2015 Integrated Resource Plan

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Volume III

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Pacific Power
Rocky Mountain Power

March 31, 2015

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

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VOLUME III – COAL ANALYSIS

Executive Summary

PacifiCorp has analyzed Regional Haze compliance alternatives for its Wyodak, Dave Johnston Unit 3, Naughton Unit 3, and Cholla Unit 4 coal-fired generating assets. Analysis of compliance alternatives was undertaken for these coal-fired generating assets in the 2015 Integrated Resource Plan (IRP) because it was anticipated, with consideration of compliance deadlines and implementation timelines for compliance alternatives applicable at the time these studies were developed, that emission control retrofit decisions would need to be made within the 2015 IRP Action Plan window. The inter-temporal and fleet-trade off compliance alternatives evaluated were developed to represent potential scenarios that might, pending agency support, achieve the appropriate balance of economic justification for PacifiCorp's customers and emissions reductions contributing to long-term visibility improvements in affected Class I areas. In those instances where on-going judicial reviews might affect the need for or timing of the Regional Haze compliance requirements being analyzed, PacifiCorp describes how different outcomes would affect its near-term coal resource actions. A summary of each generating asset studied in the 2015 IRP Volume III Coal Analysis is provided in turn below.

Wyodak

The Wyodak plant is 75 miles west of the border between Wyoming and South Dakota near Gillette, Wyoming. The single-unit plant was commissioned in 1978. PacifiCorp operates Wyodak and owns 268 MW of the 335 MW capacity. As a result of its assessment of Best Available Retrofit Technology (BART) under the Regional Haze program, the U.S. Environmental Protection Agency (EPA) determined installation of selective catalytic reduction (SCR) by March 2019. PacifiCorp has appealed EPA's SCR requirement at Wyodak, as has the state of Wyoming, and other parties have filed appeals asserting contrary positions. PacifiCorp and other parties asked the court to stay EPA's actions pending resolution of the appeals, and the court has granted the requested stay. Under the terms of the stay, the original deadline for compliance is extended on a day-for-day basis for the duration of the stay.

Dave Johnston Unit 3

The Dave Johnston plant is located near Glenrock, Wyoming. Unit 3 of the four-unit plant, owned and operated by PacifiCorp, was commissioned in 1964. The capacity of Dave Johnston Unit 3 is 220 MW. As a result of its assessment of BART under the Regional Haze program, EPA determined that installation of SCR on Dave Johnston Unit 3 by March 2019 or, in lieu of installing SCR, a commitment to shut down Dave Johnston Unit 3 by 2027. The state of Wyoming filed an appeal of the portion of EPA's final action that pertains to Dave Johnston Unit 3. The state of Wyoming sought and was granted a stay of EPA's action as it pertains to Dave Johnston Unit 3. However, the stay does not include an extension of the compliance deadline if EPA prevails in the appeal.

Naughton Unit 3

The Naughton plant is located near Kemmerer, Wyoming. Unit 3 of the three-unit plant owned and operated by PacifiCorp, was commissioned in 1971. Naughton Unit 3 has a capacity of 330 MW. EPA has approved the state of Wyoming's original Regional Haze State Implementation Plan (SIP) requirement to install SCR and a baghouse on the unit. In parallel, the state of Wyoming has authorized an alternate compliance approach via issuance of a construction permit and Regional Haze Best Available Retrofit Technology (BART) permit to convert the unit to natural gas in 2018. EPA has expressed support of the state of Wyoming's alternate compliance approach; however, EPA cannot take formal action on this alternative until it receives an amended Regional Haze SIP from Wyoming.

Cholla Unit 4

The Cholla plant is a four-unit plant located in Joseph City, Arizona. PacifiCorp owns Cholla Unit 4, which contributes 387 MW of capacity to the PacifiCorp system. Arizona Public Service (APS), the operator of the plant, owns units 1, 2, and 3.[1] PacifiCorp acquired Cholla Unit 4, which was commissioned in 1981, from APS in 1991. Under the BART determination under the Regional Haze program, installation of SCR is required at Cholla Unit 4 by December 5, 2017.[2]

Key Findings

Analysis of compliance alternatives to installation of SCR at Wyodak, Dave Johnston Unit 3, and Cholla Unit 4 and analysis of an early retirement alternative to the natural gas conversion of Naughton Unit 3 supports the following key findings:

- Inter-temporal and fleet trade-off alternatives support a strategy that avoids installation of SCR at Wyodak, consistent with PacifiCorp's on-going legal appeal of the SCR requirement.
- Eliminating the need for SCR at Dave Johnston Unit 3 with a firm commitment to retire the unit by the end of 2027 will avoid the need for incremental capital expenditures and run-rate operating costs.
- Natural gas conversion of Naughton Unit 3 in 2018 is lower cost when compared to an early retirement alternative.
- Inter-temporal and technology trade-off analysis supports a strategy that eliminates the compliance obligation to install SCR at Cholla Unit 4 with a firm commitment to cease operating the unit as a coal-fueled resource in 2025.
- Each of the findings noted above retain compliance planning flexibility associated with EPA's draft rule under §111(d) of the Clean Air Act (111(d) or 111(d) draft rule).
- Avoiding SCR at Wyodak, Dave Johnston Unit 3, Cholla Unit 4 and converting Naughton Unit 3 to natural gas in 2018 will save customers hundreds of millions of dollars when compared to the alternative compliance scenarios studied.

[1] PacifiCorp owns 37 percent of the common facilities at the Cholla plant.
[2] The requirement for SCR is being litigated; however, with denial of requests for administrative stay and judicial stay, the December 5, 2017 compliance deadline for installing SCR at Cholla Unit 4 remains in place.

Regional Haze Program

Overview

The Regional Haze program is a visibility improvement program that was enacted in 1999 and revised in 2005. Although its long-term goal is to return Class I areas in the U.S. to natural visibility conditions by 2064, the Regional Haze program also contains stringent requirements at the front end. The states, through development of state implementation plans (SIPs), and EPA are tasked with administering the Regional Haze program under two primary compliance timeframes:

(1) The initial BART planning and compliance period originally required BART controls to be in place by 2013;[3] and

(2) Long-term planning periods that require resubmittal of updated SIPs, including long-term strategy controls on BART and other units to meet reasonable progress goals, every ten years beginning in 2018.

Because the Regional Haze program may affect all emission sources that impair visibility in protected and is implemented over many years, there will continue to be emerging compliance obligations established by state and federal agencies responsible for administering the rules for several decades to come. Projects and visibility improvements deployed and achieved in the initial BART phase of the program are intended to be operated over time to support continued compliance with the program's visibility goals.

Wyodak Regional Haze Compliance Requirements

In January 2011, the state of Wyoming submitted two Regional Haze SIPs, one addressing requirements for SO_2 and one addressing NO_X and particulate matter (PM). The EPA approved the SO_2 Regional Haze SIP in December 2012. The Regional Haze SIP for NO_x and PM submitted by the state of Wyoming required the installation of low NO_X burners (LNB) as BART for NO_X emissions at Wyodak. In December 2012, EPA proposed to disapprove the portion of the Wyoming NO_X and PM SIP requiring LNB as BART for NO_X emissions at Wyodak and impose a Federal Implementation Plan (FIP) requiring selective non-catalytic reduction (SNCR) technology as BART for NO_X emissions at Wyodak. Following a public comment period on its December 2012 proposal, in June 2013 EPA withdrew its original proposal and issued a revised proposal that continued to propose a FIP requiring SNCR to be installed at Wyodak. Following a public comment period on its re-proposal, EPA issued a final action, effective March 3, 2014, which approved and disapproved several aspects of the original state SIP. In this final action, EPA disapproved the Wyoming SIP as it pertained to NO_X controls at Wyodak and instituted a FIP requiring the installation of SCR at Wyodak within five years with a NO_X emission rate of 0.07 lb/MMBtu.

[3] The Final Amendments to the Regional Haze Rule and Guidelines for Best Available Retrofit Technology (BART) Determinations (70 Fed. Reg. 128; July 6, 2005) contemplated that states would complete SIPs and the EPA would issue final approval during 2008, which in turn would require BART controls to be installed at eligible units within five years (2013). Because EPA has not yet finalized its review and approval of certain states' SIPs, the five-year clock continues to get pushed out in time from a federal compliance perspective.

PacifiCorp appealed EPA's final action as it pertains to the SCR requirement at Wyodak to the U.S. Court of Appeals for the Tenth Circuit Court. A number of other entities, including the state of Wyoming and environmental groups, appealed other aspects of EPA's final action. PacifiCorp requested, and was granted, a judicial stay of EPA's action at it pertains to Wyodak pending resolution of the appeals. Under the terms of the stay, the original deadline for compliance, March 4, 2019, is extended on a day-for-day basis for the duration of the stay. A final decision on the appeal is expected in 2016.

Dave Johnston Unit 3 Regional Haze Compliance Requirements

The State of Wyoming's 2011 Regional Haze SIP for NO_X and PM required the installation of LNB as BART for NO_X emissions at Dave Johnston Unit 3. EPA's initial 2012 proposal was to disapprove the portion of the Wyoming NO_X and PM SIP requiring LNB as BART for NO_X emissions at Dave Johnston Unit 3 and institute a FIP requiring the installation of SNCR within five years. In its 2013 re-proposal, EPA proposed a FIP that included the installation of SCR at Dave Johnston Unit 3 as BART for NO_X emissions. Finally, in its final action, effective March 3, 2014, EPA disapproved the original SIP and instituted a FIP requiring the installation of SCR at Dave Johnston Unit 3 within five years (March 4, 2019), or, in the alternative, a firm commitment to shut down the unit by 2027.

PacifiCorp did not file an appeal regarding EPA's final action as it relates to emission control requirements at Dave Johnston Unit 3. However, the state of Wyoming filed an appeal with the U.S. Court of Appeals for the Tenth Circuit of the portion of EPA's final action that pertains to Dave Johnston Unit 3. The state of Wyoming sought and was granted a stay of EPA's action as it pertains to Dave Johnston Unit 3. However, the stay does not include an extension of the compliance deadline if EPA prevails in the appeal. Accordingly, the March 2019 deadline for installation of SCR at Dave Johnston Unit 3 remains in place; the alternative compliance option to commit to shut down the unit by 2027 similarly remains in place pending the outcome of the appeal. All of the appeals associated with EPA's final action on Wyoming's Regional Haze compliance were consolidated and a final decision is expected in 2016.

Naughton Unit 3 Regional Haze Compliance Requirements

The State of Wyoming's 2011 Regional Haze SIP for NO_X and PM required the installation of SCR and baghouse as BART for Naughton Unit 3. EPA's initial 2012 proposal, and its 2013 re-proposal, was to approve the portion of the Wyoming SIP requiring SCR and baghouse at Naughton Unit 3. In its final action, effective March 3, 2014, EPA ultimately approved Wyoming's original SIP. In its final action, EPA also indicated the intent to approve, once submitted, a revised Wyoming Regional Haze SIP reflecting the conversion of Naughton Unit 3 to natural gas by June of 2018 rather than the required installation of SCR and baghouse. Permits have been issued by the state of Wyoming to implement the conversion of Naughton Unit 3 to natural gas by June 2018. Wyoming has yet to submit its revised Regional Haze SIP incorporating this alternative compliance approach to EPA for review and approval. No parties to the appeal of EPA's final action have appealed that action as it pertains to Naughton Unit 3.

Cholla Unit 4 Regional Haze Compliance Requirements

In March 2011, the state of Arizona submitted its Regional Haze SIP to EPA for review. The SIP required the installation of LNB as BART for NO_X emissions at Cholla Unit 4. By final rule dated December 5, 2012, EPA disapproved portions of the Arizona Regional Haze SIP and issued a FIP. The FIP requires, among other things, installation of SCR on Cholla Unit 4 by December 5, 2017. The FIP also institutes an averaged NO_X emission rate of 0.055 lb/MMBtu for Cholla Units 2, 3, and 4. In January and February 2013, PacifiCorp, the state of Arizona, and other Arizona utilities filed separate appeals of EPA's FIP with the Ninth Circuit Court of Appeals. In February 2013, PacifiCorp and other Arizona utilities filed petitions for reconsideration with the EPA and filed requests for administrative stay of the FIP until judicial appeals are completed. In March 2013, PacifiCorp and other Arizona utilities filed motions for judicial stay of the FIP with the U.S. Ninth Circuit Court of Appeals until the appeals are complete.

On April 3, 2013, the court consolidated the various appeals into a single docket before a single judicial panel. On April 9, 2013, EPA granted various petitions for reconsideration for the NO_X rate only, but has taken no further action to date. Although EPA may propose a new NO_X rate at some time in the future, which will undergo public comment, it is not under any timing requirement to do so. EPA did not address the various requests for administrative stay in its April 9, 2013 action.

On September 9, 2013, the court denied the judicial motions for stay. The parties completed written briefing in January 2014. In February 2015, PacifiCorp, APS and EPA filed a joint motion asking the court to sever the appeals related to the Cholla plant (including Cholla Unit 4) from the consolidated docket and to hold the Cholla plant appeals in abeyance. The motion was intended to provide time to work with the state of Arizona and EPA to approve an alternative to the requirement to install SCR at Cholla Unit 4 by December 5, 2017. The court granted the motion for abeyance and requested that the parties to provide a status report to the court every 90 days. Although the order puts the appeal on hold for Cholla Unit 4, it does not stay the compliance date. If efforts to obtain approval of an alternative to the requirement to install SCR at Cholla Unit 4 are not successful, then the appeal related to Cholla Unit 4 will be reactivated.

Coal Analysis Methodology

Overview

Present value revenue requirement differential (PVRR(d)) analyses are used to quantify the benefit or cost of Regional Haze environmental compliance alternatives relative to a benchmark. In the case of Wyodak, Dave Johnston Unit 3, and Cholla Unit 4, compliance alternatives are compared to a benchmark case in which installation of SCR emission control equipment is assumed. In the case of Naughton Unit 3, a natural gas conversion is compared to an early retirement alternative benchmark. The PVRR(d) for a given environmental compliance alternative is calculated as the difference in system costs between two System Optimizer model simulations – a benchmark simulation and a simulation for an alternative compliance scenario.

For emission control installation decisions, the benchmark System Optimizer simulation includes costs for the emission control retrofit under consideration and prospective future environmental compliance costs required for the unit to continue operating as a coal-fueled unit. When environmental compliance alternatives do not include an emission control alternative, as is the case for Naughton Unit 3, the benchmark simulation reflects an early retirement scenario. In addition to reflecting Regional Haze compliance costs for both benchmark and alternative compliance scenarios, PacifiCorp's PVRR(d) analyses reflect cost estimates for known and prospective environmental compliance costs related to the Mercury and Air Toxics Standard (MATS), coal combustion residuals (CCR), effluent limit guidelines (ELG), cooling water intake structures as may be required under the Clean Water Act (CWA), and EPA's draft 111(d) rule, as applicable. In the alternative Regional Haze compliance cases, emission control retrofit costs are modified to align with the specific alternative. For example, an early retirement alternative to installation of SCR would remove SCR costs and avoid certain future prospective compliance costs beyond the assumed retirement date. In the case of an inter-temporal, fleet trade-off, and technology trade-off scenarios, an alternative compliance case might apply costs for different emission retrofit technologies, shift emission control retrofit costs to different coal units, and/or adjust the timing of assumed early retirement or natural gas conversion dates on specific units. In each System Optimizer simulation, resource portfolio impacts, including up-front capital and run-rate operating costs for new generating units, and system dispatch impacts of the specific compliance alternative being studied are captured.[4]

111(d) Assumptions

PacifiCorp's analysis of Wyodak and Naughton Unit 3 environmental compliance alternatives assume that PacifiCorp must meet its share of state emission rate targets set by EPA in its draft 111(d) rule targeting CO_2 emission reductions at existing generating units.[5] Table V3.1 shows the interim emission rate goal and the final emission rate target by state, which are assumed to apply to PacifiCorp's system. PacifiCorp does not have existing generation affected by EPA's draft 111(d) in Idaho or California. PacifiCorp does not apply EPA's draft emission rate targets from Arizona, Colorado, and Montana to its share of emissions from Cholla Unit 4, Craig and Hayden, and Colstrip Units 3 and 4. PacifiCorp does not have retail customers in these states and does not own any other generating resources in these states. Decisions on how these states will treat non-load serving entities in their 111(d) plans will ultimately determine 111(d) compliance impacts associated with long-term operations of Cholla Unit 4, Craig and Hayden, and Colstrip Units 3 and 4.

Table V3.1 – State 111(d) Emission Rate Assumptions

State	Interim Goal (Average 2020 – 2029) (lb CO2/MWh)	Final Target (2030 and Beyond) (lb CO2/MWh)
Wyoming	1,808	1,714
Utah*	1,378	1,322
Oregon	407	372
Washington	264	215

*EPA's calculation of the Utah target treated PacifiCorp's Lake Side 2 combined cycle plant as an existing resource. The emission rate for Utah assumes Lake Side 2 is correctly classified as under construction.

Modeling of EPA's draft 111(d) rule was implemented in three steps. First, an initial System Optimizer simulation was completed for each compliance alternative under two price curve scenarios summarized in the next section. In this initial System Optimizer simulation, it was

[4] The study period used to analyze Wyodak, Dave Johnston Unit 3, and Naughton Unit 3 compliance alternatives is aligned with the 2015 IRP planning horizon covering the period 2015 – 2034. The study period for Cholla Unit 4 Regional Haze compliance alternatives is aligned with the 2013 IRP planning horizon covering the period 2013–2032.

[5] Please refer to Volume I, Chapter 3 of PacifiCorp's 2015 IRP for a more detailed description of EPA's draft 111(d) rule.

assumed that new combined cycle plants will be regulated under 111(d). Given the low emission rate targets established by EPA in its draft rule for Idaho, Oregon, and Washington, PacifiCorp assumed that no new combined cycle plants can be built in these states. CO_2 emissions and generation from fossil units regulated under 111(d), new and existing renewable generation, and incremental Class 2 DSM energy savings were reported from this initial System Optimizer simulation, which served as inputs to the next modeling step.

In the second modeling step, CO_2 emissions, generation, and Class 2 DSM energy savings reported from the initial System Optimizer simulation were loaded into PacifiCorp's 111(d) Scenario Maker modeling tool.[6] As in the first step, this was done for each Regional Haze compliance alternative under two price curve scenarios. The 111(d) Scenario Maker calculates an annual 111(d) emission rate for Utah, Oregon, Wyoming, and Washington. The 111(d) emission rate was calculated by summing all 111(d)-affected CO_2 emissions and dividing those emissions by the sum of 111(d)-affected generation, allocated renewable energy, and accumulated incremental Class 2 DSM energy efficiency savings from each state by year.[7] If the 111(d) emission rate shows that PacifiCorp would not meet its share of a state's 111(d) emission rate target based on the initial System Optimizer results, the 111(d) Scenario Maker is then used to determine compliance actions that need to be implemented in order to meet PacifiCorp's share of a state's 111(d) emission rate target. The 111(d) compliance actions implemented in the 111(d) Scenario Maker for the Wyodak and Naughton Unit 3 environmental compliance analyses include:

- Flexible allocation of 111(d) attributes from system renewable resources and cumulative Class 2 DSM energy savings from Idaho and California, where PacifiCorp does not have a 111(d) compliance obligation;[8]
- Re-dispatch of existing west side natural gas combined cycle plants with assumed minimum annual generation levels at minimum capacity to ensure these resources can be used to meet operating reserves;
- Re-dispatch of existing coal units with minimum annual generation levels equivalent to a 70 percent annual average capacity factor and without falling below coal contract minimums, as applicable; and
- Addition of new system renewable resources, as required.

In the third modeling step, annual generation minimums and maximums from fossil-fired generation affected by 111(d) regulations and any incremental renewable resources as identified in the 111(d) Scenario Maker were reported and used as inputs to a final System Optimizer simulation. The final System Optimizer simulation, configured with annual re-dispatch minimum and maximum generation levels and with any incremental system renewable resources, as

[6] Please refer to Volume I, Chapter 7 of PacifiCorp's 2015 IRP for a more detailed description of the 111(d) Scenario Maker modeling tool.
[7] Allocated system renewable energy is based on system generation allocation factor assumptions under the 2010 revised multistate protocol, unless a resource is situs assigned to a specific state. PacifiCorp assumes that renewable energy only counts under 111(d) if PacifiCorp has rights to renewable energy credits from a given renewable resource. Class 2 DSM energy savings are accumulated beginning 2017.
[8] PacifiCorp assumes one 111(d) attribute for each MWh of energy from a renewable resource in which it retains ownership of a renewable energy credit.

applicable, was completed for each Wyodak and Naughton Unit 3 Regional Haze compliance alternative and for each of two different price curve scenarios.

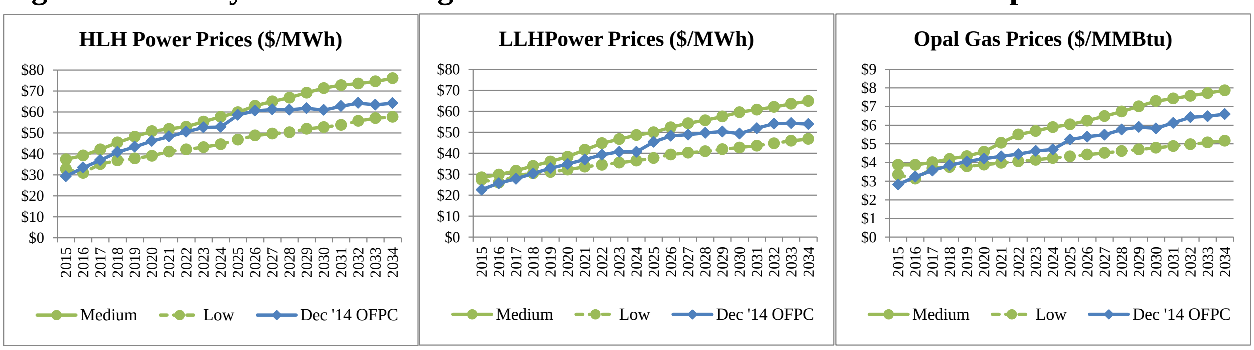
PacifiCorp's analysis of Dave Johnston Unit 3 Regional Haze compliance alternatives relies on quantifying the capital cost of an SCR and the associated cost to operate the SCR equipment over the period 2019 through 2027. The 111(d) modeling approach described above was not used in PacifiCorp's analysis of Dave Johnston Unit 3 because 111(d) compliance actions would not impact the fixed costs associated with installation of SCR. Similarly, the 111(d) modeling approach described above was not used in PacifiCorp's Cholla Unit 4 analysis, which was completed prior to EPA issuing its draft 111(d) rule. Nonetheless, implications of 111(d) regulations on the Dave Johnston Unit 3 and Cholla Unit 4 analyses are discussed later in this report.

Forward Price Curve Assumptions

Wyodak and Naughton Unit 3 Analyses

PacifiCorp's PVRR(d) analyses of Wyodak and Naughton Unit 3 Regional Haze compliance alternatives were performed using medium and low price curve scenarios. The medium price scenario is based on PacifiCorp's September 2014 official forward price curve (OFPC), consistent with medium price assumptions used throughout the 2015 IRP. Likewise, the low price scenario is consistent with low price assumptions used throughout the 2015 IRP.[9] The medium and low price assumptions, which were locked down for IRP modeling in October 2014, straddle PacifiCorp's most recent December 2014 OFPC. Figure V3.1 summarizes heavy load hour (HLH) and light load hour (LLH) wholesale power prices and natural gas prices assumed for the Wyodak and Naughton Unit 3 Regional Haze compliance analyses alongside PacifiCorp's December 2014 OFPC.[10]

Figure V3.1 – Wyodak and Naughton Unit 3 Forward Price Curve Assumptions



*Note, for presentation purposes, power prices reflect the average of Mid-Columbia and Palo Verde prices. Opal is the natural gas market hub most applicable to natural gas conversion alternatives studied in the Wyodak and Naughton Unit 3 analyses.

Dave Johnston Unit 3 Analysis

The option to shut down Dave Johnston Unit 3 by the end of 2027 as an alternative to installation of SCR coincides with the currently approved depreciable life of the Dave Johnston plant.

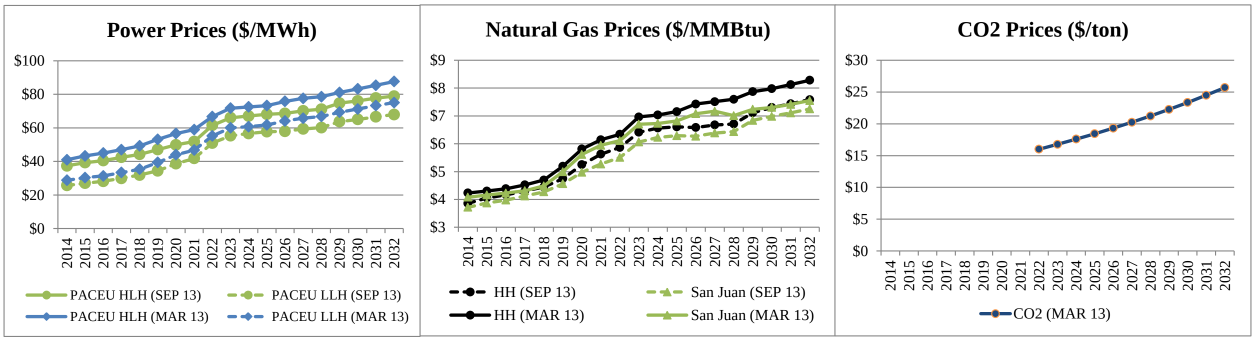
[9] Please refer to Volume I, Chapter 7 of the 2015 IRP for a description of the price scenarios used in the 2015 IRP.
[10] HLH prices cover to hours ending 7 through 22 PPT, Monday through Saturday, excluding NERC holidays. LLH prices cover all other hours.

Consequently, PacifiCorp's analysis comparing a scenario in which SCR emission control equipment is installed in 2019 assuming an end-of-life retirement at the end of the 2027 with a scenario in which SCR can be avoided with a firm commitment to retire the unit at the end of 2027 relies on quantifying the up-front SCR capital costs and the associated cost to operate the SCR equipment over the period 2019 through 2027. As such, forward price curve assumptions do not play a role in PacifiCorp's analysis of Dave Johnston Unit 3.

Cholla Unit 4

PacifiCorp performed an initial analysis of Cholla Unit 4 compliance alternatives using its March 2013 OFPC and an updated and expanded analysis of Cholla Unit 4 compliance alternatives using its September 2013 OFPC. Both price curves included a CO_2 price beginning 2022 at \$16/ton and escalating to over \$25/ton by 2032.[11] Nominal levelized power prices and natural gas prices in the September 2013 OFPC were approximately nine percent lower than those in the March 2013 OFPC over the 2018 to 2032 timeframe. Figure V3.2 summarizes wholesale power prices, natural gas prices, and CO_2 prices assumed for the Cholla Unit 4 analysis.

Figure V3.2 – Cholla Unit 4 Forward Price Curve Assumptions



* Note, for presentation purposes, power prices are shown for PacifiCorp's east system with deliveries in Utah (PACEU) as a flat product. San Juan is the natural gas market hub assumed to supply Cholla Unit 4 in gas conversion scenarios.

Wyodak Analysis

Overview

Table V3.2 summarizes the compliance scenarios studied for Wyodak. Base compliance alternatives include installation of SCR at Wyodak in 2019, an early retirement of Wyodak in 2019, and a natural gas conversion of Wyodak in 2019. In each of these scenarios, it is assumed that the compliance schedule for Wyodak as outlined in EPA's FIP for Wyoming is met and that the Dave Johnston plant is retired at the end of 2027, its currently approved depreciable life. Inter-temporal and fleet-trade off compliance alternatives represent potential scenarios that might achieve emission reductions contributing to long-term visibility improvements in affected Class I areas at a lower cost to PacifiCorp's customers. A potentially acceptable inter-temporal or fleet trade-off compliance solution would require that the state of Wyoming incorporate the alternative as a recommended amendment to its SIP for EPA review and approval. The SIP amendment and EPA review and approvals would include the appropriate public notice and

[11] PacifiCorp's analysis of Cholla Unit 4 Regional Haze compliance alternatives was performed before issuance of EPA's draft 111(d) rule. Implications of 111(d) regulations are discussed later in this report.

comment processes. As in the base compliance alternatives, each of the inter-temporal alternatives assumes that the Dave Johnston plant is retired at the end of 2027. Fleet trade-off scenarios evaluate the cost implications of avoiding SCR at Wyodak, either via a firm commitment to retire the Dave Johnston plant by the end of 2027 or via a commitment to convert Dave Johnston Units 1 and 2 to natural gas in 2022.

Table V3.2 – Wyodak Compliance Scenarios

Base Compliance Alternatives					
Case Identifier	Wyodak	Dave Johnston 1	Dave Johnston 2	Dave Johnston 3	Dave Johnston 4
SCR	SCR (3/4/2019)	Retire (12/31/2027)	Retire (12/31/2027)	Retire (12/31/2027)	Retire (12/31/2027)
Early Retirement	Retire (3/4/2019)	Retire (12/31/2027)	Retire (12/31/2027)	Retire (12/31/2027)	Retire (12/31/2027)
Gas Conversion	Conv. (6/1/2019)	Retire (12/31/2027)	Retire (12/31/2027)	Retire (12/31/2027)	Retire (12/31/2027)
Inter-temporal (IT) Compliance Alternatives					
Case Identifier	Wyodak	Dave Johnston 1	Dave Johnston 2	Dave Johnston 3	Dave Johnston 4
IT-1	SNCR (3/4/2019) Retire (12/31/2030)	Retire (12/31/2027)	Retire (12/31/2027)	Retire (12/31/2027)	Retire (12/31/2027)
IT-2	Conv. (6/1/2022)	Retire (12/31/2027)	Retire (12/31/2027)	Retire (12/31/2027)	Retire (12/31/2027)
IT-3	Retire (12/31/2027)	Retire (12/31/2027)	Retire (12/31/2027)	Retire (12/31/2027)	Retire (12/31/2027)
Fleet Trade-off (FT) Compliance Alternatives					
Case Identifier	Wyodak	Dave Johnston 1	Dave Johnston 2	Dave Johnston 3	Dave Johnston 4
FT-1	No SCR	Retire (12/31/2027)	Retire (12/31/2027)	Retire (12/31/2027)	Retire (12/31/2027)
FT-2	No SCR	Conv. (6/1/2022) Retire (12/31/2027)	Conv. (6/1/2022) Retire (12/31/2027)	Retire (12/31/2027)	Retire (12/31/2027)

Compliance Timeline

PacifiCorp has considered compliance alternatives to the Wyodak SCR requirement in EPA's FIP for Wyoming, which include: (1) early retirement; (2) cease coal-fueled operations by converting the unit to operate on natural gas; and (3) technology and inter-temporal tradeoffs. An acceptable alternate compliance solution would require that the state of Wyoming incorporate the alternative as a recommended amendment to its SIP for EPA review and approval. The SIP amendment and EPA review and approvals would include the appropriate public notice and comment processes.

Installation of SCR

A schedule to install SCR on Wyodak, with a fall 2018 tie-in outage to achieve an assumed March 4, 2019 compliance date is presented in Appendix V3-A, Figure V3-A.1. The SCR project entails installing the reactor module(s) on the unit in the boiler flue gas exit path between the economizer outlet and the air preheater inlet. Other work that may be required includes:

- Installing an ammonia receiving and delivery system.

- Installing a SCR reactor cleaning system.
- An economizer modification to limit SCR reactor inlet temperatures to avoid catalyst damage.
- Adding an economizer exit gas temperature control system to extend the operating load range of the unit, if economically justified.
- To provide NFPA 85 Code compliance, structurally reinforcing; the boiler; forced draft equipment and ductwork; and flue gas path equipment and ductwork. Alternatively and/or in addition, control system mitigations may be implemented.
- Potential modifications to the boiler induced draft equipment.
- Potential modifications to the unit auxiliary power system.

Installation of SNCR

A schedule to install SNCR on Wyodak by an assumed compliance date of March 4, 2019, is presented in Appendix V3-A, Figure V3-A.2. If a SNCR is needed, the project would entail installation of several levels of urea solution injection equipment in the boiler at critical temperature zones. Other work that may be required includes:

- Installing a urea solution receiving and transport system.
- Boiler modifications to accommodate urea solution injection locations.

Natural Gas Conversion

A schedule to convert Wyodak to 100 percent natural gas fueling is presented in Appendix A, Figure V3-A.3. The implementation schedule assumes the unit would be converted to natural gas fueling in 2019 after coal fueling is discontinued on December 31, 2018. Thereafter, a six-month tie-in outage is planned. The schedule would shift out in time under potential compliance scenarios that allow for continued coal operation beyond December 31, 2018. The following scope of work is anticipated to be required:

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

Early Retirement

A schedule for an early retirement scenario of Wyodak is presented in Appendix A, Figure V3-A.4. The implementation schedule assumes the unit would cease coal-fired operation by March 4, 2019. The schedule would shift out in time under potential compliance scenarios that allow for continued coal operation beyond March 4, 2019. Unit retirement work would include:

- Demolition, removal and disposal of electric generating equipment and ancillary systems.
- Reclamation of the site.

Annual Non-fuel Expenditure Assumptions

Annual non-fuel planned expenditures include environmental capital costs, run-rate capital costs, run-rate operations and maintenance (O&M) costs, fixed firm natural gas transportation costs, and natural gas pipeline lateral costs, as applicable. In addition, costs associated with termination of an existing coal supply agreement (CSA), which extends through 2022, are included in PacifiCorp's analysis. Detailed annual non-fuel planned expenditures for each of the Wyodak compliance alternatives are provided in Appendix V3-B. [redacted]

The 2019 Wyodak natural gas conversion case includes [redacted] (PacifiCorp share) in 2019 run-rate capital expenditures to complete the conversion of Wyodak and further includes annual fixed costs for natural gas transportation, including levelized costs for a new pipeline lateral, which would be required to transport natural gas from WBI Energy to the Wyodak plant.[12] Case IT-2 includes [redacted] (PacifiCorp share) in 2022 run-rate capital expenditures to complete a conversion Wyodak and similarly includes firm natural gas transportation and new pipeline lateral costs.[13] Case FT-2 includes [redacted] in 2022 run-rate capital expenditures to complete the conversion of Dave Johnston Units 1 and 2. Firm natural gas transportation costs and pipeline lateral costs for Case FT-2 assume natural gas is transported over the Tallgrass Interstate Gas Transmission system.[14]

PacifiCorp and Wyodak Resourced Development Corporation, a subsidiary of Black Hills Corporation, are parties to a long-term coal supply agreement (CSA), which is the sole supply for the Wydak plant through 2022. In the 2019 Early Retirement Case, liquidated damage (LD) payouts mitigated via assumed deliveries to the Dave Johnston plant total [redacted] over the 2019 – 2022 timeframe. In the 2019 Natural Gas Conversion Case, mitigated LD payments total [redacted] over the 2019 – 2022 timeframe. Under Case IT-2, mitigated LD payments total [redacted] in 2022.

Resource Portfolio Results

In the 2019 Early Retirement Case, the loss of Wyodak creates an incremental capacity need beginning in the summer of 2019, which drives the need for replacement resources over the 2019 to 2034 timeframe. Figure V3.3 summarizes the cumulative change in resource portfolio capacity when Wyodak retires in the spring of 2019 as compared to the continued coal operation case with installation of SCR. Positive values show cumulative resource portfolio additions and negative values show the cumulative capacity of resources that are removed from the portfolio when Wyodak is assumed to retire in 2019. Notable resource portfolio changes resulting from an early retirement of Wyodak in 2019 include:

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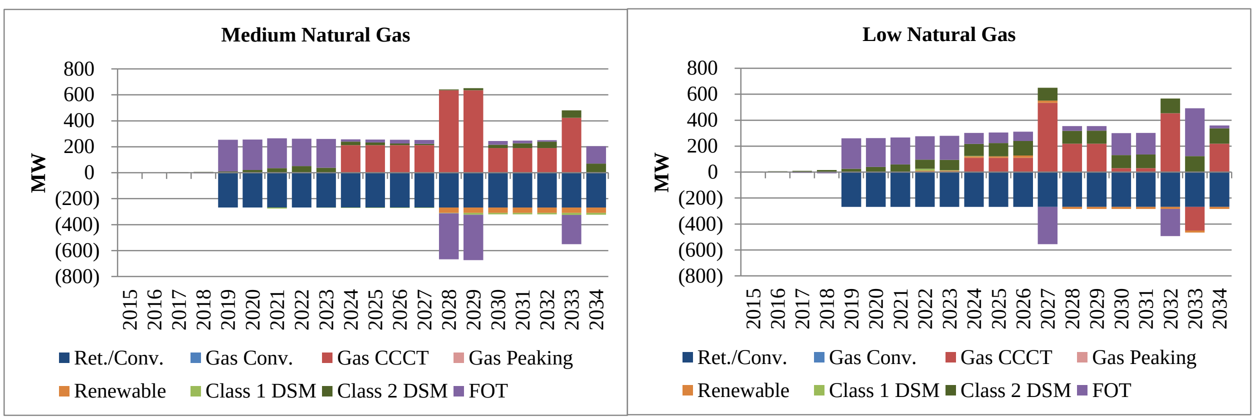
[12] It is assumed that WBI Energy would build and operate the lateral and charge PacifiCorp for its estimated [redacted] cost. The pipeline lateral capital cost [redacted]

[13] WBI Energy pipeline lateral costs for Case IT-2 are estimated at [redacted]

[14] Tallgrass Interstate Gas Transmission lateral costs are estimated at [redacted]

- In both the medium and low natural gas price scenarios, front office transactions (FOTs) and incremental Class 2 DSM replace 268 MW of retired Wyodak coal capacity over the period 2019 through 2023.
- In the medium natural gas price scenario:
  - A larger 635 MW CCCT plant is added in 2024, increasing CCCT capacity by 212 MW over the period 2024 through 2027.
  - A 423 MW CCCT plant is accelerated from 2030 to 2028, displacing FOTs and renewable capacity over the period 2028 – 2029.
  - A larger 635 MW CCCT plant is added in 2033, displacing a 401 MW CCCT plant. By the end of the study period, changes in the size and timing of CCCT resource additions defer the need for 2034 CCCT plant.
- In the low natural gas price scenario:
  - A larger 423 MW CCCT plant is added in 2024, increasing CCCT capacity by 110 MW over the period 2024 through 2026. Over this period, more FOTs and Class 2 DSM resources are added to the portfolio when compared to the medium natural gas price scenario.
  - A 423 MW CCCT plant is accelerated into 2027, deferring a 313 MW CCCT plant in 2028. By 2030, CCCT capacity changes between resource portfolios are minimal, with replacement capacity largely being met with incremental Class 2 DSM and FOT resources.
  - Changes in the timing of CCCTs from 2032 through 2034 reflect an incremental addition of a 423 MW CCCT plant in 2032, reduced CCCT capacity in 2033, and the addition of a 401 MW CCCT plant in 2034. Over this period, changes in CCCT capacity are offset by Class 2 DSM and FOTs.

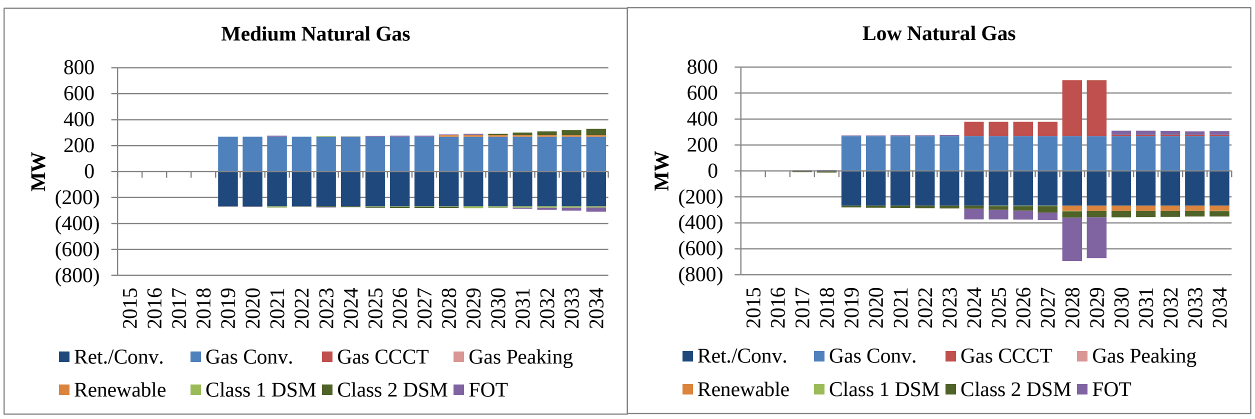
Figure V3.3 – Cumulative Increase/(Decrease) in Portfolio Resources for the 2019 Wyodak Early Retirement Case



In the 2019 Natural Gas Conversion Case, system capacity is maintained; however, with the loss of energy from a baseload plant that is replaced by an inefficient gas-fired peaking resource, system dispatch is impacted, which in turn can influence the economic selection of future resources in the portfolio. Figure V3.4 summarizes the cumulative change in resource portfolio capacity when Wyodak is converted to natural gas by the summer of 2019 as compared to the continued coal operation case with installation of SCR. Positive values show cumulative resource portfolio additions and negative values show the cumulative capacity of resources that are removed from the portfolio when Wyodak is assumed to retire in 2019. Notable resource portfolio changes resulting from a 2019 Wyodak natural gas conversion include:

- In the medium and low natural gas price scenarios, the loss of coal-fired capacity at Wyodak is offset by a gain in gas-fired capacity at Wyodak over the period 2019 through 2034.
- In the medium natural gas price scenario, cumulative Class 2 DSM resources offset the need for FOTs.
- In the low natural gas price scenario:
    - A larger 423 MW CCCT plant is added in 2024, increasing CCCT capacity by 110 MW over the period 2024 through 2027, which displaces FOTs.
    - A larger 635 MW CCCT plant is added in 2028, increasing CCCT capacity by another 322 MW in 2028 and 2029, which displaces more FOTs.
    - By 2030, differences in cumulative CCCT capacity are small. Over the period 2030 through 2034, incremental Class 1 DSM and FOTs are offset by reduced Class 2 DSM and renewable resources.

Figure V3.4 – Cumulative Increase/(Decrease) in Portfolio Resources for the 2019 Wyodak Gas Conversion Case



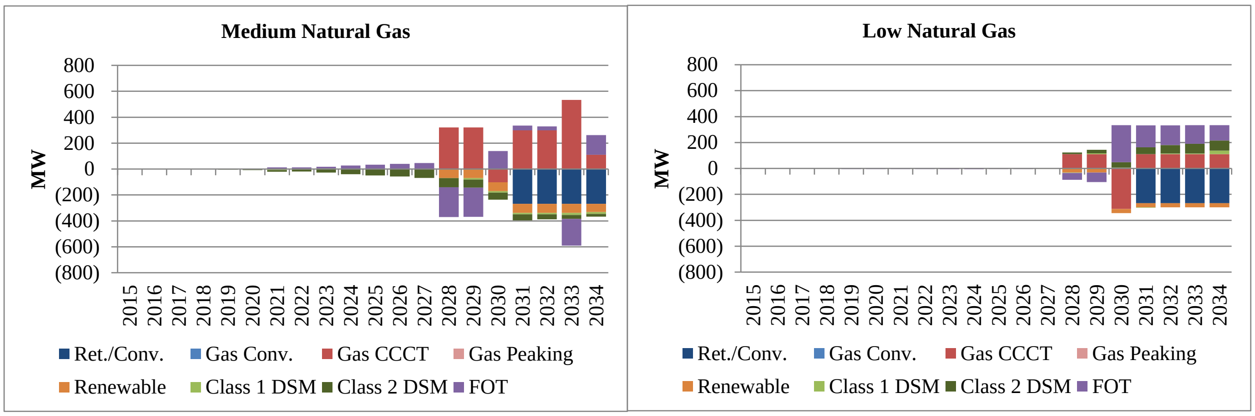
In Case IT-1, the loss of Wyodak creates an incremental capacity need beginning in the summer of 2031, which affects selection of replacement resources most notably beginning in 2028 after the Dave Johnston plant is assumed to retire. Figure V3.5 summarizes the cumulative change in resource portfolio capacity when Wyodak retires at the end of 2030 as compared to the continued coal operation case with installation of SCR. Positive values show cumulative resource portfolio additions and negative values show the cumulative capacity of resources that are removed from the portfolio when Wyodak is assumed to retire in at the end of 2030. Notable resource portfolio changes resulting from an early retirement of Wyodak at the end of 2030 include:

- In the medium natural gas price scenario:
    - Through 2027, modest increases in FOTs offset Class 2 DSM resources.
    - A larger 635 MW CCCT plant is added in 2028, increasing CCCT capacity by 322 MW in 2028 and 2029, which displaces renewable resources, Class 2 DSM, and FOTs.
    - With the larger CCCT added in 2028, CCCT plant additions in 2030 are deferred by one year to 2031, which coincides with the first year in which it is assumed Wyodak is shut down.

- A larger 635 MW CCCT plant is added in 2033, increasing CCCT capacity by an additional 234 MW, which defers the need for a 423 MW CCCT plant in 2034.

- In the low natural gas price scenario:
  - A larger 423 MW CCCT plant is added in 2028, increasing CCCT capacity by 110 MW in 2028 and 2029. Additional Class 2 DSM resources are also added. Combined, the incremental CCCT and Class 2 DSM resources displace renewable resources and FOTs.
  - With the larger CCCT added in 2028, a 423 MW CCCT plant is deferred from 2030 to 2031, which coincides with the first year in which it is assumed Wyodak is shut down.
  - From 2031 through 2034, Wyodak replacement capacity is comprised of the additional CCCT capacity supplemented with Class 2 DSM and FOTs.

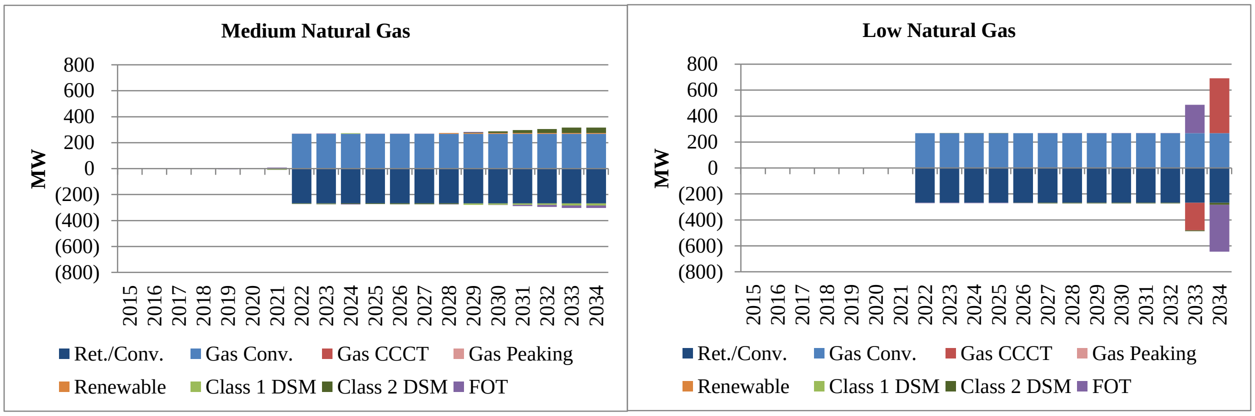
Figure V3.5 – Cumulative Increase/(Decrease) in Portfolio Resources for the 2019 SNCR and 2030 Wyodak Early Retirement Case (Case IT-1)



In Case IT-2, system capacity is maintained with a 2022 natural gas conversion of Wyodak; however, with the loss of energy from a baseload plant that is replaced by an inefficient gas-fired peaking resource, system dispatch is impacted, which in turn can influence the economic selection of future resources in the portfolio. Figure V3.6 summarizes the cumulative change in resource portfolio capacity when Wyodak is converted to natural gas by the summer of 2022 as compared to the continued coal operation case with installation of SCR. Positive values show cumulative resource portfolio additions and negative values show the cumulative capacity of resources that are removed from the portfolio when Wyodak is assumed to convert to a natural gas-fired resource in 2022. Notable resource portfolio changes include:

- In the medium and low natural gas price scenarios, the loss of coal-fired capacity at Wyodak is offset by a gain in gas-fired capacity at Wyodak over the period 2022 through 2034.
- In the medium natural gas price scenario, additional Class 2 DSM resources offset FOTs and Class 1 DSM.
- In the low natural gas price scenario:
  - A smaller 423 MW CCCT plant is added in 2033, decreasing CCCT capacity by 212 MW, which is offset by increased FOTs.
  - A new 635 MW CCCT plant is added in 2034, which displaces FOTs.

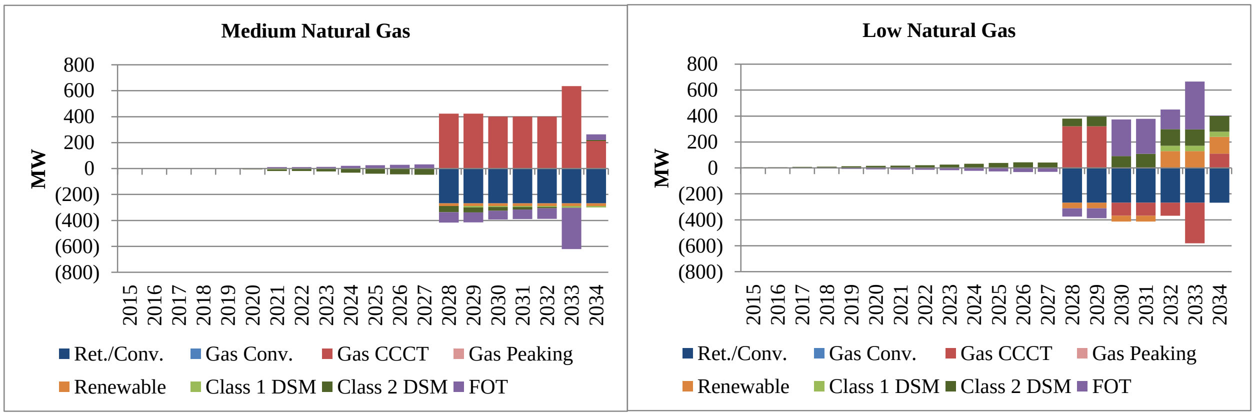
Figure V3.6 – Cumulative Increase/(Decrease) in Portfolio Resources for the 2022 Gas Conversion Case (Case IT-2)



In Case IT-3, the loss of Wyodak creates an incremental capacity need beginning in the summer of 2028. Figure V3.7 summarizes the cumulative change in resource portfolio capacity when Wyodak retires at the end of 2027 as compared to the continued coal operation case with installation of SCR. Positive values show cumulative resource portfolio additions and negative values show the cumulative capacity of resources that are removed from the portfolio when Wyodak is assumed to retire in at the end of 2027. Notable resource portfolio changes include:

- In the medium natural gas price scenario:
  - A 423 MW CCCT plant is added in 2028, which reduces renewable resources, Class 2 DSM and FOTs.
  - A larger 635 MW CCCT plant is added in 2033, adding an incremental 234 MW of CCCT capacity to the portfolio in 2033. The additional CCCT capacity displaces FOTs.
  - With the additional CCCT capacity added in 2028 and 2033, the need for a 423 CCCT plan in 2034 is eliminated.
- In the low natural gas price scenario:
  - A 313 MW CCCT plant is replaced by a 635 MW CCCT plant in 2028. Accumulated additional Class 2 DSM resources reduce renewable resources and FOTs through 2029.
  - The additional CCCT capacity displaces a 423 MW CCCT plant in 2030. Additional FOTs and Class 2 DSM resources are needed in 2030 and 2031, and additional renewables are added in 2032.
  - In 2033, a 635 MW CCCT plant is replaced with a 423 MW CCCT plant. An additional 423 MW CCCT plant is added in 2034.

Figure V3.7 – Cumulative Increase/(Decrease) in Portfolio Resources for the 2027 Wyodak Early Retirement Case (Case IT-3)

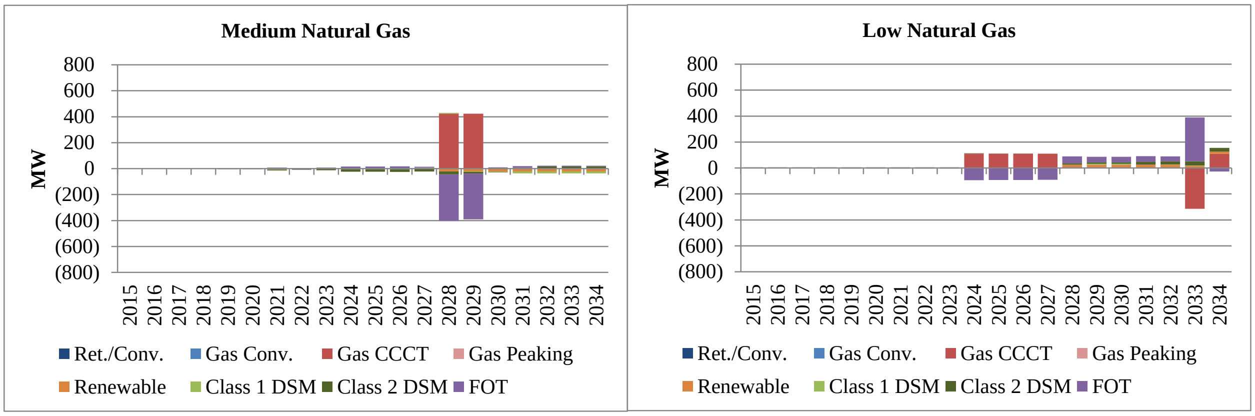


In Case FT-1, modest changes to the capacity rating of Wyodak when SCR is avoided drives slight changes to the type and timing of resources over the planning horizon.[15] Figure V3.8 summarizes the cumulative change in resource portfolio capacity when Wyodak continues operating as a coal-fired resource without SCR as compared to the continued coal operation case with installation of SCR. Positive values show cumulative resource portfolio additions and negative values show the cumulative capacity of resources that are removed from the portfolio when Wyodak is assumed to retire in 2019. Notable resource portfolio changes resulting from an early retirement of Wyodak in 2019 include:

- In the medium natural gas price scenario:
    - A 423 MW CCCT plant is accelerated from 2030 to 2028, which reduces FOTs over the 2028 to 2029 timeframe.
- In the low natural gas price scenario:'
    - A 423 MW CCCT replaces a 313 MW CCCT in 2024, which reduces FOTs over the 2023 through 2027 timeframe.
    - In 2028, two 423 MW CCCT plants replace a 635 MW CCCT plant and a 313 MW CCCT plant.
    - A 635 MW CCCT plant is replaced by a 313 MW CCCT plant in 2033 and a 423 MW CCCT plant is added in 2034.

[15] Installation of SCR is avoided under Case FT-1, which avoids a 2.4 MW de-rate on the 268 MW unit (PacifiCorp share).

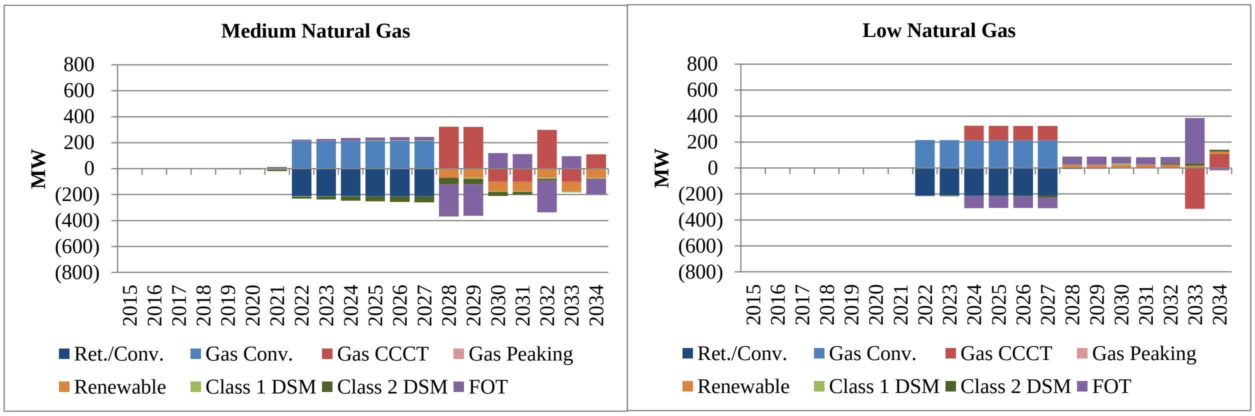
Figure V3.8 – Cumulative Increase/(Decrease) in Portfolio Resources for the No Wyodak SCR Case (Case FT-1)



In Case FT-2, system capacity is maintained with a 2022 natural gas conversion of Dave Johnston Units 1 and 2; however, with the loss of energy from baseload units that is replaced by inefficient gas-fired peaking resources, system dispatch is impacted, which in turn can influence the economic selection of future resources in the portfolio. Figure V3.9 summarizes the cumulative change in resource portfolio capacity when Dave Johnston Units 1 and 2 are converted to natural gas by the summer of 2022 as compared to the Wyodak continued coal operation case with installation of SCR in which Dave Johnston Units 1 and 2 continue operating as coal-fired assets through 2027. Positive values show cumulative resource portfolio additions and negative values show the cumulative capacity of resources that are removed from the portfolio when Dave Johnston Units 1 and 2 are assumed to convert to natural gas-fired resources in 2022. Notable resource portfolio changes include:

- In the medium and low natural gas price scenarios, the loss of coal-fired capacity at Dave Johnston Units 1 and 2 is offset by a gain in gas-fired capacity at these same units over the period 2022 through 2027.
- In the medium natural gas price scenario:
  - A 635 MW CCCT plant replaces a 313 MW CCCT plant in 2028 which offsets renewable resources, Class 2 DSM, and FOTs.
  - A 423 MW CCCT plant is eliminated in 2030, which increases FOTs in 2030 and 2031.
  - A 401 MW CCCT plant is accelerated from 2033 to 2032, and a 635 MW CCCT plant replaces a 423 MW CCCT plant in 2034.
- In the low natural gas price scenario:
  - A 423 MW CCCT plant replaces a 313 MW CCCT plant in 2024, which reduces FOTs over the period 2024 through 2027.
  - In 2028, two 423 MW CCCT plants replace a 635 MW CCCT plant and a 313 MW CCCT plant.
  - A 635 MW CCCT plant is replaced by a 313 MW CCCT plant in 2033 and a 423 MW CCCT plant is added in 2034.

Figure V3.9 – Cumulative Increase/(Decrease) in Portfolio Resources for the No Wyodak SCR and 2022 Dave Johnston 1&2 Gas Conversion Case (Case FT-2)



PVRR(d) Results

Table V3.3 summarizes the PVRR(d) results for compliance alternative relative to a benchmark case in which Wyodak continues operating as a coal-fueled generating unit with installation of SCR. On a present value revenue requirement basis, the results show:

- Installation of SCR is [redacted] and [redacted] to retiring Wyodak in 2019 under the medium and low natural gas price scenarios, respectively.
- Installation of SCR is [redacted] and [redacted] to converting Wyodak to natural gas in 2019 under the medium and low natural gas price scenarios, respectively.
- Among the inter-temporal trade-off cases, avoiding SCR by committing to retire Wyodak by the end of 2027 (Case IT-3) is least cost at [redacted] and [redacted] to installing SCR in the medium and low natural gas price scenarios, respectively.
- Among fleet trade-off cases, avoiding SCR altogether (Case FT-1) is least cost at [redacted] and [redacted] to installing SCR in the medium and low natural gas price scenarios, respectively.

Table V3.3 – Summary of Wyodak PVRR(d) Results

	PVRR(d) Benefit/(Cost) of SCR vs. Each Alternative ($m)	
Case Identifier	Medium Natural Gas	Low Natural Gas
Early Retirement	[redacted]	[redacted]
Gas Conversion	[redacted]	[redacted]
IT-1	[redacted]	[redacted]
IT-2	[redacted]	[redacted]
IT-3	[redacted]	[redacted]
FT-1	[redacted]	[redacted]
FT-2	[redacted]	[redacted]

Table V3.4 summarizes line item PVRR system cost for the continued coal operation with SCR case and Case FT-1 along with the PVRR(d) benefit/(cost) of Case FT-1 for the medium natural gas price scenario. The table also shows line item detail for the SCR case and Case IT-3 under low natural gas price assumptions.

Table V3.4 – Line Item Detail of Case FT-1 (Medium Gas) and IT-3 (Low Gas) as Compared to Installation of SCR at Wyodak in 2019 ($ million)

	Medium Natural Gas			Low Natural Gas		
	PVRR of System Costs with Wyodak SCR	PVRR of System Costs under Case FT-1	PVRR(d) Ben./(Cost) of SCR vs. FT-1	PVRR of System Costs with Wyodak SCR	PVRR of System Costs under Case IT-3	PVRR(d) Ben./(Cost) of SCR vs. IT-3
System Variable Costs						
Fuel, FOTs	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Variable O&M	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Net System Balancing	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Total Variable	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
System Fixed Costs						
New Resource Capital/Run-rate	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Existing Resource Capital/Run-rate	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Decommissioning/Stranded Cost	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Contracts	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Incremental DSM	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Transmission	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Total Fixed	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Total Costs						
Total	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

The following summarizes line-item PVRR(d) results for Case FT-1 under medium natural gas price assumptions (quoted figures are on a present value revenue requirement basis calculated through the 20-year planning horizon):

- System fuel costs increase by [redacted], largely driven by the acceleration of a CCCT plant from 2030 to 2028, partially offset by reduced FOT costs.
- Reduced non-fuel variable O&M costs from Wyodak total [redacted], which is partially offset by increased system variable O&M costs totaling [redacted].
- Net system balancing benefits increase by approximately [redacted], more than offsetting the increase in system fuel costs net of FOTs.
- Driven by the acceleration of a CCCT plant from 2030 to 2028, new resource capital costs and run-rate operating costs increase the cost of Case FT-1 by [redacted].
- Reduced capital and run-rate operating costs at Wyodak, driven largely by avoiding SCR capital costs, accounts for nearly all of the [redacted] capital and run-rate cost reduction under Case FT-1.
- With fewer Class 2 DSM resources under Case FT-1, system DSM costs are reduced by [redacted].
- In aggregate, reduced variable and fixed cost expenditures at Wyodak lower costs by [redacted], which is partially offset by increased system fixed and variable costs totaling [redacted]. The net benefit under Case FT-1 as compared to installation of SCR in 2019 is [redacted].

The following summarizes line-item PVRR(d) results for Case IT-3 under low natural gas price assumptions (quoted figures are on a present value revenue requirement basis calculated through the 20-year planning horizon):

- System fuel costs increase by [redacted], largely driven by changes in the timing and size of CCCT plants net of changes in FOT costs.

- Reduced non-fuel variable O&M costs from Wyodak total [redacted], which is offset by increased system variable O&M costs totaling [redacted].
- Net system balancing benefits increase by approximately [redacted].
- Driven by changes in the timing and size of CCCT plants, new resource capital costs and run-rate operating costs increase the cost of Case IT-3 by [redacted].
- Reduced capital and run-rate operating costs at Wyodak, driven largely by avoiding SCR capital costs and earlier retirement by 2022, accounts for nearly all of the [redacted] capital and run-rate cost reduction under Case IT-3.
- With more Class 2 DSM resources, system DSM costs are increased by [redacted].
- In aggregate, reduced variable and fixed cost expenditures at Wyodak lower costs by [redacted], which is partially offset by increased system fixed and variable costs totaling [redacted]. The net benefit under Case IT-3 as compared to installation of SCR in 2019 is [redacted].

Discussion

PacifiCorp's financial analysis shows that inter-temporal and fleet trade-off compliance alternatives may be lower cost than installation of SCR by an assumed compliance date of March 2019. However, PacifiCorp has appealed EPA's FIP requiring SCR at Wyodak, and other parties have also filed an appeal under a variety of opposition points. PacifiCorp and other parties asked the court to stay EPA's final FIP pending resolution of the appeals, and the court has granted the requested stay. PacifiCorp's financial analysis shows that customer benefits are maximized when the 2019 SCR is avoided, consistent with the Company's ongoing appeal. PacifiCorp expects the court to make a final decision on the appeals in 2016. PacifiCorp will continue to support its appeal of the portion of EPA's FIP that requires installation of SCR at Wyodak. If, following appeal, EPA's final FIP as it pertains to Wyodak is upheld, PacifiCorp will update its evaluation of alternative compliance strategies that will meet any new requirements, as applicable, and provide the associated analysis in a future IRP or IRP Update.

Consideration of 111(d) compliance risks aligns with PacifiCorp's appeal of EPA's FIP requiring SCR at Wyodak. Eliminating the SCR requirement, will save customers tens of millions in incremental capital expenditures and retains compliance planning flexibility associated with EPA's draft 111(d) rule.

Dave Johnston Unit 3 Analysis

Overview

EPA's final Regional Haze FIP in Wyoming requires the installation of SCR at Dave Johnston Unit 3 by March 2019, or a commitment to shut down Dave Johnston Unit 3 by the end of 2027. The option to commit to shutting down Dave Johnston Unit 3 by the end of 2027 coincides with the currently approved depreciable life of the Dave Johnston plant in all states but Oregon.[16] Considering potential 111(d) compliance uncertainties, PacifiCorp has maintained its planning assumption that coal plants will retire at the end of their depreciable lives as currently approved in all states but Oregon. Consequently, an analysis comparing a scenario in which SCR emission control equipment is installed in 2019 assuming an end-of-life retirement at the end of the 2027

[16] The currently approved depreciable life of the Dave Johnston plant in Oregon is 2023.

with a scenario in which SCR can be avoided with a firm commitment to retire the unit at the end of 2027 comes down to quantifying the cost of the SCR and the associated cost to operate the SCR equipment over the period 2019 through 2027.

Compliance Timeline

A schedule to install SCR on Dave Johnston Unit 3, with a fall 2018 tie-in outage to achieve an assumed March 4, 2019 compliance date is presented in Appendix V3-C, Figure V3-C.1. The SCR project entails installing the reactor module(s) on the unit in the boiler flue gas exit path between the economizer outlet and the air preheater inlet. Other work that may be required includes:

- Installing an ammonia receiving and delivery system.
- Installing a SCR reactor cleaning system.
- An economizer modification to limit SCR reactor inlet temperatures to avoid catalyst damage.
- Adding an economizer exit gas temperature control system to extend the operating load range of the unit, if economically justified.
- To provide NFPA 85 Code compliance, structurally reinforcing; the boiler; forced draft equipment and ductwork; and flue gas path equipment and ductwork. Alternatively and/or in addition, control system mitigations may be implemented.
- Potential modifications to the boiler induced draft equipment.
- Potential modifications to the unit auxiliary power system.

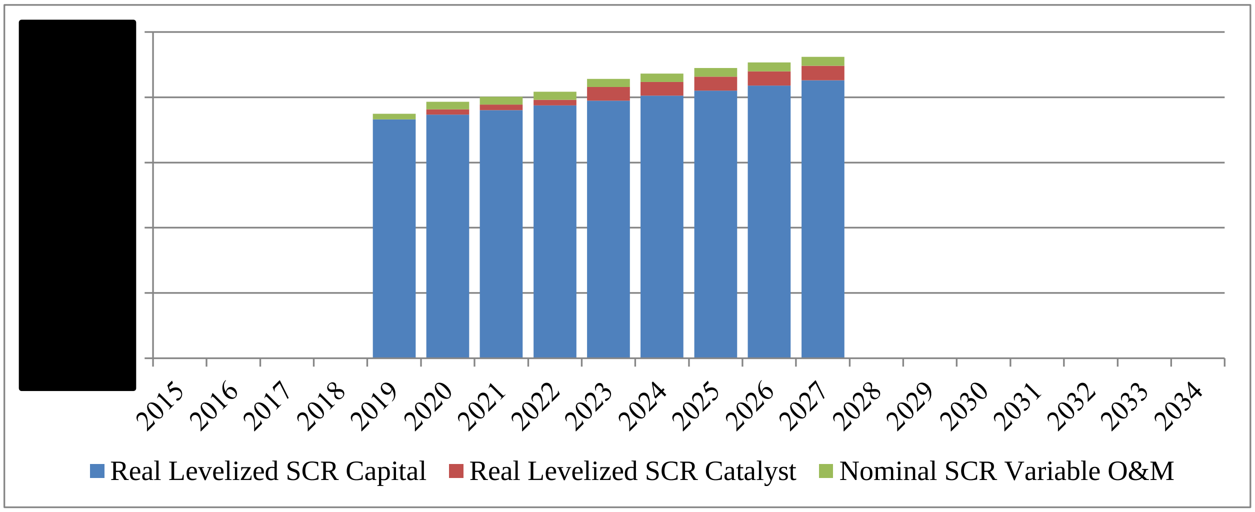
Annual Non-fuel Expenditure Assumptions

Annual non-fuel planned expenditures include environmental capital costs, run-rate capital costs, and run-rate O&M costs. Detailed annual non-fuel planned expenditures for the Dave Johnston Unit 3 compliance alternatives (with and without SCR) are provided in Appendix V3-D.

PVRR of SCR Costs

Figure V3.10 shows real levelized capital revenue requirement for up-front SCR capital costs, real levelized capital revenue requirement for catalyst replacement, and nominal variable O&M costs for SCR reagent over the period 2019 through the end of 2027. Combined, levelized annual SCR capital costs and nominal run-rate operating costs total [redacted] in 2019, rising to [redacted] by the assumed 2027 end-of-life retirement of Dave Johnston Unit 3. The PVRR of SCR capital and variable O&M for reagent is [redacted], which would be avoided with a commitment to retire Dave Johnston Unit 3 at the end of 2027.

Figure V3.10 – Annual Levelized Capital Revenue Requirement and Nominal Variable O&M Costs of SCR at Dave Johnston Unit 3



Discussion

The portion of EPA's final Regional Haze FIP requiring installation of SCR at Dave Johnston Unit 3, or a commitment to shut down the unit by the end of 2027, is currently under appeal by the state of Wyoming in the U.S. Tenth Circuit Court of Appeals. If, following appeal, EPA's final FIP as it pertains to Dave Johnston Unit 3 is upheld, PacifiCorp will commit to shutting down Dave Johnston Unit 3 by the end of 2027. If, following appeal, EPA's final FIP as it pertains to Dave Johnston Unit 3 is or will be modified, PacifiCorp will evaluate alternative compliance strategies that will meet any new requirements, as applicable, and provide the associated analysis in a future IRP or IRP Update.

Consideration of 111(d) compliance risks aligns with PacifiCorp's plans to forego installation of SCR, either via a successful appeal by the state of Wyoming, or by committing to shut down Dave Johnston Unit 3 by the end of 2027. Foregoing installation of SCR requirement will save customers tens of millions in incremental capital expenditures and retain compliance planning flexibility associated with EPA's draft 111(d) rule.

Naughton Unit 3 Analysis

Overview

PacifiCorp has obtained a construction permit and a revised Regional Haze BART permit from the state of Wyoming to convert Naughton Unit 3 to natural gas in 2018 as an alternative compliance approach to installation of SCR and baghouse.[17] EPA has confirmed support of the state of Wyoming's approved alternate compliance approach in its final Regional Haze FIP. PacifiCorp has analyzed 2018 natural gas conversion of Naughton Unit 3 against a 2018 early retirement compliance alternative assuming both medium and low natural gas price scenarios adopted for the 2015 IRP.

[17] PacifiCorp presented its analysis of the SCR and baghouse requirement at Naughton Unit 3 in Confidential Volume III of its 2013 IRP.

Compliance Timeline

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

Natural Gas Conversion

A schedule to convert Naughton Unit 3 to 100 percent natural gas fueling is presented in Appendix E, Figure V3-E.1. The implementation schedule assumes the unit would be converted to natural gas fueling in 2018 after coal fueling is discontinued on December 31, 2017. Thereafter, a six-month tie-in outage is planned. The following scope of work is anticipated to be required:

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

Early Retirement

A schedule for an early retirement scenario of Naughton Unit 3 by an assumed date of January 1, 2018 is presented in Appendix E, Figure V3-E.2. Unit retirement work would include:

- Demolition, removal and disposal of electric generating equipment and ancillary systems.
- Reclamation of the site.

Annual Non-fuel Expenditure Assumptions

Annual non-fuel planned expenditures include environmental capital costs, run-rate capital costs, run-rate O&M costs, fixed firm natural gas transportation costs, and natural gas [redacted] costs, as applicable. In addition, LD costs associated with the existing CSA, which extends through 2021, are included in PacifiCorp's analysis. Detailed annual non-fuel planned expenditures for the Naughton Unit 3 natural gas conversion and early retirement compliance alternatives are provided in Appendix V3-F.

The 2018 Naughton Unit 3 natural gas conversion case includes [redacted] in 2018 run-rate capital expenditures to complete the conversion and further includes annual fixed costs for natural gas transportation, including levelized costs for a new pipeline lateral, which would be required to transport natural gas from [redacted] to the Naughton plant.[18]

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

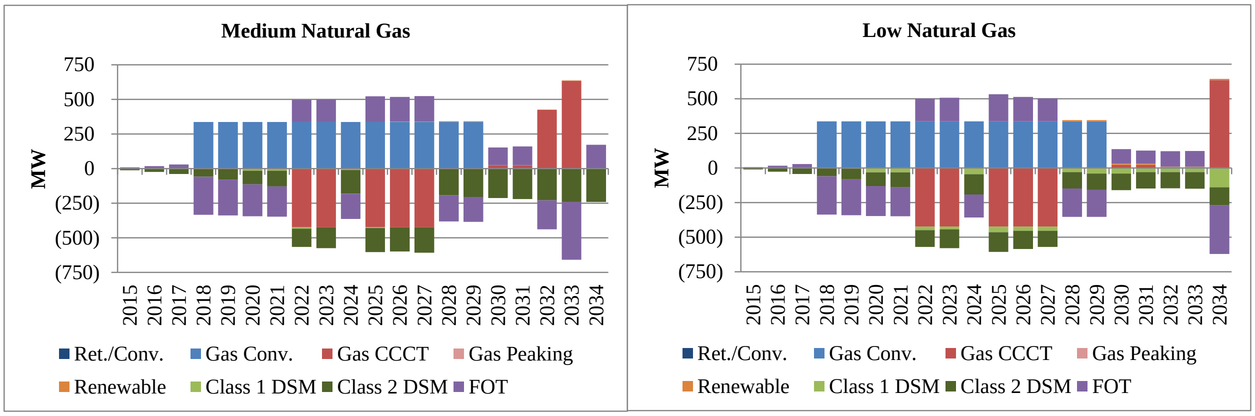
Resource Portfolio Results

In the 2019 Early Retirement Case, the loss of Naughton Unit 3 creates an incremental capacity need beginning in the summer of 2018, which drives the need for replacement resources over the 2018 to 2034 timeframe. Figure V3.11 summarizes the cumulative change in resource portfolio capacity when Naughton Unit 3 is converted to natural gas by June 2018 as compared to the early retirement case. Positive values show cumulative resource portfolio additions and negative values show the cumulative capacity of resources that are removed from the portfolio when Naughton Unit 3 is converted to natural gas in 2018. Notable resource portfolio changes resulting from an early retirement include:

- In the medium natural gas price scenario:
    - Maintaining capacity with a gas conversion defers FOTs and DSM resources from 2018 through 2021, in 2024, and from 2028 through 2029.
    - A 423 MW CCCT plant is deferred from 2022 to 2024, and along with reduced DSM, this increases FOTs over this timeframe.
    - A 423 MW CCCT plant is deferred from 2025 to 2028; FOTs increase over this period.
    - Beyond 2029, with reduced DSM resources in the portfolio, FOTs increase in 2030 through 2031 and in 2034, a CCCT resource is accelerated from 2033 to 2032, and a CCCT plant is accelerated from 2034 to 2033.
- In the low natural gas price scenario:
    - Maintaining capacity with a gas conversion defers FOTs and DSM resources from 2018 through 2021, in 2024, and from 2028 through 2029.
    - A 423 MW CCCT plant is deferred from 2022 to 2024, and along with reduced DSM, this increases FOTs over this timeframe.
    - A 423 MW CCCT plant is deferred from 2025 to 2028; FOTs increase over this period.
    - From 2030 through 2033, incremental FOT resources offset reduced DSM resources.
    - In 2034, a 635 MW CCCT is added to the portfolio, offsetting FOTs and DSM resources.

[18] It is assumed that [redacted] would complete [redacted] and charge PacifiCorp for its estimated [redacted] cost. The [redacted] costs [redacted]

Figure V3.11 – Cumulative Increase/(Decrease) in Portfolio Resources Under the 2018 Naughton Unit 3 Gas Conversion Case



PVRR(d) Results

Table V3.5 summarizes line item detail PVRR system cost detail for the 2018 natural gas conversion case and the 2018 early retirement case along with the PVRR(d) benefit/(cost) of gas conversion for both the medium and low natural gas price scenarios.

Table V3.5 – Line Item Detail of 2018 Gas Conversion as Compared to 2018 Early Retirement of Naughton Unit 3 ($ million)

	Medium Natural Gas			Low Natural Gas		
	PVRR of System Costs with 2018 Gas Conv.	PVRR of System Costs with 2018 Early Ret.	PVRR(d) Ben./(Cost) of Gas Conv. vs. Early Ret.	PVRR of System Costs with 2018 Gas Conv.	PVRR of System Costs with 2018 Early Ret.	PVRR(d) Ben./(Cost) of Gas Conv. vs. Early Ret.
System Variable Costs						
Fuel, FOTs	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Variable O&M	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Net System Balancing	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Total Variable	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
System Fixed Costs						
New Resource Capital/Run-rate	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Existing Resource Capital/Run-rate	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Decommissioning/Stranded Cost	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Contracts	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Incremental DSM	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Transmission	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Total Fixed	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Total Costs						
Total	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

The following summarizes line-item PVRR(d) results for the 2018 natural gas conversion case as compared to a 2018 early retirement of Naughton Unit 3 under medium natural gas price assumptions (quoted figures are on a present value revenue requirement basis calculated through the 20-year planning horizon):

- Fuel cost at Naughton Unit 3 increase by [redacted], which is more than offset by decreased system fuel and FOT costs totaling [redacted] driven by changes in the timing of CCCT resources.

- System variable O&M costs are reduced by [redacted], driven largely by changes in the timing of CCCT resources.
- Net system balancing benefits decrease by approximately [redacted], more than offsetting the decrease in system fuel costs, FOT costs, and variable O&M.
- Driven by the deferral of CCCT resources, new resource capital costs and run-rate operating cost savings total [redacted].
- With continued operation of Naughton Unit 3 as a gas-fired resource, capital and run-rate operating costs for existing units are [redacted] higher than in the early retirement case.
- With fewer Class 2 DSM resources under the gas conversion case, system DSM costs are reduced by [redacted].
- In aggregate, variable and fixed cost expenditures at Naughton Unit 3 increase costs by [redacted], which is more than offset by reduced system fixed and variable costs totaling [redacted]. The net benefit under the 2018 natural gas conversion case as compared to an early retirement of Naughton Unit 3 is [redacted].

The following summarizes line-item PVRR(d) results for the 2018 natural gas conversion case as compared to a 2018 early retirement of Naughton Unit 3 under low natural gas price assumptions (quoted figures are on a present value revenue requirement basis calculated through the 20-year planning horizon):

- Fuel cost at Naughton Unit 3 increase by [redacted], which is more than offset by decreased system fuel and FOT costs totaling [redacted] driven by changes in the timing of CCCT resources.
- System variable O&M costs are reduced by [redacted], driven largely by changes in the timing of CCCT resources.
- Net system balancing benefits decrease by approximately [redacted], more than offsetting the decrease in system fuel costs, FOT costs, and variable O&M.
- Driven by the deferral of CCCT resources, new resource capital costs and run-rate operating cost savings total [redacted].
- With continued operation of Naughton Unit 3 as a gas-fired resource, capital and run-rate operating costs for existing units are [redacted] higher than in the early retirement case.
- With fewer Class 2 DSM resources under the gas conversion case, system DSM costs are reduced by [redacted].
- In aggregate, variable and fixed cost expenditures at Naughton Unit 3 increase costs by [redacted], which is more than offset by reduced system fixed and variable costs totaling [redacted]. The net benefit under the 2018 natural gas conversion case as compared to an early retirement of Naughton Unit 3 is [redacted].

Discussion

The estimated up-front nominal capital cost needed to complete a natural gas conversion at Naughton Unit 3 is approximately [redacted] (about 12% of the per kW capital cost of a new combined cycle plant). These comparatively low up front capital costs, paired with relatively low run-rate operating costs, more than offset reduced net system balancing benefits associated with having a less efficient higher variable operating cost generating asset on the system. PacifiCorp's financial analysis shows that the 2018 natural gas conversion of Naughton Unit 3 is lower cost than a 2018 early retirement alternative. PacifiCorp will refresh RFPs to procure gas transportation and engineering, procurement, and construction (EPC) of the Naughton Unit 3 natural gas conversion in the first quarter of 2016. In conjunction with the RFP processes, PacifiCorp may update its economic analysis of natural gas conversion to align gas transportation and EPC cost assumptions with market bids.

Cholla Unit 4 Analysis

Overview

An initial PVRR(d) analysis of the 2017 early retirement and 2018 natural gas conversion alternatives to installation of SCR was performed in August 2013. In this analysis, it was assumed that the compliance schedule for Cholla Unit 4 as outlined in EPA's FIP for Arizona is met, requiring coal-fueled operations to cease by December 5, 2017, under either a natural gas conversion or early retirement scenario.[19] The PVRR(d) analysis reflects the difference in the present value revenue requirement between a case where Cholla Unit 4 continues operating as a coal-fueled facility, requiring SCR installation during a spring 2017 outage, and the present value revenue requirement among the 2017 early retirement and 2018 natural gas conversion alternatives.[20]

PacifiCorp refreshed and expanded its initial analysis of the early retirement and natural gas conversion alternatives for Cholla Unit 4 in January 2014 with updated forward price curve assumptions and updated capital cost assumptions for CCR/ELG compliance obligations based on updated data supplied to PacifiCorp by APS, the operator of the Cholla plant. PacifiCorp expanded its analysis by studying technology and inter-temporal trade off cases. In its updated and expanded analysis, PacifiCorp evaluated the following compliance alternatives:

- 2017 early retirement (updated);
- 2018 gas conversion (updated);
- SNCR by end of 2017, early retirement by end of 2024 (new);
- SNCR by end of 2017, gas conversion effective 2025 (new);
- No additional emission control equipment, early retirement by end of 2024 (new); and
- No additional emission control equipment, gas conversion effective 2025 (new)

Compliance Timeline

PacifiCorp considered compliance alternatives to the Cholla Unit 4 SCR requirement in EPA's FIP for Arizona, which include: (1) early retirement; (2) cease coal-fueled operations by converting the unit to operate on natural gas; and (3) technology and inter-temporal tradeoffs. An acceptable alternate compliance solution would require that the state of Arizona incorporate the alternative as a recommended amendment to its SIP for EPA review and approval. The SIP amendment and EPA review and approvals would include the appropriate public notice and comment processes.

[19] For modeling purposes, coal-fueled operations were assumed to cease by December 31, 2017. The currently approved depreciable life for Cholla 4 is 2042 for all states but Oregon. For Oregon, the currently approved depreciable life of Cholla 4 is 2028.

[20] For each alternative, it is assumed coal-fueled operations cease year-end 2017. For the natural gas conversion, it is assumed that the Cholla 4 would be available for natural gas-fueled operation by June 1, 2018.

The timeline for installing SCR by December 5, 2017, is outlined in Appendix V3-G. To evaluate key decision points associated with the natural gas conversion and early retirement alternatives in relation to SCR installation, the timelines for those alternatives are also provided. In evaluating a technology tradeoff alternative, PacifiCorp considered a case that might require installation of SNCR by December 5, 2017. The timeline for installing SNCR equipment is also provided in Appendix V3-G. To facilitate direct comparison, each timeline is built around the current December 5, 2017 compliance deadline. The timeline for compliance alternatives other than installing SCR could shift out in time under an alternate compliance outcome that allows for implementation of natural gas conversion, early retirement, or installing SNCR beyond the December 5, 2017 deadline for SCR installation.

Installation of SCR

A schedule to install SCR on Cholla Unit 4 by an assumed December 5, 2017 compliance date is presented in Appendix V3-G, Figure V3-G.1. The SCR project entails installing the reactor module(s) on the unit in the boiler flue gas exit path between the economizer exit and the air preheater inlet. Other work that may be required includes:

- Installing an ammonia receiving and delivery system.
- Installing a SCR reactor cleaning system.
- An economizer modification to limit SCR reactor inlet temperatures to avoid catalyst damage.
- Adding an economizer exit gas temperature control system to extend the operating load range of the unit, if economically justified.
- To provide NFPA 85 Code compliance, structurally reinforcing the boiler; forced draft equipment and ductwork; and flue gas path equipment and ductwork. Alternatively and/or in addition, control system mitigations may be implemented.
- Potential modifications to the boiler induced draft equipment.
- Potential modifications to the unit auxiliary power system.

Installation of SNCR

A schedule to install SNCR on Cholla Unit 4 by an assumed compliance date December 5, 2017, is presented in Appendix V3-G, Figure V3-G.2. If an SNCR is needed, the project would entail installation of several levels of urea solution injection equipment in the boiler at critical temperature zones. Other work that may be required includes:

- Installing a urea solution receiving and transport system.
- Boiler modifications to accommodate urea solution injection locations.

Natural Gas Conversion

A schedule to convert Cholla Unit 4 to 100 percent natural gas fueling is presented in Appendix V3-G, Figure V3-G.3. The implementation schedule assumes the unit would be converted to natural gas fueling in 2018 after coal fueling is discontinued on December 31, 2017. Thereafter, a six-month tie-in outage is planned. The schedule would shift out in time under potential compliance scenarios that allow for continued coal operation beyond December 31, 2017. The following scope of work is anticipated to be required:

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

Early Retirement

A schedule for an early retirement scenario of Cholla Unit 4 is presented in Appendix V3-G, Figure V3-G.4. The implementation schedule assumes the unit would cease coal-fired operation by December 31, 2017. The schedule would shift out in time under potential compliance scenarios that allow for continued coal operation beyond December 31, 2017.

Annual Non-fuel Expenditure Assumptions

Initial Analysis

Annual non-fuel planned expenditures include environmental capital costs, run-rate capital costs, run-rate O&M costs, fixed firm natural gas transportation costs, and natural gas pipeline lateral costs as applicable.[21] In addition, costs associated with termination of existing agreements, as applicable, are included in PacifiCorp's economic analysis. Contract termination-related costs include:

- Under the Asset Purchase and Power Exchange Agreement (APPEA) between PacifiCorp and APS, PacifiCorp paid APS a prepaid availability and transmission charge of [redacted] in April 1994 and [redacted] in April 1996.[22] These charges are related to the construction of transmission facilities that enable an additional 150 MW of northbound firm transmission capability on the Phoenix–Mead transmission line. The pre-paid transmission service costs began being amortized over a 50-year life in May 1997 as PacifiCorp began receiving transmission credits on its bill from APS. The unamortized prepaid balance as of December 2017 would be [redacted]. Under the early retirement scenario, the APPEA would terminate and it is assumed the unamortized balance would be written-off.

- PacifiCorp's acquisition of Cholla Unit 4 under the APPEA was subject to a pre-existing safe harbor lease, for federal income tax purposes, between APS, as property owner, and General Electric Company (GE) as tax lessor (Safe Harbor Lease). PacifiCorp assumed certain rights and obligations of APS under the Safe Harbor Lease with respect to Cholla

[21] Environmental capital costs are included for planned stack modifications (SM), SCR, mercury, and coal combustion by-product/effluent guideline limit (CCR/ELG) projects.
[22] PacifiCorp acquired Cholla 4 under the APPEA, dated September 21, 1990, at a purchase price of [redacted].

Unit 4. When APS completed construction of Cholla Unit 4 in 1981, APS sold the plant to GE (for tax purposes only) for [redacted] in cash and a 42-year note receivable in the amount of [redacted]. The [redacted] cash payment represented the value to GE of the investment tax credit and accelerated MACRS depreciation on the plant. Concurrently, for tax purposes, APS entered into a 42-year lease with GE for the plant.[23] The note receivable payments equal the lease payments and no actual cash is exchanged. Under the early retirement scenario, a casualty payment totaling [redacted] to GE is assumed for GE's loss of tax benefits associated with Cholla Unit 4.

- PacifiCorp and Peabody are parties to a long-term CSA for the El Segundo/Lee Ranch mine complex through December 2024. In both the 2017 early retirement case and the 2018 natural gas conversion case, termination of the CSA under the "Early Termination and Buy-Out" provision of the contract requires an estimated LD payment of [redacted], payable in 2018.

Detailed annual non-fuel planned expenditures, including contract termination-related costs, for the continued coal operation case, the 2017 early retirement case, and the 2018 natural gas conversion case, respectively, are provided in Appendix V3-H. In the early retirement case, annual expenditures include pre-paid transmission write-off costs and the Safe Harbor Lease casualty payment. In both the 2017 early retirement case and the 2018 natural gas conversion case, annual expenditures include LDs under the CSA. The 2018 natural gas conversion case includes [redacted] in 2018 run-rate capital expenditures to complete the conversion of the unit and further includes annual fixed costs for natural gas transportation, including levelized costs for a new pipeline lateral, which would be required to transport natural gas from El Paso Natural Gas Company's North Mainline to the Cholla plant.[24]

<u>Updated and Expanded Analysis</u>

PacifiCorp's updated analysis included updated capital costs for CCR/ELG compliance obligations. Contract-termination-related costs remain unchanged for 2017 early retirement and 2018 gas conversion cases. Pre-paid transmission write-off costs applicable to the 2024 early retirement cases total [redacted] Safe Harbor Lease costs do not apply to the 2024 early retirement cases because the contract expires November 2023. Similarly, LD costs under the CSA do not apply in the 2024 early retirement and 2025 gas conversion cases because the agreement expires at the end of 2024. Appendix V3-I contains tables detailing annual non-fuel planned expenditures, including contract termination related costs, for each case studied in PacifiCorp's updated and expanded analysis.

Resource Portfolio Results

<u>Initial Analysis</u>

In both the 2017 early retirement and 2018 natural gas conversion cases, PacifiCorp's resource portfolio is impacted when Cholla Unit 4 ceases operating as a coal-fired resource at the end of

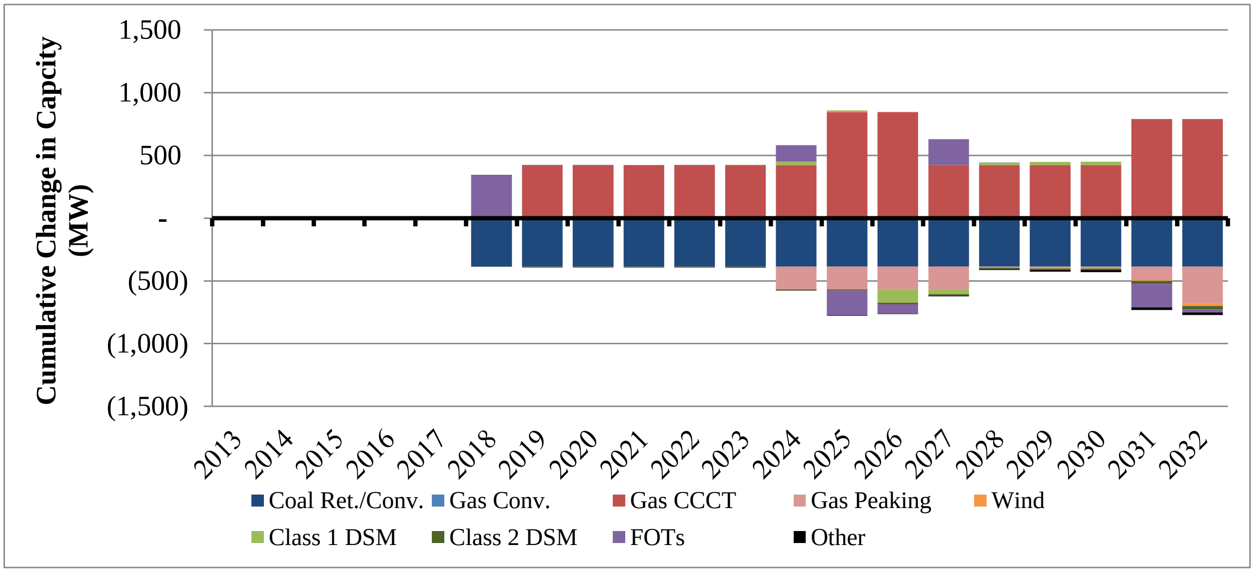
[23] The Safe Harbor Lease expires November 2023.
[24] It is assumed that El Paso Natural Gas Company would build and operate the lateral and charge PacifiCorp for its estimated [redacted] cost. The pipeline lateral capital cost is [redacted]

2017. In the case of a 2017 early retirement, the loss of Cholla Unit 4 creates an incremental capacity need beginning in the summer of 2018, which drives the need for replacement resource(s) throughout the 20-year planning horizon.[25] In the case of a 2018 natural gas conversion, system capacity is maintained; however, with the loss of energy from a baseload plant that is replaced by an inefficient gas-fired peaking resource, system dispatch is impacted, which in turn influences the economic selection of future resources in the portfolio. In either case, changes in the resource portfolio fundamentally influence the economic analysis of each compliance alternative.

Figure V3.12 summarizes the cumulative change in the resource portfolio when Cholla Unit 4 retires at the end of 2017 as compared to the continued coal operation case. Positive values show cumulative resource portfolio additions and negative values show the cumulative capacity of resources that are removed from the portfolio when Cholla Unit 4 retires at the end of 2017. Notable resource portfolio changes resulting from an early retirement of Cholla Unit 4 at the end of 2017 include:

- Front office transactions (FOTs) replace 387 MW of retired Cholla Unit 4 coal capacity in 2018.[26]
- An incremental 423 MW combined cycle combustion turbine (CCCT) plant is needed in 2019, and with changes in the system resource mix, FOTs displace a natural gas peaking resource in 2024, which is deferred to 2028.
- A 423 MW CCCT plant is accelerated from 2027 to 2025, offsetting the need for natural gas peaking capacity through 2027 and displacing FOTs and Class 1 DSM resources through 2026.
- An incremental 368 MW CCCT plant is added in 2031, displacing natural gas peaking capacity and FOTs.

Figure V3.12 – Cumulative Change in Portfolio Resources for the 2017 Cholla Unit 4 Early Retirement Case, Initial Analysis

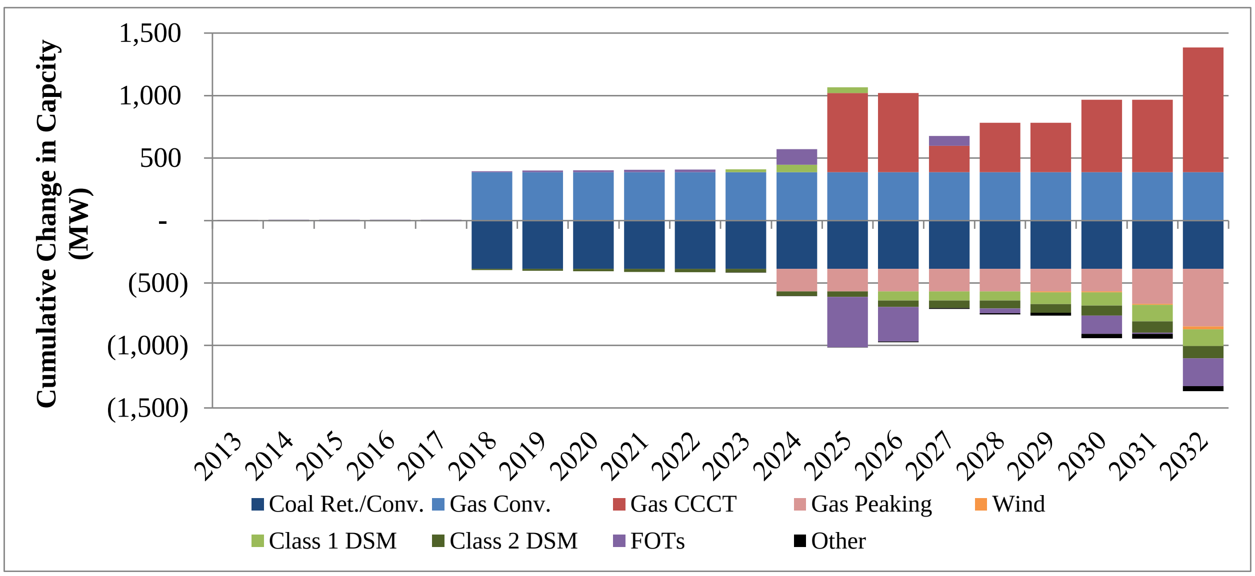


[25] PacifiCorp's coincident system peak load occurs in the summer.
[26] FOTs represent firm short-term market purchases.

Figure V3.13 summarizes the cumulative change in the resource portfolio when Cholla Unit 4 is converted to natural gas in 2018 as compared to the continued coal operation case. Positive values show cumulative resource portfolio additions and negative values show the cumulative capacity of resources that are removed from the portfolio when Cholla Unit 4 ceases operating as a coal-fired unit at the end of 2017 and begins operating as a gas-fired plant in the summer of 2018. Notable resource portfolio changes resulting from a natural gas conversion of Cholla Unit 4 include:

- With no change in capacity associated with a Cholla Unit 4 natural gas conversion, resource portfolio impacts are relatively minor over the 2018 through 2023 timeframe.
- The timing of a CCCT plant is accelerated from 2027 to 2025 and the size of this CCCT plant is increased from 423 MW to 634 MW.
- The acceleration of the 634 MW CCCT plant in 2025 displaces natural gas peaking capacity, FOTs, Class 1 DSM, and Class 2 DSM resources.
- Two CCCT plants added in 2028 totaling 846 MW are larger than the 661 MW CCCT plant added when Cholla continues operating as a coal-fired unit.
- Similarly, CCCT plants added in 2030 and 2032 total 1,449 MW, exceeding CCCT plant additions over this timeframe in the continued coal-fired operation case by 603 MW.
- The additional CCCT resources added in the out years of the planning horizon help replace baseload generation from Cholla Unit 4 and displace natural gas peaking capacity, FOTs, Class 1 DSM, and Class 2 DSM.

Figure V3.13 – Cumulative Change in Portfolio Resources for the 2018 Cholla Unit 4 Gas Conversion Case, Initial Analysis



Updated and Expanded Analysis

Figure V3.14 summarizes the cumulative change in the resource portfolio for the updated 2017 early retirement case as compared to the updated continued coal operation case. Positive values show cumulative resource portfolio additions and negative values show the cumulative capacity of resources that are removed from the portfolio when Cholla Unit 4 retires at the end of 2017. Notable resource portfolio changes resulting from an early retirement of Cholla Unit 4 at the end of 2017 include:

- Front office transactions (FOTs) replace 387 MW of retired Cholla Unit 4 coal capacity in 2018 and partially replace Cholla Unit 4 coal capacity in 2019.
- Natural gas peaking resources are accelerated from the 2025/2026 timeframe to the 2019/2020 timeframe, and more Class 1 DSM resources are added sooner, beginning 2020. These resource changes partially offset the need for FOTs and Class 2 DSM resources through 2024.
- An incremental 423 MW CCCT plant is added in 2025 and a second 423 MW CCCT plant is added in 2028. The incremental 2028 CCCT plant defers the need for gas peaking capacity, FOTs, Class 1 DSM, and Class 2 DSM resources.

Figure V3.14 – Cumulative Change in Portfolio Resources for the Updated 2017 Cholla Unit 4 Early Retirement Case, Updated and Expanded Analysis

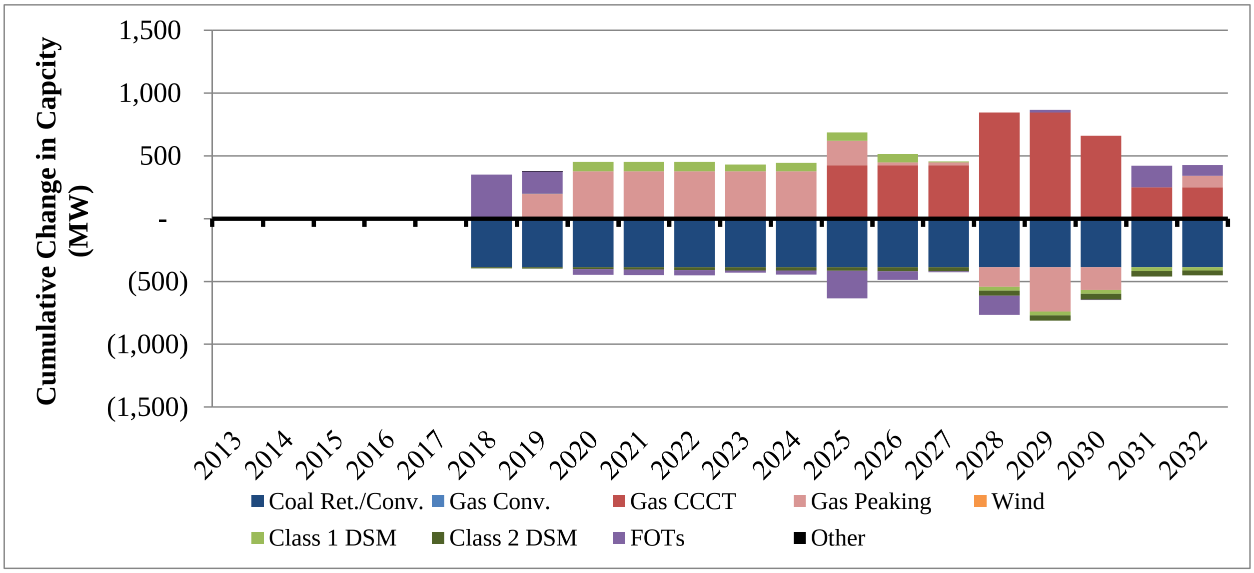


Figure V3.15 summarizes the cumulative change in the resource portfolio for the updated 2018 gas conversion case as compared to the updated continued coal operation case. Positive values show cumulative resource portfolio additions and negative values show the cumulative capacity of resources that are removed from the portfolio when Cholla Unit 4 ceases operating as a coal-fired unit at the end of 2017 and begins operating as a gas-fired plant in the summer of 2018. Notable resource portfolio changes resulting from a 2018 natural gas conversion of Cholla Unit 4 include:

- With no change in capacity associated with a Cholla Unit 4 natural gas conversion, resource portfolio impacts are relatively minor over the 2018 through 2022 timeframe.
- A 181 MW gas peaking plant is accelerated from 2025 to 2023, partially displacing FOTs, Class 1 DSM and Class 2 DSM resources in 2023 and 2024.
- An incremental 661 MW CCCT plant is added in 2026, partially displacing gas peaking resources, FOTs, Class 1 DSM, and Class 2 DSM resources through 2029.
- By the end of the study period, an incremental 461 MW of CCCT capacity is added, and with incremental FOT purchases, this additional capacity displaces gas peaking resources, Class 1 DSM and Class 2 DSM resources.

Figure V3.15 – Cumulative Change in Portfolio Resources for the Updated 2018 Cholla Unit 4 Gas Conversion Case, Updated and Expanded Analysis

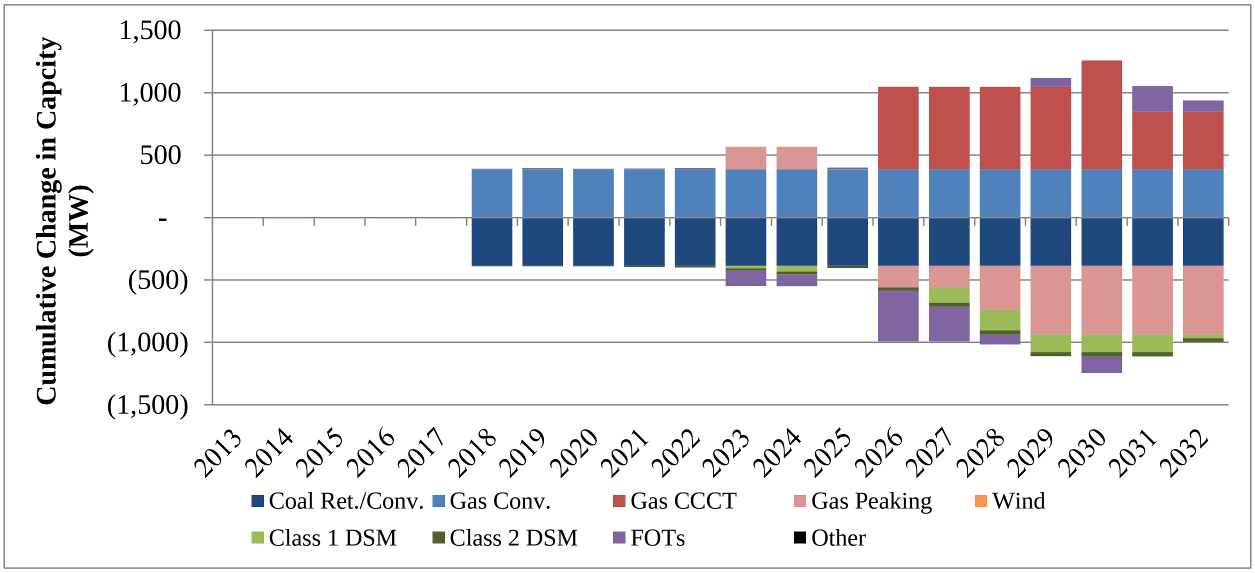


Figure V3.16 summarizes the cumulative change in the resource portfolio for cases in which Cholla 4 retires at the end of 2024 (with or without installation of SNCR in 2017) as compared to the updated continued coal operation case. Positive values show cumulative resource portfolio additions and negative values show the cumulative capacity of resources that are removed from the portfolio when Cholla Unit 4 is retired at the end of 2024. Notable resource portfolio changes resulting from a 2024 early retirement include:

- When Cholla Unit 4 retires at the end of 2024, a 423 MW CCCT plant is accelerated from 2031 to 2025 and additional Class 1 DSM and Class 2 DSM resources are added to the system, which in aggregate partially displaces gas peaking resource additions through 2031.
- By the end of the study period, an incremental gas peaking resource, FOTs, Class 1 DSM and Class 2 DSM resources combine to replace the 387 MW of retired Cholla Unit 4 capacity.

Figure V3.16 – Cumulative Change in Portfolio Resources for the 2024 Cholla Unit 4 Early Retirement Cases, Updated and Expanded Analysis

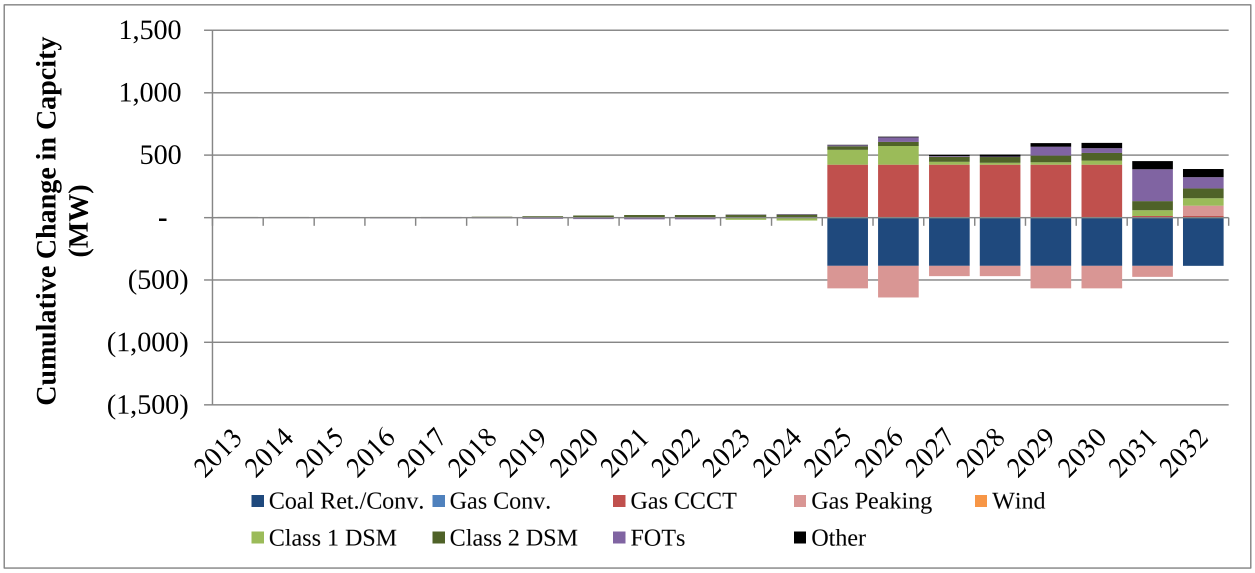
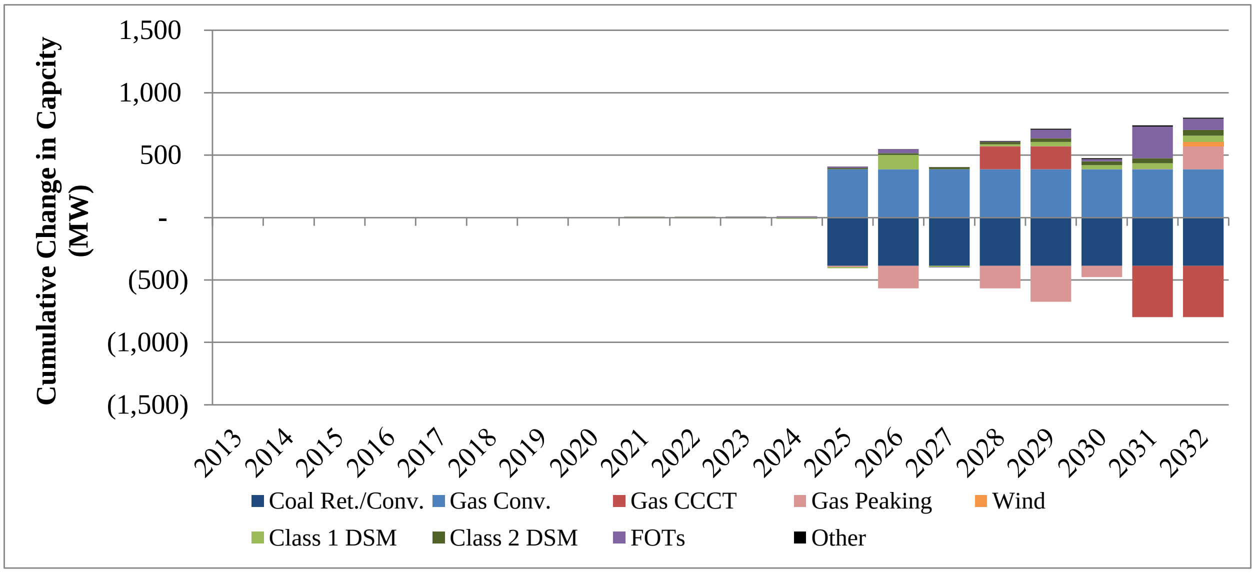


Figure V3.17 summarizes the cumulative change in the resource portfolio for cases in which Cholla Unit 4 is converted to natural gas in 2025 (with or without installation of SNCR) as compared to the updated continued coal operation case. Positive values show cumulative resource portfolio additions and negative values show the cumulative capacity of resources that are removed from the portfolio when Cholla Unit 4 ceases operating as a coal-fired unit at the end of 2024 and begins operating as a gas-fired plant in the summer of 2025. Notable resource portfolio changes resulting from a 2025 natural gas conversion of Cholla Unit 4 include:

- With no change in capacity associated with a Cholla Unit 4 natural gas conversion, resource portfolio impacts are relatively minor through 2025.
- Class 1 DSM resources and FOTs added in 2026 defer the need for a gas peaking plant by one year.
- In 2028, a 661 MW CCCT plant is replaced with two 423 MW CCCT plants, and the additional CCCT capacity, supplemented with additional Class 1 DSM, Class 2 DSM, and FOTs partially displaces the need for gas peaking resources through 2029.
- By 2030, FOTs and Class 1 DSM resources partially offset gas peaking resource capacity.
- By the end of the study period, additional gas peaking capacity, FOTs, Class 1 DSM, and Class 2 DSM resources offset the need for 411 MW of CCCT capacity.

Figure V3.17 – Cumulative Change in Portfolio Resources for the 2025 Cholla Unit 4 Gas Conversion Cases, Updated and Expanded Analysis



PVRR(d) Results

<u>Initial Analysis</u>

Table V3.6 summarizes the PVRR of system costs for the continued coal operation case, the 2017 retirement case, and the 2018 natural gas conversion case along with the PVRR(d) benefit/(cost) of each compliance alternative relative to installation of SCR. The results show that on a present value revenue requirement basis:

- Installation of SCR is [redacted] to early retirement;
- A 2018 natural gas conversion is [redacted] to installation of SCR; and
- A 2018 natural gas conversion is [redacted] to early retirement.

Table V3.6 – Cholla Unit 4 2017 Retirement/2018 Conversion PVRR(d) Results, Initial Analysis ($ million)

	System PVRR			PVRR(d)	
	Coal Operation with SCR	2017 Retirement	2018 Gas Conversion	PVRR(d) Benefit/(Cost) of SCR vs. 2017 Retirement	PVRR(d) Benefit/(Cost) of SCR vs. 2018 Gas Conversion
System Variable Costs					
Fuel, FOTs	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Variable O&M	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Emissions	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Net System Balancing	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Total Variable	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
System Fixed Costs					
New Resource Capital/Run-rate	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Existing Resource Capital/Run-rate	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Decommissioning/Stranded Cost	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Contracts	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Incremental DSM	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Transmission	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Total Fixed	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Total Costs					
Total	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

The following summarizes line-item PVRR(d) results for the 2017 retirement case (quoted figures are on a present value revenue requirement basis calculated through the 20-year planning horizon):

- Reduced fuel costs from Cholla Unit 4 total [redacted], partially offset by increased system fuel costs from replacement generation and FOTs totaling [redacted].
- Reduced non-fuel variable O&M costs from Cholla Unit 4 total [redacted], which is nearly offset by increased system variable O&M costs totaling [redacted].
- With an assumed CO_2 price beginning 2022, emissions costs are reduced by [redacted], with [redacted] of this cost savings attributed to reduced emissions from Cholla Unit 4.
- With the removal of baseload generation from Cholla Unit 4 beginning 2018, system balancing benefits are reduced, increasing the cost of the early retirement alternative by [redacted].
- Driven by the addition of a CCCT plant in 2019 and 2031, and an acceleration of a CCCT plant from 2027 to 2025, new resource capital costs and run-rate operating costs contribute [redacted] of incremental cost to the early retirement case.
- Reduced capital and run-rate operating costs at Cholla Unit 4 total [redacted] under the early retirement case, which is partially offset by accelerated decommissioning costs and recovery of stranded costs for incremental capital expenditures made between 2013 and 2017, which combined total [redacted].
- Contract-related costs for coal contract LDs, the pre-paid transmission write-off, and the casualty payment under the Safe Harbor Lease increase the cost of the 2017 early retirement case by [redacted].
- Additional CCCT plants in the resource portfolio partially displace Class 2 DSM resources and changes the timing of Class 1 DSM resources, reducing system costs by [redacted].

- In aggregate, reduced variable and fixed cost expenditures at Cholla Unit 4 reduce costs by [redacted], which is more than offset by an increase in system fixed and variable costs, including the cost of replacement generation and reduced net system balancing benefits, totaling [redacted]. The net cost under the 2017 early retirement case as compared to installation of SCR is [redacted].

The following summarizes line-item PVRR(d) results for the 2018 gas conversion case (quoted figures are on a present value revenue requirement basis calculated through the 20-year planning horizon):

- Reduced fuel costs from Cholla Unit 4 total [redacted], which is a lower cost reduction than in the 2017 early retirement case due to inclusion of natural gas fuel expenditures beginning 2018. Cholla Unit 4 fuel cost savings are partially offset by increased system fuel costs from replacement generation and FOTs totaling [redacted].
- Reduced non-fuel variable O&M costs from Cholla Unit 4 total [redacted], equal to savings in the 2017 early retirement case because reagent expenses are avoided when coal-fired operations cease in both cases. These savings are nearly offset by increased system variable O&M costs totaling [redacted].
- With an assumed CO_2 price beginning 2022, emissions costs are reduced by [redacted], which is lower than in the 2017 early retirement case given continued, albeit greatly reduced, CO_2 emissions when Cholla Unit 4 operates as a natural-gas fired unit beginning in the summer of 2018.
- With reduced generation from Cholla Unit 4 beginning 2018, system balancing benefits are lower, which increases the cost of the natural gas conversion alternative by [redacted].
- Driven by the acceleration of a CCCT plant from 2027 to 2025 and overall increase in total CCCT capacity beginning 2025, new resource capital costs and run-rate operating costs contribute [redacted] of incremental cost to the gas conversion case. As compared to the early retirement case, the present value impact of new resource costs is less because there is no incremental need for a 423 MW CCCT plant in 2019 and resource portfolio impacts occur later in the planning horizon.
- Reduced capital and run-rate operating costs at Cholla Unit 4 total [redacted] under the gas conversion case. Cost savings are less as compared to the early retirement case due continued operation of the unit, including fixed costs for natural gas transportation.
- Coal contract LDs increase the cost of the 2018 gas conversion case by [redacted]. The pre-paid transmission write-off and the casualty payment under the Safe Harbor Lease applied to the 2017 early retirement case are not applicable to the gas conversion case.
- Additional CCCT plants in the resource portfolio partially displace Class 1 and Class 2 DSM resources, reducing system costs by [redacted].
- In aggregate, reduced variable and fixed cost expenditures at Cholla Unit 4 reduce costs by [redacted], which is more than offset by an increase in system fixed and variable costs, including the cost of replacement generation and reduced net system balancing benefits, totaling [redacted]. The net savings under the 2017 early retirement case as compared to installation of SCR total [redacted].

Updated and Expanded Analysis

Table V3.7 summarizes the PVRR of system costs for the updated continued coal operation case, the 2017 retirement case, and the 2018 natural gas conversion case along with the PVRR(d) benefit/(cost) of each compliance alternative relative to installation of SCR. Table V3.8 summarizes results for the 2024 early retirement and 2025 gas conversion cases. The PVRR(d) results for the equivalent inter-temporal trade-off cases that include SNCR equipment are estimated by adding SNCR capital and operating costs, totaling [redacted] on a PVRR basis, to these two cases. The results show that on a present value revenue requirement basis:

- All cases are more favorable than installation of SCR in 2017.
- Inter-temporal cases that avoid installation of SCR with continued coal-fired operations through 2024 are lower cost relative to installation of SCR in 2017 and lower cost than a 2018 natural gas conversion.
- The 2025 natural gas conversion inter-temporal case where emission control costs are entirely avoided is the least cost alternative, with a PVRR(d) that is [redacted] favorable to installation of SCR in 2017.

Table V3.7 – Cholla Unit 4 2017 Retirement/2018 Conversion PVRR(d) Results, Updated and Expanded Analysis ($ million)

	System PVRR			PVRR(d)	
	Coal Operation with SCR	2017 Retirement	2018 Gas Conversion	PVRR(d) Benefit/(Cost) of SCR vs. 2017 Retirement	PVRR(d) Benefit/(Cost) of SCR vs. 2018 Gas Conversion
System Variable Costs					
Fuel, FOTs	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Variable O&M	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Emissions	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Net System Balancing	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Total Variable	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
System Fixed Costs					
New Resource Capital/Run-rate	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Existing Resource Capital/Run-rate	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Decommissioning/Stranded Cost	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Contracts	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Incremental DSM	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Transmission	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Total Fixed	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Total Costs					
Total	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

The following summarizes line-item PVRR(d) results for the 2017 retirement case (quoted figures are on a present value revenue requirement basis calculated through the 20-year planning horizon):

- Reduced fuel costs from Cholla Unit 4 total [redacted], and system fuel costs including the cost for FOTs are reduced by over [redacted].
- Reduced non-fuel variable O&M costs from Cholla Unit 4 total [redacted], which is partially offset by increased system variable O&M costs totaling [redacted].
- With an assumed CO_2 price beginning 2022, emissions costs are reduced by [redacted], with [redacted] of emission cost savings attributed to reduced emissions

from Cholla Unit 4 offset by [redacted] of higher CO_2 emission costs from the rest of the system.

- Beginning 2018, system balancing benefits are reduced, increasing the cost of the early retirement alternative by [redacted].
- Driven by the acceleration of natural gas peaking resources to the 2019/2020 timeframe and the addition of a 423 MW CCCT plant in 2025, new resource capital costs and run-rate operating costs contribute [redacted] of incremental cost to the updated early retirement case.
- Reduced capital and run-rate operating costs at Cholla Unit 4 total [redacted] under the early retirement case, which is partially offset by accelerated decommissioning costs and recovery of stranded costs for incremental capital expenditures made between 2013 and 2017, which combined, total [redacted].
- Contract-related costs for coal contract LDs, the pre-paid transmission write-off, and the casualty payment under the Safe Harbor Lease increase the cost of the updated 2017 early retirement case by [redacted].
- With changes in the timing of Class 1 DSM resources and partial displacement of Class 2 DSM resources, system costs are lowered by [redacted].
- In aggregate, reduced variable and fixed cost expenditures at Cholla Unit 4 reduce costs by [redacted], which is partially offset by an increase in system fixed and variable costs, including the cost of replacement generation and reduced net system balancing benefits, totaling [redacted]. With reduced natural gas prices, the updated 2017 early retirement case is lower cost than installing SCR. The net savings under the updated 2017 early retirement case relative to installation of SCR total [redacted].

The following summarizes line-item PVRR(d) results for the updated 2018 gas conversion case (quoted figures are on a present value revenue requirement basis calculated through the 20-year planning horizon):

- Reduced fuel costs from Cholla Unit 4 total [redacted], lower savings than in the updated 2017 early retirement case due to inclusion of natural gas fuel expenditures beginning 2018. Cholla Unit 4 fuel cost savings are partially offset by increased system fuel costs from replacement generation and FOTs totaling [redacted].
- Reduced non-fuel variable O&M costs from Cholla Unit 4 total [redacted], equal to savings in the updated 2017 early retirement case because reagent expenses are avoided when coal-fired operations cease in both cases. These savings are offset by increased system variable O&M costs totaling [redacted].
- With an assumed CO_2 price beginning 2022, emissions costs are reduced by [redacted], which is lower than in the updated 2017 early retirement case given continued, albeit greatly reduced, CO_2 emissions when Cholla Unit 4 operates as a natural-gas fired unit beginning 2018.
- Without baseload generation from Cholla Unit 4 beginning 2018, system balancing benefits are reduced, increasing the cost of the natural gas conversion alternative by [redacted].
- Driven by the acceleration of a of a gas peaking plant from 2025 to 2023 and incremental CCCT resource additions net of offsetting costs from reduced gas peaking resources, new resource capital costs and run-rate operating costs contribute [redacted] of incremental cost to the updated 2018 gas conversion case.

- Reduced capital and run-rate operating costs at Cholla Unit 4 total [redacted] under the updated 2018 gas conversion case. Cost savings are less as compared to the updated early retirement case due continued operation of the unit, inclusive of fixed costs for natural gas transportation.
- Coal contract LDs increase the cost of the 2018 gas conversion case by [redacted]. The pre-paid transmission write-off and the casualty-related payment under the Safe Harbor Lease applied to the updated 2017 early retirement case are not applicable to the gas conversion case.
- Class 1 and Class 2 DSM resources are partially displaced with changes in the resource mix, reducing system costs by [redacted].
- In aggregate, reduced variable and fixed cost expenditures at Cholla Unit 4 reduce costs by [redacted], which is partially offset by an increase in system fixed and variable costs, including the cost of replacement generation and reduced net system balancing benefits, totaling [redacted]. With reduced natural gas prices, the PVRR(d) in favor of a 2018 natural gas conversion improves. The net savings under the updated 2018 gas conversion case relative to installation of SCR total [redacted].

Table V3.8 – Cholla Unit 4 2024 Early Retirement/2025 Gas Conversion PVRR(d) Results, Updated and Expanded Analysis ($ million)

	System PVRR			PVRR(d)	
	Coal Operation with SCR	2024 Retirement	2025 Gas Conversion	PVRR(d) Benefit/(Cost) of SCR vs. 2024 Retirement	PVRR(d) Benefit/(Cost) of SCR vs. 2025 Conversion
System Variable Costs					
Fuel, FOTs	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Variable O&M	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Emissions	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Net System Balancing	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Total Variable	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
System Fixed Costs					
New Resource Capital/Run-rate	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Existing Resource Capital/Run-rate	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Decommissioning/Stranded Cost	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Contracts	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Incremental DSM	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Transmission	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Total Fixed	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Total Costs					
Total	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

* Adding 2017 SNCR costs increases the PVRR of the 2024 early retirement and the 2025 natural gas conversion cases by [redacted].

The following summarizes line-item PVRR(d) results for the 2024 early retirement case (quoted figures are on a present value revenue requirement basis calculated through the 20-year planning horizon):

- Reduced fuel costs from Cholla Unit 4 total [redacted], partially offset by increased system fuel costs inclusive of the cost for FOTs totaling [redacted].
- Reduced non-fuel variable O&M costs from Cholla Unit 4 total [redacted], which is partially offset by increased system variable O&M costs totaling [redacted].

- With an assumed CO_2 price beginning 2022, emissions costs are reduced by [redacted], with [redacted] of emission cost savings attributed to reduced emissions from Cholla Unit 4 offset by [redacted] of higher CO_2 emission costs from the rest of the system.
- System balancing benefits are reduced, increasing the cost of the early retirement alternative by [redacted].
- Driven by the acceleration of a 423 MW CCCT plant from 2031 to 2025, new resource capital costs and run-rate operating costs contribute [redacted] of incremental cost to the 2024 early retirement case.
- Reduced capital and run-rate operating costs at Cholla Unit 4 total [redacted] under the 2024 early retirement case, which is partially offset by accelerated decommissioning costs and recovery of stranded costs for incremental capital expenditures made between 2013 and 2024, which combined, total [redacted].
- Contract related costs for the pre-paid transmission write-off increase the cost of the 2024 early retirement case by [redacted].
- With additional Class 1 and Class 2 DSM resources, DSM system costs increase by [redacted].
- In aggregate, reduced variable and fixed cost expenditures at Cholla Unit 4 reduce costs by [redacted], which is partially offset by an increase in system fixed and variable costs, including the cost of replacement generation and reduced net system balancing benefits, totaling [redacted]. The net savings under the 2024 early retirement case as compared to installation of SCR are [redacted]. With 2017 SNCR costs, the net savings decrease to [redacted].
- As compared to the 2017 early retirement case, the net savings of the 2024 early retirement case are [redacted]. With 2017 SNCR costs, the net savings decrease to [redacted].
- As compared to the 2018 natural gas conversion case, the net savings of the 2024 early retirement case are [redacted]. With 2017 SNCR, costs the net savings decrease to [redacted].

The following summarizes line-item PVRR(d) results for the 2025 gas conversion case (quoted figures are on a present value revenue requirement basis calculated through the 20-year planning horizon):

- Reduced fuel costs from Cholla Unit 4 total [redacted], lower than the savings in the 2024 early retirement case due to inclusion of natural gas fuel expenditures beginning 2025. Cholla Unit 4 fuel cost savings are partially offset by increased system fuel costs from replacement generation and FOTs totaling [redacted].
- Reduced non-fuel variable O&M costs from Cholla Unit 4 total [redacted], equal to savings in the 2024 early retirement case because reagent expenses are avoided when coal-fired operations cease in both cases. System variable O&M costs are reduced by [redacted].
- With an assumed CO_2 price beginning 2022, emissions costs are reduced by [redacted], with [redacted] of these cost savings attributable to reduced emissions from Cholla Unit 4.
- System balancing benefits are reduced, increasing the cost of the 2025 natural gas conversion alternative by [redacted].

- With Class 1 DSM and FOTs deferring 2026 natural gas peaking capacity by one year and partially deferring CCCT capacity beginning 2030, new resource capital costs and run-rate operating costs are reduced by [redacted].
- Reduced capital and run-rate operating costs at Cholla Unit 4 total [redacted] under the 2025 gas conversion case. Cost savings are less as compared to the 2024 early retirement case due to continued operation of the unit, inclusive of fixed costs for natural gas transportation.
- Under the 2025 gas conversion case, there are no coal contract LDs, no pre-paid transmission write-off costs, and no casualty payments under the Safe Harbor Lease.
- With additional Class 1 and Class 2 DSM resources, DSM system costs increase by [redacted].
- In aggregate, reduced variable and fixed cost expenditures at Cholla Unit 4 reduce costs by [redacted], which is partially offset by an increase in system fixed and variable costs, including the cost of replacement generation and reduced net system balancing benefits, totaling [redacted]. The net savings under the 2025 gas conversion case as compared to installation of SCR are [redacted]. With 2017 SNCR costs, the net savings decrease to [redacted].
- As compared to the 2017 early retirement case, the net savings of the 2025 gas conversion case are [redacted]. With SNCR costs, the net savings decrease to [redacted].
- As compared to the 2018 natural gas conversion case, the net savings of the 2025 gas conversion case are [redacted]. With SNCR, costs the net savings decrease to [redacted].

Discussion

PacifiCorp's financial analysis shows that installation of SCR by an assumed compliance date of December 5, 2017, is not a cost effective solution for customers when evaluated against a range of compliance alternatives. Customer benefits are maximized under an assumed alternate compliance scenario in which Cholla Unit 4 continues operating through early 2025 without the installation of SCR, followed by conversion of the unit to natural gas fueling, thereby avoiding coal contract LDs, avoiding casualty payments under the Safe Harbor Lease, and avoiding or mitigating pre-paid transmission write-off expenses. This preferred compliance alternative also effectively manages utilization and depreciation of the resource over an appropriate period of time for the benefit of customers. If an alternate compliance solution that maximizes benefits for PacifiCorp customers consistent with these results cannot be reached, converting Cholla Unit 4 to a natural gas-fired unit in 2018 or later is currently assessed as the next best alternative to a 2017 early retirement outcome.

On January 16, 2015, APS and PacifiCorp submitted an application for amendment of the Cholla facility Title V permit that reflects the alternate Regional Haze compliance approach committing to cease coal-fueled operations at Cholla Unit 4 by the end of 2025. If approved, the Title V permit conditions will be incorporated into Arizona's Regional Haze SIP and submitted for EPA review and approval. It is anticipated that the Title V review and approval process will be completed in early to mid-2015. The Regional Haze SIP review and approval process will likely proceed into late 2015 or early 2016. PacifiCorp will continue permitting efforts in support of the alternative Regional Haze compliance approach that avoids installation of SCR with a commitment to cease operating Cholla Unit 4 as a coal-fired resource by the end of April 2025.

EPA's emission rate standards under its proposed 111(d) rule for the state of Arizona targets an interim emission rate goal of 735 lb/MWh over the period 2020–2029 and a final emission rate goal of 702 lb/MWh in 2030. Based on EPA's data used to calculate the Arizona emission rate standards, the Cholla plant emission rate in 2012 was 2,425 lb/MWh. If converted to natural gas, mass-based CO_2 emissions from the unit would fall dramatically due to reduced dispatch and the lower CO_2 content of natural gas as compared to coal.[27] However, the emission rate of Cholla Unit 4 operating as a gas-fired unit is expected to be within the 1,300 lb/MWh to 1,350 lb/MWh range. Whether operating as a coal-fired unit or as a gas-fired unit, the Cholla Unit 4 emission rate exceeds the final emission rate goal established for the state of Arizona by EPA in its proposed rule.

PacifiCorp does not have retail customers in Arizona and does not own any generating resources in the state other than Cholla Unit 4. With the ability to optimize its system resources for 111(d) compliance purposes, PacifiCorp could utilize system fossil emissions, fossil energy, and renewable energy, or end-use energy efficiency to achieve compliance with Arizona 111(d) targets. Without the ability to optimize the allocation of fossil emissions, fossil energy, renewable energy, or end-use energy efficiency savings from across its system for 111(d) compliance purposes, PacifiCorp would be unable to credit the Cholla Unit 4 emission rate to align with the Arizona state emission rate goal. Consequently, the state's decision on how it will treat non-load serving entities in its 111(d) plan will ultimately determine 111(d) compliance impacts associated with long-term operations of Cholla Unit 4. Consideration of 111(d) compliance risks aligns with the financial analysis showing that installation of SCR is not a cost effective Regional Haze compliance solution for customers. PacifiCorp will continue to evaluate least cost compliance alternatives for Cholla Unit 4 as EPA's proposed 111(d) rule is finalized and the state of Arizona begins to formulate its 111(d) compliance plan for submittal to EPA.

Conclusion

PacifiCorp's 2015 IRP coal analysis quantifies present value revenue requirement cost differentials among a range of Regional Haze environmental compliance alternatives at Wyodak, Dave Johnston Unit 3, Naughton Unit 3, and Cholla Unit 4. As applicable, PacifiCorp's analysis, performed using the System Optimizer model, captures resource portfolio impacts of potential Regional Haze compliance alternatives including impacts to system dispatch costs and up-front capital and run-rate operating costs for new and existing generating units. PacifiCorp's analysis reflects how different Regional Haze compliance alternatives might impact compliance costs associated with known and prospective regulations for mercury and air toxics, coal combustion by-products, effluent limits, and cooling water in-take structures. Similarly, PacifiCorp's analysis considers implications of EPA's draft 111(d) rule.

PacifiCorp's financial analysis of Regional Haze compliance alternatives to installation of SCR at Wyodak, Dave Johnston Unit 3, and Cholla Unit 4 and its analysis of a natural gas conversion alternative to early retirement at Naughton Unit 3 support the following key findings:

[27] When converted to natural gas, the annual average capacity factor for Cholla 4 is expected to range between three percent and seven percent (between 14 percent and 29 percent in July and August).

- Analysis of inter-temporal and fleet trade-off alternatives supports a strategy that avoids installation of SCR at Wyodak, consistent with PacifiCorp's on-going legal appeals. PacifiCorp will continue to support its appeal of the portion of EPA's FIP that requires installation of SCR at Wyodak. If, following appeal, EPA's final FIP as it pertains to Wyodak is upheld, PacifiCorp will update its evaluation of alternative compliance strategies that will meet any new requirements, as applicable, and provide the associated analysis in a future IRP or IRP Update.

- Foregoing installation of SCR at Dave Johnston Unit 3 with a firm commitment to retire the unit by the end of 2027 will avoid the need for incremental capital expenditures and retain compliance planning flexibility associated with EPA's draft 111(d) rule. If, following the state of Wyoming's appeal of the Dave Johnston Unit 3 SCR requirement, EPA's final FIP as it pertains to Dave Johnston Unit 3 is upheld, PacifiCorp will commit to shutting down Dave Johnston Unit 3 by the end of 2027. If, following appeal, EPA's final FIP as it pertains to Dave Johnston Unit 3 is or will be modified, PacifiCorp will evaluate alternative compliance strategies that will meet any new requirements, as applicable, and provide the associated analysis in a future IRP or IRP Update.

- Natural gas conversion of Naughton Unit 3 in 2018 is lower cost when compared to an early retirement alternative. PacifiCorp will refresh RFPs to procure gas transportation and EPC for a Naughton Unit 3 natural gas conversion in the first quarter of 2016. In conjunction with the RFP processes, PacifiCorp may update its economic analysis of natural gas conversion to align gas transportation and EPC cost assumptions with market bids.

- Analysis of inter-temporal and technology trade-off analysis supports a strategy that eliminates the compliance obligation to install SCR at Cholla Unit 4 with a firm commitment to cease operating the unit as a coal-fueled asset by April 2025. PacifiCorp will continue permitting efforts in support of an alternative Regional Haze compliance approach that avoids installation of SCR.

- Avoiding SCR at Wyodak, Dave Johnston Unit 3, Cholla Unit 4 and converting Naughton Unit 3 to natural gas in 2018 will save customers hundreds of millions of dollars.

Appendix V3-A: Wyodak Timelines

Figure V3-A.1 – Wyodak SCR Installation Schedule for Assumed March 4, 2019 Compliance Date

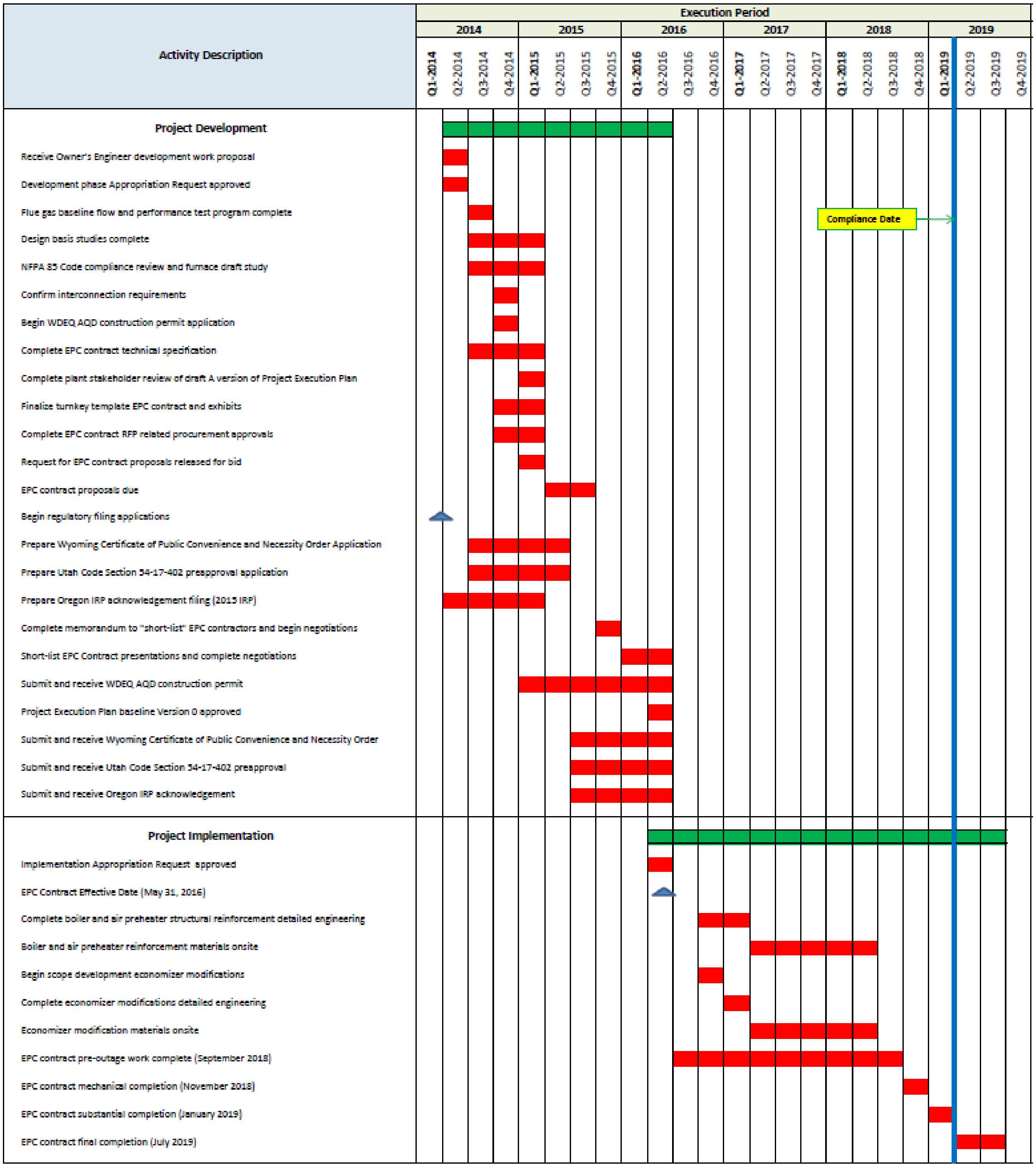


Figure V3-A.2 – Wyodak SNCR Installation Schedule for Assumed March 4, 2019 Compliance Date

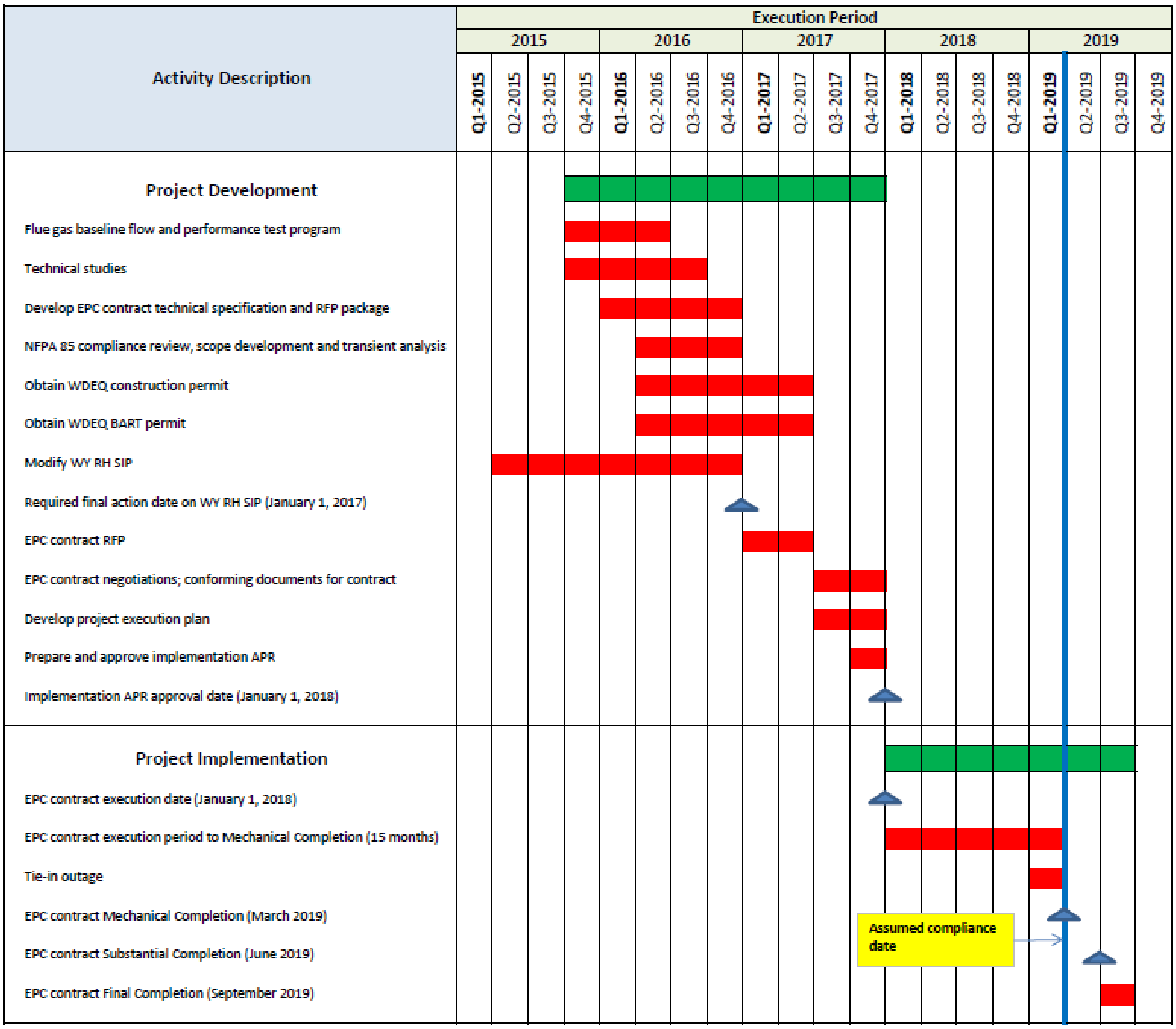


Figure V3-A.3 – Wyodak Natural Gas Conversion Schedule for Summer 2019 On-line Date

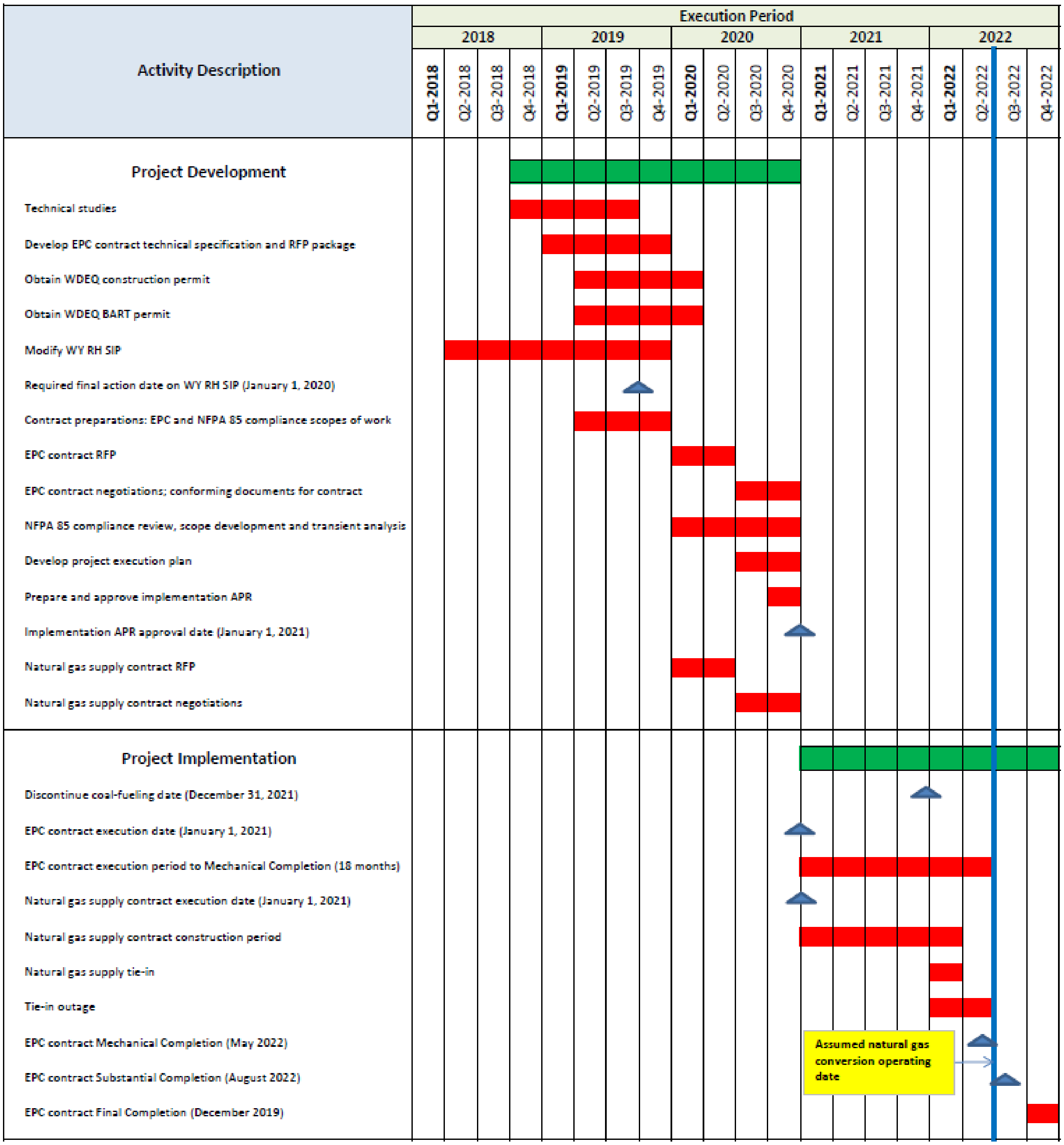
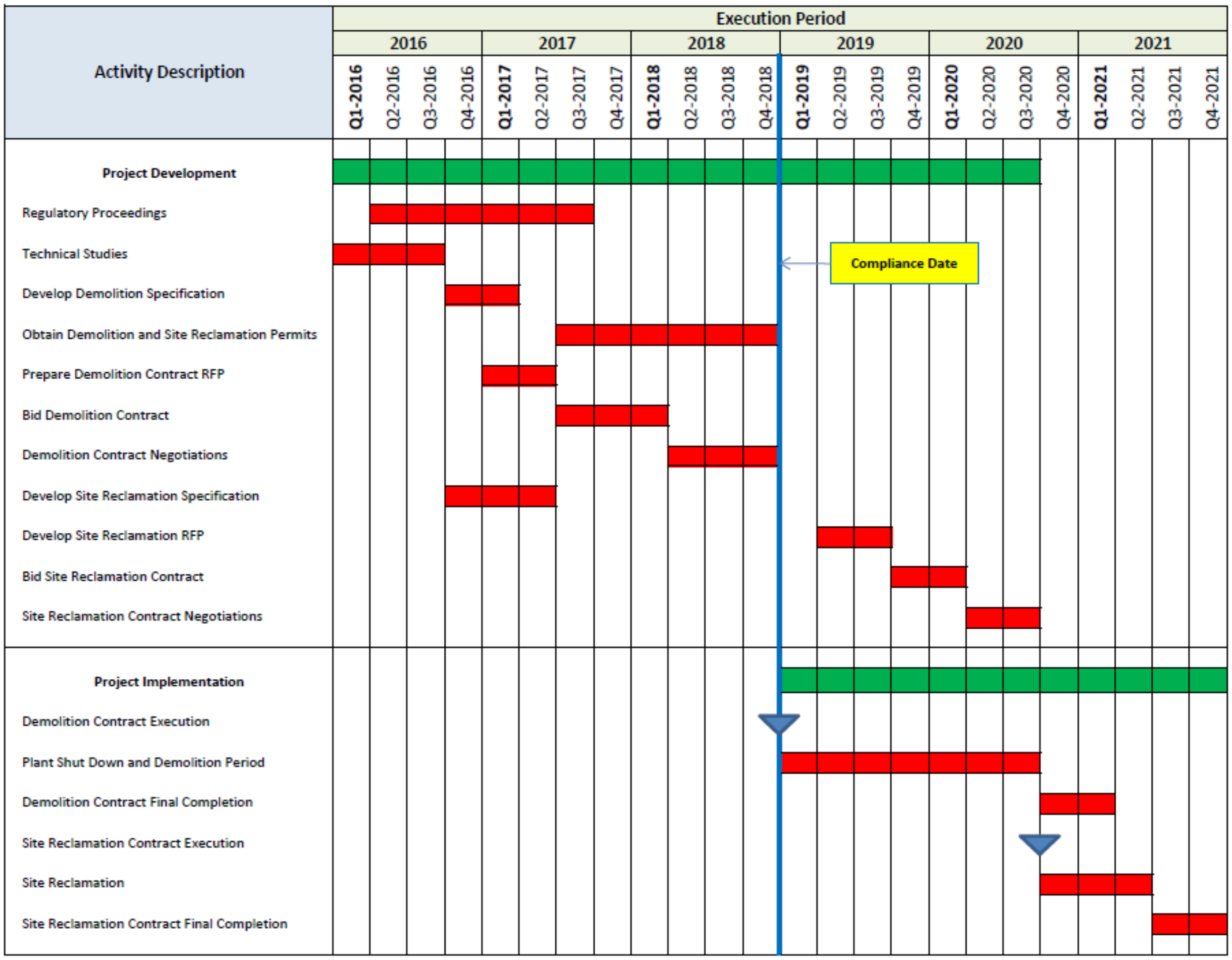


Figure V3-A.4 – Wyodak Early Retirement Schedule for an April 2019 Retirement Date



Appendix V3-B: Wyodak Compliance Alternative Annual Expenditures

Table V3-B.1 – Wyodak and Dave Johnston Annual Expenditures for the Wyodak 2019 SCR Case

Wyodak Environmental Capital (Nominal $m, with AFUDC)									
Description	2015	2017	2018	2019	2020	2021	2022	2030	Total
SCR	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Mercury	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
CWA	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
CCR	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Total	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

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

Dave Johnston 1&2 Environmental Capital (Nominal $m, with AFUDC)									
Description	2015	2017	2018	2019	2020	2021	2022	2030	Total
SCR	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Mercury	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
CWA	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
CCR	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Total	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

Dave Johnston 1&2 Run-rate Operating Cost (Nominal $m, Capital with AFUDC)										
Description	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
O&M	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Capital	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Total	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Description	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
O&M	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Capital	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Total	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

Table V3-B.2 – Wyodak and Dave Johnston Annual Expenditures for the Wyodak 2019 Early Retirement Case

Wyodak Environmental Capital (Nominal $m, with AFUDC)									
Description	2015	2017	2018	2019	2020	2021	2022	2030	Total
SCR	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Mercury	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
CWA	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
CCR	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Total	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

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

Dave Johnston 1&2 Environmental Capital (Nominal $m, with AFUDC)									
Description	2015	2017	2018	2019	2020	2021	2022	2030	Total
SCR	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Mercury	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
CWA	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
CCR	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Total	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

Dave Johnston 1&2 Run-rate Operating Cost (Nominal $m, Capital with AFUDC)										
Description	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
O&M	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Capital	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Total	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Description	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
O&M	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Capital	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Total	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

Table V3-B.3 – Wyodak and Dave Johnston Annual Expenditures for the Wyodak 2019 Gas Conversion Case

Wyodak Environmental Capital (Nominal $m, with AFUDC)									
Description	2015	2017	2018	2019	2020	2021	2022	2030	Total
SCR	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Mercury	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
CWA	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
CCR	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Total	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

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

Dave Johnston 1&2 Environmental Capital (Nominal $m, with AFUDC)									
Description	2015	2017	2018	2019	2020	2021	2022	2030	Total
SCR	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Mercury	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
CWA	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
CCR	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Total	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

Dave Johnston 1&2 Run-rate Operating Cost (Nominal $m, Capital with AFUDC)										
Description	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
O&M	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Capital	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Total	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Description	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
O&M	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Capital	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Total	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

Table V3-B.4 – Wyodak and Dave Johnston Annual Expenditures for Case IT-1

Wyodak Environmental Capital (Nominal $m, with AFUDC)									
Description	2015	2017	2018	2019	2020	2021	2022	2030	Total
SNCR	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Mercury	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
CWA	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
CCR	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Total	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

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

Dave Johnston 1&2 Environmental Capital (Nominal $m, with AFUDC)									
Description	2015	2017	2018	2019	2020	2021	2022	2030	Total
SCR	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Mercury	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
CWA	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
CCR	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Total	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

Dave Johnston 1&2 Run-rate Operating Cost (Nominal $m, Capital with AFUDC)										
Description	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
O&M	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Capital	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Total	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Description	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
O&M	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Capital	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Total	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

Table V3-B.5 – Wyodak and Dave Johnston Annual Expenditures for Case IT-2

Wyodak Environmental Capital (Nominal $m, with AFUDC)									
Description	2015	2017	2018	2019	2020	2021	2022	2030	Total
SCR	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Mercury	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
CWA	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
CCR	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Total	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

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

Dave Johnston 1&2 Environmental Capital (Nominal $m, with AFUDC)									
Description	2015	2017	2018	2019	2020	2021	2022	2030	Total
SCR	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Mercury	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
CWA	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
CCR	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Total	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

Dave Johnston 1&2 Run-rate Operating Cost (Nominal $m, Capital with AFUDC)										
Description	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
O&M	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Capital	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Total	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Description	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
O&M	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Capital	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Total	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

Table V3-B.6 – Wyodak and Dave Johnston Annual Expenditures for Case IT-3

Wyodak Environmental Capital (Nominal $m, with AFUDC)									
Description	2015	2017	2018	2019	2020	2021	2022	2030	Total
SCR	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Mercury	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
CWA	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
CCR	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Total	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

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

Dave Johnston 1&2 Environmental Capital (Nominal $m, with AFUDC)									
Description	2015	2017	2018	2019	2020	2021	2022	2030	Total
SCR	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Mercury	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
CWA	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
CCR	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Total	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

Dave Johnston 1&2 Run-rate Operating Cost (Nominal $m, Capital with AFUDC)										
Description	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
O&M	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Capital	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Total	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Description	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
O&M	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Capital	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Total	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

Table V3-B.7 – Wyodak and Dave Johnston Annual Expenditures for Case FT-1

Wyodak Environmental Capital (Nominal $m, with AFUDC)									
Description	2015	2017	2018	2019	2020	2021	2022	2030	Total
SCR	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Mercury	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
CWA	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
CCR	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Total	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

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

Dave Johnston 1&2 Environmental Capital (Nominal $m, with AFUDC)									
Description	2015	2017	2018	2019	2020	2021	2022	2030	Total
SCR	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Mercury	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
CWA	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
CCR	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Total	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

Dave Johnston 1&2 Run-rate Operating Cost (Nominal $m, Capital with AFUDC)										
Description	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
O&M	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Capital	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Total	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Description	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
O&M	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Capital	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Total	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

Table V3-B.8 – Wyodak and Dave Johnston Annual Expenditures for Case FT-2

Wyodak Environmental Capital (Nominal $m, with AFUDC)									
Description	2015	2017	2018	2019	2020	2021	2022	2030	Total
SCR	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Mercury	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
CWA	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
CCR	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Total	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

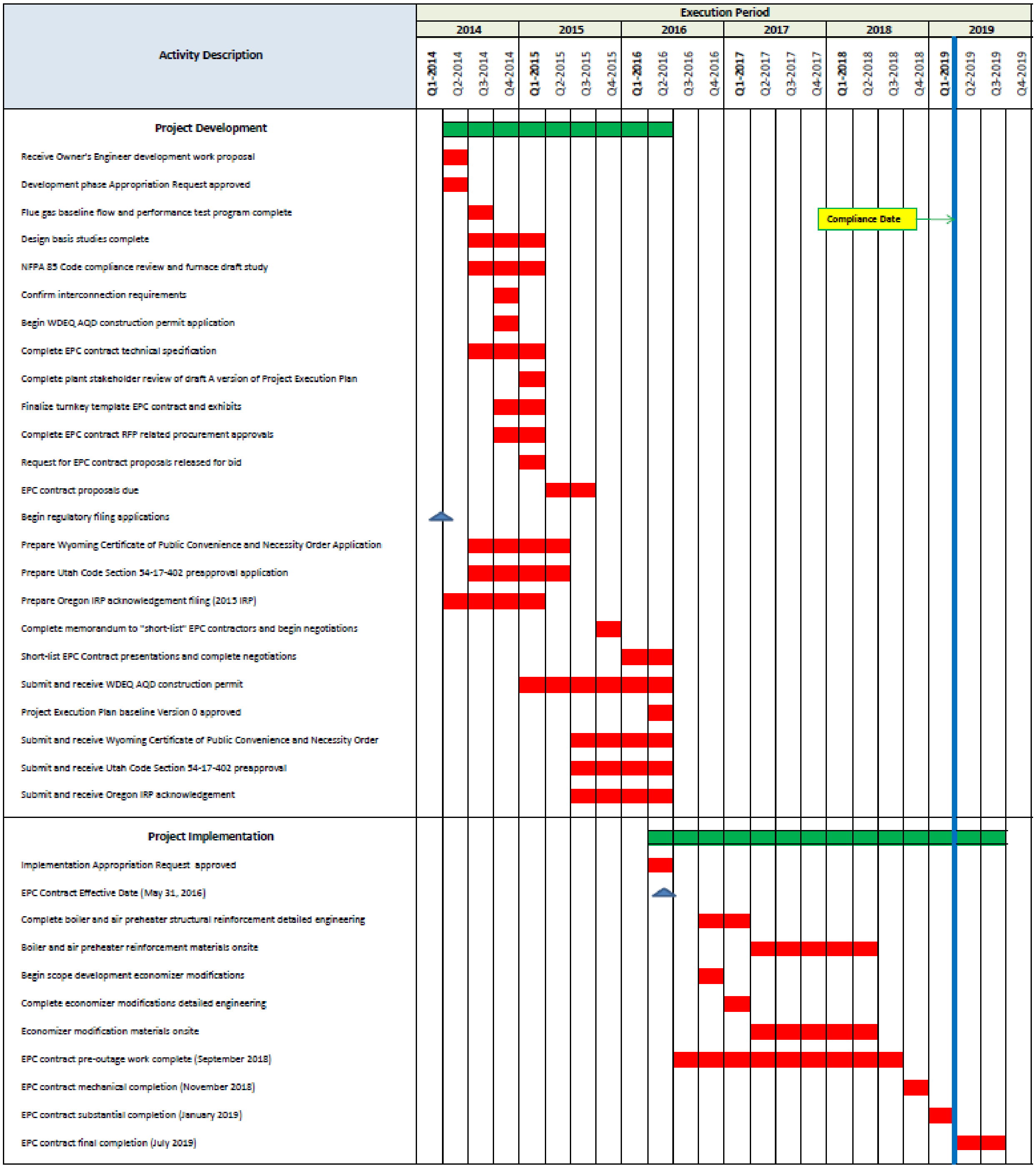
Wyodak Run-rate Operating Cost (Nominal $m, Capital with AFUDC)										
Description	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
O&M	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Capital	[redacted]	[redacted]	[redacted]	[redacted]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

Dave Johnston 1&2 Environmental Capital (Nominal $m, with AFUDC)									
Description	2015	2017	2018	2019	2020	2021	2022	2030	Total
SCR	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Mercury	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
CWA	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
CCR	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Total	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

Dave Johnston 1&2 Run-rate Operating Cost (Nominal $m, Capital with AFUDC)										
Description	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
O&M	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Capital	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Fixed Gas Trans.	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Total	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Description	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
O&M	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Capital	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Fixed Gas Trans.	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Total	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

Appendix V3-C: Dave Johnston Unit 3 SCR Timeline

Figure V3-C.1 – Dave Johnston Unit 3 SCR Installation Schedule for Assumed March 4, 2019 Compliance Date



Appendix V3-D: Dave Johnston Unit 3 Compliance Alternative Annual Expenditures

Table V3-D.1 – Dave Johnston Unit 3 Annual Expenditures for a 2019 SCR Case

Dave Johnston 3 Environmental Capital (Nominal $m, with AFUDC)							
Description	2015	2018	2019	2020	2021	2022	Total
SCR	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Mercury	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
CWA	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
CCR	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Total	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

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

Table V3-D.2 – Dave Johnston Unit 3 Annual Expenditures without SCR

Dave Johnston 3 Environmental Capital (Nominal $m, with AFUDC)							
Description	2015	2018	2019	2020	2021	2022	Total
SCR	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Mercury	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
CWA	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
CCR	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Total	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

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

Appendix V3-E: Naughton Unit 3 Timelines

Figure V3-E.1 – Naughton Unit 3 Natural Gas Conversion Schedule for a June 30, 2018 On-line Date

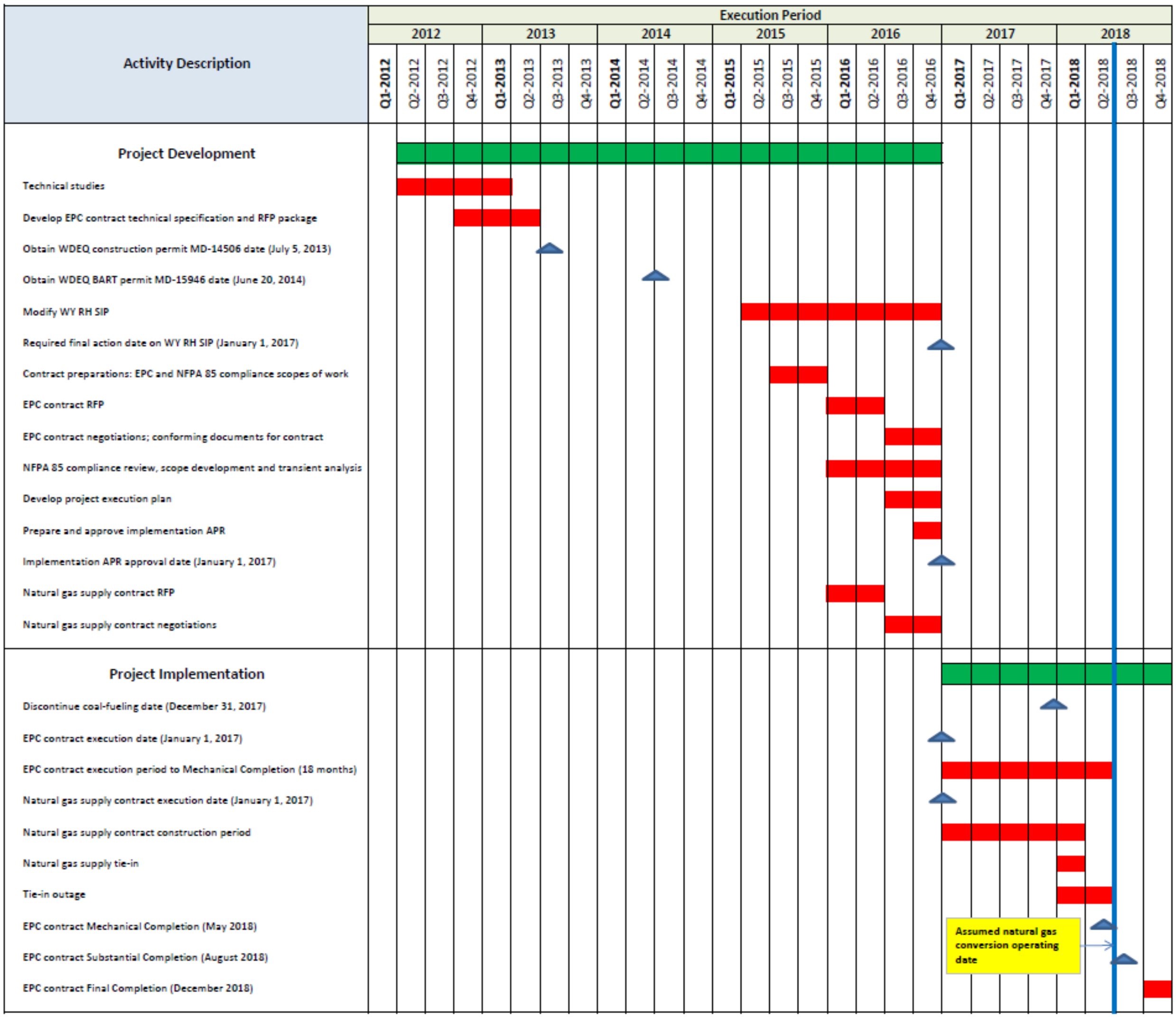
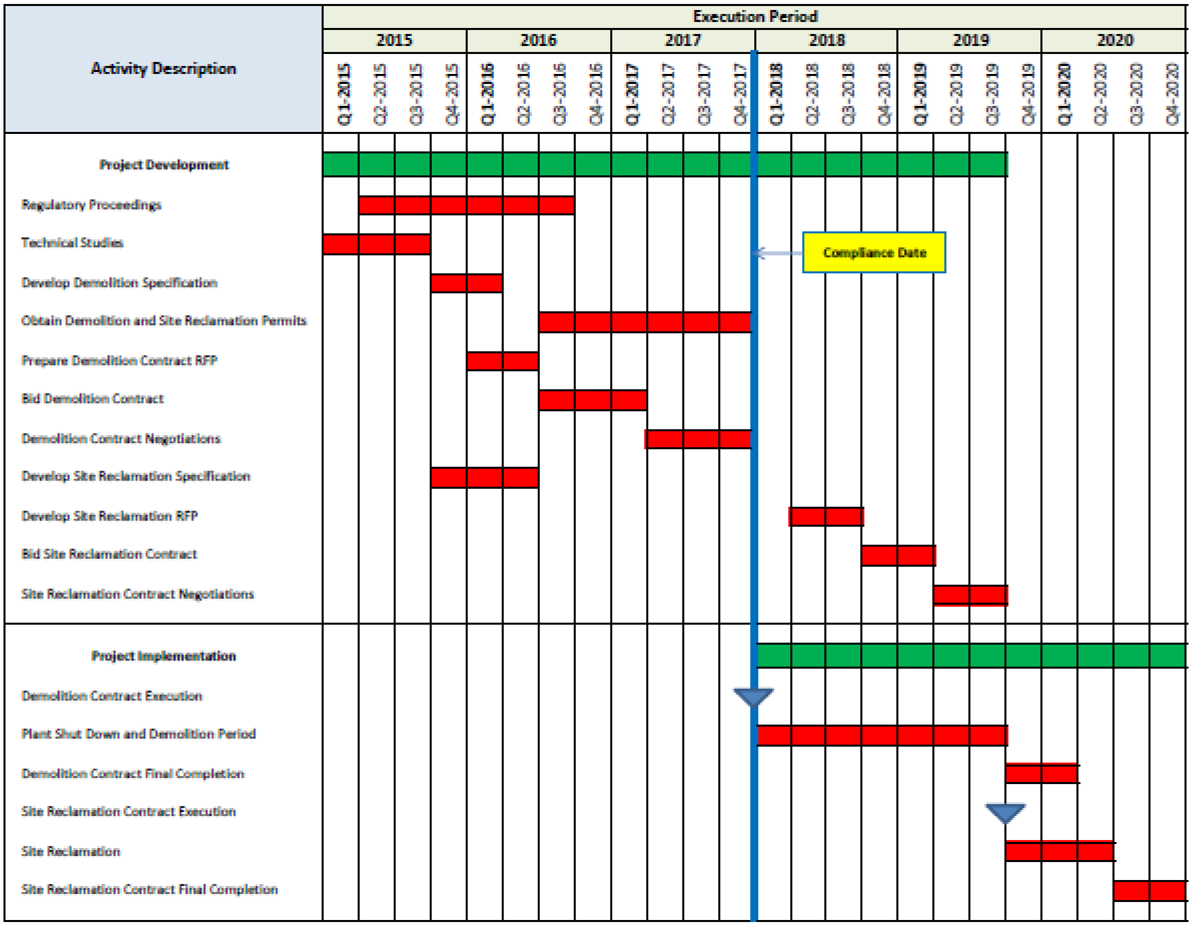


Figure V3-E.2 – Naughton Unit 3 Early Retirement Schedule for a December 31, 2017 Retirement Date



Appendix V3-F: Naughton Unit 3 Compliance Alternative Annual Expenditures

Table V3-F.1 – Naughton Unit 3 Annual Expenditures for a 2018 Gas Conversion Case

Naughton 3 Environmental Capital (Nominal $m, with AFUDC)			
Description	2015	2019	Total
Mercury	[redacted]	[redacted]	[redacted]
CWA	[redacted]	[redacted]	[redacted]
Total	[redacted]	[redacted]	[redacted]

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

Table V3-F.2 – Naughton Unit 3 Annual Expenditures for a 2018 Early Retirement Case

Naughton 3 Environmental Capital (Nominal $m, with AFUDC)			
Description	2015	2019	Total
Mercury	[redacted]	[redacted]	[redacted]
CWA	[redacted]	[redacted]	[redacted]
Total	[redacted]	[redacted]	[redacted]

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

Appendix V3-G: Cholla Unit 4 Timelines

Figure V3-G.1 – SCR Installation Schedule for Assumed December 2017 Compliance Date

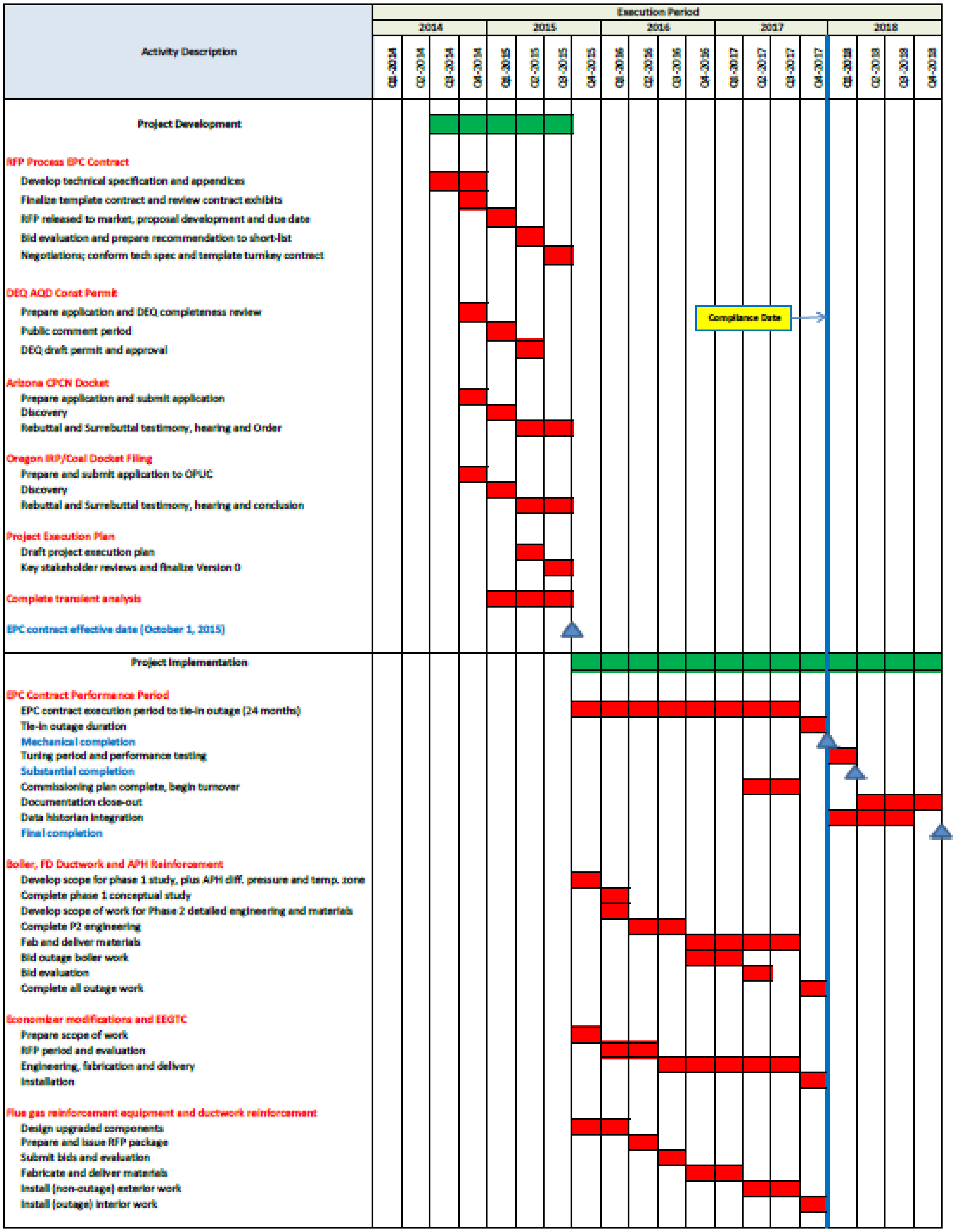


Figure V3-G.2 – SNCR Installation Schedule for Assumed December 2017 Compliance Date

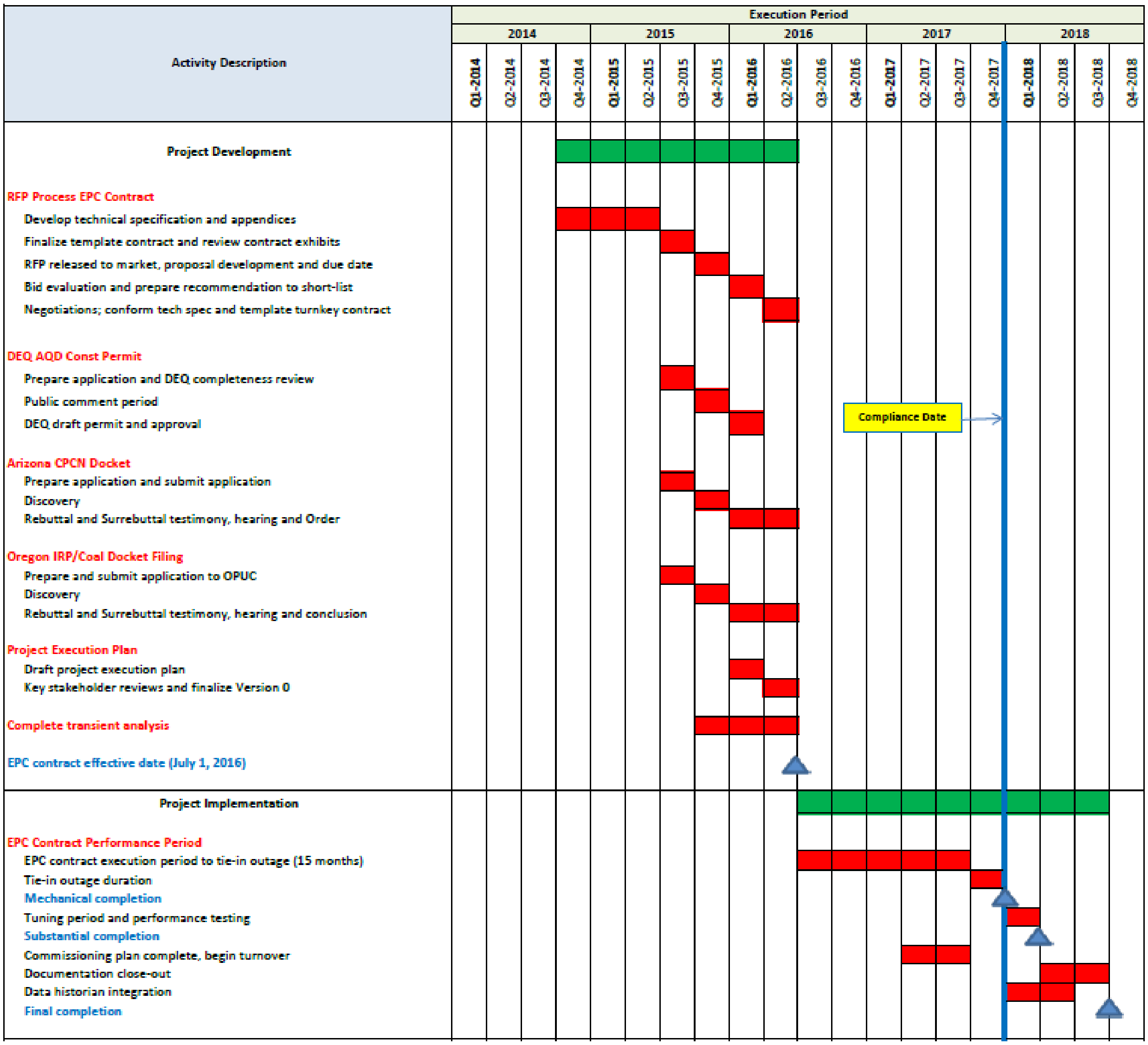


Figure V3-G.3 – Natural Gas Conversion Installation Schedule for a 2018 On-line Date

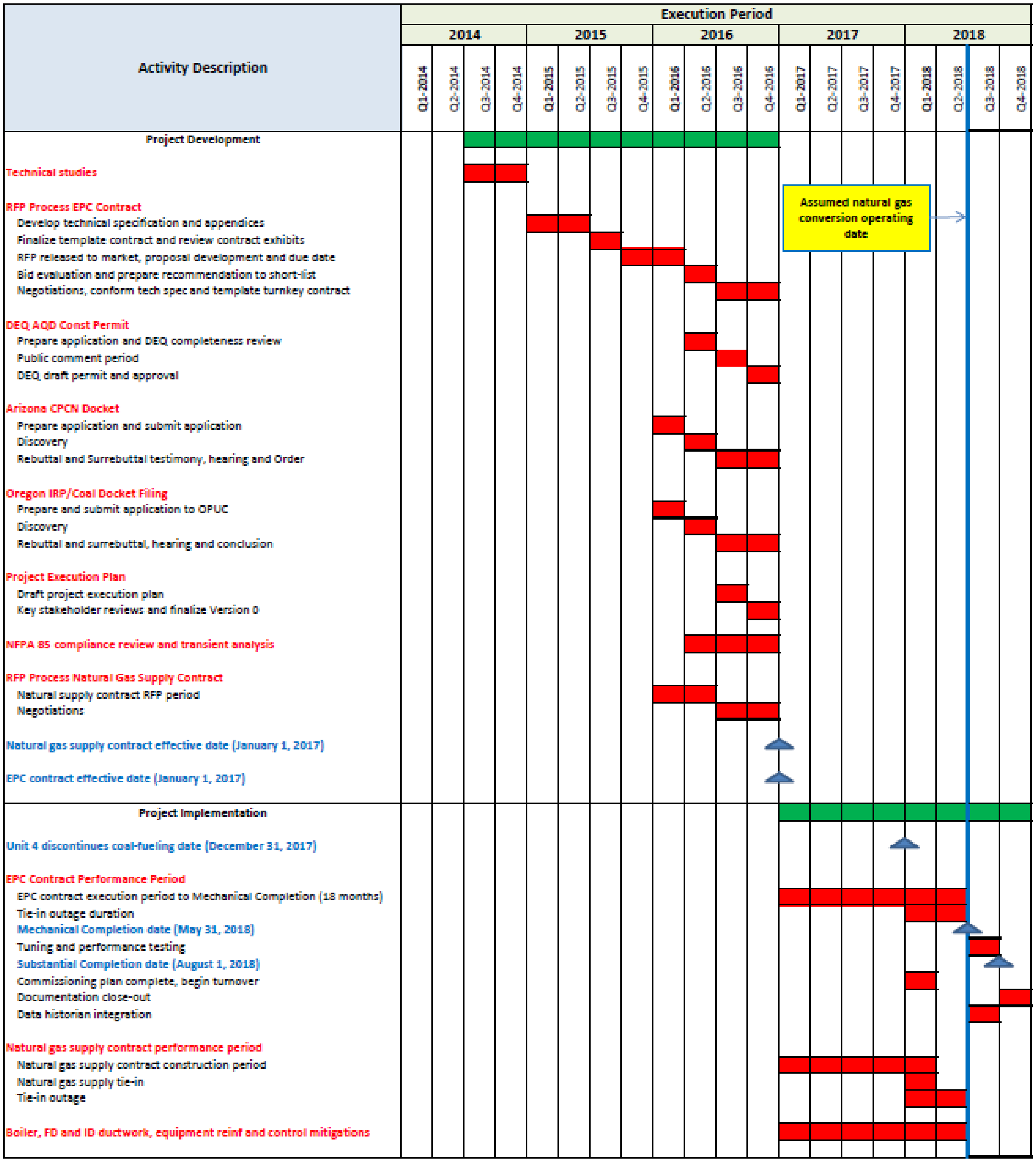
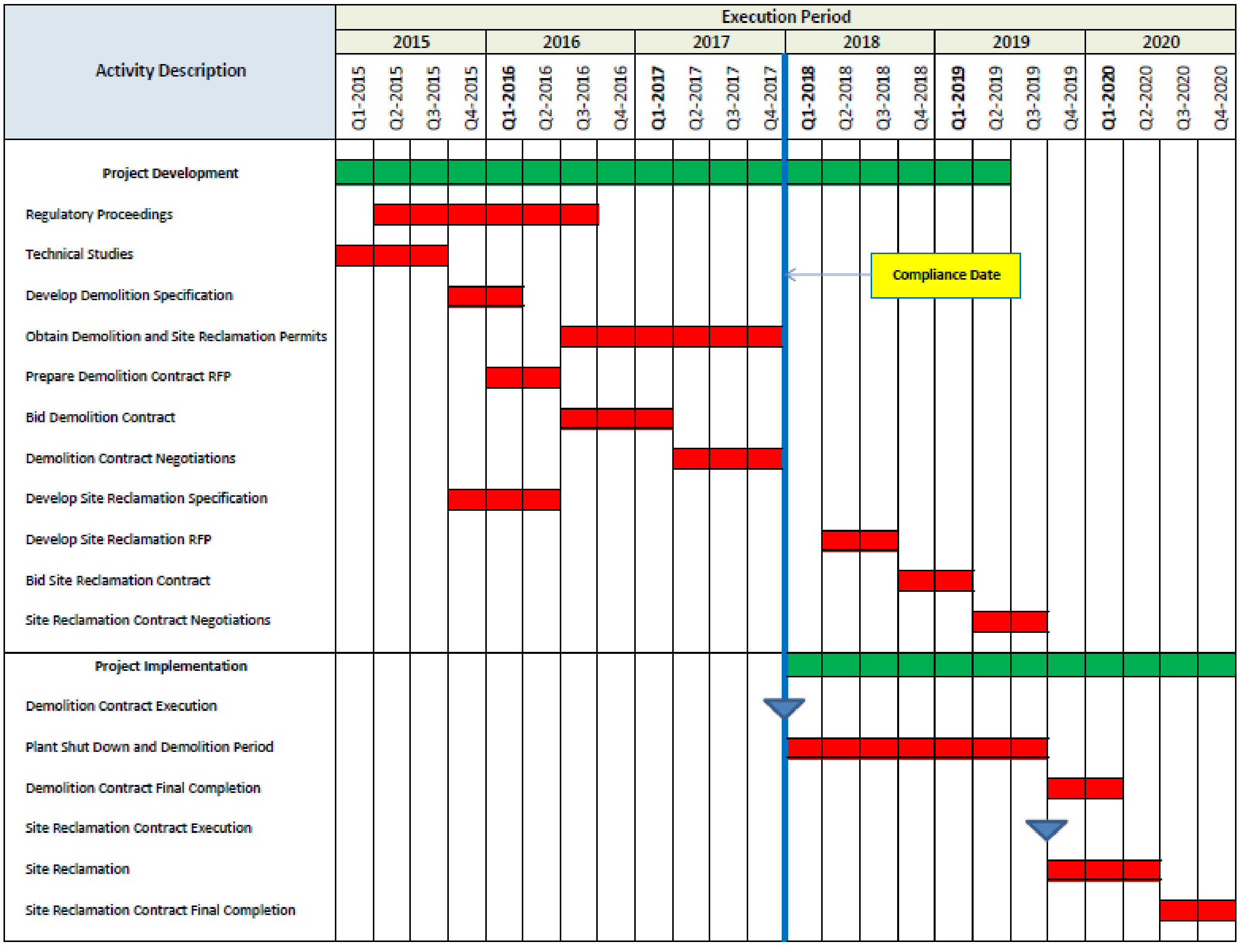


Figure V3-G.4 – Early Retirement Schedule for a Year-end 2017 Retirement Date



Appendix V3-H: Cholla Unit 4 Initial Analysis Compliance Alternative Annual Expenditures

Table V3-H.1 – Cholla Unit 4 Annual Expenditures for the Continued Coal Operation Case

Environmental Capital (Nominal $m, with AFUDC)							
Description	2013	2015	2017	2020	2025	2030	Total
SM	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
SCR	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Mercury	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
CCR/ELG	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Total	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

Run-rate Operating Cost (Nominal $m, Capital with AFUDC)										
Description	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
O&M	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Capital	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Total	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Description	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
O&M	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Capital	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Total	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

Table V3-H.2 – Cholla Unit 4 Annual Expenditures for the 2017 Early Retirement Case

Environmental Capital (Nominal $m, with AFUDC)							
Description	2013	2015	2017	2020	2025	2030	Total
SM	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
SCR	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Mercury	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
CCR/ELG	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Total	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

Run-rate Operating Cost (Nominal $m, Capital with AFUDC)										
Description	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
O&M	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Capital	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Pre-paid Trans.	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Safe Harbor	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
CSA LDs	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Total	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Description	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
O&M	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Capital	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Pre-paid Trans.	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Safe Harbor	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
CSA LDs	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Total	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

Table V3-H.3 – Cholla Unit 4 Annual Expenditures for the 2018 Gas Conversion Case

Environmental Capital (Nominal $m, with AFUDC)							
Description	2013	2015	2017	2020	2025	2030	Total
SM	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
SCR	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Mercury	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
CCR/ELG	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Total	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

Run-rate Operating Cost (Nominal $m, Capital with AFUDC)										
Description	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
O&M	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Capital	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
CSA LDs	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Fixed Gas Trans.	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Total	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Description	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
O&M	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Capital	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
CSA LDs	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Fixed Gas Trans.	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Total	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

Appendix V3-I: Cholla Unit 4 Updated/Expanded Analysis Compliance Alternative Annual Expenditures

Table V3-I.1 – Cholla Unit 4 Updated Annual Expenditures for the Continued Coal Operation Case

Environmental Capital (Nominal $m, with AFUDC)							
Description	2013	2015	2017	2020	2025	2030	Total
SM	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
SCR	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Mercury	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
CCR/ELG	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Total	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

Run-rate Operating Cost (Nominal $m, Capital with AFUDC)										
Description	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
O&M	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Capital	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Total	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Description	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
O&M	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Capital	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Total	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

Table V3-I.2 – Cholla Unit 4 Updated Annual Expenditures for the 2017 Early Retirement Case

Environmental Capital (Nominal $m, with AFUDC)							
Description	2013	2015	2017	2020	2025	2030	Total
SM	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
SCR	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Mercury	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
CCR/ELG	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Total	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

Run-rate Operating Cost (Nominal $m, Capital with AFUDC)										
Description	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
O&M	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Capital	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Pre-paid Trans.	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Safe Harbor	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
CSA LDs	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Total	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Description	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
O&M	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Capital	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Pre-paid Trans.	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Safe Harbor	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
CSA LDs	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Total	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

Table V3-I.3 – Cholla Unit 4 Updated Annual Expenditures for the 2018 Gas Conversion Case

Environmental Capital (Nominal $m, with AFUDC)							
Description	2013	2015	2017	2020	2025	2030	Total
SM	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
SCR	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Mercury	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
CCR/ELG	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Total	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

Run-rate Operating Cost (Nominal $m, Capital with AFUDC)										
Description	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
O&M	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Capital	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
CSA LDs	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Fixed Gas Trans.	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Total	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Description	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
O&M	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Capital	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
CSA LDs	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Fixed Gas Trans.	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Total	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

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Table V3-I.4 – Cholla Unit 4 Annual Expenditures for the SNCR, 2024 Retirement Case

Environmental Capital (Nominal $m, with AFUDC)							
Description	2013	2015	2017	2020	2025	2030	Total
SM	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
SNCR	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Mercury	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
CCR/ELG	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Total	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

Run-rate Operating Cost (Nominal $m, Capital with AFUDC)										
Description	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
O&M	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Capital	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Pre-paid Trans.	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Safe Harbor	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
CSA LDs	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Total	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Description	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
O&M	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Capital	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Pre-paid Trans.	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Safe Harbor	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
CSA LDs	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Total	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

*In the 2024 retirement case (without SNCR expenditures), 2017 SNCR capital costs are avoided, and SNCR-related O&M expenses are reduced by [redacted] from 2018 through 2024. No other expenditures change.

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Table V3-I.5 – Cholla Unit 4 Annual Expenditures for the SNCR, 2025 Gas Conversion Case

Environmental Capital (Nominal $m, with AFUDC)							
Description	2013	2015	2017	2020	2025	2030	Total
SM	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
SNCR	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Mercury	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
CCR/ELG	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Total	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

Run-rate Operating Cost (Nominal $m, Capital with AFUDC)										
Description	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
O&M	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Capital	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Fixed Gas Trans.	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Total	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Description	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
O&M	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Capital	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Fixed Gas Trans.	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Total	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

*In the 2025 gas conversion case (without SNCR expenditures), 2017 SNCR capital costs are avoided, and SNCR-related O&M expenses are reduced by [redacted] from 2018 through 2024. No other expenditures change.

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