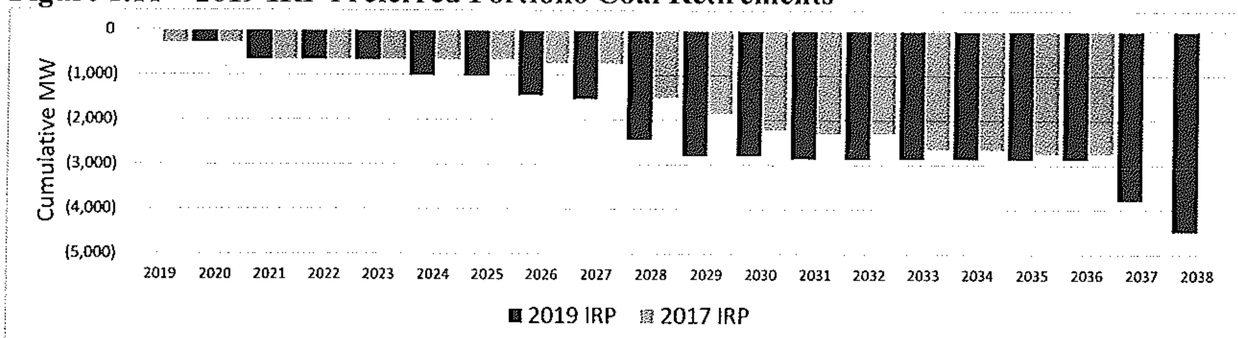
and dropping costs for new resource alternatives, of the 24 coal units currently serving PacifiCorp customers, the preferred portfolio includes retirement of 16 of the units by 2030 and 20 of the units by the end of the planning period in 2038. As shown in Figure 1.11, coal unit retirements in the 2019 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

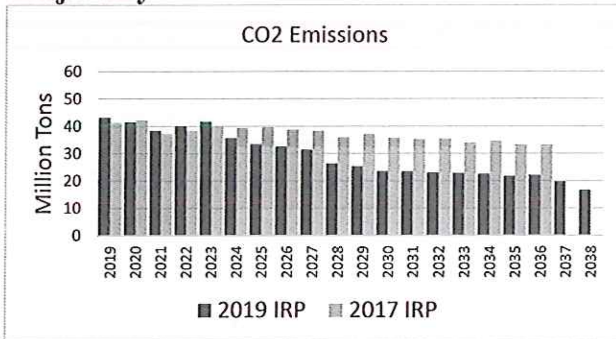
The 2019 IRP preferred portfolio reflects PacifiCorp's on-going efforts to provide cost-effective clean-energy solutions for our customers and accordingly reflects a continued trajectory of declining carbon dioxide (CO_2) emissions. PacifiCorp's emissions have been declining and continue to decline as 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.

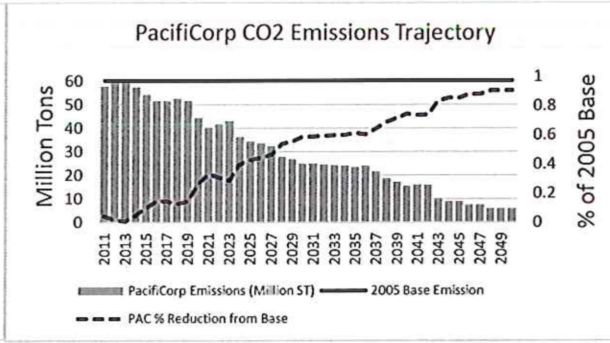
The chart on the left in Figure 1.12 compares projected annual CO_2 emissions between the 2019 IRP and 2017 IRP preferred portfolios. In this graph, emissions are not assigned to market purchases or sales, and in 2025, annual CO_2 emissions are down sixteen percent relative to the

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

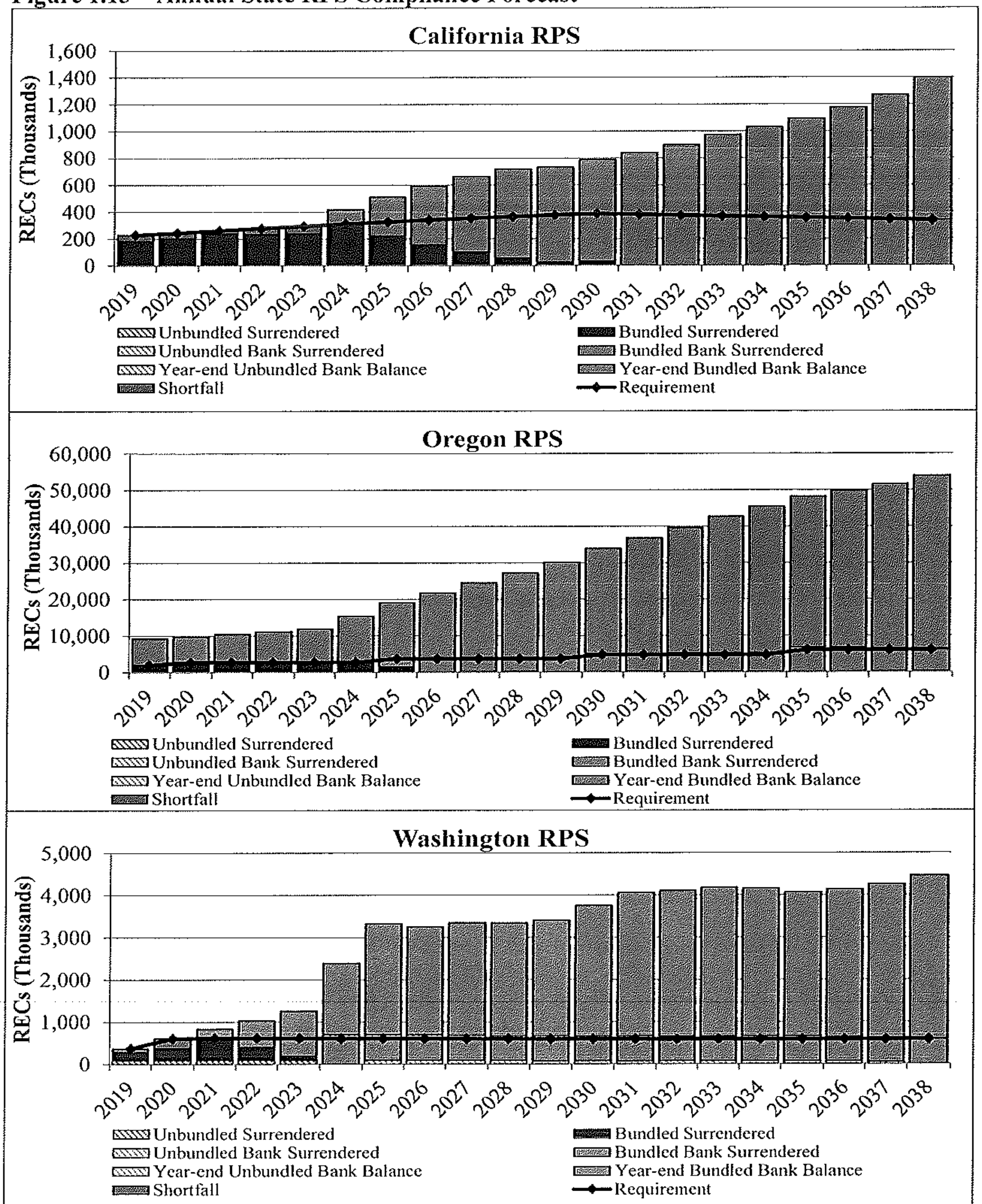
Figure 1.13 shows PacifiCorp's renewable portfolio standard (RPS) compliance forecast for California, Oregon, and Washington after accounting for new renewable resources in the preferred portfolio. While these resources are included in the preferred portfolio as cost-effective system resources and are 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%

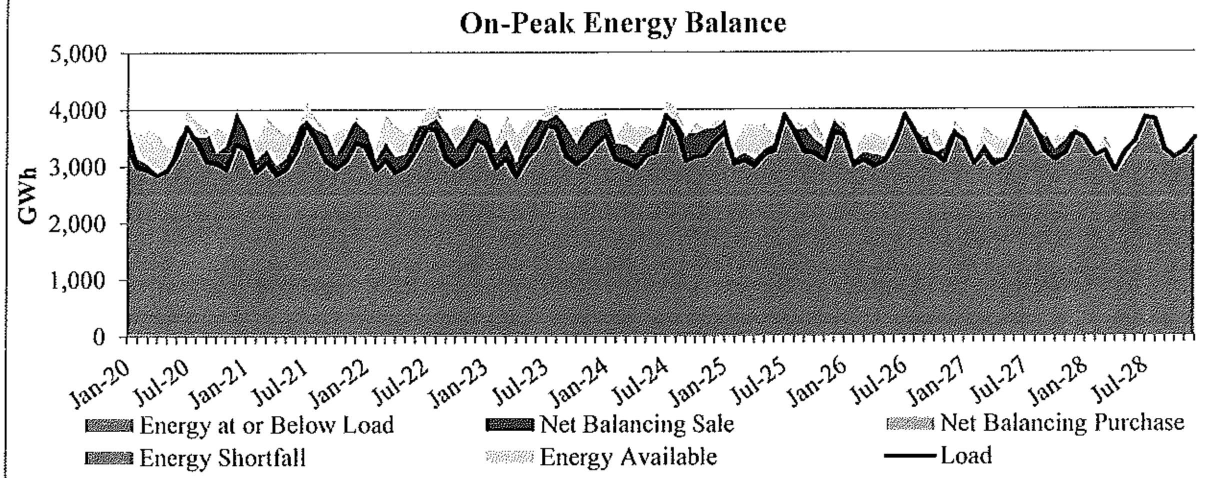
Energy Balance

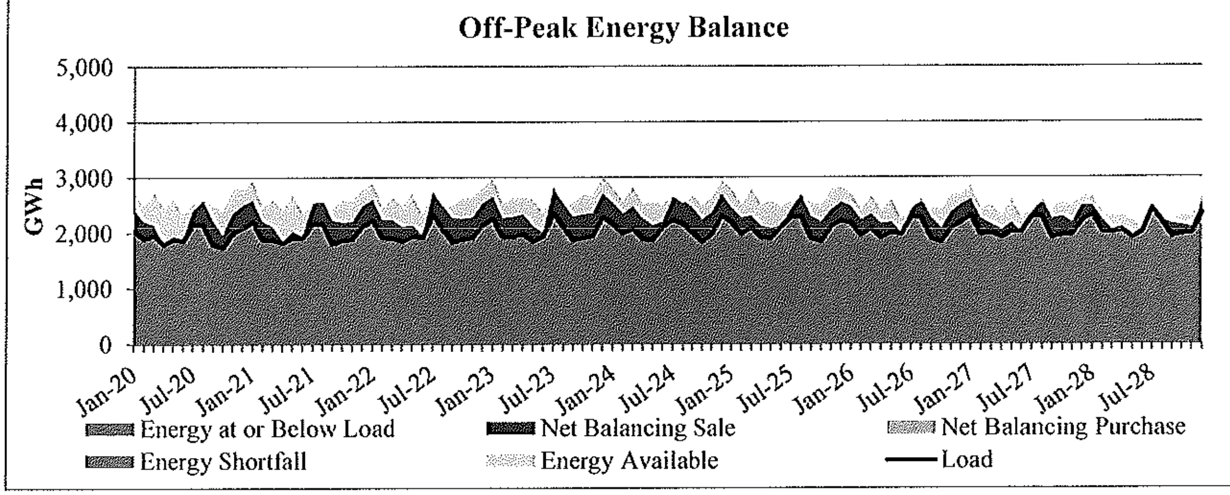
The capacity position shows how existing resources and loads balance during the coincident peak summer and winter periods, accounting for assumed coal unit retirements and incremental energy efficiency savings from the 2019 IRP preferred portfolio. Outside of these peak periods, PacifiCorp economically 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	**Naughton Unit 3:** • 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	**Cholla Unit 4:** • 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	**Jim Bridger Unit 1:** • 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	**All Source Request for Proposals:** • 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	**Energy Gateway South:** • 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	**Utah Valley Reinforcements:** • 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	**Northern Utah Reinforcements:** • 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	**Utah South Reinforcements:** • 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	**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.
3f	**Boardman to Hemmingway (B2H):** • 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.

Ex. AA-S-5

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

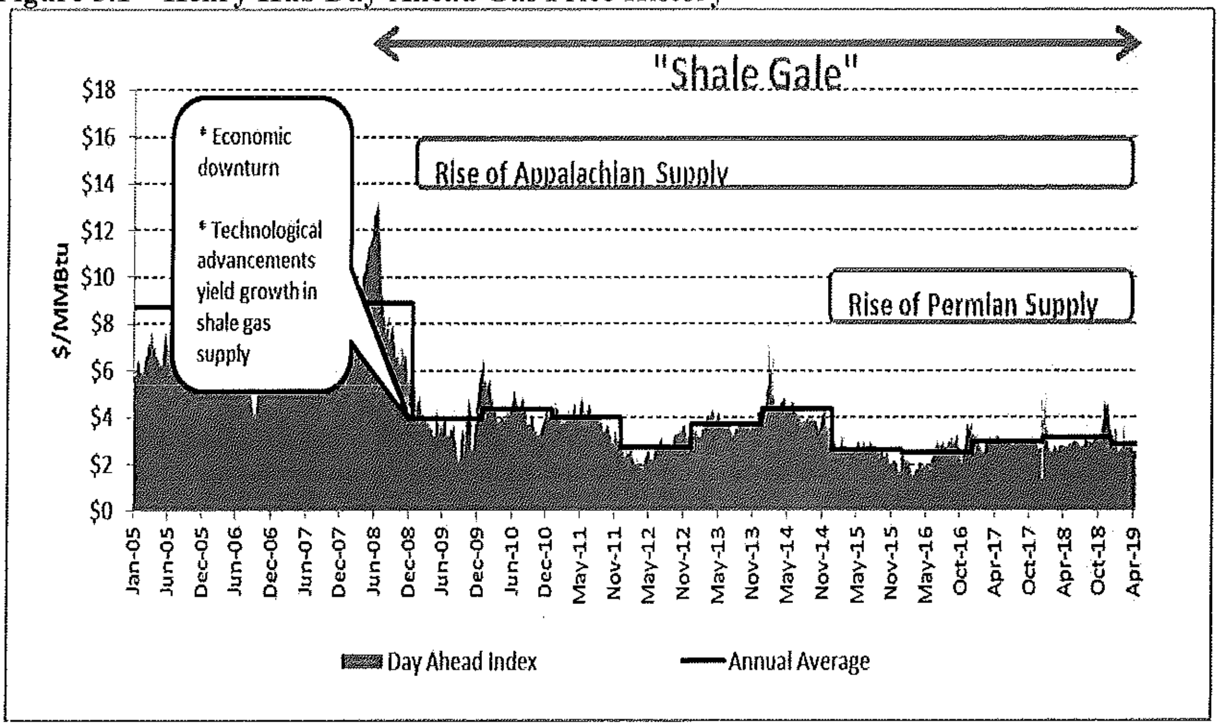
Since 2008, North American natural gas markets have undergone a remarkable paradigm shift. As shown in Figure 3.1, Henry Hub day-ahead gas prices hit a high of $13.31/MMBtu on July 2, 2008 and a low of $1.49/MMBtu on March 4, 2016. Day-ahead prices averaged $8.86/MMBtu in 2008, dropped to $3.94 in 2009,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

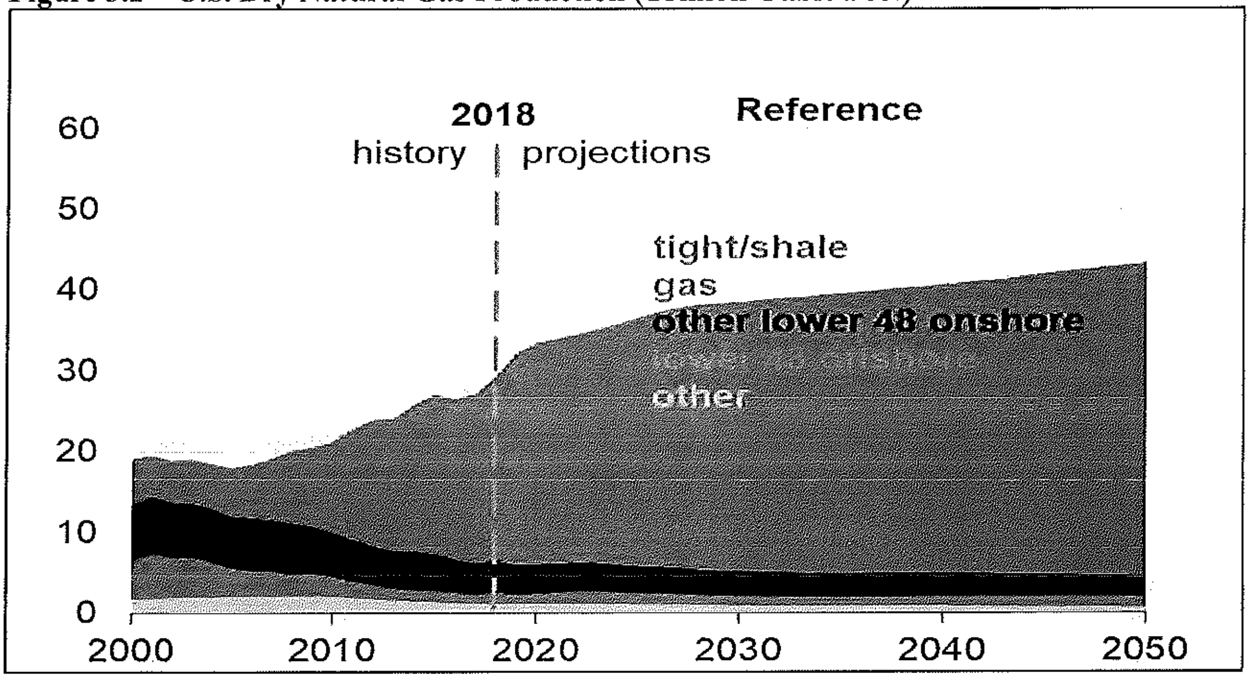
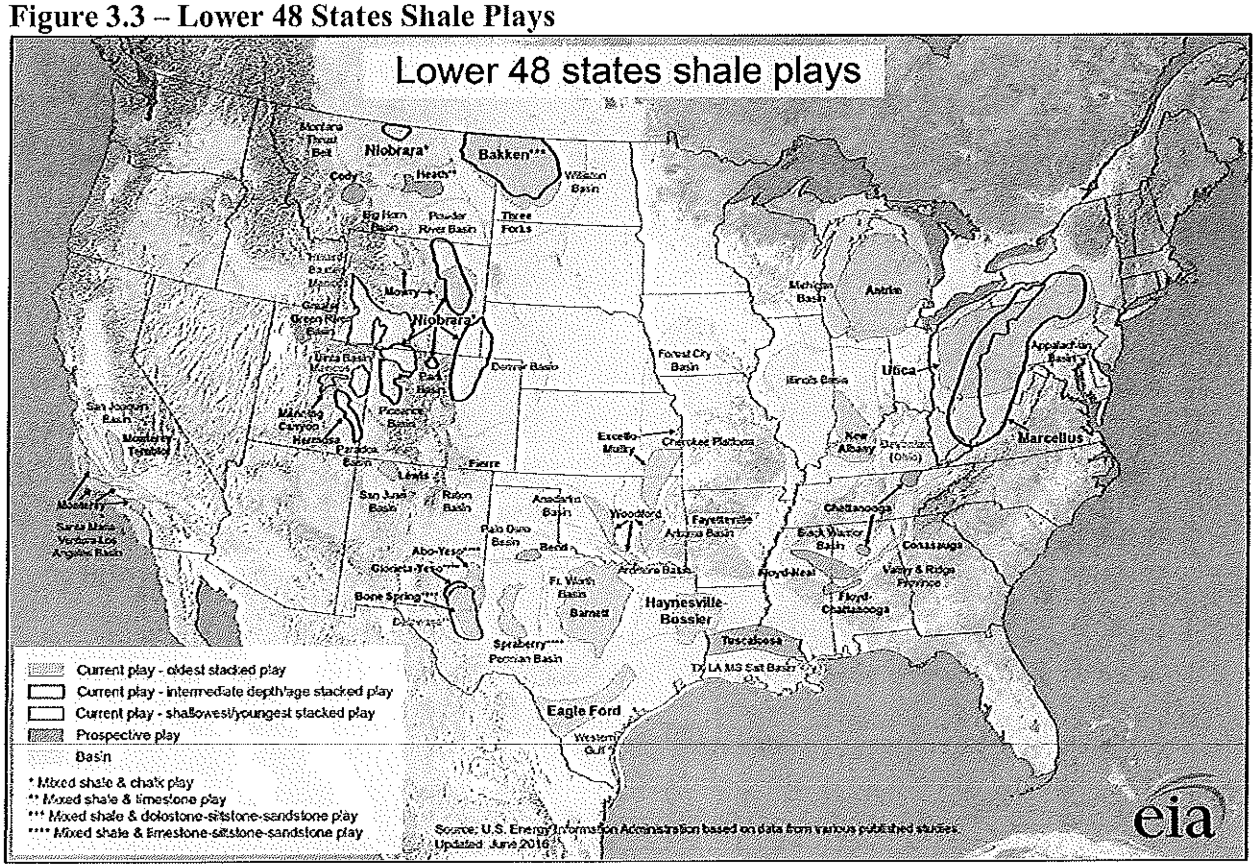
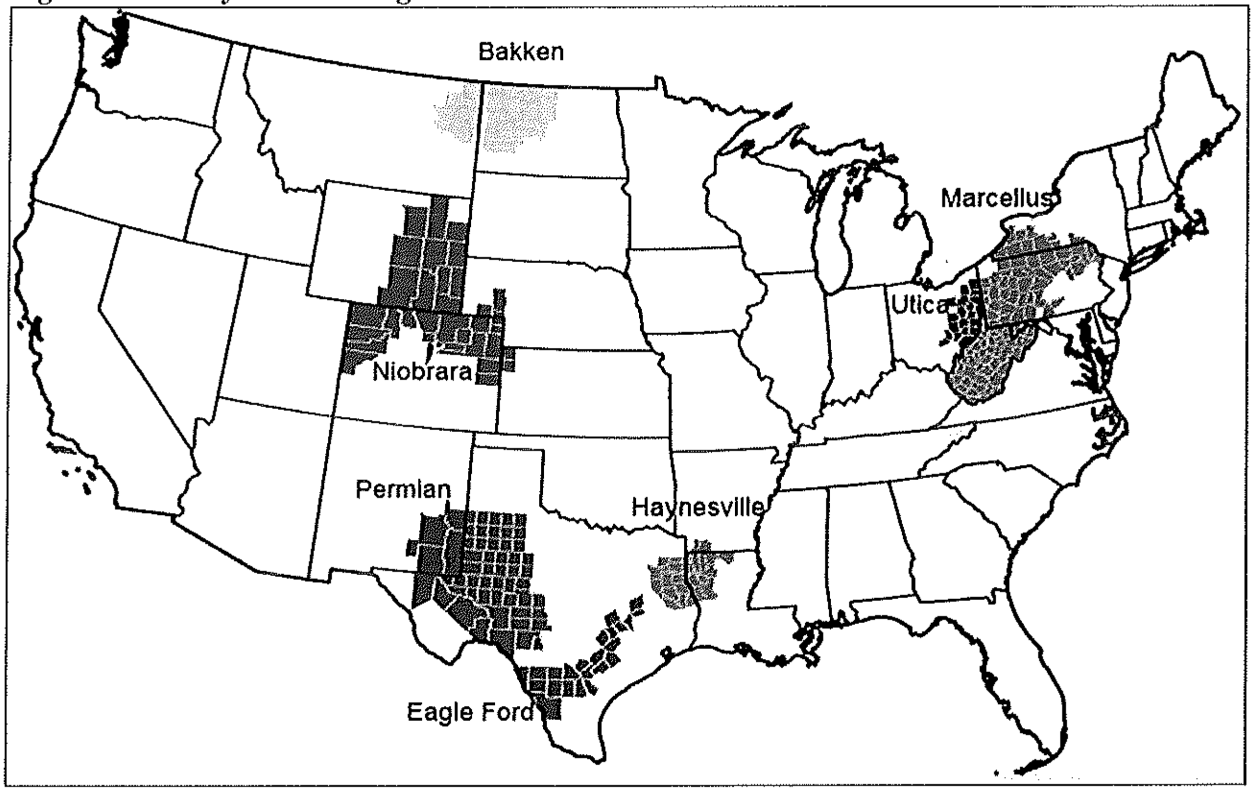


Figure 3.3 – Lower 48 States Shale Plays



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.

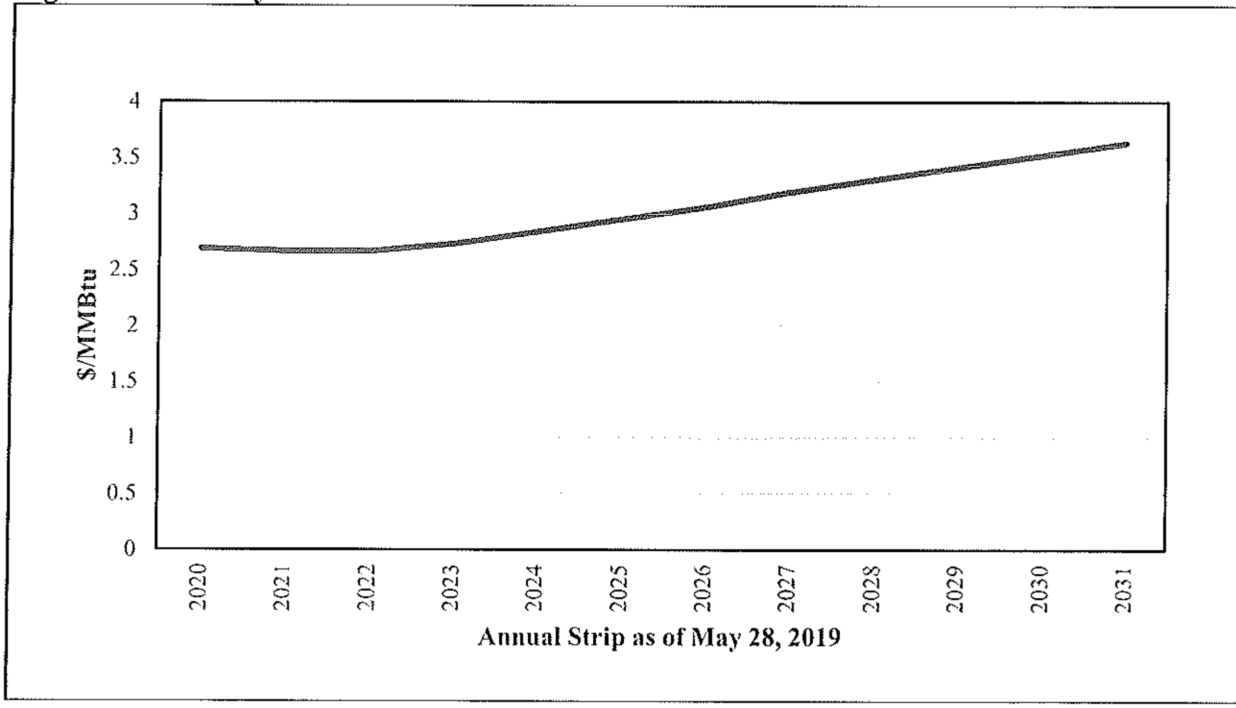
online in 2019 – 2020 will help alleviate the glut but natural gas prices are expected to remain depressed through 2020.

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 NOx 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 NOx 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 NOx 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 NOx 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.

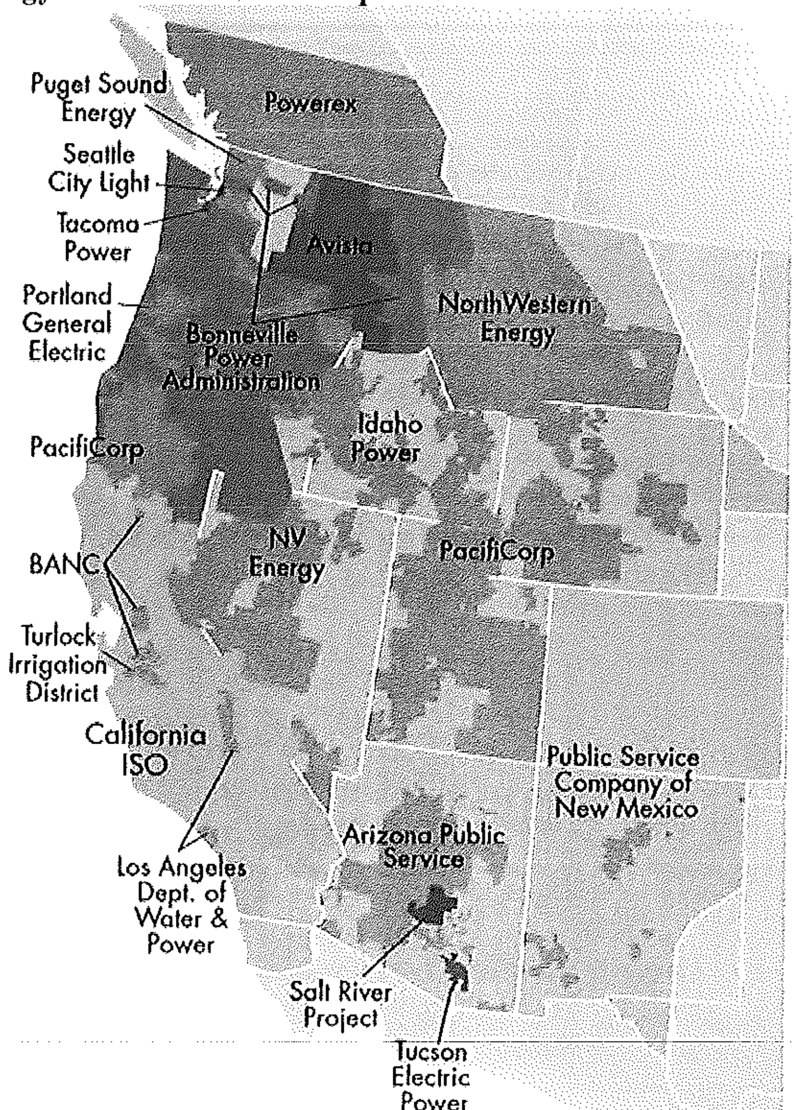
Irrigation Rate Design

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

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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

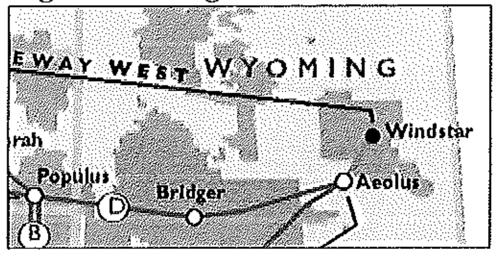
In addition to the Windstar-to-Populus line (Energy Gateway Segment D), the Gateway West transmission project also includes the Populus-to-Hemingway transmission segment (Energy Gateway Segment E). In a future IRP, PacifiCorp will support a request for acknowledgement to construct the balance of Gateway 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

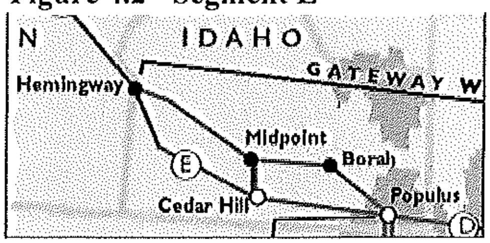


- D2—A single-circuit 500-kV line that is currently under construction running approximately 140 miles from the Aeolus substation (under construction) to a new annex substation (Anticline, also currently under construction) near the existing Bridger substation in western Wyoming; and

- 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.

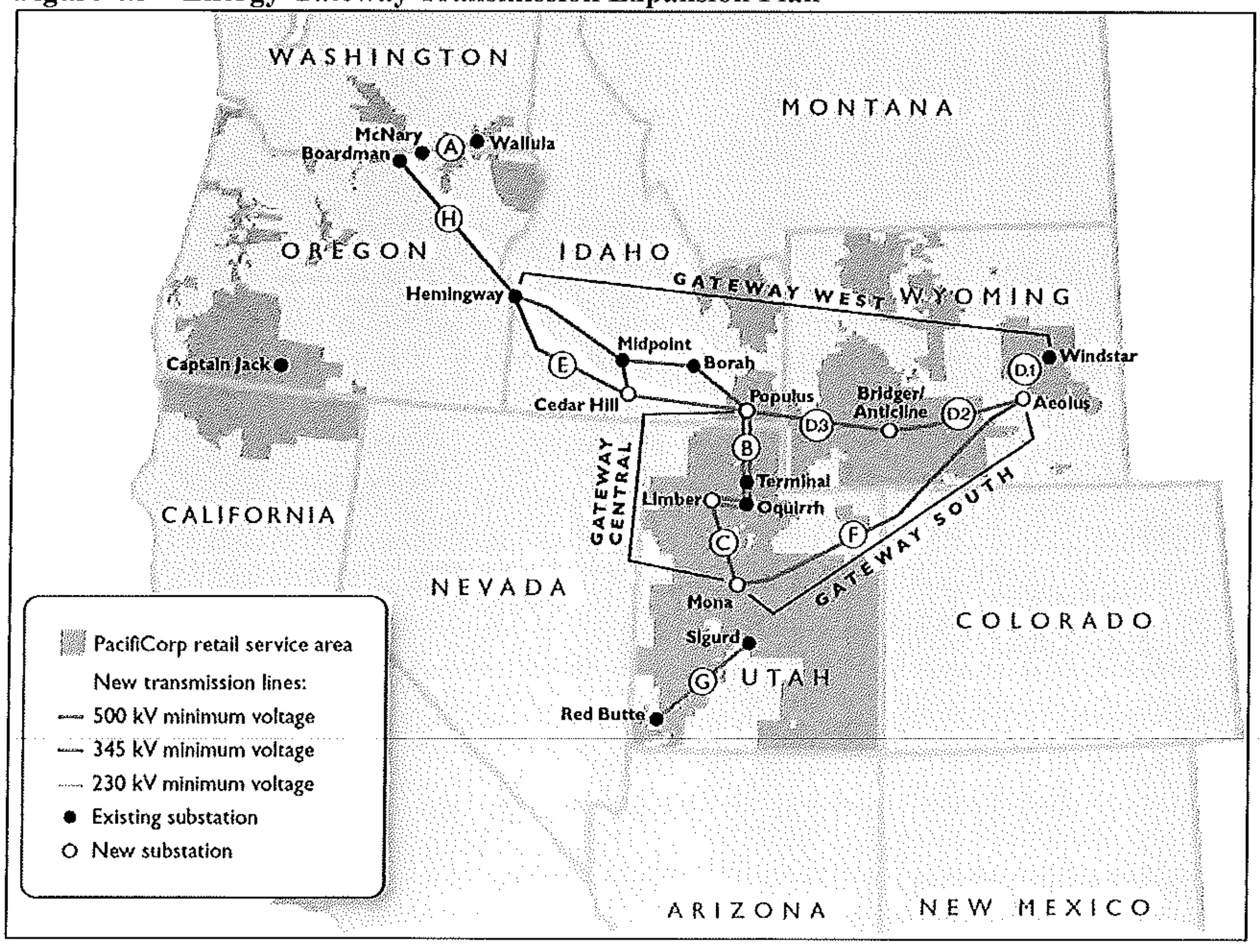
In December 2016, the BLM issued its ROD and right-of-way grant for the Gateway South project.

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
  - 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.
  - 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
     - 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.
     - 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
     - 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.
     - 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
     - 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.
     - 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.

Ex. AA-S-5

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 II Solar	QF	WY	20
Sage III 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.

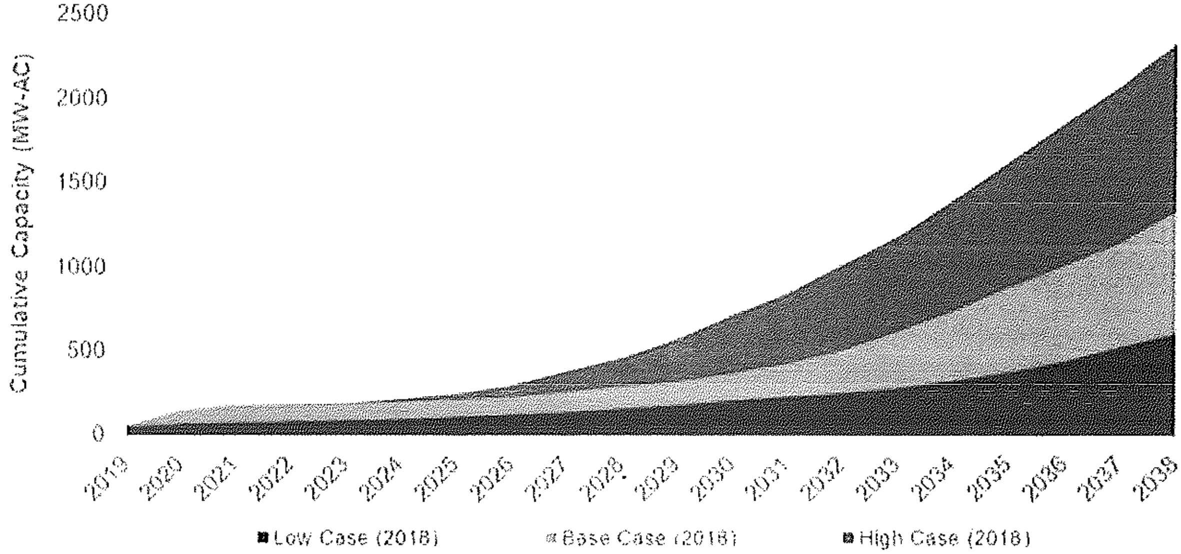
[1/] Assumes six percent for planning reserves in addition to realized irrigation load curtailment in Idaho and Utah of 170 MW and 20 MW, respectively, with an additional 3 MW from the Oregon pilot through 2020.
[2/] Due to the timing of the 2019 IRP load forecast, there is a small amount (81 MW) of 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.

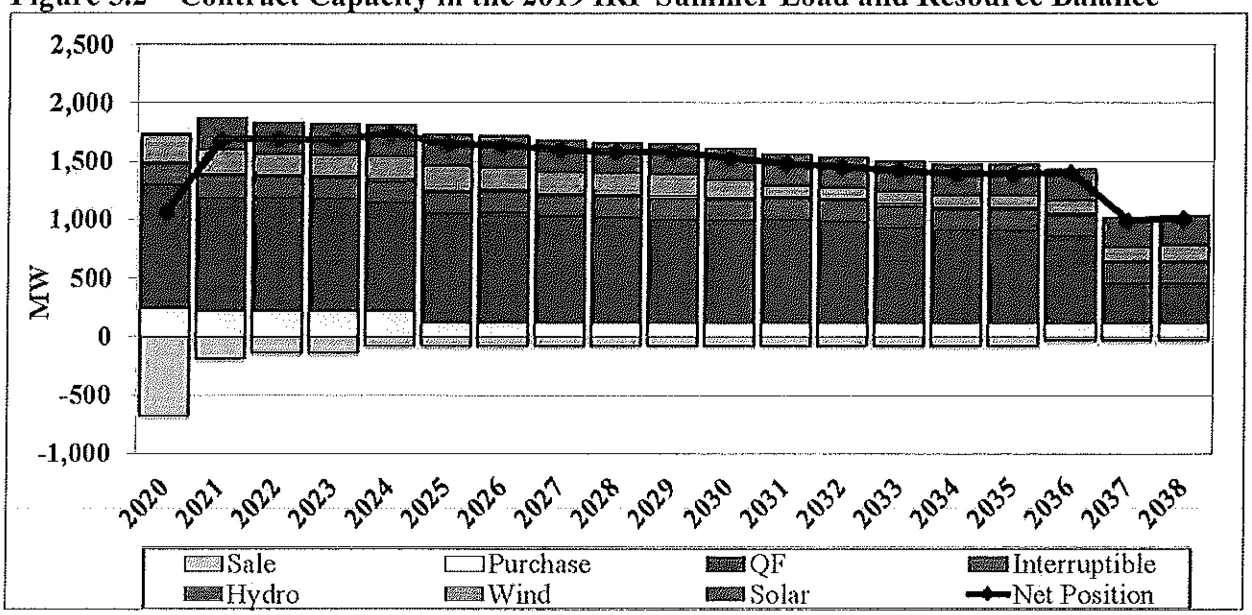
Figure 5.1 – Private Generation Market Penetration (MW_{AC}), 2019-2038



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:

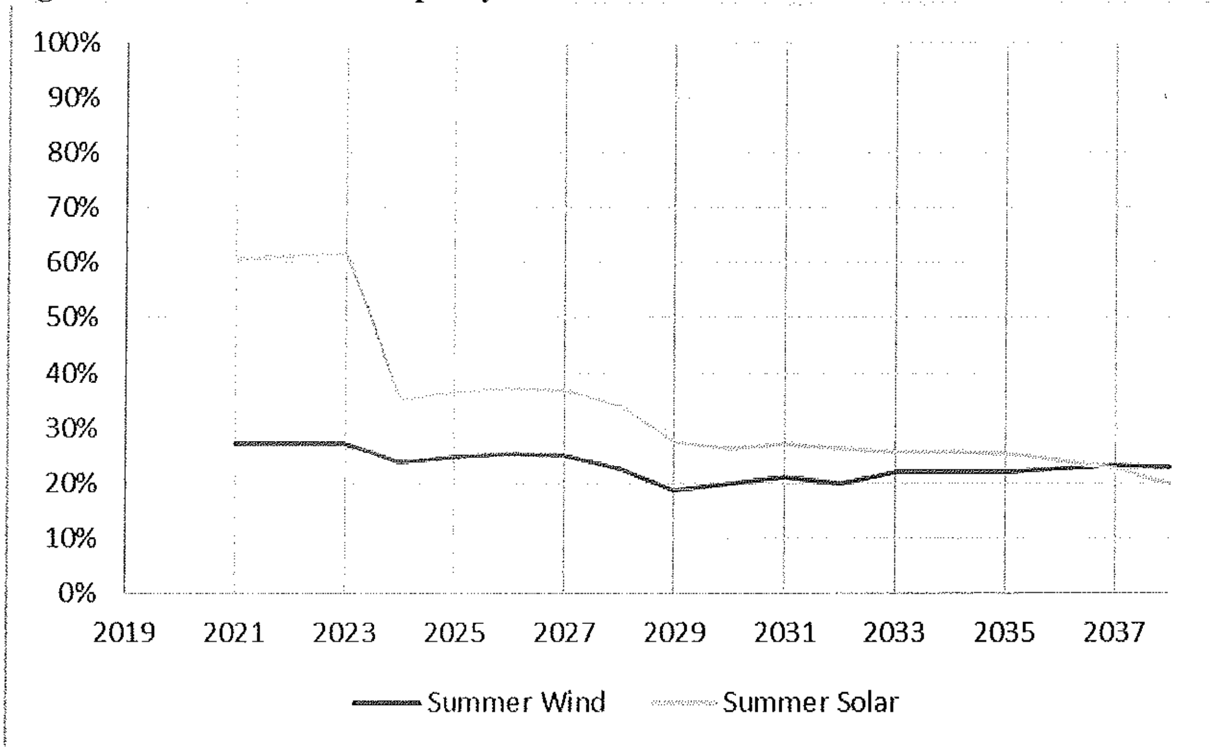
Thermal
This category includes all thermal plants that are wholly owned or partially owned by PacifiCorp. The capacity balance counts these plants at their expected availability (after derating for forced outages and maintenance) during summer or winter hours with loss of load events in the final capacity 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.

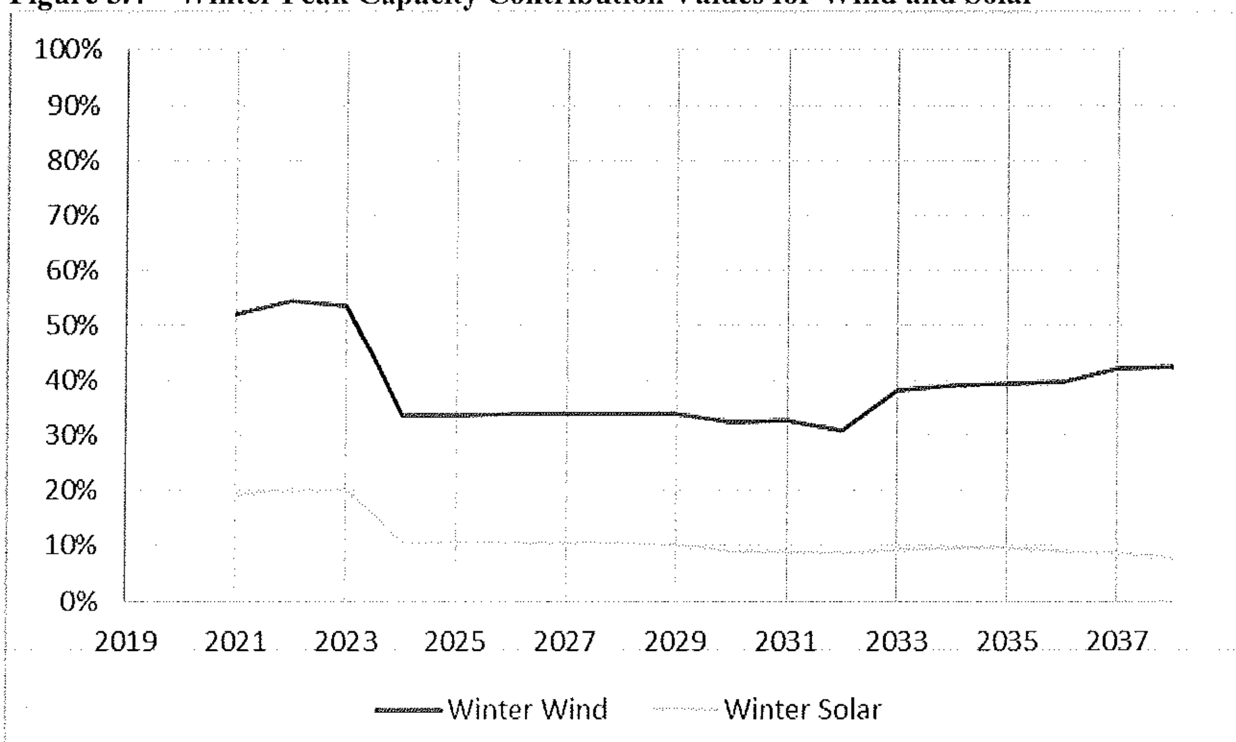
[3] Please refer to Volume II, Appendix N (Capacity Contribution Study)

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).