Rio Tinto

Rio Tinto Kennecott
4700 Daybreak Parkway,
South Jordan, Utah 84009
USA
T 801-569-6200
F 801-569-6463

**Jenny Esker**
Environmental Engineer
Environmental



Mr. Bryce Bird – Director
Department of Environmental Quality
Division of Air Quality – Emissions Inventory
P.O. Box 144820
Salt Lake City, Utah 84114-4820

November 30, 2018

Subject: **Kennecott Utah Copper's Comments on the Proposed Revisions to Section IX, Control Measures for Area and Point Sources, Part H, Emission Limits and Change in Proposed Rule R307-110-17**

Dear Mr. Bird and UDAQ staff,

Kennecott Utah Copper LLC (KUC) submits the following comments on the proposed Revisions to Section IX, Control Measures for Area and Point Sources, Part H, Emission Limits and Change in Proposed Rule R307-110-17.

The current comment period is a continuation of a rulemaking that the Utah Air Quality Board (AQB) initiated in June 2018 to implement a Serious Area PM2.5 SIP for the Salt Lake City Nonattainment Area (SLC NAA). Public comment on the initial proposed revisions to Part H of the PM2.5 SIP opened on July 1, 2018. KUC submitted comments during this first public comment period regarding the measures that the Utah Division of Air Quality (UDAQ) proposed for KUC's facilities as part of the agency's Serious Area PM2.5 SIP for the SLC NAA.

UDAQ revised the proposed conditions in Part H and, on October 3, 2018, UDAQ requested that the AQB open Part H to a second round of public comment.[1] Several of the units addressed in these additional revisions to Part H are owned and operated by KUC. KUC comments on those specific changes as well as several other provisions in the November 1 version of Part H that are currently open for public comment.[2]

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[1] For clarity, KUC refers to the version of Part H that UDAQ prepared in advance of the October 3, 2018 AQB meeting as the "October 3 version." During the October 3, 2018 AQB meeting, the AQB made several significant changes to the October 3 version before approving the package for public comment. KUC refers to the version containing the AQB's amendments as the "November 1 version," which coincides with the version of the proposed Part H that was opened for public comment on November 1.

[2] On one of the websites associated with this public comment period, UDAQ states, "[t]he only portions of this Revision open to public comment are highlighted in Red," and provides a link to the November 1 version of Part H. *See* https://deq.utah.gov/air-quality/air-quality-rule-plan-changes-open-public-comment. However, the AQB has not taken final action on any revisions of Part H and the discussion between UDAQ staff and the AQB during the October 3, 2018 AQB meeting suggested that the entirety of Part H would be open for public comment. As such, it is improper to limit public comment in the way UDAQ has suggested on its website and KUC requests that UDAQ consider the entirety of the comments submitted herein.

## I. COMMENT NO. 1. UDAQ CORRECTLY PROPOSED THAT KUC STACK TEST THE HOLMAN BOILER, REFINERY BOILERS AND IN-PIT CRUSHER EVERY THREE YEARS

At the October 3, 2018 AQB meeting, a member of the AQB noted that the October 3 version of Part H proposed to required stack testing once every three years for a number of units. Without discussing any of the specific circumstances related to any of these units, the AQB voted to amend the October 3 version of Part H to mandate that all stack testing required by the PM2.5 SIP be conducted annually.[3] KUC owns and operates several units impacted by the AQB's proposed revisions. Specifically, the AQB's proposal impacts the stack testing frequency for the Holman boiler (Conditions H.2.i.B.II and H.12.j.i.B.II), the refinery boilers (Conditions H.2.ii.B and H.12.j.ii.B) and the Bingham Canyon Mine's in-pit crusher (Condition H.12.h.i.C).

UDAQ prepared a memorandum – entitled "Response to Board Motion on SIP" – in which the agency explains why stack testing frequency on a three-year basis is sufficient for these and other units.[4] UDAQ explained that the frequency of stack testing must be determined on a case-by-case basis that considers unit-specific factors including (1) variability of the emission stream, (2) the mix of fuels combusted, (3) whether the unit operates in batch processes, and (4) the unit's history of compliance near or above the emission limitations. Further, UDAQ explained that other available data – such as parametric monitoring – should also be considered when determining the frequency of emissions testing because that data may provide assurances of continuous compliance. UDAQ explained that in preparing the proposed revisions to Part H, UDAQ staff conducted this site-specific evaluation for each of the units impacted by the AQB's amendment and determined that stack testing on a three-year basis was appropriate for these units. Finally, UDAQ explained that stack testing does impose a burden on both the owner/operator of the source as well as UDAQ's compliance staff.

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[3] The issue of the frequency of stack testing was spearheaded by AQB member Kevin Cromar. As such, Mr. Cromar's statement provides the most-relevant insight into the purpose underlying the AQB's decision to amend the October 3 version of Part H to increase stack testing frequency for these sources. Mr. Cromar stated,

> I actually personally think that three-year stack testing is typically just fine especially with the other ways to verify. My concern though is I think the general public probably doesn't understand the difference between an annual and a three-year and I think there's a some—somewhat of a feeling that certain sources aren't being held accountable. And so my question is—I don't believe that stack testing is burdensome, once a year versus three years—is there any reason we wouldn't want to move to an annual stack test as opposed to once every three years? Again, for the reason of just public assurance that these sources are being held accountable?

In other words, Mr. Cromar did not state that he believed there was a regulatory basis for increasing the stack testing frequency for the sources subject to the AQB's amendment or that there were specific facts that necessitated increased stack testing for any particular unit. Rather, Mr. Cromar stated that the only purpose for the change was to provide increased public confidence that these sources are complying with applicable emission limitations. Importantly, and consistent with EPA guidance, Mr. Cromar also acknowledged that there are other methods of assuring continuous compliance than increasing the frequency of stack testing.

[4] Utah Department of Environmental Quality, Air Quality Rule and Plan Changes Open for Public Comment, UDAQ Response to Board Motion on SIP, available at https://deq.utah.gov/air-quality/air-quality-rule-plan-changes-open-public-comment (hereinafter "UDAQ Response Memo").

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KUC agrees with UDAQ's determination.

UDAQ's analysis is grounded in the regulations governing compliance monitoring. Furthermore, a unit-specific analysis for each of the units owned and operated by KUC reveals that there is a reasonable assurance of continuous compliance at each of these units and that stack testing every three years is sufficient for these units.

Rule 307-165 is Utah's rule governing stack testing. This rule requires that stack testing for sources listed in Part H be "at least once every five years."[5] This regulation establishes the minimum requirement, meaning UDAQ can require more frequent stack testing if the agency believes more frequent stack testing is necessary. But the language employed in R307-165-2 suggests that stack testing frequency should be determined on a case-by-case basis, taking into account the specific circumstances of each emission unit, the unit's operation, and the unit's past compliance.

Such a unit-specific analysis is consistent with EPA's Compliance Assurance Monitoring Rule (CAMR). EPA developed CAMR as a complement to the Title V program. CAMR was specifically designed with the purpose of developing monitoring plans that provide a "reasonable assurance of compliance with applicable emission limitations."[6] CAMR accomplishes the goal of providing reasonable assurance of compliance by requiring the development of a "site specific" monitoring strategy which is implemented through an evaluation of the following,

> *Evaluation factors*. In designing monitoring to meet the requirements of [the CAM Rule], the owner or operator shall take into account ***site-specific factors*** including the applicability of existing monitoring equipment and procedures, the ability of monitoring to account for process and control device operational variability, the reliability and latitude built

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[5] Utah Admin. Code R307-165-2. This section also allows the UDAQ director to require additional stack testing where the director "has reason to believe than an applicable emission limitation is being exceeded."

[6] 40 CFR § 64.3(a). When EPA promulgated CAMR, the agency explained that a site-specific understanding of the unit should be considered when a developing monitoring strategy and that common-sense should apply as opposed to rigid rules.

> The general purpose of the monitoring required by part 64 is to assure compliance with emission standards through requiring monitoring of the operation and maintenance of the control equipment and, if applicable, operating conditions of the pollutant-specific emissions unit. . . . Logically, therefore, once an owner or operator has shown that the installed control equipment can comply with an emission limit, there will be a reasonable assurance of ongoing compliance with the emission limit as long as the emissions unit is operated under the conditions anticipated and the control equipment is operated and maintained properly.

62 Fed. Reg. 54900, 54918 (October 22, 1997). Further, EPA went on to explain that there is a "close nexus of first demonstrating through a performance test that the installed control equipment is capable of achieving the standard on a continuous basis and then properly operating and maintaining that equipment so as to provide a reasonable assurance of continuous compliance with the standard." *Id.*

> into the control technology, and the level of actual emissions relative to the compliance limitation.[7]

These factors are consistent with the factors that UDAQ explained that it relied on when it made the site-specific determination for stack testing frequency as part of the SIP. UDAQ focused on the potential variability of emissions, fuels, and processes as well as the level of emissions compared to the emission limitation to determine that stack testing the in-pit crusher, the Holman boiler, and the refinery boilers on a three-year basis was appropriate.

In the following paragraphs KUC provides a unit-specific analysis to show why UDAQ's determination for stack testing the three units on a three-year basis is appropriate. As quoted above, the AQB appears to believe that stack testing does not impose significant burdens on either the source or UDAQ. This mistaken understanding may be based on a view that the burden is only represented by the cost of the stack test. But stack testing requires additional coordination and resources that can interfere with the normal operation of a facility. First, employees must prepare stack testing protocols and work with the agency to obtain approval of the protocols. Then, employees must prepare the facility to run at a rate that is likely higher than typical operations. Rather than planning to meet a daily or weekly target, a high rate of production must be maintained for an approximate 10 hour window.[8] This creates an anomaly for the facility that can result in impacts to employee staffing, the typical schedule for the equipment, and the work areas adjacent to testing-related activities, all of which then may in turn effect how other day-to-day activities are planned in the days and weeks leading up to the stack test and for several days after as well. The requirements for one day of testing are much more difficult to coordinate than the routine activities executed to maintain and operate the equipment properly.

Moreover, stack tests impose burdens on regulators. Prior to conducting any stack test, a facility must notify the agency of the stack test, submit a stack test protocol to the agency for review, and, at the agency's discretion, participate in a pretest conference. Stack test results are submitted to UDAQ for review as well. Given UDAQ's finite resources, KUC believes that the AQB should refrain from imposing these pre- and post-test burdens on the state where there are reasonable assurances of continuous compliance.

Where there is little variability, little likelihood of an exceedance, or other more efficient means of ascertaining reasonable assurance of compliance, the burdens take on greater meaning. Regulations imposing more frequent stack testing that lack a genuine need for imposing additional stack testing will amplify the burdens on both state regulators and the source because there is no associated benefit. KUC believes that in the October 3 version of Part H, UDAQ attempted to strike the right balance between providing a reasonable assurance of compliance and imposing a burden on itself and KUC for the three relevant stack tests.

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[7] 40 CFR § 64.3(c).

[8] Utah Admin. Code R307-165-4 ("All tests shall be conducted while the source is operating at the ***maximum production or combustion rate*** at which such source will be operated." (emphasis added)). Indeed, in many Title V permits, UDAQ requires sources to conduct stack testing at "90 percent of the maximum firing rate."

### *The Holman Boiler*

The Holman Boiler is a natural gas-fired boiler (187 MMBtu/hr) and its emissions are controlled by flue gas recirculation and low NOx burners. The November 1 version proposes to impose a 14 lbs/hr limitation on the unit's NOx emissions and proposes to require annual stack testing for this unit. The Holman boiler is also subject to a 10% opacity limitation and an existing ***alternate monitoring plan***, which requires continuous monitoring of fuel use, stack oxygen, and steam output.[9] The Title V permit states that the alternate monitoring plan was specifically developed "to predict NOx emissions from the Holman boiler."[10]

The Holman Boiler's alternate monitoring plan generates data that provides a reasonable assurance that KUC is continuously operating the boiler in compliance with applicable emission limitations. By monitoring the Holman Boiler's fuel use, stack oxygen, and steam output, both UDAQ and KUC can calculate the emissions at the Holman boiler at any time. Furthermore, because the Holman boiler is a natural gas-fired boiler there is little variability in the boiler's emissions.

### *The Refinery Boilers*

KUC operates two Tankhouse Boilers at the Refinery primarily on natural gas (both boilers can also operate on #2 fuel oil, but KUC's Title V operating permit only allows KUC to combust fuel oil during natural gas curtailments).[11] Both the October 3 and November 1 versions of Part H propose a NOx emission limitation on these boilers. The Tankhouse Boilers' NOx emissions are controlled by flue gas recirculation, low NOx burners, and good combustion practices. Furthermore, the Title V permit imposes a 4.75 lbs/hr emission limitation for each boiler's NOx emissions, a 10% opacity limitation, and requires KUC to keep records of fuel use.[12]

Given that the boilers run primarily on natural gas, there is little variability in emissions from these boilers. Likewise, the fuel recordkeeping requirement provides additional assurance of compliance because the fuel use can be used to readily calculate the emissions from these units.

### *In-Pit Crusher*

Part H and KUC's existing Approval Order identify a crusher located within the Bingham Canyon Mine as the "in-pit crusher." Both the October 3 and November 1 versions of Part H propose a 0.78 lbs/hr (0.007 gr/dscf) emission limitation on the in-pit crusher's PM2.5 emissions. The in-pit crusher is controlled with a baghouse and is also subject to an existing 7% opacity limitation.[13]

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[9] Title V Operating Permit, Permit No. 3500030003, Last Revision April 11, 2018, Conditions II.B.24.a, 24.c.

[10] *Id.* Condition II.B.24.b.

[11] *Id.* Condition II.B.36.b. The Title V permit identifies these two units as "refinery boilers."

[12] *Id.* Conditions II.B.36.a, 36.c, & 36.d.

[13] Proposed Part H, Condition 12.h.i.C; Approval Order Number DAQE-AN105710037-15, November 10, 2015, Conditions II.B.1.c.

There are a number of facts that demonstrate why there is a reasonable assurance of continuous compliance with the in-pit crusher emission limitation that eliminates the need for testing the crusher more frequently than once every three years. For instance, KUC has reviewed the results for all stack tests for the in-pit crusher since 2009. In every instance, there is a sufficient buffer between the emissions recorded during the stack test and the emission limitation proposed in the October 3 and November 1 versions of Part H. As EPA explained, once an owner/operator "has shown that the installed control equipment can comply with an emission limit, there will be a reasonable assurance of ongoing compliance with the emission limit as long as the emission unit is operated under the conditions anticipated and the control equipment is operated and maintained properly."[14] Given the test results, there is ample data that shows both that the baghouse is capable of, and in fact does, control the in-pit crusher's particulate emissions sufficiently that KUC is in ongoing compliance with the emission limitation.

Moreover, there are other, less burdensome, mechanisms that ensure KUC is in continuous compliance with the emission limits proposed in the October 3 and November 1 versions of Part H. For example, KUC monitors pressure drop in the baghouse, which allows KUC to determine if the baghouse is operating correctly. Likewise, the opacity limitation also provides KUC with insight into whether the baghouse is controlling particulate as it was designed. KUC operates and maintains the baghouse to a level consistent with industry practice and manufacturer recommendations, as required by the applicable Approval Order (Condition I.5). These work practices and maintenance programs include, but are not limited to, daily equipment checks, regular baghouse inspections and dye tests, and scheduled replacement of all filter media.

Given KUC's maintenance program, monitoring efforts, and prior stack test results there is ample evidence to support a determination that there exists a reasonable assurance that the in-pit crusher is in continuous compliance with the emission limitations proposed in the October 3 and November 1 versions of Part H. As such, an increase in stack testing frequency is not necessary.

***Proposed Revisions to Part H to Allow Stack Testing Once Every Three Years***

Given the above analysis, KUC requests that UDAQ propose that the final version of Part H require stack testing the Holman Boiler, the Tankhouse/refinery Boilers, and the in-pit crusher every three years as UDAQ proposed in the October 1 version. KUC requests the following revisions to the proposed rule (replacement language in red; language to be struck in strikeout):

[14] 62 Fed. Reg. at 54918.

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Condition H.2.i.B.II.

| | | |
|---|---|---|
| Holman Boiler | NOx | Every ~~year~~ three years and CEMS or alternate method according to applicable NSPS standards |

Condition H.2.ii.B.

B. Stack testing to show compliance with the above limitations shall be performed as follows:

| | | |
|---|---|---|
| Tankhouse Boilers | NOx | Every ~~year~~ three years* |
| . . . | | |
| * Stack testing shall be performed on boilers that have operated more than 300 hours during a three year period. | | |

Condition H.12.h.i.C.

The In-pit crusher baghouse shall not exceed a PM2.5 emission limit of 0.78 lbs/hr (0.007 gr/dscf). PM2.5 monitoring shall be performed by stack testing every three years ~~annually~~.

Condition H.12.j.i.B.II.

| | | |
|---|---|---|
| Holman Boiler | NOx | Every ~~year~~ three years and CEMS or alternate method according to applicable NSPS standards |
| The Holman boiler shall use an EPA approved test method every three years and in between years use ~~annually or~~ an approved CEMS or alternate method accord to applicable NSPS standards. | | |

Condition H.12.j.ii.B.

B. Stack testing to show compliance with the above limitations shall be performed as follows:

| | | |
|---|---|---|
| Upgraded Tankhouse Boilers | NOx | Every ~~year~~ three years* |
| . . . | | |
| * Stack testing shall be performed on boilers that have operated more than 300 hours during a three year period. | | |

## II. COMMENT NO. 2. UDAQ CORRECTLY DETERMINED THAT BACT FOR UNIT 4 DOES NOT REQUIRE A FUEL SWITCH TO NATURAL GAS

Given that Unit 4 is a tangentially-fired boiler capable of running on coal and natural gas, the unit (and particularly the unit's coal operations) has become a focal point in UDAQ's development of a Serious Area PM2.5 SIP.[15] After extensive consideration of Unit 4's operations, the requirements created by Subpart 4 of the Clean Air Act (CAA) and EPA's PM2.5 Implementation Rule, and public comments submitted during the initial comment period for the PM2.5 SIP, UDAQ determined that a fuel switch, allowing KUC to combust natural gas only, did not constitute BACT.[16] As a result of that determination, in the October 3 version of Part H, UDAQ proposed emission limitations for both natural gas and coal operations at Unit 4 and retained the prohibition on the combustion of coal between November 1 and the end of February.

During the October 3 AQB meeting, AQB member Kevin Cromar stated that he disagreed with UDAQ's determination that natural gas combustion did not represent BACT for Unit 4. Based exclusively on Mr. Cromar's explanation that Unit 4 is capable of combusting natural gas, the AQB voted to amend Part H to prohibit KUC from combusting coal at any time at Unit 4. As a consequence of the AQB's vote, the November 1 version of Part H proposes to only authorize KUC to operate Unit 4 on natural gas.

In response to the AQB's vote, UDAQ re-examined its analysis of what constitutes BACT for Unit 4 and determined that the AQB was incorrect; UDAQ determined that a fuel switch to natural gas did not represent BACT for Unit 4.[17] Among the reasons the agency outlined in the UDAQ Response Memo are,

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[15] Since 1991 UDAQ has prohibited KUC from combusting coal at Unit 4 (as well as the entirety of UPP) between November 1 and February 28/29, which coincides with the period in which meteorological conditions create stagnant cold pools of air that lead to elevated concentrations of both PM10 and PM2.5. The seasonal prohibition on coal combustion at Unit 4 effectively removes all emissions associated with coal from the regulatorily-relevant time period. In other words, the seasonal prohibition has mooted the issue of how Unit 4's coal combustion impacts PM10/2.5 concentrations during the time of year when exceedances occur. Given the longstanding nature of the seasonal prohibition, KUC incorporated the prohibition into its Energy Management System (EMS). As explained more thoroughly in the updated BACT analysis attached to these comments as Attachment No. 1, KUC has developed a diverse mix of electrical generation units that allows the company to produce much of its energy needs. KUC also purchases energy from a third-party electric utility. Unit 4 is an important part of the mix and so is the flexibility between coal and natural gas combustion. Fundamentally, the flexibility allows KUC to operate Unit 4 on coal ***or*** natural gas during the summer months when increased market demands (and the related price increases) makes purchasing power unfavorable. As a result of the cost savings that are generated during periods of peak energy demand, KUC has been able to occasionally voluntarily idle Unit 4 during the winter months. This flexibility has an overall benefit to the SLC NAA's PM2.5 concentrations and should be retained for this reason as well as because KUC's EMS impacts the economic feasibility of a fuel switch to exclusive natural gas combustion.

[16] UDAQ, PM2.5 SIP Evaluation Report – Kennecott Utah Copper LLC – Power Plant; DAQ-2018-007701, July 1, 2018, p. 8; *see also* UAQB, Draft Agenda, Item V, Propose for Public Comment: Revisions to Section IX, Control Measures for Area and Point Sources, Part H, Emission Limits, October 3, 2018 Agenda, Attachment B, UDAQ Response to Public Comment (Response to Comment H-57).

[17] UDAQ Response Memo, pp. 2-3, available at https://deq.utah.gov/air-quality/air-quality-rule-plan-changes-open-public-comment.

- UDAQ applied BACT on a continuous basis because the controls selected as BACT (i.e., SCR with OFA) will apply to all modes of operation regardless of the time of year.

- Eliminating emissions associated with coal combustion is not necessary because the seasonal prohibition on coal combustion eliminates the emissions during the time of year that the PM2.5 SIP targets.

UDAQ's determination is grounded in the law and KUC submits the following comments in support of UDAQ's determination and requests that UDAQ re-propose the emission limitations and seasonal prohibition on the combustion of coal as presented in the October 3 version of Part H.

### A. BACT does not preclude UDAQ/AQB from Applying Seasonal Controls on Unit 4

The concept that a SIP may be designed to target a specific season is not novel.[18] In fact, EPA has repeatedly embraced the idea that a SIP may address a pollutant that manifests itself with greater seasonal concentrations with controls and limitations that apply during that season. For example, in the General Preamble, EPA directed state regulators to "focus" their efforts on seasonal emissions when preparing SIPs for ozone even though CAA section 182(b)(1)(B) directed the states to reduce emissions during the "calendar year."

> The EPA's focus on ***typical ozone season, weekday VOC emissions*** – an interpretation of the requirement in section 182(b)(1)(B) for a 15 percent reduction of actual emissions ***during the "calendar year"*** of enactment – is consistent with prior EPA guidance. This guidance stems from the fact that the ozone NAAQS is an hourly standard ***that is generally violated during ozone-season weekdays when condition are conducive of ozone formation***. These ozone seasons are typically in the summer.[19]

In other words, even though the CAA directed states to reduce VOC emissions by 15 percent for the calendar year, EPA directed that the states' efforts should be focused on emissions that occur during the ozone season.

More recently, EPA has come to understand that ozone formation may also be influenced by wintertime conditions in certain areas. EPA responded by broadening the definition of "summer day emissions" to "ozone season day emissions." But regardless of whether the ozone

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[18] In KUC's comments submitted on August 15, 2018, KUC provided extensive comments related to the legality of seasonal controls. *See* Rio Tinto Kennecott, Comments on Proposed Rulemaking: SIP Subsection Ix. Part H: Emission Limits and Operating Practices, R307-110-17, Topic 1 (containing comments related to Unit 4), pp. 1-10, August 15, 2018 (hereinafter "KUC's August 15, 2018 Comments"). KUC incorporates the comments and analysis herein as it provides further information on the law and facts governing UDAQ's consideration of this issue.

[19] 57 Fed. Reg. 13498, 13507 (April 16, 1992) (emphasis added); *see also id.* at 13516 (applying the same seasonal distinction for serious nonattainment area SIPs).

nonattainment is influenced by the meteorological conditions of the summer or winter seasons, EPA directed state regulators to continue to "focus[] planning efforts on emissions occurring during the most relevant time period."[20]

Moreover, EPA's emphasis on seasonal controls can be drawn from EPA's regulatory actions on ozone SIPs. For example, as part of EPA's 1998 NOx SIP Call, the agency rejected comments that argued EPA could use the ozone SIP to address non-ozone problems.

> However, the commenter's suggestion that EPA analyze the cost of, and assume in calculating the budgets, ***annual NOx control to address non-ozone problems*** is outside the scope of this rulemaking proceeding. Here, EPA has proposed a NOx SIP call to address the failure of certain SIPs to prohibit sources from ***emitting NOx in amounts that contribute significantly to nonattainment . . . of ozone NAAQS during the ozone season***.[21]

The resulting SIP limits, according to EPA, would apply seasonally; "For each source category, the required emission levels (***in tons per ozone season***) were determined based on the application of NOx controls."[22]

Seasonal regulation has also been applied to Serious PM2.5 NAAs. The South Coast Air Quality Management District's Serious PM2.5 analysis of BACM states that "[t]o minimize costs, some control technologies can be seasonally . . . applied during times when high ambient PM2.5 levels are a concern."[23]

All of these examples support UDAQ's determination that the seasonal prohibition on combusting coal at Unit 4 eliminates the need to further apply BACT to those operations. As such, KUC requests that UDAQ revise Part H to (1) allow for both natural gas and coal combustion at Unit 4, and (2) re-insert the seasonal prohibition on coal combustion between November 1 and the end of February.[24]

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[20] 80 Fed. Reg. 12264, 12290 (March 6, 2015).

[21] 63 Fed. Reg. 57356, 57423 (October 27, 1998) (emphasis added).

[22] *Id.* at 57399 (emphasis added). The Ozone Transport Commission (OTC), covering 12 states and the District of Columbia, provides another example of how states may impose seasonal limitations on sources as the states implement the CAA. Under the OTC, large sources of NOx are subject to an emission limitation of 0.20 lbs/MMBtu of NOx "during the period between May 1 and October 1 (the ozone season)." *See* EPA Region 1, Nitrogen Oxides Control Regulations, https://www3.epa.gov/region1/airquality/nox.html.

[23] SCAQMD, Final 2016 AQMP, Chapter 4, p. 4-49.

[24] KUC also agrees with UDAQ's determination that the seasonal prohibition on coal eliminates the need for UDAQ to conduct a BACT analysis for Unit 4's SO2 emissions associated with coal combustion. For the reasons previously provided, all SO2 emissions associated with coal will not impact PM2.5 concentrations between November 1 through the end of February because such operations are prohibited by the SIP. Given the focus on potentially applying BACT to Unit 4's coal operations, KUC completed a BACT analysis for that mode of operation, which is attached as Attachment No. 1. KUC is submitting this information to assist UDAQ in preparing a complete administrative record for the PM2.5 SIP and does not concede that the controls identified for the coal operations at Unit 4 may be implemented as part of the Serious PM2.5 SIP.

**It is not Necessary to Apply BACT to Operations that are Eliminated by the Seasonal Prohibition in the PM2.5 SIP**

In its Response to the AQB, UDAQ explained that the agency developed the PM2.5 SIP for the "primary purpose of controlling emissions that contribute to the problem being solved."[25] In other words, the SIP is designed to curtail emissions during the period of the year when meteorological conditions create stagnant cold pools of air that lead to elevated concentrations of PM2.5. There is no debate that those conditions are only present between November 1 and the end of February, which coincides with the historic and proposed (per the October 1 version) prohibition on combusting coal at Unit 4.

Given these facts coupled with the limitations imposed by Utah Code section 19-2-109,[26] there is no foundation for the AQB to make a determination that the imposition of controls on Unit 4's coal operations are necessary for the PM2.5 SIP. As the agency accurately summarized in the UDAQ Response Memo, Part H (and the SIP in its entirety) is being developed to "solve[]" a specific problem and "the seasonal control prohibiting coal as a fuel source best address[es] the problem."

Furthermore, the UDAQ Response Memo also raises the specter that the focus on Unit 4's coal operations may be motivated by a goal of attacking non-PM2.5 issues, such as controlling emissions impacting ozone concentrations in the summertime. As EPA explained in the NOx SIP call, it is not appropriate to use a SIP that is designed to bring an area into compliance with a particular NAAQS to attack an unrelated problem.[27]

## III. COMMENT NO. 3. UDAQ APPLIED OVERLY AGGRESSIVE CONTROL EFFICIENCIES TO ARRIVE AT AN UNREALISTIC EMISSION LIMITATION FOR UNIT 4'S NATURAL GAS OPERATIONS

UDAQ has proposed that KUC install selective catalytic reduction (SCR) with over-fired air (OFA) as BACT for Unit 4's NOx emissions associated with natural gas combustion.[28] KUC currently operates low NOx burners at Unit 4. In turn, UDAQ has proposed (in both the October 3 and November 1 versions of Part H) a 20 ppmv (17 lbs/hr) NOx emission limitation when KUC

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[25] UDAQ Response Memo, p. 2.

[26] In KUC's comments submitted on August 15, 2018, KUC provided an extensive discussion of section 19-2-109. *See* KUC August 15, 2018 Comments, pp. 1-10. KUC incorporates the comments and analysis herein as it provides further information on the law and facts governing UDAQ's consideration of this issue.

[27] 63 Fed. Reg. at 57423.

[28] UDAQ, PM2.5 SIP Evaluation Report – Kennecott Utah Copper LLC – Power Plant; DAQ-2018-007701, July 1, 2018, pp. 7-8; October 3, 2013 Air Quality Board package, Item V, Attachment B (UDAQ Responses to Public Comment), response to Comment H-57, p. 73.

is combusting natural gas at Unit 4.[29] KUC agrees that SCR with OFA is technically and economically feasible to install as BACT to control Unit 4's NOx emissions. However, KUC objects to the 20 ppmv (17 lbs/hr) emission limitation because UDAQ derived the emission limitation from overly-aggressive control efficiencies resulting from the installation of SCR and OFA.

Emission limitations installed as BACT must be "achievable."[30] Indeed, as EPA explained, "BACT emission limits or conditions must be met on a continual basis."[31] As a result, emission limitations that are unrealistic, based on overly-aggressive control efficiencies, or derived from best-case scenario operations do not represent BACT and cannot be implemented.

In both UDAQ's SIP Evaluation Report and its response to comments, UDAQ stated that the agency presumed SCR will reduce NOx emissions from natural gas combustion by 90% and OFA will reduce the emissions by 50%.[32] UDAQ used these control efficiencies to develop the 20 ppmv (17 lbs/hr) emission limitation, which represents a 96% reduction in NOx emissions associated with natural gas combustion at Unit 4.

Over the course of several years, KUC's technical staff has worked with consultants and third-party vendors to develop the best, and most-realistic estimates of the control efficiencies associated with SCR and OFA as applied to Unit 4. Indeed, as KUC worked with UDAQ to determine BACT for Unit 4, KUC commissioned a site-specific study providing evaluation of the potential controls at Unit 4.[33] Given that this study was not based on a detailed, engineering design of the equipment as it would be installed at Unit 4, the study provided a range of potential control efficiencies for both SCR and OFA. In turn, KUC selected control efficiencies within the range – 75% for SCR and 30% for OFA – to identify an emission limitation of 60 ppmv that can be achieved on a consistent basis at Unit 4.

In contrast, the 20 ppmv emission limitation that UDAQ proposed as BACT for Unit 4 is associated with the most-aggressive potential control efficiencies for both SCR and OFA. Given the available information, there are significant questions as to the likelihood that SCR and OFA will, in fact, meet either of these control efficiencies, and, in turn, that KUC can consistently meet the 20 ppmv emission limitation at Unit 4. Given the reliance on overly-aggressive control efficiencies, the 20 ppmv emission limitation is not BACT. KUC requests, consistent with

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[29] When UDAQ implemented the Moderate Area PM2.5 SIP for the SLC NAA, UDAQ determined that Reasonably Available Control Technology (RACT) required a NOx emission limitation of 60 ppm when Unit 4 was operating on natural gas. While UDAQ determined that SCR with OFA was not economically feasible to install on Unit 4 as part of that rulemaking, KUC voluntarily accepted the emission limitation with the understanding that SCR and OFA would be necessary to meet the 60 ppm emission limitation. In determining what constitutes BACT for Unit 4's natural gas operations, UDAQ has determined that SCR with OFA is economically feasible to install and that those controls will result in a 20 ppmv (17 lbs/hr) emission limitation.

[30] Utah Admin. Code R307-401-2.

[31] EPA New Source Review Workshop Manual, October 1990, B.56.

[32] UDAQ, PM2.5 SIP Evaluation Report – Kennecott Utah Copper LLC – Power Plant; DAQ-2018-007701, July 1, 2018, pp. 7-8; October 3, 2013 Air Quality Board package, Item V, Attachment B (UDAQ Responses to Public Comment), response to Comment H-57, p. 73.

[33] Attachment No. 1.

Attachment No. 1, that UDAQ revise Proposed Part H to impose a 60 ppmv emission limitation on Unit 4's NOx emissions when combusting natural gas.

## IV. COMMENT NO. 4. THE VMT LIMIT FOR THE BINGHAM CANYON MINE SHOULD APPLY ONLY TO DIESEL-FIRED HAUL TRUCKS

Under both the current PM10 SIP (Condition H.2.g.i.A) and the Moderate Area PM2.5 SIP (Condition H.12.j.i.A), UDAQ has limited KUC's operations at the Bingham Canyon Mine (BCM) by placing a daily mileage cap on the ore and waste haul trucks operated by KUC. In the proposed Serious Area PM2.5 SIP, UDAQ has proposed to retain the limitation on ore and haul truck operations (the limitation is the same in the October 3 and November 1 versions of Part H).[34] While UDAQ and KUC may not completely agree concerning the full reach of the preemption created by Title II of the Clean Air Act, KUC is willing to accept the continued application of a daily limit on the vehicle miles traveled at the BCM as part of the Serious PM2.5 SIP.[35]

But KUC requests a minor revision to the existing condition, which would acknowledge the purpose of the limitation and provide KUC with the flexibility to explore the viability of alternatively-powered haul trucks at the BCM. The revision KUC requests clarifies that the daily limit on the vehicle miles traveled applies to ***diesel-powered*** haul trucks only.

UDAQ imposed the limitation on the vehicle miles traveled at the BCM as a means to limit the tailpipe emissions from KUC's existing fleet of haul trucks, which are all diesel-powered. The revision that KUC requests merely clarifies the purpose of the limitation and regulates the emission sources as they currently exist.

KUC understands from its manufacturing partners that the haul truck industry is exploring the potential viability of alternatively-powered haul trucks. KUC is interested in the possibility of bringing alternatively-powered haul trucks to the fleet of vehicles that operate at the BCM if these vehicles become available. However, KUC is concerned that the SIP as it is currently proposed could create an impediment to testing and deploying alternatively-powered haul trucks at the BCM. For example, alternatively-powered haul trucks may not be as large as KUC's largest haul trucks. If that were the case, the limitation on vehicles miles traveled – if applied beyond the diesel fired fleet – could create a disincentive to deploying alternatively-powered haul trucks at the BCM.

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[34] Proposed Part H, Conditions H.2.g.i.a and H.12.h.i.a (the conditions are consistent in both the October 3 and November 1 versions).

[35] KUC commented extensively on the impact that Title II's preemption provision has on UDAQ's ability to regulate the haul truck emissions in the Serious PM2.5 SIP and incorporates those comments here. *See* Rio Tinto Kennecott, Comments on Proposed Rulemaking: SIP Subsection IX. Part H: Emission Limits and Operating Practices, R307-110-17, Topic 2, pp. 10-22, August 15, 2018

KUC requests that UDAQ revise the proposed Part H as follows:

| | |
|---|---|
| Condition H.2.g.i.A | Maximum total mileage per day for diesel-powered ore and waste haul trucks shall not exceed 30,000 miles. |
| Condition H.12.h.i.A | Maximum total mileage per day for diesel-powered ore and waste haul trucks shall not exceed 30,000 miles. |

## V. COMMENT NO. 5. THE "IMPLEMENTATION SCHEDULE" FOR HAUL TRUCKS IN PART H.2 SHOULD BE REMOVED

KUC requests that UDAQ remove Condition H.2.g.i.D from Part H because the condition is also in conflict with the preemption established in Title II of the CAA.

The provision that KUC requests that UDAQ remove states,

> Implementation Schedule
>
> KUC shall purchase new haul trucks with the highest engine Tier level available which meet mining needs. KUC shall maintain records of haul trucks purchased and retired.

The original proposed Part H revisions that were subject to public comment beginning on July 1, 2018 contained a similar "implementation schedule" in the PM2.5 portion of the proposed SIP. KUC requested that the provision be removed because it constituted an emission standard that was preempted by Title II of the CAA. UDAQ agreed with that comment as both the October 3 and November 1 versions remove the proposed condition from Part H.12.[36]

But UDAQ retained the provision in Part H.2. KUC understands that UDAQ believes that Condition H.2.g.i.D remains viable and outside of Title II's preemption because it is tied to the 30,000 vehicle miles traveled, which is not an emission standard.[37] As stated above, KUC is willing to accept the continued application of the VMT limit as part of the PM2.5 SIP. Regardless of whether the VMT limit is, or is not, in conflict with Title II does not change the fact that the requirement on the replacement of the haul trucks is preempted by Title II of the CAA.

In the interest of brevity, KUC incorporates by reference its discussion of the distinction between emission standards that are preempted by Title II and in-use regulations that are not preempted by Title II from its August 15, 2018 public comments. As the U.S. Supreme Court explained, a preempted emission standard imposes conditions that "relate to the emission

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[36] *See* October 3, 2013 Air Quality Board package, Item V, Attachment B (UDAQ Responses to Public Comment), response to Comment H-35 (stating that "to avoid any conflict with Title II, UDAQ has revised the conditions in Part H.12.j" to include the 30,000 VMT limitation and a recordkeeping requirement).

[37] KUC refers to the condition imposing a daily mileage limitation on the ore and waste haul trucks as the "VMT limit" throughout the remainder of these comments.

Rio Tinto

characteristics of a vehicle or engine."[38] Significantly, the U.S. Supreme Court applied this definition to a California regulation that dictated the composition of vehicles purchased by public and private fleet operators and found that such fleet restrictions were in preempted by Title II.

> A command, accompanied by sanctions, that certain purchasers may buy only vehicles with particular emission characteristics is as much an 'attempt to enforce' a 'standard' as a command, accompanied by sanctions, that a certain percentage of manufacturer's sales volume must consist of such vehicles.[39]

Condition H.2.g.i.B is similarly in conflict with Title II. The condition instructs KUC that it may only buy certain haul trucks which meet particular emission characteristics. As such, the condition should also be removed from Part H.2.

Furthermore, the fundamental purpose of retaining the condition in Part H.2 is unclear. Federal regulations govern the manufacture, sale and purchase of non-road equipment. These regulations are extensive and dictate what haul trucks KUC may purchase and deploy at the BCM. KUC believes – as the CAA intended – that UDAQ should leave these regulations to dictate what haul trucks KUC may deploy at the BCM. With that said, KUC re-iterates its commitment to replacing haul trucks with the highest engine tier available that meets KUC's mining needs when such replacements take place.

Should you have any questions regarding the above comments, please contact me at 801-569-6494.

Respectfully submitted,

Jenny Esker
Environmental Engineer
Environmental

Attachment: UPP Unit 4 BACT Analysis

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[38] *Engine Manufacturers Association v. S. Coast Air Quality Management Dist.*, 541 U.S. 246, 254 (2003).

[39] *Id.* at 255.

TECHNICAL MEMORANDUM

JACOBS

# BACT Analysis for Utah Power Plant Unit 4

**PREPARED FOR:** Kennecott Utah Copper LLC

**PREPARED BY:** Jacobs

**DATE:** November 27, 2018

As part of is development of a Serious $PM_{2.5}$ State Implementation Plan for the Salt Lake City Nonattainment Area, the Utah Division of Air Quality (UDAQ) has requested a Best Available Control Technology (BACT) analysis for the Utah Power Plant (UPP). Kennecott Utah Copper LLC (KUC) operates UPP in Magna, Utah. Currently, UPP operates a single coal and natural gas fired steam unit, referred to as Unit 4. Unit 4 has a capacity of 67 MW net and has a maximum heat input to 838 mmBtu per hour while operating on coal and 872 mmBtu per hour while operating on natural gas. Three smaller coal and natural gas steam units referred to as Units 1, 2 and 3 permanently ceased operation in 2016 and, as such, are not evaluated for BACT.

Unit 4 is required by the Approval Order and the Title V Operating Permit to operate on natural gas during the winter months between November 1 and February 28/29. Between March 1 and October 31, the unit can be operated on either natural gas or coal. KUC operated Unit 4 on coal during the 2017 non-winter season and on natural gas partially during the winter season.

KUC has submitted numerous iterations of BACT analyses for Unit 4's natural gas operation since 2013. The cost evaluations were based on EPA cost manuals and previous studies. KUC contracted Black & Veatch to conduct an evaluation of the air emissions control system options for Unit 4. Information from the Black & Veatch report has been used in the BACT analyses presented below and should supersede all previous submitted information for Unit 4.

The following analysis updates the prior BACT evaluations for natural gas combustion at Unit 4 as well as provides an analysis of what would constitute BACT for Unit 4's coal operations, if UDAQ were to apply BACT to Unit 4's coal operations. KUC submits the following analysis so that there is comprehensive understanding of what constitutes BACT for Unit 4's two modes of operation.

While the following top-down analysis necessarily evaluates the potential controls for the natural gas and coal operations separately, the ultimate BACT determination must account for both modes of operation in a comprehensive way. This is the case because KUC operates Unit 4 as part of the company's Energy Management System. As electricity is one of KUC's largest expenses, KUC has developed a diverse Energy Management System to control these costs. The Smelter steam generator, the Refinery combined heat and power unit (CHP), UPP Unit 4, and solar and wind systems all support KUC's ability to actively manage expenses by self-generating over half of our electrical demand on-call, with the majority of that capacity coming from Unit 4 (75MW). Each of these assets operates on a generating schedule based on market conditions and internal demand. While the Smelter steam generator and Refinery CHP operate the majority of the year (both PURPA Qualifying Facilities), KUC operates Unit 4 strategically as a dual-fuel generator based on market conditions and has occasionally voluntarily curtailed UPP generation in winter (Nov-Feb) as well as during market conditions favorable to 'going idle. KUC has been able to idle UPP for these periods, in part, due to the full-depreciation and return on investment of the initial capital costs of the unit, allowing KUC a wider opportunity to operate, ***or conversely idle,*** the plant based on the current market costs of electricity on a week-by-week basis. If

power is available for purchase at a rate lower than fuel/operation costs, Unit 4 is idled and kept in care & maintenance. During non-winter months, Unit 4's dual-fuel abilities are a vital part of the Energy Management System strategy and make it possible for KUC to 'completely idle' the unit during the winter months.

The costs of natural gas and coal change independently, thus the ability to consider the fuel with the best rate positions KUC to cost-effectively operate the plant on a partial-year schedule to produce approximately half of the company's power needs during the most critical, cost-volatile summer months rather than purchase power from an independent source. This flexibility enables KUC to not only generate when market prices are unfavorable in the summer, but these summer savings also allow KUC to *go idle* when a wider variety of market conditions are favorable for zero emissions, including winter. Without the ability to consider operation on either natural gas or coal, there is not enough flexibility to continue the strategic energy approach necessary to make Unit 4 cost-competitive against the market on a *flexible/partial-year generating basis*. Eliminating KUC's ability to combust coal in addition to natural gas would cost KUC significantly more money to operate UPP Unit 4 and would also require KUC to increase its operating season to year-round in order to recoup the additional costs (via smaller margins over a longer timeframe) for fuel, operations and maintenance costs, and capital expenditures required to cost-effectively single-source the plant. Losing fuel flexibility, as has been recently proposed, directly impacts KUC's Energy Management System and would compromise KUC's ability to voluntarily idle Unit 4 during the winter calendar months.

# 1. Formation of $NO_X$

Oxides of Nitrogen ($NO_X$) forms during the combustion process in three different ways. The dominant source of $NO_x$ formation is the oxidation of fuel-bound nitrogen (fuel $NO_x$), where a portion of the fuel-bound nitrogen is released from the coal with the volatile matter while the remaining fuel-bound nitrogen is retained in the solid portion (char). The nitrogen released from the coal is partially oxidized to nitrogen oxides (NO and $NO_2$ – referred to as $NO_x$) and partially reduced to molecular nitrogen ($N_2$). A small portion of $NO_x$ formation is due to high temperature fixation of atmospheric nitrogen in the combustion air (thermal $NO_x$). A very small amount of $NO_x$ is called "prompt" $NO_x$ that results from an interaction of hydrocarbon radicals, nitrogen, and oxygen.

In a conventional pulverized coal burner, air is introduced with turbulence to promote good mixing of fuel and air, which provides stable combustion. However, not all of the oxygen in the air is used for combustion. Some of the oxygen combines with the fuel-bound nitrogen to form $NO_x$.

## 1.1. Unit 4 Operating on Coal

The following BACT analysis has been developed for NOx emissions from the Unit 4 boiler while operating on coal.

### Step 1: Identify All Available Control Technologies

The RBLC identifies the following as potential technologies for $NO_x$ control from coal fired boiler:

- Over-fired air (OFA)
- OFA with Selective Non-catalytic Reduction (SNCR)
- OFA with Selective Catalytic Reduction (SCR)

**OFA System.** The mechanism used to lower $NO_x$ is to stage the combustion process and provide a fuel-rich condition initially; this is so oxygen needed for combustion is not diverted to combine with nitrogen and form $NO_x$. Fuel-rich conditions favor the conversion of fuel nitrogen to $N_2$ instead of $NO_x$. Additional air (or OFA) is then introduced downstream in a lower temperature zone to complete the combustion process. Based on past experience and studies, OFA system on Unit 4 would reduce emissions by about 30 percent from baseline levels.

**SNCR.** Selective non-catalytic reduction is generally utilized to achieve modest $NO_x$ reductions on smaller units. With SNCR, an amine-based reagent such as ammonia or urea is injected into the boiler within a temperature range of 1,600°F to 2,100°F, where it reduces $NO_x$ to nitrogen and water. From past project experience and studies, 60 percent reduction in $NO_x$ emissions from baseline levels was estimated for this analysis.

**SCR.** SCR works on the same chemical principle as SNCR, but SCR uses a catalyst to promote the chemical reaction. Ammonia or urea is injected into the flue-gas stream, where it reduces $NO_x$ to nitrogen and water. Unlike the high temperatures required for SNCR, in SCR the reaction takes place on the surface of a vanadium/titanium-based catalyst at a temperature range between 580° F and 750° F. Due to the catalyst, the SCR process is more efficient than SNCR and results in lower $NO_x$ emissions. Based on past experience and studies, OFA and SCR system on Unit 4 would reduce emissions by about 75 to 80 percent from baseline levels.

## Step 2: Eliminate Technically Infeasible Options

All identified control technologies are technically feasible for Unit 4.

## Step 3: Evaluate Control Effectiveness of Remaining Control Technologies

The control effectiveness of the control technologies are listed below. The emission rates listed below are obtained from the Black and Veatch report.

**TABLE 1**
$NO_x$ Control Technology Emission Rate Ranking

| Technology | Reduction in NOx Emissions from Baseline Levels | $NO_x$ Emission Rate (lb/mmBtu) |
|---|---|---|
| OFA | 30% | - |
| OFA & SNCR | 60% | 0.12 |
| OFA & SCR | 75% | 0.06 |

## Step 4: Evaluate Energy and Non-Air Quality Impacts

This step involves the consideration of energy, environmental, and economic impacts associated with each control technology. The remaining useful life of the plant is also considered during the evaluation.

**Energy Impacts.** The use of SCR will have a slightly higher energy requirement than the other control technologies. However, none of the identified control technologies are anticipated to have significant energy impacts.

**Environmental Impacts.** SNCR and SCR installation can impact the salability of fly ash due to ammonia compounds in the ash, although UPP ash is not currently sold. Unreacted ammonia (ammonia slip) may

potentially create a visible stack plume, which may negate other visibility improvements. Other environmental impacts involve the storage of ammonia, especially if anhydrous ammonia is used, and the transportation of the ammonia to the UPP site.

**Economic Impacts.** Costs for the identified control technologies were developed using vendor data and engineering estimates. A comparison of the technologies on the basis of costs is shown below.

**TABLE 2**
$NO_x$ Control Technology Cost Analysis

| Name of Control Technology | Annualized Cost of Control Option | Tons of $NO_x$ Removed (ton/year) | Costs per Ton of $NO_x$ Removed |
|---|---|---|---|
| OFA | $246,665 | 150 | $1,649 |
| OFA and SNCR | $1,214,758 | 257 | $4,736 |
| OFA and SCR | $6,179,027 | 351 | $17,520 |

All control technologies are identified as cost-effective.[1]

### Step 5: Select BACT

Based upon the technical and economic evaluation completed above, OFA and SCR with an emission rate of 0.06 lb/mmBtu are identified as BACT for $NO_x$ control on Unit 4.

## 1.2. Unit 4 Operating on Natural Gas

The following BACT analysis has been developed for NOx emissions from the Unit 4 boiler while operating on natural gas.

### Step 1: Identify All Available Control Technologies

The RBLC identifies the following as potential technologies for $NO_x$ control from natural gas fired boiler:

- Over-fired air (OFA)
- OFA with Selective Catalytic Reduction (SCR)

### Step 2: Eliminate Technically Infeasible Options

All identified control technologies are technically feasible for Unit 4.

### Step 3: Evaluate Control Effectiveness of Remaining Control Technologies

OFA with SCR is most effective in controlling $NO_X$ emissions from natural gas fired boiler. The BACT analysis presented above identifies OFA with SCR as BACT for minimizing emissions of $NO_X$ from Unit 4. Additionally, the $PM_{2.5}$ SIP approved by Utah Air Quality Board in December 2015 limits NOx emissions from Unit 4 while operating on natural gas to 60 ppmv. This emission limitation would be achieved by the installation of OFA and SCR as emission controls.

[1] To date, UDAQ has not formally announced a dollar-per-ton figure that the agency will apply to determine whether a particular control is economically feasible to install as BACT. However, informally UDAQ has suggested to KUC that the agency will apply a $25,000 per ton of pollutant reduced as the cost-effectiveness threshold for the Serious PM2.5 SIP. Throughout this document, KUC has applied the $25,000 per ton threshold to its analysis of whether controls are economically feasible to install.

Permitted $NO_X$ emissions from Unit 4 are 336 ppmv. Per the Black & Veatch report, OFA is expected to minimize $NO_X$ emissions by 30 percent and SCR would further reduce emissions by an average 75 percent. Therefore, the expected controlled $NO_X$ emission rate is approximately 60 ppmv as approved in the 2015 PM2.5 SIP.

### Step 4: Evaluate Energy and Non-Air Quality Impacts

This step involves the consideration of energy, environmental, and economic impacts associated with each control technology. The remaining useful life of the plant is also considered during the evaluation.

**Energy Impacts.** The identified control technologies are not anticipated to have significant energy impacts.

**Environmental Impacts.** Environmental impacts involve the storage of ammonia, especially if anhydrous ammonia is used, and the transportation of the ammonia to the UPP site.

**Economic Impacts.** Economic impacts are not evaluated as installation of SCR is required for Unit 4 operating on natural gas.

### Step 5: Select BACT

Based upon the technical and economic evaluation completed above with data from the Black & Veatch report, OFA and SCR with an emission rate of 60 ppmv are identified as BACT for $NO_x$ control for Unit 4 while operating on natural gas.

# 2. Formation of $SO_2$

Sulfur Dioxide ($SO_2$) forms in the boiler during the combustion process and is primarily dependent on sulfur content in the fuels combusted (coal and natural gas).

## 2.1. Unit 4 Operating on Coal

The following BACT analysis has been developed for $SO_2$ emissions from the Unit 4 while operating on coal.

### Step 1: Identify All Available Control Technologies

The following are potential technologies for $SO_2$ control from coal fired boiler:

- Spray Dryer Absorber (SDA)
- Dry Sorbent Injection (SDI)

**Spray Dryer Absorber.** A SDA uses alkaline slurry, most commonly calcium (lime), to react with $SO_2$ in the flue gas. The chemical reactions between the calcium in the lime and $SO_2$ in the flue gas readily occur, and as the reactions take place, the slurry particles dry into particulate matter that can be removed by the downstream particulate collection device. Based on past experience and studies, SDA on Unit 4 would reduce emissions by about 95 percent from baseline levels.

**Dry Sorbent Injection.** DSI injects a reagent, the three most common being hydrated lime, trona, or sodium bicarbonate (SBC), into ductwork to react with $SO_2$ in the flue gas. Based on past experience and studies, DSI on Unit 4 would reduce emissions by about 84 percent from baseline levels.

## Step 2: Eliminate Technically Infeasible Options

All control technologies are technically feasible for $SO_2$ control for Unit 4.

## Step 3: Evaluate Control Effectiveness of Remaining Control Technologies

The control effectiveness of the control technologies are listed below. The emission rates listed below are obtained from the Unit 4 study.

**TABLE 3**
$SO_2$ Control Technology Emission Rate Ranking

| Technology | Reduction in $SO_2$ Emissions from Baseline Levels | $SO_2$ Emission Rate (lb/mmBtu) |
|---|---|---|
| DSI | 84% | 0.2 |
| SDA | 95% | 0.1 |

## Step 4: Evaluate Energy and Non-Air Quality Impacts

**Energy Impacts.** The identified control technologies have similar energy requirements and are not anticipated to have significant energy impacts.

**Environmental Impacts.** The identified control technologies have similar environmental impacts and are not anticipated to have significant energy impacts over the baseline conditions.

**Economic Impacts.** SDA would require installation of a fabric filter for particulate control. As discussed below, installation of fabric filter is not economically feasible as it exceeds the UDAQ threshold of $25,000 per ton and therefore cannot be identified as BACT. Because SDA cannot be installed without a fabric filter, SDA is therefore not considered feasible for $SO_2$ control for Unit 4.

Costs for the two identified control technologies were developed using vendor data and engineering estimates. A comparison of the technologies on the basis of costs is shown below.

**TABLE 4**
$SO_2$ Control Technology Cost Analysis

| Name of Control Technology | Annualized Cost of Control Option | Tons of $SO_2$ Removed (ton/year) | Costs per Ton of $SO_2$ Removed |
|---|---|---|---|
| DSI | $3,351,423 | 870 | $3,851 |
| SDA | $5,585,530 | 984 | $5,674 |

All control technologies for $SO_2$ are identified as cost-effective based on $25,000 per ton threshold previously cited by UDAQ. UDAQ has not formally identified a threshold for economic feasibility.

## Step 5: Select BACT

Based upon the technical and economic evaluation completed above, DSI with an emission rate of 0.2 lb/mmBtu are identified as BACT for $SO_2$ control on Unit 4.

## 2.2. Unit 4 Operating on Natural Gas

The following BACT analysis has been developed for $SO_2$ emissions from the Unit 4 boiler while operating on natural gas.

### Step 1: Identify All Available Control Technologies

The RBLC identifies the following as potential technologies for $SO_2$ control from natural gas fired boiler:

- Pipeline quality natural gas
- Good combustion practices
- DSI
- SDA

### Step 2: Eliminate Technically Infeasible Options

The DSI and SDA control technologies are not feasible during natural gas operation of Unit 4 due to the inherently low sulfur content of natural gas. The remaining control technologies are technically feasible and currently employed on Unit 4 to minimize $SO_2$ emissions.

### Step 3: Evaluate Control Effectiveness of Remaining Control Technologies

Based on the above analysis, using good combustion practices and pipeline quality natural gas are the only technologies for this source.

### Step 4: Evaluate Energy and Non-Air Quality Impacts

No environmental, energy, or economic impacts are associated with using natural gas fuel or good combustion practices in a natural gas boiler.

### Step 5: Select BACT

Good combustion practices and use of pipeline quality natural gas are identified as BACT for Unit 4 while operating on natural gas.

# 3. Formation of Particulate Matter

Particulate matter ($PM_{10}/PM_{2.5}$) forms during the combustion process and is primarily dependent on organic and inorganic matter in the fuel.

## 3.1. Unit 4 Operating on Coal

The following BACT analysis has been developed for $PM_{10}/PM_{2.5}$ emissions from the Unit 4 boiler.

### Step 1: Identify All Available Control Technologies

The RBLC identifies the following as potential technologies for $PM_{10}/PM_{2.5}$ control for a coal fired boiler:

- Electrostatic Precipitator (ESP)
- Fabric Filter (FF)

**Electrostatic Precipitator.** The ESP removes particles from the flue gas by applying a high voltage electrostatic charge and collecting the particles on charged plates. Unit 4 is currently equipped with an ESP to minimize particulate emissions.

**Fabric Filter.** In the Fabric Filter control technology, flue gas is filtered by bags made of different materials. Based on past experience and information from the Black & Veatch report, FF on Unit 4 would reduce emissions by about 99 percent from uncontrolled levels.

## Step 2: Eliminate Technically Infeasible Options

Fabric filter are technically feasible for particulate emissions.

## Step 3: Evaluate Control Effectiveness of Remaining Control Technologies

The control effectiveness of the technically feasible control technology is listed below. The emission rates listed below are obtained from the Unit 4 study.

**TABLE 5**
$PM_{10}/PM_{2.5}$ Control Technology Emission Rate Ranking

| Technology | Reduction in $PM_{10}/PM_{2.5}$ Emissions from Baseline Levels | Filterable $PM_{10}/PM_{2.5}$ Emission Rate (lb/mmBtu) |
|---|---|---|
| FF | 99% | 0.03 |

## Step 4: Evaluate Energy and Non-Air Quality Impacts

This step involves the consideration of energy, environmental, and economic impacts associated with each control technology. The remaining useful life of the plant is also considered during the evaluation.

**Energy Impacts.** No energy impacts are associated with fabric filters when compared to the baseline ESP energy impacts.

**Environmental Impacts.** No new environmental impacts are associated with fabric filters.

**Economic Impacts.** Costs for the implementation of fabric filter control technology was developed using vendor data and engineering estimates and assumes a 40 percent incremental increase in $PM_{10}/PM_{2.5}$ control above the current ESP emission control effectiveness. A comparison of the fabric filter technology on the basis of costs is shown below.

**TABLE 6**
$PM_{10}/PM_{2.5}$ Control Technology Cost Analysis

| Name of Control Technology | Annualized Cost of Control Option | Tons of $PM_{10}/PM_{2.5}$ Removed (ton/year) | Costs per Ton of $PM_{10}/PM_{2.5}$ Removed |
|---|---|---|---|
| FF | $1,682,532 | 10.4 | $161,720 |

Fabric filter is not identified as cost-effective to install as BACT.

### Step 5: Select BACT

Based upon the technical and economic evaluation completed above, existing ESP is identified as BACT for $PM_{10}/PM_{2.5}$ control on Unit 4.

## 3.2. Unit 4 Operating on Natural Gas

The following BACT analysis has been developed for $PM_{10}/PM_{2.5}$ emissions from the Unit 4.

### Step 1: Identify All Available Control Technologies

The RBLC identifies the following as potential technologies for $PM_{10}/PM_{2.5}$ control from natural gas fired Unit 4:

- Pipeline quality natural gas
- Good combustion practices

### Step 2: Eliminate Technically Infeasible Options

The ESP and FF control technologies are not feasible options due to the inherently low particulate matter emissions associated with natural gas combustion. The remaining control technologies are technically feasible and currently employed on Unit 4 to minimize particulate matter emissions.

### Step 3: Evaluate Control Effectiveness of Remaining Control Technologies

Based on the above analysis, using good combustion practices and pipeline quality natural gas are the only technologies for this source.

### Step 4: Evaluate Energy and Non-Air Quality Impacts

No environmental, energy, or economic impacts are associated with using natural gas fuel or good combustion practices in a natural gas boiler.

### Step 5: Select BACT

Good combustion practices and use of pipeline quality natural gas are identified as BACT for Unit 4 while operating on natural gas.

# Attachment A
# Cost Worksheets

## Cost Effectiveness Calculations - Unit 4 with CCOFA, SOFA and SCR

**Table 1. Capital Cost Estimate**

| | | Cost | Reference |
|---|---|---|---|
| Purchased Equipment | | | |
| Total Purchased Equipment Cost | B | $10,500,000 | Vendor |
| | | | |
| Direct Installation Cost | | | |
| Foundation and supports | .08B | N/A | |
| Erection and handling | .14B | N/A | |
| Electrical | .04B | N/A | |
| Piping | .02B | N/A | |
| Painting | .01B | N/A | |
| Insulation | .01B | N/A | |
| Spare Parts | .07B | N/A | |
| Sales Taxes | .07B | N/A | |
| Building and site preparation not included | | | |
| Total Direct Installation Cost | | $7,800,000 | Vendor |
| | | | |
| Total Direct Cost | | $18,300,000 | |
| | | | |
| Indirect Cost | | | |
| Engineering | 0.10B | N/A | |
| Construction and field expenses | 0.05B | N/A | |
| Construction fee | 0.10B | N/A | |
| Start-up | 0.02B | N/A | |
| Performance test | 0.01B | N/A | |
| Contingency | 0.10B | N/A | |
| Total Indirect Cost | | $12,000,000 | Vendor |
| | | | |
| **Total Capital Cost** | | **$30,300,000** | |

**Table 2. Annual Cost**

| | | | Annual Cost | Reference |
|---|---|---|---|---|
| Direct Costs | | | | |
| Annual Operating Costs | | | $2,620,000 | Vendor |
| | | | | |
| Total Direct Cost | | | $2,620,000 | |
| | | | | |
| Indirect Costs | | | | |
| Other | | | Included in Annual Operating Costs | |
| | | | | |
| **Total Annual Costs Excluding Capital Recovery** | | | **$2,620,000** | |
| | | | | |
| Capital recovery | | | $3,559,027 | |
| | Interest | 10.0% | | KUC |
| | Lifetime | 20 years | | UDAQ |
| | | | | |
| **Total Annual Cost** | | | **$6,179,027** | |

**Table 3. Cost Effectiveness**

| | | | |
|---|---|---|---|
| 2017 Actual NOx Emissions | 427.50 | tons/year | AEI |
| OFA Control Efficiency (30%) | 30% | | Vendor Estimate |
| NOx Emissions with OFA | 299.25 | tons/year | |
| SCR Control Efficiency | 75% | | Vendor Estimate |
| Controlled Stack NOX Emissions | 74.81 | tons/year | |
| | | | |
| NOx Emission Reduction | 352.69 | tons/year | Calculated |
| | | | |
| **Cost Effectiveness for NOx** | $17,520 | $/ton | |

## Cost Effectiveness Calculations - Unit 4 with Dry Sorbent Injection (DSI)

**Table 1. Capital Cost Estimate**

| | | Cost | Reference |
|---|---|---|---|
| Purchased Equipment | | | |
| Total Purchased Equipment Cost | B | $2,900,000 | Vendor |
| | | | |
| Direct Installation Cost | | | |
| Foundation and supports | .08B | N/A | |
| Erection and handling | .14B | N/A | |
| Electrical | .04B | N/A | |
| Piping | .02B | N/A | |
| Painting | .01B | N/A | |
| Insulation | .01B | N/A | |
| Spare Parts | .07B | N/A | |
| Sales Taxes | .07B | N/A | |
| Building and site preparation not included | | | |
| Total Direct Installation Cost | | $1,000,000 | Vendor |
| | | | |
| Total Direct Cost | | $3,900,000 | |
| | | | |
| Indirect Cost | | | |
| Engineering | 0.10B | N/A | |
| Construction and field expenses | 0.05B | N/A | |
| Construction fee | 0.10B | N/A | |
| Start-up | 0.02B | N/A | |
| Performance test | 0.01B | N/A | |
| Contingency | 0.10B | N/A | |
| Total Indirect Cost | | $4,200,000 | Vendor |
| | | | |
| **Total Capital Cost** | | **$8,100,000** | |

**Table 2. Annual Cost**

| | | | Annual Cost | Reference |
|---|---|---|---|---|
| Direct Costs | | | | |
| Annual Operating Costs | | | $2,400,000 | Vendor |
| | | | | |
| Total Direct Cost | | | $2,400,000 | |
| | | | | |
| Indirect Costs | | | | |
| Other | | | Included in Annual Operating Costs | |
| | | | | |
| **Total Annual Costs Excluding Capital Recovery** | | | **$2,400,000** | |
| | | | | |
| Capital recovery | | | $951,423 | |
| | Interest | 10.0% | | KUC |
| | Lifetime | 20 years | | UDAQ |
| | | | | |
| **Total Annual Cost** | | | **$3,351,423** | |

**Table 3. Cost Effectiveness**

| | | | |
|---|---|---|---|
| 2017 Actual SO2 Emissions | 1,036.13 | tons/year | AEI |
| Control Efficiency | 84% | | Vendor Estimate |
| SO2 Emission Reduction | 870.35 | tons/year | Calculated |
| | | | |
| **Cost Effectiveness for SO2** | $3,851 | $/ton | |

## Cost Effectiveness Calculations - Unit 4 with Spray Dryer Absorber (SDA)

**Table 1. Capital Cost Estimate**

| | | Cost | Reference |
|---|---|---|---|
| Purchased Equipment | | | |
| Total Purchased Equipment Cost | B | $20,800,000 | Vendor |
| | | | |
| Direct Installation Cost | | | |
| Foundation and supports | .08B | N/A | |
| Erection and handling | .14B | N/A | |
| Electrical | .04B | N/A | |
| Piping | .02B | N/A | |
| Painting | .01B | N/A | |
| Insulation | .01B | N/A | |
| Spare Parts | .07B | N/A | |
| Sales Taxes | .07B | N/A | |
| Building and site preparation not included | | | |
| Total Direct Installation Cost | | $7,700,000 | Vendor |
| | | | |
| Total Direct Cost | | $28,500,000 | |
| | | | |
| Indirect Cost | | | |
| Engineering | 0.10B | N/A | |
| Construction and field expenses | 0.05B | N/A | |
| Construction fee | 0.10B | N/A | |
| Start-up | 0.02B | N/A | |
| Performance test | 0.01B | N/A | |
| Contingency | 0.10B | N/A | |
| Total Indirect Cost | | $7,900,000 | Vendor |
| | | | |
| **Total Capital Cost** | | **$36,400,000** | |

**Table 2. Annual Cost**

| | | | Annual Cost | Reference |
|---|---|---|---|---|
| Direct Costs | | | | |
| Annual Operating Costs | | | $1,310,000 | Vendor |
| | | | | |
| Total Direct Cost | | | $1,310,000 | |
| | | | | |
| Indirect Costs | | | | |
| Other | | | Included in Annual Operating Costs | |
| | | | | |
| **Total Annual Costs Excluding Capital Recovery** | | | **$1,310,000** | |
| | | | | |
| Capital recovery | | | $4,275,530 | |
| | Interest | 10.0% | | KUC |
| | Lifetime | 20 years | | UDAQ |
| | | | | |
| **Total Annual Cost** | | | **$5,585,530** | |

**Table 3. Cost Effectiveness**

| | | | |
|---|---|---|---|
| 2017 Actual SO2 Emissions | 1,036.13 | tons/year | AEI |
| Control Efficiency | 95% | | Vendor Estimate |
| SO2 Emission Reduction | 984.32 | tons/year | Calculated |
| | | | |
| **Cost Effectiveness for SO2** | $5,674 | $/ton | |

## Cost Effectiveness Calculations - Unit 4 with Fabric Filters (FF)

**Table 1. Capital Cost Estimate**

| | | Cost | Reference |
|---|---|---|---|
| Purchased Equipment | | | |
| Total Purchased Equipment Cost | B | $6,500,000 | Vendor |
| | | | |
| Direct Installation Cost | | | |
| Foundation and supports | .08B | N/A | |
| Erection and handling | .14B | N/A | |
| Electrical | .04B | N/A | |
| Piping | .02B | N/A | |
| Painting | .01B | N/A | |
| Insulation | .01B | N/A | |
| Spare Parts | .07B | N/A | |
| Sales Taxes | .07B | N/A | |
| Building and site preparation not included | | | |
| Total Direct Installation Cost | | $2,100,000 | Vendor |
| | | | |
| Total Direct Cost | | $8,600,000 | |
| | | | |
| Indirect Cost | | | |
| Engineering | 0.10B | N/A | |
| Construction and field expenses | 0.05B | N/A | |
| Construction fee | 0.10B | N/A | |
| Start-up | 0.02B | N/A | |
| Performance test | 0.01B | N/A | |
| Contingency | 0.10B | N/A | |
| Total Indirect Cost | | $3,000,000 | Vendor |
| | | | |
| **Total Capital Cost** | | **$11,600,000** | |

**Table 2. Annual Cost**

| | | | Annual Cost | Reference |
|---|---|---|---|---|
| Direct Costs | | | | |
| Annual Operating Costs | | | $320,000 | Vendor |
| | | | | |
| Total Direct Cost | | | $320,000 | |
| | | | | |
| Indirect Costs | | | | |
| Other | | | Included in Annual Operating Costs | |
| | | | | |
| **Total Annual Costs Excluding Capital Recovery** | | | **$320,000** | |
| | | | | |
| Capital recovery | | | $1,362,532 | |
| Interest | 10.0% | | | KUC |
| Lifetime | 20 | years | | UDAQ |
| | | | | |
| **Total Annual Cost** | | | **$1,682,532** | |

**Table 3. Cost Effectiveness**

| | | | |
|---|---|---|---|
| 2017 Actual PM2.5 Emissions | 26.01 | tons/year | AEI |
| Control Efficiency | 40% | | Estimate - additional control over ESP |
| PM2.5 Emission Reduction | 10.40 | tons/year | Calculated |
| | | | |
| **Cost Effectiveness for PM2.5** | $161,720 | $/ton | |

# Attachment B
# Unit 4 AQCS Report

# AIR QUALITY CONTROL SYSTEM OPTIONS

## Utah Power Plant Unit 4

**BLACK & VEATCH PROJECT NO. 197302**



**PREPARED FOR**

Rio Tinto Kennecott

28 NOVEMBER 2018

BLACK & VEATCH

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# 1.0 Executive Summary

## 1.1 INTRODUCTION

Black & Veatch Management Consulting, LLC (Black & Veatch) was retained by Rio Tinto Kennecott (Kennecott) to provide an environmental, technical and economic assessment of the air quality control system (AQCS) options for Utah Power Plant (UPP) Unit 4. The unit can be fueled using either coal or natural gas and is located 15 miles west of downtown Salt Lake City within Salt Lake County. Unit 4 has a capacity of 67 MW net. This report (Report) summarizes Black & Veatch's findings and conclusions from our review. A summary of UPP Unit 4 is included in Table 1-1 and the general facility location is illustrated in Figure 1-1.

**Table 1-1 UPP Unit 4 Summary**

| FACILITY NAME | CAPACITY | ARRANGEMENT | TECHNOLOGIES |
|---|---|---|---|
| UPP Unit 4 | 67 MW net | Coal/natural gas fired boiler and steam turbine | (1) Combustion Engineering Tangentially Fired Boiler<br>(1) General Electric Single Reheat Steam Turbine Generator (STG) |
| **Total Capacity** | **67 MW net** | | |

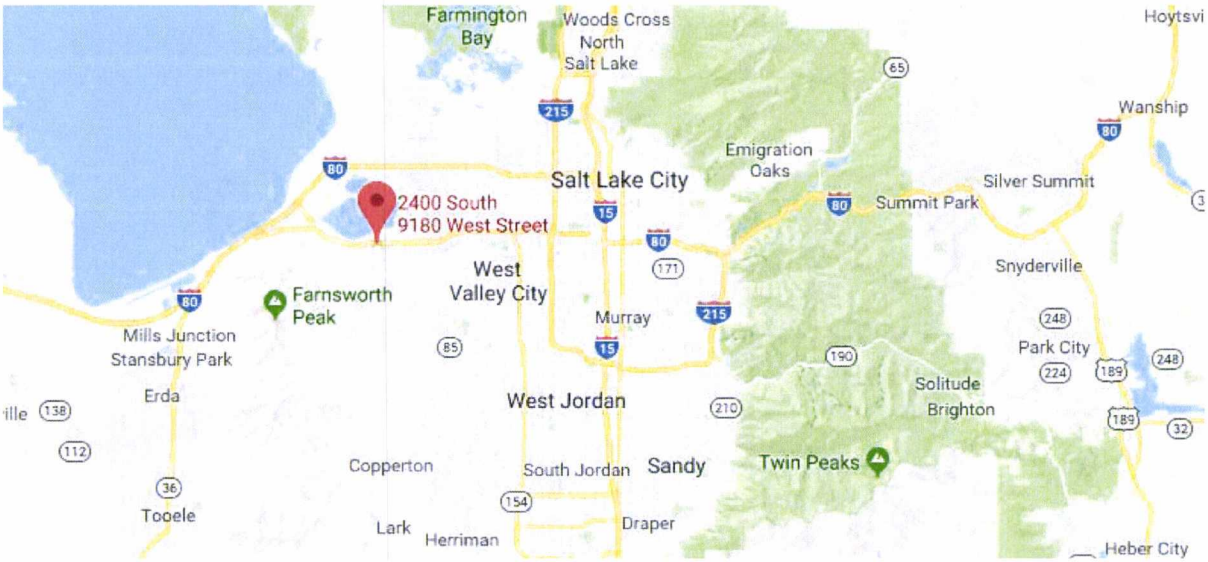


**Figure 1-1 General Facility Location (Source: Google Maps)**

## 1.2 SCOPE OF WORK

To conduct this assessment, Black & Veatch provided the following services:

- UPP Unit 4 design description.
- AQCS technology assessment.
- AQCS capital and operations & maintenance (O&M) cost assessment.

In conducting this assessment, Black & Veatch (1) had discussions with various Kennecott participants; (2) posed questions to Kennecott that Black & Veatch, in its sole judgment, chose to ask about the facilities; (3) reviewed certain technical reports prepared by others, as identified in the Report; and (4) reviewed environmental documentation related to operation.

The Black & Veatch team, which included project management specialists, engineers, financial analysis experts, AQCS technology specialists, environmental consultants and supporting engineers and consultants, gathered available data from Kennecott to assess the status of the facility. Data requests for additional or updated documentation were submitted as necessary.

The conclusions and findings that resulted from this assessment are summarized in this Report. The Report was prepared in accordance with the Agreement for the Supply of Consultancy Services (and associated Products) between Rio Tinto Services Inc. (an affiliate of Kennecott) and Black & Veatch and the purchase order with effective date of November 16, 2017 and the information contained herein was developed based on the needs of Kennecott. The level of information included in the Report reflects the knowledge of issues gained by Black & Veatch during the course of the review. The Report is solely for the use of Kennecott. The conclusions and findings are summarized in this Report.

At the request of Kennecott, in order to make this document suitable for submittal to the Utah Division of Air Quality, Black & Veatch has removed sections of this Report to protect information considered business confidential by Kennecott.

## 1.3 ASSUMPTIONS

During the assessment of UPP Unit 4, Black & Veatch used and relied upon certain information provided by Kennecott and others. Black & Veatch believes the information provided is true and correct and reasonable for the purposes of this Report. In preparing this Report and the opinions presented herein, Black & Veatch has made certain assumptions with respect to conditions that may exist, or events that may occur in the future. Black & Veatch believes that the use of this information and these assumptions is reasonable for purposes of this Report. However, some events may occur or circumstances may change that cannot be foreseen or controlled by Black & Veatch and that may render these assumptions incorrect. To the extent the actual future conditions differ from those assumed herein or provided to Black & Veatch by others, the actual results will differ from those that have been forecast.

Throughout this Report, Black & Veatch has stated assumptions and reported information provided by others, all of which were relied upon in the development of the opinions and conclusions of this Report. The following is a summary of key considerations and assumptions made in developing the opinions expressed in this Report. Black & Veatch assumes that:

- Coal, natural gas and associated transportation will continue to be available in the quantities and qualities required by the facility.
- An adequate supply of water and effluent discharge source will remain available throughout the remaining life of the facility.
- The facility will continue to be operated in accordance with good industry practice, the facility will continue to be appropriately staffed with qualified personnel, and that replacements and renewals will be made in a timely manner.
- All equipment for the facility will not be operated in a manner to cause it to exceed equipment manufacturer's ratings or recommendations.
- All contracts, agreements, rules, and regulations will be fully enforceable in accordance with their respective terms and that all parties will comply with the provisions of their respective agreements.
- All licenses, permits and approvals, and permit modifications (if necessary) will be obtained and/or renewed on a timely basis and any such renewals will not contain conditions that adversely impact the operating and maintenance costs.

In discussing UPP Unit 4, unless noted otherwise, Black & Veatch considers the equipment, systems and interconnections discussed to be those typically found in electric generation facilities of similar type.

Black & Veatch has provided recommendations for consideration where appropriate based upon previous experience and observations of similar facilities. When necessary, Black & Veatch identifies those areas it considers to have design or potential operational issues that may impact the reliable operation of UPP Unit 4. Black & Veatch considers any significant issues that may have previously occurred as having been addressed and resolved in a satisfactory manner unless noted otherwise.

## 1.4 CONCLUSIONS

On the basis of Black & Veatch's studies, analyses, and investigations of UPP Unit 4 and the assumptions previously set forth and elsewhere in this Report, Black & Veatch offers the conclusions in the following subsections.

### 1.4.1 AQCS Technology Assessment

- Black & Veatch identified closed coupled over fired air (CCOFA), separated over fired air (SOFA), selective non-catalytic reduction (SNCR) and selective catalytic reduction (SCR) as potential $NO_X$ reduction technology options; spray dryer absorber (SDA) and dry sorbent injection (DSI) as $SO_2$ reduction options; and addition of a pulsejet fabric filter (PJFF) as a PM reduction option; the scenarios applicable to these technology options are summarized in Section 3.0.

# 2.0 UPP Unit 4 Design Description

UPP Unit 4 consists of a single coal and natural gas fired steam unit and is located approximately 15 miles west of Salt Lake City, Utah near the town of Magna, Utah. The facility generating capacity is 67 MW net. Unit 4 supplies electricity to Kennecott's operations and is interconnected with the PacifiCorp owned transmission system. The facility possesses access to the necessary substation facilities, including a 44 kV switchyard, for the switching and distribution of all power produced to Kennecott's operations.

**Table 2-1 UPP Unit 4 Overview**

| CATEGORY | DATA | CATEGORY | DATA |
|---|---|---|---|
| Location | Magna, UT | | |
| Capacity | 67 MW net | | |
| Configuration | 1x75 MW STG | Technology | Boiler: Combustion Engineering Tangentially Fired<br>STG: General Electric Single Reheat |
| Fuel Type | Coal and Natural Gas | Coal Supplier | Bowie Resources, LLC (Bowie) Skyline Mine |
| Electric Interconnect | 44 kV to 138 kV transformer owned by Kennecott | Gas Interconnect | Dominion Energy, Inc. (Dominion) |

## 2.1 EQUIPMENT

Major plant equipment for Unit 4 relevant to this study is summarized in Table 2-2.

**Table 2-2 Unit 4 Major Equipment**

| COMPONENT | QTY | DESCRIPTION |
|---|---|---|
| STG | 1 | General Electric single reheat rated at 75 MW |
| Boiler | 1 | Combustion Engineering (CE) Tangential Fired, subcritical, reheat, balanced draft with a continuous rating of 650,000 lb/hr of primary steam produced when burning coal or natural gas. |
| AQCS | 1 | Electrostatic Precipitator – Neundorfer, 8 fields |

### 2.1.1 Boilers

Unit 4 boiler is a 75 MW gross balanced draft tangentially fired boiler manufactured by CE. $NO_x$ and CO emissions from the Unit 4 boiler are managed by adjusting combustion air depending on the boiler output. The boiler fires coal as a primary fuel and has the capability to burn natural gas as a secondary fuel.

### 2.1.2 Steam Turbine Generator

Unit 4 STG is a 75 MW gross single reheat unit manufactured by General Electric. The STG is original and has had minimal modification since installation outside of regular preventative and major maintenance.

### 2.1.3 AQCS

Unit 4's current AQCS consists of an electrostatic precipitator (ESP) originally manufactured by Neundorfer. There currently are no $NO_X$ or $SO_2$ controls on the unit. The ESP has six electrical fields and eight mechanical fields, with the electrical density increasing towards the back mechanical fields. Kennecott currently controls $NO_X$ and CO emissions from Unit 4 using combustion management while the boiler is in operation.

## 2.2 FUEL SUPPLY

Unit 4 burns coal as its primary fuel supplied from Bowie's Skyline mine. Unit 4 is also interconnected to Dominion's natural gas pipeline and can utilize natural gas as a secondary fuel. This pipeline is able to supply maximum station demand. Unit 4 currently utilizes coal from March to October of each year. For the November to February period the facility either utilizes natural gas or does not operate.

# 3.0 AQCS Technology Assessment

A summary of the evaluated technologies and their applicability to Kennecott's Unit 4 is provided in the sections below.

## 3.1 $NO_X$ CONTROL TECHNOLOGIES

This section evaluates Over Fired Air and Separated Over Fired Air, Selective Non-Catalytic Reduction, and Selective Catalytic Reduction. The capital and O&M cost of these $NO_X$ technologies are presented in Section 4.0.

### 3.1.1 Over Fired Air (OFA)

Over-fire air (OFA) generally refers to introducing combustion air in two stages. Combustion air is directed to the burner zone in quantities (70 percent to 90 percent) that are less than that required to theoretically burn the fuel. The remainder of the combustion air (10 percent to 30 percent) is directed to OFA ports, which are located above the top row of burners. By reducing the excess air in the primary combustion (burner) zone, $NO_X$ formation is reduced due to the limited amount of oxygen in the air. Furthermore, less oxygen means a decrease in combustion reactions and a decrease in the heat of reaction released, reducing the overall and peak temperatures in the burner zone (first stage). The additional air nozzles also spread the release of heat over a larger area in the furnace. Thermal $NO_X$ formation increases with higher temperatures, so reducing the overall and peak temperatures reduces thermal $NO_X$. Any residual unburned material, such as CO that inevitably escapes the main burner zone, is subsequently oxidized as the OFA is added.

The expected $NO_X$ reduction from a given OFA system depends on a number of factors. The stoichiometry in the burner zone decreases as the amount of OFA is increased, and a point is reached where CO emissions reach high levels and become uncontrollable. The point at which this occurs varies, depending on the balance of flows between individual burners. As the OFA amount approaches 10 to 15 percent, the probability for individual burners operating under fuel-rich conditions increases so that pockets of very high CO emissions would be formed.

A close coupled over-fire air (CCOFA) system injects air directly above the furnace burners. This orientation minimizes retrofit construction, as the ductwork can be installed right on top of the windbox and only needs to go a short distance to the injection ports. However, the short distance between the primary combustion zone and the over-fire air ports means that there is less time for the initial combustion processes to occur before the OFA is introduced. This will result in a lower emission reduction compared to a separated OFA system. Kennecott communicated that there are no OFA systems installed on Unit 4's boiler, so a new CCOFA system could potentially provide near 30% reduction in $NO_X$ emissions.

Separated over-fire air (SOFA) is similar to CCOFA in methodology, but the placement of the OFA ports is further downstream, or separated, from the primary combustion zone. Staging the introduction of combustion air optimizes the combustion process, allowing operators to limit $NO_X$ and CO formation. For Unit 4, SOFA would provide additional levels of staging than CCOFA, thereby reducing $NO_X$ emissions further. SOFA can reduce $NO_X$ formation by approximately 40 percent compared to units with no staged combustion. An additional 10 to 20 percent additional $NO_X$ reduction can be expected from a SOFA system if CCOFA staging is installed.

It is sensible to install both CCOFA and SOFA at the same time as the systems require similar modifications. While it's possible that SOFA by itself could lower Unit 4's $NO_X$ emissions by at least 30 percent, the reduction rate is highly dependent on the boiler configuration. To ensure adequate $NO_X$ reduction, Black & Veatch suggests assuming installing of both systems to lower $NO_X$ emissions by at least 30 percent. The incremental cost for installing CCOFA in addition to SOFA is estimated to be 10-20 percent of the total cost.

### 3.1.2 Selective Non-Catalytic Reduction (SNCR)

Selective non-catalytic reduction (SNCR) is a method that injects urea ($H_2N$ - CO - $NH_2$) at multiple levels in the boiler. Urea is injected into areas of the boiler where the flue gas temperature ranges from 1,600° to 2,100° F. Urea is a non-hazardous reagent if shipped in dry pelletized form with no special shipping, storage, or usage limitations. Urea is stored as 40 to 50 percent urea solution, and will need to be kept heated or circulated in freezing climates such as the Salt Lake City area. The urea solution is pumped to the boiler and atomized with compressed air at the injection nozzles.

When injecting urea into the boiler, $NO_X$ reduction should be balanced with ammonia slip for optimal performance. Ammonia slip is the ammonia that does not react with $NO_X$ and instead "slips" out of the boiler as unreacted ammonia. High levels of ammonia slip can cause several negative operational impacts.

Ammonia can be used in lieu of urea for the SNCR, but at least one major SNCR vendor does not recommend ammonia. Ammonia reacts extremely fast making it very difficult to achieve good distribution across the boiler resulting in lower performance. Urea is often more favorable as it takes time to convert from urea to ammonia, delaying the vaporization of the ammonia and allowing better distribution and performance. For these reasons, Black & Veatch recommends against using ammonia for SNCR.

Reagent injection lances are usually located between the boiler soot blowers in the pendent superheat section. Optimum injector location is mainly a function of temperature, CO concentration, and residence time. To accommodate SNCR reaction temperature and boiler turndown requirements, several levels of injection lances are normally installed. A flue gas residence time of at least 0.3 seconds in the optimum temperature range is desired to ensure adequate SNCR performance. Residence times in excess of one second yield high $NO_X$ reduction levels even under less than ideal mixing conditions. Computational fluid dynamics and chemical kinetic modelling can be performed to establish the optimum reagent injection locations and flow patterns. Additionally, detailed testing including temperature mapping and $NO_X$ and CO level measurements across the boiler cross section should be performed prior to finalization of the SNCR design. Low CO levels are critical for SNCR performance, as the CO emissions need to be below 250 ppm at the injection location in order to assure the SNCR adequately removes $NO_X$. Boiler testing should be conducted to verify the CO emissions levels in the furnace.

Most SNCR systems can achieve anywhere from 20 to 35 percent $NO_X$ reduction, depending on the initial $NO_X$ concentrations. It is reasonable to expect approximately 30 percent reduction from the SNCR at Kennecott's Unit 4.

$NO_x$ reduction with an SNCR is correlated to the starting $NO_X$ concentrations, as higher percent removal can be achieved with higher initial concentrations. Higher concentrations allow more

interaction between the pollutant and reagent, meaning increased reduction. Therefore, if SNCR is added to supplement SOFA or FGR, the removal efficiency by percentage will be less. Generally, if FGR and SOFA were added to reduce $NO_X$ concentrations, the SNCR can be expected to reduce $NO_X$ by an additional 15 percent of the $NO_X$ after FGR and SOFA are implemented.

An SNCR system can be easily installed at most facilities, as the footprint is not large. Modeling of the boiler would need to be completed to determine the optimal injection location for the reagent lances to be installed. Multiple injection levels are usually installed between the superheater bundles. In addition to the injection lances, an area would need to be cleared for the urea storage and mixing tanks. From the storage tanks, a reagent recirculation skid would be installed to provide sufficient pressure to deliver the reagent to the mixing and measurement module, which would be used to meter and control the reagent feed rate to each injection level. These skids would use compressed air and/or water, so piping from the plant's utility system would need to be provided.

### 3.1.3 Selective Catalytic Reduction (SCR)

Selective catalytic reduction (SCR) reduces $NO_X$ emissions by introducing ammonia ($NH_3$) into the flue gas upstream of a reaction chamber. Ammonia readily reduces the $NO_X$ molecules into nitrogen and water at temperatures above 1600° F. The SCR reaction chamber, which is usually installed between the economizer and air preheater, is at temperatures much less than is optimal for $NH_3$-$NO_x$ reactions, so catalysts are needed to promote the reactions. The reaction chamber contains one or multiple layers of catalyst that are made of metals and/or ceramics containing a highly porous structure.

The ammonia supply can be provided at a facility in multiple potential configurations. Anhydrous is nearly pure ammonia and is a gas at standard temperature and pressure. At most facilities, it is stored as a liquid under pressure and after being vaporized, can be injected directly into the ductwork as a gas. Anhydrous ammonia requires less storage footprint, but due to its volatility and caustic nature, special permits and area classifications must be planned for handling. Ammonia can also be delivered to a facility as a solution, with 19 percent (by weight) solutions being common. While ammonia solutions do not require special permits, the cost of transport is higher than anhydrous, as the consumer pays for the transport of water in addition to ammonia. Lastly, urea solutions can also be used, as they will decompose into ammonia. Urea is received and stored as a liquid on site, and likewise needs to be vaporized prior to being injected into the SCR. Urea systems require additional equipment to decompose the urea to ammonia prior to being injected into the SCR system.

Catalysts are imperative to the SCR, as the reactions will not occur without them. Precious metals (e.g. platinum) have previously been used as a base for SCR catalysts, but over the years, cheaper metals and their oxides have been successfully employed. Catalyst and other considerations limit the maximum operating temperature to 840° F, although there are catalysts that can operate up to 1000° F. Conventional SCR catalysts are coated by either a homogeneous ceramic or metal substrate, and the composition is vanadium-based. Titanium is included to disperse the vanadium catalyst, and tungsten is added to minimize adverse $SO_2$ and $SO_3$ oxidation reactions. An economizer bypass may be required to maintain the reactor temperature during low load operation, but this will reduce boiler efficiency at lower loads.

A number of alkali metals and trace elements (specifically arsenic) poison the catalyst, significantly reducing reactivity and life. Other elements such as sodium, potassium, and zinc can also poison the catalyst by neutralizing the active catalyst sites. Poisoning of the catalyst does not occur instantaneously, but is a steady process that occurs over the life of the catalyst. As the catalyst becomes deactivated, ammonia slip emissions increase, approaching design values. As a result, catalyst in a SCR system is consumable, requiring periodic replacement at a frequency dependent on the level of catalyst poisoning. However, effective catalyst management plans can be implemented that significantly reduce catalyst replacement requirements. For natural gas applications, significantly less catalyst poisoning is expected compared to coal burning facilities.

An SCR should be able to remove about 70 to 90 percent of the $NO_X$ from a flue gas stream, regardless of whether the unit is firing natural gas or coal. However, it is more difficult to achieve higher removal rates (near 90 percent) at lower baseline $NO_X$ levels, because at lower $NO_X$ concentrations, there is less mixing and interactions of $NO_X$ and $NH_3$ molecules.

Unit 4 does not have significant room in its flue gas ductwork, so further analysis will need to be completed to determine the feasibility of installing an SCR. Creative ductwork solutions may be able to accommodate an SCR, however pressure drop from the new equipment and associated ductwork may require installation of an additional ID fan. The addition of an ID fan has been included in the Section 4.0 cost estimates; this requirement can be confirmed if Kennecott proceeds with further study of this option.

## 3.2 ACID GAS AND $SO_X$ CONTROL TECHNOLOGIES

Acid gas controls currently do not exist on Unit 4,. The likelihood of tighter emission limits, or what the values will be, is difficult to predict. For this study when firing coal an emission target of 0.2 lb/MMBtu for $SO_2$ was chosen.

Based on the coal analysis provided by the client, as well as Black & Veatch's in-house data for the Skyline mine, composite coals were estimated for design, minimum, and maximum sulfur cases. Combustion calculations were conducted with these coals, and an hourly emission rate of 682 lb/hour was calculated for the design case, 953 lb/hour for the maximum case, and 682 lb/hour for the minimum case. Converting these to a lb/MMBtu basis, $SO_2$ removal rates of 65 percent (minimum case), 77 percent (design case), and 84 percent (maximum case) were estimated.

The predominant acid gas or sulfur oxide removal systems can achieve removal rates well in excess of the emission target identified above, and are routinely designed to do so. A wet flue gas desulfurization (WFGD) for example, commonly achieves removal rates of 98 percent. A circulating dry scrubber (CDS) can also achieve similar removal rates, although normally a few percentage points lower on an average, operating basis. While both systems are capable of achieving the potential removal rates required for Unit 4, due to their high capital and annual operating costs Black & Veatch did not include analysis of these systems as part of this study.

Similar to the WFGD and CDS, a spray dryer absorber (SDA) can achieve the lower $SO_2$ emission target identified for Unit 4. An SDA generally has lower capital cost than a WFGD and CDS and will generally require less modifications and/or footprint at the facility.

Dry sorbent injection (DSI) is often used to combat acid gases in flue gas streams, and it has demonstrated removal rates in excess of 90 percent for HCl and $SO_3$. For $SO_2$, DSI is not as effective, and the annual sorbent costs will be high to meet to the identified emission target. While an SDA will have a higher up front capital cost, the DSI system will be less efficient and have a higher annual sorbent cost.

A further description of SDA and DSI is included in the sections below.

### 3.2.1 Spray Dryer Absorber (SDA)

A SDA uses alkaline slurry, most commonly calcium (lime), to react with acid gases in the flue gas. The lime slurry is injected into a large, inverted-conical shaped vessel, concurrently with the flow of the flue gas. The chemical reactions between the calcium in the lime and acids in the flue gas readily occur, and as the reactions take place, the slurry particles dry into particulate matter that can be removed by the downstream particulate collection device. While the majority of the $SO_2$ removal occurs in the absorber, there is still a significant minority of the reaction that occurs in the particulate collection device. There are unreacted lime particles in the flue gas, and as flue gas passes over the lime particles, additional $SO_2$ removal occurs. For Unit 4, an ESP is installed. There is a small amount of $SO_2$ removal that occurs with an ESP, but significantly more residual removal occurs with a baghouse due to flue gas being forced to pass through a filter cake containing unreacted lime particles.

Lime slurry is created by mixing raw water and pebble lime in a slaker, which mixes the two components together until the right slurry qualities (e.g. temperature and density) are reached. The water quality is important, as inherent sulfate levels in the water will react with the calcium in the lime slurry before it has a chance to come into contact with the flue gas. While high quality water is not required, water sources should be screened for suitability. The slaker can be one of a handful of types, including a vertical ball mill that helps mitigate problems associated with poor water quality.

Once the slurry is created, it is held in a storage tank that must be continuously agitated to prevent the slurry particles from coming out of suspension. Feed pumps connected to the tank will transfer the lime slurry to either another head/storage tank or to the atomizer. The atomizer is located at the top of the absorber vessel and is used to introduce the lime slurry into the flue gas. The atomizer is a spinning wheel that rotates fast enough to split the lime slurry into a fine mist that is injected into the absorber vessel. This is important, because the finer the slurry droplets, the more surface area available for chemical reactions to occur.

Water in the lime slurry evaporates, and evaporation is an endothermic process that takes heat away from the flue gas. The chemical reaction occurs best in the liquid phase, so cooling the flue gas closer to its dew point helps reactions occur. The downside of this is that due to localized cold spots, cooling the flue gas temperature too close to the dew point will result in extensive corrosion downstream of the absorber. Typically, the approach temperature (the degrees that the SDA outlet temperature is above the dew point) is set at 40° F.

An SDA must be installed upstream of a particulate collection device, and at Unit 4, there is limited space in ductwork between the air heater and ESP. Thus, significant ductwork modifications would be needed to accommodate installing an SDA. The pressure drop across the absorber and associated ductwork would also be significant enough that a new ID fan would be required. There is

also no guarantee that the existing ESP can be used due to increased dust loading due to the dried slurry particles, so further evaluation would be required on reusing the ESP. At this time Black & Veatch has assumed that a pulse jet fabric filter (PJFF) would need to replace the existing ESP if an SDA is installed.

The increased level of collected particulates will result in increased waste that must be removed from site. The ash characteristics will also change due to the reacted lime and sulfur. Most landfills are readily able to take SDA byproduct, but this should be confirmed with the landfill Kennecott uses for the facility's waste.

### 3.2.2 Dry Sorbent Injection (DSI)

Dry sorbent injection (DSI) injects a reagent, the three most common being hydrated lime, trona, or sodium bicarbonate (SBC), into ductwork to react with acidic compounds in the flue gas. The reagent is injected in its dry form, with modeling completed to optimize the injection location. The flue gas' temperature and reagent's distribution have a significant impact on the DSI's effectiveness, so the injection location is a primary design consideration.

The reagent is typically trucked to site and blown into storage silos. The storage silos will have some form of metering system at the bottom, which will control the reagent's feed as needed. The reagent is transported to the injection lances by a blower. Common design considerations include preventing common flow issues in silos such as rat-holing and bridging, and using the correct materials of construction to mitigate erosion issues.

While a DSI system is much simpler than other proven $SO_2$ control technologies, with much less pieces of equipment and process streams, a DSI system is limited in its achievable removal rates. A DSI system at Unit 4 could not use hydrated lime and achieve the necessary $SO_2$ removal rates for Unit 4; only sodium based sorbents suffice, with SBC achieving the removal rates at lower normalized stoichiometric ratios (NSR) than trona. The NSR is the ratio of the mass of reagent over the mass of $SO_2$ removed, compared to the theoretical injection ratio, and the higher the NSR, the more reagent that needs to be injected. The NSR for DSI systems exponentially increases as the $SO_2$ removal rates continue to increase.

One option with DSI systems is using a mill to reduce the particle size of the injected sorbent. For installations with much lower removal rates and/or different target pollutants, improvements from milling may not justify the additional capital cost. However, for Unit 4, Black & Veatch suggests that implementation of a mill could be beneficial. Mills require routine maintenance and are an added auxiliary load, however by reducing the average particle size of the reagent, milling has been shown to significantly reduce sorbent consumption. This could provide financial benefit for installations with a high sorbent consumption rate, as would be the case for Unit 4.

For the same reasons discussed for SDA, higher DSI removal rates are achieved with a PJFF compared to with an ESP. Black & Veatch suggests that further evaluation be completed to establish if the existing ESP can be reused if a DSI is installed. The increased dust loading from the sorbent could mean a PJFF is required; however, sodium based sorbents have been known to help lower the resistivity of fly ash and improve ESP efficiency. Based on this, installation of a PJFF was not included in the capital cost estimate for DSI installation included in Section 4.0.

## 3.3 PARTICULATE MATTER CONTROL TECHNOLOGIES

Based on the provided emission test reports from Kennecott, the current Unit 4 PM emissions appear to meet the lower emission target identified. There is therefore no need to install new PM AQCS based on the lower PM emission target alone. However, if a SDA were installed to control $SO_2$ emissions, the increased particulate levels could be more than the current ESP's design limits, especially considering its age.

The predominant particulate control devices utilized in the power industry are PJFFs and ESPs. Given the potential requirement to upgrade to a PJFF in the case of SDA installation, a PJFF was included in the cost estimates in Section 4.0.

A further description of a PJFF is included in the section below.

### 3.3.1 Pulse Jet Fabric Filter (PJFF)

PJFFs have proven themselves to economically meet the low particulate emission limits for a wide range of operations and fuel characteristics. The PJFF is relatively insensitive to ash loadings and various ash types, offering superb coal flexibility. Fabric filters (FF) are the current technology of choice when low outlet particulate emissions are required for coal fired applications. FFs collect particle sizes ranging from submicron to 100 microns in diameter at high removal efficiencies (proper application of the FF technology can result in clear stacks, generally less than 5 percent opacity).

FFs are generally categorized by the type of cleaning. The two predominant cleaning methods for utility applications are reverse gas (RG) and pulse jet (PJ). Initially, utility experience in the United States was almost exclusively with reverse gas FF (RGFF). Although they are a very reliable and effective emissions control technology, RGFFs generally have a larger footprint, which is particularly difficult for retrofit implementations. PJFFs can be operated at higher flue gas velocities, and as a result, have a smaller footprint. The PJFF also generally has a lower capital cost than an RGFF and matches the performance and reliability of an RGFF. As a result, only PJFFs are considered for this study.

Cloth filter media is sewn into cylindrical tubes called bags, and each FF casing may contain thousands of these filter bags. A FF casing is typically divided into compartments that allow on-line maintenance or bag replacement after a compartment is isolated. The number of compartments is determined by maximum economic compartment size, total gas volume rate, air-to-cloth ratio (A/C ratio), and cleaning system design. Extra compartments for maintenance or off-line cleaning may increase cost, but it also increases reliability. Each compartment includes at least one hopper for temporary storage of the collected fly ash.

Fabric bags vary in composition, length, and cross section (diameter or shape). Bag selection characteristics vary with cleaning technology, emissions limits, flue gas and ash characteristics, desired bag life, capital cost, air-to-cloth ratio, and pressure differential. Fabric bags are typically guaranteed for 3 years but frequently last 5 years or more. PJFF bags are typically made of felted materials that do not rely as heavily on the dust cake's filtering capability as woven fiberglass bags do. This allows the PJFF bags to be cleaned more vigorously. The felted materials also allow the PJFF to operate at a much higher cloth velocity, which significantly reduces the size of the unit and the space required for installation.

In PJFFs, the flue gas typically enters the compartment hopper and passes from the outside of the bag to the inside, depositing particulate on the outside of the bag. To prevent the collapse of the bag, a metal cage is installed on the inside of the bag. The flue gas passes up through the center of the bag into the outlet plenum. The bags and cages are suspended from a tubesheet.

Cleaning is performed by initiating a downward pulse of air into the top of the bag that causes a ripple effect along the bag's length. This dislodges the dust cake from the bag surface, and the dust falls into the hopper. This cleaning may occur with the compartment on line or off-line. Care must be taken during design to ensure that the upward velocity between bags is minimized so that particulate is not re-entrained during the cleaning process.

The PJFF cleans bags in sequential, usually staggered, rows. During on-line cleaning, part of the dust cake from the row that is being cleaned may be captured by the adjacent rows.

# 4.0 AQCS Capital and O&M Cost Assessment

After identifying potential AQCS technologies that could be utilized for Kennecott's Unit 4, costs for each technology were evaluated. Budgetary estimates from original equipment manufacturers (OEMs) and Black & Veatch's in-house databases were used to develop up front capital and annual operating & maintenance (O&M) cost estimates.

Capital costs were estimated using OEM costs for major equipment, direct costs for construction and installation, and indirect costs for engineering, management and other fees. Annual O&M costs were based on a full time employee's salary of $100,000 per year and estimated sorbent costs based on estimated consumption rates and supplier provided information. Additional annual O&M costs, such as auxiliary loads require further analysis to estimate and were not included in this study.

The cost estimates developed in this study are order of magnitude (OoM) with an accuracy of ± 50 percent. Table 4-1 summarizes the components which make up Black & Veatch's capital cost estimate for each AQCS option.

**Table 4-1 Capital Cost Components**

| CAPITAL COST COMPONENT | ACRONYM |
|---|---|
| Purchased Equipment Cost | PEC |
| Direct Installation Costs | DIC |
| Indirect Costs | IC |
| **Total Capital Investment** | **TCI (PEC + DIC + IC)** |

PEC includes the costs from OEMs and other purchased equipment such as ductwork, structural steel, electrical, instrumentation, and if needed, new ID fans. DIC includes the cost of installing the purchased equipment. IC refers to engineering, construction management, contractor fees, startup activities and contingencies. TCI is the sum of PEC, DIC and IC.

## 4.1 $NO_X$ CONTROL TECHNOLOGIES

The capital and annual O&M costs for the $NO_X$ control technologies are provided in Table 4-2 and Table 4-3, with details of the inclusions in the cost estimates outlined in the following subsections.

**Table 4-2 $NO_X$ Control Technology Capital Cost**

| COST COMPONENT | CCOFA + SOFA (30% EMISSION REDUCTION) | SNCR (30% EMISSION REDUCTION) | SCR (80% EMISSION REDUCTION) |
|---|---|---|---|
| PEC | $800,000 | $2,200,000 | $9,700,000 |
| DIC | $800,000 | $800,000 | $7,000,000 |
| IC | $500,000 | $3,000,000 | $11,500,000 |
| **TCI** | **$2,100,000** | **$6,000,000** | **$28,200,000** |

**Table 4-3 $NO_X$ Control Technology Annual O&M Cost**

| COST COMPONENT | CCOFA + SOFA | SNCR | SCR |
|---|---|---|---|
| Annual O&M | N/A | $510,000 | $2,620,000 |

### 4.1.1 Over Fired Air (OFA)

Based on past projects and vendor quotations, Black & Veatch estimated a TCI of $2 million for installation of CCOFA + SOFA on Unit 4. This includes ductwork, nozzles, dampers, positioners, and an assumed amount of demolition and rework of existing equipment. There is no sorbent associated with the OFA systems, and there should not be a need to hire more staff for maintaining the new OFA ports. Therefore, Black & Veatch suggests there should be no additional annual O&M cost following installation of CCOFA + SOFA. There will be costs associated with periodic replacement of air nozzles and routine maintenance, however Black & Veatch suggests these requirements will be minimal on an annual basis.

### 4.1.2 Selective Non-Catalytic Reduction (SNCR)

A leading vendor provided a budgetary quote for an SNCR system, which includes the urea injection skid and the injection lances. The SNCR system design is based on a 50 percent urea solution, and typically 14 days of reagent is maintained on site. Installation factors and indirect costs were based on previous projects that Black & Veatch has executed. A TCI of approximately $6 million is estimated.

The annual O&M cost was estimated using a delivered price estimate from a urea solution provider to the greater Salt Lake City area. A 50 percent urea solution was assumed. The urea solution's injection rate should be approximately 36 gpm, with a price of $270/ton of solution assumed. The $NO/NO_2$ split was assumed to be 90 percent NO, based on the coal combustion due to coal having higher $NO_X$ emissions. The cost of an additional operator was also included. A full time employee dedicated to the SNCR should not be necessary, but a certain amount of time over the course of a year for a person earning $100,000 a year was assumed. The same was assumed for maintenance personnel, along with costs for spare parts (assumed at 2.5 percent of the direct cost, with foundation and steel related equipment removed).

### 4.1.3 Selective Catalytic Reduction (SCR)

SCR catalyst costs for different $NO_X$ removal rates were provided by two leading catalyst manufacturers, and escalation factors were applied for the SCR housing and associated systems, such as the ammonia injection skid. Factors were based on past projects by Black & Veatch, with higher installation costs applied for ductwork due to space limitations at Unit 4. Electrical modifications, including substation work, were included due to retrofits often needing extensive electrical reconfiguration.

The catalyst volume for an 80 percent reduction rate is 98 $m^3$. This equates to a 17 percent increase in catalyst volume from one case to the other, but the volume difference has a nominal impact on the overall capital cost of the SCR. Similar amounts of structural steel, the same ID fans, similar civil

and foundation work, etc. will need to be executed in either case. The quotations obtained from OEMs are budgetary in nature, but general performance guarantees that can be expected to include a 16,000 hour catalyst life guarantee, 1 percent $SO_2/SO_3$ conversion, an ammonia slip of 2 ppmvd, and pressure drops around 4 inches of water.

A SCR can use either urea or ammonia as its reagent, with ammonia being available in a solution or pure anhydrous form. Many past clients have elected not to use anhydrous ammonia due to handling requirements, so an ammonia solution and urea were used in the annual O&M cost estimate. It was also assumed one full time employee would be required to operate and maintain the SCR. Other fixed annual costs included testing for catalyst activity and maintenance labor and materials, which was assumed at 2.5 percent of the direct costs (foundation and steel equipment removed). This study assumed 29.4 percent ammonia solution would be used at a cost of $1,500/ton of solution.

Removing 80 percent of the $NO_X$ emissions would require approximately 330 lb/hour of solution, and removing $NO_X$ after OFA would require approximately 200 lb/hour of solution. These flow rates were assumed to be required 8,760 hours a year in order to estimate the annual sorbent cost. A variable annual cost also included for catalyst replacement and disposal. The catalyst replacement cost was based on a catalyst life assumption of 16,000 hours, operation for 8,760 hours/year and the cost of catalyst from the budgetary quotes received.

## 4.2 ACID GAS AND $SO_X$ CONTROL TECHNOLOGIES

The capital and O&M costs for the two $SO_2$ control technologies evaluated are provided below (Table 4-4 and Table 4-5), with details of inclusions in the cost estimated summarized in the following subsections.

**Table 4-4 $SO_2$ Control Technology Capital Cost**

| COST COMPONENT | SDA | SDA WITH PJFF | DSI |
|---|---|---|---|
| PEC | $20,800,000 | $25,300,000 | $2,900,000 |
| DIC | $7,700,000 | $8,600,000 | $1,000,000 |
| IC | $7,900,000 | $8,700,000 | $4,200,000 |
| TCI | $36,400,000 | $42,600,000 | $8,100,000 |

**Table 4-5 $SO_2$ Control Technology Annual O&M Cost**

| COST COMPONENT | SDA | SDA WITH PJFF | DSI (W/SBC AND ESP) |
|---|---|---|---|
| Annual O&M | $1,310,000 | $1,360,000 | $2,400,000 |

### 4.2.1 Spray Dryer Absorber (SDA)

Two leading SDA OEMs were contacted to provide budgetary quotes based on the combustion calculations executed by Black & Veatch and the design information provided by Kennecott. A SDA system which continues to utilize the existing ESP would have a PEC of approximately $10.0 million from the OEM. Including a new PJFF would add approximately $2.5 million to PEC. The SDA system will also require other equipment to complete the installation. For example, it is likely that the additional pressure drop from the SDA vessel will require new ID fans, which add approximately $2.5 million to PEC. Additionally, there is limited ductwork between the air preheater outlet and the ESP, so major ductwork modifications would be required to install an SDA vessel. Escalation factors from Black & Veatch's database and past projects were used to increase the vendor's equipment cost to a total installed cost. This included electrical and substation work, as substantial projects such as an SDA will often require electrical reconfiguration.

An additional two and a half full time employees were assumed to be required to operate and maintain a full SDA system, as there are many rotating pieces of equipment between the lime slaking, slurry delivery and atomizers. An additional four full time employees were assumed for the case of where the new PJFF was included in the installation. The maintenance materials cost can also be extensive and vary widely between facilities. A 2.5 percent of the total direct costs (PEC + DIC) was assumed in the annual O&M cost estimate. Pebble lime at a cost of $130/ton was used, at a consumption rate of 700 lb/hour based on the design coal.

### 4.2.2 Dry Sorbent Injection

Two leading vendors for DSI systems were contacted to provide budgetary quotes based on the combustion calculations executed by Black & Veatch and the design information provided by Kennecott. Generally, a DSI system for Unit 4 would have a TCI of $8.1 million. This includes lime receiving equipment, a storage silo with seven days residence time, injection blowers, lances and milling equipment.

Installation of a PJFF was not assumed for a DSI system, however further investigation should be conducted to confirm that the existing ESPs can continue to be utilized in the event a DSI is installed.

Black & Veatch suggests that a new DSI system would require at most one additional staff member to the maintenance crew, however some facilities have been able to maintain the new equipment with existing staff. The annual O&M costs for the DSI therefore assumed 0.5 of an additional full time employee's time. Maintenance parts were assumed to be 2.5 percent of the total direct costs. The majority of the annual O&M costs are for sorbents. The usage efficiency is low for a DSI system removing $SO_2$. As previously mentioned, hydrated lime cannot achieve the necessary removal rates, so only trona and SBC were considered. SBC has achieved the required removal rates at a lower sorbent rates than trona, but SBC is nearly twice the cost of trona. Based on the design coal conditions, approximately $2 million of SBC (priced at $200/ton) would need to be purchased annually. The estimate is the same for trona, as while trona is approximately half the cost of SBC, almost twice as much trona would need to be consumed. When the maximum sulfur coal content of 0.74 weight percent is burned, the amount of sorbent consumption almost doubles, and the annual cost of sorbent is approximately $4.0 million.

These sorbent consumption rates are reduced by near 40 percent with the addition of a PJFF, which can result in savings of approximately $1 million annually. Kennecott could consider these potential savings to evaluate the additional capital cost of a PJFF.

## 4.3 PARTICULATE MATTER CONTROL TECHNOLOGIES

The capital cost estimate for a new PJFF at Unit 4 assumed that new ID fans would be required. Escalation factors and engineering estimates were applied to the base equipment cost provided by a leading OEM (Table 4-6). Annual O&M costs assumed 1.5 full time employees, and 2.5 percent of the direct costs for maintenance parts and materials (Table 4-7).

**Table 4-6 PJFF Capital Cost**

| COST COMPONENT | PJFF |
|---|---|
| PEC | $6,500,000 |
| DIC | $2,100,000 |
| IC | $3,000,000 |
| TCI | $11,600,000 |

**Table 4-7 PJFF Annual O&M Cost**

| COST COMPONENT | PJFF |
|---|---|
| Annual O&M | $320,000 |