PacifiCorp
Rocky Mountain Power
Pacific Power
PacifiCorp Energy

2011
Integrated Resource Plan
Confidential Supplemental Coal Replacement Study

Let's turn the answers on.

September 21, 2011

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Cover Photos (Left to Right):
Wind: *McFadden Ridge I*
Thermal-Gas: *Lake Side Power Plant*
Hydroelectric: *Lemolo 1 on North Umpqua River*
Transmission: *Distribution Transformers*
Solar: *Salt Palace Convention Center Photovoltaic Solar Project*
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Introduction

This supplement to the 2011 Integrated Resource Plan (2011 IRP) presents the results of additional studies and analysis that examine the prospects of coal resource replacement over the planning horizon (Coal Replacement Study). The additional studies presented herein supplement the results and conclusions drawn from the coal utilization sensitivity analysis described and presented in Chapter 8 of the 2011 IRP. The Coal Replacement Study reflects the following improvements to the coal utilization sensitivity analysis:

- The design of the coal utilization sensitivities was improved to better capture the tradeoff in incremental investment costs planned for existing coal resources and costs for replacement resource options.

- Assumptions for incremental investment costs planned for existing coal resources were updated with the current planning assumptions and expanded to include estimated costs and reasonably anticipated compliance timelines associated with emerging rules for coal combustion residuals (CCR) and cooling water intake structures under §316(b) of the Clean Water Act (316(b)). Costs associated with mercury emissions controls expected to be required under the EPA's proposed Utility hazardous air pollutants (HAPs) maximum achievable control technology (MACT) rulemaking were incorporated into the previous coal utilization sensitivity analysis and continue to be considered in the Coal Replacement Study.

- Assumptions for market prices and potential costs ascribed to carbon dioxide emissions (CO_2) were reviewed to develop a high and low range of future prices and costs that are aligned with current economic conditions and policy developments.

The objective of the Coal Replacement Study is to test how a range of commodity market prices and CO_2 costs along with environmental compliance costs influence the economic tradeoffs that might cause coal resources to be displaced by replacement resources prior to the end of their currently approved depreciable lives. The Coal Replacement Study was performed using PacifiCorp's System Optimizer capacity expansion model, which is traditionally used to evaluate least cost resource portfolios by adding new resources that can meet projected peak load plus a planning margin.[1] For purposes of the Coal Replacement Study, the System Optimizer model was configured to further evaluate whether system costs could be lowered by replacing coal resources requiring incremental capital investments with alternative resource options.

In determining whether replacement resources would lower system costs, the System Optimizer model compares on-going fixed costs for each coal resource with the on-going fixed costs among replacement resource alternatives while considering resource performance and net variable cost differences. The on-going fixed costs for coal resources include incremental investment costs for pollution control equipment, CCR projects, and 316(b) projects. In the event of coal resource replacement, the System Optimizer model also considers decommissioning costs and costs for

[1] The 2011 IRP includes a 13% capacity planning margin.

the recovery of any remaining depreciation expense from incremental investments made prior to decommissioning.[2] If total costs for any given coal resource are higher than the total costs of replacement resource alternatives over time net of any decommissioning costs and costs for recovery of incremental depreciation expense for investments made prior to decommissioning, the System Optimizer model reports the timing and magnitude of idled coal resources and the timing and type of replacement resource additions.

Coal Replacement Study Design

Overview

The coal utilization sensitivity studies documented in the 2011 IRP were performed as a proof-of-concept analysis. In a proof-of-concept analysis, the primary purpose is to validate that new model functionality used to evaluate coal plant idling generates reasonable results under a range of test conditions and produces acceptable simulation run-times. The study was done to pave the way for future refinement of the modeling approach and was not intended to draw conclusions on the disposition of individual generating units within the system.

The Coal Replacement Study advances the proof-of-concept coal utilization sensitivity analysis in the 2011 IRP with design modifications made in two areas. First, the Coal Replacement Study was implemented with an improved representation of potential replacement resource alternatives. Second, existing resources with currently approved depreciation lives that fall within the 20-year planning period were forced to be decommissioned at the end of their depreciable lives. Each of these modifications is discussed in turn below.[3]

Replacement Resource Options

The coal utilization sensitivity analysis in the 2011 IRP allowed existing coal resources to be replaced only by brownfield natural gas combined cycle resources located at the site of the coal unit being displaced. These natural gas resource replacement options were treated as resource betterment options in the System Optimizer model. The resource betterment functionality in the in the System Optimizer model allows for the replacement of a single resource to which it is assigned. In the coal utilization sensitivity analysis, this functionality was used to simplify the model set up while allowing full replacement costs to be captured by encumbering the betterment resource options with decommissioning costs, recovery of any remaining existing depreciation expense, and any applicable liquidated damages for not meeting minimum take provisions in existing coal supply contracts. While this structure simplifies model set up and is suitable for a proof-of-concept analysis, it does not capture the economic trade-offs among a range of potential replacement resource alternatives.

[2] For purposes of the Coal Replacement Study and as referenced herein, costs for recovery of any remaining incremental depreciation expense includes all regulatory costs applicable to rate based capital expenditures.
[3] The Company evaluates the economic life of resources every five years by completing a depreciation study. The next depreciation study is scheduled to be completed in 2012. Stipulated depreciation lives currently used to establish rates in Oregon differ from those currently used to establish rates in other states. For purposes of the Coal Replacement Study, stipulated depreciation lives are based upon those used to establish rates for the majority of PacifiCorp's service territory.

For the Coal Replacement Study, resource retirement functionality within the System Optimizer model was used in lieu of the resource betterment functionality. This change in design allows existing coal resources to be displaced by a wide range of greenfield resource alternatives consistent with the resource options available in the 2011 IRP. The retirement functionality within the System Optimizer model allows replacement costs associated with decommissioning and recovery of any remaining incremental depreciation expense incurred after decommissioning to be assigned directly to the coal resource being displaced. Because these incremental costs can be assigned to the coal resource as opposed to being included as a cost for a specific betterment resource as was done in the coal utilization sensitivity studies, the range of replacement resource alternatives can be broadened. In this way, the Coal Replacement Study allows coal resources to be displaced with greenfield combined cycle resources, greenfield simple cycle resources, demand side management (DSM) resources, and front office transactions (FOT) beginning in 2015, which is currently assumed to be the first substantive environmental compliance deadline.[4,5]

Growth resources were not allowed to displace coal resources in the Coal Replacement Study. Growth resources are included as generic resource alternatives in the out years of the IRP planning horizon – beginning in 2021 in the 2011 IRP. This resource option is intended for capacity balancing in each load area such that capacity planning margins are met in the out years of the planning horizon. Growth resources are used in the IRP to manage simulation run times by simplifying resource selection beyond the first 10-years of the planning period and are ascribed costs that are derived from the forward price curve for power. As such, growth resources do not accurately reflect the true cost or risk associated with the replacement of a resource requiring capital investment or ongoing fixed costs. As such, allowing growth resources to replace coal resources would provide an artificial incentive for the System Optimizer model to decommission coal resources assuming they could be replaced by a generic resource option without appropriate cost metrics.

Intermittent renewable resource alternatives were also not allowed to displace coal resources in the Coal Replacement Study. Intermittent resources such as wind can supply system energy, but are limited in their ability to provide system capacity given the non-dispatchable and intermittent nature of wind resource generation. Because system coal resources provide valuable system capacity, intermittent resources such as wind are not suitable replacement alternatives and were not included as a replacement resource option in the Coal Replacement Study. However, the 2,100 MW of incremental wind resources included in the 2011 IRP preferred portfolio, which mitigate renewable portfolio standard compliance and fuel volatility risk, are included as system resources in the Coal Replacement Study.

Coal Resource Depreciable Life

The 2011 IRP planning horizon covers 20-years extending out through 2030, and the action plan identifies steps that will be taken to secure resource needs for the first 10-years of the planning period. Given that the action plan focuses on the first 10-years of the planning period, and considering that PacifiCorp has no commitments or obligations to decommission existing

[4] FOT limits are set forth in Chapter 6 of the 2011 IRP.
[5] It is anticipated that compliance with pending HAPs MACT rules will be required as early as 2015 for individual generation units.

resources within this timeframe, a modeling assumption was made for the 2011 IRP that no coal or gas plants are shut down during the IRP 20-year planning period. The coal utilization sensitivity analysis in the 2011 IRP allowed coal resources to be replaced by brownfield natural gas resources beginning 2016. However, the coal utilization sensitivity analysis, consistent with the broader assumption adopted in the 2011 IRP, did not address how coal resource replacement might be influenced by plant shut downs tied to their currently approved depreciable lives.

The Coal Replacement Study improves upon this design by capturing resource replacement economics while considering that the end of the currently approved depreciable lives for some coal resources fall within the 20-year planning period. This approach ensures that incremental investment costs assumed for these coal resources are aligned with their currently approved depreciation lives reflected in rates. As such, the Coal Replacement Study incorporates currently approved depreciation lives by forcing three coal plants to be decommissioned within the 20-year planning period. Carbon is assumed to be decommissioned at the end of 2020, Dave Johnston is assumed to be decommissioned at the end of 2027, and Naughton is assumed to be decommissioned at the end of 2029.

Incremental Coal Resource Investment Cost Assumptions

Overview

The coal utilization sensitivity analysis included coal resource capital investments for planned and/or ongoing pollution control equipment identified in PacifiCorp's business plan with Company commitments and/or obligations. These pollution control projects are required to meet best available retrofit technology (BART) requirements under EPA's Regional Haze Rules as implemented by states in their implementation plans and reduce emissions of sulfur dioxide (SO_2), nitrogen oxides (NO_X), particulate matter (PM), mercury (Hg) and other pollutants. The projects are also expected to support compliance with increasingly more stringent National Ambient Air Quality Standards (NAAQS) that have been and are continuing to be adopted for criteria pollutants and impending Utility HAPs MACT regulations. As such, the coal utilization sensitivity analysis also included investment costs for mercury emissions control projects. The proof-of-concept coal utilization sensitivity analysis assigned these incremental pollution control equipment investment costs to existing coal resources and assigned costs for any remaining recovery of depreciation expenses from the existing coal plant to the natural gas betterment options.

PacifiCorp performed the Coal Replacement Study using updated investment cost assumptions for the pollution control projects described above, and was expanded to include a set of pollution control project cost inputs associated with additional selective catalytic reduction (SCR) costs across the Company's generation units (see Confidential Appendix A for additional details). While no Company commitments or agency actions have been taken that require installation of this expanded list of SCR projects, the costs have been included in the analysis to conservatively capture the effect of potentially significant incremental pollution control capital investments. Other coal resource investment costs considered in the Coal Replacement Study were also expanded to include proxy CCR and 316(b) compliance projects. The coal utilization sensitivity analysis was further advanced by including remaining costs for recovery of depreciation expenses from these incremental investments in the Coal Replacement Study and removing costs for recovery of depreciation expenses from existing coal plants.

As a stand-alone concept, the perceived flexibility afforded by regulations such as the Regional Haze Rules / BART process to shut down individual units to avoid costs prior to compliance deadlines must be balanced against potential customer impacts of pursuing such a scenario on a fleet-wide basis. If that concept were applied to the pending HAPs MACT, the near-term compliance deadline for shutdowns would be in early 2015. Unless a company is in compliance with or idles facilities prior to the effective date of the HAPs MACT, Regional Haze Rule compliance flexibility would be irrelevant. Further, plant retirement prior to environmental compliance deadlines assumes that a utility can effectively secure replacement power prior to 2015. Where there is insufficient existing market capacity and/or transmission system infrastructure, even when coupled with enhanced energy efficiency, to absorb the load served by retiring facilities, it is likely an impossible and potentially catastrophic proposal to pursue retirement of facilities before compliance deadlines, if customer loads are expected to be reliably served. As such, the Coal Replacement Study does not include compliance plan scenarios whereby alternate pollution control strategies are implemented assuming flexibility in the Regional Haze Rules / BART process that would otherwise put individual units at risk of not meeting requirements with a 2015 HAPs MACT compliance deadline. This planning assumption is especially important to those states that have an expressed desire to continue the utilization of coal as a resource.

Investment Cost Assumptions

PacifiCorp has developed and executed its emissions control plan with a focus on maintaining a reasonable balance between protecting the interests of customers while complying with environmental requirements, all in the face of an uncertain regulatory environment. The emission control projects are required to comply with regional haze rules, NAAQS, stand-alone requirements in state implementation plans, BART permits and construction permits enforceable by state laws. The investment projects included in the Coal Replacement Study also further position PacifiCorp to comply with EPA’s proposed HAPs MACT rulemaking.

Investment costs considered in the Coal Replacement Study have been expanded to cover projects that would assist in achieving compliance with pending regulations for CCR and cooling water intake structures under §316(b) of the Clean Water Act, as well as costs associated with the incremental SCR installations discussed above. Cost assumptions for CCR projects assume proposed requirements under subtitle D of the Resource Conservation and Recovery Act will be established in 2012 with a compliance deadline of 2017. Cost assumptions for 316(b) projects are based on proposed rules that would require existing electric generating plant cooling water intake structures that have a design capacity of more than two million gallons per day from surface waters reflect the best technology available for minimizing adverse impacts on aquatic organisms.

Table 1 below compares the type and amount of incremental investment costs included in the Coal Replacement Study with those included in the coal utilization sensitivity analysis. Confidential Appendix A to this supplement provides annual investment costs serving as inputs to the Coal Replacement Study.

Table 1 – Summary of Incremental Investment Cost Assumptions

Description	2011 IRP Coal Utilization Sensitivity Analysis	2011 IRP Supplemental Coal Replacement Study
Required SO_2, NO_X, and PM Project Costs Included?	Yes	Yes
Hg and HAPs MACT Project Costs Included?	Yes	Yes
Incremental NO_x Project Costs Included?	No	Yes
CCR Project Costs Included?	No	Yes
316(b) Project Costs Included?	No	Yes
Total Incremental Investment Cost Included	REDACTED	REDACTED

Costs for Recovery of Remaining Depreciation Expense

The proof-of-concept coal utilization sensitivity analysis encumbered betterment natural gas resources with the costs for recovery of any remaining existing depreciation expense, but did not account for any incremental cost for recovery of depreciation expense related to the incremental coal resource investments. Given costs for recovery of existing depreciation expenses are applicable regardless of whether the coal resource is kept in service or if the coal resource is decommissioned, these costs were removed from the System Optimizer model for the Coal Replacement Study. To better reflect the cost tradeoffs considered by the System Optimizer model in determining whether a coal resource requiring incremental investment should be displaced by replacement resources, only costs for recovery of remaining depreciation of the incremental investments were used in the Coal Replacement Study.

Confidential Figure 1 shows how annual coal investment costs for SO_2, NO_X, PM, Hg and non-Hg HAPs, CCR, and 316(b) projects compare with costs for the recovery of remaining depreciation expense from incremental investments as implemented in the System Optimizer model. The up-front capital for coal investment costs are converted to a real levelized cost consistent with the treatment of all capital costs in the 2011 IRP and consistent with the System Optimizer model data requirements. The nominal net present value (NPV) of these real levelized investment costs in any given year represents the cost of capital from that year through the end of the planning period in 2030 if investments are made and the coal resource is not decommissioned. The nominal NPV of costs for the recovery of any remaining depreciation expense in any given year represents the recovery of costs for incremental investments made prior to that year. These costs represent the costs that would be incurred if future incremental investments are not made and coal resources are decommissioned in that year. The difference between these two streams of costs at any given point in time represent the capital cost tradeoff between making incremental coal investments and foregoing those investments in favor of decommissioning.

For example, as shown in Confidential Figure 1, the NPV of the remaining real levelized cost to make incremental coal investments across the fleet is approximately $2.2 billion in 2020. This is nearly REDACTED higher than the REDACTED of cost that would be incurred for recovery of remaining incremental depreciation from coal investments made in prior years if coal resources were decommissioned. This cost differential isolates the tradeoff between on-going incremental investments and costs for recovery of remaining incremental depreciation expense at any given point in time. The System Optimizer model considers this cost differential along with other cost tradeoffs related to on-going fixed costs of coal resources and replacement resources, decommissioning costs, replacement resource capital costs, and net variable cost differences between coal resources and replacement resource alternatives.

Confidential Figure 1 – Annual Incremental Coal Resource Investment Cost vs. Annual Cost for Recovery of Remaining Incremental Depreciation Expense

TABLE REDACTED

Market Price and CO_2 Cost Assumptions

<u>Overview</u>

Natural gas prices and CO_2 costs are important to the evaluation of the economic tradeoff between coal resources and replacement resource alternatives. The assumed price for natural gas directly affects the cost of fuel for natural gas-fired replacement resources while also influencing the market price for power. As such, natural gas prices are critical to setting the cost for natural gas replacement resource alternatives and in influencing the economic benefits of both coal resources and replacement resource alternatives owing to its influence in the power market. Similarly, because of the relatively high carbon content in coal, higher CO_2 costs disproportionately affect the cost of emissions at coal facilities while also directly influencing the market price for power. Just as natural gas prices influence the economic tradeoffs between coal resources and potential replacement resource alternatives, the cost ascribed to CO_2 affects the cost of emissions for coal resources, and to a lesser extent, for natural gas replacement resources. The assumed level for CO_2 costs also influences the economic benefits for both coal and all replacement resource alternatives given its potential to influence prices in the power market.

The coal utilization sensitivity analysis in the 2011 IRP was performed among different sets of assumptions for future market prices as driven by the price for natural gas and for future CO_2 costs. The analysis paired medium natural gas prices with medium CO_2 costs, high CO_2 costs, and a hard CO_2 cap for PacifiCorp's system. The analysis also paired low natural gas prices with medium CO_2 costs and high CO_2 costs. Given the outlook for market prices and the prospects for future CO_2 regulations have evolved since these assumptions were developed for the 2011 IRP, the scenarios used in the Coal Replacement Study were updated to reflect a reasonable high and low range around the most current base case projection.

Base Case

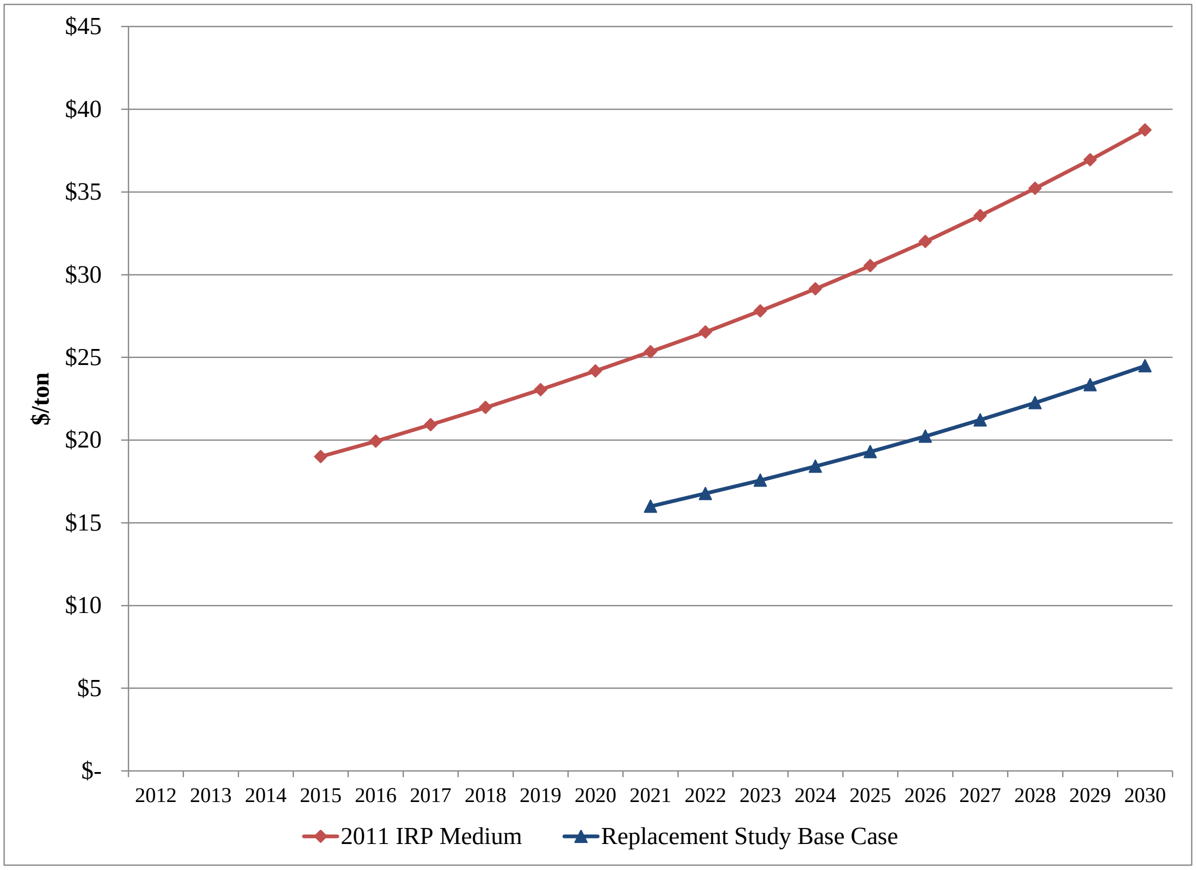
The June 30, 2011 official forward price curve (FPC) was used to set market prices for the base case. The front 72 months of the official FPC is derived from market forwards as of market close on a given quote date, which for purposes of the Coal Replacement Study, was June 30, 2011. Beyond the front 72 months of the FPC, a fundamentals-based forecast of market prices is developed using an hourly production cost dispatch model of the western interconnect consistent with current third party forecasts of long-term natural gas prices. These forecasts are blended with the forward market prices from months 73 through 84 and directly used in the FPC from months 85 and beyond.

One of the many inputs used to develop the fundamentals-based price forecast is an assumption for the cost of CO_2. The CO_2 cost assumptions applied in the base case are the same as those used to develop the June 30, 2011 FPC, which has CO_2 costs beginning in 2021 at $16.00/ton growing to $24.49/ton by 2030. The CO_2 cost and timing used in the June 30, 2011 FPC are consistent with current assumptions used by a variety of third party forecast services, which in aggregate, are expecting policy initiatives that might impute a cost on CO_2 emissions to become effective later than previously forecasted. Table 2 summarizes how the base case natural gas prices used for the Coal Replacement Study compare to medium gas prices in the 2011 IRP. Figure 2 shows differences in CO_2 cost assumptions.

Table 2 – Comparison of Base Case Natural Gas to 2011 IRP Medium Natural Gas Prices (Henry Hub $/MMBtu)

	2015	2020	2025	2030
2011 IRP Medium	$7.43	$8.09	$9.58	$10.04
Coal Replacement Study Base Case	$5.70	$7.23	$8.39	$9.98

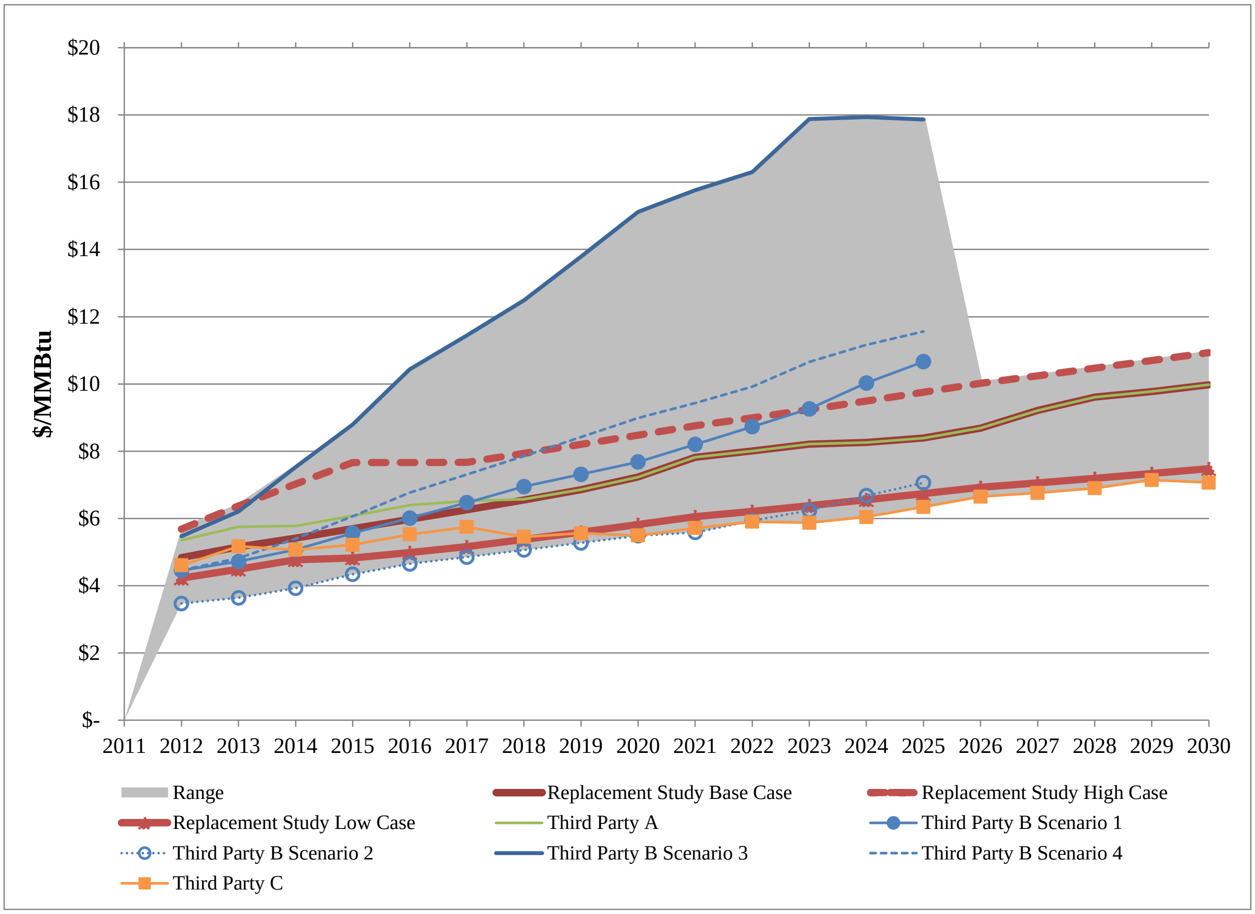
Figure 2 – Comparison of Base Case CO_2 Costs to 2011 IRP Medium CO_2 Costs



Natural Gas Price Scenarios

High and low natural gas price scenarios were developed by comparing current third party natural gas price forecasts to those in the base case and to those used in the 2011 IRP. Six different price projections from three different forecast services were included in this review. Figure 3 shows the natural gas price forecasts selected for the Coal Replacement Study alongside these third party price forecasts. The low natural gas prices used in the Coal Replacement Study are reasonably close to the low end of the range among current third party projections. The high natural gas prices used in the Coal Replacement Study align well with the highest of the third party price forecast through about 2014 before leveling off at an average 15% premium to the base case. The high case used for the Coal Replacement Study was not aligned with the highest third party price forecast over the long-term given this projection is an outlier relative to the others and is not a plausible representation of where the gas market might settle over the long-term on a sustained basis.

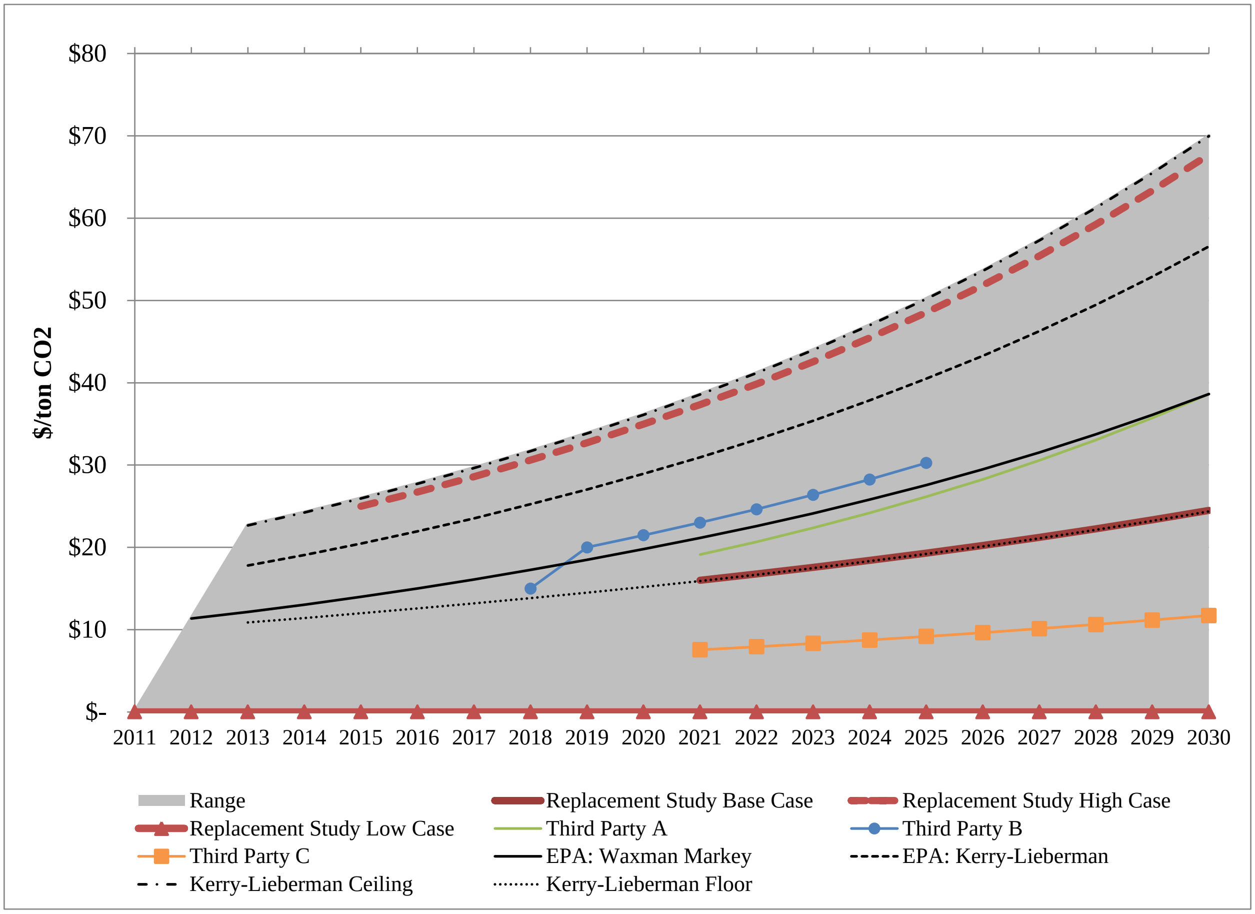
Figure 3 – Comparison of High and Low Case Natural Gas Prices to Third Party Projections (Henry Hub)



CO_2 Cost Scenarios

High and low CO_2 cost scenarios were developed by reviewing external forecasts of CO_2 costs alongside forecasts developed by EPA in their evaluation of past legislative proposals to limit greenhouse gas emissions. Three different price projections from third party forecast services along with EPA's projections for prices under the Waxman-Markey Bill and Kerry-Lieberman proposal were included in this review. Figure 4 shows the CO_2 costs selected for the Coal Replacement Study alongside these external projections. For the low case, it was assumed there would be no policy developments that would impute a cost on CO_2 emissions in the power sector within the 20-year study period. This assumption is consistent with a third party forecaster that has indicated there is real potential for a zero CO_2 cost scenario. The high CO_2 cost forecast adopted for the Coal Replacement Study is higher and starts sooner than any of the current projections from third party sources, but remains consistent with an upper limit that would have been established under the American Power Act of 2010 as proposed by Senators Kerry and Lieberman in May 2010.

Figure 4 – Comparison of High and Low Case CO_2 Costs to External Projections



Coal Replacement Study Results

Among all three scenarios evaluated in the Coal Replacement Study, none of the PacifiCorp coal resources were displaced by replacement resource alternatives before the end of the 20-year planning period or before the end of the currently approved depreciable life of each resource. In each of these scenarios, existing coal resources were assigned incremental investment costs consistent with the most current emissions control plan, plus the incremental SCR costs across the Company's generation units discussed above and in Confidential Appendix A. The analysis also incorporated cost estimates to address expected CCR regulations and upgrades to water intake structures. These findings support the basic conclusions drawn from the 2011 IRP coal utilization sensitivity analysis and show that PacifiCorp's coal fleet, with planned incremental investments, will continue to provide reliable and least cost electric service to customers. Moreover, the Coal Replacement Study shows that planned coal investments are cost effective among a range of future market price and CO_2 cost outcomes.

Appendix B shows the least cost resource portfolios for each of the three scenarios considered in the Coal Replacement Study. Appendix C provides unit level annual generation detail for each of the three scenarios studied.

Confidential Appendix A – Incremental Coal Investment Costs

Table A1 – Annual Coal Investment Costs used in the Coal Replacement Study

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Appendix B – Resource Portfolios

Table B1 – Base Case Coal Replacement Study Resource Portfolio

	BASE CASE	Capacity (MW)																				Resource Totals 2/	
	Resource	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	10-year	20-year
East																							
	Coal Ret_WY - CCCT	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	716	-	-	-	716
	CCCT F 2x1	-	-	-	625	-	597	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1,222	1,222
	CCCT G 1x1	-	-	-	-	-	-	-	-	-	388	-	-	-	-	-	-	388	-	-	358	388	1,134
	CCCT H 1x1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	475	-	-	-	-	475	-	950
	SCCT Aero UT	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	118	-	-	118
	Coal Plant Turbine Upgrades	12.1	18.9	1.8	-	-	18.0	-	-	-	-	2.4	-	-	-	-	-	-	-	-	-	51	53
	Wind, WY, 35	-	-	-	-	-	-	-	140	300	200	200	200	200	200	100	100	100	100	100	-	640	1,940
	Wind, Project II	-	-	-	-	-	-	-	160	-	-	-	-	-	-	-	-	-	-	-	-	160	160
	Total Wind	-	-	-	-	-	-	-	300	300	200	200	200	200	200	100	100	100	100	100	-	800	2,100
	CHP - Biomass	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	10	20
	CHP - Reciprocating Engine	-	-	-	-	-	-	-	0.8	0.8	-	-	0.8	0.8	0.8	-	-	-	-	-	-	2	4
	DSM, Class 1, UT-Coolkeeper	5.5	5	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	11	11
	DSM, Class 1, GO-DLC-IRR	-	-	-	-	-	-	-	8	-	-	-	-	-	1	-	1	-	-	-	-	8	10
	DSM, Class 1, UT-Curtail	-	-	-	-	-	-	-	34	38	-	-	-	-	-	-	-	-	-	-	-	71	71
	DSM, Class 1, UT-DLC-RES	-	-	-	-	-	-	-	-	85	-	-	-	-	-	-	-	-	-	-	-	85	85
	DSM, Class 1, UT-DLC-IRR	-	-	-	-	-	-	-	11	-	-	-	-	-	1	-	2	-	-	-	-	11	14
	DSM, Class 1, UT-Sch-TES	-	-	-	-	-	-	-	-	-	-	-	-	-	5	-	-	-	-	-	-	-	5
	DSM, Class 1 Total	6	5	-	-	-	-	-	53	123	-	-	-	-	7	-	3	-	-	-	-	187	196
	DSM, Class 2, GO	1	1	1	1	1	2	2	2	2	2	2	2	3	3	3	3	3	3	3	3	14	43
	DSM, Class 2, UT	41	48	41	43	44	47	50	55	71	58	67	89	86	91	78	92	64	75	89	66	499	1,296
	DSM, Class 2, WY	3	4	4	4	5	6	6	7	7	8	9	10	11	14	15	19	20	24	31	31	53	236
	DSM, Class 2 Total	44	53	46	48	50	55	59	64	80	67	78	101	100	108	96	114	87	102	123	100	566	1,575
	Micro Solar - WH	-	2.64	2.64	2.64	2.64	2.64	2.64	2.64	2.64	2.64	2.64	2.64	2.64	2.64	2.64	2.64	-	-	0.27	-	24	40
	FOT Mead Q3	-	168	264	189	99	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	72	36
	FOT Utah Q3	200	17	83	-	187	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	49	24
	FOT Mona-3 Q3	-	-	-	300	300	300	300	300	300	300	300	300	300	300	300	300	300	300	300	300	210	255
	FOT Mona-4 Q3	-	-	150	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	15	8
West																							
	Coal Plant Turbine Upgrades	-	-	3.7	-	-	-	-	8.3	-	-	-	-	-	-	-	-	-	-	-	-	12	12
	CHP - Biomass	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	42	84
	CHP - Reciprocating Engine	-	-	-	-	-	-	-	0.3	0.3	-	-	0.3	0.3	0.3	-	-	-	-	-	-	1	2
	DSM, Class 1, WW-DLC-IRR	-	-	-	-	-	-	-	3	-	-	-	-	-	-	-	-	-	-	-	-	3	3
	DSM, Class 1, WM-Curtail	-	-	-	-	-	-	-	36	-	-	-	-	-	-	-	-	-	-	-	-	36	36
	DSM, Class 1, WM-DLC-RES	-	-	-	-	-	-	-	-	6	-	-	-	-	-	-	-	-	-	-	-	6	6
	DSM, Class 1, WM-DLC-IRR	-	-	-	-	-	-	-	18	-	-	-	-	-	-	-	-	-	-	-	-	18	18
	DSM, Class 1, YA-DLC-IRR	-	-	-	-	-	-	-	6	-	-	-	-	-	-	-	-	-	-	-	-	6	6
	DSM, Class 1 Total	-	-	-	-	-	-	-	63	6	-	-	-	-	-	-	-	-	-	-	-	70	70
	DSM, Class 2, WA	4	4	4	5	5	5	5	4	5	5	5	5	5	5	5	5	4	4	4	4	45	91
	DSM, Class 2, WM	51	51	54	59	60	60	59	52	52	52	52	52	52	53	53	52	44	37	37	36	550	1,018
	DSM, Class 2, YA	6	6	6	6	6	6	6	7	7	7	8	9	9	9	9	7	6	7	6	7	64	141
	DSM, Class 2 Total	61	62	65	70	71	70	70	63	63	64	65	66	66	67	67	64	55	47	47	47	659	1,250
	OR Solar Cap Standard	-	2	2	2	3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	9	9
	OR Solar Pilot	4	2	2	1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	10	10
	Micro Solar - WH	-	1.81	1.81	1.81	1.81	1.81	1.81	1.81	1.81	1.81	1.81	1.81	1.81	1.81	0.97	1.81	-	-	-	-	16	26
	FOT COB Q3	-	400	400	400	392	342	342	342	342	342	342	342	342	342	342	342	342	342	342	342	330	336
	FOT MidColumbia Q3	-	400	400	400	400	383	400	400	400	400	254	360	400	400	308	400	250	400	400	400	358	358
	FOT MidColumbia Q3 - 2	-	271	211	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	48	24
	FOT West Main Q3	-	50	50	50	50	-	28	50	50	41	-	-	38	50	-	50	-	1	50	47	37	30
	Annual Additions, Long Term Resources	132	152	130	756	134	750	138	563	583	729	355	378	377	393	747	291	634	970	393	984		
	Annual Additions, Short Term Resources	200	1,307	1,558	1,339	1,428	1,024	1,070	1,092	1,092	1,083	895	1,001	1,080	1,092	950	1,092	892	1,043	1,092	1,089		
	Total Annual Additions	332	1,459	1,688	2,094	1,562	1,774	1,208	1,654	1,675	1,811	1,251	1,379	1,457	1,485	1,697	1,382	1,526	2,013	1,485	2,073		

1/ Front office transaction amounts reflect one-year transaction periods, and are not additive.

2/ Front office transactions are reported as a 20-year annual average.

Table B2 – High Case Coal Replacement Study Resource Portfolio

HIGH CASE	Capacity (MW)																				Resource Totals 2/	
Resource	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	10-year	20-year
East																						
Coal Ret_WY - CCCT	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	716	-	-	-	716
CCCT F 2x1	-	-	-	625	-	597	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1,222	1,222
CCCT G 1x1	-	-	-	-	-	-	-	-	-	388	-	-	-	-	-	-	-	-	-	388	388	776
CCCT H 1x1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	475	-	475	-	-	475	-	1,425
Coal Plant Turbine Upgrades	12.1	18.9	1.8	-	-	18.0	-	-	-	-	2.4	-	-	-	-	-	-	-	-	-	51	53
Wind, WY, 35	-	-	-	-	-	-	-	140	300	200	200	200	200	200	100	100	100	100	100	-	640	1,940
Wind, Project II	-	-	-	-	-	-	-	160	-	-	-	-	-	-	-	-	-	-	-	-	160	160
Total Wind	-	-	-	-	-	-	-	300	300	200	200	200	200	200	100	100	100	100	100	-	800	2,100
CHP - Biomass	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	10	20
DSM, Class 1, UT-Coolkeeper	5.5	5	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	11	11
DSM, Class 1, GO-DLC-IRR	-	-	-	-	8	-	-	-	-	-	-	-	-	1	-	1	-	-	-	-	8	10
DSM, Class 1, UT-Curtail	-	-	-	-	-	-	-	18	54	-	-	-	-	-	-	-	-	-	-	-	71	71
DSM, Class 1, UT-DLC-RES	-	-	-	-	-	-	-	-	85	-	-	-	-	-	-	-	-	-	-	-	85	85
DSM, Class 1, UT-DLC-IRR	-	-	-	-	11	-	-	-	-	-	-	-	-	1	-	2	-	-	-	-	11	14
DSM, Class 1, UT-Sch-TES	-	-	-	-	-	-	-	-	-	-	-	-	-	2	-	-	-	-	2	-	-	5
DSM, Class 1 Total	6	5	-	-	20	-	-	18	138	-	-	-	-	5	-	3	-	-	2	-	187	196
DSM, Class 2, GO	1	1	1	1	2	2	2	2	2	2	2	2	3	3	3	3	3	3	3	3	15	44
DSM, Class 2, UT	45	49	43	46	48	52	53	55	61	60	62	90	86	91	76	92	73	89	89	73	510	1,331
DSM, Class 2, WY	3	4	4	5	5	6	7	7	7	8	9	10	12	14	15	20	21	25	31	31	56	243
DSM, Class 2 Total	48	53	48	52	54	60	62	64	70	69	74	102	101	108	94	115	97	117	123	107	581	1,618
Micro Solar - WH	-	2.64	2.64	2.64	2.64	2.64	2.64	2.64	2.64	2.64	2.64	2.64	2.64	2.64	2.64	2.64	2.64	2.64	2.64	-	24	47
FOT Mead Q3	-	168	264	181	99	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	71	36
FOT Utah Q3	200	14	78	-	157	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	45	22
FOT Mona-3 Q3	-	-	-	300	300	300	300	300	300	300	300	300	300	300	300	300	300	300	300	300	210	255
FOT Mona-4 Q3	-	-	150	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	15	8
West																						
Coal Plant Turbine Upgrades	-	-	3.7	-	-	-	-	8.3	-	-	-	-	-	-	-	-	-	-	-	-	12	12
CHP - Biomass	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	42	84
DSM, Class 1, WW-DLC-IRR	-	-	-	-	-	-	-	3	-	-	-	-	-	-	-	-	-	-	-	-	3	3
DSM, Class 1, WM-Curtail	-	-	-	-	-	-	-	36	-	-	-	-	-	-	-	-	-	-	-	-	36	36
DSM, Class 1, WM-DLC-RES	-	-	-	-	-	-	-	-	-	-	-	-	-	6	-	-	-	-	-	-	-	6
DSM, Class 1, WM-DLC-IRR	-	-	-	-	-	-	-	18	-	-	-	-	-	-	-	-	-	-	-	-	18	18
DSM, Class 1, YA-DLC-IRR	-	-	-	-	-	-	-	6	-	-	-	-	-	-	-	-	-	-	-	-	6	6
DSM, Class 1 Total	-	-	-	-	-	-	-	63	-	-	-	-	-	6	-	-	-	-	-	-	63	70
DSM, Class 2, WA	4	4	5	5	5	5	5	5	5	5	5	5	5	5	5	5	4	4	4	4	46	92
DSM, Class 2, WM	51	51	54	59	60	60	59	52	52	52	52	52	53	53	53	53	45	37	37	36	551	1,021
DSM, Class 2, YA	6	6	6	6	7	7	7	7	7	7	8	9	9	9	9	7	6	7	7	7	66	143
DSM, Class 2 Total	61	62	65	70	72	71	71	63	63	64	65	66	67	67	67	65	55	47	47	47	663	1,257
OR Solar Cap Standard	-	2	2	2	3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	9	9
OR Solar Pilot	4	2	2	1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	10	10
Micro Solar - WH	-	1.81	1.81	1.81	1.81	1.81	1.81	1.81	1.81	1.81	1.81	1.81	1.81	1.81	1.81	1.81	0.97	1.81	1.81	-	16	32
FOT COB Q3	-	400	400	400	392	342	342	342	342	342	342	342	342	342	342	342	342	342	342	342	330	336
FOT MidColumbia Q3	-	400	400	400	400	299	342	400	400	390	206	313	400	400	309	400	163	301	400	400	343	336
FOT MidColumbia Q3 - 2	-	271	211	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	48	24
FOT West Main Q3	-	50	50	50	50	50	50	50	50	50	50	50	42	50	-	50	-	-	50	15	45	38
Annual Additions, Long Term Resources	136	153	133	760	159	755	142	527	582	731	351	378	377	396	746	292	736	989	282	1,022		
Annual Additions, Short Term Resources	200	1,303	1,553	1,331	1,398	990	1,033	1,092	1,092	1,081	898	1,004	1,083	1,092	951	1,092	805	943	1,092	1,057		
Total Annual Additions	336	1,456	1,686	2,091	1,556	1,746	1,176	1,618	1,673	1,812	1,249	1,382	1,460	1,488	1,697	1,384	1,541	1,932	1,374	2,079		

1/ Front office transaction amounts reflect one-year transaction periods, and are not additive.

2/ Front office transactions are reported as a 20-year annual average.

Table B3 – Low Case Coal Replacement Study Resource Portfolio

	LOW CASE	Capacity (MW)																				Resource Totals 2/	
	Resource	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	10-year	20-year
East																							
	Coal Ret_WY - CCCT	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	716	-	-	-	716
	CCCT F 2x1	-	-	-	625	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	625	625
	CCCT G 1x1	-	-	-	-	-	388	-	358	-	388	-	-	-	-	-	-	-	-	-	-	1,134	1,134
	CCCT H 1x1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	475	-	-	-	-	475	-	950
	IC Aero UT	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	186	-	-	186
	Coal Plant Turbine Upgrades	12.1	18.9	1.8	-	-	18.0	-	-	-	-	2.4	-	-	-	-	-	-	-	-	-	51	53
	Wind, WY, 35	-	-	-	-	-	-	-	140	300	200	200	200	200	200	100	100	100	100	100	-	640	1,940
	Wind, Project II	-	-	-	-	-	-	-	160	-	-	-	-	-	-	-	-	-	-	-	-	160	160
	Total Wind	-	-	-	-	-	-	-	300	300	200	200	200	200	200	100	100	100	100	100	-	800	2,100
	CHP - Biomass	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	10	20
	CHP - Reciprocating Engine	-	-	-	-	-	-	-	-	-	-	-	-	-	0.8	-	0.8	-	0.8	-	-	-	2
	DSM, Class 1, UT-Coolkeeper	5.5	5	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	11	11
	DSM, Class 1, GO-DLC-IRR	-	-	-	-	8	-	-	-	-	-	-	-	1	-	-	1	-	-	-	-	8	10
	DSM, Class 1, UT-Curtail	-	-	-	-	-	-	71	-	-	-	-	-	-	-	-	-	-	-	-	-	71	71
	DSM, Class 1, UT-DLC-RES	-	-	-	-	-	-	33	-	-	-	-	-	35	17	-	-	-	-	-	-	33	85
	DSM, Class 1, UT-DLC-IRR	-	-	-	-	11	-	-	-	-	-	-	-	1	-	-	2	-	-	-	-	11	14
	DSM, Class 1, UT-Sch-TES	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	5	-	-	-	-	-	5
	DSM, Class 1 Total	6	5	-	-	20	-	104	-	-	-	-	-	38	17	-	8	-	-	-	-	135	196
	DSM, Class 2, GO	1	1	1	1	1	2	2	2	2	2	2	2	2	3	3	3	3	3	3	3	14	42
	DSM, Class 2, UT	40	44	36	38	39	47	49	45	48	54	56	60	58	86	73	91	77	88	76	61	439	1,165
	DSM, Class 2, WY	1	1	-	4	5	5	6	6	6	7	8	9	11	13	14	19	20	24	29	28	40	213
	DSM, Class 2 Total	41	45	37	43	45	54	56	53	56	63	66	70	72	102	90	113	100	114	108	92	493	1,420
	Micro Solar - WH	-	2.64	2.64	2.64	2.64	2.64	2.64	0.27	0.27	0.27	0.27	2.64	2.64	2.64	0.27	2.64	0.27	0.27	0.27	0.27	17	29
	FOT Mead Q3	-	168	264	207	99	99	-	-	-	-	-	-	-	-	-	-	-	-	-	-	84	42
	FOT Utah Q3	200	25	97	-	119	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	44	22
	FOT Mona-3 Q3	-	-	-	300	300	300	300	300	300	300	300	300	300	300	300	300	300	300	300	300	210	255
	FOT Mona-4 Q3	-	-	150	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	15	8
West																							
	CCCT G 1x1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	388	-	388
	Coal Plant Turbine Upgrades	-	-	3.7	-	-	-	-	8.3	-	-	-	-	-	-	-	-	-	-	-	-	12	12
	IC Aero YA	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	307	-	-	-	-	307
	CHP - Biomass	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	42	84
	CHP - Reciprocating Engine	-	-	-	-	-	-	-	-	-	-	-	-	-	0.3	-	0.3	-	0.3	-	-	-	1
	DSM, Class 1, WW-DLC-IRR	-	-	-	-	3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	3	3
	DSM, Class 1, WM-Curtail	-	-	-	-	-	-	36	-	-	-	-	-	-	-	-	-	-	-	-	-	36	36
	DSM, Class 1, WM-DLC-RES	-	-	-	-	-	-	-	-	-	-	-	-	-	6	-	-	-	-	-	-	-	6
	DSM, Class 1, WM-DLC-IRR	-	-	-	-	18	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	18	18
	DSM, Class 1, YA-DLC-IRR	-	-	-	-	1	-	6	-	-	-	-	-	-	-	-	-	-	-	-	-	6	6
	DSM, Class 1 Total	-	-	-	-	22	-	42	-	-	-	-	-	-	6	-	-	-	-	-	-	63	70
	DSM, Class 2, WA	4	4	4	5	5	5	5	4	4	4	5	5	5	5	5	5	4	4	3	3	44	86
	DSM, Class 2, WM	50	51	54	59	60	60	59	51	52	52	52	52	52	52	52	52	44	37	36	36	548	1,013
	DSM, Class 2, YA	6	6	6	6	6	6	6	6	7	7	8	9	9	9	9	7	6	7	6	7	61	138
	DSM, Class 2 Total	60	61	65	69	71	70	70	61	62	63	64	65	65	66	66	64	54	47	46	46	653	1,237
	OR Solar Cap Standard	-	2	2	2	3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	9	9
	OR Solar Pilot	4	2	2	1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	10	10
	Micro Solar - WH	-	1.81	1.81	1.81	1.81	1.81	1.81	0.97	0.97	0.97	0.97	0.97	0.97	0.97	0.97	0.97	-	0.97	-	-	14	20
	FOT COB Q3	-	400	400	400	391	342	342	342	342	342	342	342	342	342	342	342	342	342	342	342	330	336
	FOT MidColumbia Q3	-	400	400	400	400	400	400	283	400	400	253	385	400	400	313	400	311	400	400	400	348	357
	FOT MidColumbia Q3 - 2	-	271	211	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	48	24
	FOT West Main Q3	-	50	50	50	50	50	50	-	34	30	-	-	50	50	-	50	-	50	50	26	36	32
	Annual Additions, Long Term Resources	128	144	121	751	170	540	282	787	425	720	338	344	383	401	737	295	566	985	446	1,006		
	Annual Additions, Short Term Resources	200	1,315	1,572	1,357	1,360	1,191	1,092	924	1,075	1,071	895	1,027	1,092	1,092	955	1,092	952	1,092	1,092	1,068		
	Total Annual Additions	328	1,459	1,693	2,108	1,530	1,730	1,374	1,711	1,500	1,791	1,233	1,371	1,475	1,493	1,692	1,387	1,518	2,076	1,537	2,074		

1/ Front office transaction amounts reflect one-year transaction periods, and are not additive.

2/ Front office transactions are reported as a 20-year annual average.

Appendix C – Existing Coal Unit Annual Generation

Table C1 – Base Case Coal Resource Generation

Base Case Annual Generation (GWh)																				
	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Carbon1	496	479	469	510	510	482	482	514	516	518	End of Depreciable Life									
Carbon2	780	743	740	787	787	784	747	794	803	804	End of Depreciable Life									
Cholla	2,678	2,899	2,827	2,899	2,904	2,956	3,060	3,107	3,107	3,107	3,099	3,086	3,078	3,068	2,506	2,433	2,638	2,657	2,629	2,542
Colstrip3	596	596	596	596	596	596	596	596	596	596	596	596	596	596	596	596	596	596	596	596
Colstrip4	508	508	508	508	508	508	508	508	508	508	508	508	508	508	508	508	508	508	508	508
Craig1	685	685	685	685	685	685	685	685	685	685	685	685	685	685	685	685	685	685	685	685
Craig2	679	679	694	694	693	693	693	693	693	693	693	693	693	693	693	693	693	693	693	693
Hayden1	309	316	316	321	320	321	338	344	344	344	344	344	344	342	339	339	344	344	342	339
Hayden2	258	262	261	261	252	263	266	268	268	268	287	287	287	287	287	287	287	287	287	287
Hunter1	2,840	3,257	3,267	3,301	3,334	3,339	3,342	3,342	3,342	3,342	3,319	3,342	3,342	3,342	3,342	3,342	3,342	3,342	3,342	3,342
Hunter2	1,749	1,985	2,049	2,069	2,102	2,106	2,116	2,116	2,116	2,116	2,099	2,114	2,116	2,115	2,114	2,116	2,116	2,116	2,116	2,116
Hunter3	3,067	3,521	3,517	3,561	3,561	3,561	3,561	3,561	3,561	3,561	3,547	3,561	3,561	3,561	3,561	3,561	3,561	3,561	3,561	3,561
Huntington1	3,672	3,672	3,672	3,672	3,672	3,672	3,651	3,672	3,672	3,672	3,672	3,672	3,672	3,672	3,672	3,672	3,672	3,672	3,672	3,672
Huntington2	3,471	3,471	3,471	3,471	3,471	3,610	3,556	3,607	3,610	3,610	3,610	3,610	3,610	3,610	3,610	3,610	3,610	3,610	3,610	3,610
JBridger1	2,661	2,661	2,661	2,661	2,661	2,661	2,661	2,723	2,723	2,723	2,723	2,711	2,712	2,699	2,700	2,703	2,718	2,723	2,712	2,723
JBridger2	2,636	2,640	2,668	2,668	2,668	2,668	2,668	2,668	2,668	2,668	2,668	2,623	2,623	2,604	2,609	2,637	2,656	2,658	2,649	2,657
JBridger3	2,490	2,554	2,579	2,615	2,729	2,729	2,729	2,729	2,729	2,729	2,729	2,676	2,678	2,665	2,665	2,665	2,687	2,687	2,687	2,701
JBridger4	2,562	2,562	2,562	2,562	2,562	2,562	2,562	2,562	2,562	2,562	2,562	2,522	2,522	2,511	2,511	2,511	2,524	2,537	2,537	2,549
Johnston1	763	752	840	840	840	840	840	840	840	840	840	840	840	840	840	840	840	End of Depreciable Life		
Johnston2	823	822	832	832	832	832	832	832	832	832	832	832	832	832	832	832	832	End of Depreciable Life		
Johnston3	1,179	1,172	1,185	1,492	1,849	1,376	1,432	1,862	1,862	1,862	1,862	1,862	1,862	1,862	1,862	1,862	1,862	End of Depreciable Life		
Johnston4	2,286	2,286	2,198	2,253	2,286	2,286	2,286	2,286	2,286	2,286	2,286	2,286	2,286	2,286	2,286	2,286	2,286	End of Depreciable Life		
Naughton1*	1,019	1,169	1,129	1,139	1,157	1,157	1,162	1,235	1,243	1,246	1,241	1,243	1,243	1,237	1,240	1,227	1,235	1,235	1,235	End of Life
Naughton2*	1,313	1,434	1,434	1,462	1,486	1,486	1,517	1,602	1,611	1,611	1,592	1,592	1,591	1,586	1,587	1,581	1,589	1,599	1,586	End of Life
Naughton3*	1,997	2,278	2,257	2,262	2,368	2,298	2,395	2,426	2,444	2,444	2,432	2,452	2,452	2,452	2,452	2,452	2,452	2,452	2,452	End of Life
Wyodak1	2,249	2,249	2,249	2,027	1,665	2,223	2,231	2,249	2,249	2,249	2,249	2,249	2,249	2,249	2,249	2,249	2,249	2,249	2,249	2,249
Grand Total	**43,768**	**45,655**	**45,666**	**46,148**	**46,498**	**46,695**	**46,917**	**47,820**	**47,871**	**47,876**	**46,475**	**46,387**	**46,383**	**46,302**	**45,747**	**45,688**	**45,983**	**40,213**	**40,151**	**34,831**

*As with the Carbon and Dave Johnston units, Naughton reaches the end of its currently expected depreciable life within the planning period (at the end of 2029)

Table C2 – High Case Coal Resource Generation

	High Case Annual Generation (GWh)																			
	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Carbon1	523	518	520	523	516	472	288	265	215	33	End of Depreciable Life									
Carbon2	807	804	807	807	804	795	752	715	728	638	End of Depreciable Life									
Cholla	3,146	3,146	3,146	3,146	2,921	2,916	2,903	2,730	2,755	2,663	2,716	2,576	2,458	2,282	1,561	1,542	1,280	1,206	1,099	857
Colstrip3	596	596	596	596	596	596	596	596	596	596	596	596	596	596	596	596	596	596	596	584
Colstrip4	508	508	508	508	508	508	508	508	508	508	508	508	508	508	508	508	508	508	508	497
Craig1	685	685	685	685	685	685	685	685	685	685	685	685	685	685	685	685	685	685	685	685
Craig2	679	679	694	694	694	694	692	692	692	691	691	688	688	688	688	687	687	687	682	675
Hayden1	348	348	348	348	321	321	318	320	311	317	317	304	299	272	248	237	215	202	198	179
Hayden2	271	271	271	271	259	258	251	251	251	251	269	269	269	261	258	240	218	223	209	197
Hunter1	3,342	3,342	3,342	3,342	3,342	3,342	3,342	3,342	3,342	3,342	3,306	3,342	3,342	3,342	3,168	2,991	2,357	2,659	2,387	1,751
Hunter2	2,116	2,116	2,116	2,116	2,116	2,116	2,116	2,116	2,116	2,116	2,091	2,108	2,108	2,109	1,970	1,851	1,280	1,415	1,066	693
Hunter3	3,421	3,561	3,561	3,561	3,561	3,561	3,561	3,561	3,561	3,561	3,546	3,561	3,561	3,561	3,452	3,323	2,919	3,079	2,891	2,123
Huntington1	3,672	3,672	3,672	3,672	3,672	3,672	3,667	3,672	3,672	3,672	3,672	3,672	3,672	3,672	3,672	3,665	3,628	3,642	3,581	3,238
Huntington2	3,471	3,471	3,471	3,471	3,471	3,610	3,595	3,610	3,610	3,603	3,610	3,610	3,610	3,610	3,610	3,582	3,511	3,541	3,371	2,907
JBridger1	2,661	2,661	2,661	2,661	2,661	2,661	2,661	2,723	2,723	2,723	2,723	2,680	2,627	2,554	2,060	1,682	981	1,087	967	573
JBridger2	2,640	2,640	2,668	2,668	2,668	2,668	2,668	2,668	2,668	2,668	2,668	2,600	2,548	2,413	1,753	1,347	466	594	555	391
JBridger3	2,533	2,553	2,578	2,613	2,729	2,729	2,729	2,729	2,729	2,729	2,729	2,503	2,262	1,870	1,021	749	175	213	223	198
JBridger4	2,562	2,562	2,562	2,562	2,562	2,562	2,562	2,562	2,562	2,562	2,562	2,468	2,446	2,283	1,545	1,158	229	348	425	213
Johnston1	763	752	840	840	840	840	840	840	840	840	840	840	840	840	840	840	835	End of Depreciable Life		
Johnston2	823	822	832	832	832	832	832	832	832	832	832	832	832	832	832	832	832	End of Depreciable Life		
Johnston3	1,179	1,172	1,185	1,492	1,848	1,853	1,856	1,862	1,862	1,862	1,862	1,862	1,862	1,862	1,862	1,854	1,763	End of Depreciable Life		
Johnston4	2,286	2,286	2,198	2,253	2,286	2,286	2,286	2,286	2,286	2,286	2,286	2,286	2,286	2,286	2,286	2,286	2,286	End of Depreciable Life		
Naughton1*	1,256	1,256	1,251	1,252	1,241	1,236	1,220	1,225	1,225	1,223	1,224	1,221	1,167	1,092	756	480	147	151	112	End of Life
Naughton2*	1,596	1,618	1,620	1,626	1,594	1,587	1,539	1,540	1,530	1,516	1,514	1,289	1,030	829	399	378	88	93	107	End of Life
Naughton3*	2,444	2,442	2,452	2,452	2,442	2,423	2,421	2,421	2,421	2,421	2,421	2,445	2,445	2,439	2,273	1,985	1,314	1,545	1,385	End of Life
Wyodak1	2,249	2,249	2,249	2,027	1,662	1,743	1,805	2,249	2,239	2,239	2,245	2,249	2,249	2,249	2,238	2,161	1,899	1,887	1,423	939
Grand Total	**46,579**	**46,734**	**46,836**	**47,019**	**46,833**	**46,968**	**46,695**	**47,001**	**46,962**	**46,579**	**45,913**	**45,195**	**44,392**	**43,135**	**38,280**	**35,660**	**28,901**	**24,362**	**22,469**	**16,702**

*As with the Carbon and Dave Johnston units, Naughton reaches the end of its currently expected depreciable life within the planning period (at the end of 2029)

Table C3 – Low Case Coal Resource Generation

Low Case Annual Generation (GWh)																				
	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Carbon1	523	520	520	523	523	523	523	523	523	523	End of Depreciable Life									
Carbon2	807	807	807	807	807	807	807	807	807	807	End of Depreciable Life									
Cholla	3,125	3,146	3,082	3,082	3,146	3,146	3,146	3,146	3,146	3,146	3,146	3,146	3,146	3,146	3,146	3,146	3,146	3,146	3,146	3,146
Colstrip3	596	596	596	596	596	596	596	596	596	596	596	596	596	596	596	596	596	596	596	596
Colstrip4	508	508	508	508	508	508	508	508	508	508	508	508	508	508	508	508	508	508	508	508
Craig1	685	685	685	685	685	685	685	685	685	685	685	685	685	685	685	685	685	685	685	685
Craig2	679	679	694	694	694	694	694	694	694	694	694	694	694	694	694	694	694	694	694	694
Hayden1	348	339	341	341	348	348	348	348	348	348	348	348	348	348	348	348	348	348	348	348
Hayden2	271	271	271	271	271	271	271	271	271	271	291	291	291	291	291	291	291	291	291	291
Hunter1	3,342	3,342	3,342	3,342	3,342	3,342	3,342	3,342	3,342	3,342	3,342	3,342	3,342	3,342	3,342	3,342	3,342	3,342	3,342	3,342
Hunter2	2,116	2,116	2,116	2,116	2,116	2,116	2,116	2,116	2,116	2,116	2,116	2,116	2,116	2,116	2,116	2,116	2,116	2,116	2,116	2,116
Hunter3	3,421	3,561	3,561	3,561	3,561	3,561	3,561	3,561	3,561	3,561	3,561	3,561	3,561	3,561	3,561	3,561	3,561	3,561	3,561	3,561
Huntington1	3,672	3,672	3,672	3,672	3,672	3,672	3,672	3,672	3,672	3,672	3,672	3,672	3,672	3,672	3,672	3,672	3,672	3,672	3,672	3,672
Huntington2	3,471	3,471	3,471	3,471	3,471	3,610	3,610	3,610	3,610	3,610	3,610	3,610	3,610	3,610	3,610	3,610	3,610	3,610	3,610	3,610
JBridger1	2,661	2,661	2,661	2,661	2,661	2,661	2,661	2,723	2,723	2,723	2,723	2,723	2,723	2,723	2,723	2,723	2,723	2,723	2,723	2,723
JBridger2	2,640	2,640	2,668	2,668	2,668	2,668	2,668	2,668	2,668	2,668	2,668	2,668	2,668	2,668	2,668	2,668	2,668	2,668	2,668	2,668
JBridger3	2,538	2,564	2,595	2,628	2,729	2,729	2,729	2,729	2,729	2,729	2,729	2,729	2,729	2,724	2,726	2,727	2,728	2,729	2,729	2,729
JBridger4	2,562	2,562	2,562	2,562	2,562	2,562	2,562	2,562	2,562	2,562	2,562	2,562	2,562	2,562	2,562	2,562	2,562	2,562	2,562	2,562
Johnston1	763	752	840	840	840	840	840	840	840	840	840	840	840	840	840	840	840	End of Depreciable Life		
Johnston2	823	822	832	832	832	832	832	832	832	832	832	832	832	832	832	832	832	End of Depreciable Life		
Johnston3	1,180	1,173	1,185	1,492	1,850	1,384	1,440	1,862	1,862	1,862	1,862	1,862	1,862	1,862	1,862	1,862	1,862	End of Depreciable Life		
Johnston4	2,286	2,286	2,198	2,253	2,286	2,286	2,286	2,286	2,286	2,286	2,286	2,286	2,286	2,286	2,286	2,286	2,286	End of Depreciable Life		
Naughton1*	1,251	1,256	1,236	1,236	1,256	1,256	1,256	1,256	1,256	1,256	1,256	1,256	1,256	1,256	1,256	1,256	1,256	1,256	1,256	End of Life
Naughton2*	1,591	1,565	1,553	1,607	1,631	1,631	1,631	1,631	1,631	1,631	1,631	1,631	1,631	1,631	1,631	1,631	1,631	1,631	1,631	End of Life
Naughton3*	2,439	2,452	2,452	2,442	2,452	2,452	2,452	2,452	2,452	2,452	2,452	2,452	2,452	2,452	2,452	2,452	2,452	2,452	2,452	End of Life
Wyodak1	2,249	2,249	2,249	2,027	1,675	2,226	2,234	2,249	2,249	2,249	2,249	2,249	2,249	2,249	2,249	2,249	2,249	2,249	2,249	2,249
Grand Total	**46,581**	**46,699**	**46,699**	**46,918**	**47,185**	**47,408**	**47,473**	**47,970**	**47,970**	**47,970**	**46,660**	**46,660**	**46,660**	**46,656**	**46,657**	**46,659**	**46,660**	**44,387**	**44,551**	**39,031**

*As with the Carbon and Dave Johnston units, Naughton reaches the end of its currently expected depreciable life within the planning period (at the end of 2029)