PACIFIC POWER
A DIVISION OF PACIFICORP

825 NE Multnomah, Suite 2000
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March 31, 2016

VIA ELECTRONIC FILING
AND OVERNIGHT DELIVERY

Public Utility Commission of Oregon
201 High Street SE, Suite 100
Salem, Oregon 97301

Attn: Filing Center

RE: Docket No. LC 62
PacifiCorp's 2015 Integrated Resource Plan Update

Please find enclosed twenty copies of PacifiCorp d/b/a Pacific Power's (PacifiCorp or Company) 2015 Integrated Resource Plan (IRP) Update (2015 IRP Update). The 2015 IRP Update is also available electronically on PacifiCorp's IRP website, at http://www.pacificorp.com/es/irp.html. The Company's 2015 IRP was filed with the Public Utility Commission of Oregon on March 31, 2015.

The 2015 IRP Update describes resource planning and procurement activities that occurred subsequent to the filing of the 2015 IRP, presents an updated load and resource balance, presents an updated resource portfolio consistent with changes in the planning environment, presents an updated action plan, and provides a status update on the action plan filed with the 2015 IRP. The 2015 IRP Update is being submitted for informational purposes only and the Company does not request acknowledgment of its 2015 IRP Update. The confidential version is provided subject to Protective Order No. 14-416 adopted for this proceeding. A redacted version is also provided.

It is respectfully requested that all data requests regarding this filing be addressed as follows:

By e-mail (preferred): datarequest@pacificorp.com

By regular mail: Data Request Response Center
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If there are any informal inquiries concerning this filing, please contact Hui Shu, Manager Valuation and Planning, at (503) 813-5540 or Erin Apperson, Manager, Regulatory Affairs, at (503) 813-6642.

Sincerely,

R Bryce Dalley / JG

R. Bryce Dalley
Vice President, Regulation

Cc: Service List LC 62

CERTIFICATE OF SERVICE

I certify that I electronically filed a true and correct copy of PacifiCorp's 2015 IRP Update with the Public Utility Commission of Oregon Filing Center, who will serve the parties listed below via electronic mail in compliance with OAR 860-001-0180. PacifiCorp will provide a Confidential CD to the following parties that can receive confidential information via Overnight Delivery.

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Dated this 31st of March, 2016.

Carrie Meyer
Supervisor, Regulatory Operations

2015

Integrated Resource Plan Update

REDACTED

Appendix B

Let's turn the answers on.

PACIFICORP
Pacific Power
Rocky Mountain Power

March 31, 2016

This 2015 Integrated Resource Plan Update Report is based upon the best available information at the time of preparation. The IRP action plan will be implemented as described herein, but is subject to change as new information becomes available or as circumstances change. It is PacifiCorp's intention to revisit and refresh the IRP action plan no less frequently than annually. Any refreshed IRP action plan will be submitted to the State Commissions for their information.

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Cover Photos (Top to Bottom):
Wind Turbine: *Marengo II*
Solar: *Residential Solar Install*
Transmission: *Populus to Terminal Tower Construction*
Demand-Side Management: *Wattsmart Flower*
Thermal-Gas: *Lake Side 1*

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CONFIDENTIAL APPENDIX B – NAUGHTON UNIT 3 ANALYSIS

Executive Summary

Consistent with action item 4a in the 2015 IRP action plan PacifiCorp has updated its analysis of regional haze compliance alternatives for the Naughton Unit 3 coal-fueled generating facility. This updated analysis also satisfies the request by the Public Utility Commission of Oregon (OPUC) in its 2015 IRP acknowledgement order.[1] The analysis incorporates updates to forecasted loads, resources, market prices, and other modeling inputs. The studies also reflect updated costs that are specific to gas conversion of Naughton Unit 3, including the cost to procure gas transportation and the most recent cost estimates for engineering, procurement, and construction (EPC) to convert the unit to operate as a gas-fired facility.

The Naughton plant is located near Kemmerer, Wyoming. Unit 3 of the three-unit plant is owned and operated by PacifiCorp and was commissioned in 1971. Naughton Unit 3 has a capacity of 330 MW. In its final action, EPA indicated support for the conversion of Naughton Unit 3 to natural gas and that it would expedite action relative to consideration of the gas conversion once the state of Wyoming submitted the requisite state implementation plan (SIP) amendment. PacifiCorp has 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. Wyoming has not yet submitted a revised regional haze SIP incorporating this alternative compliance approach to EPA.

PacifiCorp's updated analysis compares early retirement at the end of 2017 to the natural gas conversion of Naughton Unit 3 by mid-2018 across a range of scenarios. This analysis shows that the early retirement alternative is lower cost than the assessed natural gas conversion alternative. However, recognizing that Naughton Unit 3 is an important generation resource to the state of Wyoming and PacifiCorp's customers, PacifiCorp will continue to review emerging technologies, re-assess traditional gas conversion technologies and costs, and consider other potential alternatives that could be applied to Naughton Unit 3 to allow continued operation beyond year-end 2017.

Naughton Unit 3 Compliance Alternatives

Compliance Timeline

PacifiCorp has considered an early retirement compliance alternative to the planned 2018 natural gas conversion of Naughton Unit 3. Timelines for the natural gas conversion and early retirement alternative are discussed below.

[1] Order No. 16-071 in PacifiCorp's 2015 Integrated Resource Plan, Docket LC 62, dated February 29, 2016.

Natural Gas Conversion

A schedule to convert Naughton Unit 3 to 100 percent natural gas fueling is presented in Attachment B-I, Figure B-I.1. The implementation schedule assumes the unit would be converted to natural gas fueling in 2018 after coal fueling is discontinued December 31, 2017. Thereafter, a five-month tie-in outage is planned. The following scope of work is anticipated to be required:

- Installing new low oxides of nitrogen natural gas burner system;
- Main windbox modifications;
- Modifying the boiler flame scanner system;
- Installing new boiler burner front natural gas piping;
- Installing an induced flue gas recirculation system, provided to reduce oxides of nitrogen and carbon monoxide emissions;
- Potential air preheater basket modifications;
- Flue gas ductwork and equipment modifications;
- Potential boiler and flue gas path equipment structural reinforcement;
- Electrical and control system modifications; and
- Installing a natural gas delivery system.

Early Retirement

A schedule for an early retirement scenario of Naughton Unit 3 by an assumed date of January 1, 2018 is presented in Attachment B-I, Figure B-I.2. Unit retirement work would include:

- Unit 3 will be decommissioned and cleaned of all fluids;
- All hazardous materials will be removed and properly disposed of;
- Demolition, removal and disposal of electric generating equipment and ancillary systems will occur after 2029 when Units 1 and 2 are retired; and
- Reclamation and final closure of the site.

Naughton Unit 3 Analysis

Methodology

Present value revenue requirement differential (PVRR(d)) analyses are used to quantify the benefit or cost of regional haze environmental compliance alternatives relative to a benchmark. In the case of Naughton Unit 3, a natural gas conversion is compared to an early retirement alternative benchmark. The PVRR(d) for a given environmental compliance alternative is calculated as the difference in system costs between two System Optimizer model simulations—a benchmark simulation and a simulation for an alternative compliance scenario.

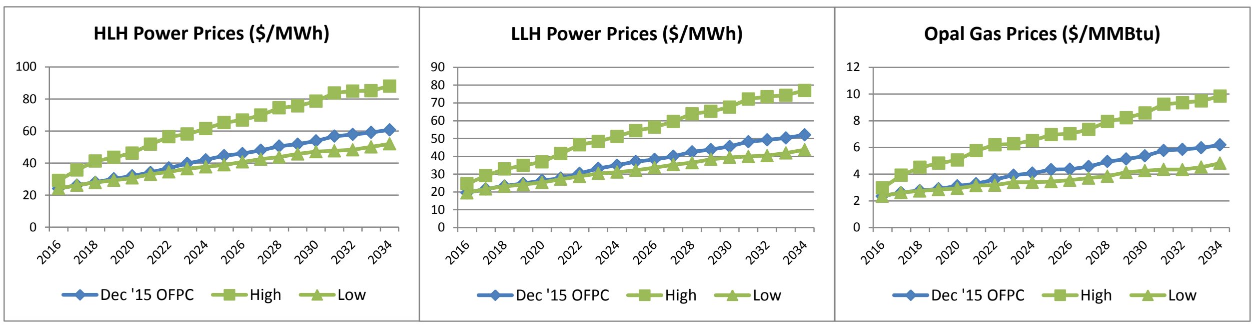
This confidential appendix presents the updated studies on the compliance alternatives of Naughton Unit 3 that were provided in PacifiCorp's 2015 IRP. The updated studies reflect the changes in load forecast, market prices, existing resources, as well as the costs to convert the unit. The studies are performed under different emission compliance scenarios: without Clean Power Plan (CPP) emission control constraints and with CPP emission control constraints that are consistent with EPA's mass-based federal implementation plan proposed for the CPP. Two book-end CPP assumptions are implemented in the studies: one assumes that PacifiCorp would not be able to receive set-aside incentives that encourage early development of renewable resources ("FIP" mass-cap), while the other assumes PacifiCorp would be able to receive these allowance set-asides, which would result in less stringent emission mass-cap constraints ("Set-aside" mass-cap). Table B.1 shows PacifiCorp's share of emission mass-cap goals that would be applicable to PacifiCorp's affected units.[2] The mass-cap constraints are implemented by applying a company-wide cap on emissions of the affected units.

Table B.1 – CPP Emission Mass-Cap Assumptions (thousand short tons)

	2022	2023	2024	2025	2026	2027	2028	2029	2030
"FIP"	42,441	40,779	38,626	41,063	40,095	38,930	38,184	37,376	36,482
"Set-aside"	47,905	46,155	43,889	42,948	41,929	40,702	39,917	39,066	38,126

The Naughton Unit 3 compliance analysis was performed using medium, high and low price curve scenarios. The medium price scenario is based on PacifiCorp's December 2015 official forward price curve (OFPC), consistent with medium price assumptions used to develop the portfolio for the 2015 IRP Update. Figure B.1 summarizes heavy load hour (HLH) and light load hour (LLH) wholesale power prices and natural gas prices assumed for this analysis.[3]

Figure B.1 – Naughton Unit 3 Forward Price Curve Assumptions



*Note, 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.

Annual Non-fuel Expenditure Assumptions

Annual non-fuel planned expenditures include environmental capital costs, run-rate capital costs, run-rate operation and maintenance (O&M) costs, fixed firm natural gas transportation costs, and natural gas [redacted] costs, as applicable. In addition, liquidated damage (LD) costs associated with the existing coal supply agreement (CSA), which extends through 2021, are included in PacifiCorp's analysis. Detailed annual non-fuel planned expenditures for the Naughton Unit 3 natural gas conversion and early retirement compliance alternatives are provided in Attachment B-II.

[2] Cholla Unit 4 is excluded based on the assumption that PacifiCorp's share of mass-cap in the state of Arizona is sufficient to cover the emission from the unit during limited time period.
[3] HLH prices cover to hours ending 7 through 22 PPT, Monday through Saturday, excluding NERC holidays. LLH prices cover all other hours.

The 2018 Naughton Unit 3 natural gas conversion case includes [redacted] in 2018 run-rate capital expenditures to complete the conversion and further includes annual fixed costs for natural gas transportation, including levelized costs for a new pipeline lateral, which would be required to transport natural gas from [redacted] to the Naughton plant.[4]

Under either the 2018 natural gas conversion or the 2018 early retirement case, PacifiCorp would be subject to LD payments under an existing CSA between PacifiCorp and Westmoreland Kemmerer, Inc. that provides for coal deliveries to the Naughton plant from January 1, 2017 through December 31, 2021. LD payments applicable to either alternative total [redacted] over the period 2018 through 2021.

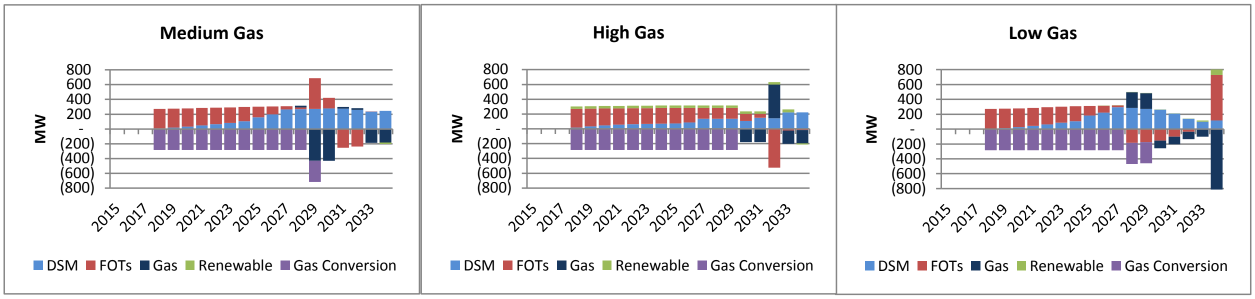
Resource Portfolio Results

In the 2018 early retirement case, the loss of Naughton Unit 3 creates an incremental capacity need beginning in the summer of 2018, which drives the need for replacement resources over the 2018 to 2034 timeframe. Figure B.2 summarizes the cumulative change in resource portfolio capacity when Naughton Unit 3 is retired at the end of 2017 as compared to the unit being converted to natural gas by June 2018, and under the "FIP" mass-cap constraint. 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 retires at end of 2017. Notable resource portfolio changes resulting from an early retirement relative to conversion include:

- In the medium natural gas price scenario:
  - Prior to 2028 and after Naughton Unit 3 is assumed to retire at the end of 2017 as opposed to being converted to gas fueled unit, front office transactions (FOTs) and demand side management resources (DSM) fill the capacity resource needs.
  - 2028 onwards, given that significant amount of DSM has been added to the system, combined cycle combustion turbines (CCCTs) are reduced and delayed.
- In the high natural gas price scenario:
  - Prior to 2028 and after Naughton Unit 3 is assumed to retire at the end of 2017 as opposed to being converted to gas fueled unit, FOTs and DSM fill the capacity resource needs.
  - In 2028, when Naughton Unit 3 retires early, a 635 MW CCCT is replaced with a 477 MW CCCT, which, in turn, accelerates a 635 MW CCCT from 2033 to 2032.
  - In 2018, 33 MW of wind resources are added when Naughton Unit 3 retires. With 52 MW of solar resources added in 2033 and 2034, a 100 MW of wind resource on the west side of the system is displaced.
- In the low natural gas price scenario:
  - Prior to 2028 and after Naughton Unit 3 is assumed to retire at the end of 2017 as opposed to being converted to a gas-fueled unit, FOTs and DSM fill the capacity resource needs.
  - In 2028, under the Naughton Unit 3 early retirement scenario, a 423 MW CCCT is replaced with a 635 MW CCCT, which, together with the addition of FOTs and DSM, displaces 1,025 MW of CCCTs on the east and west sides of the system.

[4] It is assumed that [redacted] would complete [redacted] and charge PacifiCorp for its estimated [redacted] cost. The [redacted] costs are treated as a lease with an assumed [redacted] interest rate, which effectively converts the up-front payment to a [redacted] annual expense.

Figure B.2 – Cumulative Increase/(Decrease) in Portfolio Resources Under the Naughton Unit 3 Early Retirement Case



PVRR(d) Results

Table B.2 summarizes PVRR system cost detail for the 2018 early retirement case and the 2018 natural gas conversion case along with the PVRR(d) benefit/(cost) of early retirement for the medium, high and low natural gas price scenarios, with and without CPP mass-cap constraints.

Table B.2 – Line Item Detail of 2018 Early Retirement of Naughton Unit 3 as Compared to 2018 Gas Conversion ($ million)

SO Model Results for Gas Price Scenarios without CPP Constraints by Cost Category									
	Naughton Unit 3 Retire Early (PVRR $ million)			Naughton Unit 3 Conversion (PVRR $ million)			PVRR(d) (Benefit)/Cost of Early Retirement		
Scenario	High Gas	Base Case (Dec' 2015 OFPC)	Low Gas	High Gas	Base Case (Dec' 2015 OFPC)	Low Gas	High Gas	Base Case (Dec' 2015 OFPC)	Low Gas
SO Model Simulation	Early Retirement	Early Retirement	Early Retirement	Gas-Fired	Gas-Fired	Gas-Fired	n/a	n/a	n/a
System Variable Costs									
Fuel/FOTs	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Variable O&M/Wind&Solar PPA									
Emissions									
Net System Balancing									
Total Variable									
System Fixed Costs									
New Resource Capital/Run-rate	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Existing Resource Capital/Run-rate									
Decomissioning/Stranded Cost									
Contracts									
Incremental DSM									
Transmission									
Total Fixed									
Total Costs									

1/ Includes adjustments for changes in Naughton coal supply contracts when Naughton Unit 3 ceases coal-fired operation.

2/ Fixed costs include levelized costs for incremental environmental upgrade investments, total O&M for coal resources, and fixed O&M and run-rate capital for all resources.

Table B.2 – Line Item Detail of 2018 Early Retirement of Naughton Unit 3 as Compared to 2018 Gas Conversion ($ million), Continued

SO Model Results for Gas Price Scenarios with Assumed FIP Mass-Cap by Cost Category

	Naughton Unit 3 Retire Early (PVRR $ million)			Naughton Unit 3 Conversion (PVRR $ million)			PVRR(d) (Benefit)/Cost of Early Retirement		
Scenario	High Gas	Base Case (Dec' 2015 OFPC)	Low Gas	High Gas	Base Case (Dec' 2015 OFPC)	Low Gas	High Gas	Base Case (Dec' 2015 OFPC)	Low Gas
SO Model Simulation	Early Retirement	Early Retirement	Early Retirement	Gas-Fired	Gas-Fired	Gas-Fired	n/a	n/a	n/a
System Variable Costs									
Fuel/FOTs	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Variable O&M/Wind&Solar PPA	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Emissions	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Net System Balancing	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Total Variable	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
System Fixed Costs									
New Resource Capital/Run-rate	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Existing Resource Capital/Run-rate	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Decomissioning/Stranded Cost	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Contracts	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Incremental DSM	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Transmission	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Total Fixed	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Total Costs	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

1/ Includes adjustments for changes in Naughton coal supply contracts when Naughton Unit 3 ceases coal-fired operation.
2/ Fixed costs include levelized costs for incremental environmental upgrade investments, total O&M for coal resources, and fixed O&M and run-rate capital for all resources.

SO Model Results for Gas Price Scenarios with Assumed Set-Aside Mass-Cap by Cost Category

	Naughton Unit 3 Retire Early (PVRR $ million)			Naughton Unit 3 Conversion (PVRR $ million)			PVRR(d) (Benefit)/Cost of Early Retirement		
Scenario	High Gas	Base Case (Dec' 2015 OFPC)	Low Gas	High Gas	Base Case (Dec' 2015 OFPC)	Low Gas	High Gas	Base Case (Dec' 2015 OFPC)	Low Gas
SO Model Simulation	Early Retirement	Early Retirement	Early Retirement	Gas-Fired	Gas-Fired	Gas-Fired	n/a	n/a	n/a
System Variable Costs									
Fuel/FOTs	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Variable O&M/Wind&Solar PPA	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Emissions	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Net System Balancing	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Total Variable	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
System Fixed Costs									
New Resource Capital/Run-rate	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Existing Resource Capital/Run-rate	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Decomissioning/Stranded Cost	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Contracts	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Incremental DSM	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Transmission	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Total Fixed	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Total Costs	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

1/ Includes adjustments for changes in Naughton coal supply contracts when Naughton Unit 3 ceases coal-fired operation.
2/ Fixed costs include levelized costs for incremental environmental upgrade investments, total O&M for coal resources, and fixed O&M and run-rate capital for all resources.

The following summarizes line-item PVRR(d) results for the early retirement case as compared to the gas conversion case under medium natural gas price assumptions and under the "FIP" mass-cap constraint. The values below are quoted on a present value revenue requirement basis calculated through the 20-year planning horizon:

- Fuel cost at Naughton Unit 3 decrease by [redacted], which is offset by increased system fuel and FOT costs totaling [redacted]—driven by the need to replace lost generation.
- Net system balancing benefits increase by approximately [redacted], offsetting the increase in system fuel and FOT costs.
- Early retirement of Naughton Unit 3 results in approximately [redacted] of savings in run-rate capital and operating cost of the unit and capital cost to convert the unit.
- With more Class 2 DSM resources under the early retirement case, system DSM costs are increased by [redacted].

- In aggregate, variable and fixed cost expenditures for Naughton Unit 3 decrease by [redacted], which is partially offset by increased fixed and variable costs of rest of the system totaling [redacted]. The net benefit under the 2018 Naughton Unit 3 early retirement case relative to the 2018 natural gas conversion case is [redacted].

The following summarizes line-item PVRR(d) results for the early retirement case as compared to the gas conversion case under high natural gas price assumptions and under the “FIP” mass-cap constraint. The values below are quoted on a present value revenue requirement basis calculated through the 20-year planning horizon:

- Fuel cost at Naughton Unit 3 decrease by [redacted], which is offset by increased system fuel and FOT costs totaling [redacted]—driven by the need to replace the lost generation.
- Net system balancing benefits increase by approximately [redacted], offsetting the increase in system fuel and FOT costs.
- Early retirement of Naughton Unit 3 results in approximately [redacted] of savings in run-rate capital and operating cost of the unit and capital cost to convert the unit.
- With more Class 2 DSM resources under the early retirement case, system DSM costs are increased by [redacted].
- In aggregate, variable and fixed cost expenditures for Naughton Unit 3 decrease by [redacted], which is partially offset by increased fixed and variable costs of rest of the system totaling [redacted]. The net benefit under the 2018 Naughton Unit 3 early retirement case relative to the 2018 natural gas conversion case is [redacted].

The following summarizes line-item PVRR(d) results for the early retirement case as compared to the gas conversion case under low natural gas price assumptions and under the “FIP” mass-cap constraint. The values below are quoted on a present value revenue requirement basis calculated through the 20-year planning horizon:

- Fuel cost at Naughton Unit 3 decrease by [redacted], which is offset by increased system fuel and FOT costs totaling [redacted]—driven by the need to replace the lost generation.
- Net system balancing benefits increase by approximately [redacted], offsetting the increase in system fuel and FOT costs.
- Early retirement of Naughton Unit 3 results in approximately [redacted] of savings in run-rate capital and operating cost of the unit and capital cost to convert the unit.
- With more Class 2 DSM resources under the early retirement case, system DSM costs are increased by [redacted].
- In aggregate, variable and fixed cost expenditures for Naughton Unit 3 decrease by [redacted], which is partially offset by increased fixed and variable costs of rest of the system totaling [redacted]. The net benefit under the 2018 Naughton Unit 3 early retirement case relative to the 2018 natural gas conversion case is [redacted].

Conclusion

In July 2015 the competitive bid event was reopened using an Addendum 6. The “short-listed” bidders from the previous request for proposals were asked to refresh all pricing and commercial terms to current market conditions. Refreshed proposals were received from the short-listed bidders on November 2, 2015. With updated forecasted loads, resources, market prices, and capital costs to convert the unit, PacifiCorp's financial analysis shows that the 2018 early retirement of Naughton Unit 3 is lower cost than a 2018 gas conversion alternative. Recognizing that Naughton Unit 3 is an important generation resource to the state of Wyoming and PacifiCorp's customers, PacifiCorp will continue to review emerging technologies, re-assess traditional gas conversion technologies and costs, and consider other potential alternatives that could be applied to Naughton Unit 3 to allow continued operation beyond year-end 2017.

Attachment B-I: Naughton Unit 3 Timelines

Figure B-I.1 – Naughton Unit 3 Natural Gas Conversion Schedule for a June 1, 2018 On-line Date

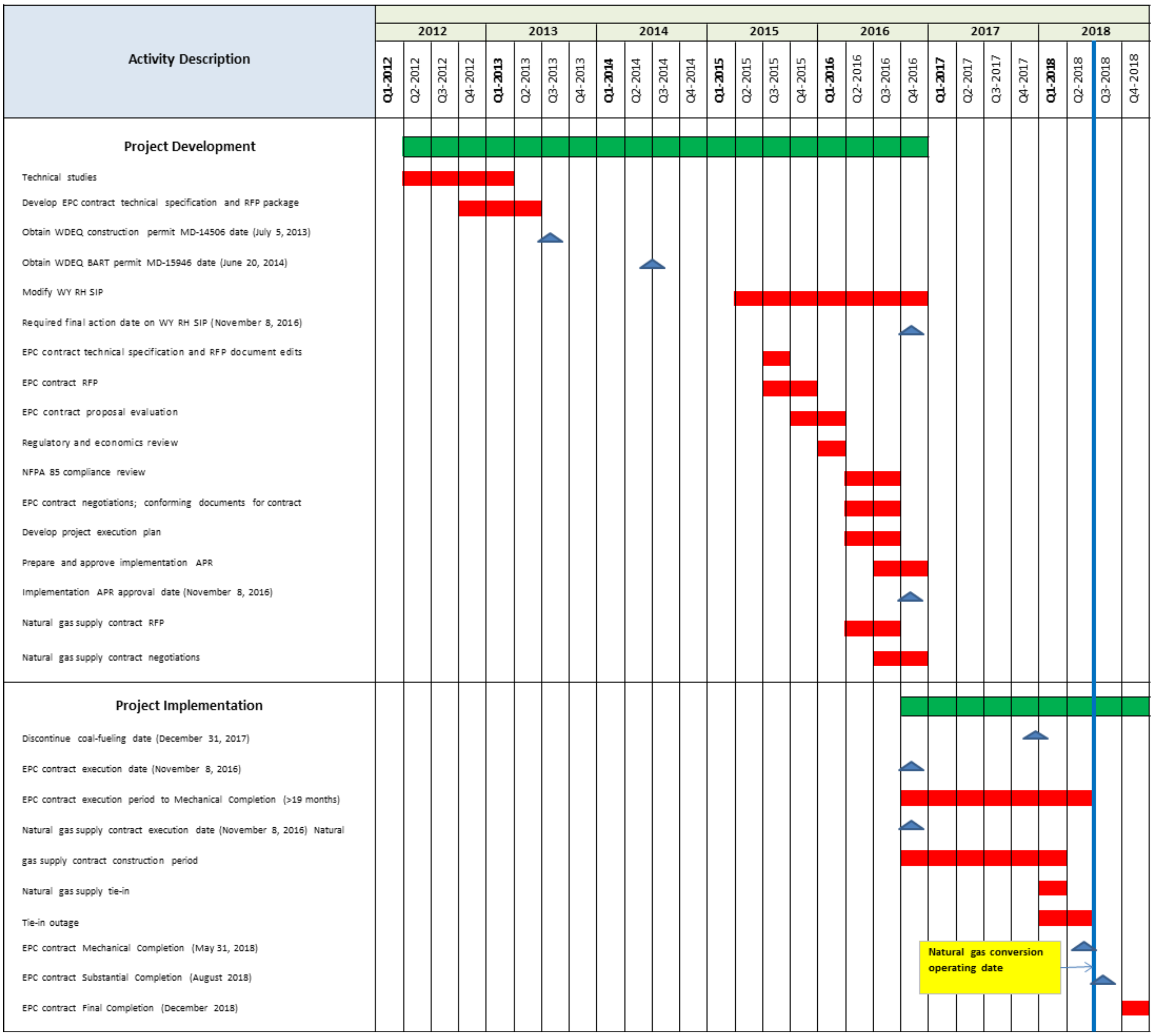


Figure B-I.2 – Naughton Unit 3 Early Retirement Decommissioning Schedule for a December 31, 2017 Retirement Date

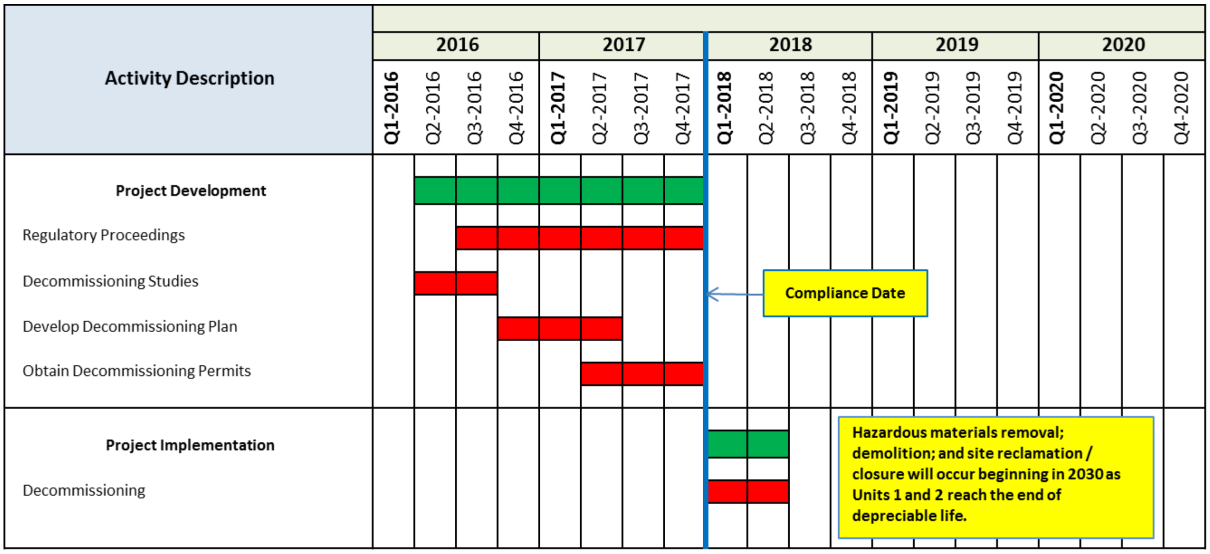
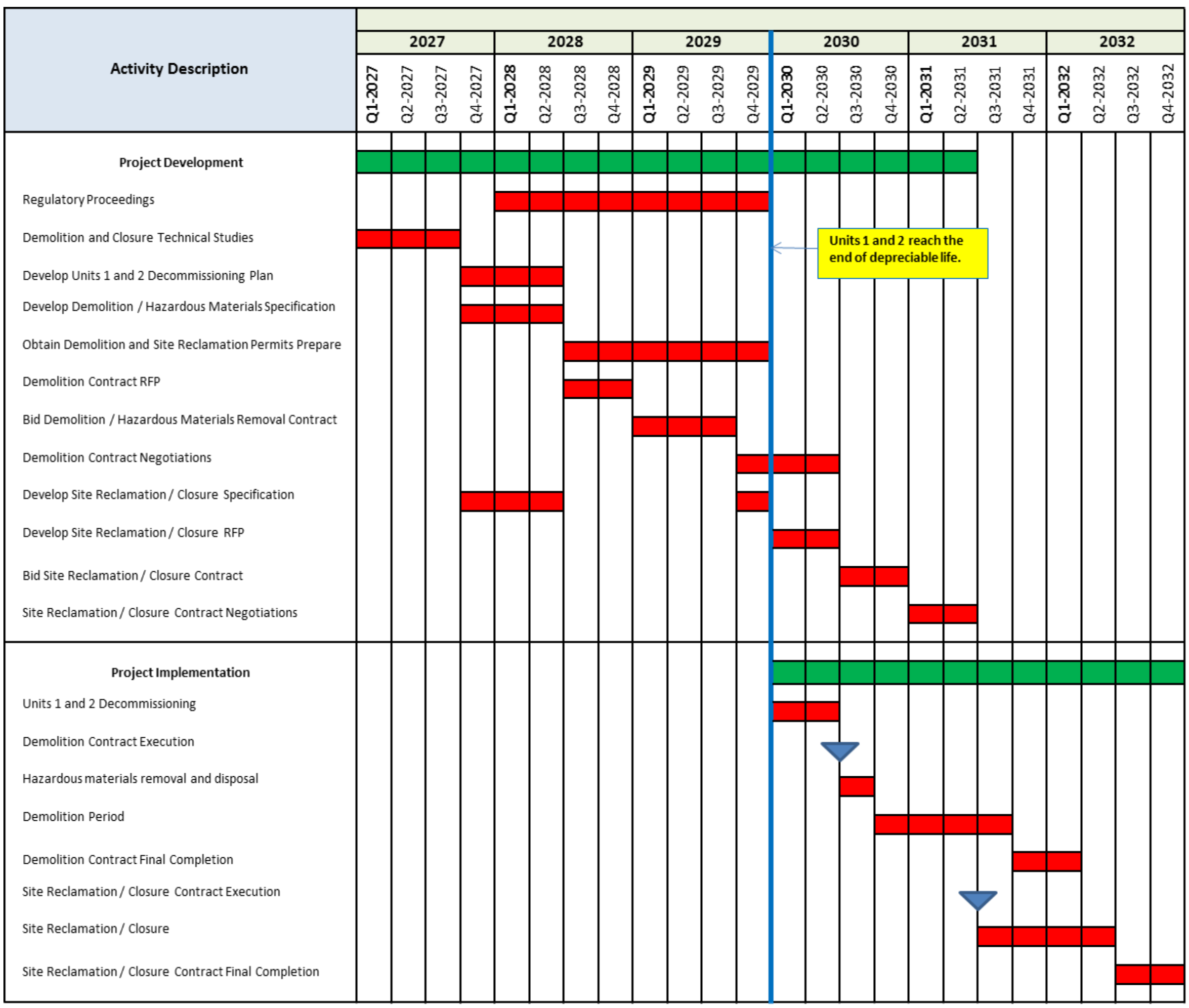


Figure B-I.3 – Naughton Unit 3 Demolition and Closure Schedule



Attachment B-II: Naughton Unit 3 Compliance Alternative Annual Expenditures

Table B-II.1 – Naughton Unit 3 Annual Expenditures for a 2018 Gas Conversion Case

Naughton Unit 3 Environmental Capital (Nominal $m, with AFUDC)			
Description	2015	2017	Total
Mercury	[redacted]	[redacted]	[redacted]
CWA	[redacted]	[redacted]	[redacted]
Effluent	[redacted]	[redacted]	[redacted]
Total	[redacted]	[redacted]	[redacted]

Naughton Unit 3 Run-rate Operating Cost (Nominal $m, Capital with AFUDC)										
Description	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
O&M	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Capital	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
CSA LDs	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Fixed Gas Trans.	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Total	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Description	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
O&M	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Capital	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
CSA LDs	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Fixed Gas Trans.	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Total	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

Table B-II.2 – Naughton Unit 3 Annual Expenditures for a 2018 Early Retirement Case

Naughton Unit 3 Environmental Capital (Nominal $m, with AFUDC)			
Description	2015	2017	Total
Mercury	[redacted]	[redacted]	[redacted]
CWA	[redacted]	[redacted]	[redacted]
Effluent	[redacted]	[redacted]	[redacted]
Total	[redacted]	[redacted]	[redacted]

Naughton Unit 3 Run-rate Operating Cost (Nominal $m, Capital with AFUDC)										
Description	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
O&M	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Capital	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
CSA LDs	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Total	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Description	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
O&M	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Capital	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
CSA LDs	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Total	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

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2015 Integrated Resource Plan Update

Let's turn the answers on.

March 31, 2016

PACIFICORP

Pacific Power
Rocky Mountain Power

This 2015 Integrated Resource Plan Update Report is based upon the best available information at the time of preparation. The IRP action plan will be implemented as described herein, but is subject to change as new information becomes available or as circumstances change. It is PacifiCorp's intention to revisit and refresh the IRP action plan no less frequently than annually. Any refreshed IRP action plan will be submitted to the State Commissions for their information.

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Cover Photos (Top to Bottom):
Wind Turbine: *Marengo II*
Solar: *Residential Solar Install*
Transmission: *Populus to Terminal Tower Construction*
Demand-Side Management: *Wattsmart Flower*
Thermal-Gas: *Lake Side 1*

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EXECUTIVE SUMMARY

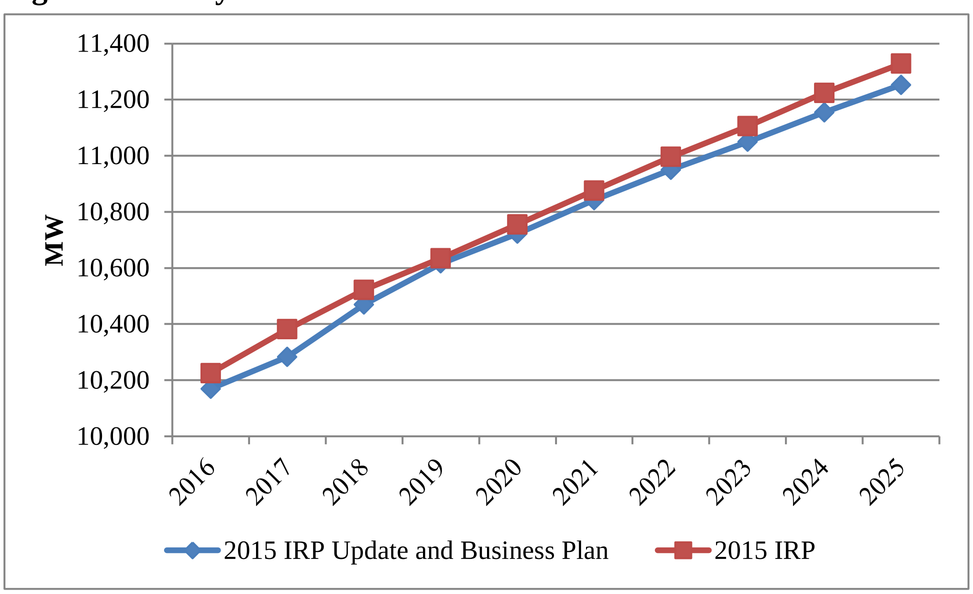
PacifiCorp submitted its 2015 Integrated Resource Plan (2015 IRP) to state regulatory commissions in March 2015. That plan provides a framework for future actions that PacifiCorp will take to provide reliable, reasonable-cost service with manageable risks for customers. This 2015 IRP Update describes resource planning and procurement activities that occurred since the 2015 IRP was filed, presents an updated load and resource balance, presents an updated resource portfolio consistent with changes in the planning environment, presents an updated action plan, and provides a status update on the action plan filed with the 2015 IRP. In presenting the updated load and resource balance and updated resource portfolio, PacifiCorp shows changes relative to the 2015 IRP and relative to its fall 2015 ten-year business plan (Business Plan), which covers the 2016 to 2025 planning horizon. In this update PacifiCorp also addresses recommendations and requirements identified by its state regulatory commissions during the 2015 IRP acknowledgement process.

2015 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 2015 IRP Update:

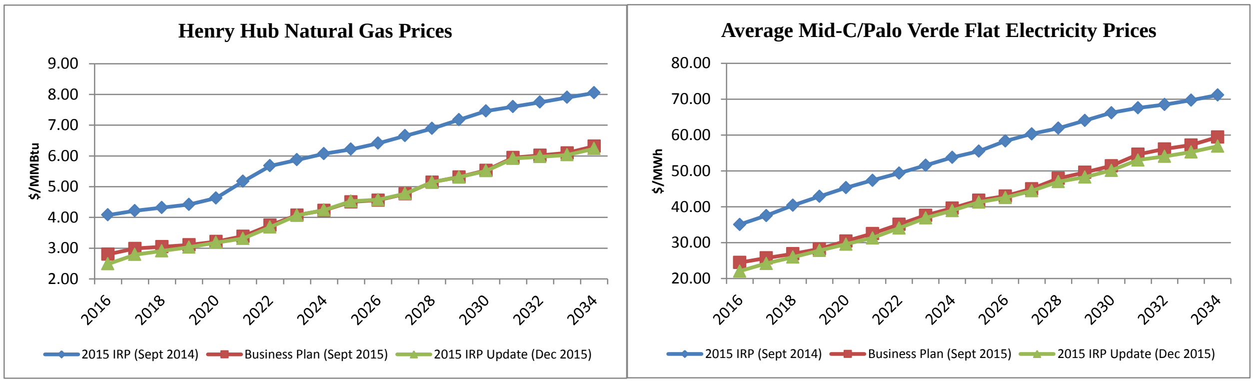
- As shown in Figure ES.1 PacifiCorp's most recent coincident system peak load forecast, used for the Business Plan and the 2015 IRP Update, is down relative to the 2015 IRP. On average, across the front ten years of the planning period, the coincident system peak is down by about 54 MW relative to the 2015 IRP.

Figure ES.1 – System Coincident Peak Load



- Figure ES.2 shows that forecasted natural gas and energy prices have declined from those assumed in the 2015 IRP. Domestic gas price forecasts continue to be driven down by growth in unconventional shale gas plays. This in turn (combined with lower forecast regional loads) impacts forward market power prices.

Figure ES.2 – Power and Natural Gas Price Comparisons (Nominal)



- PacifiCorp's updated resource portfolio continues to show that customer loads over the front ten years of the planning horizon will be met with front office transactions (firm market purchases) and energy efficiency. Over the front ten years of the planning period (2016 through 2025), accumulated acquisition of incremental energy efficiency resources meets 87% of projected load growth.

- PacifiCorp refreshed its analysis of Regional Haze compliance alternatives for Naughton Unit 3, which was assumed to convert to a natural gas-fired facility by mid-2018 in the 2015 IRP. With reduced load, lower market prices, and increased costs for gas conversion, the refreshed analysis shows that retiring Naughton Unit 3 at the end of 2017 is a lower cost alternative than the assessed gas conversion approach. As such, the capacity of the converted Unit 3 is no longer included in the 2015 IRP Update resource portfolio after year-end 2017. However, recognizing that Naughton Unit 3 is an important generation resource to the state of Wyoming and PacifiCorp's customers, PacifiCorp will continue to review emerging technologies, re-assess traditional gas conversion technologies and costs, and consider other potential alternatives that could be applied to Naughton Unit 3 to allow continued operation beyond year-end 2017.

- The state of Arizona issued a regional haze state implementation plan (SIP) requiring, among other things, the installation of SO_2, NO_X and particulate matter controls on Cholla Unit 4, which is owned by PacifiCorp but operated by Arizona Public Service. The U.S. Environmental Protection Agency (EPA) approved in part, and disapproved in part, the Arizona SIP and issued a federal implementation plan (FIP) requiring the installation of selective catalytic reduction (SCR) equipment on Cholla Unit 4. PacifiCorp filed an appeal regarding the FIP as it relates to Cholla Unit 4, and the Arizona Department of Environmental Quality and other affected Arizona utilities filed separate appeals of the FIP as it relates to their interests. With respect to the Cholla FIP requirements, the court has placed the appeals in abeyance while parties attempt to agree on an alternative compliance approach. In October 2015, EPA acknowledged receipt of the state of Arizona's re-assessed regional haze SIP that commits to ceasing operation of Cholla Unit 4 as a coal fueled resource in April 2025, in lieu of installation of SCR. EPA is currently expected to propose its final action on the Arizona SIP in mid-2016 and commence the public comment process. Similar to Naughton Unit 3, with reduced load, lower market prices, and expected costs for gas conversion, PacifiCorp has assumed Cholla Unit 4 will cease operation at the end of 2024 for capacity planning purposes in the 2015 IRP Update.

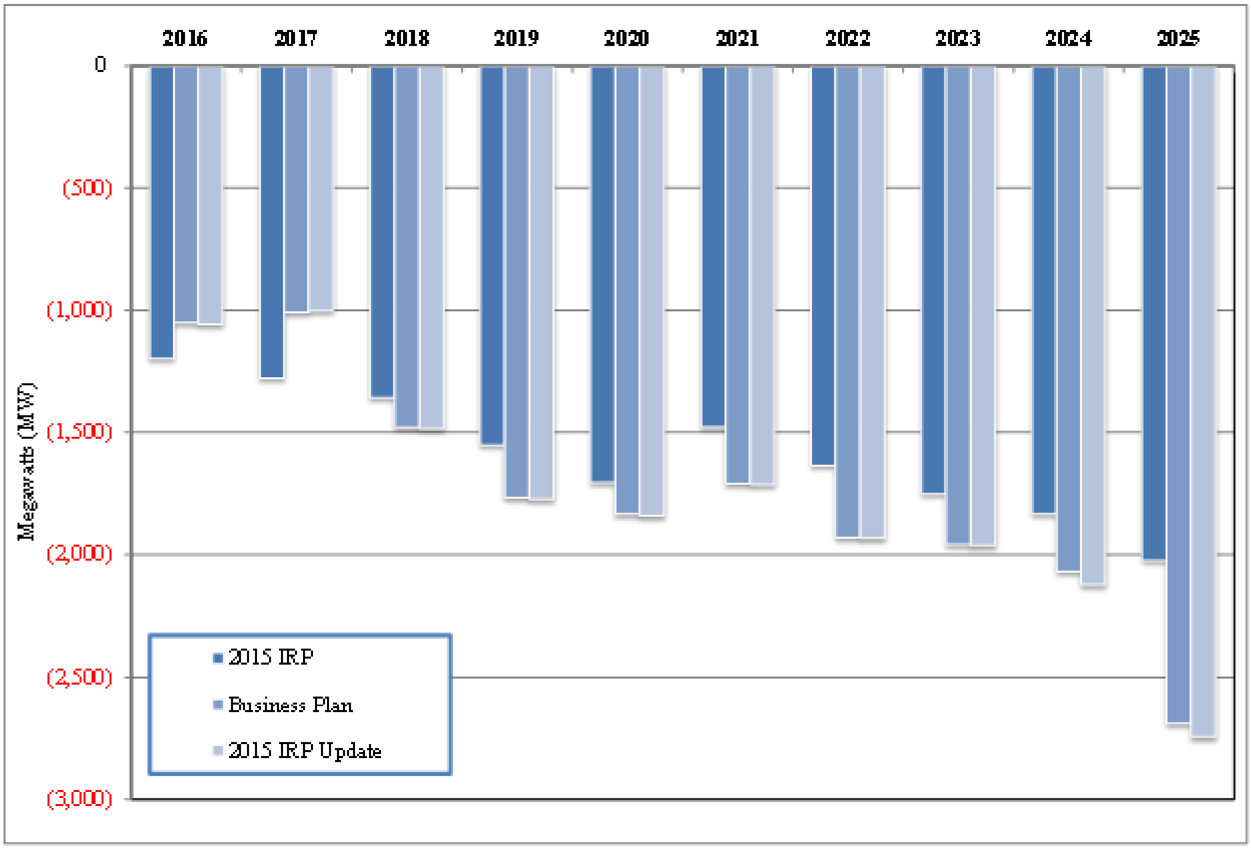
- After PacifiCorp filed its 2015 IRP, EPA issued its final rule for the Clean Power Plan (CPP). On February 9, 2016, the U.S. Supreme Court issued a stay of the CPP suspending implementation of the rule pending the outcome of the merits of litigation before the D.C. Circuit Court of Appeals. If parties petition for a writ of certiorari before the U.S. Supreme Court, the stay will remain in effect until the U.S. Supreme Court takes action to either deny the petition, or, if the U.S. Supreme Court hears the case, the stay remains in effect until the court enters its judgment. Oral argument on the CPP litigation is scheduled for June 2, 2016 before the D.C. Circuit Court of Appeals. In the 2015 IRP Update, PacifiCorp assumes a mass-based emission target to limit CO_2 emission from its affected generation facilities covered by the CPP.

- On March 8, 2016, Oregon Senate Bill 1547-B (SB 1547-B), the Clean Electricity and Coal Transition Plan, was signed into law, which, among other things, doubles the Oregon renewable portfolio standard (RPS) target to 50% by 2040. In October 2015, California Senate Bill No. 350 (SB 350) was signed into law, which among other things, expands California's RPS targets to 50% by 2030. Considering these updated RPS targets, renewable energy credit (REC) banking provisions and the market potential for RECs, PacifiCorp can meet its state RPS obligations through the planning horizon with REC purchases. However, PacifiCorp has identified the potential for a near-term, time-sensitive opportunity that may reduce state RPS compliance costs over time through the acquisition of renewable resources that can take full advantage of federal income tax deductions and credits passed in December 2015. PacifiCorp has updated its action plan to issue requests for proposals (RFPs) seeking both REC purchase and resource procurement alternatives.

Load and Resource Balance Update

Figure ES.3 summarizes the 2015 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 2015 IRP and the Business Plan. The load and resource balance has decreased by an average of 209 MW, relative to the 2015 IRP, in 2016 and 2017 reflecting to changes in the load forecast, hydro generation and qualifying facility contracts. The projected load and resource balance position is shorter beginning in 2018, relative to the 2015 IRP, primarily due to the assumed early retirement of Naughton Unit 3 at the end of 2017 and Cholla Unit 4 at the end of 2024. This is partially offset by the addition of new wind and solar qualifying facility contracts. The 2015 IRP Update load and resource balance shows is shorter by 128 MW in 2018 rising to 720 MW by 2025.

Figure ES.3 – Capacity Position Comparison



Resource Portfolio Update

Table ES.1 reports the 2015 IRP Update resource portfolio and differences relative to the 2015 IRP Preferred Portfolio.[1] The table shows the resource mix targeted to achieve a 13% planning reserve margin in each reported year. As compared to the 2015 IRP Preferred Portfolio, changes in the resource mix for the 2016-2025 planning period reflect those needed to meet capacity needs associated with the assumed early retirement of Naughton Unit 3 and Cholla Unit 4. As was the case in the 2015 IRP Preferred Portfolio, PacifiCorp continues to plan to meet its customers' needs largely through the acquisition of cost-effective energy efficiency (Class 2 Demand Side Management) resources and FOTs over the next ten years.

[1] A comparison of the portfolio changes relative to the Business Plan is presented in Chapter 5.

Table ES.1 – Comparison of 2015 IRP Update with 2015 IRP Preferred Portfolio (Megawatts)

2015 IRP Update

	Capacity (MW)											10- year Total
Resource	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2016-2025**
Expansion Options												
Gas - CCCT	-	-	-	-	-	-	-	-	-	-	-	-
Gas- Peaking	-	-	-	-	-	-	-	-	-	-	-	-
DSM - Energy Efficiency	143	128	138	146	158	142	149	155	161	162	135	**1,476**
DSM - Load Control	-	-	-	-	-	-	-	-	-	-	39	**39**
Renewable - Wind	-	-	-	-	-	-	-	-	-	-	-	-
Renewable - Geothermal	-	-	-	-	-	-	-	-	-	-	-	-
Renewable - Utility Solar	-	-	-	-	-	-	-	-	-	-	-	-
Renewable - Biomass	-	-	-	-	-	-	-	-	-	-	-	-
Front Office Transactions *	764	903	748	1,094	1,246	1,203	970	1,060	965	993	1,440	**1,062**
Existing Unit Changes												
Coal Early Retirement/Conversions	(222)	-	-	(280)	-	-	-	-	-	-	(387)	**(667)**
Thermal Plant End-of-life Retirements	-	-	-	-	-	-	-	-	-	-	-	-
Coal Plant Gas Conversion Additions	-	-	-	-	-	-	-	-	-	-	-	-
Total	**685**	**1,031**	**886**	**960**	**1,403**	**1,345**	**1,120**	**1,215**	**1,126**	**1,155**	**1,227**	

FOT in resource total are 10-year averages

2015 IRP Update less 2015 IRP Preferred Portfolio

	Capacity (MW)											10- year Total
Resource	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2016-2025**
Expansion Options												
Gas - CCCT	-	-	-	-	-	-	-	-	-	-	-	-
Gas- Peaking	-	-	-	-	-	-	-	-	-	-	-	-
DSM - Energy Efficiency	10	(11)	(8)	(0)	5	8	12	11	15	14	12	**58**
DSM - Load Control	-	-	-	-	-	-	-	(5)	(11)	-	39	**23**
Renewable - Wind	-	-	-	-	-	-	-	-	-	-	-	-
Renewable - Geothermal	-	-	-	-	-	-	-	-	-	-	-	-
Renewable - Utility Solar	-	-	-	-	-	-	-	-	-	-	-	-
Renewable - Biomass	-	-	-	-	-	-	-	-	-	-	-	-
Front Office Transactions *	37	(34)	(157)	224	311	224	202	269	205	239	670	**215**
Existing Unit Changes												
Coal Early Retirement/Conversions	-	-	-	-	-	-	-	-	-	-	-	-
Thermal Plant End-of-life Retirements	-	-	-	-	-	-	-	-	-	-	-	-
Coal Plant Gas Conversion Additions	-	-	-	(337)	-	-	-	-	-	-	(387)	**(724)**
Total	**47**	**(45)**	**(164)**	**(113)**	**315**	**232**	**214**	**275**	**209**	**252**	**333**	

FOT in resource total are 10-year averages

IRP Action Plan

PacifiCorp has updated its action plan to reflect changes in the planning environment since the IRP was filed in March 2015. Specifically, PacifiCorp updated action item 1a (Renewable Portfolio Standard Compliance) to issue RFPs for REC and near-term resource procurement opportunities that can be used to meet RPS requirements in Oregon, Washington, and California. The updated action plan also removes action item 1c (Oregon Solar Capacity Standard), which was eliminated when SB 1547-B was signed into law. As it relates to coal resource actions, action item 4a (Naughton Unit 3) has been updated consistent with PacifiCorp's most recent analysis summarized in Confidential Appendix B. Table ES.2 presents the updated action plan. Chapter 6 of the 2015 IRP Update provides a status update of PacifiCorp's 2015 IRP action plan action items.

Table ES.2 – 2015 IRP Update Action Plan

Action Item	1. Renewable Resource Actions
1a	**Renewable Portfolio Standard Compliance** • Issue a request for proposals (RFP) in spring 2016 seeking bids for new renewable resources that qualify for the Oregon, Washington, and/or California RPS and that can take full advantage of federal income tax deductions and credits renewed or extended in December 2015. • Issue a RFP in 2016 for current year and forward vintage RECs that qualify for the Oregon, Washington, and/or California RPS. • Complete the concurrent evaluation, selection, and contracting process for both the renewable resource RFP and REC RFP by fall 2016.
1b	**Renewable Energy Credit Optimization** • On a quarterly basis, and through calendar year 2016, issue reverse RFPs to sell 2016 vintage or older RECs that are not required to meet state RPS compliance obligations.
Action Item	**2. Firm Market Purchase Actions**
2a	**Front Office Transactions** – Acquire economic short-term firm market purchases for on-peak summer deliveries from 2016 through 2017 consistent with the Risk Management Policy and Commercial and Trading Front Office Procedures and Practices. These short-term firm market purchases will be acquired through multiple means: – Balance of month and day-ahead brokered transactions in which the broker provides the service of providing a

<table>
<tr><td></td><td>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.</td></tr>
<tr><th>Action Item</th><th>3. Demand Side Management (DSM) Actions</th></tr>
<tr><td>3a</td><td><u>Class 1 DSM</u>
– Pursue a west-side irrigation load control pilot beginning 2016 to test the feasibility of program design. Additional information on the proposed pilot is provided in the implementation plan section of Appendix D in Volume II of the 2015 IRP.</td></tr>
<tr><td>3b</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 implementation plan to acquire cost effective energy efficiency resources is provided in Appendix D in Volume II of the 2015 IRP.
<table><tr><th>Year</th><th>Annual Incremental Energy (GWh)</th><th>Annual Incremental Capacity* (MW)</th></tr><tr><td>2016</td><td>584</td><td>139</td></tr><tr><td>2017</td><td>616</td><td>146</td></tr><tr><td>2018</td><td>634</td><td>146</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></tr>
<tr><th>Action Item</th><th>4. Coal Resource Actions</th></tr>
<tr><td>4a</td><td><u>Naughton Unit 3</u>
• Continue to review emerging technologies, re-assess traditional gas conversion technologies and costs, and consider other potential alternatives that could be applied to Naughton Unit 3 to allow continued operation beyond year-end 2017.</td></tr>
<tr><td>4b</td><td><u>Dave Johnston Unit 3</u>
• The portion of EPA's final Regional Haze Federal Implementation Plan (FIP) requiring the installation of selective catalytic reduction (SCR) at Dave Johnston Unit 3, or a commitment to shut down Dave Johnston Unit 3 by the end of 2027, is currently under appeal by the State of Wyoming in the U.S. Tenth Circuit Court of Appeals.
• If following appeal, EPA's final FIP as it pertains to Dave Johnston Unit 3 is upheld, PacifiCorp will commit to shutting down Dave Johnston Unit 3 by the end of 2027.</td></tr>
</table>

	• If following appeal, EPA's final FIP as it pertains to Dave Johnston Unit 3 is or will be modified, PacifiCorp will evaluate alternative compliance strategies that will meet any new requirements, as applicable, and provide the associated analysis in a future IRP or IRP Update.
4c	**Wyodak** • Continue to pursue the Company'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.
4d	**Cholla Unit 4** • Continue permitting efforts in support of 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.
Action Item	**5. Transmission Actions**
5a	**Energy Gateway Permitting** • Continue permitting for the Energy Gateway transmission plan, with near term targets as follows: – For Segments D, E, and F, continue funding of the required federal agency permitting environmental consultant as actions to achieve final federal permits. – For Segments D, E, and F, continue to support the federal permitting process 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.
5b	**Wallula to McNary 230 kilovolt Transmission Line** • Complete Wallula to McNary project construction per plan with 2017 expected in-service date. Continue to support the permitting process for Walla Walla to McNary.

CHAPTER 1 – INTRODUCTION

This 2015 IRP Update describes resource planning activities that occurred after the 2015 IRP was filed in March 2015, presents an updated load and resource balance, an updated resource portfolio consistent with changes in the planning environment, presents an updated action plan, and provides a status update on the action plan filed with the 2015 IRP. In presenting the updated load and resource balance assessment and updated resource portfolio, PacifiCorp shows changes relative to the 2015 IRP and relative to its fall 2015 ten-year business plan (Business Plan), which covers the 2016 to 2025 planning horizon. In this update PacifiCorp also addresses recommendations and requirements identified by its state regulatory commissions during the 2015 IRP acknowledgement process.

In support of its business planning process, PacifiCorp refined the 2015 IRP Preferred Portfolio to reflect updates to forecasted loads, resources, market prices, and other model inputs. PacifiCorp's business planning process also considers capital expenditure and operating cost constraints with input from the business units (Pacific Power, Rocky Mountain Power, and PacifiCorp Transmission). Consideration of both capital and operating cost constraints is critical to ensure that PacifiCorp's business plan is financially supportable and affordable to customers. The 2015 IRP Preferred Portfolio served as the primary basis in establishing the resource portfolio for the Business Plan. A similar process has been completed to develop the load and resource balance and resource portfolio for this 2015 IRP Update, which considers updates to forecasted loads, resources, market prices, and other model inputs since the intervening Business Plan resource portfolio was developed.

The 2015 IRP Update also addresses recommendations and requirements identified by PacifiCorp's state regulatory commissions during the 2015 acknowledgement process. These include requests from the Washington Utilities and Transportation Commission (WUTC)[2] and Public Utility Commission of Oregon (OPUC)[3] regarding assumptions related to the use of renewable energy attributes for compliance with both state renewable portfolio standards (RPS) and the Clean Power Plan (CPP). The WUTC also requested PacifiCorp analyze its future resource needs for Washington RPS compliance based on the same allocation methodology used to allocate renewable energy generation to Washington. The OPUC also requested a study that replaces base case DSM with accelerated DSM and to report the impact on the resource portfolio. The Public Service Commission of Utah (PSCU)[4] requested an explanation, as necessary, of the interaction of requirements from the Federal Energy Regulatory Commission (FERC) Order 1000 and any Energy Gateway Project. PSCU also directed PacifiCorp to present an analysis on whether the available historical cooling degree day information is still an appropriate predictor of future normal conditions in the load forecast.

This report first describes the current planning environment, load updates, resource updates, state and federal policy updates, and Energy Gateway transmission planning and project completion forecast (Chapter 2). Next, Chapters 3 and 4 describe the changes to key inputs and assumptions

[2] Acknowledgement letter in PacifiCorp's 2015 Electric Integrated Resource Plan, Docket UE-140546, dated November 13, 2015.
[3] Order No. 16-071 in PacifiCorp's 2015 Integrated Resource Plan, Docket LC 62, dated February 29, 2016.
[4] Report and Order in PacifiCorp's 2015 Integrated Resource Plan, Docket No. 15-035-04, dated January 8, 2016.

relative to those used for the 2015 IRP. The updated resource portfolio is then presented along with a status update on the 2015 IRP Action Plan (Chapters 5 and 6, respectively). Appendix A provides additional load forecast details. Confidential Appendix B presents PacifiCorp's updated Naughton Unit 3 analysis.

CHAPTER 2 – PLANNING ENVIRONMENT

Business Plan Development

The 2015 IRP Preferred Portfolio served as the basis for the resource assumptions used in PacifiCorp's fall 2015 ten-year business plan (Business Plan), which covers the 2016 to 2025 planning horizon. Changes in the portfolio reflect updates to forecasted loads, resources, market prices, and other model inputs. PacifiCorp's business planning process also considers capital expenditure and operating cost constraints to ensure that the resulting business plan is financially supportable and affordable to customers.

Federal Policy Update

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

New Source Performance Standards (NSPS) are established under the Clean Air Act for certain industrial sources of emissions determined to endanger public health and welfare. On August 3, 2015, the U.S. Environmental Protection Agency (EPA) issued a final rule limiting carbon emissions from coal- and natural gas-fired 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.

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

EPA issued a final rule, referred to as the Clean Power Plan (CPP), regulating carbon emissions from existing power plants on August 3, 2015. Under the final rule, states would be required to submit compliance plans by September 6, 2016. However, a state may seek an extension to September 6, 2018 to submit a state plan. On August 3, 3015, EPA also issued a proposed federal plan and model trading rules for public comment. The public comment period closed January 21, 2016. Under section 111(d) of the Clean Air Act, states are required to develop standards of performance, which are the degree of emission limitation achievable through the application of the best system of emission reduction (BSER).

In the final rule, EPA set forth emission reduction goals for each state based on EPA's formulation of BSER, which is made up of three building blocks: (1) heat rate improvements at existing coal-fueled resources; (2) increased utilization of natural gas resources; and (3) increased deployment of zero-emitting resources. States would be required to meet the emission reduction goal by 2030, as well as interim goals, which would be met over three interim compliance periods: 2022-2024, 2025-2027, and 2028-2029. Utilizing its formulation of BSER, EPA established uniform national interim and final carbon emission performance standards as 1,305 lb CO_2/MWh for coal-fired power plants and 771 lb CO_2/MWh for natural gas-fired power plants, which in turn were utilized to establish projected mass-based and rate-based compliance targets for individual states.

Under the final rule, states have a number of implementation options: states may choose to adopt the rate-based standard and apply them on a subcategory or state-specific blended rate basis, or, alternatively, states may choose to adopt the standards as a mass-based state goal. In the final rule, EPA provided state mass-based goals that it stated are equivalent to the rate-based emissions goals. Under a mass-based implementation program, compliance would be demonstrated through reported stack emissions and the retirement of carbon allowances. Under a rate-based implementation program, compliance would be demonstrated through the use of megawatt-hour credits referred to as emission rate credits (ERCs) from renewable energy and, potentially, energy efficiency. States also have the option to trade with other affected resources in other states implementing similar approaches (e.g., rate state with other rate states or mass state with other mass states) so long as those states meet certain “trading ready” minimum requirements.

The federal plan proposal also includes model rules for rate-based and mass-based trading programs for potential use by any state in developing its state plan. The mass-based federal plan proposal includes a proposed allowance allocation methodology and a method for states to address leakage through allowance set-asides. For this 2015 IRP Update, PacifiCorp developed its updated resource portfolio with mass-based emission targets aligned with EPA’s proposed allowance allocation methodology. PacifiCorp will develop additional CPP scenarios in coordination with its stakeholders during the 2017 IRP public process.

On February 9, 2016, the U.S. Supreme Court issued a stay of the CPP suspending implementation of the rule pending the outcome of the merits of litigation before the D.C. Circuit Court of Appeals. If parties petition for a writ of certiorari before the U.S. Supreme Court, the stay will remain in effect until the U.S. Supreme Court takes action to either deny the petition, or, if the U.S. Supreme Court hears the case, the stay remains in effect until the court enters its judgment. Oral argument on the CPP litigation is scheduled for June 2, 2016 before the D.C. Circuit Court of Appeals.

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 certain pollutants considered harmful to public health and the environment. For a given NAAQS, EPA and/or a state identifies various control measures that once implemented are meant to achieve an air quality standard for a certain pollutant, with each standard rigorously vetted by the scientific community, industry, public interest groups, and the general public.

Particulate matter (PM), sulfur dioxide (SO_2), ozone (O_3), nitrogen dioxide (NO_2), carbon monoxide (CO), and lead are often grouped together, because under the Clean Air Act, each of these categories is linked to one or more NAAQS. These “criteria pollutants”, while undesirable, are not toxic in typical concentrations in the ambient air. Under the Clean Air Act, they are regulated differently from other types of emissions, such as hazardous air pollutants and greenhouse gases. Within the past few years, EPA established new standards for PM, SO_2, and NO_2.

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 will 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. PacifiCorp facilities will only be impacted to the extent they are located in an ozone nonattainment area.

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 impact 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. States are currently required to submit the next periodic update by July 31, 2018. However, this date may be extended as EPA has proposed that this date be changed to July 31, 2021.

The regional haze rule is intended to drive additional emissions reductions, particularly from facilities operating in the Western United States. This includes the states of 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.

In May 2011, the state of Utah issued a regional haze SIP requiring the installation of SO_2, NO_x and PM controls on Hunter Units 1 and 2 and Huntington Units 1 and 2. In December 2012, the EPA approved the SO_2 portion of the Utah regional haze SIP and disapproved the NO_x and PM portions. EPA's approval of the SO_2 SIP was appealed to federal circuit court. In addition, PacifiCorp and the state of Utah appealed EPA's disapproval of the NO_X and PM SIP. PacifiCorp and the state's appeals were dismissed. In June 2015, the state of Utah submitted a revised SIP to EPA for approval with an updated BART analysis incorporating a requirement for PacifiCorp to retire Carbon Units 1 and 2, recognizing NO_X controls previously installed on Hunter Unit 3, and concluding that no incremental controls (beyond those included in the May 2011 SIP and already installed) were required at the Hunter and Huntington units. On January 14, 2016, EPA issued a proposed rule including two co-proposals: one to approve the SIP in its entirety and one to partially approve and partially disapprove the revised Utah SIP and propose a FIP. The public comment period on EPA's proposed action closed March 14, 2016.

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

- Naughton Unit 3 by December 31, 2014 - selective catalytic reduction (SCR) equipment and a baghouse
- Jim Bridger Unit 3 by December 31, 2015 - SCR equipment

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

Different aspects of EPA's final action were appealed by a number of entities. PacifiCorp appealed EPA's action requiring SCR at Wyodak. PacifiCorp requested, and was granted, a stay of EPA's action as it pertains to Wyodak pending resolution of the appeals. With respect to Naughton Unit 3, in its final action EPA indicated support for the conversion of the unit to natural gas and that it would expedite action relative to consideration of the gas conversion once the state of Wyoming submitted the requisite SIP amendment. PacifiCorp has 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. Wyoming has not yet submitted a revised regional haze SIP incorporating this alternative compliance approach to EPA.

The state of Arizona issued a regional haze SIP requiring, among other things, the installation of SO_2, NO_X and PM controls on Cholla Unit 4, which is owned by PacifiCorp but operated by Arizona Public Service. EPA approved in part, and disapproved in part, the Arizona SIP and issued a FIP requiring the installation of SCR equipment on Cholla Unit 4. PacifiCorp filed an appeal regarding the FIP as it relates to Cholla Unit 4, and the Arizona Department of Environmental Quality and other affected Arizona utilities filed separate appeals of the FIP as it relates to their interests. With respect to the Cholla FIP requirements, the court has placed the appeals in abeyance while parties attempt to agree on an alternative compliance approach. In October 2015, EPA acknowledged receipt of the state of Arizona's alternate compliance approach for Cholla for review and final action. EPA is currently expected to propose their final action in mid-2016 for public comment.

The state of Colorado issued a regional haze SIP requiring, among other things, the installation of selective non-catalytic reduction (SNCR) technology at Craig Unit 1 by 2018. Environmental groups appealed EPA's action, in which PacifiCorp intervened in support of EPA. In July 2014, parties to the litigation, other than PacifiCorp, entered into a settlement agreement which requires installation of SCR equipment at Craig Unit 1 in 2021. The revised SIP, as reflected in the settlement, is currently pending EPA approval. PacifiCorp opposed the settlement agreement between the EPA and other parties to the litigation.

Mercury and Hazardous Air Pollutants

The Mercury and Air Toxics Standards (MATS) became effective April 16, 2012. The MATS rule requires 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 D.C. Circuit Court of Appeals 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 and landfills utilized for CCRs may need to close unless they can meet more stringent regulatory requirements. At the time the rule was published in April 2015, PacifiCorp operated 18 surface impoundments and seven landfills that contained CCRs. Prior to the effective date in October 2015, nine surface impoundments and three landfills were either closed or repurposed to no longer receive CCRs and hence are not subject to the final rule.

Water Quality Standards

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

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 does not allow the discharge of bottom ash or fly ash transport water, and directly impacts the Wyodak, Dave Johnston, and Naughton facilities.

2015 Tax Extender Legislation

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

Bonus Depreciation – Fifty percent bonus depreciation was extended for property acquired and placed in service during 2015, 2016, and 2017. For property acquired and placed in service during 2018, 40% of the eligible cost of the property qualifies for bonus depreciation. For property acquired and placed in service during 2019, 30% of the eligible cost of the property qualifies for bonus depreciation. For property placed in service after December 31, 2019, there will be no bonus depreciation.[5]

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

- 2015 – 100% retroactive
- 2016 – 100% (construction begins prior to January 1, 2017)
- 2017 – 80% (construction begins prior to January 1, 2018)
- 2018 – 60% (construction begins prior to January 1, 2019)
- 2019 – 40% (construction begins prior to 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 prior to 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 prior to January 1, 2020 as follows:

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

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

- 2015 – 30% retroactive
- 2016 – 30% (construction begins prior to January 1, 2017)

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

- 2017 – 30% (construction begins prior to January 1, 2018)
- 2018 – 30% (construction begins prior to January 1, 2019)
- 2019 – 30% (construction begins prior to January 1, 2020)
- 2020 – 26% (construction begins prior to January 1, 2021)
- 2021 – 22% (construction begins prior to January 1, 2022)
- 2022 – 10% (construction begins on or after January 1, 2022)

State Policy Update

California

Pursuant to the authority of the Global Warming Solutions Act, in October 2011, the California Air Resources Board (CARB) adopted a GHG cap-and-trade program with an effective date of January 1, 2012; compliance obligations were imposed on regulated entities beginning in 2013. The first auction of GHG 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 32 Climate Change scoping plan, which defined California's climate change priorities for the next five years and set the groundwork for post-2020 climate goals. In April 2015, Governor Brown issued an executive order to establish a mid-term reduction target for California of 40 percent below 1990 levels by 2030. CARB has subsequently been directed to update the AB 32 scoping plan to reflect the new interim 2030 target and previously-established 2050 target.

In 2002, California established a Renewable Portfolio Standard (RPS) requiring investor-owned utilities to increase procurement from eligible renewable energy resources. California's RPS requirements have been accelerated and expanded a number of times since its inception. Most recently, in October 2015, Governor Jerry Brown signed into law Senate Bill 350 which requires utilities to procure 50 percent of their electricity from renewables by 2030. The California Public Utilities Commission is currently developing rules to implement this new program.

Oregon

In 2007, the Oregon Legislature passed HB 3543 Global Warming Actions which establishes GHG reduction goals for the state that (i) by 2010, cease the growth of Oregon greenhouse gas emissions; (ii) by 2020, reduce greenhouse gas levels to 10 percent below 1990 levels; and (iii) by 2050, reduce greenhouse gas levels to at least 75 percent below 1990 levels. In 2009, the Legislature passed SB 101 which requires the Oregon Public Utility Commission (OPUC) to report to the Legislature before November 1 of each even-numbered year on the estimated rate impacts for Oregon's regulated electric and natural gas companies associated with meeting the GHG 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, 2014.

On July 3 2013, the Oregon Legislature passed Senate Bill 306 which directs the legislative revenue officer to prepare a report examining the feasibility of imposing a clean air fee or tax as a new revenue option. The report includes an evaluation of how to treat imported and exported energy sources. A final report was published December 2014.

In 2007, Oregon enacted Senate Bill 838 establishing an RPS requirement in Oregon. Under Senate Bill 838, utilities are required to deliver 25 percent of their electricity from renewable resources by 2025. On March 8, 2016, Governor Kate Brown signed Senate Bill 1547-B (SB 1547-B), the Clean Electricity and Coal Transition Plan, into law. Senate Bill 1547-B extends and expands the Oregon RPS requirement to 50 percent of electricity from renewable resources by 2040 and requires that coal-fired 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% by 2025, 35% by 2030, 45% by 2035 and 50% 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, 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% of their energy from renewable resources by 2020. Utilities must also set and meet energy conversation targets starting in 2010.

In 2008, the Washington State Legislature approved the Climate Change Framework E2SHB 2815, which establishes state GHG emissions reduction limits. Washington’s emission limits are to (i) by 2020, reduce emissions to 1990 levels; (ii) by 2035, reduce emissions to 25 percent below 1990 levels; and (iii) 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 which 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 proposed a draft of the Clean Air Rule on January 5, 2016. After further stakeholder engagement, on February 26, 2016, the proposed rule was withdrawn in order to make updates. The Department of Ecology anticipates releasing a new proposed rule for public review in spring 2016. The only PacifiCorp resource that would be subject to the proposed Clean Air Rule is the Chehalis natural gas plant.

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 to do so. 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 Senate Bill 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 via 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 impact PacifiCorp's coal-fueled resources in the future. The deferrals of variable power supply costs will go into effect in June 2016, and implementation and approval of the other programs are required by January 1, 2017. The bill will go into effect no later than May 20, 2016, unless vetoed by Governor Gary Herbert.

Greenhouse Gas Emission Performance Standards

California, Oregon and Washington have all adopted GHG emission performance standards applicable to all electricity generated within the state or delivered from outside the state that is no higher than the GHG 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 GHG based upon 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 2015 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 2.1 – 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 is required to meet 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. In 2013, the project was delayed to allow customers to determine their need as it pertains to ongoing projects and ability to move resources to their markets. In 2015, a transmission customer confirmed their need for transmission service requiring the completion of the transmission line agreed to by the parties as terms of the Transmission Service Agreement and to meet requirements of PacifiCorp's Open Access Transmission Tariff. The project is on-track to complete permitting efforts and construction for a 2017 in-service date.

Gateway West (Segments D and E): Under the National Environmental Policy Act, the 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. 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. Specifically, the sections of Gateway West that were deferred for a later ROD include the sections of Segment E from Midpoint to Hemingway and Cedar Hill to Hemingway. A draft supplemental EIS for the deferred portions of the project and the Record of Decision is anticipated in 2016.

Gateway South (Segment F): The BLM's Notice of Intent was published 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 final EIS and the Record of Decision is anticipated in 2016.

Sigurd to Red Butte (Segment G): Project construction is complete and the line was placed in service in May 2015. Sigurd to Red Butte is the third major segment of Energy Gateway to be constructed, following Mona to Oquirrh (Segment C) which was placed in service in May 2013 and Populus to Terminal (Segment B) which was placed in service in November 2010.

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. Originally planned as a single circuit 500 kV line from the Hemingway substation south of Boise, Idaho, to the Captain Jack substation near Klamath Falls, Oregon, PacifiCorp has continued to pursue alternative joint-development opportunities on other proposed lines west of Hemingway. 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 Record of Decision is anticipated in 2016 followed by the Oregon Energy Facilities Siting Council's final order on the Site Certificate.

Table 2.1 – Energy Gateway Segment In-Service Dates

Segment	2015 IRP	2015 IRP Update
Segment A: Wallula to McNary	2013-2014	2017 – Customer driven
Segment C: Mona to Oquirrh	May 2013	Completed May 2013
Segment C: Oquirrh to Terminal	June 2016	May 2017*
Segment D: Windstar to Populus	2019-2021	2021-2024*
Segment E: Populus to Hemingway	2020-2023	2020-2024*
Segment F: Aeolus to Mona	2020-2022	2020-2022
Segment G: Sigurd to Red Butte	June 2015	Completed May 2015
Segment H: West of Hemingway	Sponsor driven	

** Estimated in-service date adjusted since last IRP.*

Regional Markets

Energy Imbalance Market

PacifiCorp and the California ISO launched the Energy Imbalance Market (EIM) November 1, 2014. The EIM is a voluntary market and the first western energy market outside of California, covering six states, California, Idaho, Oregon, Utah, Washington, and Wyoming, which uses California ISO advanced market systems that automatically balance supply and demand for electricity every 15 minutes, dispatching the least-cost resources every five minutes. Since the launch of the EIM, NV Energy joined the market December 1, 2015, adding Nevada to the EIM footprint. Puget Sound Energy and Arizona Public Service are scheduled to join October 1, 2016. Portland General Electric is expected to join the EIM October 1, 2017, and other balancing authorities in the west have indicated interest. PacifiCorp continues to work with the California ISO, existing and prospective EIM entities, and stakeholders to enhance market functionality and support market growth with the addition of new EIM entities.

As predicted in studies prior to commencement of the market, the EIM has produced significant monetary benefits ($45.69 million total footprint-wide benefits as of December 31, 2015), quantified in the following categories: (1) more efficient dispatch, both inter- and intra-regional, by automating dispatch every 15 minutes and every five minutes within and across the EIM footprint; (2) reduced renewable energy curtailment by allowing balancing authority areas to export or reduce imports of renewable generation that would otherwise need to be curtailed; and (3) reduced need for flexibility reserves in all EIM balancing authority areas, also referred to as diversity benefits, which reduces cost by aggregating load, wind, and solar variability and forecast errors of the EIM footprint.

Regional ISO

The California ISO is exploring expanding into a regional ISO. PacifiCorp is exploring joining the regional ISO and becoming a full participating transmission owner (PTO). This effort is aimed at reducing costs for consumers, enhancing coordination and reliability of western electric networks, facilitating the integration of renewable resources, reducing emissions, and enhancing regional transmission planning and expansion.

PacifiCorp and the California ISO signed a memorandum of understanding in April 2015 that commits the two entities to explore the benefits of a regional ISO, recognizing that governance and other existing California ISO tariff structures and frameworks would need to accommodate a regional organization. Energy+Environmental Economics (E3) performed an initial analysis of the potential incremental benefits, beyond EIM, of integrating PacifiCorp as a PTO in a regional ISO. The study was released October 2015 and highlights that the full integration of the PacifiCorp and California ISO systems would provide the potential for cost savings.[6] Specifically, the E3 study quantifies benefits in the following four categories: (1) more efficient unit commitment and dispatch, (2) more efficient over-generation management, (3) lower peak capacity needs, and (4) renewable procurement savings. As described in more detail in the E3 study, under a regional ISO, PacifiCorp and ISO customers could develop capacity plans to meet the combined system coincident peak load, which would be lower than the sum of the non-

[6] For more background of the E3 benefit study and information: http://www.pacificorp.com/about/newsroom/2015nrl/western-grid-integration.html

coincident peak loads. As it relates to PacifiCorp's updated load and resource balance and resource portfolio, discussed in Chapter 3 and Chapter 5, respectively, this could reduce the need for firm market purchases over the near- to mid-term and displace the need for resources in the long term.

PacifiCorp continues to explore and evaluate the benefits and costs of becoming a PTO in a regional ISO. PacifiCorp will seek approval from each of its state public utility commissions to turn over operational control of its transmission assets to the ISO should further studies confirm net benefits for customers and acceptable governance structure is adopted. Integration as a PTO would result in the following primary impacts to PacifiCorp: (1) integration of PacifiCorp's two balancing authority areas (BAAs) into the regional ISO's BAA (2) turning over operational control of PacifiCorp's networked transmission assets to the regional ISO; (3) becoming subject to all requirements of the ISO tariff, as modified for regional integration, including resource adequacy requirements, transmission access charges, integrated generator interconnection studies, and many others; and (4) participation in the regional ISO's real-time and day-ahead markets.

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CHAPTER 3 – LOAD AND RESOURCE BALANCE UPDATE

Introduction

This chapter presents the update to PacifiCorp's load and resource balance, focusing on the 2016-2025 planning period covered by the fall 2015 ten-year business plan (Business Plan) and 2015 IRP Update. Updates to PacifiCorp's long-term load forecast, resources, and capacity position are presented and summarized in this chapter.

Load Forecast

PacifiCorp's 2015 IRP Update and Business Plan use the same load forecast updated and finalized in October 2015. Relative to the load forecast prepared for the 2015 IRP, PacifiCorp system sales decrease over the planning period. Changes between these two forecasts reflect the changes in economic conditions in the service territory that occurred between September 2014 and October 2015. While economic conditions continue to improve following the most recent recession, projected load growth in the residential and commercial customer classes is offset by weakness in the industrial class. A decline in commodities markets drives declines in industrial sales on the east side of the system, while the projected loss of a large customer drives declines on the west side of the system. Figures 3.1 and 3.2 compare annual load and coincident peak load forecasts, respectively, for the 2015 IRP Update and 2015 IRP. These forecast data exclude load reduction projections from new energy efficiency measures (Class 2 DSM), since such load reductions are included as resources in the resource portfolio. Appendix A includes additional details on the updated load forecast.

Figure 3.1 – Forecasted Annual Load Growth

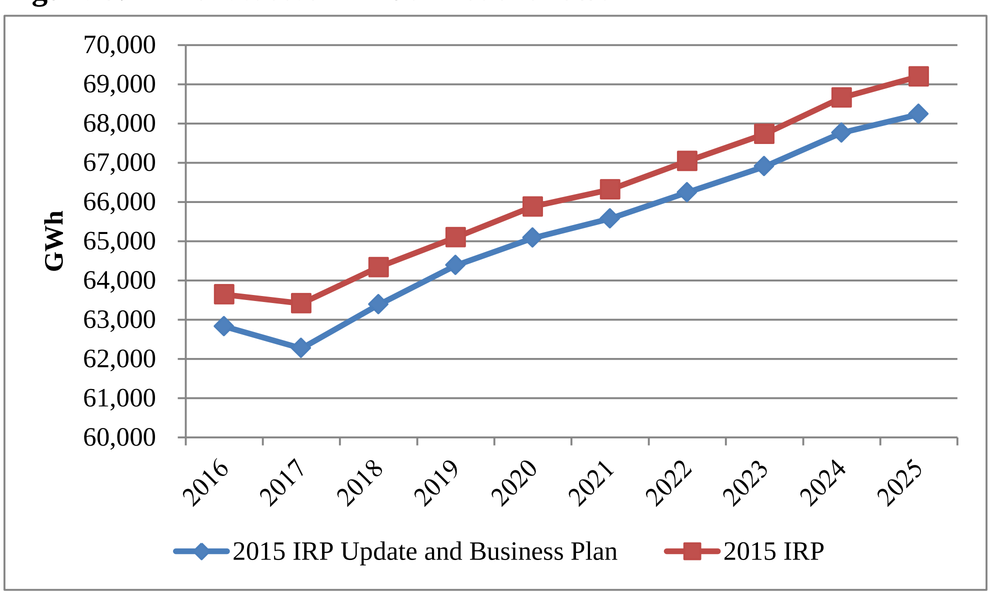
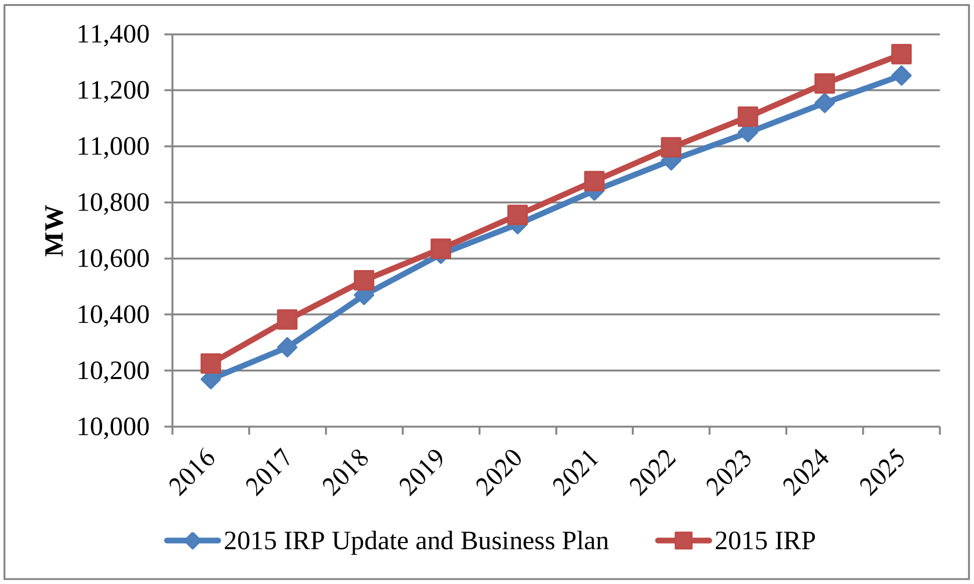


Figure 3.2 – Forecasted Annual Coincident Peak Load



Resource Updates

Existing and Firm Resources

The availability and capacity contribution from existing resources have been updated to reflect changes since assumptions were locked down for the 2015 IRP. Updates to resource capacity assumptions are presented in two steps – changes made between the 2015 IRP and the Business Plan, and changes made between the Business Plan and this 2015 IRP Update.

Changes Made between the 2015 IRP and the Business Plan

- With reduced load, lower market prices, and increased costs for gas conversion, the Business Plan assumes an early retirement of Naughton Unit 3 at the end of 2017 is a lower cost alternative to the assessed natural gas conversion. This assumption aligns with updated analysis of compliance alternatives for Naughton Unit 3 presented in Confidential Appendix B of this 2015 IRP Update. With the assumed retirement of Naughton Unit 3, existing thermal generation capacity is reduced by 337 MW over the period 2018 through 2029.

- With reduced load, lower market prices and uncertainties around state plans for implementing the clean power plan (CPP), the Business Plan assumes Cholla Unit 4 is retired at the end of 2024. PacifiCorp will continue to evaluate the most cost effective compliance alternatives for Cholla Unit 4 in future IRPs. With the assumed retirement of Cholla Unit 4, existing thermal generation capacity is reduced by 387 MW from 2025 and beyond.

- Since assumptions were locked down for the 2015 IRP, 440 MW of additional wind and solar qualifying facility contracts are included in the Business Plan portfolio (representing an increase of 167 MW of capacity at the time of system peak load). Inclusive of capacity assumed in the 2015 IRP, qualifying facility contract capacity from wind and solar projects expected to come online in the 2015 to 2017 timeframe totals 1,162 MW (representing 409 MW of capacity at the time of system peak load). This increase is partially offset by a reduction of 80 MW (11 MW of capacity at the time of system peak load) due to qualifying facility contract terminations.

- An updated hydro generation forecast reflects current projections for hydro operations accounting for planned water conditions, availability, and market prices. The Klamath River hydro peak contribution is approximately 70 MW higher to reflect its storage capability and ability to hold reserves prior to being decommissioned, assumed to occur at the end of 2020. The increase is offset by a decrease in the Lewis River hydro forecast, in part, to incorporate planned maintenance.

- Updates to interruptible contracts result in an increase in average peak capacity contribution by 20 MW during the 2016-2025 timeframe.

Changes Made between the Business Plan and the 2015 IRP Update

- Since assumptions were locked down for the Business Plan, qualifying facility contract capacity assumptions were updated. The update includes 65 MW of incremental qualifying facility contracts from wind and solar projects (representing an increase of 25 MW of capacity at the time of system peak load). Coupled with the updates applied in the Business Plan, the total amount of qualifying facility contract capacity expected to come online in the 2015 to 2017 timeframe totals 1,227 MW (representing 434 MW of capacity at the time of system peak load).

Tables 3.1 and 3.2 summarize the capacity from wind and solar power purchase agreements with qualifying facilities (QFs) that have or are expected to come online over the 2015 – 2017 timeframe.

Table 3.1 – New Qualifying Facility Wind Contracts Online 2015-2017

		2015 IRP Preferred Portfolio		2015 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)**
Blue Mountain Power Partners	UT	80	11		
Chopin	OR	10	3	10	3
Latigo Wind	UT	60	9	60	9
Mariah Wind	OR	10	3	10	3
Orem Family Wind	OR	10	3	10	3
Pioneer Wind Park I	WY	80	12	80	12
TOTAL – Purchased Wind		**250**	**39**	**170**	**28**

Table 3.2 – New Qualifying Facility Solar Contracts Online 2015-2017

		2015 IRP Preferred Portfolio		2015 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	4	10	4
Bear Creek Solar Center	OR	10	4	10	4
Beatty Solar	OR	5	2	5	2
Beryl Solar	UT	3	1	3	1
Black Cap Solar II	OR	8	3	8	3
Bly Solar Center	OR	10	4	9	3
Buckhorn Solar	UT	3	1	3	1
Cedar Valley Solar	UT	3	1	3	1
Chiloquin Solar *	OR			10	3
Collier Solar *	OR			10	4
Elbe Solar Center	OR	10	4	10	4
Enterprise Solar	UT	80	31	80	31
Escalante Solar I	UT	80	31	80	31
Escalante Solar II	UT	80	31	80	31
Escalante Solar III	UT	80	31	80	31
Ewauna Solar *	OR			1	0
Ewauna Solar 2 *	OR			3	1
Fiddler's Canyon Solar 1-3	UT	9	4	9	4
Granite Mountain - East *	UT			80	31
Granite Mountain - West *	UT			50	20
Granite Peak Solar	UT	3	1	3	1
Greenville Solar	UT	2	1	2	1
Iron Springs *	UT			80	31
Ivory Pine Solar	OR	10	4	10	4
Laho Solar	UT	3	1	3	1
Manderfield Solar	UT	2	1		
Milford Flat Solar	UT	3	1	3	1
Milford Solar 2	UT	3	1	3	1
Norwest Energy 2 (Neff) *	OR			10	4
Norwest Energy 4 (Bonanza) *	OR			6	2
Norwest Energy 5 (Arlington) *	OR			3	1
Norwest Energy 7 (Eagle Point) *	OR			10	4
Norwest Energy 9 Pendleton *	OR			6	2

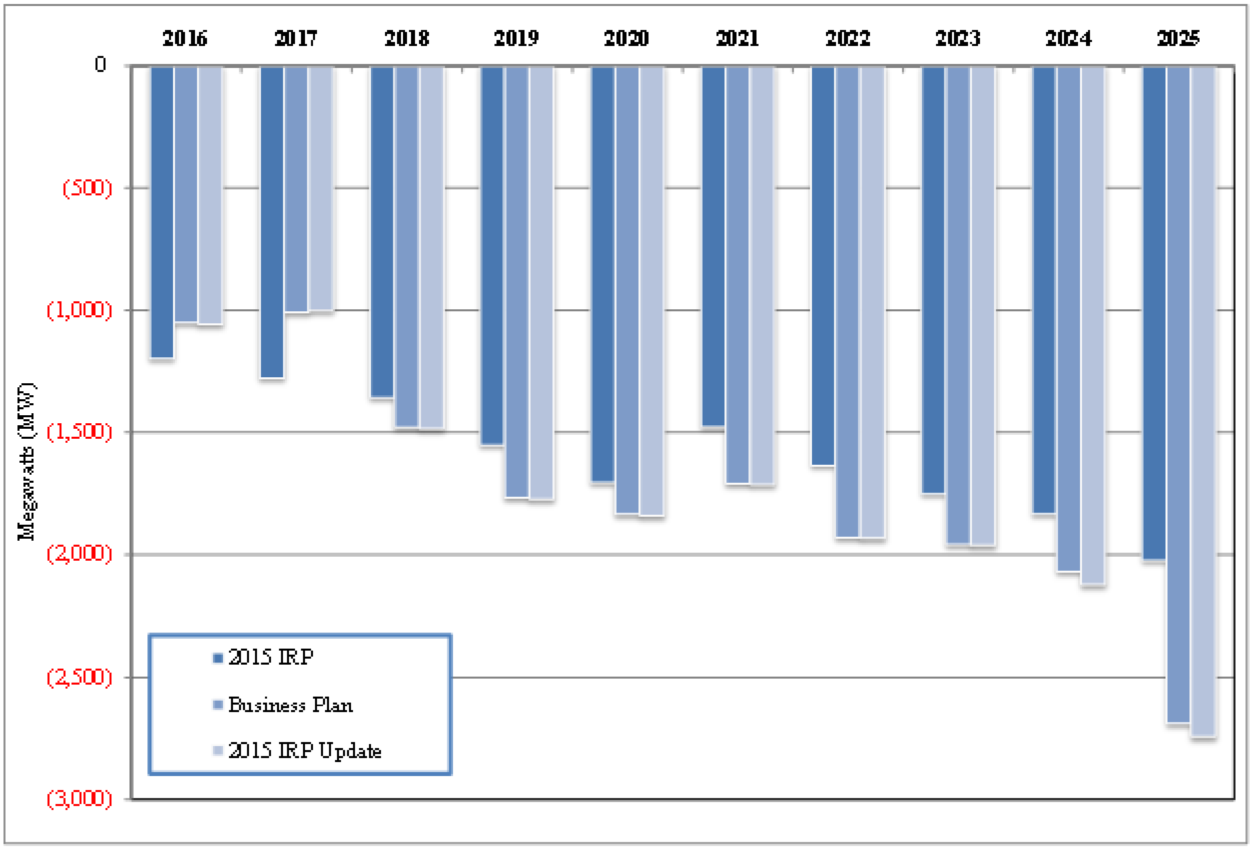
		2015 IRP Preferred Portfolio		2015 IRP Update	
Qualifying Facilities	**State**	**Capacity (MW)**	**L&R Balance Capacity at System Peak (MW)**	**Capacity (MW)**	**L&R Balance Capacity at System Peak (MW)**
OR Solar 1, LLC (Sprague River) *	OR			10	4
OR Solar 2, LLC (Agate Bay) *	OR			10	4
OR Solar 3, LLC (Turkey Hill) *	OR			10	4
OR Solar 4, LLC (Bly) *	OR			10	4
OR Solar 5, LLC (Merrill) *	OR			8	3
OR Solar 6, LLC (Lakeview) *	OR			10	4
OR Solar 7, LLC (Jacksonville) *	OR			10	4
OR Solar 8, LLC (Dairy) *	OR			10	4
Pavant Solar	UT	50	20	50	20
Pavant Solar II LLC *	UT			50	20
Quichapa Solar 1- 3	UT	9	4	9	4
South Milford Solar	UT	3	1	3	1
Sprague River Solar	OR	7	3	7	3
Three Peaks Solar *	UT			80	31
Tumbleweed Solar *	OR			10	3
Utah Red Hills Renewable Park	UT	80	31	80	31
Woodline Solar *	OR			8	3
TOTAL – Purchased Solar		**566**	**218**	**1,057**	**406**

* New since 2015 IRP.

Updated Capacity Load and Resource Balance

Figure 3.3 summarizes the 2015 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 2015 IRP and the Business Plan. The load and resource balance has decreased by an average of 209 MW, relative to the 2015 IRP, in 2016 and 2017 reflecting to changes in the load forecast, hydro generation and qualifying facility contracts. The projected load and resource balance position is shorter beginning in 2018, relative to the 2015 IRP, primarily due to the assumed early retirement of Naughton Unit 3 at the end of 2017 and Cholla Unit 4 at the end of 2024. This is partially offset by the addition of new wind and solar qualifying facility contracts. The 2015 IRP Update load and resource balance shows is shorter by 128 MW in 2018 rising to 720 MW by 2025.

Figure 3.3 – Capacity Position Comparison



Tables 3.3 through 3.5 summarize the capacity load and resource balance details from the 2015 IRP Update, Business Plan, and 2015 IRP, respectively. As was done in the 2015 IRP, the load and resource balance tables show the system position alongside assumed FOT purchases given current FOT limit assumptions, which were not updated for the 2015 IRP. PacifiCorp will evaluate its FOT limit assumptions as part of the 2017 IRP. Differences between the 2015 IRP and 2015 IRP Update are displayed in Table 3.6, and differences between the 2015 IRP and Business Plan are shown in Table 3.7.

Table 3.3 – System Capacity Load and Resource Balance without Resource Additions, 2015 IRP Update (Megawatts)

Calendar Year	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
East										
Thermal	6,397	6,397	6,116	6,116	6,116	6,113	6,110	6,108	6,105	5,717
Hydroelectric	109	109	112	112	112	112	112	112	92	92
Renewable	187	187	187	187	187	185	185	178	178	168
Purchase	355	249	249	249	249	221	221	221	221	121
Qualifying Facilities	304	469	463	460	454	447	436	434	381	378
Class 1 DSM	323	323	323	323	323	323	323	323	323	323
Sale	(728)	(653)	(652)	(652)	(652)	(171)	(171)	(171)	(144)	(144)
Non-Owned Reserves	(38)	(38)	(38)	(38)	(38)	(38)	(38)	(38)	(38)	(38)
East Existing Resources	**6,910**	**7,044**	**6,760**	**6,758**	**6,752**	**7,192**	**7,179**	**7,167**	**7,119**	**6,617**
East Total Resources	**6,910**	**7,044**	**6,760**	**6,758**	**6,752**	**7,192**	**7,179**	**7,167**	**7,119**	**6,617**
Load	6,963	7,084	7,235	7,359	7,447	7,548	7,637	7,717	7,809	7,880
Interruptible	(195)	(195)	(195)	(195)	(195)	(195)	(195)	(195)	(195)	(195)
Existing Class2 DSM	(61)	(61)	(61)	(61)	(61)	(61)	(61)	(61)	(61)	(61)
East obligation	**6,707**	**6,828**	**6,979**	**7,104**	**7,191**	**7,292**	**7,381**	**7,462**	**7,553**	**7,624**
Planning Reserves (13%)	897	913	933	949	960	973	985	995	1,007	1,016
East Reserves	**897**	**913**	**933**	**949**	**960**	**973**	**985**	**995**	**1,007**	**1,016**
East Obligation + Reserves	**7,604**	**7,741**	**7,912**	**8,052**	**8,151**	**8,265**	**8,366**	**8,457**	**8,560**	**8,640**
East Position	**(695)**	**(698)**	**(1,151)**	**(1,295)**	**(1,400)**	**(1,073)**	**(1,186)**	**(1,290)**	**(1,441)**	**(2,023)**
Available Front Office Transactions	**318**	**318**	**318**	**318**	**318**	**318**	**318**	**318**	**318**	**318**
West										
Thermal	2,251	2,248	2,248	2,248	2,248	2,245	2,241	2,239	2,239	2,239
Hydroelectric	841	826	837	736	793	623	548	654	643	632
Renewable	172	172	172	172	172	172	118	118	107	107
Purchase	18	18	18	1	1	1	1	1	1	1
Qualifying Facilities	108	177	175	174	176	166	163	155	154	154
Class 1 DSM	0	0	0	0	0	0	0	0	0	0
Sale	(165)	(165)	(165)	(165)	(165)	(161)	(110)	(110)	(80)	(80)
Non-Owned Reserves	(3)	(3)	(3)	(3)	(3)	(3)	(3)	(3)	(3)	(3)
West Existing Resources	**3,221**	**3,272**	**3,282**	**3,162**	**3,221**	**3,043**	**2,958**	**3,054**	**3,062**	**3,051**
West Total Resources	**3,221**	**3,272**	**3,282**	**3,162**	**3,221**	**3,043**	**2,958**	**3,054**	**3,062**	**3,051**
Load	3,206	3,199	3,235	3,256	3,276	3,294	3,313	3,332	3,346	3,373
Interruptible	0	0	0	0	0	0	0	0	0	0
Existing Class2 DSM	(36)	(36)	(36)	(36)	(36)	(36)	(36)	(36)	(36)	(36)
West obligation	**3,171**	**3,163**	**3,199**	**3,221**	**3,240**	**3,258**	**3,278**	**3,296**	**3,311**	**3,337**
Planning Reserves (13%)	412	411	416	419	421	424	426	429	430	434
West Reserves	**412**	**411**	**416**	**419**	**421**	**424**	**426**	**429**	**430**	**434**
West Obligation + Reserves	**3,583**	**3,575**	**3,615**	**3,640**	**3,661**	**3,682**	**3,704**	**3,725**	**3,741**	**3,771**
West Position	**(361)**	**(303)**	**(333)**	**(477)**	**(440)**	**(639)**	**(746)**	**(671)**	**(679)**	**(721)**
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	10,131	10,316	10,042	9,920	9,973	10,235	10,137	10,221	10,181	9,668
Obligation	9,878	9,992	10,178	10,324	10,431	10,550	10,659	10,758	10,863	10,961
Reserves	1,309	1,324	1,348	1,368	1,381	1,397	1,411	1,424	1,438	1,450
Obligation + Reserves	11,187	11,316	11,527	11,692	11,813	11,947	12,069	12,182	12,301	12,412
System Position	(1,056)	(1,000)	(1,484)	(1,772)	(1,840)	(1,712)	(1,932)	(1,961)	(2,120)	(2,743)
Available Front Office Transactions	**1,670**	**1,670**	**1,670**	**1,670**	**1,670**	**1,670**	**1,670**	**1,670**	**1,670**	**1,670**

Table 3.4 – System Capacity Load and Resource Balance without Resource Additions, Business Plan (Megawatts)

Calendar Year	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
East										
Thermal	6,397	6,397	6,116	6,116	6,116	6,113	6,110	6,108	6,105	5,717
Hydroelectric	109	109	112	112	112	112	112	112	92	92
Renewable	187	187	187	187	187	185	185	178	178	168
Purchase	355	249	249	249	249	221	221	221	221	121
Qualifying Facilities	304	444	437	435	429	422	412	409	407	403
Class 1 DSM	323	323	323	323	323	323	323	323	323	323
Sale	(728)	(653)	(652)	(652)	(652)	(171)	(171)	(171)	(144)	(144)
Non-Owned Reserves	(38)	(38)	(38)	(38)	(38)	(38)	(38)	(38)	(38)	(38)
East Existing Resources	**6,910**	**7,018**	**6,735**	**6,733**	**6,727**	**7,167**	**7,155**	**7,143**	**7,144**	**6,643**
East Total Resources	**6,910**	**7,018**	**6,735**	**6,733**	**6,727**	**7,167**	**7,155**	**7,143**	**7,144**	**6,643**
Load	6,963	7,084	7,235	7,359	7,447	7,548	7,637	7,717	7,809	7,880
Interruptible	(195)	(195)	(195)	(195)	(195)	(195)	(195)	(195)	(195)	(195)
Existing Class 2 DSM	(64)	(64)	(64)	(64)	(64)	(64)	(64)	(64)	(64)	(64)
East obligation	**6,704**	**6,825**	**6,976**	**7,101**	**7,188**	**7,289**	**7,378**	**7,459**	**7,550**	**7,621**
Planning Reserves (13%)	897	913	932	948	960	973	984	995	1,007	1,016
East Reserves	**897**	**913**	**932**	**948**	**960**	**973**	**984**	**995**	**1,007**	**1,016**
East Obligation + Reserves	**7,601**	**7,738**	**7,908**	**8,049**	**8,148**	**8,262**	**8,362**	**8,454**	**8,557**	**8,637**
East Position	**(691)**	**(720)**	**(1,173)**	**(1,316)**	**(1,421)**	**(1,095)**	**(1,208)**	**(1,311)**	**(1,413)**	**(1,994)**
Available Front Office Transactions	**318**	**318**	**318**	**318**	**318**	**318**	**318**	**318**	**318**	**318**
West										
Thermal	2,251	2,248	2,248	2,248	2,248	2,245	2,241	2,239	2,239	2,239
Hydroelectric	841	826	837	736	793	623	548	654	643	632
Renewable	172	173	173	173	173	173	118	118	108	108
Purchase	18	18	18	1	1	1	1	1	1	1
Qualifying Facilities	112	190	202	200	202	190	186	179	178	178
Class 1 DSM	0	0	0	0	0	0	0	0	0	0
Sale	(165)	(165)	(165)	(165)	(165)	(161)	(110)	(110)	(80)	(80)
Non-Owned Reserves	(3)	(3)	(3)	(3)	(3)	(3)	(3)	(3)	(3)	(3)
West Existing Resources	**3,225**	**3,286**	**3,309**	**3,189**	**3,248**	**3,068**	**2,982**	**3,078**	**3,087**	**3,075**
West Total Resources	**3,225**	**3,286**	**3,309**	**3,189**	**3,248**	**3,068**	**2,982**	**3,078**	**3,087**	**3,075**
Load	3,206	3,199	3,235	3,256	3,276	3,294	3,313	3,332	3,346	3,373
Interruptible	0	0	0	0	0	0	0	0	0	0
Existing Class 2 DSM	(35)	(35)	(35)	(35)	(35)	(35)	(35)	(35)	(35)	(35)
West obligation	**3,171**	**3,164**	**3,199**	**3,221**	**3,241**	**3,259**	**3,278**	**3,297**	**3,311**	**3,338**
Planning Reserves (13%)	412	411	416	419	421	424	426	429	430	434
West Reserves	**412**	**411**	**416**	**419**	**421**	**424**	**426**	**429**	**430**	**434**
West Obligation + Reserves	**3,583**	**3,575**	**3,615**	**3,640**	**3,662**	**3,682**	**3,704**	**3,725**	**3,741**	**3,772**
West Position	**(358)**	**(289)**	**(306)**	**(451)**	**(414)**	**(615)**	**(722)**	**(647)**	**(655)**	**(696)**
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	10,134	10,305	10,044	9,922	9,975	10,235	10,137	10,221	10,231	9,718
Obligation	9,875	9,989	10,175	10,322	10,429	10,548	10,656	10,756	10,861	10,959
Reserves	1,309	1,324	1,348	1,367	1,381	1,397	1,411	1,424	1,437	1,450
Obligation + Reserves	11,184	11,313	11,524	11,689	11,810	11,944	12,067	12,179	12,298	12,409
System Position	(1,050)	(1,009)	(1,480)	(1,767)	(1,835)	(1,710)	(1,930)	(1,958)	(2,067)	(2,690)
Available Front Office Transactions	**1,670**	**1,670**	**1,670**	**1,670**	**1,670**	**1,670**	**1,670**	**1,670**	**1,670**	**1,670**

Table 3.5 – System Capacity Load and Resource Balance without Resource Additions, 2015 IRP (Megawatts)

Calendar Year	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
East										
Thermal	6,397	6,397	6,453	6,449	6,448	6,444	6,439	6,434	6,431	6,430
Hydroelectric	114	114	114	114	114	114	114	114	94	94
Renewable	187	187	187	187	187	184	184	177	177	168
Purchase	406	300	300	300	300	272	272	272	272	172
Qualifying Facilities	222	348	347	346	339	337	332	331	280	279
Class 1 DSM	323	323	323	323	323	323	323	323	323	323
Sale	(732)	(656)	(656)	(656)	(656)	(175)	(175)	(175)	(144)	(144)
Non-Owned Reserves	(38)	(38)	(38)	(38)	(38)	(38)	(38)	(38)	(38)	(38)
East Existing Resources	**6,880**	**6,976**	**7,031**	**7,026**	**7,018**	**7,462**	**7,453**	**7,439**	**7,396**	**7,284**
East Total Resources	**6,880**	**6,976**	**7,031**	**7,026**	**7,018**	**7,462**	**7,453**	**7,439**	**7,396**	**7,284**
Load	6,977	7,102	7,208	7,295	7,382	7,448	7,529	7,617	7,640	7,676
Interruptible	(175)	(175)	(175)	(175)	(175)	(175)	(175)	(175)	(175)	(175)
Existing Class2 DSM	(73)	(73)	(73)	(73)	(73)	(73)	(73)	(73)	(73)	(73)
East obligation	**6,729**	**6,854**	**6,960**	**7,047**	**7,135**	**7,200**	**7,281**	**7,370**	**7,392**	**7,428**
Planning Reserves (13%)	894	910	924	935	947	955	966	977	980	985
East Reserves	**894**	**910**	**924**	**935**	**947**	**955**	**966**	**977**	**980**	**985**
East Obligation + Reserves	**7,623**	**7,764**	**7,885**	**7,982**	**8,081**	**8,155**	**8,247**	**8,347**	**8,372**	**8,413**
East Position	**(743)**	**(789)**	**(853)**	**(957)**	**(1,064)**	**(693)**	**(794)**	**(908)**	**(976)**	**(1,129)**
Available Front Office Transactions	**318**	**318**	**318**	**318**	**318**	**318**	**318**	**318**	**318**	**318**
West										
Thermal	2,251	2,248	2,248	2,248	2,248	2,245	2,241	2,239	2,239	2,239
Hydroelectric	770	752	775	725	728	643	620	652	646	643
Renewable	170	170	170	170	170	170	115	115	105	105
Purchase	22	22	22	5	5	5	5	5	5	5
Qualifying Facilities	114	140	135	134	120	120	120	115	115	115
Class 1 DSM	0	0	0	0	0	0	0	0	0	0
Sale	(160)	(160)	(160)	(160)	(160)	(156)	(105)	(105)	(78)	(78)
Non-Owned Reserves	(3)	(3)	(3)	(3)	(3)	(3)	(3)	(3)	(3)	(3)
West Existing Resources	**3,163**	**3,167**	**3,185**	**3,119**	**3,107**	**3,023**	**2,993**	**3,019**	**3,029**	**3,025**
West Total Resources	**3,163**	**3,167**	**3,185**	**3,119**	**3,107**	**3,023**	**2,993**	**3,019**	**3,029**	**3,025**
Load	3,237	3,271	3,301	3,323	3,354	3,406	3,429	3,455	3,476	3,506
Interruptible	0	0	0	0	0	0	0	0	0	0
Existing Class2 DSM	(36)	(36)	(36)	(36)	(36)	(36)	(36)	(36)	(36)	(36)
West obligation	**3,201**	**3,235**	**3,264**	**3,286**	**3,317**	**3,369**	**3,393**	**3,419**	**3,440**	**3,469**
Planning Reserves (13%)	416	421	424	427	431	438	441	444	447	451
West Reserves	**416**	**421**	**424**	**427**	**431**	**438**	**441**	**444**	**447**	**451**
West Obligation + Reserves	**3,617**	**3,655**	**3,689**	**3,714**	**3,748**	**3,807**	**3,834**	**3,863**	**3,887**	**3,920**
West Position	**(454)**	**(488)**	**(503)**	**(595)**	**(642)**	**(784)**	**(841)**	**(844)**	**(858)**	**(895)**
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	10,043	10,143	10,217	10,144	10,124	10,486	10,446	10,458	10,425	10,310
Obligation	9,930	10,089	10,225	10,333	10,452	10,569	10,674	10,788	10,832	10,897
Reserves	1,310	1,331	1,349	1,363	1,378	1,393	1,407	1,422	1,428	1,436
Obligation + Reserves	11,240	11,420	11,573	11,696	11,830	11,963	12,081	12,210	12,259	12,333
System Position	(1,197)	(1,277)	(1,357)	(1,552)	(1,706)	(1,477)	(1,635)	(1,752)	(1,834)	(2,023)
Available Front Office Transactions	**1,670**	**1,670**	**1,670**	**1,670**	**1,670**	**1,670**	**1,670**	**1,670**	**1,670**	**1,670**

Table 3.6 – System Capacity Load and Resource Balance without Resource Additions, 2015 IRP Update less 2015 IRP (Megawatts)

Calendar Year	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
East										
Thermal	0	0	(337)	(333)	(332)	(331)	(329)	(326)	(326)	(713)
Hydroelectric	(5)	(5)	(2)	(2)	(2)	(2)	(2)	(2)	(2)	(2)
Renewable	0	0	0	0	0	0	0	0	0	0
Purchase	(51)	(51)	(51)	(51)	(51)	(51)	(51)	(51)	(51)	(51)
Qualifying Facilities	82	121	115	114	115	110	105	103	102	99
Class 1 DSM	0	0	0	0	0	0	0	0	0	0
Sale	4	4	4	4	4	4	4	4	0	0
Non-Owned Reserves	0	0	0	0	0	0	0	0	0	0
East Existing Resources	**29**	**68**	**(271)**	**(268)**	**(266)**	**(271)**	**(273)**	**(272)**	**(277)**	**(667)**
East Total Resources	**29**	**68**	**(271)**	**(268)**	**(266)**	**(271)**	**(273)**	**(272)**	**(277)**	**(667)**
Load	(14)	(18)	27	65	64	100	108	100	169	204
Interruptible	(20)	(20)	(20)	(20)	(20)	(20)	(20)	(20)	(20)	(20)
Existing Class2 DSM	12	12	12	12	12	12	12	12	12	12
East obligation	**(22)**	**(26)**	**19**	**57**	**56**	**92**	**100**	**92**	**161**	**196**
Planning Reserves (13%)	3	3	8	13	13	18	19	18	27	31
East Reserves	**3**	**3**	**8**	**13**	**13**	**18**	**19**	**18**	**27**	**31**
East Obligation + Reserves	**(19)**	**(23)**	**27**	**70**	**70**	**110**	**119**	**110**	**188**	**227**
East Position	**48**	**91**	**(298)**	**(338)**	**(336)**	**(381)**	**(392)**	**(382)**	**(465)**	**(894)**
Available Front Office Transactions	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**
West										
Thermal	0	0	0	0	0	0	0	0	0	0
Hydroelectric	70	74	62	11	65	(20)	(72)	2	(3)	(11)
Renewable	3	3	3	3	3	3	3	3	3	3
Purchase	(4)	(4)	(4)	(4)	(4)	(4)	(4)	(4)	(4)	(4)
Qualifying Facilities	(6)	37	41	39	56	46	43	40	39	39
Class 1 DSM	0	0	0	0	0	0	0	0	0	0
Sale	(5)	(5)	(5)	(5)	(5)	(5)	(5)	(5)	(2)	(2)
Non-Owned Reserves	0	0	0	0	0	0	0	0	0	0
West Existing Resources	**59**	**105**	**97**	**44**	**115**	**20**	**(35)**	**35**	**33**	**25**
West Total Resources	**59**	**105**	**97**	**44**	**115**	**20**	**(35)**	**35**	**33**	**25**
Load	(31)	(72)	(66)	(66)	(78)	(112)	(116)	(123)	(130)	(133)
Interruptible	0	0	0	0	0	0	0	0	0	0
Existing Class2 DSM	1	1	1	1	1	1	1	1	1	1
West obligation	**(30)**	**(71)**	**(65)**	**(66)**	**(77)**	**(111)**	**(115)**	**(122)**	**(129)**	**(132)**
Planning Reserves (13%)	(4)	(9)	(8)	(9)	(10)	(14)	(15)	(16)	(17)	(17)
West Reserves	**(4)**	**(9)**	**(8)**	**(9)**	**(10)**	**(14)**	**(15)**	**(16)**	**(17)**	**(17)**
West Obligation + Reserves	**(34)**	**(80)**	**(74)**	**(74)**	**(87)**	**(125)**	**(130)**	**(138)**	**(146)**	**(149)**
West Position	**93**	**185**	**170**	**118**	**202**	**145**	**95**	**173**	**179**	**174**
Available Front Office Transactions	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**
System										
Total Resources	88	173	(174)	(224)	(151)	(251)	(308)	(237)	(244)	(641)
Obligation	(52)	(97)	(47)	(9)	(20)	(19)	(15)	(30)	32	64
Reserves	(1)	(7)	(0)	5	3	3	4	2	10	14
Obligation + Reserves	(53)	(103)	(47)	(4)	(17)	(15)	(11)	(28)	42	79
System Position	141	277	(128)	(220)	(134)	(235)	(297)	(209)	(286)	(720)
Available Front Office Transactions	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**

Table 3.7 – System Capacity Load and Resource Balance without Resource Additions, Business Plan less 2015 IRP (Megawatts)

Calendar Year	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
East										
Thermal	0	0	(337)	(333)	(332)	(331)	(329)	(326)	(326)	(713)
Hydroelectric	(5)	(5)	(2)	(2)	(2)	(2)	(2)	(2)	(2)	(2)
Renewable	0	0	0	0	0	0	0	0	0	0
Purchase	(51)	(51)	(51)	(51)	(51)	(51)	(51)	(51)	(51)	(51)
Qualifying Facilities	82	95	90	89	90	85	80	79	127	125
Class 1 DSM	0	0	0	0	0	0	0	0	0	0
Sale	4	4	4	4	4	4	4	4	0	0
Non-Owned Reserves	0	0	0	0	0	0	0	0	0	0
East Existing Resources	**29**	**43**	**(296)**	**(293)**	**(291)**	**(296)**	**(298)**	**(297)**	**(252)**	**(641)**
East Total Resources	**29**	**43**	**(296)**	**(293)**	**(291)**	**(296)**	**(298)**	**(297)**	**(252)**	**(641)**
Load	(14)	(18)	27	65	64	100	108	100	169	204
Interruptible	(20)	(20)	(20)	(20)	(20)	(20)	(20)	(20)	(20)	(20)
Existing Class2 DSM	9	9	9	9	9	9	9	9	9	9
East obligation	**(25)**	**(29)**	**16**	**54**	**53**	**89**	**97**	**89**	**158**	**193**
Planning Reserves (13%)	3	2	8	13	13	18	19	18	26	31
East Reserves	**3**	**2**	**8**	**13**	**13**	**18**	**19**	**18**	**26**	**31**
East Obligation + Reserves	**(22)**	**(26)**	**24**	**67**	**66**	**107**	**115**	**107**	**184**	**224**
East Position	**51**	**69**	**(320)**	**(360)**	**(358)**	**(402)**	**(413)**	**(404)**	**(437)**	**(865)**
Available Front Office Transactions	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**
West										
Thermal	0	0	0	0	0	0	0	0	0	0
Hydroelectric	70	74	62	11	65	(20)	(72)	2	(3)	(11)
Renewable	3	3	3	3	3	3	3	3	3	3
Purchase	(4)	(4)	(4)	(4)	(4)	(4)	(4)	(4)	(4)	(4)
Qualifying Facilities	(2)	51	67	66	83	70	67	63	63	63
Class 1 DSM	0	0	0	0	0	0	0	0	0	0
Sale	(5)	(5)	(5)	(5)	(5)	(5)	(5)	(5)	(2)	(2)
Non-Owned Reserves	0	0	0	0	0	0	0	0	0	0
West Existing Resources	**62**	**119**	**124**	**71**	**142**	**45**	**(11)**	**60**	**58**	**50**
West Total Resources	**62**	**119**	**124**	**71**	**142**	**45**	**(11)**	**60**	**58**	**50**
Load	(31)	(72)	(66)	(66)	(78)	(112)	(116)	(123)	(130)	(133)
Interruptible	0	0	0	0	0	0	0	0	0	0
Existing Class2 DSM	1	1	1	1	1	1	1	1	1	1
West obligation	**(30)**	**(71)**	**(65)**	**(65)**	**(77)**	**(111)**	**(115)**	**(122)**	**(129)**	**(131)**
Planning Reserves (13%)	(4)	(9)	(8)	(8)	(10)	(14)	(15)	(16)	(17)	(17)
West Reserves	**(4)**	**(9)**	**(8)**	**(8)**	**(10)**	**(14)**	**(15)**	**(16)**	**(17)**	**(17)**
West Obligation + Reserves	**(34)**	**(80)**	**(73)**	**(74)**	**(86)**	**(125)**	**(130)**	**(138)**	**(146)**	**(148)**
West Position	**96**	**199**	**197**	**145**	**228**	**170**	**119**	**197**	**203**	**198**
Available Front Office Transactions	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**
System										
Total Resources	91	162	(173)	(222)	(149)	(251)	(309)	(237)	(194)	(591)
Obligation	(55)	(99)	(49)	(12)	**(23)**	(22)	(18)	(33)	29	62
Reserves	(1)	(7)	(0)	4	3	3	4	2	10	14
Obligation + Reserves	(56)	(106)	(50)	(7)	(20)	(18)	(14)	(31)	39	76
System Position	148	268	(123)	(215)	(129)	(233)	(294)	(206)	(233)	(667)
Available Front Office Transactions	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**

Figures 3.4 through 3.6 summarize the 2015 IRP Update annual capacity position for the system, west balancing area, and east balancing area, respectively.

Figure 3.4 – 2015 IRP Update, System Capacity Position Trend

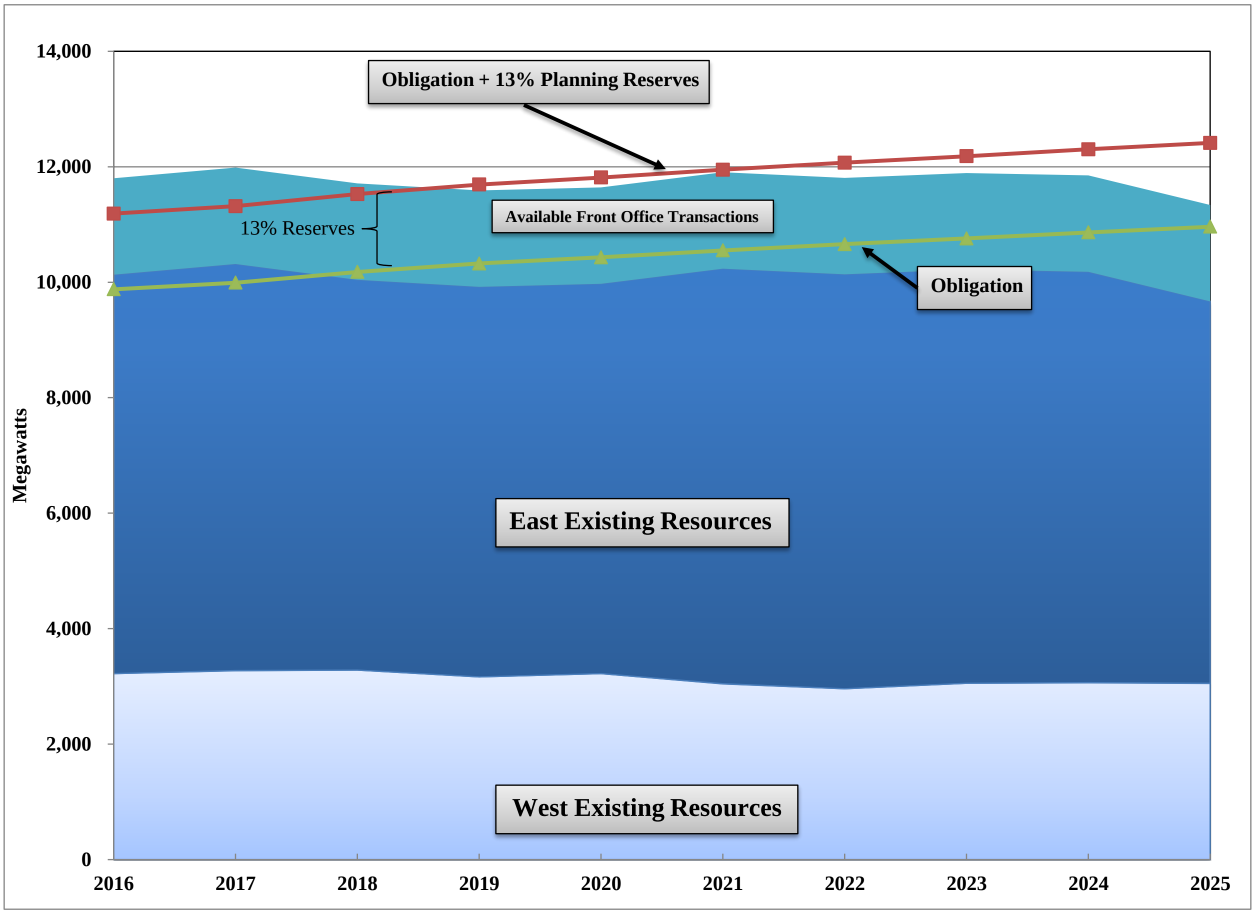


Figure 3.5 – 2015 IRP Update, West Capacity Position Trend

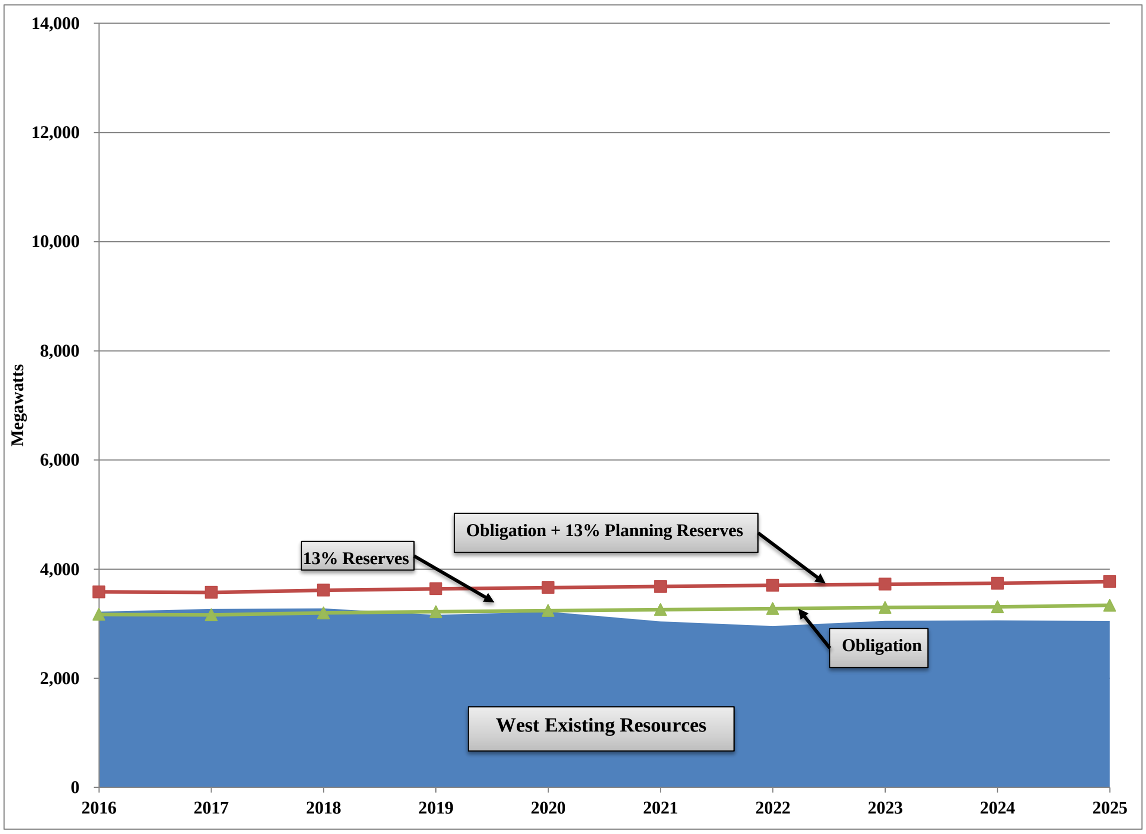
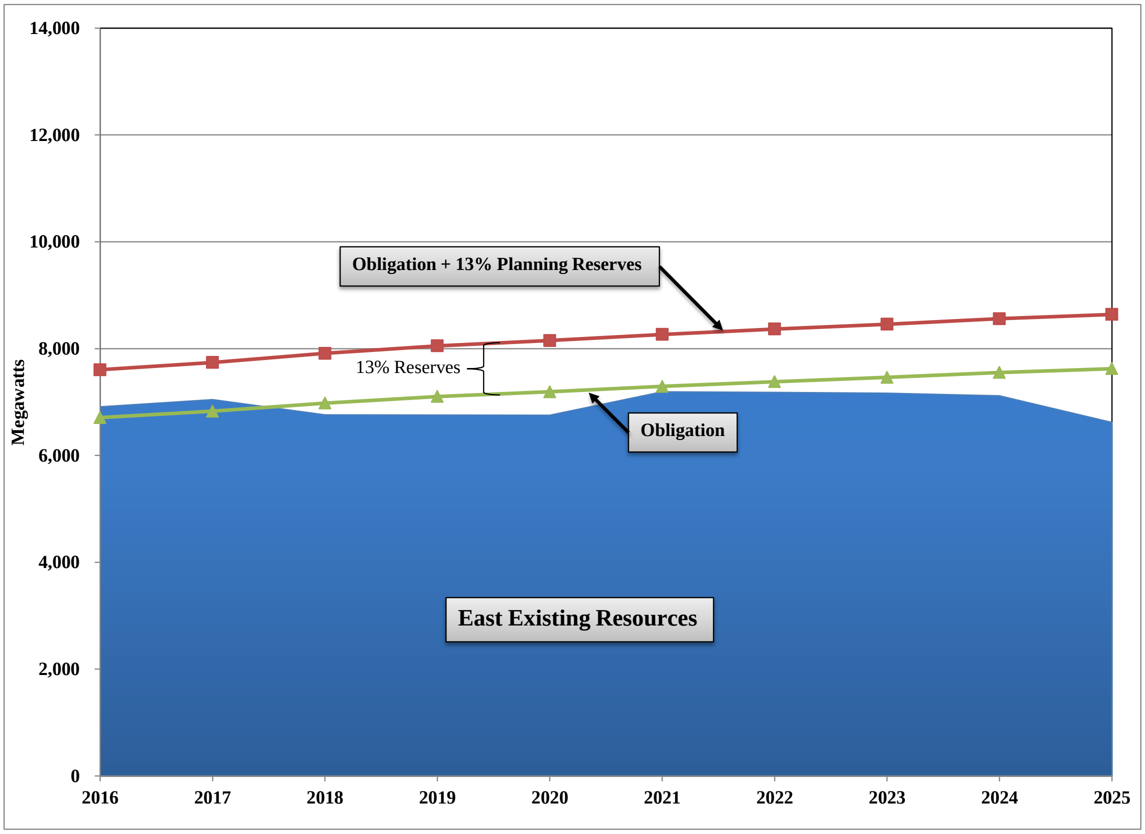


Figure 3.6 – 2015 IRP Update, East Capacity Position Trend



Changes to the 2015 IRP Update load and resource balance relative to the 2015 IRP are described below:

PacifiCorp West

- Peak loads are lower in the 2015 IRP Update than in the 2015 IRP. This difference is primarily driven by changes in projected sales to several large commercial and industrial customers, including a large industrial customer leaving the system in 2017.
- On average, the addition of incremental wind and solar qualifying facility contracts increase system capacity at the time of peak load by 37 MW over the 2016-2025 timeframe.
- Updated hydro generation forecast reflecting Klamath River hydro facilities' storage capability and the current stream-flow projections result in an average increase of 56 MW in system capacity from 2016 to 2020, and an average decrease of 21 MW over the 2021-2025 timeframe.

PacifiCorp East

- Peak loads are initially lower in the 2015 IRP Update than in the 2015 IRP due to a decline in the oil market driving reductions in industrial sales on the east side of the system. Projected increases in residential and commercial sales increase in the 2015 IRP Update peak forecast as compared to the 2015 IRP starting in 2018.
- The assumed early retirement of Naughton Unit 3 at end of 2017 reduces system capacity by 337 MW from 2018 through 2029. The assumed early retirement of Cholla Unit 4 at end of 2024 reduces system capacity by 387 MW from 2025 and beyond.
- On average, the addition of incremental wind and solar qualifying facility contracts increase system capacity at the time of peak load by 107 MW over the 2016-2025 timeframe, which is partially offset by an average decrease of 50 MW of peak capacity from purchase contracts.
- Updated terms of interruptible contracts are updated to reflect the latest terms, which reduces system capacity by 20 MW.

CHAPTER 4 – MODELING ASSUMPTIONS UPDATE

General Assumptions

In line with the 2015 IRP, the study period for both the fall 2015 ten-year business plan (Business Plan) and the 2015 IRP Update is 2015 through 2034, with a focus on the 2016-2025 planning horizon. Updated resource portfolios were developed assuming a 13% planning reserve margin consistent with the stochastic loss of load probability study included in the 2015 IRP.

PacifiCorp has not made any changes to general inflation assumptions (1.9%) and its discount factor (6.66%) in this 2015 IRP Update. However, PacifiCorp has modified the assumptions regarding the federal production tax credits and federal investment tax credits for qualifying renewable resources, as described in Chapter 2.

Natural Gas and Power Market Price Updates

Portfolio modeling for the 2015 IRP Update was prepared using PacifiCorp's December 31, 2015 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 of Aurora's electricity price forecast.

Natural Gas Market Prices

PacifiCorp's December 2015 natural gas OFPC reflects a fundamentals-based forecast that was issued in November 2015, which is heavily influenced by cost-effective domestic supply expansion largely due to growth in the Marcellus and Utica shale plays.

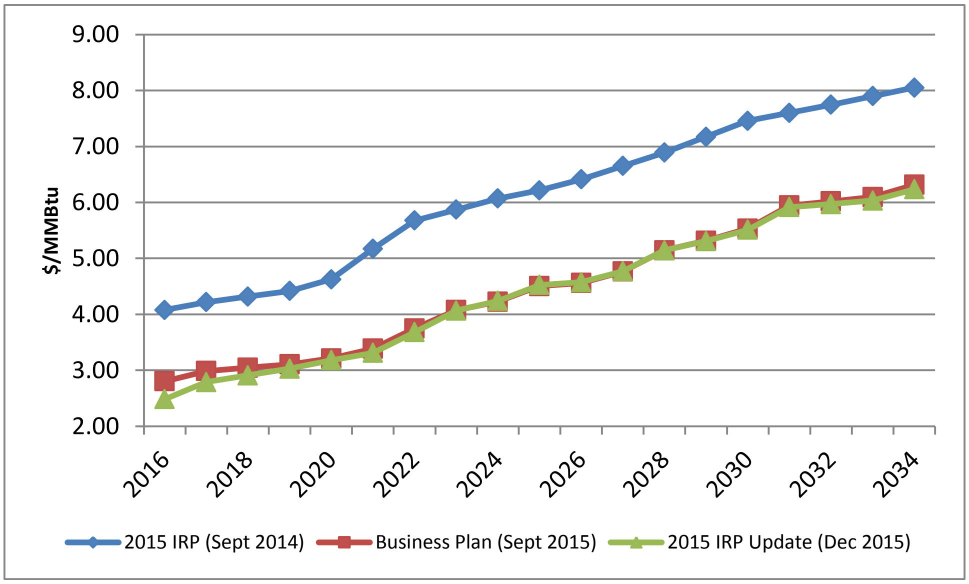
The September 2014 natural gas OFPC, which was used in the 2015 IRP, was based on an expert third-party long-term natural gas price forecast initially issued May 2014 with a front two-year update in August 2014. This price forecast also reflected a considerable portion of domestic natural gas demand being met by unconventional shale production.

In summer 2014, surveyed expert third-party natural gas price forecasters expected 57% to 70% of 2020 production to come from shale, by December 2015 expectations had increased to 62% to

75%. In the course of one year, 2014 to 2015, Marcellus and Utica shale production alone increased from an average of 14.4 billion cubic feet per day (BCF/D) to almost 19 BCF/D.

Figure 4.1 compares the nominal annual Henry Hub natural gas prices from the September 2014 (2015 IRP), September 2015 (Business Plan), and December 2015 (2015 IRP Update) OFPCs.

Figure 4.1 – 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. Figures 4.2 and 4.3 compare the average annual flat and heavy-load-hour electricity prices for the Palo Verde market hub from the September 2014, September 2015 (Business Plan), and December 2015 OFPCs, and Figure 4.4 and 4.5 show the comparison for the Mid-Columbia market hub.

Figure 4.2 – Average Annual Flat Palo Verde Electricity Prices (Nominal)

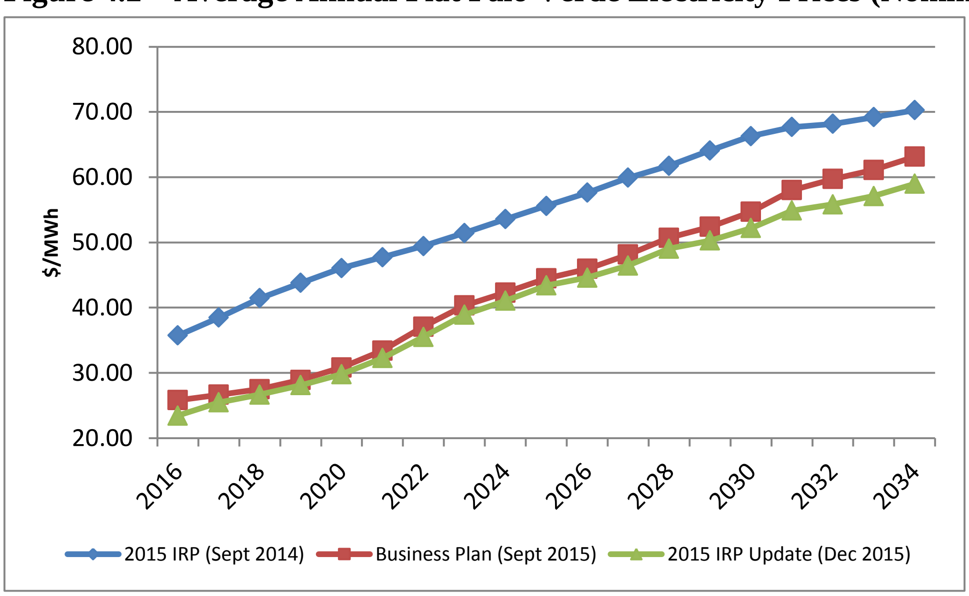


Figure 4.3 – Average Annual Heavy Load Hour Palo Verde Electricity Prices (Nominal)

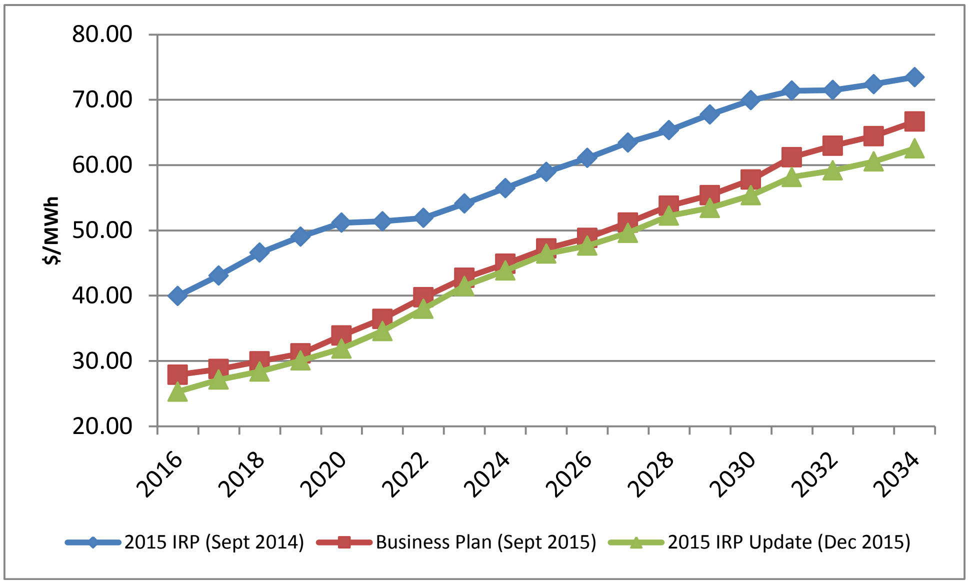


Figure 4.4 – Average Annual Flat Mid-Columbia Electricity Prices (Nominal)

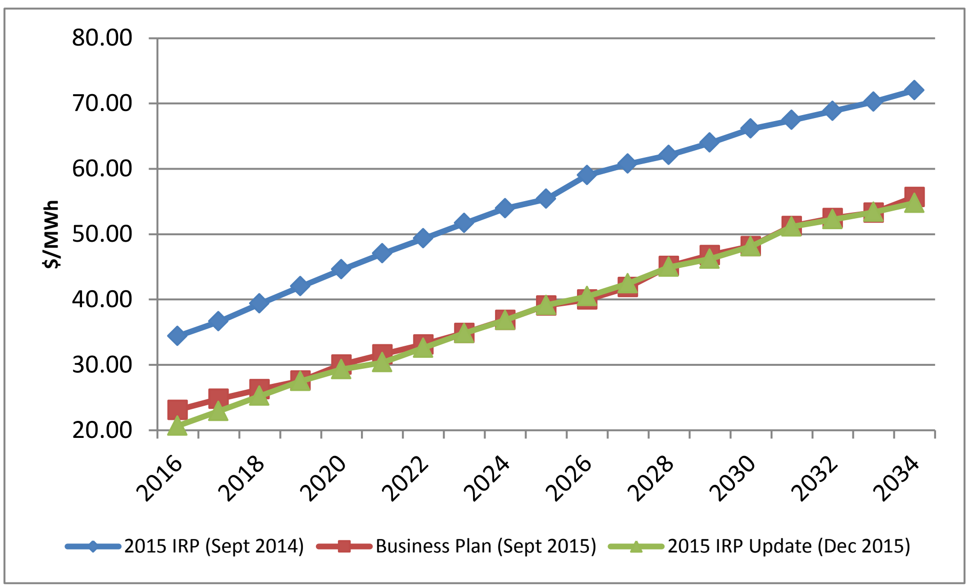
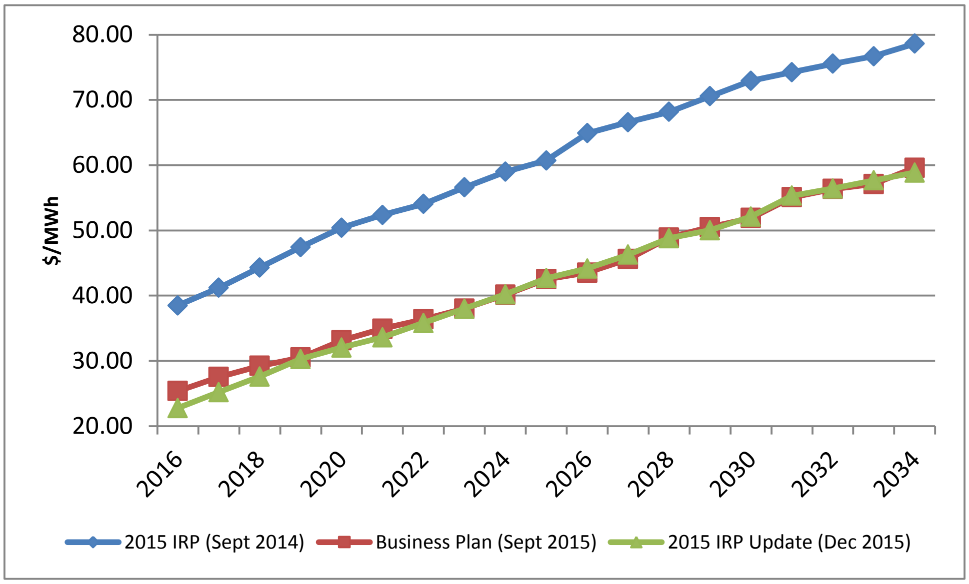


Figure 4.5 – Average Annual Heavy Load Hour Mid-Columbia Electricity Prices (Nominal)



Carbon Dioxide Emission Policy

After PacifiCorp filed its 2015 IRP, EPA issued its final CPP, setting emission reduction goals for existing fossil generation. On February 9, 2016, the U.S. Supreme Court issued a stay of the CPP suspending implementation of the rule pending the outcome of the merits of litigation before the D.C. Circuit Court of Appeals. If parties petition for a writ of certiorari before the U.S. Supreme Court, the stay will remain in effect until the U.S. Supreme Court takes action to either deny the petition, or, if the U.S. Supreme Court hears the case, the stay remains in effect until the court enters its judgment. Oral argument on the CPP litigation is scheduled for June 2, 2016 before the D.C. Circuit Court of Appeals. In the 2015 IRP Update, considering uncertainty in the timing and details around individual state decisions related to CPP implementation, PacifiCorp assumes a mass-based emission target based on EPA's proposed mass-based FIP to limit CO_2 emissions from its existing affected generation facilities.

Transmission Topology

The transmission topology modeled in the 2015 IRP Update was modified to represent and align transmission rights consistent with the Idaho asset exchange agreement, which was finalized November 4, 2015 between PacifiCorp and Idaho Power Company. In addition to maintaining the 1,600 MW of westbound transfer capability, the Idaho asset exchange agreement now allows PacifiCorp to serve its Goshen load directly from Jim Bridger plant.

Supply-side Resources

The supply side resource costs for 50 MW_{AC} solar photovoltaic (PV) projects are updated to reflect lower market costs for PV modules and mounting structures. A solar option is added for Washington which includes an effective sales tax rate of about 2%. Engineering and owner costs are decreased slightly to reflect increasing levels of certainty for large commercial PV projects.

Projected costs, in real terms, during the 20-year study period continue to reflect a downward trend as in the 2015 IRP. Costs for five-MW fixed tilt solar array projects have not been updated because those projects are being outperformed in the market by larger single axis projects. While costs for solar projects have been reduced for the 2015 IRP Update, there is risk with adding incremental solar resources that have generation profiles aligning with expected output from increasing solar resource penetration levels in California. With increased solar generation, market prices can be very low in the mid-afternoon, particularly during the spring season and other low-load times of the year. Table 4.1 shows the updated costs of solar resources.

Table 4.1 – Updated Cost of Solar Resources, 2014$ - (50 MW_{AC} Single Axis Tracking)

Location/Technology	2015 IRP Update Total (with Owner's Costs) $\$/W_{AC}$	2015 IRP Total (with Owner's Costs) $\$/W_{AC}$
Utah/Single Axis Tracking	$2.318	$2.702
Oregon/Single Axis Tracking	$2.429	$2.829
Washington/Single Axis Tracking	$2.476	n/a

The supply side resource costs for wind resources have also been updated. Market conditions and competition led to cost reductions for turbines and balance of plant costs on a $/kW basis. PacifiCorp previously incorporated a combination of land lease and land ownership options for new wind generation projects, but determined that using both ownership structures made it more difficult to compare IRP cost assumptions to typical wind development projects. For the 2015 IRP Update, PacifiCorp structured the capital cost and fixed O&M to reflect wind projects based on leased land which reduced capital costs by removing land purchase costs and increased fixed O&M costs to cover annual lease payments. To provide greater definition of project costs, PacifiCorp created separate line items for each state to address sales tax impacts. For Utah and Oregon there are no state sales taxes whereas sales taxes of 2% are applied for Washington wind resources and 6% for Idaho and Wyoming wind resources. Table 4.2 shows the updated costs of wind resources.

Table 4.2 – Updated Cost of Wind Resources, 2014$

	2015 IRP Update		2015 IRP	
Location	Capital Cost $/W	Fixed O&M $/kW-year	Capital Cost $/W	Fixed O&M $/kW-year
Washington	$1.712	$36.56	$2.135	$34.46
Oregon	$1.672	$36.56	$2.135	$34.46
Idaho	$1.735	$36.56	$2.188	$34.46
Utah	$1.672	$36.56	$2.188	$34.46
Wyoming	$1.735	$36.56	$2.156	$34.46

The 2015 IRP Update adds information for battery storage costs summarized in the table below. Data from the Department of Energy (DOE) Global Energy Storage Database was compiled to produce the information in this table. It shows how installed costs vary with nameplate duration. The results differ from the tables produced in the 2015 IRP based on the limited sizing duration data provided in the 2014 HDR storage study. Table 4.3 shows the updated costs of battery storage resources.

Table 4.3 – Updated Cost of Energy Storage, 2014$

Average 1 MW Battery Cost	Duration			
Standardized at a 20 year life	1 hour	2 hours	4 hours	8 hours
Lithium Ion				
Installed Cost, $/kWh energy storage	**1,725**	**1,223**	**972**	**846**
Installed Cost, $/kW	**1,725**	**2,446**	**3,887**	**6,770**
Sodium Sulfur				
Installed Cost, $/kWh energy storage	**N/A**	**N/A**	**N/A**	**720**
Installed Cost, $/kW	**N/A**	**N/A**	**N/A**	**5,763**
Vanadium Redox				
Installed Cost, $/kWh energy storage	**2,028**	**1,525**	**1,274**	**1,149**
Installed Cost, $/kW	**2,028**	**3,051**	**5,097**	**9,190**

Due to extension in federal production tax credits and investment tax credits, the levelized cost of renewable resources are lower, not only due to updated capital costs and O&M costs, but also due to the application of tax credits that get passed through to customers. Table 4.4 shows updated costs of the renewable resources with and without applicable tax credits, assuming the projects are built as rate-based assets, considering timing of construction and in-service dates. First year real levelized costs for wind and solar resources are presented for 2018, 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 2018 and 2021/2023 were considered in the Company's analysis, but are now shown. Levelized costs for Pacific Northwest wind projects are shown at two different capacity factors, 29% and 35%, reflecting the range of performance anticipated from wind facilities in the region. The table also reports updated storage costs.

Table 4.4 – Updated Supply Side Resource Table, 2014$

Supply Side Resource Options Mid-Calendar Year 2014 Dollars ($)	Capital Cost ($/kW)			Fixed Cost ($/kW-Yr)					
Resource Description	Total Capital Cost	Payment Factor	Annual Payment ($/kW-Yr)	O&M	Capitalized Premium	O&M Capitalized	Gas Transportation	Total	Total Fixed ($/kW-Yr)
2.0 MW turbine 29% CF WA_2018	$1,712	7.399%	$126.69	36.56	2.96%	1.08	0.00	37.65	$164.34
2.0 MW turbine 35% CF WA_2018	$1,712	7.399%	$126.69	36.56	2.96%	1.08	0.00	37.65	$164.34
2.0 MW turbine 29% CF OR_2018	$1,672	7.399%	$123.70	36.56	2.96%	1.08	0.00	37.65	$161.35
2.0 MW turbine 35% CF OR_2018	$1,672	7.399%	$123.70	36.56	2.96%	1.08	0.00	37.65	$161.35
2.0 MW turbine 31% CF ID_2018	$1,735	7.399%	$128.40	36.56	2.96%	1.08	0.00	37.65	$166.05
2.0 MW turbine 31% CF UT_2018	$1,672	7.399%	$123.70	36.56	2.96%	1.08	0.00	37.65	$161.35
2.0 MW turbine 43% CF WY_2018	$1,735	7.399%	$128.40	36.56	2.96%	1.08	0.00	37.65	$166.05
2.0 MW turbine 29% CF WA_2021	$1,712	7.399%	$126.69	36.56	2.96%	1.08	0.00	37.65	$164.34
2.0 MW turbine 35% CF WA_2021	$1,712	7.399%	$126.69	36.56	2.96%	1.08	0.00	37.65	$164.34
2.0 MW turbine 29% CF OR_2021	$1,672	7.399%	$123.70	36.56	2.96%	1.08	0.00	37.65	$161.35
2.0 MW turbine 35% CF OR_2021	$1,672	7.399%	$123.70	36.56	2.96%	1.08	0.00	37.65	$161.35
2.0 MW turbine 31% CF ID_2021	$1,735	7.399%	$128.40	36.56	2.96%	1.08	0.00	37.65	$166.05
2.0 MW turbine 31% CF UT_2021	$1,672	7.399%	$123.70	36.56	2.96%	1.08	0.00	37.65	$161.35
2.0 MW turbine 43% CF WY_2021	$1,735	7.399%	$128.40	36.56	2.96%	1.08	0.00	37.65	$166.05
PV Poly-Si Single Tracking 31.6% AC CF (1.34 MWdc/Mwac) UT_2018	$2,318	8.029%	$186.12	33.59	2.34%	0.79	0.00	34.38	$220.50
PV Poly-Si Single Tracking 29.2% AC CF (1.34 MWdc/Mwac) OR_2018	$2,429	8.029%	$195.01	34.16	2.34%	0.80	0.00	34.96	$229.97
PV Poly-Si Single Tracking 29.2% AC CF (1.34 MWdc/Mwac) WA_2018	$2,476	8.029%	$198.80	34.16	2.34%	0.80	0.00	34.96	$233.76
PV Poly-Si Single Tracking 31.6% AC CF (1.34 MWdc/Mwac) UT_2023	$2,318	8.029%	$186.12	33.59	2.34%	0.79	0.00	34.38	$220.50
PV Poly-Si Single Tracking 29.2% AC CF (1.34 MWdc/Mwac) OR_2023	$2,429	8.029%	$195.01	34.16	2.34%	0.80	0.00	34.96	$229.97
PV Poly-Si Single Tracking 29.2% AC CF (1.34 MWdc/Mwac) WA_2023	$2,476	8.029%	$198.80	34.16	2.34%	0.80	0.00	34.96	$233.76
Lithium Ion Battery (8 MWh/day)	$6,770	10.428%	$706.00	54.88	0.00%	0.00	0.00	54.88	$760.88
Sodium-Sulfur Battery (8 MWh/day)	$5,763	10.428%	$600.95	41.52	0.00%	0.00	0.00	41.52	$642.47
Vanadium RedOx Battery (8 MWh/day)	$9,190	10.428%	$958.37	95.00	0.00%	0.00	0.00	95.00	$1,053.37

Table 4.4 – Updated Supply Side Resource Table, 2014$, Continued*

Supply Side Resource Options Mid-Calendar Year 2014 Dollars ($)	Convert to Mills					Variable Costs (mills/kWh)					Total Costs and Credits (Mills/kWh)		
				Levelized Fuel									
Resource Description	Capacity Factor	Total Fixed (Mills/kWh)	Storage Efficiency	c/mmBtu	Mills/kWh	O&M	Capitalized Premium	O&M Capitalized	Integration Cost	Environmental	Total Resource Cost	PTC Tax Credits / ITC (Solar Only)	Total Resource Cost-With PTC / ITC Credits
2.0 MW turbine 29% CF WA_2018	29%	64.69	na	0	0.00	0.00	0.00%	0.00	3.06	0.00	67.75	(19.45)	48.30
2.0 MW turbine 35% CF WA_2018	35%	53.60	na	0	0.00	0.00	0.00%	0.00	3.06	0.00	56.66	(19.26)	37.40
2.0 MW turbine 29% CF OR_2018	29%	63.51	na	0	0.00	0.00	0.00%	0.00	3.06	0.00	66.57	(19.42)	47.15
2.0 MW turbine 35% CF OR_2018	35%	52.62	na	0	0.00	0.00	0.00%	0.00	3.06	0.00	55.68	(19.24)	36.44
2.0 MW turbine 31% CF ID_2018	31%	61.15	na	0	0.00	0.00	0.00%	0.00	3.06	0.00	64.20	(19.39)	44.81
2.0 MW turbine 31% CF UT_2018	31%	59.42	na	0	0.00	0.00	0.00%	0.00	3.06	0.00	62.47	(19.35)	43.12
2.0 MW turbine 43% CF WY_2018	43%	44.08	na	0	0.00	0.67	0.00%	0.00	3.06	0.00	47.81	(19.10)	28.70
2.0 MW turbine 29% CF WA_2021	29%	64.69	na	0	0.00	0.00	0.00%	0.00	3.06	0.00	67.75	(7.35)	60.40
2.0 MW turbine 35% CF WA_2021	35%	53.60	na	0	0.00	0.00	0.00%	0.00	3.06	0.00	56.66	(7.35)	49.31
2.0 MW turbine 29% CF OR_2021	29%	63.51	na	0	0.00	0.00	0.00%	0.00	3.06	0.00	66.57	(7.35)	59.22
2.0 MW turbine 35% CF OR_2021	35%	52.62	na	0	0.00	0.00	0.00%	0.00	3.06	0.00	55.68	(7.35)	48.33
2.0 MW turbine 31% CF ID_2021	31%	61.15	na	0	0.00	0.00	0.00%	0.00	3.06	0.00	64.20	(7.35)	56.86
2.0 MW turbine 31% CF UT_2021	31%	59.42	na	0	0.00	0.00	0.00%	0.00	3.06	0.00	62.47	(7.35)	55.12
2.0 MW turbine 43% CF WY_2021	43%	44.08	na	0	0.00	0.67	0.00%	0.00	3.06	0.00	47.81	(7.35)	40.46
PV Poly-Si Single Tracking 31.6% AC CF (1.34 MWdc/Mwac) UT 2018	32%	79.65	na	0	0.00	0.00	0.00%	0.00	0.76	0.00	80.42	(10.93)	69.49
PV Poly-Si Single Tracking 29.2% AC CF (1.34 MWdc/Mwac) OR 2018	29%	89.91	na	0	0.00	0.00	0.00%	0.00	0.76	0.00	90.67	(12.39)	78.28
PV Poly-Si Single Tracking 29.2% AC CF (1.34 MWdc/Mwac) WA 2018	29%	91.39	na	0	0.00	0.00	0.00%	0.00	0.76	0.00	92.15	(12.63)	79.52
PV Poly-Si Single Tracking 31.6% AC CF (1.34 MWdc/Mwac) UT 2023	32%	79.65	na	0	0.00	0.00	0.00%	0.00	0.76	0.00	80.42	(3.22)	77.19
PV Poly-Si Single Tracking 29.2% AC CF (1.34 MWdc/Mwac) OR 2023	29%	89.91	na	0	0.00	0.00	0.00%	0.00	0.76	0.00	90.67	(3.66)	87.01
PV Poly-Si Single Tracking 29.2% AC CF (1.34 MWdc/Mwac) WA 2023	29%	91.39	na	0	0.00	0.00	0.00%	0.00	0.76	0.00	92.15	(3.73)	88.42
Lithium Ion Battery (8 MWh/day)	33%	260.58	91%	474	33.83	0.00	0.00%	0.00	0.00	0.00	294.41	0.00	294.41
Sodium-Sulfur Battery (8 MWh/day)	33%	220.02	75%	474	41.05	0.00	0.00%	0.00	0.00	0.00	261.08	0.00	261.08
Vanadium RedOx Battery (8 MWh/day)	33%	360.74	75%	474	41.05	0.00	0.00%	0.00	0.00	0.00	401.80	0.00	401.80

*Total costs shown in mills/kWh represent the first year real levelized cost, which escalates annually the assumed annual rate of inflation net of assumed annual real cost declines that are applicable to solar resources.

CHAPTER 5 – PORTFOLIO DEVELOPMENT

Introduction

PacifiCorp used the System Optimizer (SO) capacity expansion optimization model to develop resource portfolios based on inputs and assumptions updated throughout its business planning process. Similarly, the SO model was used to develop resource portfolios for the 2015 IRP Update consistent with its most recent load and resource balance as described in Chapter 3. This chapter presents the 2015 IRP Update and Business Plan portfolios along with comparisons to the 2015 IRP preferred portfolio.

2015 IRP Update Resource Portfolio

The 2015 IRP Update focuses on changes that occurred after PacifiCorp filed its 2015 IRP and includes comparisons to the resource portfolio developed for the Business Plan. These involve updates to load forecasts, changes in existing resources and any additions to PacifiCorp's contracts with other entities.

Table 5.1 summarizes the annual capacity in the 2015 IRP Update relative to the 2015 IRP preferred portfolio for the 10-year period 2016 through 2025. Consistent with the change in PacifiCorp's load and resource balance, driven by the assumed retirement of Naughton Unit 3 at the end of 2017 and Cholla Unit 4 at the end of 2024, thermal resource capacity is lower in the 2015 IRP Update. The reduction in thermal generation is offset by increased front office transactions (FOTs) and demand side management (DSM) resources. With the assumed retirement of Cholla Unit 4 at the end of 2024, FOTs reach 1,440 MW in 2025, well beyond the near-term action plan window. The level of FOTs shown in 2025 is 670 MW higher than in the 2015 IRP, yet below the assumed 1,575 MW FOT limit. PacifiCorp has not updated its FOT limits for the 2015 IRP Update. PacifiCorp will review its FOT limits during the 2017 IRP public process. Table 5.2 summarizes the 2015 IRP Update load and resource balance, inclusive of incremental resources, for 2016-2025, and Table 5.3 displays the detailed 2015 IRP Update resource portfolio through 2034.

Class 2 DSM selections in the 2015 IRP Update were updated to reflect updated information on actual and projected acquisitions in the near-term and the value of Class 2 DSM resources to the system. Energy selections of Class 2 DSM for 2015 were updated to reflect preliminary year-end actual acquisitions in each state. For 2016 and 2017, Oregon and Washington projections were modified to reflect current Energy Trust of Oregon projections and the approved "Demand Side Management 2016-2017 Business Plan" filed with the Washington Utilities and Transportation Commission (WUTC).[7] For Utah, 2017 projections were set at 2015 IRP levels to reflect an increase in funding from 3.62% to 4%, as approved by the Utah Public Service Commission in 2015. Beginning in 2018, the IRP model was optimized Class 2 DSM selections to provide current information on the need for, and value of, Class 2 DSM in the medium- and long-term.

[7] Washington Utilities and Transportation Commission, Docket UE-152072, Order 01, December 17, 2015.

Table 5.1 – Comparison of 2015 IRP Update with 2015 IRP Preferred Portfolio (Megawatts)

2015 IRP Update

	Capacity (MW)											10- year Total
Resource	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2016-2025**
Expansion Options												
Gas - CCCT	-	-	-	-	-	-	-	-	-	-	-	-
Gas- Peaking	-	-	-	-	-	-	-	-	-	-	-	-
DSM - Energy Efficiency	143	128	138	146	158	142	149	155	161	162	135	**1,476**
DSM - Load Control	-	-	-	-	-	-	-	-	-	-	39	**39**
Renewable - Wind	-	-	-	-	-	-	-	-	-	-	-	-
Renewable - Geothermal	-	-	-	-	-	-	-	-	-	-	-	-
Renewable - Utility Solar	-	-	-	-	-	-	-	-	-	-	-	-
Renewable - Biomass	-	-	-	-	-	-	-	-	-	-	-	-
Front Office Transactions *	764	903	748	1,094	1,246	1,203	970	1,060	965	993	1,440	**1,062**
Existing Unit Changes												
Coal Early Retirement/Conversions	(222)	-	-	(280)	-	-	-	-	-	-	(387)	**(667)**
Thermal Plant End-of-life Retirements	-	-	-	-	-	-	-	-	-	-	-	-
Coal Plant Gas Conversion Additions	-	-	-	-	-	-	-	-	-	-	-	-
Turbine Upgrades	-	-	-	-	-	-	-	-	-	-	-	-
Total	**685**	**1,031**	**886**	**960**	**1,403**	**1,345**	**1,120**	**1,215**	**1,126**	**1,155**	**1,227**	

FOT in resource total are 10-year averages

2015 IRP Preferred Portfolio

	Capacity (MW)											10- year Total
Resource	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2016-2025**
Expansion Options												
Gas - CCCT	-	-	-	-	-	-	-	-	-	-	-	-
Gas- Peaking	-	-	-	-	-	-	-	-	-	-	-	-
DSM - Energy Efficiency	133	139	146	146	153	135	137	144	146	149	123	**1,419**
DSM - Load Control	-	-	-	-	-	-	-	5	11	-	-	**16**
Renewable - Wind	-	-	-	-	-	-	-	-	-	-	-	-
Renewable - Geothermal	-	-	-	-	-	-	-	-	-	-	-	-
Renewable - Utility Solar	-	-	-	-	-	-	-	-	-	-	-	-
Renewable - Biomass	-	-	-	-	-	-	-	-	-	-	-	-
Front Office Transactions *	727	937	904	870	935	979	769	791	761	754	771	**847**
Existing Unit Changes												
Coal Early Retirement/Conversions	(222)	-	-	(280)	-	-	-	-	-	-	(387)	**(667)**
Thermal Plant End-of-life Retirements	-	-	-	-	-	-	-	-	-	-	-	-
Coal Plant Gas Conversion Additions	-	-	-	337	-	-	-	-	-	-	387	**724**
Turbine Upgrades	-	-	-	-	-	-	-	-	-	-	-	-
Total	**638**	**1,077**	**1,050**	**1,073**	**1,088**	**1,113**	**906**	**941**	**917**	**903**	**893**	

FOT in resource total are 10-year averages

2015 IRP Update less 2015 IRP Preferred Portfolio

	Capacity (MW)											10- year Total
Resource	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2016-2025**
Expansion Options												
Gas - CCCT	-	-	-	-	-	-	-	-	-	-	-	-
Gas- Peaking	-	-	-	-	-	-	-	-	-	-	-	-
DSM - Energy Efficiency	10	(11)	(8)	(0)	5	8	12	11	15	14	12	**58**
DSM - Load Control	-	-	-	-	-	-	-	(5)	(11)	-	39	**23**
Renewable - Wind	-	-	-	-	-	-	-	-	-	-	-	-
Renewable - Geothermal	-	-	-	-	-	-	-	-	-	-	-	-
Renewable - Utility Solar	-	-	-	-	-	-	-	-	-	-	-	-
Renewable - Biomass	-	-	-	-	-	-	-	-	-	-	-	-
Front Office Transactions *	37	(34)	(157)	224	311	224	202	269	205	239	670	**215**
Existing Unit Changes												
Coal Early Retirement/Conversions	-	-	-	-	-	-	-	-	-	-	-	-
Thermal Plant End-of-life Retirements	-	-	-	-	-	-	-	-	-	-	-	-
Coal Plant Gas Conversion Additions	-	-	-	(337)	-	-	-	-	-	-	(387)	**(724)**
Turbine Upgrades	-	-	-	-	-	-	-	-	-	-	-	-
Total	**47**	**(45)**	**(164)**	**(113)**	**315**	**232**	**214**	**275**	**209**	**252**	**333**	

FOT in resource total are 10-year averages

Table 5.2 – 2015 IRP Update Capacity Load and Resource Balance (Megawatts)

Calendar Year	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
East										
Thermal	6,397	6,397	6,116	6,116	6,116	6,113	6,110	6,108	6,105	5,717
Hydroelectric	109	109	112	112	112	112	112	112	92	92
Renewable	187	187	187	187	187	185	185	178	178	168
Purchase	355	249	249	249	249	221	221	221	221	121
Qualifying Facilities	304	469	463	460	454	447	436	434	381	378
Class 1 DSM	323	323	323	323	323	323	323	323	323	323
Sale	(728)	(653)	(652)	(652)	(652)	(171)	(171)	(171)	(144)	(144)
Non-Owned Reserves	(38)	(38)	(38)	(38)	(38)	(38)	(38)	(38)	(38)	(38)
Transfers	624	550	915	850	911	552	563	561	605	742
East Existing Resources	**7,534**	**7,594**	**7,675**	**7,608**	**7,663**	**7,744**	**7,743**	**7,728**	**7,724**	**7,360**
Front Office Transactions	0	0	0	109	64	0	0	0	0	315
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	40
Other	0	0	0	0	0	0	0	0	0	0
East Planned Resources	**0**	**0**	**0**	**109**	**64**	**0**	**0**	**0**	**0**	**356**
East Total Resources	**7,534**	**7,594**	**7,675**	**7,717**	**7,726**	**7,744**	**7,743**	**7,728**	**7,724**	**7,715**
Load	6,963	7,084	7,235	7,359	7,447	7,548	7,637	7,717	7,809	7,880
Interruptible	(195)	(195)	(195)	(195)	(195)	(195)	(195)	(195)	(195)	(195)
Existing Class 2 DSM	(61)	(61)	(61)	(61)	(61)	(61)	(61)	(61)	(61)	(61)
New Class 2 DSM	(62)	(131)	(209)	(297)	(376)	(461)	(551)	(646)	(740)	(817)
East obligation	**6,645**	**6,698**	**6,770**	**6,807**	**6,815**	**6,831**	**6,830**	**6,816**	**6,813**	**6,806**
Planning Reserves (13%)	889	896	905	910	911	913	913	911	911	910
East Reserves	**889**	**896**	**905**	**910**	**911**	**913**	**913**	**911**	**911**	**910**
East Obligation + Reserves	**7,534**	**7,594**	**7,675**	**7,717**	**7,727**	**7,744**	**7,743**	**7,728**	**7,724**	**7,717**
East Position	**0**	**0**	**0**	**(0)**	**(0)**	**0**	**0**	**0**	**(0)**	**(1)**
East Reserve Margin	13%	13%	13%	13%	13%	13%	13%	13%	13%	13%
West										
Thermal	2,251	2,248	2,248	2,248	2,248	2,245	2,241	2,239	2,239	2,239
Hydroelectric	841	826	837	736	793	623	548	654	643	632
Renewable	172	172	172	172	172	172	118	118	107	107
Purchase	18	18	18	1	1	1	1	1	1	1
Qualifying Facilities	108	177	175	174	176	166	163	155	154	154
Class 1 DSM	0	0	0	0	0	0	0	0	0	0
Sale	(165)	(165)	(165)	(165)	(165)	(161)	(110)	(110)	(80)	(80)
Non-Owned Reserves	(3)	(3)	(3)	(3)	(3)	(3)	(3)	(3)	(3)	(3)
Transfers	(625)	(551)	(916)	(851)	(912)	(553)	(564)	(562)	(606)	(743)
West Existing Resources	**2,596**	**2,721**	**2,366**	**2,311**	**2,309**	**2,490**	**2,394**	**2,492**	**2,456**	**2,307**
Front Office Transactions	957	793	1,160	1,212	1,212	1,028	1,124	1,023	1,053	1,212
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	**957**	**793**	**1,160**	**1,212**	**1,212**	**1,028**	**1,124**	**1,023**	**1,053**	**1,212**
West Total Resources	**3,553**	**3,514**	**3,526**	**3,523**	**3,521**	**3,518**	**3,517**	**3,515**	**3,509**	**3,519**
Load	3,206	3,199	3,235	3,256	3,276	3,294	3,313	3,332	3,346	3,373
Interruptible	0	0	0	0	0	0	0	0	0	0
Existing Class 2 DSM	(36)	(36)	(36)	(36)	(36)	(36)	(36)	(36)	(36)	(36)
New Class 2 DSM	(26)	(54)	(79)	(103)	(125)	(145)	(165)	(185)	(206)	(223)
West obligation	**3,144**	**3,110**	**3,120**	**3,117**	**3,116**	**3,114**	**3,112**	**3,111**	**3,105**	**3,114**
Planning Reserves (13%)	409	404	406	405	405	405	405	404	404	405
West Reserves	**409**	**404**	**406**	**405**	**405**	**405**	**405**	**404**	**404**	**405**
West Obligation + Reserves	**3,553**	**3,514**	**3,525**	**3,523**	**3,521**	**3,518**	**3,517**	**3,515**	**3,509**	**3,519**
West Position	**0**	**(0)**	**0**	**0**	**0**	**(0)**	**0**	**(0)**	**(0)**	**(0)**
West Reserve Margin	13%	13%	13%	13%	13%	13%	13%	13%	13%	13%
System										
Total Resources	11,087	11,107	11,201	11,239	11,247	11,262	11,260	11,243	11,232	11,234
Obligation	9,789	9,807	9,890	9,924	9,931	9,944	9,942	9,927	9,918	9,920
Reserves	1,298	1,300	1,311	1,315	1,316	1,318	1,318	1,316	1,315	1,315
Obligation + Reserves	11,087	11,107	11,201	11,239	11,247	11,262	11,260	11,243	11,232	11,235
System Position	0	(0)	0	(0)	(0)	0	0	0	(0)	(1)
Reserve Margin	13%	13%	13%	13%	13%	13%	13%	13%	13%	13%

Table 5.3 – 2015 IRP Update, Detailed Portfolio (Megawatts)

		Capacity (MW)																				Resource Totals 1/	
	Resource	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	10-year	20-year
East	**Existing Plant Retirements/Conversions**																						
	Hayden 1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(45)	-	-	-	-	(45)
	Hayden 2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(33)	-	-	-	-	(33)
	Hunter 2 (Coal Early Retirement/Conversions)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(269)	-	-	(269)
	Huntington 2 (Coal Early Retirement/Conversions)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(450)	-	-	-	-	-	(450)
	Carbon 1 (Coal Early Retirement/Conversions)	(67)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(67)	(67)
	Carbon 2 (Coal Early Retirement/Conversions)	(105)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(105)	(105)
	Cholla 4 (Coal Early Retirement/Conversions)	-	-	-	-	-	-	-	-	-	-	(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)	(50)	-	-	(280)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(330)	(330)
	Gadsby 1-6	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(358)	-	-	(358)
	Expansion Resources																						
	CCCT - DJohns - F 2x1	-	-	-	-	-	-	-	-	-	-	-	-	-	635	-	-	-	-	-	-	-	635
	CCCT - Utah-N - J 1x1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	423	-	-	423
	CCCT - Utah-S - F 2x1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	635	-	-	-	-	-	635
	Total CCCT	-	-	-	-	-	-	-	-	-	-	-	-	-	635	-	635	-	-	423	-	-	1,693
	DSM, Class 1, ID-Curtail	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	2.3	-	2.3
	DSM, Class 1, ID-Irrigate	-	-	-	-	-	-	-	-	-	-	12.4	-	4.0	-	-	3.5	-	-	4.6	1.4	-	25.9
	DSM, Class 1, UT-Curtail	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	6.0	-	6.0
	DSM, Class 1, UT-DLC-RES	-	-	-	-	-	-	-	-	-	-	13.1	24.0	10.7	-	-	-	-	-	15.0	5.0	-	67.7
	DSM, Class 1, UT-Irrigate	-	-	-	-	-	-	-	-	-	-	13.2	-	-	-	-	3.3	-	-	-	2.5	-	19.0
	DSM, Class 1, WY-Curtail	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1.0	-	1.0
	DSM, Class 1, WY-Irrigate	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1.5	-	1.5
	DSM, Class 1 Total	-	-	-	-	-	-	-	-	-	-	38.6	24.0	14.7	-	-	6.9	-	-	19.6	19.8	-	123.5
	DSM, Class 2, ID	5	3	3	5	5	4	4	5	5	5	5	5	5	4	5	5	3	3	4	3	44	88
	DSM, Class 2, UT	71	74	81	89	98	89	97	101	106	105	85	85	84	83	81	75	72	73	71	70	909	1,688
	DSM, Class 2, WY	6	7	7	11	14	12	13	15	15	16	13	13	14	14	14	14	14	15	15	15	116	257
	DSM, Class 2 Total	82	83	92	105	117	105	114	120	126	126	103	103	103	101	100	94	89	91	90	89	1,070	2,033
	FOT Mona Q3	-	-	-	-	103	60	-	-	-	-	297	297	300	49	80	300	2	126	300	300	16	111
West	**Expansion Resources**																						
	CCCT - SOregonCal - J 1x1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	454	-	-	-	-	454
	CCCT - WillamValcc - J 1x1	-	-	-	-	-	-	-	-	-	-	-	-	-	477	-	-	-	-	-	-	-	477
	Total CCCT	-	-	-	-	-	-	-	-	-	-	-	-	-	477	-	-	454	-	-	-	-	932
	DSM, Class 1, CA-Irrigate	-	-	-	-	-	-	-	-	-	-	-	-	3.6	-	-	-	-	-	-	0.6	-	4.2
	DSM, Class 1, OR-Curtail	-	-	-	-	-	-	-	-	-	-	-	-	10.6	-	-	-	-	-	-	11.7	-	22.3
	DSM, Class 1, OR-Irrigate	-	-	-	-	-	-	-	-	-	-	-	-	8.4	-	-	-	-	-	-	-	-	8.4
	DSM, Class 1, WA-Curtail	-	-	-	-	-	-	-	-	-	-	-	-	9.2	-	-	-	-	-	-	-	-	9.2
	DSM, Class 1, WA-Irrigate	-	-	-	-	-	-	-	-	-	-	-	-	4.5	-	-	-	-	-	-	0.6	-	5.1
	DSM, Class 1 Total	-	-	-	-	-	-	-	-	-	-	-	-	36.4	-	-	-	-	-	-	12.9	-	49.3
	DSM, Class 2, CA	2	1	2	2	2	1	1	2	2	2	1	2	2	1	1	1	1	1	1	1	16	29
	DSM, Class 2, OR	49	36	37	31	29	27	25	25	23	24	22	22	22	21	21	20	19	19	19	18	305	508
	DSM, Class 2, WA	10	8	8	9	10	9	9	9	11	11	9	9	9	9	8	7	7	7	7	6	93	170
	DSM, Class 2 Total	61	45	47	42	41	37	35	35	36	36	32	32	32	30	30	29	27	27	27	25	415	707
	FOT COB Q3	-	28	-	219	268	268	95	185	90	118	268	268	268	253	268	268	230	173	268	268	127	190
	FOT MidColumbia Q3	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400
	FOT MidColumbia Q3 - 2	264	375	248	375	375	375	375	375	375	375	375	375	375	375	375	375	375	375	375	375	351	363
	FOT NOB Q3	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100
	Existing Plant Retirements/Conversions	(222)	-	-	(280)	-	-	-	-	-	-	(387)	-	-	(762)	-	(807)	(77)	-	(627)	-		
	Annual Additions, Long Term Resources	143	128	138	146	158	142	149	155	161	162	173	159	186	1,244	130	764	571	118	560	147		
	Annual Additions, Short Term Resources	764	903	748	1,094	1,246	1,203	970	1,060	965	993	1,440	1,440	1,443	1,177	1,223	1,443	1,107	1,174	1,443	1,443		
	Total Annual Additions	907	1,031	886	1,240	1,403	1,345	1,120	1,215	1,126	1,155	1,614	1,600	1,629	2,421	1,353	2,207	1,678	1,292	2,003	1,590		

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

Business Plan Resource Portfolio

The Business Plan resource portfolio was updated from 2015 IRP preferred portfolio to reflect changes in existing resource assumptions, as well as assumptions around DSM resources. The main change in existing resources adopted in the Business Plan was the assumed early retirement of Naughton Unit 3 at the end of 2017 and the assumed early retirement of Cholla Unit 4 at the end of 2024. Class 2 DSM selections in the 2015 IRP preferred portfolio were finalized in February 2015. In developing the business plan in the following months, certain Class 2 DSM acquisition levels for 2015-2025 were modified to reflect updated near-term commitments, delivery challenges in certain markets, and uncertainty around upcoming regulatory activity. No modifications were made for the period 2026-2034.

The reduction in existing thermal resources and DSM, as discussed above, are offset by changes in FOTs. Table 5.4 shows the capacity load and resource balance from the Business Plan, inclusive of incremental resources, over the period 2016-2025. Table 5.5 summarizes the annual capacity of incremental resources assumed in the Business Plan.

Table 5.4 – 2015 Fall Business Plan Capacity Load and Resource Balance (Megawatts)

Calendar Year	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
East										
Thermal	6,397	6,397	6,116	6,116	6,116	6,113	6,110	6,108	6,105	5,717
Hydroelectric	109	109	112	112	112	112	112	112	92	92
Renewable	187	187	187	187	187	185	185	178	178	168
Purchase	355	249	249	249	249	221	221	221	221	121
Qualifying Facilities	304	444	437	435	429	422	412	409	407	403
Class 1 DSM	323	323	323	323	323	323	323	323	323	323
Sale	(728)	(653)	(652)	(652)	(652)	(171)	(171)	(171)	(144)	(144)
Non-Owned Reserves	(38)	(38)	(38)	(38)	(38)	(38)	(38)	(38)	(38)	(38)
Transfers	612	559	932	888	949	608	638	661	682	800
East Existing Resources	**7,521**	**7,577**	**7,667**	**7,620**	**7,675**	**7,774**	**7,793**	**7,803**	**7,826**	**7,443**
Front Office Transactions	0	0	0	105	68	0	0	0	0	309
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
East Planned Resources	**0**	**0**	**0**	**105**	**68**	**0**	**0**	**0**	**0**	**309**
East Total Resources	**7,521**	**7,577**	**7,667**	**7,725**	**7,744**	**7,774**	**7,793**	**7,803**	**7,826**	**7,752**
Load	6,963	7,084	7,235	7,359	7,447	7,548	7,637	7,717	7,809	7,880
Interruptible	(195)	(195)	(195)	(195)	(195)	(195)	(195)	(195)	(195)	(195)
Existing Class 2 DSM	(64)	(64)	(64)	(64)	(64)	(64)	(64)	(64)	(64)	(64)
New Class 2 DSM	(71)	(142)	(214)	(286)	(358)	(431)	(504)	(576)	(646)	(783)
East obligation	**6,633**	**6,683**	**6,762**	**6,814**	**6,830**	**6,858**	**6,874**	**6,883**	**6,904**	**6,838**
Planning Reserves (13%)	888	894	904	911	913	917	919	920	923	914
East Reserves	**888**	**894**	**904**	**911**	**913**	**917**	**919**	**920**	**923**	**914**
East Obligation + Reserves	**7,521**	**7,577**	**7,667**	**7,725**	**7,744**	**7,775**	**7,792**	**7,803**	**7,826**	**7,752**
East Position	**0**	**(0)**	**(0)**	**(0)**	**(0)**	**(0)**	**0**	**0**	**(0)**	**(0)**
East Reserve Margin	13%	13%	13%	13%	13%	13%	13%	13%	13%	13%
West										
Thermal	2,251	2,248	2,248	2,248	2,248	2,245	2,241	2,239	2,239	2,239
Hydroelectric	841	826	837	736	793	623	548	654	643	632
Renewable	172	173	173	173	173	173	118	118	108	108
Purchase	18	18	18	1	1	1	1	1	1	1
Qualifying Facilities	112	190	202	200	202	190	186	179	178	178
Class 1 DSM	0	0	0	0	0	0	0	0	0	0
Sale	(165)	(165)	(165)	(165)	(165)	(161)	(110)	(110)	(80)	(80)
Non-Owned Reserves	(3)	(3)	(3)	(3)	(3)	(3)	(3)	(3)	(3)	(3)
Transfers	(613)	(560)	(933)	(889)	(950)	(609)	(639)	(662)	(684)	(802)
West Existing Resources	**2,612**	**2,726**	**2,376**	**2,301**	**2,298**	**2,459**	**2,343**	**2,417**	**2,403**	**2,274**
Front Office Transactions	936	781	1,140	1,212	1,212	1,047	1,155	1,068	1,076	1,212
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	5	17	17	17
Other	0	0	0	0	0	0	0	0	0	0
West Planned Resources	**936**	**781**	**1,140**	**1,212**	**1,212**	**1,047**	**1,161**	**1,085**	**1,092**	**1,228**
West Total Resources	**3,548**	**3,507**	**3,517**	**3,512**	**3,510**	**3,506**	**3,504**	**3,501**	**3,495**	**3,502**
Load	3,206	3,199	3,235	3,256	3,276	3,294	3,313	3,332	3,346	3,373
Interruptible	0	0	0	0	0	0	0	0	0	0
Existing Class 2 DSM	(35)	(35)	(35)	(35)	(35)	(35)	(35)	(35)	(35)	(35)
New Class 2 DSM	(31)	(60)	(87)	(113)	(135)	(156)	(177)	(198)	(218)	(239)
West obligation	**3,140**	**3,104**	**3,112**	**3,108**	**3,106**	**3,103**	**3,101**	**3,099**	**3,093**	**3,099**
Planning Reserves (13%)	408	403	405	404	404	403	403	403	402	403
West Reserves	**408**	**403**	**405**	**404**	**404**	**403**	**403**	**403**	**402**	**403**
West Obligation + Reserves	**3,548**	**3,507**	**3,517**	**3,512**	**3,510**	**3,506**	**3,504**	**3,502**	**3,495**	**3,502**
West Position	**0**	**(0)**	**0**	**(0)**	**0**	**0**	**0**	**(0)**	**(0)**	**0**
West Reserve Margin	13%	13%	13%	13%	13%	13%	13%	13%	13%	13%
System										
Total Resources	11,069	11,084	11,183	11,237	11,253	11,281	11,297	11,305	11,321	11,254
Obligation	9,773	9,787	9,874	9,922	9,936	9,961	9,974	9,982	9,996	9,937
Reserves	1,296	1,298	1,309	1,315	1,317	1,320	1,322	1,323	1,325	1,317
Obligation + Reserves	11,069	11,085	11,183	11,238	11,253	11,281	11,296	11,305	11,321	11,254
System Position	0	(0)	0	(0)	(0)	0	0	0	(0)	(0)
Reserve Margin	13%	13%	13%	13%	13%	13%	13%	13%	13%	13%

Table 5.5 –Business Plan, Detailed Portfolio (Megawatts)

		Capacity (MW)											Resource Totals 1/
	Resource	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	10-year
East	**Existing Plant Retirements/Conversions**												
	Carbon 1 (Coal Early Retirement/Conversions)	(67)	-	-	-	-	-	-	-	-	-	-	-
	Carbon 2 (Coal Early Retirement/Conversions)	(105)	-	-	-	-	-	-	-	-	-	-	-
	Cholla 4 (Coal Early Retirement/Conversions)	-	-	-	-	-	-	-	-	-	-	(387)	(387)
	Naughton 3 (Coal Early Retirement/Conversions)	(50)	-	-	(280)	-	-	-	-	-	-	-	(280)
	Expansion Resources												
	DSM, Class 2, ID	3	3	3	3	4	3	3	3	3	3	3	32
	DSM, Class 2, UT	61	61	63	63	63	63	64	63	63	61	65	629
	DSM, Class 2, WY	4	6	7	7	7	7	8	8	7	8	8	73
	DSM, Class 2 Total	67	70	73	73	74	73	75	75	73	72	76	734
	FOT Mona Q3	-	-	-	-	99	64	-	-	-	-	291	45
West	**Expansion Resources**												
	DSM, Class 1, OR-Curtail	-	-	-	-	-	-	-	-	10.6	-	-	10.6
	DSM, Class 1, OR-Irrigate	-	-	-	-	-	-	-	5.0	-	-	-	5.0
	DSM, Class 1 Total	-	-	-	-	-	-	-	5.0	10.6	-	-	15.6
	DSM, Class 2, CA	1	1	2	2	2	1	1	1	1	1	1	14
	DSM, Class 2, OR	33	32	27	24	22	19	18	18	17	16	15	208
	DSM, Class 2, WA	8	8	8	8	8	6	7	7	8	7	6	73
	DSM, Class 2 Total	43	41	36	34	32	26	26	26	26	24	23	295
	FOT COB Q3	-	8	-	201	268	268	113	215	133	140	268	161
	FOT MidColumbia Q3	400	400	400	400	400	400	400	400	400	400	400	400
	FOT MidColumbia Q3 - 2	261	375	237	375	375	375	375	375	375	375	375	361
	FOT NOB Q3	100	100	100	100	100	100	100	100	100	100	100	100
	Existing Plant Retirements/Conversions	(222)	-	-	(280)	-	-	-	-	-	-	(387)	
	Annual Additions, Long Term Resources	110	111	109	107	106	99	102	106	110	96	99	
	Annual Additions, Short Term Resources	761	883	737	1,076	1,242	1,207	988	1,090	1,008	1,015	1,434	
	Total Annual Additions	871	994	846	1,183	1,348	1,306	1,090	1,196	1,117	1,111	1,533	

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

Renewable Portfolio Standard Compliance

Oregon

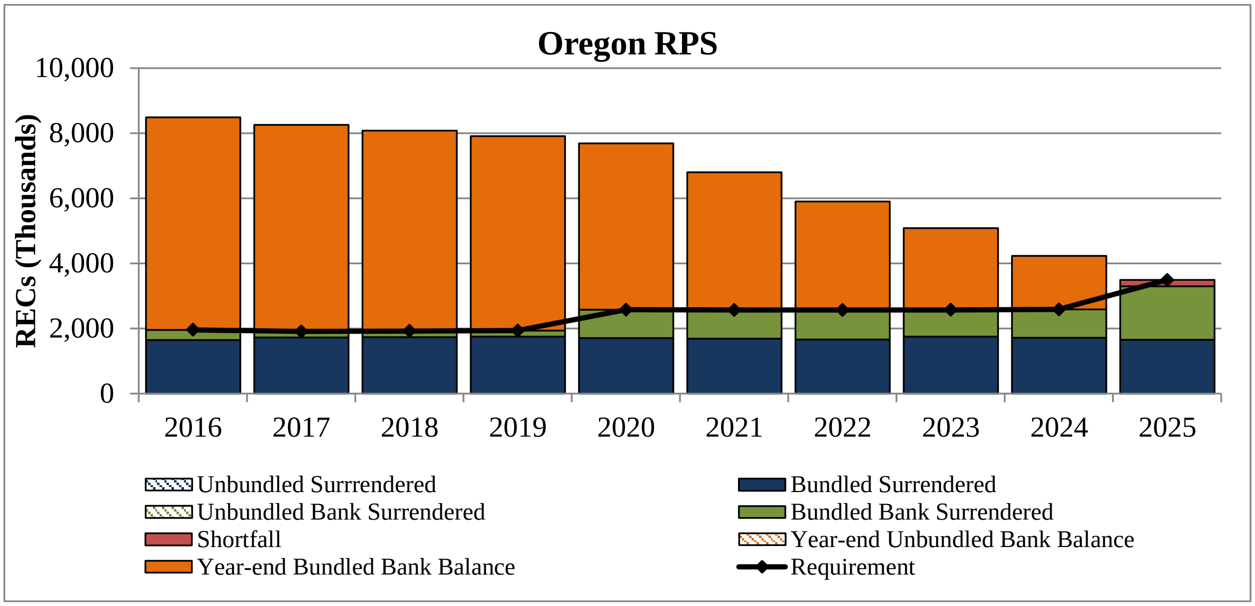
On March 8, 2016, Oregon Senate Bill 1547-B (SB 1547-B), the Clean Electricity and Coal Transition plan, was signed into law, which doubles the Oregon RPS target to 50% by 2040. Table 5.6 summarizes how the bill affects RPS targets for Oregon relative to those assumed in the 2015 IRP. In addition to revising RPS targets, SB 1547-B includes other provisions that influence how the company will plan to meet its RPS compliance requirements. One of these provisions introduces a five year banking limitation on renewable energy credits (RECs) issued after March 8, 2016. RECs issued on or before March 8, 2016 can be banked indefinitely. Another provision in SB 1547-B provides an early action incentive that allows for indefinite banking of RECs from new qualifying renewable resources that are issued over the first five years of the renewable resource's operation. New qualifying renewable resources include facilities that come online between March 8, 2016 and December 31, 2022. At the same time, SB 1547-B eliminates the requirement to surrender older vintage RECs for compliance first, prior to the surrender of newer vintage RECs.

Table 5.6 – Oregon RPS Targets

Year	2015 IRP	2015 IRP Update
2016	15%	15%
2020	20%	20%
2025	25%	27%
2030	25%	35%
2035	25%	45%
2040	25%	50%

Figure 5.1 shows PacifiCorp's baseline RPS compliance position for Oregon for the front ten years of the planning horizon if no further action were taken. The baseline position indicates an initial shortfall, with the use of the existing bank, would occur in 2025.

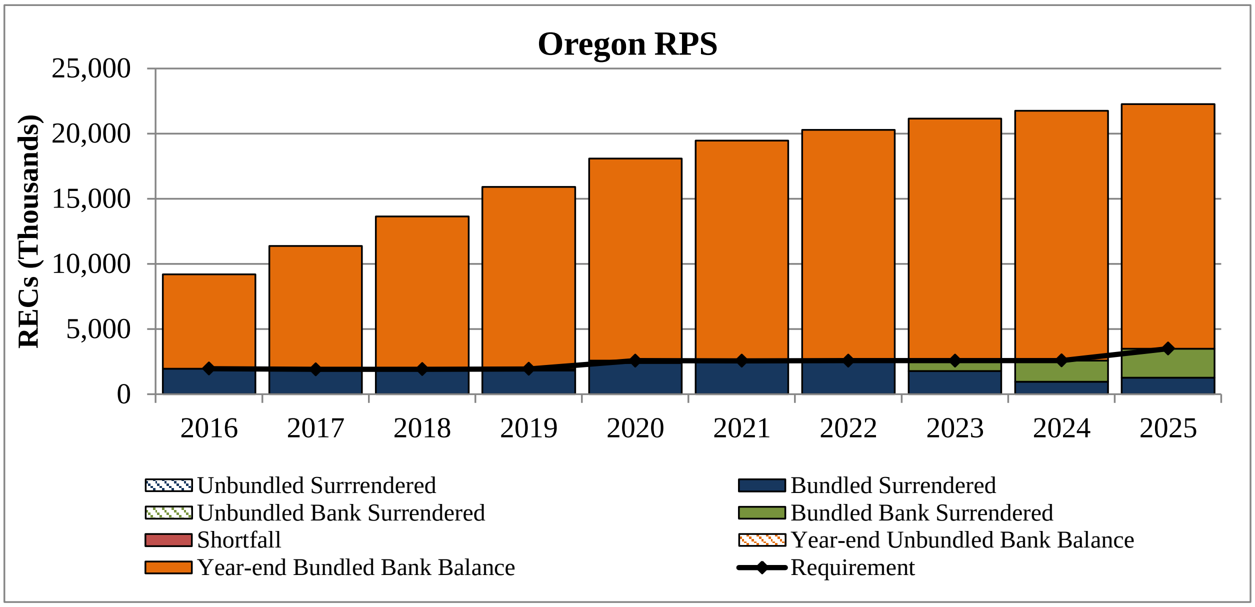
Figure 5.1 – Baseline Oregon RPS Compliance Position



Considering the flexible provisions in the new law, updated RPS targets, updated REC banking provisions and the market potential for RECs, PacifiCorp can meet its Oregon RPS obligations through the 20-year IRP planning horizon through a number of flexible alternatives including the purchase of eligible RECs.[8] Figure 5.2 shows PacifiCorp's RPS compliance forecast for Oregon, inclusive of REC purchase volumes that contribute to meeting RPS targets through the IRP planning horizon. Over the front ten years of the planning horizon, nearly 19 million RECs are needed to build the bank, which can be used to meet RPS requirements as the target rises over time. Over this same period, PacifiCorp estimates that there will be at least 23 million RECs generated from qualifying facility projects that have power purchase agreements with PacifiCorp in which the project developers hold title to the RECs. This volume is over and above eligible RECs from other facilities in the market with whom PacifiCorp is familiar through its industry leading Blue Sky program.

[8] Under the Oregon RPS, RECs purchased from qualifying facility projects located in Oregon do not apply toward the 20% annual unbundled REC limit. RECs purchased from qualifying facilities in other states could be acquired as a bundled REC if the REC is purchased with the energy in the same contract.

Figure 5.2 – Oregon RPS Compliance Position with REC Purchases



REC purchases represent one avenue for achieving RPS compliance. PacifiCorp has also identified the potential for near-term, time-sensitive renewable resource acquisition opportunities that may reduce RPS compliance costs. The current planning environment, as fully described in Chapter 2, creates a potentially unique opportunity for the company to pursue low-cost renewable resources in the near-term as a way to reduce long-term RPS compliance costs. As discussed in Chapter 2, federal tax extender legislation passed in late 2015 retroactively and prospectively extended certain expired and expiring federal income tax deductions and credits over a multi-year phase out period. The most time-sensitive of these income tax credits is the federal production tax credit (PTC) for wind resources. To take advantage of the full PTC, currently set at 2.3 cents per kilowatt-hour, growing at inflation, for the first ten years of operation, a wind facility must commence construction by January 1, 2017. Under Internal Revenue Service (IRS) guidance, projects can demonstrate they have commenced construction by either starting work of a significant physical nature or by paying or incurring at least five percent of the total cost of the facility by January 1, 2017.

The PTC equates to over 3.7 cents per kilowatt-hour when grossed up by PacifiCorp's marginal tax rate. Consequently, the after-tax cost of a wind project that is eligible for 100% of the PTC is reduced by over $37/MWh growing at inflation for the first ten years. For a 100 MW wind facility operating at a 29% capacity factor, this equates to over $102 million over ten years—after-tax cost savings that are passed through to customers. If the up-front capital cost for this wind facility is $180 million (about $1,800/kW), then the PTCs received through the first ten years of operation cover 57% of the initial capital investment. If the project operates at a 35% capacity factor, the PTC savings increase to nearly $124 million, representing about 69% of the initial capital investment. If a wind facility is unable to demonstrate it has commenced construction by January 1, 2017 but can commence construction by January 1, 2018, then the PTC is reduced by 20%. This one year delay would reduce PTC savings by between $20 million (29% capacity factor) to $25 million (35% capacity factor) for a 100 MW project.

In addition to the time-sensitive opportunity to take full advantage of PTC benefits, SB 1547-B also includes an opportunity to lower RPS compliance costs through the near-term acquisition of renewable resources since RECs issued during the first five years of a new renewable facilities' operation can be banked indefinitely. RECs generated during this time period will allow PacifiCorp to build a bank of RECs that are not subject to a five year banking limit. Growing the bank now will allow the company to defer future RPS compliance needs, when cost savings from tax incentives will no longer be available.

Near-term renewable resource procurement also provides value to customers because new renewable resources provide incremental energy and capacity that can also reduce system emissions. This additional energy and capacity will immediately offset fuel costs, purchased power and associated emissions. It will also offset the need for replacement resources as existing generating assets retire and reduce the Company's risk associated with the future greenhouse gas regulations. Procurement of renewable resources can further enable access to high quality renewable resource sites, which can provide future repowering and/or redevelopment value. With increased state RPS targets (i.e., Oregon and California targets now reach 50%) and the anticipated need to reduce greenhouse gas emissions through both state and federal policies such as the Clean Power Plan, demand for renewable resources is expected to grow and place upward pressure on future renewable resource costs, particularly if incremental transmission infrastructure is needed. Therefore, the acquisition of renewable resources now has the potential to optimally position the company and its Oregon customers in the face of increased and expanded carbon regulation.

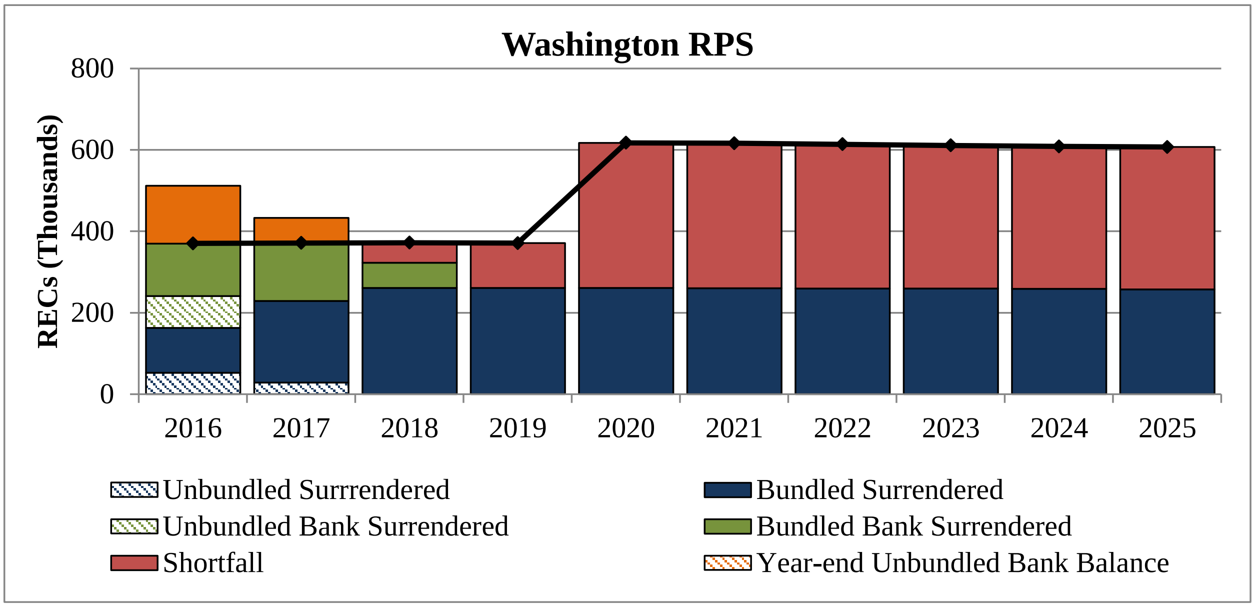
To fully evaluate Oregon RPS compliance alternatives that consider potential near-term, time-sensitive resource procurement opportunities, PacifiCorp intends to issue requests for proposals (RFPs) seeking both REC purchase and resource procurement alternatives. Resource proposals will be evaluated concurrent with REC proposals to comprehensively assess RPS compliance alternatives, considering both cost and risk metrics. Because proposals for new wind facilities must be able to demonstrate that they initiated construction by January 1, 2017 to take full advantage of PTC cost savings, PacifiCorp intends to issue this RFP in spring 2016 to complete the RFP evaluation, selection and contracting process by fall 2016. This schedule provides the best opportunity for customers to benefit from potentially cost effective wind and solar proposals that can take full advantage of the PTC and ITC.

Notwithstanding the near-term renewable resource value incentives and opportunities, PacifiCorp will also consider longer term opportunities to take advantage of retiring coal facilities on its network that will free up transmission in renewable resource rich areas and provide access to low cost resources which today are constrained by lack of transmission.

Washington

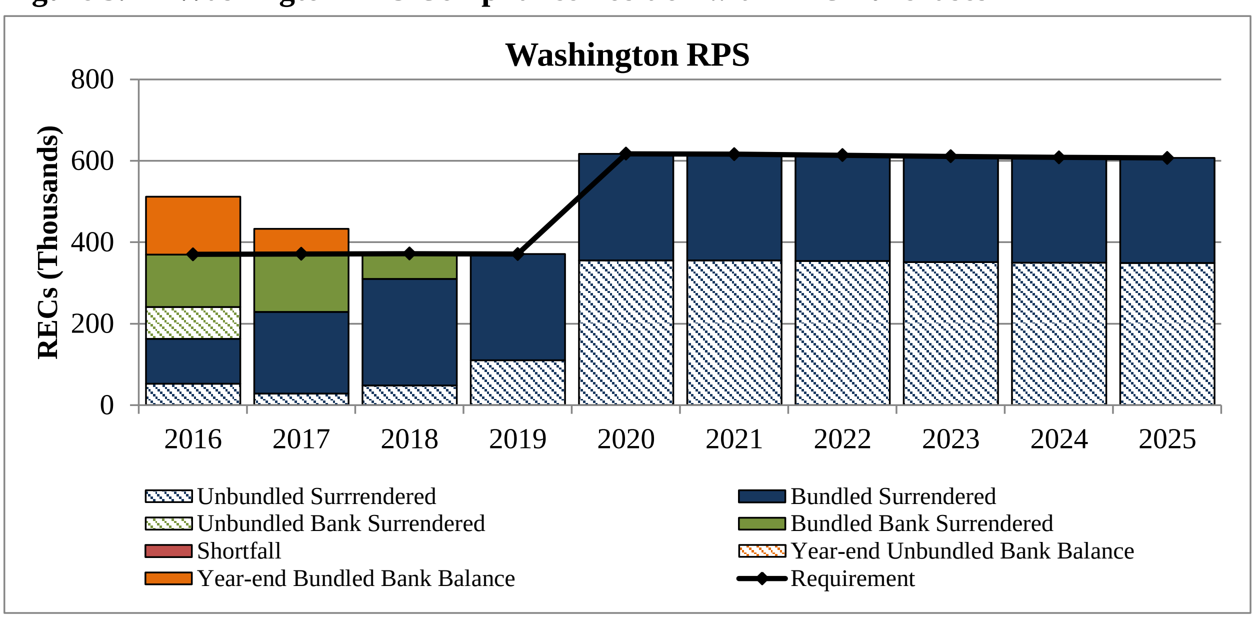
Figure 5.3 shows PacifiCorp's baseline RPS compliance position for Washington for the front ten years of the planning horizon, prior to procuring incremental unbundled RECs. This baseline position incorporates PacifiCorp's most recent procurement of unbundled RECs for Washington's RPS. The baseline position indicates a potential shortfall in 2018 if no further action were taken.

Figure 5.3 – Baseline Washington RPS Compliance Position



Washington RPS rules do not impose restrictions on the use of unbundled RECs and effectively impose a one year life on all banked RECs. PacifiCorp can meet its Washington RPS targets with unbundled REC purchases through the IRP planning horizon. Figure 5.4 shows PacifiCorp's Washington RPS compliance position with unbundled REC purchase volumes required to achieve compliance. As requested by the Washington Utilities and Transportation Commission in its 2015 IRP acknowledgement letter, Washington RPS compliance is presented consistent with how Washington is currently allocated eligible renewable resources. Over the front ten years of the planning horizon, nearly 2.3 million additional unbundled RECs are needed to meet Washington RPS targets. As discussed above, PacifiCorp will consider whether near-term, time-sensitive resource procurement provides a low cost opportunity to displace or supplement unbundled REC purchases as an alternative approach to achieving compliance with the Washington RPS.

Figure 5.4 – Washington RPS Compliance Position with REC Purchases



California

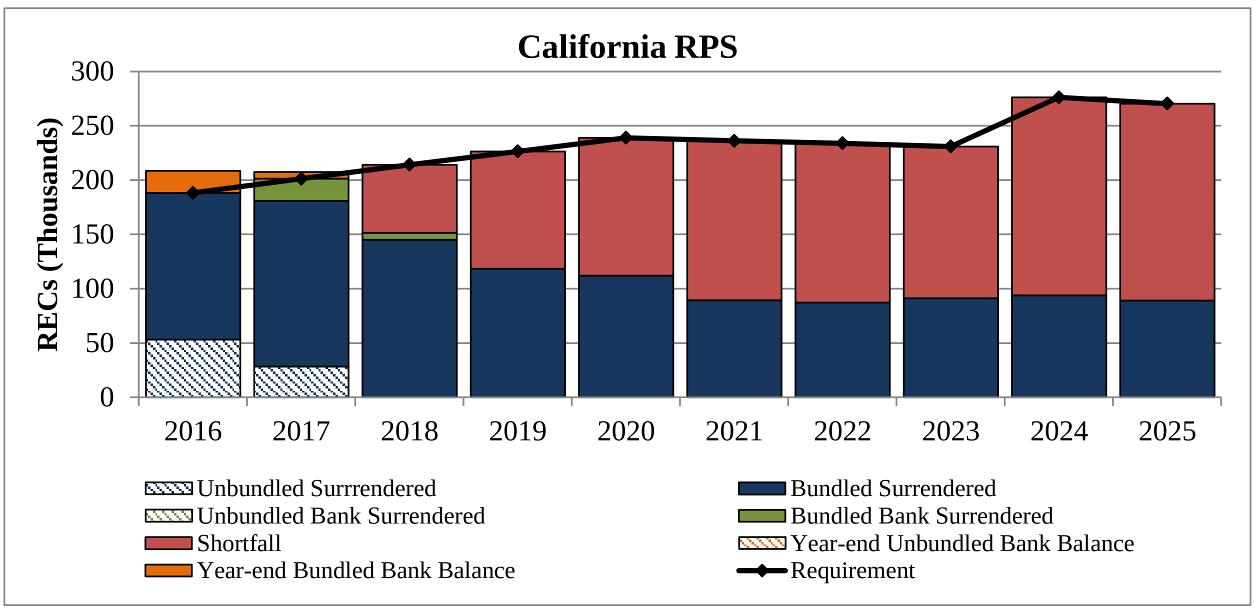
In October 2015, California Senate Bill No. 350 (SB 350) was signed into law, expanding the RPS target to 50% by 2030. Table 5.7 summarizes how the bill affects interim RPS targets for California relative to those assumed in the 2015 IRP.

Table 5.7 – California RPS Targets

Year	2015 IRP	2015 IRP Update
2016	25%	25%
2017	27%	27%
2018	29%	29%
2019	31%	31%
2020	33%	33%
2024	33%	40%
2027	33%	45%
2030	33%	50%

Figure 5.5 shows PacifiCorp's baseline RPS compliance position for California for the front ten years of the planning horizon. This baseline position includes unbundled RECs that have been procured for California RPS compliance.[9] The baseline position indicates a potential shortfall beginning 2018 if no further action were taken.

Figure 5.5 – Baseline California RPS Compliance Position

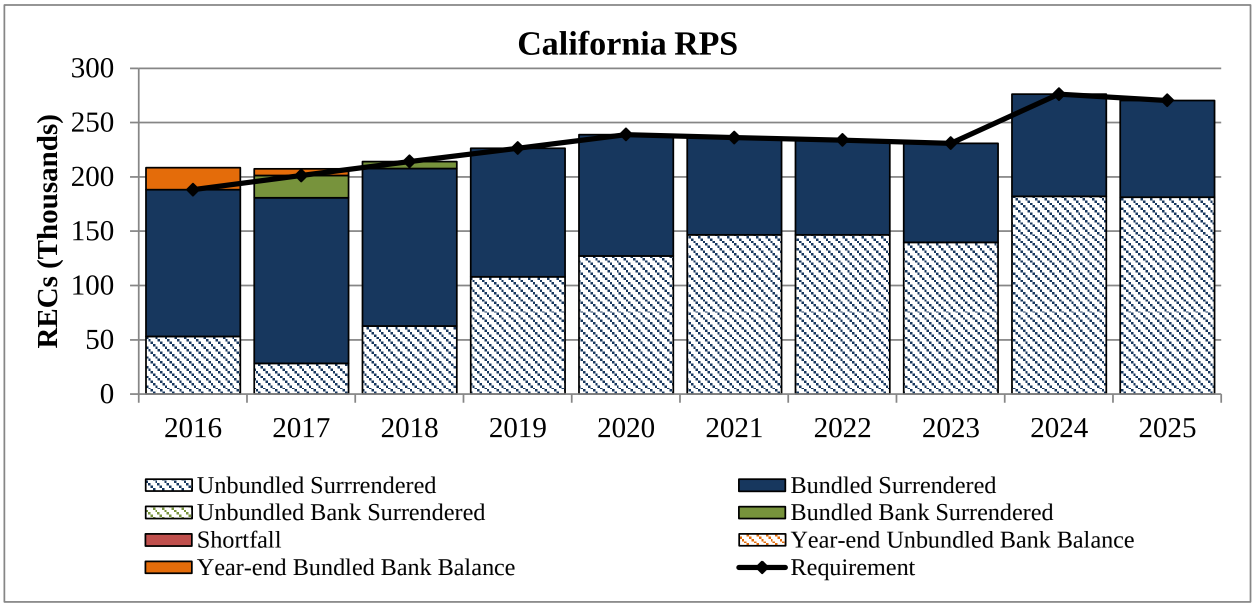


PacifiCorp is not restricted from using unbundled RECs to meet its RPS targets in California, and unbundled REC purchases can be used to achieve compliance through the IRP planning horizon. Figure 5.6 shows PacifiCorp's California RPS compliance position with unbundled REC purchase volumes required to achieve compliance. Over the front ten years of the planning horizon, over one million additional unbundled RECs are needed to meet California RPS targets. As discussed above, PacifiCorp will consider whether near-term, time-sensitive resource

[9] PacifiCorp selected a response to an unbundled REC RFP which meets the Company's needs and pricing criteria. The contract is currently under review with the California Public Utilities Commission.

procurement provides a low cost opportunity to displace or supplement unbundled REC purchases as an alternative approach to achieving compliance with the California RPS.

Figure 5.6 – California RPS Compliance Position with REC Purchases



Utah

Utah Senate Bill 202, the Energy Resource and Carbon Emission Reduction Initiative, provides that beginning in 2025, 20% of adjusted retail sales of all Utah utilities be supplied by renewable energy, if cost effective. Retail electric sales are adjusted by deducting the amount of generation from sources that produce zero or reduced carbon emissions, and for sales avoided as a result of energy efficiency and demand side management programs. Qualifying renewable energy sources can be located anywhere in the Western Electricity Coordinating Council area, and unbundled RECs can be used for up to 20% of the annual qualifying electricity target. Solar facilities located in Utah receive credit for 2.4 kilowatt-hours of qualifying electricity for each kilowatt-hour of generation. PacifiCorp has been building a bank of RECs from existing and contracted qualifying resources since 1995. This bank will be used to meet Utah's RPS goals well beyond the IRP planning horizon.

Carbon Dioxide Emissions

Figure 5.7 shows annual total CO_2 emissions of the resource portfolio and from coal-fueled generation facilities for both the 2015 IRP preferred portfolio and 2015 IRP Update resource portfolio. Emissions from the 2015 IRP Update resource portfolio are lower primarily due to reduced generation levels from fossil fired resources. Figure 5.8 shows the total generation and generation from coal-fueled facilities from the 2015 IRP and 2015 IRP Update. Figure 5.9 shows emissions from affected units under the FIP-based mass cap proposed by EPA for the Clean Power Plan.

Figure 5.7 – Total CO_2 Emissions

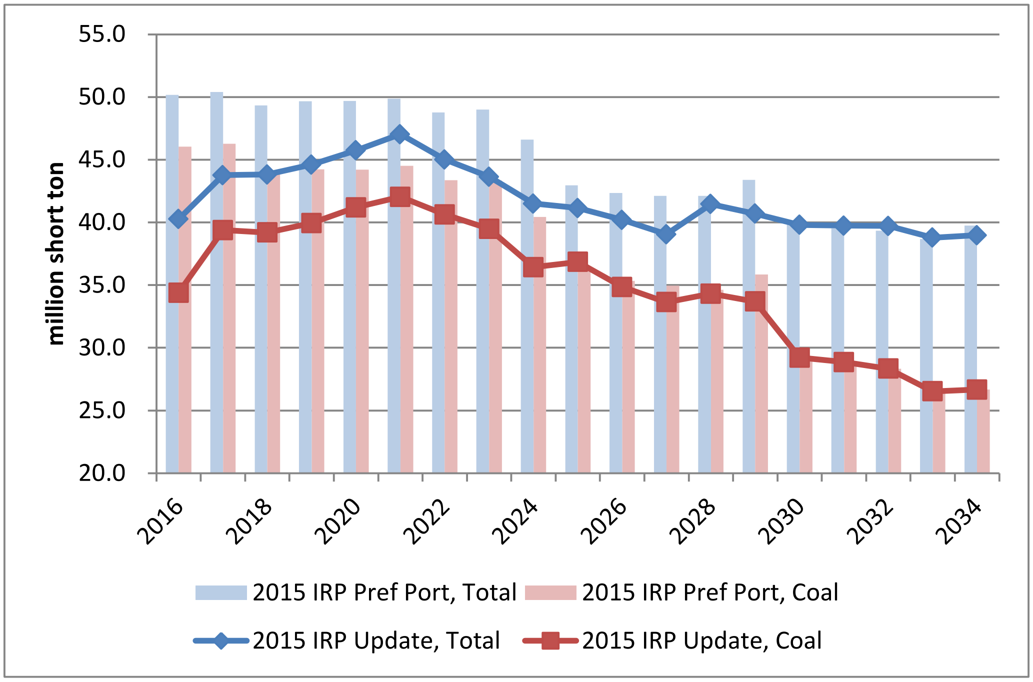


Figure 5.8 – Total Thermal Generation

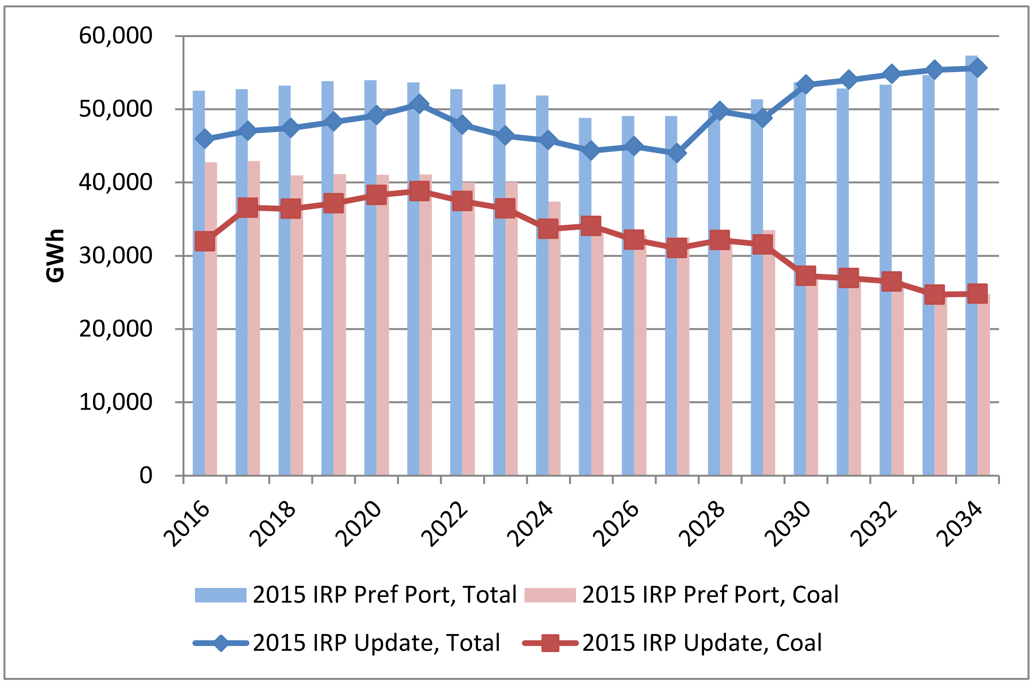
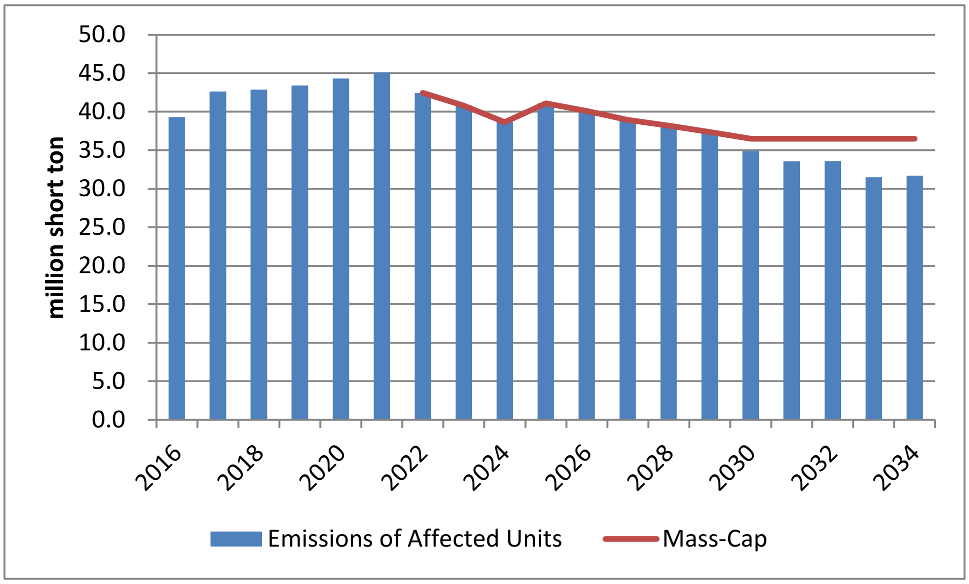
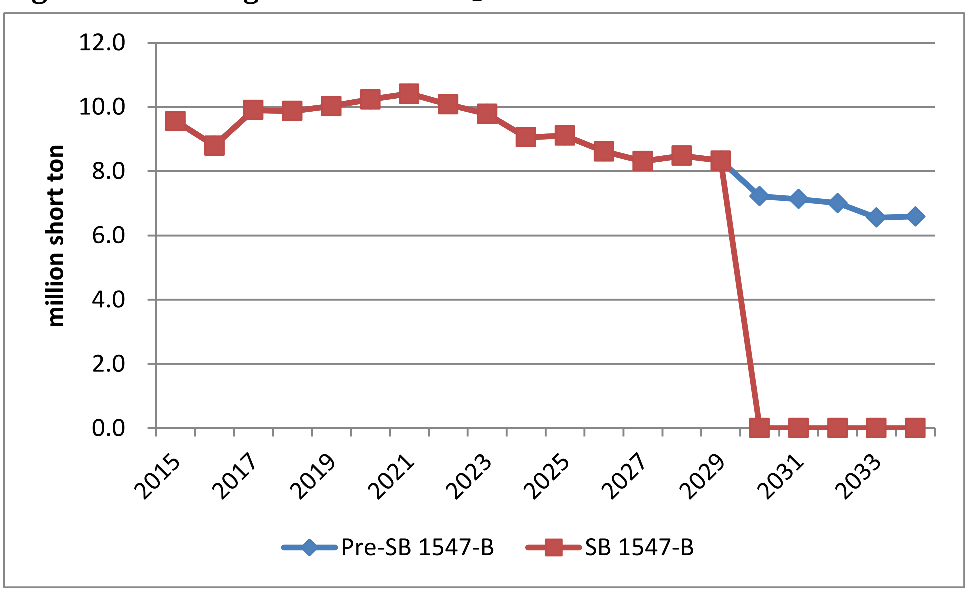


Figure 5.9 – Mass-Cap and Emissions from Affected Units



Oregon SB 1547-B requires that coal-fired resources are eliminated from Oregon's allocation of electricity by January 1, 2030. Figure 5.10 shows the reduction in emissions from coal resources allocated to Oregon customers accounting for this provision of SB 1547-B.

Figure 5.10 – Oregon Share of CO_2 Emission from Coal-fueled Resources



Sensitivity Studies and Responses to Commission Requests

Clean Power Plan and Allocation of Renewable Energy Attributes

In its 2015 IRP acknowledgement letter, the WUTC encouraged the Company to use the 2015 IRP Update as an opportunity to begin modeling EPA's final CPP rule and to actively and constructively participate in Washington's process and any multi-state or regional efforts that emerge. The WUTC further requested PacifiCorp re-run Sensitivity Case S-15 in the 2015 IRP

Update, accounting for the final CPP rule, to determine whether lower cost compliance options that do not assume an early retirement of the Chehalis plant are available to meet its obligations without having to double allocate renewable energy.

PacifiCorp has and will continue to actively and constructively participate in the Washington Department of Ecology's CPP stakeholder process, which has included two utility stakeholder meetings so far. PacifiCorp is also engaging with state agencies on an informal basis and is participating in various regional efforts including efforts being led by the Center for New Energy Economy, WEST Associates, and the Western Interstate Energy Board.

Sensitivity Case S-15 from the 2015 IRP assumes state RPS-eligible RECs and CPP renewable attributes would need to be surrendered at the same time, forcing PacifiCorp to meet its share of emission rate targets outlined in the draft CPP rule with either situs-assigned renewable resources, or alternatively, by eliminating PacifiCorp's CPP compliance obligation in Washington by retiring the Chehalis plant. Given the low emission rate targets in EPA's draft rule for the state of Washington, PacifiCorp concluded that significant levels of situs-assigned renewable resources would be required to achieve compliance with draft emission rate targets proposed for the state of Washington, and determined that an early retirement of Chehalis would be lower cost when developing the resource portfolio for Sensitivity Case S-15.

When developing Sensitivity Case S-15 for the 2015 IRP, PacifiCorp determined an early retirement of Chehalis would be lower cost than adding situs-assigned renewable resources based on preliminary analysis performed during the public process that was presented to stakeholders at the January 29-30, 2015 public input meeting.[10] This preliminary sensitivity analysis was produced for Sensitivity Case S-10, which developed standalone resource portfolios for the east and west balancing authority areas. In its preliminary modeling for this Sensitivity Case S-10, PacifiCorp developed one CPP compliance scenario assuming Chehalis retired early, eliminating PacifiCorp's CPP obligation in Washington, and another scenario assuming incremental renewable resources were added to meet then-current emission rate targets. This preliminary analysis showed that a renewable-based compliance solution would require over 1,100 MW of incremental renewable resources and that the present value revenue requirement (PVRR) of system costs were $515 million higher (over 77%) than the Chehalis early retirement alternative.

Since PacifiCorp performed these sensitivity analyses for the 2015 IRP, EPA issued its final CPP rule as summarized in Chapter 2. In its final rule, EPA significantly increased the emission rate targets for the state of Washington and provided states with a number of implementation options, including an alternative to adopt mass-based goals that EPA has determined are equivalent to the updated rate-based targets. Considering that the emission rate of the Chehalis plant falls below the final rate-based targets established for the state of Washington, PacifiCorp would not anticipate needing to eliminate its CPP compliance obligation by retiring Chehalis early or needing to acquire emission reduction credits (ERCs) to reduce its share of the Washington state emission rate targets should Washington adopt a rate-based plan. Moreover, should Washington adopt a mass-based plan, ERCs would not be used to achieve compliance, eliminating the concern of double-allocating renewable energy altogether.

[10] The referenced analysis is summarized beginning on slide 78 of the presentation, which is available on PacifiCorp's website: http://www.pacificorp.com/content/dam/pacificorp/doc/Energy_Sources/Integrated_Resource_Plan/2015IRP/PacifiCorp_2015IRP_PIM06_2015-01-29-30.pdf

Considering that the U.S. Supreme Court issued a stay of the CPP suspending implementation of the rule, PacifiCorp has not performed comprehensive resource portfolio analysis of the CPP final rule in this 2015 IRP Update. PacifiCorp developed its updated resource portfolio assuming system mass cap emission rate targets consistent with EPA's proposed mass-based FIP to limit CO_2 emissions from its existing affected generation facilities. PacifiCorp will evaluate CPP compliance scenarios, with input from its stakeholders, during the 2017 IRP public process.

Historical Cooling Degree Days

In its order regarding PacifiCorp's 2013 IRP, the Public Service Commission of Utah (PSCU) directed PacifiCorp to perform a study on whether the available historical cooling degree day information, or some other alternative, is an appropriate predictor of future normal conditions. The request for the study was a result of a discussion on whether PacifiCorp should consider climate change implications when forecasting load. Changes in climate would ultimately be reflected by the data on historical weather and load, and the impact on the forecast of load would be guided by the historical relationship between weather on load. To respond to this order, PacifiCorp prepared a study to test the impacts of different historical weather patterns on the load forecast. There are no meaningful differences between using a five-year, ten-year, or 20-year normal weather pattern in the models. The results are presented on page nine of Appendix A to PacifiCorp's 2015 IRP report.[11] PacifiCorp also prepared extreme weather scenarios to study the impacts of less likely weather patterns, which are presented on page 18 of Appendix A to PacifiCorp's 2015 IRP report. The portfolio impact of different levels of load forecast is reflected by Sensitivity Cases S-01, S-02 and S-03 in PacifiCorp's 2015 IRP.

Interaction of FERC Order 1000 and Energy Gateway

The PSCU also requested that PacifiCorp explain, as necessary, the interaction of requirements by the FERC Order 1000 and any Energy Gateway Project. PacifiCorp continues to participate in the Northern Tier Transmission Group that satisfies regional transmission planning requirements under the FERC's Order No.1000 in addition to PacifiCorp's local transmission planning requirements pursuant to Attachment K of its Open Access Transmission Tariff. Energy Gateway is also considered in the NTTG biennial transmission planning cycle efforts as well as at the Western Electricity Coordinating Council's Transmission Expansion Policy and Planning Committee.

Accelerated Class 2 DSM

As recommended by the OPUC, PacifiCorp performed a sensitivity study on Class 2 DSM by replacing baseline DSM potential with accelerated DSM potential when developing an optimized resource portfolio. Table 5.8 shows the portfolio with accelerated DSM, the 2015 IRP Update portfolio with baseline DSM, and the differences between these two portfolios.

[11] http://www.pacificorp.com/content/dam/pacificorp/doc/Energy_Sources/Integrated_Resource_Plan/2015IRP/PacifiCorp_2015IRP-Vol2-Appendices.pdf

The sensitivity shows that when accelerated DSM potential is assumed, a slightly higher amount of Class 2 DSM resource is selected in the early years, while the total amount of Class 2 DSM selected over the 20-year study period is lower. The amount of DSM in 2015 through 2017 is the same between the two portfolios, because, as described earlier in this chapter, Class 2 DSM selections are fixed to reflect the most up to date planning for 2015 through 2017 and optimized beginning in 2018. The amount of Class 2 DSM in 2015 through 2017 exceeds the amount selected in the 2015 IRP, and thus, they were not modified in the accelerated sensitivity case. The portfolio with accelerated DSM also includes a larger CCCT in 2028 and delayed a CCCT in 2031. FOTs are generally less until 2031. For the 20-year study period, the portfolio added 41 MW less CCCT capacity, and added a total of 88 MW of utility solar on the east side of PacifiCorp's system. The present value revenue requirement (PVRR) of system costs from the portfolio with accelerated DSM is approximately $45 million higher than the portfolio developed with baseline DSM assumptions.

Table 5.8 – Portfolio Comparison of Accelerated DSM Study and 2015 IRP Update (Megawatts)

Accelerated DSM portfolio

Summary Portfolio Capacity by Resource Type and Year, Installed MW																					
	Installed Capacity, MW																				
Resource	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**Total**
Expansion Options																					
Gas - CCCT	-	-	-	-	-	-	-	-	-	-	-	-	-	1,314	-	635	-	-	635	-	**2,584**
Gas- Peaking	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	**-**
DSM - Energy Efficiency	143	128	138	149	164	149	153	155	157	155	128	128	126	107	110	103	101	101	101	96	**2,590**
DSM - Load Control	-	-	-	-	-	-	-	-	-	-	22	29	63	-	-	-	-	-	86	9	**208**
Renewable - Wind	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	**-**
Renewable - Geothermal	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	**-**
Renewable - Utility Solar	-	-	-	-	-	-	-	-	-	-	1	3	-	-	-	-	-	-	-	84	**88**
Renewable - Biomass	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	**-**
Front Office Transactions	764	903	748	1,088	1,231	1,179	942	1,032	941	975	1,443	1,443	1,441	984	1,044	1,286	1,359	1,441	1,438	1,443	**1,156**
Existing Unit Changes																					
Coal Early Retirement/Conversions	(222)	-	-	(280)	-	-	-	-	-	-	(387)	-	-	-	-	(450)	-	-	(269)	-	**(1,608)**
Thermal Plant End-of-life Retirements	-	-	-	-	-	-	-	-	-	-	-	-	-	(762)	-	(357)	(77)	-	(358)	-	**(1,554)**
Coal Plant Gas Conversion Additions	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	**-**
Turbine Upgrades	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	**-**
Total	**685**	**1,031**	**886**	**957**	**1,395**	**1,328**	**1,095**	**1,188**	**1,098**	**1,129**	**1,207**	**1,602**	**1,630**	**1,643**	**1,154**	**1,217**	**1,383**	**1,541**	**1,634**	**1,632**	

2015 IRP Update

Summary Portfolio Capacity by Resource Type and Year, Installed MW																					
	Installed Capacity, MW																				
Resource	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**Total**
Expansion Options																					
Gas - CCCT	-	-	-	-	-	-	-	-	-	-	-	-	-	1,112	-	635	454	-	423	-	**2,625**
Gas- Peaking	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	**-**
DSM - Energy Efficiency	143	128	138	146	158	142	149	155	161	162	135	136	135	131	130	122	117	118	117	114	**2,740**
DSM - Load Control	-	-	-	-	-	-	-	-	-	-	39	24	51	-	-	7	-	-	20	33	**173**
Renewable - Wind	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	**-**
Renewable - Geothermal	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	**-**
Renewable - Utility Solar	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	**-**
Renewable - Biomass	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	**-**
Front Office Transactions	764	903	748	1,094	1,246	1,203	970	1,060	965	993	1,440	1,440	1,443	1,177	1,223	1,443	1,107	1,174	1,443	1,443	**1,164**
Existing Unit Changes																					
Coal Early Retirement/Conversions	(222)	-	-	(280)	-	-	-	-	-	-	(387)	-	-	-	-	(450)	-	-	(269)	-	**(1,608)**
Thermal Plant End-of-life Retirements	-	-	-	-	-	-	-	-	-	-	-	-	-	(762)	-	(357)	(77)	-	(358)	-	**(1,554)**
Coal Plant Gas Conversion Additions	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	**-**
Turbine Upgrades	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	**-**
Total	**685**	**1,031**	**886**	**960**	**1,403**	**1,345**	**1,120**	**1,215**	**1,126**	**1,155**	**1,227**	**1,600**	**1,629**	**1,659**	**1,353**	**1,400**	**1,600**	**1,292**	**1,376**	**1,590**	

Portfolio Difference

Summary Portfolio Capacity by Resource Type and Year, Installed MW

Resource	Installed Capacity, MW																				
	2015	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**Total**
Expansion Options																					
Gas - CCCT	-	-	-	-	-	-	-	-	-	-	-	-	-	202	-	-	(454)	-	212	-	**(41)**
Gas- Peaking	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	**-**
DSM - Energy Efficiency	-	-	-	3	7	6	3	(0)	(4)	(8)	(6)	(8)	(9)	(24)	(21)	(20)	(16)	(18)	(16)	(19)	**(150)**
DSM - Load Control	-	-	-	-	-	-	-	-	-	-	(17)	5	12	-	-	(7)	-	-	66	(24)	**35**
Renewable - Wind	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	**-**
Renewable - Geothermal	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	**-**
Renewable - Utility Solar	-	-	-	-	-	-	-	-	-	-	1	3	-	-	-	-	-	-	-	84	**88**
Renewable - Biomass	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	**-**
Front Office Transactions	-	-	-	(6)	(15)	(24)	(28)	(28)	(25)	(18)	3	3	(2)	(194)	(179)	(157)	253	267	(4)	0	**(8)**
Existing Unit Changes																					
Coal Early Retirement/Conversions	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	**-**
Thermal Plant End-of-life Retirements	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	**-**
Coal Plant Gas Conversion Additions	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	**-**
Turbine Upgrades	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	**-**
Total	**0**	**0**	**0**	**(3)**	**(8)**	**(17)**	**(25)**	**(28)**	**(29)**	**(26)**	**(19)**	**2**	**1**	**(16)**	**(199)**	**(184)**	**(218)**	**249**	**258**	**42**	

CHAPTER 6 – ACTION PLAN STATUS UPDATE

This chapter provides an update to the action items listed in the Action Plan of PacifiCorp's 2015 IRP. Some of the action items have been superseded or eliminated since they were identified in the 2015 IRP. The status for all action items is provided in Table 6.1 below.

Table 6.1 – 2015 IRP Action Plan Status Update

<table>
<tr><th>Action Item</th><th>Activity</th><th>Status</th></tr>
<tr><td>1a</td><td><u>Renewable Portfolio Standard Compliance</u>
• The Company will pursue unbundled REC request for proposals (RFP) to meet its state RPS compliance requirements.
– Issue at least annually, RFPs seeking then current-year or forward-year vintage unbundled RECs that will qualify in meeting Washington renewable portfolio standard targets through 2017.
– Issue at least annually, RFPs seeking then current-year or forward-year vintage unbundled RECs that will qualify in meeting California renewable portfolio standard targets through 2017.
– With a projected bank balance extending out through 2027, defer issuance of RFPs seeking unbundled RECs that will qualify in meeting Oregon renewable portfolio standard targets until states begin to develop implementation plans under EPA's draft 111(d) rule, providing clarity on whether an unbundled REC strategy is the least cost compliance alternative for Oregon customers.</td><td>For the Washington renewable portfolio standard, the Company did not issue a REC RFP in 2015. The Company determined that its current needs did not warrant issuance of a RFP.

For the California renewable portfolio standard requirements, the Company issued a REC RFP on October 2, 2015 with bids due October 22, 2015. An offer meeting the Company's needs and specific pricing criteria was selected and is currently under review with the California Public Utilities Commission.

Action Item 1a has been revised in the 2015 IRP Update, as presented in the Executive Summary, to reflect changes in state RPS targets and banking provisions and changes in federal tax credits.</td></tr>
<tr><td>1b</td><td><u>Renewable Energy Credit Optimization</u>
• On a quarterly basis, and through calendar year 2016, issue reverse RFPs to sell 2016 vintage or older RECs that are not required to meet state RPS compliance obligations.</td><td>The Company issued a reverse RFP in February 2015 and June 2015 to sell RECs. The Company will continue to issue reverse RFPs in 2016 to seek REC sale opportunities for RECs allocated to states that do not have a state RPS compliance need.</td></tr>
<tr><td>1c</td><td><u>Oregon Solar Capacity Standard</u>
• Conclude negotiations with shortlisted bids from the 2013S Request for Proposals (RFP), seeking up to 7 MW_{AC} of competitively priced capacity from qualifying solar systems that will be used to satisfy PacifiCorp's obligation under Oregon's 2020 solar capacity standard.</td><td>The Oregon Solar Capacity Standard was eliminated with the passage of Oregon Senate Bill 1547-B. This action item was deleted from the updated action plan presented in the Executive Summary.</td></tr>
</table>

Action Item	Activity	Status
2a	**<u>Front Office Transactions</u>** – Acquire economic short-term firm market purchases for on-peak summer deliveries from 2015 through 2017 consistent with the Risk Management Policy and Commercial and Trading Front Office Procedures and Practices. These short-term firm market purchases will be acquired through multiple means: – Balance of month and day-ahead brokered transactions in which the broker provides the service of providing a competitive price. – Balance of month, day-ahead, and hour-ahead transactions executed through an exchange, such as Intercontinental Exchange (ICE), in which the exchange provides the service of providing a competitive price. – Prompt month forward, balance of month, day-ahead, and hour-ahead non-brokered transactions.	For 2015, PacifiCorp acquired approximately 950 MW to 4,300 MW of short-term firm market purchases explicitly for delivery during the on-peak summer period. For 2016, as of early February 2016, the Company has acquired approximately 550 MW to 650 MW of short-term firm market purchases explicitly for delivery during the on-peak summer period. For 2017, as of early February 2016, the Company has not procured any short-term firm market purchases explicitly for delivery during the on-peak summer period.
3a	**<u>Class 1 DSM</u>** – Pursue a west-side irrigation load control pilot beginning 2016 to test the feasibility of program design. Additional information on the proposed pilot is provided in the implementation plan section of Appendix D in Volume II of the 2015 IRP.	On March 4, 2016, PacifiCorp filed with the Oregon Public Utilities Commission to implement an Irrigation Load Control pilot program. The proposed pilot program would begin in 2016 and target 3 MW of controlled load.

<table>
<tr><th>Action Item</th><th>Activity</th><th>Status</th></tr>
<tr><td>3b</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 implementation plan to acquire cost effective energy efficiency resources is provided in Appendix D in Volume II of the 2015 IRP.
<table>
<tr><th>Year</th><th>Annual Incremental Energy (GWh)</th><th>Annual Incremental Capacity* (MW)</th></tr>
<tr><td>2015</td><td>551</td><td>133</td></tr>
<tr><td>2016</td><td>584</td><td>139</td></tr>
<tr><td>2017</td><td>616</td><td>146</td></tr>
<tr><td>2018</td><td>634</td><td>146</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 2015, PacifiCorp acquired 589 GWh of Class 2 DSM, 7% above the Action Plan target. The Company is on track to achieve its 2016 Class 2 DSM target.</td></tr>
<tr><td>4a</td><td><u>Naughton Unit 3</u>
• Issue an RFP to procure gas transportation and resume engineering, procurement, and construction (EPC) contract procurement activities for the Naughton Unit 3 natural gas conversion in the first quarter of 2016.
• PacifiCorp may update its economic analysis of natural gas conversion in conjunction with the RFP processes to align gas transportation and EPC cost assumptions with market bids.</td><td>In July 2015 the competitive bid event was reopened using an Addendum 6 and all previous (2013) company responses to bid period requests for information. The “short-listed” bidders were asked to refresh all pricing and commercial terms to current market conditions. The only scope modifications for the 2015 refresh were that the bidders were to: (1) exclude updating the SCR option pricing; and (2) the pricing validity date must be extended to December 31, 2016. Refreshed proposals were received from the short-listed bidders on November 2, 2015.

These refreshed proposals informed PacifiCorp’s updated analysis of the Naughton Unit 3 gas conversion alternative, as summarized in Confidential Appendix B to this 2015 IRP Update. Action Item 4a has been</td></tr>
</table>

Action Item	Activity	Status
		updated accordingly as presented in the updated action plan in the Executive Summary.
4b	**<u>Dave Johnston Unit 3</u>** • The portion of EPA's final Regional Haze Federal Implementation Plan (FIP) requiring the installation of selective catalytic reduction (SCR) at Dave Johnston Unit 3, or a commitment to shut down Dave Johnston Unit 3 by the end of 2027, is currently under appeal by the State of Wyoming in the U.S. Tenth Circuit Court of Appeals. • If following appeal, EPA's final FIP as it pertains to Dave Johnston Unit 3 is upheld, PacifiCorp will commit to shutting down Dave Johnston Unit 3 by the end of 2027. • If following appeal, EPA's final FIP as it pertains to Dave Johnston Unit 3 is or will be modified, PacifiCorp will evaluate alternative compliance strategies that will meet any new requirements, as applicable, and provide the associated analysis in a future IRP or IRP Update.	PacifiCorp is still awaiting results of appeal of EPA's final regional haze FIP.
4c	**<u>Wyodak</u>** • Continue to pursue the Company'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 is still awaiting results of appeal of EPA's final regional haze FIP.
4d	**<u>Cholla Unit 4</u>** • Continue permitting efforts in support of an alternative Regional Haze compliance approach that avoids installation of SCR with a commitment to cease operating Cholla Unit 4 as a	In 2015, permit applications and studies required to amend the facility's Title V permit and the Arizona regional haze SIP were submitted to the Arizona Department of Environmental Quality and EPA,

Action Item	Activity	Status
	coal-fueled resource by the end of April 2025.	respectively. The EPA acknowledged receipt of the final Arizona regional haze SIP amendment from Arizona Department of Environmental Quality on October 26, 2015. EPA is currently preparing for their review, public comment process, and final action.
5a	**<u>Energy Gateway Permitting</u>** • Continue permitting for the Energy Gateway transmission plan, with near term targets as follows: – For Segments D, E, and F, continue funding of the required federal agency permitting environmental consultant as actions to achieve final federal permits. – For Segments D, E, and F, continue to support the federal permitting process 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.	PacifiCorp continues to fund the required federal agency permitting environmental consultant as actions to achieve final federal permits. – A final EIS for the Gateway South project, Segment F, is anticipated first quarter 2016 and the final Record of Decision second quarter 2016. – A draft supplemental EIS for the deferred portions of Segment E for the Gateway West project is anticipated first quarter 2016. A final Record of Decision is anticipated in December 2016. – PacifiCorp continues to support the Boardman to Hemingway project consistent with the project 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 of activities and plans associated with the permitting phase of the project.
5b	**<u>Wallula to McNary 230 kilovolt Transmission Line</u>** • Complete Wallula to McNary project construction per plan with 2017 expected in-service date. Continue to support the permitting process for Walla Walla to McNary.	Updates on the construction are as follows – Received the Umatilla County Conditional Use Permit December 2015. – Continue permitting efforts with the Bureau of Land Management, the U.S. Army Corps of Engineers, U.S. Fish and Wildlife agencies, Bureau of Indian Affairs, and the Confederated Tribes of the Umatilla Indian Reservation. – Bonneville Power Administration continues work on the studies and the development of the plan of service

Action Item	Activity	Status
		required to interconnect at the McNary substation. – Right of way appraisal work is scheduled for first quarter 2016. – Note that all permitting documentation as required by each agency has been submitted and that various agencies are working through their required processes.

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APPENDIX A – ADDITIONAL LOAD FORECAST DETAILS

The load forecast presented in Chapter 3 represents the data used for capacity expansion modeling, and excludes load reductions from incremental energy efficiency resources (Class 2 DSM). Tables A.1 and A.2 report the October 2015 (2015 IRP Update) annual load and coincident peak load forecasts. These forecast data include reduction in loads for both distributed generation and new energy efficiency measures (Class 2 DSM), and have not been adjusted for line-losses.

Table A.1 – October 2015 (2015 IRP Update): Forecasted Annual Load Growth, 2016 through 2025 (Megawatt-hours)

Year	Total	OR	WA	CA	UT	WY	ID	SE-ID
2016	56,920,222	13,022,611	4,099,940	745,074	24,830,260	9,591,503	3,477,804	1,153,030
2017	55,580,892	12,715,915	4,085,272	737,702	24,908,433	9,685,196	3,448,374	
2018	55,896,683	12,822,029	4,079,018	730,863	25,049,965	9,763,711	3,451,096	
2019	56,207,036	12,849,252	4,069,749	722,665	25,284,842	9,827,527	3,453,001	
2020	56,314,053	12,819,960	4,063,519	716,384	25,457,899	9,803,611	3,452,680	
2021	56,205,931	12,769,059	4,039,095	707,205	25,487,966	9,752,466	3,450,140	
2022	56,233,170	12,773,767	4,025,178	700,233	25,577,211	9,702,548	3,454,232	
2023	56,243,085	12,799,681	4,007,953	690,117	25,652,375	9,633,596	3,459,363	
2024	56,424,298	12,867,245	4,003,015	679,539	25,792,573	9,613,965	3,467,962	
2025	56,360,934	12,865,292	3,979,977	663,862	25,846,991	9,538,532	3,466,281	
Average Annual Growth Rate for 2016-2025								
2016-2025	**-0.11%**	**-0.13%**	**-0.33%**	**-1.27%**	**0.45%**	**-0.06%**	**-0.04%**	

Table A.2 – October 2015 (2015 IRP Update): Forecasted Annual Coincident Peak Load (Megawatts)

Year	Total	OR	WA	CA	UT	WY	ID	SE-ID
2016	9,951	2,267	723	144	4,771	1,331	714	
2017	9,911	2,227	721	144	4,765	1,340	713	
2018	9,980	2,240	720	142	4,817	1,347	714	
2019	10,003	2,241	716	141	4,839	1,352	713	
2020	10,005	2,243	716	138	4,856	1,346	706	
2021	10,006	2,242	714	138	4,859	1,339	714	
2022	9,996	2,244	712	137	4,857	1,331	716	
2023	9,973	2,246	708	136	4,847	1,320	716	
2024	9,959	2,261	715	135	4,830	1,300	719	
2025	9,961	2,274	715	130	4,852	1,290	700	
Average Annual Growth Rate for 2016-2025								
2016-2025	**0.01%**	**0.03%**	**-0.12%**	**-1.17%**	**0.19%**	**-0.34%**	**-0.22%**	

Tables A.3 and A.4 report the September 2014 (2015 IRP) annual load and coincident peak load forecasts. These forecast data include reduction in loads for both distributed generation and new energy efficiency measures (Class 2 DSM), and have not been adjusted for line-losses.

Table A.3 – September 2014 (2015 IRP): Forecasted Annual Load Growth, 2016 through 2025 (Megawatt-hours)

Year	Total	OR	WA	CA	UT	WY	ID	SE-ID
2016	57,520,472	13,130,326	4,053,343	770,324	24,859,021	10,093,387	3,461,042	1,153,030
2017	56,674,813	13,134,849	4,048,309	767,939	25,090,125	10,164,886	3,468,704	
2018	57,004,095	13,146,512	4,053,605	767,434	25,294,074	10,260,988	3,481,482	
2019	57,346,137	13,185,105	4,057,536	766,591	25,568,374	10,271,982	3,496,549	
2020	57,741,106	13,214,731	4,060,617	764,114	25,830,740	10,359,862	3,511,043	
2021	57,818,735	13,189,208	4,040,875	758,757	25,994,725	10,316,336	3,518,834	
2022	58,154,197	13,224,659	4,036,682	756,518	26,245,188	10,359,347	3,531,804	
2023	58,505,705	13,278,459	4,040,509	755,385	26,541,576	10,341,950	3,547,826	
2024	59,070,023	13,358,920	4,057,429	756,514	26,910,407	10,417,356	3,569,396	
2025	59,291,219	13,347,506	4,052,651	753,447	27,180,526	10,376,693	3,580,395	
Average Annual Growth Rate for 2016-2025								
2016-2025	**0.34%**	**0.18%**	**0.00%**	**-0.25%**	**1.00%**	**0.31%**	**0.38%**	

Table A.4 – September 2014 (2015 IRP): Forecasted Annual Coincident Peak Load (Megawatts)

Year	Total	OR	WA	CA	UT	WY	ID	SE-ID
2016	9,949	2,265	722	148	4,734	1,385	696	
2017	9,985	2,269	721	148	4,756	1,393	698	
2018	10,044	2,268	725	147	4,800	1,403	700	
2019	10,082	2,272	722	147	4,836	1,404	701	
2020	10,139	2,281	724	145	4,883	1,412	695	
2021	10,189	2,286	723	145	4,921	1,407	706	
2022	10,243	2,294	723	146	4,960	1,411	710	
2023	10,295	2,301	724	146	5,005	1,408	712	
2024	10,357	2,304	725	146	5,054	1,415	714	
2025	10,406	2,316	729	143	5,121	1,410	686	
Average Annual Growth Rate for 2016-2025								
2016-2025	**0.50%**	**0.25%**	**0.11%**	**-0.33%**	**0.88%**	**0.20%**	**-0.16%**	

Tables A.5 and A.6 show the October 2015 (2015 IRP Update) forecast changes relative to the September 2014 (2015 IRP) load forecast for loads and coincident system peaks. These forecast data include reduction in loads for both distributed generation and new energy efficiency measures (Class 2 DSM), and have not been adjusted for line-losses.

Changes between these two forecasts are due to increases in Class 2 DSM and changes in economic conditions in the service territory that occurred between September 2014 and October 2015. While economic conditions continue to improve following the most recent recession, projected load growth in the residential and commercial customer classes is offset by forecasted increases in utility-sponsored energy efficiency programs. Weakness in commodities markets drove additional demand decreases in the Wyoming commercial and industrial and Utah industrial customer classes.

Table A.5 – Annual Load Growth Change: October 2015 (2015 IRP Update) Forecast less September 2014 (2015 IRP) Forecast (Megawatt-hours)

Year	Total	OR	WA	CA	UT	WY	ID	SE-ID
2016	-600,250	-107,716	46,598	-25,250	-28,761	-501,884	16,762	
2017	-1,093,921	-418,934	36,963	-30,237	-181,692	-479,691	-20,330	
2018	-1,107,412	-324,483	25,414	-36,571	-244,109	-497,277	-30,386	
2019	-1,139,101	-335,854	12,213	-43,925	-283,533	-444,454	-43,548	
2020	-1,427,053	-394,770	2,902	-47,730	-372,841	-556,251	-58,362	
2021	-1,612,803	-420,149	-1,779	-51,551	-506,760	-563,870	-68,694	
2022	-1,921,028	-450,892	-11,504	-56,285	-667,977	-656,798	-77,571	
2023	-2,262,620	-478,778	-32,556	-65,268	-889,201	-708,354	-88,463	
2024	-2,645,725	-491,675	-54,415	-76,975	-1,117,834	-803,391	-101,434	
2025	-2,930,284	-482,215	-72,674	-89,585	-1,333,535	-838,161	-114,114	

Table A.6 – Annual Coincidental Peak Growth Change: October 2015 (2015 IRP Update) Forecast less September 2014 (2015 IRP) Forecast (Megawatts)

Year	Total	OR	WA	CA	UT	WY	ID	SE-ID
2016	1	2	2	-3	38	-54	18	
2017	-74	-42	0	-4	9	-53	15	
2018	-64	-29	-5	-5	17	-56	14	
2019	-79	-30	-6	-6	3	-52	12	
2020	-134	-39	-8	-7	-27	-65	11	
2021	-183	-44	-9	-8	-62	-68	8	
2022	-247	-50	-11	-9	-103	-80	6	
2023	-322	-55	-15	-10	-157	-88	4	
2024	-397	-43	-10	-11	-224	-115	5	
2025	-445	-43	-13	-14	-269	-120	14	

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