



ENERGY
STRATEGIES

PacifiCorp Coal Unit Valuation Study

*A Unit-by-Unit Cost Analysis of PacifiCorp's
Coal-Fired Generation Fleet*

Prepared for Sierra Club

June 20, 2018

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Acknowledgements

This report was prepared under a consulting services agreement with Sierra Club's Environmental Law Program. Energy Strategies would like to extend our appreciation to Jeremy Fisher, Senior Technical Advisor, and Gloria Smith, Managing Attorney, for their insights and feedback throughout the development of this report. While a number of people provided input and support to Energy Strategies in the preparation of this report, the opinions, and findings expressed in this document are those of Energy Strategies, LLC.

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1. Executive Summary

The economics of coal-fired generation in the Western Interconnect have changed significantly in the past decade. Market drivers such as energy efficiency, falling costs of renewable energy, low natural gas prices, and the cost of complying with environmental regulations are eroding the cost competitiveness of much of the Western Interconnect's coal fleet. Despite this market trend, coal remains a significant fuel in the Company's portfolio. The Company has an ownership interest in 24 aging coal units that provide power to meet 59 percent of PacifiCorp's load. Data also suggests the costs of operating these units is increasing.

As the cost of renewable energy and natural gas decline, it is reasonable to consider whether the continued operation of the Company's coal units is warranted if lower cost resource options exist. At the request of the Sierra Club, Energy Strategies conducted an assessment of each of PacifiCorp's coal units against comparable replacement energy. This economic analysis was designed to compare the going-forward incremental costs of operating the coal units against three replacement resources: market purchases, wind energy, and solar photovoltaic (PV) energy. Our study employed a cashflow spreadsheet model and used publicly available data for the analysis. For each unit, the study examined a business-as-usual (BAU) case, in which it was assumed the coal unit operated to the end of its depreciable life, and a case in which the coal unit was replaced at the end of 2022. To determine a relative valuation, we compared the net present value (NPV) of the all-in cost of the coal scenario against the NPV of the replacement scenarios. We report the relative economic merit of each coal unit relative to market, wind, and solar replacement options.

Eleven of PacifiCorp's coal units, representing 2,730 megawatts (MW), are consistently higher cost than replacement resource options. Those eleven units were found to be higher cost than obtaining comparable firm energy through market purchases. Twelve coal units, representing 3,173 MW of generation, were higher cost than replacement energy from solar PV, and all but two of PacifiCorp's coal plants were higher cost than wind energy on a net present value basis.

In addition to the BAU analysis, the study also reviewed how capital expenditures to meet federal Regional Haze standards could impact the going-forward costs of seven PacifiCorp coal units. The study found that four of the seven at-risk units were already higher cost than the three replacement scenarios, even before environmental controls. With environmental controls, the cost of continuing to operate Hunter Unit 1 exceeded the cost of wholesale market purchases, and the cost of both Hunter 1 and 2 were higher when solar PV was the replacement resource.

The high-level approach used here is similar to that used in utility resource planning, which typically looks for the lowest cost to provide electricity services from the long-term perspective of a customer today – i.e. the present value of all foreseeable costs. A more detailed modeling approach would account for the dispatch of the coal units against prevailing energy prices, the timing of energy required and produced by market, solar, and wind options, and any transmission constraints that prevent these buildout options. Accordingly, the findings reported in here are not intended to be definitive

statements. Rather, they are indicative of relative economic merit and are meant to engage a meaningful discussion on the future of PacifiCorp's coal fleet.

2. Introduction

PacifiCorp's coal fleet makes up one half of the Company's firm generating capacity and almost two-thirds of its annual energy production, making the economics of the coal fleet a significant driver of customer rates. Alternatives to coal-fired electricity capable of reducing Company operating expenses and thereby customer rates are understandably of interest to a wide range of stakeholders. As the cost of alternative resources have declined, it's reasonable to reconsider the cost-effectiveness of continuing to operate the Company's coal units if lower costs alternatives exist. At the request of the Sierra Club, Energy Strategies conducted an independent assessment of PacifiCorp's coal fleet to determine the economic merit of each coal unit relative to market, wind, and solar replacement options.

The analysis conducted by Energy Strategies establishes a business-as-usual (BAU) case in which the present value of each coal unit's ongoing operating and capital expenses over its operating life is compared to the present value costs of three replacement resources. The study employed a discounted cash flow spreadsheet model populated with a database of operating costs compiled from public sources. The analysis also compared the levelized cost of energy LCOE of each coal unit and replacement resource. In addition to the BAU case, the study also included an analysis of how future expenditures on environmental controls would impact the operating costs of seven coal units relative to replacement resources. Environmental control costs included in this analysis were those necessary to comply with the Regional Haze Rule.

This study is intended to evaluate, at a high-level, the cost competitiveness of PacifiCorp's coal units relative to replacement energy options. Our analysis is comprised of a cash-flow assessment which compares the all-in incremental costs of operating PacifiCorp's coal units to replacement energy from market purchases and renewables. It is, however, limited in that it does not examine the operational impacts of the replacement energy, or the extent to which these replacement resources meet capacity or resource adequacy criteria. The findings are meant to be indicative and directional, and meant to spur an informed conversation on the relative merits of maintaining or replacing PacifiCorp's coal fleet for the benefit of ratepayers.

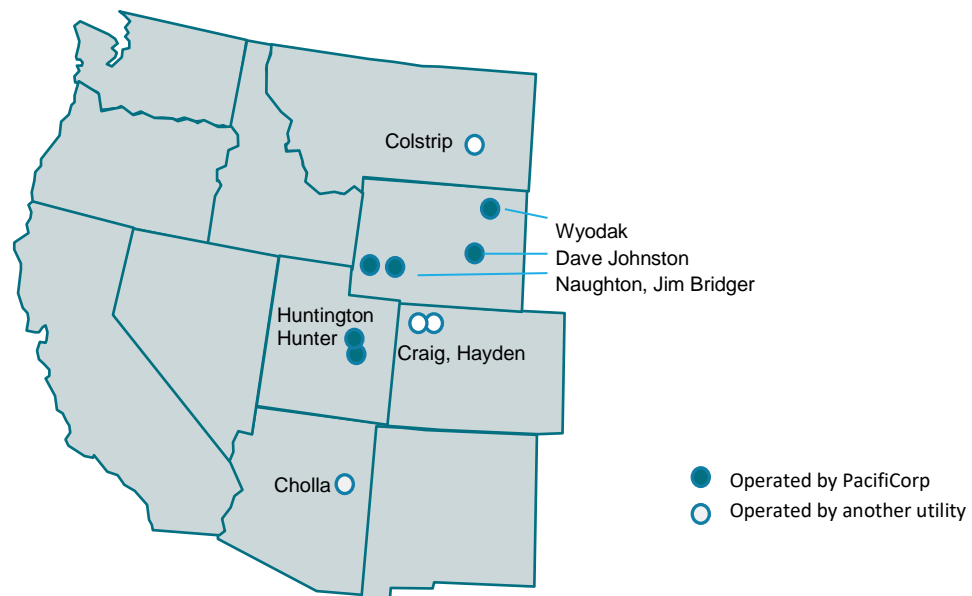
3. PacifiCorp's Coal Fleet

Market drivers such as energy efficiency, falling costs of renewable technologies, low natural gas prices, environmental regulations, and costs of maintaining aging plant infrastructure are marginalizing the cost competitiveness of much of the Western Interconnect's coal fleet. Evidence of these cost pressures can be found in the significant amount of coal-fired capacity that has been retired within the Western Interconnect in recent years. Since 2010, more than 4,582 MW of coal-fired generation in the Western U.S. interconnection have been retired. Over the same period, 27,118 MW of wind and solar have been added to the region's generation portfolio. Looking forward, an additional 7,789 MW of coal-fired

generation will likely be retired in the West by 2030. Despite these market developments, coal remains a significant fuel in PacifiCorp's power mix.

PacifiCorp currently has an ownership interest in ten coal plants in the Western U.S. comprising 24 generating units in Wyoming, Utah, Arizona, Colorado, and Montana. (See Appendix 7.2: Profile of PacifiCorp Coal Units.) Total operating capacity of these units is 5,975 MW, which accounted for over half of the Company's firm generation capacity and contributed an estimated 59 percent of PacifiCorp's total generation in 2017. Figure 1 shows the location of the ten plants.

Figure 1: Location of PacifiCorp's Coal Fleet



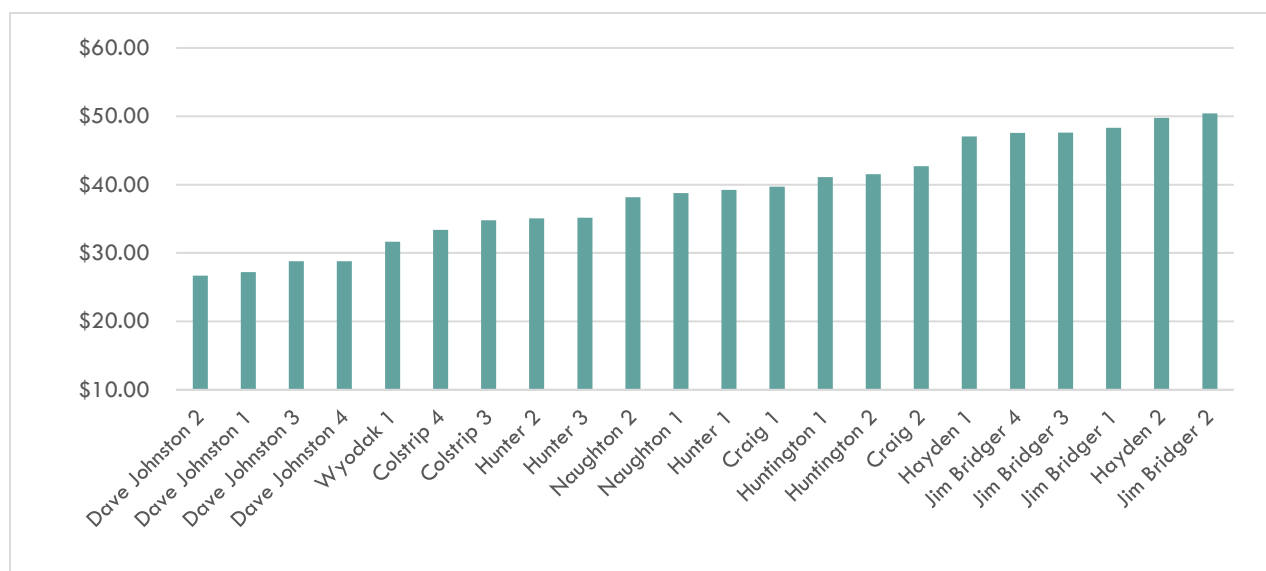
PacifiCorp's coal fleet is aging. The average age of the 22 coal units evaluated in this study is 43 years. (Two units were not studied because of near-term retirement dates.) The oldest unit in the Company's coal fleet, Dave Johnston 1, began service in 1959. The newest coal unit in which the Company has an ownership interest, but does not operate, is Colstrip 4. This unit began operations in 1986. Fifty-nine percent of PacifiCorp's coal-fired generation capacity, 3,494 MW, is more than 40 years old and 90 percent of the fleet was built between 30 to 50 years ago.

The costs of operating PacifiCorp's coal units have also increased. Between 2009 and 2016 operation and maintenance (O&M) costs of the Company's coal fleet have risen 53 percent. In 2009 the average total variable and fixed O&M costs per MWh was \$19.33. By 2016 those costs had risen to \$29.56 per MWh. In 2016, Units 1-4 of the Dave Johnston plant had the lowest O&M costs, ranging from \$19.24 per MWh to \$20.02 per MWh. Jim Bridger and Cholla were the highest cost units to operate among the Company's coal fleet, with costs ranging between \$37 and \$43 per MWh.

Figure 2 ranks each unit on the basis of the levelized cost of electricity (LCOE). As indicated below, the LCOE across the Company's coal fleet varies between \$26.72 and \$50.43 per MWh. The LCOE of Jim

Bridger Unit 2 and Hayden 2 have the highest LCOE among PacifiCorp's 22 units at \$50.43 and \$49.75 respectively. The lowest LCOEs are from the Dave Johnston units, ranging between \$26.72 and \$28.81 per MWh.

Figure 2: PacifiCorp Coal Units' Levelized Cost of Electricity, in \$ per MWh



According to PacifiCorp's 2017 IRP Update, the Company is planning on retiring ten coal units with a capacity of 2,267 MW by 2030. The coal plants planned for retirement are listed in Table 1.

Table 1: Planned Coal Unit Retirements, 2019 to 2030

Plant	Unit	County, State	Year in Service	PacifiCorp Owned Capacity (MW)	Expected Year of Retirement
Cholla	4	Navajo, AZ	1981	380.0	2021
Craig	1	Moffat, CO	1980	82.5	2026
Dave Johnston	1	Converse, WY	1959	106.0	2028
	2	Converse, WY	1961	106.0	2028
	3	Converse, WY	1964	220.0	2028
	4	Converse, WY	1972	330.0	2028
Jim Bridger	1	Sweetwater, WY	1974	355.8	2029
Naughton	1	Lincoln, WY	1963	156.0	2030
	2	Lincoln, WY	1968	201.0	2030
	3	Lincoln, WY	1971	330.0	2019

4. Methodology

A discounted cashflow spreadsheet model and publicly available data was used to estimate the total going-forward fuel, operating costs, and future capital expenditures for PacifiCorp's 22 coal units on the basis of \$/MWh. The \$/MWh value for each cost category was then multiplied by the coal units' estimated generation in each year to calculate total expenditures on fuel, operations, and incremental capital. Total costs of generation were then discounted back to the present at a nominal discount rate of 6.91% to calculate a present value in 2019 dollars.

Annual projections of fuel and O&M expenses were based upon data reported by PacifiCorp in its Form 1 filings with the Federal Energy Regulatory Commission (FERC) and its Form 860 and Form 923 filings with the U.S. Energy Information Administration (EIA). The FERC and EIA data utilized in this study was accessed by subscription using S&P Global's Market Intelligence platform. Capital expenditures were estimated using the same methodology used by the EIA's National Energy Modeling System (NEMS). The NEMS model assumes the average annual capital additions for existing coal plants that are more than 30 years old is \$27 per kW-year.

The estimated present value of each coal unit's cost was then compared to the estimated present value of the costs of three assumed resource replacement scenarios: wholesale market purchases, wind energy, and solar photovoltaic (PV) energy. Under the replacement scenarios, market purchases, solar PV and wind energy were assumed to replace each unit's projected generation over the period spanning from 2023 to the planned date of the coal unit's retirement. To enable an equivalent comparison of the present value of costs of each replacement scenario to the BAU case, the cost of each replacement power scenario also included operating and capital costs of each coal unit for the period 2019 through 2022.

As described above, the methodology utilized in this study was designed as a high-level, unit-by-unit analysis and intentionally bounded to a specific set of costs assumptions. It did not include a host of other costs including capacity replacement, and transmission-related expenses for example. Nor did it explicitly account for how the closure of a large number of coal units would affect the Company's power system or the broader changes in the economics of wholesale power markets.

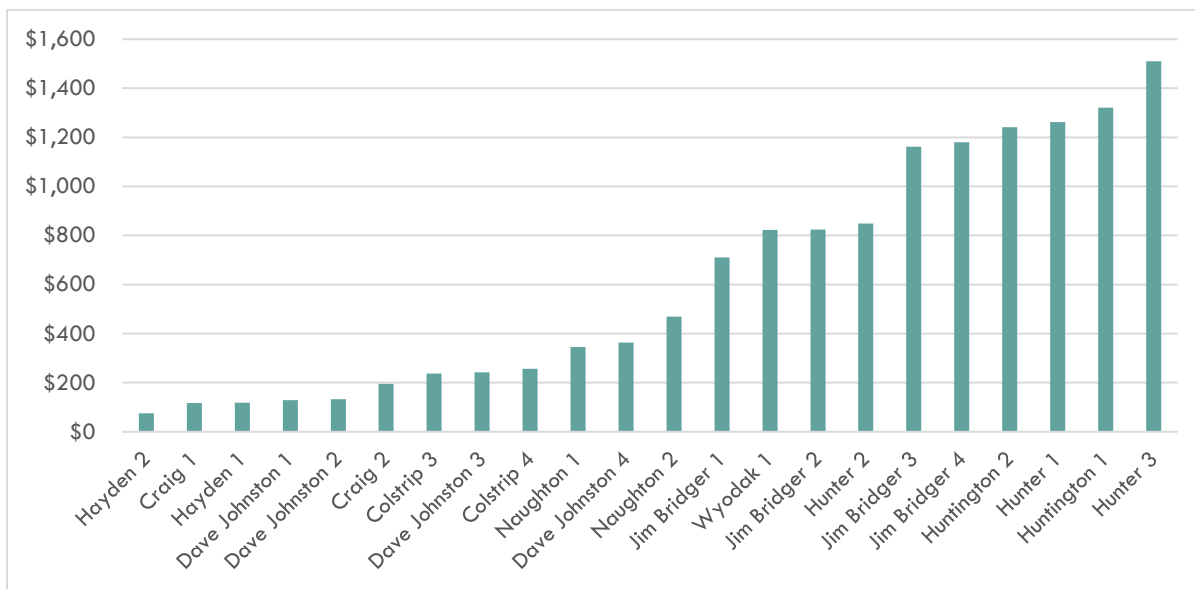
5. Comparative Cost Assessment of PacifiCorp's Coal Units

This analysis compared the cost of electricity generated for each of 22 of PacifiCorp's coal units to the cost of electricity from three alternative sources of electricity and utilized two metrics for costs comparison: LCOE in \$ per MWh, and the Net Present Value (NPV) of the cost of electricity generation, measured in discounted total dollars. Cholla Unit 4 and Naughton Unit 3 were not included in this analysis due to their planned retirement dates at the end of 2019 and 2020.

Business-As-Usual (BAU) Case

The BAU case is defined as all PacifiCorp coal units continuing to operate at historic levels of production until their announced retirement dates. Over the expected life of these coal units, the estimated NPV of fuel, operating costs, and capital additions is \$11.7 billion. NPV costs of individual units range from \$76 million for Hayden Unit 2 to more than \$1.51 billion for Hunter Unit 3. NPV correlates strongly with MW capacity and remaining operating life of the unit. Therefore, higher NPVs are generally seen for coal units in which PacifiCorp owns large amounts of capacity whose planned retirement dates are 2035 or later. The two highest NPVs are for Huntington 1, at 459 MW owned capacity, and Hunter 3, at 460 MW owned capacity. Figure 3 shows the ranking of NPVs across the 22 analyzed coal units.

Figure 3: Net Present Value, Operating and Incremental Capital Costs, in \$Millions



Replacement with Market Purchases

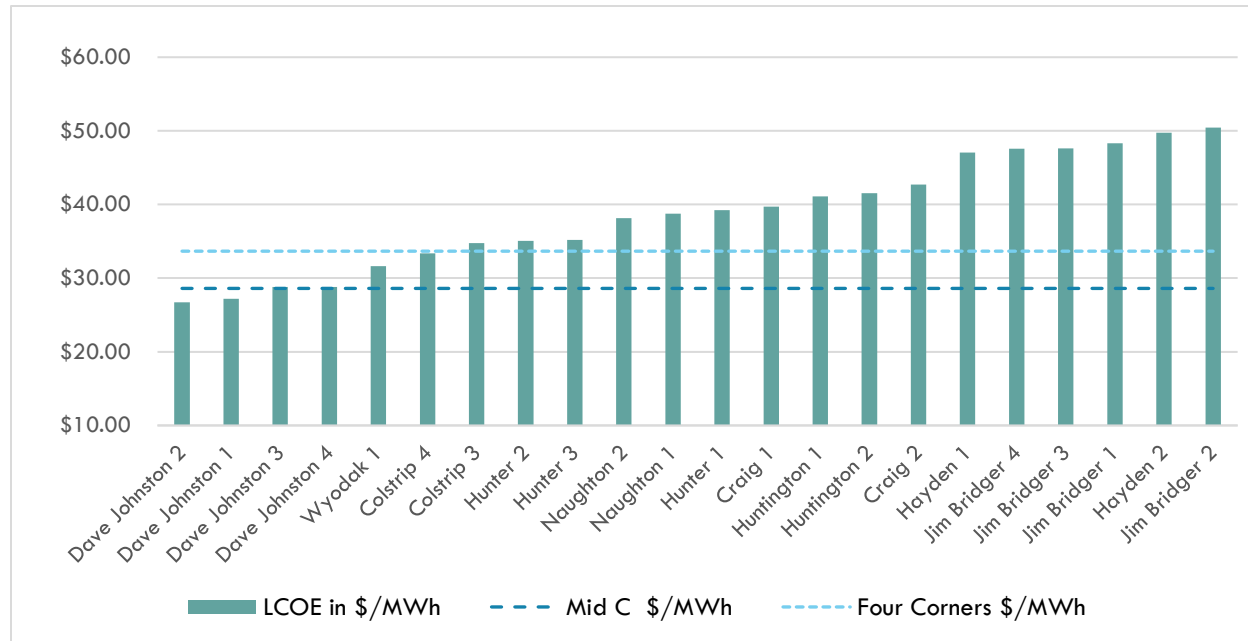
To assess the present value of going forward costs of the coal units against market purchases, the analysis estimated the costs of replacing each coal unit’s generation with energy purchased from one or more market hubs identified in PacifiCorp’s 2017 IRP Update. The assumed forward prices for wholesale electricity were taken from the same source.

For this analysis, we assumed market purchases to replace generation from the Colstrip and Jim Bridger coal units will be transacted at Mid-Columbia (Mid C). Market transactions at Four Corners will be used to replace power from all remaining units. In order to estimate the cost of market purchases, a simplifying assumption was made that each unit’s generation is 50% on-peak and 50% off-peak.

Figure 4 compares the estimated LCOE for market purchases at Mid C and Four Corners to the LCOE of each of PacifiCorp’s analyzed coal units. As illustrated by Figure 4, most of the coal units have LCOEs

higher than the LCOE of market purchases, especially market purchases at Mid C (which includes a substantial amount of hydroelectricity). For this analysis LCOE is one of two metrics used to compare the costs of PacifiCorp’s coal units to the costs of replacement resources.

Figure 4: LCOE of Mid C and Four Corners Market Purchases Compared to PacifiCorp Coal Units, in \$/MWh



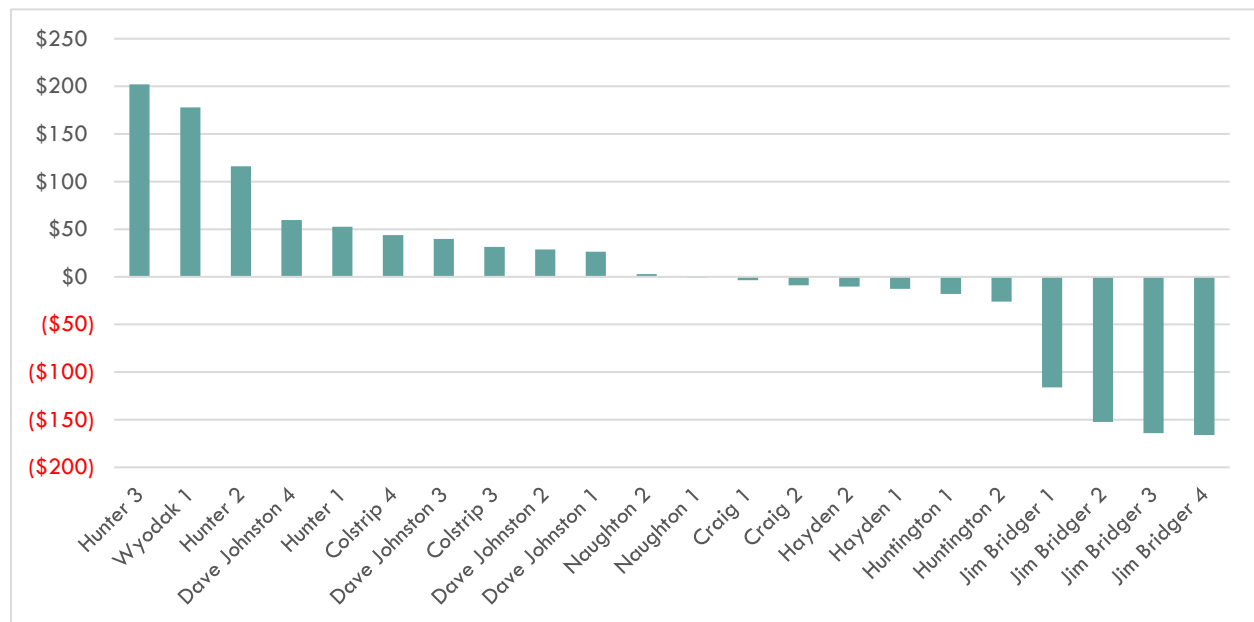
The more important metric in this analysis is NPV of costs, and more specifically, the *difference* in the NPV costs between the coal units and the potential replacement resource. This difference indicates whether the present value costs of operating the coal units are higher than the costs of the replacement resource. For example, the model results show that the NPV cost to run Jim Bridger 4 is \$1,180 million over its remaining life, while the NPV cost to replace Jim Bridger 4 with market purchases is \$1,014 million. In this case the NPV of the cost of the coal unit is higher than the NPV of the market purchase alternative. Therefore, if the NPV coal costs are subtracted from the NPV alternative costs, the result is negative (\$166 million in this case), and this represents *savings* if Jim Bridger 4 is replaced with market purchases.

Figure 5 illustrates the difference in the estimated NPV costs of market purchases compared to each PacifiCorp coal unit. Coal units whose differences are positive represent units whose costs are less than market purchases. Those units whose differences are shown as negative in the figure are coal unit’s whose NPV costs are greater than market purchases and indicate potential savings of replacing coal generated energy with less costly market purchases.

Figure 5 identifies 11 coal units whose present value costs are higher than the costs of market purchases. The units whose costs are higher include Craig 1 and 2, Jim Bridger 1 – 4, Hayden 1 – 2, Huntington 1 and 2, and Naughton 1. The difference in NPV costs for Naughton 2 is near zero, indicating this coal unit’s costs are only marginally lower than market purchases. The Figure also shows the

potential savings if PacifiCorp purchased power from the wholesale market instead of continuing to operate these eleven units. The NPV savings associated with replacing the energy from these 11 coal units in this scenario range from \$915,000 for Naughton 1 to \$166 million for Jim Bridger 4. As a further point of reference, the NPV cost savings of replacing Huntington 2 generation with market purchases is \$26 million.

Figure 5: NPV Market Purchases Costs/(Savings) Relative to Coal, in \$Millions



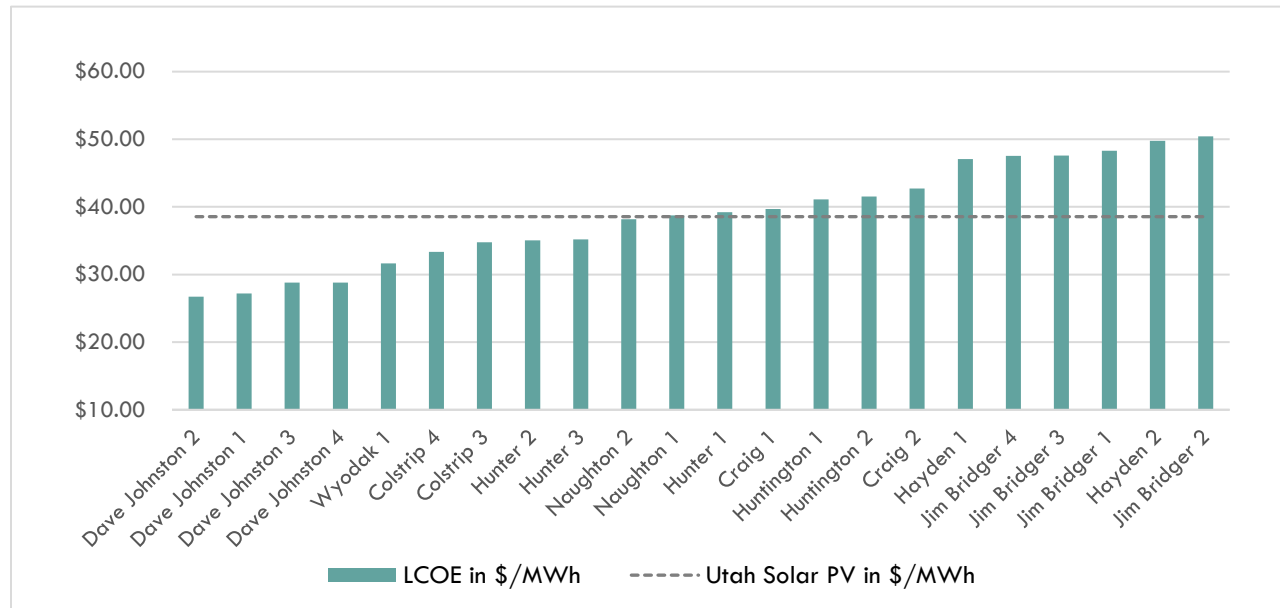
Replacement with Solar PV

The solar PV replacement resource used in this analysis was selected from the Supply-Side Resource Table reported on page 64 of PacifiCorp’s 2017 IRP Update. The assumed replacement resource for this scenario was a 2021 50 MW Utah solar PV single-axis tracking resource with a capital cost of \$1,392 per kW. Its total resource costs, with Investment Tax Credits (ITC), was reported in the Company’s 2017 IRP Update as \$33.36 per MWh, in 2017\$. This analysis assumes the solar PV resource has made the necessary safe harbor investments to qualify for the ITC and comes on line in 2023. The 2017 cost reported in the IRP was escalated at the rate of inflation to derive a \$38.55 LOCE for a 2023 solar PV resource.

The solar resource cost used in this analysis is considered a conservative cost estimate relative to what is currently available in the market. For example, the median price of 75 solar PV projects submitted in response to Xcel Energy’s 2017 All-Resources RFP was \$29.50 per MWh. Xcel’s 2017 All-Source Solicitation 120-Day Report filed with the Colorado Public Utility Commission (CPUC) stated that the solar PV resources selected for inclusion in its electricity plan portfolio included “solar PV at between \$23 – \$27 per MWh . . . “.

Figure 6 shows the LCOE of the coal units compared to the \$38.55 per MWh LCOE for the solar PV resource. Of the 22 coal units evaluated in this study, the LCOE of 11 units is higher than the LCOE of the solar PV replacement resource. As previously stated, LCOE is a simplified economic metric and used in this analysis as a data point for comparison, not a final determinate of cost effectiveness of a resource.

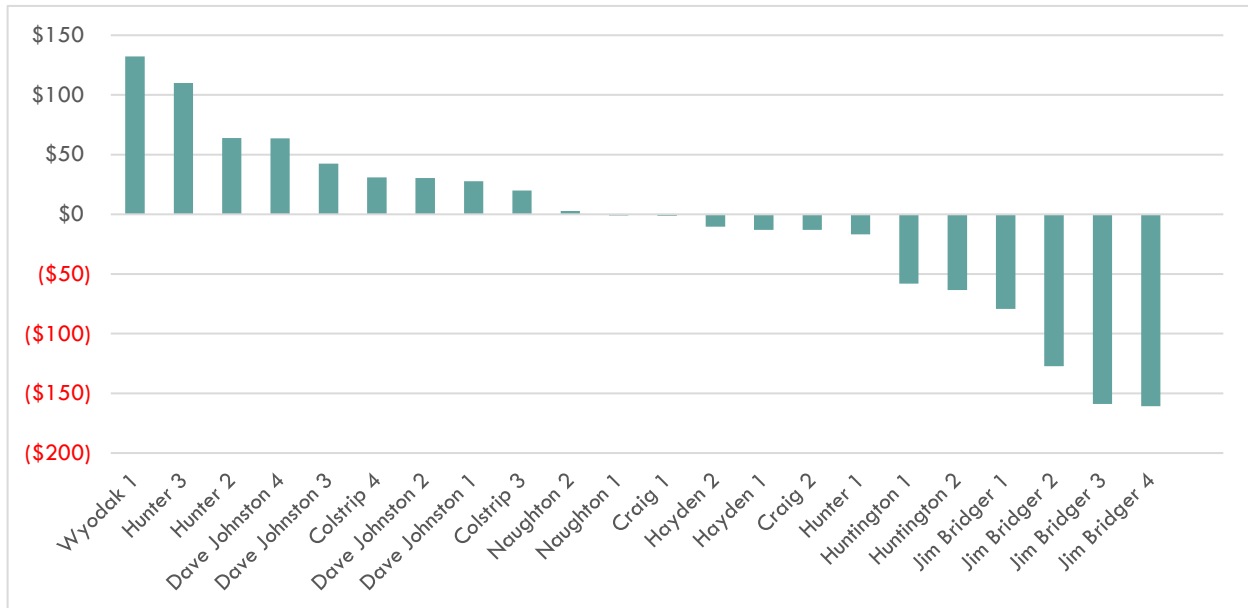
Figure 6: LCOE of Utah Solar PV Compared to PacifiCorp Coal Units, in \$/MWh



When using the difference in NPV costs as a metric, 12 coal units are shown to have higher cost compared to the solar PV replacement resource. The higher cost units are Craig 1 and 2, Jim Bridger 1 – 4, Hayden 1 – 2, Huntington 1 and 2, and Naughton 1 plus Hunter 1. Figure 7 illustrates these results. The difference in NPV costs of Naughton 2 is again near zero indicating this coal units is only marginally less costly to operate on the basis of NPV cost than solar PV.

Figure 7 also shows the present value savings if the energy generation from each unit was replaced with the solar PV resource assumed in this analysis. The present value savings in the solar PV replacement scenario range from \$1.07 million to \$161 million. Again, the largest savings are achieved with replacing energy from Jim Bridger 4 and the other Jim Bridger units and the smallest savings are associated with replacing energy generation from Naughton 1.

Figure 7: NPV Solar PV Costs/(Savings) Relative to Coal, in \$Millions



Replacement with Wind

The baseline performance and cost assumptions for replacement wind resources also came from the Supply-Side Resource Table in PacifiCorp’s 2017 IRP Update. Wyoming wind was selected as the replacement resource for all of the coal units in PacifiCorp’s fleet in this scenario. The capital cost of this resource is \$1,415 per kW for a project built in 2022. Its total resource costs of energy, with the Production Tax Credit (PTC), is \$24.01 per MWh in 2017\$. As with solar PV, this analysis assumes the wind resource comes on line in 2023 has made the necessary safe harbor investments and taken all other steps to qualify for the PTC. The 2017 cost reported in the IRP was escalated at the rate of inflation to derive a \$27.56 per MWh LCOE for a 2023 Wyoming wind resource.

As with the solar PV cost assumptions, Energy Strategies believes this is a conservative cost estimate. PacifiCorp’s 2017 IRP Update reported the new wind projects it proposes to acquire under its Energy Vision program would have a capital cost of \$1,310 per kW and a total resource cost of energy of \$17.36 per MWh when the Production Tax Credit was included. The wind projects Xcel Energy selected and included in its preferred electric plan portfolio for the 2017 All-Source Solicitation 120-Day Report included wind projects with levelized pricing of between \$11 – \$18 per MWh.

The LCOE of the Wyoming wind replacement power resource is significantly less than the LCOE for most of PacifiCorp’s coal units. Figure 8 shows this comparison. Only two units of PacifiCorp’s Dave Johnston plant have an LCOE that is lower than the wind replacement resource.

Figure 8: LCOE of Wyoming Wind Compared to PacifiCorp Coal Units, in \$/MWh

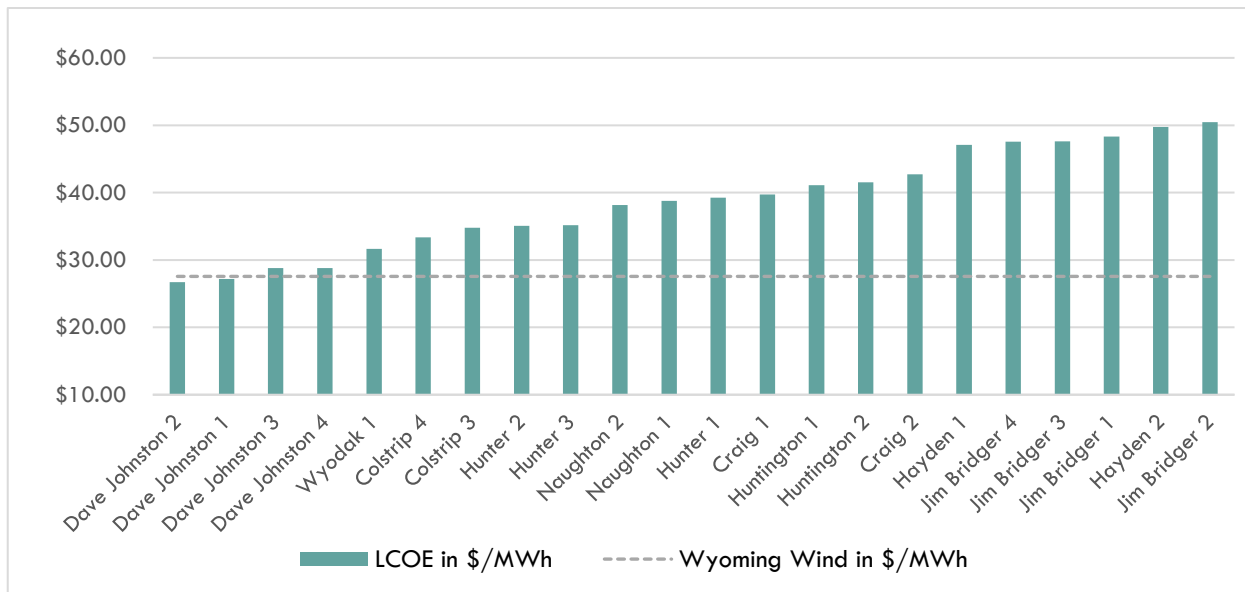
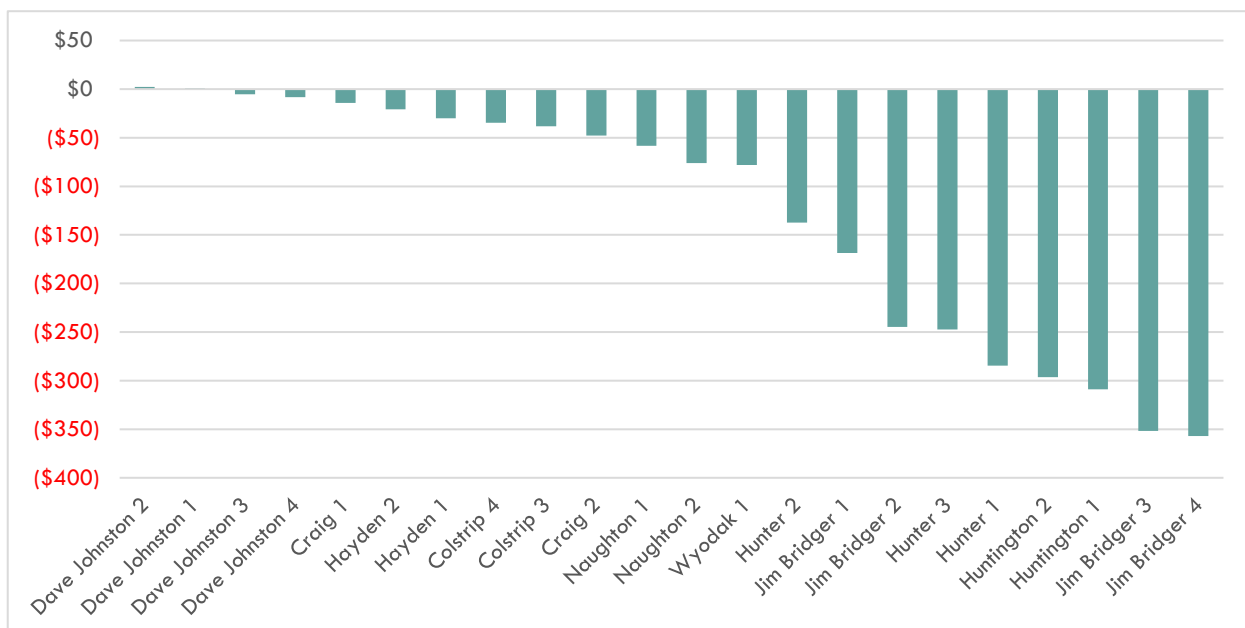


Figure 9 illustrates the difference in the estimated NPV costs of wind when compared to the NPV costs of each PacifiCorp coal unit. In this replacement scenario, there is a dramatic increase in the number of PacifiCorp coal units whose costs are higher than the replacement resource. Twenty (20) coal units' NPV costs exceed the costs of replacement energy from the wind resource. The only two coal units whose costs are lower are Dave Johnston 1 and 2. Because of the lower cost of wind the potential savings for each unit are higher than the other replacement scenarios. Savings range from \$5.37 million for Dave Johnston 3 to over \$350 million savings each for Jim Bridger units 3 and 4.

Figure 9: NPV Wind Costs/(Savings) Relative to Coal, in \$Millions

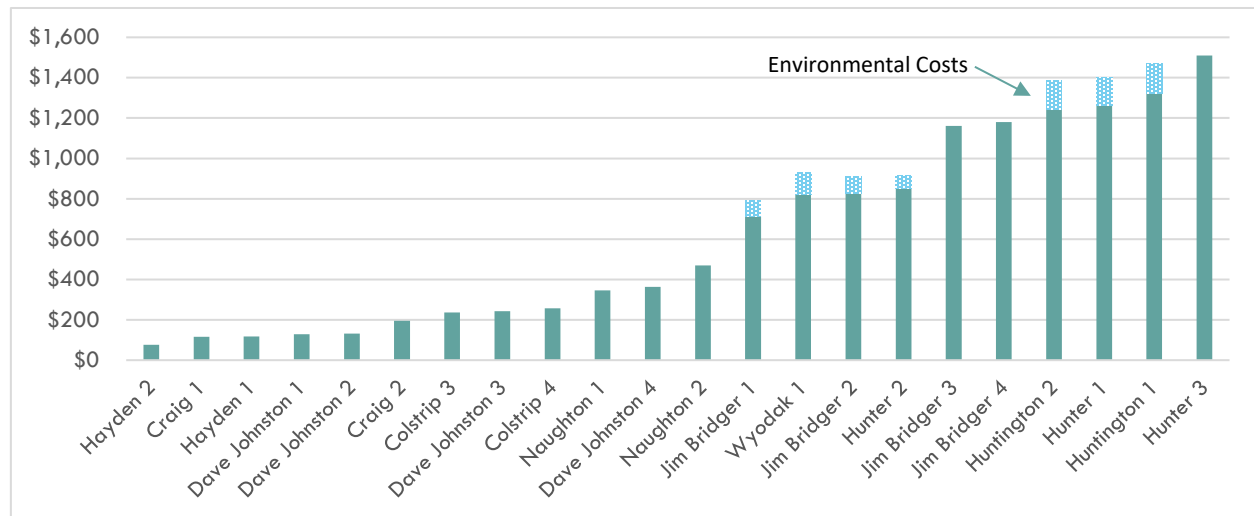


Cost Assessment Scenario with Environment Controls

In addition to the BAU case, this study also included an analysis of how expenditures on environmental controls might impact the going-forward cost of PacifiCorp’s coal units relative to the BAU and replacement resources. Based on the Company’s 2017 IRP, Energy Strategies identified seven coal units that potentially could incur the additional capital expense of installing Selective Catalytic Reduction (SCR) control technology to comply with federal Regional Haze standards. These units include: Hunter 1 and 2, Huntington 1 and 2, Jim Bridger 1 and 2, and Wyodak. Upfront capital and ongoing O&M cost estimates assumed for SCR in this analysis ranged from \$275 to \$345 million (in 2015\$) and were obtained from the data set associated with the Synapse Energy Economics’ Coal Asset Valuation Tool (CAVT).

Adding SCR systems increases the LCOE and present value costs. The present value costs of operating these controlled units increases by \$665 million under this scenario. Figure 10 shows the NPV costs of the 22 units with the addition of environmental controls for the seven affected units.

Figure 10: Net Present Value, Operating and Capital Costs, plus SCR Environmental Controls, in \$Millions



The study found that present value costs of four of the seven at-risk units evaluated in this sensitivity case were already higher than the three replacement resources, without the added cost of environmental controls. These four units were Jim Bridger 1 and 2, and Huntington 1 and 2. With the added costs of environmental controls, the cost of continuing to operate Hunter Unit 1 were higher relative to wholesale market purchases, and the cost of both Hunter 1 and 2 were higher than solar PV when it was the replacement resource. Figure 11 (market purchases) and Figure 12 (solar PV) show the differences in present value costs/savings against coal, with the Hunter units called out.

Figure 11: NPV Market Purchases Costs/(Savings) Relative to Coal, in \$Millions

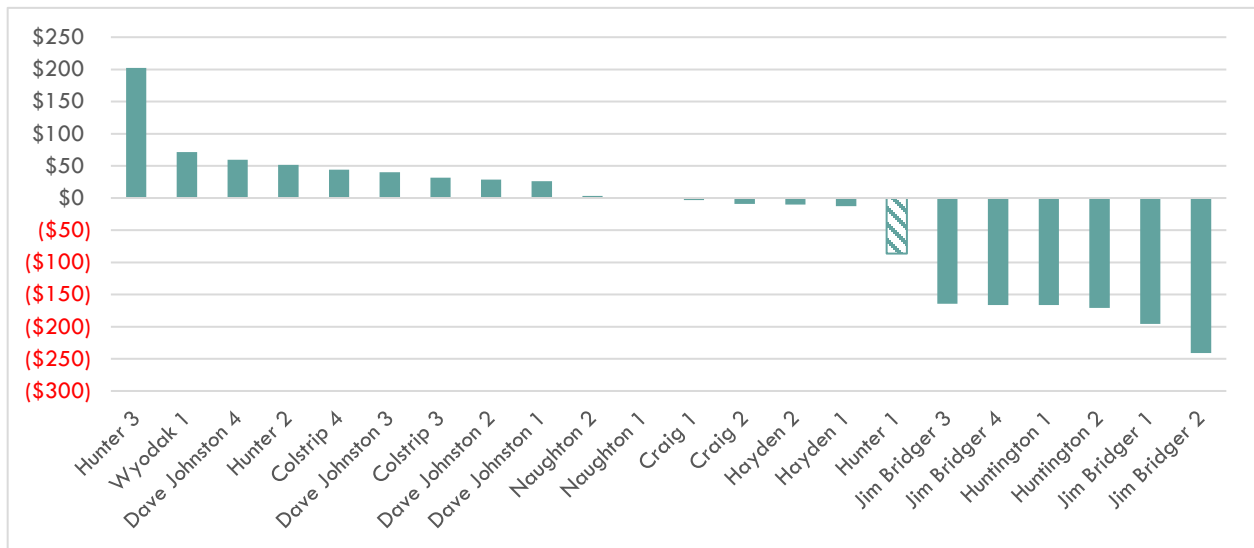
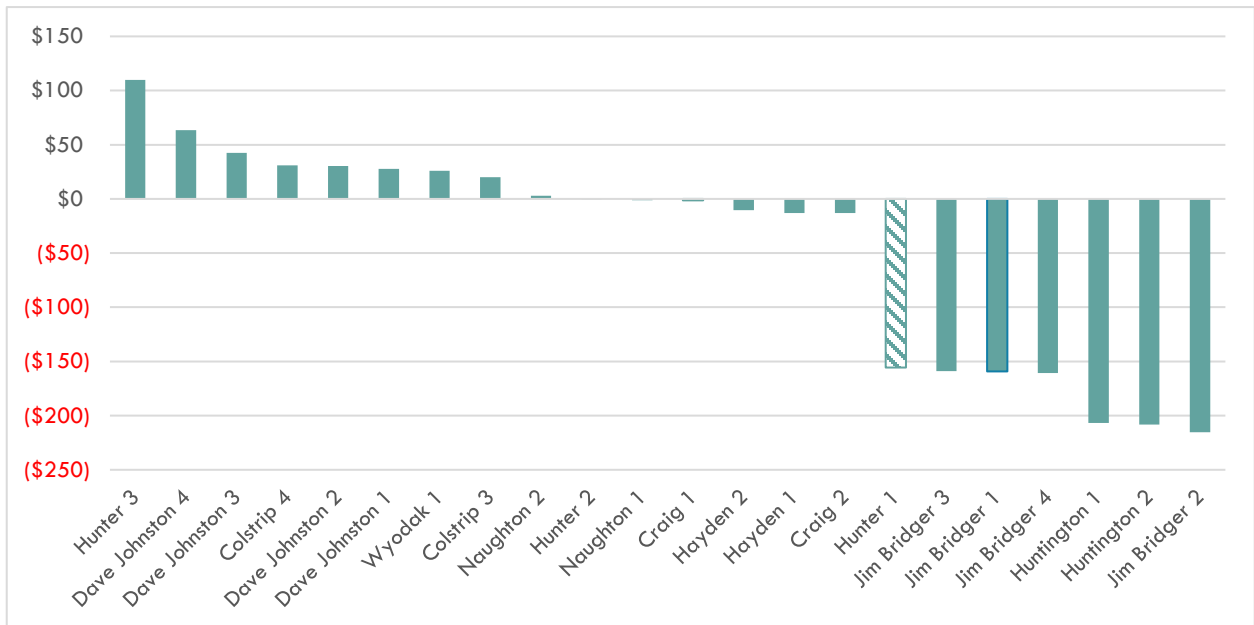


Figure 12: NPV Solar PV Costs/(Savings) Relative to Coal, in \$Millions



The addition of SCR does not change the number of coal units that are higher cost relative to the wind replacement resource. The total number of coal units whose costs are higher remained at 20 units.

6. Caveats

The analysis described in this report was focused on comparing the estimated present value of the operating and capital costs of energy from individual PacifiCorp coal units to the cost for replacing that

energy using market purchases and renewable resources. The study did not evaluate other possible costs, including transmission-related expenses, operational impacts, coal contract costs or damages, and the cost of replacement capacity if required.

Transmission-related expenses could be incurred in the retirement of specific units, or incremental addition of new resources in constrained or remote locations. These costs are highly specific to individual units and their replacement resources and require a separate form of analysis. Operational impacts – i.e. avoided or incurred costs on other units based on the retirement and/or replacement of various coal units – are typically assessed through dispatch models. These impacts can result in incremental costs (i.e. less efficient dispatch) or net savings as the cost of market energy falls. Coal contract terms and potential damages for early termination are considered proprietary information of the operator. In general, PacifiCorp holds few very long-term coal contracts.

With respect to replacement capacity, the study assumed that wholesale market purchases are transacted as firm resources and thus have an implied capacity value. We did not account for the capacity value of the Company's coal units relative to wind or solar. However, to the extent that this study demonstrates that NPV costs savings are achieved, it is not beyond reason to assume these savings could be used to mitigate capacity replacement costs, if necessary.

7. Summary of Findings

Coal units are long-life assets and the economics of coal-fired generation under a regulated cost-of-service business model are complex. It is clear, nevertheless, that the ongoing costs of operating PacifiCorp's coal units to supply electricity to customers are increasing while the cost of renewable energy is falling. Using publicly available data from PacifiCorp and other vetted sources, this study found that eleven of PacifiCorp's coal units, representing 2,730 megawatts (MW), are consistently higher cost than replacement energy options, and in many cases substantially so. This reality poses a fundamental question of whether some of PacifiCorp's coal units are in fact least cost resources.

The going-forward cost of eleven coal units were consistently shown to be higher regardless of the replacement power scenario: Craig 1 and 2, Jim Bridger 1 – 4, Hayden 1 – 2, Huntington 1 and 2, and Naughton 1. With the added costs of environmental controls, the cost of continuing to operate Hunter Unit 1 were higher relative to wholesale market purchases, and the cost of both Hunter 1 and 2 were higher than solar PV when it was the replacement resource.

The study also compared the LCOE of PacifiCorp's coal units against the LCOE of the three replacement resources. LCOE across the Company's coal fleet varied between \$26.72 and \$50.43 per MWh. At the upper end of the spectrum, the LCOE of Jim Bridger Unit 2 and Hayden 2 have the highest LCOE among PacifiCorp's twenty-two units, while the Dave Johnston plant had the lowest LCOEs. Most of the coal units have LCOEs higher than market purchases, especially market purchases at Mid-C. The LCOE of eleven coal units was higher than the solar PV replacement resource, and the LCOE of the Wyoming wind replacement resource was less than the LCOE for all but two of the twenty-two coal units evaluated in this study.

8. Appendices

8.1. Assumptions

Assumption	Value	Description
Fuel		Fuel Cost is the cost of fuel for the plants in \$/MWh produced. Fuel costs were taken from FERC and EIA documents as reported by S&P Global Market Intelligence Platform (formerly known as SNL)
Variable O&M		Variable O&M is the variable cost of Operations and Maintenance for the plants in \$/MWh produced. Variable Costs were taken from FERC and EIA documents as reported by S&P Global Market Intelligence Platform (formerly known as SNL)
Fixed O&M		Fixed Cost is the fixed cost of Operations and Maintenance for the plants in \$/kW-yr. Fixed Costs were taken from FERC and EIA documents as reported by S&P Global Market Intelligence Platform (formerly known as SNL)
Environmental Control Costs		Upfront capital and ongoing O&M cost estimates for SCRs for PacifiCorp's coal units were obtained from Synapse Energy Economics' Coal Asset Valuation Tool (CAVT)
Capital Additions	\$27/kW-yr	Annual capital costs for each unit were based on the \$27/kW-yr cost factor used by the EIA NEMS model. The factor was applied to the percent of operating capacity owned by PacifiCorp for each unit
Forward Market Prices		Study used the published Official Forward Price Curve (OFPC) used by PacifiCorp in its 2017 IRP Update, adjusted to remove the embedded CO ₂ price adder
Forecast Period	27 years	NPV calculated for the period 2019 through 2046, the last year of retirement of PacifiCorp's coal units
Inflation Rate	2.27%	Represents the rate of inflation PacifiCorp uses in the 2017 IRP. Applied as an annual escalation rate for rate and cost projections in the cashflow model
Nominal Discount Rate	6.91%	Rate used in present value calculations in this study. Equals PacifiCorp's 6.91% WACC from the 2017 IRP Update. Represents the value at which total future costs were discounted back to the present, 2019

8.2. Profile of PacifiCorp Coal Units

Plant	Unit	County, State	Year in Service	PacifiCorp Owned Capacity MW	Expected Date of Retirement	Operator
Cholla	4	Navajo, AZ	1981	380.0	12/1/2020	APS
Colstrip	3	Rosebud, MT	1984	74.0	12/1/2046	PSE
	4	Rosebud, MT	1986	74.0	12/1/2046	PSE
Craig	1	Moffat, CO	1980	82.5	12/1/2025	Tri-State
	2	Moffat, CO	1979	82.5	12/1/2034	Tri-State
Dave Johnston	1	Converse, WY	1959	106.0	12/1/2027	PacifiCorp
	2	Converse, WY	1961	106.0	12/1/2027	PacifiCorp
	3	Converse, WY	1964	220.0	12/1/2027	PacifiCorp
	4	Converse, WY	1972	330.0	12/1/2027	PacifiCorp
Hayden	1	Routt, CO	1965	43.9	12/1/2030	Xcel Energy
	2	Routt, CO	1976	33.0	12/1/2030	Xcel Energy
Hunter	1	Emery, UT	1978	442.7	12/1/2042	PacifiCorp
	2	Emery, UT	1980	258.0	12/1/2042	PacifiCorp
	3	Emery, UT	1883	460.0	12/1/2042	PacifiCorp
Huntington	1	Emery, UT	1977	459.0	12/1/2036	PacifiCorp
	2	Emery, UT	1974	450.0	12/1/2036	PacifiCorp
Jim Bridger	1	Sweetwater, WY	1974	355.8	12/1/2028	PacifiCorp
	2	Sweetwater, WY	1975	353.1	12/1/2032	PacifiCorp
	3	Sweetwater, WY	1976	350.4	12/1/2037	PacifiCorp
	4	Sweetwater, WY	1979	355.1	12/1/2037	PacifiCorp
Naughton	1	Lincoln, WY	1963	156.0	12/1/2019	PacifiCorp
	2	Lincoln, WY	1968	201.0	12/1/2029	PacifiCorp
	3	Lincoln, WY	1971	330.0	12/1/2029	PacifiCorp
Wyodak	1	Campbell, WY	1978	272.0	12/1/2039	PacifiCorp

7.3. PacifiCorp Coal Units Operational Profile

Plant	Unit	Operating Capacity MW	Average Annual Generation (MWh)	Heat Rate	Average Capacity Factor (%)
Craig	1	428	4,575,560	10,635	70.58
	2	428	5,165,626	10,827	79.69
Colstrip	3	740	2,753,744	10,131	73.45
	4	740	2,245,720	10,105	59.90
Dave Johnston	1	106	693,652	11,566	74.70
	2	106	728,788	11,899	78.49
	3	220	1,239,917	11,056	64.34
	4	400	1,857,621	10,709	64.26
Hayden	1	179	1,189,363	11,252	75.85
	2	262	1,409,488	10,746	61.41
Hunter	1	471	2,501,997	10,545	60.64
	2	430	2,945,472	10,235	78.20
	3	460	3,134,673	9,932	77.79
Huntington	1	459	2,797,872	10,276	69.58
	2	450	2,601,905	10,530	66.00
Jim Bridger	1	531	2,944,255	10,370	63.30
	2	527	2,528,930	10,195	54.78
	3	523	3,058,638	10,532	66.76
	4	530	3,110,987	10,777	67.01
Naughton	1	156	1,108,821	10,487	81.14
	2	201	1,527,687	11,199	86.76
Wyodak	1	340	2,565,053	12,249	86.12

8.4. PacifiCorp Coal Units Cost Assumptions

The historical year 2017 was used for the operating data below. SNL was the source for the annual generation, heat rate, and capacity factor. The expected retirement date was based on 2017 IRP Regional Haze Case 5 except where specific units were updated in the 2017 IRP update.

Operations & Maintenance Costs					
Plant	Unit	Fixed O&M (2017\$/kw-yr)	Fuel Cost (2017 \$/MWh)	Variable Non-Fuel O&M (2017\$/MWh)	Capital Expense 2015\$000
Craig	1	\$37.38	\$16.27	\$3.35	\$1,998
	2	\$37.38	\$16.27	\$3.35	\$1,998
Colstrip	3	\$45.47	\$19.75	\$3.34	\$2,228
	4	\$45.47	\$19.75	\$3.34	\$2,228
Dave Johnston	1	\$27.60	\$11.01	\$4.08	\$2,862
	2	\$27.60	\$11.01	\$4.08	\$2,862
	3	\$27.60	\$11.01	\$4.08	\$5,940
	4	\$27.60	\$11.01	\$4.08	\$8,910
Hayden	1	\$36.93	\$27.29	\$3.89	\$1,184
	2	\$36.93	\$27.29	\$3.89	\$891
Hunter	1	\$30.95	\$20.38	\$2.59	\$11,954
	2	\$30.95	\$19.28	\$2.59	\$6,966
	3	\$30.95	\$19.32	\$2.59	\$12,420
Huntington	1	\$13.71	\$25.61	\$3.27	\$12,393
	2	\$13.71	\$25.61	\$3.27	\$12,150
Jim Bridger	1	\$36.99	\$29.64	\$0.65	\$9,606
	2	\$36.99	\$29.64	\$0.65	\$9,533
	3	\$36.99	\$29.64	\$0.65	\$9,461
	4	\$36.99	\$29.64	\$0.65	\$9,588
Naughton	1	\$27.77	\$22.16	\$3.70	\$4,212
	2	\$27.77	\$22.16	\$3.70	\$5,427
Wyodak	1	\$39.72	\$14.76	\$3.76	\$7,344

Environmental capital and operating costs were obtained from the data set for the Synapse CAVT model.

Environmental Control Costs					
Plant	Unit	Type of Additional Environmental Controls	Cost in 2015\$ Millions	Year Added	Regulation Trigger
Hunter	1	SCR	\$273.00	2023	Regional Haze
	2	SCR	\$273.00	2023	Regional Haze
Huntington	1	SCR	\$274.00	2023	Regional Haze
	2	SCR	\$277.00	2023	Regional Haze
Jim Bridger	1	SCR	\$286.00	2022	Regional Haze
	2	SCR	\$285.00	2021	Regional Haze
Wyodak	1	SCR	\$345.00	2022	Regional Haze

8.5. Table of Results: Levelized Cost of Electricity

Business as Usual Case Levelized Cost of Electricity (LCOE) \$/MWH					
Plant	Unit	Coal	Market Purchases	Utah Solar PV	Wyoming Wind
Craig	1	\$34.77	\$28.61	\$38.55	\$27.56
	2	\$33.37	\$28.61	\$38.55	\$27.56
Colstrip	3	\$39.71	\$33.66	\$38.55	\$27.56
	4	\$42.71	\$33.66	\$38.55	\$27.56
Dave Johnston	1	\$27.20	\$33.66	\$38.55	\$27.56
	2	\$26.72	\$33.66	\$38.55	\$27.56
	3	\$28.80	\$33.66	\$38.55	\$27.56
	4	\$28.81	\$33.66	\$38.55	\$27.56
Hayden	1	\$47.07	\$33.66	\$38.55	\$27.56
	2	\$49.75	\$33.66	\$38.55	\$27.56
Hunter	1	\$39.24	\$33.66	\$38.55	\$27.56
	2	\$35.07	\$33.66	\$38.55	\$27.56
	3	\$35.17	\$33.66	\$38.55	\$27.56
Huntington	1	\$41.10	\$33.66	\$38.55	\$27.56
	2	\$41.54	\$33.66	\$38.55	\$27.56
Jim Bridger	1	\$48.31	\$28.61	\$38.55	\$27.56
	2	\$50.43	\$28.61	\$38.55	\$27.56
	3	\$47.60	\$28.61	\$38.55	\$27.56
	4	\$47.55	\$28.61	\$38.55	\$27.56
Naughton	1	\$38.76	\$33.66	\$38.55	\$27.56
	2	\$38.17	\$33.66	\$38.55	\$27.56
Wyodak	1	\$31.64	\$33.66	\$38.55	\$27.56

8.6. Table of Results: NPV of Costs of Coal and Three Alternatives

Business as Usual Case NPV of Coal Unit Costs and Replacement Resources \$Millions					
Plant	Unit	Coal	Solar Alternative	Wind Alternative	Market Purchases Alternative
Colstrip	3	\$236.5	\$256.5	\$198.4	\$267.9
	4	\$256.3	\$287.3	\$221.7	\$300.2
Craig	1	\$116.6	\$115.2	\$102.4	\$113.1
	2	\$196.0	\$182.9	\$148.2	\$187.0
Dave Johnston	1	\$128.3	\$155.9	\$129.2	\$154.5
	2	\$132.5	\$162.8	\$134.7	\$161.3
	3	\$242.4	\$284.8	\$237.0	\$282.3
	4	\$363.3	\$426.8	\$355.2	\$423.0
Hayden	1	\$118.2	\$105.1	\$88.3	\$105.5
	2	\$76.0	\$65.6	\$55.3	\$65.8
Hunter	1	\$1,262.6	\$1,245.9	\$977.8	\$1,315.1
	2	\$848.8	\$912.7	\$711.3	\$964.8
	3	\$1,510.1	\$1,620.0	\$1,262.7	\$1,712.3
Huntington	1	\$1,321.0	\$1,262.9	\$1,012.1	\$1,303.2
	2	\$1,241.1	\$1,177.8	\$944.5	\$1,215.2
Jim Bridger	1	\$710.8	\$631.4	\$542.1	\$594.7
	2	\$824.2	\$697.1	\$579.4	\$671.7
	3	\$1,161.6	\$1,002.8	\$809.8	\$997.4
	4	\$1,180.3	\$1,019.6	\$823.3	\$1,014.1
Naughton	1	\$345.8	\$344.8	\$287.4	\$344.9
	2	\$469.4	\$472.2	\$393.2	\$472.4
Wyodak	1	\$822.3	\$954.7	\$744.1	\$1,000.2

8.7. Table of Results: Effect of Environmental Control Costs on LCOE and NPV

		Without Environmental Control Costs		With Environmental Control Costs	
Plant	Unit	LCOE \$/MWh	NPV Millions\$	LCOE \$/MWh	NPV Millions\$
Hunter	1	\$39.24	\$1,263	\$44.94	\$1,402
	2	\$35.07	\$849	\$38.58	\$913
Huntington	1	\$35.17	\$1,510	\$35.17	\$1,510
	2	\$41.10	\$1,321	\$47.61	\$1,470
Jim Bridger	1	\$41.54	\$1,241	\$48.36	\$1,386
	2	\$48.31	\$711	\$58.14	\$791
Wyodak	1	\$50.43	\$824	\$58.68	\$912

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