 1000 plant being developed by Blue Castle Holdings in Green River, Utah rated at 2,234 MW and 2) the 570 MW NuScale Small Modular Reactor (SMR) being developed for construction at the Idaho National Lab site. Blue Castle Holdings (BCH) did not provide updated pricing, therefore costs were escalated by two years from the costs used in the 2017 IRP. NuScale provided an update on their design, licensing and costs. NuScale's update resulted in a significant decline in the capital cost number for the Small Modular Reactor (SMR) resource option.

In 2016 BCH provided a detailed cost analysis of the Vogtle plant construction and eliminated unexpected costs which would not apply to the Green River site such as geotechnical problems encountered at the Vogtle site. The Vogtle plant was a first of a kind (FOAK) plant but the Green River plant would be an Nth of a kind (NOAK) plant based on the Vogtle plant AP 1000 design. PacifiCorp added a 3.7 percent delay cost to BCH's capital cost estimate for potential unforeseen problems not encountered on the Vogtle project. Details of the BCH project can be found at www.bluecastleproject.com.

NuScale is developing an advanced reactor design in the SMR category. Although it is an FOAK technology, the design has inherent safety features which support reduced capital costs and operating cost estimates. PacifiCorp has a seat on the NuScale advisory board, however PacifiCorp has no monetary interest in NuScale or the SMR project being developed for the Idaho National Lab site. PacifiCorp added five percent contingency and ten percent delay costs due to the project being FOAK. Details of NuScale's SMR can be found at www.nuscalepower.com.

PacifiCorp's capital cost estimates include a 10.36 percent owner's cost for the BCH and NuScale projects. Despite the cost improvements due to the learning curve associated with the AP-1000's previous installations or the NuScale SMR's simplified design attributes, nuclear generation is still expected to have a high LCOE relative to other generation options.

Demand-side Resources

Resource Options and Attributes

Source of Demand-Side Management Resource Data

PacifiCorp conducted a Conservation Potential Assessment (CPA) with for 2019-2038, which provided DSM resource opportunity estimates for the 2019 IRP. The study was conducted by

Applied Energy Group (AEG) on behalf of the company. The CPA provided a broad estimate of the size, type, location and cost of demand-side resources.[2] For the purpose of integrated resource planning, the DSM information from the CPA was converted into supply curves by type of resource (i.e. energy-based energy efficiency and demand response) for modeling against competing supply-side alternatives.

Demand-Side Management Supply Curves

DSM resource supply curves are a compilation of point estimates showing the relationship between the cumulative quantity and cost of resources, providing a representative look at how much of a particular resource can be acquired at a particular price point. Resource modeling utilizing supply curves allows the selection of least-cost resources (e.g. products and quantities) based on each resource's competitiveness against alternative resource options. Due to the timing of the 2019 IRP planning and modeling, PacifiCorp had established, funded and begun acquiring 2019 DSM program acquisition targets. To ensure that the 2019 IRP analysis is consistent with existing planned energy efficiency acquisition levels (i.e., Class 2 DSM), expected DSM savings in each state were fixed for calendar year 2019. Beyond 2019, the model optimized DSM selections.

As with supply-side resources, the development of DSM supply curves requires specification of quantity, availability, and cost attributes. Attributes specific to DSM curves include:

- Resource quantities available in each year either in terms of megawatts or megawatt-hours, recognizing that some resources may come from stock additions not yet built, and that elective resources cannot all be acquired in the first year of the planning period;
- Persistence of resource savings (e.g., energy efficiency equipment measure lives);
- Seasonal availability and hours available (e.g., irrigation load control programs);
- The hourly shape of the resource (e.g., load shape of the resource); and
- Levelized resource costs (e.g., dollars per kilowatt per year for energy efficiency, or dollars per megawatt-hour over the resource's life for demand response resources).

Once developed, DSM supply curves are treated like discrete supply-side resources in the IRP modeling environment.

Demand Response: DSM Capacity Supply Curves

The potential and costs for demand response resources were provided at the state level, with impacts specified separately for summer and winter peak periods. Resource price differences between states for similar resources reflect differences in each market, such as irrigation pump size and hours of operation, as well as product performance differences. For instance, residential air conditioning load control in Oregon is more expensive than Utah on a unitized or dollar-per-kilowatt-year basis due to climatic differences that result in a lower load impact per installed switch.

Table 6.6 and Table 6.7 show the summary level demand response resource supply curve information, by control area. For additional detail on demand response resource assumptions used to develop these supply curves, see Volume 3 of the 2019 CPA.[3] Potential shown is incremental to the existing DSM resources identified in Table 5.12. For existing program offerings, it is

[2] The 2019 Conservation Potential Study is available on PacifiCorp's demand-side management web page. www.pacificorp.com/energy/integrated-resource-plan/support.html.

[3] The CPA can be found at: www.pacificorp.com/energy/integrated-resource-plan/support.html.

assumed that the PacifiCorp could begin acquiring incremental potential in 2019. For resources representing new product offerings, it is assumed PacifiCorp could begin acquiring potential in 2020, accounting for the time required for program design, regulatory approval, vendor selection, etc.

Table 6.6 – Demand Response Program Attributes West Control Area

Product	Summer 20-Year Potential (MW)	Summer Levelized Cost ($/kW-yr)	Winter 20-Year Potential (MW)	Winter Levelized Cost ($/kW-yr)
DLC Cooling & WH - Res and C&I	33	$44 - $48	18	$136 - $157
DLC Space Heating Res & C&I	n/a	n/a	82	$7 - $27
DLC Room AC - Res	1	$352	n/a	n/a
DLC Smart Thermostat - Res	84	$31 - $54	84	$30 - $91
DLC Smart Appliance - Res	4	$210	4	$221
DLC Elec Vehicle Charging - Res	1	$763	1	$773
DLC Irrigation	26	$37 - $40	n/a	n/a
Third Party Contracts	50	$55 - $56	43	$94 - $100
Ice Energy Storage	3	$134	n/a	n/a
Ancillary Services	9	$14 - $20	n/a	n/a

[1] For consistency in modeling, water heating potential for both seasons is included with the central air conditioning product.

Table 6.7 – Demand Response Program Attributes East Control Area

Product	Summer 20-Year Potential (MW)	Summer Levelized Cost ($/kW-yr)	Winter 20-Year Potential (MW)	Winter Levelized Cost ($/kW-yr)
DLC Cooling & WH - Res and C&I	64	($4) - $49	20	$171 - $458
DLC Space Heating Res & C&I	n/a	n/a	55	$9 - $18
DLC Room AC - Res	2	$185	n/a	n/a
DLC Smart Thermostat - Res	167	$5 - $56	41	$77 - $285
DLC Smart Appliance - Res	8	$211	8	$222
DLC Elec Vehicle Charging - Res	4	$686	5	$696
DLC Irrigation	14	$14 - $44	n/a	n/a
Third Party Contracts	118	$53 - $63	90	$100 - $142
Ice Energy Storage	2	$143	n/a	n/a
Ancillary Services	20	($3) - $2	n/a	n/a

[1] For consistency in modeling, water heating potential for both seasons is included with the central air conditioning product.

Energy Efficiency DSM, Energy Supply Curves

The 2019 CPA provided the information to fully assess the potential contribution from DSM energy efficiency resources over the IRP planning horizon. The CPA analysis accounts for known changes in building codes, advancing equipment efficiency standards, market transformation, resource cost changes, changes in building characteristics and state-specific resource evaluation considerations (e.g. cost-effectiveness criteria).

DSM energy efficiency resource potential was assessed by state down to the individual measure and building levels (e.g. specific appliances, motors, lighting configurations for residential buildings, and small offices). The CPA provided DSM energy efficiency resource information at the following granularity:

- **State:** Washington, California, Idaho, Utah, Wyoming[4]
- **Measure:**
  - 89 residential measures
  - 130 commercial measures
  - 111 industrial measures
  - 22 irrigation measures
  - 11 street lighting measures

- **Facility type[5]:**
  - Six residential facility types
  - 28 commercial facility types
  - 30 industrial facility types
  - Two irrigation facility type
  - Four street lighting types

The 2019 CPA levelized total resource costs over the study period at PacifiCorp's cost of capital, consistent with the treatment of supply-side resources. Costs include measure costs and a state-specific adder for program administrative costs for all states except Utah and Idaho. Consistent with regulatory mandates, Utah and Idaho DSM energy efficiency resource costs were levelized using utility costs instead of total resource costs (i.e. incentive and a state specific adder for program administration costs).

The technical potential for all DSM energy efficiency resources across all states except Oregon over the twenty-year CPA planning horizon totaled 12.1 million MWh.[6] The technical potential represents the total universe of possible savings before adjustments for what is likely to be realized (i.e. technical achievable potential). When the achievable assumptions described below are considered the technical potential is reduced to a technical achievable potential for modeling consideration of 9.6 million MWh for all five states. The technical achievable potential for all six states for modeling consideration is 13.2 million MWh. The technical achievable potential, representing available potential at all costs, is provided to the IRP model for economic screening relative to supply-side alternatives.

Despite the granularity of DSM energy efficiency resource information available, it was impractical to model the resource supply curves at this level of detail. The combination of measures

[4] Oregon's DSM potential was assessed in a separate study commissioned by the Energy Trust of Oregon.
[5] Facility type includes such attributes as existing or new construction, single or multi-family. Facility types are more fully described in Chapter 4 of Volume 2 of the 2019 CPA.
[6] The identified technical potential represents the cumulative impact of DSM measure installations in the 20th year of the study period for California, Idaho, Washington, Wyoming, and Utah. This may differ from the sum of individual years' incremental impacts due to the introduction of improved codes and standards over the study period. ETO provides PacifiCorp with technical achievable potential.

by building type and state generated over 37,880 separate permutations or distinct measures that could be modeled using the supply curve methodology. To reduce the resource options for consideration without losing the overall resource quantity available or its relative cost, resources were consolidated into bundles, using ranges of levelized costs to reduce the number of combinations to a more manageable number. The range of measure costs in each of the 27 bundles used in the development of the DSM supply curves for the 2019 IRP are the same as those developed for the 2017 IRP.

Bundle development began with the energy efficiency technical potential identified by the 2019 CPA. To account for the practical limits associated with acquiring all available resources in any given year, the technical potential by measure was adjusted to reflect the amount that is realistically achievable over the 20-year planning horizon. Consistent with the Northwest Power and Conservation Council's aggressive regional planning assumptions, it was assumed that 85 percent of the technical potential for discretionary (retrofit) resources and on average up to 74 percent of lost-opportunity (new construction or equipment upgrade on failure) could be achievable over the 20-year planning period.[7]

For Wyoming, the 2017 CPA applied market ramp rates on top of measure ramp rates to reflect state-specific considerations affecting acquisition rates, such as age of programs, small and rural markets, and current delivery infrastructure for the industrial market. This mechanism was used solely in the Wyoming industrial sector to reflect that program momentum is still building. Recent program accomplishments within this market indicate that this trend has come to an end, therefore the "emerging" market ramp rate was removed from the 2019 CPA.

For Oregon, the company does not assess potential for the Energy Trust of Oregon (ETO). Neither PacifiCorp nor the ETO performed an economic screening of measures in the development of the DSM energy efficiency supply curves used in the development of the 2019 IRP, allowing resource opportunities to be economically screened against supply-side alternatives in a consistent manner across PacifiCorp's six states.

Twenty-seven cost bundles were available across six states (including Oregon), which equates to 189 DSM energy efficiency resource supply curves. Table 6.9 shows the 20-year MWh potential for DSM energy efficiency cost bundles, designated by ranges of $/MWh. Table 6.10 shows the associated bundle price after applying cost credits afforded to DSM energy efficiency resources within the model. These cost credits include the following:

- A state-specific transmission and distribution investment deferral cost credit (Table 6.8)
- Stochastic risk reduction credit of $4.74/MWh[8]
- Northwest Power Act 10-percent credit (Oregon and Washington resources only)[9]

[7] The Northwest's achievability assumptions include savings realized through improved codes and standards and market transformation, and thus, applying them to identified technical potential represents an aggressive view of what could be achieved through utility DSM programs.
[8] PacifiCorp developed this credit from two sets of production dispatch simulations of a given resource portfolio, and each set has two runs with and without DSM. One simulation is on deterministic basis and another on stochastic basis. Differences in production costs between the two sets of simulations determine the dollar per MWh stochastic risk reduction credit.
[9] The formula for calculating the $/MWh credit is: (Bundle price - ((First year MWh savings x market value x 10%) + (First year MWh savings x T&D deferral x 10%))/First year MWh savings. The levelized forward electricity price for the Mid-Columbia market is used as the proxy market value.

Table 6.8 – State-specific Transmission and Distribution Credits

State	Transmission Deferral Value ($/KW-year)	Distribution Deferral Value ($/KW-year)	Total
California	$4.16	$6.58	$10.74
Oregon	$4.16	$9.20	$13.36
Washington	$4.16	$11.79	$15.95
Idaho	$4.16	$11.07	$15.22
Utah	$4.16	$9.02	$13.18
Wyoming	$4.16	$5.26	$9.41

The bundle price is the average levelized cost for the group of measures in the cost range, weighted by the potential of the measures. In specifying the bundle cost breakpoints, narrow cost ranges were defined for the lower-cost resources to ensure cost accuracy for the bundles considered more likely to be selected during the resource selection phase of the IRP.

To capture the time-varying impacts of Energy Efficiency resources, each bundle has an annual 8,760 hourly load shape specifying the portion of the maximum capacity available in any hour of the year. These shapes are created by spreading measure-level annual energy savings over 8,760 load shapes, differentiated by state, sector, market segment, and end use accounting for the hourly variance of Energy Efficiency impacts by measure. These hourly impacts are then aggregated for all measures in a given bundle to create a single weighted average load shape for that bundle.

Table 6.9 – 20-Year Cumulative Energy Efficiency Potential by Cost Bundle (MWh)

Bundle	California	Idaho	Oregon	Utah	Washington	Wyoming
<= 10	38,912	98,747	549,917	1,418,505	210,292	394,131
10 - 20	5,902	35,788	109,045	566,451	76,449	111,399
20 - 30	4,600	67,228	344,713	693,917	69,502	68,278
30 – 40	33,081	47,387	611,481	583,173	166,070	251,490
40 – 50	13,351	24,007	527,253	347,710	52,089	233,920
50 - 60	6,383	38,617	260,480	243,779	46,787	167,890
60 – 70	3,769	18,357	200,163	126,915	47,964	74,670
70 – 80	7,788	8,773	168,229	187,482	29,400	30,877
80 – 90	2,953	12,369	70,325	137,044	24,985	14,797
90 – 100	4,346	14,246	11,637	143,151	23,308	41,359
100 – 110	4,338	7,669	56,015	183,773	18,899	85,951
110 – 120	2,303	15,195	39,623	136,567	14,302	20,700
120 – 130	2,189	13,926	15,688	86,346	25,419	13,837
130 – 140	10,391	7,160	115,146	93,739	35,915	6,266
140 – 150	7,600	4,996	62,573	174,762	18,017	19,605
150 - 160	1,930	5,055	137,281	43,708	13,759	9,608
160 – 170	1,947	9,360	33,284	46,478	10,014	6,732
170 – 180	2,458	2,396	72,957	44,581	7,050	17,150
180 – 190	1,723	1,843	15,798	37,927	11,791	10,135
190 – 200	795	1,362	2,294	34,678	20,928	4,693
200 – 250	14,147	32,139	2,924	115,841	56,428	44,598
250 – 300	10,007	8,305	4,795	100,695	17,555	19,324
300 – 400	11,658	13,731	4,220	170,174	31,286	23,599
400 – 500	1,848	4,078	17,134	55,579	11,608	9,894
500 – 750	6,087	10,509	46,965	131,028	24,455	12,672
750 – 1,000	5,567	4,268	42,758	26,471	22,776	16,008
> 1,000	5,423	9,639	21,631	110,459	23,582	29,420

Table 6.10 – Energy Efficiency Adjusted Prices by Cost Bundle

Bundle	Levelized Bundle Price after Adjustments ($/Mwh)					
	California	Idaho	Oregon	Utah	Washington	Wyoming
<= 10	0.00	0.00	0.00	0.00	0.00	0.00
10 - 20	7.17	7.38	3.78	8.51	3.22	9.15
20 - 30	17.16	19.50	16.95	18.80	13.09	19.80
30 – 40	30.89	26.09	24.24	28.65	21.00	29.79
40 – 50	39.40	37.37	30.92	36.97	32.09	38.65
50 - 60	48.22	47.70	45.59	47.03	42.11	49.10
60 – 70	58.30	56.11	55.38	58.39	51.24	59.58
70 – 80	68.96	68.95	61.14	68.37	61.77	68.31
80 – 90	75.19	78.50	75.41	77.77	71.98	77.34
90 – 100	85.37	86.97	80.72	87.31	84.14	89.22
100 – 110	96.01	97.72	93.21	97.58	93.27	101.60
110 – 120	106.63	106.27	104.52	106.11	102.29	109.79
120 – 130	116.57	116.90	111.81	118.16	108.59	118.19
130 – 140	128.80	128.48	122.02	126.21	122.26	129.51
140 – 150	136.45	137.75	130.87	133.88	131.34	137.47
150 - 160	149.00	149.10	146.47	146.57	141.99	145.73
160 – 170	156.75	155.37	150.50	158.40	152.30	159.28
170 – 180	167.97	167.15	160.56	167.95	163.07	168.35
180 – 190	179.45	175.72	174.23	177.40	170.44	178.51
190 – 200	188.51	187.27	187.86	187.81	179.70	189.38
200 – 250	226.03	203.75	221.72	213.95	209.13	225.45
250 – 300	272.36	272.99	266.16	264.04	260.89	261.66
300 – 400	324.14	347.69	345.42	322.75	314.55	339.77
400 – 500	423.36	432.51	402.40	431.52	431.94	430.26
500 – 750	604.98	655.21	618.22	611.51	583.68	576.48
750 – 1,000	903.32	836.74	871.60	878.69	867.09	890.11
> 1,000	4,170.84	3,473.61	1,977.88	3,913.95	4,293.67	3,965.04

Distribution Efficiency

PacifiCorp continues to evaluate distribution energy efficiency. The company's streetlight efficiency improvements continue, with older mercury vapor, metal halide and incandescent company owned streetlights being replaced with more efficient lights; high pressure sodium or light emitting diode (LED) each year. The savings associated with this ongoing effort is expected to be too small to warrant reporting.

PacifiCorp continues to develop its CYME CYMDIST® (power flow software) investment in ways that improve engineering response time and, indirectly, distribution system efficiency. In the last biennial period, more than 300 large (Level 2 and Level 3) distributed energy resource (DER) applications were studied in CYME. This resulted in more than 29 MW (nameplate) of approved private generation across the company. Any energy savings resulting from these approvals across the service territory has not been determined.

Neither of these distribution energy efficiency related activities have been modeled as potential resources in this IRP.

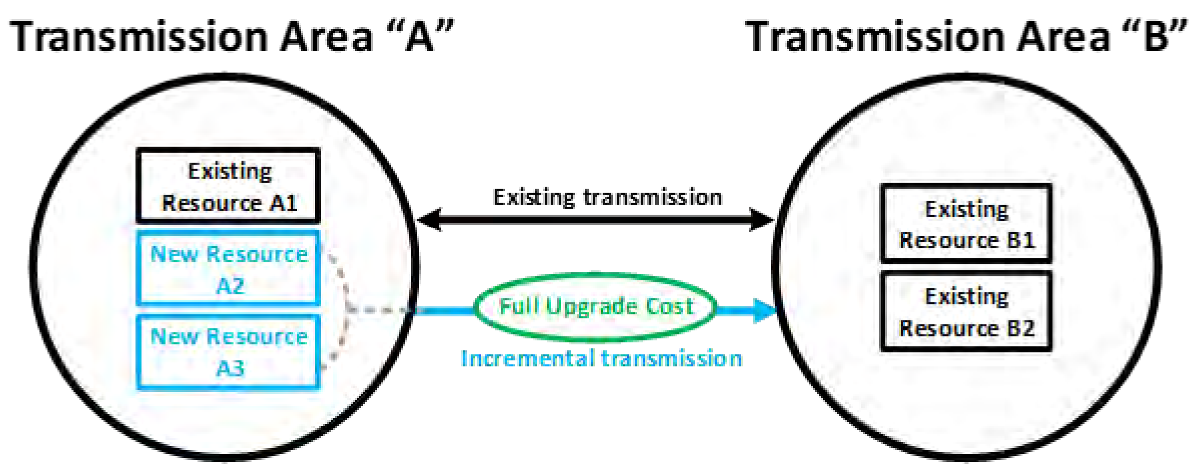
Transmission Resources

As part of it 2019 IRP, PacifiCorp was successfully able to provide the SO model with the ability to view costs and transmission capability associated with certain transmission upgrades that the model could incorporate along with new resource selections as it deemed optimal. This is an improvement from previous IRPs, where transmission upgrades and associated costs had to be determined and accounted for post-portfolio development. New transmission modeling capabilities include the endogenous consideration of 1) new incremental transmission options tied to resource selections, 2) existing transmission rights tied to the use of post-retirement brownfield sites, and 3) incorporation of costs associated with these transmission options.

Limitations of this approach include transmission options that interact with multiple or complex elements of the IRP transmission topology. Transmission options that are too complex to be captured by the modeling enhancements were therefore studied as sensitivity cases.

Figure 6.7 illustrates the new incremental transmission option modeling capability between two generic transmission areas in the IRP topology. Because the incremental transmission segment (shown in blue) is associated with new resource additions, the model selects them together, endogenously considering the upgrade cost in relation to the benefits of the new expansion resources.

Figure 6.7 – Endogenous Transmission Modeling



In many cases, transmission upgrades do not add incremental transmission capacity to the system, but rather increase interconnection capability. The upgrade cost in such cases is to accommodate additional capacity at a location, and the transmission topology itself is unaffected. For example, additional transmission capacity or transmission reinforcements that are confined to a transmission area incur an upgrade cost but would not add transmission capacity to the larger system. A map of PacifiCorp's transmission system model topology is provided in Volume I, Chapter 7 (Modeling and Portfolio Evaluation Approach).

Table 6.11 reports the endogenous incremental transmission options included in the 2019 IRP.

Table 6.11 – Transmission Integration Options by Location and Capacity Increment

IRP Bubble	Added Resource MW		IRP Year	Description of Integration	Affected Topology Path(s)		
	Min	Max			Incremental Capacity (if any)	From Bubble	To Bubble
Portland/N. Coast	1	130	2024	Portland area local reinforcement	-	-	-
	131	580	2030	Portland area (Troutdale) to Albany area 230 kV transmission	450	Portland	Willamette
Willamette	1	615	2024	Albany area local reinforcement	-	-	-
	616	1115	2030	Albany area to Roseburg area 500 kV transmission	1500	Willamette	South-Central Oregon
Yakima	1	405	2024	Yakima area local reinforcement	-	-	-
	406	835	2030	Yakima area to Bend area 230 kV transmission	450	Yakima	South-Central Oregon
Walla Walla	1	100	2030	Walla Walla area to Yakima lower valley transmission	200	Walla Walla	Yakima
South-Central OR/N. California	1	500	2024	Medford area 500-230 kV and 230 kV reinforcement	-	-	-
	501	975	2025	Medford area 500-230 kV and 230 kV reinforcement	-	-	-
Bridger	1	650	2026	Energy Gateway segment D.2 (Anticline-Populus 500 kV transmission line)	650	Bridger	Bridger West (Populus)
Goshen	1	450	2023	Southern Idaho reinforcement	-	-	-
	451	1100	2029	Southern Idaho reinforcement	800	Goshen	Utah North
Wyoming NE	1	460	2023	Energy Gateway segment D.1 (Windstar - Shirley Basin 230 kV line)	-	-	-
Wyoming SW	1	100	2024	Southwest Wyoming area reinforcement	-	-	-
	101	500	2026	Separation of double circuit 230 kV lines, Southwest Wyoming/northern Utah area	-	-	-
Aeolus	1	1920	2024	Energy Gateway segment F (Aeolus-Clover 500 kV transmission line)	1700	Aeolus	Utah South
Utah North	1	300	2021	Northern Utah 345 kV reinforcement	-	-	-
	301	900	2024	Northern Utah 345 kV reinforcement	-	Utah North	Utah North
Utah South	1	300	2021	Utah Valley area 345-138 kV and 138 kV local reinforcement	-	-	-
	301	800	2027	Utah Valley area local 138 kV reinforcement	-	-	-

Market Purchases

PacifiCorp and other utilities engage in purchases and sales of electricity on an ongoing basis to balance the system and maximize the economic efficiency of power system operations. In addition to reflecting spot market purchase activity and existing long-term purchase contracts in the IRP portfolio analysis, PacifiCorp modeled front office transactions (FOT). FOTs are proxy resources, assumed to be firm, that represent procurement activity made on an on-going forward basis to help the company cover short positions.

As proxy resources, FOTs represent a range of purchase transaction types. They are usually standard products, such as heavy load hour (HLH), light load hour (LLH), and super peak (hours ending 13 through 20) and typically rely on standard enabling agreements as a contracting vehicle. FOT prices are determined at the time of the transaction, usually via an exchange or third party broker, and are based on the then-current forward market price for power. An optimal mix of these purchases would include a range of volumes and terms for these transactions.

Solicitations for FOTs can be made years, quarters or months in advance, however, most transactions made to balance PacifiCorp's system are made on a balance of month, day-ahead, hour-ahead, or intra-hour basis. Annual transactions can be available three or more years in advance. Seasonal transactions are typically delivered during quarters and can be available from one to three years or more in advance. The terms, points of delivery, and products will all vary by individual market point.

Three FOT types were included for portfolio analysis in the 2019 IRP: an annual flat product, a HLH July for summer, and a HLH December for winter product. An annual flat product reflects energy provided to PacifiCorp at a constant delivery rate over all the hours of a year. The HLH transactions represent purchases received 16 hours per day, six days per week for July and December. Table 6.12 shows the FOT resources included in the IRP models, identifying the market hub, product type, annual megawatt capacity limit, and availability. PacifiCorp develops its FOT limits based upon its active participation in wholesale power markets, its view of physical delivery constraints, market liquidity and market depth, and with consideration of regional resource supply (see Volume II, Appendix J for an assessment of western resource adequacy). Prices for FOT purchases are associated with specific market hubs and are set to the relevant forward market prices, time period, and location, plus appropriate wheeling charges, as applicable. Additional discussion of how FOTs are modeled during the resource portfolio development process of the IRP is included in Volume I, Chapter 7 (Modeling and Portfolio Evaluation Approach).

Table 6.12 - 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 ("7x24") or Heavy Load Hour ("6X16")	400	400
Heavy Load Hour ("6X16")	375	375
California Oregon Border (COB)		
Flat Annual ("7x24") or Heavy Load Hour ("6X16")	250	250
Nevada Oregon Border (NOB)		
Heavy Load Hour ("6X16")	100	100
Mona		
Heavy Load Hour ("6X16")	300	300

CHAPTER 7 – MODELING AND PORTFOLIO EVALUATION APPROACH

CHAPTER HIGHLIGHTS

- The Integrated Resource Plan (IRP) modeling approach is used to assess the comparative cost, risk, and reliability attributes of resource portfolios. The 2019 IRP modeling and evaluation approach consists of three basic steps used to select a preferred portfolio—coal studies, portfolio development, and final portfolio screening.
- PacifiCorp uses the System Optimizer (SO) model to produce unique resource portfolios across a range of different planning cases. Informed by the public-input process, PacifiCorp ultimately produced over 50 different resource portfolios, informed by the coal studies summarized in Volume II, Appendix R (Coal Studies). Each resource portfolio is unique with regard to the type, timing, location, and amount of new resources that could be pursued to serve customers over the next 20 years.
- PacifiCorp uses the Planning and Risk model (PaR) to perform stochastic risk analysis of the portfolios produced by the SO model. For top-performing resource portfolios, PaR studies were developed to evaluate cost and risk among three natural gas price scenarios (low, medium, and high) and three carbon dioxide (CO_2) price scenarios (zero, medium, high). An additional price-policy scenario was developed to evaluate performance assuming a CO_2 price signal that aligns with the social cost of carbon. Taken together, there are four distinct price-policy scenarios (medium gas/medium CO_2, high gas/high CO_2, low gas/zero CO_2, and the social cost of carbon). The resulting cost and risk metrics are then used to compare portfolio alternatives and inform selection of the preferred portfolio.
- Taking into consideration stakeholder comments received during the public-input process, PacifiCorp also developed eight sensitivity cases designed to highlight the impact of specific planning assumptions on future resource selections along with the associated impact on system costs and stochastic risks. These sensitivities are informative in nature and support development of an acquisition path analysis, but were not considered for selection of the preferred portfolio.
- Informed by comprehensive modeling, PacifiCorp's preferred portfolio selection process involves evaluating cost and risk metrics reported from PaR, comparing resource portfolios on the basis of expected costs, low-probability high-cost outcomes, reliability, CO_2 emissions and other criteria.

Introduction

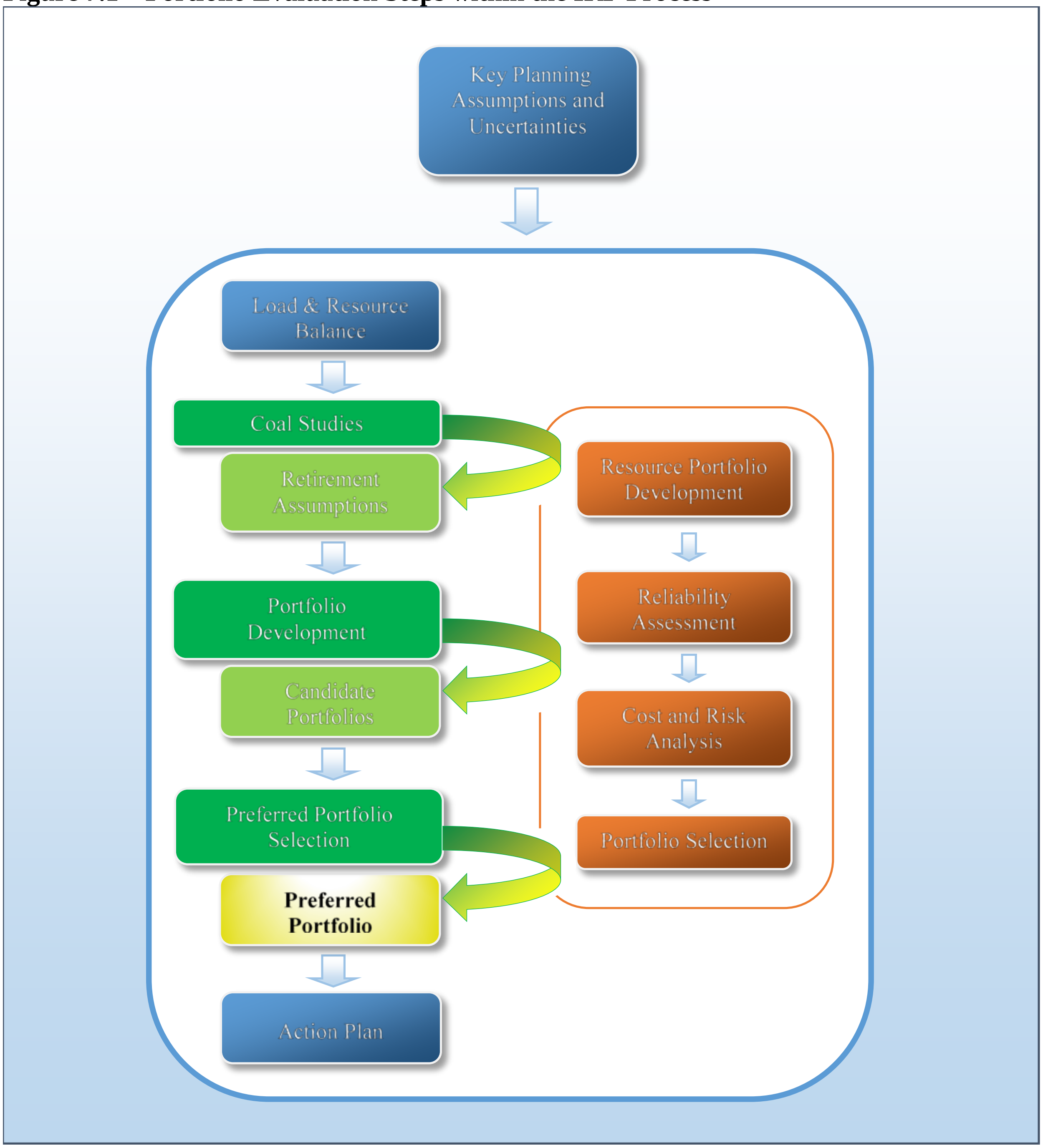
IRP modeling is used to assess the comparative cost, risk, and reliability attributes of different resource portfolios, each meeting a target planning reserve margin. These portfolio attributes form the basis of an overall quantitative portfolio performance evaluation.

The first section of this chapter describes the screening and evaluation processes for portfolio selection. Following sections summarize portfolio risk analyses, document key modeling assumptions, and describe how this information is used to select the preferred portfolio. The last section of this chapter describes the cases examined at each modeling and evaluation step. The results of PacifiCorp's modeling and portfolio analysis are summarized in Chapter 8 (Modeling and Portfolio Evaluation Approach).

Modeling and Evaluation Steps

Figure 7.1 summarizes the three modeling and evaluation steps for the 2019 IRP, highlighted in green. The three steps are (1) coal studies, (2) portfolio development, and (3) the final portfolio screening. The result of the final screening step is selection of the preferred portfolio.

Figure 7.1 – Portfolio Evaluation Steps within the IRP Process



For each modeling and evaluation step, PacifiCorp developed unique resource portfolios, analyzed cost and stochastic risk metrics for each portfolio, and selected, based on comparative cost and risk metrics, the specific portfolios considered in the next modeling and evaluation step. The outcomes of each can inform the need for additional studies to test or refine assumptions in a subsequent screening analysis. The basic portfolio evaluations within each step are highlighted in orange in Figure 7.1 above and include:

- Resource Portfolio Development
  All IRP models are configured and loaded with the best available information at the time a model run is produced. This information is fed into the SO model, which is used to produce resource portfolios with sufficient capacity to achieve a target planning reserve margin. Each resource portfolio is uniquely characterized by the type, timing, location, and amount of new resources in PacifiCorp's system over time.

- Reliability Assessment
  The 2019 IRP adds a reliability assessment phase to its portfolio processing, accounting for demonstrated reliability shortfalls driven by the replacement of flexible, dispatchable resources with intermittent variable resources. The reliability assessment uses up to 16 PaR deterministic model runs to assess hourly capacity shortfalls for years 2023 through 2038. This information is then used in the SO model to optimize the selection of additional reliability resources.

- Cost and Risk Analysis
  Resource portfolios developed by the SO model are simulated in PaR to produce metrics that support comparative cost and risk analysis among the different resource portfolio alternatives. Stochastic risk modeling of resource portfolio alternatives is performed using Monte Carlo sampling of stochastic variables across the 20-year study horizon, which include load, natural gas and wholesale electricity prices, hydro generation, and unplanned thermal outages.

- Portfolio Selection
  The portfolio selection process is based upon modeling results from the resource portfolio development and cost and risk analysis steps. The screening criteria are based on the present value revenue requirement (PVRR) of system costs, assessed across a range of price-policy scenarios on an expected-value basis and on an upper-tail stochastic risk basis. Portfolios are ranked using a risk-adjusted PVRR metric, a metric that combines the expected value PVRR with upper-tail stochastic risk PVRR. The final selection process considers cost-risk rankings, robustness of performance across pricing scenarios and other supplemental modeling results, including reliability and CO_2 emissions data.

Resource Portfolio Development

Resource expansion plan modeling, performed with the SO model, is used to produce resource portfolios with sufficient capacity to achieve a target planning reserve margin over the 20-year study horizon. Each resource portfolio is uniquely characterized by the type, timing, location, and amount of new resources in PacifiCorp's system over time. These resource portfolios reflect a combination of planning assumptions such as resource retirements, CO_2 prices, wholesale power and natural gas prices, load growth net of assumed private generation penetration levels, cost and performance attributes of potential transmission upgrades, and new and existing resource cost and performance data, including assumptions for new supply-side resources and incremental demand-side resources (DSM). Changes to these input variables cause changes to the resource mix, which influences system costs and risks.

System Optimizer

The SO model operates by minimizing operating costs for existing and prospective new resources, subject to system load balance, reliability and other constraints. Over the 20-year planning horizon, it optimizes resource additions subject to resource costs and capacity constraints (summer peak loads, winter peak loads, plus a target planning reserve margin for each load area represented in the model). In the event that an early retirement of an existing generating resource is assumed for a given planning scenario, the SO model will select additional resources as required to meet summer and winter peak loads inclusive of the target planning reserve margin.

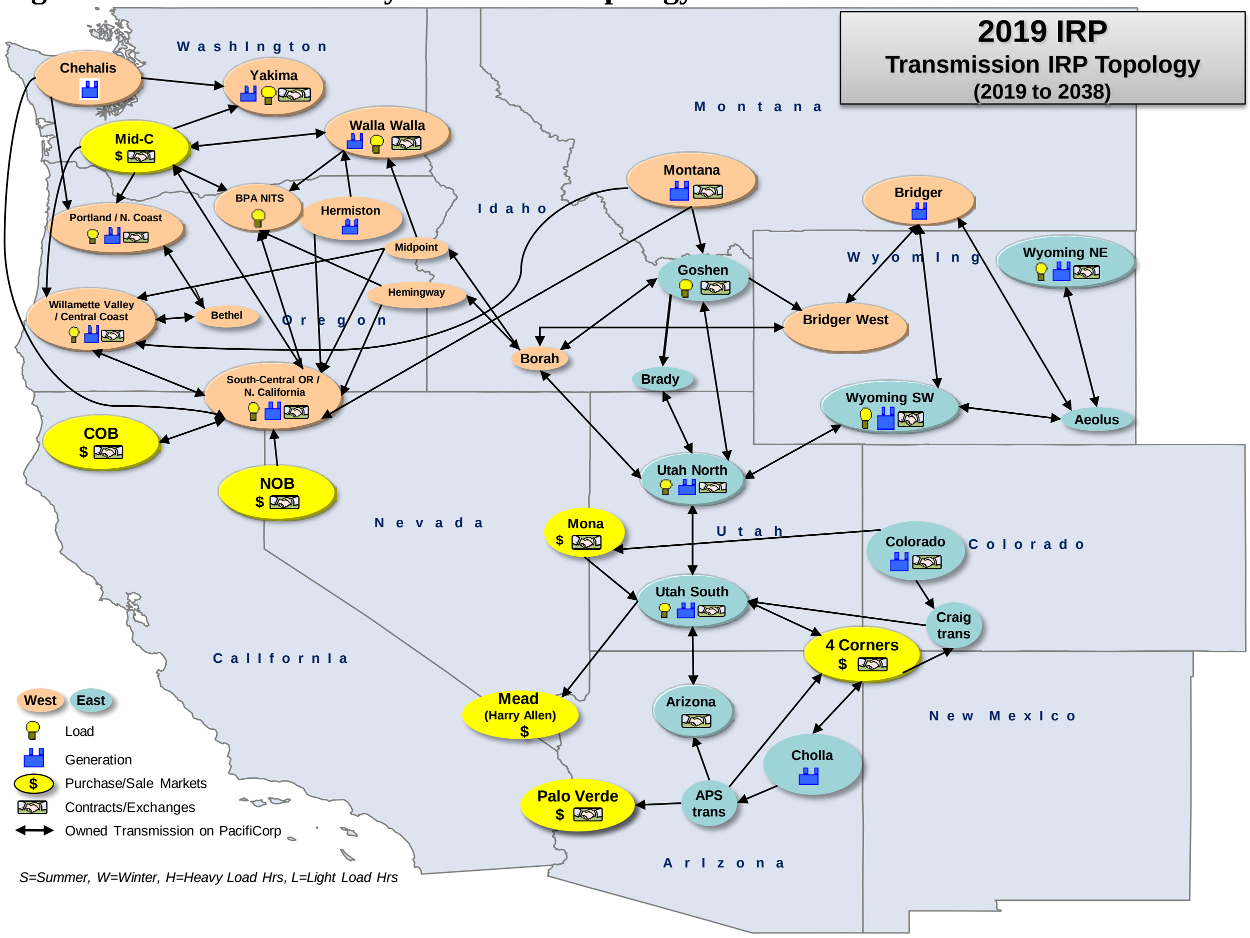
To accomplish these optimization objectives, the SO model performs a time-of-day least-cost dispatch for existing and potential planned generation, while considering cost and performance of existing contracts and new DSM alternatives within PacifiCorp's transmission system. Resource dispatch is based on a representative-week method. Time-of-day hourly blocks are simulated according to a user-specified day-type pattern representing an entire week. Each month is represented by one week, and the model scales output results to the number of days in the month and then the number of months in the year. Dispatch also determines optimal electricity flows between zones and includes spot market transactions for system balancing. The model minimizes the system PVRR, which includes the net present value cost of existing contracts, spot market purchase costs, spot market sale revenues, generation costs (fuel, fixed and variable operation and maintenance, decommissioning, emissions, unserved energy, and unmet capacity), costs of DSM resources, amortized capital costs for existing coal resources and potential new resources, and costs for potential transmission upgrades.

The SO model is also used in developing the reliability portfolio for each case, receiving reliability requirements determined by the PaR model as described in Volume II, Appendix R, Figure R.1 (Coal Studies), applies to all resource portfolio-development in the 2019 IRP.

Transmission System

PacifiCorp uses a transmission topology that captures major load centers, generation resources, and market hubs interconnected via firm transmission paths. Transfer capabilities across transmission paths are based upon the firm transmission rights of PacifiCorp's merchant function, including transmission rights from PacifiCorp's transmission function and other regional transmission providers. Figure 7.2 shows the 2019 IRP transmission system model topology.

Figure 7.2 – Transmission System Model Topology



Transmission Costs

In developing resource portfolios for the 2019 IRP, PacifiCorp includes new modeling to endogenously select transmission options, in consideration of relevant costs and benefits. These costs are influenced by the type, timing, location, and amount of new resources as well as any assumed resource retirements, as applicable, in any given portfolio. Additional details on endogenous transmission modeling are provided in Volume I, Chapter 6 (Resource Options).

Resource Adequacy

Resource adequacy is modeled in the portfolio-development process by ensuring each portfolio meets a target planning reserve margin. In its 2019 IRP, PacifiCorp continues to apply a 13 percent target planning reserve margin. The planning reserve margin, which influences the need for new resources, is applied to PacifiCorp's coincident system peak load forecast net of offsetting "load resources" such as energy efficiency. Planning to achieve a 13 percent planning reserve margin ensures that PacifiCorp has sufficient resources to meet its peak load, recognizing that there is a possibility for load fluctuation and extreme weather conditions, fluctuation of variable generation resources, a possibility for unplanned resource outages, and reliability requirements to carry sufficient contingency and regulating reserves. Volume II, Appendix I (Planning Reserve Margin Study) summarizes PacifiCorp's updated planning reserve margin study that supports selection of a 13 percent target planning reserve margin in the 2019 IRP.

New Resource Options

Dispatchable Thermal Resources

The SO model performs time-of-day least cost dispatch of existing and potential new thermal resources to meet load while minimizing costs. Dispatch costs applicable to thermal resources include fuel costs, non-fuel variable operations & maintenance (VOM) costs, and the cost of emissions, as applicable. For existing and potential new dispatchable thermal resources, the SO model uses generator-specific inputs for fuel costs, VOM, heat rates, emission rates, and any applicable price for emissions to establish the dispatch cost of each generating unit for each dispatch interval. Thermal resources are dispatched by least cost merit order. The power produced by these resources can be used to meet load or to make off-system sales at times when resource dispatch costs fall below market prices. Conversely, at times when dispatch costs exceed market prices, off-system purchases can displace dispatchable thermal generation to minimize system energy costs. Dispatch of thermal resources reflects any applicable transmission constraints connecting generating resources with both load and market bubbles as defined in the transmission topology for the model.

Front Office Transactions

Front office transactions (FOTs) represent short-term firm market purchases for physical delivery of power. PacifiCorp is active in the western wholesale power markets and routinely makes short-term firm market purchases for physical deliveries on a forward basis (i.e., prompt month forward, balance of month, day-ahead, and hour-ahead). These transactions are used to balance PacifiCorp's system as market and system conditions become more certain when the time between an effective transaction date and real time delivery is reduced. Balance of month and day-ahead physical firm market purchases are most routinely acquired through a broker or an exchange, such as the Intercontinental Exchange (ICE). Hour-ahead transactions can also be made through an exchange. For these types of transactions, the broker or the exchange provides a competitive price. Non-brokered transactions can also be used to make firm market purchases among a wide range of forward delivery periods.

From a modeling perspective, it is not feasible to incorporate all of the short-term firm physical power products, which differ by delivery pattern and delivery period, that are available through brokers, exchanges, and non-brokered transactions. However, considering that PacifiCorp routinely uses these types of firm transactions, which obligate the seller to back the transaction with reserves when balancing its system, it is important that the capacity contribution of short-term firm market purchases are accounted for in the portfolio-development process. For capacity optimization modeling, short-term firm forward transactions are represented as FOTs and configured in the SO model with either an annual flat, summer-on-peak (July), or winter on-peak (December) delivery pattern in every year of the twenty-year planning horizon. As configured in SO, FOTs contribute capacity toward meeting the 2019 IRP's 13 percent target planning reserve margin and supply system energy consistent with the assumed FOT delivery pattern.

Unlike FOTs, system balancing transactions do not contribute capacity toward meeting the 13 percent target planning reserve margin. System balancing transactions include hourly off-system sales and hourly off-system purchases, representing market activities that minimize system energy costs as part of the economic dispatch of system resources, including energy from any FOTs included in a resource portfolio.

A description of FOT limits assumed in the 2019 IRP is included in Volume I, Chapter 6 (Resource Options). PacifiCorp's evaluation of resource adequacy in the western power markets is summarized in Volume II, Appendix J (Western Resource Adequacy Evaluation).

Demand-Side Management

The SO model can select incremental DSM resources during portfolio optimization development in each modeling and evaluation step. Selection of DSM resources is made from supply curves that define how much of a DSM resource can be acquired at a given cost.

Energy Efficiency (Class 2 DSM) resources are characterized with supply curves that represent achievable technical potential of the resource by state, by year, and by measures specific to PacifiCorp's service territory. For modeling purposes, these data are aggregated into cost bundles. Each cost bundle of the energy efficiency supply curves specifies the aggregate energy savings profile of all measures included within the cost bundle. Each cost bundle has both a summer and winter capacity contribution based on aggregate energy savings during on-peak hours in July and December aligning with periods where PacifiCorp is most likely to exhibit capacity shortfalls.

Demand Response (Class 1 DSM) resources, representing direct load control capacity resources, are also characterized with supply curves representing achievable technical potential by state and by year for specific direct load control program categories (i.e., air conditioning, irrigation, and commercial curtailment). The SO model evaluates demand response resources by considering capacity contribution, cost, and operating characteristics. Operating characteristics include variables such as total number of hours per year and hours per event that the demand response resource is available. Additional discussion of DSM resources modeled in the 2019 IRP is included in Volume I, Chapter 6 (Resource Options) and in Volume II, Appendix D (Demand-Side Management Resources).

Wind and Solar Resources

Certain wind and solar resources are dispatchable by the model up to fixed energy profiles that vary by day and month. The fixed energy profiles for wind and solar resources represents the expected generation levels in which half of the time actual generation would fall below expected levels, and half of the time actual generation would be above expected levels assuming no curtailments.

The capacity contribution of wind and solar resources, represented as a percentage of resource capacity, is a measure of the ability for these resources to reliably meet demand over time. These values are dependent on the underlying portfolio, and are expected to decline as the penetration of resources of the same type increases. For the purposes of portfolio selection, PacifiCorp developed capacity-contribution values specific to the five wind profiles and five solar profiles used for proxy resources. In addition, PacifiCorp developed contribution values for two levels of wind and solar penetration. A "high" capacity-contribution block allowed for up to 2,000 MW of new wind capacity and 1,000 MW of new solar capacity (roughly a 50 percent increase from the initial portfolio levels). Any additional wind and solar capacity beyond the first block was assigned a "low" capacity-contribution value, calculated based on an additional 2,000 MW of new wind capacity and 1,000 MW of new solar capacity. PacifiCorp also developed capacity-contribution values for each of the wind and solar locations when combined with lithium-ion battery storage with a maximum output equal to 25 percent of the renewable resource nameplate capacity and assuming a four-hour storage duration. Volume II, Appendix N (Capacity Contribution Study) summarizes PacifiCorp's capacity contribution study and the resulting values.

Energy Storage Resources

Energy storage resources are distinguished from other resources by the following three attributes:

- Energy take – generation or extraction of energy from a storage reservoir;
- Energy return – energy used to fill (or charge) a storage reservoir; and
- Storage cycle efficiency – an indicator of the energy loss involved in storing and extracting energy over the course of the take-return cycle.

Modeling energy storage resources requires specification of the size of the storage reservoir, defined in gigawatt-hours. The SO model dispatches a storage resource to optimize energy used by the resource subject to constraints such as storage-cycle efficiency, the daily balance of take and return energy, and fuel costs (for example, the cost of natural gas for expanding air with gas turbine expanders). To determine the least-cost resource expansion plan, the SO model accounts for conventional generation system performance and cost characteristics of the storage resource, including capital cost, size of the storage and time to fill the storage, heat rate (if fuel is used), operating and maintenance cost, minimum capacity, and maximum capacity. Because they are energy-limited, an energy storage resource may not be able to cover the entirety of an extended outage. For the 2019 IRP, PacifiCorp calculated capacity contribution values based on the duration of energy storage. Volume II, Appendix N (Capacity Contribution Study) summarizes the capacity contribution study and the resulting values for energy storage.

Capital Costs and End-Effects

The SO model uses annual capital recovery factors to convert capital dollars into real levelized revenue requirement costs to address end-effects that arise with capital-intensive projects that have different lives and in-service dates. All capital costs evaluated in the IRP are converted to real levelized revenue requirement costs. Use of real levelized revenue requirement costs is an established and preferred methodology for analyzing capital-intensive resource decisions among resource alternatives that have unequal lives and/or when it is not feasible to capture operating costs and benefits over the entire life of any given resource. To achieve this, the real levelized revenue requirement method spreads the return of investment (book depreciation), return on investment (equity and debt), property taxes and income taxes over the life of the investment. The result is an annuity or annual payment that grows at inflation such that the PVRR is identical to the PVRR of the nominal annual requirement when using the same nominal discount rate. For the 2019 IRP, the PVRR is calculated inclusive of real levelized capital revenue requirement through the end of the 2038 planning period.

General Assumptions

Study Period and Date Conventions

PacifiCorp executes its 2019 IRP models for a 20-year period beginning January 1, 2019 and ending December 31, 2038. Future IRP resources reflected in model simulations are given an in-service date of January 1st of a given year, with the exception of coal unit natural gas conversions, which are given an in-service date of June 1st of a given year, recognizing the desired need for these alternatives to be available during the summer peak load period.

Inflation Rates

The 2019 IRP model simulations and cost data reflect PacifiCorp's corporate inflation rate schedule unless otherwise noted. A single annual escalation rate value of 2.28 percent is assumed. The annual escalation rate reflects the average of annual inflation rate projections for the period 2019 through 2038, using PacifiCorp's September 2018 inflation curve. PacifiCorp's inflation curve is a straight average of forecasts for the Gross Domestic Product inflator and the Consumer Price Index.

Discount Factor

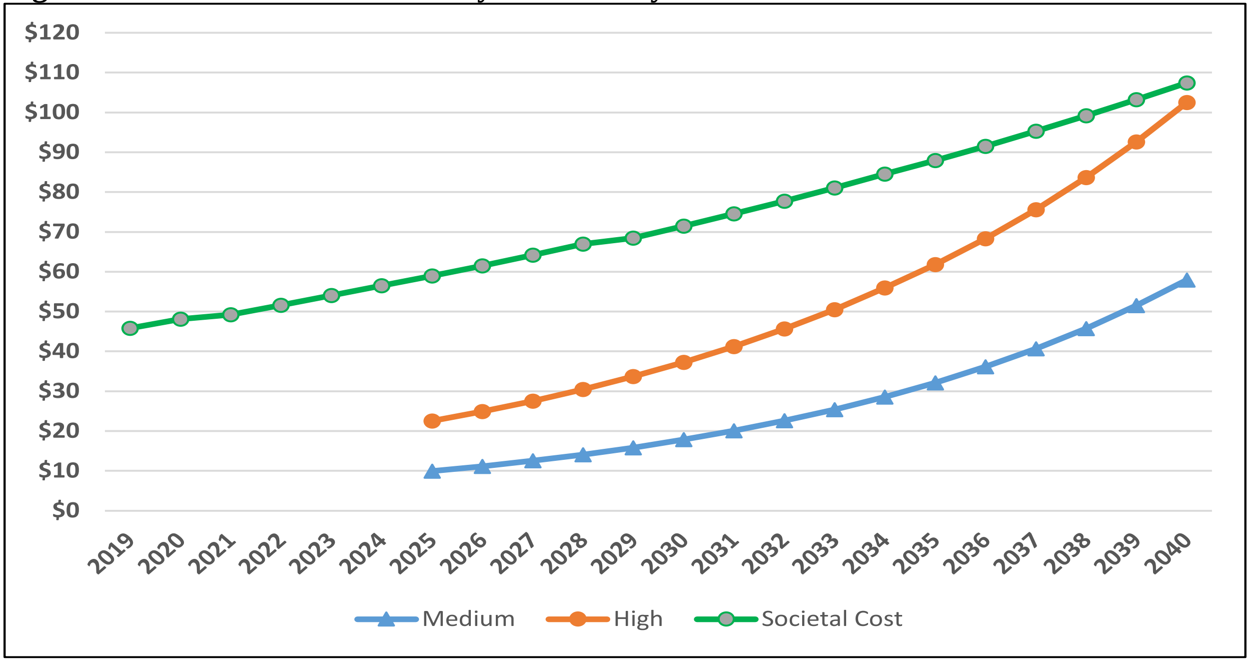
The discount rate used in present-value calculations is based on PacifiCorp's after-tax weighted average cost of capital (WACC). The value used for the 2017 IRP is 6.92 percent. The use of the after-tax WACC complies with the Public Utility Commission of Oregon's IRP guideline 1a, which requires that the after-tax WACC be used to discount all future resource costs.[1] PVRR figures reported in the 2019 IRP are reported in January 1, 2019 dollars.

CO2 Price Scenarios

PacifiCorp uses four different CO_2 price scenarios in the 2019 IRP—zero, medium, high, and a price forecast that aligns with the social cost of carbon. The medium and high scenario are derived from expert third-party multi-client "off-the-shelf" subscription services. Both of these scenarios apply a CO_2 price as a tax beginning 2025. PacifiCorp initially proposed using a medium CO_2 price forecast beginning in 2030, consistent with the start year assumed by the third-party forecast reviewed, but in response to stakeholder interests, PacifiCorp agreed to align the start year in the medium case with the start year proposed for the high case (2025). Figure 7.3 summarizes the CO_2 price assumptions used in the 2019 IRP (the zero price, no CO_2 scenario is not shown).

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

Figure 7.3 – CO_2 Prices Modeled by Price-Policy Scenarios



Wholesale Electricity and Natural Gas Forward Prices

For 2019 IRP modeling purposes, eight electricity price forecasts were used: the official forward price curve (OFPC) and seven scenarios. Unlike scenarios, which are alternative spot price forecasts, the OFPC represents PacifiCorp's official quarterly outlook. The OFPC is compiled using market forwards, followed by a market-to-fundamentals blending period that transitions to a pure fundamentals-based forecast.

At the time PacifiCorp's 2019 IRP modeling was initiated, the September 2018 OFPC was the most current OFPC available. 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 September 28, 2018. 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 OFPC reflects an expert third-party multi-client "off-the-shelf" price forecast. The fundamentals portion of the electricity OFPC reflects prices as forecast by AURORAxmp[3] (Aurora), a WECC-wide market model. Aurora uses the expert third-party natural gas price forecast to produce a consistent electricity price forecast for market hubs in which PacifiCorp participates. PacifiCorp updates its natural gas price forecasts each quarter for the OFPC and, as a corollary, the electricity OFPC is also updated.

Scenarios pairing medium gas prices with alternative CO_2 price assumptions reflect OFPC forwards through October 2021 before transitioning to a pure fundamentals forecast. Scenarios using high or low gas prices, regardless of CO_2 price assumptions, do not incorporate any market forwards since scenarios are designed to reflect an alternative view to that of the market. As such, the low and high natural gas price scenarios are purely fundamental forecasts. Low and high natural

[2] The September 2018 OFPC prompt month is November 2018; October 2018 is "balance of month".
[3] AURORAxmp is a proprietary production cost simulation model, developed by Energy Exemplar, LLC.

gas price scenarios are also derived from expert third-party multi-client "off-the-shelf" subscription services.

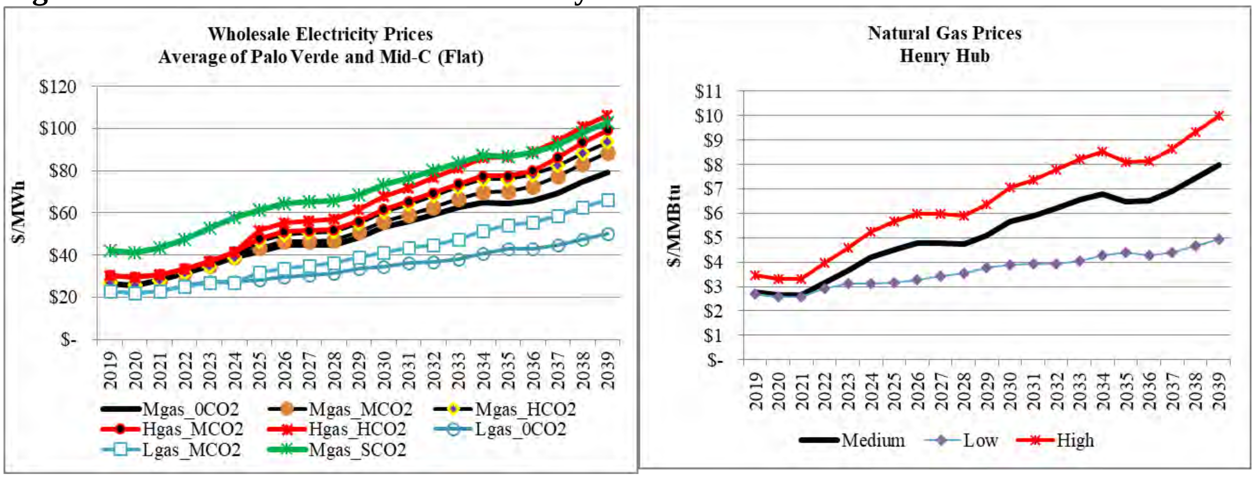
PacifiCorp's OFPC for electricity and each of its seven scenarios were developed from one of three (medium, low, high) underlying expert third-party natural gas price forecasts in conjunction with one of four CO_2 price scenarios.[4] The September 2018 OFPC does not assume any CO_2 policy or tax in conjunction with its medium gas price forecast. However, PacifiCorp's 2019 IRP "medium case" price forecast is not the OFPC but a scenario that couples medium gas with a medium CO_2 price, applied for forecasting purposes as a tax. Thus, the 2019 IRP medium case differs from that of the September 2018 OFPC by assuming a medium CO_2 price starting in 2025. This medium CO_2 price serves as a proxy for a potential future CO_2 policy, whose implementation and design specifics are not known.

The 2019 IRP medium CO_2 compliance assumption differs from that used in either PacifiCorp's 2015 or 2017 IRPs. In its 2015 IRP PacifiCorp's OFPC incorporated the U.S. Environmental Protection Agency's (EPA's)[5] proposed Clean Power Plan (CPP) rule to improve CO_2 emissions performance rates for affected power plants. To reflect the CPP in Aurora, PacifiCorp applied state emission rate constraints in the model, assuming energy efficiency goals assumed by EPA in its calculation of state emission rate targets. Upon finalization of the CPP, and in its 2017 IRP, PacifiCorp's OFPC for electricity and each of its six scenarios were developed from one of three (low, medium, high) underlying expert third-party natural gas price forecasts in conjunction with one of three CO_2 compliance designs tied to the CPP. But on March 28, 2017, President Trump issued an Executive Order directing the EPA to review the CPP and, if appropriate, suspend, revise, or rescind the CPP, as well as related rules and agency actions. Thus, essentially rendering the CPP an artifact of the Obama Administration. On June 19, 2019 the EPA issued its Affordable Clean Energy (ACE) Rule replacing the CPP. ACE does not set CO_2 emission cuts by state but, instead, allows states to determine efficiency improvements.

Figure 7.4 summarizes the eight wholesale electricity price forecasts and three natural gas price forecasts used in the base and scenario cases for the 2019 IRP.

[4] Zero CO_2, medium CO_2 price, high CO_2 price, and a social based cost of CO_2.
[5] EPA: Environmental Protection Agency.

Figure 7.4 – Nominal Wholesale Electricity and Natural Gas Price Scenarios



Cost and Risk Analysis

Planning and Risk

PaR uses the same common input assumptions described for SO model with additional data provided by the SO model results (e.g., the capacity expansion portfolio including reliability resource additions). While the SO model supplies a capacity view developing an optimized portfolio for each case, PaR is able to bring the advantages of stochastic-driven risk metrics to the evaluation of the studies while also capturing additional operational considerations that the SO model does not asses (i.e., operating reserve requirements). While PaR cost-risk metrics are ultimately used in the preferred portfolio selection, the SO model results can be informative, especially in their role as a magnitude and direction indicator to compare to PaR outcomes.

PaR is also used to perform the hourly deterministic reliability assessments for each case, as described in detail in Volume II, Appendix R (Coal Studies). The PaR reliability assessment informs selection of reliability resources in the SO model. Figure R.1 (Reliability Studies Methodology Process), presented in Volume II, Appendix R (Coal Studies) applies to all resource portfolio development in the 2019 IRP.

Cost and Risk Analysis

Once unique resource portfolios are developed using the SO model, additional modeling is performed to produce metrics that support comparative cost and risk analysis among the different resource portfolio alternatives. Stochastic risk modeling of resource portfolio alternatives is performed with PaR.

The stochastic simulation in PaR produces a dispatch solution that accounts for chronological commitment and dispatch constraints. The PaR simulation incorporates stochastic risk in its production cost estimates by using the Monte Carlo sampling of stochastic variables, which include: load, wholesale electricity and natural gas prices, hydro generation, and thermal unit outages. Wind and solar generation is not modeled with stochastic parameters; however, the incremental reserve requirements associated with uncertainty and variability in wind generation, as determined in the updated flexible reserve study, are captured in the stochastic simulations.

PacifiCorp's updated flexible reserve study is provided in Volume II, Appendix F (Flexible Reserve Study).

The stochastic parameters used in PaR for the 2019 IRP are developed with a short-run mean reverting process, whereby mean reversion represents a rate at which a disturbed variable returns to its expected value. Stochastic variables may have log-normal or normal distribution as appropriate. The log-normal distribution is often used to describe prices because such distribution is bounded on the low end by zero and has a long, asymmetric "tail" reflecting the possibility that prices could be significantly higher than the average. Unlike prices, load generally does not have such skewed distribution and is generally better described by a normal distribution. Volatility and mean reversion parameters are used for modeling the volatilities of the variables, while accounting for seasonal effects. Correlation measures how much the random variables tend to move together.

Stochastic Model Parameter Estimation
Stochastic parameters are developed with econometric modeling techniques. The short-run seasonal stochastic parameters are developed using a single period auto-regressive regression equation (commonly called an AR(1) process). The standard error of the seasonal regression defines the short run volatility, while the regression coefficient for the AR(1) variable defines the mean reversion parameter. Loads and commodity prices are mean-reverting in the short term. For instance, natural gas prices are expected to hover around a moving average within a given month and loads are expected to hover near seasonal norms. These built-in responses are the essence of mean reversion. The mean reversion rate tells how fast a forecast will revert to its expected mean following a shock. The short-run regression errors are correlated seasonally to capture inter-variable effects from informational exchanges between markets, inter-regional impacts from shocks to electricity demand and deviations from expected hydroelectric generation performance. The stochastic parameters are used to drive the stochastic processes of the following variables:

- Representative natural gas prices for PacifiCorp's east and west balancing authority areas;
- Electricity market prices for Mid-C, COB, Four Corners, and Palo Verde;
- Loads for California, Idaho, Oregon, Utah, Washington and Wyoming regions; and
- Hydro generation.

Volume II, Appendix H (Stochastic Parameters) discusses the methodology on how the stochastic parameters for the 2019 IRP were developed.

For unplanned thermal outages, PacifiCorp assumes a uniform distribution around an expected rate. For existing units, the expected unplanned outage rates by unit are based on its historical performance during the 4-year period ending December 2015. For new resources, the unplanned outage rates are as specified for those resources as listed in the supply-side resource table in Volume I, Chapter 6 (Resource Options). Table 7.1 through Table 7.8 summarize updated stochastic parameters and seasonal price correlations for the 2019 IRP.

Table 7.1 – Short-Term Load Stochastic Parameters

Short-Term Volatility	CA/OR without Portland	Portland	ID	UT	WA	WY
Winter 2019 IRP	0.042	0.039	0.035	0.021	0.053	0.016
Spring 2019 IRP	0.035	0.033	0.065	0.028	0.037	0.018
Summer 2019 IRP	0.042	0.050	0.051	0.045	0.050	0.016
Fall 2019 IRP	0.042	0.039	0.042	0.035	0.043	0.017
Short-Term Mean Reversion	**CA/OR without Portland**	**Portland**	**ID**	**UT**	**WA**	**WY**
Winter 2019 IRP	0.188	0.177	0.153	0.363	0.181	0.273
Spring 2019 IRP	0.368	0.241	0.204	0.595	0.341	0.254
Summer 2019 IRP	0.194	0.280	0.095	0.213	0.157	0.235
Fall 2019 IRP	0.257	0.242	0.218	0.249	0.203	0.267

Table 7.2 – Short-Term Gas Price Parameters

Short-Term Volatility	East Gas	West Gas
Winter 2019 IRP	0.111	0.120
Spring 2019 IRP	0.039	0.061
Summer 2019 IRP	0.025	0.049
Fall 2019 IRP	0.036	0.044
Short-Term Mean Reversion	**East Gas**	**West Gas**
Winter 2019 IRP	0.110	0.092
Spring 2019 IRP	0.152	0.265
Summer 2019 IRP	0.102	0.105
Fall 2019 IRP	0.071	0.107

Table 7.3 – Short-Term Electricity Price Parameters

Short-Term Volatility	Four Corners	COB	Mid-Columbia	Palo Verde
Winter 2019 IRP	0.098	0.134	0.166	0.092
Spring 2019 IRP	0.104	0.261	0.475	0.075
Summer 2019 IRP	0.155	0.300	0.213	0.141
Fall 2019 IRP	0.101	0.102	0.103	0.098
Short-Term Mean Reversion	**Four Corners**	**COB**	**Mid-Columbia**	**Palo Verde**
Winter 2019 IRP	0.125	0.119	0.140	0.110
Spring 2019 IRP	0.434	0.551	0.551	0.211
Summer 2019 IRP	0.338	0.463	0.271	0.220
Fall 2019 IRP	0.370	0.257	0.279	0.415

Table 7.4 – Winter Season Price Correlation

	Natural Gas East	Four Corners	COB	Mid - Columbia	Palo Verde	Natural Gas West
Natural Gas East	1.000					
Four Corners	0.629	1.000				
COB	0.353	0.576	1.000			
Mid - Columbia	0.382	0.573	0.942	1.000		
Palo Verde	0.662	0.835	0.610	0.594	1.000	
Natural Gas West	0.891	0.567	0.395	0.421	0.609	1.000

Table 7.5 – Spring Season Price Correlation

	Natural Gas East	Four Corners	COB	Mid - Columbia	Palo Verde	Natural Gas West
Natural Gas East	1.000					
Four Corners	0.204	1.000				
COB	0.099	0.338	1.000			
Mid - Columbia	0.069	0.358	0.864	1.000		
Palo Verde	0.327	0.621	0.392	0.307	1.000	
Natural Gas West	0.553	0.058	0.080	0.070	0.132	1.000

Table 7.6 – Summer Season Price Correlation

	Natural Gas East	Four Corners	COB	Mid - Columbia	Palo Verde	Natural Gas West
Natural Gas East	1.000					
Four Corners	0.052	1.000				
COB	-0.004	0.272	1.000			
Mid - Columbia	0.024	0.290	0.848	1.000		
Palo Verde	-0.001	0.521	0.444	0.506	1.000	
Natural Gas West	0.453	0.054	0.050	0.096	0.009	1.000

Table 7.7 – Fall Season Price Correlation

	Natural Gas East	Four Corners	COB	Mid - Columbia	Palo Verde	Natural Gas West
Natural Gas East	1.000					
Four Corners	0.135	1.000				
COB	0.149	0.362	1.000			
Mid - Columbia	0.124	0.223	0.780	1.000		
Palo Verde	0.129	0.528	0.627	0.444	1.000	
Natural Gas West	0.731	0.100	0.128	0.133	0.066	1.000

Table 7.8 – Hydro Short-Term Stochastic

	Short Term Volatility	Short-Term Mean Reversion
Winter 2019 IRP	0.212	0.632
Spring 2019 IRP	0.162	0.501
Summer 2019 IRP	0.168	1.512
Fall 2019 IRP	0.301	0.863

Figure 7.5 and Figure 7.6 show annual electricity prices at the first, 10th, 25th, 50th, 75th, 90th, and 99th percentiles for Mid-C and Palo Verde market hubs based on a Monte Carlo simulation using short-term volatility and mean reversion parameters. For Mid-C electricity prices, differences between the first and 99th percentiles range from $21.64/MWh to $79.88/MWh during the 20-year study period. For Palo Verde electricity prices, the difference between the first and 99th percentiles range from $26.57/MWh to $99.34/MWh.

Figure 7.5 – Simulated Annual Mid-C Electricity Market Prices

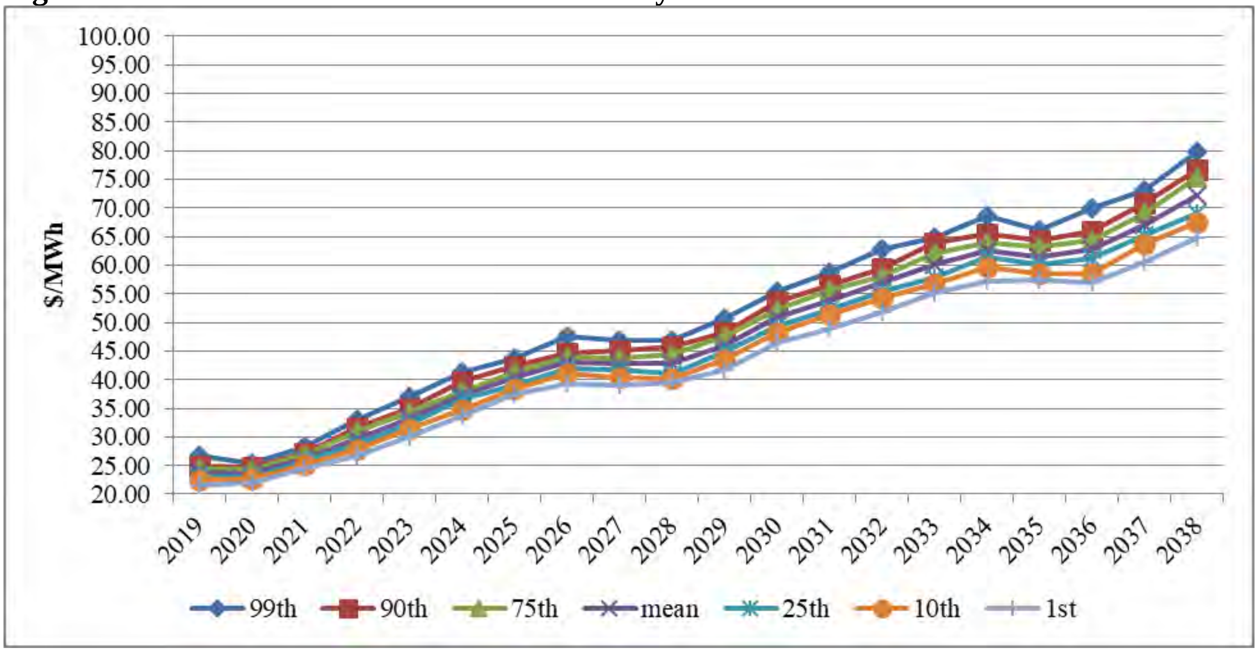


Figure 7.6 – Simulated Annual Palo Verde Electricity Market Prices

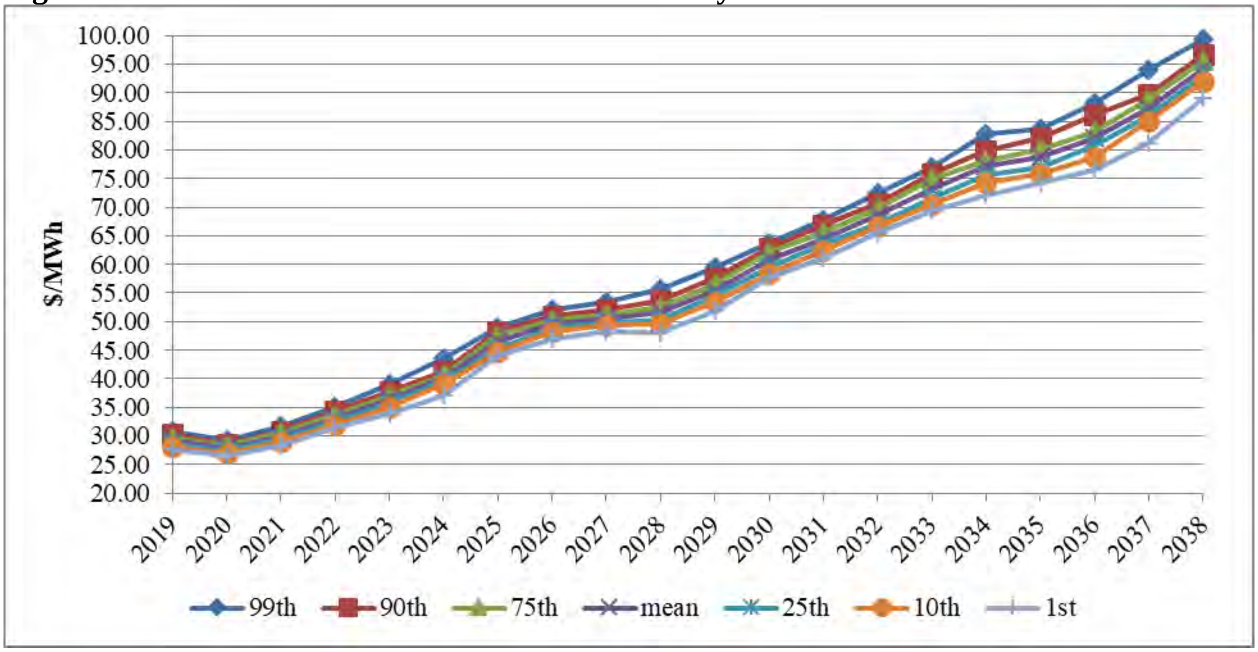


Figure 7.7 and Figure 7.8 show annual electricity prices at the first, 10th, 25th, 50th, 75th, 90th, and 99th percentiles for west and east natural gas prices. For west natural gas prices, differences between the first and 99th percentiles range from $1.85/ Million British thermal units (MMBtu) to $7.22/MMBtu during the 20-year study period. For east natural gas prices, differences between the first and 99th percentiles range from $2.00/MMBtu to $7.64/MMBtu.

Figure 7.7 – Simulated Annual Western Natural Gas Market Prices

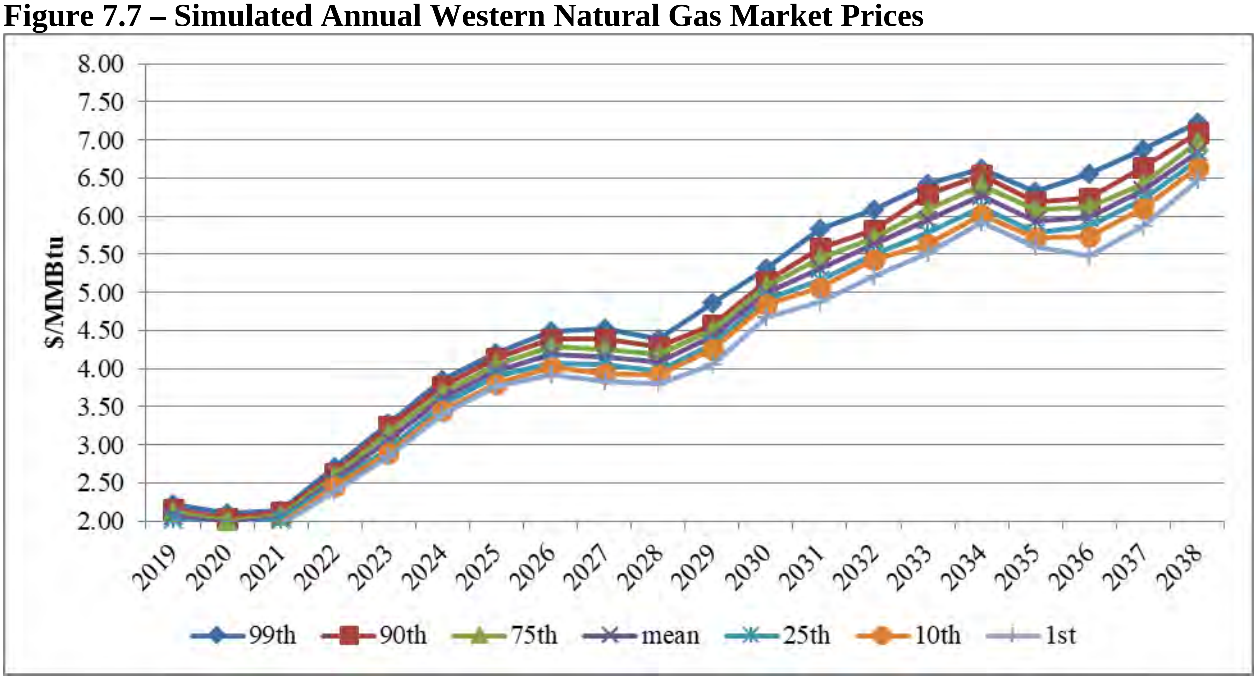


Figure 7.8 - Simulated Annual Eastern Natural Gas Market Prices

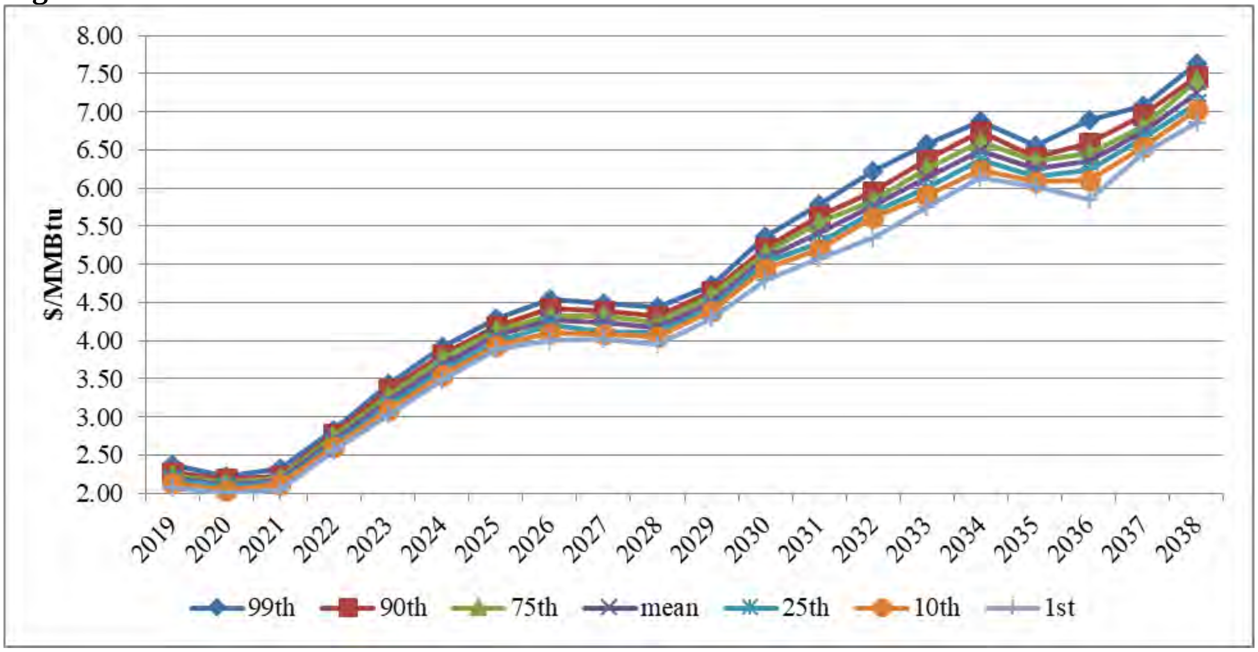


Figure 7.9 through Figure 7.14 show annual loads by load area and for PacifiCorp's system at the first, 10th, 25th, 50th, 75th, 90th, and 99th percentiles based on a Monte Carlo simulation using short-term volatility and mean reversion parameters. For Idaho (Goshen) load, the annual differences between the first and 99th percentiles range from 192 gigawatt-hours (GWh) to 348 GWh. For Utah load, the annual difference ranges from 1,204 GWh to 2,772 GWh. For Wyoming load, the annual difference range from 137 GWh to 271 GWh. For Oregon/California load, annual differences range from 746 GWh to 1,528 GWh. For Washington load, the annual difference ranges from 315 GWh to 557 GWh. For PacifiCorp's system load, the annual difference ranges from 2,386 GWh to 4,354 GWh.

Figure 7.9 - Simulated Annual Idaho (Goshen) Load

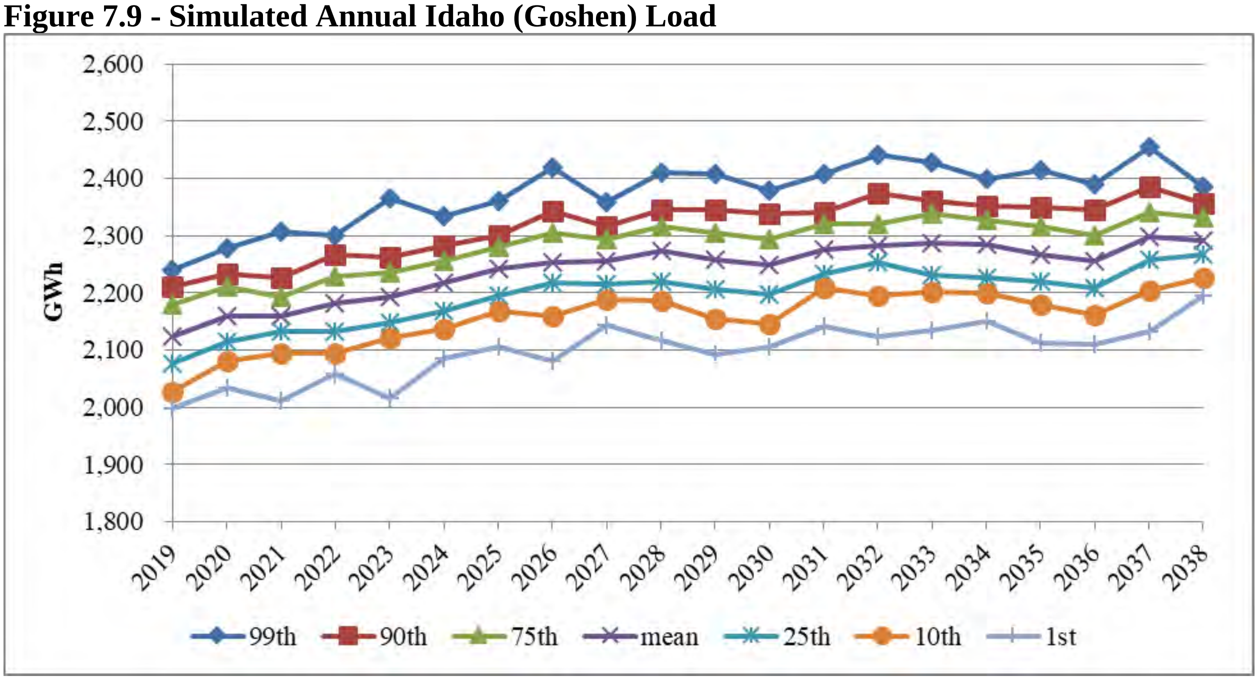


Figure 7.10 - Simulated Annual Utah Load

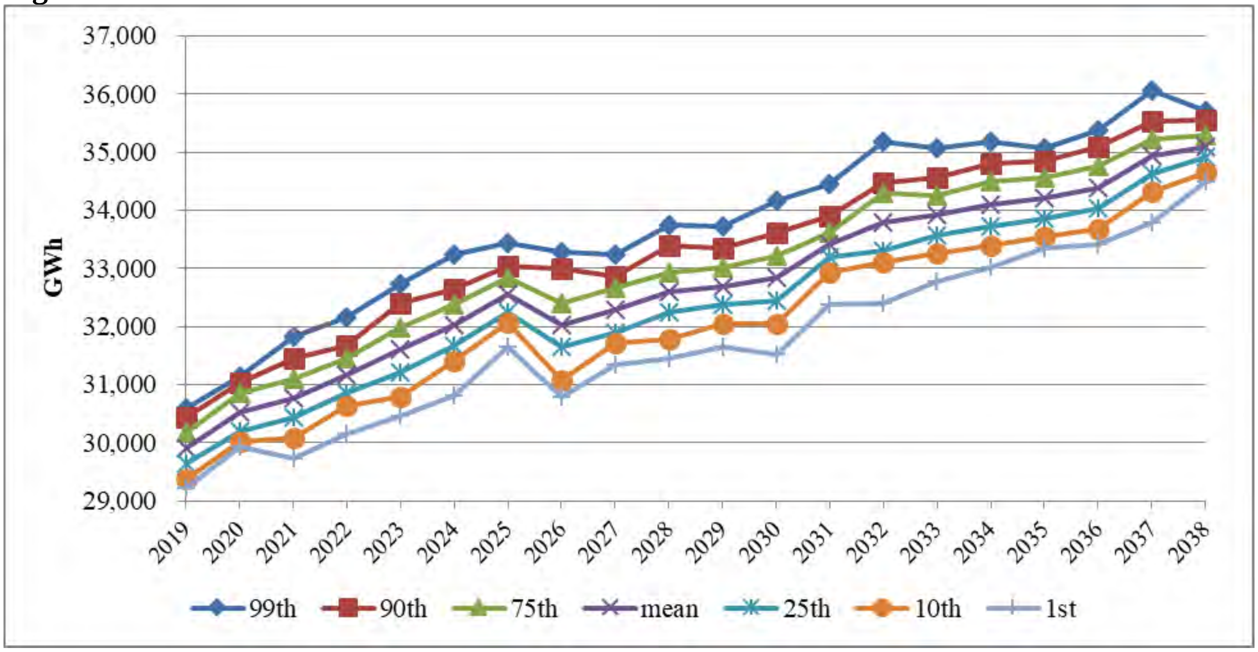


Figure 7.11 - Simulated Annual Wyoming Load

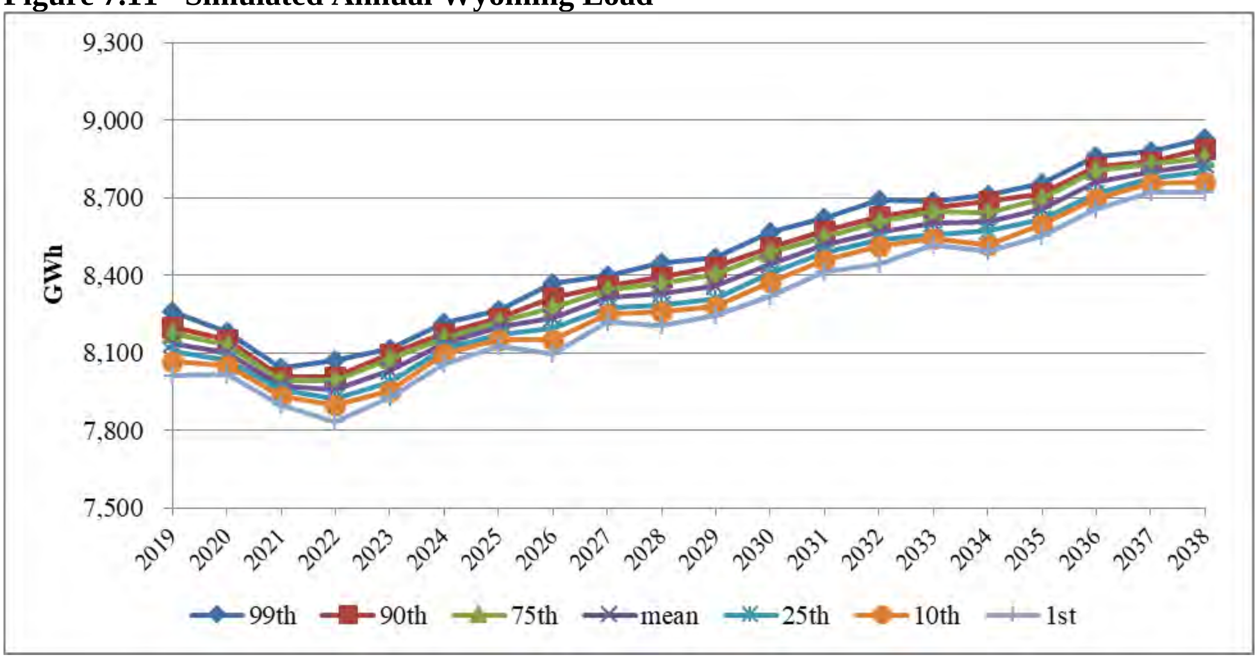


Figure 7.12 - Simulated Annual Oregon/California Load

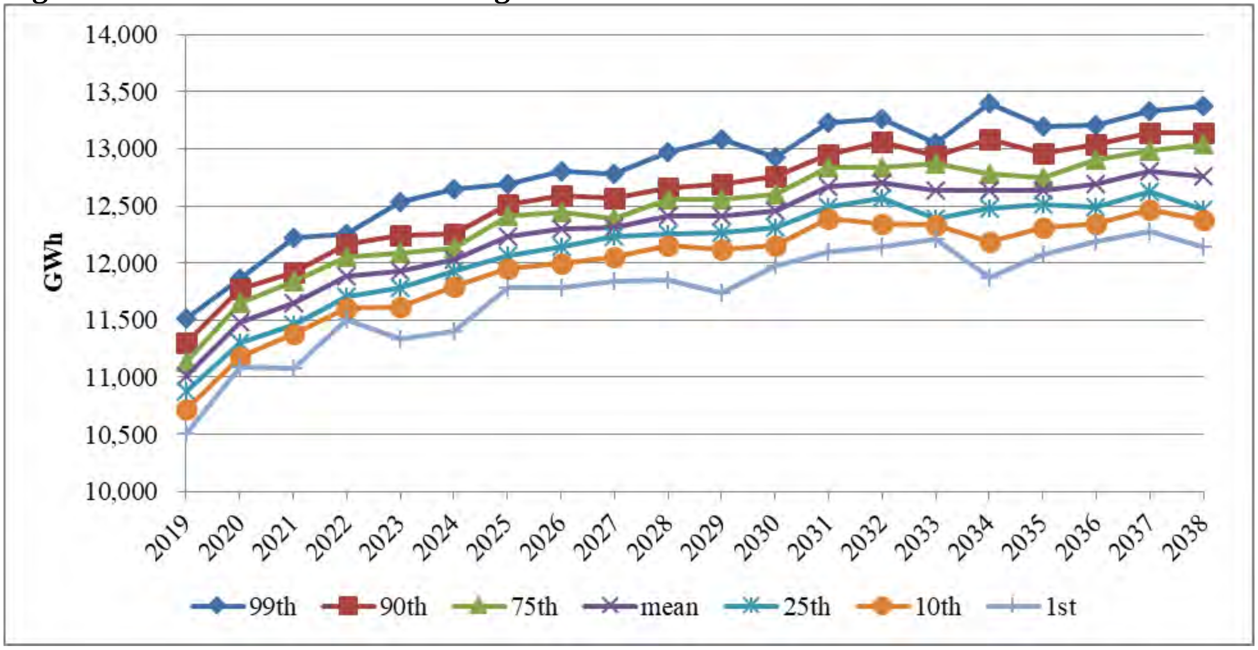


Figure 7.13 - Simulated Annual Washington Load

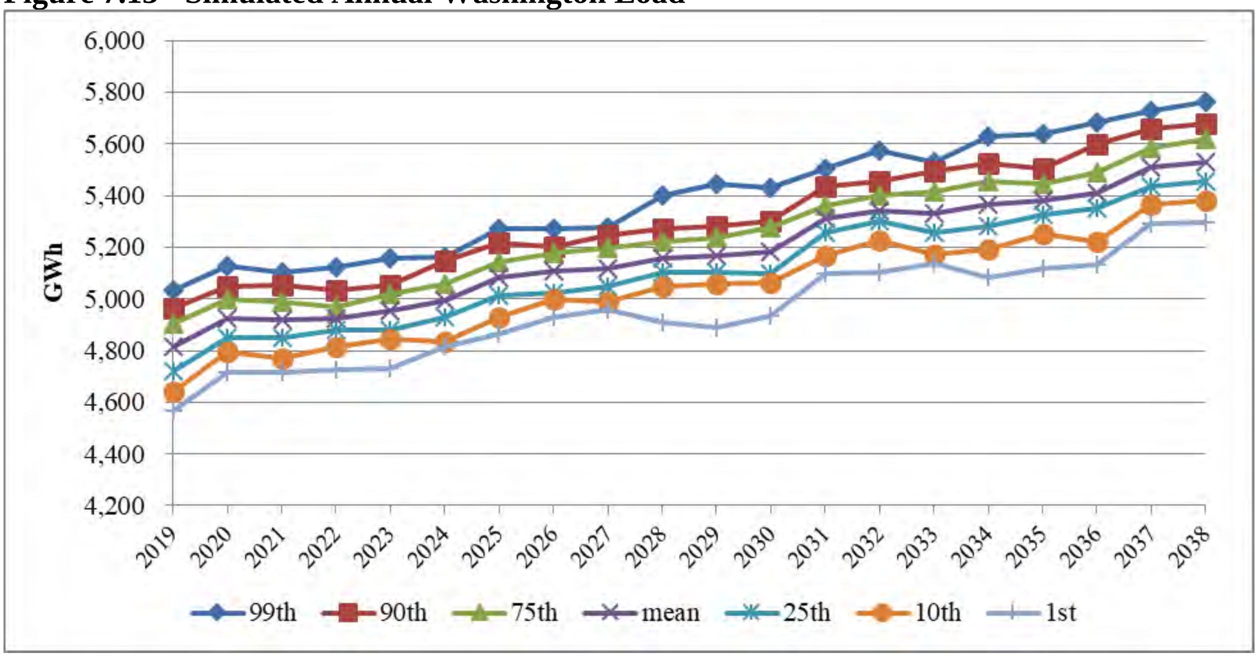


Figure 7.14 - Simulated Annual System Load

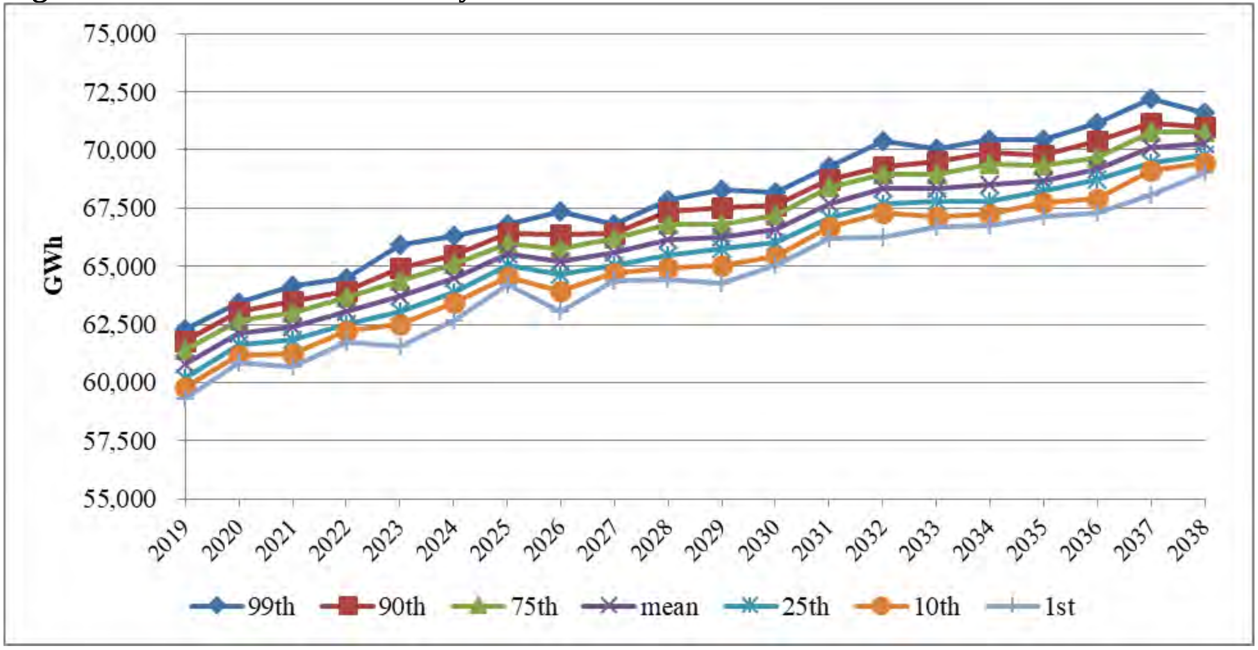
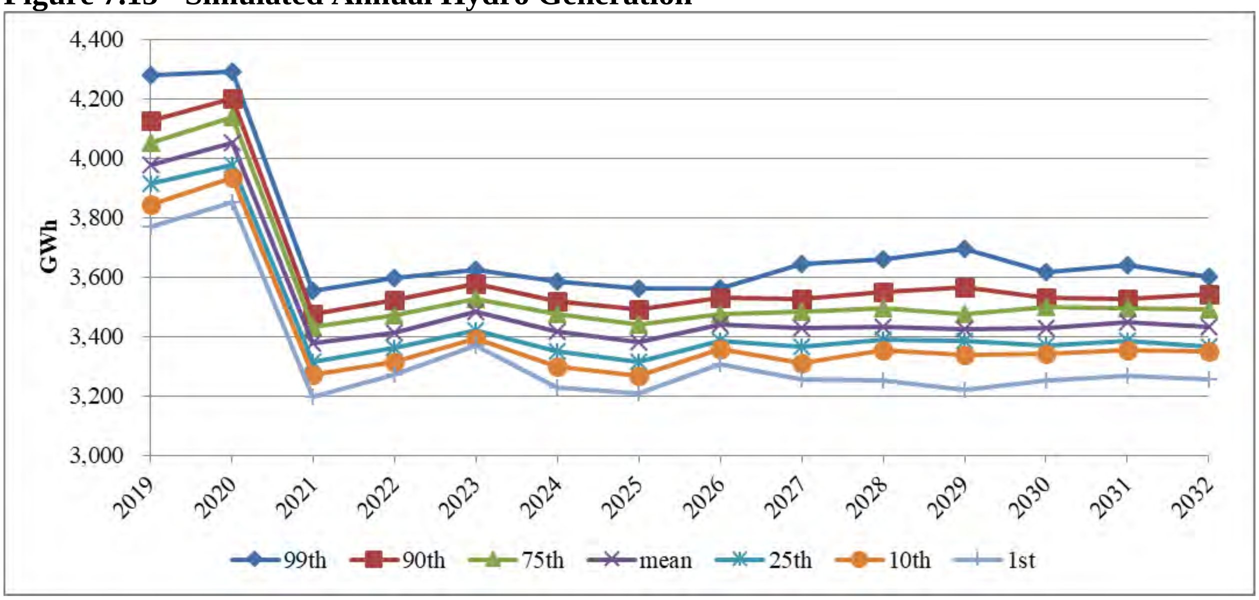


Figure 7.15 shows hydro generation at the first, 10th, 25th, 50th, 75th, 90th, and 99th percentiles based on a Monte Carlo simulation using short-term volatility and mean reversion parameters. PacifiCorp can dispatch its hydro generation on a limited basis to meet load and reserve obligations. The parameters developed for the hydro stochastic process approximate the volatility of hydro conditions as opposed to variations due to dispatch. The drop in 2021 is due to the assumed decommissioning of the Klamath River projects. Annual differences in hydro generation between the first and 99th percentiles range from 253 GWh to 512 GWh.

Figure 7.15 - Simulated Annual Hydro Generation



Monte Carlo Simulation

During model execution, the PaR model makes time-path-dependent Monte Carlo draws for each stochastic variable based on input parameters. The Monte Carlo draws are percentage deviations from the expected forward value of each variable. The Monte Carlo draws of the stochastic variables among all resource portfolios modeled are the same, which allows for a direct comparison of stochastic results among all of the resource portfolios being analyzed. In the case of natural gas prices, electricity prices, and regional loads, the PaR model applies Monte Carlo draws on a daily basis. In the case of hydroelectric generation, Monte Carlo draws are applied on a weekly basis.

For the 2019 IRP, PaR is configured to conduct 50 Monte Carlo iterations for the 20-year study period. For each of the 50 Monte Carlo iterations, PaR generates a set of natural gas prices, electricity prices, loads, hydroelectric generation and thermal outages. Then, the model optimizes resource dispatch to minimize costs while meeting load and wholesale sale obligations subject to operating and physical constraints. In a 50-iteration simulation, the resource portfolio is fixed. The end result of the Monte Carlo simulation is 50 production cost figures for the 20-year study period reflecting a wide range of cost outcomes for the portfolio.

The expected values of the Monte Carlo simulation are the average result of all 50 iterations. Results from subsets of the 50 iterations are also summarized to capture particularly adverse cost conditions, and to derive associated cost measures as indicators of high-end portfolio risk. These cost measures, and others are used to assess portfolio performance, which are described below.

Stochastic Portfolio Performance Measures

Stochastic simulation results for each unique resource portfolio are summarized, enabling direct comparison among resource portfolio results during the preferred portfolio selection process. The cost and risk stochastic measures reported from PaR include:

- Stochastic mean PVRR;
- Risk-adjusted mean PVRR;
- Upper-tail Mean PVRR;
- 5th and 95th percentile PVRR;
- Average annual mean and upper-tail energy not served (ENS);
- Loss of load probability; and
- Cumulative CO_2 emissions.

Stochastic Mean PVRR

The stochastic mean PVRR is the average of system net variable operating costs among 50 iterations, combined with the real levelized capital costs and fixed costs taken from the SO model for any given resource portfolio.[6] The net variable cost from stochastic simulations, expressed as a net present value, includes system costs for fuel, variable O&M, unit start-up, market contracts, system balancing market purchases expenses and sales revenues, and ENS costs applicable when available resources fall short of load obligations. Capital costs for new and existing resources, taken from the SO model, are calculated on an escalated real-levelized basis. Other components in the stochastic mean PVRR include fixed costs for new DSM resources in the portfolio, also taken from the SO model, and CO_2 emission costs for any scenarios that include a CO_2 price assumption.

[6] Fixed costs are not affected by stochastic variables, and therefore, do not change across the 50 PaR iterations.

Risk-Adjusted PVRR

The risk-adjusted PVRR incorporates the expected-value cost of low-probability, high cost outcomes. This measure is calculated as the PVRR of stochastic mean system variable costs plus five percent of system variable costs from the 95th percentile. The PVRR of system fixed costs, taken from the SO model, are then added to this system variable cost metric. This metric expresses a low-probability portfolio cost outcome as a risk premium applied to the expected (or mean) PVRR based on 50 Monte Carlo simulations for each resource portfolio. The rationale behind the risk-adjusted PVRR is to have a consolidated stochastic cost indicator for portfolio ranking, combining expected cost and high-end cost risk concepts.

Upper-Tail Mean PVRR

The upper-tail mean PVRR is a measure of high-end stochastic cost risk. This measure is derived by identifying the Monte Carlo iterations with the three highest production costs on a net present value basis. The portfolio's real levelized fixed costs, taken from the SO model, are added to these three production costs, and the arithmetic average of the resulting PVRRs is computed.

95th and 5th Percentile PVRR

The 5th and 95th percentile PVRRs are also reported from the 50 Monte Carlo iterations. These measures capture the extent of upper-tail (high cost) and lower-tail (low cost) stochastic outcomes. As described above, the 95th percentile PVRR is used to derive the high-end cost risk premium for the risk-adjusted mean PVRR measure. The 5th percentile PVRR is reported for informational purposes.

Production Cost Standard Deviation

To capture production cost volatility risk, PacifiCorp uses the standard deviation of the stochastic production cost from the 50 Monte Carlo iterations. The production cost is expressed as a net present value of annual costs over the period 2019 through 2038. This measure meets Oregon IRP guidelines to report a stochastic measure that addresses the variability of costs in addition to a measure addressing the severity of bad outcomes.

Average and Upper-Tail Energy Not Served

Certain iterations of a stochastic simulation will have ENS, a condition where there are insufficient resources, inclusive of system balancing purchases, available to meet load or operating reserve requirements because of physical constraints. This occurs when Monte Carlo draws of stochastic variables result in a load obligation that is higher than the capability of the available resources in the portfolio. For example, this might occur in Monte Carlo draws with large load shocks concurrent with a random unplanned plant outage event. Consequently, ENS, when averaged across all 50 iterations, serves as a measure of reliability that can be compared among resource portfolios. PacifiCorp calculates an average annual value over the 2019 through 2038 planning horizon as well as the upper-tail ENS (average of the three iterations with the highest ENS). In the 2019 IRP, ENS is nominally priced at $1,000/MWh.

Loss of Load Probability

Loss of load probability (LOLP) reports the probability and extent that available resources of a portfolio cannot serve load during the peak-load period of July in the 20-year period. PacifiCorp reports LOLP statistics, which are calculated from ENS events that exceed threshold levels.

Cumulative CO_2 Emissions

Annual CO_2 emissions from each portfolio are reported from PaR and summed for the twenty year planning period. Comparison of total CO_2 emissions is used to identify potential outliers among resource portfolios that might otherwise be comparable with regard to expected cost, upper-tail cost risk, and/or ENS.

Forward Price Curve Scenarios

Top-performing resource portfolios developed with the SO model during the portfolio-development process are analyzed in PaR with up to four price-policy scenarios. The price curve scenarios are developed from PacifiCorp's September 2018 OFPC. PaR results using each of these scenarios inform selection of the preferred portfolio.

Price assumptions for each of these scenarios are subject to short-term volatility and mean reversion stochastic parameters when used in PaR. The approach for producing wholesale electricity and natural gas price scenarios used for PaR simulations is identical to the approach used to develop price scenarios for the portfolio-development process.

Other PaR Modeling Methods and Assumptions

Transmission System

The base transmission topology used for the SO model, shown in Figure 7.2, is identical to the transmission topology used for PaR simulations. Any transmission upgrades selected by the SO model that provide incremental transfer capability among bubbles in this topology are also included in PaR.

Resource Adequacy

The resource portfolio developed with the SO model, which meets an assumed 13 percent target planning reserve margin, is fixed in all PaR simulations. With fixed resources, the unit commitment and dispatch logic in PaR accounts for operating reserve requirements. These reserve requirements include contingency reserves, which are calculated as 3 percent of load and 3 percent of generation. In addition, PaR reserve requirements account for regulation reserves. PacifiCorp's regulation reserve assumptions are outlined in PacifiCorp's flexible reserve study, provided in Volume II, Appendix F (Flexible Reserve Study), including PaR's use in the reliability assessment phase of the portfolio-development process.

Energy Storage Resources

Given the complexity of PacifiCorp's system, the PaR model experienced difficulty optimizing the dispatch for battery storage resources. To improve upon this shortcoming in the PaR model, PacifiCorp developed and tested a method to produce an optimized peak-shave/valley-fill profile for these resource outside of PaR that is based on load net of wind, solar, energy efficiency resources, and private generation resources in any given portfolio. Fixed hourly dispatch, charging, and operating reserves are entered as inputs to PaR. This methodological enhance was presented and discussed with stakeholders at the March 21, 2019 IRP public-input meeting.

General Assumptions

The general assumptions applied in the SO model for the study period (20-years beginning 2019) annual inflation rates (2.28 percent), and discount rates (6.92 percent) are also applied in PaR.

Other Cost and Risk Considerations

In addition to reviewing stochastic PVRR, ENS, and CO_2 emissions data from PaR, PacifiCorp considers other cost and risk metrics in its comparative analysis of resource portfolios. These metrics include fuel source diversity, and customer rate impacts.

Fuel Source Diversity
PacifiCorp considers relative differences in resource mix among portfolios by comparing the capacity of new resources in portfolios by resource type, differentiated by fuel source. PacifiCorp also provides a summary of fuel source diversity differences among top performing portfolios based on forecasted generation levels of new resources in the portfolio. Generation share is reported among thermal resources, renewable resources, storage resources, DSM resources and FOTs.

Customer Rate Impacts
To derive a rate impact measure, PacifiCorp computes the percentage change in nominal annual revenue requirement from top performing resource portfolios (with lowest risk adjusted mean PVRRs) relative to a benchmark portfolio selected during the final preferred portfolio screening process. Annual revenue requirement for these portfolios is based on the stochastic production cost results from PaR and capital costs reported by the SO model on a real levelized basis. The real levelized capital costs are adjusted to nominal dollars consistent with the timing of when new resources are added to the portfolio. While this approach provides a reasonable representation of relative differences in projected total system revenue requirement among portfolios, it is not a prediction of future revenue requirement for rate-making purposes.

Market Reliance
To assess market reliance risk, PacifiCorp develops a series of portfolios designed to quantify the risk associated with relying on FOTs for a given portfolio. These studies apply a price scalar to market prices in the peak months of July, August, and December. In the SO model, FOTs include a premium to capture the risk of price spikes where the magnitude of these price spikes are based upon the variance between historical forward prices and actual prices from an historical period. This approach, which captures the severity and volume of potential high-price hours while maintaining the shape of the underlying price curve.

Portfolio Selection

The final action in each modeling and evaluation step is portfolio selection. In the first step, to performing portfolios are identified based on their relative performance with regard to mean system costs, risk-adjusted system costs, which account for upper tail stochastic risk, reliability metrics and cumulative CO_2 emissions.

Additional refined analysis is performed on these cases to ensure there relative cost and risk metrics are comparable by performing more granular reliability analysis that also better captures potential cost savings of combining battery storage resources with solar resources. Additional analysis can be performed to further assess the relative differences among top-performing portfolios.

Within each step, each portfolio that is under examination is compared on the basis of cost-risk metrics, and the least-cost, least-risk portfolio is chosen. Risk metrics examined include the mean PVRR, upper-tail PVRR, risk-adjusted PVRR, mean ENS, upper-tail ENS, and emissions. As noted above, market reliance risk was also evaluated and quantified. The comparisons of outcomes are detailed, ranked and assessed in the next chapter.

Final Evaluation and Preferred Portfolio Selection

Due to the lengthy nature of the IRP cycle, the final step is the last opportunity to consider whether top-performing portfolios merit additional study based on observations in the model results across all studies, additional sensitivities, possible updates driven by recent events, and additional stakeholder feedback. Additional sensitivities may refine the portfolio selection based on portfolio optimization and cost and risk analysis steps. For the 2019 IRP this included additional analysis to assess market price risk, the impact of relying on new natural gas resources, and additional studies to assess incremental transmission investments that cannot be adequately captured in the improved endogenous transmission upgrade methodology discussed earlier in this chapter and in Chapter 6 (Resource Options).

During the final screening process, the results of any further resource portfolio developments are ranked by risk-adjusted mean PVRR, the primary metric used to identify top performing portfolios. Portfolio rankings are reported for the four price-policy price curve scenarios. Resource portfolios with the lowest risk-adjusted mean PVRR receive the highest rank. Final screening also considers system cost PVRR data from the SO model and other comparative portfolio analysis. At this stage, PacifiCorp reviews additional stochastic metrics from PaR looking to identify if expected and ENS results and CO_2 emissions results can be used to differentiate portfolios that might be closely ranked on a risk-adjusted mean PVRR basis.

Case Definitions

Case definitions specify a combination of planning assumptions used to develop each unique resource portfolio analyzed in the 2019 IRP, organized here into major development categories:

- Coal Studies
- Portfolio Development Cases
    - Initial portfolio cases
    - C-series cases
    - CP-series cases
    - FOT cases
- Preferred Portfolio Selection

  - No new gas cases
  - Energy Gateway Transmission cases
  - Dave Johnston wind alternative
- Sensitivity Cases

Additional detail for all portfolios can be found in Volume II, Appendix M (Case Study Fact Sheets).

Coal Studies

The coal study cases are described in detail in Volume II, Appendix R (Coal Studies). Results from the coal studies informed the portfolio-development phase of the 2019 IRP by driving coal retirement assumptions in the initial portfolio development step of the portfolio-development process.

Portfolio Development Cases

Informed by the public-input process and focused on the retirement outcomes of the coal studies, these cases build diversity around varying key retirement dates, and implement modeling refinements to improve results and test evolving outcomes through the IRP process.

Initial Portfolio Cases
As informed by the Coal Studies, the over half of initial portfolios explore variations in retirement timing for Jim Bridger Units 1 and 2 and Naughton Units 1 and 2. The initial portfolios also explore potentially significant interactions with additional retirement options including the potential to convert Naughton Unit 3 to natural gas, potential tradeoffs to retire Gadsby steam units early, and the timing of other coal unit retirements that were not a focus of the Coal Study (i.e., Cholla Unit 4 and jointly owned facilities where PacifiCorp is not the operator). The initial portfolios also consider how resource selections change with price-policy assumptions that deviate from the medium natural gas price and medium CO_2 price assumptions used to develop many resource portfolios. All of the initial portfolios include the new reliability assessment phase of portfolio development that was incorporated in the 2019 IRP cycle.

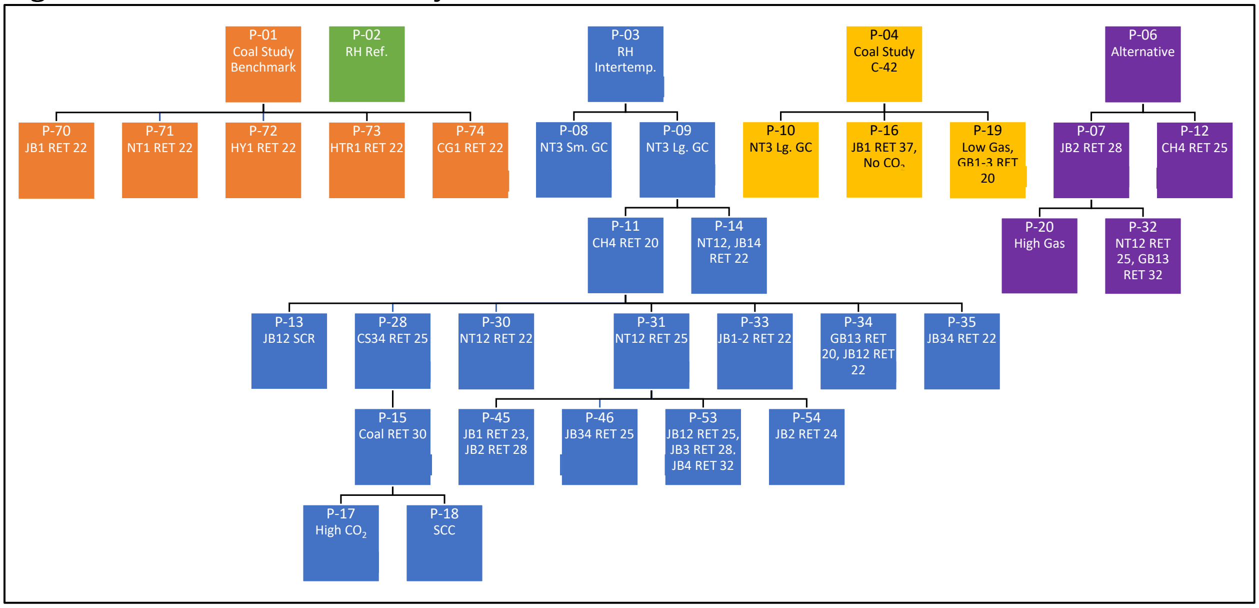
Table 7.9 provides the initial portfolio definitions for this IRP. Additional information, including coal unit retirement assumptions, are provided for each case in Volume II, Appendix M (Case Study Fact Sheets).

Table 7.9 – Initial Portfolio Case Definitions

Case	Description	Parent Case
P-01	Coal Study Benchmark	-
P-02	Regional Haze Reference	-
P-03	Regional Haze Intertemporal	-
P-04	Coal Study C-42	-
P-06	Gadsby Alternative Case	-
P-07	Gadsby Alternative Case	P-06
P-08	Naughton 3 Small Gas Conversion	P-03
P-09	Naughton 3 Large Gas Conversion	P-03
P-10	Naughton 3 Large Gas Conversion	P-04
P-11	Cholla 4 Retirement 2020	P-09
P-12	Cholla 4 Retirement 2025	P-06
P-13	Jim Bridger 1&2 SCRs	P-11
P-14	Naughton 1&2 and Jim Bridger 1-4 Retirement 2022	P-09
P-15	Retire All Coal by 2030	P28
P-16	Jim Bridger 1&2 Retirement 2022, No CO_2	P04
P-17	High CO_2	P-15
P-18	Social Cost of Carbon	P-15
P-19	Low Gas	P-04
P-20	High Gas	P-07
P-28	Colstrip 3&4 Retirement 2025	P-11
P-30	Naughton 1&2 Retirement 2022	P-11
P-31	Naughton 1&2 Retirement 2025	P-11
P-32	Naughton 1&2 Retirement 2025 with Gadsby 1-3 Retirement 2032	P-07
P-33	Jim Bridger 1&2 Retirement 2022	P-11
P-34	Jim Bridger 1&2 Retirement 2022, with Gadsby 1-3 Retirement 2020)	P-11
P-35	Jim Bridger 3&4 Retirement 2022	P-11
P-45	Jim Bridger 1 Retirement 2023 and Jim Bridger 2 Retirement 2038	P-31
P-46	Jim Bridger 3&4 Retirement 2025	P-31
P-53	Jim Bridger 1&2 Retirement 2025, Jim Bridger 3 Retirement 2028, and Jim Bridger 4 Retirement 2032	P-31
P-54	Jim Bridger 2 Retirement 2024	P-31

Initial portfolio case refinements and additions were modeled on the basis of outcomes and stakeholder feedback throughout the 2019 IRP public-input process. This led to the developing assumptions for many cases as a variant from another case, lending itself to a "family tree" structure as a means to describe the relationship among cases. Figure 7.16 summarizes the case definitions in this family tree format. Note, cases P-70 through P-74 were developed in response to stakeholder interest to reaffirm Coal Study findings that early retirement of units at the Naughton and Jim Bridger plant were most likely to generate cost savings. These cases were higher cost than most of the other cases and were not evaluated as potential candidates for the preferred portfolio. The top row of cases in this figure represent "parent cases" from which all other cases were derived. The text in each box of the family tree describes what changed relative to the case from which it was derived (i.e., case P-08 retains all attributes of case P-03, except case P-08 assumes a small gas conversation at Naughton Unit 3 in 2020).

Figure 7.16 – Initial Case Family Tree



C-Series Cases

In the C-series, top-performing portfolios from the initial portfolio cases were examined with additional deterministic test years used to ascribe reliability resources covering 2023 through 2030, plus 2038. This provides a total of nine years of hourly PaR reliability assessment rather than the three years (2023, 2030, and 2038) employed in the initial portfolio cases.

When reliability resources are added in the two-step portfolio development process adopted for this IRP cycle, incremental battery resources are routinely added to remedy initial reliability shortfalls in each case. This indicates that if the SO model were able to assess the incremental reliability requirement in its *initial* resource portfolio, it would likely pair batteries with any of the new solar resources it initially added to take advantage of cost savings for this combined resource alternative.

Test runs performed by the IRP modeling team confirmed that if stand-alone solar resources were not allowed in the initial portfolio development case, that the SO model selected solar+battery combination resource options, and that when these portfolios were analyzed for reliability (using the additional test years as described above) and run through the PaR model, the overall system PVRR was lower.

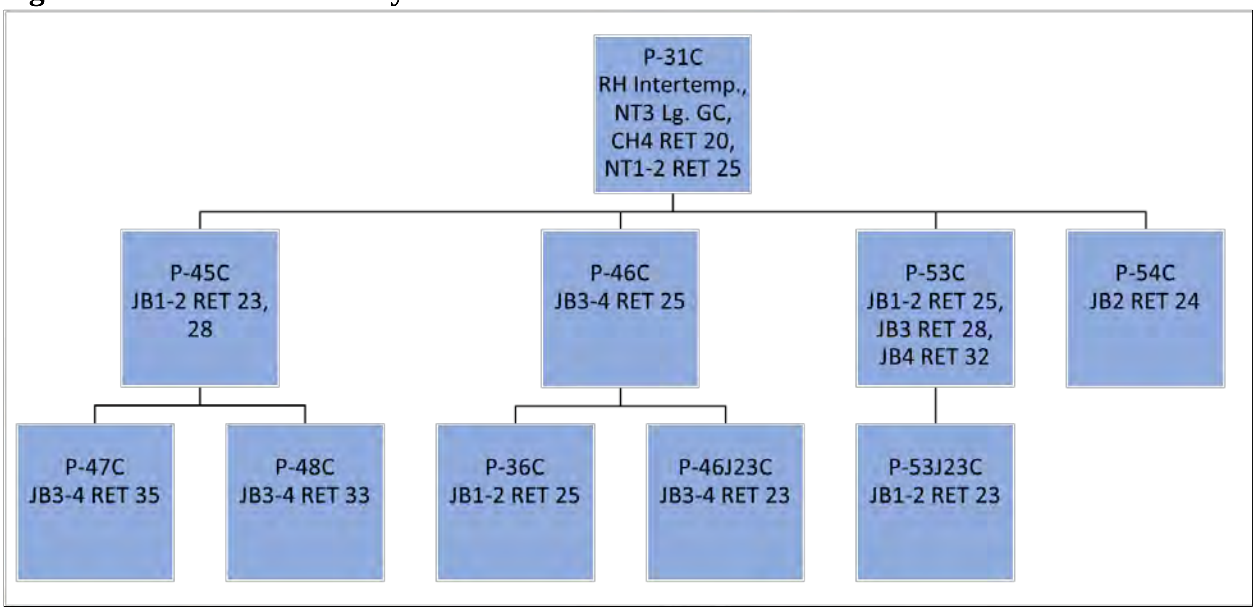
Consequently, for the five cases with the lowest system PVRR from the initial step of the portfolio-development process and for additional cases developed after stakeholder discussion at the September 2019 public-input meeting, PacifiCorp disabled stand-alone solar resources—in each case, solar+battery is added to the portfolio and system costs were reduced.

In addition to the five top performing cases derived from the initial portfolios (P-31C, P-45C, P-46C, P-53C and P-54C), the C-series includes five additional cases developed after discussion at the September 5-6, 2019 public-input meeting (P-36C, P-46J23C, P-47C, P-48C, P-53J23C). Table 7.10 provides the C-series portfolio definitions for this IRP. Figure 7.17 shows the family tree relationship for the C-series of cases.

Table 7.10 – C-Series Case Definitions

Case	Description (Change from Parent Case)	Parent Case
P-31C	Naughton 1-2 Retire 2025	P-11
P-36C	Jim Bridger 1-2 Retire 2025	P-46
P-45C	Jim Bridger 1 & 2 Retire 2023 and 2038	P-31
P-46C	Jim Bridger 3 & 4 Retire 2025	P-31
P-46J23C	Jim Bridger 3 & 4 Retire 2023	P-46
P-47C	Jim Bridger 3 & 4 Retire 2035	P-45
P-48C	Jim Bridger 3 & 4 Retire 2033	P-45
P-53C	Jim Bridger 1 & 2 Retire 2025, Jim Bridger 3-4 Retire 2028/2032	P-31
P-53J23C	Jim Bridger 1 & 2 Retire 2023	P-53
P-54C	Jim Bridger 2 Retire 2024	P-31

Figure 7.17 – C-Series Family Tree



CP-Series Cases

In the CP-series[7], top-performing portfolios informed by the C-series cases are examined with additional deterministic years covering 2023 through 2038. This provides a total of 16 years of hourly PaR reliability assessment, and fleshes out any granular variances driven by mapping results from a single reliability test year to multiple simulation years in the back-end of the study period.

Table 7.11 provides the CP-series portfolio definitions for this IRP. While the P-54C, P-54J23C, and P-31C cases were not evaluated in the CP-series, the family tree relationships for the cases in the table below are unchanged from the family tree relationships depicted for the C-series of cases.

[7] "CP" refers to "C-Prime", an expansion of the deterministic runs used for reliability assessment in the C-Series cases.

Table 7.11 – CP-Series Case Definitions

Case	Description (Change from Parent Case)	Parent Case
P-36CP	Jim Bridger 1-2 Retire 2025	P-46
P-45CP	Jim Bridger 1-2 Retire 2023 and 2038	P-31
P-46CP	Jim Bridger 3 & 4 Retire 2025	P-31
P-46J23CP	Jim Bridger 3 & 4 Retire 2023	P-46
P-47CP	Jim Bridger 3 & 4 Retire 2035	P-45
P-48CP	Jim Bridger 3 & 4 Retire 2033	P-45
P-53CP	Jim Bridger 1 & 2 Retire 2025, Jim Bridger 3-4 Retire 2028/2032	P-31

Front Office Transaction (FOT) Portfolios

PacifiCorp ran a series of FOT studies designed to quantify the impact and risk of market reliance for a given portfolio. These cases use an escalating scalar to elevate market prices during the peak months of July, August and December of every study year. As FOT prices are calculated as market price plus a premium, FOT prices are elevated with the market.

The scalar targets a maximum escalation based on the largest difference between each month's highest Mid-C forward price and the highest Mid-C historical price in the sample year of 2018. This yields a maximum peak scalar of 3.72 times higher than the forward price curve in the month of August; 3.70 times higher in the month of July; and 1.77 times higher in the month of December. The higher the original forward price in a given hour, the higher the scalar. This has the effect of increasing both the severity and frequency of high-price hours (increases upward volatility) while maintaining the shape of the underlying price curve.

Figure 7.18 illustrates the differences between the underlying forward price curve (FPC) and the escalating scaled price curve in each peak month in the sample year 2021.

Figure 7.18 – Sample Year 2021 FOT MidC FPC and Scaled Price Curves

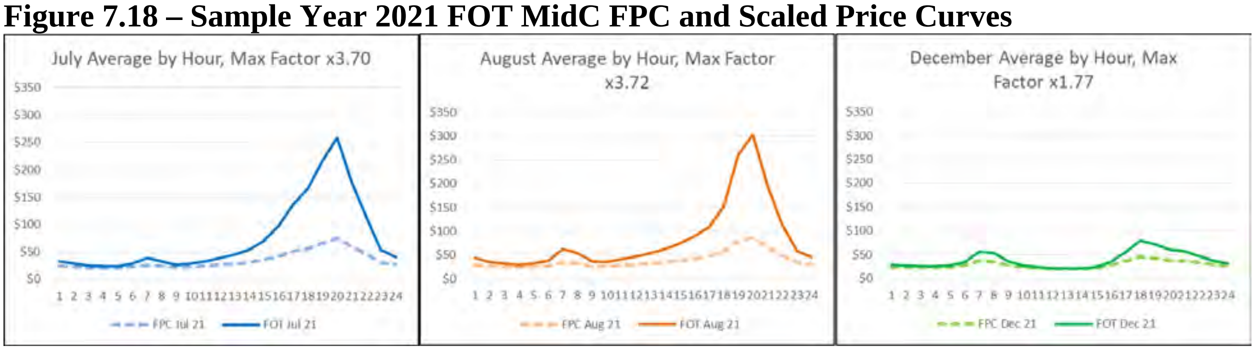


Table 7.12 lists the CP-series of cases where for which FOT scenarios were developed to evaluate market-reliance risk.

Table 7.12 – Front Office Transaction (FOT) Case Definitions

Case	Description
P-45CP-FOT	P-45CP with FOT price curve
P-46CP-FOT	P-46CP with FOT price curve
P-47CP-FOT	P-47CP with FOT price curve
P-48CP-FOT	P-48CP with FOT price curve
P-53CP-FOT	P-53CP with FOT price curve

2028-2029 Wyoming Wind Case

In reviewing CP-series case results, PacifiCorp identified that 620 MW of Wyoming wind resources added to each portfolio in the 2028-2029 timeframe, which coincides with the assumed retirement of Dave Johnston, were being curtailed at relatively significant levels. Consequently, and considering it unreasonable to potentially include highly curtailed new wind in a leading candidate for the preferred portfolio, PacifiCorp produced an incremental portfolio as a variant of the least cost CP-series case (P-45CP) that eliminated the 620 MW of incremental Wyoming wind coming online after the retirement of Dave Johnston. This case is referred to as P-45CNW.

Preferred Portfolio Selection Cases

Certain additional cases were developed directly from the top-performing case (P-45CNW) based on analysis of portfolios from the initial cases through the CP-series of cases as described above to evaluate the impacts of specific future scenarios not considered elsewhere, but which may be adopted into the preferred portfolio if the analysis warrants their inclusion. In the 2019 IRP, there are two types of preferred portfolio selection cases:

- No Gas portfolios
- Gateway portfolios (excluding gateway south, which is modeled as an option in all cases)

"No Gas" Cases

PacifiCorp ran two cases as variants of P-45CNW to evaluate portfolio impacts of excluding new natural gas capacity from the portfolio. The first case, P-29 does not allow the model to select new natural gas resources (excluding the Naughton Unit 3 gas conversion). The second case, P-29PS is a variant of P-29 with the addition of a 400 MW pumped storage project located in northeast Wyoming that comes online in 2028 following retirement of the Dave Johnston plant. Table 7.13 provides the No-Gas case definitions for this IRP.

Table 7.13 – No Gas Case Definitions

Case	Description	Parent Case
P-29	P-45CNW, No New Gas Option	P-45CNW
P-29 PS	P-45CNW, No New Gas Option with pumped hydro storage	P-45CNW

Gateway Cases

PacifiCorp modeled four Energy Gateway transmission cases, expanding on scenarios defined in previous IRP cycles. The full build-out of all Energy Gateway segments was performed in two cases (P-23 and P-25) to assess the potential value in two different coal retirement scenarios. The Energy Gateway cases developed for the 2019 IRP are summarized in Table 7.14 and Table 7.15.

Table 7.14 – Additional Gateway Case Definitions

Case	P-22	P-23	P-25	P-26
Base Case	P-45CNW	P-36CNW	P-45CNW	P-45CNW
Segments*	(D3), (F)	(D3), (E), (F), (H)	(D3), (E), (F), (H)	(F), (H)

Table 7.15 – Gateway Segment Definitions

Segment	Description	Incremental Capacity	Approximate Mileage	Build Year
(D3) Bridger/Anticline - Populus	500 kV single circuit	1700 MW + PathC 1000 MW	200 mi	2025
(E) Populus - Hemingway	500 kV single circuit	1260 MW	500 mi	2025
(F)* Aeolus - Clover	500 kV single circuit	1700 MW	400 mi	2023
(H) Boardman - Hemingway	500 kV single circuit	600 MW	290 mi	2026

* Note: Energy Gateway South Segment F is modeled as an option, and is selected in each Energy Gateway case summarized above.

Sensitivity Case Definitions

PacifiCorp initially identified 8 sensitivities based on prior IRP cycle experience, stakeholder feedback, and anticipated areas of interest. Each sensitivity is designed to highlight the impact of specific planning assumptions on future resource selections along with the associated impact on system costs and stochastic risks. These sensitivities were developed for informational purposes and serve to illustrate how the system behaves under a variety of conditions which helps inform the acquisition path analysis presented in Volume 1, Chapter 9 (Action Plan). All sensitivities, as summarized in Table 7.16, were run as a variant of case P-45CNW. Additional details on the sensitivity cases can be found in Volume II, Appendix M: Case Study Fact Sheets.

Table 7.16 – Sensitivity Case Definitions

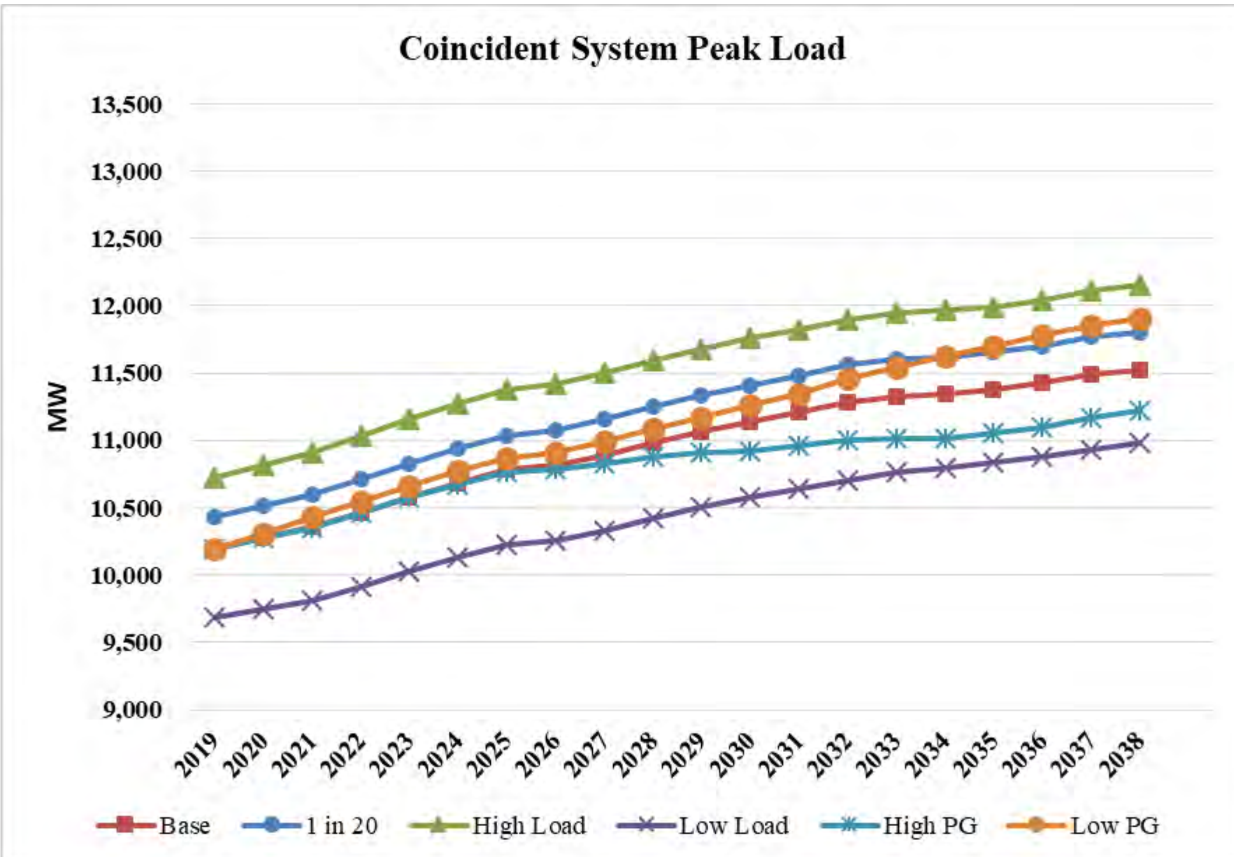
Case	Description	Load Forecast	Private Generation	Resources	Customer Preference	SO Model CO2 Price
S-01	Low Load	Low	Base	Optimized	Base	Base
S-02	High Load	High	Base	Optimized	Base	Base
S-03	1 in 20 Load Growth	1 in 20	Base	Optimized	Base	Base
S-04	Low Private Generation	Base	Low	Optimized	Base	Base
S-05	High Private Generation	Base	High	Optimized	Base	Base
S-06	Business Plan	Base	Base	Align first three years	Base	Base
S-07	No Customer Preference	Base	Base	Optimized	No targeted renewables	Base
S-08	High Customer Preference	Base	Base	Optimized	High	Base

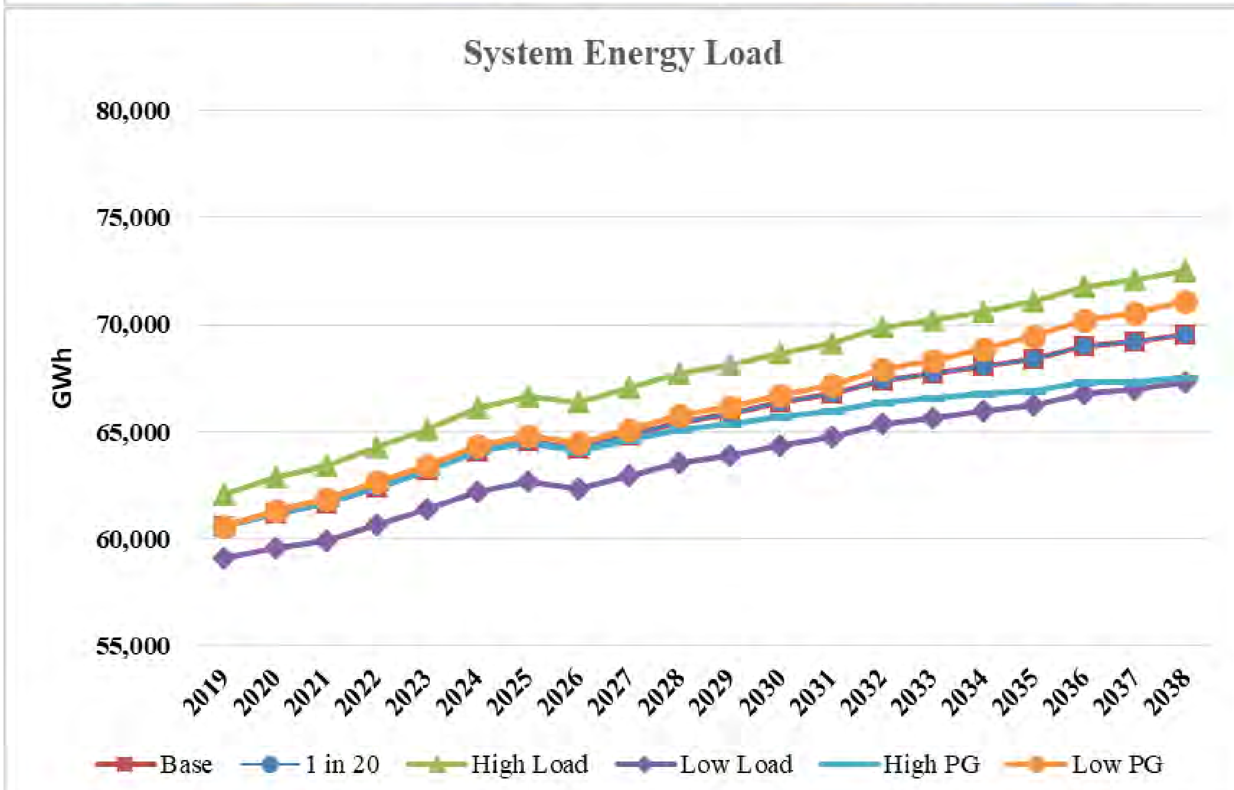
Load Sensitivities

PacifiCorp includes three different load forecast sensitivities. The low load forecast sensitivity (S-01) reflects pessimistic economic growth assumptions from IHS Global Insight and low Utah and Wyoming industrial loads. The high load forecast sensitivity (S-02) reflects optimistic economic growth assumptions from IHS Global Insight and high Utah and Wyoming industrial loads. The low and high industrial load forecasts focus on increased uncertainty in industrial loads further out in time. To capture this uncertainty, PacifiCorp modeled 1,000 possible annual loads for each year based on the standard error of the medium scenario regression equation. The low and high industrial load forecast is taken from 5^{th} and 95^{th} percentile.

The third load forecast sensitivity (S-03) is a 1-in-20 (5 percent probability) extreme weather scenario. The 1-in-20 peak weather scenario is defined as the year for which the peak has the chance of occurring once in 20 years. This sensitivity is based on 1-in-20 peak weather for July in each state. Figure 7.19 compares the low, high, and 1-in-20 load sensitivities, net of base case private generation levels, alongside the base case load forecast.

Figure 7.19 - Load and Private Generation Sensitivity Assumptions

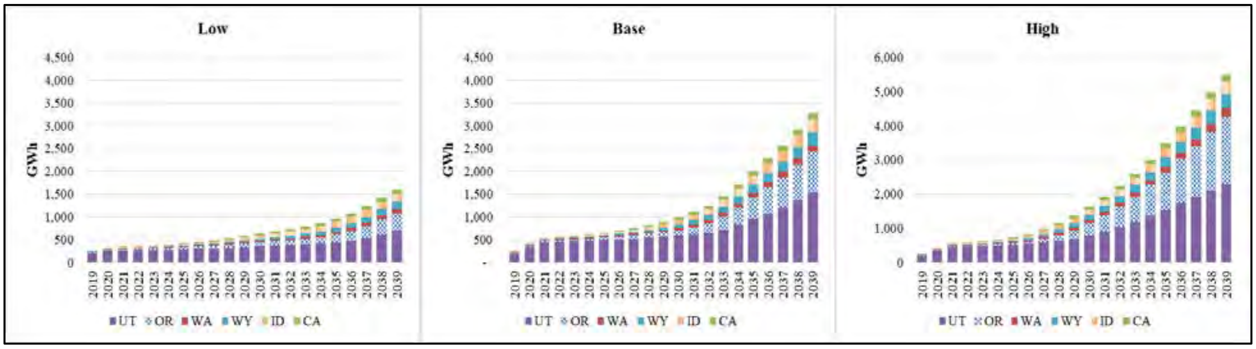




Private Generation Sensitivities

Two private generation sensitivities are analyzed. As compared to base private generation penetration levels that incorporated annual reductions in technology costs, the low private generation sensitivity (S-04) reflects lesser reductions in technology costs, reduced technology performance levels, and lower retail electricity rates. In contrast, the high private generation sensitivity (S-05) reflects more aggressive technology cost reduction assumptions, greater technology performance levels, and higher retail electricity rates. Figure 7.20 summarizes private generation penetration levels for the low and high sensitivities alongside the base case.

Figure 7.20 - Private Generation Sensitivity Assumptions



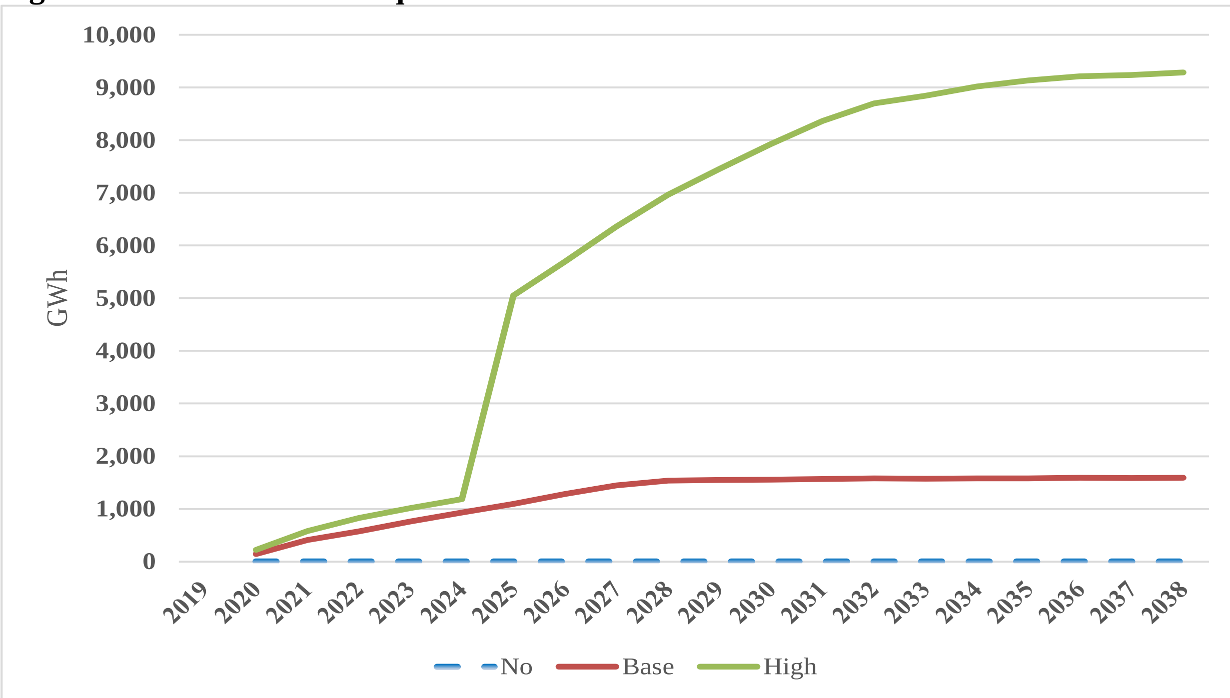
Business Plan Sensitivity

Case S-06 complies with the Utah requirement to perform a business plan sensitivity consistent with the commission's order in Docket No. 15-035-04. Over the first three years, resources align with those assumed in PacifiCorp's December 2018 Business Plan. Beyond the first three years of the study period, unit retirement assumptions are aligned with those identified in the preferred portfolio. All other resource selections are optimized within the SO model simulation.

Customer Preference Sensitivities

PacifiCorp includes two customer preference sensitivities. The first sensitivity is a no customer preference sensitivity (S-07) that assumes there are no customer preference resource requirements. The second sensitivity (S-08) is a high customer preference sensitivity that assumes proliferation of customer preference resources at higher levels than anticipated with close to 9,300 GWh of customer preference resources being added by the end of the twenty-year planning period. Figure 7.21 illustrates the relative customer preference generation requirements for these sensitivities.

Figure 7.21 – Generation Requirements for Customer Preference Sensitivities



East/West Split

Pursuant to a requirement by the Washington Utilities and Transportation Commission, PacifiCorp's IRP is to include a sensitivity that produces standalone resource portfolios for the west control area (WCA) compared to operation as part of PacifiCorp's integrated system. PacifiCorp will incorporate this sensitivity as part of its 2019 IRP Update pursuant to the Washington Utilities and Transportation Commission's July 26, 2019 order approving PacifiCorp's request for a waiver to WAC 480-100-238(4) in Docket UE-180259.

CHAPTER 8 – MODELING AND PORTFOLIO SELECTION RESULTS

CHAPTER HIGHLIGHTS

- Using a range of cost and risk metrics to evaluate a wide range of resource portfolios, PacifiCorp selected a preferred portfolio reflecting a bold vision shared with our customers for a future where energy is delivered affordably, reliably and without greenhouse gas emissions.
- The 2019 Integrated Resource Plan (IRP) preferred portfolio includes accelerated coal retirements and investment in transmission infrastructure that will facilitate adding over 6,400 megawatt (MW) of new renewable resources by the end of 2023, with nearly 11,000 MW of new renewable resources over the 20-year planning period through 2038.[1]
- Near-term, by the end of 2023, the preferred portfolio includes nearly 3,000 MW of new solar resources, more than 3,500 MW of new wind resources, nearly 600 MW of battery storage capacity (all collocated with new solar resources), and over 700 MW of incremental energy efficiency and new direct load control resources.[2]
- To facilitate the delivery of new renewable energy resources to PacifiCorp customers across the West, the preferred portfolio includes a 400-mile transmission line known as Gateway South, planned to come online by the end of 2023, that will connect southeastern Wyoming and northern Utah. The preferred portfolio further includes near-term transmission upgrades in Utah and Washington. Ongoing investment in transmission infrastructure in Idaho, Oregon, Utah, Washington, and Wyoming will facilitate continued and long-term growth in new renewable resources.
- Energy efficiency continues to play a key role in PacifiCorp's resource mix. In addition to continued investment in energy efficiency programs, the preferred portfolio continues to show a role for direct load control programs with total new capacity reaching 444 MW by the end of the planning period.
- Driven in part by ongoing cost pressures on existing coal-fired facilities and dropping costs for new resource alternatives, of the 24 coal units currently serving PacifiCorp customers, the preferred portfolio includes retirement of 16 of the units by 2030 and 20 of the units by the end of the planning period in 2038. Coal unit retirements in the 2019 IRP preferred portfolio will reduce coal-fueled generation capacity by over 1,000 MW by the end of 2023, nearly 1,500 MW by the end of 2025, nearly 2,800 MW by 2030, and nearly 4,500 MW by 2038.
- In the 2019 IRP preferred portfolio, Naughton Unit 3 is converted to natural gas in 2020, providing a low-cost reliable resource for meeting load and reliability requirements. New natural gas peaking resources appear in the preferred portfolio starting in 2026, which is outside the action-plan window and provides time for PacifiCorp to continue to evaluate whether non-emitting capacity resources can be used to supply the flexibility necessary to maintain system reliability into the future.
- The preferred portfolio shows an overall decline in reliance on wholesale market firm purchases in the 2019 IRP preferred portfolio relative to the market purchases included in

[1] Resources acquired through customer partnerships, used for renewable portfolio standard compliance, or for third-party sales of renewable attributes are included in the total capacity figures quoted.
[2] *Id*.

the 2017 IRP preferred portfolio. In particular, reliance on market purchases during summer peak periods averages 366 MW per year over the 2020-2027 timeframe—down 60 percent from market purchases identified in the 2017 IRP preferred portfolio.

- The 2019 IRP preferred portfolio reflects PacifiCorp's on-going efforts to provide cost-effective clean-energy solutions for our customers and accordingly reflects a continued trajectory of declining carbon dioxide (CO_2) emissions. As compared to the 2017 IRP, projected carbon dioxide (CO_2) emissions in 2025, are down sixteen percent relative to the 2017 IRP preferred portfolio. By 2030, average annual CO_2 emissions are down 34 percent relative to the 2017 IRP preferred portfolio, and down 35 percent in 2035. By the end of the planning horizon, system CO_2 emissions are projected to fall from 43.1 million tons in 2019 to 16.7 million tons in 2038—a 61.3 percent reduction.

Introduction

This chapter reports modeling and performance evaluation results for the resource portfolios developed with a broad range of input assumptions using the System Optimizer (SO) model and the Planning and Risk model (PaR). Using model data from the portfolio-development process and subsequent cost and risk analysis of unique portfolio alternatives, PacifiCorp steps through its preferred portfolio selection process and presents the 2019 IRP preferred portfolio.

The chapter is organized around the three modeling and evaluation steps identified in the previous chapter: (1) coal studies; (2) portfolio development; and (3) preferred portfolio selection. The final preferred portfolio selection is informed by all relevant case results and incorporates any refinements indicated by preceding results, recent relevant events and stakeholder feedback. This chapter also presents modeling results for additional 2019 IRP sensitivity cases that, while informative, were not considered for selection as the preferred portfolio.

Results of resource portfolio cost and risk analysis from each step are presented as PacifiCorp steps through the following discussion of its portfolio evaluation processes. Stochastic modeling results from PaR are also summarized in Volume II, Appendix L (Stochastic Simulation Results).

Coal Studies

The 2019 IRP included a thorough and robust economic analysis of PacifiCorp's coal units. The coal study analysis conducted in the 2019 IRP was initially prompted by the Public Utility Commission of Oregon (OPUC) as set forth in its 2017 IRP acknowledgement order, which administratively established certain modeling requirements. PacifiCorp met these requirements and then developed a more complete coal study. The coal study effort is comprised of the following three key phases:

- Phase One - Unit-by-unit coal studies.
- Phase Two - Stacked coal studies.
- Phase Three - Reliability coal studies.

The three phases of the coal studies are detailed in Volume II, Appendix R (Coal Studies).

Coal Studies Conclusions

Each of the coal study phases show that early retirement of certain coal units has potential to reduce overall system costs. In particular, the coal studies showed that the greatest customer benefits were most likely to be realized with potential early retirement of coal units at the Naughton and Jim Bridger coal plants located in Wyoming.

The portfolio-development process considers other planning factors not fully evaluated in the coal studies (i.e., Regional Haze compliance, alternative retirement dates for jointly owned coal plants where PacifiCorp is a minority owner and not an operator, alternative timing of potential retirements when accounting for incremental capacity to maintain reliability). Consistent with the findings from the coal study, more than half of the cases developed in the initial phase of the portfolio-development process evaluated varying combinations of retirement dates for Naughton and Jim Bridger units.

Portfolio Development

The following discussion begins with an examination of *initial portfolios* exploring variations in retirement timing for the Jim Bridger 1 & 2 and Naughton 1 & 2 units. The initial portfolios also explore potentially significant interactions with additional retirement options including possible Naughton 3 gas conversion, Gadsby gas unit retirements, and the timing of Cholla retirement.

Following the initial portfolios, PacifiCorp refines top-performing cases with two stages of additional reliability requirements, referred to as the C-series of cases and the CP-series of cases.

In the C-series of cases, top-performing portfolios are examined with a more granular assessment of reliability requirements through the production of hourly deterministic Planning and Risk Model (PaR) studies covering 2023 through 2030, plus 2038. This provides a total of nine years of hourly PaR reliability assessment rather than the three years (2023, 2030, and 2038) used to develop the initial portfolios. As described in Volume I, Chapter 7 (Modeling and Portfolio Evaluation Approach), in addition to expanding the reliability assessment step of portfolio development the C-series also removes proxy stand-alone solar resources from the resource options available to the SO model, which lowers the present-value revenue requirement (PVRR) in all cases.

Top-performing portfolios from the C-series of cases were further examined in the CP-series of cases with additional deterministic PaR studies covering 2023 through 2038. This provides a total of 16 years of hourly PaR reliability assessment, and fleshes out any granular variances in the back-end of the study period.

As discussed in Volume I, Chapter 7 (Modeling and Portfolio Evaluation Approach), PacifiCorp produced a variant of the top-performing CP-series case to eliminate Wyoming wind resources that were added in the 2028-2029 timeframe. This case, along with other cases from the CP-series, were further analyzed to quantify market reliance risk in a series of front office transaction (FOT) cases. Final selection cases were also developed to evaluate the impact of removing all new natural gas resource from the top-performing portfolio and to assess the impact of adding additional Energy Gateway transmission segments to the top-performing portfolio.

Initial Portfolio Development

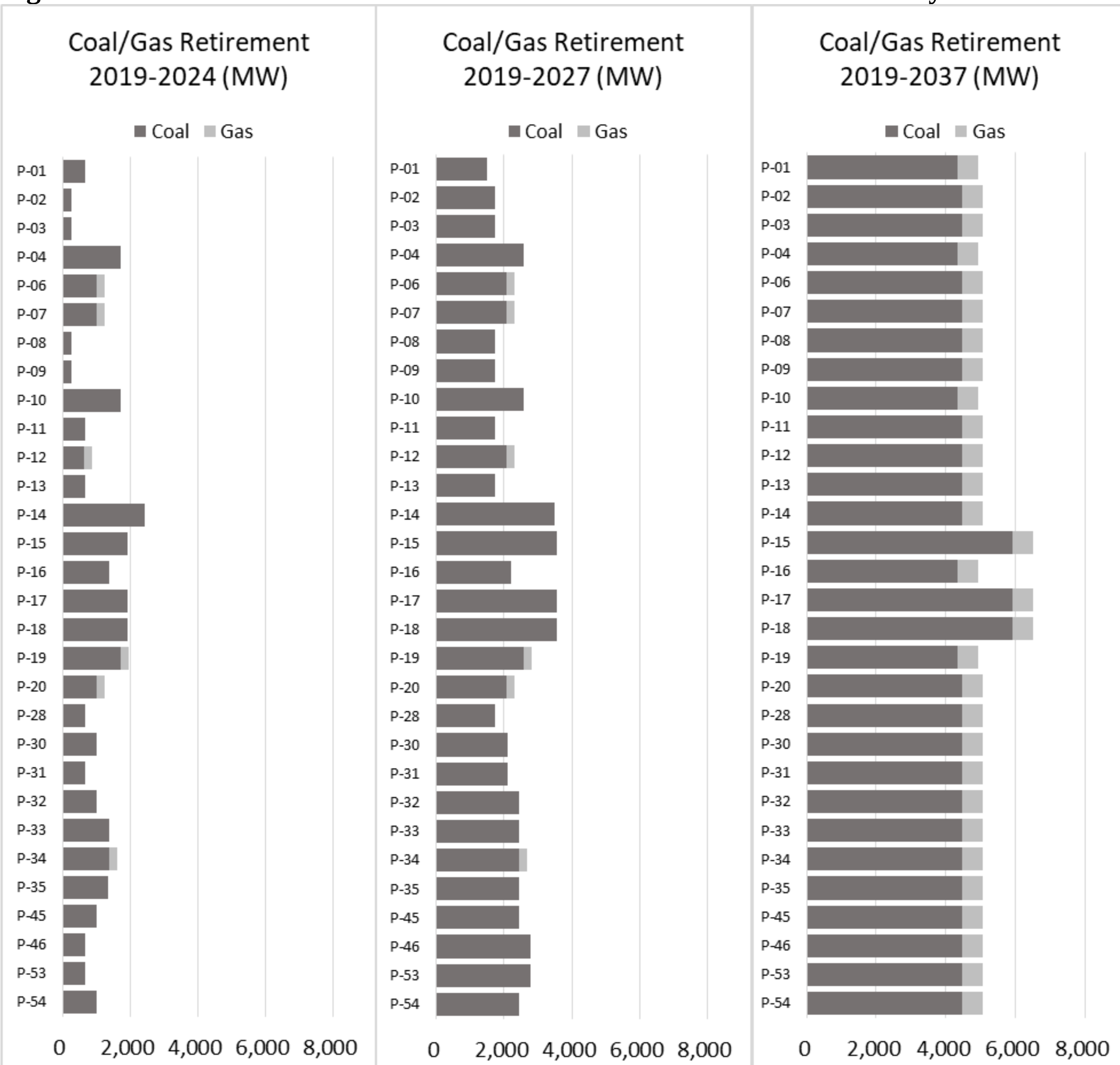
The following tables and figures present resource additions and system costs for the initial portfolios. Additional information is provided for these cases in Volume II, Appendix K (Capacity Expansion Results Detail), including detailed resource portfolio results showing new resource capacity and changes to existing resource capacity by year. Summary portfolio results are also shown in the case fact sheets presented in Volume II, Appendix M (Case Study Fact Sheets).

Coal and Gas Resource Retirements

Figure 8.1 summarizes the cumulative nameplate coal and gas retirements by case over the near-term, mid-term, and long-term among the initial portfolio cases. Note, in reporting cumulative capacity in this figure and in the similar figures that follow, the mid-term results include capacity retired in the near-term, and similarly, the long-term results include capacity retired in the near-term and in the mid-term. Unit-specific retirement dates for each case can be found in Volume II, Appendix M (Case Study Fact Sheets).

By the end of the study period, coal retirements are similar among nearly all cases (P-15, P-17 and P-18 are exceptions), with slight variations dependent upon timing for Colstrip Units 3 and 4. Cases P-15, P-17, and P-18 assume all coal is retired by the end of 2030. By the end of the study period, gas retirements are the same among all cases. Cases P-06, P-17, P-12, P-19, P-20, and P-34 assume the gas-fueled Gadsby Units 1-3 retire at the end of 2020. Among the five cases with the lowest PVRR (cases P-31, P-45, P-46, P-53, and P-54), coal unit retirements range from 667 MW to 1,023 MW through 2024 and range between 2,091 MW and 2,797 MW through the end of 2027.

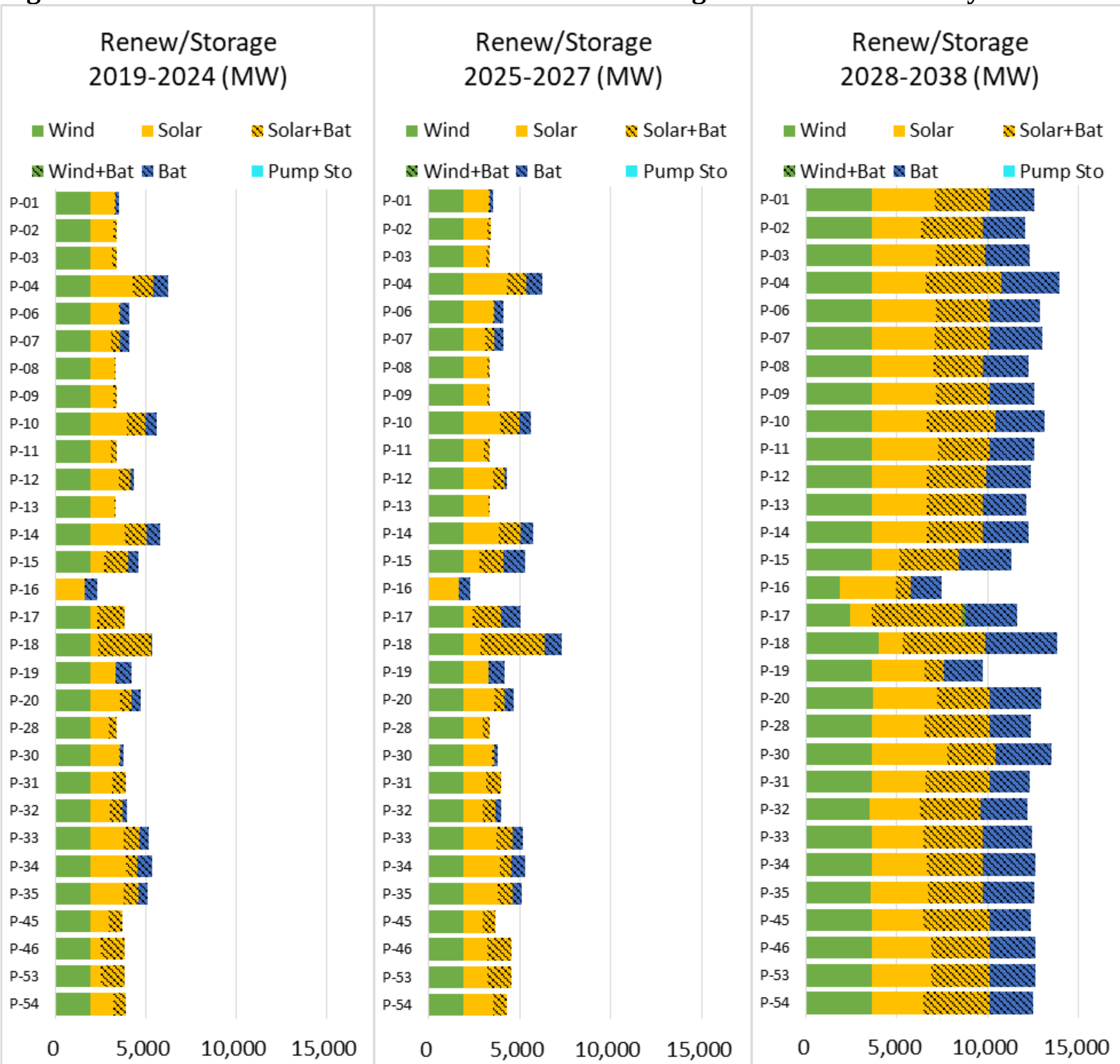
Figure 8.1 – Initial Portfolios Coal and Gas Resource Retirements Summary



New Renewable and Storage Resources

Figure 8.2 reports the nameplate capacity of new renewables and storage resource additions for each initial case. Near-term renewable additions through 2024 range from 1,633 MW to 5,475 MW. In all cases but one (case P-16, which eliminates CO_2 price assumptions through the study period), the SO model selects Energy Gateway South in 2024 (a proxy for year-end 2023) along with 1,920 MW of new wind in eastern Wyoming. Excluding case P-16, the minimum penetration of new renewable capacity is 3,290 MW through 2024 (a proxy for year-end 2023). Through the mid-term, renewable capacity grows up to 6,372 MW by 2027. Through 2027, new solar capacity ranges between 1,370 MW and 4,452 MW—cases with more early coal retirements have more solar capacity. Through 2038, the total new renewable capacity ranges between 5,574 MW and 10,711 MW, and new battery storage capacity ranges between 1,903 MW and 4,558 MW. Among the five cases with the lower PVRR (cases P-31, P-45, P-46, P-53, and P-54), the total new renewable capacity ranges between 3,674 MW and 4,536 MW through 2027 and over 10,000 MW through 2038.

Figure 8.2 – Initial Portfolios New Renewable and Storage Resources Summary

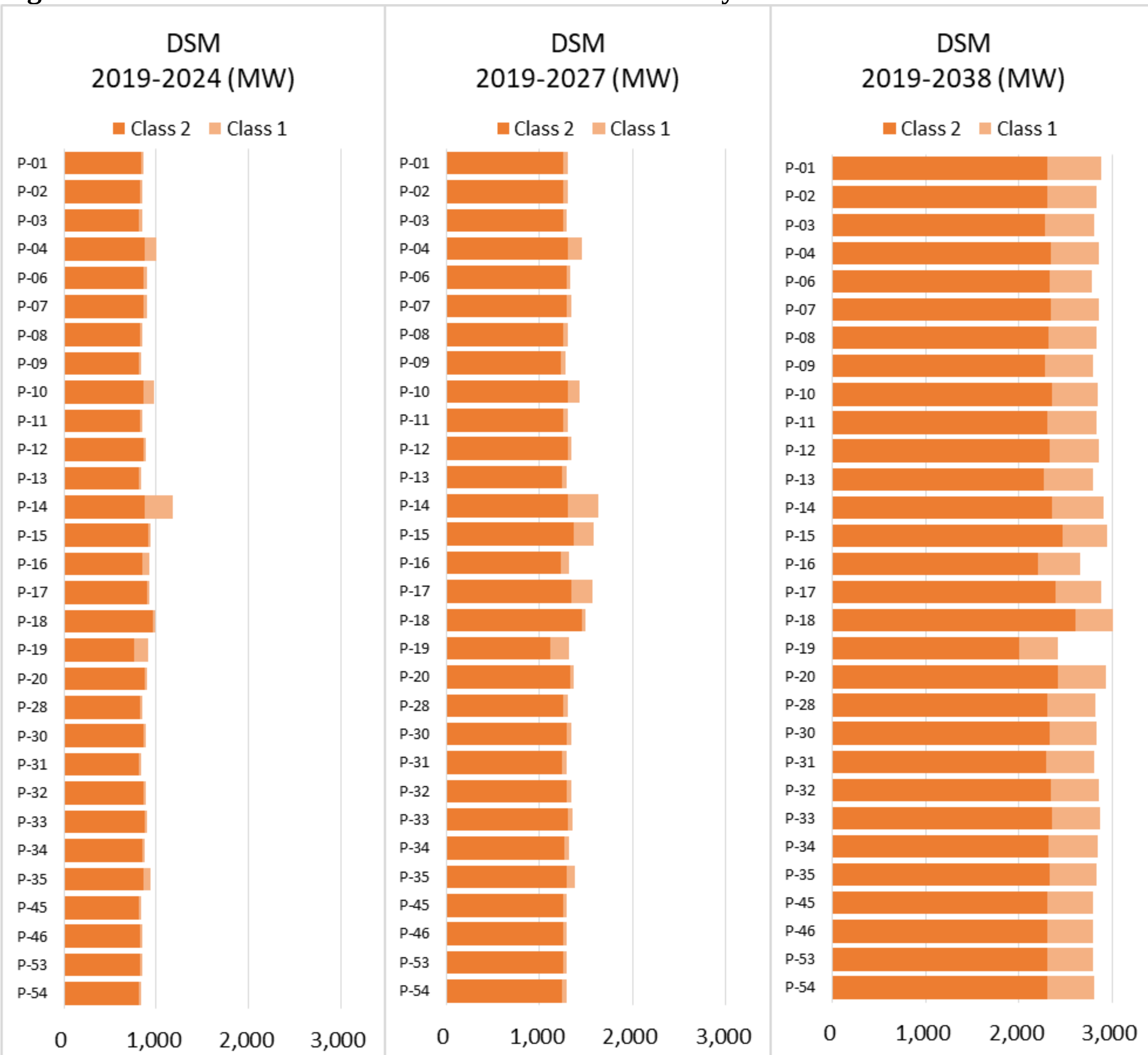


Note: For wind or renewable resources paired with battery, the capacity for the renewable resource is shown in the graph. The battery capacity paired with these resources is 25 percent of the renewable resource capacity.

Incremental Demand-Side Management (DSM)

Figure 8.3 summarizes aggregated demand-side Management (DSM) selections by case. Selected volumes of DSM are relatively stable among all initial cases. Through 2024, Class 2 DSM (energy efficiency) selections range between 763 MW (case P-19) and 965 MW (case P-18) and Class 1 DSM (demand response and direct-load control) ranges between 11 MW and 19 MW. Through 2027, Class 2 DSM selections range between 1,116 MW (case P-19) and 1,455 MW (case P-18) and Class 1 DSM ranges between 45 MW and 322 MW. More Class 1 DSM resources are accelerated into the mid-term among those cases that have higher levels of accelerated coal and gas retirements (cases P-04, P-10, P-14, P-15, P-16, P-17 and P-19). Through 2038, Class 2 DSM selections range between 2,005 MW (case P-19) and 2,603 MW (case P-18) and Class 1 DSM ranges between 417 MW and 583 MW.

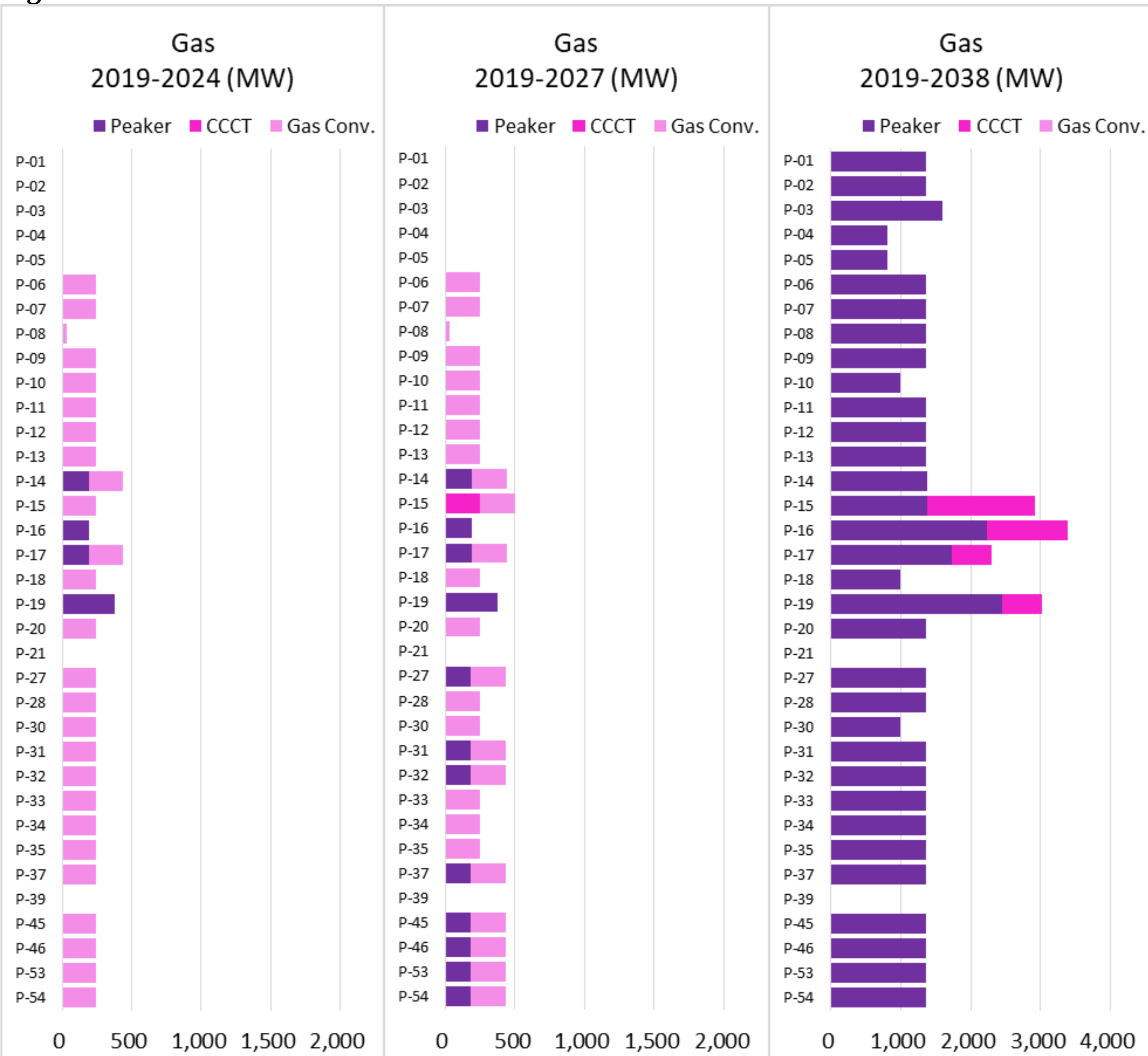
Figure 8.3 – Initial Portfolios Incremental DSM Summary



New Natural Gas Resources

Figure 8.4 summarizes cumulative natural gas expansion resources for each initial portfolio. In cases where Naughton Unit 3 converts to natural gas in 2020, it is assumed to retire at the end of 2029, so it does not show up in the results through 2038. Four cases (P-14, P-16, P-17, and P-19) include new gas peaking capacity in 2023. Through 2038, new peaking gas capacity ranges between 813 MW and 2,458 MW. Case P-15 includes new combined-cycle combustion turbine (CCCT) gas capacity beginning 2027—through 2038, new CCCT capacity in this case totals 1,541 MW. Three additional cases include CCCT capacity, albeit at reduced levels relative to case P-15 (cases P-16, P-17 and P-19). Among the five cases with the lowest PVRR (cases P-31, P-45, P-46, P-53, and P-54), new peaking gas capacity is added in 2026 (185 MW)—by 2038, new gas peaking capacity totals 1,367 MW.

Figure 8.4 – Initial Portfolios New Natural Gas Resources



- Note: Scale change in the 'through 2038' column due to P15's addition of CCCT resources.

Summer Front Office Transactions (FOT)

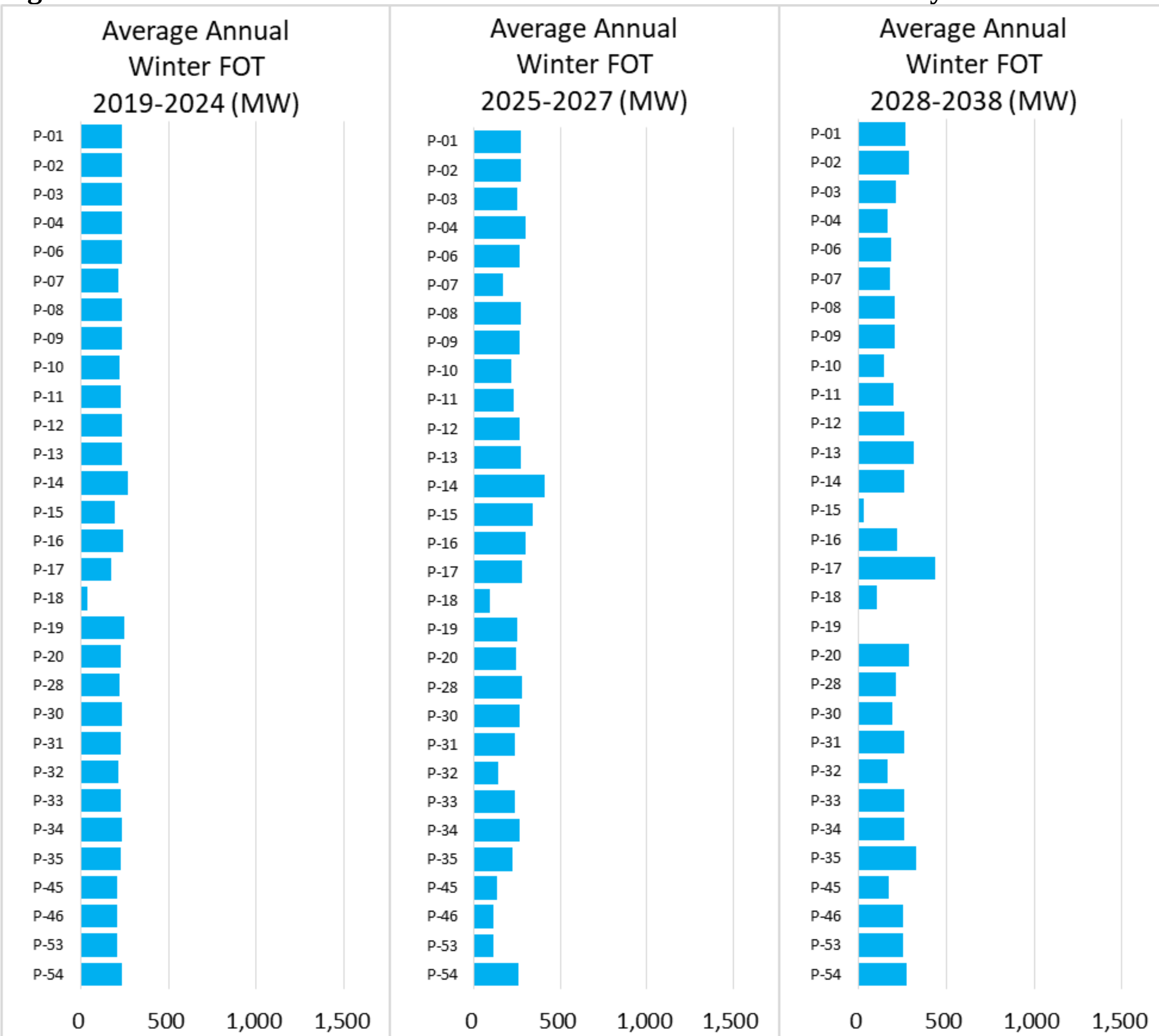
Figure 8.5 summarizes the average of FOTs for each initial portfolio during the summer peak. The summer FOT limit assumed for the 2019 IRP is 1,425 MW. Through the near-term, average annual summer FOT purchases range between 543 MW (cases P-46 and P-53) and 1,031 MW (case P-19). In the 2025-2027 timeframe, a period where there are resource-adequacy concerns in the region, summer average annual FOT purchases range between 168 MW (case P-31) and 1,290 MW (case P-16)—reliance on the market grows in cases with more accelerated coal retirements. Over the long term, the level of summer FOTs is relatively stable among all cases, ranging between 1,241 MW (Case P-13) and 1,362 MW (Case P-15).

Figure 8.5 – Initial Portfolios Summer Front Office Transactions Summary

Winter Front Office Transactions

Figure 8.6 summarizes the average of FOTs for each initial portfolio during the winter peak. The winter FOT limit assumed for the 2019 IRP is 1,425 MW. Relative to the summer period, winter FOTs are much smaller among all cases and timeframes. Winter FOT purchases are also relatively stable among most cases through both the short and mid-term. Over the long term, winter FOT purchases are reduced when incremental capacity is added to the system—CCCT additions in P-15 and P-19 significantly reduce winter FOT purchases.

Figure 8.6 – Initial Portfolios Winter Front Office Transactions Summary



CO_2 Emissions

Figure 8.7 reports cumulative CO_2 emissions for each initial portfolio. Total CO_2 emissions through 2022 are very stable, ranging between 162 and 164 million tons. Through 2027, total CO_2 emissions range between 318 and 353 million tons. Through 2038, total CO_2 emissions range between 427 and 670 million tons. Among the five cases with the lowest PVRR (cases P-31, P-45, P-46, P-53, and P-54), total CO_2 emissions through 2038 range between 560 and 588 million tons.

Figure 8.7 – Initial Portfolios CO_2 Emissions Summary

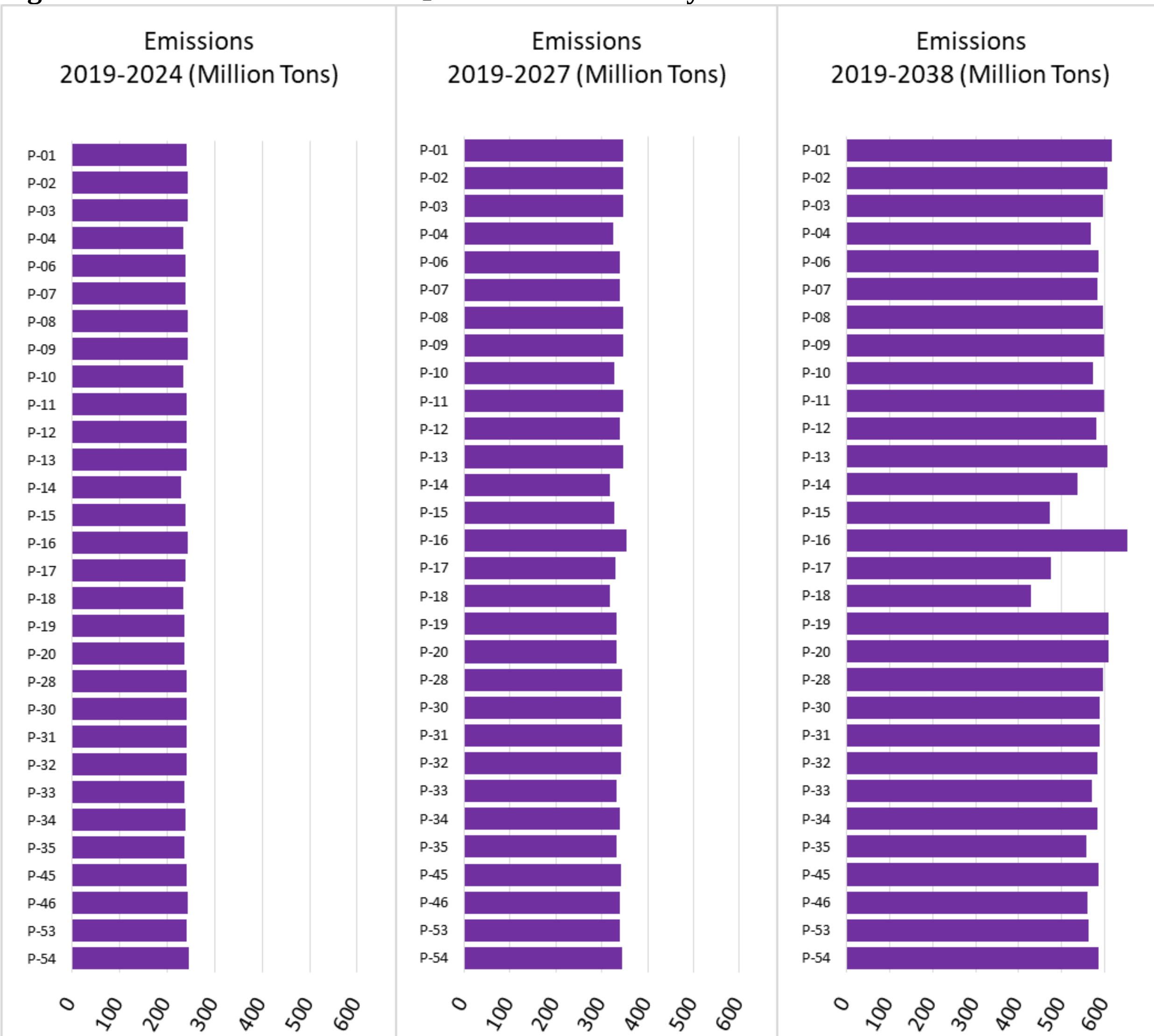


Table 8.1 summarizes results for the initial portfolios, including the stochastic mean PVRR, the risk-adjusted PVRR, amount of energy not served (ENS) as a percentage of load, and CO_2 emissions for each case.

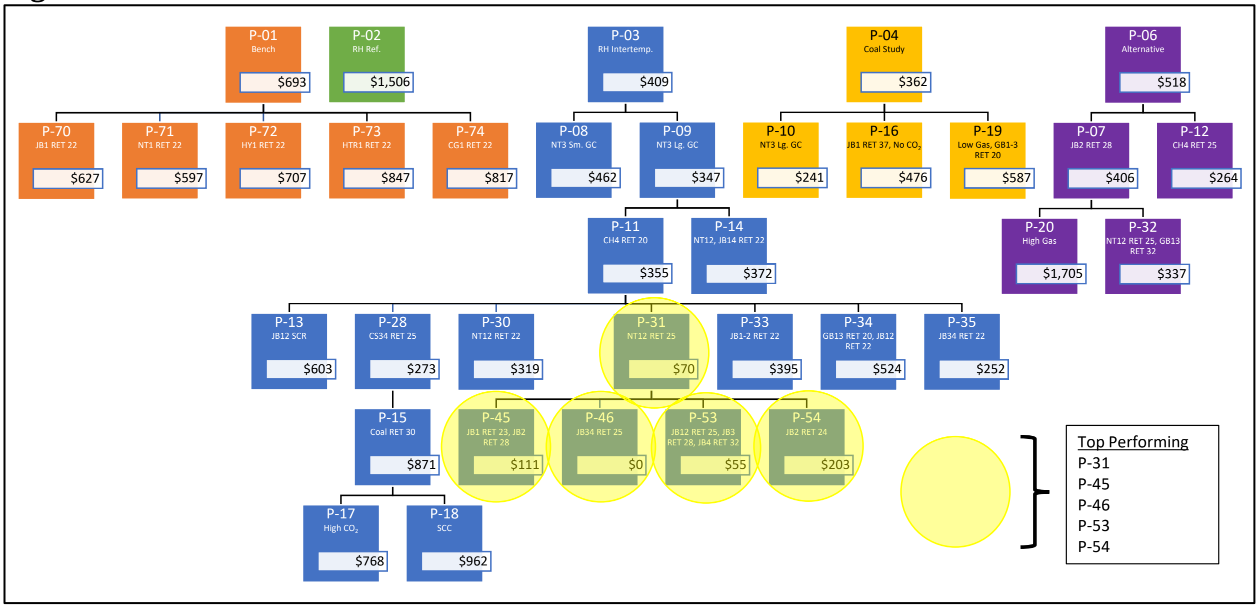
Table 8.1 – Initial Portfolio Cost and Risk Results Summary

	Stochastic Mean			Risk Adjusted			ENS Average Percent of Load			CO2 Emissions		
Case	PVRR ($m)	Change from Lowest Cost Portfolio ($m)	Rank	PVRR ($m)	Change from Lowest Cost Portfolio ($m)	Rank	Average Annual ENS, 2019-2038 % of Average Load	Change from Lowest ENS Portfolio	Rank	Total CO2 Emissions, 2019-2038 (Thousand Tons)	Change from Lowest Emission Portfolio	Rank
P46	**23,413**	**0**	**1**	**24,605**	**0**	**1**	**0.012%**	**0.006%**	**26**	**560,199**	**133,090**	**6**
P53	**23,468**	**55**	**2**	**24,662**	**57**	**2**	**0.012%**	**0.006%**	**27**	**562,025**	**134,915**	**7**
P31	**23,484**	**70**	**3**	**24,678**	**72**	**3**	**0.009%**	**0.002%**	**19**	**588,421**	**161,312**	**19**
P45	**23,525**	**111**	**4**	**24,722**	**116**	**4**	**0.008%**	**0.001%**	**10**	**583,981**	**156,872**	**15**
P54	**23,616**	**203**	**5**	**24,819**	**213**	**5**	**0.009%**	**0.002%**	**17**	**584,377**	**157,267**	**16**
P10	23,655	241	6	24,864	259	6	0.009%	0.003%	21	571,707	144,597	11
P35	23,666	252	7	24,871	266	7	0.010%	0.004%	23	557,489	130,379	5
P28	23,686	273	9	24,888	283	9	0.008%	0.002%	14	594,322	167,212	20
P30	23,733	319	10	24,941	336	10	0.010%	0.003%	22	587,905	160,795	18
P11	23,768	355	13	24,976	370	13	0.008%	0.001%	9	596,911	169,801	23
P12	23,678	264	8	24,886	281	8	0.008%	0.002%	13	579,167	152,057	12
P13	24,016	603	24	25,234	629	24	0.008%	0.001%	11	604,396	177,286	25
P14	23,786	372	15	25,000	394	15	0.015%	0.009%	28	535,774	108,664	4
P32	23,750	337	11	24,959	354	11	0.008%	0.002%	15	583,565	156,455	14
P09	23,760	347	12	24,970	365	12	0.009%	0.002%	20	597,855	170,745	24
P04	23,775	362	14	24,993	387	14	0.011%	0.004%	24	567,901	140,792	8
P33	23,809	395	16	25,024	419	16	0.007%	0.001%	7	569,586	142,476	10
P07	23,819	406	17	25,033	427	18	0.007%	0.000%	5	581,583	154,474	13
P03	23,822	409	18	25,033	427	17	0.008%	0.002%	12	595,728	168,619	21
P08	23,875	462	19	25,092	486	19	0.009%	0.002%	18	595,956	168,846	22
P16	23,889	476	20	25,097	491	20	0.007%	0.000%	2	669,944	242,834	30
P06	23,932	518	21	25,151	546	21	0.007%	0.001%	6	585,907	158,798	17
P34	23,938	524	22	25,157	551	22	0.008%	0.001%	8	568,422	141,312	9
P19	24,000	587	23	25,211	606	23	0.007%	0.000%	3	607,157	180,047	27
P01	24,106	693	25	25,327	721	25	0.006%	0.000%	1	616,896	189,786	29
P17	24,182	768	26	25,400	795	26	0.057%	0.051%	29	475,390	48,281	3
P15	24,285	871	27	25,516	911	27	0.012%	0.005%	25	472,569	45,459	2
P18	24,376	962	28	25,602	997	28	0.111%	0.104%	30	427,110	0	1
P02	24,919	1,506	29	26,183	1,577	29	0.009%	0.002%	16	605,872	178,763	26
P20	25,118	1,705	30	26,385	1,780	30	0.007%	0.000%	3	607,157	180,047	27

PacifiCorp identified the first five cases in the table (in bold) as top-performing cases selected for more refined C-series analysis.

Figure 8.8 summarizes the stochastic mean PVRR relationships among the initial portfolio cases in the "family tree" format summarized in Volume I, Chapter 7 (Modeling and Portfolio Evaluation Approach). Dollar figures associated with each case represent the increase in system PVRR relative to the lowest-cost case (case P-46). Note, that cases P-70 through P-74 were developed in response to stakeholder interests to reaffirm conclusions from the coal study, which indicate that potential early coal unit retirements should be focused on Naughton and Jim Bridger units.

Figure 8.8 – Relative Cost of Stochastic Mean to the Lowest-Cost Initial Case



C-Series Portfolios

In the C-series of cases, top-performing portfolios from the initial set of portfolios, and additional portfolios produced in response to stakeholder interest, receive an expanded reliability analysis. For each of these cases, PacifiCorp produced six additional deterministic hourly studies to ensure that each year is analyzed through 2030 (i.e., adding test years for 2024-2029). This improves the granularity at which reliability resources are applied and provides for a better comparison of cost and risk metrics between these cases.

As described in Volume I, Chapter 7 (Modeling and Portfolio Evaluation Approach), in addition to expanding the reliability assessment step of portfolio development the C-series also removes proxy stand-alone solar resources from the resource options available to the SO model. This allows the SO model to efficiently combine renewables and storage resources in order to accrue combined economic benefits that would otherwise be lost.

As noted above, in addition to the five top performing cases derived from the initial portfolios, the C-series includes five additional cases developed after stakeholder discussion at the September 5-6, 2019 public-input meeting. Table 8.2 summarizes the five additional C-series cases.

Table 8.2 – Additional C-Series Cases

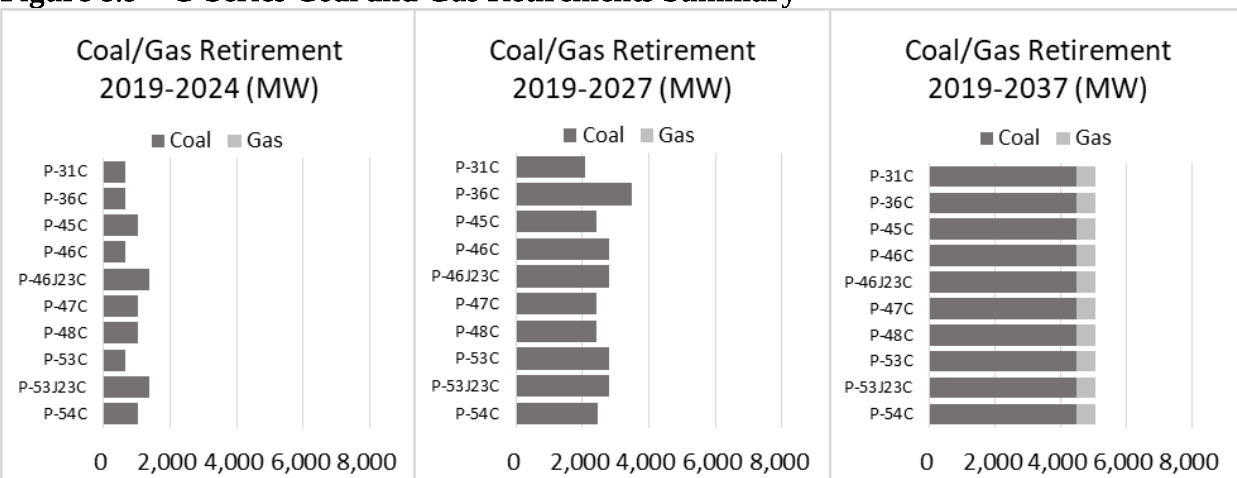
Case	Description
P-36C	A variant of Case P-14 with Jim Bridger 1-2 and Naughton 1-2 retired at the end of 2025.
P-46J23C	A variant of Case P-46 with Jim Bridger 3-4 retired at the end of 2023.
P-47C	A variant of Case P-45 with Jim Bridger 3-4 retired at the end of 2035.
P-48C	A variant of Case P-45 with Jim Bridger 3-4 retired at the end of 2033.
P-53J23C	A variant of Case P-53 with Jim Bridger 1-2 retired at the end of 2023.

C-Series Portfolio Development

Coal and Gas Resource Retirements

Figure 8.9 summarizes cumulative nameplate coal and gas retirements for each C-series case over the near-term, mid-term, and long-term. Note, in reporting cumulative capacity in this figure and the similar figures that follow, the mid-term results include capacity retired in the near-term, and similarly, the long-term results include capacity retired in the near-term and in the mid-term. Unit-specific retirement dates for each case can be found in Volume II, Appendix M (Case Study Fact Sheets). Through 2027, total coal retirements range between 2,091 MW (case P-31C) and 3,499 MW (case P-36C). Through the end of 2037, total coal retirements approach 4,500 MW in each case.

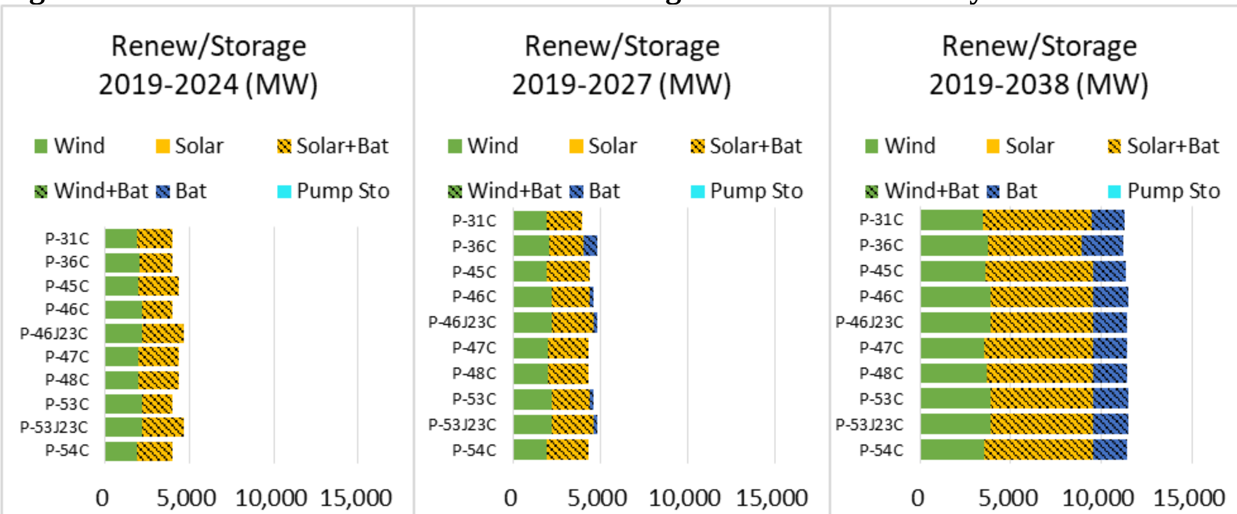
Figure 8.9 – C-Series Coal and Gas Retirements Summary



New Renewable and Storage Resources

Figure 8.10 summarizes the nameplate capacity of new renewables and storage resource additions for each C-series case. In all cases the SO model selects Energy Gateway South in 2024 (a proxy for year-end 2023) along with 1,920 MW of new wind in eastern Wyoming. Through 2027, new renewable capacity ranges between 3,992 MW (case P-31C) and 4,645 MW (cases P-46J23C and P-53J23C). By the end of 2038, new renewable capacity ranges between 8,905 MW (case P-36C) and 9,574 MW (cases P-46C, P-47C, P-48C, P-53C, P-53J23C and P-54C). New battery capacity ranges between 518 MW and 729 MW through 2027 and over 3,300 MW by the end of 2038.

Figure 8.10 – C-series New Renewable and Storage Resources Summary

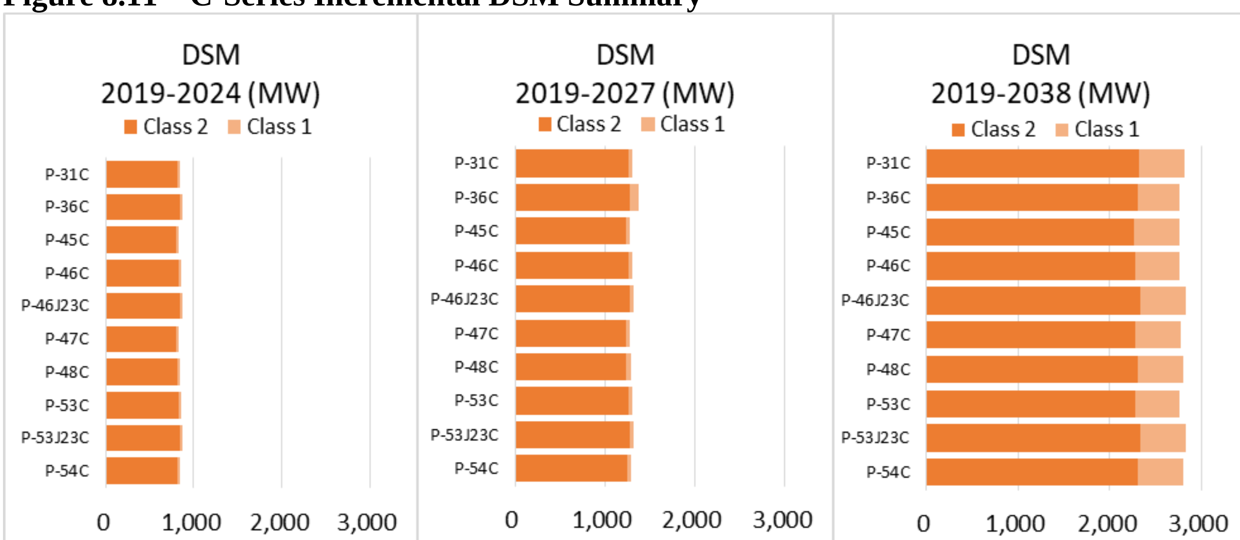


Note: For wind or renewable resources paired with battery, the capacity for the renewable resource is shown in the graph. The battery capacity paired with these resources is 25 percent of the renewable resource capacity.

Incremental Demand-Side Management (DSM)

Figure 8.11 summarizes aggregated DSM selections by case. Selected volumes of DSM are relatively stable among all C-series cases. On average, Class 2 DSM capacity totals 826 MW through 2024, 1,257 MW through 2027, and 2,299 MW through 2038. On average, Class 1 DSM capacity totals 29 MW through 2022, 45 MW through 2027, and 485 MW through 2038.

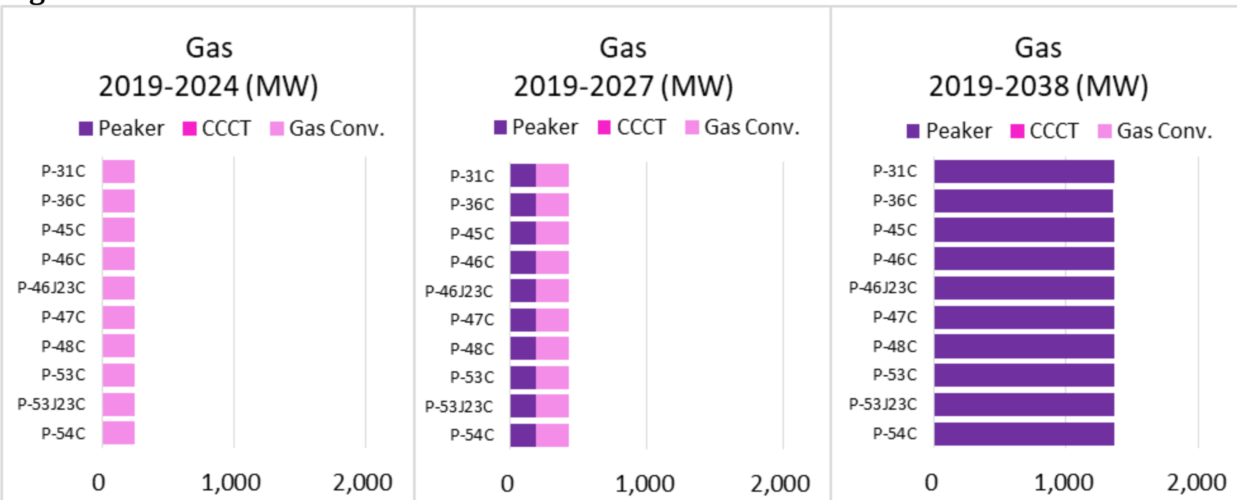
Figure 8.11 – C-Series Incremental DSM Summary



New Natural Gas Resources

Figure 8.12 summarizes cumulative natural gas expansion resources for each C-series portfolio. In cases where Naughton 3 converts to natural gas, it is assumed to retire at the end of 2029, so it does not show up in the results through 2038. Each case includes the large gas conversion of Naughton Unit 3 in 2020, and includes 185 MW of new peaking gas capacity in 2026. Case P-36C includes 1,356 MW of new peaking gas through the end of 2038; all other C-series cases include 1,367 MW of new gas peaking gas capacity through the end of 2038. None of these cases include new gas CCCT capacity.

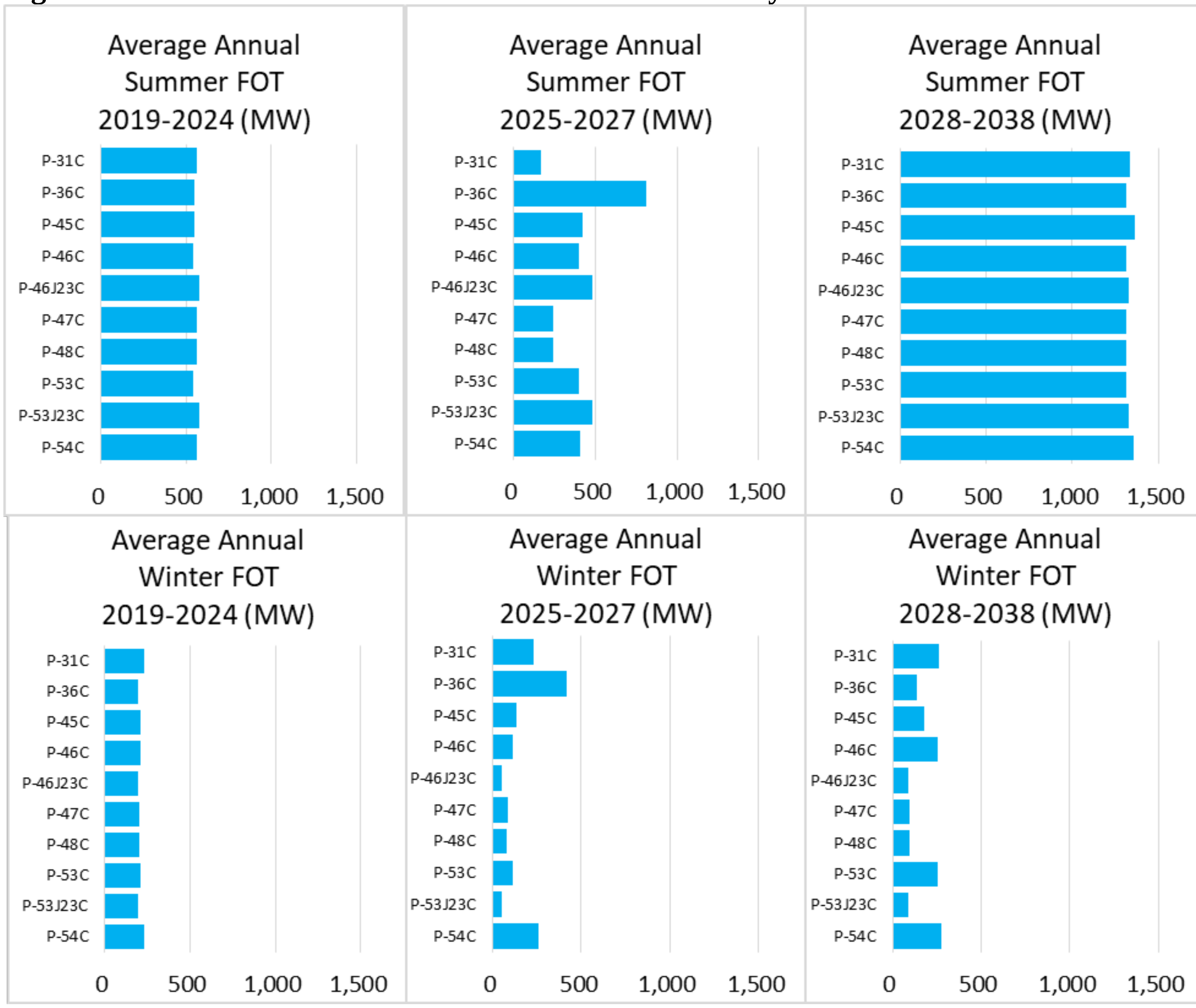
Figure 8.12 – C-Series New Natural Gas Resource



Front Office Transactions

Figure 8.13 summarizes the average of FOTs for each C-Series portfolio during the summer and winter peak periods. The summer and winter FOT limit assumed for the 2019 IRP is 1,425 MW. Market reliance is reduced in the 2025 to 2027 timeframe, coinciding with the addition of new transmission, new wind, and new solar+battery resources—on average, summer FOT purchases are 406 MW per year over this period. Longer-term, summer FOTs increase similarly among these cases, on average ranging between 1,310 MW and 1,361 MW each year from 2028-2038. Winter FOTs remain well below the volumes included in each portfolio to cover the summer peak period.

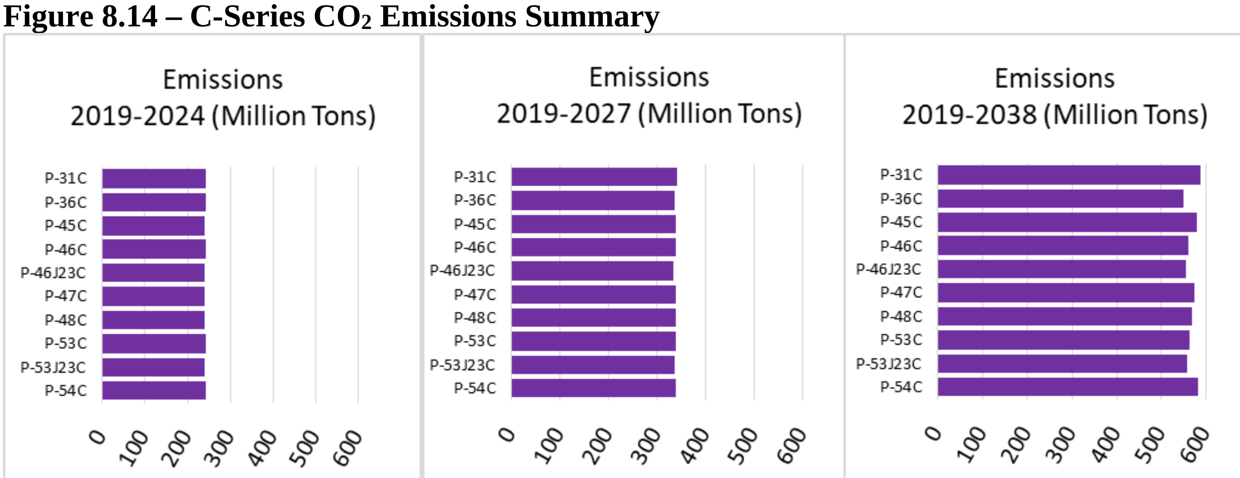
Figure 8.13 – C-Series Front Office Transactions Summary



CO_2 Emissions

Figure 8.14 reports cumulative CO_2 emissions for each C-series portfolio. Total CO_2 emissions is similar among these cases through 2027. Through 2038, total CO_2 emissions range between 550 million tons (case P-36C) and 588 million tons (case P-31C).

Figure 8.14 – C-Series CO_2 Emissions Summary



C Series Case Cost and Risk Summary

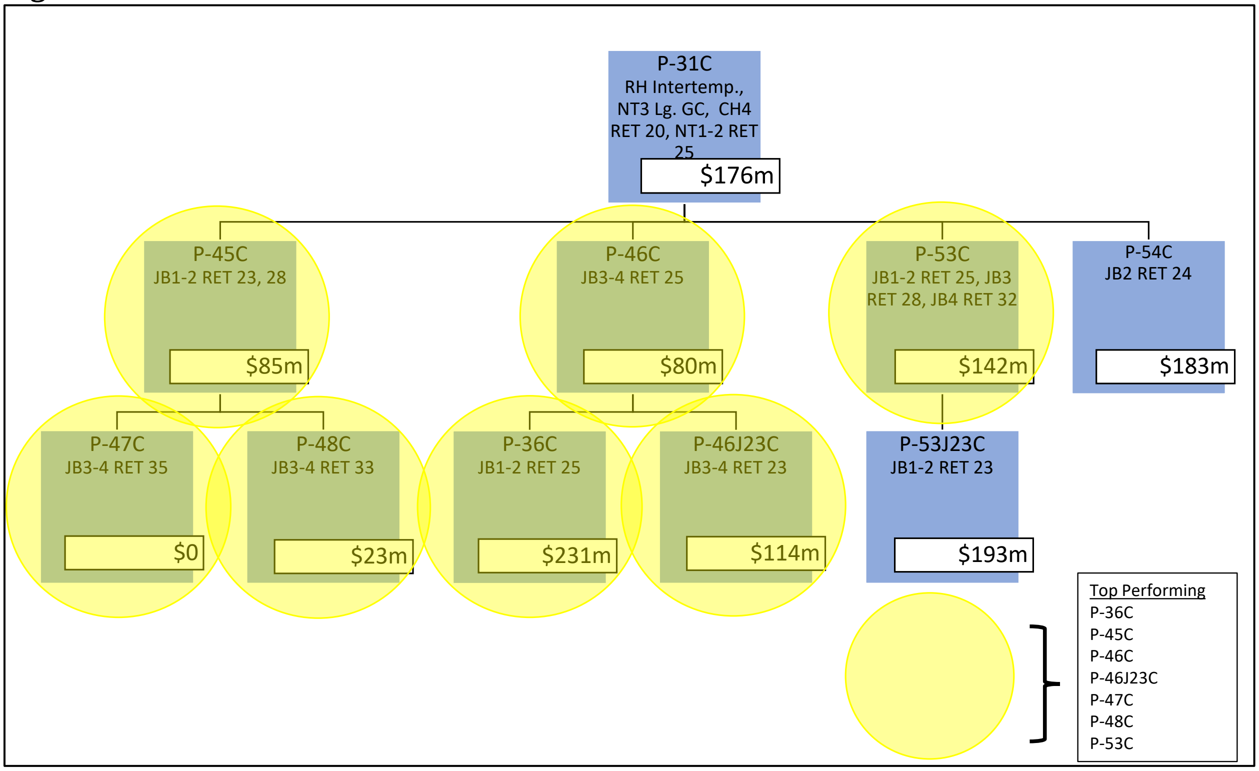
Table 8.3 – C Series Case Cost and Risk Results Summary

Case	Stochastic Mean			Risk Adjusted			ENS Average Percent of Load			CO2 Emissions		
	PVRR ($m)	Change from Lowest Cost Portfolio ($m)	Rank	PVRR ($m)	Change from Lowest Cost Portfolio ($m)	Rank	Average Annual ENS, 2019-2038 % of Average Load	Change from Lowest ENS Portfolio	Rank	Total CO2 Emissions, 2019-2038 (Thousand Tons)	Change from Lowest Emission Portfolio	Rank
P47C	**23,198**	**$0**	**1**	**24,367**	**$0**	**1**	**0.012%**	**0.002%**	**7**	**573,088**	**22,855**	**7**
P48C	**23,221**	**$23**	**2**	**24,391**	**$24**	**2**	**0.011%**	**0.001%**	**5**	**567,025**	**16,792**	**6**
P46C	**23,278**	**$80**	**3**	**24,462**	**$95**	**3**	**0.011%**	**0.001%**	**3**	**560,210**	**9,977**	**4**
P45C	**23,283**	**$85**	**4**	**24,468**	**$101**	**4**	**0.010%**	**0.000%**	**1**	**578,607**	**28,374**	**8**
P46J23C	**23,312**	**$114**	**5**	**24,488**	**$121**	**5**	**0.013%**	**0.002%**	**9**	**553,673**	**3,440**	**2**
P53C	**23,340**	**$142**	**6**	**24,528**	**$161**	**6**	**0.011%**	**0.001%**	**4**	**562,972**	**12,739**	**5**
P31C	23,374	$176	7	24,562	$195	8	0.010%	0.000%	2	588,334	38,101	10
P54C	23,381	$183	8	24,558	$191	7	0.012%	0.002%	6	581,465	31,232	9
P53J23C	23,391	$193	9	24,570	$203	9	0.012%	0.002%	8	556,990	6,757	3
P36C	**23,430**	**$231**	**10**	**24,614**	**$247**	**10**	**0.013%**	**0.003%**	**10**	**550,233**	**0**	**1**

PacifiCorp identified the cases in bold in Table 8.3 as top-performing cases selected for more refined analysis in the next step of the portfolio-development process (cases P-36C, P-46JC23C, P-47C, P-48C, P-46C, P-45C, and P53C). While cases P36C does not perform well on cost metrics relative to the other cases, in response to stakeholder interests, PacifiCorp included this case the list of top-performing C-series cases given its high ranking in total CO_2 emissions.

Figure 8.15 summarizes the stochastic mean PVRR relationships among the C-series cases in the "family tree" format summarized in Volume I, Chapter 7 (Modeling and Portfolio Evaluation Approach). Dollar figures associated with each case represent the increase in system PVRR relative to the lowest-cost case (case P-47C).

Figure 8.15 – Relative Cost of Stochastic Mean to the Lowest-Cost C Series Case



CP-Series Portfolios

In the CP-series of cases, top-performing portfolios from the C-series of cases are further refined. The CP-series includes the additional solar+battery analysis, and to ensure that there is no potential for an inconsistent application of annual reliability requirements beyond 2030, adds seven additional years (i.e., 2031-2037) of hourly deterministic analysis to the reliability assessment. This addition yields a total of 16 deterministic studies covering the period 2023-2038.

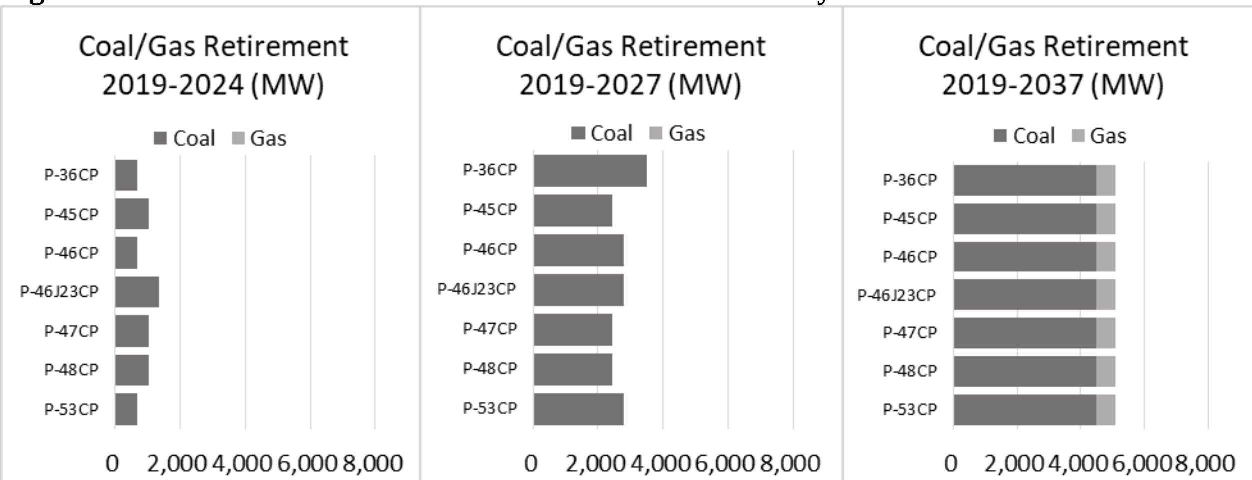
This refinement further improves the granularity at which reliability resources are applied and therefore provides an improved comparison of cost and risk metrics between the top-performing cases. The resulting portfolios were also evaluated among a range of price-policy scenarios.

CP-Series Portfolio Development

Coal and Gas Resource Retirements

Figure 8.16 summarizes cumulative nameplate coal and gas retirements for each CP-series case over the near-term, mid-term, and long-term. Note, in reporting cumulative capacity in this figure and the similar figures that follow, the mid-term results include capacity retired in the near-term, and similarly, the long-term results include capacity retired in the near-term and in the mid-term. Unit-specific retirement dates for each case can be found in Volume II, Appendix M (Case Study Fact Sheets). Through 2027, total coal retirements range between 2,441 MW (case P-45CP, P-47CP, P-48CP) and 3,499 MW (case P-36CP). Through the end of 2037, total coal retirements approach 4,500 MW in each case.

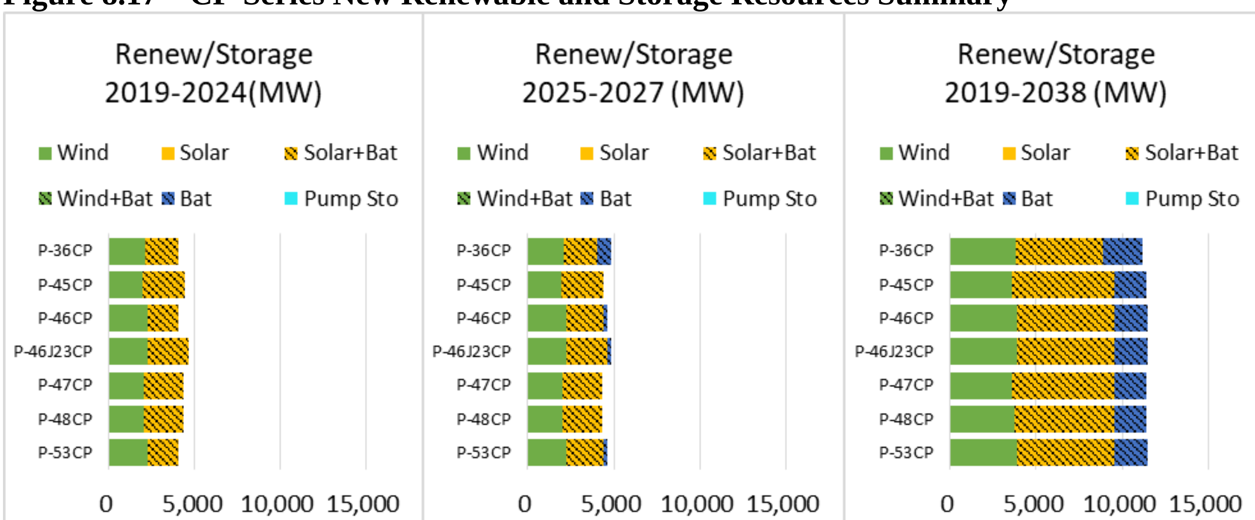
Figure 8.16 – CP-Series Coal and Gas Retirements Summary



New Renewable and Storage Resources

Figure 8.17 summarizes the nameplate capacity of new renewables and storage resource additions for each CP-series case. In all cases the SO model selects Energy Gateway South in 2024 (a proxy for year-end 2023) along with 1,920 MW of new wind in eastern Wyoming. Through 2027, new renewable capacity ranges between 3,339 MW (case P-47CP) and 4,409 MW (cases P-46CP and P-53CP). By the end of 2038, new renewable capacity ranges between 9,512 MW (case P-45CP) and 9,574 MW in the other four cases. New battery capacity ranges between 587 MW and 729 MW through 2027 and over 3,300 MW by the end of 2038.

Figure 8.17 – CP-Series New Renewable and Storage Resources Summary

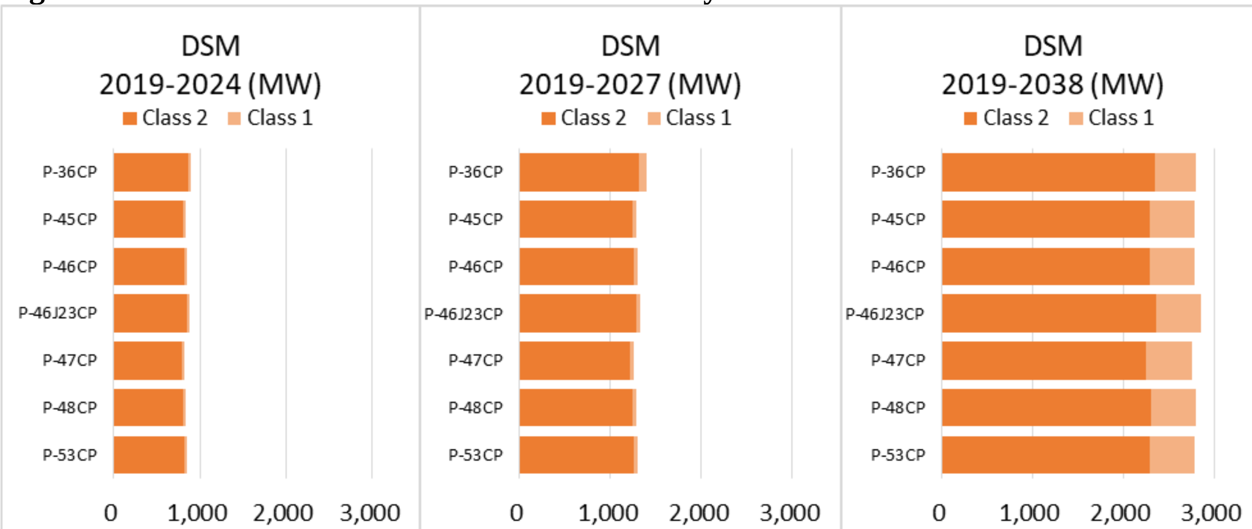


Note: For wind or renewable resources paired with battery, the capacity for the renewable resource is shown in the graph. The battery capacity paired with these resources is 25 percent of the renewable resource capacity.

Incremental Demand-Side Management (DSM)

Figure 8.18 summarizes aggregated DSM selections by case. Selected volumes of DSM are relatively stable among all CP-series cases. On average, Class 2 DSM capacity totals 826 MW through 2024, 1,259 MW through 2027, and 2,306 MW through 2038. On average, Class 1 DSM capacity totals 29 MW through 2024, 45 MW through 2027, and 487 MW through 2038.

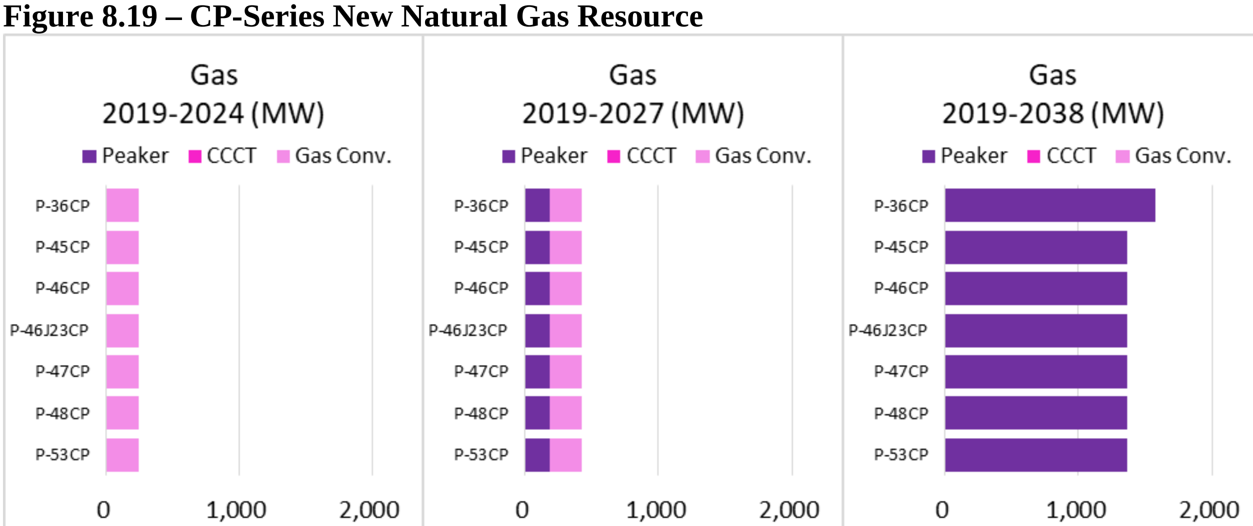
Figure 8.18 – CP-Series Incremental DSM Summary



New Natural Gas Resources

Figure 8.19 summarizes cumulative natural gas expansion resources for each CP series portfolio. In cases where Naughton Unit 3 converts to natural gas, it is assumed to retire at the end of 2029, so it does not show up in the results through 2038. Each case includes 185 MW of new peaking gas capacity in 2026. All CP-series cases except case P-36C include 1,367 MW of new gas peaking gas capacity through the end of 2038. Case P-36CP, includes 210 MW of gas peaking capacity over and above the other CP-series cases, added in 2028. None of the cases include new gas CCCT capacity.

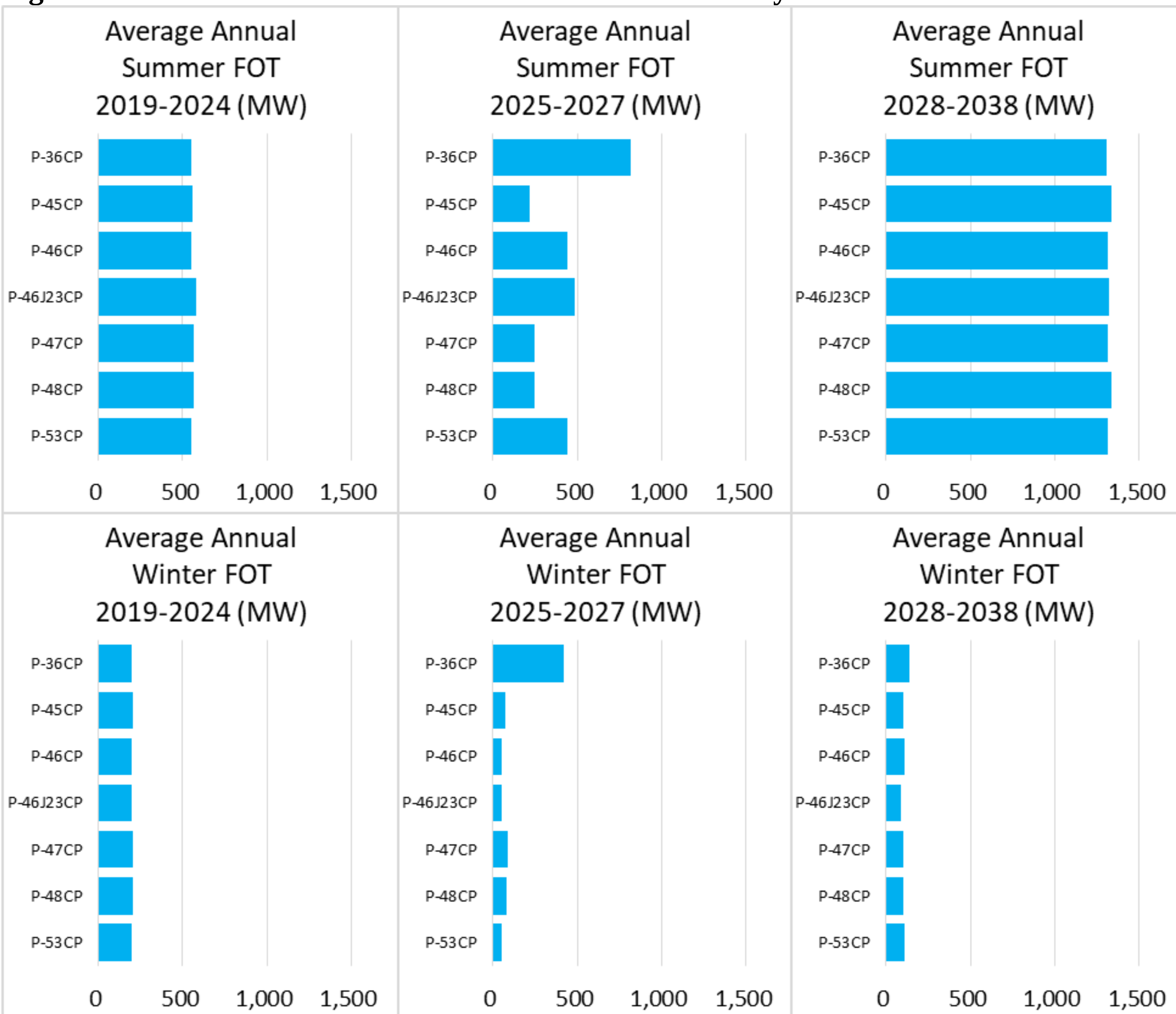
Figure 8.19 – CP-Series New Natural Gas Resource



Front Office Transactions

Figure 8.20 summarizes summer and winter FOTs for each CP-series case. The summer and winter FOT limit assumed for the 2019 IRP is 1,425 MW. Market reliance is reduced in the 2025 to 2027 timeframe, coinciding with the addition of new transmission, new wind, and new solar+battery resources—on average, summer FOT purchases are 411 MW per year over this period. Removing P-36CP (an outlier with nearly double the FOTs of other CP-series cases) from the mix yields an average of 344 MW per year. Longer-term, summer FOTs increase similarly among these cases, on average ranging between 1,310 MW and 1,334 MW each year from 2028-2038. Winter FOTs remain well below the volumes included in each portfolio to cover the summer peak period.

Figure 8.20 – CP-Series Front Office Transactions Summary



CO_2 Emissions

Figure 8.21 reports cumulative CO_2 emissions for each CP-series portfolio. Total CO_2 emissions is similar among these cases through 2027. Through 2038, total CO_2 emissions range between 558 million tons (case P-46CP) and 577 million tons (case P-45CP).

Figure 8.21 – CP-Series CO2 Emissions Summary

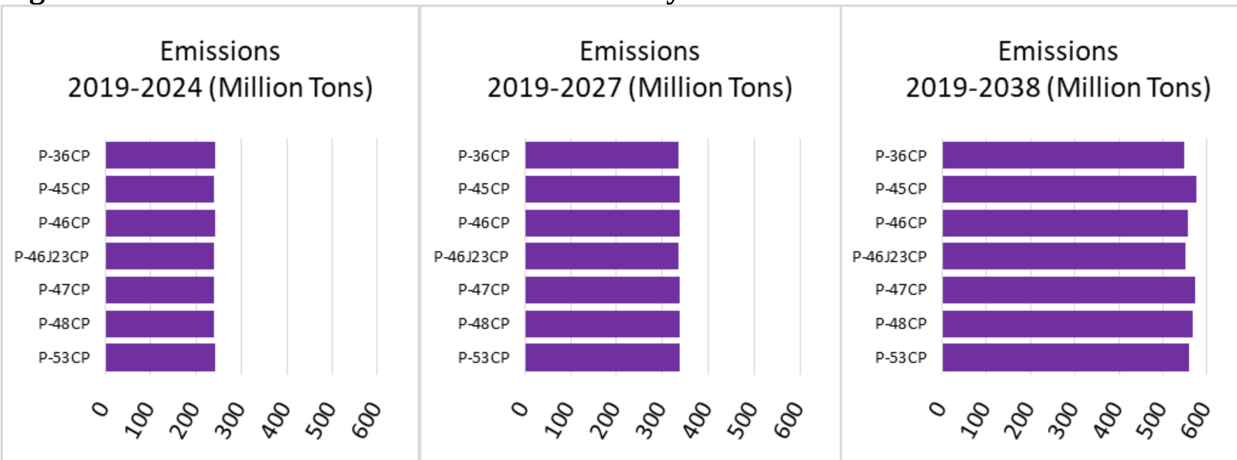
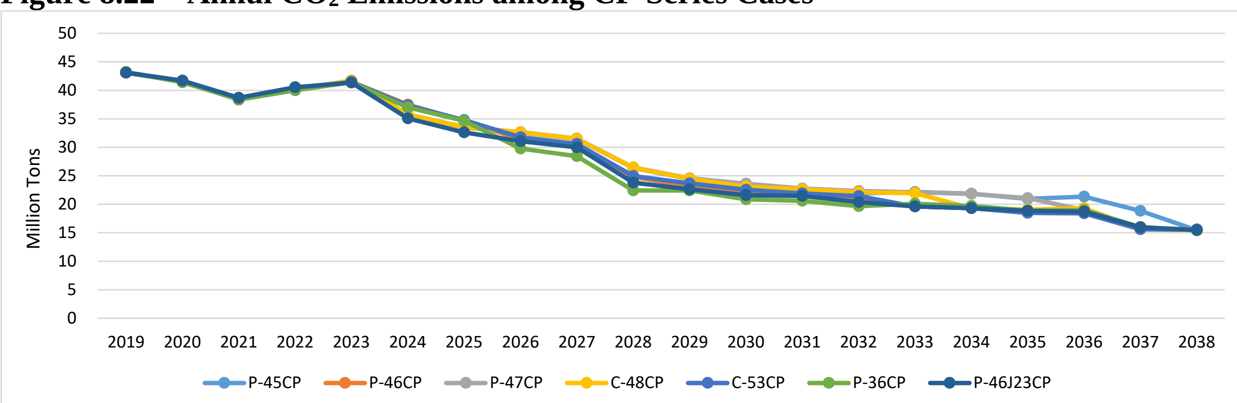


Figure 8.22 shows the annual emissions profile for each of the seven CP-series cases through the end of the planning period in 2038.

Figure 8.22 – Annul CO_2 Emissions among CP-Series Cases



CP-Series Cost and Risk Summary

The following tables and figures report the results of the CP-series cases for four price-policy scenarios. Each scenario assumes a low, medium or high gas price future, combined with either a zero, medium or high CO_2 price future. In addition to the seven CP-series cases, results from the five initial portfolios that were developed under varying natural gas price and CO_2 price assumptions are presented (cases P-16 through P-20).

CP-Series Medium Gas/Medium CO_2 Scenario

In the medium gas/medium CO_2 price-policy scenario, Case P-45CP outperforms other cases on stochastic mean costs, risk-adjusted costs, and energy not served (ENS). While case P-45CP has higher cumulative CO_2 emissions, the case with the lowest cumulative emissions (case P-36CP) has a risk-adjusted cost that is $235m higher than case P-45CP. Further, as shown in the figure above, the annual emissions profile among the CP-series of cases is similar. None of the price-policy cases outperform case P-45CP on cost metrics.

Table 8.4 – CP-Series, Medium Gas/Medium CO_2 Results Summary

	Stochastic Mean			Risk Adjusted			ENS Average Percent of Load			CO2 Emissions		
Case	PVRR ($m)	Change from Lowest Cost Portfolio ($m)	Rank	PVRR ($m)	Change from Lowest Cost Portfolio ($m)	Rank	Average Annual ENS, 2019-2038 % of Average Load	Change from Lowest ENS Portfolio	Rank	Total CO2 Emissions, 2019-2038 (Thousand Tons)	Change from Lowest Emission Portfolio	Rank
P45CP	**23,192**	**$0**	**1**	**24,360**	**$0**	**1**	**0.010%**	**0.000%**	**1**	**577,439**	**28,013**	**7**
P48CP	23,205	$13	2	24,374	$13	2	0.013%	0.003%	2	567,889	18,463	5
P47CP	23,219	$27	3	24,388	$28	3	0.013%	0.004%	7	573,649	24,222	6
P46CP	23,292	$100	4	24,465	$105	4	0.013%	0.003%	6	557,824	8,397	3
P46J23CP	23,303	$112	5	24,478	$118	5	0.013%	0.003%	2	552,065	2,639	2
P53CP	23,348	$156	6	24,524	$164	6	0.013%	0.003%	5	560,553	11,127	4
P36CP	23,413	$221	7	24,595	$235	7	0.013%	0.003%	2	549,427	0	1

Table 8.5 – Price-Policy Cases, Medium Gas/Medium CO_2 Results Summary

	Stochastic Mean			Risk Adjusted			ENS Average Percent of Load			CO2 Emissions		
Case	PVRR ($m)	Change from Lowest Cost Portfolio ($m)	Rank	PVRR ($m)	Change from Lowest Cost Portfolio ($m)	Rank	Average Annual ENS, 2019-2038 % of Average Load	Change from Lowest ENS Portfolio	Rank	Total CO2 Emissions, 2019-2038 (Thousand Tons)	Change from Lowest Emission Portfolio	Rank
P16	23,889	$0	1	25,097	$0	1	0.007%	0.000%	1	669,944	242,834	5
P19	24,000	$111	2	25,211	$115	2	0.007%	0.000%	2	607,157	180,047	3
P17	24,182	$292	3	25,400	$303	3	0.057%	0.051%	4	475,390	48,281	2
P18	24,376	$487	4	25,602	$506	4	0.111%	0.104%	5	427,110	0	1
P20	25,118	$1,229	5	26,385	$1,289	5	0.007%	0.000%	2	607,157	180,047	3

CP-Series Low Gas/No CO_2 Scenario

In the low gas/zero CO_2 scenario, Case P-45CP outperforms other cases on stochastic mean costs, risk-adjusted costs, and ENS. While P-45CP has higher cumulative CO_2 emissions, the case with the lowest cumulative emissions (case P-46J23CP) has a risk-adjusted cost that is $222m higher than case P-45CP. Further, as shown in the figure above, the annual emissions profile among the CP-series of cases is similar. Cases P-16 and P-19, which were developed without a CO_2 price assumption and with low gas price assumptions, respectively, are among the top-performing price-policy cases when analyzed in a low gas/zero CO_2 price-policy scenario.

Table 8.6 – CP-Series, Low Gas/Zero CO_2 Results Summary

Case	Stochastic Mean			Risk Adjusted			ENS Average Percent of Load			CO2 Emissions		
	PVRR ($m)	Change from Lowest Cost Portfolio ($m)	Rank	PVRR ($m)	Change from Lowest Cost Portfolio ($m)	Rank	Average Annual ENS, 2019-2038 % of Average Load	Change from Lowest ENS Portfolio	Rank	Total CO2 Emissions, 2019-2038 (Thousand Tons)	Change from Lowest Emission Portfolio	Rank
P45CP	**20,094**	**$0**	**1**	**21,105**	**$0**	**1**	**0.010%**	**0.000%**	**1**	**577,806**	**28,502**	**7**
P47CP	20,130	$36	2	21,143	$38	2	0.013%	0.004%	7	572,966	23,661	5
P48CP	20,173	$79	3	21,187	$83	3	0.013%	0.003%	3	567,163	17,859	4
P46CP	20,285	$191	4	21,305	$201	4	0.013%	0.003%	6	555,322	6,018	2
P46J23CP	20,306	$212	5	21,327	$222	5	0.013%	0.003%	3	549,304	0	1
P53CP	20,327	$233	6	21,349	$245	6	0.013%	0.003%	5	558,186	8,882	3
P36CP	23,192	$3,098	7	24,360	$3,256	7	0.010%	0.000%	1	577,439	28,135	6

Table 8.7 – Price-Policy Cases, Low Gas/No CO_2 Results Summary

Case	Stochastic Mean			Risk Adjusted			ENS Average Percent of Load			CO2 Emissions		
	PVRR ($m)	Change from Lowest Cost Portfolio ($m)	Rank	PVRR ($m)	Change from Lowest Cost Portfolio ($m)	Rank	Average Annual ENS, 2019-2038 % of Average Load	Change from Lowest ENS Portfolio	Rank	Total CO2 Emissions, 2019-2038 (Thousand Tons)	Change from Lowest Emission Portfolio	Rank
P16	19,448	$0	1	20,427	$0	1	0.007%	0.000%	1	674,184	255,509	5
P19	20,194	$746	2	21,209	$782	2	0.007%	0.000%	2	607,941	189,266	4
P20	20,833	$1,386	3	21,881	$1,453	3	0.007%	0.000%	3	579,150	160,476	3
P17	21,013	$1,565	4	22,071	$1,643	4	0.057%	0.051%	4	465,998	47,324	2
P18	22,456	$3,008	5	23,587	$3,160	5	0.111%	0.105%	5	418,674	0	1

CP-Series High Gas/High CO_2 Scenario

In the high gas/high CO_2 scenario, Case P-48CP outperforms other cases on stochastic mean costs and risk-adjusted costs. Case P-45CP ranks second in stochastic mean and risk-adjusted cost and first in ENS. While P-45CP has higher cumulative CO_2 emissions, the case with the lowest cumulative emissions (case P-36CP) has a risk-adjusted cost that is $155m higher than case P-45CP. Further, as shown in the figure above, the annual emissions profile among the CP-series of cases is similar. Cases P-18, P-20, and P-17, which were developed using a social cost of carbon CO_2 price assumption, a high gas price assumption, and a high CO_2 price assumption, respectively, are among the top-performing price-policy cases when analyzed in a high gas/high CO_2 price-policy scenario.

Table 8.8 – CP-Series, High Gas/High CO_2 Results Summary

	Stochastic Mean			Risk Adjusted			ENS Average Percent of Load			CO2 Emissions		
Case	PVRR ($m)	Change from Lowest Cost Portfolio ($m)	Rank	PVRR ($m)	Change from Lowest Cost Portfolio ($m)	Rank	Average Annual ENS, 2019-2038 % of Average Load	Change from Lowest ENS Portfolio	Rank	Total CO2 Emissions, 2019-2038 (Thousand Tons)	Change from Lowest Emission Portfolio	Rank
P48CP	27,736	$0	1	29,135	$0	1	0.013%	0.003%	2	562,313	18,221	5
P45CP	**27,786**	**$51**	**2**	**29,188**	**$53**	**2**	**0.010%**	**0.000%**	**1**	**571,643**	**27,550**	**7**
P47CP	27,805	$69	3	29,208	$72	3	0.013%	0.004%	7	568,183	24,090	6
P46J23CP	27,812	$76	4	29,215	$79	4	0.013%	0.003%	2	549,152	5,059	2
P46CP	27,814	$78	5	29,217	$82	5	0.013%	0.003%	6	553,331	9,239	3
P36CP	27,881	$145	6	29,290	$155	6	0.013%	0.003%	2	544,092	0	1
P53CP	27,889	$153	7	29,296	$161	7	0.013%	0.003%	5	556,201	12,108	4

Table 8.9 – Price-Policy Cases, High Gas/High CO_2 Results Summary

	Stochastic Mean			Risk Adjusted			ENS Average Percent of Load			CO2 Emissions		
Case	PVRR ($m)	Change from Lowest Cost Portfolio ($m)	Rank	PVRR ($m)	Change from Lowest Cost Portfolio ($m)	Rank	Average Annual ENS, 2019-2038 % of Average Load	Change from Lowest ENS Portfolio	Rank	Total CO2 Emissions, 2019-2038 (Thousand Tons)	Change from Lowest Emission Portfolio	Rank
P18	27,785	$0	1	29,187	$0	1	0.112%	0.105%	5	431,628	0	1
P20	28,397	$612	2	29,832	$646	2	0.007%	0.000%	3	572,793	141,165	3
P17	28,858	$1,073	3	30,312	$1,125	3	0.057%	0.051%	4	478,795	47,167	2
P19	29,224	$1,439	4	30,701	$1,514	4	0.007%	0.000%	2	598,587	166,960	4
P16	29,847	$2,062	5	31,357	$2,170	5	0.007%	0.000%	1	653,963	222,335	5

CP-Series Social Cost of Carbon Scenario

In the social cost of carbon scenario, case P-46J23CP outperforms other cases on stochastic mean costs and risk-adjusted costs. While case P-45CP ranks sixth in these metrics and first in ENS, case P-46J23CP has a risk-adjusted PVRR cost that is $118m higher cost than P-45CP when the medium gas/medium CO_2 price-policy assumptions is applied. The highest ranking portfolio with regard to cumulative CO_2 emissions is case P-36CP. Case P-18, which was developed using a social cost of carbon CO_2 price assumption, is among the top-performing price-policy cases when analyzed in a social cost of carbon price-policy scenario. Case P-18 has a risk-adjusted PVRR that is over $1.2b higher cost than case P-45CP when medium gas/medium CO_2 price-policy assumptions are applied.

As was discussed with stakeholders at the October 3-4, 2019 public-input meeting, PacifiCorp applied social cost of carbon CO_2 prices to this price-policy scenario analysis such that the price for the social cost of carbon is reflected in market prices and dispatch costs. Consequently, it assumes that system operations (plant dispatch and market transactions) are not aligned with actual market forces (i.e., market transactions at the Mid-Columbia market do not reflect the social cost of carbon and PacifiCorp does not directly incur emissions costs at the price assumed for the social cost of carbon). Consequently, and unlike the other price-policy scenarios reviewed above, the model results for the social cost of carbon price-policy scenario represent cost drivers that are materially divergent from the cost drivers in the market. This creates challenges in understanding how to interpret the results from this price-policy scenario.

Table 8.10 – CP-Series Social Cost of Carbon Results Summary

	Stochastic Mean			Risk Adjusted			ENS Average Percent of Load			CO2 Emissions		
Case	PVRR ($m)	Change from Lowest Cost Portfolio ($m)	Rank	PVRR ($m)	Change from Lowest Cost Portfolio ($m)	Rank	Average Annual ENS, 2019-2038 % of Average Load	Change from Lowest ENS Portfolio	Rank	Total CO2 Emissions, 2019-2038 (Thousand Tons)	Change from Lowest Emission Portfolio	Rank
P46J23CP	36,555	$0	1	38,394	$0	1	0.013%	0.003%	3	411,129	5,160	2
P36CP	36,561	$6	2	38,405	$11	2	0.010%	0.000%	1	405,969	0	1
P46CP	36,703	$149	3	38,550	$155	3	0.013%	0.003%	6	414,320	8,351	3
P48CP	36,798	$243	4	38,649	$254	4	0.013%	0.003%	3	424,073	18,104	5
P53CP	36,829	$274	5	38,681	$287	5	0.013%	0.003%	5	418,116	12,147	4
P45CP	**36,934**	**$379**	**6**	**38,791**	**$397**	**6**	**0.010%**	**0.000%**	**1**	**432,168**	**26,199**	**7**
P47CP	36,936	$381	7	38,794	$399	7	0.013%	0.004%	7	429,251	23,282	6

Table 8.11 – Price-Policy Case Results Summary

	Stochastic Mean			Risk Adjusted			ENS Average Percent of Load			CO2 Emissions		
Case	PVRR ($m)	Change from Lowest Cost Portfolio ($m)	Rank	PVRR ($m)	Change from Lowest Cost Portfolio ($m)	Rank	Average Annual ENS, 2019-2038 % of Average Load	Change from Lowest ENS Portfolio	Rank	Total CO2 Emissions, 2019-2038 (Thousand Tons)	Change from Lowest Emission Portfolio	Rank
P18	35,276	$0	1	37,051	$0	1	0.112%	0.105%	5	321,000	0	1
P17	36,415	$1,139	2	38,247	$1,197	2	0.057%	0.051%	4	366,220	45,221	2
P20	37,527	$2,251	3	39,421	$2,370	3	0.007%	0.000%	3	437,132	116,133	3
P19	38,396	$3,120	4	40,334	$3,283	4	0.007%	0.000%	2	459,469	138,469	4
P16	39,712	$4,436	5	41,717	$4,666	5	0.007%	0.000%	1	496,702	175,703	5

Based upon the results summarized above, PacifiCorp identified case P-45CP as the top-performing case in the CP-series of cases. Relative cost differences between case P-45CP and the cases with the lowest cumulative CO_2 emissions (cases P-36CP and P-46J23CP) do not support consideration of these two cases for potential selection as the preferred portfolio.

Front Office Transaction Portfolios

Five of the CP-series cases (all but cases P-36CP and P-46J23CP) were further analyzed for FOT risk. The FOT studies are designed to quantify the impact and risk of market reliance. As detailed in Volume I, Chapter 7 (Modeling and Portfolio Evaluation Approach), these cases use an escalating scalar to elevate market prices during the peak months of July, August and December of every study year. This has the effect of increasing costs for market purchases or for acquisition of the alternative resources required to avoid the high market prices.

Higher FOT costs from market risk increased the PVRR by similar amounts among the cases, $820 million (3.6 percent), on average. Case P-45CP has a risk-adjusted PVRR that is $25m higher than Case P-47CP, which has the lowest PVRR when higher FOT costs are applied.

These results suggest that the risk of higher FOT costs is not materially different between cases P-45CP and P-47CP and these results do not justify driving the selection of any over the other CP-series of cases as beneficial to case P-45CP.

Table 8.12 reports FOT case evaluation results. Table 8.13 quantifies the increased system cost of escalated FOT pricing compared to the system cost of each portfolio under the medium gas, medium CO_2 price-policy scenario.

Table 8.12 – FOT Case Results Summary

	Stochastic Mean			Risk Adjusted			ENS Average Percent of Load			CO2 Emissions		
Case	PVRR ($m)	Change from Lowest Cost Portfolio ($m)	Rank	PVRR ($m)	Change from Lowest Cost Portfolio ($m)	Rank	Average Annual ENS, 2019-2038 % of Average Load	Change from Lowest ENS Portfolio	Rank	Total CO2 Emissions, 2019-2038 (Thousand Tons)	Change from Lowest Emission Portfolio	Rank
P47CP	24,001	$0	1	25,209	$0	1	0.010%	0.000%	2	535,827	13,317	4
P45CP	24,024	$23	2	25,233	$25	2	0.009%	0.000%	1	540,134	17,623	5
P48CP	24,098	$97	3	25,312	$104	3	0.012%	0.002%	3	533,930	11,419	3
P46CP	24,099	$98	4	25,314	$105	4	0.013%	0.004%	5	522,510	0	1
P53CP	24,164	$163	5	25,382	$173	5	0.013%	0.003%	4	525,364	2,854	2

Table 8.13 – FOT Case System Cost Impact Summary

	Stochastic Mean		
Case	PVRR ($m)	Change from CP Portfolio ($m)	Rank
P47CP	24,001	$782	1
P45CP	24,024	$832	4
P48CP	24,098	$892	5
P46CP	24,099	$807	2
P53CP	24,164	$815	3

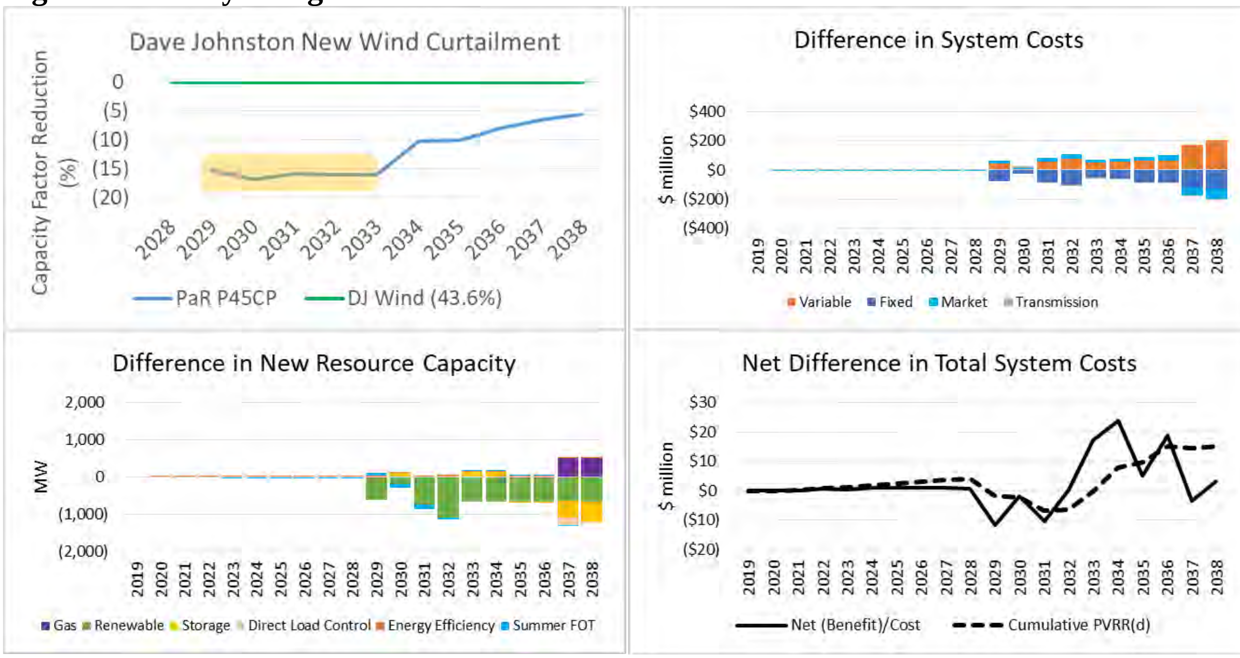
2028-2029 Wyoming Wind Case

As detailed in Volume I, Chapter 7 (Modeling and Portfolio Evaluation Approach), PacifiCorp identified that 620 MW of Wyoming wind resources added to each portfolio in the 2028-2029 timeframe, which coincides with the assumed retirement of Dave Johnston, were being curtailed at relatively significant levels—through 2038, capacity factors average 32 percent, down from the 43.6 percent assumed without curtailment. From 2029 through 2033 the level of curtailment is higher, with output falling below a 30 percent capacity factor.

Upon observing this modeled outcome, PacifiCorp produced an new portfolio as a variant of the least cost CP series case (P-45CP) that eliminated the 620 MW of incremental Wyoming wind coming online after the retirement of Dave Johnston. This case is referred to as P-45CNW.

While the stochastic mean PVRR of P-45CNW is $15m higher than case P-45CP, as illustrated in Figure 8.23, PacifiCorp advanced Case P-45CNW as the baseline for evaluating additional “No New Natural Gas” and Energy Gateway transmission cases on the basis that it is not reasonable to include heavily curtailed wind resources in the leading case for the preferred portfolio. Further, the shifts in system costs contributing to the $15m increase in system PVRR are all beyond the action plan window, which will allow PacifiCorp to continue to evaluate potential incremental wind additions in eastern Wyoming when Dave Johnston retires in future IRPs.

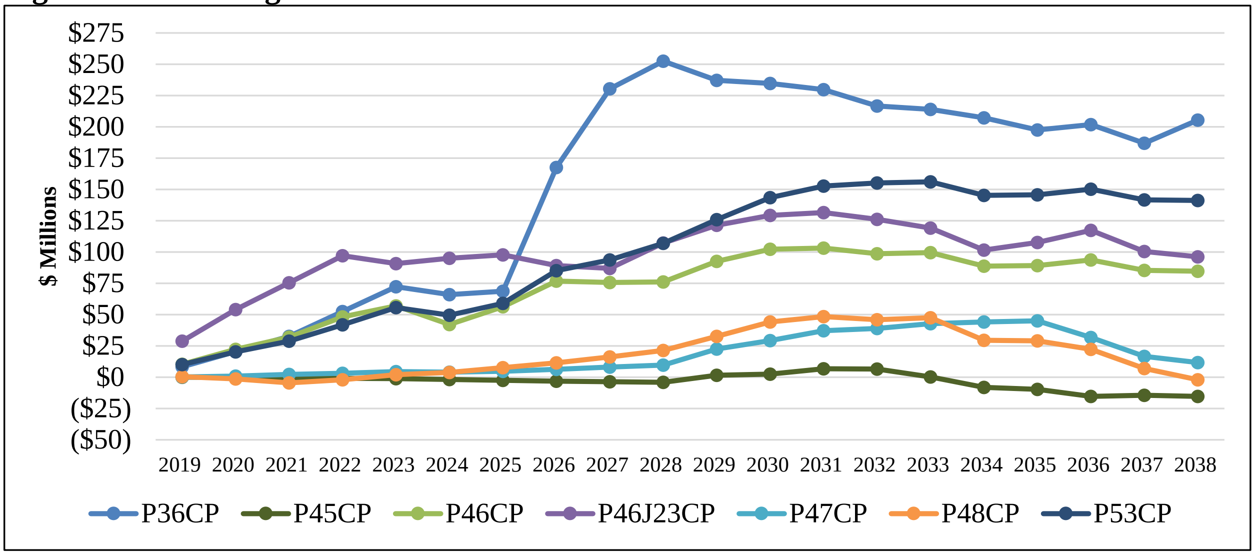
Figure 8.23 – Wyoming Wind Alternative Portfolio and Cost Evaluation



Customer Rate Pressure

Figure 8.24 shows the difference in the cumulative PVRR, as an indicator of rate pressure over time, between among the CP-series of cases discussed earlier relative to case P-45CNW when applying medium gas, medium CO_2 price-policy assumptions. Cases P-36CP, P-46CP, P-46J23CP, and P-53CP consistently trend higher than case P-45CNW. Through 2024, cases P-45CP, P-47CP, and P-48CP track relatively close to case P45-CNW. After 2024, cases P-47CP and P-48CP trend higher then case P-45CNW, and then start to converge with case P-45CNW over the longer-term.

Figure 8.24 – Change in the Cumulative PVRR relative to P-45CNW



Portfolio Development Conclusions

Based on the findings of the initial portfolios, C-series of cases, CP-series of cases, the FOT cases used to analyze market-reliance risk, and the case that eliminates highly curtailed Wyoming wind in the 2028-2029 timeframe, PacifiCorp identified case P-45CNW as the top-performing case at the conclusion of the portfolio-development process. As described below, case P-45CNW serves as the basis for additional analysis to inform final selection of the preferred portfolio.

Preferred Portfolio Selection

"No New Natural Gas" Portfolios

The "No New Natural Gas" cases, defined in Volume I, Chapter 7 (Modeling and Portfolio Evaluation Approach), provide two views of impacts stemming from an assumption that no new gas resources are acquired through the end of the study period. The first case, P-29 does not allow the model to select new natural gas resources (excluding the Naughton Unit 3 gas conversion). The second case, P-29PS is a variant of P-29 with the addition of a 400 MW pumped storage project located in northeast Wyoming that is assumed to come online in 2028 following retirement of the Dave Johnston plant.

As seen in Figure 8.25, case P-29 accelerates renewable resources from 2036 to 2032 and adds incremental battery storage resources beginning 2030 relative to case P-45CNW. Under P-29, system costs begin to decrease in 2027, however over the long term, incremental costs for new battery storage resources and market purchases reverse the trend.

Figure 8.25 – P-29 No Gas Case Resource and Cost Compared to P-45CNW

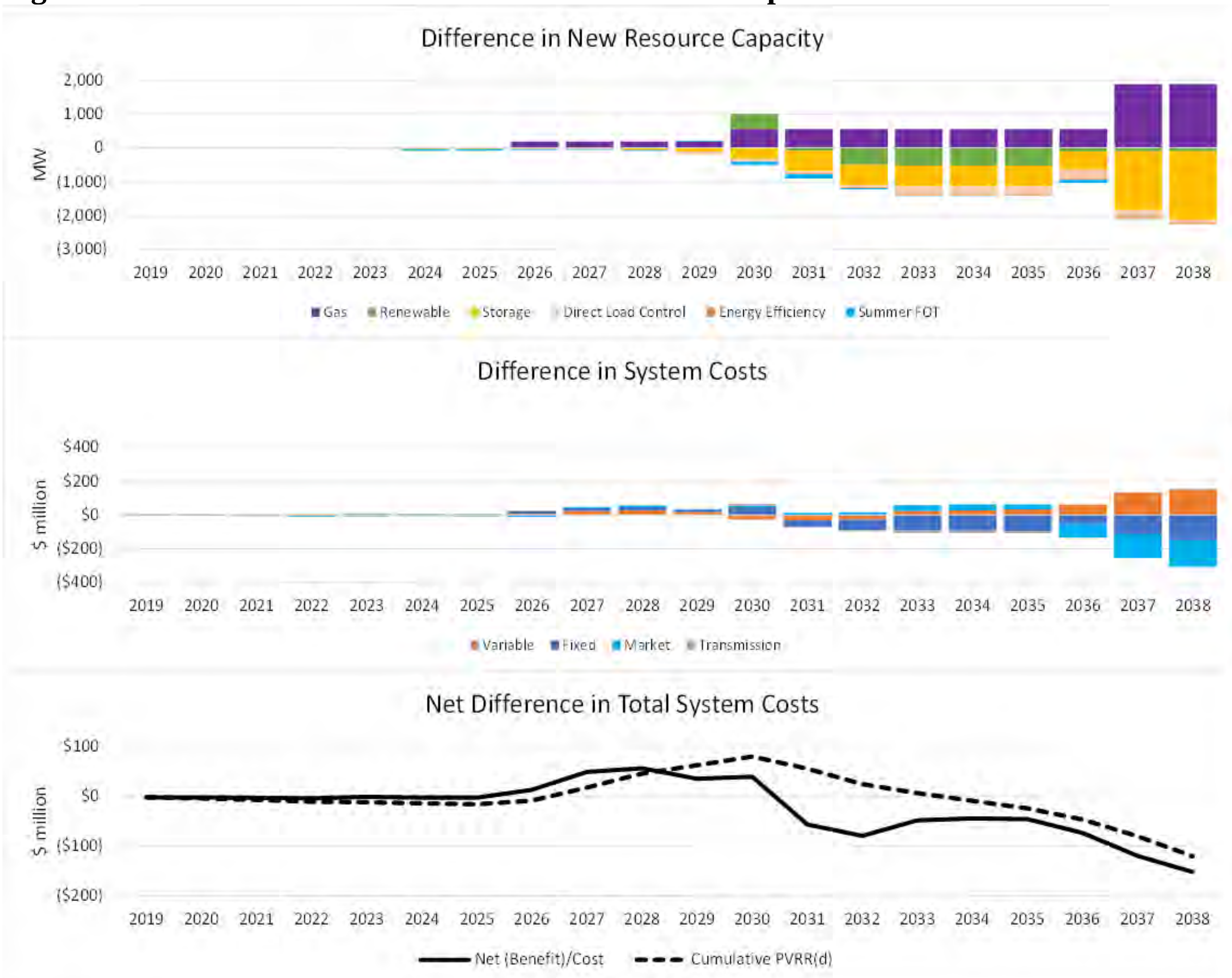


Figure 8.26 summarizes P-29PS portfolio and cost differences compared to P-45CNW, eliminating new gas and adding pumped storage (400 MW) and battery storage (227 MW) in 2028. By the end of the study period, case P-29PS adds an additional 1,575 MW of battery storage. System costs increase beginning 2028 with incremental fixed cost for the storage resources, and added market purchases costs increasingly contribute to the added system costs in the 2036-2038 timeframe.

Table 8.14 summarizes the results of the "No New Natural Gas" cases. Both of these cases result in higher costs than case P-45CNW. Neither case justifies altering selection of Case P-45CNW as the top-performing portfolio.

Figure 8.26 – P-29PS No Gas with Pumped Hydro Storage Compared to P-45CNW

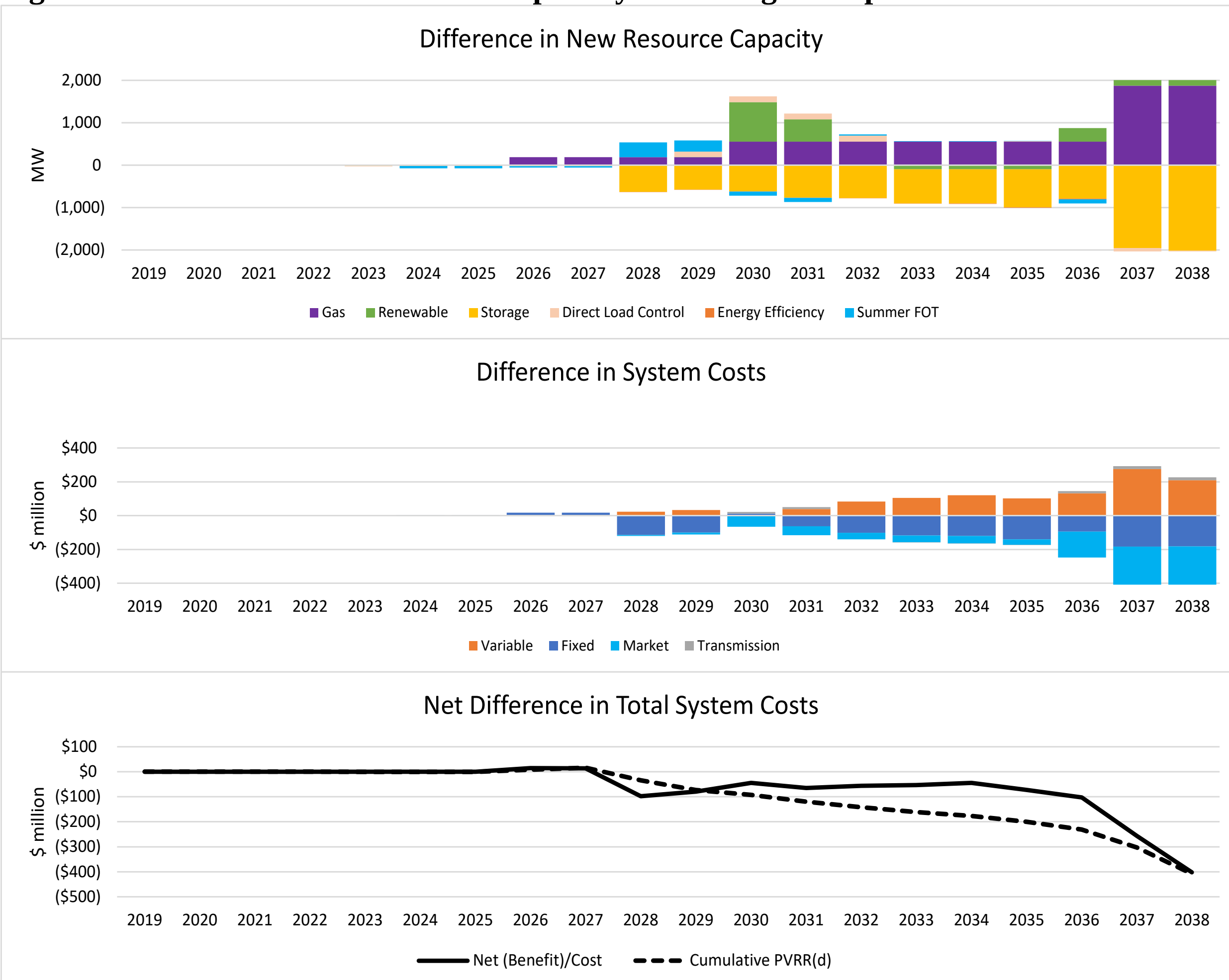


Table 8.14 – No Gas Results Summary

Case	Stochastic Mean			Risk Adjusted			ENS Average Percent of Load			CO2 Emissions		
	PVRR ($m)	Change from Lowest Cost Portfolio ($m)	Rank	PVRR ($m)	Change from Lowest Cost Portfolio ($m)	Rank	Average Annual ENS, 2019-2038 % of Average Load	Change from Lowest ENS Portfolio	Rank	Total CO2 Emissions, 2019-2038 (Thousand Tons)	Change from Lowest Emission Portfolio	Rank
P45CNW	**23,207**	**$0**	**1**	**24,376**	**$0**	**1**	**0.008%**	**0.002%**	**2**	**585,641**	**8,835**	**3**
P29	23,328	$121	2	24,503	$127	2	0.006%	0.000%	1	580,126	3,320	2
P29PS	23,616	$409	3	24,806	$430	3	0.047%	0.040%	3	576,806	0	1

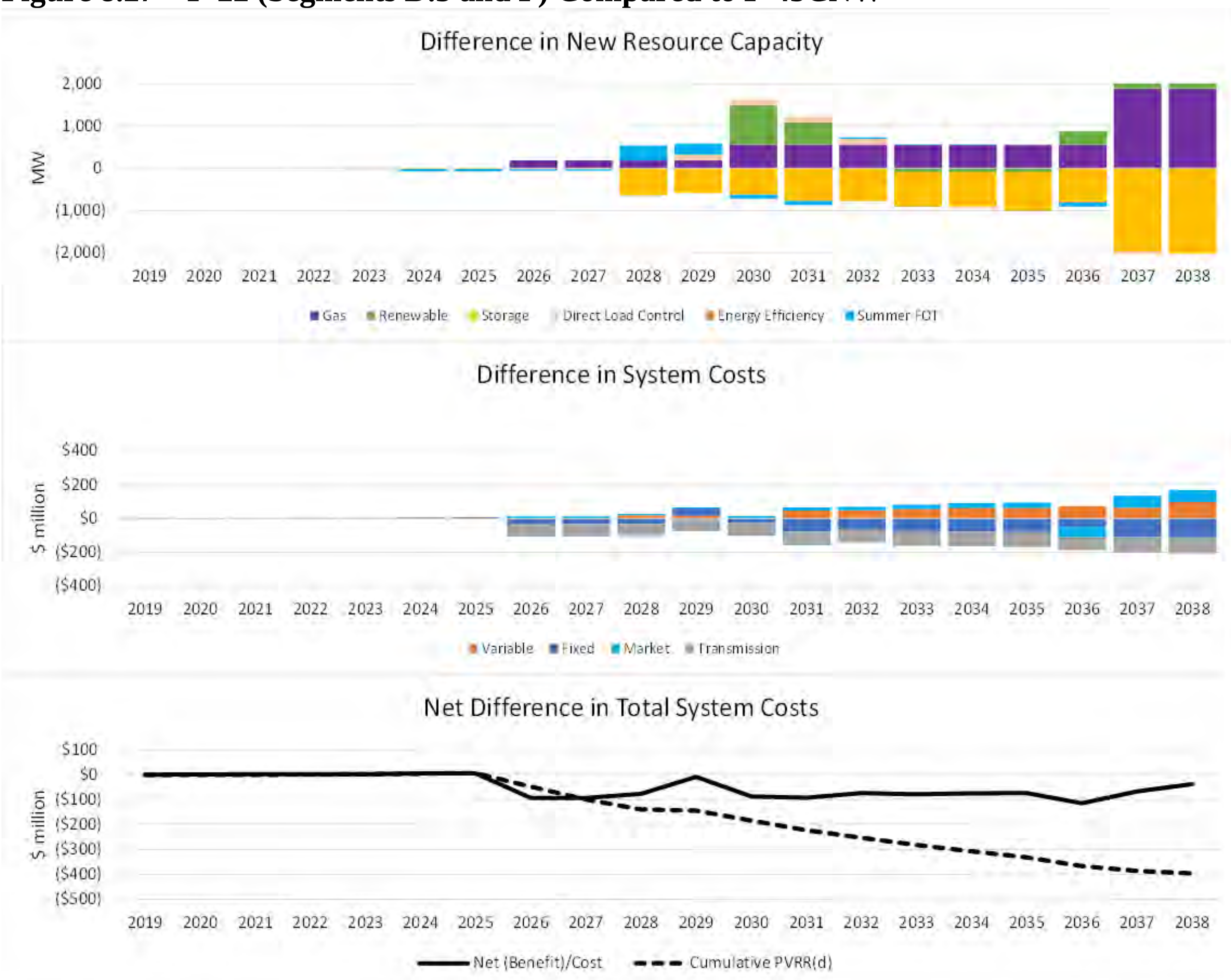
Energy Gateway Transmission Cases

PacifiCorp modeled four Energy Gateway transmission cases, expanding on scenarios defined in previous IRP cycles. The full build-out of all Energy Gateway segments was performed in two cases (P-23 and P-25) to assess the potential value in two different coal retirement scenarios. All of these cases include the endogenous selection of Gateway South in 2024 (as a proxy for year-end 2023). Full case definitions for the Energy Gateway studies are provided in Volume I, Chapter 7 (Modeling and Portfolio Evaluation Approach).

P-22 Evaluation

Case P-22 includes the approximately 200 mile Bridger/Anticline-to-Populus Energy Gateway transmission segment (sub-segment D.3). The stochastic mean PVRR of case P-45CNW is $396m lower cost than Case P-22, driven primarily by D.3 transmission project costs where the net portfolio cost impacts are largely offsetting. Case P-45CNW sees higher market, emissions and DSM costs, but reduced capital and fixed operations and maintenance costs that are aligned with the increased proportion of generating resources as opposed to storage resources. Figure 8.27 reports portfolio and cost differences compared to case P-45CNW.

Figure 8.27 – P-22 (Segments D.3 and F) Compared to P-45CNW



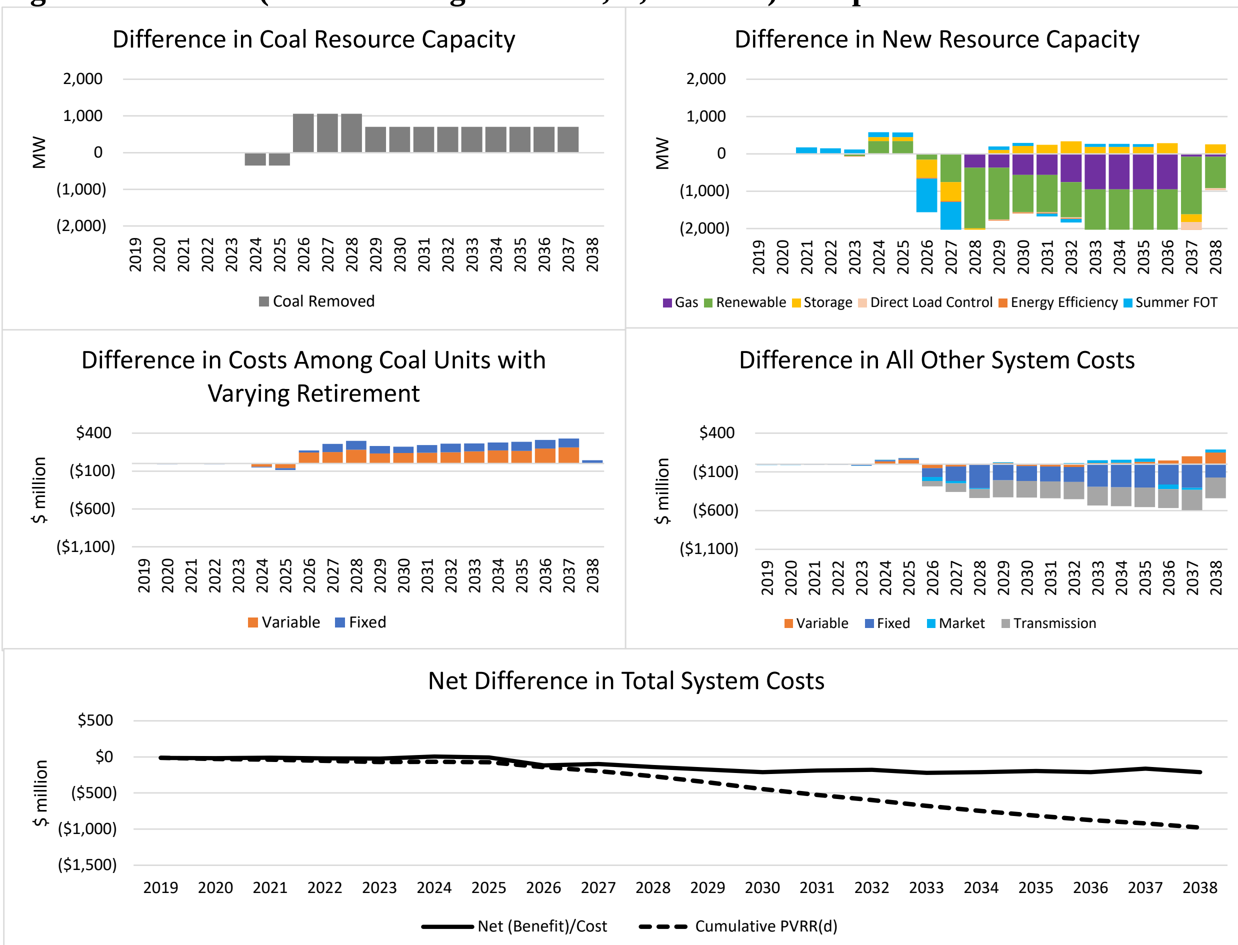
P-23 Evaluation

Relative to case P-36CNW, case P-23 includes the approximately 200 mile Bridger/Anticline-to-Populus transmission sub-segment (D.3), the approximately 500 mile Populus-to-Hemingway transmission segment (E), and the approximately 290 mile Boardman-to-Hemingway segment (H). A variant of stakeholder requested P-36CNW, P-23 features early retirement of the entire Bridger plant in 2025, and also Naughton Units 1-2 in 2025.

As seen in Figure 8.28, the reduction of thermal resources due to highly accelerated retirements causes P-23 to accelerate significant thermal and renewable additions into 2028.

The stochastic mean PVRR of case P-45CNW is $977m lower cost than case P-23, driven primarily by transmission project costs where the net portfolio variable and fixed cost impacts are largely offsetting.

Figure 8.28 – P-23 (Additional segments D.3, E, F and H) Compared to P-45CNW



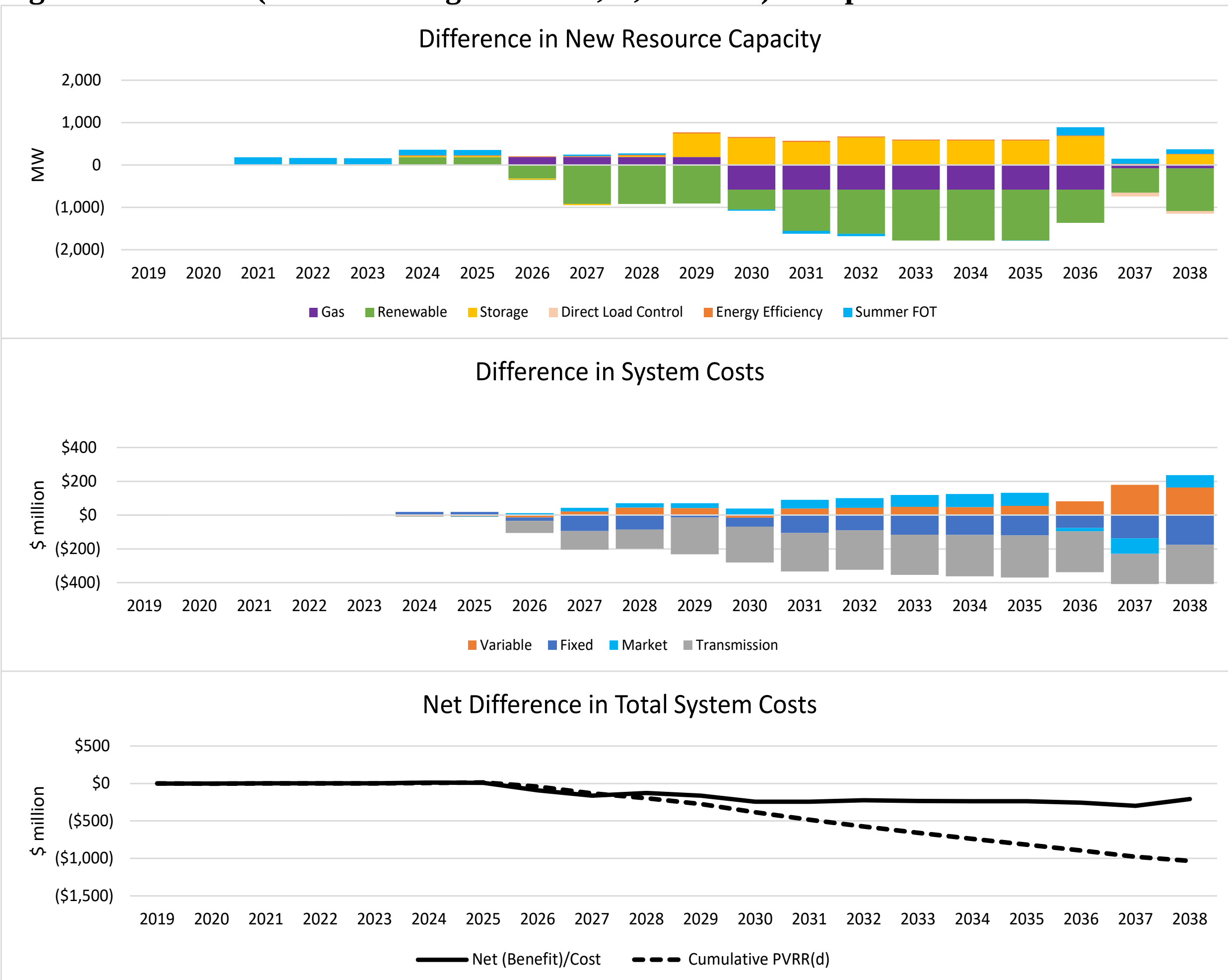
P-25 Evaluation

Case P-25 includes the approximately 200 mile Bridger/Anticline-to-Populus transmission sub-segment (D.3), the approximately 500 mile Populus-to-Hemingway transmission segment (E), and the approximately 290 mile Boardman-to*Hemingway segment (H). Although the Energy Gateway additions match case P-23, P-25 is a variant of P-45CNW.

As seen in Figure 8.29, Gas capacity is accelerated approximately 6 years (~500 MW) into 2030.

The stochastic mean PVRR of case P-45CNW is approximately $1.0b lower cost than case P-25, driven primarily by transmission project costs where the net portfolio variable and fixed cost impacts are largely offsetting.

Figure 8.29 – P-25 (Additional segments D.3, E, F and H) Compared to P-45CNW



P-26 Evaluation

Case P-26 includes the approximately 290 mile Boardman-to-Hemingway transmission segment (H). As seen in Figure 8.30 gas capacity is accelerated approximately 6 years (~500 MW) into 2030.

The stochastic mean PVRR of case P-45CNW is approximately $98m lower cost than case P-26. In Table 8.15 case P-26 ranks second among gateway cases in 3 of 4 categories, including stochastic mean, risk-adjusted PVRR and low ENS. These results are promising, and signal that with motivated project partners and potentially significant regional reliability benefits, updated modeling that can better capture the value of this project will ultimately support a business case to move forward with the project. Consequently, PacifiCorp has included an action item in its 2019 IRP action plan to continue to evaluate and support the Boardman-to-Hemmingway project.

Table 8.15 reports a summary of the Energy Gateway cases.

Figure 8.30 – P-26 (Segments F and H) Compared to P-45CNW

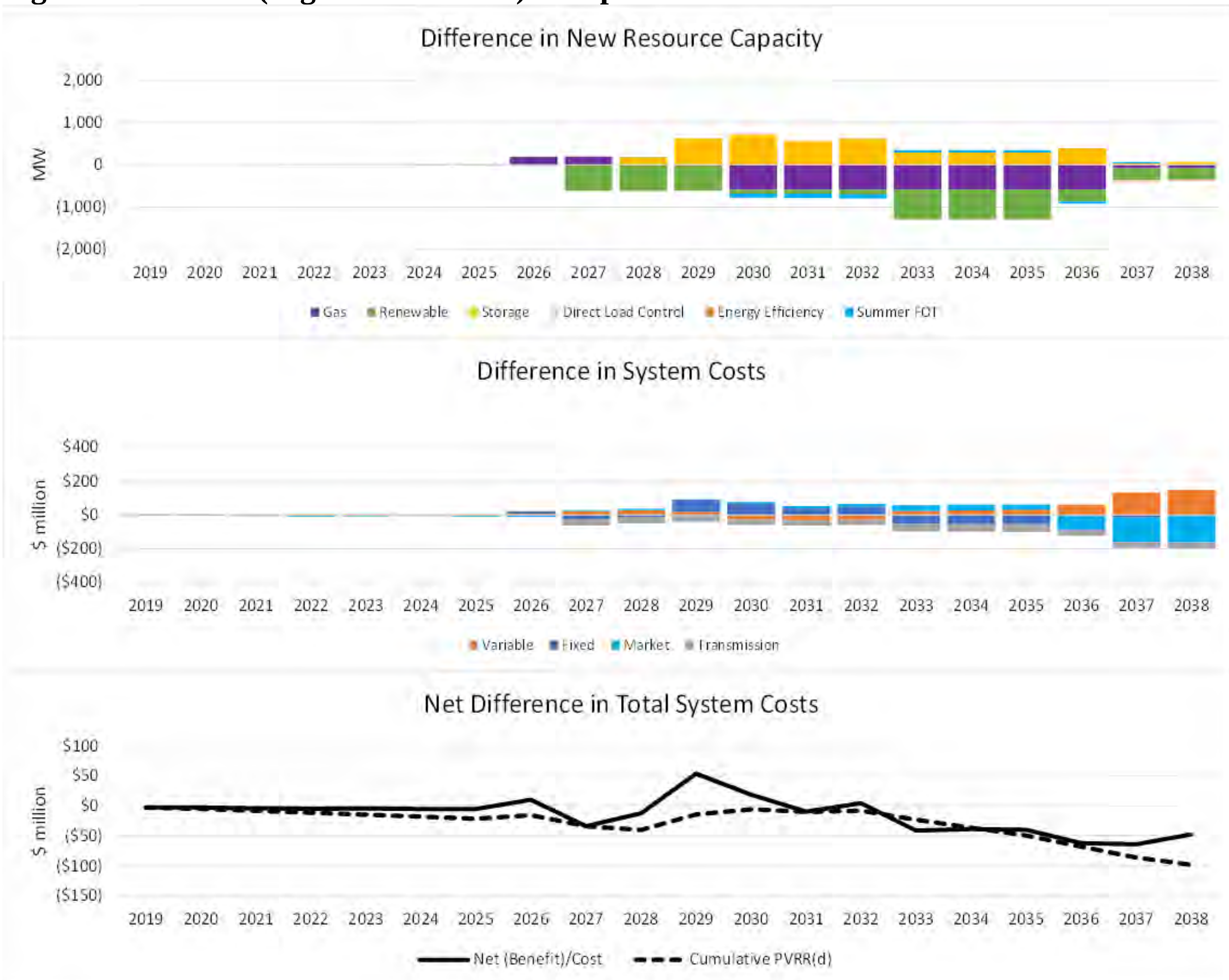


Table 8.15 – Gateway Case Results Summary

Case	Stochastic Mean			Risk Adjusted			ENS Average Percent of Load			CO2 Emissions		
	PVRR ($m)	Change from Lowest Cost Portfolio ($m)	Rank	PVRR ($m)	Change from Lowest Cost Portfolio ($m)	Rank	Average Annual ENS, 2019-2038 % of Average Load	Change from Lowest ENS Portfolio	Rank	Total CO2 Emissions, 2019-2038 (Thousand Tons)	Change from Lowest Emission Portfolio	Rank
P45CNW	**23,207**	$0	1	**24,376**	$0	1	**0.008%**	0.002%	5	**585,641**	40,831	5
P-26	23,305	$98	2	24,479	$104	2	0.006%	0.000%	2	580,126	35,315	3
P-22	23,603	$396	3	24,792	$416	3	0.007%	0.001%	4	581,028	36,217	4
P-23	24,184	$977	4	25,402	$1,026	4	0.007%	0.001%	3	544,811	0	1
P-25	24,239	$1,032	5	25,460	$1,084	5	0.006%	0.000%	1	580,014	35,204	2

Gateway Studies Conclusions

While the results above did not compel PacifiCorp to alter its selection of case P-45CNW as the top-performing portfolio, the company remains confident that additional Energy Gateway segments will provide incremental regional and customer benefits with an ongoing transition to the regional resource mix and as new markets develop.

As discussed above, case P-26, which includes the Boardman-to-Hemingway transmission line, shows significant potential for producing customer benefits. This project has motivated partners and is expected to provide incremental benefits not captured in the current analysis that can be further explored in future IRPs and IRP Updates. Consequently, PacifiCorp will remain an active participate in the ongoing development of this project and has included an action item in its action plan to continue its partnership in this project. Some of the incremental benefits of Boardman-to-Hemmingway not captured in the analysis above include:

- Connecting geographical diversity to help balance the intermittency of resources like wind and solar, to help meet clean-energy standards and bolsters resource adequacy.
- Decreasing market reliance by providing incremental infrastructure that can connect additional resources to load.
- Improved reliability by increasing ability to share operating reserves among utilities and providing additional source for energy to flow.
- Help alleviate transmission congestion.
- Improved access to participate in the Energy Imbalance Market and generate customer benefits.

PacifiCorp has also included an action item to continue permitting the Energy Gateway transmission plan, as it is anticipated these additional segments will also provide incremental value that can continue to be evaluated in future IRPs and IRP Updates.

Final Preferred Portfolio Selection

Case P-45CNW entered the final evaluations as the top candidate for preferred portfolio, and for purposes of the 2019 IRP, the “No New Natural Gas” and Energy Gateway cases did not change P-45CNW’s top status. Consequently, PacifiCorp selected the resource portfolio from case P-45CNW as the 2019 IRP preferred portfolio.

The 2019 IRP Preferred Portfolio

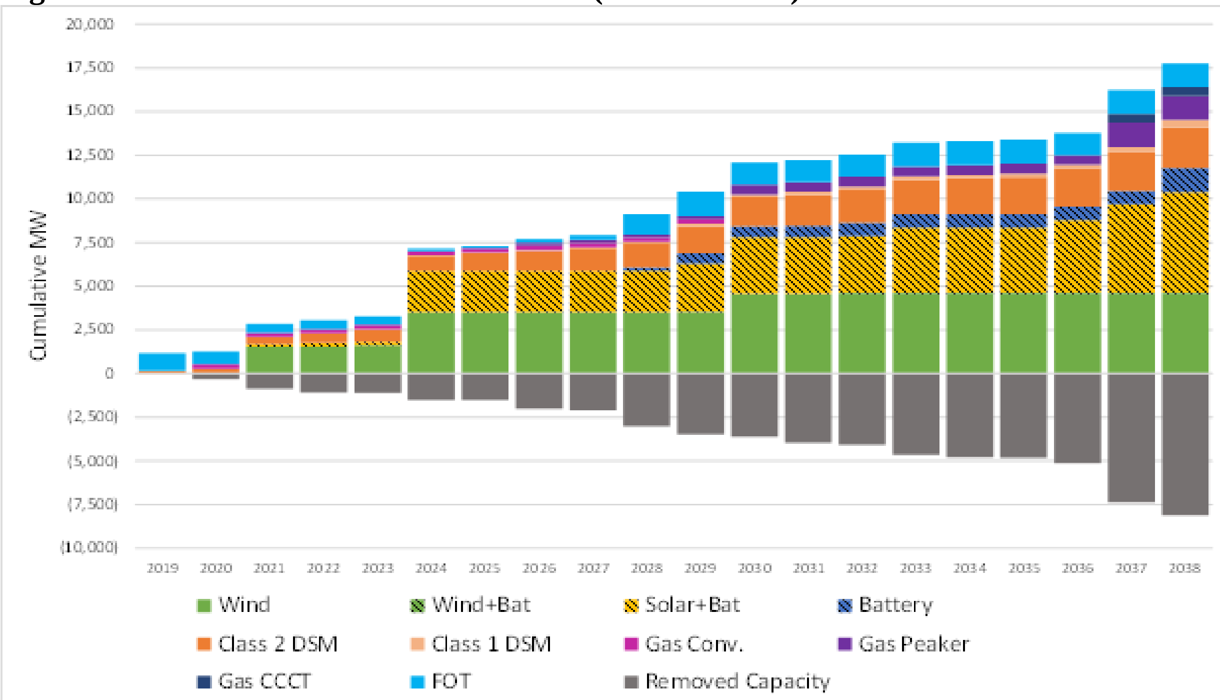
PacifiCorp’s selection of the 2019 IRP preferred portfolio is supported by comprehensive data analysis and an extensive stakeholder-input process. Figure 8.31 shows that PacifiCorp’s preferred portfolio continues to include new renewables, facilitated by incremental transmission investments, demand-side management (DSM) resources, and for the first time, significant battery storage resources. By the end of 2023, the preferred portfolio includes nearly 3,000 MW of new solar resources and more than 3,500 MW of new wind resources, inclusive of resources that will come online by the end of 2020 that were not in the 2017 IRP.[3] The preferred portfolio also includes nearly 600 MW of battery storage capacity (all collocated with new solar resources), and over 700 MW of incremental energy efficiency and new direct load control resources.

Over the 20-year planning horizon, the preferred portfolio includes more than 4,600 MW of new wind resources, more than 6,300 MW of new solar resources, more than 2,800 MW of battery storage (nearly 1,400 MW of which are stand-alone storage resources starting in 2028), and more

[3] *Id*.

than 2,700 MW of incremental energy efficiency and new direct load control resources.[4] While the preferred portfolio includes new natural gas peaking capacity beginning 2026, this falls outside of the 2019 IRP action plan window, which provides time for PacifiCorp to continue to evaluate whether non-emitting capacity resources can be used to supply the flexibility necessary to maintain long-term system reliability.

Figure 8.31 – 2019 IRP Preferred Portfolio (All Resources)



To facilitate the delivery of new renewable energy resources to PacifiCorp customers across the West, the preferred portfolio includes a 400-mile transmission line known as Gateway South, planned to come online by the end of 2023, that will connect southeastern Wyoming and northern Utah. The new transmission line is in addition to the 140-mile Gateway West transmission line in Wyoming currently under construction as part of PacifiCorp's Energy Vision 2020 initiative. The preferred portfolio further includes near-term transmission upgrades in Utah and Washington. Ongoing investment in transmission infrastructure in Idaho, Oregon, Utah, Washington, and Wyoming will facilitate continued and long-term growth in new renewable resources. Table 8.16 summarizes the incremental transmission projects included in the 2019 IRP preferred portfolio, and Table 8.17 summarizes the total amount of initial capital investment required to deliver incremental transmission and resource investments through the 20-year planning period of the 2019 IRP.

[4] *Id.*

Table 8.16 – Transmission Projects Included in the 2019 IRP Preferred Portfolio*

Year	Resource(s)	From	To	Description
2023	69 MW Wind (2023) 231 MW Solar (2024)	Within Southern UT Transmission Area		Enables 300 MW of interconnection: UT Valley 345-138 kV + 138 kV reinforcement ($8m)
2024	354 MW Solar (2024)	Within Bridger WY Transmission Area		Reclaimed transmission upon retirement of Jim Bridger 1 ($0)
2024	674 MW Solar (2024)	Within Northern UT Transmission Area		Enables 600 MW of interconnection: Northern UT 345 kV reinforcement ($30m)
2024	1,920 MW Wind (2024)	Aeolus WY	UT North	Enables 1,920 MW of interconnection with 1,700 MW of TTC: Energy Gateway South ($1,752m)
2024	395 MW Solar (2024) 10 MW Wind (2029)	Within Yakima WA Transmission Area		Enables 405 MW of interconnection: local reinforcement ($3m)
2024	359 MW Solar (2024)	Within Bridger WY Transmission Area		Reclaimed transmission upon retirement of Jim Bridger 2 ($0)
2030	1,040 MW Wind (2030) 60 MW Wind (2032)	Goshen ID	UT North	Enables 1,100 MW of interconnection with 800 MW of TTC ($254m)
2030	500 MW Solar (2030)	Within Southern UT Transmission Area		Enables 500 MW of interconnection: UT Valley local area reinforcement ($206m)
2033	475 MW Solar (2033)	Within Southern OR Transmission Area		Enables 475 MW of interconnection: Medford area 500 kV-230 kV reinforcement ($102m)
2036	419 MW Solar (2036)	Yakima WA	Southern OR	Enables 430 MW of interconnection with 450 MW of TTC: Yakima WA to Bend OR 230 kV ($255m)
2037	909 MW Solar (2037)	Southern UT	Northern UT	Reclaimed transmission upon retirement of Huntington 1-2 ($0)
2037	443 MW Gas (2037)	Within Willamette Valley OR Transmission Area		Enables 615 MW of interconnection: Albany OR area reinforcement ($40m)
2037	370 MW Gas (2037)	Within Southwest WY Transmission Area		Enables 500 MW of interconnection: separation of double circuit 230 kV lines ($39m)
2038	702 MW Solar (2038)	Within Bridger WY Transmission Area		Reclaimed transmission upon retirement of Jim Bridger 3-4 ($0)

*Note: 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.

Table 8.17 – Total Initial Capital to Deliver Preferred Portfolio Transmission and Resource Investments ($ million)

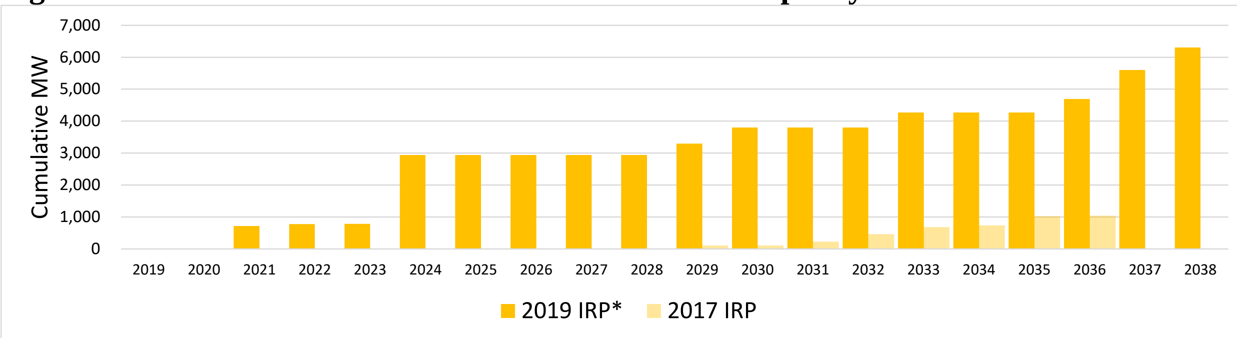
State	Transmission	Resources	Total
Idaho	$254	$1,659	$1,912
Oregon	$264	$2,540	$2,804
Utah	$1,004	$3,466	$4,470
Washington	$136	$1,509	$1,644
Wyoming	$765	$5,376	$6,141
Colorado	$370	$0	$370
Total	$2,792	$14,550	$17,342

New Solar Resources

The 2019 IRP preferred portfolio includes more than 3,000 MW of new solar by the end of 2023, which accounts for resources that will come online by the end of 2020 but not in the 2017 IRP, and more than 6,300 MW of new solar by 2038 as shown in Figure 8.32.[5]

[5] *Id.*

Figure 8.32 – 2019 IRP Preferred Portfolio New Solar Capacity*

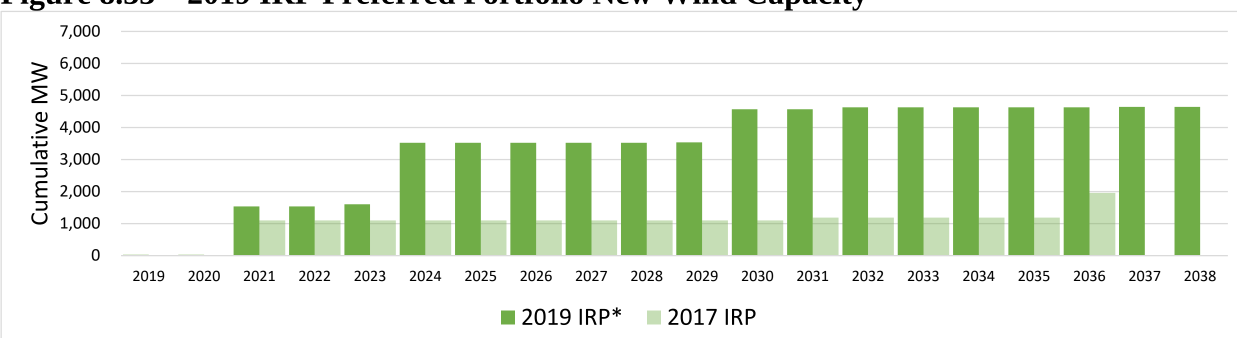


*Note: 2019 IRP solar capacity shown in the figure includes 559 MW of contracted new solar (all power-purchase agreements) that was not identified in the 2017 IRP. These resources will be online by the end of 2020 and are shown in the first full year of operation (the year after year-online dates). Resources acquired through customer partnerships, used for renewable portfolio standard compliance, or for third-party sales of renewable attributes are included in the total capacity figures quoted.

New Wind Resources

As shown in Figure 8.33, PacifiCorp's 2019 IRP preferred portfolio includes more than 3,500 MW of new wind generation by the end of 2023, which accounts for new resources that will come online by the end of 2020 but not in the 2017 IRP, and more than 4,600 MW of new wind by 2038.[6]

Figure 8.33 – 2019 IRP Preferred Portfolio New Wind Capacity*



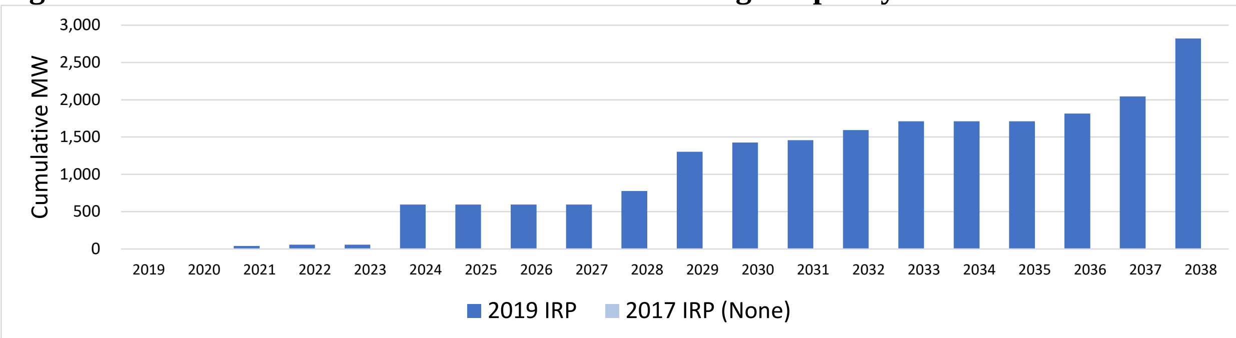
*Note: 2019 IRP wind capacity shown in the figure includes 1,533 MW of contracted new wind (21 percent power-purchase agreements) that was either identified in the 2017 IRP and is under construction or that was not identified in the 2017 IRP and is under contract. These resources will come on-line by the end of 2020. These resources are shown in the first full year of operation (the year after year-end online dates). Resources acquired through customer partnerships, used for renewable portfolio standard compliance, or for third-party sales of renewable attributes are included in the total capacity figures quoted.

New Storage Resources

This is the first PacifiCorp IRP that identifies new battery storage resources as part of its least-cost, least-risk portfolio. As shown in Figure 8.34, PacifiCorp's 2019 IRP preferred portfolio includes nearly 600 MW of battery storage by the end of 2023. All of the storage resources planned through this period are paired with new solar generation. The plan also adds nearly 1,400 MW of stand-alone storage resources starting in 2028.

[6] *Id.*

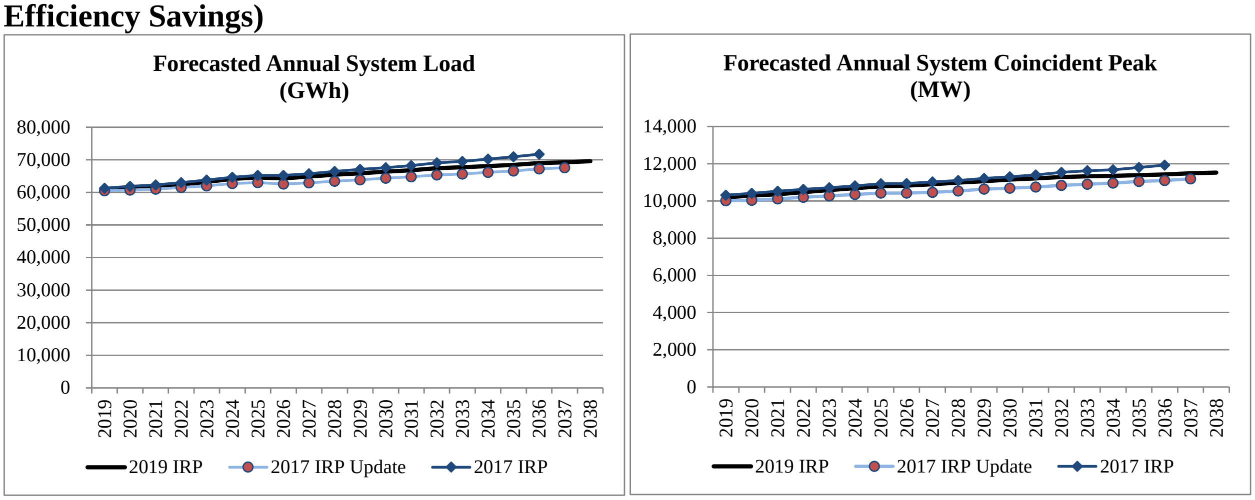
Figure 8.34 – 2019 IRP Preferred Portfolio New Storage Capacity



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 resource portfolios for the IRP. Consequently, the load forecast used as an input to the IRP does not reflect any incremental investment in new energy efficiency programs; rather, the load forecast is reduced by the selected additions of energy efficiency resources in the IRP. Figure 8.35 shows that PacifiCorp's load forecast before incremental energy efficiency savings has increased relative to projected loads used in the 2017 IRP and 2017 IRP Update. On average, forecasted system load is up 2.4 percent and forecasted coincident system peak is up 3.4 percent when compared to the 2017 IRP Update. Over the planning horizon, the average annual growth rate, before accounting for incremental energy efficiency improvements, is 0.73 percent for load and 0.64 percent for peak. Changes to PacifiCorp's load forecast are driven by higher projected demand from data centers driving up the commercial forecast and an increase the residential forecast.

Figure 8.35 – Load Forecast Comparison between Recent IRPs (Before Incremental Energy Efficiency Savings)

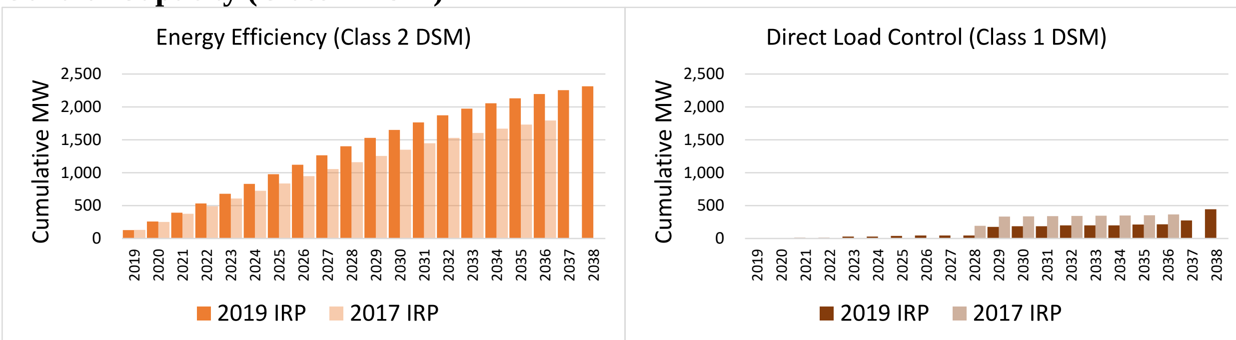


DSM resources continue to play a key role in PacifiCorp's resource mix. The chart to the left in Figure 8.36 compares total energy efficiency savings in the 2019 IRP preferred portfolio relative to the 2017 IRP preferred portfolio.

In addition to continued investment in energy efficiency programs, the preferred portfolio continues to show a role for incremental direct load control programs with total capacity reaching

444 MW by the end of the planning period. The chart to the right in Figure 8.36 compares total incremental capacity of direct load control program capacity in the 2019 IRP preferred portfolio relative to the 2017 IRP preferred portfolio and does not include capacity from existing programs.

Figure 8.36 – 2019 IRP Preferred Portfolio Energy Efficiency (Class 2 DSM) and Direct Load Control Capacity (Class 1 DSM)



Wholesale Power Market Prices and Purchases

Figure 8.37 shows that the 2019 IRP's base case forecast for natural gas and power prices has increased from those in the 2017 IRP and 2017 IRP Update. These forecasts are based on prices observed in the forward market and on projections from third-party experts. The higher power prices observed in the 2019 IRP are primarily driven by the assumption of a carbon price that is higher and starts earlier (2025) than what was assumed in the 2017 IRP Update (2030).[7] Moreover, the 2019 IRP assumed higher natural gas prices than either the 2017 IRP or 2017 IRP Update as Henry Hub, in particular, is boosted by increasing LNG exports. While not shown in the figure below, the 2019 IRP also evaluated low and high price scenarios when evaluating the cost and risk of different resource portfolios.

Figure 8.37 – Comparison of Power Prices and Natural Gas Prices in Recent IRPs

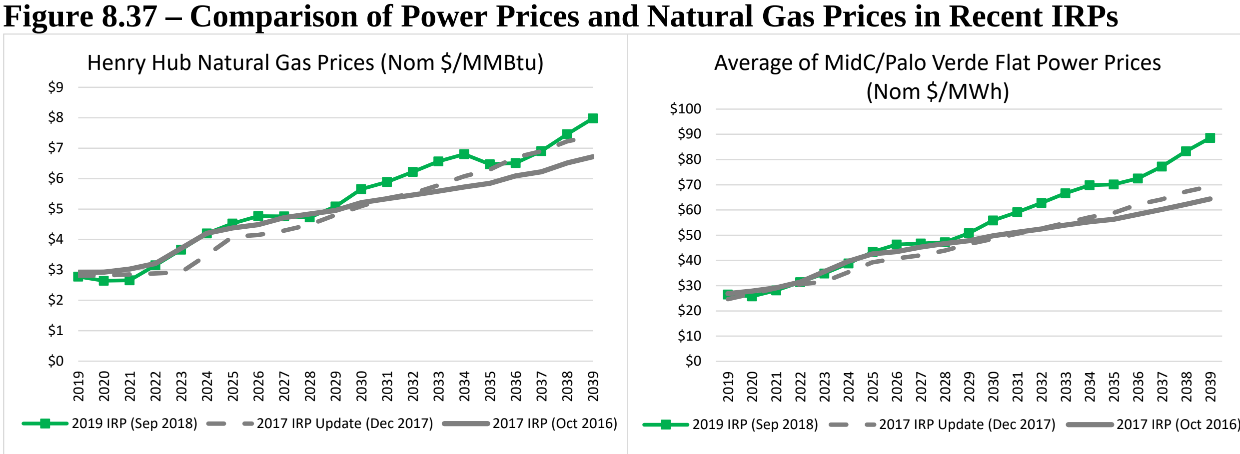
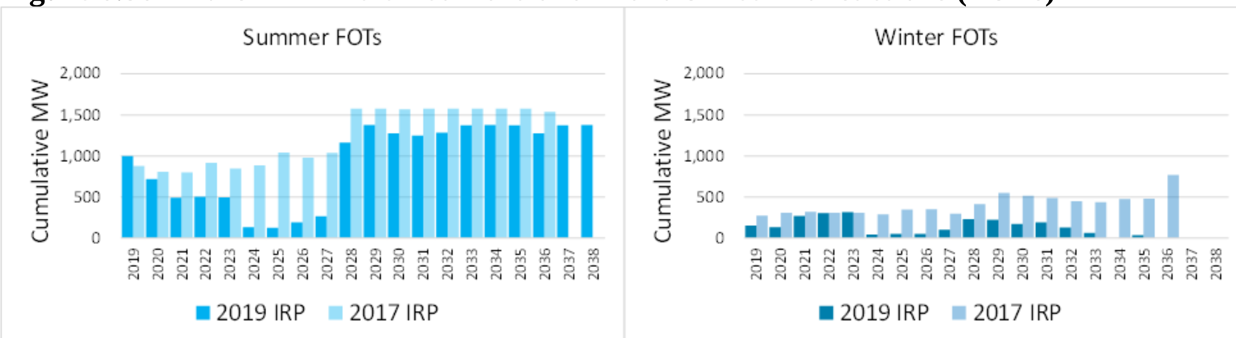


Figure 8.38 shows an overall decline in reliance on wholesale market firm purchases in the 2019 IRP preferred portfolio relative to the market purchases included in the 2017 IRP preferred portfolio. In particular, reliance on market purchases during summer peak periods averages 366 MW per year over the 2020-2027 timeframe—down 60 percent from market purchases identified in the 2017 IRP preferred portfolio. This reduction in market purchases coincides with the period

[7] The 2017 IRP did not assume a carbon price but, instead, reflected implementation of the Clean Power Plan.

over which there are resource adequacy concerns in the region. While market purchases increase beyond 2027, PacifiCorp is actively participating in regional efforts to develop day-ahead markets and a resource adequacy program that will help unlock regional diversity and facilitate market transactions over the long term.

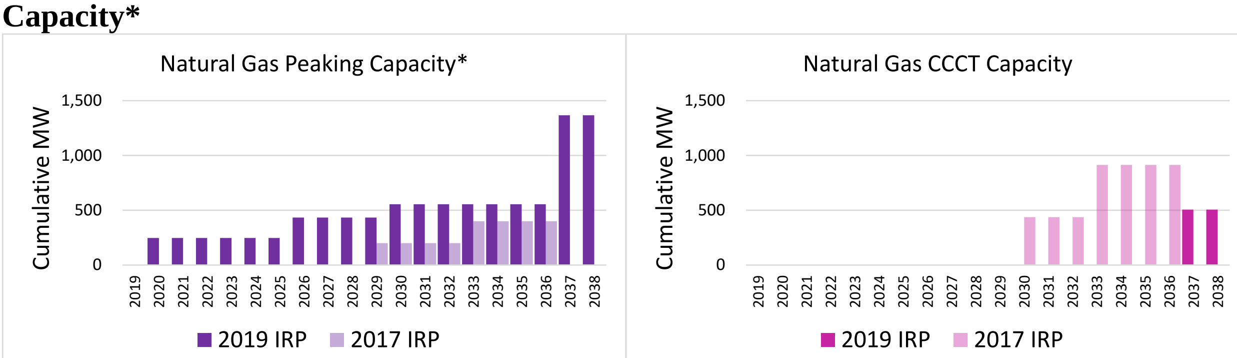
Figure 8.38 – 2019 IRP Preferred Portfolio Front Office Transactions (FOTs)



Natural Gas Resources

In the 2019 IRP preferred portfolio, Naughton Unit 3 is converted to natural gas in 2020, providing a low-cost reliable resource for meeting load and reliability requirements. New natural gas peaking resources appear in the preferred portfolio starting in 2026, which is outside the action-plan window. This provides time for PacifiCorp to continue to evaluate whether non-emitting capacity resources can be used to supply the flexibility necessary to maintain system reliability long into the future.

Figure 8.39 – 2019 IRP Preferred Portfolio Natural Gas Peaking and Combined Cycle Capacity*



* Note: 2019 IRP natural gas peaking capacity includes the conversion of Naughton Unit 3 to natural gas in 2020 (247 MW).

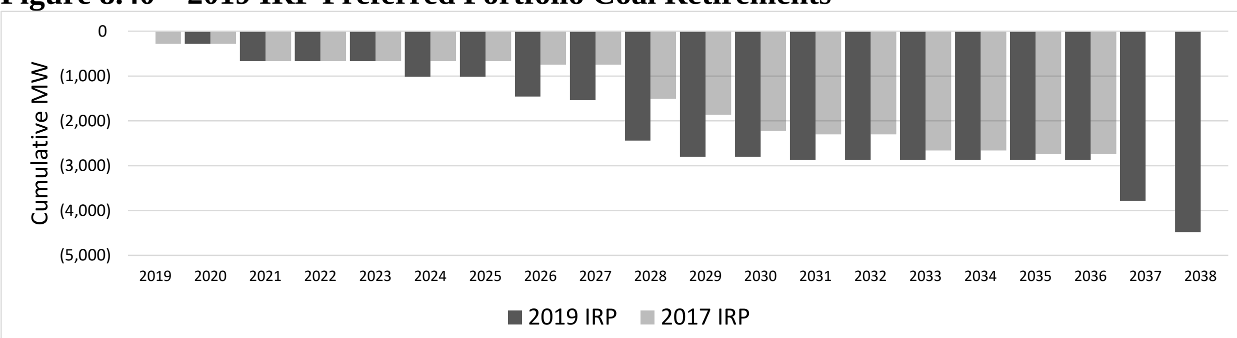
Coal Retirements

Coal resources have been an important resource in PacifiCorp's resource portfolio. Changes in how PacifiCorp has been operating these assets (i.e., by lowering operating minimums) has allowed the company to buy increasingly low-cost, zero-emissions renewable energy from market participants, which is accessed by our expansive transmission grid. PacifiCorp's coal resources will continue to play a pivotal role in following fluctuations in renewable energy as those units approach retirement dates. Driven in part by ongoing cost pressures on existing coal-fired facilities and dropping costs for new resource alternatives, of the 24 coal units currently serving PacifiCorp customers, the preferred portfolio includes retirement of 16 of the units by 2030 and 20 of the units by the end of the planning period in 2038. As shown in Figure 8.40, coal unit retirements in the 2019 IRP preferred portfolio will reduce coal-fueled generation capacity by over 1,000 MW by the end of 2023, nearly 1,500 MW by the end of 2025, nearly 2,800 MW by 2030, and nearly 4,500 MW by 2038.

Coal unit retirements scheduled under the preferred portfolio include:

- 2019 = Naughton Unit 3 (same as 2017 IRP), converted to natural gas in 2020
- 2020-2023 = Cholla Unit 4 (same as 2017 IRP)
- 2023 = Jim Bridger Unit 1 (instead of 2028 in the 2017 IRP)
- 2025 = Naughton Units 1-2 (instead of 2029 in the 2017 IRP)
- 2025 = Craig Unit 1 (same as 2017 IRP)
- 2026 = Craig Unit 2 (instead of 2034 in the 2017 IRP)
- 2027 = Dave Johnston Units 1-4 (same as 2017 IRP)
- 2027 = Colstrip Units 3-4 (instead of 2046 in the 2017 IRP)
- 2028 = Jim Bridger Unit 2 (instead of 2032 in the 2017 IRP)
- 2030 = Hayden Units 1-2 (same as 2017 IRP)
- 2036 = Huntington Units 1-2 (same as 2017 IRP)
- 2037 = Jim Bridger Units 3-4 (same as 2017 IRP)

Figure 8.40 – 2019 IRP Preferred Portfolio Coal Retirements*



* 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.

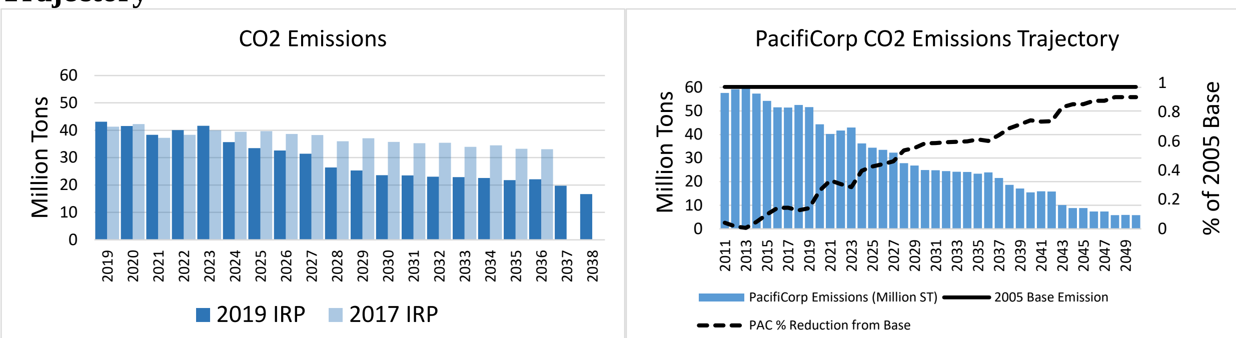
Carbon Dioxide Emissions

The 2019 IRP preferred portfolio reflects PacifiCorp's on-going efforts to provide cost-effective clean-energy solutions for our customers and accordingly reflects a continued trajectory of declining carbon dioxide (CO_2) emissions. PacifiCorp's emissions have been declining and continue to decline as a result of a number of factors, including PacifiCorp's participation in the Energy Imbalance Market (EIM), which reduces customer costs and maximizes use of clean energy; PacifiCorp's on-going expansion of renewable resources and transmission; and Regional Haze compliance that capitalizes on flexibility.

The chart on the left in Figure 8.41 compares projected annual CO_2 emissions between the 2019 IRP and 2017 IRP preferred portfolios. In this graph, emissions are not assigned to market purchases or sales, and in 2025, annual CO_2 emissions are down sixteen percent relative to the 2017 IRP preferred portfolio. By 2030, average annual CO_2 emissions are down 34 percent relative to the 2017 IRP preferred portfolio, and down 35 percent in 2035. By the end of the planning horizon, system CO_2 emissions are projected to fall from 43.1 million tons in 2019 to 16.7 million tons in 2038—a 61.3 percent reduction.

The chart of the right in Figure 8.41 includes historical data, assigns emissions at a rate of 0.4708 tons/megawatt hours (MWh) to market purchases (with no credit to market sales), and extrapolates projections out through 2050. This graph demonstrates that relative to a 2005 baseline (a ubiquitous baseline year in the industry), system CO_2 emissions are down 43 percent in 2025, 59 percent in 2030, 61 percent in 2035, 74 percent in 2040, 85 percent in 2045, and 90 percent in 2050.

Figure 8.41 – 2019 IRP Preferred Portfolio CO_2 Emissions and PacifiCorp CO_2 Emissions Trajectory*



*Note: PacifiCorp CO_2 Emissions Trajectory reflects actual emissions through 2018 from owned facilities, specified sources and unspecified sources. From 2019 through the end of the twenty-year planning period in 2038, emissions reflect those from the 2019 IRP preferred portfolio with market purchases assigned the California Air Resources Board default emission factor (0.4708 tons/MWh) – emissions from sales are not removed. Beyond 2038, emissions reflect the rolling average emissions of each resource from the 2019 IRP preferred portfolio through the life of the resource.

Renewable Portfolio Standards

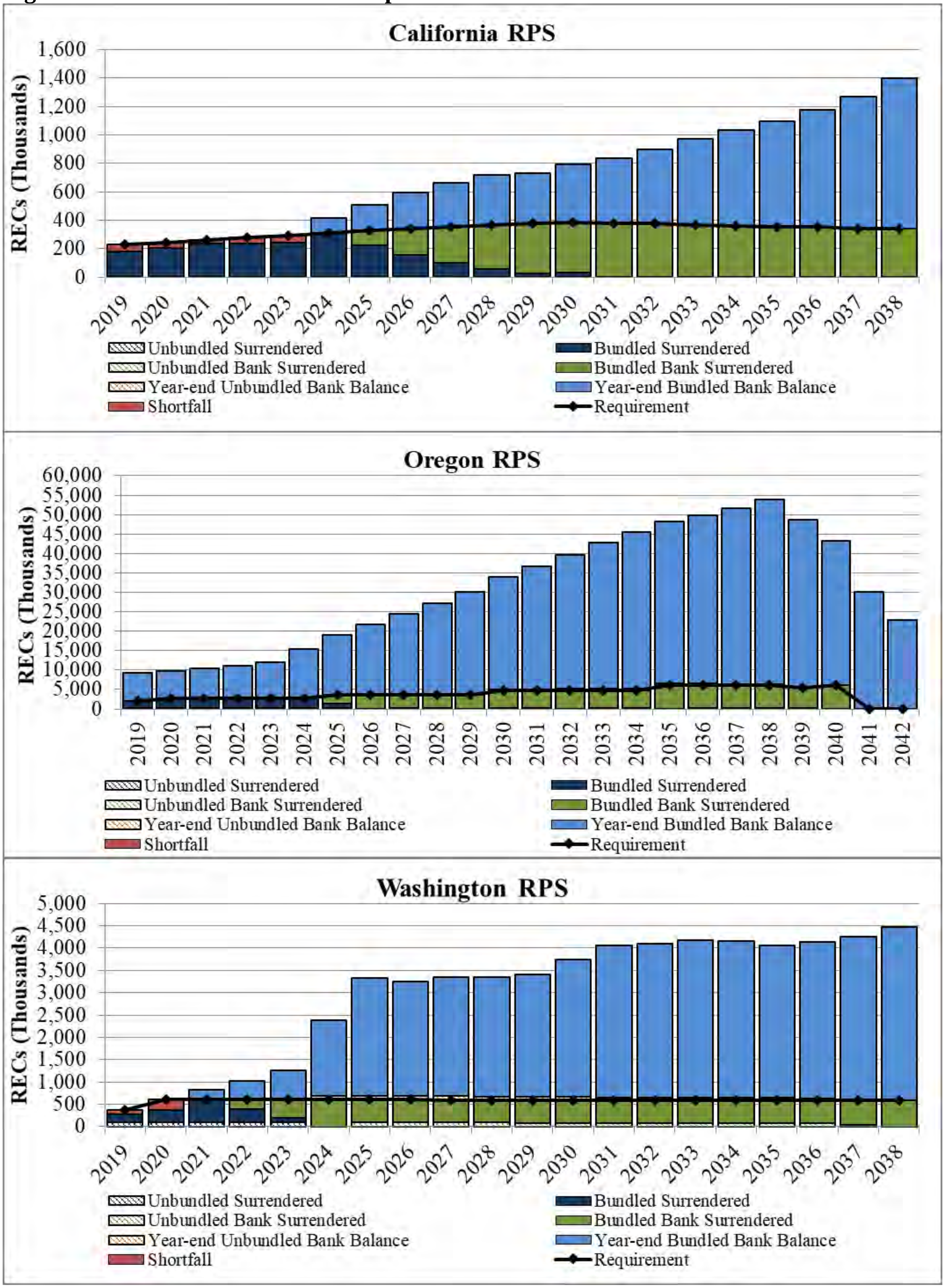
Figure 8.42 shows PacifiCorp's renewable portfolio standard (RPS) compliance forecast for California, Oregon, and Washington after accounting for new renewable resources in the preferred portfolio. While these resources are not included in the preferred portfolio as cost-effective system resources and 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 2038 with the addition of new renewable resources and transmission in the 2019 IRP preferred portfolio. The California RPS compliance position is also improved by the addition of new renewable resources and transmission in the 2019 IRP preferred portfolio but requires a small amount of unbundled renewable energy credit (REC) purchases under 150 thousand RECs per year to achieve compliance through Compliance Period 4. Washington RPS compliance is achieved with the benefit of repowered wind assets located in the west side, Marengo, Leaning Juniper and Goodnoe Hills, increased system renewable resources contributing to the west side beginning 2021[8], and unbundled REC purchases under 300 thousand

[8] PacifiCorp will propose the Multi-State Protocol allocation methodology in a December 13, 2019 Washington general rate case (GRC) filing. The methodology would allocate a system generation share of all non-emitting system resources to Washington. The 2019 IRP Annual State RPS Compliance Forecast reflected in Figure 8.42 reflects PacifiCorp's proposal to be filed in the rate case starting in 2021. Upon approval, the effective date of the new allocation methodology would be January 1, 2021.

RECs per year through 2021. Under current allocation mechanisms, Washington customers do not benefit from the new renewable resources added to the east side of PacifiCorp's system. While not shown in Figure 8.42, 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 2019 IRP preferred portfolio.

Figure 8.42 – Annual State RPS Compliance Forecast



Capacity and Energy

Figure 8.43 displays how preferred portfolio resources meet PacifiCorp's capacity needs over time. Through 2038, PacifiCorp meets its capacity needs, including a 13 percent target planning reserve margin, through incremental acquisition of wind and solar resources, enabled by investment in transmission infrastructure, battery storage resources, new DSM, natural gas and wholesale power market purchases.

Figure 8.43 – Meeting PacifiCorp's Capacity Needs with Preferred Portfolio Resources

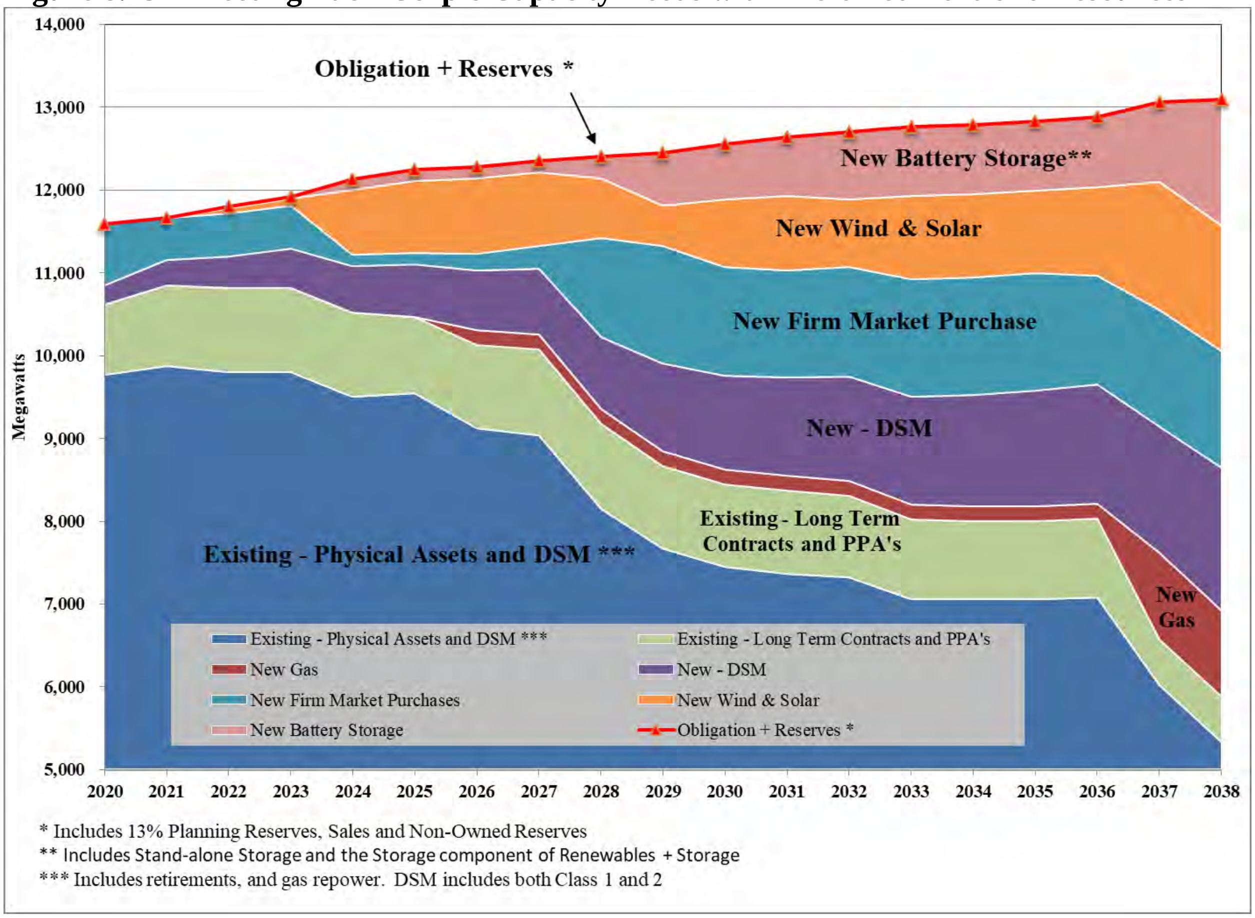


Figure 8.44 and Figure 8.45 show how PacifiCorp's system energy and nameplate capacity mix is projected to change over time. In developing these figures, purchased power is reported in identifiable resource categories where possible. Energy mix figures are based upon base price curve assumptions. Renewable capacity and generation reflect categorization by technology type and not disposition of renewable energy attributes for regulatory compliance requirements.[9] On an energy basis, coal generation drops below 40 percent by 2025, falls to 22 percent by 2030, and declines to less than 6 percent by the end of the planning period. On a capacity basis, coal resources drop to 24 percent by 2025, fall to 13 percent by 2030, and decline to 5 percent by the end of the

[9]The projected PacifiCorp 2019 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 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 2019 IRP preferred portfolio energy mix includes owned resources and purchases from third parties.

planning period. Reduced energy and capacity from coal is offset primarily by increased energy and capacity from renewable resources, DSM resources, and to a smaller extent later in the plan, new natural gas resources.

Figure 8.44 – Projected Energy Mix with Preferred Portfolio Resources

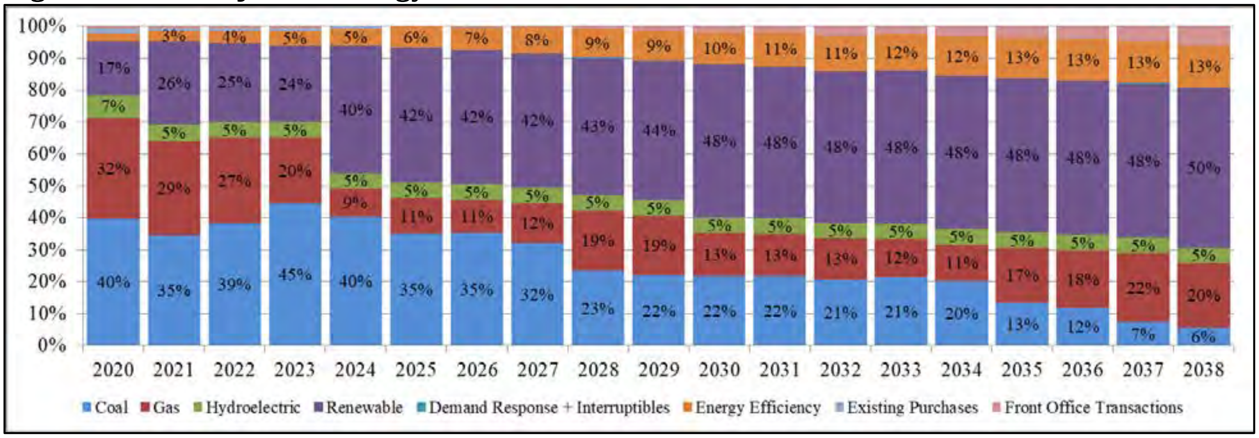
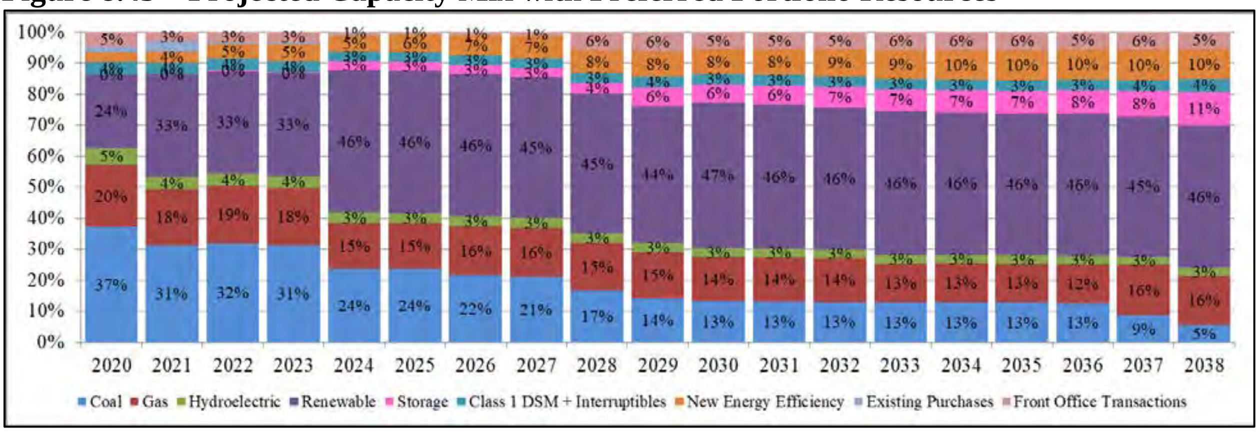


Figure 8.45 – Projected Capacity Mix with Preferred Portfolio Resources



Detailed Preferred Portfolio

Table 8.18 provides line-item detail of PacifiCorp's 2019 IRP preferred portfolio showing new resource capacity along with changes in existing resource capacity through the 20-year planning horizon. Table 8.19 and Table 8.20 show line-item detail of PacifiCorp's peak load and resource capacity balance for summer, including preferred portfolio resources, over the 20-year planning horizon. Table 8.21 and Table 8.22 show line-item detail of PacifiCorp's peak load and resource capacity balance for winter, including preferred portfolio resources, over the twenty year planning horizon.

Table 8.18 – PacifiCorp's 2019 IRP Preferred Portfolio (The 2019 Preferred Portfolio includes repowering 905 MW of existing wind resources, not shown in the table)

		Capacity (MW)																				Resource Totals 1/	
	P45CNW	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	10-year	20-year
East	**Existing Plant Retirements and PPA Termination**																						
	Craig 1 (Coal Early Retirement/Conversions)	-	-	-	-	-	-	-	(82)	-	-	-	-	-	-	-	-	-	-	-	-	(82)	(82)
	Craig 2 (Coal Early Retirement/Conversions)	-	-	-	-	-	-	-	-	(82)	-	-	-	-	-	-	-	-	-	-	-	(82)	(82)
	Hayden 1	-	-	-	-	-	-	-	-	-	-	-	-	(44)	-	-	-	-	-	-	-	-	(44)
	Hayden 2	-	-	-	-	-	-	-	-	-	-	-	-	(33)	-	-	-	-	-	-	-	-	(33)
	Huntington 1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(459)	-	-	(459)
	Huntington 2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(450)	-	-	(450)
	Colstrip 3 (Coal Early Retirement/Conversions)	-	-	-	-	-	-	-	-	-	(74)	-	-	-	-	-	-	-	-	-	-	(74)	(74)
	Colstrip 4 (Coal Early Retirement/Conversions)	-	-	-	-	-	-	-	-	-	(74)	-	-	-	-	-	-	-	-	-	-	(74)	(74)
	Cholla 4 (Coal Early Retirement/Conversions)	-	-	(387)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(387)	(387)
	DaveJohnston 1	-	-	-	-	-	-	-	-	-	(99)	-	-	-	-	-	-	-	-	-	-	(99)	(99)
	DaveJohnston 2	-	-	-	-	-	-	-	-	-	(106)	-	-	-	-	-	-	-	-	-	-	(106)	(106)
	DaveJohnston 3	-	-	-	-	-	-	-	-	-	(220)	-	-	-	-	-	-	-	-	-	-	(220)	(220)
	DaveJohnston 4	-	-	-	-	-	-	-	-	-	(330)	-	-	-	-	-	-	-	-	-	-	(330)	(330)
	Naughton 1 (Coal Early Retirement/Conversions)	-	-	-	-	-	-	-	(156)	-	-	-	-	-	-	-	-	-	-	-	-	(156)	(156)
	Naughton 2 (Coal Early Retirement/Conversions)	-	-	-	-	-	-	-	(201)	-	-	-	-	-	-	-	-	-	-	-	-	(201)	(201)
	Naughton 3 (Coal Early Retirement/Conversions)	-	(280)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(280)	(280)
	Gadsby 1-6	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(356)	-	-	-	-	-	-	(356)
	Retire - Hydro	-	-	-	-	-	(20)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(20)	(20)
	Retire - Wind	-	-	-	-	-	-	-	-	-	-	-	(40)	-	-	-	-	-	-	-	-	-	(40)
	Expire - Wind PPA	-	(27)	(17)	(49)	(0)	-	-	(65)	(3)	-	(19)	(99)	(200)	(45)	(181)	(80)	-	(60)	(80)	-	(160)	(924)
	Expire - Solar PPA	-	-	-	-	(1)	(1)	-	-	-	-	-	-	-	-	-	-	(35)	(94)	(849)	-	(1)	(979)
	Retire - Other	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(1)	-	-	-	(32)	-	(33)
	Coal Ret_WY - Gas RePower	-	247	-	-	-	-	-	-	-	-	-	(247)	-	-	-	-	-	-	-	-	247	-
	Expansion Resources																						
	CCCT - DJohns - J 1x1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	505	-	-	505
	Total CCCT	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	505	-	-	505
	SCCT Frame NTN	-	-	-	-	-	-	-	185	-	-	-	370	-	-	-	-	-	-	-	-	185	555
	SCCT Frame WYSW	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	370	-	-	370
	Total SCCT	-	-	-	-	-	-	-	185	-	-	-	370	-	-	-	-	-	-	370	-	185	925
	Wind, GO	-	-	-	-	-	-	-	-	-	-	-	1,040	-	-	-	-	-	-	-	-	-	1,040
	Wind, UT	-	-	-	-	69	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	69	69
	Wind, WYAE	-	-	-	-	-	1,920	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1,920	1,920
	Wind+Storage, GO	-	-	-	-	-	-	-	-	-	-	-	-	-	60	-	-	-	-	-	-	-	60
	Total Wind	-	-	-	-	69	1,920	-	-	-	-	-	1,040	-	60	-	-	-	-	-	-	1,989	3,089
	Utility Solar+Storage - PV - Utah-S	-	-	-	-	-	231	-	-	-	-	-	500	-	-	-	-	-	-	-	-	231	731
	Utility Solar+Storage - PV - Huntington	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	909	-	-	909
	Utility Solar+Storage - PV - Utah-N	-	-	159	64	3	674	-	-	-	-	-	-	-	-	-	-	-	-	-	-	900	900
	Total Solar	-	-	159	64	3	904	-	-	-	-	-	500	-	-	-	-	-	-	909	-	1,131	2,540
	Demand Response, ID-Irrigate	-	-	-	-	-	-	-	-	-	-	-	-	-	5.2	-	-	-	3.7	-	1.8	-	10.6
	Demand Response, UT-Cool/WH	4.1	-	7.0	-	9.9	-	-	7.2	-	-	6.7	-	-	6.8	-	-	7.0	-	-	7.2	28.1	55.9
	Demand Response, UT-3rd Party Contracts	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	76.7	-	76.7
	Demand Response, UT-Irrigate	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1.9	-	1.9
	Demand Response, UT-Thermostat	-	-	-	-	-	-	-	-	-	-	116.7	8.2	-	-	-	-	8.3	-	-	5.1	-	138.3
	Demand Response, WY-Cool/WH	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	5.2	-	5.2
	Demand Response, WY-3rd Party Contracts	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	37.3	-	37.3
	Demand Response, WY-Irrigate	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1.8	-	-	1.8
	Demand Response, WY-Thermostat	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	5.5	1.2	-	6.7
	Demand Response, UT-Ancillary Services	-	-	-	-	8.3	-	5.3	-	-	-	-	-	-	-	-	-	-	-	3.2	-	13.5	16.7
	Demand Response, WY-Ancillary Services	-	-	-	-	-	-	3.0	-	-	-	-	-	-	-	-	-	-	-	-	-	3.0	3.0
	Demand Response Total	4.1	-	7.0	-	18.1	-	8.2	7.2	-	-	123.3	8.2	-	12.0	-	-	15.3	3.7	10.5	136.5	44.6	354.1
	Energy Efficiency, ID	6	6	6	7	7	7	7	7	7	7	7	6	6	6	5	4	4	3	3	3	69	117
	Energy Efficiency, UT	58	67	67	68	69	68	67	65	65	62	57	56	52	52	48	36	32	25	22	23	656	1,058
	Energy Efficiency, WY	10	10	11	14	15	16	16	18	18	17	16	15	13	12	11	9	8	7	5	5	146	248
	Energy Efficiency Total	74	83	85	88	92	92	91	90	90	87	80	77	72	70	65	49	45	35	30	32	870	1,423
	Battery Storage - Utah-S	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	195	-	195.0
	Battery Storage - WYSW	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	15.0	-	15.0
	Battery Storage - Idaho	-	-	-	-	-	-	-	-	-	-	-	-	30.0	-	-	-	-	-	-	150.0	-	180.0
	FOT East - Summer	-	-	-	-	-	-	-	-	-	88	300	199	174	206	298	300	300	300	300	300	9	138
West	**Existing Plant Retirements and PPA Termination**																						
	JimBridger 1 (Coal Early Retirement/Conversions)	-	-	-	-	-	(351)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(351)	(351)
	JimBridger 2 (Coal Early Retirement/Conversions)	-	-	-	-	-	-	-	-	-	-	(356)	-	-	-	-	-	-	-	-	-	-	(356)
	JimBridger 3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(349)	-	(349)
	JimBridger 4	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(353)	-	(353)
	Hermiston	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(237)	-	-	(237)
	Retire - Hydro	-	(1)	(169)	-	(1)	-	-	(1)	-	(7)	-	-	(6)	-	-	(75)	-	(1)	-	-	(179)	(262)
	Expire - Wind PPA	-	-	-	(175)	-	(41)	-	-	-	-	(75)	(10)	-	(20)	(20)	-	-	(10)	(10)	-	(216)	(360)
	Expire - Solar PPA	-	-	-	-	-	-	-	-	-	(2)	-	-	(67)	(49)	-	-	(1)	(115)	(175)	(11)	(2)	(420)
	Expansion Resources																						
	SCCT Frame WV	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	443	-	-	443
	Total SCCT	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	443	-	-	443
	Wind+Storage, YK	-	-	-	-	-	-	-	-	-	-	10	-	-	-	-	-	-	-	11	-	-	20
	Total Wind	-	-	-	-	-	-	-	-	-	-	10	-	-	-	-	-	-	-	11	-	-	20
	Utility Solar+Storage - PV - Jbridger	-	-	-	-	-	354	-	-	-	-	359	-	-	-	-	-	-	-	-	702	354	1,415
	Utility Solar+Storage - PV - S-Oregon	-	-	-	-	-	500	-	-	-	-	-	-	-	-	475	-	-	-	-	-	500	975
	Utility Solar+Storage - PV - Yakima	-	-	-	-	-	395	-	-	-	-	-	-	-	-	-	-	-	419	-	-	395	815
	Total Solar	-	-	-	-	-	1,249	-	-	-	-	359	-	-	-	475	-	-	419	-	702	1,249	3,205
	Demand Response, OR-Ancillary Services	-	-	-	-	-	-	-	-	-	-	8	-	-	-	-	-	-	-	-	-	-	8
	Demand Response, WA-Ancillary Services	-	-	-	-	-	-	-	-	-	-	1.9	-	-	-	-	-	-	-	-	-	-	1.9
	Demand Response, CA-Cool/WH	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1.5	-	1.5
	Demand Response, CA-3rd Party Contracts	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1.1	-	1.1
	Demand Response, CA-Irrigate	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	4.8	-	-	4.8
	Demand Response, CA-Thermostat	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	5.8	-	-	5.8
	Demand Response, OR-3rd Party Contracts	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	10.9	-	10.9
	Demand Response, OR-Irrigate	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	13.3	-	-	13.3
	Demand Response, WA-Cool/WH	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	7.7	-	7.7
	Demand Response, WA-3rd Party Contracts	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	10.9	-	10.9
	Demand Response, WA-Irrigate	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	8.3	-	-	8.3
	Demand Response, WA-Thermostat	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	16.6	-	-	16.6
	Demand Response Total	-	-	-	-	-	-	-	-	-	-	9.4	-	-	-	-	-	-	-	48.8	32.1	-	90.2
	Energy Efficiency, CA	1	2	2	2	2	2	2	2	2	2	2	2	2	2	2	1	1	1	1	1	18	33
	Energy Efficiency, OR	40	37	37	42	41	46	43	41	41	38	35	32	31	30	26	26	25	25	24	23	405	680
	Energy Efficiency, WA	11	10	10	11	12	12	12	11	11	11	10	9	9	8	8	6	6	5	4	4	111	179
	Energy Efficiency Total	52	49	48	55	55	59	56	54	54	51	46	43	42	40	35	33	33	30	29	28	533	892
	Battery Storage - S-Oregon	-	-	-	-	-	-	-	-	-	-	210	-	-	60	-	-	-	-	-	180	-	450
	Battery Storage - Willamette Valley	-	-	-	-	-	-	-	-	-	75	45	-	-	-	-	-	-	-	-	-	75	120
	Battery Storage - Portland NC	-	-	-	-	-	-	-	-	-	-	105	-	-	-	-	-	-	-	-	-	-	105
	Battery Storage - Walla Walla	-	-	-	-	-	-	-	-	-	-	75	-	-	60	-	-	-	-	-	60	-	195
	Battery Storage - Yakima	-	-	-	-	-	-	-	-	-	105	-	-	-	-	-	-	-	-	-	-	105	105
	FOT West - Summer	998	719	493	503	498	131	126	191	264	1,075	1,075	1,075	1,075	1,075	1,075	1,075	1,074	977	1,074	1,075	500	782
	FOT West - Winter	151	131	268	303	314	44	51	53	100	232	222	173	192	128	63	-	35	-	-	-	165	123
	Existing Plant Retirements/Conversions	-	(61)	(573)	(224)	(1)	(412)	-	(505)	(85)	(912)	(449)	(396)	(350)	(114)	(557)	(156)	(36)	(280)	(2,260)	(745)		
	Annual Additions, Long Term Resources	130	132	299	206	237	4,225	155	336	143	318	1,063	2,038	144	303	574	82	93	488	2,355	1,530		
	Annual Additions, Short Term Resources	1,149	850	761	806	812	175	177	244	364	1,394	1,597	1,447	1,441	1,409	1,435	1,375	1,410	1,277	1,374	1,375		
	Total Annual Additions	1,279	982	1,060	1,012	1,049	4,400	333	580	507	1,712	2,661	3,485	1,584	1,712	2,010	1,457	1,503	1,765	3,729	2,905		

Table 8.19 – Preferred Portfolio Summer Capacity Load and Resource Balance (2020-2029)

Calendar Year	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
East										
Thermal	5,963	5,634	5,634	5,634	5,634	5,634	5,217	5,140	4,481	4,481
Hydroelectric	74	74	74	74	74	74	74	74	74	74
Renewable	406	843	859	866	876	906	898	891	827	718
Purchases	242	215	215	215	215	115	115	115	115	115
Qualifying Facilities	891	666	665	665	617	619	621	620	610	590
Demand Response	323	323	323	323	323	323	323	323	323	323
Sales	(655)	(175)	(175)	(175)	(148)	(148)	(66)	0	0	0
Non-Owned Reserves	(35)	(35)	(35)	(35)	(35)	(35)	(35)	(35)	(35)	(35)
Transfers	271	(140)	(137)	(134)	(392)	(388)	(322)	(292)	307	365
East Existing Resources	**7,481**	**7,405**	**7,423**	**7,433**	**7,163**	**7,100**	**6,826**	**6,836**	**6,703**	**6,632**
Front Office Transactions	0	0	0	0	0	0	0	0	90	309
Gas	0	0	0	0	0	0	179	179	179	179
Wind	0	0	0	15	324	339	345	342	309	255
Wind+Storage	0	0	0	0	0	0	0	0	0	0
Solar	0	0	0	0	0	0	0	0	0	0
Solar+Storage	0	0	63	72	214	244	258	251	187	88
Demand Response	4	11	11	28	28	36	43	43	43	162
Other	1	1	1	1	1	1	1	1	1	1
East Planned Resources	**5**	**12**	**74**	**117**	**568**	**620**	**826**	**816**	**810**	**994**
East Total Resources	**7,486**	**7,416**	**7,498**	**7,550**	**7,731**	**7,720**	**7,652**	**7,652**	**7,512**	**7,626**
Load	7,039	7,108	7,185	7,276	7,405	7,442	7,460	7,523	7,604	7,678
Private Generation	(125)	(166)	(173)	(176)	(202)	(188)	(195)	(204)	(218)	(233)
Existing Resources:										
Interruptible	(177)	(177)	(177)	(177)	(177)	(177)	(177)	(177)	(177)	(177)
Energy Efficiency	(51)	(51)	(51)	(51)	(51)	(51)	(51)	(51)	(51)	(51)
New Resources:										
Energy Efficiency	(93)	(140)	(190)	(242)	(293)	(344)	(395)	(446)	(495)	(540)
East obligation	**6,592**	**6,572**	**6,593**	**6,629**	**6,681**	**6,682**	**6,641**	**6,644**	**6,663**	**6,677**
Planning Reserves (13%)	880	877	880	885	892	892	886	887	889	891
East Reserves	**880**	**877**	**880**	**885**	**892**	**892**	**886**	**887**	**889**	**891**
East Obligation + Reserves	**7,471**	**7,450**	**7,474**	**7,514**	**7,573**	**7,574**	**7,528**	**7,531**	**7,552**	**7,568**
East Position	**14**	**(34)**	**24**	**36**	**158**	**146**	**125**	**121**	**(40)**	**58**
East Reserve Margin	14%	13%	14%	14%	16%	16%	15%	15%	13%	14%
West										
Thermal	2,048	2,048	2,048	2,048	1,736	1,736	1,736	1,736	1,598	1,265
Hydroelectric	570	570	570	570	570	570	570	570	570	570
Renewable	383	379	287	289	289	298	302	300	273	240
Purchases	1	1	1	1	1	1	1	1	1	1
Qualifying Facilities	390	292	285	278	278	279	278	246	243	231
Demand Response	3	0	0	0	0	0	0	0	0	0
Sales	(165)	(161)	(110)	(110)	(80)	(80)	(80)	(80)	(80)	(78)
Non-Owned Reserves	(3)	(3)	(3)	(3)	(3)	(3)	(3)	(3)	(3)	(3)
Transfers	(272)	139	136	133	391	387	320	291	(308)	(365)
West Existing Resources	**2,955**	**3,265**	**3,214**	**3,206**	**3,182**	**3,189**	**3,126**	**3,062**	**2,296**	**1,861**
Front Office Transactions	741	508	518	513	135	130	197	272	1,107	1,107
Gas	0	0	0	0	0	0	0	0	0	0
Wind	0	0	0	0	0	0	0	0	0	0
Wind+Storage	0	0	0	0	0	0	0	0	0	7
Solar	0	0	0	0	0	0	0	0	0	0
Solar+Storage	0	0	0	0	253	288	305	297	221	132
Demand Response	0	0	0	0	0	0	0	0	0	9
Other	0	0	0	0	0	0	0	0	169	578
West Planned Resources	**741**	**508**	**518**	**513**	**388**	**419**	**502**	**569**	**1,497**	**1,833**
West Total Resources	**3,696**	**3,772**	**3,732**	**3,719**	**3,571**	**3,608**	**3,627**	**3,631**	**3,793**	**3,695**
Load	3,387	3,441	3,486	3,513	3,529	3,570	3,597	3,626	3,657	3,684
Private Generation	(21)	(26)	(29)	(32)	(45)	(39)	(44)	(51)	(58)	(66)
Existing Resources:										
Interruptible	0	0	0	0	0	0	0	0	0	0
Energy Efficiency	(30)	(30)	(30)	(30)	(30)	(30)	(30)	(30)	(30)	(30)
New Resources:										
Energy Efficiency	(52)	(76)	(102)	(127)	(153)	(178)	(202)	(225)	(247)	(266)
West obligation	**3,285**	**3,310**	**3,325**	**3,324**	**3,301**	**3,323**	**3,321**	**3,321**	**3,323**	**3,321**
Planning Reserves (13%)	427	430	432	432	429	432	432	432	432	432
West Reserves	**427**	**430**	**432**	**432**	**429**	**432**	**432**	**432**	**432**	**432**
West Obligation + Reserves	**3,712**	**3,740**	**3,757**	**3,756**	**3,730**	**3,755**	**3,753**	**3,753**	**3,755**	**3,753**
West Position	**(15)**	**32**	**(25)**	**(37)**	**(159)**	**(147)**	**(126)**	**(122)**	**39**	**(59)**
West Reserve Margin	13%	14%	12%	12%	8%	9%	9%	9%	14%	11%
System										
Total Resources	11,182	11,189	11,229	11,269	11,302	11,327	11,279	11,283	11,305	11,320
Obligation	9,876	9,882	9,918	9,953	9,982	10,005	9,962	9,966	9,985	9,998
Reserves	1,307	1,308	1,312	1,317	1,321	1,324	1,318	1,319	1,321	1,323
Obligation + Reserves	11,183	11,190	11,231	11,270	11,303	11,328	11,281	11,284	11,306	11,321
System Position	(1)	(1)	(1)	(1)	(1)	(1)	(1)	(1)	(1)	(1)
Reserve Margin	13%	13%	13%	13%	13%	13%	13%	13%	13%	13%

Table 8.20 – Preferred Portfolio Summer Capacity Load and Resource Balance (2030-2038)

Calendar Year	2030	2031	2032	2033	2034	2035	2036	2037	2038
East									
Thermal	4,242	4,169	4,169	3,838	3,838	3,838	3,838	2,984	2,984
Hydroelectric	74	74	74	74	74	74	74	74	74
Renewable	723	706	675	725	726	724	737	740	697
Purchases	115	115	115	115	115	115	115	115	115
Qualifying Facilities	595	599	587	555	536	536	503	125	120
Demand Response	323	323	323	323	323	323	323	323	323
Sales	0	0	0	0	0	0	0	0	0
Non-Owned Reserves	(35)	(35)	(35)	(35)	(35)	(35)	(35)	(35)	(35)
Transfers	198	354	440	653	413	667	887	887	364
East Existing Resources	**6,235**	**6,306**	**6,348**	**6,248**	**5,991**	**6,242**	**6,443**	**5,213**	**4,643**
Front Office Transactions	205	179	213	307	309	309	309	309	309
Gas	179	179	179	179	179	179	179	831	831
Wind	479	508	475	527	528	526	539	553	540
Wind+Storage	0	0	24	27	27	27	27	28	28
Solar	0	0	0	0	0	0	0	0	0
Solar+Storage	163	188	154	188	184	182	186	456	392
Demand Response	170	170	182	183	183	183	199	203	214	349
Other	1	29	29	29	29	28	28	28	366
East Planned Resources	**1,197**	**1,254**	**1,257**	**1,439**	**1,440**	**1,450**	**1,472**	**2,419**	**2,816**
East Total Resources	**7,431**	**7,559**	**7,605**	**7,688**	**7,430**	**7,692**	**7,915**	**7,632**	**7,459**
Load	7,760	7,830	7,923	8,007	7,935	8,019	8,104	8,196	8,280
Private Generation	(249)	(264)	(281)	(316)	(227)	(261)	(295)	(330)	(374)
Existing Resources:									
Interruptible	(177)	(177)	(177)	(177)	(177)	(177)	(177)	(177)	(177)
Energy Efficiency	(51)	(51)	(51)	(51)	(51)	(51)	(51)	(51)	(51)
New Resources:									
Energy Efficiency	(583)	(623)	(662)	(698)	(725)	(750)	(769)	(785)	(802)
East obligation	**6,700**	**6,713**	**6,751**	**6,763**	**6,754**	**6,780**	**6,811**	**6,853**	**6,876**
Planning Reserves (13%)	894	896	901	902	901	904	909	914	917
East Reserves	**894**	**896**	**901**	**902**	**901**	**904**	**909**	**914**	**917**
East Obligation + Reserves	**7,594**	**7,609**	**7,652**	**7,665**	**7,655**	**7,684**	**7,720**	**7,767**	**7,793**
East Position	**(162)**	**(50)**	**(46)**	**22**	**(225)**	**8**	**195**	**(134)**	**(334)**
East Reserve Margin	11%	13%	13%	14%	10%	13%	16%	11%	8%
West									
Thermal	1,265	1,265	1,265	1,265	1,265	1,265	1,265	1,053	411
Hydroelectric	570	570	570	570	570	570	570	570	570
Renewable	249	259	248	266	266	265	270	275	270
Purchases	1	1	1	1	1	1	1	1	1
Qualifying Facilities	228	229	222	223	223	223	217	201	201
Demand Response	0	0	0	0	0	0	0	0	0
Sales	(78)	(78)	(78)	(78)	(78)	(78)	(24)	(24)	(24)
Non-Owned Reserves	(3)	(3)	(3)	(3)	(3)	(3)	(3)	(3)	(3)
Transfers	(199)	(354)	(441)	(653)	(414)	(668)	(888)	(888)	(365)
West Existing Resources	**2,034**	**1,889**	**1,785**	**1,592**	**1,831**	**1,576**	**1,409**	**1,185**	**1,062**
Front Office Transactions	1,107	1,107	1,107	1,107	1,107	1,107	1,006	1,107	1,107
Gas	0	0	0	0	0	0	0	208	208
Wind	0	0	0	0	0	0	0	0	0
Wind+Storage	8	8	8	9	9	9	9	19	18
Solar	0	0	0	0	0	0	0	0	0
Solar+Storage	171	198	162	259	254	251	308	488	531
Demand Response	9	9	9	9	9	9	9	57	89
Other	578	578	690	690	690	690	690	690	916
West Planned Resources	**1,873**	**1,900**	**1,977**	**2,075**	**2,070**	**2,066**	**2,022**	**2,569**	**2,869**
West Total Resources	**3,907**	**3,790**	**3,762**	**3,666**	**3,901**	**3,642**	**3,431**	**3,754**	**3,931**
Load	3,709	3,745	3,773	3,803	3,788	3,814	3,842	3,881	3,912
Private Generation	(79)	(102)	(134)	(173)	(155)	(191)	(226)	(260)	(300)
Existing Resources:									
Interruptible	0	0	0	0	0	0	0	0	0
Energy Efficiency	(30)	(30)	(30)	(30)	(30)	(30)	(30)	(30)	(30)
New Resources:									
Energy Efficiency	(285)	(303)	(320)	(335)	(349)	(363)	(376)	(387)	(399)
West obligation	**3,314**	**3,310**	**3,289**	**3,265**	**3,254**	**3,231**	**3,210**	**3,204**	**3,184**
Planning Reserves (13%)	431	430	428	424	423	420	417	417	414
West Reserves	**431**	**430**	**428**	**424**	**423**	**420**	**417**	**417**	**414**
West Obligation + Reserves	**3,745**	**3,740**	**3,717**	**3,689**	**3,677**	**3,651**	**3,627**	**3,621**	**3,598**
West Position	**161**	**49**	**46**	**(23)**	**224**	**(8)**	**(196)**	**133**	**333**
West Reserve Margin	18%	14%	14%	12%	20%	13%	7%	17%	23%
System									
Total Resources	11,338	11,349	11,368	11,354	11,331	11,334	11,346	11,386	11,390
Obligation	10,014	10,024	10,040	10,028	10,008	10,011	10,021	10,057	10,060
Reserves	1,325	1,326	1,328	1,327	1,324	1,324	1,326	1,330	1,331
Obligation + Reserves	11,339	11,350	11,368	11,355	11,332	11,335	11,347	11,387	11,391
System Position	(1)	(1)	(1)	(1)	(1)	(1)	(1)	(1)	(1)
Reserve Margin	13%	13%	13%	13%	13%	13%	13%	13%	13%

Table 8.21 – Preferred Portfolio Winter Capacity Load and Resource Balance (2020-2029)

Calendar Year	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
East										
Thermal	6,020	5,692	5,692	5,692	5,692	5,692	5,275	5,199	4,545	4,545
Hydroelectric	54	54	54	54	54	54	54	54	54	54
Renewable	992	1,536	1,594	1,579	1,020	1,020	1,010	1,009	1,010	1,001
Purchases	727	228	228	228	115	115	115	115	115	115
Qualifying Facilities	672	460	465	413	335	333	334	334	333	326
Demand Response	0	0	0	0	0	0	0	0	0	0
Sales	(173)	(173)	(173)	(173)	(148)	(148)	(66)	(52)	0	(77)
Non-Owned Reserves	(35)	(35)	(35)	(35)	(35)	(35)	(35)	(35)	(35)	(35)
Transfers	(159)	(154)	(151)	(146)	(400)	(394)	(391)	(390)	(440)	(325)
East Existing Resources	**8,100**	**7,608**	**7,675**	**7,611**	**6,632**	**6,637**	**6,295**	**6,235**	**5,582**	**5,606**
Front Office Transactions	0	0	0	0	0	0	0	0	0	0
Gas	0	0	0	0	0	0	180	180	180	180
Wind	0	0	0	24	681	681	684	684	684	678
Wind+Storage	0	0	0	0	0	0	0	0	0	0
Solar	0	0	0	0	0	0	0	0	0	0
Solar+Storage	0	0	39	35	61	61	64	64	64	68
Demand Response	0	0	0	0	0	0	0	0	0	0
Other	1	1	1	1	1	1	1	1	1	1
East Planned Resources	**1**	**1**	**40**	**60**	**743**	**743**	**929**	**929**	**929**	**927**
East Total Resources	**8,101**	**7,609**	**7,715**	**7,671**	**7,375**	**7,379**	**7,224**	**7,164**	**6,511**	**6,532**
Load	5,629	5,680	5,743	5,807	5,855	5,921	5,847	5,889	5,939	5,993
Private Generation	(1)	(1)	(1)	(2)	(2)	(3)	(3)	(4)	(5)	(5)
Existing Resources:										
Interruptible	(177)	(177)	(177)	(177)	(177)	(177)	(177)	(177)	(177)	(177)
Energy Efficiency	(28)	(28)	(28)	(28)	(28)	(28)	(28)	(28)	(28)	(28)
New Resources:										
Energy Efficiency	(79)	(119)	(161)	(205)	(249)	(293)	(337)	(381)	(424)	(463)
East obligation	**5,344**	**5,355**	**5,376**	**5,396**	**5,399**	**5,420**	**5,301**	**5,298**	**5,305**	**5,319**
Planning Reserves (13%)	718	719	722	724	725	728	712	712	713	714
East Reserves	**718**	**719**	**722**	**724**	**725**	**728**	**712**	**712**	**713**	**714**
East Obligation + Reserves	**6,062**	**6,074**	**6,098**	**6,120**	**6,123**	**6,148**	**6,014**	**6,010**	**6,018**	**6,033**
East Position	**2,039**	**1,535**	**1,617**	**1,551**	**1,252**	**1,232**	**1,211**	**1,154**	**493**	**499**
East Reserve Margin	52%	42%	44%	42%	37%	36%	36%	35%	23%	23%
West										
Thermal	2,040	2,040	2,040	2,040	1,728	1,728	1,728	1,728	1,590	1,258
Hydroelectric	670	670	670	670	670	670	670	670	670	670
Renewable	672	351	232	230	137	137	138	138	137	136
Purchases	1	1	1	1	1	1	1	1	1	1
Qualifying Facilities	142	102	93	88	75	75	72	45	45	33
Demand Response	0	0	0	0	0	0	0	0	0	0
Sales	(154)	(154)	(113)	(113)	(81)	(81)	(81)	(81)	(81)	(78)
Non-Owned Reserves	(3)	(3)	(3)	(3)	(3)	(3)	(3)	(3)	(3)	(3)
Transfers	157	153	149	146	399	393	390	389	439	324
West Existing Resources	**3,526**	**3,161**	**3,071**	**3,059**	**2,926**	**2,920**	**2,915**	**2,888**	**2,799**	**2,342**
Front Office Transactions	135	277	312	323	46	52	54	103	239	256
Gas	0	0	0	0	0	0	0	0	0	0
Wind	0	0	0	0	0	0	0	0	0	0
Wind+Storage	0	0	0	0	0	0	0	0	0	4
Solar	0	0	0	0	0	0	0	0	0	0
Solar+Storage	0	0	0	0	59	59	62	62	62	87
Demand Response	0	0	0	0	0	0	0	0	0	0
Other	0	0	0	0	0	0	0	0	180	615
West Planned Resources	**135**	**277**	**312**	**323**	**104**	**111**	**116**	**164**	**481**	**962**
West Total Resources	**3,661**	**3,438**	**3,383**	**3,382**	**3,030**	**3,031**	**3,031**	**3,052**	**3,279**	**3,303**
Load	3,416	3,458	3,499	3,529	3,550	3,576	3,605	3,640	3,672	3,706
Private Generation	(0)	(0)	(0)	(0)	(1)	(1)	(1)	(1)	(2)	(2)
Existing Resources:										
Interruptible	0	0	0	0	0	0	0	0	0	0
Energy Efficiency	(28)	(28)	(28)	(28)	(28)	(28)	(28)	(28)	(28)	(28)
New Resources:										
Energy Efficiency	(61)	(90)	(121)	(153)	(185)	(216)	(246)	(275)	(303)	(328)
West obligation	**3,327**	**3,340**	**3,350**	**3,347**	**3,335**	**3,331**	**3,329**	**3,335**	**3,340**	**3,347**
Planning Reserves (13%)	432	434	435	435	434	433	433	434	434	435
West Reserves	**432**	**434**	**435**	**435**	**434**	**433**	**433**	**434**	**434**	**435**
West Obligation + Reserves	**3,759**	**3,774**	**3,785**	**3,782**	**3,769**	**3,764**	**3,762**	**3,769**	**3,774**	**3,783**
West Position	**(98)**	**(337)**	**(402)**	**(400)**	**(739)**	**(733)**	**(732)**	**(717)**	**(494)**	**(479)**
West Reserve Margin	10%	3%	1%	1%	(9%)	(9%)	(9%)	(8%)	(2%)	(1%)
System										
Total Resources	11,762	11,047	11,098	11,053	10,406	10,411	10,255	10,216	9,791	9,836
Obligation	8,671	8,695	8,725	8,743	8,734	8,751	8,631	8,634	8,645	8,666
Reserves	1,150	1,153	1,157	1,160	1,158	1,161	1,145	1,145	1,147	1,150
Obligation + Reserves	9,821	9,848	9,883	9,902	9,892	9,912	9,776	9,779	9,792	9,815
System Position	1,941	1,198	1,215	1,151	513	499	479	437	(1)	20
Reserve Margin	36%	27%	27%	26%	19%	19%	19%	18%	13%	13%

Table 8.22 – Preferred Portfolio Winter Capacity Load and Resource Balance (2030-2038)

Calendar Year	2030	2031	2032	2033	2034	2035	2036	2037	2038
East									
Thermal	4,311	4,239	4,239	3,908	3,908	3,908	3,908	3,054	3,054
Hydroelectric	54	54	54	54	54	54	54	54	54
Renewable	942	891	846	1,015	1,036	1,039	1,045	1,099	1,073
Purchases	115	115	115	115	115	115	115	115	115
Qualifying Facilities	325	326	310	284	251	251	222	26	26
Demand Response	0	0	0	0	0	0	0	0	0
Sales	(77)	0	0	0	0	0	0	0	0
Non-Owned Reserves	(35)	(35)	(35)	(35)	(35)	(35)	(35)	(35)	(35)
Transfers	(395)	(490)	(451)	(306)	(150)	(307)	(359)	82	(278)
East Existing Resources	**5,241**	**5,100**	**5,078**	**5,035**	**5,180**	**5,026**	**4,950**	**4,395**	**4,009**
Front Office Transactions	0	0	0	0	0	0	0	0	0
Gas	180	180	180	180	180	180	180	881	881
Wind	947	953	898	1,105	1,131	1,135	1,142	1,213	1,219
Wind+Storage	0	0	28	35	35	36	36	38	38
Solar	0	0	0	0	0	0	0	0	0
Solar+Storage	79	79	67	108	112	113	111	254	228
Demand Response	0	0	0	0	0	0	0	0	0
Other	1	31	31	31	31	30	30	30	390
East Planned Resources	**1,207**	**1,243**	**1,204**	**1,459**	**1,490**	**1,493**	**1,498**	**2,416**	**2,756**
East Total Resources	**6,449**	**6,343**	**6,282**	**6,494**	**6,670**	**6,519**	**6,449**	**6,811**	**6,765**
Load	6,023	6,074	6,113	6,180	6,232	6,287	6,320	6,380	6,431
Private Generation	(6)	(7)	(8)	(9)	(10)	(12)	(14)	(15)	(17)
Existing Resources:									
Interruptible	(177)	(177)	(177)	(177)	(177)	(177)	(177)	(177)	(177)
Energy Efficiency	(28)	(28)	(28)	(28)	(28)	(28)	(28)	(28)	(28)
New Resources:									
Energy Efficiency	(502)	(537)	(572)	(604)	(628)	(650)	(668)	(683)	(698)
East obligation	**5,310**	**5,324**	**5,328**	**5,362**	**5,389**	**5,420**	**5,434**	**5,477**	**5,510**
Planning Reserves (13%)	713	715	716	720	724	728	729	735	739
East Reserves	**713**	**715**	**716**	**720**	**724**	**728**	**729**	**735**	**739**
East Obligation + Reserves	**6,023**	**6,040**	**6,044**	**6,083**	**6,113**	**6,147**	**6,163**	**6,212**	**6,249**
East Position	**425**	**303**	**238**	**412**	**558**	**372**	**286**	**599**	**516**
East Reserve Margin	21%	19%	18%	21%	24%	20%	19%	24%	23%
West									
Thermal	1,258	1,258	1,258	1,258	1,258	1,258	1,258	1,034	392
Hydroelectric	670	670	670	670	670	670	670	670	670
Renewable	135	135	128	155	159	159	160	169	170
Purchases	1	1	1	1	1	1	1	1	1
Qualifying Facilities	33	33	27	29	29	29	25	24	24
Demand Response	0	0	0	0	0	0	0	0	0
Sales	(78)	(78)	(78)	(78)	(78)	(78)	(78)	(78)	(78)
Non-Owned Reserves	(3)	(3)	(3)	(3)	(3)	(3)	(3)	(3)	(3)
Transfers	394	488	450	305	148	305	358	(83)	277
West Existing Resources	**2,410**	**2,505**	**2,453**	**2,337**	**2,184**	**2,341**	**2,392**	**1,735**	**1,454**
Front Office Transactions	255	284	302	197	216	257	279	353	457
Gas	0	0	0	0	0	0	0	215	215
Wind	0	0	0	0	0	0	0	0	0
Wind+Storage	4	4	4	5	5	5	5	11	11
Solar	0	0	0	0	0	0	0	0	0
Solar+Storage	69	68	58	120	125	126	145	209	247
Demand Response	0	0	0	0	0	0	0	0	0
Other	615	615	735	735	735	735	735	735	975
West Planned Resources	**943**	**971**	**1,098**	**1,058**	**1,081**	**1,123**	**1,164**	**1,524**	**1,906**
West Total Resources	**3,353**	**3,476**	**3,551**	**3,395**	**3,264**	**3,464**	**3,555**	**3,259**	**3,360**
Load	3,727	3,751	3,782	3,816	3,849	3,880	3,902	3,933	3,967
Private Generation	(2)	(3)	(3)	(4)	(4)	(5)	(7)	(8)	(11)
Existing Resources:									
Interruptible	0	0	0	0	0	0	0	0	0
Energy Efficiency	(28)	(28)	(28)	(28)	(28)	(28)	(28)	(28)	(28)
New Resources:									
Energy Efficiency	(352)	(374)	(396)	(415)	(433)	(450)	(467)	(482)	(497)
West obligation	**3,345**	**3,346**	**3,355**	**3,369**	**3,384**	**3,396**	**3,400**	**3,415**	**3,431**
Planning Reserves (13%)	435	435	436	438	440	441	442	444	446
West Reserves	**435**	**435**	**436**	**438**	**440**	**441**	**442**	**444**	**446**
West Obligation + Reserves	**3,780**	**3,781**	**3,791**	**3,808**	**3,824**	**3,838**	**3,842**	**3,859**	**3,877**
West Position	**(426)**	**(305)**	**(239)**	**(413)**	**(559)**	**(373)**	**(287)**	**(600)**	**(517)**
West Reserve Margin	0%	4%	6%	1%	(4%)	2%	5%	(5%)	(2%)
System									
Total Resources	9,802	9,819	9,834	9,889	9,935	9,984	10,004	10,070	10,125
Obligation	8,655	8,670	8,683	8,732	8,773	8,816	8,834	8,892	8,941
Reserves	1,148	1,150	1,152	1,158	1,163	1,169	1,171	1,179	1,185
Obligation + Reserves	9,803	9,820	9,835	9,890	9,936	9,985	10,005	10,071	10,126
System Position	(1)	(2)	(1)	(1)	(2)	(1)	(1)	(1)	(1)
Reserve Margin	13%	13%	13%	13%	13%	13%	13%	13%	13%

Additional Sensitivity Analysis

In addition to the resource portfolios developed and studied as part of the portfolio-development process that supports selection of the preferred portfolio, a number of additional sensitivity cases were completed to better understand how certain modeling assumptions influence the resource mix and timing of future resource additions. These sensitivity cases are useful in understanding how PacifiCorp's resource plan would be affected by changes to uncertain planning assumptions and to address how alternative resources and planning paradigms affect system costs and risk.

Table 8.23 lists additional sensitivity studies performed for the 2019 IRP. To isolate the impact of a given planning assumption, all sensitivity cases are compared to the preferred portfolio, case P-45CNW.

Table 8.23 – Summary of Additional Sensitivity Cases

Case	Description	Parent Case	SO PVRR ($m)	Load	Private Gen	CO_2 Policy	FOTs	Customer Preference Target	First Year of New Thermal
S-01	Low Load	P-45CNW	20,617	Low	Base	Base	Base	Base	2030
S-02	High Load	P-45CNW	22,602	High	Base	Base	Base	Base	2026
S-03	1 in 20 Load Growth	P-45CNW	21,634	1 in 20	Base	Base	Base	Base	2026
S-04	Low Private Generation	P-45CNW	21,758	Base	Low	Base	Base	Base	2029
S-05	High Private Generation	P-45CNW	21,371	Base	High	Base	Base	Base	2030
S-06	Business Plan	P-45CNW	21,695	Base	Base	Base	Base	Base	2028
S-07	No Customer Preference	P-45CNW	21,609	Base	Base	Base	Base	None	2030
S-08	All Customer Preference	P-45CNW	21,636	Base	Base	Base	Base	High	2030

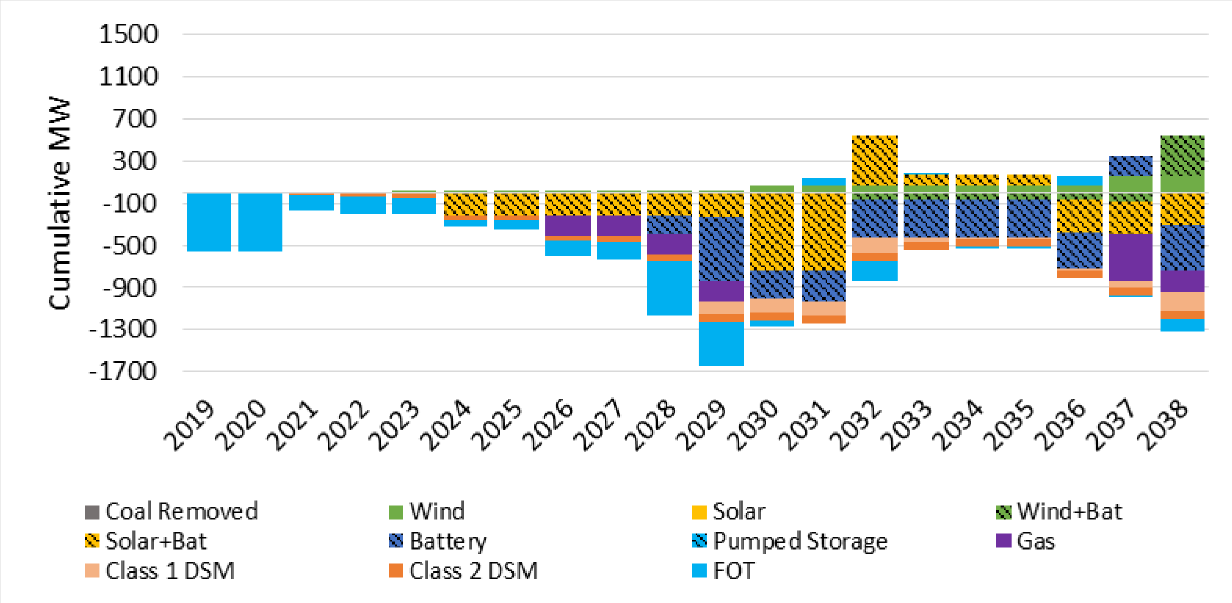
Low Load Growth Sensitivity (S-01)

Table 8.24 shows the PVRR impacts of the S-01 sensitivity relative to P-45CNW. The reduced loads lower system costs significantly over the 20-year study period. Figure 8.46 summarizes portfolio impacts. FOTs are reduced by an average of 275 MW from 2019 to 2024, and by an average of 129 MW from 2025 to 2027, followed thereafter by an average of 103 MW less per year. Over the full portfolio, cumulative wind is higher by 162 MW, offset by a decrease of 346 MW of wind with battery, solar with battery and standalone battery. Renewable and storage resources are reduced by 184 MW by the end of the study period, gas peakers are 221 MW less and DSM decreases by 251 MW.

Table 8.24 – Stochastic Mean PVRR (Benefit)/Cost of S-01 vs. P-45CNW

Medium Gas - Medium CO_2 ($ Million)		
P-45CNW	**S-01**	**(Benefit) / Cost Relative to P-45CNW**
$23,207	$22,080	($1,127)

Figure 8.46 – Increase/(Decrease) in Nameplate Capacity of S-01 Relative to Case P-45CNW



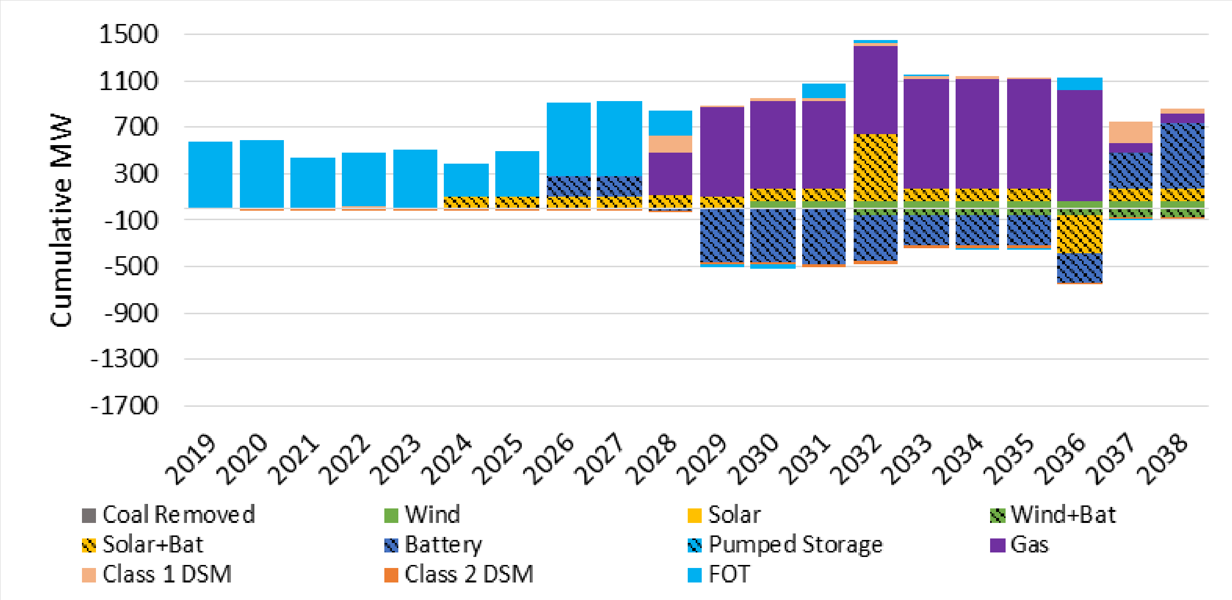
High Load Growth Sensitivity (S-02)

Table 8.25 shows the PVRR impacts of the S-02 sensitivity relative to P-45CNW. Higher loads result in significantly increased resource requirements which translate into higher system costs. Figure 8.47 summarizes the resource portfolio impacts. Annual FOTs increase by an average of 472 MW through 2024 and 556 MW from 2025 to 2027, followed by 35 MW thereafter. Renewable and storage resources increase by 670 MW by the end of the study period. An additional 953 MW of natural gas peaking capacity is shifted earlier, split between 2028, 2029 and 2033 instead of 370 MW of gas peaker and 505 MW of Gas CCCT in 2037, for a net increase of 78 MW. DSM increases by 23 MW by the end of the study period.

Table 8.25 – Stochastic Mean PVRR (Benefit)/Cost of S-02 vs. P-45CNW

Medium Gas - Medium CO_2 ($ Million)		
P-45CNW	S-02	(Benefit) / Cost Relative to P-45CNW
$23,207	$24,346	$1,139

Figure 8.47 – Increase/(Decrease) in Nameplate Capacity of S-02 Relative to Case P-45CNW



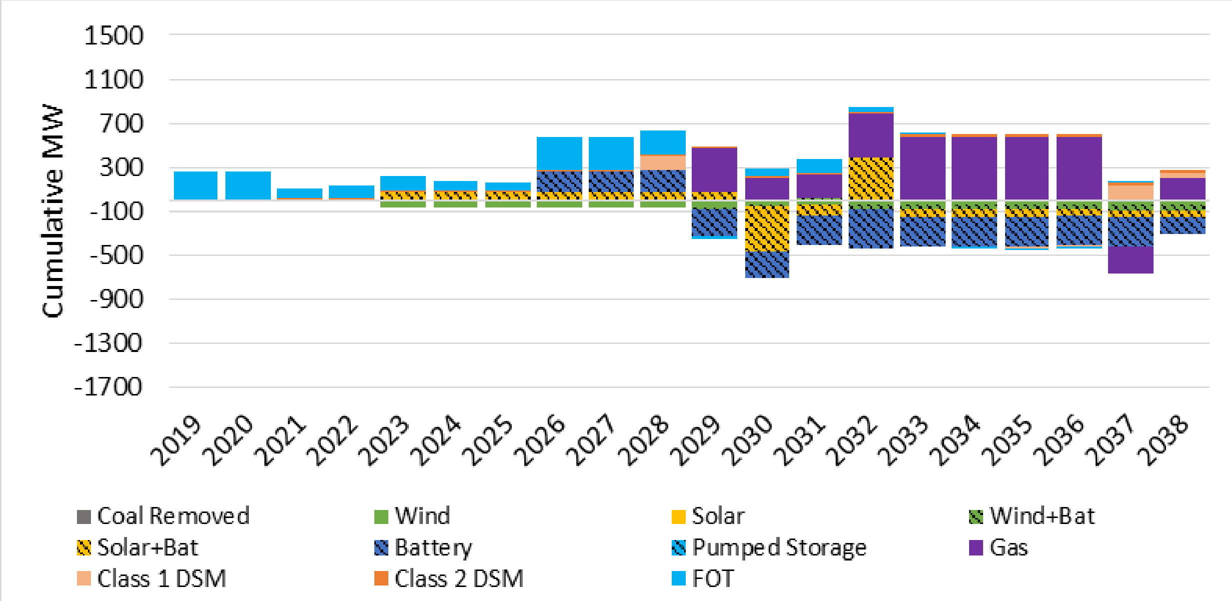
1-in-20 Load Growth Sensitivity (S-03)

Table 8.26 shows the PVRR impacts of the S-03 sensitivity relative to P-45CNW. This sensitivity assumes 1-in-20 extreme weather conditions during the summer (July) for each state. System costs are higher due to requirements to meet additional peak load. Figure 8.48 summarizes resource portfolio impacts. Higher peak loads require more annual FOTs, 158 MW greater on average from 2019-2024, 220 MW more 2025-2027 and 36 MW thereafter. Renewables and storage are decreased by 304 MW, offset by an increase of 210 MW in gas peakers and a 62 MW increase in DSM by the end of the study period.

Table 8.26 – Stochastic Mean PVRR (Benefit)/Cost of S-03 vs. P-45CNW

Medium Gas - Medium CO_2 ($ Million)		
P-45CNW	**S-03**	**(Benefit) / Cost Relative to P-45CNW**
$23,207	$23,388	$181

Figure 8.48 – Increase/(Decrease) in Nameplate Capacity of S-03 Relative to Case P-45CNW



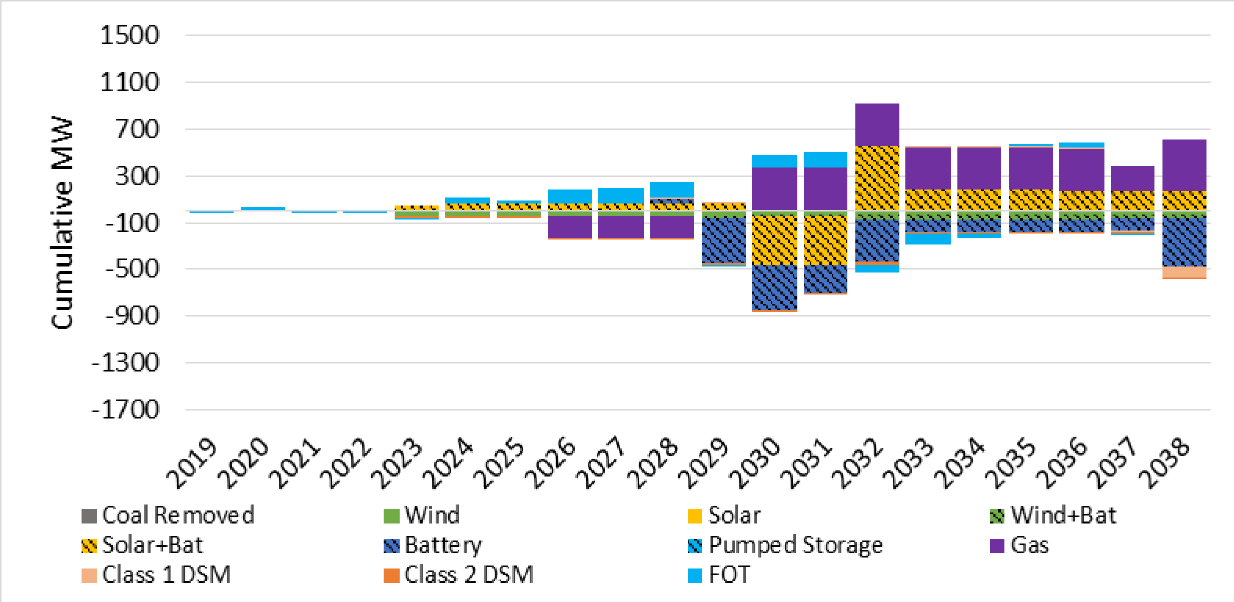
Low Private Generation Sensitivity (S-04)

Table 8.27 shows the PVRR impacts of the S-04 sensitivity relative to P-45CNW. The lower private generation assumption result in higher net loads, increasing system costs. Figure 8.49 summarizes portfolio impacts. Annual average FOTs increase by 6 MW from 2019-2024 and then 98 MW from 2025-2027, leveling out to 17 MW higher on average thereafter. Renewables and storage decrease by 305 MW over the long-term, along with 114 MW less DSM, which are offset by an increase of 443 MW in gas peakers.

Table 8.27 – Stochastic Mean PVRR (Benefit)/Cost of S-04 vs. P-45CNW

Medium Gas - Medium CO_2 ($ Million)		
P-45CNW	S-04	(Benefit) / Cost Relative to P-45CNW
$23,207	$23,308	$101

Figure 8.49 – Increase/(Decrease) in Nameplate Capacity of S-04 Relative to Case P-45CNW



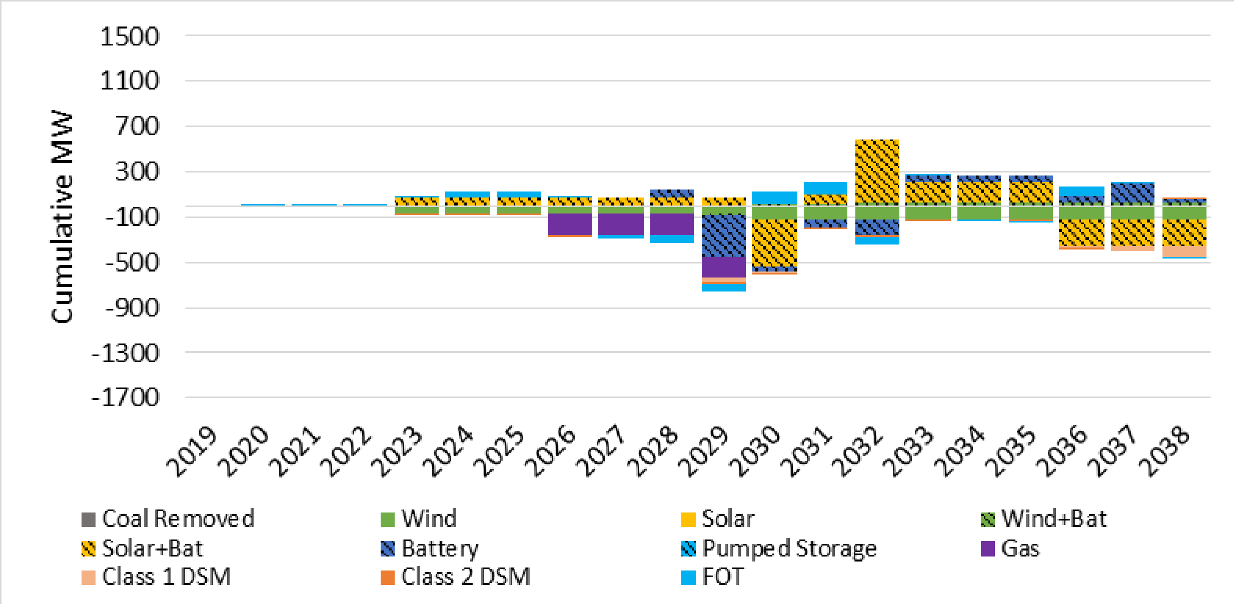
High Private Generation Sensitivity (S-05)

Table 8.28 shows the PVRR impacts of the S-05 sensitivity relative to P-45CNW. The higher private generation assumptions decrease net load, which in turn decreases system costs. Figure 8.50 summarizes portfolio impacts, which are minor for FOTs and natural gas over the long-term. There is 300 MW less renewable capacity and 92 MW less DSM.

Table 8.28 – Stochastic Mean PVRR (Benefit)/Cost of S-05 vs. P-45CNW

Medium Gas - Medium CO_2 ($ Million)		
P-45CNW	**S-05**	**(Benefit) / Cost Relative to P-45CNW**
$23,207	$22,970	($238)

Figure 8.50 – Increase/(Decrease) in Nameplate Capacity of S-05 Relative to Case P-45CNW



Business Plan Sensitivity (S-06)

Table 8.29 shows the PVRR impacts of the S-06 sensitivity relative to P-45CNW. System costs increase by \$72m when studied in SO and \$831m when analyzed using PaR. This sensitivity complies with Utah requirements to perform a business plan sensitivity consistent with the Public Service Commission of Utah's order in Docket No. 15-035-04, summarized as follows:

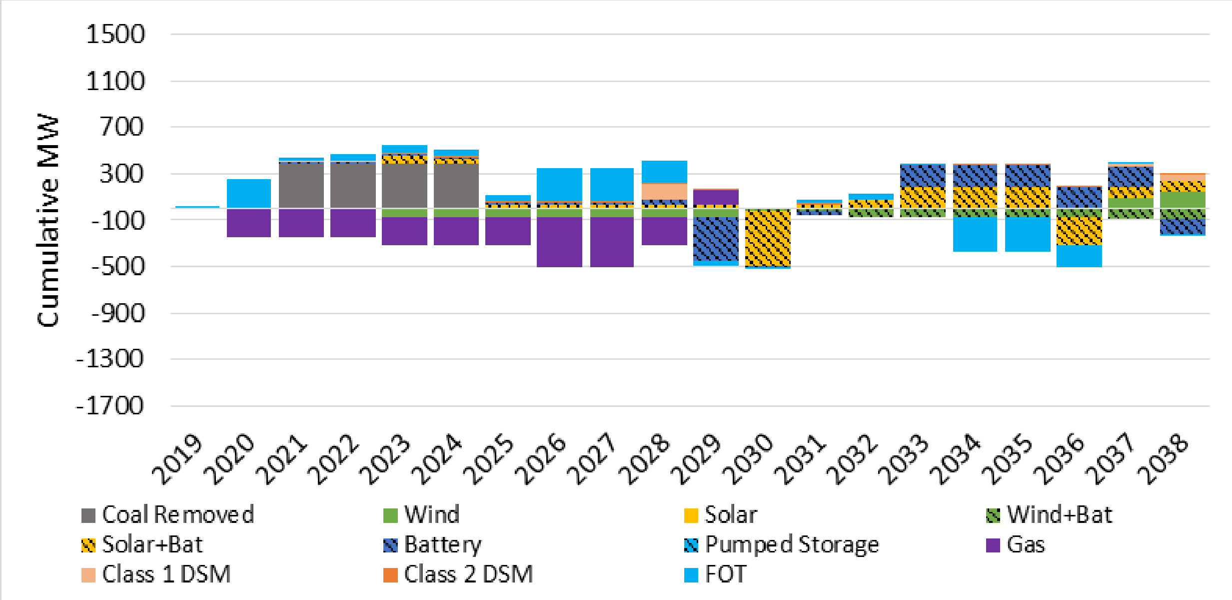
- Over the first three years, resources align with those assumed in PacifiCorp's December 2018 Business Plan.
- Beyond the first three years of the study period, unit retirement assumptions are aligned with the preferred portfolio.
- All other resources are optimized.

Figure 8.51 summarizes resource portfolio impacts, showing differences associated with the preferred portfolio's assumptions of Naughton Unit 3's gas conversion and Cholla Unit 4's 2020 retirement. These are coupled with an average annual increase of 77 MW FOTs 2019-2024, 207 MW higher average annual FOTs 2025-2027 and then 51 MW less FOTs thereafter. There is a difference in the timing of new renewable resources and storage, which net 23 MW higher through the longer term. DSM increases by 57 MW.

Table 8.29 – Stochastic Mean PVRR (Benefit)/Cost of S-06 vs. P-45CNW

Medium Gas - Medium CO_2 (\$ Million)		
P-45CNW	**S-06**	**(Benefit) / Cost Relative to P-45CNW**
\$23,207	\$24,038	\$831

Figure 8.51 – Increase/(Decrease) in Nameplate Capacity of S-06 Relative to Case P-45CNW



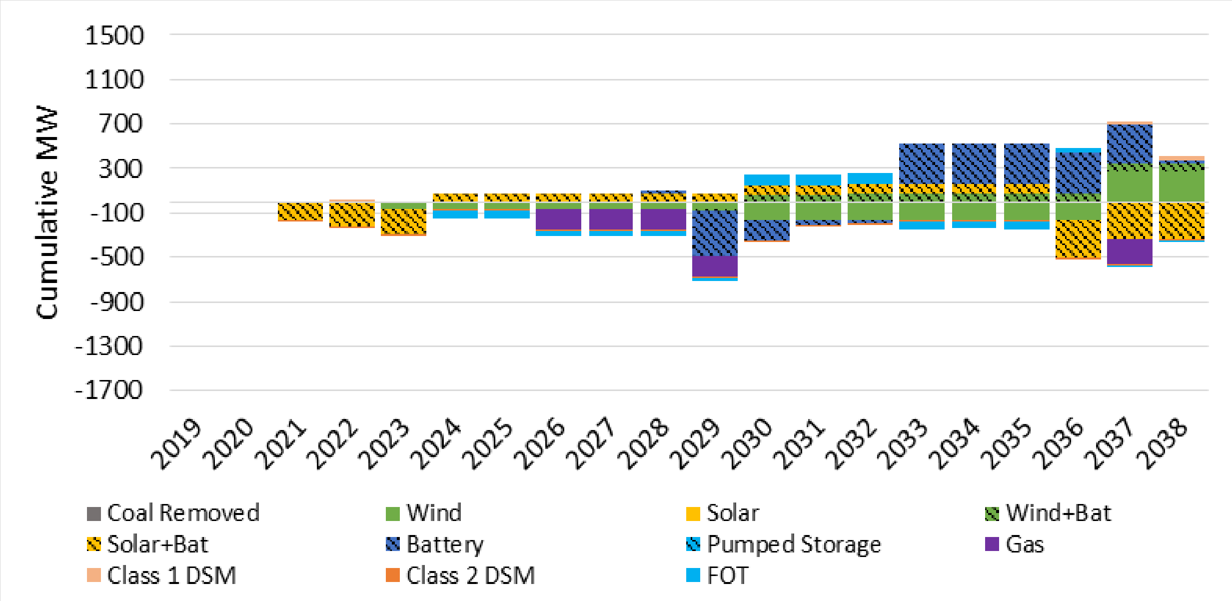
No Customer Preference Sensitivity (S-07)

Table 8.30 shows the PVRR impacts of the S-07 sensitivity relative to P-45CNW. The no customer preference sensitivity reflects no renewable resources specifically assigned to customer preference, compared to base renewable resource proxy options. Figure 8.52 summarizes portfolio impacts, which are zero for FOTs until 2024, when FOTs are 77 MW less, followed by an annual FOT average decrease of 55 MW 2025-2027 and an average annual increase of 3 MW thereafter. There is a 30 MW increase in renewable and storage capacity and 32 MW more DSM. Gas peaking resources are postponed and net to zero.

Table 8.30 – Stochastic Mean PVRR (Benefit)/Cost of S-07 vs. P-45CNW

Medium Gas - Medium CO_2 ($ Million)		
P-45CNW	**S-07**	**(Benefit) / Cost Relative to P-45CNW**
$23,207	$23,126	($81)

Figure 8.52 – Increase/(Decrease) in Nameplate Capacity of S-07 Relative to Case P-45CNW



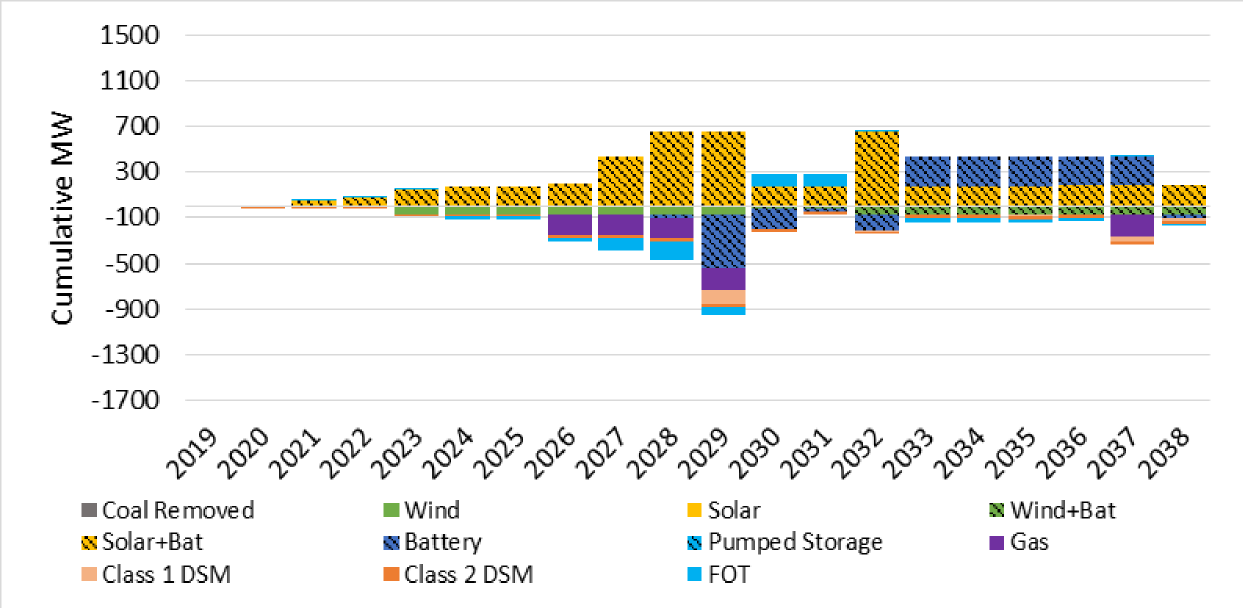
High Customer Preference Sensitivity (S-08)

Table 8.31 shows the PVRR impacts of the S-08 sensitivity relative to P-45CNW. The high customer preference sensitivity reflects a wider range of renewable resources assigned to customer preference, compared to base renewable resource proxy options. Figure 8.53 summarizes portfolio impacts, which are zero for natural gas over the long term, delaying peakers. The annual average FOTs are zero until a 2024 decrease of 20 MW followed by 51 MW less on average 2025-2027, and 12 MW less on average thereafter. Renewable resources and storage increase by 80 MW, slightly offset by a decrease of 62 MW DSM.

Table 8.31 – PVRR (Benefit)/Cost of S-08 vs. P-45CNW

Medium Gas - Medium CO_2 ($ Million)		
P-45CNW	**S-08**	**(Benefit) / Cost Relative to P-45CNW**
$23,207	$23,186	($22)

Figure 8.53 – Increase/(Decrease) in Nameplate Capacity of S-08 Relative to Case P-45CNW



CHAPTER 9 – ACTION PLAN

CHAPTER HIGHLIGHTS

- The 2019 Integrated Resource Plan (IRP) action plan identifies steps that PacifiCorp will take over the next two-to-four years to deliver resources in the preferred portfolio.
- PacifiCorp's 2019 IRP action plan includes action items for existing resources, new resources, transmission, demand-side management (DSM) resources, short-term firm market purchases (front office transactions or FOTs), and the purchase and sale of renewable energy credits (RECs).
- The 2019 IRP acquisition path analysis provides insight on how changes in the planning environment might influence future resource procurement activities. Key uncertainties addressed in the acquisition path analysis include load, distributed generation, carbon dioxide (CO_2) emission polices, Regional Haze outcomes, and availability of purchases from the market.
- PacifiCorp further discusses how it can mitigate procurement delay risk, summarizes planned procurement activities tied to the action plan, assesses trade-offs between owning or purchasing third-party power, discusses its hedging practices, and identifies the types of risks borne by customers and the types of risks borne by shareholders.

Introduction

PacifiCorp's 2019 IRP action plan identifies the steps the company will take over the next two-to-four years to deliver its preferred portfolio, with a focus on the front ten years of the planning horizon. Associated with the action plan is an acquisition path analysis that anticipates potential major regulatory actions and other trigger events during the action plan time frame that could materially impact resource acquisition strategies.

Resources included in the 2019 IRP preferred portfolio help define the actions included in the action plan, focusing on the size, timing, type, and amount of resources needed to meet load obligations, and current and potential future state regulatory requirements.

The 2019 IRP action plan is based on the latest and most accurate information available at the time portfolios are being developed and analyzed on cost and risk metrics. PacifiCorp recognizes that the preferred portfolio, upon which the action plan is based, is developed in an uncertain planning environment and that resource acquisition strategies need to be regularly evaluated as planning assumptions change.

Resource information used in the 2019 IRP, such as capital and operating costs, are based upon recent cost-and-performance data. However, it is important to recognize that the resources identified in the plan are proxy resources, which act as a guide for resource procurement and not as a commitment. Resources evaluated as part of procurement initiatives may vary from the proxy resources identified in the plan with respect to resource type, timing, size, cost and location. PacifiCorp recognizes the need to support and justify resource acquisitions consistent with then-current laws, regulatory rules and commission orders.

In addition to presenting the 2019 IRP action plan, reporting on progress in delivering the prior action plan, and presenting the 2019 IRP acquisition path analysis, Chapter 9 covers the following resource procurement topics:

- Procurement delays;
- IRP action plan linkage to the business plan;
- Resource procurement strategy;
- Assessment of owning assets vs. purchasing power;
- Managing carbon risk for existing plants;
- Purpose of hedging; and
- Treatment of customer and investor risks.

The 2019 IRP Action Plan

The 2019 IRP action plan identifies specific actions PacifiCorp will take over the next two to four years to deliver its preferred portfolio. Action items are based on the type and timing of resources in the preferred portfolio, findings from analysis completed over the course of portfolio modeling, and feedback received by stakeholders in the 2019 IRP public-input process. Table 9.1 details specific 2019 IRP action items by resource category.

Table 9.1 – 2019 IRP Action Plan

Action Item	1. Existing Resource Actions
1a	**<u>Naughton Unit 3:</u>** • PacifiCorp will complete the gas conversion of Naughton Unit 3, including completion of all required regulatory notices and filings, in 2020. Initiate procurement of materials in Q4 2019. Conversion completed in 2020.
1b	**<u>Cholla Unit 4:</u>** • PacifiCorp will initiate the process of retiring Cholla Unit 4, including all required regulatory notices and filings, as soon as practicable, but will remove Cholla Unit 4 from service no later than January 2023 and earlier if possible. • PacifiCorp will continue to coordinate with the plant operator to transition employees, develop plans to cease plant operations, safely remove the unit from service, finalize decommissioning plans and confirm joint-ownership obligations; complete required regulatory notices and filings; administer termination, amendment, or close-out of existing permits, contracts and other agreements; and coordinate with state and local stakeholders as appropriate. • By the end of Q1 2020, the plant operator will be requested to develop plans to cease plant operations, safely remove the unit from service, finalize decommissioning plans, and confirm joint-ownership obligations. • By the end of Q2 2020, the plant operator will be requested to file required transmission interconnection and transmission services unit retirement notices/request for study. • By the end of Q4 2020, PacifiCorp will finalize an employee transition agreement with the plant operator.
1c	**<u>Jim Bridger Unit 1:</u>** • PacifiCorp will initiate the process of retiring Jim Bridger Unit 1 by the end of December 2023, including completion of all required regulatory notices and filings. By the end of Q2 2020, file a request with PacifiCorp transmission to study the year-end 2023 retirement of Jim Bridger Unit 1. By the end of Q2 2021, confirm transmission system reliability assessment and year-end 2023 retirement economics in 2021 IRP filing. • By the end of Q2 2021, finalize an employee transition plan. • By the end of Q2 2021, develop a community action plan in coordination with community leaders. • By the end of Q4 2021, initiate the process with the Wyoming Public Service Commission for approval of a reverse request for proposals for a potential sale of Jim Bridger Unit 1.

	• By the end of Q4 2023, administer termination, amendment, or close-out of existing permits, contracts, and other agreements.
1d	**<u>Naughton Units 1-2:</u>** • 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 2022, file a request with PacifiCorp transmission to study the year-end 2025 retirement of Naughton Units 1 and 2. • By the end of Q2 2022, finalize an employee transition plan. • By the end of Q2 2022, develop a community action plan in coordination with community leaders. • By the end of Q2 2023, confirm transmission system reliability assessment and year-end 2025 retirement economics in 2023 IRP filing. • By the end of Q4 2023, initiate the process with the Wyoming Public Service Commission for approval of a reverse request for proposals for a potential sale of Naughton Units 1 and 2. • By the end of Q4 2023, administer termination, amendment, or close-out of existing permits, contracts, and other agreements.
1e	**<u>Craig Unit 1:</u>** • The plant operator will be requested to administer termination, amendment, or close-out of existing permits, contracts, and other agreements to support retiring Craig Unit 1, including completion of all required regulatory notices and filings, by the end of December 2025.
Action Item	**2. New Resource Actions**
2a	**<u>Customer Preference Request for Proposals:</u>** • PacifiCorp will work with customers to achieve their respective resource preference requirements. By the end of Q4 2019, sign a fifteen year 80 megawatt (MW) Power Purchase Agreement (PPA) for Utah solar for six Utah Schedule 34 customers. By the end of Q4 2019, sign two 20-year PPAs of approximately 80 MW for a large Utah Schedule 34 customer. Monitor the finalization of rules by the Public Service Commission of Utah for House Bill (HB) 411 (anticipated by the end of Q1 2020), that provides a path forward for development of a program for participating communities to begin procuring renewable resources.
2b	**<u>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 2023. • By the end of Q4 2019, file a request for interconnection queue reform with the Federal Energy Regulatory Commission (FERC) and make state filings to initiate the process of identifying an independent evaluator. • In Q1 2020, file a draft all-source RFP with the Public Utility Commission of Oregon, the Public Service Commission of Utah, and the Washington Utilities and Transportation Commission, as applicable.

<table>
<tr><td></td><td>In Q2 2020, receive approval from FERC to reform the interconnection queue.
In Q2 2020, receive approval of the all-source RFP from applicable state regulatory commissions and issue the RFP to the market.
In Q3 2020, identify a preliminary final shortlist from the all-source RFP and initiate transmission interconnection studies consistent with queue reform as approved by FERC.
In Q2 2021, 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 2022 execute definitive agreements with winning bids from the all-source RFP.
By Q4 2023, winning bids from the all-source RFP achieve commercial operation.</td></tr>
<tr><th>Action Item</th><th>3. Transmission Action Items</th></tr>
<tr><td>3a</td><td><u>Energy Gateway South:</u>
By December 31, 2023, PacifiCorp will seek to build the approximately 400-mile, 500-kilovolt (kV) transmission line from the Aeolus substation near Medicine Bow, Wyoming to the Clover substation near Mona, Utah.
By Q2 2021, receive the final CPCN from the Wyoming Public Service Commission and the Public Service Commission of Utah (initial filing dates for the CPCN to be determined after stakeholder engagement).
By the end of Q4 2021, issue full notice to proceed to construct Energy Gateway South.
In Q4 2023, construction of Energy Gateway South is completed and placed in service.</td></tr>
<tr><td>3b</td><td><u>Utah Valley Reinforcements:</u>
Utah Valley Reinforcements: As necessary to facilitate interconnection of customer-preference resources, PacifiCorp will proceed with system reinforcements in the Utah Valley.
In Q2 2020, complete the Spanish Fork 345 kV/138 kV transformer upgrade.
In Q4 2020, complete rebuild of approximately five miles of the Spanish Fork-Timp138 kV line in the Utah Valley.</td></tr>
<tr><td>3c</td><td><u>Northern Utah Reinforcements:</u>
Rebuild two miles of the Morton Court –Fifth West 138 kV line.
Loop existing Populus Terminal 345 kV line into both Bridger and Ben Lomond; build 345 kV yard with 345/138 transformer and 138 kV yard buildout at Bridger plus ancillary 345 kV and 230 kV circuit breakers at Ben Lomond.
Complete identified plan of service supporting 2019 IRP preferred portfolio for resource additions in northern Utah.</td></tr>
<tr><td>3d</td><td><u>Utah South Reinforcements:</u></td></tr>
</table>

	• Develop plan of service in support of 2019 IRP preferred portfolio for resource additions in southern Utah. • Complete rebuild of the Mona –Clover #1 & #2 345 kV lines. • Identify route and terminals for new approximately 70-mile 345 kV line in southern/central Utah. • Yakima Washington Reinforcements: To facilitate interconnection of preferred portfolio resources in the Yakima area, PacifiCorp will proceed with protection system and remedial action scheme upgrades to local 230 kV and 115 kV substations not otherwise included in network upgrade requirements for generator interconnection requests. • In Q2 2020, complete the Vantage-Pomona Heights 230 kV line (in process). • By Q2 2022, establish the type and location of new resources and finalize project scope, as necessary.
3e	**<u>Yakima Washington Reinforcements:</u>** • To facilitate interconnection of preferred portfolio resources in the Yakima area, PacifiCorp will proceed with protection system and remedial action scheme upgrades to local 230 kV and 115 kV substations not otherwise included in network upgrade requirements for generator interconnection requests. • In Q2 2020, complete the Vantage-Pomona Heights 230 kV line (in process). • By Q2 2022, establish the type and location of new resources and finalize project scope, as necessary.
3f	**<u>Boardman to Hemmingway:</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 analysis in efforts to identify customer benefits that may include contributions to reliability, interconnection of additional resources, geographical diversity of intermittent resources, Energy Imbalance Market, and resource adequacy. • Continue negotiations for plan of service post B2H for parties to the permitting agreement.
3g	**<u>Energy Gateway West:</u>** • Energy Gateway West Segment D.2, continue construction with target in-service date of 12/31/2020. • Continue permitting for the Energy Gateway transmission plan, with near term targets as follows: • For Segments D.3, and E, continue funding of the required federal agency permitting environmental consultant actions required as part of the federal permits. Also, continue to support the projects by providing information and participating in public outreach.

Action Item	4. Demand-Side Management (DSM) Actions

4a

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 will be provided in Appendix D in Volume II of the 2019 IRP.

Year	Annual Incremental Energy (GWh)	Annual Incremental Capacity (MW)
2019	562	126
2020	536	132
2021	538	133
2022	571	143

* Note, Class 2 DSM capacity figures reflect projected maximum annual hourly energy savings, which is similar to a nameplate rating for a supply-side resource.

- Energy Efficiency Bundling: PacifiCorp will continue to evaluate alternate bundling methodologies of Class 2 DSM in the 2019 IRP.
- Direct-Load Control: PacifiCorp will acquire cost-effective Class 1 DSM (i.e., demand response) in Utah targeting approximately 29 MW of incremental capacity from 2020 through 2023.

Action Item	5. Front Office Transactions

5a

Market Purchases:

- Acquire short-term firm market purchases for on-peak delivery from 2019-2021 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.

Action Item	6. Renewable Energy Credit Actions

6a

Renewable Portfolio Standards (RPS):

- PacifiCorp will pursue unbundled RFPs to meet its state RPS compliance requirements.
- As needed, issue RFPs seeking then current-year vintage unbundled RECs that will qualify in meeting California RPS targets through 2020. As needed, issue RFPs seeking then current-year or forward-year vintage unbundled RECs that will qualify in meeting Washington RPS targets.

6b

Renewable Energy Credit Sales:

- Maximize the sale of RECs that are not required to meet state RPS compliance obligations.

Progress on Previous Action Plan Items

This section describes progress that has been made on previous action plan items documented in the 2017 IRP and the 2017 IRP Update reports filed with the state commissions on April 4, 2017 and May 1, 2018, respectively. Many of these action items have been superseded in some form by items identified in the current IRP action plan. The status for all action items is summarized in Table 9.2.

Table 9.2 – 2017 IRP Action Plan Status Update

Action Item	Activity	Status
1a	**Wind Repowering** • PacifiCorp will implement the wind repowering project, taking advantage of safe-harbor wind-turbine-generator equipment purchase agreements executed in December 2016. – Continue to refine and update the economic analysis of plant-specific wind repowering opportunities that maximize customer benefits before issuing the notice to proceed. – By September 2017, complete technical and economic analysis of other potential repowering opportunities at PacifiCorp wind plants not studied in the 2017 IRP (i.e., Foote Creek I and Goodnoe Hills). – Pursue regulatory review and approval as necessary. – By May 2018, issue the engineering, procurement, and construction (EPC) notice to proceed to begin implementing the wind repowering for specific projects consistent with updated financial analysis.	PacifiCorp has continued to refine and update its economic analysis of wind repowering, which has been provided in regulatory filings in California, Idaho, Oregon, Utah, and Wyoming. PacifiCorp completed technical and economic analysis of repowering Goodnoe Hills in 2018 and included this facility is in the scope of the wind repowering project described in regulatory filings. PacifiCorp completed technical and economic analysis of Foote Creek I in 2019, which demonstrated that repowering the facility provides economic benefits to customers. Regulatory approval of the wind repowering project was received from the Idaho Public Service Commission on December 28, 2017; the Public Service Commission of Wyoming on December 18, 2018, the Public Service Commission of Utah on May 29, 2018, and the Public Utility Commission of Oregon on September 16, 2019. Regulatory approval is pending in California. In June 2018, PacifiCorp issued notices to proceed to begin implementing certain wind repowering projects, consistent with the updated financial analysis. Except for Foote Creek I, PacifiCorp issued notices to proceed for the remainder of the wind repowering projects by the end of December 2018.

Action Item	Activity	Status
	– By December 31, 2020, complete installation of wind repowering equipment on all identified projects.	In July 2019, PacifiCorp acquired the Eugene Water & Electric Board's minority interest in the Foote Creek I wind project and cancelled the power purchase agreement with Bonneville Power Administration. PacifiCorp issued notices to proceed related to repowering efforts at Foote Creek I in late July 2019. The Public Service Commission of Wyoming issued a Certificate of Public Convenience and Necessity related to repowering the Foote Creek I facility on September 12, 2019. PacifiCorp is on track to complete installation of the wind repowering equipment on all of its existing projects by December 31, 2020.
1b	**<u>Wind Request for Proposals</u>** • PacifiCorp will issue a wind resource request for proposals (RFP) for at least 1,100 MW of Wyoming wind resources that will qualify for federal wind production tax credits and achieve commercial operation by December 31, 2020. – April 2017, notify the Utah Public Service Commission of intent to issue the Wyoming wind resource RFP. – May-June, 2017, file a draft Wyoming wind RFP with the Utah Public Service Commission and the Washington Utilities and Transportation Commission. – May-June, 2017, file to open a Wyoming wind RFP docket with the Public Utility Commission of Oregon and initiate the Independent Evaluator RFP. – June-July, 2017, file a draft Wyoming wind RFP with the Public Utility Commission of Oregon and file a Public Convenience and	PacifiCorp completed all of the notice and draft filing requirements related to the RFP (the 2017R Request for Proposals (2017R RFP)). In accordance with the Utah and Oregon RFP proceedings, the 2017R RFP was issued on September 27, 2017. Bid results were received, evaluated and PacifiCorp established a final shortlist that included four wind projects in Wyoming totaling 1,311. PacifiCorp ultimately executed contracts to move forward with four projects totaling 1,150 MW. The 2017R RFP was monitored by two independent evaluators. On April 12, 2018, PacifiCorp received conditional CPCNs for the TB Flats I & II wind project, the Cedar Springs wind project, the Ekola Flats wind project, and associated network upgrades from the Wyoming Public Service Commission. These conditional CPCNs were required to secure the necessary rights-of-way. Final CPCNs to allow construction to initiate were issued by the Wyoming Public Service Commission on March 12, 2019 for TB Flats I &

Action Item	Activity	Status
	Necessity (CPCN) application with the Public Service Commission of Wyoming. – By August 2017, obtain approval of the Wyoming wind resource RFP from the Public Utility Commission of Oregon, the Utah Public Service Commission, and the Washington Utilities and Transportation Commission. – By August 2017, issue the Wyoming wind RFP to the market. – By October 2017, Wyoming wind RFP bids are due. – November-December, 2017, complete initial shortlist bid evaluation. – By January 2018, complete final shortlist bid evaluation, seek acknowledgement of the final shortlist from the Public Utility Commission of Oregon, and seek approval of winning bids from the Utah Public Service Commission. – By March 2018, receive CPCN approval from the Wyoming Public Service Commission. – Complete construction of new wind projects by December 31, 2020.	II, April 17, 2019 for Ekola Flats and network upgrades, and September 6, 2019 for Cedar Springs. All of the new wind projects resulting from the 2017R RFP are underway and on track to achieve commercial operation by the end of 2020.
1c	**<u>Renewable Portfolio Standard Compliance</u>** • PacifiCorp will issue unbundled REC request for proposals (RFP) 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 renewable portfolio standard targets through 2020.	PacifiCorp will continue to evaluate the need for unbundled RECs and issue RFPs to meet its state RPS compliance requirements as needed for both California Oregon, and Washington. PacifiCorp will issue an RFP seeking unbundled RECs in the fourth quarter of 2019 to meet state RPS compliance requirements in California and Washington.

Action Item	Activity	Status
	– As needed, issue RFPs seeking low-cost then-current-year, forward-year, or older vintage unbundled RECs that will qualify in meeting Oregon renewable portfolio standard targets, deferring the currently projected 2035 initial shortfall after accounting for preferred portfolio renewable resources.	
1d	**<u>Renewable Energy Credit Optimization</u>** • Before filing the 2017 IRP Update, evaluate potential opportunities to re-allocate RECs from Utah, Wyoming, and Idaho to Oregon, Washington, or California. • Maximize the sale of RECs that are not required to meet state RPS compliance obligations.	PacifiCorp issued reverse RFPs in June 2017, September 2017, My 2018, October 2018, and April 2019. PacifiCorp will continue to engage in bilateral REC sales and issue reverse RFPs to maximize the sale of RECs that are not required to meet state RPS compliance obligations.
Action Item	**2. Transmission Actions**	**Status**
2a	**<u>Aeolus to Bridger/Anticline</u>** • By December 31, 2020, PacifiCorp will build the 140-mile, 500 kV transmission line running from the Aeolus substation near Medicine Bow, Wyoming, to the Jim Bridger power plant (a sub-segment of the Energy Gateway West transmission project). This includes pursuing regulatory review and approval as necessary – June-July 2017, file a CPCN application with the Public Service Commission of Wyoming. – By March 2018, receive conditional CPCN approval from the Wyoming Public Service Commission pending acquisition of rights of way.	PacifiCorp filed a CPCN application with the Public Service Commission of Wyoming on June 30, 2017. On April 12, 2018, PacifiCorp received a conditional CPCN for the Aeolus-to-Bridger/Anticline transmission line from the Wyoming Public Service Commission. This CPCN was required to secure the necessary rights-of-way. The Wyoming Industrial Siting Counsel issued the siting permit on October 24, 2018. On April 9, 2019, the Public Service Commission of Wyoming issued the full CPCN. PacifiCorp issued full notice to proceed to the EPC contractors. Construction began on April 10, 2019

Action Item	Activity	Status
	– By December 2018, obtain Wyoming Industrial Siting permit and issue EPC limited notice to proceed. – By April 2019, issue EPC final notice to proceed. – Complete construction of the transmission line by December 31, 2020.	The 140-mile, 500 kV Aeolus to Bridger transmission project is underway and on-track to achieve commercial operation by the end of 2020.
2b	**Energy Gateway Permitting** • Continue permitting for the Energy Gateway transmission plan, with the following near-term targets: – For Segments D1, D3, E, and F, continue funding of the required federal agency permitting environmental consultant actions required as part of the federal permits. – For Segments D, E, and F, continue to support the projects by providing information and participating in public outreach. – For Segment H (Boardman to Hemingway), continue to support the project under the conditions of the Boardman to Hemingway Transmission Project Joint Permit Funding Agreement.	Final environmental and records of decision have been issued for Gateway Segments D1, D3, E and F. PacifiCorp will continue the work necessary to meet requirements within the records of decision and will continue to meet regularly with the Bureau of Land Management to review progress. PacifiCorp continues to support Gateway Segment H (Boardman-to-Hemingway) consistent with the Joint Permit Funding Agreement. As a participant in the project PacifiCorp continues to collaborate with Idaho Power, the lead organization in the permitting process, by providing guidance on activities and plans associated with the permitting phase of the project.
2c	**Wallula to McNary 230 kV Transmission Line** • Complete Wallula to McNary project construction per plan with a 2018 expected in-service date. Continue to support the permitting and construction process for Walla Walla to McNary.	Wallula to McNary project is complete, and the line went in-service January 2019.

2d	**<u>Planning Studies</u>** • Complete planning studies that include proposed coal unit retirement assumptions from the 2017 IRP preferred portfolio and two other scenarios. • Summarize studies in the 2017 IRP Update.	Planning studies were completed in 2018 and included in PacifiCorp's 2017 IRP Update.
3a	**<u>Front Office Transactions</u>** • Acquire economic short-term firm market purchases for on-peak summer deliveries from 2017 through 2019 consistent with the Risk Management Policy and Commercial and Trading 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 the service of providing a competitive price. – Balance of month, day-ahead, and hour-ahead transactions executed through an exchange, such as Intercontinental Exchange (ICE), in which the exchange provides the service of providing a competitive price. – Prompt month-forward, balance-of-month, day-ahead, and hour-ahead non-brokered transactions.	For 2018, PacifiCorp acquired approximately 2,225 MW to 2,765 MW of short-term firm market purchases inclusive of forward hedging transactions, not accounting for any offsetting hedging or balancing sales for delivery during the on-peak summer period. For 2019, as of end of September 2019, the company has acquired approximately 1,100 MW to 2,030 MW of short-term market purchases inclusive of forward hedging transactions, not accounting for any offsetting hedging sales for delivery during the on-peak summer period. For 2020, as of end of September 2019, the company has acquired approximately 150 MW of short-term firm market purchases explicitly for delivery during the on-peak summer period inclusive of forward hedging transaction, not accounting for any offsetting hedging sales for delivery during the on-peak summer period.
4a	**<u>Class 2 DSM</u>** • Acquire cost-effective Class 2 DSM (energy efficiency) resources targeting annual system energy and capacity selections from the preferred portfolio as summarized in the following table. PacifiCorp's state-specific processes for planning for DSM acquisitions is provided in Appendix D in Volume II of the 2017 IRP.	In 2017, PacifiCorp achieved the Action Plan target of 646 gigawatt hours (GWh). In 2018, PacifiCorp achieved 98 percent of the Action Plan target of 559 GWh.

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<tr><th>Year</th><th>Annual Incremental Energy (GWh)</th><th>Annual Incremental Capacity* (MW)</th></tr>
<tr><td>2017</td><td>646</td><td>154</td></tr>
<tr><td>2018</td><td>559</td><td>128</td></tr>
</table>
*Class 2 DSM capacity figures reflect projected maximum annual hourly energy savings, which is similar to a nameplate rating for a supply-side resource.
</td>
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<tr>
<td>5a</td>
<td><u>Hunter Units 1 and 2</u>

The U.S. Environmental Protection Agency (EPA)’s final Regional Haze Federal Implementation Plan (FIP) for Utah requires the installation of selective catalytic reduction (SCR) on Hunter Units 1 and 2 in 2021 and is currently under appeal by the state of Utah and other parties in the U.S. Tenth Circuit Court of Appeals.
As influenced by the litigation schedule and outcomes, PacifiCorp will update its economic analysis of alternative Regional Haze compliance strategies for the units, as applicable, and will provide the associated analysis in a future IRP or IRP Update.

</td>
<td>PacifiCorp continues to support the state of Utah in its appeal of the EPA’s FIP for Utah as it pertains to Hunter Units 1 and 2. The state of Utah submitted a revised Regional Haze State Implementation Plan (SIP) on July 3, 2019, for EPA review and approval. The EPA requested an additional minor revision to the SIP which Utah anticipates it will submit before year-end 2019. Litigation of the FIP appeal is currently held in abeyance while EPA reviews the revised SIP. Please see Chapter 6 (Resource Options) of the 2019 IRP for more information. PacifiCorp will provide additional updates and the associated analysis in future IRP filings, as applicable.</td>
</tr>
<tr>
<td>5b</td>
<td><u>Huntington Units 1 and 2</u>

The EPA’s final Regional Haze FIP for Utah requires the installation of SCR on Huntington Units 1 and 2 in 2021 and is currently under appeal by the state of Utah and other parties in the U.S. Tenth Circuit Court of Appeals.
As influenced by the litigation schedule and outcomes, PacifiCorp will update its economic analysis of alternative Regional Haze compliance strategies for the units, as applicable, and will provide the associated analysis in a future IRP or IRP Update.

</td>
<td>PacifiCorp continues to support the state of Utah in its appeal of the EPA’s FIP for Utah as it pertains to Hunter Units 1 and 2. The state of Utah submitted a revised Regional Haze State Implementation Plan (SIP) on July 3, 2019, for EPA review and approval. The EPA requested an additional minor revision to the SIP which Utah anticipates it will submit before year-end 2019. Litigation of the FIP appeal is currently held in abeyance while EPA reviews the revised SIP. Please see Chapter 6 (Resource Options) of the 2019 IRP for more information. PacifiCorp will provide additional updates and the associated analysis in future IRP filings, as applicable.</td>
</tr>
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5c	**<u>Dave Johnston Unit 3</u>** • The EPA's final Regional Haze FIP requires the installation of SCR at Dave Johnston Unit 3 in 2019 or a commitment to shut down Dave Johnston Unit 3 by the end of 2027. PacifiCorp's commitment to the latter must be included in a permit before the 2019 compliance deadline. • PacifiCorp will update its analysis of the commitment to shut down Dave Johnston Unit 3 by the end of 2027 as part of its 2017 IRP Update.	PacifiCorp studied retirement of Dave Johnston Unit 3 in the 2017 IRP Update and the 2019 IRP. PacifiCorp does not plan to proceed with installation of SCR on Dave Johnston Unit 3, and will submit a permit revision before the end of 2019 to make the 2027 shut down date enforceable. Please see Chapter 6 (Resource Options) of the 2019 IRP for more information. PacifiCorp will provide additional updates in future IRP filings as applicable.
5d	**<u>Jim Bridger Units 1 and 2</u>** • The Wyoming Regional Haze SIP and EPA's final Regional Haze FIP for Wyoming require the installation of SCR on Jim Bridger Units 1 and 2 in 2021 and 2022. • PacifiCorp will update its economic analysis of alternative Regional Haze compliance strategies for the units and will provide the associated analysis in its 2017 IRP Update.	PacifiCorp developed a Jim Bridger Regional Haze compliance alternative for the state of Wyoming and EPA to consider in 2018, and submitted a permit application with the state of Wyoming in February 2019. The state of Wyoming has incorporated the compliance alternative into a revised Wyoming Regional Haze SIP and a state permit. Wyoming is currently in the process of responding to public comments on the plan. It is expected that the state of Wyoming will submit the revised Wyoming Regional Haze SIP by year-end 2019 for EPA review and approval. Please see Chapter 6 (Resource Options) of the 2019 IRP for more information. PacifiCorp will provide additional updates and analysis on Jim Bridger Units 1 and 2 in future IRP filings as applicable.
5e	**<u>Naughton Unit 3</u>** • PacifiCorp will update its economic analysis of natural gas conversion in its 2017 IRP Update.	PacifiCorp studied Naughton Unit 3 gas conversion in the 2017 IRP Update and the 2019 IRP. Please see Chapter 6 (Resource Options) of the 2019 IRP for more information.
5f	**<u>Wyodak</u>** • Continue to pursue PacifiCorp's appeal of the portion of EPA's final Regional Haze FIP that requires the installation of SCR at Wyodak, recognizing that the	PacifiCorp continues to support the state of Wyoming in its appeal of the EPA's FIP for Wyoming as it pertains to Wyodak. The requirement for SCR at Wyodak is currently stayed as part of the FIP litigation proceedings. Please see

	compliance deadline for SCR under the FIP is currently stayed by the court. • If following appeal, EPA's final FIP as it pertains to installation of SCR at Wyodak is upheld (with a modified schedule that reflects the final stay duration), PacifiCorp will update its evaluation of alternative compliance strategies that will meet Regional Haze compliance obligations and provide the associated analysis in a future IRP or IRP Update.	Chapter 6 (Resource Options) of the 2019 IRP for more information. PacifiCorp will provide additional updates and the associated analysis in future IRP filings, as applicable.
5g	**Cholla Unit 4** • EPA has approved the Arizona SIP incorporating an alternative Regional Haze compliance approach that avoids installation of SCR with a commitment to cease operating Cholla Unit 4 as a coal-fueled resource by the end of April 2025, with the option of natural gas conversion thereafter. • PacifiCorp will update its evaluation of Cholla Unit 4 alternatives that meet its Regional Haze compliance obligations and provide the associated analysis in a future IRP or IRP Update.	Please see Chapter 6 (Resource Options) of the 2019 IRP for more information. PacifiCorp will provide additional updates and the associated analysis in future IRP filings, as applicable.
5h	**Craig Unit 1** • EPA is yet to approve the Colorado SIP incorporating an alternative Regional Haze compliance approach that avoids installation of SCR with a commitment to cease operating Craig Unit 1 as a coal-fueled resource by the end of 2025, with an option for natural gas conversion. • PacifiCorp will update its evaluation of Craig Unit 1 alternatives that meet its Regional Haze compliance obligations and provide the associated analysis in a future IRP or IRP Update, as required.	Please see Chapter 6 (Resource Options) of the 2019 IRP for more information. PacifiCorp will provide additional updates and the associated analysis in future IRP filings as applicable.

Acquisition Path Analysis

Resource and Compliance Strategies

PacifiCorp worked with stakeholders to define portfolio cost and risk analysis in the 2019 IRP. This analysis reflects a combination of specific planning assumptions related to coal unit retirements, potential Regional Haze compliance outcomes, Energy Gateway transmission investments, customer-preference renewable resources, targeted resource procurement outcomes (i.e., no new natural gas), market-reliance risk, market price assumptions, and CO_2 price assumptions. PacifiCorp further analyzed sensitivity cases on planning assumptions related primarily to the load forecasts and private generation penetration levels. The array of planning assumptions that define the studies used to develop resource portfolios provides the framework for a resource acquisition path analysis by evaluating how resource selections are impacted by changes to planning assumptions.

Given current load expectations, portfolio modeling performed for the 2019 IRP shows the resource acquisition path in the preferred portfolio is robust among a wide range of policy and market conditions, particularly in the near-term, when cost-effective renewable resources that qualify for federal income tax credits, FOTs, and energy efficiency resources are consistently selected. With regard to renewable resource acquisition, the portfolio development modeling performed in the 2019 IRP shows that new renewable resource needs are driven primarily by economics and reliability. Beyond load, CO_2 policy also influences resource selections in the 2019 IRP. For these reasons, the acquisition path analysis focuses on economic, load, reliability, and environmental policy trigger events that would require alternative resource acquisition strategies. For each trigger event, PacifiCorp identifies the planning scenario assumption affecting both short-term (2019-2028) and long-term (2029-2038) resource strategies.

Acquisition Path Decision Mechanism

The Utah Commission requires that PacifiCorp provide "[a] plan of different resource acquisition paths with a decision mechanism to select among and modify as the future unfolds."[1] PacifiCorp's decision mechanism is centered on the IRP process and ongoing updates to the IRP modeling tools between IRP cycles. The same modeling tools used in the IRP are also used to evaluate and inform the procurement of resources. The IRP models are used on a macro-level to evaluate alternative portfolios and futures as part of the IRP process, and then on a micro-level to evaluate the economics and system benefits of individual resources as part of the supply-side resource procurement and DSM target-setting/valuation processes. PacifiCorp uses the IRP and the IRP modeling tools to serve as decision support tools that can be used to guide prudent resource acquisition paths that maintain system reliability at a reasonable cost. Table 9.3 summarizes PacifiCorp's 2019 IRP acquisition path analysis, which provides insight on how changes in the planning environment might influence future resource procurement activities. Changes in procurement activities driven by changes in the planning environment will ultimately be reflected in future IRPs and resource procurement decisions.

[1] Public Service Commission of Utah, In the Matter of Analysis of an Integrated Resource Plan for PacifiCorp, Report and Order, Docket No. 90-2035-01, June 1992, p. 28.

Table 9.3 – Near-term and Long-term Resource Acquisition Paths

Trigger Event	Planning Scenario(s)	Near-Term Resource Acquisition Strategy (2020-2028)	Long Term Resource Acquisition Strategy (2029-2038)
Higher sustained load growth	High economic drivers and high Utah and Wyoming industrial loads	• Within the action plan window, there would be no change to the resource procurement strategy focused on an all-source RFP and incremental transmission upgrades. • Increase acquisition of summer FOTs: on average, annual purchases are up 460 MW per year. • Increase and accelerate solar+battery procurement: solar+battery capacity begins to rise as early as 2021—by 2028, solar+battery capacity is increased by 103 MW. • Increase and accelerate stand-alone battery procurement: 165 MW of stand-alone battery capacity is accelerated into 2026. • Increase flexible capacity procurement: in 2028, new gas-peaking capacity increases by 370 MW. • Accelerate Class I DSM procurement: in 2028, new direct-load control capacity increases by 149 MW.	• Accelerate flexible capacity procurement: new peaking gas capacity is accelerated—increased by 759 MW in 2029 and by 959 MW in 2033. By the end of 2038, gas capacity is similar to a base load forecast case. • Defer procurement of stand-alone battery capacity: with an accelerated deployment of new gas capacity, stand-alone battery storage capacity is down by 450 MW in 2029, down by 255 MW by 2033.

Trigger Event	Planning Scenario(s)	Near-Term Resource Acquisition Strategy (2020-2028)	Long Term Resource Acquisition Strategy (2029-2038)
Lower sustained load growth	Low economic drivers suppress load requirements with reduced demand from Utah and Wyoming industrial loads	• Within the action plan window, there would be no change to the resource procurement strategy focused on an all-source RFP and incremental transmission upgrades. • Reduce acquisition of summer FOTs: on average, annual purchases are down 220 MW per year. • Reduce and defer solar+battery capacity procurement: solar+battery capacity begins to fall as early as 2021—by 2028, solar+battery capacity is reduced by 220 MW. • Reduce and defer stand-alone battery procurement: stand-alone battery storage capacity declines beginning 2028 (180 MW). • Reduce flexible capacity procurement: 185 MW of new peaking gas capacity is deferred from 2026 to 2030. • Reduce energy efficiency procurement: through 2028, incremental energy efficiency procurement is down by 67 MW.	• Defer flexible capacity procurement: new peaking gas capacity remains relatively stable from 2030 through 2036—by 2038 new peaking gas capacity is down by 221 MW. • Adjust timing of solar+battery procurement: the timing for solar+battery capacity shifts—reduced by 720 MW by 2031, higher by 109 MW by 2035, and down by over 300 MW by 2038. • Increase stand-alone solar procurement: stand-alone solar is higher through the last ten years of the planning period—by 2038 it's up by 162 MW. • Reduce stand-along battery storage procurement: stand-alone battery storage capacity is down through the last ten years of the planning period—by 2038 it is reduced by 420 MW.
Higher sustained private generation penetration levels	More aggressive technology cost reductions, improved technology performance, and higher electricity retail rates	• Within the action plan window, there would be no change to the resource procurement strategy focused on an all-source RFP and incremental transmission upgrades. • Small changes to the portfolio would require minimal changes to the resource acquisition strategy. • Delay procurement of flexible resource capacity: a 185 MW gas peaking plant is deferred by one year from 2026 to 2027.	• Small changes to the portfolio would require minimal changes to the resource acquisition strategy. • Timing differences in stand-alone solar, stand-alone battery and solar+battery capacity would need to be assessed in procurement processes to achieve the appropriate balance of energy and capacity.

Trigger Event	Planning Scenario(s)	Near-Term Resource Acquisition Strategy (2020-2028)	Long Term Resource Acquisition Strategy (2029-2038)
Lower sustained private generation penetration levels	Less aggressive technology cost reductions, reduced technology performance, and lower electricity retail rates	• Within the action plan window, there would be no change to the resource procurement strategy focused on an all-source RFP and incremental transmission upgrades. • Delay procurement of flexible resource capacity: a 185 MW gas peaking plant is deferred by three years from 2026 to 2029.	• Accelerate procurement of flexible resource capacity: new gas peaking capacity increases by 370 MW in 2030. • Timing differences in stand-alone solar, stand-alone battery and solar+battery capacity would need to be assessed in procurement processes to achieve the appropriate balance of energy and capacity.
High CO_2 prices with accelerated coal retirements	Fossil-fired generation is faced with a high CO_2 price beginning in 2025 at $22.57/ton and reaching $83.69/ton by 2038 that drives all coal to be retired by 2030	• Within the action plan window, there would be no change to the resource procurement strategy focused on an all-source RFP and incremental transmission upgrades. • Accelerate procurement of flexible resource capacity: new gas peaking capacity increases by 195 MW as early as 2023 and is 514 MW higher than the base case by 2028. • Increase procurement of market purchases: summer FOTs increase with the potential for accelerated coal retirements. • Increase procurement of energy efficiency: energy efficiency capacity is accelerated and increases by 80 MW by 2028. • Accelerate procurement of direct-load control resources: by 2028, direct-load control capacity is up by 194 MW.	• Accelerate and increase procurement of flexible resource capacity: by 2029, new gas peaking capacity is 1,151 MW higher than in the base case and by 2038 it is 434 MW higher than the base case. • Accelerate and increase procurement of battery storage capacity: by 2038 battery storage capacity is increased by over 1,200 MW. • Accelerate procurement of direct-load control resources: by 2030, direct-load control capacity is up by 68 MW and in the 2031-2037 timeframe it is up by over 240 MW.

Trigger Event	Planning Scenario(s)	Near-Term Resource Acquisition Strategy (2020-2028)	Long Term Resource Acquisition Strategy (2029-2038)
Jim Bridger and Naughton Units retire by the end of 2025	Retirements for Naughton Units 1-2 and Jim Bridger Units 3-4 all occur by the end of 2025.	• Within the action plan window, there would be no change to the resource procurement strategy focused on an all-source RFP and incremental transmission upgrades. • Increase procurement of market purchases: summer FOTs increase beginning 2026 and through 2028 by as much as 960 MW per year. • Accelerate procurement of flexible resource capacity: new gas peaking capacity is 210 MW higher in 2028. • Adjust timing and volumes for procurement of battery storage capacity: battery storage capacity is down by about 100 MW in 2024, but increases by about by about 500 MW by 2026. • Increase procurement of energy efficiency: energy efficiency capacity is accelerated and increases by over 40 MW by 2028. • Accelerate procurement of direct-load control resources: by 2028, direct-load control capacity is up by 161 MW.	• Accelerate procurement of flexible resource capacity: new gas peaking capacity is between about 400 MW and 600 MW higher over the 2029 to 2034 timeframe, over 800 MW higher in the 2035-2036, and down by about 300 MW in 2037-2038. • Increase procurement of battery storage capacity: battery storage capacity is up by over 100 MW from 2030-2036, and is up by about 700 MW by 2038. • Accelerate procurement of renewable capacity: total renewable capacity is up by between 350 MW and over 1,200 MW from 2029-2037.
Low market prices	On average, levelized gas and power prices are down by approximately 25 percent relative to the base forecast	• Within the action plan window, there would be no change to the resource procurement strategy focused on an all-source RFP and incremental transmission upgrades. • The near-term RFP process would assess potential changes to the resource mix, based on market bids that maximize value for customers, with potential changes to wind, solar, battery storage, and battery storage collated with solar.	• Accelerate procurement of flexible resource capacity: new gas peaking capacity increases by 342 MW in 2029 and by 1,518 MW in 2038. • Shifts in the precise timing and need for wind, solar, battery storage, and battery storage collated with solar would need to be evaluated through future competitive solicitation processes. • Reduce energy efficiency procurement: energy efficiency capacity is down by about 100 MW in this timeframe.

Trigger Event	Planning Scenario(s)	Near-Term Resource Acquisition Strategy (2020-2028)	Long Term Resource Acquisition Strategy (2029-2038)
High market prices	On average, levelized gas prices are up by about 25 percent and power prices by about 10 percent relative to the base forecast	• Within the action plan window, there would be no change to the resource procurement strategy focused on an all-source RFP and incremental transmission upgrades. • Increase renewable procurement and battery storage procurement in the 2023 timeframe: higher prices increase renewable capacity by about 260 MW and battery storage capacity by over 400 MW. • Increase procurement of energy efficiency: energy efficiency capacity is accelerated and increases by over 60 MW by 2028.	• Increase renewable procurement: higher prices increase renewable capacity by 720 MW in 2029 rising to over 1,200 MW by 2038. • Accelerate procurement of flexible resource capacity: new gas peaking capacity is higher by between 130 MW and 370 MW in the 2032-2036 timeframe, but down by over 500 MW in the 2037-2038 timeframe. • Battery storage capacity procurement would be adjusted in accordance with changes to gas capacity: battery storage capacity is down by about 300 MW in the 2032-2036 timeframe and up by 300-700 MW in the 2037-2038 timeframe. • Increase procurement of direct-load control resources: direct-load control capacity is up by between 40 MW and over 200 MW over the long term.
No customer-preference resource demand	No resources are added to meet customer-preference targets	• Within the action plan window, there would be no change to the resource procurement strategy focused on an all-source RFP and incremental transmission upgrades. • Reduce procurement of customer-preference renewables: total renewable capacity is down by nearly 300 MW through 2023, but up by 10 MW from 2024-2028.	• Longer term, the total volume of renewables is similar without customer preference resource demand. • Future RFP processes would evaluate timing adjustments for battery storage capacity and new gas peaking capacity; however, in aggregate, these capacity resources are not materially different from the base case.

Trigger Event	Planning Scenario(s)	Near-Term Resource Acquisition Strategy (2020-2028)	Long Term Resource Acquisition Strategy (2029-2038)
High customer-preference resource demand	Additional resources are added to meet higher customer-preference targets that exceed base case levels by over 3.5x in 2025 (5.7 GWh) rising to over 4.8x by 2038 (9.3 GWh).	• Within the action plan window, there would be no change to the resource procurement strategy focused on an all-source RFP and incremental transmission upgrades. • Accelerate procurement of renewable resources: by the 2024-2025 timeframe, renewable capacity is up by about 100 MW and by 2028, it is up by over 550 MW. • Accelerate procurement of battery storage capacity: by the 2024-2025 timeframe, battery storage capacity is up by about 50 MW and by 2028, it is up by over 130 MW. • Delay procurement of flexible resource capacity: new gas peaking capacity is 185 MW lower from 2026-2029. • Reduce procurement of market purchases: summer FOTs increase beginning 2026 and through 2028 by 20 to 160 MW over the 2024-2028 timeframe.	• Accelerate procurement of renewable resources: in the 2029-2038 timeframe, renewable capacity is up by over 570 MW in 2029 and up by 100 MW by 2030. • Accelerate procurement of battery storage capacity: in 2029 battery storage capacity is up by over 550 MW and in the 2029-2038 timeframe, battery storage capacity is up by over 280 MW.

Procurement Delays

The main procurement risk is an inability to procure resources in the required timeframe to meet the least-cost, least-risk mix of resources identified in the preferred portfolio. There are various reasons why a particular proxy resource cannot be procured in the timeframe identified in the 2019 IRP. There may not be any cost-effective opportunities available through an RFP, the successful RFP bidder may experience delays in permitting and/or default on their obligations, or there might be a material and sudden change in the market for fuel and materials. Moreover, there is always the risk of unforeseen environmental or other electric utility regulations that may influence the PacifiCorp's entire resource procurement strategy.

Possible paths PacifiCorp could take in the event of a procurement delay or sudden change in procurement need can include combinations of the following:

- In circumstances where PacifiCorp is engaged in an active RFP where a specific bidder is unable to perform, alternative bids can be pursued.

- PacifiCorp can issue an emergency RFP for a specific resource and with specified availability.
- PacifiCorp can seek to negotiate an accelerated delivery date of a potential resource with the supplier/developer.
- PacifiCorp can seek to procure near-term purchased power and transmission until a longer-term alternative is identified, acquired through customized market RFPs, exchange transactions, brokered transactions or bi-lateral, sole source procurement.
- Accelerate acquisition timelines for direct load control programs.
- Procure and install temporary generators to address some or all of the capacity needs.
- Temporarily drop below the target 13 percent planning reserve margin.
- Implement load control initiatives, including calls for load curtailment via existing load curtailment contracts.

IRP Action Plan Linkage to Business Planning

The 2019 IRP includes a sensitivity (case S-06) that complies with the Utah requirement to perform a business plan sensitivity case consistent with the commission's order in Docket No. 15-035-04. This order sets forth the following parameters for this sensitivity case:

- Over the first three years, resources align with those assumed in PacifiCorp's December 2018 Business Plan.
- Beyond the first three years of the study period, unit retirement assumptions are aligned with the preferred portfolio.
- All other resources are optimized.

Differences between PacifiCorp's 2019 IRP preferred portfolio and case S-07 are driven by assumptions for Naughton Unit 3 and Cholla Unit 4. Case S-07 does not include the Naughton Unit 3 gas conversion and assumes Cholla Unit 4 retires in early 2025 instead of 2020. In the near-term, the preferred portfolio has lower summer FOTs, slight changes in the volumes and timing associated with DSM resources, and slight changes in customer-preference renewable resources. None of these differences have any bearing on the 2019 IRP action plan, which calls for, among other things, issuance of an all-source RFP and advancement of transmission investments that will enable adding new renewable resources to the system. Over the long term, the change in resources from case S-06 relative to the preferred portfolio are largely associated with timing; however, the overall long-term portfolio resource mix is similar to the resources included in the preferred portfolio and would not materially alter PacifiCorp's long-term resource procurement plans. Table 9.4 compares the 2019 IRP preferred portfolio with portfolio from sensitivity case S-06.

Table 9.4 – Comparison of the 2019 IRP Preferred Portfolio with Sensitivity Case S-06

2019 IRP Preferred Portfolio

Resource	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	Resource Totals 2019-2038
	Capacity (MW)																				
Expansion Options																					
Gas - CCCT	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	505	-	**505**
Gas- Peaking	-	-	-	-	-	-	-	185	-	-	-	370	-	-	-	-	-	-	813	-	**1,367**
DSM - Energy Efficiency	126	132	133	143	147	151	147	144	143	138	126	120	114	110	99	82	77	65	58	59	**2,315**
DSM - Load Control	4	-	7	-	18	-	8	7	-	-	133	8	-	12	-	-	15	4	59	169	**444**
Renewable - Wind	-	-	-	-	69	1,920	-	-	-	-	-	1,040	-	-	-	-	-	-	-	-	**3,029**
Renewable - Wind+Storage	-	-	-	-	-	-	-	-	-	-	10	-	-	60	-	-	-	-	11	-	**81**
Renewable - Utility Solar	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Renewable - Utility Solar+Storage	-	-	159	64	3	2,154	-	-	-	-	359	500	-	-	475	-	-	419	909	702	**5,745**
Renewable - Biomass	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Storage - Other	-	-	-	-	-	-	-	-	-	180	435	-	30	120	-	-	-	-	-	600	**1,365**
Front Office Transactions - Summer	998	719	493	503	498	131	126	191	264	1,163	1,375	1,274	1,249	1,281	1,373	1,375	1,374	1,277	1,374	1,375	**921**
Front Office Transactions - Winter	151	131	268	303	314	44	51	53	100	232	222	173	192	128	63	-	35	-	-	-	**123**
Existing Unit Changes																					
Coal Early Retirement/Conversions	-	(280)	(387)	-	-	(351)	-	(439)	(82)	(148)	(356)	-	-	-	-	-	-	-	-	-	**(2,042)**
Thermal Plant End-of-life Retirements	-	-	-	-	-	-	-	-	-	(755)	-	-	(77)	-	(356)	-	-	-	(909)	(702)	**(2,799)**
Retire - Hydro	-	(1)	(169)	-	(1)	(20)	-	(1)	-	(7)	-	-	(6)	-	-	(75)	-	(1)	-	-	**(282)**
Retire - Wind	-	-	-	-	-	-	-	-	-	-	-	(40)	-	-	-	-	-	-	-	-	**(40)**
Expire - Wind PPA	-	(27)	(17)	(224)	(0)	(41)	-	(65)	(3)	-	(93)	(109)	(200)	(65)	(201)	(80)	-	(70)	(90)	-	**(1,284)**
Expire - Solar PPA	-	-	-	-	(1)	(1)	-	-	-	(2)	-	-	(67)	(49)	-	-	(36)	(209)	(1,024)	(11)	**(1,399)**
Retire - Other	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(1)	-	-	-	(32)	**(33)**
Coal Plant Gas Conversion Additions	-	247	-	-	-	-	-	-	-	-	-	(247)	-	-	-	-	-	-	-	-	-
Total	**1,279**	**922**	**488**	**788**	**1,048**	**3,988**	**333**	**75**	**422**	**800**	**2,211**	**3,089**	**1,234**	**1,598**	**1,453**	**1,301**	**1,467**	**1,485**	**1,706**	**2,160**	

Study includes Naughton 3 conversion at the beginning of 2020.
FOT in resource total are 20-year averages.

2019 IRP Preferred Portfolio less Sensitivity Case S-06

Resource	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	Resource Totals 2019-2038
	Capacity (MW)																				
Expansion Options																					
Gas - CCCT	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Gas- Peaking	-	-	-	-	-	-	-	185	-	(185)	(370)	370	-	-	-	-	-	-	-	-	-
DSM - Energy Efficiency	(9)	(2)	3	0	(5)	-	0	(4)	(0)	(0)	2	(0)	5	7	(0)	0	1	(1)	(1)	(3)	**(7)**
DSM - Load Control	-	-	(8)	-	8	-	-	-	-	(126)	126	8	(8)	-	-	-	-	-	(23)	(26)	**(50)**
Renewable - Wind	-	-	-	-	69	-	-	-	-	-	-	(60)	-	-	-	-	-	-	(92)	(58)	**(141)**
Renewable - Wind+Storage	-	-	-	-	-	-	-	-	-	-	10	-	-	60	-	-	-	-	11	-	**81**
Renewable - Utility Solar	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Renewable - Utility Solar+Storage	-	-	-	-	(69)	36	-	-	-	-	-	500	(500)	(45)	(100)	-	-	419	(338)	-	**(97)**
Renewable - Biomass	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Storage - Other	-	-	(15)	-	-	-	-	-	-	(30)	420	(360)	30	(45)	(195)	-	-	15	-	315	**135**
Front Office Transactions - Summer	(13)	(245)	(28)	(52)	(62)	(60)	(60)	(280)	(281)	(195)	37	4	(32)	(45)	(2)	298	298	191	(1)	5	**(526)**
Front Office Transactions - Winter	2	8	9	9	9	(9)	(9)	(9)	(11)	(11)	3	1	4	(8)	(4)	(300)	(299)	(305)	-	-	**(46)**
Existing Unit Changes																					
Coal Early Retirement/Conversions	-	(280)	(387)	-	-	(351)	-	(439)	(82)	(148)	(356)	-	-	-	-	-	-	-	-	-	**(2,042)**
Thermal Plant End-of-life Retirements	-	-	-	-	-	-	-	-	-	(755)	-	-	(77)	-	(356)	-	-	-	(909)	(702)	**(2,799)**
Retire - Hydro	-	(1)	(169)	-	(1)	(20)	-	(1)	-	(7)	-	-	(6)	-	-	(75)	-	(1)	-	-	**(282)**
Retire - Wind	-	-	-	-	-	-	-	-	-	-	-	(40)	-	-	-	-	-	-	-	-	**(40)**
Expire - Wind PPA	-	(27)	(17)	(224)	(0)	(41)	-	(65)	(3)	-	(93)	(109)	(200)	(65)	(201)	(80)	-	(70)	(90)	-	**(1,284)**
Expire - Solar PPA	-	-	-	-	(1)	(1)	-	-	-	(2)	-	-	(67)	(49)	-	-	(36)	(209)	(1,024)	(11)	**(1,399)**
Retire - Other	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(1)	-	-	-	(32)	**(33)**
Coal Plant Gas Conversion Additions	-	247	-	-	-	-	-	-	-	-	-	(247)	-	-	-	-	-	-	-	-	-
Total	**(20)**	**(300)**	**(611)**	**(267)**	**(51)**	**(446)**	**(69)**	**(614)**	**(378)**	**(1,459)**	**(221)**	**67**	**(852)**	**(191)**	**(859)**	**(158)**	**(36)**	**38**	**(2,467)**	**(512)**	

FOT in resource total are 20-year averages.

Sensitivity Case S-06

Resource	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	Resource Totals 2019-2038
	Capacity (MW)																				
Expansion Options																					
Gas - CCCT	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	505	-	**505**
Gas- Peaking	-	-	-	-	-	-	-	-	-	185	370	-	-	-	-	-	-	-	813	-	**1,367**
DSM - Energy Efficiency	135	134	129	142	151	151	147	148	144	138	124	120	109	104	100	81	76	67	59	63	**2,322**
DSM - Load Control	4	-	15	-	10	-	8	7	-	126	7	-	8	12	-	-	15	4	83	195	**494**
Renewable - Wind	-	-	-	-	-	1,920	-	-	-	-	-	1,100	-	-	-	-	-	-	92	58	**3,170**
Renewable - Wind+Storage	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Renewable - Utility Solar	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Renewable - Utility Solar+Storage	-	-	159	64	73	2,118	-	-	-	-	359	-	500	45	575	-	-	-	1,247	702	**5,842**
Renewable - Biomass	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Storage - Other	-	-	15	-	-	-	-	-	-	210	15	360	-	165	195	-	-	(15)	-	285	1,230
Front Office Transactions - Summer	1,010	964	521	555	560	191	187	472	545	1,357	1,338	1,269	1,281	1,327	1,375	1,077	1,077	1,086	1,375	1,370	947
Front Office Transactions - Winter	149	123	259	294	305	53	60	62	111	243	219	172	188	136	67	300	334	305	-	-	**169**
Existing Unit Changes																					
Coal Early Retirement/Conversions	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Thermal Plant End-of-life Retirements	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Retire - Hydro	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Retire - Wind	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Expire - Wind PPA	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Expire - Solar PPA	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Retire - Other	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Coal Plant Gas Conversion Additions	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Total	**1,299**	**1,222**	**1,099**	**1,055**	**1,099**	**4,433**	**402**	**688**	**800**	**2,259**	**2,432**	**3,022**	**2,087**	**1,788**	**2,312**	**1,459**	**1,503**	**1,447**	**4,173**	**2,672**	

Study includes Naughton 3 retirement at the end of 2019.
FOT in resource total are 20-year averages.

Resource Procurement Strategy

To acquire resources outlined in the 2019 IRP action plan, PacifiCorp intends to continue using competitive solicitation processes in accordance with applicable laws, rules, and/or guidelines in each of the states in which PacifiCorp operates. PacifiCorp will also continue to pursue opportunistic acquisitions identified outside of a competitive procurement process that provide economic benefits to customers. Regardless of the method for acquiring resources, PacifiCorp will support its resource procurement activities with the appropriate financial analysis using then-current assumptions for inputs such as load forecasts, commodity prices, resource costs, and policy developments. Any such financial analysis will account for any applicable long-term system benefits with least-cost, least-risk planning principles in mind. The sections below profile the general procurement approaches for the key resource categories covered in the 2019 IRP action plan.

Renewable Resources, Storage Resources, and Dispatchable Resources

PacifiCorp will use a competitive RFPs to procure supply-side resources consistent applicable laws, rules, and/or guidelines in each of the states in which PacifiCorp operates. In Oregon and Utah, these state requirements involve the oversight of an independent evaluator, which is also being considered in revised rules being developed in Washington. The all-source RFPs outline the types of resources being pursued, defines specific information required of potential bidders and details both price and non-price scoring metrics that will be used to evaluate proposals.

Renewable Energy Credits

PacifiCorp uses shelf RFPs as the primary mechanism under which REC RFPs and reverse REC RFPs will be issued to the market. The shelf RFPs are updated to define the product definition, timing, and volume and further provide schedule and other applicable criteria to bidders.

Demand-side Management

PacifiCorp offers a robust portfolio of Class 1 (demand response and direct-load control) and Class 2 (energy efficiency) DSM programs and initiatives, most of which are offered in multiple states, depending on size of the opportunity and the need. Programs are reassessed on a regular bases. PacifiCorp provides Class 4 DSM offerings, and has continued ***watt***smart outreach and communications. Educating customers regarding energy efficiency and load management opportunities is an important component of PacifiCorp's long-term resource acquisition plan. PacifiCorp will evaluate how to best incorporate potential Class 1 DSM programs into the broader all-source RFP process discussed above.

Assessment of Owning Assets versus Purchasing Power

As PacifiCorp acquires new resources, it will need to determine whether it is better to own a resource or purchase power from another party. While the ultimate decision will be made at the time resources are acquired, and will primarily be based on cost, there are other considerations that may be relevant.

With owned resources, PacifiCorp is in a better position to control costs, make life extension improvements (as is being implemented with the wind repower project analyzed in the 2017 IRP), use the site for additional resources in the future, change fueling strategies or sources (as is being implemented for the Naughton Unit 3 gas conversion), efficiently address plant modifications that may be required as a result of changes in environmental or other laws and regulations, and utilize the plant at embedded cost as long as it remains economic. In addition, by owning a plant, PacifiCorp can hedge itself against the uncertainty of third-party performance consistent with the terms and conditions outlined in a power purchase agreement over time.

Alternately and depending on contractual terms, purchasing power from a third party in a long term contract may help mitigate and may avoid liabilities associated with closure of a plant. A long-term power purchase agreement relinquishes control of construction cost, schedule, ongoing costs and environmental and regulatory compliance. Purchase power agreements can also protect and cap the buyer's exposure to events that may not cover actual seller financial impacts. However, credit rating agencies can impute debt associated with long-term resource contracts that may result from a competitive procurement process, and such imputation may affect PacifiCorp's credit ratios and credit rating.

Managing Carbon Risk for Existing Plants

CO_2 reduction regulations at the federal, regional, or state levels could prompt PacifiCorp to continue to look for measures to lower CO_2 emissions of fossil-fired power plants through cost-effective means. The cost, timing, and compliance flexibility afforded by CO_2 reduction rules will impact what types of measures might be cost-effective and practical from operational and regulatory perspectives. As evident in the 2019 IRP, known and prospective environmental regulations can impact utilization of resources and investment decisions.

Compliance strategies will be affected by how and whether states or the federal government choose to implement greenhouse gas policies. State or federal frameworks could impute a carbon tax or implement a cap-and-trade framework. Under a cap-and-trade policy framework, examples of factors affecting carbon compliance strategies include the allocation of emission allowances, the cost of allowances in the market, and any flexible compliance mechanisms such as opportunities to use carbon offsets, allowance/offset banking and borrowing, and safety valve mechanisms. Under a CO_2 tax framework, the tax level and details around how the tax might be assessed would affect compliance strategies.

To lower the emission levels for existing fossil-fired power plants, options include changes in plant dispatch, unit retirements, changing the fuel type, deployment of plant efficiency improvement projects, and adoption of new technologies such as CO_2 capture with sequestration, when commercially proven. As mentioned above, plant CO_2 emission risk may also be addressed by acquiring offsets or other environmental attributes that could become available in the market under certain regulatory frameworks. PacifiCorp's compliance strategies will evolve and continue to be reassessed in future IRP cycles as market forces and regulatory outcomes evolve.

Purpose of Hedging

While PacifiCorp focuses every day on minimizing net power costs for customers, the company also focuses every day on mitigating price risk to customers, which is done through hedging consistent with a robust risk management policy. For years PacifiCorp has followed a consistent hedging program that limits risk to customers, has tracked risk metrics assiduously and has diligently documented hedging activities. PacifiCorp's risk management policy and hedging program exists to achieve the following goals: (1) ensure reliable sources of electric power are available to meet PacifiCorp's customers' needs; (2) reduce volatility of net power costs for PacifiCorp's customers. The purpose is solely to reduce customer exposure to net power cost volatility and adverse price movement. PacifiCorp does not engage in a material amount of proprietary trading activities. Hedging is done solely for the purpose of limiting financial losses due to unfavorable wholesale market changes. Hedging modifies the potential losses and gains in net power costs associated with wholesale market price changes. The purpose of hedging is not to reduce or minimize net power costs. PacifiCorp cannot predict the direction or sustainability of changes in forward prices. Therefore, PacifiCorp hedges, in the forward market, to reduce the volatility of net power costs consistent with good industry practice as documented in the company's risk management policy.

Risk Management Policy and Hedging Program

PacifiCorp's risk management policy and hedging program were designed to follow electric industry best practices and are periodically reviewed at least annually by the company's risk oversight committee. The risk oversight committee includes PacifiCorp representatives from the front office, finance, risk management, treasury, and legal department. The risk oversight committee makes recommendations to the president of Pacific Power, who ultimately must approve any change to the risk management policy. PacifiCorp's current policy is also consistent with the guidelines that resulted from collaborative hedging workshops with parties in Utah, Oregon, Idaho and Wyoming that took place in 2011 and 2012.

The main components of PacifiCorp's risk management policy and hedging program are natural gas percent hedged volume limits, value-at-risk (VaR) limits and time to expiry VaR (TEVaR) limits. These limits force PacifiCorp to monitor the open positions it holds in power and natural gas on behalf of its customers on a daily basis and limit the size of these open positions by prescribed time frames in order to reduce customer exposure to price concentration and price volatility. The hedge program requires purchases of natural gas at fixed prices in gradual stages in advance of when it is required to reduce the size of this short position and associated customer risk. Likewise, on the power side, PacifiCorp either purchases or sells power in gradual stages in advance of anticipated open short or long positions to manage price volatility on behalf of customers.

Since 2003, PacifiCorp's hedge program has employed a portfolio approach of dollar cost averaging to progressively reduce net power cost risk exposure over a defined time horizon while adhering to best practice risk management governance and guidelines. PacifiCorp's current portfolio hedging approach is defined by increasing risk tolerance levels represented by progressively increasing percentage of net power costs across the forward hedging period. PacifiCorp incorporated a time to expiry value at risk (TEVaR) metric in May 2010. In May 2012, as a result of multiple hedging collaboratives, the company reintroduced natural gas percent hedge volume limits of forecast requirements into its policy. There has been no conflict to-date between the new volume limits and PacifiCorp's VaR and TEVaR limits, although the volume limits would supersede in such conflict, consistent with the guidelines from the hedging collaboratives.

The primary governance of PacifiCorp's hedging activities is documented in the company's Risk Management Policy. In May 2010, PacifiCorp moved from hedging targets based on volume percentages to targets based on the "to expiry value-at-risk" or TEVaR metric. The primary goal of this change was to increase the transparency of the combined natural gas and power exposure by period. It enhances the progressive approach to hedging that PacifiCorp has employed for many years and provides the benefit of a more sophisticated measure of risk that responds to changes in the market and changes in open natural gas and power positions. Importantly, the TEVaR metric automatically reduces hedge requirements as commodity price volatility decreases and increases hedge requirements as correlations among commodities diverge, all the while maintaining the same customer risk exposure.

Dollar cost averaging is the term used to describe gradually hedging over a period of time rather than all at once. This method of hedging, which is widely used by many utilities, captures time diversification and eliminates speculative bursts of market timing activity. Its use means that at times PacifiCorp buys at relatively higher prices and at other times relatively lower prices, essentially capturing an array of prices at many levels. While doing so, PacifiCorp steadily and adaptively meets its hedge goals through the use of this technique while staying within VaR and TEVaR and natural gas percent hedge volume limits.

The result of these program changes in combination with changes in the market (such as reduced volatility to which PacifiCorp's program automatically responds), has been a significant decrease in PacifiCorp's longer-dated hedge activity, *i.e.*, four years forward on a rolling basis.

As a result of the hedging collaboratives, PacifiCorp made the following material changes to its policy in May 2012: (l) a reduction in the standard hedge horizon from 48 months to 36 months and (2) a percent hedged range guideline for natural gas for each of the three forward l2-month periods, which includes a minimum natural gas open position in each of the forward 12-month periods. The percent hedged range guideline is greater for the first rolling twelve months and gradually smaller for the second and third rolling twelve-month periods. PacifiCorp also agreed to provide a new confidential semi-annual hedging report.

Cost Minimization

While hedging does not minimize net power costs, PacifiCorp takes many actions to minimize net power costs for customers. First, the company is engaged in integrated resource planning to plan resource acquisitions that are anticipated to provide the lowest cost resources to our customers in the long-run. PacifiCorp then issues competitive requests for proposals to assure that the resources we acquire are the lowest cost resources available on a risk-adjusted basis. In operations, PacifiCorp optimizes its portfolio of resources on behalf of customers by maintaining and operating a portfolio of assets that diversifies customer exposure to fuel, power market and emissions risk and utilize an extensive transmission network that provides access to markets across the western United States. Independent of any natural gas and electric price hedging activity, to provide reliable supply and minimize net power costs for customers, PacifiCorp commits generation units daily, dispatches in real time all economic generation resources and all must-take contract resources, serves retail load, and then sells any excess generation to generate wholesale revenue to reduce net power costs for customers. PacifiCorp also purchases power when it is less expensive to purchase power than to generate power from our owned and contracted resources.

Hedging cannot be used to minimize net power costs. Hedging does not produce a different expected outcome than not hedging and therefore cannot be considered a cost minimization tool. Hedging is solely a tool to mitigate customer exposure to net power cost volatility and the risk of adverse price movement. However, PacifiCorp does minimize the cost of hedging by transacting in liquid markets and utilizing robust protections to mitigate the risk of counterparty default. In addition, PacifiCorp reduces the amount of hedging required to achieve a given risk tolerance through its portfolio hedge management approach, which takes into account offsetting exposures when these commodities are correlated, as opposed to hedging commodity exposures to natural gas and power in isolation without regard for offsets.

Portfolio

PacifiCorp has a short position in natural gas because of its ownership of gas-fired electric generation that requires it to purchase large quantities of natural gas to generate electricity to serve its customers. PacifiCorp may have short or long positions in power depending on the shortfall or excess of the company's total economic generation relative to customer load requirements at a given point in time.

PacifiCorp hedges its net energy (combined natural gas and power) position on a portfolio basis to take full advantage of any natural offsets between its long power and short natural gas positions. Analysis has shown that a "hedge only power" or "hedge only natural gas" approach results in higher risk (*i.e.*, a wider distribution of outcomes). There is a natural need for an electric company with natural gas fired electricity generation assets to have a hedge program that simultaneously manages natural gas and power open positions with appropriate coordinated metrics. PacifiCorp's risk management department incorporates daily updates of forward prices for natural gas, power, volatilities and correlations to establish daily changes in open positions and risk metrics which inform the hedging decisions made every day by company traders.

PacifiCorp's hedge program does not rely on a long power position. However, the company's hedge program takes into account its full portfolio and utilizes continuously updated correlations of natural gas and power prices and thereby takes advantage of offsetting natural gas and power positions in circumstances when prices are correlated and a forecast long power position offsets a forecast short natural gas position. This has the effect of reducing the amount of natural gas hedging that PacifiCorp would otherwise pursue. Ignoring this correlation would instead result in the need for more natural gas hedges to achieve the same level of customer risk reduction.

PacifiCorp's customers have benefited from offsetting power and natural gas positions. Power and natural gas prices are closely related because natural gas is often the fuel on the margin in efficient dispatch, as is practiced throughout the western U.S. This means power sales tend to be more valuable in periods when natural gas is high cost, producing revenues that are a credit or offset to the high cost fuel. If spot natural gas prices depart from prior forward prices, power prices will tend to do so in the same direction, thereby naturally hedging some of the unexpected cost variance.

Effectiveness Measure

The goal of the hedging program is to reduce volatility in PacifiCorp's net power costs primarily due to changes in market prices. The goal is not to "beat the market" and, therefore, should not be measured on the basis of whether it has made or lost money for customers. This reduction in volatility is calculated and reported in the company's confidential semi-annual hedging report which it began producing as a result of the hedging collaborative.

Instruments

PacifiCorp's hedging program allows the use of several instruments including financial swaps, fixed price physical and options for these products. PacifiCorp chooses instruments that generally have greater liquidity and lower transaction costs. The company also considers, with respect to options, the likelihood of disallowance of the option premium in its six jurisdictions. There is no functional difference between financial swaps and fixed price physical transactions; both instruments are equally effective in hedging the PacifiCorp's fixed price exposure.

Treatment of Customer and Investor Risks

The IRP standards and guidelines in Utah require that PacifiCorp "identify which risks will be borne by ratepayers and which will be borne by shareholders." This section addresses this requirement. Three types of risk are covered: stochastic risk, capital cost risk, and scenario risk.

Stochastic Risk Assessment

Several of the uncertain variables that pose cost risks to different IRP resource portfolios are quantified in the IRP production cost model using stochastic statistical tools. The variables addressed with such tools include retail loads, natural gas prices, wholesale electricity prices, hydroelectric generation, and thermal unit availability. Changes in these variables that occur over the long-term are typically reflected in normalized revenue requirements and are thus borne by customers. Unexpected variations in these elements are normally not reflected in rates, and are therefore borne by investors unless specific regulatory mechanisms provide otherwise. Consequently, over time, these risks are shared between customers and investors. Between rate cases, investors bear these risks. Over a period of years, changes in prudently incurred costs will be reflected in rates and customers will bear the risk.

Capital Cost Risks

The actual cost of a generating or transmission asset is expected to vary from the cost assumed in the IRP. State commissions may determine that a portion of the cost of an asset was imprudent and therefore should not be included in the determination of rates. The risk of such a determination is borne by investors. To the extent that capital costs vary from those assumed in this IRP for reasons that do not reflect imprudence by PacifiCorp, the risks are borne by customers.

Scenario Risk Assessment

Scenario risk assessment pertains to abrupt or fundamental changes to variables that are appropriately handled by scenario analysis as opposed to representation by a statistical process or expected-value forecast. The single most important scenario risks of this type facing PacifiCorp continues to be government actions related to emissions and changes in load and transmission infrastructure. These scenario risks relate to the uncertainty in predicting the scope, timing, and cost impact of emission and policies and renewable standard compliance rules.

To address these risks, PacifiCorp evaluates resources in the IRP and for competitive procurements using a range of CO_2 policy assumptions consistent with the scenario analysis methodology adopted for PacifiCorp's 2019 IRP portfolio development and evaluation process. The company's use of IRP sensitivity analysis covering different resource policy and cost assumptions also addresses the need for consideration of scenario risks for long-term resource planning. The extent to which future regulatory policy shifts do not align with PacifiCorp's resource investments determined to be prudent by state commissions is a risk borne by customers.