ROCKY MOUNTAIN POWER
A DIVISION OF PACIFICORP

1407 W North Temple, Suite 330
Salt Lake City, Utah 84116

May 1, 2018

VIA ELECTRONIC FILING
AND OVERNIGHT DELIVERY

Utah Public Service Commission
Heber M. Wells Building, 4th Floor
160 East 300 South
Salt Lake City, UT 84114

Attention: Gary Widerburg
Commission Secretary

RE: Docket No. 17-035-16
PacifiCorp's 2017 Integrated Resource Plan Update

Please find enclosed PacifiCorp's 2017 Integrated Resource Plan Update (2017 IRP Update). Copies of the 2017 IRP Update are also available electronically on PacifiCorp's website, at www.pacificorp.com/irp. Confidential workpapers for the 2017 IRP Update will be available to state regulators and any party who has intervened in this Docket and certified that it agrees to be bound by the Commission's confidentiality rules, R746-1-602 and -603. As requested by the Commission, Rocky Mountian Power is also providing seven (7) printed copies of the filing via overnight delivery.

PacifiCorp's 2017 IRP Update provides a number of updates including a description of resource planning, procurement activities, and status of the Energy Vision 2020 projects since the 2017 IRP, an updated load and resource balance, an updated resource portfolio reflecting updates to load forecast, market prices and other model inputs, and a status update on action plan items from the 2017 IRP.

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Informal inquiries may be directed to Jana Saba, Utah Regulatory Affairs Manager, at (801) 220-2823.

Sincerely,

Joelle Steward

Joelle Steward
Vice President, Regulation

Enclosures

cc: Service List

CERTIFICATE OF SERVICE

Docket No. 17-035-16

I hereby certify that on May 1, 2018, a true and correct copy of the foregoing was served by electronic mail and/or overnight delivery to the following:

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Jennifer Angell
Supervisor, Regulatory Operations

2017 INTEGRATED RESOURCE PLAN UPDATE

May 1, 2018

PACIFICORP
A BERKSHIRE HATHAWAY ENERGY COMPANY

This 2017 Integrated Resource Plan Update is based upon the best available information at the time of preparation. The IRP action plan will be implemented as described herein, but is subject to change as new information becomes available or as circumstances change. It is PacifiCorp's intention to revisit and refresh the IRP action plan no less frequently than annually. Any refreshed IRP action plan will be submitted to the State Commissions for their information.

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Cover Photos (Top to Bottom):
Wind Turbine: *Marengo Wind Project*
Solar: *Pavant Solar Plant*
Transmission: *Sigurd to Red Butte Transmission Line*
Demand-Side Management: *Smart thermostat*
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CHAPTER 1– EXECUTIVE SUMMARY

PacifiCorp submitted its 2017 Integrated Resource Plan (IRP) to state regulatory commissions on April 4, 2017. That plan provides a framework for future actions that PacifiCorp will take to provide reliable and reasonably priced service for its customers through the least-cost, least-risk resource portfolio. The 2017 IRP Update reflects resource planning and procurement activities that have occurred since the 2017 IRP and presents an updated load-and-resource balance and an updated resource portfolio consistent with changes in the planning environment. The 2017 IRP Update also provides a status update for the action plan filed with the 2017 IRP in Chapter 10. In presenting the updated load-and-resource balance and updated resource portfolio, PacifiCorp shows changes relative to the 2017 IRP which covers the 2017 to 2036 planning horizon. In the 2017 IRP Update PacifiCorp also addresses recommendations and requirements identified by its state regulatory commissions during the 2017 IRP acknowledgement or acceptance process.

2017 IRP Update Highlights

PacifiCorp's long-term planning process involves balanced consideration of cost, risk, uncertainty, supply reliability/delivery, and long-run public policy goals. The following summarizes the key highlights of PacifiCorp's 2017 IRP Update:

- PacifiCorp's 2017 IRP Update preferred portfolio includes updated cost-and-performance information for the Energy Vision 2020 projects, which include 1,311 MW of new wind, repowering just over 999 MW of existing wind capacity, and the new 140-mile, 500 kilovolt (kV) Aeolus-to-Bridger/Anticline transmission line in Wyoming. Collectively, these resources contribute to meeting the capacity need identified in PacifiCorp's updated load-and-resource balance and are on track to be in service by the end of 2020. The Energy Vision 2020 projects continue to be a central feature of the 2017 IRP Update least-cost, least-risk preferred portfolio and will provide substantial benefits for customers.

  - The 1,311 MW of new wind projects were identified through a robust competitive bidding process. Updated economic analysis of these new wind resources, enabled by the Aeolus-to-Bridger/Anticline transmission line, shows that they will provide substantial customer benefits. In addition to creating construction jobs and tax revenue in the state of Wyoming, the new wind projects will qualify for the full value of federal production tax credits (PTCs) and generate zero-fuel-cost energy.

  - The new 500-kv, 140-mile Aeolus-to Bridger/Anticline transmission line, which is needed to strengthen the electric reliability of PacifiCorp's transmission system, will provide critical voltage support to the Wyoming transmission network, mitigate the impact of outages on the existing system, enhance the company's ability to comply with mandated reliability and performance standards, and reduce line losses. The new transmission line will also relieve existing transmission constraints, increase transfer capability and enable interconnection of new capacity.

  - The 999 MW of repowered wind facilities located in Oregon, Washington and Wyoming, will provide substantial customer benefits and optimize the existing wind fleet by using new technology that increases zero-fuel-cost energy production, reduces ongoing operating costs by avoiding capital expenditures related to component failures, renews the existing wind fleet with new turbines that extend the useful life of the wind facilities by up to 13 years, requalifies the wind facilities to receive the full value of PTCs for another 10 years, and improves delivery of wind energy into the transmission system through enhanced voltage support and power quality.

- With reduced loads and lower renewable resource costs, the updated preferred portfolio contains no new natural gas resources through the 20-year planning horizon. This is the first time an IRP has not included new fossil-fueled generation as a least-cost, least-risk resource for PacifiCorp.

- Through the end of 2036, the updated preferred portfolio includes over 2,700 MW of new wind resources, 1,860 MW of new solar resources, 1,877 MW of incremental energy efficiency resources, and approximately 268 MW of direct-load control resources.

- The 2017 IRP Update preferred portfolio continues to assume existing owned coal capacity will be reduced by 3,650 MW through the end of 2036.

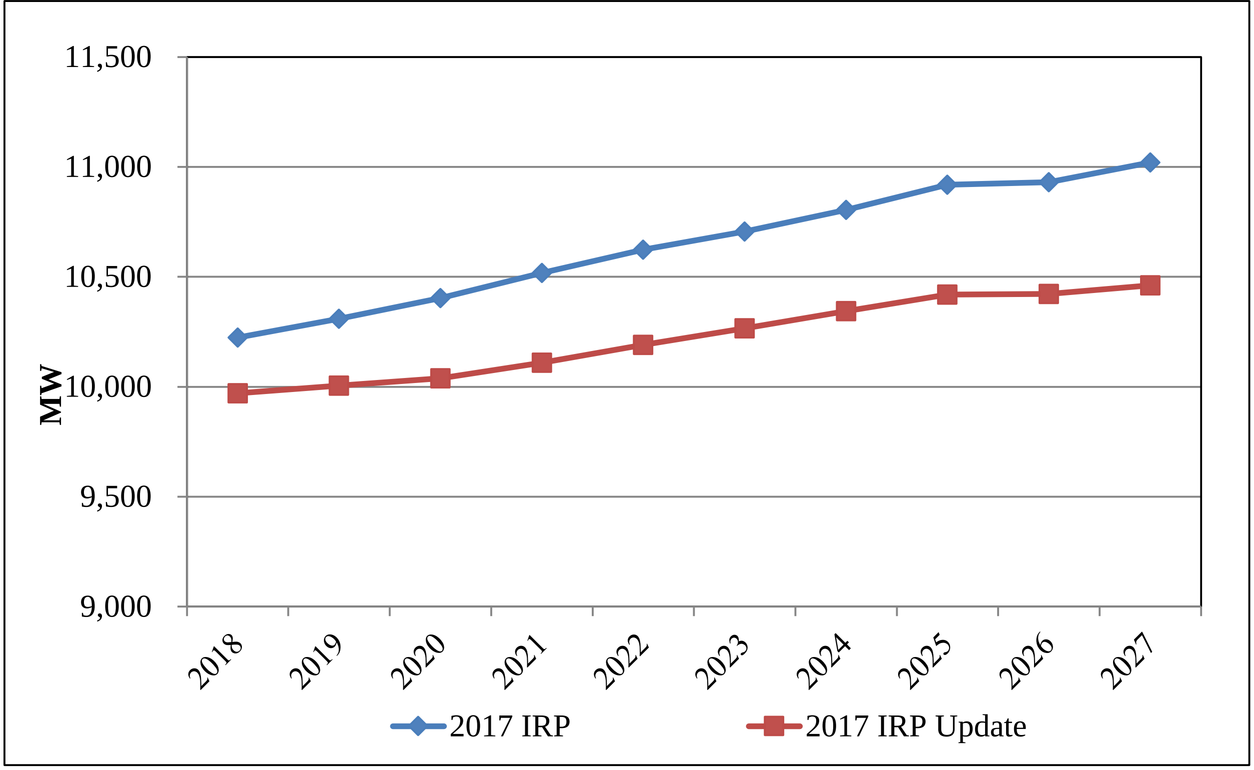
- In accordance with action items in the 2017 IRP action plan, PacifiCorp completed unit-specific coal studies in the 2017 IRP Update for Naughton Unit 3, Cholla Unit 4, Dave Johnston Unit 3, and Jim Bridger Units 1 and 2. Consistent with the findings from these studies, the 2017 IRP Update continues to assume no incremental selective catalytic reduction (SCR) emission-reduction systems will be needed to satisfy regional haze compliance obligations. PacifiCorp continues to assume Cholla Unit 4 retires at the end of 2020, Dave Johnston Unit 3 retires at the end of 2027, and Jim Bridger Units 1 and 2 retire at the end of 2028 and 2032, respectively. The 2017 IRP Update assumes Naughton Unit 3 retires end of January 2019, shifted one month from the 2017 IRP that assumed retirement at the end of 2018.

- On March 28, 2017, President Trump issued an Executive Order directing the U.S. Environmental Protection Agency (EPA) to review the Clean Power Plan (CPP) and, if appropriate, suspend, revise, or rescind the CPP, as well as related rules and agency actions. On October 10, 2017, the EPA issued a proposal to repeal the CPP and the EPA will take comments on the proposed repeal until April 26, 2018. In addition, the EPA published in the Federal Register an Advance Notice of Proposed Rulemaking December 28, 2017, seeking public input on, without committing to, a potential replacement rule. The public comment period for the Advance Notice of Proposed Rulemaking concluded February 26, 2018. PacifiCorp will continue to follow activities related to the CPP; however, the company has not included the CPP in its assumptions for the 2017 IRP Update. Rather, the 2017 IRP Update includes a medium CO_2 price assumption starting in 2030 to reflect possible regulatory changes in the future.

- On December 22, 2017, President Trump signed into law H.R. 1 (Tax Reform Act) which generally impacts PacifiCorp for tax years beginning in 2018 and going forward. The Tax Reform Act reduced the federal corporate income tax rate from a top rate of 35 percent to an across-the-board federal corporate income tax rate of 21 percent. The Tax Reform Act left intact the federal tax credit rules and phase-outs for wind and solar facilities as enacted in the 2015 tax extender legislation. Public utility property will no longer be eligible for bonus depreciation for property placed in service after September 27, 2017, unless it was subject to a written binding contract on September 27, 2017. PacifiCorp's 2017 IRP Update accounts for the Tax Reform Act, and updated economic analysis of Energy Vision 2020 projects are greater than originally estimated in the 2017 IRP despite the reduction in federal corporate income tax rate.

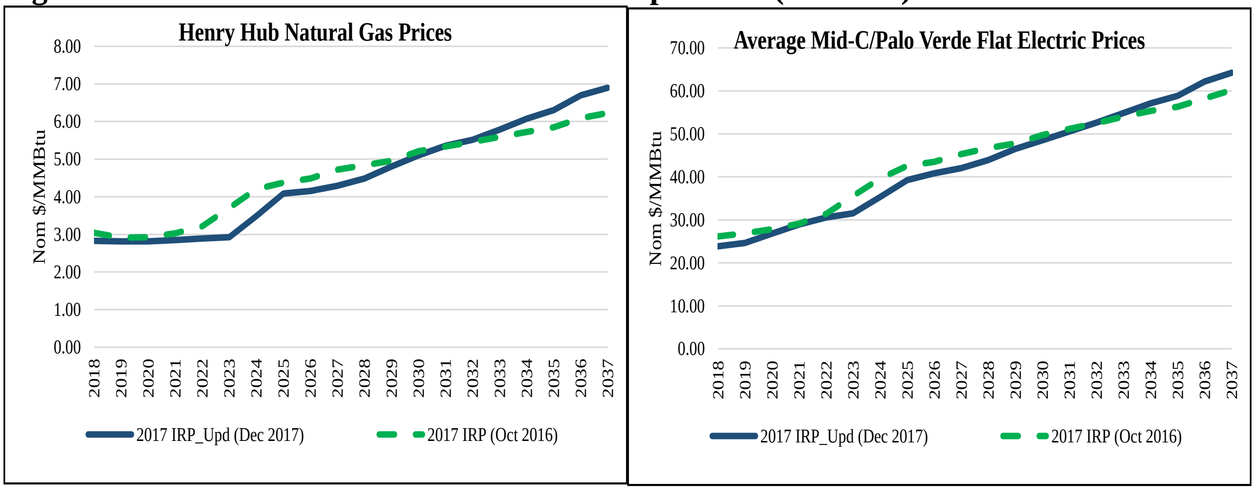
- As shown in Figure 1.1 PacifiCorp's most recent coincident system peak load forecast, is down relative to the 2017 IRP. On average, across the first ten years of the planning period, the coincident system peak is down by roughly 424 MW relative to the 2017 IRP reflecting a less favorable outlook for the industrial segment and the adoption of more efficient appliances by residential customers.

Figure 1.1 – System Coincident Peak Load



- Figure 1.2 shows that forecasted natural gas and energy prices have declined from those in the 2017 IRP through about the 2030-2031 time frame. Domestic gas price forecasts continue to be driven down by growth in unconventional shale-gas plays. This in turn (combined with lower forecasted regional loads) impacts forward market power prices.

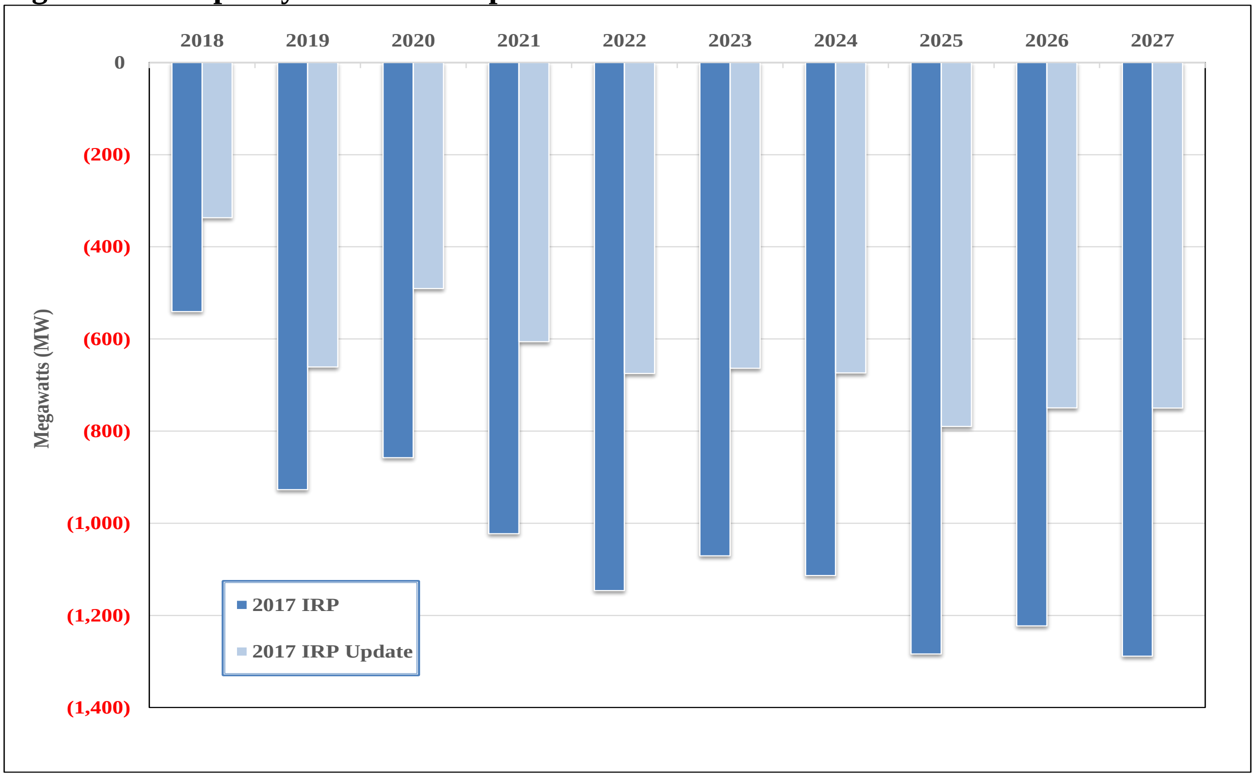
Figure 1.2 – Power and Natural Gas Price Comparisons (Nominal)



Load-and-Resource Balance

Figure 1.3 summarizes the 2017 IRP Update capacity load-and-resource balance, before acquiring new resources and making firm market purchases, alongside the load-and-resource balance from the 2017 IRP. The load-and-resource balance capacity need has decreased by an average of 408 MW, relative to the 2017 IRP, reflecting a lower load forecast and an increase in qualifying facility contracts. The capacity need in both the 2017 IRP and the 2017 IRP Update increases at the end of January 2019 due to the assumed early retirement of Naughton Unit 3 and at the end of 2020 due to the assumed early retirement of Cholla Unit 4. The 2017 IRP Update load-and-resource balance continues to show a capacity need throughout the planning period, but this need has been reduced relative to the 2017 IRP by 204 MW in 2018 rising to 539 MW by 2027.

Figure 1.3 – Capacity Position Comparison



Preferred Portfolio Update

Table 1.1 reports the 2017 IRP Update preferred portfolio and differences relative to the 2017 IRP preferred portfolio. The table shows the resource mix that achieves a 13-percent planning reserve margin in each reported year. As compared to the 2017 IRP preferred portfolio, changes in the resource mix reflect updates to Energy Vision 2020 new wind resources and a reduced load forecast that result in removal of the need for a new natural gas simple cycle combustion turbine (SCCT) and combined cycle combustion turbine (CCCT) and reduced reliance on higher risk market transactions throughout the 20-year planning horizon. As was the case in the 2017 IRP preferred portfolio, PacifiCorp continues to plan to meet its customers' needs largely through the acquisition of cost-effective Energy Vision 2020 resources, energy efficiency (Class 2 demand-side management (DSM)) resources, and front-office transactions (FOTs), over the next ten years.

Table 1.1 – Comparison of 2017 IRP Update with 2017 IRP Preferred Portfolio (Megawatts)

2017 IRP Update

	Capacity (MW)																				10- year Total
Resource	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**	**2036**	**2017-2036**
Expansion Options																					
Gas - CCCT	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Gas- Peaking	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
DSM - Energy Efficiency	150	119	126	122	105	99	96	95	100	96	90	90	84	88	87	75	70	63	61	61	**1,877**
DSM - Load Control	-	-	-	-	-	-	-	-	-	-	-	-	68	-	-	-	50	48	90	12	**268**
Renewable - Wind	-	-	-	911	400	-	-	-	-	-	-	-	-	121	-	-	800	-	333	149	**2,713**
Renewable - Geothermal	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Renewable - Utility Solar	-	-	-	-	-	-	-	-	-	-	-	-	-	651	95	132	976	-	6	-	**1,860**
Renewable - Biomass	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Storage - Pumped Hydro	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Storage - CAES	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Storage - Other	-	-	1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	**1**
Front Office Transactions - Summer *	402	319	624	463	395	445	419	428	538	499	500	1,247	1,575	1,575	1,575	1,575	1,575	1,564	1,575	1,544	**942**
Front Office Transactions - Winter *	253	308	303	296	303	305	310	304	317	330	343	357	758	794	809	776	868	924	1,031	1,486	**559**
Nuclear	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
IGCC with CCS	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Existing Unit Changes																					
Coal Early Retirement/Conversions	-	-	(280)	-	(387)	-	-	-	-	(82)	-	-	(354)	-	-	-	(359)	-	-	-	**(1,463)**
Thermal Plant End-of-life Retirements	-	-	-	-	-	-	-	-	-	-	-	(762)	-	(357)	(77)	-	(358)	-	(82)	-	**(1,635)**
Coal Plant Gas Conversion Additions	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Turbine Upgrades	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Total	**805**	**746**	**774**	**1,792**	**815**	**848**	**825**	**827**	**954**	**843**	**934**	**933**	**2,132**	**2,871**	**2,489**	**2,559**	**3,623**	**2,599**	**3,014**	**3,252**	

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

2017 IRP Update less 2017 IRP Preferred Portfolio

	Capacity (MW)																				10- year Total
Resource	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**	**2036**	**2017-2036**
Expansion Options																					
Gas - CCCT	-	-	-	-	-	-	-	-	-	-	-	-	-	(436)	-	-	(477)	-	-	-	**(913)**
Gas- Peaking	-	-	-	-	-	-	-	-	-	-	-	-	(200)	-	-	-	(200)	-	-	-	**(400)**
DSM - Energy Efficiency	(4)	(9)	(5)	0	(18)	(15)	(22)	(23)	(12)	(15)	(19)	(11)	(12)	(7)	(10)	(8)	(4)	(3)	(2)	(2)	**(200)**
DSM - Load Control	-	-	-	-	-	-	-	-	-	-	-	(193)	(71)	(5)	(3)	(3)	47	44	87	-	**(98)**
Renewable - Wind	-	-	-	911	(701)	-	-	-	-	-	-	-	-	121	(85)	-	800	-	333	(625)	**754**
Renewable - Geothermal	-	-	-	-	-	-	-	-	-	-	-	-	(30)	-	-	-	-	-	-	-	**(30)**
Renewable - Utility Solar	-	-	-	-	-	-	-	-	-	-	-	(11)	(97)	651	(23)	(104)	751	(48)	(285)	(13)	**820**
Renewable - Biomass	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Storage - Pumped Hydro	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Storage - CAES	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Storage - Other	-	-	1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	**1**
Front Office Transactions - Summer *	(98)	(202)	(254)	(345)	(404)	(471)	(425)	(457)	(504)	(479)	(540)	(328)	-	9	-	-	-	(11)	-	6	**(225)**
Front Office Transactions - Winter *	(28)	(24)	30	(11)	(16)	(3)	4	17	(31)	(21)	47	(55)	207	278	319	326	431	447	552	720	**159**
Nuclear	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
IGCC with CCS	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Existing Unit Changes																					
Coal Early Retirement/Conversions	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Thermal Plant End-of-life Retirements	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0	-	-	-	-	-	0
Coal Plant Gas Conversion Additions	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Turbine Upgrades	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Total	**(130)**	**(235)**	**(228)**	**556**	**(1,139)**	**(489)**	**(443)**	**(462)**	**(547)**	**(515)**	**(512)**	**(599)**	**(203)**	**610**	**199**	**210**	**1,348**	**430**	**684**	**86**	

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

CHAPTER 2 – INTRODUCTION

This 2017 IRP Update describes resource planning activities that occurred after the 2017 IRP was filed in April 2017, presents an updated load-and-resource balance, an updated resource portfolio consistent with changes in the planning environment, and provides a status update on the action plan filed with the 2017 IRP. In presenting the updated load and resource balance assessment and updated resource portfolio, PacifiCorp shows changes relative to the 2017 IRP and relative to its fall 2017 10-year business plan (Business Plan), which covers the 2018 to 2027 planning horizon. In this update PacifiCorp also addresses recommendations and requirements identified by its state regulatory commissions during the 2017 IRP acknowledgement process, as applicable.

PacifiCorp updated the 2017 IRP Update preferred portfolio reflect updates to forecasted loads, resources, market prices, and other model inputs. The 2017 IRP Update also includes the most recent analysis of Energy Vision 2020 projects, which includes new wind and transmission, plus wind repowering.

Chapters 1 and 2 of the 2017 IRP Update provide summary information. Chapter 3 describes the current planning environment, load updates, resource updates, state and federal policy updates, and Energy Gateway transmission planning and project completion forecast. Chapters 4 provides updated load-and-resource balance information. Chapter 5describes changes to key inputs and assumptions relative to those used for the 2017 IRP. Studies conducted in response to the 2017 IRP coal resource action plan items are discussed in Chapter 6. A summary of Energy Vision 2020 is presented in Chapter 7. Chapter 8 presents the updated resource portfolio. Chapter 9 presents transmission studies consistent with the 2017 IRP action plan. A status update on the 2017 IRP Action Plan is provided in Chapter 10. The Appendix provides additional load forecast details.

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CHAPTER 3 – THE PLANNING ENVIRONMENT

Federal Policy Update

Federal Climate Change Legislation

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

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

New Source Performance Standards (NSPS) are established under the Clean Air Act for certain industrial sources of emissions determined to endanger public health and welfare. On October 23, 2015, the U.S. Environmental Protection Agency (EPA) finalized a rule limiting carbon emissions from coal-fueled and natural-gas-fueled power plants. New natural-gas-fueled power plants can emit no more than 1,000 pounds of carbon dioxide (CO_2) per megawatt-hour (MWh). New coal-fueled power plants can emit no more than 1,400 pounds of CO_2/MWh. The final rule largely exempts simple cycle combustion turbines from meeting the standards.

The NSPS was appealed to the U.S. Court of Appeals - D.C. Circuit and oral argument was scheduled for April 17, 2017. However, oral argument was deferred and the court held the case in abeyance for an indefinite period of time. Until such time as the EPA undertakes further action to reconsider the NSPS or the court takes action, any new fossil-fueled generating facilities constructed by relevant registrants will be required to meet the NSPS established in the EPA's October 23, 2015 final rule.

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

On August 3, 2015, EPA issued a final rule, referred to as the Clean Power Plan (CPP), regulating carbon emissions from existing power plants. The CPP required states to develop standards of performance, which are the degree of emissions limitations achievable through the application of the best system of emission reduction (BSER).

EPA's proposal calculated state-specific emission rate targets to be achieved based on the BSER. The final CPP established the BSER as including: (a) heat rate improvements; (b) increased utilization of existing combined-cycle natural gas-fueled generating facilities; and (c) increased deployment of new and incremental non-carbon generation placed in service after 2012. The compliance period would have begun in 2022, with three interim periods of compliance and with the final goal to be achieved by 2030. The CPP was expected to reduce CO_2 emissions in the power sector to 32 percent below 2005 levels by 2030.

On March 28, 2017, President Trump issued an Executive order directing EPA to review the CPP and, if appropriate, suspend, revise, or rescind the CPP, as well as related rules and agency actions. On October 10, 2017, EPA issued a proposal to repeal the CPP and the public comment period on EPA's proposal closed April 26, 2018. In addition, EPA published an Advance Notice of Proposed

Rulemaking in the *Federal Register* December 28, 2017, seeking public input on, without committing to, a potential replacement rule. The public comment period for the Advance Notice of Proposed Rulemaking concluded February 26, 2018. Given the current status of the CPP, PacifiCorp does not assume applicability of any CPP emission limits in the 2017 IRP Update.

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 (SIP) 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. Under the final rule, EPA is required to designate areas in the country as being in "attainment" or "nonattainment" of the revised standards by October 2017. State compliance dates will be set depending on the ozone level in the area. EPA is currently in the process of making attainment/nonattainment classifications. PacifiCorp facilities will only be affected to the extent they are located in an ozone nonattainment area.

On January 9, 2018, EPA published the results for the air quality designations for the 2010 SO_2 primary NAAQS-Round three in the *Federal Register*. The Utah county of Emery, where PacifiCorp's Hunter and Huntington Generation Stations are located, was classified as attainment/unclassifiable. The Wyoming counties of Campbell and Lincoln, where PacifiCorp's Wyodak and Naughton generation stations are located, were classified as attainment/unclassifiable. The eastern portion of Sweetwater County, where PacifiCorp's Jim Bridger generation station is located, was classified as attainment/unclassifiable. PacifiCorp's facility has conducted on-site ambient SO2 monitoring to demonstrate compliance and is currently working with the state and federal agencies to terminate the monitoring site. Converse County, where PacifiCorp's Dave Johnston generation station is located, will not be designated until December 31, 2020. The classification of attainment/unclassifiable maintains the regulatory status quo for the affected facilities. PacifiCorp facilities located in areas classified as attainment/unclassifiable will be required to demonstrate ongoing compliance by performing modeling every three years using actual facility emission data.

On January 23, 2017, Gadsby and Lake Side were identified as major sources subject to Utah's serious nonattainment area SIP for $PM_{2.5}$ and $PM_{2.5}$ precursors. On April 28, 2017, PacifiCorp submitted a best-available control measure analysis for Gadsby and Lake Side to Utah Department of Air Quality for review. PacifiCorp proposed ammonia limits for the Gadsby and Lake Side facilities. Utah has until December 31, 2019 to demonstrate attainment through modeling or monitoring. If the state cannot demonstrate attainment through the measures proposed in the SIP, then the Lake Side and Gadsby facilities may be subject to more stringent environmental regulation.

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 SIPs. States are currently required to submit the next periodic update by July 31, 2021. EPA's final action on the regional haze rule amendments was published in the *Federal Register* on January 10, 2017, and has been appealed by several states and industry groups. On January 17, 2018, EPA announced its decision to revisit certain aspects of the 2017 regional haze rule revisions. EPA intends to commence a notice-and-comment rulemaking process and expressed plans to finalize EPA guidance documents for regional haze SIP revisions due in 2021. On January 30, 2018, the U.S. Court of Appeals – D.C. Circuit issued an order holding the case in abeyance and directing EPA to submit a status report every 90 days, starting April 30, 2018.

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.

Utah Regional Haze

In May 2011, the state of Utah issued a regional haze SIP requiring the installation of SO_2, NO_x and PM controls on Hunter Units 1 and 2 and Huntington Units 1 and 2. In December 2012, EPA approved the SO_2 portion of the Utah regional haze SIP and disapproved the NO_X and PM portions. EPA's approval of the SO_2 SIP was appealed to federal circuit court. In addition, PacifiCorp and the state of Utah appealed EPA's disapproval of the NO_X and PM SIP. PacifiCorp and the state's appeals were dismissed. In June 2015, the state of Utah submitted a revised SIP to EPA for review and approval with an updated BART analysis incorporating a requirement for PacifiCorp to retire Carbon Units 1 and 2, recognizing NO_X controls previously installed on Hunter Unit 3, and concluding that no incremental controls (beyond those included in the May 2011 SIP and already installed) were required at the Hunter and Huntington units. On June 1, 2016, EPA issued a final rule to partially approve and partially disapprove Utah's regional haze SIP and propose a federal implementation plan (FIP). The FIP final rule requires the installation of selective catalytic reduction (SCR) controls at four of PacifiCorp's units in Utah by August 4, 2021: Hunter Units 1 and 2, and Huntington Units 1 and 2. On September 2, 2016, PacifiCorp and other parties 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 EPA's FIP is stayed or reversed, the controls are required to be installed by August 4, 2021. On September 11, 2017, the U.S. 10th Circuit Court of Appeals granted the petition for stay and the request for abatement. The compliance deadline of the FIP and the litigation will be stayed indefinitely pending EPA's reconsideration.

Wyoming Regional Haze

On January 30, 2014, EPA published its final action in Wyoming, published in the *Federal Register*, requiring installation of the following NO_X and PM controls at PacifiCorp facilities:

- Jim Bridger Unit 3 by December 31, 2015: SCR equipment
- Jim Bridger Unit 4 by December 31, 2016: SCR equipment
- Naughton Unit 3 by January 30, 2019: SCR equipment and a baghouse
- 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

Different aspects of EPA's final action were appealed by a number of entities. PacifiCorp appealed EPA's action requiring SCR at Wyodak and was granted a stay of the Wyodak SCR requirement pending resolution of the appeals. For Naughton Unit 3, EPA indicated support for the conversion of the unit to natural gas in its final action and stated that it would expedite consideration of the gas conversion once the state of Wyoming submitted the requisite SIP amendment. PacifiCorp obtained a construction permit and revised regional haze BART permit from the state of Wyoming to convert Naughton Unit 3 to natural gas in 2018. In late 2017 PacifiCorp submitted a petition to the state of Wyoming requesting that the requirement to convert Naughton 3 to natural gas be delayed one year which was approved by the state of Wyoming. The permit allows PacifiCorp to continue with coal-fueled operation through January 30, 2019, with the option of gas conversion available thereafter. The Wyoming Department of Environmental Quality submitted a proposed revision to the Wyoming SIP, including a change to the Naughton Unit 3 compliance date, to the EPA for review and approval November 28, 2017.

Arizona Regional Haze

EPA took final action approving the Arizona regional haze SIP revision and withdrawing the FIP for the Cholla power plant on March 16, 2017 allowing Cholla Unit 4 to continue coal-fueled operations through April 30, 2025, with the option to convert to burn natural gas by July 31, 2025.

Colorado Regional Haze

In 2016, the owners of Craig Unit 1, state and federal agencies, and parties to previous Colorado regional haze settlements reached an agreement to propose an alternate regional haze compliance plan for Craig Unit 1 that incorporated retirement of the unit by December 31, 2025, with an option for conversion of the unit to natural gas by August 31, 2023. The terms of this agreement were approved by the Colorado Air Quality Board on December 15, 2016. The Colorado Department of Public Health and Environment submitted the associated Colorado SIP amendment for EPA's review and approval on May 27, 2017. EPA's review and approval process is expected to carry through 2018.

Mercury and Hazardous Air Pollutants

The Mercury and Air Toxics Standards (MATS) became effective April 16, 2012. The MATS rule requires that new and existing coal-fueled facilities achieve emission standards for mercury, acid gases and other non-mercury hazardous air pollutants. Existing sources were required to comply with the new standards by April 16, 2015. However, individual sources may have been granted up to one additional year, at the discretion of the Title V permitting authority, to complete installation of controls or for transmission system reliability reasons. In June 2015, the U.S. Supreme Court found that EPA did not properly consider costs in making its determination to regulate hazardous pollutants from power plants. In December 2015, the U.S. Court of Appeals – D.C. Circuit ruled that MATS may be enforced as EPA modifies the rule to comply with the Supreme Court decision. By April 2015, PacifiCorp had taken the required actions to comply with MATS across its generation facilities.

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 rule was 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. PacifiCorp operates seven impoundments and four landfills that are subject to the final rule. Three impoundments are currently being closed.

The final CCR regulation was self-implementing; however, in December 2016 the Coal Combustion Residuals Regulatory Improvement Act was signed, which sets forth the process and standards for EPA approval (and withdrawal) of a state's permitting program for CCR 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.
On March 1, 2018, EPA proposed to amend the April 2015 final CCR rule. EPA is proposing to allow states or EPA the ability to incorporate flexibilities into the coal ash permit programs of state, and EPA-issued permits. Comments on the rule amendment were due April 30, 2018, and EPA plans to hold a public hearing on the proposal.

Water Quality Standards

Cooling Water Intake Structures

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

Effluent Limit Guidelines

EPA first issued effluent guidelines for the Steam Electric Power Generating Point Source Category (i.e., the Steam Electric effluent guidelines) in 1974, with subsequent revisions in 1977 and 1982. On November 3, 2015, EPA finalized revised effluent-limit guidelines. The rule prohibits the discharge of bottom ash or fly ash transport water and directly impacts the Wyodak, Dave Johnston, and Naughton facilities. On September 18, 2017, EPA postponed certain compliance dates for the Steam Electric effluent guidelines. EPA intends to conduct a new rulemaking regarding the appropriate technology bases and associated limits for the best available economically achievable technology effluent limitations and pretreatment standards for existing sources requirements applicable to flue gas desulfurization (FGD) wastewater and bottom ash transport water discharged from steam electric power plants. The earliest compliance date for plants to meet the new FGD wastewater and bottom ash wastewater limitations is as soon as possible beginning November 1, 2020.

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

Bonus depreciation under the 2015 Tax Extender Legislation was superseded by the 2017 Tax Reform Act. Please refer to the bonus depreciation discussion under the 2017 Tax Reform Act section of this chapter.

Production Tax Credit (Wind)

The production tax credit (PTC), currently 2.4 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)

2017 Tax Reform Act

On December 22, 2017, President Trump signed into law H.R. 1 (Tax Reform Act) which generally impacts PacifiCorp for tax years beginning in 2018 and going forward.

Reduction in the Federal Corporate Income Tax Rate

The Tax Reform Act reduced the federal corporate income tax rate from a top rate of 35 percent to an across-the-board federal corporate income tax rate of 21 percent.

Bonus Depreciation

100 percent bonus depreciation was enacted for property placed in service after September 27, 2017, with a phase-out beginning in 2023. However, this new provision for bonus depreciation does not apply to public-utility property. Public-utility property is no longer eligible for bonus depreciation if placed in service after September 27, 2017, unless it was subject to a written binding contract on September 27, 2017. For public-utility property subject to a written binding contract on September 27, 2017, and placed in service during 2018, 40 percent of the eligible cost of the property qualifies for bonus depreciation. For public-utility property subject to a written binding contract on September 27, 2017, and placed in service during 2019, 30 percent of the eligible cost of the property qualifies for bonus depreciation. For public-utility property placed in service after December 31, 2019, there will be no bonus depreciation.

Wind Investment and Production Tax Credits and Solar Investment Tax Credits

The Tax Reform Act left intact the federal tax credit rules and phase outs for wind and solar facilities as enacted in the 2015 Tax extender Legislation.

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 July 2017, California Governor Jerry Brown signed AB 398, extending the state's California Cap and Trade program from January 1, 2021 through December 31, 2030.

In 2002, California established a renewable portfolio standard (RPS) requiring investor-owned utilities to increase procurement from eligible renewable energy resources. California's RPS requirements have been accelerated and expanded a number of times since its inception. Most recently, Governor Jerry Brown signed into law Senate Bill (SB) 350 in October 2015, which requires utilities to procure 50 percent of their electricity from renewables by 2030. SB 350 also requires California utilities to develop integrated resource plans that incorporate a greenhouse gas emission reduction planning component. The California Public Utilities Commission is currently developing rules to implement this new program.

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 10 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 10 percent below 1990 levels by 2020 and 15 percent below 2005 levels by 2020. The OPUC submitted its most recent report November 1, 2016.

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. Ecology initiated the rulemaking process in September 2015 and finalized the Clean Air Rule on January 5, 2016. While the rules for the Clean Air Rule were being finalized by the Department of Ecology in September 2016, a lawsuit was filed by a coalition of employer groups challenging the Department of Ecology's authority to implement the rule. 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.

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.

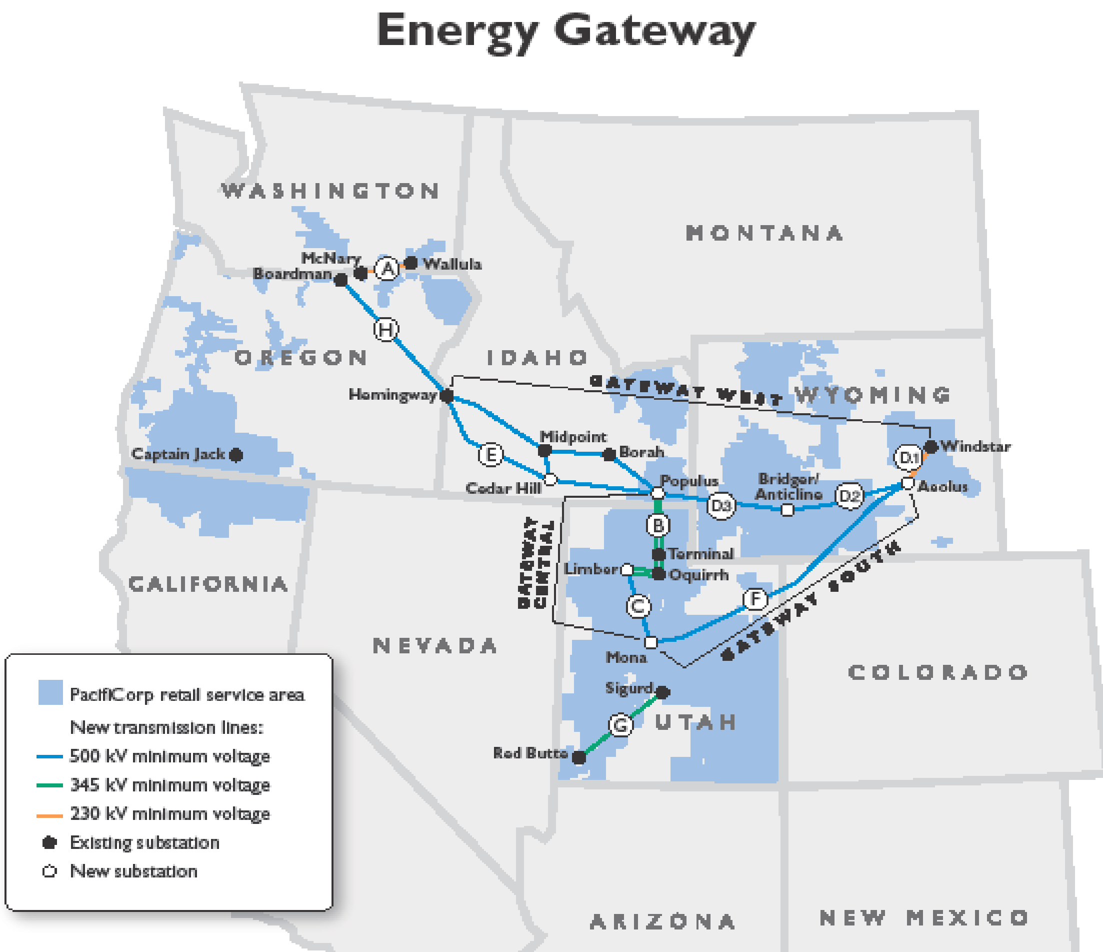
Greenhouse Gas Emission Performance Standards

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 March 2013, the Washington Department of Commerce issued a new rule, effective April 6, 2013, lowering the emissions performance standard to 970 lb CO_2/MWh.

Energy Gateway Transmission Program Planning

As discussed in the 2017 IRP, the Energy Gateway transmission project continues to play an important role in PacifiCorp's commitment to provide safe, reliable, reasonably priced electricity to meet the needs of our customers. Energy Gateway's design and extensive footprint provides needed system reliability improvements and supports the development of a diverse range of cost-effective resources required for meeting customers' energy needs. The IRP has incorporated Energy Gateway as part of a solution for delivering the least cost resource portfolio for multiple IRP planning cycles. PacifiCorp continues to develop methods, in parallel with current industry best practices and regional transmission planning requirements, to better quantify all the benefits of transmission that are essential to serve customers. For example, Energy Gateway is designed to relieve operating limitations, increase capacity, and improve operations and reliability in the existing electric transmission grid. Figure 3.1 shows a high-level geography of the Energy Gateway transmission project.

Figure 3.1 – Energy Gateway Map



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

Energy Gateway Transmission Project Updates

Wallula to McNary (Segment A)

This project meets the requirements under PacifiCorp's Open Access Transmission Tariff to provide transmission service to a point-to-point transmission customer when the existing transmission system does not have the capacity to serve the need. In addition, this project is needed to improve reliability and support future resource growth. These requirements will continue to drive the project forward. The OPUC issued a Certificate of Public Convenience and Necessity (CPCN) in September 2011. Local, state and federal permitting is complete and the majority of private rights of way have been acquired. The next steps will be completion of all detailed design, issuing the construction contract and completing construction. The project is on-track to complete permitting efforts and construction for a 2018 in-service date.

Gateway West (Segments D and E)

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

- Gateway West (Segment D1): A single-circuit 230 kV line that will run approximately 75 miles between the existing Windstar substation in eastern Wyoming and the planned Aeolus substation near Medicine Bow, Wyoming.

- Gateway West (Segment D2): A single-circuit 500 kV line running approximately 140 miles from the planned Aeolus substation to a new annex substation (Anticline) near the existing Bridger substation in western Wyoming; and a single-circuit 230 kV line running approximately 14 miles from the Shirley Basin substation near Medicine Bow to the planned Aeolus substation, also near Medicine Bow; and a single-circuit 345 kV line running approximately five miles from the planned Anticline substation near Point of Rocks, Wyoming, to the existing Jim Bridger substation. PacifiCorp received a conditional CPCN from the Wyoming Public Service Commission on April 12, 2018.

- Gateway West (Segment D3): A single-circuit 500 kV line running approximately 200 miles between the new annex substation (Anticline) and the Populus substation in southeast Idaho.

Gateway West (Segment E)

The BLM released its final EIS April 26, 2013, followed by the ROD November 14, 2013, providing a right-of-way grant for most of the project. The agency chose to defer its decision on the western-most portion of the project located in Idaho in order to perform additional review of the Morley Nelson Snake River Birds of Prey Conservation Area. In September 2014, the BLM announced their intent to conduct a supplemental EIS for the final two segments. A draft supplemental EIS was published in March 2016 and a final ROD was issued January 19, 2017. On April 17, 2017 the Interior Board of Land Appeals remanded the January 2017 ROD back to BLM for reconsideration. In response to a request from Idaho Governor Otter to the Secretary of the Interior, the January 2017 ROD for the Gateway West project was officially rescinded and remanded back to the BLM Idaho State Office for further consideration. President Trump signed the Fiscal Year 2017 Consolidated Appropriations Act into law in May 2017, which included an agreement to route segments 8 and 9 of the Gateway West Transmission Line Project through the Morley Nelson Snake River Birds of Prey National Conservation Area (NCA). House Resolution 2104 directs the Secretary of Interior to grant right of way for the route (Alternative 1) through the NCA. The BLM published the final environmental assessment for segments 8 and 9 on January 5, 2018. The ROD for segments 8 and 9 was approved on April 19, 2018.

Gateway South (Segment F)

The BLM published its Notice of Intent in the *Federal Register* in April 2011, followed by public scoping meetings throughout the project area. Comments on this project from agencies and other interested stakeholders were considered as the BLM developed the draft EIS, which was issued in February 2014. A ROD was issued by the BLM in January 2017, and by the U.S. Forest Service in May 2017. PacifiCorp will continue to assess construction timing to best meet customer and system needs. PacifiCorp continues to work with the federal agencies on meeting notice-to-proceed requirements.

Boardman to Hemingway (Segment H)

Energy Gateway Segment H represents a significant improvement in the connection between PacifiCorp's east and west control areas and will help deliver more diverse resources to serve its customers in Oregon, Washington and California. Idaho Power leads the permitting efforts on this project and PacifiCorp continues to support the permitting efforts under the conditions of the Boardman to Hemingway Transmission Project Joint Permit Funding Agreement. The Bureau of Land Management's Record of Decision was issued in November of 2017, this will be followed by the U.S. forest Service Record of Decision and the Oregon Energy Facilities Siting Council's final order on the Site Certificate.

In-Service Dates

Table 3.1 summarizes the in-service dates for segments of the Energy Gateway transmission project.

Table 3.1– Energy Gateway Segment In-Service Dates

Segment & Name	Description	Approximate Mileage	Status and Scheduled In Service
(A) Wallula-McNary	230 kV, single circuit	30 mi	• Status: local permitting completed • Scheduled in service: 2018, sponsor driven
(B) Populus-Terminal	345 kV, double circuit	135 mi	• Placed in service: November 2010
(C) Mona-Oquirrh	500 kV single circuit 345 kV double circuit	100 mi	• Placed in service: May 2013
Oquirrh-Terminal	345 kV double circuit	14 mi	• Status: rights-of-way acquisition underway • Scheduled in-service: 2021
(D1) Windstar-Aeolus	New 230 kV single circuit Re-built 230 kV single circuit	75 mi	• Status: permitting continues • Scheduled in-service: 2019-2024
(D2) Aeolus-Bridger/Anticline	500 kV single circuit	140 mi	• Status: permitting continues • Conditional CPCN received April 2018 • Rights-of-way acquisition underway • Scheduled in-service: 2020
(D3) Bridger/Anticline-Populus	500 kV single circuit	200 mi	• Status: permitting continues • Scheduled in-service: 2020-2024
(E) Populus-Hemingway	500 kV single circuit	500 mi	• Status: permitting continues • Scheduled in service: 2020-2024
(F) Aeolus-Mona	500 kV single circuit	400 mi	• Status: permitting continues • Scheduled in service: 2020-2024
(G) Sigurd-Red Butte	345 kV single circuit	170 mi	• Placed in service: May 2015
(H) Boardman-Hemingway	500 kV single circuit	500 mi	• Status: pursuing joint-development and/or firm capacity opportunities with project sponsors • Scheduled in service: sponsor driven

Energy Imbalance Market

PacifiCorp and the California Independent System Operator (CAISO) launched the energy-imbalance market (EIM) November 1, 2014. The EIM is a voluntary market and the first western energy market outside of California. The EIM provides for more efficient dispatch of participating resources in real-time through an automated system that dispatches generation across the EIM footprint, which currently includes PacifiCorp, NV Energy, Puget Sound Energy, Arizona Public Service, Portland General Electric, Idaho Power Company, Powerex, and the CAISO balancing authority areas (collectively, EIM Area). Entities scheduled to join the EIM include the Balancing Authority of Northern California (April 2019), Seattle City Light (April 2020), Los Angeles Dept. of Water and Power (April 2020), and Salt River Project (April 2020). CENACE Baja California is investigating future entry into the market. PacifiCorp continues to work with the CAISO, existing and prospective EIM entities, and stakeholders to enhance market functionality and support market growth.

CHAPTER 4 – LOAD-AND-RESOURCE BALANCE UPDATE

Introduction

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

System Coincident Peak Load Forecast

The 2017 IRP Update relies on PacifiCorp's August 2017 load forecast. Figure 4.1 compares PacifiCorp's most recent load forecast to the forecast used for the 2017 IRP. Figure 4.2 compares PacifiCorp's most recent coincident system peak load forecast to the forecast used for the 2017 IRP. Considering that PacifiCorp analyzes incremental energy efficiency and direct-load control programs as demand-side resource options in its IRP, both figures exclude incremental energy efficiency savings and direct-load control capacity included in the updated resource portfolio. The compounded average annual growth rate (CAGR) for system load is 0.55 percent over the period 2018 through 2027. The CAGR for system coincident peak is 0.54 percent over the period 2018 through 2027.

Figure 4.1 – Forecasted Annual Load (GWh)

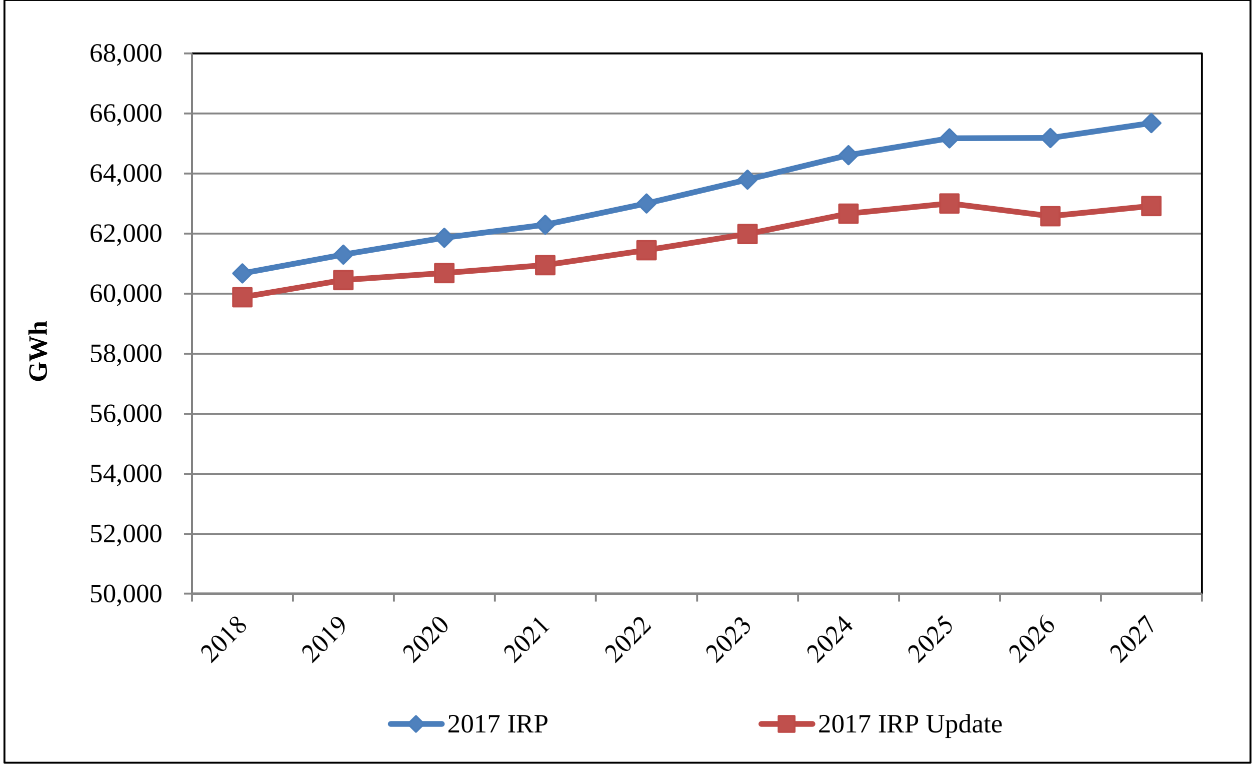
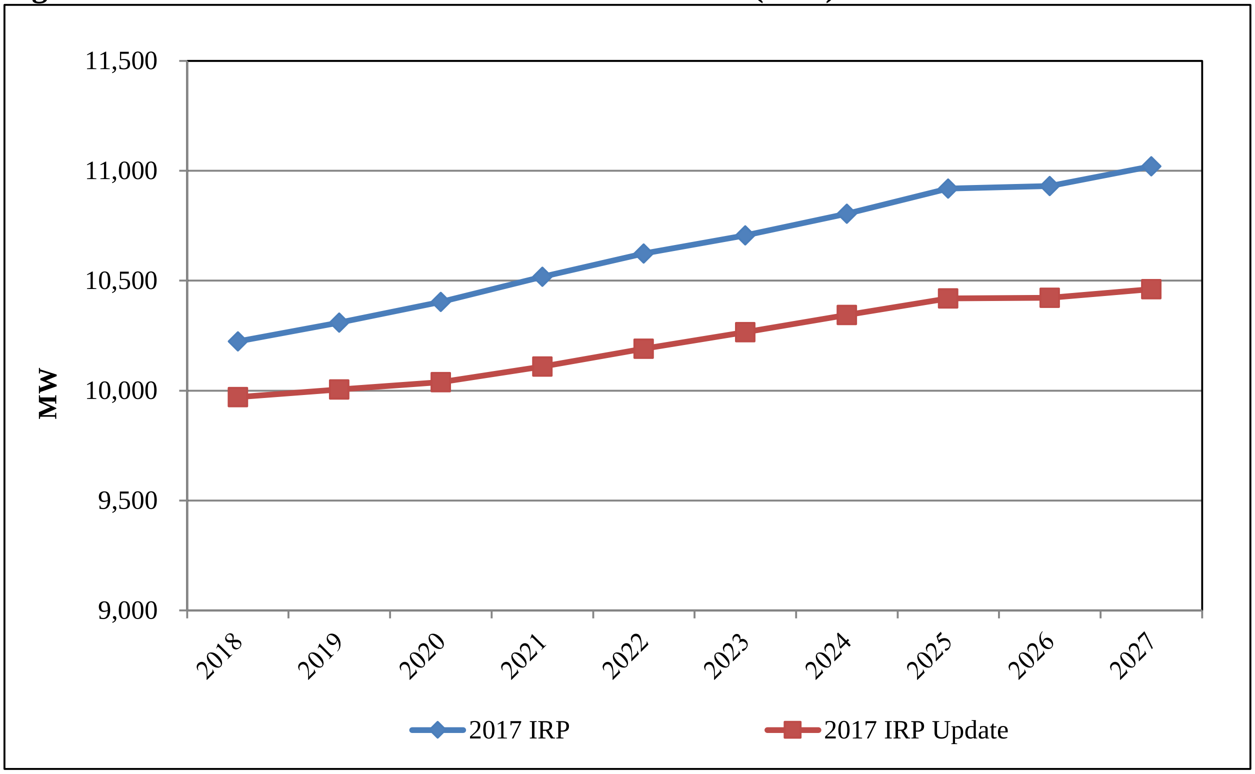


Figure 4.2 – Forecasted Annual Coincident Peak Load (MW)



Wind and Solar Qualifying Facility Resource Updates

Table 4.1 and Table 4.2 summarize the capacity from wind and solar power-purchase agreements (PPAs) with qualifying facilities (QFs) that have or are expected to come online over the 2017-2021 time frame assumed in the 2017 IRP Update compared to the 2017 IRP.

Table 4.1 – Qualifying Facility Wind PPAs

		2017 IRP Preferred Portfolio		2017 IRP Update	
Qualifying Facilities	**State**	**Capacity (MW)**	**L&R Balance Capacity at System Peak (MW)**	**Capacity (MW)**	**L&R Balance Capacity at System Peak (MW)**
Casper Wind (Chevron)	WY	17	3	17	3
Chopin	WA	10	1	10	1
Everpower [(1)]	WY			239	38
Foote Creek II	WY	2	0	2	0
Foote Creek III	WY	25	4	25	4
Latigo Wind	UT	60	9	60	9
Mariah Wind	OR	10	1	10	1
Meadow Creek Project – Five Pine	ID	40	6	40	6

		2017 IRP Preferred Portfolio		2017 IRP Update	
Qualifying Facilities	**State**	**Capacity (MW)**	**L&R Balance Capacity at System Peak (MW)**	**Capacity (MW)**	**L&R Balance Capacity at System Peak (MW)**
Meadow Creek Project – North Point	ID	80	13	80	13
Monticello Wind (1)	UT			79	13
Mountain Wind Power I	WY	61	10	61	10
Mountain Wind Power II	WY	80	13	80	13
Orchard Wind	WA	40	5	40	5
Oregon Wind Farms I & II	OR	65	8	65	8
Orem Family Wind	OR	10	1	10	1
Pioneer Wind Park I	WY	80	13	80	13
Power County Wind Park North	ID	23	4	23	4
Power County Wind Park South	ID	23	4	23	4
Spanish Fork Wind Park 2	UT	19	3	19	3
Three Mile Canyon	WA	10	1	10	1
Tooele Army Depot (1)	UT			3	0
Small Wind	WY	0.2	0	0.2	0
TOTAL – Purchased Wind		**654**	**97**	**975**	**148**

(1) New since the 2017 IRP

Table 4.2 – Qualifying Facility Solar PPAs

		2017 IRP Preferred Portfolio		2017 IRP Update	
Qualifying Facilities	**State**	**Capacity (MW)**	**L&R Balance Capacity at System Peak (MW)**	**Capacity (MW)**	**L&R Balance Capacity at System Peak (MW)**
Adams Solar Center	OR	10	6	10	6
Bear Creek Solar Center	OR	10	6	10	6
Beatty Solar (3)	OR	5	3		
Beryl Solar	UT	3	1	3	1
Black Cap Solar II	OR	8	5	8	5
Bly Solar Center	OR	9	6	9	6
Buckhorn Solar	UT	3	1	3	1
Cedar Valley Solar	UT	3	1	3	1
Chiloquin Solar	OR	10	5	10	5
Collier Solar	OR	10	6	10	6

		2017 IRP Preferred Portfolio		2017 IRP Update	
Qualifying Facilities	**State**	**Capacity (MW)**	**L&R Balance Capacity at System Peak (MW)**	**Capacity (MW)**	**L&R Balance Capacity at System Peak (MW)**
Elbe Solar Center	OR	10	6	10	6
Enterprise Solar	UT	80	47	80	47
Escalante Solar I	UT	80	47	80	47
Escalante Solar II	UT	80	47	80	47
Escalante Solar III	UT	80	47	80	47
Ewauna Solar	OR	1	1	1	1
Ewauna Solar 2	OR	3	2	3	2
SunE Solar XVII Project 1 – 3 (2)	UT	9	5	9	5
Granite Mountain - East	UT	80	47	80	47
Granite Mountain - West	UT	50	30	50	30
Granite Peak Solar	UT	3	1	3	1
Greenville Solar	UT	2	1	2	1
Iron Springs	UT	80	47	80	47
Ivory Pine Solar	OR	10	6	10	6
Laho Solar	UT	3	1	3	1
Merrill Solar	OR	10	6	10	6
Milford Flat Solar	UT	3	2	3	2
Milford Solar 2	UT	3	1	3	1
Norwest Energy 2 (Neff)	OR	10	6	10	6
Norwest Energy 4 (Bonanza)	OR	6	4	6	4
Norwest Energy 7 (Eagle Point)	OR	10	6	10	6
Norwest Energy 9 Pendleton	OR	6	3	6	3
OR Solar 2, LLC (Agate Bay)	OR	10	6	10	6
OR Solar 3, LLC (Turkey Hill)	OR	10	6	10	6
OR Solar 5, LLC (Merrill)	OR	8	5	8	5
OR Solar 6, LLC (Lakeview)	OR	10	6	10	6
OR Solar 7, LLC (Jacksonville)	OR	10	6	10	6
OR Solar 8, LLC (Dairy)	OR	10	6	10	6
Pavant Solar	UT	50	29	50	29
Pavant Solar II LLC	UT	50	30	50	30
Pavant Solar III LLC	UT	20	12	20	12
Quichapa Solar 1- 3	UT	9	5	9	5
Sage I Solar (1)	WY			20	8
Sage II Solar (1)	WY			20	8
Sage III Solar (1)	WY			18	7
South Milford Solar	UT	3	2	3	2

		2017 IRP Preferred Portfolio		2017 IRP Update	
Qualifying Facilities	**State**	**Capacity (MW)**	**L&R Balance Capacity at System Peak (MW)**	**Capacity (MW)**	**L&R Balance Capacity at System Peak (MW)**
Sprague River Solar	OR	7	5	7	5
Sweetwater Solar	WY	80	48	80	48
Three Peaks Solar	UT	80	47	80	47
Tumbleweed Solar	OR	10	5	10	5
Utah Red Hills Renewable Park	UT	80	47	80	47
Woodline Solar	OR	8	5	8	5
Small Solar	UT	1	0	1	0
TOTAL – Purchased Solar		**1,145**	**679**	**1,197**	**699**

(1) New since the 2017 IRP

(2) Formerly Fiddler's Canyon Solar 1-3

(3) Contract terminated

Updated Capacity Load-and-Resource Balance

Load-and-Resource Balance Components

Capacity and energy balances make use of the same load-and-resource components in their calculations. The main component categories consist of the following: resources, obligation, reserves, system position, new Energy Vision 2020 wind, and available front-office transactions (FOTs).

The resource categories include resources by type—thermal, hydroelectric, renewable, QFs, purchases, existing Class 1 demand-side management (DSM), sales, and non-owned reserves. Categories in the obligation section include load, private generation, interruptible contracts, existing Class 2 DSM, and new Class 2 DSM from the updated resource portfolio. Both resources and obligations can be represented as either a positive or negative value, which is consistent with how these elements are represented in portfolio modeling.

A description of each of the resource categories, including a description of variances from the summer load-and-resource balance in the 2017 IRP, is provided below.

Existing Resources

<u>Thermal</u>
This category includes all thermal plants that are wholly owned or partially owned by PacifiCorp. The capacity balance counts thermal plants at maximum dependable capability at time of system summer or winter peak, as applicable. The energy balance also counts them at maximum dependable capability, but de-rates them for forced outages and maintenance. 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. In the 2017

IRP Update, certain coal plants had small increases in the assumed capacity when compared to the 2017 IRP. These changes reflect a reduced level of parasitic load associated with installation of selective catalytic reduction systems, which results in a 16 MW increase in summer capacity relative to the 2017 IRP.

Hydroelectric

This category includes all hydroelectric generation resources in PacifiCorp's system, as well as a number of contracts providing capacity and energy from various counterparties. The capacity balance counts these resources by the maximum capability that is sustainable for one hour at the time of system summer peak, an approach consistent with current Western Electric Coordinating Council (WECC) capacity-reporting practices. 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. An updated hydro generation forecast reflects changes to the Umpqua River hydro facilities peak capacity projections with varying impacts in specific years throughout the planning period.

Renewable

This category includes geothermal and variable (wind and solar) renewable resource capacity. The capacity balance counts geothermal capacity at the maximum dependable capability while the energy balance counts the maximum dependable capability after forced outages. 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. PacifiCorp defines the peak capacity contribution of wind and solar resources as the availability among hours with the highest loss-of-load probability. PacifiCorp updated its capacity contribution values for solar and wind resources, differentiated by resource type and balancing authority area in the 2017 IRP and uses these same capacity-contribution values, as shown in Table 4.3 below, in the 2017 IRP Update. PacifiCorp's wind repowering project results in a net two MW increase in peak capacity by 2021.

Table 4.3 – Summer Peak Capacity Contribution Values for Wind and Solar

	East Balancing Authority Area			West Balancing Authority Area		
	Wind	**Fixed Tilt Solar PV**	**Single Axis Tracking Solar PV**	**Wind**	**Fixed Tilt Solar PV**	**Single Axis Tracking Solar PV**
Capacity Contribution Percentage	15.8%	37.9%	59.7%	11.8%	53.9%	64.8%

Purchases

This includes all major purchase contracts for firm capacity and energy in the PacifiCorp system.[1] The capacity balance counts these by the maximum contract availability at the time of system summer peak. The energy balance counts contracts at optimal economic model dispatch. Purchases are considered firm and thus planning reserves are not held for them. There were no changes in purchases from what was assumed in the 2017 IRP.

Qualifying Facilities

All QFs that provide capacity and energy are included in this category. Like other purchases, the capacity balance counts non-wind and non-solar QFs at maximum system summer peak availability. The capacity balance counts wind and solar QFs using the assumed capacity-contribution values summarized in Table 4.3 above. The energy balance counts QFs at expected generation levels. By 2022, the addition of incremental wind and solar QF contracts increases system capacity at the time of peak load by 71 MW. Other QF contracts increase the capacity at the time of peak load by an additional six MW.

Dispatchable Load Control (Class 1 DSM)

Existing dispatchable load control program capacity is categorized as an increase to resource capacity. This is in line with the treatment of DSM capacity in the latest version of the System Optimizer model that PacifiCorp uses to select resources. There were no changes in Class 1 DSM from what was assumed in the 2017 IRP.

Sales

This includes all contracts for the sale of firm capacity and energy. The capacity balance counts these contracts by the maximum obligation at time of system summer peak and the energy balance counts them by expected model dispatch. All sales contracts are firm and thus planning reserves are held for them when accounting for these contracts in the capacity balance. There were no changes in sales from what was assumed in the 2017 IRP.

Non-owned Reserves

Non-owned reserve capacity is categorized as a decrease to resource capacity to represent the capacity required to provide reserves as a balancing authority for load and generation that are in PacifiCorp's balancing authority area (BAA) but not owned by PacifiCorp. There are a number of counterparties that operate in PacifiCorp control areas that purchase operating reserves. The annual reserve obligation is about 3 MW and 38 MW on the west and east BAAs, respectively. The non-owned reserves do not contribute to the energy obligation because this requirement is for capacity only. The non-owned reserves were updated in the 2017 IRP Update resulting in a small, three-MW decrease relative to the 2017 IRP.

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

Obligation

The obligation is the total electricity demand that PacifiCorp must serve, consisting of forecasted retail load less private generation, existing Class 2 DSM, new Class 2 DSM from the preferred portfolio, and interruptible contracts. A description of each of these obligation categories, including a description of variances from the summer load-and-resource balance in the 2017 IRP, is provided below.

Load and Private Generation

The largest component of the obligation is retail load. In the 2017 IRP, the hourly retail load at a location is first reduced by hourly private generation at the same location. The system coincident peak is determined by summing the net loads for all locations (topology bubbles with loads) and then finding the highest hourly system load by year. Loads reported by east and west BAAs reflect loads at the time of PacifiCorp's coincident system summer peak. The energy balance counts the load on a monthly basis by on-peak and off-peak hours. Summer peak loads net of private generation are lower in the 2017 IRP Update than in the 2017 IRP.

PacifiCorp's 2017 IRP Update load forecast was finalized in August 2017. Relative to the load forecast prepared for the 2017 IRP, PacifiCorp system sales decrease over the planning period. While economic conditions continue to improve following the most recent recession, a less favorable outlook for select industrial customers results in lower sales projections relative to the 2017 IRP. Further, the 2017 IRP Update forecast projects that residential customers are likely to use more efficient appliances, which results in a lower residential forecast relative to the 2017 IRP load forecast.

Furthermore, the 2017 IRP Update incorporates a methodological update for the treatment of private generation and how it affects the coincident peak. In previous IRPs, the load forecast summed the hourly output for seven different private-generation sources to produce the hourly private-generation shape within each state. For the 2017 IRP Update, since a high percentage of forecasted private generation is solar (>90%), a more appropriate methodology was adopted to weight the seven individual private-generation sources by annual capacity. This improvement to the methodology results in better alignment of solar occurring at the time of coincident peak than was identified when using the prior, unweighted approach.

Class 2 DSM

An adjustment is made to load to remove the projected embedded Class 2 DSM as a reduction to load. Due to timing issues with the vintage of the load forecast, there was a level of 2016 Class 2 DSM that was not incorporated in the forecast for the 2017 IRP. The 2016 Class 2 DSM forecast of 100 MW was accounted for by adding an existing Class 2 DSM resource in the load-and-resource balance; this adjustment was not required for the 2017 IRP Update because the 2016 projected embedded Class 2 DSM is included in the load forecast. The DSM line also includes the selected Class 2 DSM from the 2017 IRP Update resource portfolio, which, consistent with a reduction in overall load, results in a decrease in incremental Class 2 DSM totaling 77 MW by 2027 when compared to the 2017 IRP.

Interruptible Contracts

PacifiCorp has interruptible contracts for approximately 195 MW of load interruption capability. These contracts allow the use of 195 MW of capacity for meeting reserve requirements. Both the capacity balance and energy balance count these resources at the level of full load interruption available. Interruptible resources directly curtail load and thus full planning reserves are not held for the load that may be curtailed. As with Class 1 DSM, this resource is categorized as a decrease to the peak load. There were no changes in interruptible contracts from what was assumed in the 2017 IRP.

Planning Reserves

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

System Position

The system position is the resource surplus or deficit after subtracting obligation plus required reserves from total resources. While similar, the system position calculation is slightly different for capacity and energy. Thus, the position calculation for each of these balances are presented in their respective sections later in this chapter.

Energy Vision 2020 Wind

For the 2017 IRP Update, PacifiCorp has incorporated capacity from the new Energy Vision 2020 wind projects as a separate line item starting in 2021. While these projects are undergoing a regulatory review and approval processes, the capacity contribution associated with these wind resources, and their associated impact on the system position, is provided for informational purposes.

Available FOTs

As is the case with Energy Vision 2020 wind resources, PacifiCorp also shows available capacity from uncommitted FOT resources. These resources are shown as the amount of uncommitted FOTs that *could* be used to satisfy any remaining short system capacity position (after accounting for the capacity contribution from Energy Vision 2020 wind resources) up to the maximum level of FOT procurement assumed available for planning purposes. As is the case with Energy Vision 2020 wind resources, these data are shown for informational purposes. Any resource that is lower cost and lower risk can displace FOTs when selecting resources in the preferred portfolio.

Capacity Balance Determination and Results

Methodology

The system position, which represents the projected capacity need, nets existing resources against the projected obligation while accounting for planning reserves. The basic formulae used to establish the system position are summarized below.

Existing Resources = Thermal + Hydro + Renewable + Firm Purchases + Qualifying Facilities + Existing Class 1 DSM – Firm Sales – Non-owned Reserves

The peak load, interruptible contracts, existing Class 2 DSM, and new Class 2 DSM from the preferred portfolio are netted together for each of the annual system summer and winter peaks, as applicable, to compute the annual peak obligation:

Obligation = Load – Interruptible Contracts – New and Existing Class 2 DSM

The amount of reserves to be added to the obligation is then calculated. This is accomplished by the net system obligation calculated above multiplied by the 13 percent target planning reserve margin (PRM) adopted for the 2017 IRP. The formula for this calculation is:

Planning Reserves = Obligation x PRM

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

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

Informational Calculations

As discussed above, for informational purposes, PacifiCorp has also shown how the system capacity position is affected by Energy Vision 2020 wind resources:

System Position with New Energy Vision 2020 Wind = (System Capacity Position) + (New EV 2020 Wind)

Similarly, and also for informational purposes, PacifiCorp also shows how the potential acquisition of uncommitted FOTs *could* be used, if lower cost and lower risk than other resource alternatives, to meet any remaining system capacity shortfall:

Net Surplus (Deficit) = (System Position with New Energy Vision 2020 Wind) + (Uncommitted FOT's to meet remaining Need)

"Uncommitted FOT's to meet remaining Need" refers to that portion of available FOT's that could be used to meet any remaining capacity deficit calculated in the "System Position w/New EV 2020 Wind" calculation without exceeding the maximum level of FOT procurement assumed available for planning purposes.

Figure 4.3 summarizes the 2017 IRP Update capacity load-and-resource balance, prior to acquiring any new resources and making firm market purchases, alongside the load-and-resource balance from the 2017 IRP. Before accounting for Energy Vision 2020 wind resources and uncommitted FOTs, PacifiCorp shows a capacity deficit beginning 2018. This deficit is lower, on average, than in the 2017 IRP by approximately 408 MW over the 2018-2027 time frame due in large part to the decreased load forecast net of private generation.

Figure 4.3 – Summer Capacity Position Comparison Chart

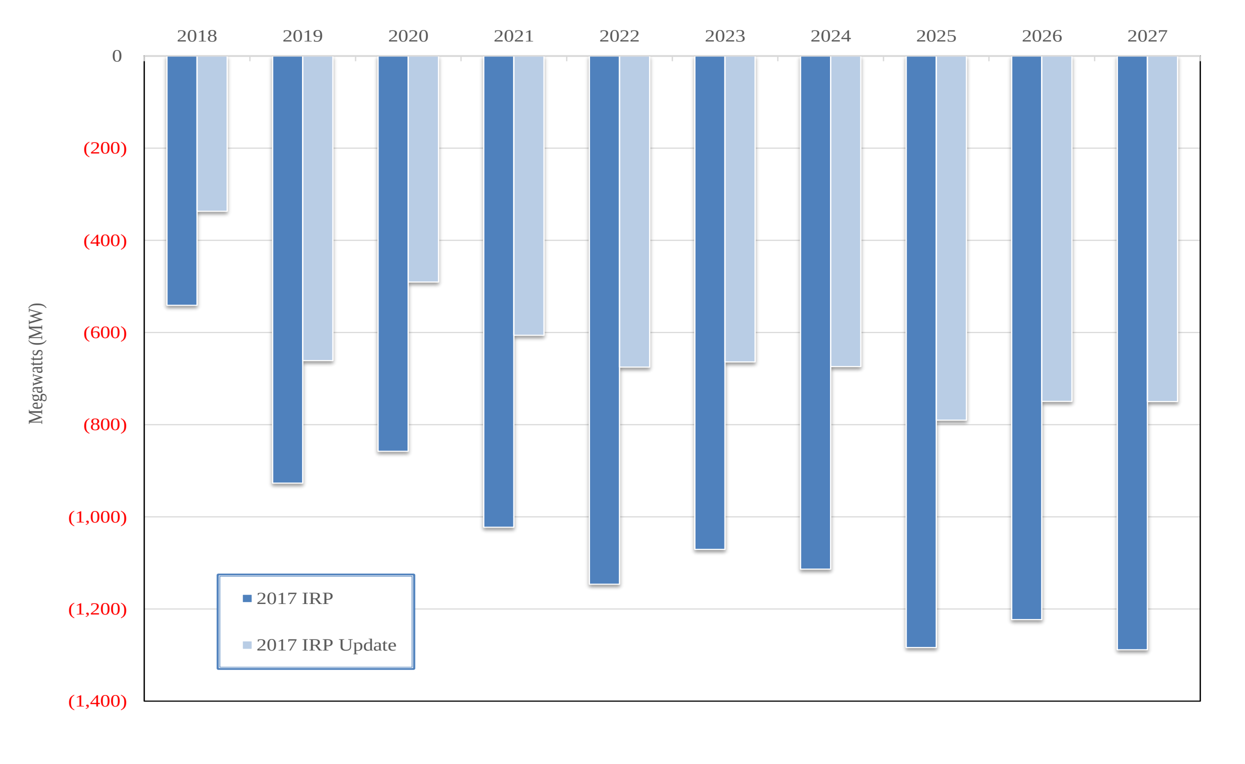


Table 4.4 through Table 4.7 present the capacity load-and-resource balance details from the 2017 IRP Update and the 2017 IRP for the summer and winter peak. The load-and-resource balance tables show the system position before Energy Vision 2020 wind resources and uncommitted FOTs. Line-item differences between the 2017 IRP and 2017 IRP Update are shown in Table 4.8 and Table 4.9.

Table 4.4 – Summer Peak - System Capacity Load and Resource Balance without Resource Additions, 2017 IRP Update (2018-2027) (Megawatts)[2]

Calendar Year	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
East										
Thermal	6,403	6,123	6,123	5,736	5,736	5,736	5,736	5,736	5,654	5,654
Hydroelectric	107	114	114	114	114	114	93	93	93	93
Renewable	196	194	199	197	190	190	190	190	180	180
Purchases	249	249	249	221	221	221	221	121	121	121
Qualifying Facilities	648	691	743	735	738	734	679	674	670	666
Class 1 DSM	323	323	323	323	323	323	323	323	323	323
Sales	(655)	(655)	(655)	(175)	(175)	(175)	(148)	(148)	(66)	(66)
Non-Owned Reserves	(35)	(35)	(35)	(35)	(35)	(35)	(35)	(35)	(35)	(35)
East Existing Resources	**7,236**	**7,004**	**7,061**	**7,117**	**7,112**	**7,108**	**7,061**	**6,955**	**6,941**	**6,937**
Load	6,853	6,911	6,972	7,041	7,115	7,183	7,259	7,321	7,322	7,365
Private Generation	(108)	(166)	(202)	(213)	(220)	(226)	(234)	(242)	(252)	(269)
Interruptible	(195)	(195)	(195)	(195)	(195)	(195)	(195)	(195)	(195)	(195)
DSM	(118)	(172)	(226)	(273)	(319)	(365)	(410)	(460)	(509)	(555)
East obligation	**6,432**	**6,378**	**6,349**	**6,360**	**6,382**	**6,397**	**6,421**	**6,424**	**6,365**	**6,346**
Planning Reserves (13%)	862	855	851	852	855	857	860	860	853	850
East Obligation + Reserves	**7,294**	**7,233**	**7,200**	**7,212**	**7,236**	**7,254**	**7,281**	**7,284**	**7,218**	**7,196**
East Position	**(58)**	**(229)**	**(139)**	**(95)**	**(124)**	**(146)**	**(220)**	**(329)**	**(277)**	**(260)**
Available Front Office Transactions	**318**	**318**	**318**	**318**	**318**	**318**	**318**	**318**	**318**	**318**
West										
Thermal	2,254	2,254	2,254	2,254	2,254	2,254	2,254	2,254	2,254	2,254
Hydroelectric	861	747	790	643	587	624	655	655	645	658
Renewable	90	88	95	95	65	65	60	60	59	58
Purchases	18	1	1	1	1	1	1	1	1	1
Qualifying Facilities	235	220	227	203	194	187	185	184	182	150
Class 1 DSM	3	3	3	0	0	0	0	0	0	0
Sales	(165)	(165)	(165)	(161)	(110)	(110)	(80)	(80)	(80)	(80)
Non-Owned Reserves	(3)	(3)	(3)	(3)	(3)	(3)	(3)	(3)	(3)	(3)
West Existing Resources	**3,294**	**3,146**	**3,203**	**3,034**	**2,988**	**3,018**	**3,072**	**3,072**	**3,058**	**3,039**
Load	3,238	3,279	3,293	3,312	3,331	3,351	3,366	3,395	3,415	3,436
Private Generation	(13)	(19)	(25)	(31)	(37)	(42)	(48)	(55)	(63)	(71)
Interruptible	0	0	0	0	0	0	0	0	0	0
DSM	(64)	(94)	(122)	(144)	(163)	(181)	(198)	(214)	(228)	(242)
West obligation	**3,161**	**3,166**	**3,146**	**3,137**	**3,132**	**3,129**	**3,120**	**3,126**	**3,124**	**3,123**
Planning Reserves (13%)	411	412	409	408	407	407	406	406	406	406
West Obligation + Reserves	**3,572**	**3,578**	**3,554**	**3,545**	**3,539**	**3,535**	**3,526**	**3,533**	**3,530**	**3,529**
West Position	**(279)**	**(432)**	**(351)**	**(511)**	**(551)**	**(518)**	**(453)**	**(461)**	**(472)**	**(490)**
Available Front Office Transactions	**1,352**	**1,352**	**1,352**	**1,352**	**1,352**	**1,352**	**1,352**	**1,352**	**1,352**	**1,352**
System										
Total Resources	10,530	10,150	10,264	10,151	10,101	10,126	10,133	10,027	9,999	9,976
Obligation	9,594	9,544	9,495	9,497	9,513	9,526	9,541	9,550	9,490	9,469
Reserves	1,273	1,266	1,260	1,260	1,262	1,264	1,266	1,267	1,259	1,256
Obligation + Reserves	10,867	10,811	10,755	10,757	10,775	10,790	10,807	10,817	10,749	10,725
System Position	(337)	(661)	(490)	(606)	(675)	(664)	(674)	(790)	(749)	(750)
New EV2020 Wind	0	0	0	207	207	207	207	207	207	207
System Position w/ New Wind	(337)	(661)	(490)	(399)	(468)	(457)	(467)	(583)	(542)	(543)
Available Front Office Transactions	**1,670**	**1,670**	**1,670**	**1,670**	**1,670**	**1,670**	**1,670**	**1,670**	**1,670**	**1,670**
Uncommited FOT's to meet remaining Need	337	661	490	399	468	457	467	583	542	543
Net Surplus (Deficit)	0	0	0	0	0	0	0	0	0	0

[2] The DSM line includes selected Class 2 DSM from the 2017 IRP Update resource portfolio.

Table 4.4 (cont.) – Summer Peak - System Capacity Load and Resource Balance without Resource Additions, 2017 IRP Update (2028-2036) (Megawatts)[3]

Calendar Year	2028	2029	2030	2031	2032	2033	2034	2035	2036
East									
Thermal	4,892	4,892	4,535	4,459	4,459	4,102	4,102	4,021	4,021
Hydroelectric	93	93	93	93	93	93	93	93	93
Renewable	180	180	158	126	126	126	126	126	126
Purchases	121	121	121	121	121	121	121	121	121
Qualifying Facilities	662	655	652	648	637	605	589	584	532
Class 1 DSM	323	323	323	323	323	323	323	323	323
Sales	(66)	(66)	(66)	0	0	0	0	0	0
Non-Owned Reserves	(35)	(35)	(35)	(35)	(35)	(35)	(35)	(35)	(35)
East Existing Resources	**6,171**	**6,164**	**5,782**	**5,736**	**5,725**	**5,337**	**5,320**	**5,234**	**5,182**
Load	7,445	7,521	7,601	7,543	7,640	7,716	7,789	7,872	7,953
Private Generation	(288)	(303)	(324)	(236)	(261)	(284)	(308)	(333)	(354)
Interruptible	(195)	(195)	(195)	(195)	(195)	(195)	(195)	(195)	(195)
DSM	(602)	(645)	(690)	(734)	(771)	(805)	(835)	(863)	(892)
East obligation	**6,360**	**6,378**	**6,393**	**6,378**	**6,413**	**6,432**	**6,451**	**6,481**	**6,512**
Planning Reserves (13%)	852	855	856	854	859	862	864	868	872
East Obligation + Reserves	**7,213**	**7,233**	**7,249**	**7,232**	**7,272**	**7,294**	**7,315**	**7,349**	**7,384**
East Position	**(1,042)**	**(1,068)**	**(1,467)**	**(1,496)**	**(1,547)**	**(1,957)**	**(1,995)**	**(2,116)**	**(2,203)**
Available Front Office Transactions	**318**	**318**	**318**	**318**	**318**	**318**	**318**	**318**	**318**
West									
Thermal	2,254	1,900	1,900	1,900	1,900	1,541	1,541	1,541	1,541
Hydroelectric	653	653	653	653	653	653	653	653	653
Renewable	55	54	54	53	53	53	53	53	53
Purchases	1	1	1	1	1	1	1	1	1
Qualifying Facilities	149	138	133	132	99	97	97	96	94
Class 1 DSM	0	0	0	0	0	0	0	0	0
Sales	(80)	(78)	(78)	(78)	(78)	(78)	(78)	(78)	(24)
Non-Owned Reserves	(3)	(3)	(3)	(3)	(3)	(3)	(3)	(3)	(3)
West Existing Resources	**3,030**	**2,666**	**2,660**	**2,659**	**2,626**	**2,265**	**2,264**	**2,264**	**2,316**
Load	3,457	3,503	3,495	3,513	3,532	3,554	3,575	3,620	3,612
Private Generation	(78)	(86)	(93)	(72)	(80)	(89)	(100)	(111)	(122)
Interruptible	0	0	0	0	0	0	0	0	0
DSM	(255)	(268)	(280)	(291)	(303)	(313)	(322)	(332)	(342)
West obligation	**3,124**	**3,150**	**3,122**	**3,150**	**3,149**	**3,152**	**3,152**	**3,176**	**3,149**
Planning Reserves (13%)	406	410	406	409	409	410	410	413	409
West Obligation + Reserves	**3,530**	**3,560**	**3,528**	**3,559**	**3,559**	**3,562**	**3,562**	**3,589**	**3,558**
West Position	**(500)**	**(894)**	**(867)**	**(900)**	**(933)**	**(1,297)**	**(1,298)**	**(1,325)**	**(1,242)**
Available Front Office Transactions	**1,352**	**1,352**	**1,352**	**1,352**	**1,352**	**1,352**	**1,352**	**1,352**	**1,352**
System									
Total Resources	9,201	8,830	8,442	8,395	8,351	7,602	7,585	7,497	7,497
Obligation	9,484	9,528	9,514	9,527	9,562	9,585	9,603	9,658	9,661
Reserves	1,258	1,264	1,262	1,264	1,268	1,271	1,274	1,281	1,281
Obligation + Reserves	10,743	10,792	10,777	10,791	10,831	10,856	10,877	10,938	10,943
System Position	(1,542)	(1,962)	(2,334)	(2,396)	(2,480)	(3,254)	(3,293)	(3,441)	(3,445)
New EV2020 Wind	207	207	207	207	207	207	207	207	207
System Position w/ New Wind	(1,335)	(1,755)	(2,127)	(2,189)	(2,273)	(3,047)	(3,085)	(3,234)	(3,238)
Available Front Office Transactions	**1,670**	**1,670**	**1,670**	**1,670**	**1,670**	**1,670**	**1,670**	**1,670**	**1,670**
Uncommited FOT's to meet remaining Need	1,335	1,670	1,670	1,670	1,670	1,670	1,670	1,670	1,670
Net Surplus (Deficit)	0	(86)	(458)	(519)	(604)	(1,378)	(1,416)	(1,564)	(1,569)

[3] The DSM line includes selected Class 2 DSM from the 2017 IRP Update resource portfolio.

Table 4.5 – Winter Peak – System Capacity Load and Resource Balance without Resource Additions, 2017 IRP Update (2018-2027) (Megawatts) [4]

Calendar Year	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
East										
Thermal	6,513	6,233	6,233	5,846	5,846	5,846	5,846	5,846	5,763	5,763
Hydroelectric	72	72	72	72	72	72	72	72	72	72
Renewable	196	199	197	190	190	190	190	190	180	180
Purchases	734	734	734	235	235	235	121	121	121	121
Qualifying Facilities	691	742	740	745	736	682	678	673	668	664
Class 1 DSM	0	0	0	0	0	0	0	0	0	0
Sales	(173)	(173)	(173)	(173)	(173)	(173)	(148)	(148)	(66)	(66)
Non-Owned Reserves	(35)	(35)	(35)	(35)	(35)	(35)	(35)	(35)	(35)	(35)
East Existing Resources	**7,998**	**7,772**	**7,768**	**6,879**	**6,870**	**6,816**	**6,723**	**6,718**	**6,703**	**6,700**
Load	5,560	5,590	5,629	5,669	5,730	5,785	5,823	5,877	5,804	5,825
Private Generation	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)
Interruptible	(195)	(195)	(195)	(195)	(195)	(195)	(195)	(195)	(195)	(195)
DSM	(56)	(84)	(111)	(147)	(183)	(218)	(253)	(291)	(328)	(363)
East obligation	**5,310**	**5,311**	**5,323**	**5,328**	**5,352**	**5,372**	**5,375**	**5,392**	**5,280**	**5,267**
Planning Reserves (13%)	716	716	717	718	721	724	724	726	712	710
East Obligation + Reserves	**6,025**	**6,026**	**6,041**	**6,045**	**6,073**	**6,096**	**6,099**	**6,118**	**5,992**	**5,977**
East Position	**1,973**	**1,746**	**1,727**	**834**	**797**	**720**	**625**	**600**	**711**	**723**
Available Front Office Transactions	**318**	**318**	**318**	**318**	**318**	**318**	**318**	**318**	**318**	**318**
West										
Thermal	2,316	2,316	2,316	2,316	2,316	2,316	2,316	2,316	2,316	2,316
Hydroelectric	917	943	940	785	784	786	783	787	784	794
Renewable	90	95	95	95	65	65	60	59	58	56
Purchases	1	1	1	1	1	1	1	1	1	1
Qualifying Facilities	224	211	220	195	183	177	176	175	171	144
Class 1 DSM	0	0	0	0	0	0	0	0	0	0
Sales	(162)	(162)	(154)	(154)	(113)	(113)	(81)	(81)	(81)	(81)
Non-Owned Reserves	(3)	(3)	(3)	(3)	(3)	(3)	(3)	(3)	(3)	(3)
West Existing Resources	**3,383**	**3,402**	**3,415**	**3,235**	**3,233**	**3,228**	**3,251**	**3,253**	**3,246**	**3,227**
Load	3,342	3,376	3,384	3,408	3,431	3,455	3,473	3,498	3,521	3,547
Private Generation	0	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)
Interruptible	0	0	0	0	0	0	0	0	0	0
DSM	(55)	(80)	(105)	(130)	(152)	(173)	(193)	(211)	(228)	(244)
West obligation	**3,286**	**3,295**	**3,278**	**3,278**	**3,279**	**3,282**	**3,280**	**3,287**	**3,293**	**3,303**
Planning Reserves (13%)	427	428	426	426	426	427	426	427	428	429
West Obligation + Reserves	**3,713**	**3,723**	**3,705**	**3,704**	**3,705**	**3,709**	**3,707**	**3,714**	**3,721**	**3,732**
West Position	**(330)**	**(321)**	**(290)**	**(468)**	**(473)**	**(481)**	**(456)**	**(461)**	**(475)**	**(506)**
Available Front Office Transactions	**1,352**	**1,352**	**1,352**	**1,352**	**1,352**	**1,352**	**1,352**	**1,352**	**1,352**	**1,352**
System										
Total Resources	11,381	11,174	11,183	10,114	10,103	10,044	9,975	9,971	9,949	9,926
Obligation	8,596	8,606	8,602	8,605	8,631	8,655	8,655	8,678	8,573	8,570
Reserves	1,143	1,144	1,144	1,144	1,147	1,150	1,151	1,154	1,140	1,139
Obligation + Reserves	9,739	9,750	9,745	9,749	9,778	9,805	9,805	9,832	9,713	9,709
System Position	1,643	1,425	1,438	365	324	239	169	139	237	217
New EV2020 Wind	0	0	144	207	207	207	207	207	207	207
System Position w/ New Wind	1,643	1,425	1,582	572	531	446	376	346	444	424
Available Front Office Transactions	**1,670**	**1,670**	**1,670**	**1,670**	**1,670**	**1,670**	**1,670**	**1,670**	**1,670**	**1,670**
nmited FOT's to meet remaining Need	0	0	0	0	0	0	0	0	0	0
Net Surplus (Deficit)	1,643	1,425	1,582	572	531	446	376	346	444	424

[4] The DSM line includes selected Class 2 DSM from the 2017 IRP Update resource portfolio.

Table 4.5 (cont.) – Winter Peak – System Capacity Load and Resource Balance without Resource Additions, 2017 IRP Update (2028-2036) (Megawatts)[5]

Calendar Year	2028	2029	2030	2031	2032	2033	2034	2035	2036
East									
Thermal	5,001	5,001	4,644	4,568	4,568	4,212	4,212	4,130	4,130
Hydroelectric	72	72	72	72	72	72	72	72	72
Renewable	180	164	126	126	126	126	126	126	126
Purchases	121	121	121	121	121	121	121	121	121
Qualifying Facilities	657	653	650	646	635	590	587	570	175
Class 1 DSM	0	0	0	0	0	0	0	0	0
Sales	(66)	(66)	(66)	0	0	0	0	0	0
Non-Owned Reserves	(35)	(35)	(35)	(35)	(35)	(35)	(35)	(35)	(35)
East Existing Resources	**5,930**	**5,911**	**5,512**	**5,498**	**5,488**	**5,086**	**5,083**	**4,985**	**4,589**
Load	5,884	5,943	5,984	6,041	6,091	6,150	6,209	6,269	6,311
Private Generation	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)
Interruptible	(195)	(195)	(195)	(195)	(195)	(195)	(195)	(195)	(195)
DSM	(397)	(429)	(463)	(497)	(525)	(551)	(573)	(594)	(615)
East obligation	**5,292**	**5,319**	**5,326**	**5,349**	**5,371**	**5,404**	**5,440**	**5,480**	**5,500**
Planning Reserves (13%)	713	717	718	721	724	728	733	738	740
East Obligation + Reserves	**6,005**	**6,036**	**6,043**	**6,069**	**6,094**	**6,132**	**6,173**	**6,217**	**6,240**
East Position	**(75)**	**(125)**	**(531)**	**(571)**	**(607)**	**(1,045)**	**(1,090)**	**(1,233)**	**(1,651)**
Available Front Office Transactions	**318**	**318**	**318**	**318**	**318**	**318**	**318**	**318**	**318**
West									
Thermal	2,316	1,962	1,962	1,962	1,962	1,602	1,602	1,602	1,602
Hydroelectric	788	788	788	788	788	788	788	788	788
Renewable	55	54	54	53	53	53	53	53	53
Purchases	1	1	1	1	1	1	1	1	1
Qualifying Facilities	143	134	133	102	98	97	96	95	11
Class 1 DSM	0	0	0	0	0	0	0	0	0
Sales	(81)	(78)	(78)	(78)	(78)	(78)	(78)	(78)	(78)
Non-Owned Reserves	(3)	(3)	(3)	(3)	(3)	(3)	(3)	(3)	(3)
West Existing Resources	**3,219**	**2,858**	**2,856**	**2,826**	**2,821**	**2,461**	**2,461**	**2,460**	**2,375**
Load	3,572	3,599	3,615	3,636	3,657	3,684	3,708	3,731	3,746
Private Generation	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)
Interruptible	0	0	0	0	0	0	0	0	0
DSM	(260)	(274)	(288)	(302)	(316)	(329)	(341)	(353)	(365)
West obligation	**3,312**	**3,325**	**3,327**	**3,333**	**3,341**	**3,355**	**3,367**	**3,377**	**3,380**
Planning Reserves (13%)	431	432	432	433	434	436	438	439	439
West Obligation + Reserves	**3,743**	**3,757**	**3,759**	**3,766**	**3,775**	**3,791**	**3,805**	**3,817**	**3,820**
West Position	**(524)**	**(899)**	**(903)**	**(940)**	**(954)**	**(1,330)**	**(1,344)**	**(1,357)**	**(1,444)**
Available Front Office Transactions	**1,352**	**1,352**	**1,352**	**1,352**	**1,352**	**1,352**	**1,352**	**1,352**	**1,352**
System									
Total Resources	9,149	8,769	8,369	8,324	8,309	7,548	7,543	7,444	6,965
Obligation	8,604	8,643	8,652	8,682	8,712	8,759	8,807	8,857	8,880
Reserves	1,144	1,149	1,150	1,154	1,158	1,164	1,170	1,177	1,180
Obligation + Reserves	9,748	9,792	9,802	9,836	9,870	9,923	9,978	10,034	10,060
System Position	(599)	(1,024)	(1,434)	(1,512)	(1,561)	(2,375)	(2,434)	(2,590)	(3,095)
New EV2020 Wind	207	207	207	207	207	207	207	207	207
System Position w/ New Wind	(392)	(817)	(1,227)	(1,304)	(1,354)	(2,168)	(2,227)	(2,382)	(2,888)
Available Front Office Transactions	**1,670**	**1,670**	**1,670**	**1,670**	**1,670**	**1,670**	**1,670**	**1,670**	**1,670**
Uncommited FOT's to meet remaining Need	392	817	1,227	1,304	1,354	1,670	1,670	1,670	1,670
Net Surplus (Deficit)	0	0	0	0	0	(499)	(558)	(713)	(1,219)

[5] The DSM line includes selected Class 2 DSM from the 2017 IRP Update resource portfolio.

Table 4.6 – Summer Peak - System Capacity Load and Resource Balance without Resource Additions, 2017 IRP (2018-2027) (Megawatts)[6]

Calendar Year	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
East										
Thermal	6,406	6,126	6,126	5,739	5,739	5,739	5,739	5,735	5,645	5,645
Hydroelectric	106	113	113	113	113	113	92	92	92	92
Renewable	201	201	201	199	191	191	191	191	181	181
Purchases	249	249	249	221	221	221	221	121	121	121
Qualifying Facilities	646	689	681	672	661	657	603	598	594	590
Class 1 DSM	323	323	323	323	323	323	323	323	323	323
Sales	(652)	(652)	(652)	(172)	(172)	(172)	(146)	(146)	(63)	(63)
Non-Owned Reserves	(37)	(37)	(37)	(37)	(37)	(37)	(37)	(37)	(37)	(37)
East Existing Resources	**7,241**	**7,012**	**7,004**	**7,058**	**7,038**	**7,034**	**6,987**	**6,878**	**6,856**	**6,853**
Load	7,102	7,152	7,250	7,353	7,443	7,509	7,589	7,688	7,692	7,774
Private Generation	(61)	(83)	(100)	(108)	(114)	(118)	(123)	(131)	(141)	(153)
Interruptible	(195)	(195)	(195)	(195)	(195)	(195)	(195)	(195)	(195)	(195)
DSM	(190)	(246)	(298)	(355)	(410)	(468)	(527)	(584)	(641)	(697)
East obligation	**6,657**	**6,629**	**6,657**	**6,695**	**6,725**	**6,728**	**6,744**	**6,779**	**6,714**	**6,729**
Planning Reserves (13%)	891	887	891	896	900	900	902	907	898	900
East Obligation + Reserves	**7,547**	**7,516**	**7,548**	**7,591**	**7,624**	**7,628**	**7,646**	**7,685**	**7,612**	**7,629**
East Position	**(306)**	**(504)**	**(544)**	**(533)**	**(586)**	**(594)**	**(659)**	**(807)**	**(756)**	**(776)**
Available Front Office Transactions	**318**	**318**	**318**	**318**	**318**	**318**	**318**	**318**	**318**	**318**
West										
Thermal	2,247	2,247	2,247	2,247	2,247	2,247	2,247	2,247	2,247	2,247
Hydroelectric	859	717	806	635	549	644	648	634	651	644
Renewable	93	93	93	93	62	62	57	57	56	55
Purchases	18	1	1	1	1	1	1	1	1	1
Qualifying Facilities	200	202	207	198	195	186	185	184	182	150
Class 1 DSM	3	3	3	0	0	0	0	0	0	0
Sales	(165)	(165)	(165)	(161)	(110)	(110)	(80)	(80)	(80)	(80)
Non-Owned Reserves	(2)	(2)	(2)	(2)	(2)	(2)	(2)	(2)	(2)	(2)
West Existing Resources	**3,253**	**3,097**	**3,191**	**3,011**	**2,942**	**3,028**	**3,056**	**3,042**	**3,056**	**3,016**
Load	3,192	3,252	3,268	3,291	3,315	3,338	3,364	3,391	3,414	3,437
Private Generation	(9)	(12)	(15)	(17)	(20)	(23)	(26)	(29)	(33)	(37)
Interruptible	0	0	0	0	0	0	0	0	0	0
DSM	(97)	(126)	(152)	(175)	(196)	(214)	(232)	(248)	(263)	(278)
West obligation	**3,086**	**3,115**	**3,101**	**3,098**	**3,099**	**3,101**	**3,106**	**3,114**	**3,117**	**3,122**
Planning Reserves (13%)	401	405	403	403	403	403	404	405	405	406
West Obligation + Reserves	**3,487**	**3,519**	**3,504**	**3,501**	**3,502**	**3,505**	**3,510**	**3,518**	**3,523**	**3,528**
West Position	**(235)**	**(423)**	**(313)**	**(489)**	**(560)**	**(477)**	**(454)**	**(476)**	**(467)**	**(513)**
Available Front Office Transactions	**1,352**	**1,352**	**1,352**	**1,352**	**1,352**	**1,352**	**1,352**	**1,352**	**1,352**	**1,352**
System										
Total Resources	10,494	10,109	10,194	10,069	9,980	10,062	10,043	9,920	9,912	9,869
Obligation	9,743	9,743	9,758	9,793	9,824	9,829	9,850	9,892	9,831	9,851
Reserves	1,292	1,292	1,294	1,298	1,302	1,303	1,306	1,311	1,303	1,306
Obligation + Reserves	11,035	11,035	11,052	11,092	11,126	11,132	11,156	11,203	11,135	11,157
System Position	(541)	(927)	(858)	(1,023)	(1,146)	(1,070)	(1,113)	(1,284)	(1,223)	(1,288)
New Wind	0	0	0	174	174	174	174	174	174	174
System Position w/ New Wind	(541)	(927)	(858)	(849)	(972)	(897)	(940)	(1,110)	(1,049)	(1,115)
Available Front Office Transactions	**1,670**	**1,670**	**1,670**	**1,670**	**1,670**	**1,670**	**1,670**	**1,670**	**1,670**	**1,670**
Uncommited FOT's to meet remaining Need	541	927	858	849	972	897	940	1,110	1,049	1,115
Net Surplus (Deficit)	0	0	0	0	0	0	0	0	0	0

[6] The Load and Private Generation lines include an offsetting adjustment (average of 43 MW) from the 2017 IRP that nets to zero. The DSM line includes selected Class 2 DSM from the 2017 IRP Preferred Portfolio.

Table 4.6 (cont.) – Summer Peak - System Capacity Load and Resource Balance without Resource Additions, 2017 IRP (2028-2036) (Megawatts)[7]

Calendar Year	2028	2029	2030	2031	2032	2033	2034	2035	2036
East									
Thermal	4,883	4,883	4,526	4,449	4,449	4,092	4,092	4,010	4,010
Hydroelectric	92	92	92	92	92	92	92	92	92
Renewable	181	181	159	127	127	127	127	127	127
Purchases	121	121	121	121	121	121	121	121	121
Qualifying Facilities	586	580	576	573	562	530	514	506	454
Class 1 DSM	323	323	323	323	323	323	323	323	323
Sales	(63)	(63)	(63)	0	0	0	0	0	0
Non-Owned Reserves	(37)	(37)	(37)	(37)	(37)	(37)	(37)	(37)	(37)
East Existing Resources	**6,087**	**6,081**	**5,698**	**5,648**	**5,637**	**5,249**	**5,232**	**5,143**	**5,091**
Load	7,842	7,951	8,044	8,152	8,299	8,393	8,460	8,584	8,721
Private Generation	(164)	(182)	(205)	(226)	(250)	(275)	(300)	(323)	(343)
Interruptible	(195)	(195)	(195)	(195)	(195)	(195)	(195)	(195)	(195)
DSM	(749)	(799)	(848)	(898)	(940)	(977)	(1,008)	(1,037)	(1,067)
East obligation	**6,733**	**6,775**	**6,796**	**6,832**	**6,914**	**6,946**	**6,957**	**7,029**	**7,115**
Planning Reserves (13%)	901	906	909	914	924	928	930	939	950
East Obligation + Reserves	**7,634**	**7,681**	**7,705**	**7,746**	**7,838**	**7,875**	**7,887**	**7,968**	**8,065**
East Position	**(1,547)**	**(1,600)**	**(2,007)**	**(2,097)**	**(2,201)**	**(2,626)**	**(2,654)**	**(2,825)**	**(2,974)**
Available Front Office Transactions	**318**	**318**	**318**	**318**	**318**	**318**	**318**	**318**	**318**
West									
Thermal	2,247	1,893	1,893	1,893	1,893	1,534	1,534	1,534	1,534
Hydroelectric	644	644	644	644	644	644	644	644	644
Renewable	52	51	51	51	51	51	51	51	51
Purchases	1	1	1	1	1	1	1	1	1
Qualifying Facilities	149	138	133	132	99	97	97	96	94
Class 1 DSM	0	0	0	0	0	0	0	0	0
Sales	(80)	(78)	(78)	(78)	(78)	(78)	(78)	(78)	(24)
Non-Owned Reserves	(2)	(2)	(2)	(2)	(2)	(2)	(2)	(2)	(2)
West Existing Resources	**3,012**	**2,648**	**2,643**	**2,642**	**2,608**	**2,247**	**2,247**	**2,246**	**2,298**
Load	3,461	3,487	3,512	3,536	3,559	3,585	3,608	3,634	3,660
Private Generation	(42)	(48)	(56)	(64)	(73)	(82)	(92)	(102)	(113)
Interruptible	0	0	0	0	0	0	0	0	0
DSM	(291)	(304)	(316)	(328)	(340)	(350)	(360)	(370)	(379)
West obligation	**3,128**	**3,135**	**3,140**	**3,144**	**3,147**	**3,154**	**3,157**	**3,162**	**3,168**
Planning Reserves (13%)	407	408	408	409	409	410	410	411	412
West Obligation + Reserves	**3,534**	**3,543**	**3,548**	**3,553**	**3,556**	**3,564**	**3,567**	**3,574**	**3,580**
West Position	**(522)**	**(894)**	**(905)**	**(911)**	**(948)**	**(1,316)**	**(1,320)**	**(1,327)**	**(1,282)**
Available Front Office Transactions	**1,352**	**1,352**	**1,352**	**1,352**	**1,352**	**1,352**	**1,352**	**1,352**	**1,352**
System									
Total Resources	9,099	8,729	8,341	8,290	8,246	7,496	7,479	7,389	7,389
Obligation	9,861	9,910	9,936	9,976	10,061	10,100	10,114	10,191	10,283
Reserves	1,307	1,314	1,317	1,322	1,333	1,338	1,340	1,350	1,362
Obligation + Reserves	11,168	11,223	11,253	11,298	11,395	11,438	11,454	11,541	11,645
System Position	(2,068)	(2,495)	(2,912)	(3,008)	(3,149)	(3,942)	(3,975)	(4,152)	(4,256)
New Wind	174	174	174	174	174	174	174	174	174
System Position w/ New Wind	(1,895)	(2,321)	(2,738)	(2,834)	(2,975)	(3,768)	(3,801)	(3,978)	(4,082)
Available Front Office Transactions	**1,670**	**1,670**	**1,670**	**1,670**	**1,670**	**1,670**	**1,670**	**1,670**	**1,670**
Uncommited FOT's to meet remaining Need	1,670	1,670	1,670	1,670	1,670	1,670	1,670	1,670	1,670
Net Surplus (Deficit)	(225)	(651)	(1,069)	(1,165)	(1,306)	(2,099)	(2,131)	(2,309)	(2,413)

[7] The Load and Private Generation lines include an offsetting adjustment (average of 43 MW) from the 2017 IRP that nets to zero. The DSM line includes selected Class 2 DSM from the 2017 IRP Preferred Portfolio.

Table 4.7 Winter Peak – System Capacity Load and Resource Balance without Resource Additions, 2017 IRP (2018-2027) (Megawatts)[8]

Calendar Year	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
East										
Thermal	6,514	6,234	6,234	5,847	5,847	5,847	5,847	5,843	5,753	5,753
Hydroelectric	72	72	72	72	72	72	72	72	72	72
Renewable	201	201	199	191	191	191	191	191	181	181
Purchases	734	734	734	235	235	235	121	121	121	121
Qualifying Facilities	688	680	676	668	658	604	600	595	591	588
Class 1 DSM	21	21	21	21	21	21	21	21	21	21
Sales	(170)	(170)	(170)	(170)	(170)	(170)	(146)	(146)	(63)	(63)
Non-Owned Reserves	(37)	(37)	(37)	(37)	(37)	(37)	(37)	(37)	(37)	(37)
East Existing Resources	**8,023**	**7,735**	**7,729**	**6,826**	**6,816**	**6,762**	**6,670**	**6,661**	**6,640**	**6,636**
Load	5,620	5,691	5,604	5,777	5,856	5,932	5,965	5,929	5,934	6,092
Private Generation	(20)	(29)	(35)	(38)	(40)	(42)	(44)	(46)	(50)	(54)
Interruptible	(195)	(195)	(195)	(195)	(195)	(195)	(195)	(195)	(195)	(195)
DSM	(132)	(173)	(213)	(256)	(297)	(340)	(383)	(425)	(469)	(511)
East obligation	**5,274**	**5,294**	**5,161**	**5,288**	**5,323**	**5,355**	**5,343**	**5,262**	**5,220**	**5,332**
Planning Reserves (13%)	711	714	696	713	717	721	720	709	704	718
East Obligation + Reserves	**5,985**	**6,007**	**5,857**	**6,001**	**6,040**	**6,076**	**6,063**	**5,971**	**5,924**	**6,050**
East Position	**2,039**	**1,728**	**1,872**	**826**	**776**	**686**	**607**	**689**	**716**	**586**
Available Front Office Transactions	**318**	**318**	**318**	**318**	**318**	**318**	**318**	**318**	**318**	**318**
West										
Thermal	2,308	2,308	2,308	2,308	2,308	2,308	2,308	2,308	2,308	2,308
Hydroelectric	915	943	937	784	782	783	779	786	786	784
Renewable	93	93	93	93	62	62	57	56	55	53
Purchases	1	1	1	1	1	1	1	1	1	1
Qualifying Facilities	192	195	197	190	183	177	176	175	171	144
Class 1 DSM	0	0	0	0	0	0	0	0	0	0
Sales	(162)	(162)	(154)	(154)	(113)	(113)	(81)	(81)	(81)	(81)
Non-Owned Reserves	(2)	(2)	(2)	(2)	(2)	(2)	(2)	(2)	(2)	(2)
West Existing Resources	**3,345**	**3,377**	**3,381**	**3,221**	**3,221**	**3,215**	**3,238**	**3,244**	**3,238**	**3,207**
Load	3,291	3,306	3,417	3,360	3,379	3,400	3,417	3,542	3,559	3,499
Private Generation	(2)	(3)	(3)	(4)	(5)	(5)	(6)	(7)	(7)	(8)
Interruptible	0	0	0	0	0	0	0	0	0	0
DSM	(109)	(143)	(174)	(201)	(225)	(246)	(267)	(286)	(304)	(321)
West obligation	**3,180**	**3,160**	**3,239**	**3,155**	**3,149**	**3,149**	**3,144**	**3,249**	**3,247**	**3,169**
Planning Reserves (13%)	413	411	421	410	409	409	409	422	422	412
West Obligation + Reserves	**3,593**	**3,571**	**3,661**	**3,565**	**3,559**	**3,558**	**3,553**	**3,671**	**3,670**	**3,581**
West Position	**(248)**	**(194)**	**(280)**	**(344)**	**(338)**	**(343)**	**(315)**	**(428)**	**(431)**	**(374)**
Available Front Office Transactions	**1,352**	**1,352**	**1,352**	**1,352**	**1,352**	**1,352**	**1,352**	**1,352**	**1,352**	**1,352**
System										
Total Resources	11,369	11,112	11,110	10,047	10,037	9,978	9,908	9,905	9,878	9,843
Obligation	8,453	8,453	8,400	8,443	8,472	8,503	8,487	8,511	8,467	8,501
Reserves	1,124	1,124	1,117	1,123	1,127	1,131	1,129	1,132	1,126	1,130
Obligation + Reserves	9,578	9,578	9,518	9,566	9,599	9,634	9,616	9,643	9,593	9,632
System Position	1,791	1,534	1,592	481	438	344	292	262	285	212
New Wind	0	0	0	174	174	174	174	174	174	174
System Position w/ New Wind	1,791	1,534	1,592	655	612	517	466	436	459	386
Available Front Office Transactions	**1,670**	**1,670**	**1,670**	**1,670**	**1,670**	**1,670**	**1,670**	**1,670**	**1,670**	**1,670**
Uncommited FOT's to meet remaining Need	0	0	0	0	0	0	0	0	0	0
Net Surplus (Deficit)	1,791	1,534	1,592	655	612	517	466	436	459	386

[8] The Load and Private Generation lines include an offsetting adjustment (average of 15 MW) from the 2017 IRP that nets to zero. The DSM line includes selected Class 2 DSM from the 2017 IRP Preferred Portfolio.

Table 4.7 (cont.) – Winter Peak – System Capacity Load and Resource Balance without Resource Additions, 2017 IRP (2028-2036) (Megawatts)[9]

Calendar Year	2028	2029	2030	2031	2032	2033	2034	2035	2036
East									
Thermal	4,991	4,991	4,634	4,557	4,557	4,200	4,200	4,118	4,118
Hydroelectric	72	72	72	72	72	72	72	72	72
Renewable	181	165	127	127	127	127	127	127	127
Purchases	121	121	121	121	121	121	121	121	121
Qualifying Facilities	580	577	573	570	559	514	511	493	109
Class 1 DSM	21	21	21	21	21	21	21	21	21
Sales	(63)	(63)	(63)	0	0	0	0	0	0
Non-Owned Reserves	(37)	(37)	(37)	(37)	(37)	(37)	(37)	(37)	(37)
East Existing Resources	**5,867**	**5,848**	**5,449**	**5,431**	**5,420**	**5,018**	**5,015**	**4,915**	**4,532**
Load	6,180	6,266	6,332	6,264	6,464	6,545	6,630	6,722	6,750
Private Generation	(58)	(65)	(73)	(81)	(89)	(98)	(107)	(115)	(123)
Interruptible	(195)	(195)	(195)	(195)	(195)	(195)	(195)	(195)	(195)
DSM	(550)	(587)	(624)	(661)	(692)	(719)	(742)	(764)	(786)
East obligation	**5,376**	**5,419**	**5,440**	**5,327**	**5,488**	**5,532**	**5,586**	**5,648**	**5,646**
Planning Reserves (13%)	724	730	733	718	739	745	751	760	759
East Obligation + Reserves	**6,100**	**6,149**	**6,172**	**6,045**	**6,226**	**6,277**	**6,337**	**6,408**	**6,406**
East Position	**(234)**	**(301)**	**(723)**	**(614)**	**(806)**	**(1,258)**	**(1,322)**	**(1,492)**	**(1,874)**
Available Front Office Transactions	**318**	**318**	**318**	**318**	**318**	**318**	**318**	**318**	**318**
West									
Thermal	2,308	1,954	1,954	1,954	1,954	1,595	1,595	1,595	1,595
Hydroelectric	784	784	784	784	784	784	784	784	784
Renewable	52	51	51	51	51	51	51	51	51
Purchases	1	1	1	1	1	1	1	1	1
Qualifying Facilities	143	134	133	102	98	97	97	96	11
Class 1 DSM	0	0	0	0	0	0	0	0	0
Sales	(81)	(78)	(78)	(78)	(78)	(78)	(78)	(78)	(78)
Non-Owned Reserves	(2)	(2)	(2)	(2)	(2)	(2)	(2)	(2)	(2)
West Existing Resources	**3,205**	**2,844**	**2,843**	**2,812**	**2,807**	**2,448**	**2,447**	**2,446**	**2,362**
Load	3,515	3,538	3,546	3,680	3,607	3,628	3,648	3,668	3,654
Private Generation	(10)	(11)	(13)	(14)	(16)	(18)	(21)	(23)	(25)
Interruptible	0	0	0	0	0	0	0	0	0
DSM	(337)	(352)	(367)	(381)	(395)	(408)	(420)	(433)	(445)
West obligation	**3,168**	**3,175**	**3,167**	**3,285**	**3,195**	**3,202**	**3,208**	**3,212**	**3,184**
Planning Reserves (13%)	412	413	412	427	415	416	417	418	414
West Obligation + Reserves	**3,580**	**3,588**	**3,578**	**3,712**	**3,611**	**3,618**	**3,625**	**3,630**	**3,598**
West Position	**(375)**	**(744)**	**(736)**	**(899)**	**(803)**	**(1,170)**	**(1,178)**	**(1,184)**	**(1,236)**
Available Front Office Transactions	**1,352**	**1,352**	**1,352**	**1,352**	**1,352**	**1,352**	**1,352**	**1,352**	**1,352**
System									
Total Resources	9,072	8,691	8,292	8,243	8,228	7,466	7,462	7,361	6,893
Obligation	8,545	8,594	8,607	8,612	8,683	8,734	8,793	8,860	8,830
Reserves	1,136	1,143	1,144	1,145	1,154	1,161	1,168	1,177	1,173
Obligation + Reserves	9,681	9,737	9,751	9,757	9,837	9,895	9,962	10,037	10,003
System Position	(609)	(1,045)	(1,459)	(1,514)	(1,609)	(2,429)	(2,500)	(2,676)	(3,110)
New Wind	174	174	174	174	174	174	174	174	174
System Position w/ New Wind	(435)	(871)	(1,285)	(1,340)	(1,436)	(2,255)	(2,326)	(2,502)	(2,936)
Available Front Office Transactions	**1,670**	**1,670**	**1,670**	**1,670**	**1,670**	**1,670**	**1,670**	**1,670**	**1,670**
Uncommited FOT's to meet remaining Need	435	871	1,285	1,340	1,436	1,670	1,670	1,670	1,670
Net Surplus (Deficit)	0	0	0	0	0	(586)	(657)	(833)	(1,267)

[9] The Load and Private Generation lines include an offsetting adjustment (average of 15 MW) from the 2017 IRP that nets to zero. The DSM line includes selected Class 2 DSM from the 2017 IRP Preferred Portfolio.

Table 4.8 – Summer Peak – System Capacity Load and Resource Balance without Resource Additions, 2017 IRP Update less 2017 IRP (2018-2027) (Megawatts)[10]

Calendar Year	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
East										
Thermal	(2)	(2)	(2)	(2)	(2)	(2)	(2)	2	9	9
Hydroelectric	1	1	1	1	1	1	1	1	1	1
Renewable	(6)	(8)	(3)	(1)	(1)	(1)	(1)	(1)	(1)	(1)
Purchases	0	0	0	0	0	0	0	0	0	0
Qualifying Facilities	2	1	62	62	77	77	77	77	76	76
Class 1 DSM	0	0	0	0	0	0	0	0	0	0
Sales	(3)	(3)	(3)	(3)	(3)	(3)	(3)	(3)	(3)	(3)
Non-Owned Reserves	3	3	3	3	3	3	3	3	3	3
East Existing Resources	**(5)**	**(8)**	**57**	**60**	**74**		**74**	**78**	**85**	**84**
Load	(249)	(241)	(278)	(312)	(328)	(326)	(329)	(368)	(370)	(408)
Private Generation	(47)	(83)	(102)	(105)	(106)	(108)	(111)	(111)	(110)	(116)
Interruptible	0	0	0	0	0	0	0	0	0	0
DSM	72	73	72	82	90	104	117	124	132	142
East obligation	**(224)**	**(251)**	**(308)**	**(335)**	**(343)**	**(330)**	**(323)**	**(355)**	**(349)**	**(383)**
Planning Reserves (13%)	(29)	(33)	(40)	(44)	(45)	(43)	(42)	(46)	(45)	(50)
East Obligation + Reserves	**(253)**	**(283)**	**(348)**	**(379)**	**(388)**	**(373)**	**(365)**	**(401)**	**(394)**	**(432)**
East Position	**248**	**276**	**405**	**438**	**462**	**447**	**439**	**478**	**479**	**516**
Available Front Office Transactions	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**
West										
Thermal	7	7	7	7	7	7	7	7	7	7
Hydroelectric	2	30	(16)	8	37	(20)	7	21	(6)	14
Renewable	(2)	(5)	3	3	3	3	3	3	3	3
Purchases	0	0	0	0	0	0	0	0	0	0
Qualifying Facilities	35	18	20	5	(0)	1	(0)	0	0	0
Class 1 DSM	0	0	0	0	0	0	0	0	0	0
Sales	0	0	0	0	0	0	0	0	0	0
Non-Owned Reserves	(1)	(1)	(1)	(1)	(1)	(1)	(1)	(1)	(1)	(1)
West Existing Resources	**41**	**49**	**13**	**22**	**46**	**(10)**	**16**	**30**	**3**	**23**
Load	46	27	26	21	16	13	1	4	2	(1)
Private Generation	(3)	(8)	(11)	(14)	(17)	(19)	(22)	(26)	(30)	(34)
Interruptible	0	0	0	0	0	0	0	0	0	0
DSM	32	32	30	31	33	34	34	35	35	35
West obligation	**75**	**52**	**44**	**39**	**33**	**27**	**14**	**13**	**7**	**1**
Planning Reserves (13%)	10	7	6	5	4	4	2	2	1	0
West Obligation + Reserves	**85**	**59**	**50**	**44**	**37**	**31**	**15**	**15**	**8**	**1**
West Position	**(44)**	**(10)**	**(38)**	**(22)**	**9**	**(41)**	**1**	**15**	**(5)**	**22**
Available Front Office Transactions	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**
System										
Total Resources	36	41	70	82	120	64	90	108	87	107
Obligation	(149)	(199)	(263)	(296)	(310)	(303)	(309)	(342)	(342)	(382)
Reserves	(19)	(26)	(34)	(38)	(40)	(39)	(40)	(44)	(44)	(50)
Obligation + Reserves	(168)	(225)	(297)	(335)	(351)	(342)	(350)	(386)	(386)	(432)
System Position	204	266	367	417	471	407	440	494	473	539
New EV2020 Wind	0	0	0	33	33	33	33	33	33	33
System Position w/ New Wind	204	266	367	450	504	440	473	527	507	572
Available Front Office Transactions	0	0	0	0	0	0	0	0	0	0
Uncommitted FOT's to meet remaining Need	(204)	(266)	(367)	(450)	(504)	(440)	(473)	(527)	(507)	(572)
Net Surplus (Deficit)	0	0	0	0	0	0	0	0	0	0

[10] The DSM line reflects differences in Class 2 DSM resources between the 2017 IRP Update resource portfolio and the 2017 IRP Preferred Portfolio, which includes a level of 2016 Class 2 DSM (100 MW) that was not incorporated in the load forecast for the 2017 IRP. The 2016 Class 2 DSM forecast of 100 MW was accounted for by adding an existing Class 2 DSM resource in the load-and-resource balance; this adjustment was not required for the 2017 IRP Update because the 2016 projected embedded Class 2 DSM is included in the load forecast.

Table 4.8 (cont.) – Summer Peak – System Capacity Load and Resource Balance without Resource Additions, 2017 IRP Update less 2017 IRP (2028-2036) (Megawatts)[11]

Calendar Year	2028	2029	2030	2031	2032	2033	2034	2035	2036
East									
Thermal	9	9	9	10	10	11	11	11	11
Hydroelectric	1	1	1	1	1	1	1	1	1
Renewable	(1)	(1)	(1)	(1)	(1)	(1)	(1)	(1)	(1)
Purchases	0	0	0	0	0	0	0	0	0
Qualifying Facilities	76	76	76	75	75	75	75	78	78
Class 1 DSM	0	0	0	0	0	0	0	0	0
Sales	(3)	(3)	(3)	0	0	0	0	0	0
Non-Owned Reserves	3	3	3	3	3	3	3	3	3
East Existing Resources	**84**	**84**	**84**	**88**	**88**	**88**	**88**	**91**	**91**
Load	(397)	(429)	(442)	(609)	(659)	(677)	(671)	(712)	(768)
Private Generation	(124)	(122)	(119)	(10)	(11)	(9)	(8)	(10)	(11)
Interruptible	0	0	0	0	0	0	0	0	0
DSM	148	154	158	164	169	172	173	174	176
East obligation	**(373)**	**(397)**	**(404)**	**(454)**	**(501)**	**(514)**	**(506)**	**(547)**	**(603)**
Planning Reserves (13%)	(48)	(52)	(52)	(59)	(65)	(67)	(66)	(71)	(78)
East Obligation + Reserves	**(421)**	**(448)**	**(456)**	**(514)**	**(566)**	**(581)**	**(572)**	**(618)**	**(681)**
East Position	**505**	**532**	**540**	**601**	**654**	**669**	**659**	**709**	**772**
Available Front Office Transactions	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**
West									
Thermal	7	7	7	7	7	7	7	7	7
Hydroelectric	9	9	9	9	9	9	9	9	9
Renewable	3	3	3	3	3	3	3	3	3
Purchases	0	0	0	0	0	0	0	0	0
Qualifying Facilities	0	0	0	0	0	0	0	0	0
Class 1 DSM	0	0	0	0	0	0	0	0	0
Sales	0	0	0	0	0	0	0	0	0
Non-Owned Reserves	(1)	(1)	(1)	(1)	(1)	(1)	(1)	(1)	(1)
West Existing Resources	**18**	**18**	**18**	**18**	**18**	**18**	**18**	**18**	**18**
Load	(3)	16	(17)	(23)	(27)	(31)	(33)	(15)	(48)
Private Generation	(36)	(37)	(37)	(8)	(8)	(8)	(9)	(9)	(8)
Interruptible	0	0	0	0	0	0	0	0	0
DSM	36	36	36	37	37	37	37	37	37
West obligation	**(4)**	**15**	**(18)**	**6**	**2**	**(1)**	**(5)**	**14**	**(19)**
Planning Reserves (13%)	(0)	2	(2)	1	0	(0)	(1)	2	(2)
West Obligation + Reserves	**(4)**	**17**	**(20)**	**6**	**2**	**(1)**	**(5)**	**16**	**(22)**
West Position	**22**	**1**	**38**	**11**	**15**	**19**	**23**	**2**	**39**
Available Front Office Transactions	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**
System									
Total Resources	101	101	101	105	105	106	106	108	108
Obligation	(376)	(382)	(422)	(449)	(499)	(515)	(510)	(534)	(622)
Reserves	(49)	(50)	(55)	(58)	(65)	(67)	(66)	(69)	(81)
Obligation + Reserves	(425)	(431)	(476)	(507)	(564)	(582)	(577)	(603)	(703)
System Position	527	533	578	612	669	688	682	711	811
New EV2020 Wind	33	33	33	33	33	33	33	33	33
System Position w/ New Wind	560	566	611	646	702	721	715	744	844
Available Front Office Transactions	0	0	0	0	0	0	0	0	0
Uncommitted FOT's to meet remaining Need	(335)	0	0	0	0	0	0	0	0
Net Surplus (Deficit)	225	566	611	646	702	721	715	744	844

[11] The DSM line reflects differences in Class 2 DSM resources between the 2017 IRP Update resource portfolio and the 2017 IRP Preferred Portfolio, which includes a level of 2016 Class 2 DSM (100 MW) that was not incorporated in the load forecast for the 2017 IRP. The 2016 Class 2 DSM forecast of 100 MW was accounted for by adding an existing Class 2 DSM resource in the load-and-resource balance; this adjustment was not required for the 2017 IRP Update because the 2016 projected embedded Class 2 DSM is included in the load forecast.

Table 4.9 – Winter Peak – System Capacity Load and Resource Balance without Resource Additions, 2017 IRP Update less 2017 IRP (2018-2027) (Megawatts)[12]

Calendar Year	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
East										
Thermal	(1)	(1)	(1)	(1)	(1)	(1)	(1)	3	10	10
Hydroelectric	(1)	(1)	(1)	(1)	(1)	(1)	(1)	(1)	(1)	(1)
Renewable	(6)	(2)	(1)	(1)	(1)	(1)	(1)	(1)	(1)	(1)
Purchases	0	0	0	0	0	0	0	0	0	0
Qualifying Facilities	3	62	63	77	78	78	78	77	77	77
Class 1 DSM	(21)	(21)	(21)	(21)	(21)	(21)	(21)	(21)	(21)	(21)
Sales	(3)	(3)	(3)	(3)	(3)	(3)	(3)	(3)	(3)	(3)
Non-Owned Reserves	3	3	3	3	3	3	3	3	3	3
East Existing Resources	**(25)**	**37**	**39**	**53**	**54**	**54**	**54**	**57**	**64**	**64**
Load	(60)	(102)	25	(108)	(126)	(147)	(143)	(51)	(131)	(267)
Private Generation	20	29	35	38	40	42	43	46	50	54
Interruptible	0	0	0	0	0	0	0	0	0	0
DSM	76	89	102	109	115	122	131	135	141	148
East obligation	**36**	**17**	**162**	**39**	**29**	**17**	**31**	**130**	**61**	**(65)**
Planning Reserves (13%)	5	2	21	5	4	2	4	17	8	(8)
East Obligation + Reserves	**41**	**19**	**183**	**45**	**33**	**20**	**35**	**146**	**69**	**(73)**
East Position	**(66)**	**18**	**(144)**	**8**	**21**	**34**	**18**	**(89)**	**(5)**	**137**
Available Front Office Transactions	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**
West										
Thermal	7	7	7	7	7	7	7	7	7	7
Hydroelectric	2	(0)	2	1	2	3	4	0	(2)	10
Renewable	(2)	3	3	3	3	3	3	3	3	3
Purchases	0	0	0	0	0	0	0	0	0	0
Qualifying Facilities	32	16	23	4	1	1	(0)	(0)	(0)	(0)
Class 1 DSM	0	0	0	0	0	0	0	0	0	0
Sales	0	0	0	0	0	0	0	0	0	0
Non-Owned Reserves	(1)	(1)	(1)	(1)	(1)	(1)	(1)	(1)	(1)	(1)
West Existing Resources	**38**	**25**	**34**	**15**	**12**	**13**	**13**	**9**	**7**	**19**
Load	51	70	(33)	48	52	55	56	(44)	(38)	49
Private Generation	2	3	3	4	5	5	6	7	7	8
Interruptible	0	0	0	0	0	0	0	0	0	0
DSM	54	63	69	71	73	74	75	75	76	77
West obligation	**107**	**135**	**39**	**123**	**130**	**134**	**137**	**38**	**45**	**134**
Planning Reserves (13%)	14	18	5	16	17	17	18	5	6	17
West Obligation + Reserves	**120**	**153**	**44**	**139**	**147**	**151**	**154**	**43**	**51**	**151**
West Position	**(82)**	**(127)**	**(10)**	**(124)**	**(135)**	**(139)**	**(141)**	**(33)**	**(43)**	**(132)**
Available Front Office Transactions	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**
System										
Total Resources	13	63	73	67	66	66	67	66	71	83
Obligation	143	152	201	162	159	151	168	167	106	69
Reserves	19	20	26	21	21	20	22	22	14	9
Obligation + Reserves	161	172	227	183	180	171	190	189	119	78
System Position	(148)	(110)	(154)	(116)	(114)	(105)	(123)	(123)	(48)	5
New EV2020 Wind	0	0	144	33	33	33	33	33	33	33
System Position w/ New Wind	(148)	(110)	(10)	(83)	(81)	(72)	(89)	(89)	(15)	38
Available Front Office Transactions	0	0	0	0	0	0	0	0	0	0
Uncommited FOT's to meet remaining Need	0	0	0	0	0	0	0	0	0	0
Net Surplus (Deficit)	(148)	(110)	(10)	(83)	(81)	(72)	(89)	(89)	(15)	38

[12] The DSM line reflects differences in Class 2 DSM resources between the 2017 IRP Update resource portfolio and the 2017 IRP Preferred Portfolio, which includes a level of 2016 Class 2 DSM (81 MW) that was not incorporated in the load forecast for the 2017 IRP. The 2016 Class 2 DSM forecast of 81 MW was accounted for by adding an existing Class 2 DSM resource in the load-and-resource balance; this adjustment was not required for the 2017 IRP Update because the 2016 projected embedded Class 2 DSM is included in the load forecast.

Table 4.9 (cont.) – Winter Peak – System Capacity Load and Resource Balance without Resource Additions, 2017 IRP Update less 2017 IRP (2028-2036) (Megawatts)[13]

Calendar Year	2028	2029	2030	2031	2032	2033	2034	2035	2036
East									
Thermal	10	10	10	11	11	12	12	12	12
Hydroelectric	(1)	(1)	(1)	(1)	(1)	(1)	(1)	(1)	(1)
Renewable	(1)	(1)	(1)	(1)	(1)	(1)	(1)	(1)	(1)
Purchases	0	0	0	0	0	0	0	0	0
Qualifying Facilities	77	77	76	76	76	76	76	78	66
Class 1 DSM	(21)	(21)	(21)	(21)	(21)	(21)	(21)	(21)	(21)
Sales	(3)	(3)	(3)	0	0	0	0	0	0
Non-Owned Reserves	3	3	3	3	3	3	3	3	3
East Existing Resources	**64**	**63**	**63**	**67**	**67**	**68**	**68**	**69**	**58**
Load	(296)	(323)	(348)	(223)	(373)	(395)	(422)	(454)	(439)
Private Generation	58	65	73	80	89	98	107	115	122
Interruptible	0	0	0	0	0	0	0	0	0
DSM	153	159	161	164	167	169	170	170	171
East obligation	**(84)**	**(100)**	**(114)**	**21**	**(117)**	**(129)**	**(145)**	**(168)**	**(146)**
Planning Reserves (13%)	(11)	(13)	(15)	3	(15)	(17)	(19)	(22)	(19)
East Obligation + Reserves	**(95)**	**(113)**	**(129)**	**24**	**(132)**	**(145)**	**(164)**	**(190)**	**(165)**
East Position	**159**	**177**	**192**	**43**	**199**	**213**	**232**	**259**	**223**
Available Front Office Transactions	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**
West									
Thermal	7	7	7	7	7	7	7	7	7
Hydroelectric	5	5	5	5	5	5	5	5	5
Renewable	3	3	3	3	3	3	3	3	3
Purchases	0	0	0	0	0	0	0	0	0
Qualifying Facilities	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	0
Class 1 DSM	0	0	0	0	0	0	0	0	0
Sales	0	0	0	0	0	0	0	0	0
Non-Owned Reserves	(1)	(1)	(1)	(1)	(1)	(1)	(1)	(1)	(1)
West Existing Resources	**14**	**14**	**14**	**14**	**14**	**14**	**14**	**14**	**14**
Load	57	61	69	(45)	51	56	60	63	92
Private Generation	9	11	12	14	16	18	20	23	25
Interruptible	0	0	0	0	0	0	0	0	0
DSM	77	78	78	79	79	79	80	80	79
West obligation	**144**	**150**	**160**	**49**	**146**	**153**	**159**	**165**	**196**
Planning Reserves (13%)	19	19	21	6	19	20	21	21	26
West Obligation + Reserves	**163**	**169**	**181**	**55**	**165**	**173**	**180**	**187**	**222**
West Position	**(149)**	**(156)**	**(167)**	**(41)**	**(151)**	**(159)**	**(166)**	**(173)**	**(208)**
Available Front Office Transactions	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**
System									
Total Resources	77	77	77	81	81	81	81	83	71
Obligation	60	50	46	70	29	25	14	(3)	50
Reserves	8	6	6	9	4	3	2	(0)	7
Obligation + Reserves	67	56	52	79	33	28	16	(4)	57
System Position	10	21	26	2	48	53	66	87	15
New EV2020 Wind	33	33	33	33	33	33	33	33	33
System Position w/ New Wind	43	55	59	36	82	87	99	120	48
Available Front Office Transactions	0	0	0	0	0	0	0	0	0
Uncommited FOT's to meet remaining Need	(43)	(55)	(59)	(36)	(82)	0	0	0	0
Net Surplus (Deficit)	0	0	0	0	0	87	99	120	48

[13] The DSM line reflects differences in Class 2 DSM resources between the 2017 IRP Update resource portfolio and the 2017 IRP Preferred Portfolio, which includes a level of 2016 Class 2 DSM (81 MW) that was not incorporated in the load forecast for the 2017 IRP. The 2016 Class 2 DSM forecast of 81 MW was accounted for by adding an existing Class 2 DSM resource in the load-and-resource balance; this adjustment was not required for the 2017 IRP Update because the 2016 projected embedded Class 2 DSM is included in the load forecast.

Figure 4.4 through Figure 4.7 are graphic representations of the above tables for the 2017 IRP Update annual capacity position for the summer system, winter system, east balancing area, and west balancing area, respectively. Also shown in the system capacity position graphs are the capacity contribution from Energy Vision 2020 wind resources and uncommitted FOTs, which as discussed above, are provided for informational purposes.

Figure 4.4 – Summer System Capacity Position Trend

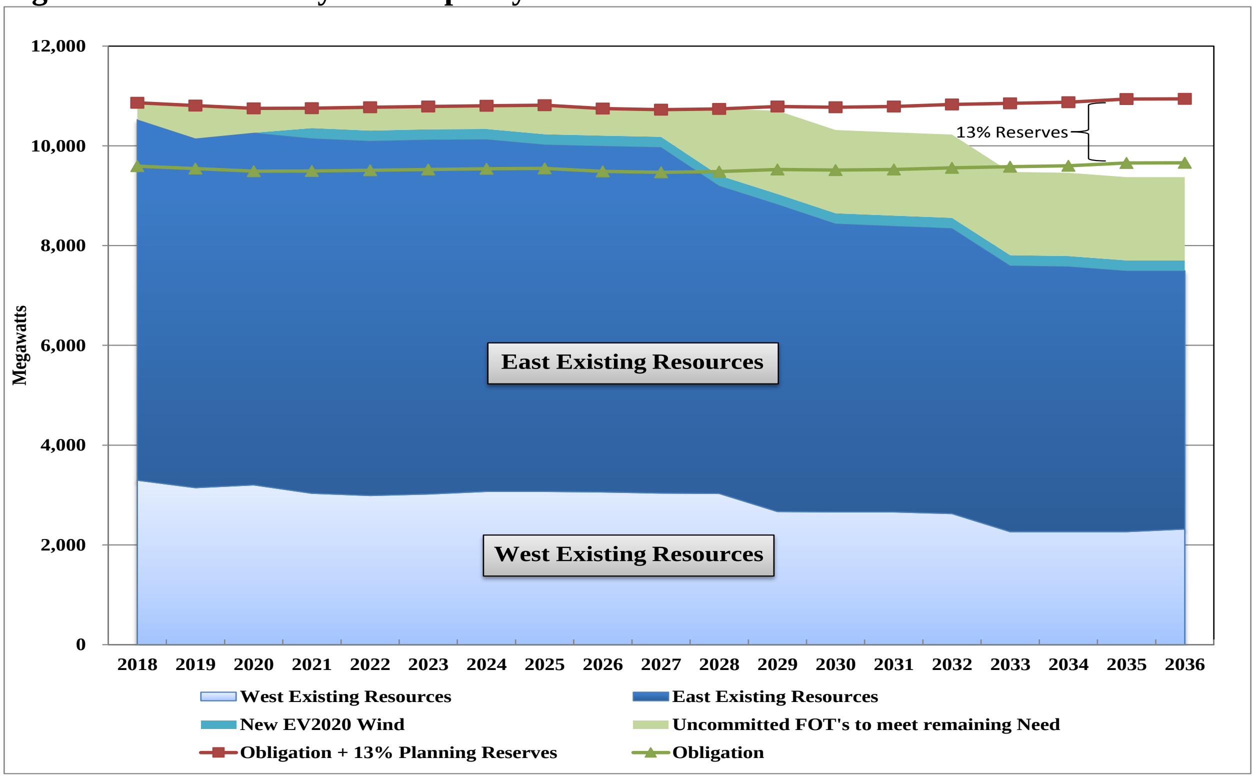


Figure 4.5 – Winter System Capacity Position Trend

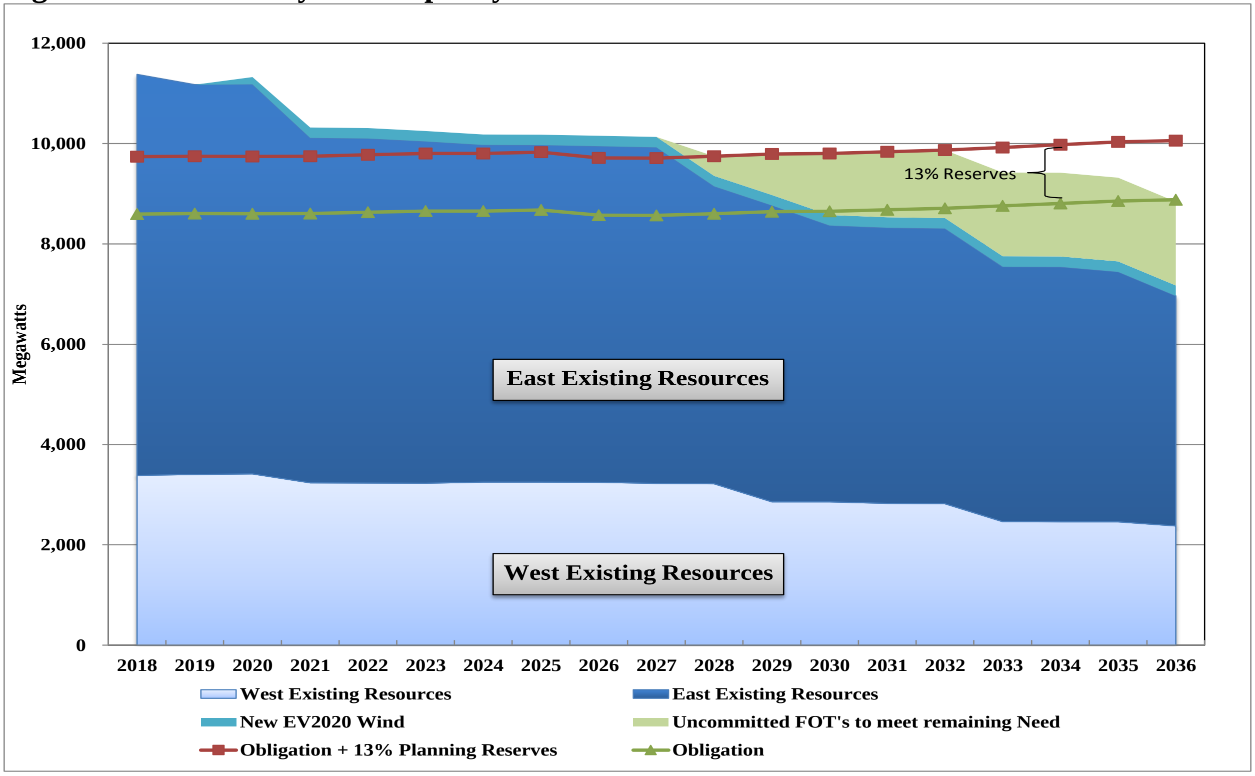


Figure 4.6 – East Summer Position Trend

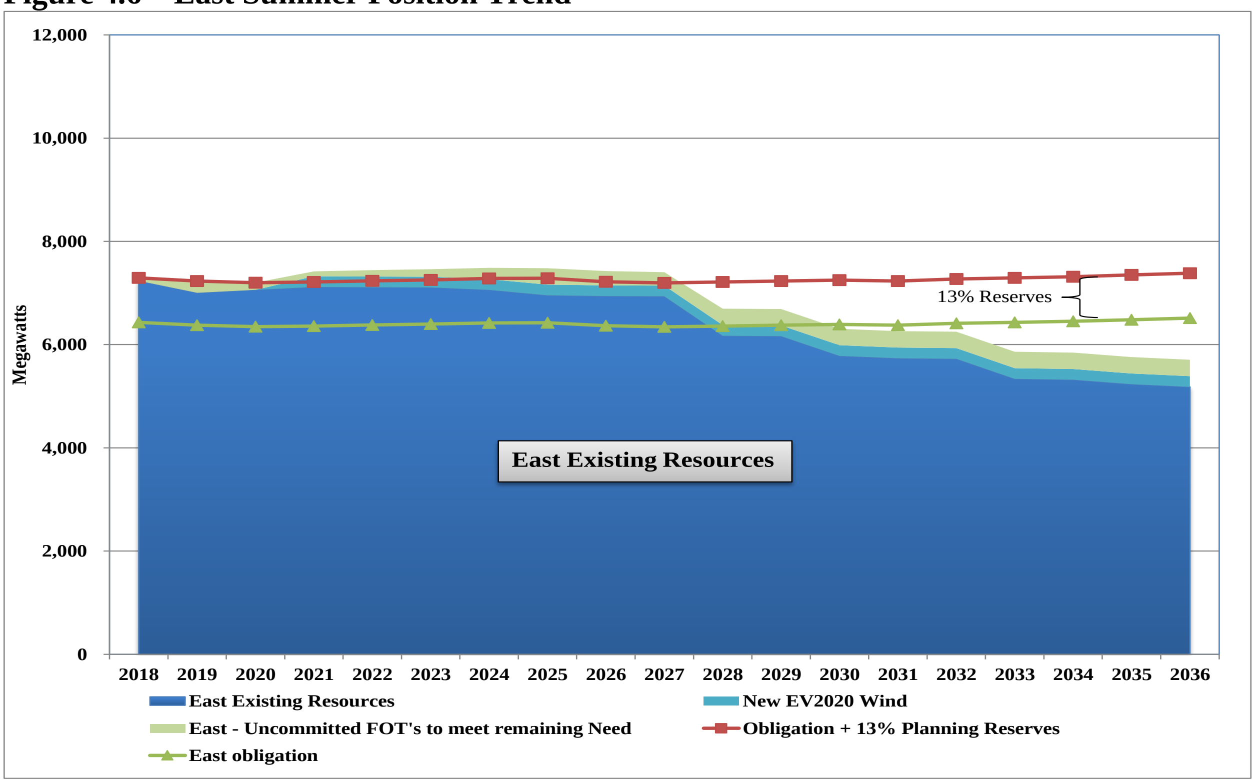
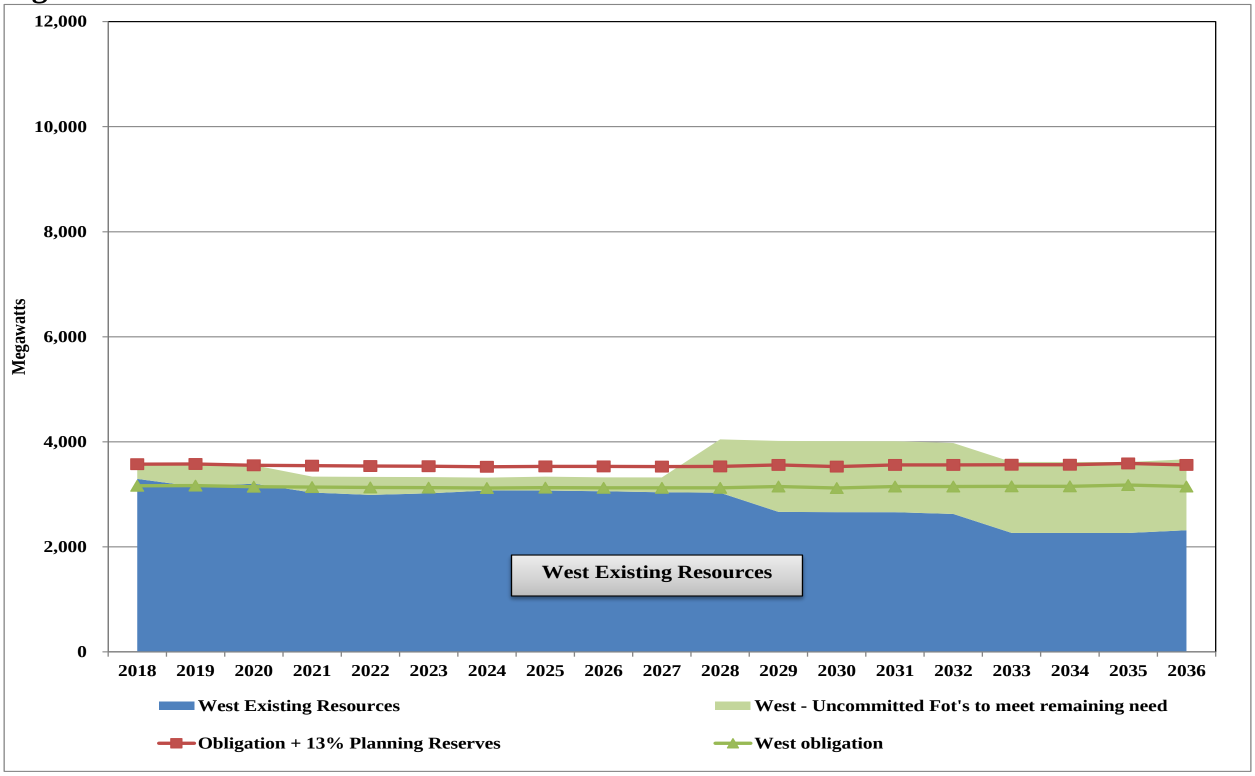


Figure 4.7 – West Summer Position Trend

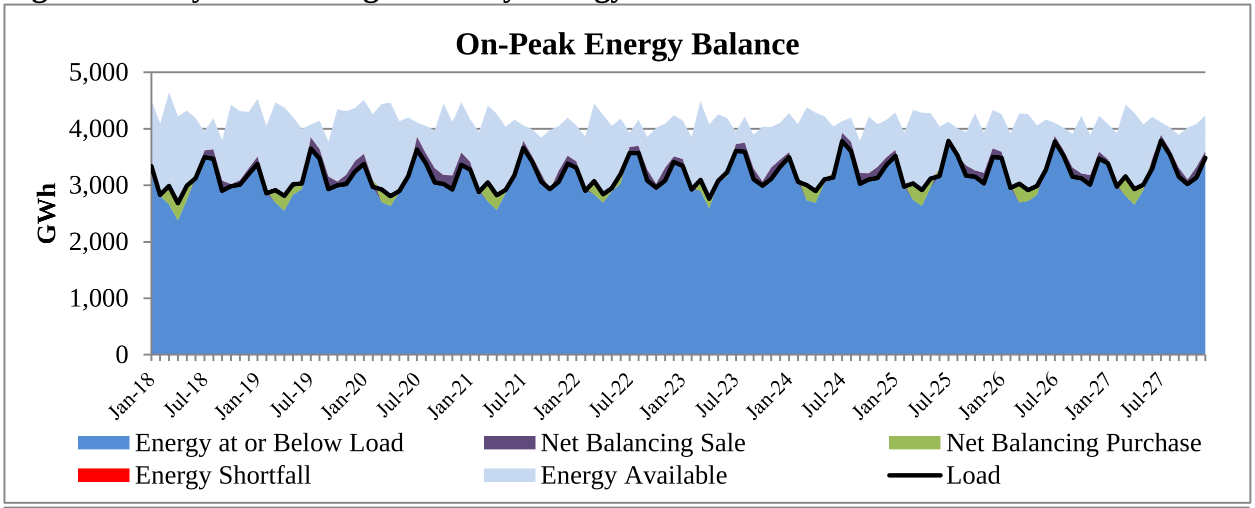


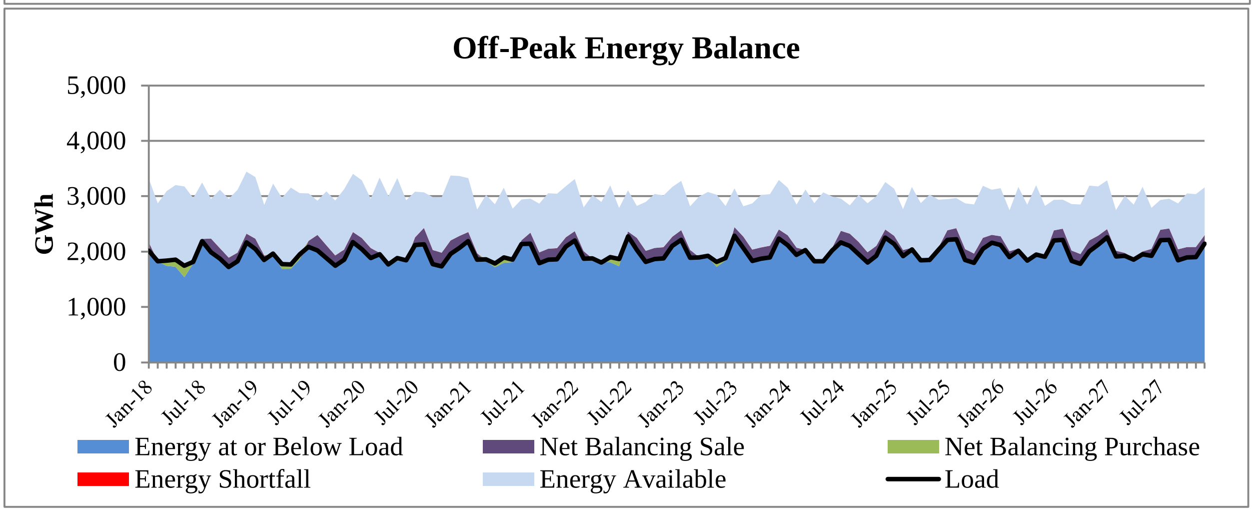
Energy Balance Results

The capacity position shows how existing resources and loads, accounting for coal unit retirements and incremental energy efficiency savings from the 2017 IRP Update resource portfolio, balance during the coincident summer and winter peak. Outside of these peak periods, PacifiCorp economically dispatches its resources to meet changing load conditions taking into consideration prevailing market conditions. In those periods when variable costs of system resources are less than the prevailing market price for power, PacifiCorp can dispatch resources that in aggregate exceed then-current load obligations facilitating off system sales that reduce customer costs. Conversely, at times when system resource costs fall below prevailing market prices, system balancing market purchases can be used to meet then-current system load obligations to reduce customer costs. The economic dispatch of system resources is critical to how PacifiCorp manages net power costs.

Figure 4.8 provides a snapshot of how existing system resources could be used to meet forecasted load across on-peak and off-peak periods given the assumptions about resource availability and wholesale power and natural gas prices. This snapshot does not reflect energy from Energy Vision 2020 wind resources. At times, resources are economically dispatched above load levels facilitating net system balancing sales. At other times, economic conditions result in net system balancing purchases, which occur more often during on-peak periods. Figure 4.8 also shows how much energy is available from existing resources at any given point in time. Those periods where all available resource energy falls below forecasted loads are highlighted in red, and indicate short energy positions without the addition of incremental resources to the portfolio. During on-peak periods and during off-peak periods, there are no energy shortfalls through the 2027 time frame, however, the forecast shows on-going net balancing purchases in all years beginning 2018.

Figure 4.8 – System Average Monthly Energy Positions





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CHAPTER 5 – MODELING AND ASSUMPTIONS UPDATE

General Assumptions

Consistent with the 2017 IRP, the study period for the 2017 IRP Update is 2017-2036, with a focus on the 2018-2027 planning horizon. Updated resource portfolios were developed assuming a 13 percent planning reserve margin consistent with the stochastic loss-of-load-probability study included in the 2017 IRP.

PacifiCorp has updated certain general assumptions in the 2017 IRP Update from the 2017 IRP as discussed below.

Inflation Rates

The 2017 IRP Update model simulations and cost data reflect PacifiCorp's corporate inflation rate schedule unless otherwise noted. A single annual escalation rate value of 2.27 percent is assumed whereas 2.22 percent was assumed in the 2017 IRP. The annual escalation rate reflects the average of annual inflation rate projections for the period 2017 through 2036, using PacifiCorp's December 2017 inflation curve. PacifiCorp's inflation curve is a straight average of forecasts for gross domestic product and consumer price index.

Discount Factor

The discount rate used in present-value calculations is based on PacifiCorp's after-tax weighted average cost of capital (WACC). The value used for the 2017 IRP Update is 6.91 percent, updated for the 2017 Tax Reform Act that reduced the federal income tax rate, up from 6.57 percent in the 2017 IRP. The use of the after-tax WACC complies with the Public Utility Commission of Oregon's IRP guideline 1a, which requires that the after-tax WACC be used to discount all future resource costs.[1] Present-value revenue requirement values reported in the 2017 IRP Update are reported in January 1, 2017 dollars.

Production Tax Credits (PTCs)

The 2017 IRP Update model applies PTC benefits for eligible resources on a nominal basis rather than on a levelized basis. This approach better reflects how the federal PTC benefits for these projects will flow through to customers, conforms the treatment of PTC benefits with other costs and benefits that are not actually spread over the life of an asset, and appropriately weights the contribution of PTC benefits in present-value calculations.

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

Front Office Transactions (FOTs)

FOT modeling assumptions have not changed from the 2017 IRP to the 2017 IRP Update. Three types of FOTs are modeled: an annual flat product, a heavy-load hour (HLH) July summer product, and a HLH December winter product. An annual flat product reflects energy provided to PacifiCorp at a constant delivery rate over all the hours of a year. The HLH transactions represent purchases received 16-hours per day, six-days per week for July and December. Table 5.1 reports the FOT resources included in the 2017 IRP and 2017 IRP Update modeling assumptions, identifying the market hub, product type, annual capacity limit, and availability associated with the product. PacifiCorp develops its FOT limits based upon its active participation in wholesale power markets, its view of physical delivery constraints, market liquidity and market depth, and with consideration of regional resource supply. Prices for FOT purchases are associated with specific market hubs and are set to the relevant forward market prices, time period, and location, plus appropriate wheeling charges, as applicable.

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

Market Hub/Proxy FOT Product Type Available over Study Period	Megawatt Limit and Availability (MW)	
	Summer (July)	Winter (December)
Mid-Columbia (Mid-C)		
Flat Annual ("7x24") or Heavy Load Hour ("6X16")	400	400
Heavy Load Hour ("6X16")	375	375
California Oregon Border (COB)		
Flat Annual ("7x24") or Heavy Load Hour ("6X16")	400	400
Nevada Oregon Border (NOB)		
Heavy Load Hour ("6X16")	100	100
Mona		
Heavy Load Hour ("6X16")	300	300

Stochastic Parameters

PacifiCorp has not modified its stochastic parameters from the 2017 IRP in its 2017 IRP Update modeling assumptions. PacifiCorp provided a detailed description of its stochastic parameters and their development in Volume II, Appendix H of the 2017 IRP. While PacifiCorp discussed its short-term correlation estimation process and calculation in Appendix H of the 2017 IRP, the discussion did not include descriptions of the reason for the (sometimes) low correlations subsequently requested by the Public Utility Commission of Oregon.[2]

[2] See discussion and requirement to explain the reasons for the (sometimes) low correlations in the short-term forecast pursuant to the Public Utility Commission of Oregon's 2017 IRP acknowledgement order issued April 27, 2018, Docket LC 67.

The drivers for deviations can be different for different stochastic variables. One event can impact a different combination of stochastic variables than another event. For example, load deviations are usually due to weather/temperature deviations; generation deviations can also be driven by weather deviations, renewable resource forecast deviations, and unplanned generator unit outages. Power market prices can be affected by drivers that affect either load or generation, as well as the unit commitment stack and the current marginal resource. For all of these categories, deviation events which impact one part of PacifiCorp's system do not necessarily affect other parts of the system, due to its geographic diversity and transmission constraints.

An example of low correlations from the 2017 IRP stochastic parameters is the correlation between Kern-Opal natural gas price deviations, which can be caused by weather deviations in PacifiCorp's east balancing area, and hydro, which is primarily driven by weather deviations in PacifiCorp's west balancing area. Another example from the same table is the correlation between Mid-C power market price deviations, which can be caused by drivers such as northwest weather deviations or resource mix, and Wyoming load deviations, which can be driven by planned or unplanned changes in industrial customer usage. Other examples include low correlations between different load areas, which have deviations driven by local weather deviations and customer types, and low correlations between west power markets (COB and Mid-C) and east power markets (PV and 4C), which have deviations driven by regional factors, such as weather deviations, resource stacks, and planned and unplanned outages.

Flexible Reserve Study

Appendix A of the Public Utility Commission of Oregon's 2017 IRP acknowledgement order issued April 27, 2018 in Docket LC-67, states that "In the IRP Update, PacifiCorp will model natural gas and storage for meeting flexible reserve study needs." Due to the timing of the issuance of the order following completion of analysis supporting the 2017 IRP Update, PacifiCorp was not able to conduct an updated flexible reserve study to fully incorporate this requirement but plans to update its flexible reserve study in the 2019 IRP. PacifiCorp's supply-side tables, Table 5.5 and Table 5.6 included in later discussion in this chapter, includes a variety of natural gas and storage resources, which can help meet the flexible reserve obligations associated with the company's portfolio. PacifiCorp recognizes, however, that while the IRP models include flexible reserve obligations, they may not capture all of the value associated with flexible resources such as natural gas and energy storage resources, particularly intra-hour. For instance, flexible resources can provide additional net benefits when dispatched in the energy imbalance market or when they defer transmission and distribution system upgrades. PacifiCorp plans to further explore where possible, the additional benefits and resource potential for various flexible resource applications, including natural gas and storage, in the 2019 IRP.

Natural Gas and Power Market Price Updates

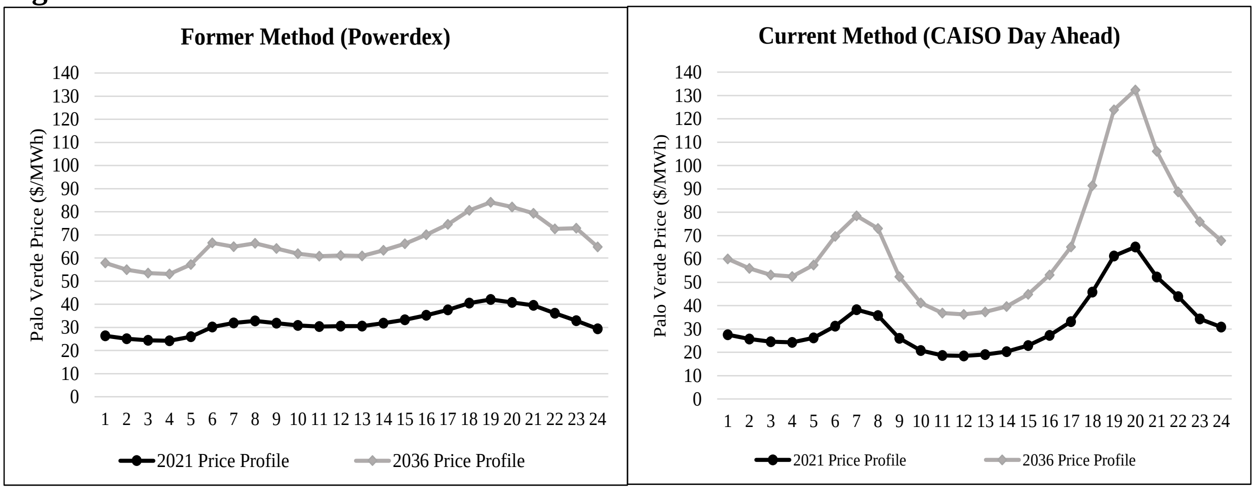
Portfolio modeling for the 2017 IRP Update was prepared using PacifiCorp's December 29, 2017 official forward price curve (OFPC). OFPCs are produced for both natural gas and power prices by point of delivery. For both natural gas and power, PacifiCorp's OFPCs are developed using forward market prices in tandem with a fundamentals-based price forecast. The first 72 months of the OFPC, beginning with the prompt month, represent broker quotes or settled forward prices per the end-of-quarter quote date, followed by 12 months of blended prices that transition to a market fundamentals-based forecast, starting in month 85.

For the natural gas OFPC, the fundamentals-based component is developed using expert third-party forecasting services with consideration given to underlying supply/demand assumptions, forecast documentation, peer-to-peer forecast price comparisons, date of issuance, location granularity, and forecast horizon. For power, the fundamentals-based component is produced using AuroraXmp® (Aurora), a production cost simulation model. PacifiCorp's fundamentals-based natural gas price forecast is a key driver the electricity price forecast produced using Aurora.

For wholesale power prices, PacifiCorp uses hourly price scalars, which are applied to monthly on-peak and off-peak prices in the forward price curve, to derive hourly market price profiles that vary by month and day type (*i.e.*, weekdays, Saturdays, and Sundays/holidays). The shape of the hourly price curves or scalars were updated to reflect one year of day-ahead hourly market price data available from the California Independent System Operator (CAISO). Prior to implementing this update, PacifiCorp used five years of hourly Powerdex price data to develop its hourly price scalars. The company's review of the Powerdex data shows that the five-year price history is not supported by a significant volume of reported transactions and that the resulting hourly price shapes do not align with hourly prices observed in operations that are being increasingly influenced by growth in solar resources across the region. The updated hourly price scalars are supported by a large volume of market transactions and produce hourly price profiles that are more aligned with operational experience.

Figure 5.1 shows average hourly price profiles as derived from historical Powerdex alongside hourly price profiles derived from historical CAISO data, which is used in the 2017 IRP Update. In both figures, the hourly price profile is based on the average hourly prices from representative months (January, April, July, and October).

Figure 5.1 – Scalars



Natural Gas Market Prices

PacifiCorp's December 2017 natural gas OFPC reflects a fundamentals-based forecast, issued November 2017, heavily influenced by a cost-effective domestic supply expansion largely due to growth in the Marcellus, Utica, and Permian plays.

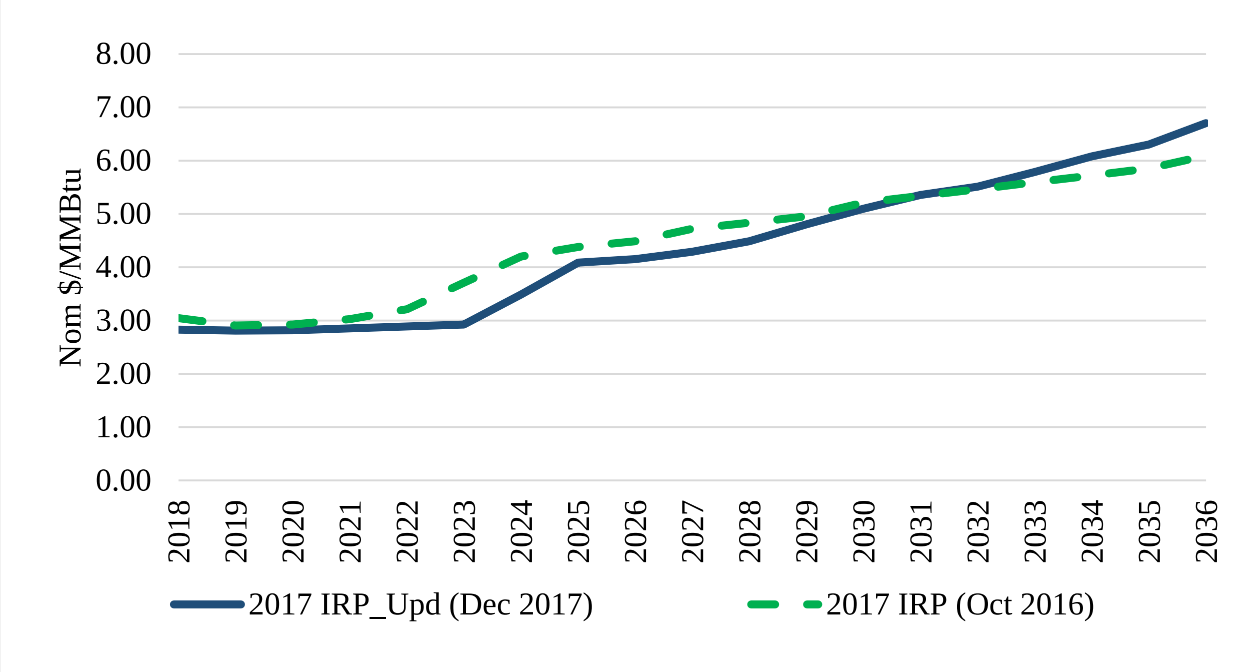
The October 2016 natural gas OFPC, which was used in the 2017 IRP, was based on an expert third-party long-term natural gas price forecast issued August 2016.

A significant price driver, since August 2016, has been the "rediscovery" of the Permian basin. The Permian basin, located in west Texas and southeast New Mexico, is becoming as well known for gas as it is for oil. It has been in production since 1920 but horizontal drilling and fracking have liberated oil volumes, consisting of 20 percent – 50 percent natural gas, previously untouched. Moreover the Permian contains six to eight geological formations, stacked on top of each other, with each layer being its own reservoir. Thus, producers can access multiple reservoirs from the same acreage. This stratification coupled with the potential for triple cash-flow streams (from crude, natural gas, and natural gas liquids) yields low break-even prices with the associated gas being ultra-low cost.[3] It is produced solely as a by-product to oil drilling and its production is indifferent to the price of natural gas. Thus, associated gas volumes may continue to enter the market even when it is seemingly uneconomic to develop other natural gas resources.

Figure 5.2 compares the nominal annual Henry Hub natural gas prices from the October 2016 (2017 IRP), and December 2017 (2017 IRP Update) OFPCs.

[3] *Land Rush in Permian Basin, Where Oil Is Stacked Like a Layer Cake*, January 17, 2017, New York Times.

Figure 5.2 – Henry Hub Natural Gas Prices (Nominal)



Power Market Prices

The natural gas fundamentals forecast described above is a key input to the Aurora model, and consequently, the gas curve shape is reflected in wholesale electricity prices. Figure 5.3 and Figure 5.4 compare the average annual flat and heavy-load-hour electricity prices for the Palo Verde market hub from the October 2016 and December 2017 OFPCs; Figure 5.5 and Figure 5.6 show the comparison for the Mid-Columbia market hub.

Figure 5.3 – Average Annual Flat Palo Verde Electricity Prices (Nominal)

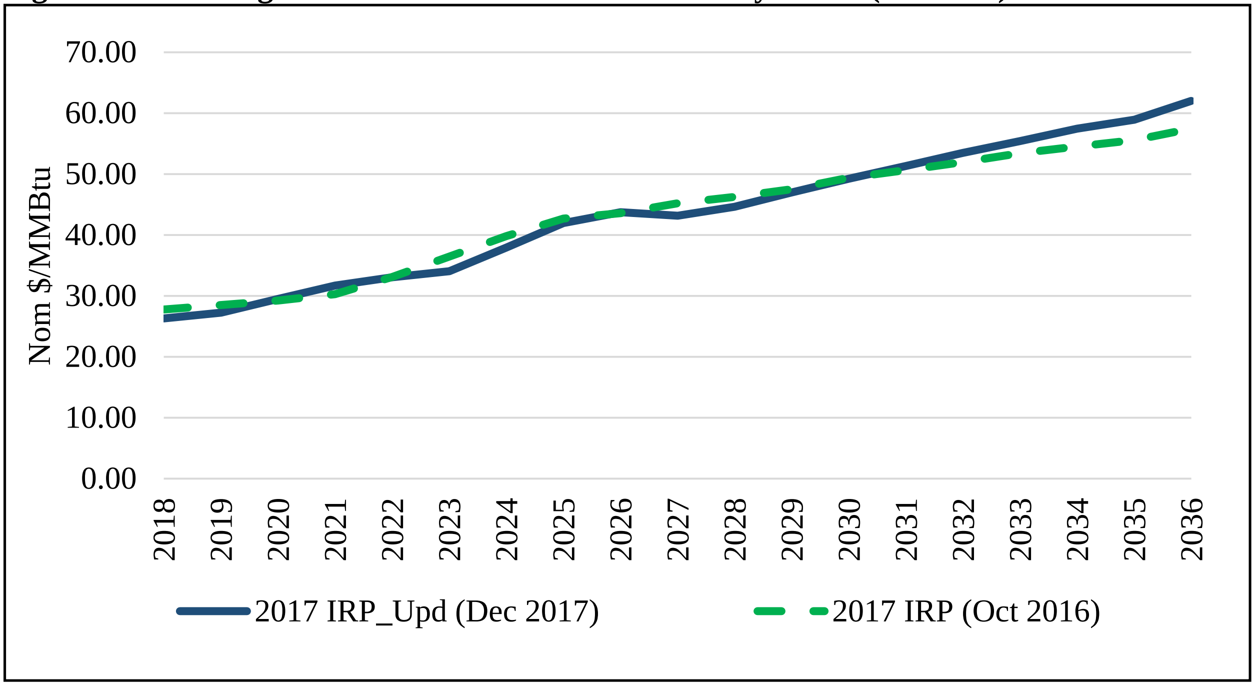


Figure 5.4 – Average Annual Heavy Load Hour Palo Verde Electricity Prices (Nominal)

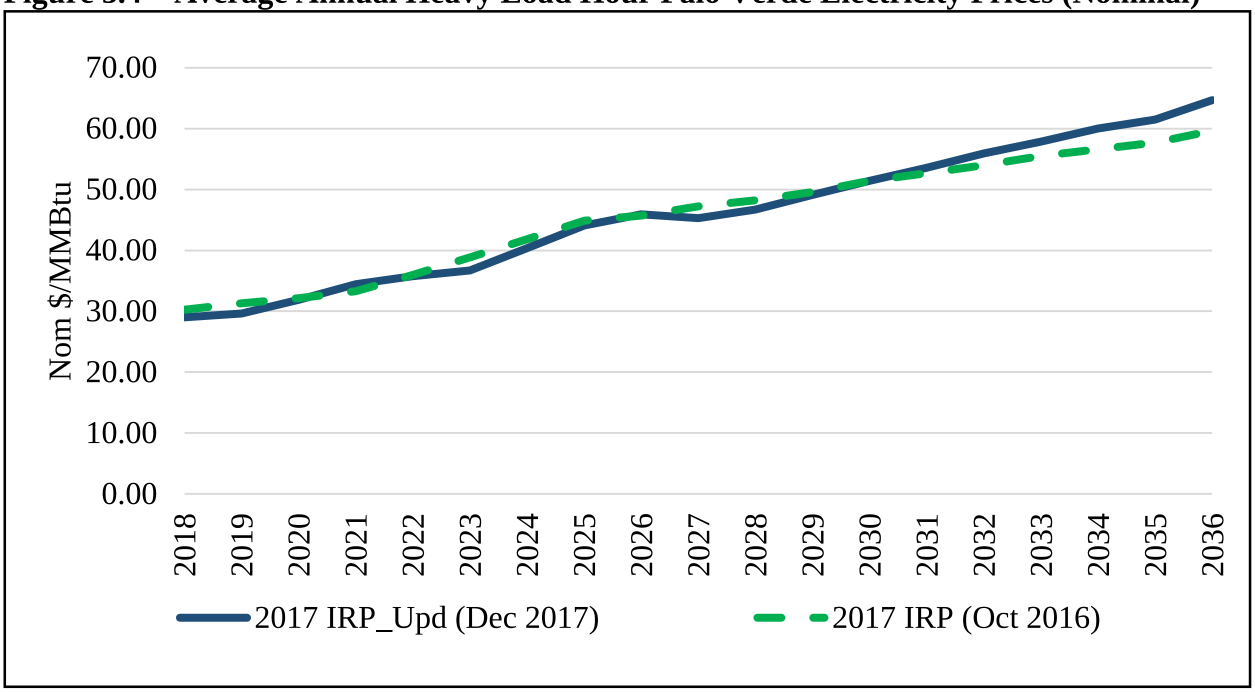


Figure 5.5 – Average Annual Flat Mid-Columbia Electricity Prices (Nominal)

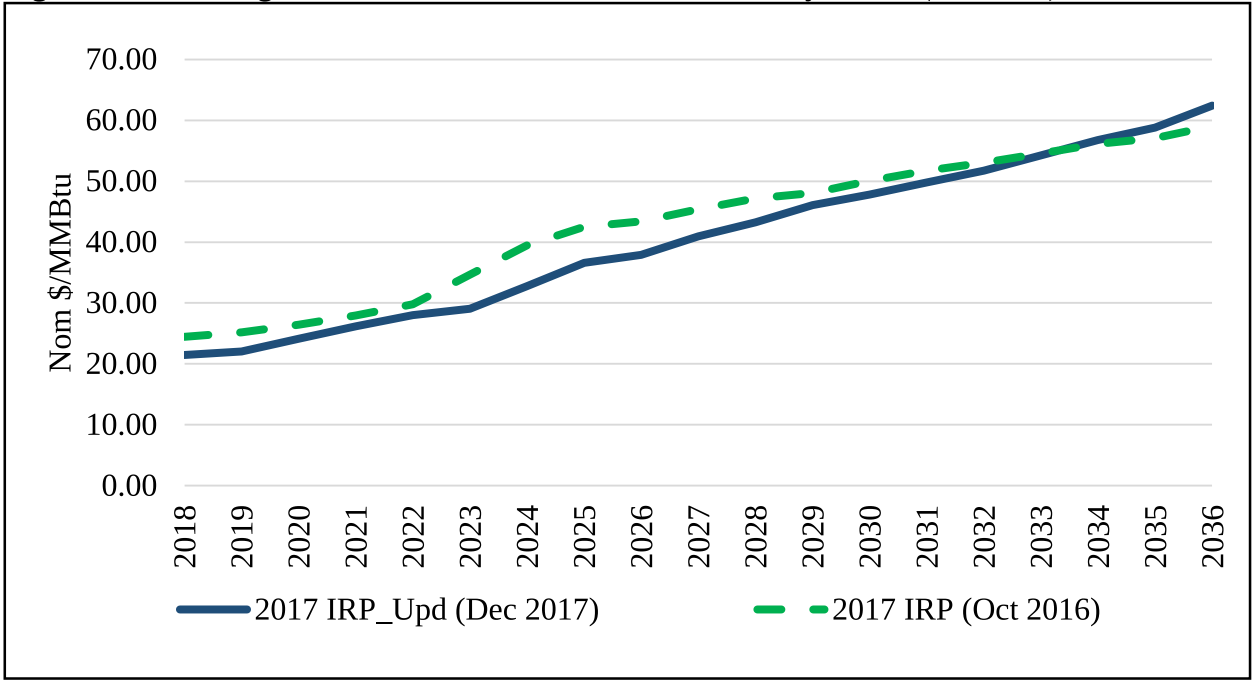
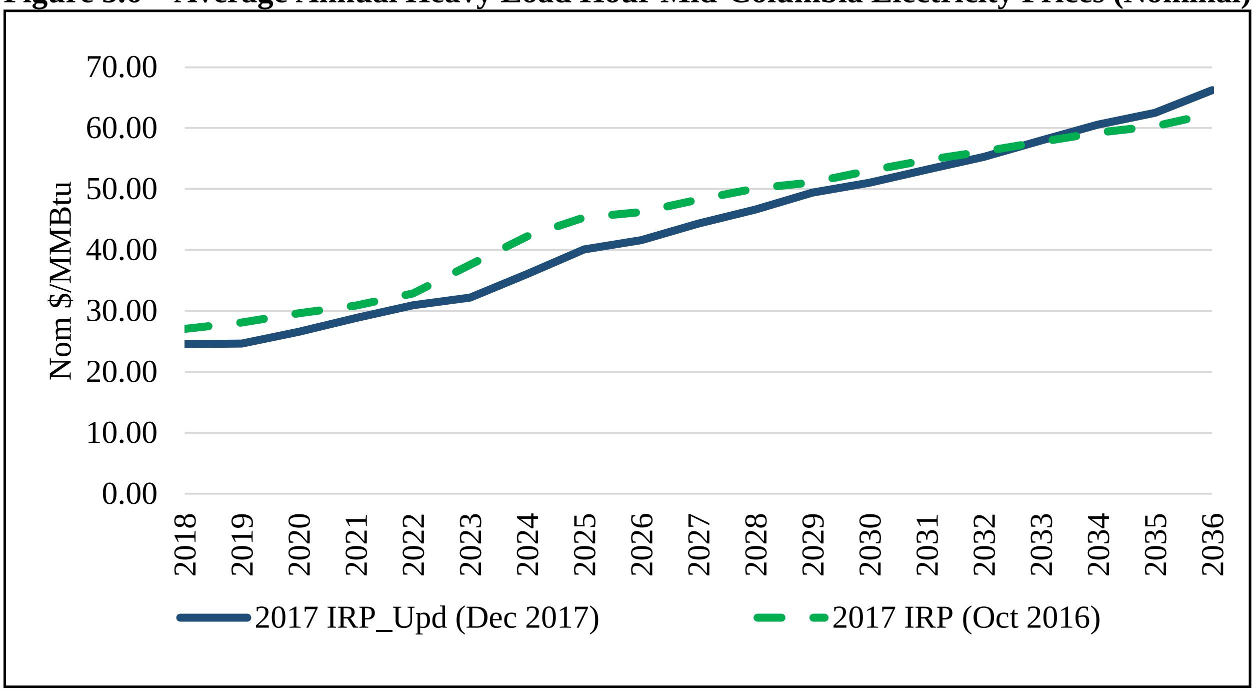


Figure 5.6 – Average Annual Heavy Load Hour Mid-Columbia Electricity Prices (Nominal)

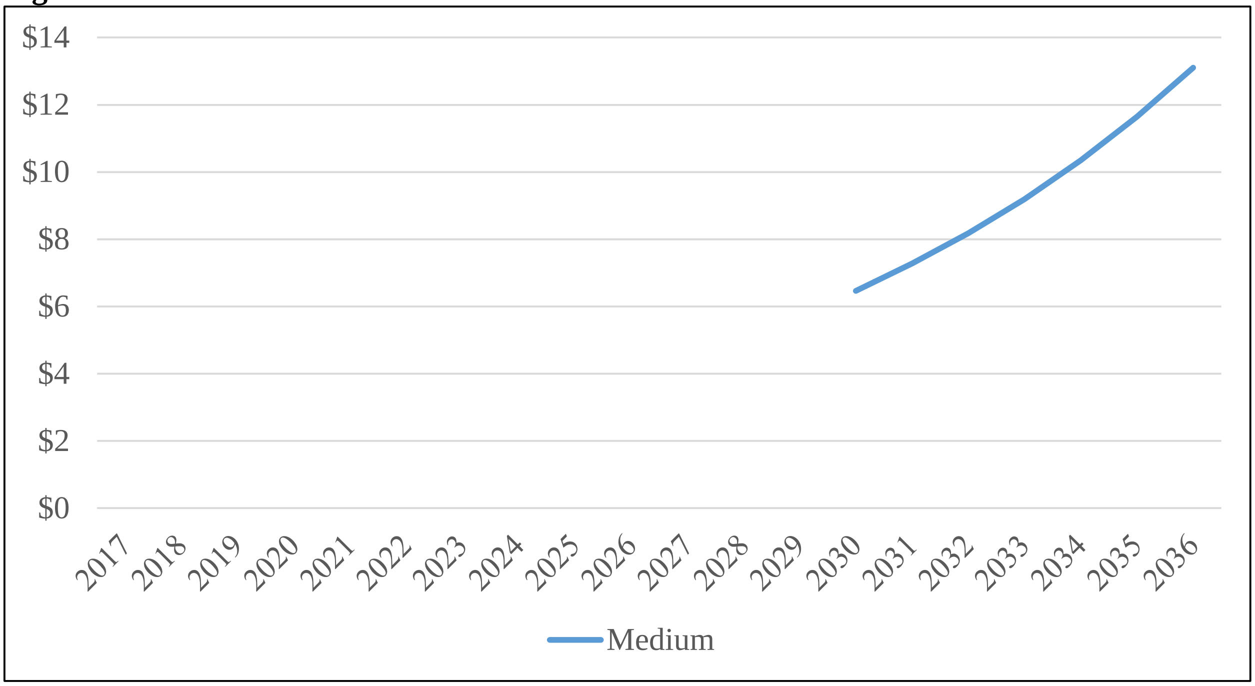


Carbon Dioxide Emission Policy

On March 28, 2017, President Trump issued an Executive order directing the U.S. Environmental Protection Agency (EPA) to review the Clean Power Plan (CPP) and, if appropriate, suspend, revise, or rescind the CPP, as well as related rules and agency actions. On October 10, 2017, EPA issued a proposal to repeal the CPP and the public comment period on EPA's proposal closed April 26, 2018. In addition, EPA published an Advance Notice of Proposed Rulemaking in the *Federal*

Register December 28, 2017, seeking public input on, without committing to, a potential replacement rule. The public comment period for the Advance Notice of Proposed Rulemaking concluded February 26, 2018. Given the current status of the CPP, PacifiCorp does not assume applicability of any CPP emission limits in the 2017 IRP Update however, in the 2017 IRP Update, PacifiCorp does assume a medium CO_2 price as shown in Figure 5.7 below.

Figure 5.7 – Medium CO_2 Price



Supply-Side Resources

The cost for supply-side 50 MW_{AC} solar photovoltaic (PV) projects are updated to reflect lower market costs for PV modules and mounting structures as well as the 30 percent tariff on imported modules. Engineering and owner costs are decreased slightly to reflect increasing levels of certainty for large commercial PV projects. The levelized cost of energy calculated from these updated cost assumptions are more reasonably aligned with power-purchase agreement bids that submitted into the recent 2017S Request for Proposals.

Projected costs, in real terms, during the 20-year study period continue to reflect a downward trend as in the 2017 IRP. Figure 5.8 shows the nominal year-by-year escalation percentages for wind, solar and other resources. Wind and solar escalate below other resource options due to declining cost curves for these resources.

Figure 5.8 – Nominal Year-by-Year Escalation for Different Resource Types

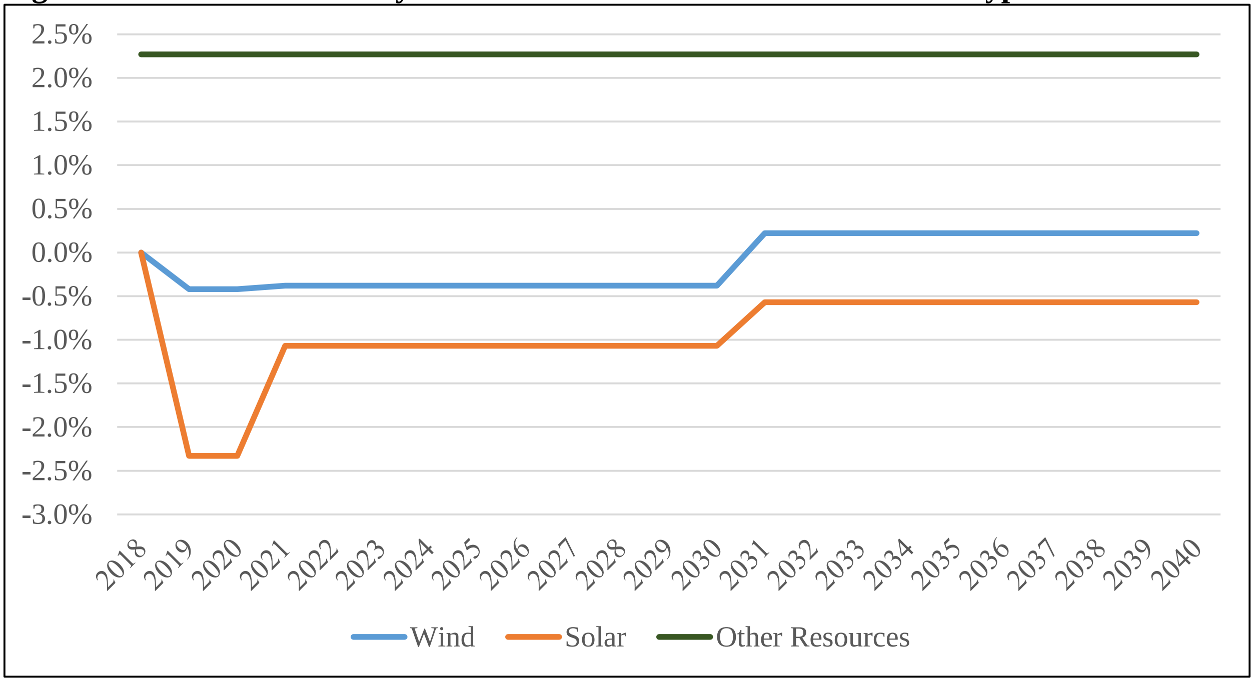


Table 5.2 reports the updated cost assumptions for new single-axis tracking solar resources.

Table 5.2 – Updated Cost of Solar Resources - (50 MW$_{AC}$ Single Axis Tracking)

Location/Technology	2017 IRP Update		2017 IRP	
	Total (with Owner's Costs) $/W$_{AC}$	Fixed O&M $/kW-year	Total (with Owner's Costs) $/W$_{AC}$	Fixed O&M $/kW-year
	2017$		2016$	
Utah/Single Axis Tracking	$1.392	$19.690	$1.800	$19.410
Oregon/Single Axis Tracking	$1.427	$19.720	$1.774	$19.440

The resource capital costs for wind resources have been updated to more closely align with market data for wind turbine and construction costs, as informed by bids submitted into the recent 2017R Request for Proposals. Market conditions, more precise construction bids, and technology changes led to cost reductions on a $/kW basis. As was the case in the 2017 IRP, PacifiCorp continues to assume that that new projects will be built on leased land, and consequently, PacifiCorp has not updated its fixed operations and maintenance (O&M) cost assumptions since the 2017 IRP. Table 5.3 summarizes the updated cost assumptions for new wind resources.

Table 5.3 – Updated Cost of Wind Resources

Location	2017 IRP Update		2017 IRP	
	Capital Cost $/kW	Fixed O&M $/kW-year	Capital Cost $/kW	Fixed O&M $/kW-year
	2017$		2016$	
Washington	$1.465	$36.455	$1.800	$36.455
Oregon	$1.444	$36.455	$1.774	$36.455
Idaho	$1.475	$36.455	$1.811	$36.455
Utah	$1.413	$36.455	$1.735	$36.455
Wyoming	$1.415	$36.455	$1.737	$36.455

The 2017 IRP Update provides updated capital cost information for battery energy storage as summarized in Table 5.4 below to reflect an update to capital costs, provided by DNV GL, based on installations and contracts that have been executed for the installation of energy storage systems in 2016 and 2017. DNV GL's "Cost Update to Battery Energy Storage Study" is included as Volume II, Appendix P to the 2017 IRP. The average one-MW battery costs are estimates of the total installation costs to PacifiCorp in 2017 dollars. A change was made to the way lithium-ion battery costs were calculated. The original 2017 IRP costs for lithium-ion batteries were averaged costs for NCM, LiFePO4, and LTO batteries. For the 2017 Update, it was determined that the company is unlikely to procure LTO batteries, so updated lithium-ion battery costs are based on average costs for NCM and LiFePO4 battery systems.

Note that the costs represented in this update are averages based on the following assumptions:

- Using a standardized 20-year life required different operating profiles for the three battery types listed. Both lithium-ion and sodium-sulfur batteries had similar profiles with 365 cycles per year: about half of the days at an 80 percent depth of discharge (DoD), and about half of the days at a 20 percent DoD. This is a very simplified way of representing actual complex usage profiles which may vary greatly depending upon use cases. Flow batteries are assumed to be capable of operating at 500 cycles per year at 100 percent DoD.

- Costs were developed using a proxy site, and an average additional owners cost of 21 percent. Depending on the location, owner's costs may vary from less than 10 percent to greater than 40 percent.

- Costs were validated against actual U.S. projects listed in the U.S. Department of Energy's Global Energy Storage Database. For sodium-sulfur batteries, only projects with NGK batteries in the six to eight MW range were listed. Therefore, sodium-sulfur batteries in the one, two and four hour options are considered to unavailable (N/A).

Table 5.4 – Updated Cost of Energy Storage, 2017 Dollars

Average 1 MW Battery Costs Standardized at a 20 year life.	Duration 1 hour	2 hours	4 hours	8 hours	8 MW 4 hours
Lithium Ion					
Installed Cost, $/kWh energy storage	**1,319**	**1,014**	**862**	**786**	**831**
Installed Cost, $/kW	**1,319**	**2,029**	**3,449**	**6,289**	**3,324**
Sodium Sulfur					
Installed Cost, $/kWh energy storage	**N/A**	**N/A**	**N/A**	**1,036**	**N/A**
Installed Cost, $/kW	**N/A**	**N/A**	**N/A**	**8,286**	**N/A**
Flow					
Installed Cost, $/kWh energy storage	**1,936**	**1,365**	**1,080**	**937**	**1,049**
Installed Cost, $/kW	**1,936**	**2,731**	**4,320**	**7,499**	**4,195**

Due to extension in federal production tax credits (PTCs) and investment tax credits (ITCs), the levelized cost of renewable resources are lower, not only due to updated capital costs and O&M costs, but also due to the nominal treatment of tax credits to more closely align with how these credits would get passed through to customers. Table 5.5 shows updated costs of the renewable resources with and without applicable tax credits, considering timing of construction and in-service dates. First year real levelized costs for wind and solar resources are presented for 2017, assuming a 2018 wind project meets IRS guidance demonstrating the project began construction by January 1, 2017, and for the last year in which PTCs (wind) and ITCs (solar) are phased down. Wind and solar resources with online dates between 2019 and 2023/2024, the tax credit period, were considered in the company's analysis.

Solar ITCs are now treated as an upfront benefit rather than being amortized over the life of the asset. This approach is more consistent with how independent power producers can price ITC benefits into PPA prices. Levelized costs for Pacific Northwest wind projects are shown at 38 percent, reflecting the upper range of performance anticipated from wind facilities in the region. For modeling purposes, a commercial operation date of January 1 is assumed, which is a proxy for December 31 of the prior year. The cost for Energy Vision 2020 new wind resources are also shown in the Table 5.5 and Table 5.6, which reflect the aggregate cost of winning company-owned bids from the 2017R Request for Proposals, but presented in 2017 dollars.

Table 5.5 – Updated Supply-Side Resource Table, (2017$)

Description		Resource Characteristics				Costs			Operating Characteristics				Environmental			
Fuel	Resource	Elevation (AFSL)	Net Capacity (MW)	Commercial Operation Year	Design Life (yrs)	Base Capital ($/KW)	Var O&M ($/MWh)	Fixed O&M ($/KW-yr)	Average Full Load Heat Rate (HHV Btu/KWh)/ Efficiency	EFOR (%)	POR (%)	Water Consumed (Gal/MWh)	SO2 (lbs/MM Btu)	NOx (lbs/MM Btu)	Hg (lbs/T BTu)	CO2 (lbs/MM Btu)
Wind	EV 2020 New Wind	6,500	1,111	2020/2021	30	1,310	1.18	25.53	n/a	*	0.0	n/a	n/a	n/a	n/a	n/a
Wind	2.0 MW turbine 38% CF WA, 2022 (80% PTC)	1,500	100	2022	30	1,465	0.00	36.45	n/a	*	0.0	n/a	n/a	n/a	n/a	n/a
Wind	2.0 MW turbine 38% CF OR, 2022 (80% PTC)	1,500	100	2022	30	1,444	0.00	36.45	n/a	*	0.0	n/a	n/a	n/a	n/a	n/a
Wind	2.0 MW turbine 38% CF ID, 2022 (80% PTC)	4,500	100	2022	30	1,475	0.00	36.45	n/a	*	0.0	n/a	n/a	n/a	n/a	n/a
Wind	2.0 MW turbine 31% CF UT, 2022 (80% PTC)	4,500	100	2022	30	1,413	0.00	36.45	n/a	*	0.0	n/a	n/a	n/a	n/a	n/a
Wind	3.3 MW turbine 41.3% CF WY, 2022 (80% PTC)	6,500	100	2022	30	1,415	0.65	36.45	n/a	*	0.0	n/a	n/a	n/a	n/a	n/a
Wind	2.0 MW turbine 38% CF WA, 2024 (40% PTC)	1,500	100	2024	30	1,465	0.00	36.45	n/a	*	0.0	n/a	n/a	n/a	n/a	n/a
Wind	2.0 MW turbine 38% CF OR, 2024 (40% PTC)	1,500	100	2024	30	1,444	0.00	36.45	n/a	*	0.0	n/a	n/a	n/a	n/a	n/a
Wind	2.0 MW turbine 38% CF ID, 2024 (40% PTC)	4,500	100	2024	30	1,475	0.00	36.45	n/a	*	0.0	n/a	n/a	n/a	n/a	n/a
Wind	2.0 MW turbine 31% CF UT, 2024 (40% PTC)	4,500	100	2024	30	1,413	0.00	36.45	n/a	*	0.0	n/a	n/a	n/a	n/a	n/a
Wind	3.3 MW turbine 41.3% CF WY, 2024 (40% PTC)	6,500	100	2024	30	1,415	0.65	36.45	n/a	*	0.0	n/a	n/a	n/a	n/a	n/a
Solar	PV Poly-Si Fixed Tilt 26.8% AC CF (1.35 MWdc/Mwac) UT, 2021 (30% ITC)	4,500	50	2021	25	1,364	0.00	18.45	n/a	*	0.0	n/a	n/a	n/a	n/a	n/a
Solar	PV Poly-Si Single Tracking 31.1% AC CF (1.25 MWdc/Mwac) UT, 2021 (30% ITC)	4,500	50	2021	25	1,392	0.00	19.41	n/a	*	0.0	n/a	n/a	n/a	n/a	n/a
Solar	PV Poly-Si Fixed Tilt 24.9% AC CF (1.35 MWdc/Mwac) OR, 2021 (30% ITC)	4,800	50	2021	25	1,400	0.00	18.47	n/a	*	0.0	n/a	n/a	n/a	n/a	n/a
Solar	PV Poly-Si Single Tracking 28.8% AC CF (1.25 MWdc/Mwac) OR, 2021 (30% ITC)	4,800	50	2021	25	1,427	0.00	19.44	n/a	*	0.0	n/a	n/a	n/a	n/a	n/a
Solar	PV Poly-Si Fixed Tilt 26.8% AC CF (1.35 MWdc/Mwac) UT, 2024 (10% ITC)	4,500	50	2024	25	1,364	0.00	18.45	n/a	*	0.0	n/a	n/a	n/a	n/a	n/a
Solar	PV Poly-Si Single Tracking 31.1% AC CF (1.25 MWdc/Mwac) UT, 2024 (10% ITC)	4,500	50	2024	25	1,392	0.00	19.41	n/a	*	0.0	n/a	n/a	n/a	n/a	n/a
Solar	PV Poly-Si Fixed Tilt 24.9% AC CF (1.35 MWdc/Mwac) OR, 2024 (10% ITC)	4,800	50	2024	25	1,400	0.00	18.47	n/a	*	0.0	n/a	n/a	n/a	n/a	n/a
Solar	PV Poly-Si Single Tracking 28.8% AC CF (1.25 MWdc/Mwac) OR, 2024 (10% ITC)	4,800	50	2024	25	1,427	0.00	19.44	n/a	*	0.0	n/a	n/a	n/a	n/a	n/a
Battery Storage	Lithium Ion Battery (7.2 MWh/day)	1,500	1	2019	20	3,449	0.00	19.47	1	0.0	0.0	0	0	0	0	0
Battery Storage	Flow Battery (7.2 MWh/day)	1,500	1	2019	20	4,320	0.00	47.00	1	0.0	0.0	0	0	0	0	0

Table 5.6 – Updated Supply-Side Resource Table

Supply Side Resource Options Mid-Calendar Year 2017 Dollars ($)		Capital Cost $/kW			Fixed Cost					
					Fixed O&M $/kW-Yr					
Resource Description	Elevation (AFSL)	Total Capital Cost	Payment Factor	Annual Payment ($/kW-Yr)	O&M	Capitalized Premium	O&M Capitalized	Gas Transportation	Total	Total Fixed ($/kW-Yr)
EV 2020 New Wind	6,500	$1,310	5.284%	$69.20	25.53	3.008%	0.77	0.00	26.29	$95.49
2.0 MW turbine 38% CF WA, 2022 (80% PTC)	1,500	$1,465	7.106%	$104.13	36.45	3.061%	1.12	0.00	37.57	$141.70
2.0 MW turbine 38% CF OR, 2022 (80% PTC)	1,500	$1,444	7.106%	$102.64	36.45	3.061%	1.12	0.00	37.57	$140.21
2.0 MW turbine 38% CF ID, 2022 (80% PTC)	4,500	$1,475	7.106%	$104.78	36.45	3.061%	1.12	0.00	37.57	$142.36
2.0 MW turbine 31% CF UT, 2022 (80% PTC)	4,500	$1,413	7.106%	$100.41	36.45	3.061%	1.12	0.00	37.57	$137.98
3.3 MW turbine 41.3% CF WY, 2022 (80% PTC)	6,500	$1,415	7.106%	$100.55	36.45	3.061%	1.12	0.00	37.57	$138.12
2.0 MW turbine 38% CF WA, 2024 (40% PTC)	1,500	$1,465	7.106%	$104.13	36.45	3.061%	1.12	0.00	37.57	$141.70
2.0 MW turbine 38% CF OR, 2024 (40% PTC)	1,500	$1,444	7.106%	$102.64	36.45	3.061%	1.12	0.00	37.57	$140.21
2.0 MW turbine 38% CF ID, 2024 (40% PTC)	4,500	$1,475	7.106%	$104.78	36.45	3.061%	1.12	0.00	37.57	$142.36
2.0 MW turbine 31% CF UT, 2024 (40% PTC)	4,500	$1,413	7.106%	$100.41	36.45	3.061%	1.12	0.00	37.57	$137.98
3.3 MW turbine 41.3% CF WY, 2024 (40% PTC)	6,500	$1,415	7.106%	$100.55	36.45	3.061%	1.12	0.00	37.57	$138.12
PV Poly-Si Fixed Tilt 26.8% AC CF (1.35 MWdc/Mwac) UT, 2021 (30% ITC)	4,500	$1,364	7.720%	$105.30	18.45	1.461%	0.27	0.00	18.72	$124.01
PV Poly-Si Single Tracking 31.1% AC CF (1.25 MWdc/Mwac) UT, 2021 (30% ITC)	4,500	$1,392	7.720%	$107.49	19.41	1.461%	0.28	0.00	19.69	$127.18
PV Poly-Si Fixed Tilt 24.9% AC CF (1.35 MWdc/Mwac) OR, 2021 (30% ITC)	4,800	$1,400	7.720%	$108.08	18.47	1.461%	0.27	0.00	18.74	$126.82
PV Poly-Si Single Tracking 28.8% AC CF (1.25 MWdc/Mwac) OR, 2021 (30% ITC)	4,800	$1,427	7.720%	$110.15	19.44	1.461%	0.28	0.00	19.72	$129.87
PV Poly-Si Fixed Tilt 26.8% AC CF (1.35 MWdc/Mwac) UT, 2024 (10% ITC)	4,500	$1,364	7.720%	$105.30	18.45	1.461%	0.27	0.00	18.72	$124.01
PV Poly-Si Single Tracking 31.1% AC CF (1.25 MWdc/Mwac) UT, 2024 (10% ITC)	4,500	$1,392	7.720%	$107.49	19.41	1.461%	0.28	0.00	19.69	$127.18
PV Poly-Si Fixed Tilt 24.9% AC CF (1.35 MWdc/Mwac) OR, 2024 (10% ITC)	4,800	$1,400	7.720%	$108.08	18.47	1.461%	0.27	0.00	18.74	$126.82
PV Poly-Si Single Tracking 28.8% AC CF (1.25 MWdc/Mwac) OR, 2024 (10% ITC)	4,800	$1,427	7.720%	$110.15	19.44	1.461%	0.28	0.00	19.72	$129.87
Lithium Ion Battery (7.2 MWh/day)	1,500	$3,449	9.445%	$325.74	19.47	0.000%	0.00	0.00	19.47	$345.21
Flow Battery (7.2 MWh/day)	1,500	$4,320	9.445%	$408.03	47.00	0.000%	0.00	0.00	47.00	$455.03

Table 5.6 (cont.) – Updated Supply-Side Resource Table

Supply Side Resource Options Mid-Calendar Year 2017 Dollars ($) Resource Description	Elevation (AFSL)	Convert to Dollars per Megawatt-hour: Capacity Factor 1/	Total Fixed ($/MWh)	Storage Efficiency	Levelized Fuel: ¢/ mmBtu	Levelized Fuel: $/MWh	Variable Costs ($/MWh): O&M	Capitalized Premium	O&M Capitalized	Integration Cost	Total Costs and Credits ($/MWh) Credits: Total Resource Cost	PTC Tax Credits / ITC (Solar Only)	Total Resource Cost - With PTC / ITC Credits
EV 2020 New Wind	6500	39%	28.09	na	0	-	1.18	0.00%	0.00	0.59	29.86	(12.50)	17.36
2.0 MW turbine 38% CF WA, 2022 (80% PTC)	1500	38%	42.57	na	0	-	0.00	0.00%	0.00	0.59	43.15	(15.32)	27.83
2.0 MW turbine 38% CF OR, 2022 (80% PTC)	1500	38%	42.12	na	0	-	0.00	0.00%	0.00	0.59	42.71	(15.32)	27.38
2.0 MW turbine 38% CF ID, 2022 (80% PTC)	4500	38%	42.76	na	0	-	0.00	0.00%	0.00	0.59	43.35	(15.32)	28.03
2.0 MW turbine 31% CF UT, 2022 (80% PTC)	4500	31%	50.81	na	0	-	0.00	0.00%	0.00	0.59	51.40	(15.32)	36.07
3.3 MW turbine 41.3% CF WY, 2022 (80% PTC)	6500	41%	38.18	na	0	-	0.65	0.00%	0.00	0.59	39.41	(15.32)	24.09
2.0 MW turbine 38% CF WA, 2024 (40% PTC)	1500	38%	42.57	na	0	-	0.00	0.00%	0.00	0.59	43.15	(7.66)	35.49
2.0 MW turbine 38% CF OR, 2024 (40% PTC)	1500	38%	42.12	na	0	-	0.00	0.00%	0.00	0.59	42.71	(7.66)	35.04
2.0 MW turbine 38% CF ID, 2024 (40% PTC)	4500	38%	42.76	na	0	-	0.00	0.00%	0.00	0.59	43.35	(7.66)	35.69
2.0 MW turbine 31% CF UT, 2024 (40% PTC)	4500	31%	50.81	na	0	-	0.00	0.00%	0.00	0.59	51.40	(7.66)	43.73
3.3 MW turbine 41.3% CF WY, 2024 (40% PTC)	6500	41%	38.18	na	0	-	0.65	0.00%	0.00	0.59	39.41	(7.66)	31.75
PV Poly-Si Fixed Tilt 26.8% AC CF (1.35 MWdc/Mwac) UT, 2021 (30% ITC)	4500	27%	52.82	na	0	-	0.00	0.00%	0.00	0.62	53.44	(15.84)	37.60
PV Poly-Si Single Tracking 31.1% AC CF (1.25 MWdc/Mwac) UT, 2021 (30% ITC)	4500	31%	46.68	na	0	-	0.00	0.00%	0.00	0.62	47.30	(13.94)	33.36
PV Poly-Si Fixed Tilt 24.9% AC CF (1.35 MWdc/Mwac) OR, 2021 (30% ITC)	4800	25%	58.14	na	0	-	0.00	0.00%	0.00	0.62	58.76	(17.50)	41.26
PV Poly-Si Single Tracking 28.8% AC CF (1.25 MWdc/Mwac) OR, 2021 (30% ITC)	4800	29%	51.48	na	0	-	0.00	0.00%	0.00	0.62	52.10	(15.42)	36.67
PV Poly-Si Fixed Tilt 26.8% AC CF (1.35 MWdc/Mwac) UT, 2024 (10% ITC)	4500	27%	52.82	na	0	-	0.00	0.00%	0.00	0.62	53.44	(5.12)	48.32
PV Poly-Si Single Tracking 31.1% AC CF (1.25 MWdc/Mwac) UT, 2024 (10% ITC)	4500	31%	46.68	na	0	-	0.00	0.00%	0.00	0.62	47.30	(4.50)	42.80
PV Poly-Si Fixed Tilt 24.9% AC CF (1.35 MWdc/Mwac) OR, 2024 (10% ITC)	4800	25%	58.14	na	0	-	0.00	0.00%	0.00	0.62	58.76	(5.65)	53.11
PV Poly-Si Single Tracking 28.8% AC CF (1.25 MWdc/Mwac) OR, 2024 (10% ITC)	4800	29%	51.48	na	0	-	0.00	0.00%	0.00	0.62	52.10	(4.98)	47.12
Lithium Ion Battery (7.2 MWh/day)	1500	25%	157.63	85%	296	22.02	0.00	0.00%	0.00	-	179.65	-	179.65
Flow Battery (7.2 MWh/day)	1500	25%	207.77	72%	296	25.99	0.00	0.00%	0.00	-	233.77	-	233.77

1/ Equivalent forced outage rate included in capacity factor

Intra-Hour Dispatch Credit

The energy-imbalance market (EIM) provides economically optimized dispatch instructions to participating units of PacifiCorp's fleet of diverse resources every five minutes. Prior to the EIM, PacifiCorp would resolve load-resource imbalances within the hour through manual dispatches of generation within its balancing authority area (BAA). With the introduction of the EIM, whose footprint spans multiple BAAs, the aforementioned imbalances are resolved with least-cost generation sourced from across the EIM footprint, on a five-minute basis. This sub-hourly dispatch process increases efficiency and lowers cost. In addition, the EIM provides PacifiCorp with a way to value the changes in generation within the hour through locational-marginal pricing at five and fifteen-minute intervals.

In contrast to actual operations, PacifiCorp's production cost models used to estimate the economic value(s) of a resource plan over the long term are hourly dispatch models, which cannot capture the sub-hourly benefits/requirements of generation flexibility, or the EIM benefits related to intra-hour economic opportunities. For example, an hourly production cost model can replace a megawatt-hour (MWh) from a generation resource with a market purchase of energy with no recognition of the fact that electricity requirements do not stay constant across the hour. In this scenario, value is lost at the sub-hourly level given that market purchases are fixed products that have no intra-hour flexibility. These discrepancies between modeling and operations created a need to develop an intra-hour dispatch credit in order to capture value realized from sub-hourly dispatches to meet PacifiCorp's load-and-resource changes, as well as transfers across the EIM footprint. The methodology for calculating the intra-hour dispatch credit for units participating in EIM is discussed further below.

PacifiCorp's participation in the EIM includes PacifiCorp's submission of a balanced load-resource hourly base schedule. Within the hour, the EIM provides PacifiCorp with fifteen-minute advisory schedules and five-minute dispatch schedules. The determination of sub-hourly benefits incorporates the difference among these three schedules, moving from the hourly schedule to the fifteen-minute schedule and then to the five-minute schedule. By taking into account the cost of generation, a margin is calculated and attributed to a specific unit in a specific interval. This margin represents the intra-hour value realized through moving that unit in the EIM. EIM dispatches can be in response to changes in PacifiCorp's load, changes in variable resources or changes in transfers into or out of the BAA.

Determination of Intra-Hour Dispatch Credit:

$Base = PacifiCorp's\ Hourly\ Base\ Schedule$
$D_{15} = EIM's\ Fifteen\ Minute\ Advisory\ Schedule$
$D_5 = EIM's\ Five\ Minute\ Dispatch\ Schedule$
$P_{15} = EIM's\ Fifteen\ Minute\ Market\ Price$
$P_5 = EIM's\ Five\ Minute\ Market\ Price$
$Bid = PacifiCorp's\ Cost\ of\ Generation$

$$Intra - Hour\ Dispatch\ Credit = (D_{15} - Base) * P_{15} + (D_5 - D_{15}) * P_5 - (D_5 - Base) * Bid$$

In the 2017 IRP Update, PacifiCorp incorporated unit specific intra-hour dispatch credits as part of its 2017 IRP preferred portfolio and coal studies discussed in Chapter 6. The average intra-hour dispatch credit value is $6.47 kw/yr based on the following units: Dave Johnston Units 3-4, Hunter Unit 3, Huntington Units 1-2, Jim Bridger Units 1-2, and Naughton Units 1-3.

Intra-Hour Dispatch Credit Further Exploration

In addition to coal resources providing flexibility to the market, PacifiCorp is also exploring how energy storage resources, such as batteries, have the potential to provide EIM-dispatch benefits due to their ability to respond rapidly with no start-up costs, minimum load costs and an ability to move both up and down across a varying capacity sizes. Some of the items that PacifiCorp is reviewing for potential benefits of energy storage resources are storage capacity, charge and discharge rates, efficiency, and degradation rates. PacifiCorp does not yet have any direct experience with energy storage resources participating in EIM, and market structures for energy storage resources continue to evolve, but as the market continues towards additional renewable generation, incentives will continue to be explored towards resources with low cost minimum operating levels while still supporting integration needs. PacifiCorp anticipates further exploration and discussion of such credits with robust stakeholder engagement as part of its 2019 IRP public input process.

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CHAPTER 6 – REGIONAL HAZE CASES

Introduction

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

This chapter discusses regional haze case definitions and presents study results developed in accordance with action items 5c, 5d, 5e, and 5g of the 2017 IRP action plan. PacifiCorp used its resource expansion plan model, the System Optimizer (SO) model, and its stochastic risk model, the Planning and Risk model (PaR) to perform these studies under three price-policy scenarios.

Regional Haze Case Definitions

The four coal resource action items in the 2017 IRP action plan were studied relative to the 2017 IRP Update resource portfolio. In addition to analyzing known and prospective regional haze compliance requirements, these studies incorporate compliance cost assumptions related to the Mercury and Air Toxics Standard (MATS), coal combustion residuals (CCR), effluent limit guidelines (ELG), and cooling water intake structures as may be required under the Clean Water Act (CWA).

Each compliance case drives the timing and magnitude of run-rate capital and operations and maintenance costs for each individual coal unit in PacifiCorp's fleet. For instance, if a specific regional haze compliance case assumes an early retirement for a given coal unit as part of a compliance plan, the run-rate operating costs for that unit are customized to reflect the assumed early closure date. This can include changes to the timing of planned maintenance throughout the twenty year planning horizon and avoidance of future costs related to known or assumed MATS, CCR, ELG or CWA compliance requirements, as applicable. Compliance alternatives for coal units in any given compliance case can include, continued operations through the end of a unit's assumed depreciable life, early retirement, conversion to gas-plant operations, or installation of a selective catalytic reduction (SCR) system to continue operations with reduced emissions.

Individual unit outcomes under any regional haze compliance case will ultimately be determined by ongoing rulemaking, results of litigation, and future negotiations with state and federal agencies, partner plant owners, and other vested stakeholders. While the regional haze compliance cases represent a range of strategic paths to be evaluated, no individual unit commitments are being made at this time.

Table 6.1 summarizes key assumptions for regional haze compliance cases that address the four coal resource action items studied in the 2017 IRP Update. The 2017 IRP Update resource portfolio assumptions are also included for reference.

Table 6.1 - Regional Haze Case Assumptions

	2017 IRP (Pref. Port)	2017 IRP Update (Pref. Port)	2017 IRP Update DJ3 SCR	2017 IRP Update JB1 & JB2 SCR	2017 IRP Update NAU3 GC	2017 IRP Update NAU3 42 MW GC	2017 IRP Update CHOL4 GC
Hunter 1	No SCR;NOX+ 2021 Ret. 2042	No SCR;NOX+ 2022 Ret. 2042	No SCR;NOX+ 2022 Ret. 2042	No SCR;NOX+ 2022 Ret. 2042	No SCR;NOX+ 2022 Ret. 2042	No SCR;NOX+ 2022 Ret. 2042	No SCR;NOX+ 2022 Ret. 2042
Hunter 2	No SCR;NOX+ 2021 Ret. 2042	No SCR;NOX+ 2023 Ret. 2042	No SCR;NOX+ 2023 Ret. 2042	No SCR;NOX+ 2023 Ret. 2042	No SCR;NOX+ 2023 Ret. 2042	No SCR;NOX+ 2023 Ret. 2042	No SCR;NOX+ 2023 Ret. 2042
Huntington 1	No SCR; Ret. 2036	No SCR; NOX+ 2022 Ret. 2036	No SCR; NOX+ 2022 Ret. 2036	No SCR; NOX+ 2022 Ret. 2036	No SCR; NOX+ 2022 Ret. 2036	No SCR; NOX+ 2022 Ret. 2036	No SCR; NOX+ 2022 Ret. 2036
Huntington 2	No SCR; Ret. 2036	No SCR; NOX+ 2023 Ret. 2036	No SCR; NOX+ 2023 Ret. 2036	No SCR; NOX+ 2023 Ret. 2036	No SCR; NOX+ 2023 Ret. 2036	No SCR; NOX+ 2023 Ret. 2036	No SCR; NOX+ 2023 Ret. 2036
Jim Bridger 1	No SCR Ret. 2028	No SCR Ret. 2028	No SCR Ret. 2028	SCR 12/31/2022 Ret 2037	No SCR Ret. 2028	No SCR Ret. 2028	No SCR Ret. 2028
Jim Bridger 2	No SCR Ret. 2032	No SCR Ret. 2032	No SCR Ret. 2032	SCR 12/31/2021 Ret 2037	No SCR Ret. 2032	No SCR Ret. 2032	No SCR Ret. 2032
Naughton 3	No Gas Conv. Ret. 2018	No Gas Conv. Ret. 1/30/2019	No Gas Conv. Ret. 1/30/2019	No Gas Conv. Ret. 1/30/2019	Gas Conv. 1/31/2019 to 6/1/2019 Ret. 2029	Gas Conv. 42 MW 1/31/2019 to 5/20/2019 Ret. 2029	No Gas Conv. Ret. 1/30/2019
Cholla 4	No Gas Conv. Ret. 2020	No Gas Conv. Ret. 2020	No Gas Conv. Ret. 2020	No Gas Conv. Ret. 2020	No Gas Conv. Ret. 2020	No Gas Conv. Ret. 2020	Gas Conv. 12/31/2024 to 6/1/2025 Ret. 2042
Craig 1	No SCR Ret. 2025	No SCR Ret. 2025	No SCR Ret. 2025	No SCR Ret. 2025	No SCR Ret. 2025	No SCR Ret. 2025	No SCR Ret. 2025
Dave Johnston 3	No SCR Ret. 2027	No SCR Ret. 2027	SCR + 2019 Ret. 2027	No SCR Ret. 2027	No SCR Ret. 2027	No SCR Ret. 2027	No SCR Ret. 2027

Regional Haze Case Analysis and Results

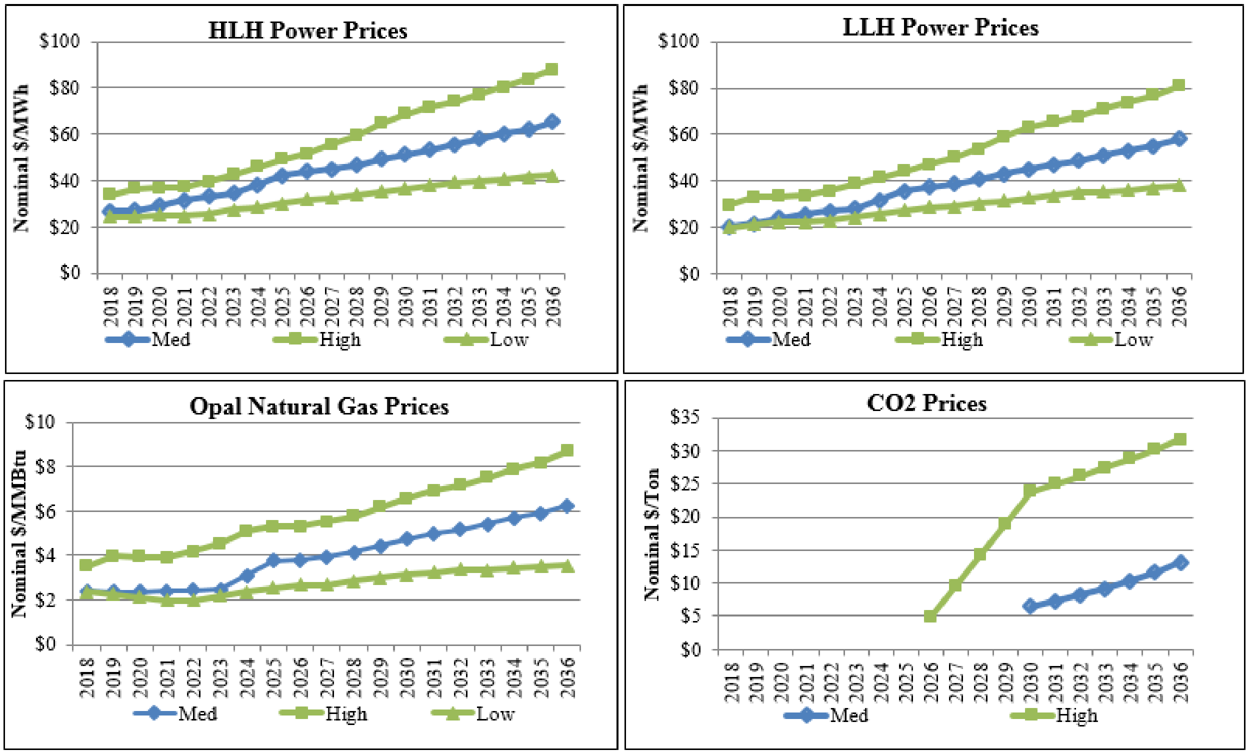
The following sections describe PacifiCorp's analysis consistent with 2017 IRP action plan items 5c, 5d, 5e, and 5g. All studies incorporate updates to forecasted loads, resources, market prices, and other modeling inputs and are compared to the 2017 IRP Update preferred portfolio that includes the assumed retirement dates from the 2017 IRP preferred portfolio in order to assess the present-value revenue-requirement differential (PVRR(d)) for the studied action.

PacifiCorp's SO model was used to develop resource portfolios under three price-policy scenarios for a benchmark case (*i.e.*, the 2017 IRP Update preferred portfolio and the alternative compliance scenario. PVRR(d) analyses are used to quantify the benefit or cost of the regional haze environmental compliance alternatives relative to the benchmark for each of the three price-policy scenarios. The PVRR(d) for a given environmental compliance alternative is calculated as the difference in system costs between the two PaR simulations—the benchmark simulation and the alternative compliance scenario.

Each of the studies, which are described in more detail in the following sections of this chapter, were performed using medium, high and low price-curve scenarios. The medium price scenario is based on PacifiCorp's December 2017 official forward price curve (OFPC), consistent with medium price assumptions used to develop the portfolio for the 2017 IRP Update.

Figure 6.1 summarizes heavy-load hour (HLH) and light-load hour (LLH) wholesale power prices, natural gas prices, and CO_2 prices assumed for this analysis.[1] The low price-policy scenario assumes there are no CO_2 prices throughout the planning horizon.

Figure 6.1 – Forward Price Curve Assumptions[2]



Dave Johnston Unit 3

Consistent with action item 5c in the 2017 IRP action plan, PacifiCorp has updated its analysis of regional haze compliance alternatives and its analysis of the retirement of Dave Johnston Unit 3 by the end of 2027 as reflected in the 2017 IRP preferred portfolio. Dave Johnston Unit 3 is one of four units located at the Dave Johnston plant in Glenrock, Wyoming. The EPA's final regional haze federal implementation plan (FIP) requires the installation of SCR equipment at Dave Johnston Unit 3 in 2019 or a commitment to retire Dave Johnston Unit 3 by the end of 2027. The major project schedule for Dave Johnston Unit 3 SCR is reported in Figure 6.7 at the end of this chapter.

PacifiCorp's updated analysis compares installing SCR equipment by March 2019 with a case that does not install SCR equipment but nonetheless retires Dave Johnston 3 in 2027. This analysis shows that retirement at the end of 2027 without installing SCR equipment is lower cost than installing SCR equipment.

[1] HLH prices cover hours ending seven through 22 PPT, Monday through Saturday, excluding holidays. LLH prices cover all other hours.
[2] For presentation purposes, power prices reflect the average of Mid-Columbia and Palo Verde prices. Opal is the natural gas market hub most applicable to natural gas conversion alternatives studied in the Naughton Unit 3 analysis.

In the case SCR equipment is installed and Dave Johnston retires at the end of 2027, portfolio changes are *de minimis* when compared to the preferred portfolio. This is expected because Dave Johnston Unit 3 retains the same essential operating costs and characteristics with or without the installation of SCR equipment. The most significant of these shifts in the resource portfolio (changes in portfolio resources are less than 12 MW in all years of the study) is a decrease in renewables additions in 2035. The sole driver for these small portfolio shifts is a slight (two MW) reduction in Dave Johnston Unit 3 capacity associated with the SCR equipment. Figure 6.2 summarizes the cumulative change in resource portfolio nameplate capacity when SCR equipment is installed in 2019 and Dave Johnston Unit 3 is retired at the end of 2027 as compared to not installing SCR equipment and retiring at the end of 2027 under the medium gas, medium CO_2 (MM) price-policy scenario. Positive values show cumulative resource portfolio additions and negative values show the cumulative capacity of resources that are removed from the portfolio when Dave Johnston Unit 3 is assumed to install SCR equipment and then retire at end of 2027. There are no notable portfolio changes resulting from installing SCR equipment in 2019 relative to not installing SCR equipment.

Figure 6.2 – Cumulative Increase/(Decrease) in Portfolio Resources under the Dave Johnston Unit 3 Install SCR Equipment (Price-Scenario MM)

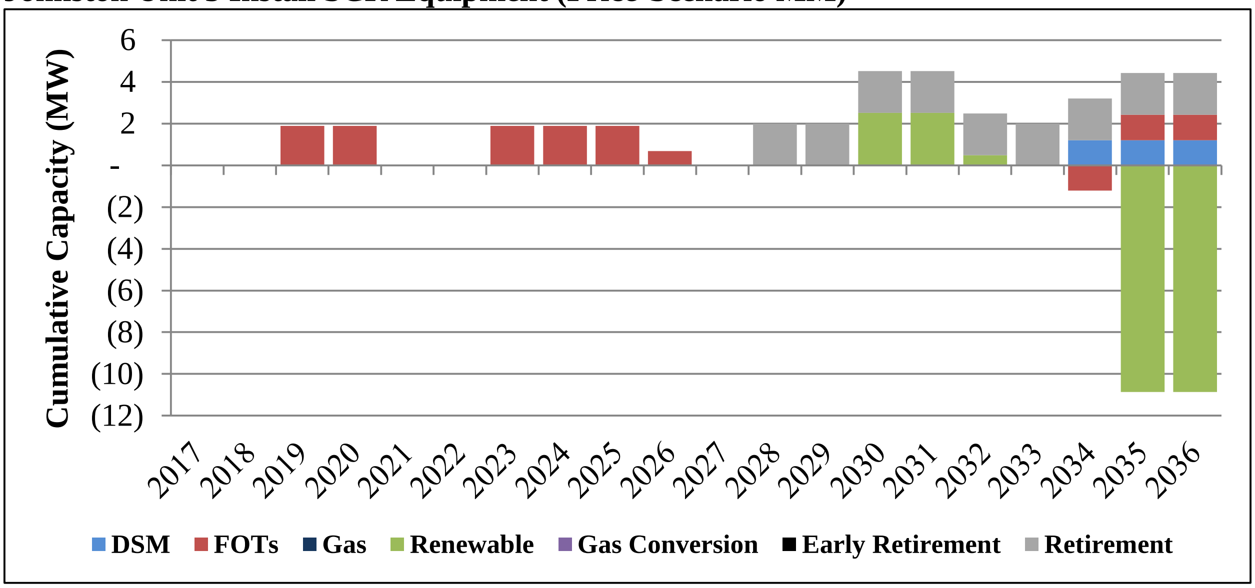


Table 6.2 reports the PVRR(d) impacts of installing SCR equipment in 2019 and retiring Dave Johnston Unit 3 the end of 2027 relative to the 2017 IRP Update preferred portfolio that does not install SCR equipment and includes retirement at the end of 2027 for each of the three price-policy scenarios.

Table 6.2 – PVRR Cost/(Benefit) of the Dave Johnston Unit 3 Install SCR Equipment Case Relative to the 2017 IRP Update Preferred Portfolio by Price-Policy Scenario

PVRR(d) Cost/(Benefit) ($ million)	System Optimizer			PaR Stochastic Mean		
	Low Gas, Zero CO_2	Med Gas, Med CO_2	High Gas, High CO_2	Low Gas, Zero CO_2	Med Gas, Med CO_2	High Gas, High CO_2
Change from 17 IRP Update Pref-Port	$94	$97	$106	$100	$101	$105

The PVRR(d) results are attributed almost entirely to the cost of the SCR equipment, and the slight changes among price-policy scenarios are associated with the impact on system costs associated with slight change in capacity of Dave Johnston Unit 3.

The net cost increase in each price-policy scenario does not support installing SCR equipment on Dave Johnston Unit 3. Consequently, PacifiCorp continues to assume retirement of Dave Johnston Unit 3 at the end of 2027 in the 2017 IRP Update.

Jim Bridger Units 1 & 2

Consistent with action item 5d in the 2017 IRP action plan, PacifiCorp has updated its analysis of regional haze compliance alternatives relative to the Jim Bridger Units 1 and 2 in the 2017 IRP Update preferred portfolio. The 2017 IRP preferred portfolio assumed an early retirement date of 2028 for Jim Bridger Unit 1 and an early retirement date of 2032 for Jim Bridger Unit 2. The Jim Bridger plant consists of four units and is located just outside of Rock Springs, Wyoming. The Wyoming regional haze state implementation plan (SIP) and EPA's final regional haze FIP for Wyoming require the installation of SCR on Jim Bridger Units 1 and 2 by the end of 2022 and 2021 respectively. The major project schedule for Jim Bridger Unit 1 SCR, and Unit 2 SCR is reported in Figure 6.8 and Figure 6.9 at the end of the chapter.

PacifiCorp's updated analysis compares installing SCR equipment on Jim Bridger Units 1 and 2 in 2022 and 2021 respectively with retirement in 2037 versus the 2017 IRP Update preferred portfolio assumption, where Jim Bridger Unit 1 is assumed to retire in 2028 followed by Jim Bridger Unit 2 in 2032 with no SCR installations. This analysis shows that the early retirement scenario without the installation of SCR equipment is lower cost.

In the case where it is assumed that SCR equipment is installed and the Jim Bridger units retire at the end of 2037, the continued operation of the Jim Bridger Units 1 and 2 fills incremental net-capacity needs beginning 2029, driving a lower need for incremental renewables, demand-side management (DSM) and front-office transaction (FOT) resources over the 2029 to 2036 time frame. Figure 6.3 summarizes the cumulative change in resource portfolio nameplate capacity when SCR equipment is installed at Jim Bridger Unit 1 in 2022 and Jim Bridger Unit 2 in 2021 under the medium gas, medium CO_2 price-policy scenario. Positive values show cumulative resource portfolio additions and negative values show the cumulative capacity of resources that are removed from the portfolio when SCR equipment is installed at Jim Bridger Unit 1 in 2022 and Jim Bridger Unit 2 in 2021. In the medium natural gas, medium CO_2 price-policy scenario, notable resource portfolio changes resulting from installing SCR equipment and retiring Jim

Bridger units in 2037 relative to not installing SCR equipment and retiring Jim Bridger Units 1 and 2 early include:

- The installation of SCR in 2021 and 2022 results in minimal shifts in DSM and FOTs in the years leading up to the retirement dates assumed in the preferred portfolio.
- Starting in 2029, the continued operation of Jim Bridger Unit 1 with SCR displaces FOTs and DSM.
- Starting in 2030, the continued operation of Jim Bridger Unit 1 with SCR and the continued operation of Jim Bridger Unit 2 with SCR in 2033 displaces renewable resource additions (both wind and solar).

Figure 6.3 – Cumulative Increase/(Decrease) in Portfolio Resources under the Jim Bridger Units 1 & 2 Install SCR Equipment and Retire 2037 (Price-Scenario MM)

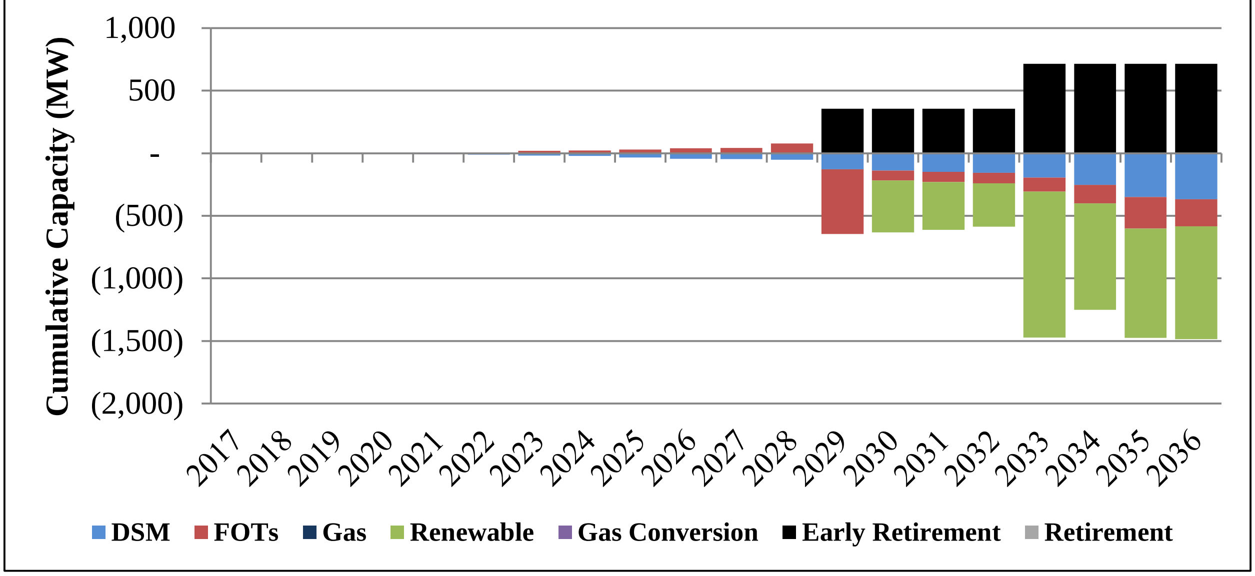


Table 6.3 shows the PVRR(d) impacts of installing SCR equipment at Jim Bridger Unit 1 in 2022 and Jim Bridger Unit 2 in 2021 and retiring at the end of 2037 relative to the 2017 IRP Update preferred portfolio that does not install SCR equipment and includes early retirement at the end of 2028 for Jim Bridger Unit 1 and 2032 for Jim Bridger Unit 2 for each of the three price-policy scenarios.

Table 6.3 – PVRR Cost/(Benefit) of the Jim Bridger Units 1 & 2 Install SCR Equipment and Retire 2037 Case Relative to the 2017 IRP Update Preferred Portfolio by Price-Policy Scenario

PVRR(d) Cost/(Benefit) ($ million)	System Optimizer			PaR Stochastic Mean		
	Low Gas, Zero CO_2	Med Gas, Med CO_2	High Gas, High CO_2	Low Gas, Zero CO_2	Med Gas, Med CO_2	High Gas, High CO_2
Change from 17 IRP Update Pref-Port	$157	$179	$193	$89	$83	$150

The following summarizes observations and results for installing SCR equipment at Jim Bridger Unit 1 in 2022 and Jim Bridger Unit 2 in 2021 and retiring at the end of 2037 relative to the 2017 IRP Update preferred portfolio that does not install SCR equipment and includes early retirement at the end of 2028 for Jim Bridger Unit 1 and 2032 for Jim Bridger Unit 2 under medium natural gas price, medium CO_2 price-policy scenario:

- Fuel costs increase due to the extended years of Jim Bridger Units 1 and 2 operation beginning in 2029 and the displacement of renewable resources and FOTs which do not carry a fuel expense.
- Extended operations of Jim Bridger Units 1 and 2 reduces system balancing purchases, offsetting fuel cost increases.
- SCR installation in 2021 and 2022 increases capital costs.
- Extended operations of Jim Bridger Units 1 and 2 increases emissions costs relative to the preferred portfolio.
- Offsetting costs and benefits result in a net $83 million cost (PaR stochastic mean), as the value of extended generation does not fully offset the cost of SCR installation.
- PaR, which has additional granularity and more refined unit commitment and dispatch logic relative to the SO model, reports a PVRR(d) that shows installation of SCR is lower cost when compared to the SO model results. PaR is able to mitigate costs with increased spot market net sales. However, PaR results still show that installation of SCRs is higher cost.

Naughton Unit 3

Consistent with action item 5e in the 2017 IRP action plan, PacifiCorp has updated its analysis of regional haze compliance alternatives for Naughton Unit 3. The 2017 IRP preferred portfolio assumed an early retirement date of 2018 for Naughton Unit 3. The Naughton plant consists of three units for a combined generating capability of 637 MW and is located near Kemmerer, Wyoming.

PacifiCorp's updated analysis includes two gas conversion cases for Naughton Unit 3. The first case analyzes the full gas conversion of Naughton Unit 3 in June 2019 with retirement in 2029, increasing its capacity slightly from 280 MW to 285 MW. The second case analyzes a limited gas conversion of Naughton Unit 3 that would enable the plant to run on gas at a lower generating capacity of 42 MW, without the capital investment of a full gas conversion, and also with retirement in 2029. These cases are compared to the 2017 IRP Update preferred portfolio assumption where Naughton Unit 3 is assumed to retire at the end of January 2019. This analysis shows that the early retirement scenario without the gas conversion is lower cost whereas a limited gas conversion of Naughton Unit 3 and retirement in 2029 shows benefit in two of the three price-policy scenarios. Each case is discussed in more detail below.

Naughton Unit 3 – Maximum Generating Capacity Gas Conversion

This case studies conversion of Naughton Unit 3 to natural gas with the capital investment necessary to enable it to operate up to 285 MW generating capacity in June 2019 with retirement in 2029. The case creates a lower incremental capacity need beginning in the summer of 2019, which drives the need for lower replacement resources over the 2019 to 2029 time frame. The major project schedule for Naughton Unit 3 maximum gas conversion is reported in Figure 6.10 at the end of this chapter.

Figure 6.4 summarizes the cumulative change in resource portfolio capacity when Naughton Unit 3 is assumed to convert to gas and retire in 2029 relative to the 2017 IRP Update preferred portfolio that includes early retirement of Naughton Unit 3 at the end of January 2019 under the medium gas, medium CO_2 price-policy scenario. Positive values show cumulative resource portfolio additions and negative values show the cumulative capacity of resources that are removed from the portfolio when Naughton Unit 3 is assumed to convert to gas in June 2019 and retire in 2029. The conversion of Naughton Unit 3 to full capacity natural gas operation from 2019 through 2029 reduces the capacity need for west side summer FOTs during this period with the exception of 2021 and 2022. During this two-year window, the system's ability to transfer capacity from the Naughton Unit 3 location (in the Utah North topology bubble) to the west becomes constrained and no offsetting displacement of capacity resources is available.

Figure 6.4 – Cumulative Increase/(Decrease) in Portfolio Resources under the Naughton Unit 3 Maximum Gas Conversion and Retire 2029 (Price-Scenario MM)

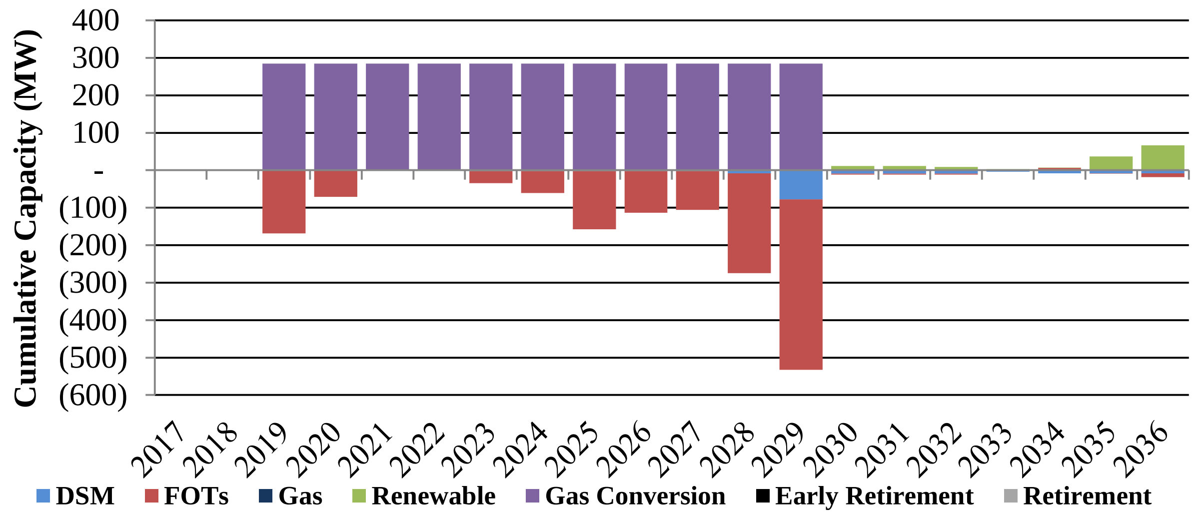


Table 6.4 shows the PVRR(d) impact of converting Naughton Unit 3 to natural gas with maximum generating capacity and retiring at the end of 2029 relative to the 2017 IRP Update preferred portfolio that includes early retirement at the end of January 2019 for Naughton Unit 3 for each of the three price-policy scenarios.

Table 6.4 – PVRR Cost/(Benefit) of the Naughton Unit 3 Maximum Gas Conversion and Retire 2029 Case Relative to the 2017 IRP Update Preferred Portfolio by Price-Policy Scenario

PVRR(d) Cost/(Benefit) ($ million)	System Optimizer			PaR Stochastic Mean		
	Low Gas, Zero CO_2	Med Gas, Med CO_2	High Gas, High CO_2	Low Gas, Zero CO_2	Med Gas, Med CO_2	High Gas, High CO_2
Change from 17 IRP Update Pref-Port	$58	$63	$77	$61	$64	$71

The PVRR(d) results indicate that the fixed costs of converting and operating Naughton Unit 3 as a natural gas fueled facility with maximum generating capability are not covered by the operational benefits accounting for reduced FOT and DSM. The PVRR(d) ranges from $61 million to $71 million higher costs for Naughton Unit 3 when assumed to operate at maximum generating capacity under this gas conversion scenario relative to the 2017 IRP Update preferred portfolio that assumes Naughton Unit 3 retires at the end of January 2019.

The cost increase in each price-policy scenario does not support converting Naughton Unit 3 to gas with maximum generating capacity in June 2019 with an assumed retirement in 2029 relative to early retirement in January 2019 as is assumed in the 2017 IRP Update preferred portfolio.

Naughton Unit 3 – Limited Gas Conversion

This case studies a limited gas conversion of Naughton Unit 3, allowing continued operation through 2029, but reducing unit capacity from its current level of 280 MW to 42 MW. This limited conversion option takes advantage of existing natural gas-fueling arrangements, eliminating the capital investment that would be required to operate the unit up to its maximum generating capability. Similar to the case that assumes maximum gas-conversion capacity, the limited gas conversion is assumed to occur in June 2019 with retirement of the unit in 2029, which creates a lower incremental capacity need beginning in the summer of 2019 and a lower need for replacement resources over the 2019 to 2029 time frame. The major project schedule for Naughton Unit 3 minimum gas conversion is reported in Figure 6.11 at the end of the chapter.

Figure 6.5 summarizes the cumulative change in resource portfolio nameplate capacity when Naughton Unit 3 is assumed to convert to gas on a limited basis and retire in 2029 relative to the 2017 IRP Update preferred portfolio that includes early retirement of Naughton Unit 3 at the end of January 2019 under the medium gas, medium CO_2 price-policy scenario. Positive values show cumulative resource portfolio additions and negative values show the cumulative capacity of resources that are removed from the portfolio when Naughton Unit 3 is assumed to convert to gas on a limited basis in June 2019 and retire in 2029. The portfolio changes are similar to those from the Naughton Unit 3 maximum gas conversion case and mainly include the reduction of FOT and a reduction of DSM in 2029.

Figure 6.5 – Cumulative Increase/(Decrease) in Portfolio Resources under the Naughton Unit 3 Limited Gas Conversion and Retire 2029 (Price-Scenario MM)

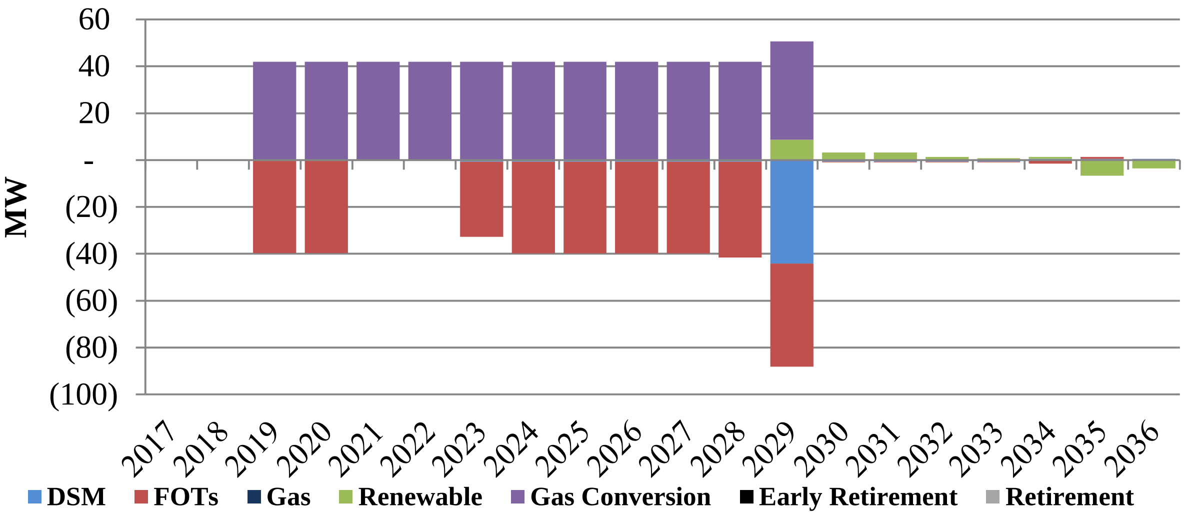


Table 6.5 shows the PVRR(d) impact of converting Naughton Unit 3 to natural gas with limited generating capacity and retiring at the end of 2029 relative to the 2017 IRP Update preferred portfolio that includes early retirement at the end of January 2019 for Naughton Unit 3 for each of the three price-policy scenarios.

Table 6.5 – PVRR Cost/(Benefit) of the Naughton Unit 3 Limited Gas Conversion and Retire 2029 Case Relative to the 2017 IRP Update Preferred Portfolio by Price-Policy Scenario

PVRR(d) Cost/(Benefit) ($ million)	System Optimizer			PaR Stochastic Mean		
	Low Gas, Zero CO_2	Med Gas, Med CO_2	High Gas, High CO_2	Low Gas, Zero CO_2	Med Gas, Med CO_2	High Gas, High CO_2
Change from 17 IRP Update Pref-Port	($4)	($0.4)	$13	$0.5	$3	$11

With limited fixed costs, this case shows there is potential for benefits of operating the unit at a limited capacity, accounting for reduced FOT and DSM. This is evidenced by the slight benefits coming out of the SO model for the low gas, zero CO_2 and medium gas, medium CO_2 price-policy scenarios. The SO model benefits shown for these price-policy scenarios warrant further analysis of the Naughton Unit 3 plant in the 2019 IRP. PacifiCorp will continue to assume early retirement of Naughton Unit 3 in January 2019 in this 2017 IRP Update while continuing to evaluate the economics of gas conversion options in the 2019 IRP.

Cholla Unit 4

Consistent with action item 5g in the 2017 IRP action plan, PacifiCorp has updated its analysis of regional haze compliance alternatives for Cholla Unit 4. With consideration of environmental compliance and unit economics, the 2017 IRP preferred portfolio assumed Cholla Unit 4 retires in 2020. The Cholla plant consists of four units for a combined generating capability of 995 megawatts. PacifiCorp owns 37 percent of the plant's common facilities and all of Unit 4 which was commissioned in 1981 with a generating capability of 395 MW. Arizona Public Service Company owns Units 1, 2 and 3 and operates the entire facility. EPA has approved the Arizona SIP incorporating an alternative regional haze compliance approach that avoids installation of SCR equipment with a commitment to cease operating Cholla Unit 4 as a coal-fueled resource by the end of April 2025, with the option of natural gas conversion thereafter. The major project schedule for Cholla Unit 4 gas conversion is reported in Figure 6.12 at the end of the chapter.

PacifiCorp's updated analysis compares a scenario where it is assumed Cholla Unit 4 continues to operate as a gas-fueled facility by the end of April 2025 and assuming retirement in 2042 to the 2017 IRP Update preferred portfolio, which assumes Cholla Unit 4 retires at the end of 2020. This analysis shows that the early retirement scenario without the gas conversion is lower cost.

In the case that assumes conversion of Cholla Unit 4 and retirement in 2042, extended operation of the resource fills a projected capacity need beginning 2021, driving a lower need for incremental renewable resources, DSM and FOT resources over the 2021 to 2036 time frame. Figure 6.6 summarizes the cumulative change in resource portfolio nameplate capacity under the medium natural gas, medium CO_2 price-policy scenario when Cholla Unit 4 is assumed to convert to gas and retire in 2042 relative to the 2017 IRP Update preferred portfolio that includes early retirement of Cholla Unit 4 at the end of 2020. Positive values show cumulative resource portfolio additions and negative values show the cumulative capacity of resources that are removed from the portfolio when Cholla Unit 4 continues to operate and is assumed to convert to gas at the end of April 2025 retire in 2042. In the medium natural gas, medium CO_2 price-policy scenario, continued operation of Cholla Unit 4 after 2020 followed by conversion to natural gas in 2025 reduces FOT and DSM resources. Beginning 2030, wind and solar resource additions are also reduced.

Figure 6.6 – Cumulative Increase/(Decrease) in Portfolio Resources under the Cholla Unit 4 Gas Conversion and Retire 2042 Medium Natural Gas (Price-Scenario MM)

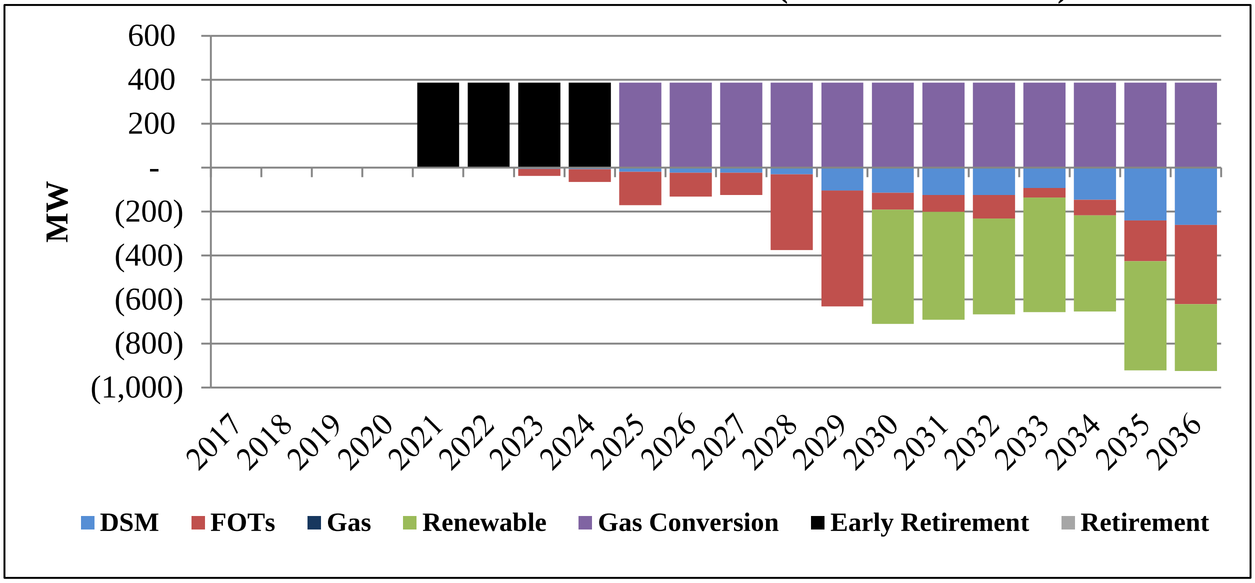


Table 6.6 shows the PVRR(d) impact of assuming Cholla Unit 4 converts to natural gas in 2025 and retires at the end of 2042 relative to the 2017 IRP Update preferred portfolio that includes early retirement at the end of 2020 for each price-policy scenario.

Table 6.6 – PVRR Cost/(Benefit) of the Cholla Unit 4 Gas Conversion and Retire 2042 Case Relative to the 2017 IRP Update Preferred Portfolio by Price-Policy Scenario

PVRR(d) Cost/(Benefit) ($ million)	System Optimizer			PaR Stochastic Mean		
	Low Gas, Zero CO_2	Med Gas, Med CO_2	High Gas, High CO_2	Low Gas, Zero CO_2	Med Gas, Med CO_2	High Gas, High CO_2
Change from 17 IRP Update Pref-Port	$129	$128	$168	$114	$69	$104

The following summarizes observations and results from this study under the medium natural gas price, medium CO_2 price-policy scenario:

- Fuel and variable operation and maintenance costs increase when Cholla Unit 4 continues generating and then converts to natural-gas-fueled operations in 2025. These costs are offset by reduced costs from new DSM and FOT.
- Increased thermal generation when Cholla Unit 4 continues to operate until 2042 as a natural-gas-fueled resource enables more spot market sales and reduces spot market purchases. These benefits are offset by increased CO_2 emission costs starting in 2030.
- Fixed costs related to Cholla Unit 4 are incurred after 2020 for operations and gas conversion in 2025. This is offset by lower fixed costs for renewables.

The PVRR(d) reported out of the SO model is nearly the same the medium natural gas, medium CO_2 and low natural gas, zero CO_2 price-policy scenarios. PaR, which has additional granularity and more refined unit commitment and dispatch logic relative to the SO model, reports a lower net cost in the medium natural gas, medium CO_2 price-policy scenario. However, these results still show that it is lower cost to retire Cholla Unit 4 in 2020. Overall, the increase in present-value system costs in each price-policy scenario does not support converting Cholla Unit 4 to natural gas at the end of April 2025. Subject to further evaluation PacifiCorp will continue to assume early retirement of Cholla Unit 4 at the end of 2020 in the 2017 IRP Update while continuing to evaluate the economics of early retirement and gas conversion options in the 2019 IRP.

Figure 6.7 through Figure 6.12 show illustrative timelines for each regional haze study.

Figure 6.7 – Dave Johnston Unit 3 SCR Project Milestone Schedule

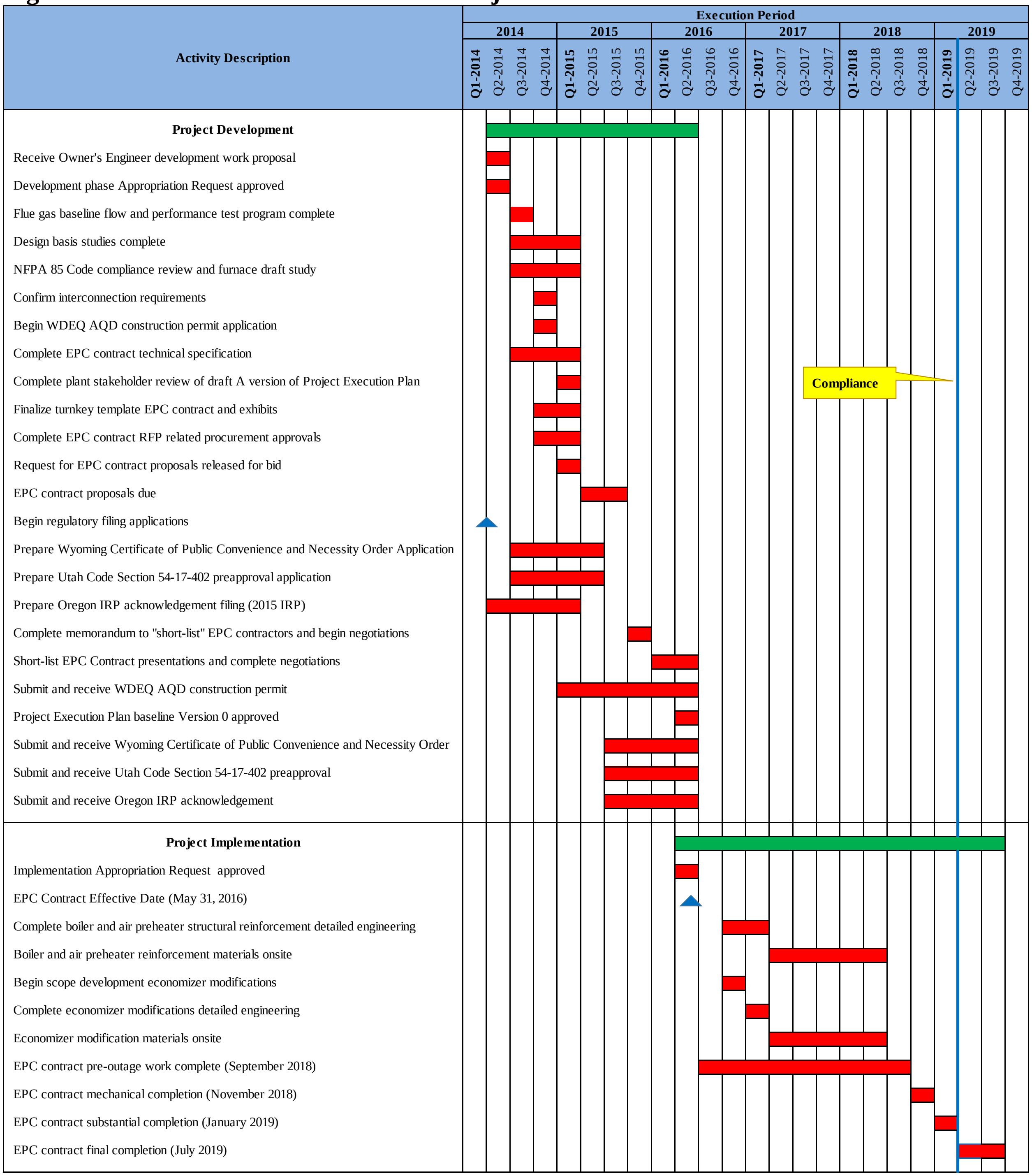


Figure 6.8 – Jim Bridger Unit 1 SCR Project Milestone Schedule

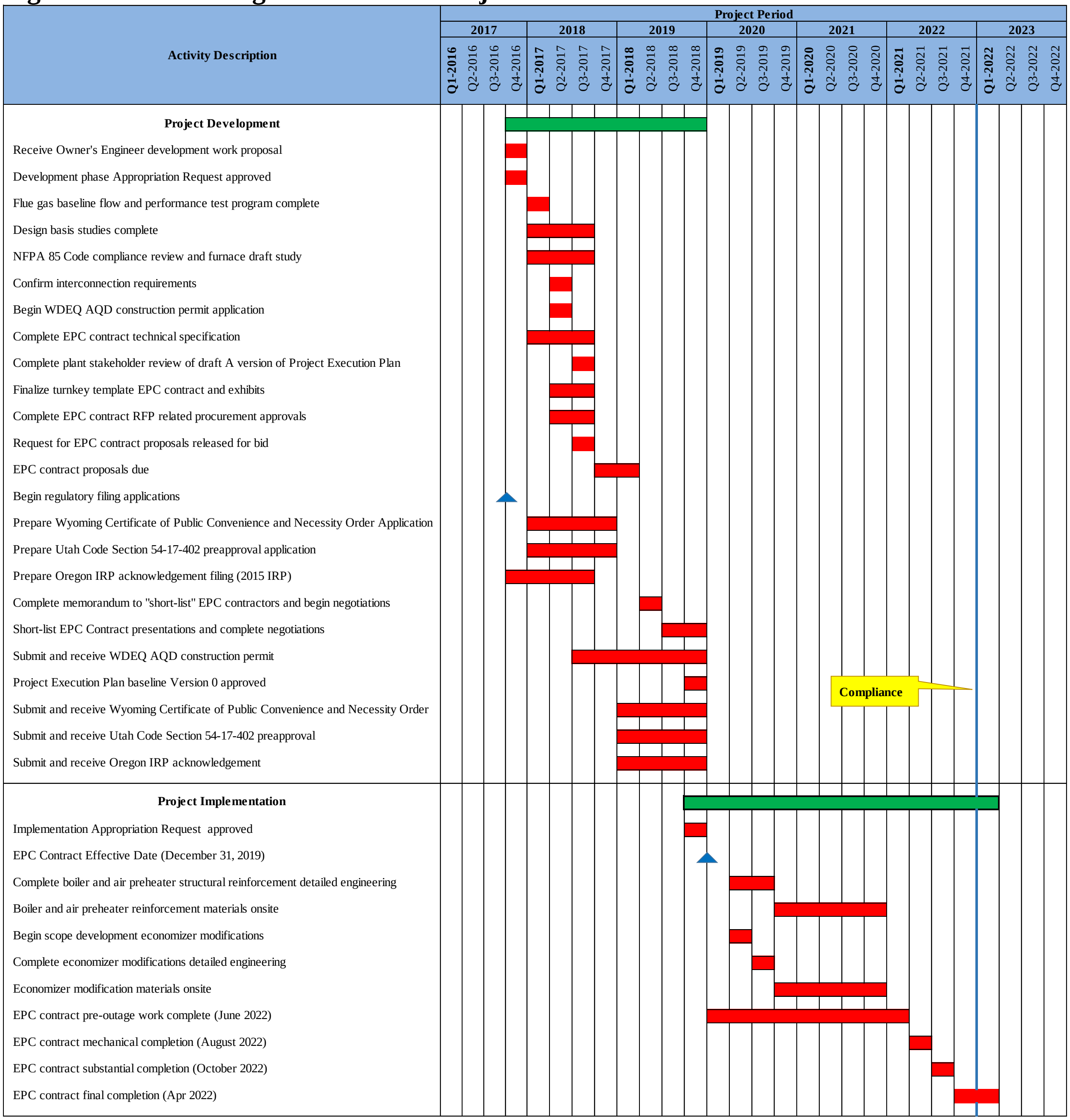


Figure 6.9 – Jim Bridger Unit 2 SCR Project Milestone Schedule

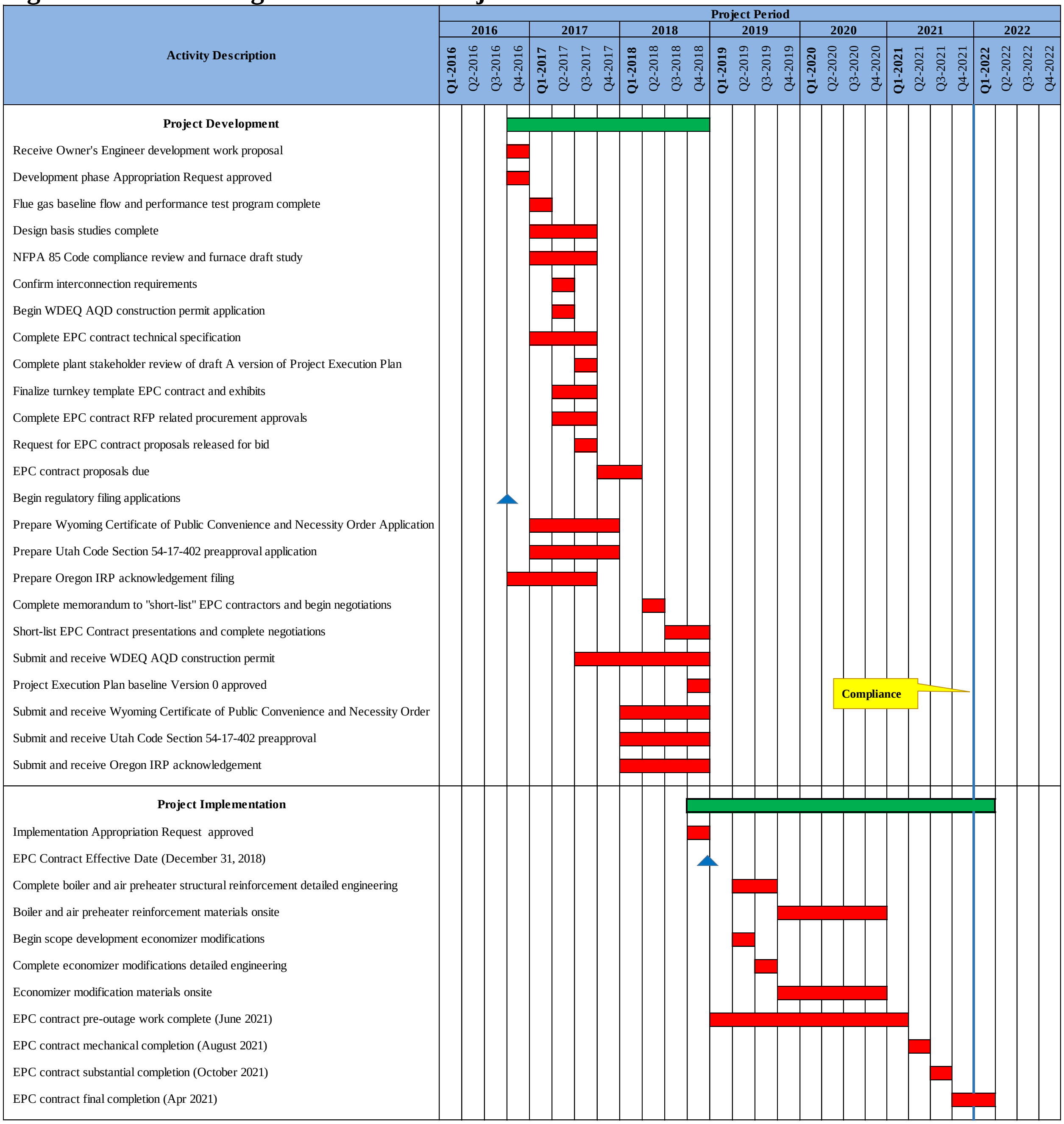


Figure 6.10 – Naughton Unit 3 Maximum Natural Gas Conversion Project Milestone Schedule

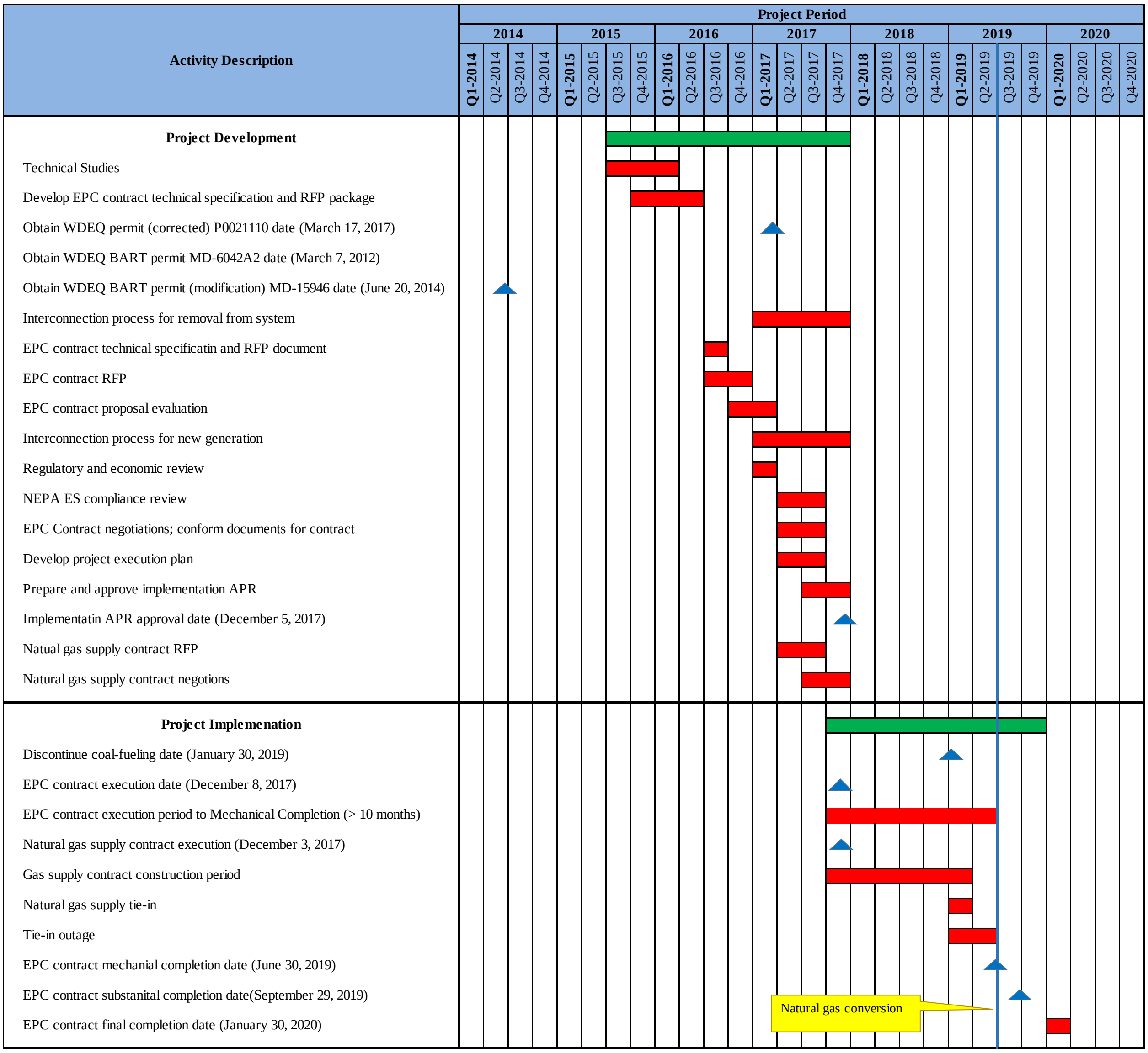


Figure 6.11 – Naughton Unit 3 Limited Natural Gas Conversion Project Milestone Schedule

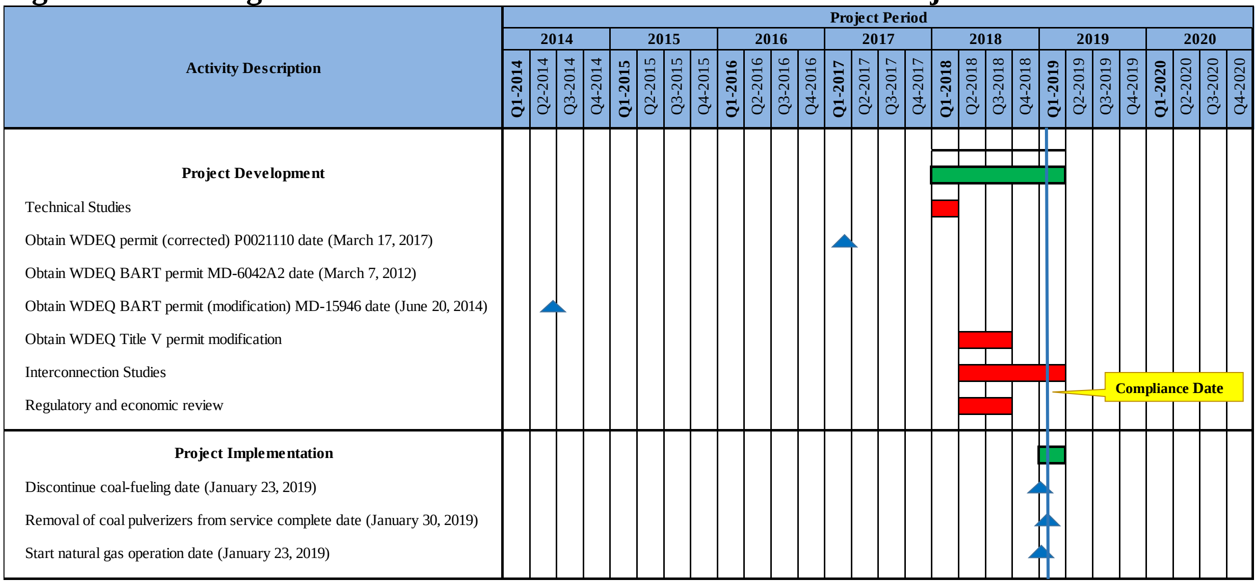
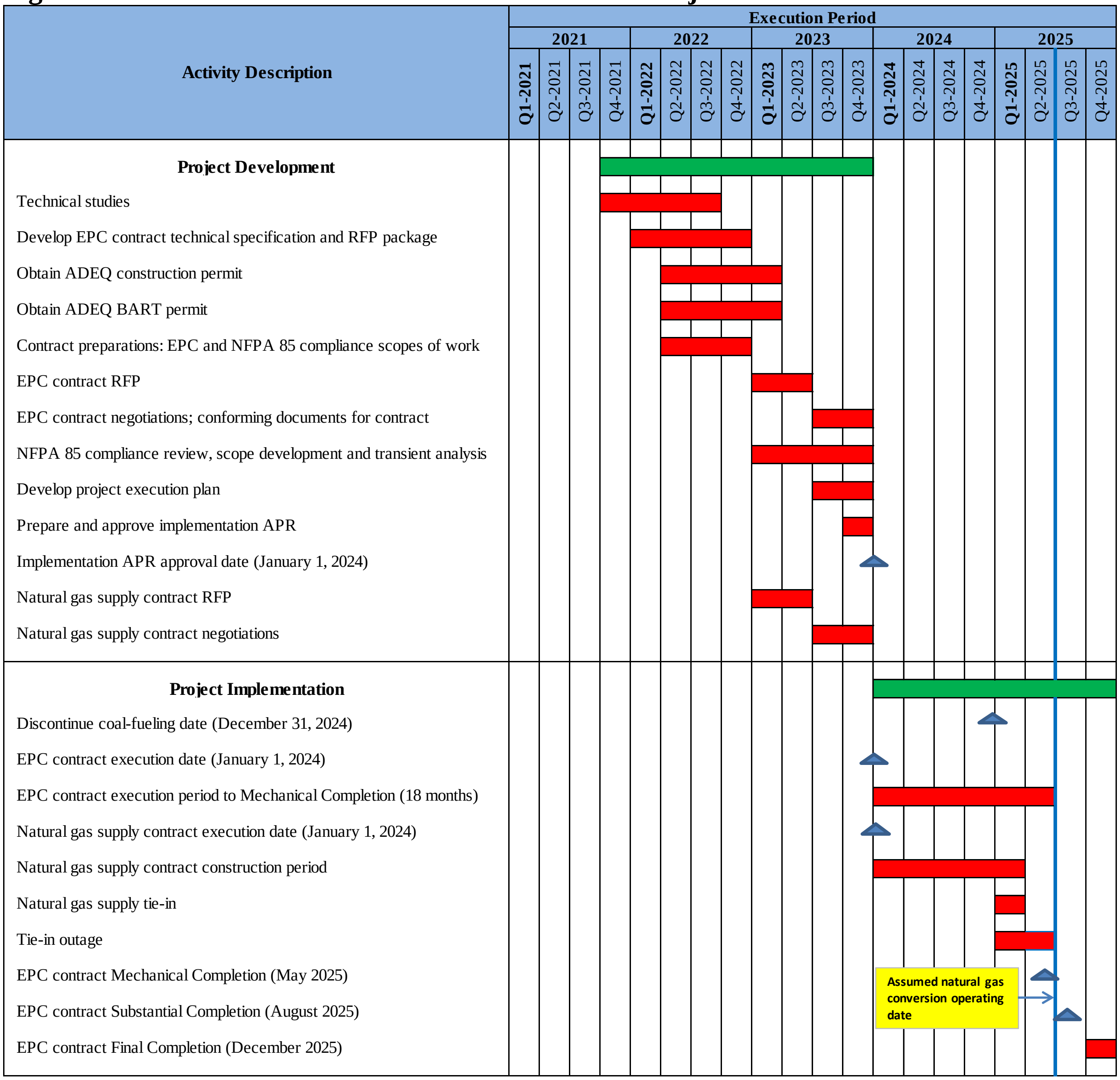


Figure 6.12 – Cholla Unit 4 Natural Gas Conversion Project Milestone Schedule



CHAPTER 7 – ENERGY VISION 2020 UPDATE

Introduction

PacifiCorp's 2017 Integrated Resource Plan (IRP) presented its preferred portfolio, identifying least-cost, least-risk resources providing near-term and long-term benefits to customers. The 2017 IRP preferred portfolio included 1,100 MW of new Wyoming wind resources, enabled by the proposed Aeolus-to-Bridger/Anticline transmission line, and maximizing customer benefits through wind production tax credits (PTCs). In addition, the preferred portfolio reflected repowering 905 MW of existing wind resources by the end of 2020, re-qualifying these zero-emission resources to receive the full value of PTCs for an additional ten years. These three major components of the preferred portfolio (new wind and transmission, plus repowering) are collectively described as the Energy Vision 2020 projects, providing significant net benefits to customers over the 20-year planning horizon.

This chapter summarizes updated analysis of Energy Vision 2020 resources. The 2017 IRP Update preferred portfolio includes 1,311 MW of new Wyoming wind, the Aeolus-to-Bridger/Anticline transmission line, and just over 999 MW of repowered wind. By displacing higher cost uncommitted market purchases and other resources, the 2017 IRP Update preferred portfolio continues to provide the least-cost, least-risk means of meeting system needs identified in Chapter 4. This chapter also describes analysis conducted since filing the 2017 IRP, outlines regulatory milestones and concludes with considerations for the 2019 IRP.

Energy Vision 2020 Project Updates

The 2017 IRP lays out PacifiCorp's long-term plan to deliver reliable electricity supply at a reasonable cost. The 2017 IRP identified the best mix of resources to serve customers over the short- and long-term, based on an analysis of the costs and risks associated with various resource portfolios. The 2017 IRP identified the preferred portfolio as the least-cost, least-risk portfolio that could be delivered through specific action items to deliver resources at a reasonable cost and with manageable risks, while ensuring compliance with state and federal regulatory obligations.

PacifiCorp's 2017 IRP identified wind repowering as a least-cost, least-risk resource. The 2017 IRP also identified significant new wind (Wind Projects) and transmission resources (Transmission Projects) as a component of the least-cost, least-risk resource portfolio (collectively, the Combined Projects).

After filing the 2017 IRP, PacifiCorp conducted a comprehensive updated economic analysis in support of its application for approval of the Energy Vision 2020 projects in Idaho, Utah, and Wyoming. Consistent with analysis in the 2017 IRP, this analysis demonstrated that wind repowering and the Combined Projects will provide substantial customer benefits. Additional filings, incorporating updated data and assumptions to reflect results of the 2017R Request for Proposals (RFP), changes in the federal income tax rate for corporations, an updated load forecast, and updated market price and CO_2 price assumptions.

Energy Vision 2020 project risks have been materially reduced since the 2017 IRP. When the company made its initial filings, it was uncertain whether federal tax-reform legislation would be introduced and how that legislation might impact PTC benefits, which are critical to the economic benefits of the Energy Vision 2020 projects. Similarly, at that time, the company had not yet issued the 2017R RFP and had not received firm pricing for wind resource bids solicited through a competitive bidding process. At this time, these uncertainties have been eliminated and replaced with known tax law changes and competitive pricing for repowering and the Combined Projects. Also since filing the 2017 IRP, PacifiCorp received conditional certificates of public convenience and necessity (CPCNs) for the Aeolus-to-Bridger/Anticline transmission line, the TB Flats I & II wind project, the Cedar Springs wind project, the Ekola Flats wind project, and associated network upgrades from the Wyoming Public Service Commission. These CPCNs are required to secure the necessary rights-of-ways, which has been initiated, before construction begins.

In the latest analysis that serves as the basis for the 2017 IRP Update, the company analyzed nine different scenarios, each with varying natural gas and carbon dioxide (CO_2) price assumptions (price-policy scenarios).[1] Both repowering and the Combined Projects continue to show significant customer benefits which are quantified and described later in this chapter.

Modeling and Approach Summary

PacifiCorp uses two models to optimize and evaluate the least-cost, least-risk portfolio for meeting customer needs and minimizing system costs. For this update, and consistent with the 2017 IRP, these models were used to evaluate dozens of economic scenarios and sensitivities to inform an updated preferred portfolio, demonstrating continuing customer benefits as a result of the Energy Vision 2020 projects.

The System Optimizer (SO) model operates by minimizing operating costs for existing and prospective new resources, subject to system load balance, reliability and other constraints.[2] Over the 20-year planning horizon, it optimizes resource additions subject to resource costs and capacity constraints (summer peak loads, winter peak loads, plus a target planning reserve margin for each load area represented in the model). In the event that an early retirement of an existing generating resource is assumed for a given planning scenario, the SO model will select additional resources as required to meet summer and winter peak loads inclusive of the target planning reserve margin.

The Planning and Risk model (PaR) uses the same common input assumptions described for the SO model with additional data provided by the SO model results (*i.e.*, the selected resource portfolio).[3] While the SO model solves to ensure there is sufficient capacity for each case, PaR considers stochastic-driven risk metrics to the evaluation of the studies. While PaR cost-risk metrics are ultimately used when selecting a preferred portfolio in the IRP, SO model results remain valuable and informative.

[1] The CO_2 price assumptions used in the Energy Vision 2020 results analysis in this chapter were inadvertently modeled in 2012 real dollars instead of nominal dollars. Consequently, the PVRR(d) net benefits in the six price-policy scenarios that use medium and high CO_2 price assumptions are conservative.
[2] For a detailed description of System Optimizer's role in IRP analysis, please refer to the PacifiCorp 2017 IRP, Chapter 6 – Modeling and Portfolio Evaluation Approach, pages 145-156, which is publicly available at the following website link: http://www.pacificorp.com/es/irp.html.
[3] For a detailed description of the Planning and Risk model's role in IRP analysis, please refer to the PacifiCorp 2017 IRP, Chapter 6 – Modeling and Portfolio Evaluation Approach, pages 156-169, which is publicly available at the following website link: http://www.pacificorp.com/es/irp.html.

Common Assumption Updates

During the period between the April 4, 2017 filing of the 2017 IRP and the preparation of this 2017 IRP Update, PacifiCorp has continued to refine its economic analysis supporting the Energy Vision 2020 projects. The analysis represented here incorporates the most current modeled assumptions, reflecting: (1) updated cost-and-performance assumptions for the wind repowering project and the Combined Projects; (2) current price-policy scenario assumptions, including more current natural gas and CO_2 prices; (3) recent changes in the federal tax rate for corporations, and (4) nominal modeling of production tax credits. This most recent analysis also incorporates the updates and refinements made in the second half of 2017, which included updates to PacifiCorp's load forecast. This section summarizes updates to price-policy scenario assumptions, federal tax assumptions, and PTC modeling assumption that are applicable to the updated analysis of the wind repowering project and the Combined Projects.

Price-policy Scenarios

The repowering project economic analysis uses nine price-policy scenarios, developed by pairing three natural-gas price forecasts (low, medium, and high) with three CO_2 price forecasts (zero, medium, and high). The medium natural-gas price assumptions were derived from PacifiCorp's December 2017 official forward price curve (OFPC). The low and high natural gas price assumptions and the medium and high CO_2 price assumptions are based on assumptions adopted by third-party experts. Figure 7.1 shows natural gas price assumptions and Figure 7.2 shows the CO_2 price assumptions used in the updated analysis.

Figure 7.1 – Henry Hub Natural Gas Price Assumptions

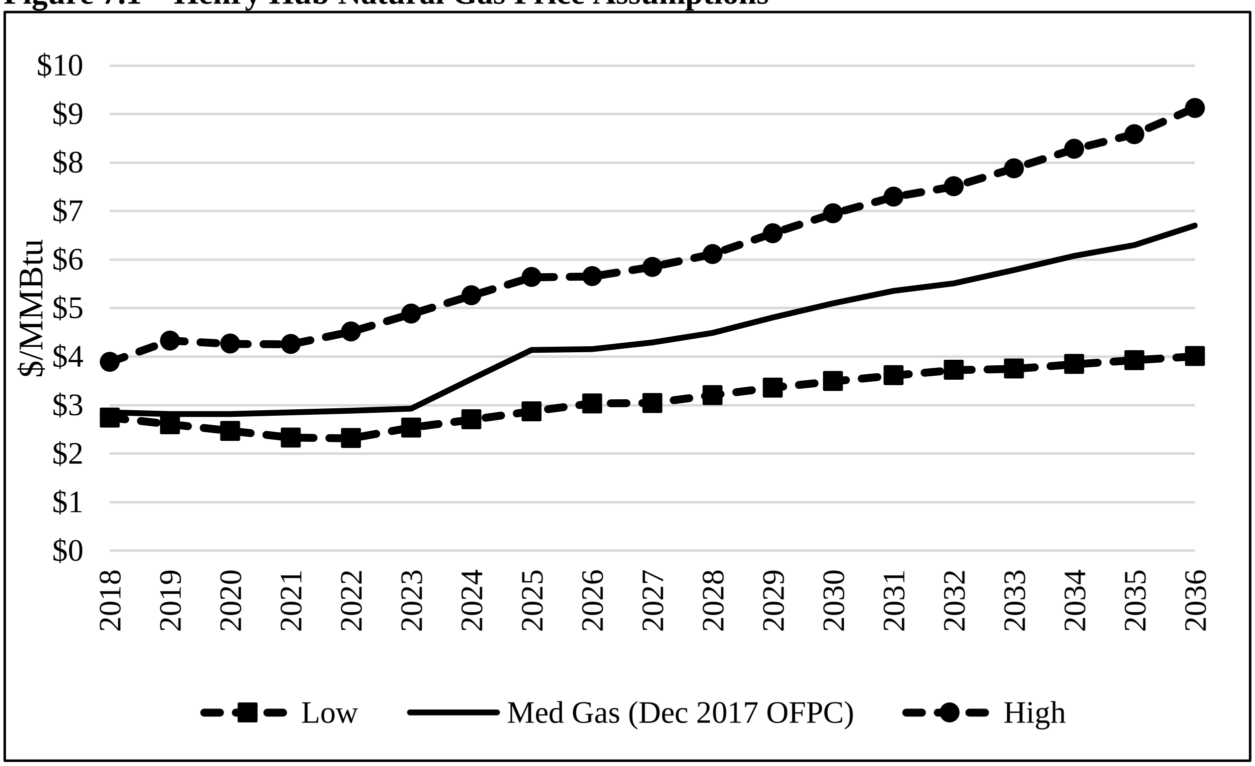
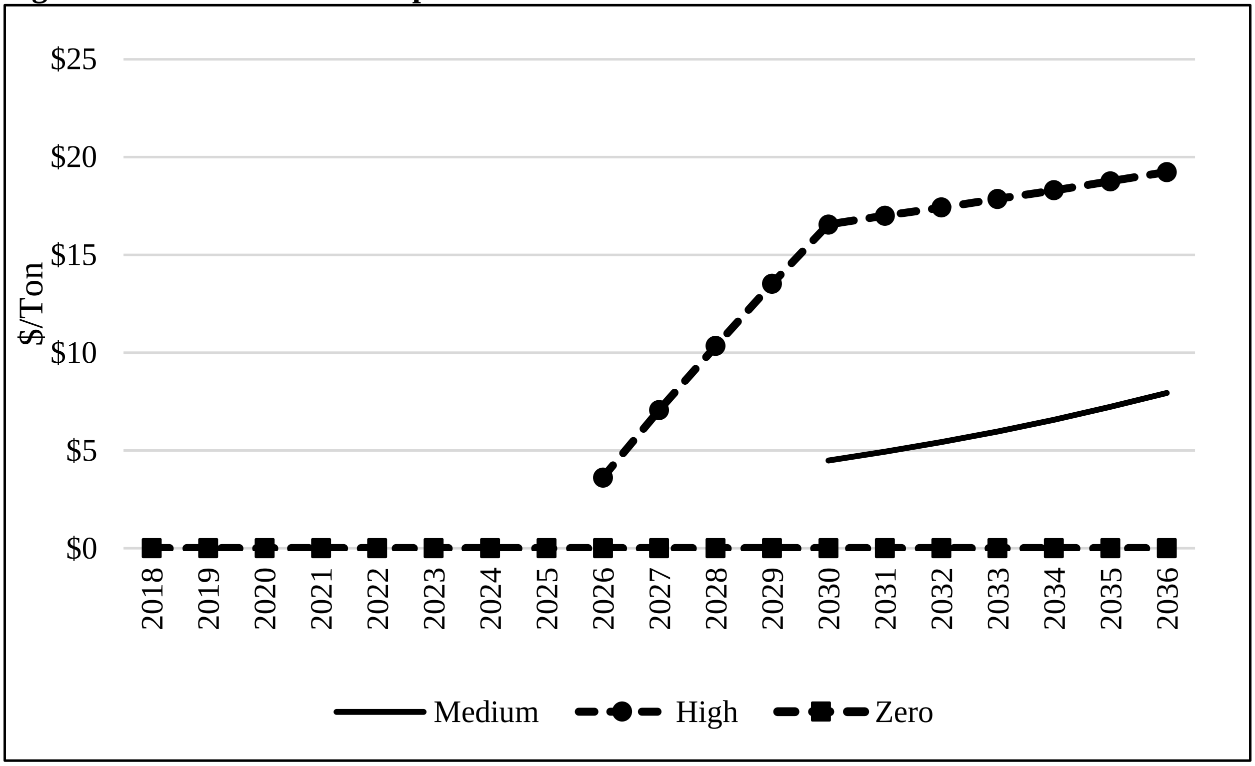


Figure 7.2 – CO_2 Price Assumptions



Federal Tax Rate

PacifiCorp's updated analysis assumes a 21 percent federal income tax rate as provided in H.R. 1, which was passed by Congress on December 20, 2017, and became law on December 22, 2017. Based on an assumed net state income tax rate of 4.54 percent, the effective combined federal and state income tax rate used in the updated analysis is 24.587 percent. The effective combined federal and state income tax rate affects PacifiCorp's post-tax weighted average cost of capital, which is used as the discount rate in the SO model and PaR. With the changes in tax law, PacifiCorp's discount rate was updated from 6.57 percent, as was assumed in the 2017 IRP, to 6.91 percent. The modified income tax rate also affects the capital revenue requirement for all new resource options available for selection in the SO model.

Capital revenue requirement is levelized in the SO and PaR models to avoid potential distortions in the economic analysis of capital-intensive assets that have different lives and in-service dates. This is achieved through annual capital recovery factors, which are expressed as a percentage of the initial capital investment for any given resource alternative in any given year. Capital recovery factors, which are based on the revenue requirement for specific types of assets, are differentiated by each asset's assumed life, book-depreciation rates, and tax-depreciation rates. Because capital revenue requirement accounts for the impact of income taxes on rate-based assets, the capital recovery factors applied to new resource costs in the SO model were updated for each of PacifiCorp's system simulations.

Finally, the updated income tax rate affects the tax gross-up of all PTC-eligible resources. As noted above, the current value of federal PTCs is $24/MWh, which equates to a $31.82/MWh reduction in revenue requirement assuming an effective combined federal and state income tax rate of 24.587

percent, adjusted for inflation over time. The impact of the updated income tax rate assumptions were applied to all PTC-eligible resource alternatives available in the SO model.

Production Tax Credit Modeling

In recent analysis including this 2017 IRP Update, the Company applied PTC benefits on a nominal basis rather than on a levelized basis. This approach better reflects how the federal PTC benefits for the repowered assets and Wind Projects will flow through to customers, conforms the treatment of PTC benefits with other costs and benefits that are not actually spread over the life of an asset, and appropriately weights the contribution of PTC benefits in present-value calculations.

Wind Repowering

Recent advancements in wind generation technology, including innovations in wind turbine design and control systems, allow modern wind turbines to generate greater energy from available wind resources. To take advantage of these recent technologies, PacifiCorp intends to repower most of its Wyoming wind fleet (Glenrock I, Glenrock III, Rolling Hills, Seven Mile Hill I, Seven Mile Hill II, High Plains, McFadden Ridge, and Dunlap); the Marengo I, Marengo II and Goodnoe Hills facilities in Washington; and the Leaning Juniper facility in Oregon. The combined current capacity of these facilities is just over 999 MW, with 594 MW in Wyoming, 304.6 MW in Washington, and 100.5 MW in Oregon.

Efficiency Improvements and Extended Project Life

Wind repowering involves the installation of new rotors with longer blades and new nacelles with higher-capacity generators. Longer blades increase the wind-swept area of the wind turbine and allow it to produce more energy at lower wind speeds. The nacelle is the housing that sits atop the tower and contains the gear box, low- and high-speed shafts, generator, controller, and brake. The new nacelles will include sophisticated control systems and more robust mechanical and generator components necessary to handle the greater loads that come with longer blades. Together, the new rotors and nacelles are estimated to increase wind project generation by approximately 26 percent.

In addition, the innovative technologies provide for greater control of power quality and voltage, allowing PacifiCorp to more easily integrate the energy from the wind facilities into the transmission system and support the reliability of the grid. The new equipment also reduces future operating costs and extends the useful life of each wind plant by at least 10 years. PacifiCorp intends to file new depreciation rates in 2019. At that time, PacifiCorp will reset the 30-year depreciable life of the repowered wind facilities, effectively extending the depreciable life of the facilities by 10 to 13 years.

Over the current life of the repowered facilities, incremental annual energy production is approximately 738 GWh. Over the extended life, the incremental annual energy production is approximately 3,500 GWh. Importantly, because the wind repowering project involves efficiency improvements to existing facilities, these benefits can be achieved without the costs and complexity of permitting and constructing wholly new facilities.

Production Tax Credits and Customer Benefits

The cost-effectiveness of the wind repowering project is driven in part by the fact that repowering requalifies PacifiCorp's existing wind facilities for PTCs, which are set to expire 10 years from their original commercial operation date (expiration dates range from 2016 through 2020). Currently, wind facilities qualifying for the PTC receive 2.4 cents per kilowatt-hour—or $24/MWh—a value that is adjusted annually based upon an inflation index.

To requalify for PTCs, the repowered wind facility must meet the Internal Revenue Service's 80/20 test—meaning that the fair market value of the retained property (*i.e.*, the tower and foundation) is no more than 20 percent of the facility's total value after installation of the new property (*i.e.*, nacelle and rotor). PacifiCorp has designed its wind repowering project to satisfy this test to ensure that the repowered wind facilities are PTC eligible.

Further, to ensure the repowered facilities are eligible for 100 percent of available PTC benefits, in December 2016, PacifiCorp contracted with global wind industry leaders General Electric, Inc., and Vestas-American Wind Technology, Inc., to purchase new wind-turbine generator equipment. These "safe-harbor equipment" purchases allow the repowered wind facilities to qualify for 100 percent of the value of PTCs, assuming commercial operation by the end of 2020.

PacifiCorp's construction schedule will maximize the value of the existing PTCs by minimizing the period between the expiration of the original PTCs and the eligibility for the new PTCs. The original PTCs expire 10 years after each plant became commercially operational. Thus, the PTCs for most of the facilities will expire in 2018 and 2019. Achieving commercial operation in 2019 for most of the facilities will minimize the time during which any wind facilities are ineligible for PTCs.

Updated Data and Assumptions

During the period between the April 4, 2017 filing of the 2017 IRP and the preparation of this 2017 IRP Update, PacifiCorp has continued to refine its economic analysis supporting the wind repowering project. In addition to the assumption updates summarized earlier in this chapter, the updated analysis of the wind repowering project incorporates the most current cost-and-performance assumptions for the wind repowering project.

Cost estimates for the wind repowering project have been updated consistent with findings from technical review studies. These technical review studies have led to a change in turbine specifications at the Leaning Juniper facility to ensure turbine loading remains within allowable limits. Project costs have been updated to account for the need to strengthen foundations at the Leaning Juniper and Goodnoe Hills facilities. Updated cost assumptions also reflect information received through a competitive bidding process for installation, foundation retrofits, as applicable, and other construction services needed to complete the wind repowering project.

Performance estimates for the wind repowering project have been updated to reflect: a) updated turbine specifications for nearly all facilities, including larger rotor diameters and higher capacity generators for the Wyoming wind facilities; b) a change in turbine specifications at the Leaning Juniper and Goodnoe Hills facilities; c) the incorporation of four years of historical production data and increased wake losses into the estimates of increased energy production for the repowered facilities; and d) increased incremental energy production at the Marengo I and II facilities to reflect a modified interconnection agreement that will allow the facilities to operate at their full repowered capacity.

Repowering Results

The SO model and PaR were used to calculate the present-value revenue requirement differential ("PVRR(d)") between a simulation with and without the wind repowering project after applying the modeling updates summarized above. These simulations continue to cover a forecast horizon out through 2036. PacifiCorp also updated its calculation of the PVRR(d) from the change in nominal revenue requirement due to the wind repowering project through 2050.

Project-by-Project Results

Table 7.1 summarizes the PVRR(d) results for each wind facility within the scope of the wind repowering project under the medium natural gas price, medium CO_2 price-policy scenario. The PVRR(d) between cases with and without wind repowering are shown for each wind facility based on system modeling results from the SO model and for PaR, before accounting for the substantial increase in incremental energy beyond the 2036 time frame. When applying medium natural gas, medium CO_2 price-policy assumptions, benefits from repowering the Leaning Juniper wind facility are equal to costs. All other wind facilities are projected to deliver net benefits.

Table 7.1 - Project-by-Project SO Model and PaR PVRR(d) (Benefit)/Cost of Repowering with Medium Natural Gas and Medium CO2 Price Policy Assumptions ($ million)

Wind Facility	SO Model PVRR(d)	PaR Stochastic-Mean PVRR(d)	PaR Risk-Adjusted PVRR(d)
Glenrock 1	($25)	($21)	($23)
Glenrock 3	($8)	($7)	($7)
Seven Mile Hill 1	($33)	($28)	($29)
Seven Mile Hill 2	($7)	($7)	($7)
High Plains	($17)	($13)	($13)
McFadden Ridge	($5)	($4)	($4)
Dunlap Ranch	($30)	($26)	($27)
Rolling Hills	($12)	($9)	($10)
Leaning Juniper	$0	$0	$0
Marengo 1	($35)	($33)	($34)
Marengo 2	($15)	($14)	($15)
Goodnoe Hills	($18)	($18)	($19)
Total	($205)	($180)	($189)

Table 7.2 summarizes the PVRR(d) results for each wind facility within the scope of the wind repowering project under the low natural gas price, zero CO_2 price-policy scenario. The PVRR(d) between cases with and without wind repowering are shown for each wind facility based on system modeling results from the SO model and for PaR, before accounting for the substantial increase in incremental energy beyond the 2036 time frame. When applying low natural gas and zero CO_2 price-policy assumptions, costs from repowering the Leaning Juniper wind facility are slightly higher than the benefits. All other wind facilities are projected to deliver net benefits.

Table 7.2 - Project-by-Project SO Model and PaR PVRR(d) (Benefit)/Cost of Wind Repowering with Low Natural Gas and No CO2 Price Policy Assumptions ($ million)

Wind Facility	SO Model PVRR(d)	PaR Stochastic-Mean PVRR(d)	PaR Risk-Adjusted PVRR(d)
Glenrock 1	($21)	($21)	($22)
Glenrock 3	($7)	($6)	($6)
Seven Mile Hill 1	($28)	($28)	($29)
Seven Mile Hill 2	($6)	($6)	($6)
High Plains	($12)	($9)	($10)
McFadden Ridge	($4)	($3)	($3)
Dunlap Ranch	($25)	($22)	($24)
Rolling Hills	($9)	($7)	($7)
Leaning Juniper	$6	$3	$4
Marengo 1	($27)	($25)	($26)
Marengo 2	($11)	($10)	($11)
Goodnoe Hills	($13)	($15)	($15)
Total	($157)	($149)	($156)

Table 7.3 summarizes the PVRR(d) results for each wind facility calculated off of the change in annual nominal revenue requirement through 2050 for both price-policy scenarios. Unlike the results summarized in Table 7.1 and Table 7.2, these results account for the substantial increase in incremental energy beyond the 2036 time frame. Each of the wind facilities within the scope of the proposed repowering project show net benefits with repowering under the medium natural gas and medium CO_2 price-policy scenario and all facilities show net benefits under the low natural gas and zero CO2 price-policy scenario, except for the Leaning Juniper wind facility, where the benefits are equal to the costs. However, these results are conservative, as the assumed benefits do not account for the capacity value of the repowered wind facilities in the period when they would have otherwise hit the end of their depreciable lives (*i.e.*, beyond 2036).

Table 7.3 - Project-by-Project Nominal Revenue Requirement PVRR(d) (Benefit)/Cost of Wind Repowering ($ million)

Wind Facility	Medium Natural Gas and Medium CO_2	Low Natural Gas and Zero CO_2
Glenrock 1	($33)	($33)
Glenrock 3	($11)	($6)
Seven Mile Hill 1	($41)	($40)
Seven Mile Hill 2	($10)	($6)
High Plains	($22)	($6)
McFadden Ridge	($7)	($2)
Dunlap Ranch	($39)	($23)
Rolling Hills	($15)	($5)
Leaning Juniper	($8)	$0
Marengo 1	($50)	($22)
Marengo 2	($20)	($7)
Goodnoe Hills	($26)	($19)
Total	($282)	($170)

A further assessment of the magnitude of the PVRR(d) results must be considered in relation to the specific attributes of the repowered wind facility, including the size of the facility, the expected cost to repower the facility, and the level of annual energy output expected after the new equipment is installed. For example, the PVRR(d) for McFadden Ridge shows a $7 million benefit when repowered (using medium natural gas and medium CO_2 price-policy assumptions)—the lowest PVRR(d) among all of the project-by-project results. The PVRR(d) benefit for McFadden Ridge is approximately 14 percent of the $50 million benefit for Marengo I, which yields the highest PVRR(d) among all of the project-by-project results. However, the current capacity of McFadden Ridge (28.5 MW) is approximately 20 percent of the current capacity of Marengo I (140.4 MW). Similarly, the expected energy output after repowering McFadden Ridge (approximately 117 GWh per year) is approximately 24 percent of the expected energy output after repowering Marengo I (approximately 488 GWh per year).

A reasonable metric to evaluate the relative benefits among the wind facilities that captures the specific attributes of each facility is the nominal levelized net benefit per incremental MWh expected after the facility is repowered. This metric captures the specific repowering cost for each facility net of the specific benefits of each facility per incremental MWh of energy expected after the facility is repowered. Table 7.4 shows the nominal levelized net benefit of repowering per MWh of expected incremental energy output after repowering for each wind facility. When using medium natural gas, medium CO_2 price-policy assumptions, the table shows the Seven Mile Hill II facility produces the largest net benefit per incremental MWh ($37/MWh), and Leaning Juniper produces the smallest net benefit per incremental MWh ($7/MWh).

Table 7.4 - Nominal Levelized Net Benefit per MWh of Incremental Energy Output after Repowering

Wind Facility	Medium Natural Gas and Medium CO_2	Low Natural Gas and Zero CO_2
Glenrock 1	$29/MWh	$29/MWh
Glenrock 3	$28/MWh	$16/MWh
Seven Mile Hill 1	$30/MWh	$29/MWh
Seven Mile Hill 2	$36/MWh	$23/MWh
High Plains	$17/MWh	$5/MWh
McFadden Ridge	$17/MWh	$5/MWh
Dunlap Ranch	$28/MWh	$17/MWh
Rolling Hills	$19/MWh	$7/MWh
Leaning Juniper	$7/MWh	$0/MWh
Marengo 1	$25/MWh	$11/MWh
Marengo 2	$21/MWh	$8/MWh
Goodnoe Hills	$26/MWh	$18/MWh
Weighted Average	$23/MWh	$14/MWh

All Repower Project Results

Table 7.5 reports that in this latest analysis over a 20-year period, repowering reduces customer costs in all nine price-policy scenarios. The outcome is consistent in both the SO model and PaR results. Under the central price-policy scenario, assuming medium natural-gas, medium CO_2 price-policy assumptions, the PVRR(d) net benefits range between $180 million, when derived from PaR stochastic-mean results, and $204 million, when derived from SO model results. PaR risk-adjusted results range from $146 million when assessed with low natural gas, medium CO_2 price-policy assumptions to $260 million when assessed with high natural gas, medium CO_2 price-policy assumptions. In the expected medium natural gas, medium CO_2 price-policy scenario, wind repowering results in PaR risk-adjusted customer benefits of $189 million.

Table 7.5 - SO Model and PaR PVRR(d) (Benefit)/Cost of Wind Repowering ($ million)

Price-Policy Scenario	SO Model PVRR(d)	PaR Stochastic Mean PVRR(d)	PaR Risk-Adjusted PVRR(d)
Low Gas, Zero CO_2	($159)	($141)	($148)
Low Gas, Medium CO_2	($158)	($139)	($146)
Low Gas, High CO_2	($183)	($165)	($173)
Medium Gas, Zero CO_2	($201)	($171)	($180)
Medium Gas, Medium CO_2	($204)	($180)	($189)
Medium Gas, High CO_2	($215)	($193)	($203)
High Gas, Zero CO_2	($257)	($234)	($246)
High Gas, Medium CO_2	($260)	($248)	($260)
High Gas, High CO_2	($273)	($240)	($252)

Projected system net benefits increase with higher natural-gas price assumptions, and similarly, generally increase with higher CO_2 price assumptions. Conversely, system net benefits generally decline when low natural-gas prices and low CO_2 prices are assumed. This trend holds true when looking at the results from the two simulations used to calculate the PVRR(d) for all nine of the price-policy scenarios. Importantly, both models continue to show that the net benefits from the wind repowering project are robust across a range of price-policy assumptions.

The wind repowering project creates these benefits by:

- Increasing energy production from the wind facilities by approximately 25.7 percent;
- Reducing ongoing operating costs associated with aging wind turbines;
- Extending the useful lives of the wind facilities by at least 10 years;
- Increasing the output of renewable energy from existing assets, while avoiding the environmental impacts and view-shed issues associated with new facilities;
- Reducing customer costs by requalifying the wind facilities for PTCs for an additional 10 years; and
- Improving the ability of the wind facilities to deliver cost-effective renewable energy into the transmission system through enhanced voltage support and power quality.

These benefit trends hold true for annual data over the period 2017 through 2050. Table 7.6 summarizes the updated PVRR(d) results for each price-policy scenario calculated off of the change in annual nominal revenue requirement through 2050.

Table 7.6 - Nominal Revenue Requirement PVRR(d) (Benefit)/Cost of Wind Repowering ($ million)

Price-Policy Scenario	Annual Revenue Requirement PVRR(d)
Low Gas, Zero CO_2	($127)
Low Gas, Medium CO_2	($121)
Low Gas, High CO_2	($223)
Medium Gas, Zero CO_2	($224)
Medium Gas, Medium CO_2	($273)
Medium Gas, High CO_2	($321)
High Gas, Zero CO_2	($389)
High Gas, Medium CO_2	($386)
High Gas, High CO_2	($466)

When system costs and benefits from the wind repowering project are extended through 2050, covering the full depreciable life of the repowered wind facilities, the wind repowering project reduces customer costs in all nine price-policy scenarios. Customer benefits range from $121 million in the low natural gas, medium CO_2 price-policy scenario to $466 million in the high natural gas, high CO_2 price-policy scenario. Under the central price-policy scenario, assuming medium natural-gas prices and medium CO_2 prices, the PVRR(d) benefits of the wind repowering project are $273 million. While changes in federal income tax law have reduced net benefits relative to the economic analysis summarized prior to the passage of H.R. 1, the wind repowering project continues to provide significant customer benefits in all price-policy scenarios, and the updated economic analysis reconfirms that upside benefits outweigh downside risks.

Repowering Project Upside

The PVRR(d) results presented in Table 7.1 throughTable **7.6** do not reflect the potential renewable energy credits (REC) value of incremental energy output from the repowered facilities. Accounting for the updated performance estimates discussed above, customer benefits for all price-policy scenarios would improve by approximately $6 million for every dollar assigned to the incremental RECs that will be generated from the repowered facilities through 2036. Benefits for all price-policy scenarios would improve by approximately $12 million for every dollar assigned to the incremental RECs that will be generated from the repowered facilities through 2050. Quantifying the potential upside associated with incremental REC revenues is intended to simply communicate that the net benefits from the repowering project could improve if the incremental RECs can be monetized in the market. Moreover, as noted earlier, none of the economic analyses account for the capacity value of the repowered wind facilities in the period when they would have otherwise hit the end of their depreciable lives (*i.e.*, beyond 2036).

New Wind and Transmission (Combined Projects)

Analysis conducted in the 2017 IRP covered a wide range of studies, including regional haze cases, price-policy cases and sensitivities. Wyoming wind was consistently selected in the optimized portfolios of nearly all cases, up to the maximum capacity of Wyoming wind capable of interconnecting to the transmission system without incremental investment in Energy Gateway transmission infrastructure. Based on these results, PacifiCorp further analyzed Energy Gateway sensitivities. This analysis showed that the combination of new wind and new transmission resulted in the least-cost, least-risk combination of resources to meet load and resource needs over the 20-year planning horizon. Enabled by the transmission projects described later in this chapter, and based on the results of PacifiCorp's 2017R RFP, 1,311 MW of new wind resources will be placed in service by the end of 2020, creating substantial benefits for customers.

Wind Projects

Extension of federal PTCs created a time-limited opportunity for PacifiCorp to acquire significant cost-effective, zero-fuel cost wind resources, generating PTCs from the Wind Projects that will help meet projected capacity needs and provide substantial benefits for customers. The additional capacity from the Wind Projects will reduce reliance on more costly and less certain resources, in particular uncommitted front office transactions (market purchases) over the near term and defer the need for higher-cost resource alternatives over the long term. While not valued as part of this analysis, the new wind energy will also produce additional RECs, further increasing the value of these new resources.

To achieve the full customer benefits of the PTCs, PacifiCorp must develop the Wind Projects with the Transmission Projects and bring them into service together. The Wind Projects are not economic without the Transmission Projects, which are needed to relieve existing congestion and to interconnect new PTC-eligible wind facilities in high-wind areas of Wyoming. The Transmission Projects are not economic without incremental cost-effective wind facilities producing zero-fuel-cost energy and PTCs.

2017R RFP

The 2017 IRP Update preferred portfolio relies on the extensive analysis conducted in the Company's 2017R RFP, and advances PacifiCorp's commitment to low-cost energy with plans to add 1,311 MW of new Wyoming wind resources by the end of 2020.[4] These new zero-emission wind facilities will connect to a new 140-mile, 500 kV transmission line running from the Aeolus substation near Medicine Bow, Wyoming, to the Jim Bridger power plant (a sub-segment of the Energy Gateway West transmission project). In addition to providing significant economic benefits for PacifiCorp's customers, the wind and transmission project will reduce market reliance, improve transmission reliability, and provide economic development benefits.

PacifiCorp received initial bids for Wyoming wind projects on October 17, 2017, and initial bids for non-Wyoming wind projects on October 24, 2017. The 2017R RFP was well received by the market, as indicated by the fact the company received Wyoming wind proposals from nine bidders offering 49 bid alternatives for 13 wind projects. PacifiCorp also received non-Wyoming wind proposals from five bidders offering 15 bid alternatives for six wind projects. In aggregate, 5,219 MW of new wind resource capacity was bid into the 2017R RFP (4,624 MW of Wyoming wind and 595 MW of non-Wyoming wind).

The 2017R RFP was monitored by two independent evaluators—one retained by PacifiCorp and appointed by the Public Utility Commission of Oregon and one retained by the Public Service Commission of Utah—and resulted in a final shortlist consisting of four projects: (1) the TB Flats I & II project providing 500 MW of capacity in Carbon and Albany Counties, Wyoming; (2) the Cedar Springs project providing 400 MW of capacity in Converse County, Wyoming; (3) the Ekola Flats project providing 250 MW of capacity in Carbon County, Wyoming; and (4) the Uinta project providing 161 MW of capacity in Uinta County, Wyoming. Together, these least-cost, least-risk projects will provide 1,311 MW of zero-fuel cost, emission-free generation to serve PacifiCorp's customers. Approximately 1,150 MW of this capacity (TB Flats I & II, Cedar Springs, and Ekola Flats) is located within the transmission-constrained area of PacifiCorp's transmission system in eastern Wyoming and is enabled by the Aeolus-to-Bridger/Anticline transmission line. The remaining 161 MW of capacity (Uinta) is located in western Wyoming.

PacifiCorp selected the final-shortlist projects after performing detailed and comprehensive economic analysis of all bids received. Using the same models and methodology used in the 2017 IRP, PacifiCorp determined the optimum combination of bids to maximize customer benefits. Extensive modeling confirms that the final shortlist resources meet both near-term and long-term resource needs and are the least-cost, least-risk path available to serve PacifiCorp's customers. PacifiCorp's risk assessment further demonstrates that the final-shortlist resources provide substantial customer benefits across nearly every natural gas and CO_2 price-policy scenarios studied. Relative to the 2017 IRP, the 2017R RFP results demonstrate increased customer benefits from the new wind resources, in combination with construction of the Aeolus-to-Bridger/Anticline 500-kV transmission line and associated infrastructure (transmission project).

Transmission Projects

While the Aeolus-to-Bridger/Anticline transmission line has long been recognized as an integral component of PacifiCorp's long-term transmission planning, its construction and that of the other components of the Transmission Projects has not been economic until now. The Transmission Projects will contribute to meeting PacifiCorp's short- and long-term capacity need and will strengthen the overall reliability of the existing transmission system.

[4] 2017 Wind IRP issued September 27, 2017, approved by the Public Service Commission of Utah on September 22, 2017, and the Public Utility Commission of Oregon on September 27, 2017

Congestion on the current transmission system in eastern Wyoming limits the ability to deliver energy from eastern Wyoming to the Jim Bridger area. The Aeolus-to-Bridger/Anticline line will relieve this congestion and increase the transmission capacity across Wyoming by approximately 950 MW.[5] The Transmission Projects will allow PacifiCorp to interconnect 1,311 MW of wind resources and create substantial benefits for customers throughout its service area. Construction of the Transmission Projects will also enable PacifiCorp to more efficiently use existing generation resources in Wyoming to serve loads in Utah, Wyoming, Idaho, and the Pacific Northwest. The Transmission Projects also better position PacifiCorp to interconnect future resources in southeastern Wyoming and provide greater flexibility in managing existing resources.

In addition to increasing the transmission capacity out of southeastern Wyoming, the Transmission Projects will also provide critical voltage support to the Wyoming transmission network and enhance the overall reliability of the transmission system by adding incremental new transmission capacity westbound between the company's existing thermal and renewable facilities, the proposed Wind Projects in eastern Wyoming, and other sources of energy in northern Utah. Additional transmission paths will mitigate the impact of outages on the existing system. The Transmission Projects will also enhance PacifiCorp's ability to comply with mandated North American Electric Reliability Corporation and Western Electricity Coordinating Council reliability and performance standards.

The Aeolus-to-Bridger/Anticline line is also an important component of PacifiCorp's Energy Gateway Transmission project and has long been recognized as a key transmission segment in the region's long-term transmission planning. By acting on this time-limited opportunity to develop the Transmission Projects and the associated Wind Projects, PacifiCorp can deliver substantial benefits for its customers.

Wyoming CPCNs

On April 12, 2018, PacifiCorp received conditional CPCNs for the Aeolus-to-Bridger/Anticline transmission line, the TB Flats I & II wind project, the Cedar Springs wind project, the Ekola Flats wind project, and associated network upgrades from the Wyoming Public Service Commission. These CPCNs are required to secure the necessary rights-of-ways, which has been initiated, before construction begins.

Production Tax Credits and Customer Benefits

The substantial customer benefits resulting from the acquisition of the Wind Projects reflects the fact that these facilities can qualify for 100 percent of federal PTCs by achieving commercial operation by December 31, 2020.

PacifiCorp's approach to the Combined Projects is to mitigate risk and ensure that appropriate off-ramps exist in the project review, approval, and implementation processes before significant capital outlays or commitments are made in case the necessary approvals are not received, project economic benefits erode, or the associated benefits are placed at risk. With timely regulatory

[5] The updated economic analysis assumes the incremental transfer capability is 750 MW. Subsequent transmission studies have confirmed the transfer capability is 950 MW. Consequently, the economic analysis presented in this chapter is conservative.

reviews and approvals, and successful transmission rights of way (ROW) acquisition, PacifiCorp fully expects it will successfully meet the requirements necessary to ensure eligibility for 100 percent of the PTCs.

Updated Data and Assumptions

During the period between the April 4, 2017 filing of the 2017 IRP and the preparation of this 2017 IRP Update, PacifiCorp has continued to refine its economic analysis supporting the Combined Projects. In addition to the assumption updates summarized earlier in this chapter, the updated analysis of the Combined Projects incorporates the most current cost-and-performance assumptions.

Wind Projects

Table 7.7 presents the winning wind bids from the 2017R RFP. The updated best-and-final pricing received on December 21, 2017 was used in the model analysis to establish the winning projects, and the model results are presented later in this chapter. The total capacity of the winning bids is 1,311 MW, assuming commercial operation by the end of 2021.

Table 7.7 - 2017R RFP Final Shortlist

Project Name (Bidder)	Location	Capacity (MW)
TB Flats I & II (PacifiCorp)	Carbon & Albany Counties, WY	500
Cedar Springs (NextEra Energy Acquisitions)	Converse County, WY	400
Ekola Flats (PacifiCorp)	Carbon County, WY	250
Uinta (Invenergy Wind Development)	Uinta County, WY	161

The TB Flats I & II and Ekola Flats projects are company-benchmark resources that will be developed under engineer, procure, and construction (EPC) agreements. The Uinta project is being developed by Invenergy Wind Development under a build-transfer agreement (BTA). The Cedar Springs project is being developed by NextEra Energy Acquisitions as a 50-percent BTA and a 50-percent power-purchase agreement (PPA). In total, the updated final shortlist includes 361 MW that will be developed under BTAs, 750 MW of benchmark capacity that will be developed under EPC agreements, and 200 MW that will deliver energy and capacity under a PPA.

In aggregate, the winning bids are expected to operate at a capacity-weighted average annual capacity factor of 39.4 percent.

Transmission Interconnection-Restudy Process

Separate from the 2017R RFP process, the company completed an interconnection-restudy process to ensure that interconnection studies reflected the most current long-term transmission plan to construct the Aeolus-to-Bridger/Anticline D.2 segment of the Energy Gateway project by the end of 2020. PacifiCorp transmission restudied, in serial interconnection-queue order, interconnection requests that do not already have an interconnection agreement to determine whether the staging of the Energy Gateway West project would affect the cost or timing of projects whose previous interconnection studies depended on Gateway West in its entirety. Affected projects located in the constrained area of PacifiCorp's transmission system in eastern Wyoming were restudied through the point in the interconnection queue where additional segments of the Energy Gateway project beyond just the Aeolus-to-Bridger/Anticline D.2 segment would be required to interconnect. PacifiCorp transmission posted the restudied system-impact studies (SISs) on PacifiCorp's open access same-time information system on January 29, 2018, as well as certain updated restudied SISs on February 9, 2018.

The interconnection-restudy process showed that the Aeolus-to-Bridger/Anticline transmission line will enable interconnection of up to 1,510 MW of new wind capacity within the constrained area of PacifiCorp's transmission system in eastern Wyoming. However, to honor an executed interconnection agreement with a 240 MW qualifying facility (QF) project in the area, PacifiCorp must reserve sufficient interconnection capacity for this QF's interconnection, which results in an incremental capacity of 1,270 MW. This is up from the 1,030 MW assumed in previous studies. The interconnection-restudy process confirms that all bids selected to the 2017R final shortlist can secure interconnection service either because they hold an interconnection-queue position that does not require Energy Gateway South (Ekola Flats, TB Flats I and II, and Cedar Springs) or because the project is not located in the constrained area of the company's eastern Wyoming transmission system (Uinta).

New Wind and Transmission Results

As a component of the 2017R RFP, PacifiCorp produced updated portfolio-development studies using the SO model to create a bid portfolio containing the least-cost combination of viable bids. In choosing the least-cost combination of bids, the SO model was configured to select from all viable bid alternatives. Consistent with the increased interconnection capability identified during the interconnection-restudy process, the SO model was also configured to select up to 1,270 MW of bids located in this area of PacifiCorp's transmission system.

Table 7.8 summarizes the updated PVRR(d) results for each price-policy scenario. The PVRR(d) between cases with and without the Combined Projects, reflecting the final shortlist from the 2017R RFP, are shown for the SO model and for PaR, which was used to calculate both the stochastic-mean PVRR(d) and the risk-adjusted PVRR(d).

Table 7.8 - SO Model and PaR PVRR(d) (Benefit)/Cost of the Combined Projects ($ million)

Price-Policy Scenario	SO Model PVRR(d)	PaR Stochastic-Mean PVRR(d)	PaR Risk-Adjusted PVRR(d)
Low Gas, Zero CO_2	(185)	(150)	(156)
Low Gas, Medium CO_2	(208)	(179)	(188)
Low Gas, High CO_2	(370)	(337)	(355)
Medium Gas, Zero CO_2	(377)	(319)	(334)
Medium Gas, Medium CO_2	(405)	(357)	(386)
Medium Gas, High CO_2	(489)	(448)	(469)
High Gas, Zero CO_2	(699)	(568)	(596)
High Gas, Medium CO_2	(716)	(603)	(633)
High Gas, High CO_2	(781)	(694)	(728)

Over a 20-year period, the Combined Projects reduce customer costs in all nine price-policy scenarios. This outcome is consistent in both the SO model and PaR results. Under the central price-policy scenario, when applying medium natural gas, medium CO_2 price-policy assumptions, the PVRR(d) net benefits range between $357 million, when derived from PaR stochastic-mean results, and $405 million, when derived from SO model results.

The Combined Projects create these benefits by:

- Reducing customer costs by generating significant PTC benefits;
- Contributing to meeting system capacity needs, thereby reducing reliance on uncommitted front office transactions (market purchases) in the near term and deferring the need for higher cost resource alternatives over the long term;
- Reducing system fuel costs;
- Increasing transmission capability in a constrained area, enabling better use of resources;
- Avoiding emissions costs in the medium and high CO_2 price scenarios;

Table 7.9 summarizes the updated PVRR(d) results for each price-policy scenario calculated off of the change in annual nominal revenue requirement through 2050.

Table 7.9 - Nominal Revenue Requirement PVRR(d) (Benefit)/Cost of the Combined Projects ($ million)

Price-Policy Scenario	Annual Revenue Requirement PVRR(d)
Low Gas, Zero CO_2	184
Low Gas, Medium CO_2	127
Low Gas, High CO_2	(147)
Medium Gas, Zero CO_2	(92)
Medium Gas, Medium CO_2	(167)
Medium Gas, High CO_2	(304)
High Gas, Zero CO_2	(448)
High Gas, Medium CO_2	(499)
High Gas, High CO_2	(635)

When system costs and benefits from the Combined Projects are extended out through 2050, covering the full depreciable life of the owned-wind projects included in the updated 2017R RFP final shortlist, the Combined Projects reduce customer costs in seven out of nine price-policy scenarios.

In those price-policy scenarios showing net benefits, customer net benefits range from $92 million in the medium natural gas, zero CO_2 price-policy scenario to $635 million in the high natural gas, high CO_2 price-policy scenario. Under the central price-policy scenario, when applying medium natural gas, medium CO_2 price-policy assumptions, the PVRR(d) benefits of the Combined Projects are $167 million. The Combined Projects provide significant customer benefits in all price-policy scenarios, and the net benefits are unfavorable only when low natural-gas prices are paired with zero or medium CO_2 prices. These results continue to show that upside benefits far outweigh downside risks.

Potential Wind Projects Upside

The PVRR(d) results presented in Table 7.8 andTable 7.9 do not reflect the potential value of RECs generated by the incremental energy output from the Wind Projects. Accounting for the performance estimates from these wind facilities, customer benefits for all price-policy scenarios would improve by approximately $34 million for every dollar assigned to the incremental RECs that will be generated from the winning bids through 2036. When calculated from expected wind generation through 2050, customer benefits would increase by approximately $43 million in all price-policy scenarios. Quantifying the potential upside associated with incremental REC revenues is simply intended to communicate that the net benefits from the winning bids could improve if the incremental RECs can be monetized in the market.

Also, projects with large wind turbines are expected to require less O&M costs because there are fewer turbines on a given site. The default O&M assumptions applied to BTA and benchmark-EPC bids in the updated economic analysis are based on the company’s experience in operating and maintaining the existing fleet of owned-wind facilities, and do not reflect expected cost savings associated with operating and maintaining wind facilities proposing to use larger wind turbines. Three of the winning bids--Invenergy Wind Development's Uinta project, the company’s TB Flats I & II project, and the company’s Ekola Flats project--will use larger equipment for a portion of the wind turbines at each facility. If the O&M cost elements applicable to the larger-turbine equipment are reduced by 42 percent, which is equivalent to an approximately 18-percent reduction in total O&M costs, beyond the proposed O&M agreement period, customer benefits calculated through 2036 for all price-policy scenarios would improve by approximately $19 million.

Finally, the updated economic analysis assumes the incremental transfer capability associated with the Aeolus-to-Bridger/Anticline transmission line is 750 MW. Subsequent transmission studies have confirmed the transfer capability is 950 MW. Consequently, the economic analysis presented in this chapter is conservative.

Conclusion

PacifiCorp continues to pursue regulatory approvals for the Energy Vision 2020 projects, consistent with the timing of the associated action plan items further described in Chapter 10.

The updated economic analysis of the wind repowering project supports repowering just over 999 MW of existing wind resource capacity located in Wyoming, Oregon, and Washington. The updated economic analysis shows significant net customer benefits in all of the scenarios analyzed. The wind repowering project will replace equipment at existing wind facilities with modern technology to improve efficiency, increase energy production, extend the operational life, reduce run-rate operating costs, reduce net power costs, and deliver substantial federal PTC benefits that will be passed on to customers.

The results of the 2017R RFP confirm that the Combined Projects are the least-cost, least-risk resources available to serve PacifiCorp's customers. The substantial volume of bids that were submitted into the 2017R RFP produced competitive project costs, allowing PacifiCorp to obtain greater wind generating capacity at lower overall capital costs, with increased net benefits for customers. The Combined Projects show net customer benefits under all price-policy scenarios through 2036 and in seven of nine scenarios through 2050.

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CHAPTER 8 – PORTFOLIO DEVELOPMENT

Introduction

PacifiCorp used the System Optimizer (SO) model to develop an updated preferred portfolio based on inputs and assumptions updated since the 2017 Integrated Resource Plan (IRP) was filed April 4, 2017. This updated resource portfolio is consistent with PacifiCorp's most recent load-and-resource balance as described in Chapter 4. This chapter presents the 2017 IRP Update preferred portfolio and a comparison of changes relative to the 2017 IRP preferred portfolio. This chapter also includes a sensitivity comparing the 2017 IRP Update preferred portfolio to the fall 2017 business plan.

2017 IRP Update Preferred Portfolio

The 2017 IRP Update focuses on changes that occurred after PacifiCorp filed its 2017 IRP. These include updates to load forecasts, changes in existing resources, any additions to PacifiCorp's contracts with other entities, and changes to Energy Vision 2020 resources.

Table 8.1 summarizes the annual capacity in the 2017 IRP Update relative to the 2017 IRP preferred portfolio for the 10-year period 2018 through 2027. Consistent with the change in PacifiCorp's load-and-resource balance, the reduction in peak loads decreases the need to add new resources relative the 2017 IRP. The reduction in load reduces front-office transaction (FOT) and demand-side management (DSM) resources. An additional 211 MW of new wind is added as part of Energy Vision 2020 new wind resources described in Chapter 7. The level of summer FOTs in 2027 is 493 MW, which is lower than in the 2017 IRP and below the assumed 1,575-MW FOT limit. PacifiCorp has not updated its FOT limits for the 2017 IRP Update but will review its FOT limits during the 2019 IRP public process. The updated portfolio does not include any natural gas resources through the 20-year planning horizon. Table 8.2 (summer) and Table 8.3 (winter) summarizes the 2017 IRP Update load and resource balance, inclusive of incremental resources, for 2018-2036, and Table 8.4 presents the 2017 IRP Update preferred portfolio through 2036.

Class 2 DSM selections in the 2017 IRP Update were updated to reflect more current information on actual and projected acquisitions in the near-term (2018-2020) and the value of Class 2 DSM resources to the system. For 2018-2020, Oregon and Washington projections were modified to reflect current Energy Trust of Oregon projections and the approved "Demand Side Management 2018-2019 Business Plan" filed with the Washington Utilities and Transportation Commission (WUTC).[1] For Utah, 2018-2020 projections match the 2017 IRP preferred portfolio selections. 2018-2020 projections for California align with forecasted achievements in 2018 and the 2017 IRP preferred portfolio selections for 2019 and 2020. For 2018-2020 Wyoming Class 2 DSM was updated to reflect proposed targets currently under review by the Wyoming Public Service Commission. From 2021 on, the SO model optimized Class 2 DSM selections to reflect the updated load-and-resource balance, and the associated value of Class 2 DSM in relation to other resource alternatives over the medium and long term.

[1] Washington Utilities and Transportation Commission, Docket UE-171092, Order 01, January 12, 2018.

Table 8.1 – Comparison of 2017 IRP Update with 2017 IRP Preferred Portfolio (Megawatts)

2017 IRP Update

	Capacity (MW)																				10- year Total
Resource	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**	**2036**	**2017-2036**
Expansion Options																					
Gas - CCCT	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Gas- Peaking	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
DSM - Energy Efficiency	150	119	126	122	105	99	96	95	100	96	90	90	84	88	87	75	70	63	61	61	**1,877**
DSM - Load Control	-	-	-	-	-	-	-	-	-	-	-	-	68	-	-	-	50	48	90	12	**268**
Renewable - Wind	-	-	-	911	400	-	-	-	-	-	-	-	-	121	-	-	800	-	333	149	**2,713**
Renewable - Geothermal	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Renewable - Utility Solar	-	-	-	-	-	-	-	-	-	-	-	-	-	651	95	132	976	-	6	-	**1,860**
Renewable - Biomass	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Storage - Pumped Hydro	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Storage - CAES	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Storage - Other	-	-	1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	**1**
Front Office Transactions - Summer *	402	319	624	463	395	445	419	428	538	499	500	1,247	1,575	1,575	1,575	1,575	1,575	1,564	1,575	1,544	**942**
Front Office Transactions - Winter *	253	308	303	296	303	305	310	304	317	330	343	357	758	794	809	776	868	924	1,031	1,486	**559**
Nuclear	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
IGCC with CCS	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Existing Unit Changes																					
Coal Early Retirement/Conversions	-	-	(280)	-	(387)	-	-	-	-	(82)	-	-	(354)	-	-	-	(359)	-	-	-	**(1,463)**
Thermal Plant End-of-life Retirements	-	-	-	-	-	-	-	-	-	-	-	(762)	-	(357)	(77)	-	(358)	-	(82)	-	**(1,635)**
Coal Plant Gas Conversion Additions	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Turbine Upgrades	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Total	**805**	**746**	**774**	**1,792**	**815**	**848**	**825**	**827**	**954**	**843**	**934**	**933**	**2,132**	**2,871**	**2,489**	**2,559**	**3,623**	**2,599**	**3,014**	**3,252**	

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

2017 IRP Preferred Portfolio

	Capacity (MW)																				Total
Resource	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**	**2036**	**2017-2036**
Expansion Options																					
Gas - CCCT	-	-	-	-	-	-	-	-	-	-	-	-	-	436	-	-	477	-	-	-	**913**
Gas- Peaking	-	-	-	-	-	-	-	-	-	-	-	-	200	-	-	-	200	-	-	-	**400**
DSM - Energy Efficiency	154	128	131	122	123	114	118	118	112	111	109	102	96	95	96	83	75	65	63	63	**1,923**
DSM - Load Control	-	-	-	-	-	-	-	-	-	-	-	193	140	5	3	3	3	4	3	12	**365**
Renewable - Wind	-	-	-	-	1,100	-	-	-	-	-	-	-	-	-	85	-	-	-	-	774	**1,959**
Renewable - Geothermal	-	-	-	-	-	-	-	-	-	-	-	-	30	-	-	-	-	-	-	-	**30**
Renewable - Utility Solar	-	-	-	-	-	-	-	-	-	-	-	11	97	-	118	237	226	48	291	13	**1,040**
Renewable - Biomass	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Storage - Pumped Hydro	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Storage - CAES	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Storage - Other	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Front Office Transactions - Summer *	500	521	878	807	799	916	844	885	1,042	978	1,040	1,575	1,575	1,566	1,575	1,575	1,575	1,575	1,575	1,539	**1,167**
Front Office Transactions - Winter *	281	332	273	307	319	308	306	287	348	351	297	412	551	516	490	451	437	477	479	766	**399**
Nuclear	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
IGCC with CCS	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Existing Unit Changes																					
Coal Early Retirement/Conversions	-	-	(280)	-	(387)	-	-	-	-	(82)	-	-	(354)	-	-	-	(359)	-	-	-	**(1,463)**
Thermal Plant End-of-life Retirements	-	-	-	-	-	-	-	-	-	-	-	(762)	-	(357)	(78)	-	(358)	-	(82)	-	**(1,636)**
Coal Plant Gas Conversion Additions	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Turbine Upgrades	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Total	**935**	**981**	**1,002**	**1,236**	**1,954**	**1,337**	**1,268**	**1,289**	**1,501**	**1,358**	**1,445**	**1,531**	**2,334**	**2,261**	**2,290**	**2,349**	**2,275**	**2,169**	**2,329**	**3,166**	

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

2017 IRP Update less 2017 IRP Preferred Portfolio

	Capacity (MW)																				10- year Total
Resource	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**	**2036**	**2017-2036**
Expansion Options																					
Gas - CCCT	-	-	-	-	-	-	-	-	-	-	-	-	-	(436)	-	-	(477)	-	-	-	**(913)**
Gas- Peaking	-	-	-	-	-	-	-	-	-	-	-	-	(200)	-	-	-	(200)	-	-	-	**(400)**
DSM - Energy Efficiency	(4)	(9)	(5)	0	(18)	(15)	(22)	(23)	(12)	(15)	(19)	(11)	(12)	(7)	(10)	(8)	(4)	(3)	(2)	(2)	**(200)**
DSM - Load Control	-	-	-	-	-	-	-	-	-	-	-	(193)	(71)	(5)	(3)	(3)	47	44	87	-	**(98)**
Renewable - Wind	-	-	-	911	(701)	-	-	-	-	-	-	-	-	121	(85)	-	800	-	333	(625)	**754**
Renewable - Geothermal	-	-	-	-	-	-	-	-	-	-	-	-	(30)	-	-	-	-	-	-	-	**(30)**
Renewable - Utility Solar	-	-	-	-	-	-	-	-	-	-	-	(11)	(97)	651	(23)	(104)	751	(48)	(285)	(13)	**820**
Renewable - Biomass	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Storage - Pumped Hydro	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Storage - CAES	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Storage - Other	-	-	1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	**1**
Front Office Transactions - Summer *	(98)	(202)	(254)	(345)	(404)	(471)	(425)	(457)	(504)	(479)	(540)	(328)	-	9	-	-	-	(11)	-	6	**(225)**
Front Office Transactions - Winter *	(28)	(24)	30	(11)	(16)	(3)	4	17	(31)	(21)	47	(55)	207	278	319	326	431	447	552	720	**159**
Nuclear	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
IGCC with CCS	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Existing Unit Changes																					
Coal Early Retirement/Conversions	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Thermal Plant End-of-life Retirements	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0	-	-	-	-	-	0
Coal Plant Gas Conversion Additions	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Turbine Upgrades	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Total	**(130)**	**(235)**	**(228)**	**556**	**(1,139)**	**(489)**	**(443)**	**(462)**	**(547)**	**(515)**	**(512)**	**(599)**	**(203)**	**610**	**199**	**210**	**1,348**	**430**	**684**	**86**	

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

Table 8.2 – 2017 IRP Update Summer Capacity Load and Resource Balance (Megawatts)

Calendar Year	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
East										
Thermal	6,403	6,123	6,123	5,736	5,736	5,736	5,736	5,736	5,654	5,654
Hydroelectric	107	114	114	114	114	114	93	93	93	93
Renewable	196	194	199	197	190	190	190	190	180	180
Purchases	249	249	249	221	221	221	221	121	121	121
Qualifying Facilities	648	691	743	735	738	734	679	674	670	666
Class 1 DSM	323	323	323	323	323	323	323	323	323	323
Sales	(655)	(655)	(655)	(175)	(175)	(175)	(148)	(148)	(66)	(66)
Non-Owned Reserves	(35)	(35)	(35)	(35)	(35)	(35)	(35)	(35)	(35)	(35)
Transfers	62	231	142	(90)	(77)	(71)	(1)	108	56	38
East Existing Resources	**7,298**	**7,235**	**7,203**	**7,028**	**7,035**	**7,037**	**7,060**	**7,063**	**6,997**	**6,975**
Front Office Transactions	0	0	0	0	0	0	0	0	0	0
Gas	0	0	0	0	0	0	0	0	0	0
Wind	0	0	0	207	207	207	207	207	207	207
Solar	0	0	0	0	0	0	0	0	0	0
Class 1 DSM	0	0	0	0	0	0	0	0	0	0
Other	0	1	1	1	1	1	1	1	1	1
East Planned Resources	**0**	**1**	**1**	**208**	**208**	**208**	**208**	**208**	**208**	**208**
East Total Resources	**7,298**	**7,236**	**7,204**	**7,236**	**7,243**	**7,245**	**7,268**	**7,271**	**7,205**	**7,183**
Load	6,853	6,911	6,972	7,030	7,104	7,172	7,248	7,309	7,310	7,354
Private Generation	(108)	(166)	(202)	(213)	(220)	(226)	(234)	(242)	(252)	(269)
Existing Resources:	0	0	0	0	0	0	0	0	0	0
Interruptible	(195)	(195)	(195)	(195)	(195)	(195)	(195)	(195)	(195)	(195)
Class 2 DSM	0	0	0	0	0	0	0	0	0	0
New Resources:	0	0	0	0	0	0	0	0	0	0
Class 2 DSM	(118)	(172)	(226)	(273)	(319)	(365)	(410)	(460)	(509)	(555)
East obligation	**6,432**	**6,378**	**6,349**	**6,348**	**6,370**	**6,386**	**6,409**	**6,412**	**6,354**	**6,334**
Planning Reserves (13%)	862	855	851	851	853	856	859	859	851	849
East Reserves	**862**	**855**	**851**	**851**	**853**	**856**	**859**	**859**	**851**	**849**
East Obligation + Reserves	**7,294**	**7,233**	**7,200**	**7,199**	**7,223**	**7,241**	**7,268**	**7,271**	**7,205**	**7,183**
East Position	**4**	**4**	**3**	**36**	**20**	**4**	**(0)**	**(0)**	**(0)**	**(0)**
East Reserve Margin	13%	13%	13%	14%	14%	13%	13%	13%	13%	13%
West										
Thermal	2,254	2,254	2,254	2,254	2,254	2,254	2,254	2,254	2,254	2,254
Hydroelectric	861	747	790	643	587	624	655	655	645	658
Renewable	90	88	95	95	65	65	60	60	59	58
Purchases	18	1	1	1	1	1	1	1	1	1
Qualifying Facilities	235	220	227	203	194	187	185	184	182	150
Class 1 DSM	3	3	3	0	0	0	0	0	0	0
Sales	(165)	(165)	(165)	(161)	(110)	(110)	(80)	(80)	(80)	(80)
Non-Owned Reserves	(3)	(3)	(3)	(3)	(3)	(3)	(3)	(3)	(3)	(3)
Transfers	(63)	(232)	(143)	88	76	70	(0)	(109)	(57)	(40)
West Existing Resources	**3,231**	**2,913**	**3,060**	**3,122**	**3,064**	**3,088**	**3,072**	**2,963**	**3,001**	**2,999**
Front Office Transactions	338	661	490	419	471	444	454	570	529	530
Gas	0	0	0	0	0	0	0	0	0	0
Wind	0	0	0	0	0	0	0	0	0	0
Solar	0	0	0	0	0	0	0	0	0	0
Class 1 DSM	0	0	0	0	0	0	0	0	0	0
Other	0	0	0	0	0	0	0	0	0	0
West Planned Resources	**338**	**661**	**490**	**419**	**471**	**444**	**454**	**570**	**529**	**530**
West Total Resources	**3,569**	**3,574**	**3,551**	**3,541**	**3,535**	**3,532**	**3,526**	**3,533**	**3,530**	**3,529**
Load	3,238	3,279	3,293	3,312	3,331	3,351	3,366	3,395	3,415	3,436
Private Generation	(13)	(19)	(25)	(31)	(37)	(42)	(48)	(55)	(63)	(71)
Existing Resources:	0	0	0	0	0	0	0	0	0	0
Interruptible	0	0	0	0	0	0	0	0	0	0
Class 2 DSM	0	0	0	0	0	0	0	0	0	0
New Resources:	0	0	0	0	0	0	0	0	0	0
Class 2 DSM	(64)	(94)	(122)	(144)	(163)	(181)	(198)	(214)	(228)	(242)
West obligation	**3,161**	**3,166**	**3,146**	**3,137**	**3,132**	**3,129**	**3,120**	**3,126**	**3,124**	**3,123**
Planning Reserves (13%)	411	412	409	408	407	407	406	406	406	406
West Reserves	**411**	**412**	**409**	**408**	**407**	**407**	**406**	**406**	**406**	**406**
West Obligation + Reserves	**3,572**	**3,578**	**3,554**	**3,545**	**3,539**	**3,535**	**3,526**	**3,533**	**3,530**	**3,529**
West Position	**(4)**	**(4)**	**(4)**	**(3)**	**(4)**	**(4)**	**0**	**(0)**	**(0)**	**0**
West Reserve Margin	13%	13%	13%	13%	13%	13%	13%	13%	13%	13%
System										
Total Resources	10,867	10,811	10,755	10,777	10,779	10,777	10,794	10,804	10,735	10,712
Obligation	9,594	9,544	9,495	9,485	9,502	9,515	9,529	9,539	9,478	9,457
Reserves	1,273	1,266	1,260	1,258	1,261	1,262	1,264	1,265	1,257	1,255
Obligation + Reserves	10,867	10,811	10,755	10,744	10,762	10,777	10,793	10,804	10,735	10,712
System Position	0	0	(0)	33	17	(0)	0	(0)	(0)	(0)
Reserve Margin	13%	13%	13%	14%	13%	13%	13%	13%	13%	13%

Table 8.2 (Cont.) – 2017 IRP Update Summer Capacity Load and Resource Balance (Megawatts)

Calendar Year	2028	2029	2030	2031	2032	2033	2034	2035	2036
East									
Thermal	4,892	4,892	4,535	4,459	4,459	4,102	4,102	4,021	4,021
Hydroelectric	93	93	93	93	93	93	93	93	93
Renewable	180	180	158	126	126	126	126	126	126
Purchases	121	121	121	121	121	121	121	121	121
Qualifying Facilities	662	655	652	648	637	605	589	584	532
Class 1 DSM	323	323	323	323	323	323	323	323	323
Sales	(66)	(66)	(66)	0	0	0	0	0	0
Non-Owned Reserves	(35)	(35)	(35)	(35)	(35)	(35)	(35)	(35)	(35)
Transfers	670	457	837	866	917	692	691	703	753
East Existing Resources	**6,841**	**6,621**	**6,618**	**6,602**	**6,642**	**6,029**	**6,012**	**5,937**	**5,935**
Front Office Transactions	151	318	318	318	318	318	307	318	318
Gas	0	0	0	0	0	0	0	0	0
Wind	207	207	226	226	226	353	353	353	376
Solar	0	0	0	0	0	477	477	480	480
Class 1 DSM	0	72	72	72	72	100	151	246	258
Other	1	1	1	1	1	1	0	0	0
East Planned Resources	**359**	**599**	**618**	**618**	**618**	**1,249**	**1,288**	**1,396**	**1,432**
East Total Resources	**7,200**	**7,219**	**7,236**	**7,219**	**7,259**	**7,278**	**7,299**	**7,333**	**7,367**
Load	7,433	7,510	7,590	7,531	7,628	7,705	7,778	7,861	7,941
Private Generation	(288)	(303)	(324)	(236)	(261)	(284)	(308)	(333)	(354)
Existing Resources:	0	0	0	0	0	0	0	0	0
Interruptible	(195)	(195)	(195)	(195)	(195)	(195)	(195)	(195)	(195)
Class 2 DSM	0	0	0	0	0	0	0	0	0
New Resources:	0	0	0	0	0	0	0	0	0
Class 2 DSM	(602)	(645)	(690)	(734)	(771)	(805)	(835)	(863)	(892)
East obligation	**6,349**	**6,367**	**6,381**	**6,366**	**6,402**	**6,421**	**6,440**	**6,470**	**6,501**
Planning Reserves (13%)	851	853	855	853	858	860	862	866	870
East Reserves	**851**	**853**	**855**	**853**	**858**	**860**	**862**	**866**	**870**
East Obligation + Reserves	**7,199**	**7,220**	**7,236**	**7,219**	**7,259**	**7,281**	**7,302**	**7,336**	**7,371**
East Position	**0**	**(0)**	**(0)**	**0**	**(0)**	**(3)**	**(3)**	**(3)**	**(4)**
East Reserve Margin	13%	13%	13%	13%	13%	13%	13%	13%	13%
West									
Thermal	2,254	1,900	1,900	1,900	1,900	1,541	1,541	1,541	1,541
Hydroelectric	653	653	653	653	653	653	653	653	653
Renewable	55	54	54	53	53	53	53	53	53
Purchases	1	1	1	1	1	1	1	1	1
Qualifying Facilities	149	138	133	132	99	97	97	96	94
Class 1 DSM	0	0	0	0	0	0	0	0	0
Sales	(80)	(78)	(78)	(78)	(78)	(78)	(78)	(78)	(24)
Non-Owned Reserves	(3)	(3)	(3)	(3)	(3)	(3)	(3)	(3)	(3)
Transfers	(671)	(458)	(837)	(866)	(917)	(693)	(692)	(704)	(754)
West Existing Resources	**2,359**	**2,208**	**1,823**	**1,793**	**1,708**	**1,572**	**1,572**	**1,560**	**1,561**
Front Office Transactions	1,171	1,352	1,352	1,352	1,352	1,352	1,352	1,352	1,319
Gas	0	0	0	0	0	0	0	0	0
Wind	0	0	0	0	0	0	0	39	39
Solar	0	0	353	414	499	613	613	613	613
Class 1 DSM	0	0	0	0	0	25	25	25	25
Other	0	0	0	0	0	0	0	0	0
West Planned Resources	**1,171**	**1,352**	**1,705**	**1,766**	**1,850**	**1,989**	**1,989**	**2,029**	**1,996**
West Total Resources	**3,530**	**3,560**	**3,528**	**3,559**	**3,559**	**3,562**	**3,562**	**3,589**	**3,558**
Load	3,457	3,503	3,495	3,513	3,532	3,554	3,575	3,620	3,612
Private Generation	(78)	(86)	(93)	(72)	(80)	(89)	(100)	(111)	(122)
Existing Resources:	0	0	0	0	0	0	0	0	0
Interruptible	0	0	0	0	0	0	0	0	0
Class 2 DSM	0	0	0	0	0	0	0	0	0
New Resources:	0	0	0	0	0	0	0	0	0
Class 2 DSM	(255)	(268)	(280)	(291)	(303)	(313)	(322)	(332)	(342)
West obligation	**3,124**	**3,150**	**3,122**	**3,150**	**3,149**	**3,152**	**3,152**	**3,176**	**3,149**
Planning Reserves (13%)	406	410	406	409	409	410	410	413	409
West Reserves	**406**	**410**	**406**	**409**	**409**	**410**	**410**	**413**	**409**
West Obligation + Reserves	**3,530**	**3,560**	**3,528**	**3,559**	**3,559**	**3,562**	**3,562**	**3,589**	**3,558**
West Position	**0**	**0**	**0**	**0**	**0**	**(1)**	**(0)**	**(0)**	**(1)**
West Reserve Margin	13%	13%	13%	13%	13%	13%	13%	13%	13%
System									
Total Resources	10,730	10,779	10,763	10,778	10,818	10,839	10,861	10,922	10,925
Obligation	9,473	9,517	9,503	9,516	9,551	9,573	9,592	9,646	9,650
Reserves	1,257	1,263	1,261	1,262	1,267	1,270	1,272	1,279	1,280
Obligation + Reserves	10,729	10,779	10,763	10,778	10,818	10,843	10,864	10,925	10,929
System Position	0	(0)	0	0	0	(3)	(3)	(4)	(5)
Reserve Margin	13%	13%	13%	13%	13%	13%	13%	13%	13%

Table 8.3 – 2017 IRP Update Winter Capacity Load and Resource Balance (Megawatts)

Calendar Year	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
East										
Thermal	6,513	6,233	6,233	5,846	5,846	5,846	5,846	5,846	5,763	5,763
Hydroelectric	72	72	72	72	72	72	72	72	72	72
Renewable	196	199	197	190	190	190	190	190	180	180
Purchases	734	734	734	235	235	235	121	121	121	121
Qualifying Facilities	691	742	740	745	736	682	678	673	668	664
Class 1 DSM	0	0	0	0	0	0	0	0	0	0
Sales	(173)	(173)	(173)	(173)	(173)	(173)	(148)	(148)	(66)	(66)
Non-Owned Reserves	(35)	(35)	(35)	(35)	(35)	(35)	(35)	(35)	(35)	(35)
Transfers	3	7	31	(141)	(144)	(146)	(135)	(126)	(126)	(143)
East Existing Resources	**8,001**	**7,779**	**7,799**	**6,738**	**6,727**	**6,670**	**6,589**	**6,592**	**6,577**	**6,557**
Front Office Transactions	0	0	0	0	0	0	0	0	0	0
Gas	0	0	0	0	0	0	0	0	0	0
Wind	0	0	144	207	207	207	207	207	207	207
Solar	0	0	0	0	0	0	0	0	0	0
Class 1 DSM	0	0	0	0	0	0	0	0	0	0
Other	0	1	1	1	1	1	1	1	1	1
East Planned Resources	**0**	**1**	**145**	**208**	**208**	**208**	**208**	**208**	**208**	**208**
East Total Resources	**8,001**	**7,780**	**7,944**	**6,946**	**6,935**	**6,878**	**6,797**	**6,800**	**6,785**	**6,765**
Load	5,560	5,590	5,617	5,658	5,718	5,774	5,811	5,866	5,792	5,814
Private Generation	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)
Existing Resources:	0	0	0	0	0	0	0	0	0	0
Interruptible	(195)	(195)	(195)	(195)	(195)	(195)	(195)	(195)	(195)	(195)
Class 2 DSM	0	0	0	0	0	0	0	0	0	0
New Resources:	0	0	0	0	0	0	0	0	0	0
Class 2 DSM	(56)	(84)	(111)	(147)	(183)	(218)	(253)	(291)	(328)	(363)
East obligation	**5,310**	**5,311**	**5,312**	**5,316**	**5,341**	**5,361**	**5,363**	**5,380**	**5,269**	**5,255**
Planning Reserves (13%)	716	716	716	716	720	722	723	725	710	709
East Reserves	**716**	**716**	**716**	**716**	**720**	**722**	**723**	**725**	**710**	**709**
East Obligation + Reserves	**6,025**	**6,026**	**6,028**	**6,032**	**6,060**	**6,083**	**6,085**	**6,105**	**5,979**	**5,964**
East Position	**1,976**	**1,753**	**1,916**	**914**	**875**	**795**	**711**	**695**	**806**	**801**
East Reserve Margin	51%	46%	50%	31%	30%	28%	27%	26%	29%	29%
West										
Thermal	2,316	2,316	2,316	2,316	2,316	2,316	2,316	2,316	2,316	2,316
Hydroelectric	917	943	940	785	784	786	783	787	784	794
Renewable	90	95	95	95	65	65	60	59	58	56
Purchases	1	1	1	1	1	1	1	1	1	1
Qualifying Facilities	224	211	220	195	183	177	176	175	171	144
Class 1 DSM	0	0	0	0	0	0	0	0	0	0
Sales	(162)	(162)	(154)	(154)	(113)	(113)	(81)	(81)	(81)	(81)
Non-Owned Reserves	(3)	(3)	(3)	(3)	(3)	(3)	(3)	(3)	(3)	(3)
Transfers	(4)	(8)	(32)	140	142	145	133	125	125	142
West Existing Resources	**3,380**	**3,395**	**3,383**	**3,375**	**3,375**	**3,373**	**3,385**	**3,378**	**3,371**	**3,368**
Front Office Transactions	326	321	314	321	323	329	322	336	349	364
Gas	0	0	0	0	0	0	0	0	0	0
Wind	0	0	0	0	0	0	0	0	0	0
Solar	0	0	0	0	0	0	0	0	0	0
Class 1 DSM	0	0	0	0	0	0	0	0	0	0
Other	0	0	0	0	0	0	0	0	0	0
West Planned Resources	**326**	**321**	**314**	**321**	**323**	**329**	**322**	**336**	**349**	**364**
West Total Resources	**3,706**	**3,716**	**3,697**	**3,696**	**3,698**	**3,702**	**3,707**	**3,714**	**3,721**	**3,732**
Load	3,342	3,376	3,384	3,408	3,431	3,455	3,473	3,498	3,521	3,547
Private Generation	0	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)
Existing Resources:	0	0	0	0	0	0	0	0	0	0
Interruptible	0	0	0	0	0	0	0	0	0	0
Class 2 DSM	0	0	0	0	0	0	0	0	0	0
New Resources:	0	0	0	0	0	0	0	0	0	0
Class 2 DSM	(55)	(80)	(105)	(130)	(152)	(173)	(193)	(211)	(228)	(244)
West obligation	**3,286**	**3,295**	**3,278**	**3,278**	**3,279**	**3,282**	**3,280**	**3,287**	**3,293**	**3,303**
Planning Reserves (13%)	427	428	426	426	426	427	426	427	428	429
West Reserves	**427**	**428**	**426**	**426**	**426**	**427**	**426**	**427**	**428**	**429**
West Obligation + Reserves	**3,713**	**3,723**	**3,705**	**3,704**	**3,705**	**3,709**	**3,707**	**3,714**	**3,721**	**3,732**
West Position	**(7)**	**(7)**	**(7)**	**(8)**	**(7)**	**(8)**	**0**	**0**	**(0)**	**0**
West Reserve Margin	13%	13%	13%	13%	13%	13%	13%	13%	13%	13%
System										
Total Resources	11,707	11,496	11,641	10,642	10,633	10,580	10,504	10,514	10,506	10,497
Obligation	8,596	8,606	8,590	8,594	8,619	8,643	8,643	8,667	8,561	8,558
Reserves	1,143	1,144	1,142	1,143	1,146	1,149	1,149	1,152	1,138	1,138
Obligation + Reserves	9,739	9,750	9,732	9,736	9,765	9,792	9,792	9,819	9,700	9,696
System Position	1,968	1,746	1,909	906	867	788	711	695	806	801
Reserve Margin	36%	34%	36%	24%	23%	22%	22%	21%	23%	23%

Table 8.3 (Cont.) - 2017 IRP Update Winter Capacity Load and Resource Balance (Megawatts)

Calendar Year	2028	2029	2030	2031	2032	2033	2034	2035	2036
East									
Thermal	5,001	5,001	4,644	4,568	4,568	4,212	4,212	4,130	4,130
Hydroelectric	72	72	72	72	72	72	72	72	72
Renewable	180	164	126	126	126	126	126	126	126
Purchases	121	121	121	121	121	121	121	121	121
Qualifying Facilities	657	653	650	646	635	590	587	570	175
Class 1 DSM	0	0	0	0	0	0	0	0	0
Sales	(66)	(66)	(66)	0	0	0	0	0	0
Non-Owned Reserves	(35)	(35)	(35)	(35)	(35)	(35)	(35)	(35)	(35)
Transfers	(146)	(97)	291	331	367	202	247	70	464
East Existing Resources	**5,784**	**5,814**	**5,803**	**5,829**	**5,854**	**5,288**	**5,330**	**5,054**	**5,054**
Front Office Transactions	0	0	0	0	0	0	0	318	318
Gas	0	0	0	0	0	0	0	0	0
Wind	207	207	226	226	226	353	353	353	376
Solar	0	0	0	0	0	477	477	480	480
Class 1 DSM	0	0	0	0	0	0	0	0	0
Other	1	1	1	1	1	1	0	0	0
East Planned Resources	**208**	**208**	**227**	**227**	**227**	**831**	**830**	**1,150**	**1,174**
East Total Resources	**5,992**	**6,022**	**6,030**	**6,057**	**6,081**	**6,119**	**6,160**	**6,204**	**6,227**
Load	5,872	5,931	5,972	6,029	6,079	6,138	6,197	6,257	6,299
Private Generation	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)
Existing Resources:	0	0	0	0	0	0	0	0	0
Interruptible	(195)	(195)	(195)	(195)	(195)	(195)	(195)	(195)	(195)
Class 2 DSM	0	0	0	0	0	0	0	0	0
New Resources:	0	0	0	0	0	0	0	0	0
Class 2 DSM	(397)	(429)	(463)	(497)	(525)	(551)	(573)	(594)	(615)
East obligation	**5,280**	**5,307**	**5,314**	**5,337**	**5,359**	**5,392**	**5,429**	**5,468**	**5,488**
Planning Reserves (13%)	712	715	716	719	722	726	731	736	739
East Reserves	**712**	**715**	**716**	**719**	**722**	**726**	**731**	**736**	**739**
East Obligation + Reserves	**5,992**	**6,023**	**6,030**	**6,056**	**6,081**	**6,118**	**6,160**	**6,204**	**6,227**
East Position	**(0)**	**(0)**	**(0)**	**0**	**0**	**0**	**0**	**(0)**	**0**
East Reserve Margin	13%	13%	13%	13%	13%	13%	13%	13%	13%
West									
Thermal	2,316	1,962	1,962	1,962	1,962	1,602	1,602	1,602	1,602
Hydroelectric	788	788	788	788	788	788	788	788	788
Renewable	55	54	54	53	53	53	53	53	53
Purchases	1	1	1	1	1	1	1	1	1
Qualifying Facilities	143	134	133	102	98	97	96	95	11
Class 1 DSM	0	0	0	0	0	0	0	0	0
Sales	(81)	(78)	(78)	(78)	(78)	(78)	(78)	(78)	(78)
Non-Owned Reserves	(3)	(3)	(3)	(3)	(3)	(3)	(3)	(3)	(3)
Transfers	145	96	(292)	(332)	(367)	(203)	(248)	(70)	(465)
West Existing Resources	**3,364**	**2,953**	**2,565**	**2,494**	**2,454**	**2,259**	**2,212**	**2,389**	**1,910**
Front Office Transactions	379	803	841	858	823	920	980	775	1,257
Gas	0	0	0	0	0	0	0	0	0
Wind	0	0	0	0	0	0	0	39	39
Solar	0	0	353	414	499	613	613	613	613
Class 1 DSM	0	0	0	0	0	0	0	0	0
Other	0	0	0	0	0	0	0	0	0
West Planned Resources	**379**	**803**	**1,194**	**1,272**	**1,322**	**1,533**	**1,592**	**1,427**	**1,909**
West Total Resources	**3,743**	**3,757**	**3,759**	**3,767**	**3,776**	**3,791**	**3,805**	**3,817**	**3,819**
Load	3,572	3,599	3,615	3,636	3,657	3,684	3,708	3,731	3,746
Private Generation	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)
Existing Resources:	0	0	0	0	0	0	0	0	0
Interruptible	0	0	0	0	0	0	0	0	0
Class 2 DSM	0	0	0	0	0	0	0	0	0
New Resources:	0	0	0	0	0	0	0	0	0
Class 2 DSM	(260)	(274)	(288)	(302)	(316)	(329)	(341)	(353)	(365)
West obligation	**3,312**	**3,325**	**3,327**	**3,333**	**3,341**	**3,355**	**3,367**	**3,377**	**3,380**
Planning Reserves (13%)	431	432	432	433	434	436	438	439	439
West Reserves	**431**	**432**	**432**	**433**	**434**	**436**	**438**	**439**	**439**
West Obligation + Reserves	**3,743**	**3,757**	**3,759**	**3,766**	**3,775**	**3,791**	**3,805**	**3,817**	**3,820**
West Position	**(0)**	**(0)**	**0**	**0**	**0**	**(0)**	**(0)**	**0**	**(0)**
West Reserve Margin	13%	13%	13%	13%	13%	13%	13%	13%	13%
System									
Total Resources	9,735	9,779	9,789	9,823	9,857	9,910	9,964	10,021	10,047
Obligation	8,593	8,632	8,641	8,670	8,700	8,747	8,796	8,845	8,869
Reserves	1,142	1,147	1,149	1,152	1,156	1,163	1,169	1,175	1,178
Obligation + Reserves	9,735	9,779	9,789	9,823	9,857	9,910	9,965	10,021	10,047
System Position	(0)	(0)	(0)	0	0	(0)	(0)	0	(0)
Reserve Margin	13%	13%	13%	13%	13%	13%	13%	13%	13%

Table 8.4 – PacifiCorp's 2017 IRP Update, Detailed Preferred Portfolio (Megawatts)*

		Capacity (MW)																				Resource Totals 1/	
	Resource	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	10-year	20-year
East	**Existing Plant Retirements/Conversions**																						
	Craig 1 (Coal Early Retirement/Conversions)	-	-	-	-	-	-	-	-	-	(82)	-	-	-	-	-	-	-	-	-	-	(82)	(82)
	Craig 2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(82)	-	-	(82)
	Hayden 1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(44)	-	-	-	-	-	-	(44)
	Hayden 2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(33)	-	-	-	-	-	-	(33)
	Cholla 4 (Coal Early Retirement/Conversions)	-	-	-	-	(387)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(387)	(387)
	DaveJohnston 1	-	-	-	-	-	-	-	-	-	-	-	(106)	-	-	-	-	-	-	-	-	-	(106)
	DaveJohnston 2	-	-	-	-	-	-	-	-	-	-	-	(106)	-	-	-	-	-	-	-	-	-	(106)
	DaveJohnston 3	-	-	-	-	-	-	-	-	-	-	-	(220)	-	-	-	-	-	-	-	-	-	(220)
	DaveJohnston 4	-	-	-	-	-	-	-	-	-	-	-	(330)	-	-	-	-	-	-	-	-	-	(330)
	Naughton 1	-	-	-	-	-	-	-	-	-	-	-	-	-	(156)	-	-	-	-	-	-	-	(156)
	Naughton 2	-	-	-	-	-	-	-	-	-	-	-	-	-	(201)	-	-	-	-	-	-	-	(201)
	Naughton 3 (Coal Early Retirement/Conversions)	-	-	(280)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(280)	(280)
	Gadsby 1-6	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(358)	-	-	-	-	(358)
	Expansion Resources																						
	Wind, Djohnston	-	-	-	-	-	-	-	-	-	-	-	-	-	121	-	-	-	-	-	-	-	121
	Wind, GO	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	800	-	-	-	-	800
	Wind, UT	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	149	-	149
	251C-Cedar Springs WD - 2	-	-	-	-	400	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	400	400
	100B-Ekola Flats WD - 1 (P)	-	-	-	250	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	250	250
	102B-TB Flats WD - 3 (P)	-	-	-	500	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	500	500
	245B-Uinta WD Energy Center - 2	-	-	-	161	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	161	161
	Total Wind	-	-	-	911	400	-	-	-	-	-	-	-	-	121	-	-	800	-	-	149	1,311	2,380
	Utility Solar - PV - Utah-S	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	799	-	6	-	-	805
	Total Solar	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	799	-	6	-	-	805
	DSM, Class 1, ID-Cool/WH	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	3.4	1.3	-	4.7
	DSM, Class 1, ID-Curtail	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1.9	-	-	1.9
	DSM, Class 1, ID-Irrigate	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	18.2	-	3.1	-	-	21.3
	DSM, Class 1, UT-Cool/WH	-	-	-	-	-	-	-	-	-	-	-	-	68.4	-	-	-	-	-	-	-	-	68.4
	DSM, Class 1, UT-Curtail	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	43.2	40.5	2.2	-	85.9
	DSM, Class 1, UT-Irrigate	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	3.1	-	-	3.3	-	6.3
	DSM, Class 1, WY-Cool/WH	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	4.8	-	2.9	-	7.7
	DSM, Class 1, WY-Curtail	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	3.1	-	40.7	2.0	-	45.8
	DSM, Class 1, WY-Irrigate	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1.9	-	-	-	-	1.9
	DSM, Class 1 Total	-	-	-	-	-	-	-	-	-	-	-	-	68.4	-	-	-	26.3	48.0	89.6	11.6	-	243.8
	DSM, Class 2, ID	3	6	6	5	4	4	5	5	5	5	4	4	4	4	4	4	3	3	2	2	47	83
	DSM, Class 2, UT	78	51	58	56	54	50	48	47	54	52	49	52	48	53	52	43	42	35	33	33	549	989
	DSM, Class 2, WY	7	10	10	10	9	11	12	12	12	13	12	11	10	9	9	7	6	7	7	7	106	189
	DSM, Class 2 Total	88	67	74	71	67	66	65	64	71	70	65	67	62	66	65	54	51	45	42	42	702	1,261
	Battery Storage - East	-	-	1.0	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1	1
	FOT Mona - SMR	-	-	-	-	-	-	-	-	-	-	-	142	300	300	300	300	300	289	300	300	-	127
	FOT Mona - WTR	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	300	300	-	30
West	**Existing Plant Retirements/Conversions**																						
	JimBridger 1 (Coal Early Retirement/Conversions)	-	-	-	-	-	-	-	-	-	-	-	-	(354)	-	-	-	-	-	-	-	-	(354)
	JimBridger 2 (Coal Early Retirement/Conversions)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(359)	-	-	-	-	(359)
	Expansion Resources																						
	Wind, WallaW	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	136	-	-	136
	Wind, YK	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	125	-	-	125
	Wind, SO	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	73	-	-	73
	Total Wind	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	333	-	-	333
	Utility Solar - PV - S-Oregon	-	-	-	-	-	-	-	-	-	-	-	-	-	21	95	120	169	-	-	-	-	405
	Utility Solar - PV - Yakima	-	-	-	-	-	-	-	-	-	-	-	-	-	630	-	12	8	-	-	-	-	650
	Total Solar	-	-	-	-	-	-	-	-	-	-	-	-	-	651	95	132	177	-	-	-	-	1,055
	DSM, Class 1, CA-Cool/WH	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	2.4	-	-	-	-	2.4
	DSM, Class 1, CA-Irrigate	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	3.7	-	-	-	-	3.7
	DSM, Class 1, OR-Irrigate	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	12.8	-	-	-	-	12.8
	DSM, Class 1, WA-Irrigate	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	4.8	-	-	-	-	4.8
	DSM, Class 1 Total	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	23.7	-	-	-	-	23.7
	DSM, Class 2, CA	1	1	1	2	1	1	1	1	1	1	1	1	1	1	1	1	1	0	0	0	11	18
	DSM, Class 2, OR	51	44	40	41	29	24	23	23	20	18	18	17	16	16	16	17	15	15	16	16	313	477
	DSM, Class 2, WA	10	7	11	8	8	8	7	7	8	7	6	6	5	5	4	4	3	3	2	2	81	121
	DSM, Class 2 Total	62	52	52	51	38	33	32	31	29	26	25	24	22	22	21	21	19	18	19	18	405	616
	FOT COB - SMR	-	-	-	-	-	-	-	-	-	-	-	230	400	400	400	400	400	400	400	369	-	170
	FOT MidColumbia - SMR	311	315	400	392	395	400	387	370	400	399	400	400	400	400	400	400	400	400	400	400	377	389
	FOT MidColumbia - SMR - 2	-	-	124	-	-	45	-	-	38	-	-	375	375	375	375	375	375	375	375	375	21	179
	FOT NOB - SMR	90	4	100	71	-	-	32	58	100	100	100	100	100	100	100	100	100	100	100	100	55	78
	FOT COB - WTR	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	49	-	311	-	18
	FOT MidColumbia - WTR	253	308	303	296	303	305	310	304	317	330	343	357	400	400	400	400	400	400	400	400	303	346
	FOT MidColumbia - WTR2	-	-	-	-	-	-	-	-	-	-	-	-	258	294	309	276	368	375	231	375	-	124
	FOT NOB - WTR	-	-	-	-	-	-	-	-	-	-	-	-	100	100	100	100	100	100	100	100	-	40
	Existing Plant Retirements/Conversions	-	-	(280)	-	(387)	-	-	-	-	(82)	-	(762)	(354)	(357)	(77)	-	(717)	-	(82)	-		
	Annual Additions, Long Term Resources	150	119	127	1,033	504	99	96	95	100	96	90	90	153	859	181	207	1,897	111	489	222		
	Annual Additions, Short Term Resources	655	627	927	759	698	749	729	732	855	829	843	1,604	2,333	2,369	2,384	2,351	2,443	2,488	2,606	3,030		
	Total Annual Additions	805	746	1,054	1,792	1,202	848	825	827	954	925	934	1,695	2,486	3,228	2,566	2,559	4,340	2,599	3,095	3,252		

1/ Front office transaction amounts reflect one-year transaction periods, are not additive, and are reported as a 10/20-year annual average.

* The 2017 IRP Update Preferred Portfolio includes repowering 999 MW of existing wind resources, not shown in the table, assuming commercial operation by the end of 2020.

Renewable Portfolio Standards (RPS)

Figure 8.1 shows PacifiCorp's RPS compliance forecast for California, Oregon, and Washington after accounting for Energy Vision 2020 projects and new renewable resources in the preferred portfolio. While these resources are included in the preferred portfolio as cost-effective system resources, they also contribute to meeting state-RPS.

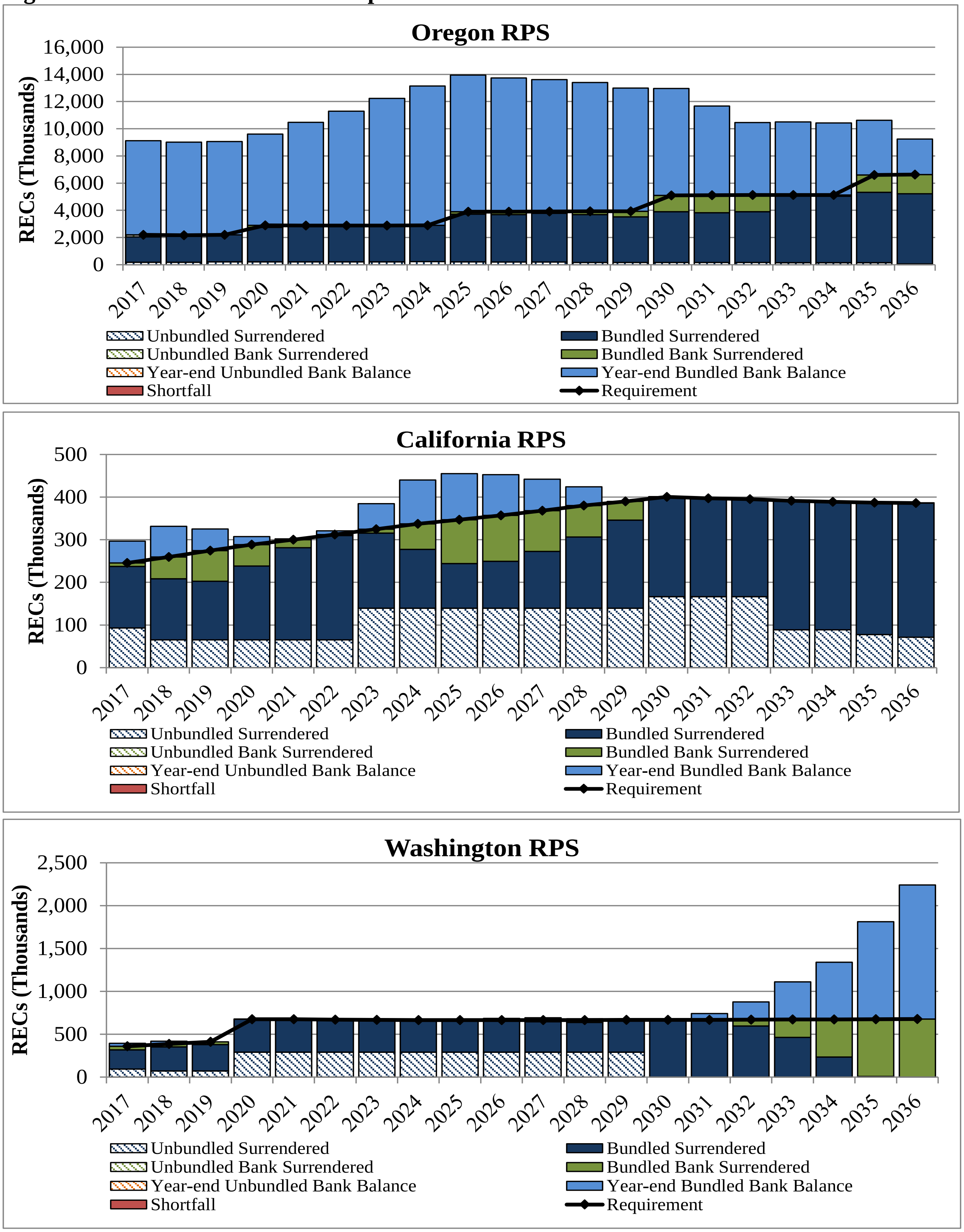
Oregon RPS compliance is achieved through 2036 with the addition of repowered wind and new renewable resources in the 2017 IRP Update preferred portfolio. As shown in Figure 8.1, no additional REC purchases are required to achieve Oregon RPS compliance through 2036.

The California RPS compliance position is also improved by the addition of repowered wind and new renewable resources in the 2017 IRP Update preferred portfolio. As RPS targets increase, California requires some level of unbundled REC purchases (under 167,000 RECs per year) to achieve compliance through the planning horizon. In the 2017 IRP, California RPS Requirement targets were developed around three-year compliance periods. For the 2017 IRP Update, annual compliance targets are used, producing consistent incremental changes from year-to-year.

Washington RPS compliance is achieved with the benefit of the repowered wind assets located in the west side—Marengo I and II, Goodnoe Hills, and Leaning Juniper—as well as new renewable resources added to the west side beginning 2030, and unbundled REC purchases (under 290,000 RECs per year). Under the current allocation mechanisms, Washington customers do not benefit from the remainder of the repowered wind or new renewable resources added to the east side of PacifiCorp's system. Under an alternative allocation mechanism, in which Washington would receive its system-allocated share of repowered wind and new wind located in Wyoming, the state's RPS targets could be met without the need for any incremental unbundled REC purchases throughout the 20-year planning period.

While not shown in Figure 8.1, 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 before considering the addition of repowered wind and new renewable resources in the 2017 IRP Update preferred portfolio.

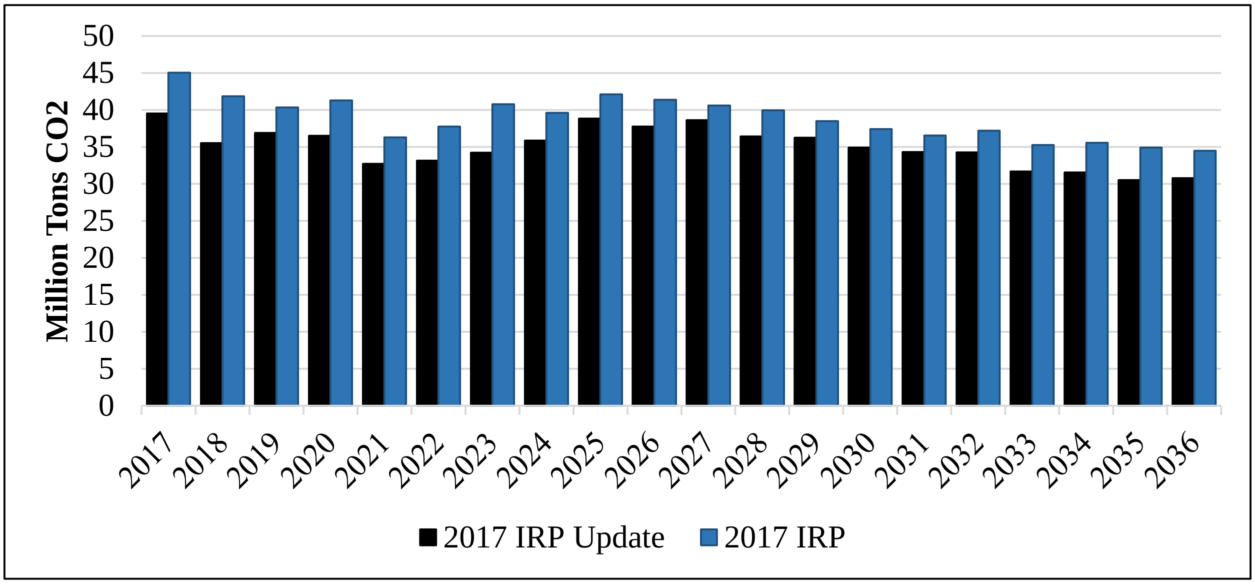
Figure 8.1 – Annual State RPS Compliance Forecast



Carbon Dioxide Emissions

The 2017 IRP Update preferred portfolio continues to reflect PacifiCorp's on-going efforts to provide cost-effective clean energy solutions for our customers and accordingly reflects a continued trajectory of declining 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, which reduces customer costs and maximizes use of clean energy, PacifiCorp's on-going expansion of renewable resources, and regional haze compliance strategies that leverage flexibility. Figure 8.2 compares projected annual CO_2 emissions between the 2017 IRP Update preferred portfolio and the 2017 IRP preferred portfolios (as reported by PaR). Over the first 10 years of the planning horizon, average annual CO_2 emissions are down by over 4.6 million tons (11 percent) relative to the 2017 IRP. By the end of the planning horizon, system CO_2 emissions are projected to fall from 39.5 million tons in 2017 to 30.8 million tons in 2036—a reduction of 22 percent.

Figure 8.2 – Comparison of CO_2 Emission Forecasts between the 2017 IRP Update Preferred Portfolio and the 2017 IRP Preferred Portfolio



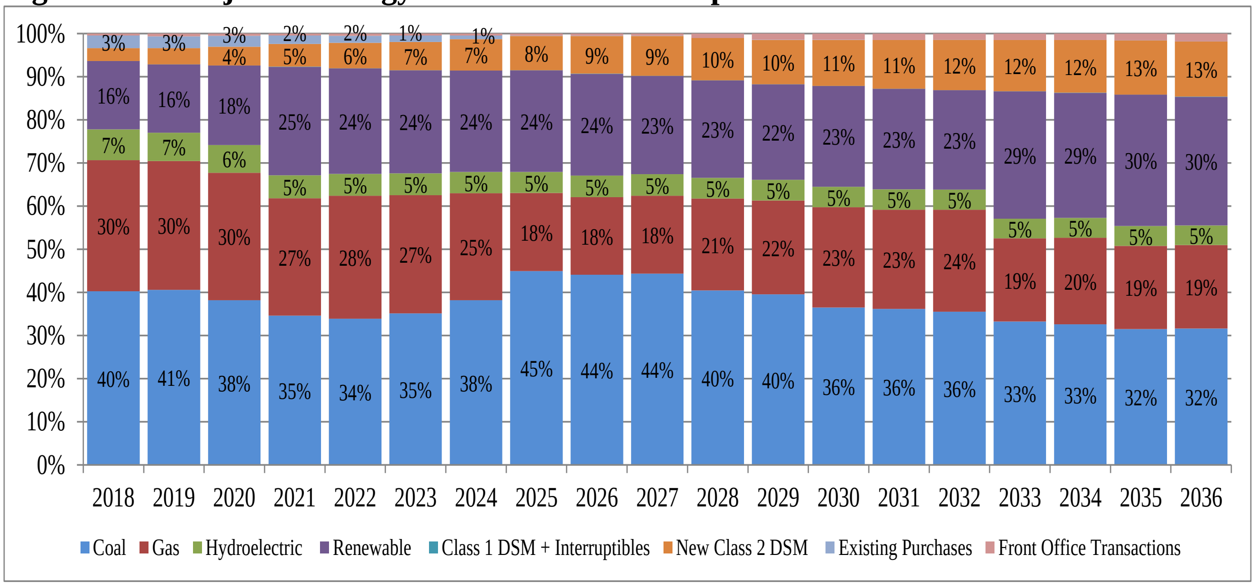
Projected Energy Mix

Figure 8.3 shows how PacifiCorp's system energy mix is projected to change over time. In developing this figure, purchased power is reported in identifiable resource categories where possible. Figure 8.3 is based upon base price curve assumptions. Renewable generation reflects categorization by technology type and not disposition of renewable energy attributes for regulatory compliance requirements.[2] On an energy basis, coal generation drops below 45 percent by 2025,

[2]The projected PacifiCorp 2017 IRP Update preferred portfolio "energy mix" is based on energy production and not resource capability, capacity or delivered energy. All or some of the renewable energy attributes associated with wind, biomass, geothermal and qualifying hydro facilities in PacifiCorp's energy mix may be: (a) used in future years to comply with renewable portfolio standards or other regulatory requirements; (b) sold to third parties in the form of renewable energy credits or other environmental commodities; or (c) excluded from energy purchased. PacifiCorp's 2017 IRP Update portfolio energy mix includes owned resources and purchases from third parties.

drops below 40 percent by 2030, and declines to 32 percent by the end of the planning period. This result reflects relatively low natural gas natural gas prices prior to 2025 and coal retirements thereafter. Reduced energy from coal is offset primarily by increased energy from renewable resources and DSM resources. No new natural gas generating units are included in the 2017 IRP Update preferred portfolio through the entire 20-year planning period.

Figure 8.3 – Projected Energy Mix with 2017 IRP Update Preferred Portfolio Resources



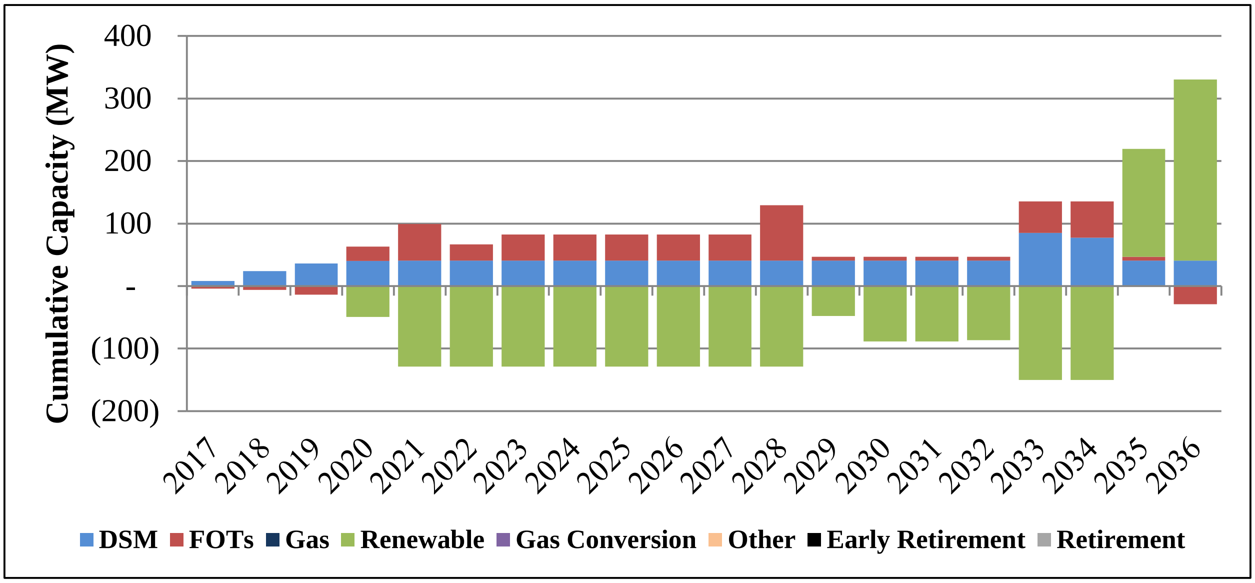
Sensitivity Studies

Business Plan Sensitivity

Figure 8.4 shows a comparison of the resource portfolio from the business plan sensitivity with the 2017 IRP Update preferred portfolio. This sensitivity complies with requirements to perform a business plan sensitivity in accordance with the Public Service Commission of Utah's order in Docket No. 15-035-04, which is summarized as follows:

- Over the first three years, resources align with those assumed in PacifiCorp's fall 2017 business plan.
- Beyond the first three years of the study period, unit retirement assumptions are aligned with the preferred portfolio.
- All other resources are optimized.

Figure 8.4 – Cumulative Increase/(Decrease) in 2017 Business Plan and 2017 IRP Update Preferred Portfolio



Key differences between the Business Plan sensitivity and the 2017 IRP Update preferred portfolio include timing and assumptions around Energy Vision 2020 projects, wind repowering, and Class 2 DSM, as described below:

- The Energy Vision 2020 new wind and transmission projects that are included in the fall 2017 business plan reflect proxy wind resources totaling 1,182 MW, which includes a 320 MW proxy PPA. These proxy assumptions were developed before the 2017R Request for Proposals (RFP) was finalized. The 2017 IRP Update preferred portfolio includes Energy Vision 2020 new wind totaling 1,311 MW, consistent with the final shortlist from the 2017R RFP (see Chapter 7).
- The fall 2017 business plan includes repowering existing wind resources at a slightly different capacity than what is assumed in the 2017 IRP Update. This difference in capacity is driven by interconnection limits. The business plan also reflected an earlier version of repowering equipment at certain facilities that had assumed lower incremental energy output relative to the 2017 IRP Update.
- With less new wind and less incremental energy from wind repowering, DSM resources in the fall 2017 business plan are slightly higher relative to the 2017 IRP Update preferred portfolio.
- FOT resources are higher in the fall 2017 business plan beginning 2020. There is a reduction in FOTs in 2036 with the addition of incremental renewable resources.

Table 8.5 shows the impact of the business plan sensitivity with the initial estimate of 1,182 MW of new wind versus the 2017 IRP Update preferred portfolio with 1,311 MW of Energy Vision 2020 new wind.

Table 8.5 – PVRR Cost/(Benefit) of the Business Plan Relative to the 2017 IRP Update Preferred Portfolio (Price-Scenario MM)

	Medium Gas – Medium CO_2	
	System Optimizer	**PaR Stochastic Mean**
Change from 17 IRP Update Pref-Port	$422	$233

The SO model PVRR(d) is a reflection of higher QF wind project costs, higher fuel costs from lower renewables, higher fixed costs, higher DSM costs, and higher system balancing purchase costs.

The PaR PVRR(d) is a reflection of higher QF wind project costs, higher fuel costs from lower renewables, higher fixed costs, and higher DSM costs, offset by system balancing sales.

Foote Creek I Sensitivity

Preliminary assessment of Foote Creek I shows potential for customer benefits by acquiring the remaining portion of Foote Creek I, which is co-owned with the Eugene Water & Electric Board, and repowering this wind facility. Foote Creek I is the oldest wind facility in PacifiCorp's wind fleet, having been brought online in 1999. PacifiCorp will explore this opportunity further in the 2019 IRP.

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CHAPTER 9 – TRANSMISSION STUDIES

Introduction

The 2017 Integrated Resource Plan (IRP) action plan identifies specific resource actions PacifiCorp will take over the next two to four years to deliver resources included in the 2017 IRP preferred portfolio. Action items are based on the type and timing of resources in the preferred portfolio, which is selected based on analysis completed during the development of the 2017 IRP. This chapter discusses transmission studies completed in response to the following action item (please refer to the 2017 IRP, Volume I, Table 1.4):

- Complete planning studies that include proposed coal unit retirement assumptions from the 2017 IRP preferred portfolio and two other scenarios.
- Summarize studies in the 2017 IRP Update.

In the 2017 IRP proceeding, PacifiCorp was required by the Public Utility Commission of Oregon to provide Dave Johnston early retirement transmission analysis to the commission and parties in that proceeding.[1] The information provided in scenarios two and three of this chapter are in response to that directive.

In recognition of the transmission planning process and the planning tools available for such an analysis, various coal retirement scenarios were assessed to provide a response to this action item based on prior studies, system knowledge and new study efforts. These coal units are synchronous machines with large spinning shafts that provide higher inertia and help to provide stable and reliable operation, particularly during system disturbances. Proposed retirement of those plants in the 2017 IRP preferred portfolio that are directly interconnected to PacifiCorp's transmission system were considered. Cholla Unit 4 and Hayden Units 1 and 2, located in Arizona and Colorado, respectively, are not directly connected to PacifiCorp's transmission system and hence, their retirement does not directly impact transmission-system operations. It is noted that additional detailed studies will accompany any final coal retirement decision(s) and results may be different than those identified herein.

Description of Transmission Studies

Table 9.1 lists the assumed coal-unit retirements in the 2017 IRP preferred portfolio that inform the transmission system assessment summarized in this chapter. Four scenarios are considered:

1. Scenario 1 reflects the following coal-unit retirement and Energy Vision 2020 assumptions:
    - Jim Bridger Unit 1 at the end of 2028
    - Jim Bridger Unit 2 at the end of 2032
    - Naughton Unit 3 at the end of 2018
    - Cholla Unit 4 at the end of 2020

[1] See the Public Utility Commission of Oregon's 2017 IRP acknowledgement order issued April 27, 2018, Docket LC 67.

- Energy Vision 2020 projects, including the Aeolus-to-Bridger/Anticline transmission line (sub-segment D.2), are online by the end of 2020.

2. Scenario 2 reflects the following coal-unit retirement and Energy Vision 2020 assumptions:
   - Dave Johnston Unit 1 at the end of 2027
   - Dave Johnston Unit 2 at the end of 2027
   - Dave Johnston Unit 3 at the end of 2027
   - Dave Johnston Unit 4 at the end of 2027
   - Energy Vision 2020 projects, *without* sub-segment D.2, are online by the end of 2020, and

3. Scenario 3 reflects the following coal-unit retirement and Energy Vision 2020 assumptions:
   - Dave Johnston Unit 1 at the end of 2027
   - Dave Johnston Unit 2 at the end of 2027
   - Dave Johnston Unit 3 at the end of 2027
   - Dave Johnston Unit 4 at the end of 2027
   - No Energy Vision 2020 project

4. Scenario 4 reflects the following coal-unit retirement and Energy Vision 2020 assumptions:
   - Naughton Unit 1 at the end of 2029
   - Naughton Unit 2 at the end of 2029
   - Energy Vision 2020 projects, including sub-segment D.2, are online by the end of 2020.

Table 9.1 – Assumed Coal-Unit Retirements in the 2017 IRP Preferred Portfolio

Coal Unit	PacifiCorp Percentage Ownership Share (%)	State	Assumed Retirement Year	Summer Load and Resource Balance Capacity (MW)
Naughton 3	100	WY	2018	280
Cholla 4	100	AZ	2020	387
Craig 1	19	CO	2025	82
DJ 1	100	WY	2027 (end-of-life)	106
DJ 2	100	WY	2027 (end-of-life)	106
DJ 3	100	WY	2027 (end-of-life)	220
DJ 4	100	WY	2027 (end-of-life)	330
Bridger 1	67	WY	2028	354
Naughton 1	100	WY	2029 (end-of-life)	201
Naughton 2	100	WY	2029 (end-of-life)	280
Hayden 1	24	CO	2030 (end-of-life)	45
Hayden 2	13	CO	2030 (end-of-life)	33
Bridger 2	67	WY	2032	359

Transmission Impact Assessment – Scenario 1

The Aeolus West Transfer Capability Assessment (February 2018) was relied upon to identify the system impacts for Scenario 1. This assessment includes the retirement of Jim Bridger Units 1 and 2. The Jim Bridger generation units are among the largest synchronous machines on the PacifiCorp system and play an integral role in voltage support and dynamic stability for the transmission system. Energy Vision 2020 projects were considered in service and include significant new wind generation, a new 140-mile 500-kV transmission line from the proposed Aeolus substation near Medicine Bow, Wyoming, to the Jim Bridger power plant, and subsystem facilities.

The impact of retiring Jim Bridger Unit 1 had limited impact on voltage due to the support provided by the three remaining Bridger units as well as the presence of existing capacitor banks at the Bridger facility, which can be switched on to provide voltage support during outage conditions (typical line and major equipment outages aligned with NERC standards criteria). Retirement of both Jim Bridger Unit 1 and Unit 2 resulted in the remaining Jim Bridger units using close to their maximum reactive capability when near full output, with the existing capacitors online. Therefore, new reactive support to control voltage under outage conditions likely would be required if both units were retired. A dynamic voltage device, such as a static var compensator or synchronous condenser, at the Jim Bridger 345-kV bus is probable under this scenario. Due to the potential for sub-synchronous resonance at Jim Bridger, this analysis will be required for all unit retirements and proposed facility additions.

With an assumed retirement of any of the Jim Bridger units, the Bridger remedial action scheme (RAS) would need to be modified accordingly. Currently, up to two Jim Bridger generation units are armed to trip under certain 345-kV transmission line outage conditions.

Importantly, the study demonstrated that the Energy Vision 2020 transmission improvements and the new wind generation provide increased transmission capacity and power flow to support the existing 2,400 MW Bridger West transmission path rating, even if the two Jim Bridger units are retired.

Retirement of Naughton Unit 3 did not have a significant impact on system performance. It is noted that this unit also is part of a tRAS and if the unit were retired, the Naughton RAS would need to be modified to reflect this change.

Anticipated high-level system improvements for Scenario 1 include the following with a non-binding estimate of $45-$70 million:

1. Install a new dynamic voltage device at or near Bridger
2. Modification of Bridger and Naughton RASs

Transmission Impact Assessment – Scenario 2

This transmission system assessment was performed to assess the impacts of the full retirement of all four Dave Johnston coal units with a total capacity of 762 MW and determine if the end-of-life retirement (end of 2027) of Dave Johnston will require transmission system improvements. The Energy Gateway west D.2 transmission project was not considered; however, the new and repowered wind generation was assumed based on preliminary 2017 RFP shortlist resources.

Study results indicated that under this scenario, various 230-kV transmission line segments between the Point of Rocks substation in central Wyoming and the Dave Johnston substation in eastern Wyoming, overload above their continuous ratings under normal conditions, and above emergency ratings under system outage conditions. Voltage levels outside of approved limits were also observed at multiple locations in eastern and central Wyoming under outage conditions. The new wind turbine technology provides improved reactive response, but cannot provide all of the required voltage support.

To mitigate these issues the following system improvements were identified, with a high-level non-binding estimate of $810 million:

1. Build a new 140-mile 230-kV line between Bridger-Latham-Freezeout.
2. Build a new 230-kV line between Freezeout-Shirley Basin-Windstar.
3. Rebuild the existing 230-kV lines from Point of Rocks to Freezeout substations (Point of Rocks-Bitter Creek-Bar X-Echo Springs-Latham-Platte-Standpipe-Freezeout).
4. Rebuild the following substations: Point of Rocks, Bitter Creek, Bar X, Echo Springs, Latham, Platte, Standpipe, Freezeout, Shirley Basin and Windstar to support higher transmission line capacity.
5. Install a +350/-125 MVAr Static Var Compensator (SVC) at Latham substation
6. Install five, 40 MVAr each switched shunt capacitors at Latham substation
   Replace the three existing 345/230-kV 200-MVA auto transformers at Jim Bridger substation with at least two 345/230 700-MVA auto transformers.

Transmission Impact Assessment – Scenario 3

This scenario analyzed the impacts of the full retirement of all four Dave Johnston coal units in 2027 with no Energy Vision 2020 wind or transmission facilities. Study results indicate that retiring Dave Johnston with no generation additions, significantly changes the directional power flow in eastern Wyoming, which can result in west-to-east flows to meet load requirements versus the currently predominant east-to-west flows for this area. As more power from the Jim Bridger generation facility and other western Wyoming and Utah resources are needed to serve Wyoming loads, the three Jim Bridger 345/230-kV auto transformers overload under normal and outage conditions (typical line and major equipment outages aligned with NERC standards criteria). This change in power flow also results in decreased flows to the PacifiCorp-west system.

The Dave Johnston plant retirement also impacts the ability to control voltages in the area; high voltages were observed during light load, no wind conditions and low voltages were observed during heavy load conditions. As such, reactive support in the form of capacitors and reactors would be required. A preliminary assessment of required facilities under this scenario is as follows with a high-level estimate of $23-$33 million:

1. Replace the three existing 345/230 kV 200 MVA auto transformers with at least two 700 MVA transformers. Note that replacement of one of the transformers is proposed by 2020 to resolve identified North American Electric Corporation (NERC) Planning Standard TPL-001-4 thermal overload issues.
2. Install a 30-MVAr shunt capacitor and 50-MVAr shunt reactor.

Without the D.2 projects, the study noted that installation of a dispatchable replacement resource at Dave Johnston of approximately 650 MW dispatchable resource would mitigate the aforementioned impacts of the Jim Bridger transformer overload and would provide necessary voltage support. A high level non-binding cost estimate to replace Dave Johnston generation with a 650 MW dispatchable resource is $1,257/kilowatt for an approximate total of $817 million (this is based on a Combined Cycle Combustion Turbine in the 650 MW range, per Table 6.1 in the 2017 IRP).

Transmission Impact Assessment – Scenario 4

This transmission system assessment considers the impact of an end-of-life retirement of Naughton Units 1 and 2 with a total capacity of 357 MW.

Historically, the Naughton units have provided transmission operators the capability to control voltage on the Naughton 230-kV bus and the surrounding system under normal operation and outage conditions (typical line and major equipment outages aligned with NERC standards criteria). Area shunt capacitors are used to support post disturbance voltages. Naughton units being off line under normal conditions leads to the conclusion that additional shunt capacitors will be required in the area with the assumed retirement of Units 1 and 2.

Anticipated high-level system improvements for Scenario 4 include the following with a non-binding estimate of $6-$15 million:

1. Install two new 30-MVAr capacitor banks near Naughton

Conclusions

The system review shows that additional infrastructure will be required to maintain a safe reliably operating transmission system with the retirement of coal resources per the four scenarios reviewed. The addition of the D.2 transmission line provides needed transmission system support with and without the resource retirements and the addition of new wind resources per the 2017 IRP preferred portfolio. The addition of new wind from Energy Vision 2020 using new turbine technology does provide needed voltage support but cannot provide all of the system requirements absent the coal facilities.

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CHAPTER 10 – ACTION PLAN STATUS UPDATE

This chapter provides an update to the action items listed in the Action Plan of PacifiCorp's 2017 IRP. The status for all action items is provided in Table 10.1 below.

Table 10.1 – 2017 IRP Action Plan Status Update

Action Item	1. Renewable Resource Actions	Status
1a	**Wind Repowering** • PacifiCorp will implement the wind repowering project, taking advantage of safe-harbor wind-turbine-generator equipment purchase agreements executed in December 2016. – Continue to refine and update the economic analysis of plant-specific wind repowering opportunities that maximize customer benefits before issuing the notice to proceed. – By September 2017, complete technical and economic analysis of other potential repowering opportunities at PacifiCorp wind plants not studied in the 2017 IRP (i.e., Foote Creek I and Goodnoe Hills). – Pursue regulatory review and approval as necessary. – By May 2018, issue the engineering, procurement, and construction (EPC) notice to proceed to begin implementing the wind repowering for specific projects consistent with updated financial analysis.	PacifiCorp has continued to refine and update its economic analysis of wind repowering, which has been filed in support of regulatory applications in Idaho, Utah, and Wyoming. Regulatory approval was received from the Idaho Public Service Commission on December 28, 2017. PacifiCorp continues to seek regulatory approval in Utah and Wyoming. PacifiCorp completed technical and economic analysis of other repowering opportunities. Goodnoe Hills has been included in the scope of wind repowering for regulatory approval and the preliminary assessment of Foote Creek I shows potential customer benefits, warranting further study and exploration in the 2019 IRP as described in Chapter 8. PacifiCorp is on track to issue EPC construction notices to proceed for specific repowering projects beginning in July 2018, given a delay in regulatory proceedings due to additional economic analysis undertaken to address changes in tax law. Please see Chapter 7 for further information related to the wind repowering project.

	– By December 31, 2020, complete installation of wind repowering equipment on all identified projects.	PacifiCorp is on track to complete installation of the wind repowering equipment on all identified projects by December 31, 2020.
1b	**<u>Wind Request for Proposals</u>** • PacifiCorp will issue a wind resource request for proposals (RFP) for at least 1,100 MW of Wyoming wind resources that will qualify for federal wind production tax credits and achieve commercial operation by December 31, 2020. – April 2017, notify the Utah Public Service Commission of intent to issue the Wyoming wind resource RFP. – May-June, 2017, file a draft Wyoming wind RFP with the Utah Public Service Commission and the Washington Utilities and Transportation Commission. – May-June, 2017, file to open a Wyoming wind RFP docket with the Public Utility Commission of Oregon and initiate the Independent Evaluator RFP. – June-July, 2017, file a draft Wyoming wind RFP with the Public Utility Commission of Oregon and file a Public Convenience and Necessity (CPCN) application with the Public Service Commission of Wyoming. – By August 2017, obtain approval of the Wyoming wind resource RFP from the Public Utility Commission of Oregon, the Utah Public Service Commission, and the Washington Utilities and Transportation Commission.	PacifiCorp completed all of the notice and draft filing requirements related to the RFP. In accordance with the Utah and Oregon RFP proceedings, a system-wide wind resource RFP (the 2017R Request for Proposals (RFP)) was issued on September 27, 2017. Bid results were received, evaluated and PacifiCorp established a final shortlist that includes four wind projects in Wyoming totaling 1,311. The 2017R RFP was monitored by two independent evaluators, and both agreed with the company's final shortlist. On April 12, 2018, PacifiCorp received conditional CPCNs for the TB Flats I & II wind project, the Cedar Springs wind project, the Ekola Flats wind project, and associated network upgrades from the Wyoming Public Service Commission. These CPCNs are required to secure the necessary rights-of-ways, which has been initiated, before construction begins. PacifiCorp continues to work towards achieving upcoming milestones including approval and acknowledgement of the final shortlist by the Utah Public Service Commission and the Public Utility Commission of Oregon, respectively. Hearings and public meetings are scheduled in April-May 2018. • Contract negotiations with final shortlist counterparties have commenced and are anticipated to be complete by June 2018.

	– By August 2017, issue the Wyoming wind RFP to the market. – By October 2017, Wyoming wind RFP bids are due. – November-December, 2017, complete initial shortlist bid evaluation. – By January 2018, complete final shortlist bid evaluation, seek acknowledgement of the final shortlist from the Public Utility Commission of Oregon, and seek approval of winning bids from the Utah Public Service Commission. – By March 2018, receive CPCN approval from the Wyoming Public Service Commission. – Complete construction of new wind projects by December 31, 2020.	Please see Chapter 7 for further information related to these new wind resources.
1c	**<u>Renewable Portfolio Standard Compliance</u>** • PacifiCorp will issue unbundled REC request for proposals (RFP) to meet its state RPS compliance requirements. – As needed, issue RFPs seeking then-current-year or forward-year vintage unbundled RECs that will qualify in meeting California renewable portfolio standard targets through 2020. – As needed, issue RFPs seeking low-cost then-current-year, forward-year, or older vintage unbundled RECs that will qualify in meeting Oregon renewable portfolio standard targets, deferring the currently projected 2035 initial shortfall after accounting for preferred portfolio renewable resources.	PacifiCorp will continue to evaluate the need for unbundled RECs and issue RFPs to meet its state RPS compliance requirements as needed for both California and Oregon. Since March 31, 2017, no additional RFPs have been issued for either state.

<table>
<tr><td>1d</td><td><u>Renewable Energy Credit Optimization</u>
• Before filing the 2017 IRP Update, evaluate potential opportunities to re-allocate RECs from Utah, Wyoming, and Idaho to Oregon, Washington, or California.
• Maximize the sale of RECs that are not required to meet state RPS compliance obligations.</td><td>PacifiCorp has initiated discussions with Oregon and Utah stakeholders to evaluate potential opportunities to re-allocate RECs from Utah to Oregon, Washington or California.

PacifiCorp issued two reverse RFPs to sell RECs—one in June 2017 and one in September 2017—and completed several bilateral transactions. PacifiCorp will continue to issue reverse RFPs to maximize the sale of RECs that are not required to meet state RPS compliance obligations.</td></tr>
<tr><th>Action Item</th><th>2. Transmission Actions</th><th>Status</th></tr>
<tr><td>2a</td><td><u>Aeolus to Bridger/Anticline</u>
• By December 31, 2020, PacifiCorp will build the 140-mile, 500 kV transmission line running from the Aeolus substation near Medicine Bow, Wyoming, to the Jim Bridger power plant (a sub-segment of the Energy Gateway West transmission project). This includes pursuing regulatory review and approval as necessary.
– June-July 2017, file a CPCN application with the Public Service Commission of Wyoming.
– By March 2018, receive conditional CPCN approval from the Wyoming Public Service Commission pending acquisition of rights of way.
– By December 2018, obtain Wyoming Industrial Siting permit and issue EPC limited notice to proceed.
– By April 2019, issue EPC final notice to proceed.
– Complete construction of the transmission line by December 31, 2020.</td><td>PacifiCorp filed a CPCN application with the Public Service Commission of Wyoming on June 30, 2017.

On April 12, 2018, PacifiCorp received a conditional CPCN for the Aeolus-to-Bridger/Anticline transmission line from the Wyoming Public Service Commission. This CPCN is required to secure the necessary rights-of-ways, which has been initiated, before construction begins.

The balance of the regulatory review items remain on track to be completed as outlined.

Project activities required to achieve the 2020 in-service date continue, including all state regulatory approvals, public outreach and rights of way negotiations.

Please see Chapter 7 for further information related to the Aeolus-to-Bridger/Anticline transmission line.</td></tr>
</table>

2b	**<u>Energy Gateway Permitting</u>** • Continue permitting for the Energy Gateway transmission plan, with the following near-term targets: – For Segments D1, D3, E, and F, continue funding of the required federal agency permitting environmental consultant actions required as part of the federal permits. – For Segments D, E, and F, continue to support the projects by providing information and participating in public outreach. – For Segment H (Boardman to Hemingway), continue to support the project under the conditions of the Boardman to Hemingway Transmission Project Joint Permit Funding Agreement.	Final environmental and records of decisions have been issued for all Gateway Segments D1, D3, E and F. PacifiCorp will continue the work necessary to meet requirements within the records of decision and will continue to meet regularly with the Bureau of Land Management to review progress. PacifiCorp continues to support the Boardman to Hemingway project consistent with the Joint Permit Funding Agreement. As a participant in the project PacifiCorp continues to collaborate with Idaho Power, the lead organization in the permitting process, by providing guidance on activities and plans associated with the permitting phase of the project.
2c	**<u>Wallula to McNary 230 kV Transmission Line</u>** • Complete Wallula to McNary project construction per plan with a 2018 expected in-service date. Continue to support the permitting and construction process for Walla Walla to McNary.	Project line construction is on track for a 2018 completion date. All local, state and federal land-use permitting is complete, private right of easement acquisition is under way.
2d	**<u>Planning Studies</u>** • Complete planning studies that include proposed coal unit retirement assumptions from the 2017 IRP preferred portfolio and two other scenarios. • Summarize studies in the 2017 IRP Update.	These studies have been completed and are summarized in Chapter 9.
Action Item	**3. Firm Market Purchase Actions**	**Status**
3a	**<u>Front Office Transactions</u>** • Acquire economic short-term firm market purchases for on-peak summer deliveries from 2017 through 2019 consistent with the Risk Management Policy and	For 2017, PacifiCorp acquired approximately 1,575 MW to 2,400 MW of short-term firm market purchases inclusive of forward hedging transactions, not accounting for any

	Commercial and Trading Front Office Procedures and Practices. These short-term firm market purchases will be acquired through multiple means: – Balance of month and day-ahead brokered transactions in which the broker provides the service of providing a competitive price. – Balance of month, day-ahead, and hour-ahead transactions executed through an exchange, such as Intercontinental Exchange (ICE), in which the exchange provides the service of providing a competitive price. – Prompt month-forward, balance-of-month, day-ahead, and hour-ahead non-brokered transactions.	offsetting hedging or balancing sales for delivery during the on-peak summer period. For 2018, as of mid-March 2018, the Company has acquired approximately 775 MW to 975 MW of short-term firm market purchases inclusive of forward hedging transactions, not accounting for any offsetting hedging sales for delivery during the on-peak summer period. For 2019, as of mid-March 2018, the Company has acquired approximately 175 MW of short-term firm market purchases explicitly for delivery during the on-peak summer period inclusive of forward hedging transactions, not accounting for any offsetting hedging sales for delivery during the on-peak summer period.

<table>
<tr><th>Action Item</th><th>4. Demand Side Management (DSM) Actions</th><th>Status</th></tr>
<tr><td>4a</td><td><u>Class 2 DSM</u>
• Acquire cost-effective Class 2 DSM (energy efficiency) resources targeting annual system energy and capacity selections from the preferred portfolio as summarized in the following table. PacifiCorp’s state-specific processes for planning for DSM acquisitions is provided in Appendix D in Volume II of the 2017 IRP.
<table>
<tr><th>Year</th><th>Annual Incremental Energy (GWh)</th><th>Annual Incremental Capacity* (MW)</th></tr>
<tr><td>2017</td><td>646</td><td>154</td></tr>
<tr><td>2018</td><td>559</td><td>128</td></tr>
<tr><td>2019</td><td>571</td><td>131</td></tr>
<tr><td>2020</td><td>527</td><td>122</td></tr>
</table>
*Class 2 DSM capacity figures reflect projected maximum annual hourly energy savings, which is similar to a nameplate rating for a supply-side resource.</td><td>Initial review indicates that in 2017, PacifiCorp achieved the Action Plan target of 646 GWh. PacifiCorp is on track to achieve its 2018 Class 2 DSM target.</td></tr>
<tr><th>Action Item</th><th>5. Coal Resource Actions</th><th>Status</th></tr>
<tr><td>5a</td><td><u>Hunter Units 1 and 2</u>
• The EPA’s final Regional Haze Federal Implementation Plan (FIP) for Utah requires the installation of selective catalytic reduction (SCR) on Hunter Units 1 and 2 in 2021 and is currently under appeal by the state of Utah and other parties in the U.S. Tenth Circuit Court of Appeals.
• As influenced by the litigation schedule and outcomes, PacifiCorp will update its economic analysis of alternative Regional Haze compliance strategies for the units, as applicable, and will</td><td>PacifiCorp will provide updates in future IRP filings as applicable.</td></tr>
</table>

	provide the associated analysis in a future IRP or IRP Update.	
5b	**<u>Huntington Units 1 and 2</u>** • The EPA's final Regional Haze FIP for Utah requires the installation of SCR on Huntington Units 1 and 2 in 2021 and is currently under appeal by the state of Utah and other parties in the U.S. Tenth Circuit Court of Appeals. • As influenced by the litigation schedule and outcomes, PacifiCorp will update its economic analysis of alternative Regional Haze compliance strategies for the units, as applicable, and will provide the associated analysis in a future IRP or IRP Update.	PacifiCorp will provide updates in future IRP filings as applicable.
5c	**<u>Dave Johnston Unit 3</u>** • The EPA's final Regional Haze FIP requires the installation of SCR at Dave Johnston Unit 3 in 2019 or a commitment to shut down Dave Johnston Unit 3 by the end of 2027. PacifiCorp's commitment to the latter must be included in a permit before the 2019 compliance deadline. • PacifiCorp will update its analysis of the commitment to shut down Dave Johnston Unit 3 by the end of 2027 as part of its 2017 IRP Update.	PacifiCorp has studied retirement of Dave Johnston Unit 3 in the 2017 IRP Update. Please see Chapter 6, Regional Haze Cases for more information. PacifiCorp will provide additional updates in future IRP filings as applicable.
5d	**<u>Jim Bridger Units 1 and 2</u>** • The Wyoming Regional Haze State Implementation Plan (SIP) and EPA's final Regional Haze FIP for Wyoming require the installation of SCR on Jim Bridger Units 1 and 2 in 2021 and 2022. • PacifiCorp will update its economic analysis of alternative Regional Haze compliance strategies for	PacifiCorp has studied retirement of Jim Bridger Units 1 and 2 in the 2017 IRP Update. Please see Chapter 6, Regional Haze Cases for more information. PacifiCorp will provide additional updates in future IRP filings as applicable.

	the units and will provide the associated analysis in its 2017 IRP Update.	
5e	**<u>Naughton Unit 3</u>** • PacifiCorp will update its economic analysis of natural gas conversion in its 2017 IRP Update.	PacifiCorp has studied gas conversion of Naughton Unit 3 in the 2017 IRP Update. Please see Chapter 6, Regional Haze Cases for more information. PacifiCorp will provide additional updates in future IRP filings as applicable.
5f	**<u>Wyodak</u>** • Continue to pursue PacifiCorp's appeal of the portion of EPA's final Regional Haze FIP that requires the installation of SCR at Wyodak, recognizing that the compliance deadline for SCR under the FIP is currently stayed by the court. • If following appeal, EPA's final FIP as it pertains to installation of SCR at Wyodak is upheld (with a modified schedule that reflects the final stay duration), PacifiCorp will update its evaluation of alternative compliance strategies that will meet Regional Haze compliance obligations and provide the associated analysis in a future IRP or IRP Update.	PacifiCorp will provide additional updates in future IRP filings as applicable.
5g	**<u>Cholla Unit 4</u>** • EPA has approved the Arizona SIP incorporating an alternative Regional Haze compliance approach that avoids installation of SCR with a commitment to cease operating Cholla Unit 4 as a coal-fueled resource by the end of April 2025, with the option of natural gas conversion thereafter. • PacifiCorp will update its evaluation of Cholla Unit 4 alternatives that meet its Regional Haze compliance obligations and provide the associated analysis in a future IRP or IRP Update.	PacifiCorp has studied gas conversion of Cholla Unit 4 in the 2017 IRP Update. Please see Chapter 6, Regional Haze Cases for more information. PacifiCorp will provide additional updates in future IRP filings as applicable.

5h	**<u>Craig Unit 1</u>** • EPA is yet to approve the Colorado SIP incorporating an alternative Regional Haze compliance approach that avoids installation of SCR with a commitment to cease operating Craig Unit 1 as a coal-fueled resource by the end of 2025, with an option for natural gas conversion. • PacifiCorp will update its evaluation of Craig Unit 1 alternatives that meet its Regional Haze compliance obligations and provide the associated analysis in a future IRP or IRP Update, as required.	PacifiCorp will provide additional updates in future IRP filings as applicable.

APPENDIX – ADDITIONAL LOAD FORECAST DETAILS

The load forecast presented in Chapter 4 represents the data used for capacity expansion modeling, and excludes load reductions from incremental energy efficiency resources (Class 2 DSM).The load forecast used in the 2017 IRP Update was produced in August 2017. The average annual energy growth rate for the 10-year period (2018 through 2027) is 0.55 percent. Relative to the load forecast prepared for the 2017 IRP, PacifiCorp's 2027 forecasted energy requirement decreased in all jurisdictions other than Oregon and Idaho, while PacifiCorp system energy requirement decreased approximately 4.2 percent. Table A.1 and Table A.2 illustrate the annual load and coincident peak load forecast when not reducing load projections to account for new energy efficiency measures (Class 2 DSM).[1]

Table A.1 - Forecasted Annual Load Growth, 2018 through 2027 (Megawatt-hours), at Generation, pre-DSM

Year	Total	OR	WA	CA	UT	WY	ID
2018	59,876,340	14,828,080	4,568,290	903,060	25,660,060	10,023,590	3,893,260
2019	60,448,530	15,148,080	4,602,170	899,340	25,871,850	10,006,200	3,920,890
2020	60,684,390	15,171,700	4,622,620	891,670	26,029,500	10,029,430	3,939,470
2021	60,952,640	15,218,700	4,620,810	883,870	26,210,610	10,063,780	3,954,870
2022	61,451,780	15,316,170	4,634,340	880,000	26,499,690	10,140,100	3,981,480
2023	61,983,040	15,423,000	4,652,580	876,680	26,802,770	10,216,900	4,011,110
2024	62,662,000	15,570,800	4,689,120	875,620	27,164,620	10,315,860	4,045,980
2025	63,004,770	15,629,340	4,701,470	868,930	27,378,200	10,360,020	4,066,810
2026	62,578,260	15,721,380	4,728,450	864,610	26,741,980	10,429,410	4,092,430
2027	62,922,460	15,817,000	4,754,380	860,700	26,874,580	10,498,300	4,117,500
Average Annual Growth Rate for 2018-2027							
2018 - 2027	**0.55%**	**0.72%**	**0.44%**	**-0.53%**	**0.52%**	**0.52%**	**0.62%**

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

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

Year	Total	OR	WA	CA	UT	WY	ID
2018	9,971	2,326	752	148	4,687	1,283	775
2019	10,005	2,355	757	147	4,685	1,280	780
2020	10,038	2,359	763	146	4,704	1,284	782
2021	10,109	2,368	768	145	4,750	1,289	789
2022	10,190	2,377	772	145	4,803	1,298	795
2023	10,266	2,386	778	146	4,850	1,306	800
2024	10,344	2,391	783	144	4,902	1,317	806
2025	10,419	2,406	791	143	4,961	1,324	794
2026	10,422	2,414	797	142	4,922	1,332	816
2027	10,462	2,421	803	142	4,933	1,340	823
Average Annual Growth Rate for 2018-2027							
2018 - 2027	0.54%	0.45%	0.73%	-0.49%	0.57%	0.49%	0.67%

Table A.3 and Table A.4 show the forecast changes relative to the 2017 IRP load forecast for loads and coincident system peak, respectively. The 2017 IRP Update incorporates a methodological update for the treatment of private generation and how it affects the coincident peak. In previous IRPs, the load forecast summed the hourly kW for seven different private generation sources to produce the hourly private generation shape within each state. For the 2017 IRP Update, since a high percentage of forecasted private generation is solar (>90%), a more appropriate methodology was adopted where the seven individual private generation sources were weighted by annual MW. The result was that the aggregated hourly shapes for each state better reflect the individual contribution for each of these private generation sources.

As such, the improved methodology results in the coincident peak being lower than it would have been using the unweighted approach. For example, when holding all else constant, the improved methodology results in the coincident peak for 2018 to be 49 MW (0.5%) lower, while the coincident peak for 2027 is 149 MW (1.4%) lower when compared to the unweighted private generation methodology used in the 2017 IRP.

Table A.3 - Annual Load Growth Change: 2017 IRP Forecast less 2017 IRP Update Forecast (Megawatt-hours) at Generation, pre-DSM

Year	Total	OR	WA	CA	UT	WY	ID
2018	(794,110)	91,380	70,860	(1,160)	(977,630)	(27,330)	49,770
2019	(852,840)	266,450	65,360	(2,550)	(1,084,650)	(144,390)	46,940
2020	(1,178,910)	219,920	59,380	(6,160)	(1,230,920)	(263,410)	42,280
2021	(1,344,560)	198,830	35,300	(8,270)	(1,336,400)	(270,360)	36,340
2022	(1,555,250)	171,360	19,250	(9,900)	(1,462,450)	(304,960)	31,450
2023	(1,816,690)	146,830	5,680	(11,240)	(1,595,700)	(390,030)	27,770
2024	(1,948,360)	122,770	(3,360)	(12,390)	(1,731,800)	(347,940)	24,360
2025	(2,166,790)	94,580	(19,040)	(13,880)	(1,846,430)	(403,540)	21,520
2026	(2,604,720)	86,460	(24,730)	(14,670)	(2,152,220)	(518,450)	18,890
2027	(2,761,190)	77,190	(31,860)	(15,150)	(2,283,320)	(525,070)	17,020

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

Year	Total	OR	WA	CA	UT	WY	ID
2018	(254)	18	28	(3)	(383)	36	51
2019	(305)	6	18	(5)	(412)	35	53
2020	(365)	(0)	21	(6)	(448)	16	52
2021	(409)	(6)	20	(6)	(466)	10	39
2022	(434)	(14)	20	(7)	(478)	6	39
2023	(440)	(21)	20	(5)	(491)	4	53
2024	(461)	(34)	20	(7)	(507)	13	54
2025	(500)	(37)	23	(8)	(521)	6	37
2026	(509)	(44)	24	(8)	(524)	(11)	54
2027	(559)	(51)	25	(8)	(546)	(18)	40

Table A.5 and Table A.6 provide total system and state-level forecasted retail sales summaries measured at the customer meter by customer class including retail load reduction projections from new energy efficiency measures from the 2017 IRP Update preferred portfolio.

Table A.5 - System Annual Retail Sales Forecast 2018 through 2027 (Megawatt-hours), post-DSM

System Retail Sales – Megawatt-hours (MWh)						
Year	Residential	Commercial	Industrial	Irrigation	Lighting	**Total**
2018	15,842,460	17,655,267	18,840,636	1,472,163	139,346	**53,949,872**
2019	15,666,962	17,776,306	18,904,276	1,468,159	138,470	**53,954,173**
2020	15,317,343	17,799,587	18,951,777	1,463,425	137,705	**53,669,838**
2021	15,139,319	17,776,502	18,979,641	1,459,882	136,290	**53,491,634**
2022	15,103,151	17,824,771	19,029,805	1,456,569	135,254	**53,549,550**
2023	15,101,463	17,887,389	19,076,640	1,453,414	134,294	**53,653,199**
2024	15,171,117	17,991,108	19,151,692	1,449,714	133,771	**53,897,402**
2025	15,109,350	17,980,093	19,152,679	1,445,707	132,355	**53,820,183**
2026	15,114,358	18,007,469	18,331,019	1,442,171	131,322	**53,026,339**
2027	15,139,947	18,026,099	18,378,406	1,438,641	130,355	**53,113,447**
Average Annual Growth Rate						
2018-27	**-0.5%**	**0.2%**	**-0.3%**	**-0.3%**	**-0.7%**	**-0.2%**

Table A.6 - Annual Load Growth Change: 2017 IRP Forecast less 2017 IRP Update Forecast (Megawatt-hours) at Retail, Post-DSM

System Retail Sales – Megawatt-hours (MWh)						
Year	Residential	Commercial	Industrial	Irrigation	Lighting	**Total**
2018	177,449	273,632	(666,708)	79,206	(3,727)	(140,147)
2019	131,349	330,248	(738,992)	86,811	(4,721)	(195,304)
2020	(45,432)	284,028	(843,911)	94,082	(5,946)	(517,179)
2021	(71,403)	233,291	(866,246)	102,042	(6,983)	(609,300)
2022	(113,880)	196,864	(938,715)	108,965	(8,033)	(754,799)
2023	(121,453)	160,865	(1,084,944)	116,707	(8,999)	(937,824)
2024	(141,892)	130,274	(1,101,119)	127,023	(9,930)	(995,645)
2025	(96,134)	53,616	(1,269,773)	154,074	(10,943)	(1,169,160)
2026	(98,987)	(15,380)	(1,612,854)	198,321	(11,976)	(1,540,876)
2027	(101,065)	(85,816)	(1,682,937)	244,120	(12,943)	(1,638,641)

Residential

Over the 2018-2027 timeframe, the average annual growth of the residential class sales forecast declined from -0.3 percent in the 2017 IRP to -0.5 percent in the 2017 IRP Update. The number of residential customers across PacifiCorp's system is expected to grow at an annual average rate of 1.0 percent, reaching approximately 1.8 million customers in 2027, with Rocky Mountain Power states adding 1.4 percent per year and Pacific Power states adding 0.4 percent per year. It is expected that residential customers are likely to use more efficient appliances, which is having an adverse impact on the residential forecast, relative to the 2017 IRP load forecast.

Commercial

Average annual growth of the commercial class sales forecast declined from 0.5 percent annual average growth in the 2017 IRP to 0.2 percent expected average annual growth in the 2017 IRP Update. The number of commercial customers across PacifiCorp's system is expected to grow at an annual average rate of 1.0 percent, reaching approximately 229,000 customers in 2027, with Rocky Mountain Power states adding 1.3 percent per year and Pacific Power states adding 0.5 percent per year. Relative to the 2017 IRP, the Company increased its commercial forecast in the earlier years of the 2017 IRP Update load forecast, but lowered its commercial load expectations in the later years of the forecast. This is attributable to a more optimistic outlook for the commercial sector in Oregon and Washington, and a relatively less favorable outlook for the sector over the long-term in Utah.

Industrial

Average annual growth of the industrial class sales forecast declined from 0.3 percent annual average growth in the 2017 IRP to -0.3 percent expected annual growth in the 2017 IRP Update. A portion of the Company's industrial load is in the extractive industry in Utah and Wyoming. The Company has seen several large industrial customers lower their expectations for load growth given less favorable conditions within their particular sectors. Table A.7 through Table A.12 provide additional detail for the class level forecast within each jurisdiction.

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

Oregon Retail Sales – Megawatt-hours (MWh)						
Year	Residential	Commercial	Industrial	Irrigation	Lighting	**Total**
2018	5,583,761	5,243,692	1,707,309	328,153	36,758	**12,899,673**
2019	5,563,312	5,307,667	1,786,249	327,434	36,675	**13,021,337**
2020	5,464,674	5,264,941	1,784,727	326,644	36,627	**12,877,613**
2021	5,397,546	5,248,107	1,789,182	326,267	36,467	**12,797,570**
2022	5,375,546	5,252,996	1,789,987	326,187	36,460	**12,781,177**
2023	5,367,170	5,259,993	1,793,616	326,273	36,483	**12,783,535**
2024	5,385,442	5,279,002	1,797,358	326,265	36,634	**12,824,700**
2025	5,360,638	5,273,844	1,800,475	326,259	36,611	**12,797,826**
2026	5,355,605	5,283,714	1,803,726	326,317	36,722	**12,806,085**
2027	5,354,934	5,292,903	1,806,948	326,362	36,843	**12,817,991**
Average Annual Growth Rate						
2018-27	**-0.46%**	**0.10%**	**0.63%**	**-0.06%**	**0.03%**	**-0.07%**

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

Washington Retail Sales – Megawatt-hours (MWh)						
Year	Residential	Commercial	Industrial	Irrigation	Lighting	**Total**
2018	1,583,963	1,531,076	754,506	159,634	10,095	**4,039,274**
2019	1,578,843	1,538,986	745,572	159,279	10,027	**4,032,706**
2020	1,561,096	1,551,553	736,309	159,035	10,005	**4,017,998**
2021	1,546,875	1,551,753	719,218	158,918	9,947	**3,986,711**
2022	1,543,783	1,558,459	700,585	158,885	9,933	**3,971,644**
2023	1,542,404	1,566,411	683,400	158,920	9,934	**3,961,069**
2024	1,548,222	1,579,063	671,923	158,925	9,974	**3,968,107**
2025	1,541,570	1,581,426	660,230	158,816	9,949	**3,951,991**
2026	1,541,584	1,589,087	652,050	158,777	9,971	**3,951,470**
2027	1,543,786	1,598,326	642,080	158,835	10,019	**3,953,045**
Average Annual Growth Rate						
2018-27	**-0.29%**	**0.48%**	**-1.78%**	**-0.06%**	**-0.08%**	**-0.24%**

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

California Retail Sales – Megawatt-hours (MWh)						
Year	Residential	Commercial	Industrial	Irrigation	Lighting	**Total**
2018	376,905	226,895	57,710	95,417	2,019	**758,945**
2019	373,803	222,688	57,395	95,533	2,003	**751,420**
2020	366,846	218,992	57,238	95,370	1,989	**740,435**
2021	361,570	214,662	56,850	95,097	1,968	**730,146**
2022	358,646	210,869	56,590	94,761	1,946	**722,812**
2023	356,306	207,051	56,384	94,432	1,930	**716,102**
2024	355,551	203,762	56,276	94,045	1,922	**711,555**
2025	351,818	199,186	55,797	93,628	1,901	**702,331**
2026	349,659	195,159	55,472	93,254	1,888	**695,432**
2027	348,027	190,977	55,144	92,867	1,870	**688,884**
Average Annual Growth Rate						
2018-27	**-0.88%**	**-1.90%**	**-0.50%**	**-0.30%**	**-0.85%**	**-1.07%**

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

Utah Retail Sales – Megawatt-hours (MWh)						
Year	Residential	Commercial	Industrial	Irrigation	Lighting	**Total**
2018	6,580,325	8,750,826	7,726,318	220,942	76,102	**23,354,513**
2019	6,449,969	8,797,719	7,770,716	220,356	75,601	**23,314,360**
2020	6,257,058	8,841,810	7,836,627	219,757	75,119	**23,230,372**
2021	6,186,442	8,834,748	7,873,530	219,125	74,180	**23,188,025**
2022	6,186,852	8,864,904	7,919,273	218,567	73,441	**23,263,037**
2023	6,202,050	8,904,636	7,962,165	218,117	72,750	**23,359,718**
2024	6,246,505	8,964,872	8,012,795	217,650	72,281	**23,514,103**
2025	6,233,228	8,962,794	8,022,097	216,990	71,264	**23,506,373**
2026	6,251,555	8,979,066	7,188,909	216,355	70,443	**22,706,328**
2027	6,280,581	8,983,885	7,224,382	215,778	69,658	**22,774,284**
Average Annual Growth Rate						
2018-27	**-0.52%**	**0.29%**	**-0.74%**	**-0.26%**	**-0.98%**	**-0.28%**

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

Idaho Retail Sales – Megawatt-hours (MWh)						
Year	Residential	Commercial	Industrial	Irrigation	Lighting	**Total**
2018	700,024	519,581	1,713,474	643,556	2,604	**3,579,240**
2019	697,720	533,400	1,713,216	641,179	2,580	**3,588,094**
2020	686,874	546,324	1,713,424	638,320	2,553	**3,587,495**
2021	681,434	556,258	1,712,508	636,273	2,521	**3,588,994**
2022	681,551	568,547	1,712,418	634,075	2,488	**3,599,079**
2023	683,092	581,261	1,712,128	631,689	2,449	**3,610,619**
2024	687,631	594,841	1,712,500	628,967	2,416	**3,626,355**
2025	685,857	604,016	1,711,073	626,284	2,367	**3,629,598**
2026	687,235	614,079	1,710,416	623,895	2,327	**3,637,953**
2027	689,253	623,959	1,709,822	621,396	2,288	**3,646,719**
Average Annual Growth Rate						
2018-27	**-0.17%**	**2.05%**	**-0.02%**	**-0.39%**	**-1.42%**	**0.21%**

Table A.12 - Forecasted Retail Sales Growth in Wyoming, post-DSM

Wyoming Retail Sales – Megawatt-hours (MWh)						
Year	Residential	Commercial	Industrial	Irrigation	Lighting	**Total**
2018	1,017,483	1,383,197	6,881,318	24,460	11,768	**9,318,226**
2019	1,003,316	1,375,846	6,831,130	24,379	11,585	**9,246,256**
2020	980,796	1,375,968	6,823,453	24,298	11,412	**9,215,926**
2021	965,453	1,370,975	6,828,353	24,201	11,208	**9,200,189**
2022	956,774	1,368,994	6,850,953	24,094	10,986	**9,211,800**
2023	950,441	1,368,037	6,868,947	23,983	10,746	**9,222,155**
2024	947,765	1,369,569	6,900,840	23,863	10,544	**9,252,582**
2025	936,239	1,358,827	6,903,006	23,730	10,262	**9,232,064**
2026	928,719	1,346,363	6,920,445	23,573	9,971	**9,229,071**
2027	923,366	1,336,049	6,940,030	23,403	9,677	**9,232,524**
Average Annual Growth Rate						
2018-27	**-1.07%**	**-0.38%**	**0.09%**	**-0.49%**	**-2.15%**	**-0.10%**

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