EXPERT REPORT OF KENNETH J. SNELL, SARGENT & LUNDY LLC ON BEHALF OF AMEREN MISSOURI

United States of America and Sierra Club v. Ameren Missouri
In the United States District Court for the Eastern District of Missouri Eastern Division
Case No. 11-cv-00077

Kenneth J. Snell
April 23, 2018
Amended April 27, 2018
Corrected June 18, 2018

Sargent & Lundy

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CONTENTS

ATTACHMENT 1 - Sargent & Lundy DSI Experience Summary Presentation

FIGURES AND TABLES

1. Introduction

1.1 Purpose of Report/Scope of Assignment

I have been retained by Schiff Hardin, LLP, counsel for Ameren Missouri, to provide an expert opinion in the matter titled United States of America and Sierra Club v. Ameren Missouri. Specifically, I was engaged to evaluate the technical feasibility, effectiveness, and costs of dry sorbent injection (DSI) for sulfur dioxide (SO_2) control on Ameren's Rush Island Units 1 and 2, as well as other related opinions set forth below. In addition, I was asked to review and comment on control technology costs, technical conclusions, and other opinions offered by Dr. James E. Staudt in his March 7, 2018 amended expert report (the "Staudt Report").[1]

1.2 Kenneth J. Snell Background and Qualifications

I am a Senior Consultant at Sargent & Lundy LLC (Sargent & Lundy) and manage Sargent & Lundy's Environmental Technologies and Licensing Group. Sargent & Lundy is a full-service engineering consulting firm providing expertise in all areas of power plant engineering and design. Sargent & Lundy has extensive experience with the specification, evaluation, selection, and implementation of air pollution control technologies for coal-fueled utility power facilities, including extensive experience with wet flue gas desulfurization (WFGD), dry flue gas desulfurization (DFGD), and DSI control technologies.

Since 2000, Sargent & Lundy has provided, or is currently providing, engineering services for the implementation of approximately 40 WFGD projects and 30 DFGD projects. Our work on WFGD and DFGD projects includes all project-related activities, from evaluation and conceptual design, through detailed design, specification, installation, construction management, initial startup and commissioning, and troubleshooting of existing systems. With respect to DSI control systems, Sargent & Lundy has been involved with the evaluation, design, specification and/or installation of 28 DSI control systems specifically designed for the removal of SO_2 emissions, and 41 DSI systems designed for the removal of other acid gas emissions, including sulfur trioxide (SO_3) and hydrochloric acid (HCl). In addition, Sargent & Lundy was actively involved with testing DSI systems using various calcium- and sodium-based reagents on 11 of the

[1] James E. Staudt, *Expert Report of James E. Staudt – Prepared on Behalf of Plaintiffs*, United States of America and Sierra Club v. Ameren Missouri, December 15, 2017, Amended March 7, 2018 (the "Staudt Report).

units noted above. Attachment 1 to this report provides a summary of the DSI projects for which Sargent & Lundy provided technical and design support.

I have been employed with Sargent & Lundy for 18 years, and have held the position of Senior Manager for nine years. I have a Bachelor of Arts Degree in Environmental Studies from the University of Kansas, a Bachelor of Science Degree in Chemical Engineering from the University of Illinois at Chicago, and a Juris Doctorate from John Marshall Law School in Chicago, IL. Prior to working at Sargent & Lundy I was employed as a Senior Environmental Compliance Manager and Associate Environmental Counsel at Safety-Kleen Corporation. I have worked in the field of environmental regulations, compliance, and control technologies for more than 30 years.

In my current position, I am involved in all aspects of environmental compliance at power plants, including regulatory evaluations, compliance planning, and air pollution control technology conceptual design, costs, and specification. Over the past decade, I have participated in flue gas desulfurization control technology evaluations for numerous power plants around the country. I have prepared control technology evaluations for SO_2 control systems on coal-fired units firing a range of fuels, from high-sulfur eastern bituminous coal to low-sulfur Powder River Basin (PRB) coal. I have evaluated the technical feasibility and compared the effectiveness and cost-effectiveness of WFGD, DFGD, and DSI control systems for the SO_2 emissions control on bituminous and subbituminous coal-fired steam electric generating units. With respect to DSI, I have evaluated the technical feasibility and effectiveness of DSI control systems using Trona and sodium bicarbonate, and DSI control systems located upstream of both ESP and fabric filter particulate collection systems.

My involvement on these projects generally focuses on the technical feasibility, effectiveness, conceptual design, costs, and cost-effectiveness of the air pollution control systems. A majority of my work on flue gas desulfurization systems relates to technology evaluations for compliance with federal air quality regulations, including the federal New Source Review Prevention of Significant Deterioration (NSR/PSD) regulations, Clean Air Interstate Rule, Regional Haze Rule, and Mercury and Air Toxics Standard.

1.3 Information Required by Federal Rules of Civil Procedure

The information required by Federal Rules of Civil Procedure is as listed below and as presented in Section 6 of this report.

- Appendix A – Kenneth J. Snell CV
- Appendix B – Kenneth J. Snell Publications List - Past 10 Years
- Appendix C – Kenneth J. Snell Expert Witness Testimony Experience - Past 4 Years
- Appendix D – Documents Considered in Preparing this Expert Report
- Appendix E – Kenneth J. Snell Compensation Rate for this Proceeding

2. EXECUTIVE SUMMARY OF FINDINGS AND CONCLUSIONS

My opinions are based on my review of the Staudt Report, a review of industry data and industry publications, emissions data and test results from Rush Island, and my experience and knowledge of air pollution control technologies available to reduce SO_2 emissions from coal-fired steam electric generating units. The following is a summary of my opinions, and my full opinions are included throughout this report:

1. DSI is a technically feasible and cost-effective control technology to achieve SO_2 reductions at Rush Island Units 1 and 2. Specifically, performance tests conducted on Rush Island Unit 1 demonstrate that DSI can be applied to achieve approximately 50% SO_2 removal efficiency with Trona injection upstream of the air heaters and an injection rate equivalent to a Normalized Stoichiometric Ratio (NS Ratio) of approximately 1.25.
2. Given the robust design of the Rush Island electrostatic precipitator (ESP) particulate control systems, already-low particulate matter (PM) emissions achieved at Rush Island, and improved fly ash resistivity associated with the DSI reagent, it is my opinion that an SO_2 removal efficiency of 50% can be achieved with the existing Rush Island Unit 1 and 2 ESPs.
3. Capital costs to install DSI control on Rush Island Units 1 and 2 to achieve 50% SO_2 control would total approximately $29,797,000 (2017$) with no upgrades to the existing ESPs. If Ameren chooses to upgrade the existing ESPs with new high-frequency transformer/rectifier (T/R) sets to provide an additional margin of compliance with PM emission limits, capital costs for the DSI control system, including ESP upgrades and assuming an in-service date of 2022, would total approximately $42,601,000 (2022$).
4. DSI control systems could be installed on Rush Island Units 1 and 2 within approximately 18-months from the date a decision is made to install the control systems. The same overall project timeline would apply with or without ESP upgrades.
5. With respect to the WFGD cost estimate Dr. Staudt prepared to support his evaluation of BACT for Rush Island Units 1 and 2, it is my opinion that:
   a. Dr. Staudt used an inaccurate methodology to escalate control technology costs from 2010 (the date the cost estimate was originally prepared) to 2016 (the date Dr. Staudt assumed WFGD controls would have become operational at Rush Island);
   b. Dr. Staudt incorrectly removed capital costs, including an allowance for funds used during construction (AFUDC), Property Taxes, and certain owner's costs, from the WFGD cost estimate; thus, underestimating the costs Ameren would incur to install the technology on Rush Island Units 1 and 2;

c. Dr. Staudt failed to adequately account for advanced wastewater treatment costs that Ameren would likely incur to discharge WFGD wastewaters in compliance with the Steam Electric Effluent Limitation Guideline and/or Missouri's Antidegradation Rule; and

d. Dr. Staudt underestimated auxiliary power requirements and auxiliary power costs for the WFGD absorber area.

e. As a result, it is my opinion that Dr. Staudt underestimated the total capital investment required to install WFGD on Rush Island Units 1 and 2, underestimated the total annual costs (i.e., annualized capital recovery costs plus annual operating and maintenance costs) to operate the control technology, and thus overstated the cost-effectiveness of the control technology.

6. It is my opinion that had Dr. Staudt properly escalated capital costs from 2010 to 2016, included all indirect capital costs Ameren would incur to install the WFGD controls, and included costs for advanced WFGD wastewater treatment support facilities, that the total capital cost of WFGD control on Rush Island Units 1 and 2 would total $896.7 million (2016$) compared to Dr. Staudt's estimate of $581.8 million. Escalating these costs to an in-service date of 2025, capital costs for WFGD on Rush Island Units 1 and 2 total approximately $1,067 million (2025$).

7. With respect to other technical conclusions and opinions offered by Dr. Staudt, I offer the following opinions:

a. The incremental cost data Dr. Staudt relied on to support his conclusion that "the incremental cost of controlling SO_2 over 90% changes very little between 93% and 94.3%" are not representative of units, such as Rush Island Units 1 and 2, that fire low-sulfur PRB coal, and that the cost data actually supports my conclusion that the incremental cost of SO_2 removal becomes significantly more expensive at controlled emission rates below approximately 0.06 lb/MMBtu.

b. The co-benefit mercury control correlation equations used by Dr. Staudt to support his opinions that WFGD on Rush Island Units 1 and 2 would have the co-benefit of reducing mercury emissions and that WFGD would avoid the need for activated carbon for mercury control at Rush Island, are not necessarily representative of mercury control on PRB-fired units, and that the installation of WFGD on Rush Island Units 1 and 2 will provide no co-benefit mercury removal.

c. I disagree with Dr. Staudt's assertion that his Rush Island WFGD capital cost estimate was conservatively high because he did not adjust costs for the lower SO_2 removal rates assumed in his report, as it is my opinion that changing the sulfur content of the PRB coal fired at

Rush Island, and the inlet SO_2 loading to the WFGD control system, will have no appreciable effect on control system sizing or capital costs.

d. I disagree with Dr. Staudt's assertion that WFGD control could be installed on Rush Island Units 1 and 2 within approximately 3-years after a decision is made to proceed with the project. It is my opinion that the WFGD project would take a total of approximately 60-months (5-years) from a decision to proceed to commercial operation. It is also my opinion that prior work done by engineering firms on behalf of Ameren, including conceptual design layouts, costs, and preliminary equipment specifications would not reduce the project schedule by any appreciable amount.

8. With respect to cost estimates Dr. Staudt prepared for SO_2 controls at Ameren's Labadie Station, it is my opinion that the approach used by Dr. Staudt resulted in inaccurate capital cost estimates for the installation of SO_2 controls on Labadie Units 1-4 for the following reasons:

   a. Dr. Staudt calculated WFGD and DFGD capital costs for Labadie by adjusting, based on total generating capacity (MW), capital costs prepared by Shaw (WFGD) and Black & Veatch (DFGD) for Rush Island. In my opinion, adjusting the Rush Island cost estimates based solely on capacity fails to take into consideration significant space constraints at Labadie which would likely add significant costs to the control systems at Labadie.

   b. Space constraints at the Labadie station would require Ameren to locate the WFGD, DFGD, or retrofit fabric filter baghouse (FF) control systems south of the existing Unit 4 generator building, approximately 800 feet from the existing Unit 1 ESP. The location of the retrofit control systems would require extensive ductwork and have a significant impact on both equipment and installation costs of the WFGD, DFGD, and FF control systems.

   c. The approach used by Dr. Staudt to account for "economies of scale" at Labadie (i.e., using U.S.EPA's IPM cost algorithms to calculate a $/kW estimate at various gross generating rates) is not accurate, as the IPM cost algorithms were developed based on an analysis of cost data for controls installed on individual units, and estimating an economies of scale based on cumulative gross generation would not reflect costs associated with installing multiple control system trains on multiple units.

   d. Dr. Staudt used the IPM cost algorithms to estimate DSI capital costs and DSI with retrofit fabric filter (DSI/FF) capital costs at Labadie. It is my opinion that the IPM cost algorithms, developed by Sargent & Lundy for U.S.EPA, are not intended to provide costs for any individual project, and do not adequately account for site-specific constraints, process equipment limitations, and operating conditions that could have a significant effect on control system costs and must be evaluated on a case-by-case basis.

9. Based on my review of capital costs developed by Dr. Staudt for control systems on Labadie Units 1-4, it is my opinion that Dr. Staudt underestimated the total capital required to install WFGD on all four units by at least $675.5 million (2016$), not including additional costs Ameren would likely incur due to significant space constraints at the Labadie Station.

10. Based on my review of capital costs developed for the DSI/FF control option, it is my opinion that Dr. Staudt underestimated the total capital required to install the DSI/FF control systems, including support facilities, by at least $150 million (2016$) by removing certain indirect capital costs from the cost estimate and applying an incorrect escalation factor. Furthermore, it is my opinion that Dr. Staudt did not adequately account for the additional costs Ameren would incur with locating the fabric filters south of the Unit 4 generator building.

3. Dry Sorbent Injection is a Technically Feasible and Cost-Effective SO_2 Control System at Rush Island

In this section of my report, I evaluate the technical feasibility, effectiveness, and costs of dry sorbent injection (DSI) installed on Rush Island Units 1 and 2 for sulfur dioxide (SO_2) control. Based on my knowledge of DSI control systems installed on coal-fired boilers for SO_2 control, it is my opinion that DSI is a technically feasible and cost-effective SO_2 control technology for Rush Island Units 1 and 2. It is also my opinion, based on a review of DSI test data available for Rush Island Unit 1, that sodium-based DSI injected upstream of the units' air heaters could achieve SO_2 removal efficiencies of approximately 50%. Furthermore, based on my review of design parameters for the existing Rush Island electrostatic precipitator (ESP) particulate matter (PM) control systems, and a review of control efficiencies currently achieved with the ESPs, it is my opinion that an SO_2 removal efficiency of 50% could be achieved without installation of additional PM control technology, such as a fabric filter baghouse.

3.1 Introduction – Dry Sorbent Injection Process Description

DSI involves the injection of a calcium- or sodium-based reagent into the ductwork downstream of a coal-fired boiler and upstream of the unit's particulate control system. Sodium-based DSI control systems are typically specified for SO_2 control using either sodium bicarbonate (SBC, $NaHCO_3$) or Trona (sodium sesquicarbonate, $Na_2CO_3 \cdot NaHCO_3 \cdot 2H_2O$) as the reagent.[2] Given the proper temperature profile, residence time, and stoichiometry, these reagents decompose to sodium carbonate (Na_2CO_3), which reacts with SO_2 in the flue gas to form stable sodium salt particles. The following equations provide a general representation of the reactions occurring in a sodium-based DSI control system:[3]

$$2NaHCO_3 \longrightarrow Na_2CO_3 + H_2O + CO_2 \quad (1)$$

$$2Na_2CO_3 \cdot NaHCO_3 \cdot 2H_2O \longrightarrow 3Na_2CO_3 + 5H_2O + CO_2 \quad (2)$$

$$Na_2CO_3 + SO_2 + \tfrac{1}{2}O_2 \longrightarrow Na_2SO_4 + CO_2 \quad (3)$$

The resulting sodium salts, sodium carbonate, and sodium sulfate (Na_2SO_4) can be removed from the flue gas as PM in the unit's particulate collection device, typically an ESP or fabric filter.

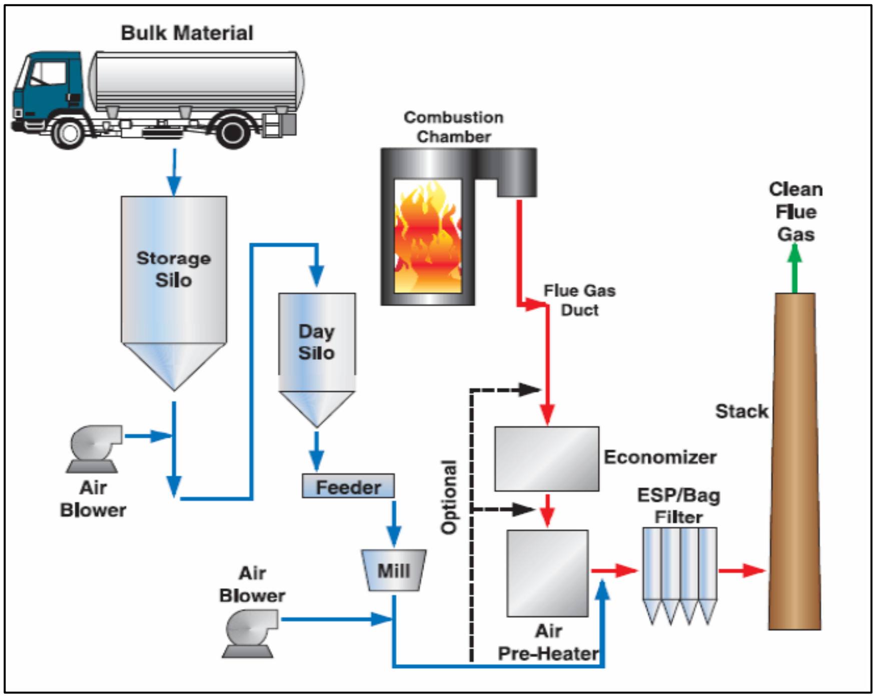
A DSI control system consists of reagent storage facilities and equipment to convey, pulverize, and inject the reagent into the flue-gas ductwork. The reagent can be injected into the flue gas prior to the economizer in the boiler, prior to the air heater, or prior to the particulate control device (ESP or fabric filter). A simplified process flow diagram of a typical DSI control system is shown Figure 1.[4]

[2] U.S. Department of Energy (DOE)/National Energy Technology Laboratory (NETL), NETL-2002/1160, *Integrated Dry NO_X/SO_2 Emissions Control System – A DOE Assessment*, October 2001, p. 16. ("NETLa-2002/116")

[3] Ibid.

[4] Institute of Clean Air Companies (ICAC), *Dry Sorbent Injection of Sodium Sorbents by Solvay Chemicals*, Emission Control and Measurement Workshop, March 24-25, 2010, p. 5. ("ICAC, March 2010").

Figure 1. Simplified Typical DSI Control System Process Flow Diagram



Sodium-based DSI has been demonstrated to be a technically feasible and cost-effective control technology for moderate SO_2 reduction on coal fired boilers. DSI control systems have been installed on coal-fired boilers to achieve SO_2 removal efficiencies of 30% up to approximately 80%.[5] As discussed in more detail below, the SO_2 removal efficiency that can be achieved on any given unit is a function of multiple unit-specific operating parameters, including the type of fuel burned, SO_2 concentrations in the flue gas, the sodium-based reagent used, flue gas temperatures, residence time between the reagent injection location and particulate control system, and the type of particulate control system.

3.1.1 Process Design Parameters

Design parameters that affect the SO_2 removal efficiency of a DSI system include: (1) flue gas temperature at the reagent injection location; (2) the sodium (Na) to SO_2 stoichiometric ratio; (3) residence time between the reagent injection location and the particulate control system; and (4) the type of particulate control

[5] U.S. Environmental Protection Agency, EPA –CICA Fact Sheet, EPA-452/F-03-034, *Flue Gas Desulfurization*, p. 5.

system on the unit. The effect each design parameter has on SO_2 collection efficiency is described in the following subsections.

3.1.1.1 Temperature

DSI performance is dependent on the injection temperature profile. Decomposition of the sodium-based reactant to Na_2CO_3 occurs within a temperature window of approximately 300-600°F.[6] Within this temperature window, the sodium-based sorbents also experience what is referred to as a "popcorn effect," where the thermal decomposition reaction results in an expanded particle with a high surface-to-mass ratio.[7] The high surface-to-mass ratio improves the chemical availability of the sodium compound.[8] Sintering of the reactant may occur at higher temperatures resulting in glass-like material with very little surface area to carry out the chemical reactions and significantly lower SO_2 removal efficiencies.

Test data from the Rush Island Unit 1 DSI test program, discussed in more detail in Section 3.2 of my report, determined that Trona was more effective than SBC at Rush Island, concluding that this "may be the result of the air preheater inlet temperatures that were generally over 700 ^oF, which may have caused the SBC to start to melt thus reducing the availability of pore space on the SBC particles surfaces."[9] Flue gas temperatures above approximately 700 ^oF tend to favor Trona as the DSI reactant, as SBC is more susceptible to sintering at these temperatures. Based on air heater inlet temperatures at Rush Island, and Rush Island Unit 1 test results, it is my opinion that Trona would be specified as the preferred DSI reagent on Rush Island Units 1 and 2.

3.1.1.2 Stoichiometric Ratio

The stoichiometric ratio refers to the moles of Na injected into the flue gas compared to the moles of SO_2 in the flue gas, and is typically expressed as a Normalized Stoichiometric Ratio (NS Ratio) when referring

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[6] Karl B. Schnelle, Jr., Ph.D., P.E. and Charles A. Brown, P.E., *Air Pollution Control Technology Handbook*, (Florida: CRC Press, 2002), p. 269.

[7] Id., p. 278.

[8] ADA-Environmental Solutions, Inc., *TOXECON™ Retrofit for Multi-Pollutant Control on Three 90-MW Coal-Fired Boilers, Topical Report: Performance and Economic Assessment of Trona-Based SO_2/NO_X Removal at the Presque Isle Power Plant,* August 25, 2008, p. 4.

[9] AM-REM-00196411, p. AM-REM-00196464.

to DSI control systems. For sodium-based reagents, the NS Ratio is one-half the number of moles of Na injected per mole of SO_2 in the flue gas because it takes two moles of Na to react with one mole of SO_2 (see equation 3 above). Theoretically, an NS Ratio of one (1) should result in complete SO_2 removal; however, not all the reagent reacts with SO_2. Factors affecting utilization include flue gas temperature, reagent particle size (e.g., milled vs. unmilled), SO_2 concentration, mixing, and type of particulate control device.[10] Site-specific tests are typically conducted to determine reagent utilization and to establish the NS Ratio and reagent injection rate needed to achieve the desired SO_2 removal efficiency. Ameren conducted DSI tests on Rush Island Unit 1 in September 2011. Results of those tests are discussed in more detail in Section 3.2 of this report.

3.1.1.3 Residence Time

Residence time between the reagent injection point and the particulate control system also plays an important role in the ability of the reagent to react with SO_2 in the flue gas. Longer ductwork between the injection point and particulate control system provides greater residence time and additional time for the reaction kinetics to occur, increasing reagent utilization and SO_2 removal. In general, a residence time of 1.0 second or more is desired for adequate mixing and reaction time.[11] Based on information provided by Ameren, the Rush Island air heaters are located approximately 150-250 feet upstream of the inlet to the ESP, providing between 2.5 and 4.0 seconds residence time, depending on load and flue gas flow through the ductwork. This arrangement provides sufficient residence time within an appropriate temperature window for the Na-SO_2 reactions.

3.1.1.4 Particulate Collection

The type of particulate collection device also affects the reagent utilization and the SO_2 removal efficiency that can be achieved at a given injection rate. DSI control systems have demonstrated the ability to effectively capture SO_2 on units equipped with ESPs adequately sized to handle increased particulate

[10] DOE/NETL-2002/1160, p. 16.

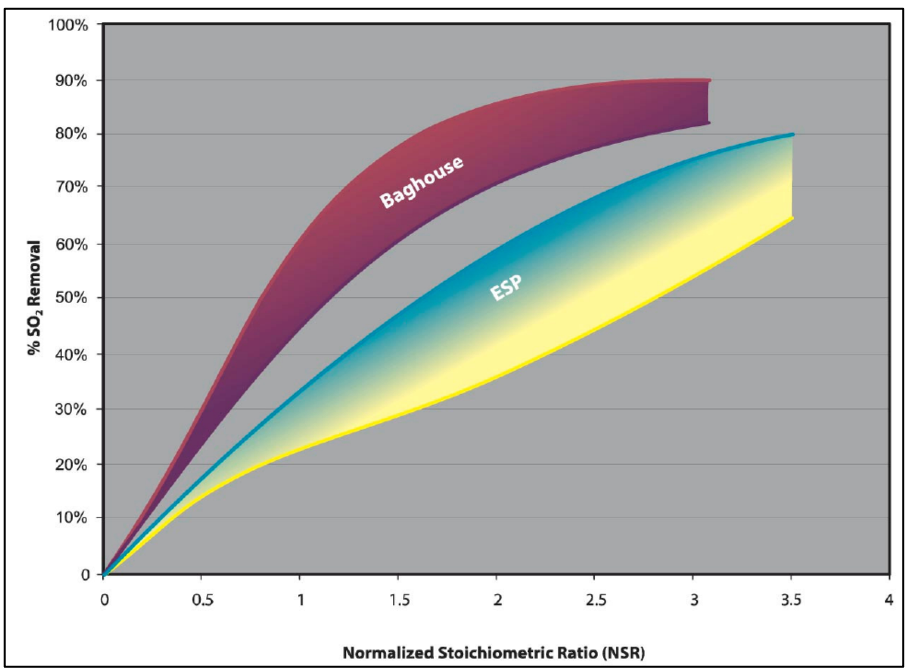
[11] See, Yougen Kong and Michael Wood, *Dry Injection of Sodium Sorbents for Air Pollution Control,* SOLVair Solutions/Solvay Chemicals, Inc., ENVIRONMENTAL Engineer, spring 2011, p. 21

loading from the DSI system. As discussed in more detail in Section 3.5, the Rush Island ESPs are of robust design and are adequately sized for DSI control technology.

3.1.2 DSI SO_2 Removal Efficiencies

Figure 2 shows DSI performance data published by Solvay Chemicals showing the SO_2 removal efficiency as a function of NS Ratio using Trona.[12] Removal efficiencies are shown for units equipped with an ESP and units equipped with a fabric filter. The Solvay data show SO_2 removal efficiencies between approximately 25% to 50% at NS Ratios between 1.25 and 2.0 on units equipped with an ESP. The wide band of removal efficiencies at a given NS Ratio is attributable to operating parameters other than the particulate control system that effect DSI performance, including temperature profile and residence time. On units equipped with an ESP, removal efficiency is also a function of the size of the ESP and the ability of the ESP to effectively handle the increase in particulate loading to the system. ESPs with a large specific collection area (SCA), such as those on Rush Island Units 1 and 2, can achieve a greater level of SO_2 removal efficiencies.

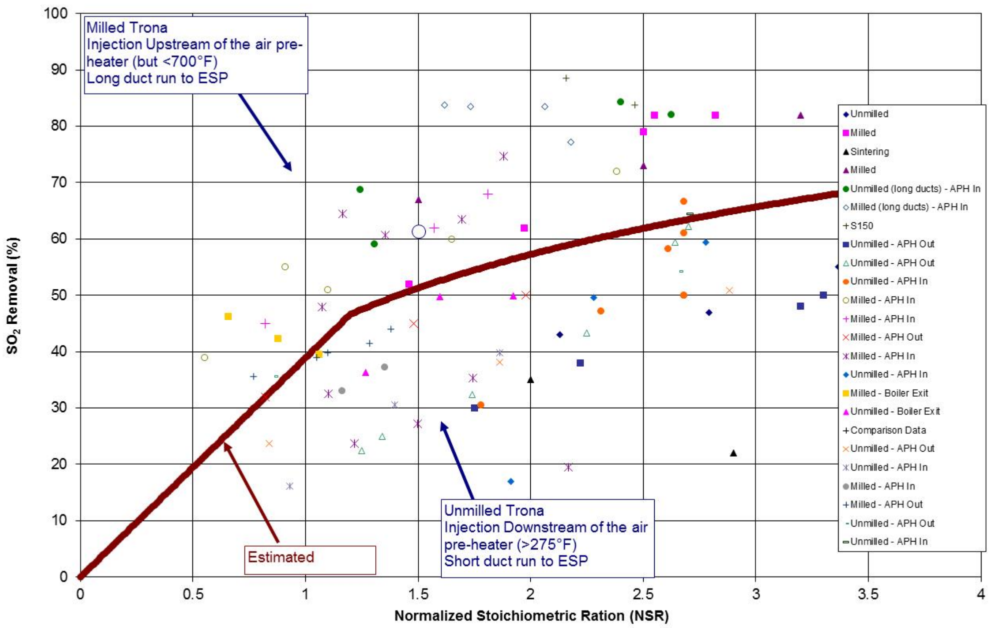
Figure 2. Solvay Chemicals Trona Performance Curve



[12] ICAC, March 2010, p. 9.

Figure 3 provides a summary of DSI test data available to Sargent & Lundy on PRB-fired units equipped with an ESP.[13] Individual data points are distinguished based on operating parameters such as: (1) milled vs. unmilled Trona; (2) Trona injection location (boiler exit, air heater inlet, and air heater outlet); and (3) relative distance between the injection point and ESP inlet. The test data show SO_2 removal efficiencies between approximately 30% to 65% at NS Ratios between 1.25 and 2.0. Higher SO_2 removal efficiencies are achieved on units utilizing milled Trona injected upstream of the air heater and having relatively long duct runs between the reagent injection location and the ESP inlet. These are all design parameters that can be incorporated into a DSI system on Rush Island Units 1 and 2.

Figure 3. Sargent & Lundy Trona/ESP Performance Curve



3.1.3 DSI Reagent Injection Rates

The reagent injection rate needed to achieve a given level of SO_2 removal will be a function of the design parameters discussed above. Table 1 provides the Trona injection rate measured at two PRB-fired units to achieve approximately 50% SO_2 removal. Both units are similar in size to Rush Island Units 1 and 2 and

[13] Underlying test data summarized in Figure 3 are proprietary and confidential, and cannot be provided by Sargent & Lundy without consent of the client.

are equipped with ESP control systems. Injection rates shown in Table 1 correspond to an NS Ratio of approximately 1.2–1.4, which is consistent with the test results summarized in Figure 3.

Table 1. Trona Injection Rates to Achieve 50% SO_2 Removal

Utility/Size	Fuel	Uncontrolled SO_2 Emission Rate (lb/hr)	SO_2 Removal Efficiency (%)	Sorbent Type	Nominal Sorbent Injection Rate (lb/hr)	Particulate Collector	NS Ratio
Southeast Power Utility (580 MW)	PRB	4,750	55	Trona	16,000	ESP	1.4
Western Power Utility (600 MW)	PRB	3,600	50	Trona	10,000	ESP	1.2

Notes:

1. Underlying test data are confidential and cannot be provided without consent of the client.
2. NS Ratio was calculated as follows:

$$NSR = \frac{16{,}000\text{ lb Trona}}{\text{hr}}\ x\ 0.95\ (purity)\ x\ \frac{\text{lb mole Trona}}{226\text{ lb Trona}}\ x\ \frac{3\text{ moles Na}}{1\text{ lb mole Trona}}\ x\ \frac{1\text{ mole SO2}}{2\text{ moles Na}}\ x\ \frac{64\text{ lb SO2}}{\text{lb mole SO2}}\ x\ \frac{\text{hr}}{4750\text{ lb SO2}}$$

Although SO_2 removal efficiency must be evaluated on a unit-specific basis taking into consideration the design parameters discussed above, test data available from coal-fired units equipped with an ESP demonstrate that DSI systems can achieve approximately 50% SO_2 removal while using an ESP as the particulate collection device. In his deposition taken on March 1, 2018, Plaintiff's air pollution control expert Dr. James E. Staudt, concurred that DSI at Ameren's Labadie plant could achieve 50% SO_2 removal without the need to install a fabric filter.[14] Because injection rates and removal efficiencies are unit-specific, performance tests should be conducted to evaluate system operating parameters and SO_2 removal efficiencies, and to identify potential balance-of-plant (BOP) impacts. Ameren has conducted DSI performance tests at Rush Island Unit 1. Test results are evaluated in detail in the following section.

3.2 Rush Island Dry Sorbent Injection Test Program Results

In September 2011, Ameren conducted a DSI test program at Rush Island Unit 1.[15] The test program was conducted over a period of approximately four weeks to determine the feasibility and effectiveness of the technology at Rush Island. The study focused on acid gas and mercury reductions to meet the proposed

[14] Deposition of James E. Staudt, Case No. 4:11-cv-00077 (RWS), March 1, 2018, p. 120:1-121:14. ("Staudt Deposition")

[15] AM-REM-00196411.

Utility MACT standards,[16] but also included an evaluation of impacts to ESP operation, resulting particulate emissions, and the impacts on SO_2 emissions.[17]

The Rush Island Unit 1 ductwork downstream of the boiler splits into two parallel paths (A-side and B-side) with each path including a separate air heater, ESP, and induced draft (ID) fan. This arrangement afforded Ameren the opportunity to inject dry sorbents into the B-side, while sampling downstream of both the A-side and B-side to determine performance with and without DSI injection.[18] The program included testing with both Trona and SBC injected before and after the unit's air heater. Test results determined that Trona injected upstream of the unit's air heater provided the most effective SO_2 control.[19]

SO_2 removal rates during the test program ranged between 25% and approximately 60% when Trona was injected ahead of the air heater.[20] Removal efficiencies were closely related to the Trona injection rate and NS Ratio. Figure 4 and Figure 5 show SO_2 removal efficiency as a function of the Trona feed rate (lb/hr B-side) and the calculated NS Ratio, respectively.[21]

[16] Id., p. AM-REM-00196420

[17] Ibid.

[18] Id., p. AM-REM-00196427.

[19] Id., p. AM-REM-00196421.

[20] Id., p. AM-REM-00196448.

[21] Id., p. AM-REM-00196484. Test data used to generate Figure 4 and Figure 5 taken from Table 3-10.

Figure 4. Rush Island Unit 2: SO_2 Removal vs. Trona Injection Rate

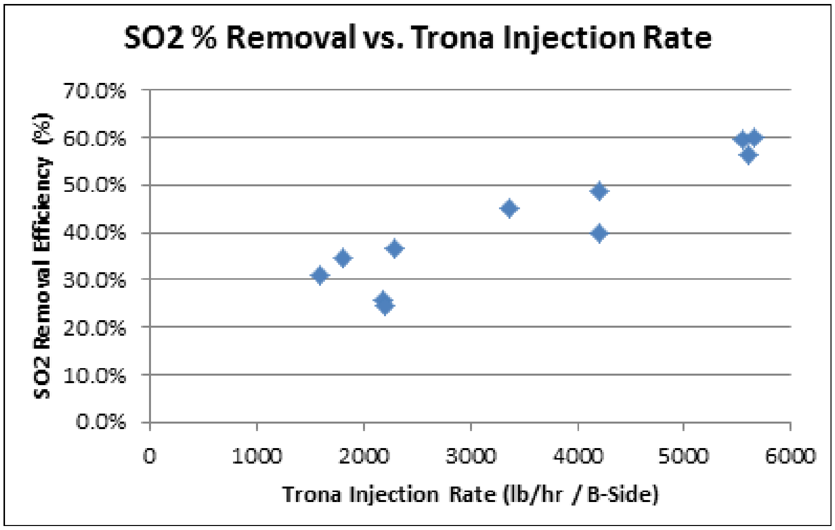
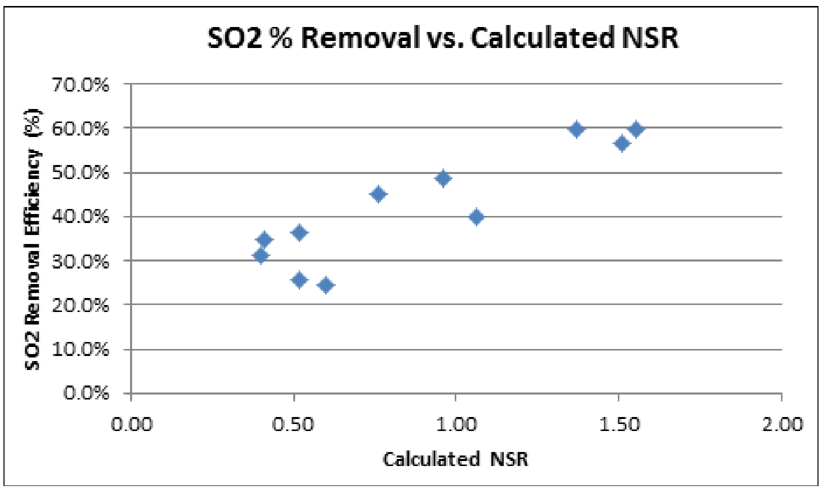


Figure 5. Rush Island Unit 2: SO_2 Removal vs. Calculated NS Ratio



Test results from Rush Island Unit 1 are consistent with industry data, in that Trona injected upstream of the air heater achieved the highest SO_2 control. Based on industry data summarized in Sections 3.1.2 and 3.1.3, and on Rush Island DSI performance test data summarized in Figure 4 and Figure 5, it is my opinion that sodium-based DSI control on Rush Island Units 1 and 2 will achieve SO_2 removal efficiencies of approximately 50% at a Trona injection rate in the range of 8,000-12,000 lb/hr (total per unit for both ESPs) and an NS Ratio of 1.25 to 1.5.

3.3 Co-benefits of Dry Sorbent Injection

In addition to reacting with SO_2, sodium-based sorbents will readily react with other acid gases in the flue gas, including sulfur trioxide (SO_3), hydrochloric acid (HCl), and hydrofluoric acid (HF).[22] Sodium-based sorbents are highly reactive with these acid gases, and can readily achieve removal efficiencies of 90% or more.[23] The DSI test program at Rush Island Unit 1 also showed significant acid gas removal efficiencies at low Trona injection rates, concluding that "with a small addition of Trona, a significant percentage of HCl were removed with the resulting concentrations, at least in this test, near the detection limit."[24] Sodium-based DSI systems will also provide an incremental reduction in nitrogen oxide (NO_X) emissions, as nitrogen dioxide (NO_2) in the flue gas will react with sodium to form sodium nitrate, thus reducing NO_X emissions.[25]

3.4 Potential Balance-of-Plant Impacts with Dry Sorbent Injection

Potential balance-of-plant (BOP) impacts to existing equipment and systems must be taken into consideration when evaluating the technical feasibility of the DSI control system. Potential impacts include increased loading to the particulate control system, increased fly ash generation rates, adding sodium compounds to the fly ash, mercury capture levels, and increased PM emissions.

DSI control systems add a significant quantity of particulates (i.e., reagent) into the flue gas, resulting in increased loading to the particulate control system and increased fly ash generation rates. Based on the design parameters for Rush Island Units 1 and 2, ash generation rates at full load would be expected to increase from approximately 28,880 lb/hr (14.4 tph) to approximately 35,915 lb/hr (18 tph) with Trona injection at an injection rate of 10,000/hr per unit for 50% SO_2 removal, an increase of approximately 24%.[26] However, based on information provided by Ameren, the Rush Island ash handling system is

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[22] Institute of Clean Air Companies (ICAC), *Dry Sorbent Injection for Acid Gas Control: Process Chemistry, Waste Disposal and Plant Operational Impacts*, July 2016, p. 15. ("ICAC, July 2016")

[23] ENVIRONMENTAL Engineer, 2011, p. 23.

[24] AM-REM-00196411, p.AM-REM-00196487.

[25] ICAC, July 2016, p. 16.

[26] Ken Snell Rush Island ESP Upgrade and DSI Cost Estimate.xlsx, "Summary O&M – 50%" worksheet.

designed to handle up to 40 tph per unit; thus, no significant modification would be needed for DSI operation.

Adding sodium-based compounds to the fly ash will likely prevent the fly ash from being sold as a concrete additive or other commercial product. Therefore, ash disposal costs should be included as an annual operating cost, as discussed in Section 3.8.2.

Sorbent injection systems can affect mercury control on units equipped with an activated carbon injection (ACI) mercury control system. For example, DSI reagents readily react with SO_3, which competes with mercury for active absorption sites. Thus, injecting Trona to remove SO_3 will enhance mercury removal with activated carbon.[27] On the other hand, Trona readily reacts with HCl and HF in the flue gas, both of which tend to oxidize elemental mercury. Oxidized mercury is more readily captured with activated carbon. Thus, injecting Trona could adversely affect mercury capture. Results from the Rush Island Unit 1 test program did indicate that Trona increased the measured mercury, as mercury concentrations on the B-side ESP outlet were higher than A-side concentrations during periods of Trona injection.[28] However, given the low HCl and HF concentrations found in PRB coal, it is my opinion that any increase in mercury emissions could be mitigated with an incremental increase in the amount of activated carbon that is injected.

Finally, potential operational impacts to the particulate control system associated with DSI reagent injection need to be considered when evaluating the technical feasibility and effectiveness of DSI control. On units equipped with an ESP, which is generally considered a constant collection efficiency control system, increased loading could result in an unacceptable increase in controlled PM emissions. The design and operation of the ESP must be evaluated to identify any changes or upgrades that may be needed to successfully operate the DSI control system, while keeping controlled PM emissions within allowable levels. The design and effectiveness of the Rush Island ESPs, and potential upgrades to the ESPs that could be installed to provide an additional margin of compliance, are discussed in the following section.

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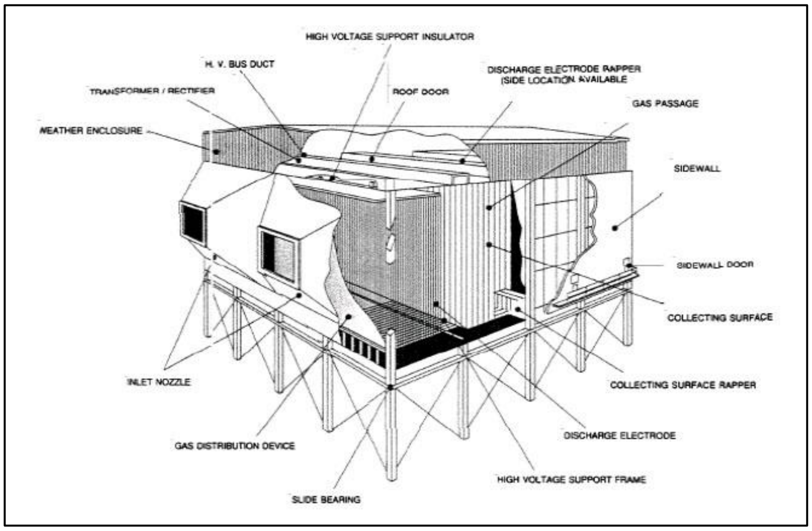
[27] ENVIRONMENTAL Engineer, p. 23.

[28] AM-REM-00196411, p. AM-REM-00196491.

3.5 Electrostatic Precipitator Upgrades

Rush Island Units 1 and 2 are equipped with six ESPs supplied by Lodge-Cottrell. Ductwork downstream of both boilers splits into two parallel paths, with each path having a separate air heater, ESP, and ID fan. The ESPs are designed to electrostatically separate particles from the flue gas stream, while imposing minimal pressure loss on the flue gas stream. Major components of an ESP are the discharge electrodes; collection electrodes; high-voltage electrical systems; rappers; and ash collection hoppers. Figure 6 shows the major components of an ESP particulate matter control system.[29]

Figure 6. Electrostatic Precipitator Components



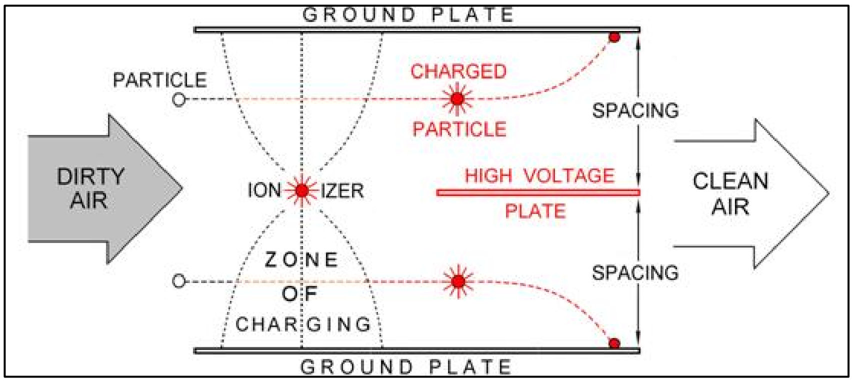
(Source: U.S.EPA https://www.epa.gov/air-emissions-monitoring-knowledge-base/monitoring-control-technique-electrostatic-precipitators#box3)

In an ESP, transformer-rectifier sets (T/R sets) energize the discharge electrodes with a negative potential, producing an electrical field between the discharge electrodes and the positively-grounded collecting plates. Particulate matter that enters the electrical field develops a negative charge and migrates towards the collection plates, as shown in Figure 7. Particulate matter is removed from the plates by mechanical rappers, which cause the collected material to fall into hoppers for collection and either beneficial reuse or disposal.

[29] Source: U.S.EPA https://www.epa.gov/air-emissions-monitoring-knowledge-base/monitoring-control-technique-electrostatic-precipitators#box3. A general description of ESP technology is available at: OAQPS, Control Cost Manual, Section 6, Chapter 3, Electrostatic Precipitators, EPA/452/B-02-001, September 1999.

Migration and collection of the charged particles depends upon the particulate resistivity and the electrical field between the two electrodes, as well as the gas flow profile and velocity.[30]

Figure 7. Particulate Matter Collection Using Electrostatic Precipitators



Source: http://www.aircleancompany.com/Air_Clean_ESP.htm

Key design parameters of an ESP include the specific collection area, aspect ratio, design gas velocity, and corona power.[31] Specific collection area (SCA) is defined as the ratio of collection surface area to the gas flow rate into the collector (i.e. sq. ft. collection are per 1,000 acfm gas flow). In general, increases in the SCA of a precipitator design will increase the collection efficiency of the precipitator. Aspect ratio, which relates to the length of an ESP to its height, is an important factor in reducing rapping loss or dust re-entrainment. Flue gas velocity through the ESP is an important design parameter, as gas velocities must be reduced for adequate particle migration and collection. Corona power is the power that energizes the discharge electrodes and creates the electric field within the ESP. The strength of the field is based on the rating of the T/R set. In general, collection efficiency will increase as the corona power is increased, assuming the corona power is applied effectively (i.e., maintains a good sparking rate).

Based on ESP design information available from Ameren, key operating parameters of the Rush Island ESPs, assuming a flue gas flow rate of 2,500,000 acfm at 325 ^{o}F, include a specific collecting area (SCA) of 394 sq. ft./kacfm (based on 12-inch collecting spacing); a design gas velocity of 4.57 fps; a flue gas

[30] See, e.g., Horn, J., Upgrading Your ESP Performance, Power Engineering, March, 16, 2015, p. 1/7.

[31] A general description of ESP design parameters is available at: http://www.neundorfer.com/wp-content/uploads/2016/05/ESP-KnowledgeBase-03-Design_Parameters.pdf

treatment time of 11.83 seconds; an aspect ratio 1.40; and an installed corona power density of 1.81 watts/sq. ft. All of these design parameters support the conclusion that the Rush Island Units 1 and 2 ESPs are generously sized and robust in their design.

Rush Island Units 1 and 2 currently achieve controlled PM emission rates in the range of 0.009 to 0.014 lb/MMBtu.[32] Assuming inlet particulate loading of 27,260 lb/hr (4.47 lb/MMBtu at a full load heat input of 6,100 MMBtu/hr), the ESPs currently achieve particulate matter removal efficiencies of 99.68 to 99.79%. This level of performance is consistent with the robust design and sizing of the Rush Island ESPs, and compares favorably with performance levels achieved with fabric filter control systems.

As noted above, DSI results in increased particulate loading to the ESPs. Assuming a constant removal efficiency of 99.7% and DSI particulate loading of 8,000 to 10,000 lb/hr (1.31 to 1.64 lb/MMBtu at a full load heat input of 6,100 MMBtu/hr), controlled PM emissions would increase by approximately 0.004 to 0.005 lb/MMBtu. Thus, even assuming the ESPs operate at a constant removal efficiency, controlled PM emissions from Rush Island Units 1 and 2 would remain below the MATS PM emission limit of 0.03 lb/MMBtu.[33]

Furthermore, introducing sodium compounds into the flue gas will reduce fly ash resistivity and enhance ESP performance. One of the primary parameters of ESP performance is the particulate resistivity.[34] Particulate resistivity is a measure of how well the particulate, when deposited on the ESP collecting electrodes, conducts electricity to ground. High-resistivity fly ash, which is typical on PRB-fired units, can hold tightly to the collecting plates and reduce collection efficiency.[35] The addition of sodium compounds to the flue gas will reduce fly ash resistivity and improve ESP performance, making the ESPs more efficient.

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[32] See, Ken Snell Rush Island Units 1 & 2 PM 30 Day Rolling Average Data 2015 - 2017 .xlsx

[33] Dr. Staudt agrees with this conclusion, stating that any incremental increase in PM emissions from DSI at the Labadie Station would "be in the range of 0.003 to 0.004 lb/MMBtu…keeping the total outlet PM emission rate well under the MATS emission limit of 0.030 lb/MMBtu." See, Staudt Report, p. 66.

[34] Robert Mastropietro, *Fly Ash Resistivity with Injected Reagents and Predicted Impacts on Electrostatic Precipitators*, Lodge Cottrell, p. 1.

[35] Id., p. 4.

Improved ESP performance with Trona injection was verified during the Rush Island Unit 1 DSI test program. At an injection rate of 4,000 lb/hr (B-side only), B-side PM emissions were approximately 40% below A-side baseline emissions (i.e., 0.010 lb/MMBtu B-side compared with 0.014 lb/MMBtu A-side).[36] As discussed above, these results are not unexpected, as introducing sodium into the flue gas can improve ESP performance more than the added particulate load degrades that performance.

Based on my review of the Rush Island ESP design parameters and results from the Rush Island Unit 1 DSI test program, it is my opinion that due to all these factors: the robust size and design of the Rush Island ESPs, the particulate matter collection efficiencies currently achieved at Rush Island, and the significant reduction in fly ash resistivity associated with Trona injection, there would be no increase in particulate emissions even taking into account the higher inlet loading to the ESP.

Nevertheless, to provide an additional margin of compliance so as to ensure that PM emissions do not increase, Ameren may wish to upgrade the existing T/R sets with new high frequency technology that results in greater collection efficiencies. T/R sets are the ESP components that produce the high voltage needed to charge particles in the flue gas such that the particles migrate away from the discharge electrodes and towards the collecting plates. Migration and collection of the charged particles is a function of the electrical field between the two electrodes as well as the particulate resistivity. More current can be supplied to the ESP with high frequency T/R sets, and the higher corona current and increased average voltage achieved with high frequency T/R sets will improve collection efficiency.[37] While I have concluded that the existing ESPs, with the existing T/R sets, are adequately designed to handle the increased particulate loading from sorbent injection at 50% SO_2 removal, I have conservatively assumed that Ameren may upgrade its T/R sets for added compliance margin, and I include costs for these upgrades in my cost analysis below.

3.6 Dry Sorbent Injection Effectiveness - Conclusions

Based on a review of industry data, industry publications, my experience and knowledge, and Rush Island DSI test results, it is my opinion that DSI is a technically feasible control technology to achieve moderate

[36] AM-REM_00196411 at page AM-REM-00196493.

[37] Alstom Power, *Results from ESP-upgrades, Including Control Systems*, not dated.

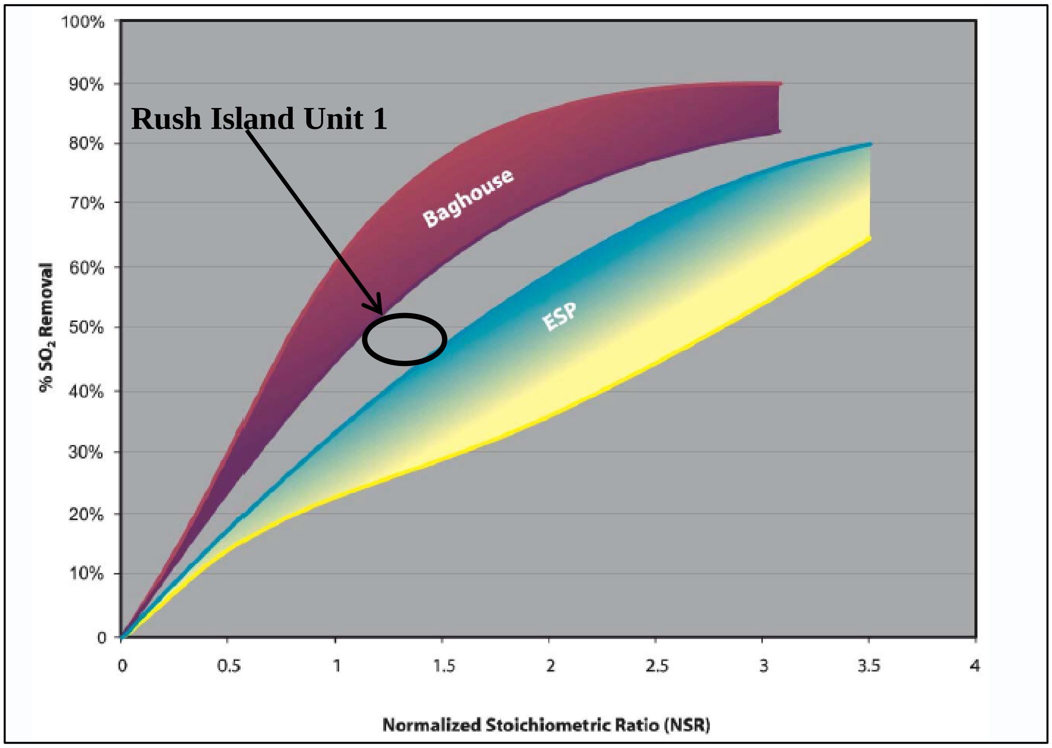
SO_2 reductions at Rush Island Units 1 and 2. Dr. Staudt concurred with this conclusion stating that 50% SO_2 removal was a reasonable assumption for DSI control on Ameren's Labadie Units.[38] Given the robust design of the Rush Island ESPs, and the particulate matter control efficiencies currently achieved, the same conclusion would apply to Rush Island. Specifically, performance tests conducted on Rush Island Unit 1 demonstrate that DSI can be applied to achieve approximately 50% SO_2 removal, with Trona injected upstream of the air heaters at an injection rate equivalent to an NS Ratio of approximately 1.25, without adversely affecting the existing ESPs or resulting in an unacceptable increase in PM emissions.

Figure 8 shows where the Rush Island Unit 1 ESP performed during the DSI performance test program as compared with general industry data published by Solvay Chemicals.[39] DSI at Rush Island performed toward the upper end of ESP performance, and approached performance expected with a fabric filter. These results support the conclusions that DSI would be an effective SO_2 control technology on Rush Island Units 1 and 2, and that the ESPs at Rush Island are robustly sized and capable of handling increased particulate loading associated with DSI.

[38] Staudt Deposition, p. 123:21-124:11.

[39] ICAC, March 2010, p. 9.

Figure 8. Solvay Chemicals Trona Performance Curve



3.7 Dry Sorbent Injection – Construction Timeline

DSI is a relatively simple air pollution control system. DSI control system components include storage silo(s); truck unloading station(s); a pneumatic conveying system, including blowers and mills; a dehumidification system, including heat exchangers and chillers; and reagent injection piping and lances. A majority of the equipment associated with a DSI system is prefabricated and shop-assembled for installation at the facility.

Table 2 provides a typical engineering, procurement, and construction timeline for a DSI control system based on my knowledge of actual DSI projects performed by Sargent & Lundy. In general, it is my experience that a DSI system can be installed within 12 months from award of a contract; that is, after design, specification, and procurement of the major equipment is complete. Design, specification, and procurement of the equipment will add an additional 6 months to the overall project schedule. This timeline is consistent with Dr. Staudt's opinion that DSI control projects have an overall duration of approximately

18 months.[40] Assuming a decision to install DSI is made on January 1, 2021, it is my opinion that the control systems could be in service by July 1, 2022.[41]

In the event that Ameren installs upgraded T/R sets as described above, the new T/R sets could be specified, fabricated, and installed within the same project schedule. Therefore, the overall project schedule shown in Table 2 would also be met if new T/R sets are implemented as part of the DSI control system project.

Table 2. DSI Engineering/Procurement/Construction Schedule

DSI System Schedule Activity	Time Frame
Design/Specification/Procurement	6 months
Detail Engineering/Fabrication	6 months
Construction	4 months
Commissioning and Startup	2 months
Duration	18 months

3.8 Dry Sorbent Injection – Capital and O&M Cost Estimate at Rush Island

Sargent & Lundy prepared cost estimates for the installation and operation of DSI on Rush Island Units 1 and 2 at two levels of SO_2 control - 30% and 50%. Cost estimates include both the capital costs to engineer, procure, and install the DSI control system, and annual operations and maintenance (O&M) costs. Costs were developed assuming a design SO_2 inlet concentration of 0.62 lb. SO_2/MMBtu heat input to the boiler (based on the highest 30-day rolling average emissions between 2015 and 2017 for Rush Island Units 1 and 2), and using Trona injected at the air heater inlet as the DSI reagent. The highest 30-day average emission rate was used as the design basis to ensure DSI components are adequately sized for all reasonably anticipated uncontrolled SO_2 emissions.

[40] Staudt Deposition, p. 120:20-122:17.

[41] Counsel for Ameren has asked me to assume a January 2021 start date for implementation of the pollution control technology based on the assumptions that this case will proceed to a trial in the remedy phase in or about the first quarter of 2019; that a final order will be entered in or about the summer of 2019; that the case is likely to be appealed by one or both sides; and that the appeal process will take approximately 18 months to complete in full, before a final order not subject to appeal is entered.

3.8.1 DSI Capital Costs

Equipment costs, including the truck receiving and unloading system, reagent storage, milling equipment, and the reagent conveying and injection equipment, were estimated based on equipment costs and recent vendor quotes for similarly sized control systems. A conceptual level general arrangement drawing was prepared to provide a basis for developing mechanical, civil/structural, and electrical material quantities, including earthwork for foundations, concrete work, mechanical and electrical equipment for the control system, and instrumentation and controls. Material quantities were developed based on project experience at similarly sized power plants, adjusted based on actual size and capacity differences and taking into consideration the specific site layout.

Table 3 shows the capital cost for a DSI system at Rush Island, assuming 30% and 50% SO_2 removal, with and without the new T/R sets. The DSI Equipment, Material, and Labor line item includes the costs to purchase and install the DSI control system components. Direct Construction Costs include items such as labor supervision, site services and temporary facilities, freight on process equipment and materials, and the contractor's general and administrative costs and profit. Indirect Construction Costs include engineering services, construction management support, and startup/commissioning support. Owner's Costs include the project-related costs that Ameren would incur to purchase, manage, administer, and implement the DSI construction project. Other project-related costs that Ameren would incur to install the DSI control system, includes an Allowance for Funds Used During Construction (AFUDC). AFUDC accounts for the time-value of money associated with the distribution of construction cash flows over the installation period.

Capital costs to install the new T/R sets are shown separately and represent the total capital cost (i.e., equipment and materials, labor, and indirect construction costs) to upgrade the ESPs. Purchased equipment costs for the new T/R sets were based on budgetary quotes provided by equipment vendors. Material and installation costs, including new cables and motor control centers, were developed based on experience on similar projects.

DSI and T/R set costs were escalated to July 2022, the projected in-service date of the equipment, assuming equipment and material costs escalate at an average rate of 1% per year based on a conservative evaluation of the Handy-Whitman indexes, and labor costs escalate at an average rate of 3% per year based on historic ENR labor cost escalation. Escalation is described in Section 4.1.1.

Table 3. Capital Cost Estimate – Rush Island Units 1 and 2[42]

Parameter	Capital Cost 30% SO_2 Removal	Capital Cost 50% SO_2 Removal
Equipment, Material, and Labor	$7,146,000	$14,470,000
Direct Construction	$2,325,000	$4,708,000
Indirect Construction	$1,146,000	$2,320,000
Owner's Cost	$1,062,000	$2,150,000
Contingency	$2,336,000	$4,730,000
AFUDC	$701,000	$1,419,000
Total DSI System Cost (2017$)	$14,716,000	$29,797,000
T/R Set Replacement, if necessary (2017$)	$7,981,000	$7,981,000
Total T/R Set and DSI System Cost (2017$)	$22,697,000	$37,778,000
Total T/R Set and DSI System Cost (2022$)	$25,988,000	$42,601,000

3.8.2 DSI O&M Costs

Annual O&M costs include both variable and fixed O&M costs. Variable O&M costs are generally proportional to the operation of the DSI control system and include the reagent costs, auxiliary power required to operate the system, and byproduct waste management and disposal costs. First-year variable O&M costs for the Rush Island Units 1 and 2 DSI control systems at SO_2 removal efficiencies of 30% and 50% are summarized in Table 4. Variable O&M costs were calculated based on the system parameters, consumption rates, and unit costs listed in Table 4, and assuming a 75% annual capacity factor for each unit.

Fixed O&M costs are generally independent of the level of operation, and include operating personnel and maintenance costs. Annual maintenance costs, including material and labor, are estimated as a percentage of the total capital equipment cost. Because DSI control systems are relatively simple, annual maintenance

[42] Ken Snell Rush Island ESP Upgrade and DSI Cost Estimate.xlsx

costs (maintenance and labor) were estimated at 1.0% of the direct equipment, material, and labor cost. Fixed O&M costs for the Rush Island Units 1 and 2 DSI control systems are summarized in Table 5.

Table 4. Variable O&M Rates and First-Year Costs (2017$)

Parameter	Unit	30% SO_2 Removal	50% SO_2 Removal
DSI System (per Unit)			
Trona Consumption	lb/hr	4,000	10,000
Increased Activated Carbon Consumption	lb/hr	20	20
DSI Byproduct Rate	lb/hr	2,814	7,035
Fly Ash Make Rate	lb/hr	28,880	28,880
Waste/Fly Ash Rate @ 100% CF	ton/yr	138,900	157,400
Auxiliary Power Consumption	kW	519	640
Unit Cost	Units	Value	
Trona	$/ton	250	
Carbon	$/lb	1	
Waste Disposal	$/ton	50	
Auxiliary Power Cost	$/MWh	30	
First-Year Variable O&M Costs @ 75% CF per Unit			
Trona Cost	$/year	$3,285,000	$8,212,500
Carbon Cost	$/year	$131,400	$131,400
Waste Disposal Cost	$/year	$5,209,000	$5,902,300
Auxiliary Power Cost	$/year	$102,300	$126,200
Total First Year Variable O&M Cost per Unit	$/year	$8,727,700	$14,372,400
Total First-Year Variable O&M Cost Total for Two Units	$/year	$17,455,400	$28,744,800

Notes: (See, Ken Snell Rush Island ESP Upgrade and DSI Cost Estimate.xlsx).

1. First-year costs are calculated using an annual capacity factor of 75%.
2. Increased activated carbon consumption was conservatively estimated at 20 lb/hr (20% increase from baseline injection rate of 100 lb/hr) to account for any potential increase in mercury emissions associated with sorbent injection.
3. Lost revenue from fly ash sales is not included in the O&M cost analysis.

Table 5. Fixed O&M First-Year Costs (2017$)*

Parameter	Unit	30% SO_2 Removal	50% SO_2 Removal
Number of Operators	--	0.5	1.0
First-Year Fixed O&M Costs			
Operating Labor	$/year	$83,500	$167,000
Maintenance Material and Labor	$/year	$70,100	$141,900
Total First Year Fixed O&M Cost per Unit	$/year	$153,600	$308,900
Total First-Year Fixed O&M Cost Total for Two Units	$/year	$307,200	$617,800

*Ken Snell Rush Island ESP Upgrade and DSI Cost Estimate.xlsx.

3.8.3 Total Annual DSI Costs

Total annual costs for the DSI control system include the annual O&M costs and an annual capital recovery cost. The capital recovery cost is calculated by multiplying the total capital cost by a capital recovery factor (CRF) to convert capital costs into equal annual payments over the life of the control system. The CRF is calculated using an equivalent uniform annual cash flow method, where the CRF is defined according to the following formula: [43]

$$CRF = [i\,(1 + i)^n] / [(1 + i)^n - 1] \qquad (4)$$

Assuming an equipment life of 23 years and an interest rate of 7%, total annual costs for the DSI control systems on Rush Island Units 1 and 2 are calculated as shown in Table 6. Equipment life was based on a 2022 in-service date and an assumed retirement date of 2045 based on Ameren Missouri's 2017 Integrated Resource Plan and Risk Analysis.[44]

[43] EPA Air Pollution Control Cost Manual, January 2002, p. 2-21.

[44] Ameren Missouri's 2017 Integrated Resource Plan and Risk Analysis.pdf, page 2

Table 6. Total Annual Estimated Capital Costs (23-Year Service Life)

Parameter	30% SO_2 Removal		50% SO_2 Removal	
	DSI	DSI with T/R Set Replacement	DSI	DSI with T/R Set Replacement
Total Capital Cost	$14,716,000	$22,697,000	$29,797,000	$37,778,000
Capital Recovery Factor	0.0887	0.0887	0.0887	0.0887
Capital Recovery Cost	$1,306,000	$2,014,000	$2,644,000	$3,352,000
Annual Variable O&M	$17,455,400	$17,455,400	$28,744,800	$28,744,800
Annual Fixed O&M	$307,200	$307,200	$617,800	$617,800
Total Annual Cost	$19,068,600	$19,776,600	$32,006,600	$32,714,600

Notes: (Ken Snell Rush Island ESP Upgrade and DSI Cost Estimate.xlsx).

1. Total capital costs are shown for both units (2017$).
2. Variable and fixed O&M Costs are shown for both units.
3. Service life based on the retirement date in Ameren Missouri's 2017 Integrated Resource Plan and Risk Analysis.pdf, page 2

Capital and O&M costs summarized in Table 4 through Table 6 demonstrate that variable O&M costs represent the most significant cost for DSI control systems.[45] In my opinion, the relatively low capital investment of a DSI system would allow Ameren greater long-term flexibility for the Rush Island generating station compared to high capital SO_2 control alternatives, including wet and dry flue gas desulfurization. For example, assuming an in-service date of 2025, installation of wet FGD on Rush Island Units 1 and 2 would cost approximately $1.067 billion as discussed in further detail in Section 4.1.4 (see Table 8). Assuming an equipment life of 20-years based on the planned retirement date of 2045, the annualized capital recovery cost of the WFGD system would be at least $84.6 million, more than 30-times the capital recovery cost of the DSI control system. Moreover, in the event Rush Island 1 or 2 were to cease firing coal prior to the assumed 20-year equipment life, Ameren would incur significantly less stranded capital expenditures with the DSI option. Given the potential for significant stranded capital expenditures, requiring Ameren to install high-capital SO_2 control technology would limit the company's options with respect to future operations at the Rush Island generating station.

[45] Dr. Staudt concurs with this conclusion. See, Staudt Deposition, pp. 119:16-121:2.

4. CRITIQUE OF EXPERT REPORT OF JAMES E. STAUDT, PREPARED ON BEHALF OF PLAINTIFFS, DECEMBER 15, 2017 (AMENDED MARCH 7, 2018)

In this section of my report, I comment on opinions offered by Dr. James Staudt in his report dated December 15, 2017 and Amended March 7, 2018. Dr. Staudt was retained by the United States to examine Best Available Control Technology (BACT) for the control of SO_2 emissions from Rush Island Units 1 and 2, as well as methods to reduce SO_2 emissions from another Ameren-owned plant.[46] Based on his evaluation of air pollution control technologies available to Rush Island, including SO_2 removal efficiency and control system costs, Dr. Staudt concluded that "Ameren would likely select wet FGD as its [SO_2] control technology" at Rush Island. He further concluded, based on control technology cost estimates included in his report that WFGD would be a cost-effective SO_2 control option for Rush Island.[47]

Based on my review of Dr. Staudt's report, I offer the following opinions regarding the WFGD cost estimate Dr. Staudt relied upon in his evaluation of BACT for Rush Island Units 1 and 2:

1. Dr. Staudt used an inaccurate methodology to escalate control technology costs from 2010 (the date the cost estimate was originally prepared) to 2016 (the date Dr. Staudt assumed WFGD controls would have become operational at Rush Island).
2. Dr. Staudt incorrectly removed capital costs, including an allowance for funds used during construction (AFUDC) and certain owner's costs, from the WFGD cost estimate.
3. Dr. Staudt failed to adequately account for wastewater treatment costs associated with WFGD controls.
4. Dr. Staudt underestimated auxiliary power requirements, heat rate impacts, and auxiliary power costs for the WFGD control system.

As a result, it is my opinion that Dr. Staudt underestimated the total capital investment required to install WFGD on Rush Island Units 1 and 2, underestimated the total annual costs to operate the control technology, and thus overstated the cost-effectiveness of the control technology. I discuss the basis for each adjustment in the subsections below.

In addition to the control technology cost estimating issues, I offer the following opinions with respect to technical issues discussed in Dr. Staudt's report:

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[46] Staudt Report, p. 4.

[47] Id., p. 48.

1. Dr. Staudt's reliance on SO_2 removal efficiencies achieved with WFGD on units firing high-sulfur fuel is irrelevant to an evaluation of removal efficiencies achievable on units firing low-sulfur PRB, and overstates removal efficiencies achievable at Rush Island.
2. Dr. Staudt's analysis of co-benefit mercury control with WFGD was based on co-benefit mercury control correlations developed for a general class of coal-fired boilers, which would not be representative of co-benefit mercury control on the Rush Island units. In my opinion, installation of a WFGD on Rush Island Units 1 and 2 would not provide co-benefit mercury emissions control; however, costs to mitigate for any increase in mercury emissions would be minimal.
3. Dr. Staudt's assertion that his WFGD capital cost estimate was conservatively high because he did not adjust costs for lower SO_2 removal rates is incorrect, as WFGD control system sizing and costs are primarily a function of fuel characteristics other than sulfur content and the SO_2 removal rate would have only a minor impact to control system capital costs.
4. Dr. Staudt assumed an overly optimistic project timeline for the design, procurement, and construction of a WFGD control system.

4.1 Wet Flue Gas Desulfurization (WFGD) Capital Cost Estimate

I understand that BACT is defined in 40 CFR Part 52 as an emissions limitation based on the maximum degree of reduction determined to be achievable on a case-by-case basis taking into account energy, environmental, and economic impacts and other costs. Economic impacts associated with a particular control technology are generally evaluated based on average and incremental cost-effectiveness. Cost-effectiveness is expressed in terms of dollars/ton of pollutant removed ($/ton) on an annualized basis, that is, total annual costs to install and operate the control system divided by annual emission reductions.

Dr. Staudt developed historic WFGD costs (i.e., 2010) and 2016 WFGD costs to support his economic impacts analysis of WFGD control at Rush Island, and to calculate the average cost-effectiveness of the WFGD control system. Dr. Staudt suggested that costs could be developed following the methodology described in U.S.EPA's Control Cost Manual, which generally results in a study level cost estimate with accuracy in the range of ±30%.[48] However, Dr. Staudt noted that "in this case we have the benefit of Ameren's engineering studies that provided cost estimates" and that "[t]hese studies were generally more comprehensive than the estimating methodology described as a 'study level' in the CCM.[49] Therefore,

[48] Id., p 34.

[49] Id. p. 35.

Dr. Staudt relied on the 2010 Shaw Cost Estimate (AM-REM-00194950 and AM-REM-00294505), with adjustments, as the basis for his WFGD cost estimates.[50]

To develop his cost estimates, Dr. Staudt relied on costs by Shaw with the following exceptions:[51]

1. Escalation: Rather than using the approach used by Shaw, Dr. Staudt used the Chemical Engineering Process Cost (CEPC) Index to escalate the 2010 Shaw Cost Estimate to 2016 dollars.
2. Dr. Staudt removed AFUDC, Property Taxes, and certain Owner's Costs, including Corporate Overhead, from the Shaw cost estimate, and reallocated property taxes from a capital cost to an indirect annual cost, based on his assertion that these costs are "not included per the U.S.EPA Control Cost Manual" and, therefore, usually not included in a BACT cost analysis.
3. Dr. Staudt based his annual auxiliary power cost estimate on a 2009 B&V ID booster fan study,[52] adjusted based on a lower fuel uncontrolled SO_2 emission rate.

Based on my review of the adjustments made by Dr. Staudt to the 2010 Shaw Cost Estimate, it is my opinion that Dr. Staudt underestimated WFGD control technology costs by using an escalation index that is not representative of the electric power industry, eliminating indirect costs from the cost estimate that Ameren would incur to install the control technology, and underestimating the auxiliary power costs required to operate the control system. I discuss each adjustment to the WFGD cost estimate in detail below.

4.1.1 Cost Escalation Methodology

Escalation represents the increase in equipment, material, and labor costs expected to occur from the date a project cost estimate is prepared through the construction of the project. Based on my experience, on large air pollution control system retrofit projects, engineers commonly apply escalation through the in-service date of the control technology. Escalation is calculated as a percentage of the base costs using published industry cost indexes. Cost indexes typically used for power plant cost estimating include Handy-Whitman, *Engineering News-Record* (ENR), and the U.S. Bureau of Labor Statistics. The CEPC Index is generally used for chemical process equipment.

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[50] Id., p. 46.

[51] Id., p. 44.

[52] BV2-0003012.

Dr. Staudt backed out escalation included in the 2010 Shaw Cost Estimate and used the CEPC Index chemical process composite index to escalate costs from 2010 to 2016.[53] Based on the Rush Island WFGD construction schedule in Dr. Staudt's report, he escalated construction costs for the Rush Island WFGD from 2010 to 2016, the assumed commercial operating date of the Rush Island FGD.[54] Dr. Staudt stated that he used the CEPC Index because it "is based upon actual, historical, escalation data rather than projections."[55] He also indicated in his deposition that he has only used the CEPC Index to escalate capital cost and was not familiar with other cost indexes.[56]

Dr. Staudt applied an escalation rate of 1.7% to the total plant cost (excluding escalation, AFUDC, Corporate Overhead, and Property Taxes) based on the CEPC Index.[57] The CEPC Index used by Dr. Staudt is a composite index of several sub-indexes.[58] Sub-indexes that make up the composite index include Equipment, Buildings, Construction Labor, and Engineering and Supervision. Indexes are compiled and, with weighting and normalizing factors developed from the chemical process industry, are summed to make the composite CEPC Index.[59]

The CEPC Index was developed to provide a simplified method of escalating construction costs associated with chemical process equipment and chemical process plants. While some of these types of process equipment are used in air pollution control systems, most are not. Thus, weighting factors based on the chemical processing industry used to develop the composite CEPC Index would not necessarily be representative of air pollution control systems.[60] In my opinion, air pollution control system costs should

[53] AMEREM_JES0000001.

[54] Staudt Report, Figure 18, p. 39.

[55] Staudt Report, p. 44.

[56] Staudt Deposition, p. 180:3-17.

[57] AMEREM_JES0000001, sheet AM-REM-00294505. Note that in Worksheet titled "CEPCI" Dr. Staudt shows 2010 index of 550.8 and 2016 index of 541.7 which actually translates to a 1.7% reduction in overall project costs rather than a 1.7% increase.

[58] William M. Vatavuk, *Updating the CE Plant Cost Index*, (CEPCI) "Chemical Engineering," January 2002, pp. 62-70

[59] Ibid.

[60] William M. Vatavuk, *Air Pollution Control Escalate Equipment Costs*, "Chemical Engineering," December 1995, p. 89, available at http://infohouse.p2ric.org/ref/27/26839.pdf.

be escalated using one or more index more closely related to the utilities industry, as equipment costs, construction materials (e.g., concrete, steel, etc.), and labor costs all escalate at different rates.

A more appropriate index is the Handy-Whitman index, which provides a total steam product plant index, as well as numerous utility-related sub-indexes, including boiler plant equipment, structural equipment, installed piping, and electrical equipment.[61] Index numbers are developed from commodity prices and wage rates, as applicable, prevailing on January 1 and July 1 of each year. The proportions of basic materials, labor, equipment, and other cost components are based on data furnished by utility sources willing to assist in the index, to reflect current construction practices, and are provided on a regional basis. Sargent &Lundy's cost estimating group routinely relies on the Handy-Whitman Index to escalate project costs.

The Handy-Whitman Total Steam Production Plant cost index for the Northcentral Region, including Missouri, increased from 587 (July 1, 2010) to 683 (July 1, 2016), an increase of 16.4%.[62] The Handy-Whitman Coal-Fired Plant Equipment Cost index increased from 597 (July 1, 2010) to 700 (July 1, 2016), an increase of 17.3%.[63] The Handy-Whitman cost indexes vary significantly from the composite CEPC Index used by Dr. Staudt; however, it is my opinion that because the Handy-Whitman cost indexes are based on data provided by the utility industry, they more accurately reflect the actual change in plant costs at coal-fired steam electric generating stations.

Engineering New-Record (ENR) also publishes a Construction Cost Index that is widely used in the construction industry. The ENR Construction Cost Index includes labor and materials components. The ENR Construction Cost Index increased from 8804.8 to 10337.1 between June 2010 and June 2016, an increase of 17.4%. During the same time period, the ENR Skilled Labor index increased by 16.9% (from 8449.0 to 9878.5) and the ENR Material Price index increased by 13.4% (from 2712.8 to 3075.2).[64] The Handy-Whitman and ENR cost indexes show similar escalation in construction costs between 2010 and

[61] Handy-Whitman Index of Public Utility Electricity Construction Costs," (Whitman, Requardt and Associates, LLP), ISSN 1092-955X, 2017).

[62] See, Ken Snell E3-Handy-Whitman Northcentral Tables.xlsx.

[63] Ibid.

[64] See, Ken Snell ENR Tables.xlsx.

2016 and, in my opinion, are more representative of the utility industry than the composite CEPC Index used by Dr. Staudt.

By relying on the composite CEPC Index to escalate equipment, material, and construction-related costs, Dr. Staudt did not accurately account for construction cost increases identified in indexes developed for the utility industry. To determine the cost impact, I applied 16.9% escalation to all of the labor-specific line items in the 2010 Shaw Cost Estimate (based on the ENR Skilled Labor index); 13.4% escalation to material costs (based on the ENR Material Price index), and 17.3% escalation on all equipment costs (based on the Handy-Whitman Boiler Plant Equipment Cost index). Cost impacts are shown in Table 7.

Table 7. Comparison of Dr. Staudt and S&L Wet FGD Capital Cost Escalation Methodology (2016$)

Parameter	(A) Shaw 2010 Cost Estimate (Note 1) $1,000	(B) Dr. Staudt Cost Estimate (Note 2) $1,000	(C) S&L Cost Estimate (Note 3) $1,000	S&L Remarks
Construction Contracts				
Direct Costs	$239,800	$243,829	$280,863	44% labor/56% equipment
Construction Services	$68,797	$69,953	$80,424	100% labor
Project Office Services	$48,870	$49,691	$57,129	100% labor
Allowances	$12,958	$13,176	$12,958	Assumed no increase
Fees and G&A	$40,845	$41,531	$40,845	Assumed no increase
Escalation	$59,740	Re-Calculated by Staudt (Note 2)	S&L included in each line item above	
Contractor Contingency	$35,465	$36,061	$40,721	Based on Shaw Contractor Contingency %
Subtotal	$506,476	$454,241	$512,940	
Owner's Cost				
Ameren Engineering	$19,891	$20,225	$23,253	100% labor
Ameren Supervision	$13,489	$13,716	$15,769	100% labor
Owner's Engineer	$11,034	$11,219	$12,899	100% labor
Training and Procedures	$1,594	$1,621	$1,863	100% labor
Spare Parts	$3,270	$3,325	$3,708	100% materials
Property Taxes	$22,932	Excluded by Staudt	S&L did not include for comparative purposes only	
ACIP	$12,960	$13,178	$12,960	Assumed no increase
Project Auditing	$950	$966	$950	Assumed no increase
Permit Fees	$350	$356	$350	Assumed no increase
FGD Studies	$4,797	$4,878	$4,797	Assumed no increase
Subtotal	$91,267	$69,484	$76,549	
Contingency	$57,099	$58,058	$56,310	Based on Shaw Contingency %
Total Project Cost	$654,839	$581,788	$645,800	
Cost Difference (Dr. Staudt v. S&L)			$64,012 11%	

Notes: See, Ken Snell Rush Island WFGD Cost Analysis.xlsx

1. Column A: Based on Shaw 2010 Cost Estimate, AM-REM-00294538; Project Cost Estimating/Tracking Report Form – GEN-FRM-2160-01.
2. Column B: Staudt cost estimate applying 1.7% escalation to all line items, including equipment, materials, construction and labor costs. See Staudt spreadsheet "Cost Analysis 12-14-2017_1538.xlsx (AMEREM_JES0000001).xlsx, Sheet Titled "Technology Cost_Cur_RI."
3. Column C: Cost estimate applying 16.9% escalation to all of the labor-specific line items (ENR Skilled Labor index); 13.4% escalation to material costs (ENR Material Price index), and 17.3% escalation on all equipment costs (Handy-Whitman Boiler Plant Equipment Cost index).
4. Total Project Cost shown in this table excludes AFUDC, Property Taxes, certain Owner's Costs, and contingency.

By applying a 1.7% escalation rate based on the composite CEPC Index, Dr. Staudt failed to accurately allow for equipment cost, material cost, and labor cost increases identified by Handy-Whitman and ENR. Applying the Handy-Whitman and ENR cost indexes as described above, it is my opinion that Dr. Staudt failed to accurately account for approximately $58.7 million in direct equipment and installation cost escalation, $6 million in indirect construction cost escalation, and approximately $64.7 million in total project cost escalation.

4.1.2 Excluded Costs

As noted in Table 7, Dr. Staudt removed AFUDC, Property Taxes, and certain Owner's Costs from the 2010 Shaw Cost Estimate, asserting that these costs are typically not included in a cost estimate prepared in accordance with the Control Cost Manual.[65] For reasons discussed below, it is my opinion that AFUDC, Property Taxes, and Owner's Costs are indirect capital costs, as that term is defined in the Control Cost Manual, and all there line items account for actual costs that Ameren would incur to install WFGD controls at Rush Island. These costs should be included in order to provide an accurate estimate of the total capital requirements for the project, and to allow Ameren to prepare a meaningful financial assessment of the competing control technologies.

4.1.2.1 Allowance for Funds Used During Construction (AFUDC)

Dr. Staudt excluded AFUDC from the WFGD control system cost estimate based on his assertion that AFUDC is not included per the U.S.EPA's Control Cost Manual and, therefore, not included in a BACT cost analysis.[66] In his deposition, Dr. Staudt explained that he removed AFUDC from the capital cost estimate because cost estimates prepared in accordance with the Control Cost Manual represent "overnight" costs; that is, capital costs are calculated as if the entire plant, or air pollution control system, could be built overnight.[67] However, based on my review of the 2002 Control Cost Manual, specifically Section 1, Chapter 2 "Cost Estimation: Concepts and Methodology," I see nothing to support his interpretation, and nothing that suggests capital costs calculated using the Control Cost Manual represent overnight costs.

[65] Staudt Report, pp. 37 and 44.

[66] Id., p. 44.

[67] Staudt Deposition, pp. 162:11-15.

Moreover, neither the word "overnight" nor the overnight cost estimating concept appears in the 2002 Control Cost Manual. In a subsequent version of the Control Cost Manual, dated November 2017, U.S.EPA revised Section 1, Chapter 2 of the manual to include a statement that "[t]he method for estimating [Total Capital Investment] TCI in this Manual is an 'overnight' estimation method" and that cost items such as AFUDC are treated separately in Section 2.5.3 of the manual. However, this statement was not included in the 2002 Control Cost Manual. More importantly, overnight cost estimating does not reflect how costs are actually borne for pollution control projects, which take years to construct.

The cost estimating methodology described in the Control Cost Manual requires the analyst to annualize total capital costs in constant net-present-value dollars over the economic life of the control system using a capital recovery factor (CRF).[68] The approach involves determining the net present value of the investment and determining the equal payment that would have to be made at the end of each year to attain the same level of expenditure.[69] AFUDC accounts for the time-value of money associated with the distribution of construction cash flows over the construction period, which for a WFGD project, could be spread over a construction period of approximately 36 months. AFUDC can be calculated as a capital cost and annualized over the life of the project using the equivalent uniform annual cash flow method described in the manual.

Appendix B to the Draft 1990 New Source Review Manual ("Estimating Capital Costs") describes the approach that should be used to prepare BACT cost estimates. The NSR Manual defines indirect installation costs to "include (but are not limited to) engineering, construction, start-up, performance tests, and contingency." The NSR Manual states that these costs "may be developed by the applicant for the specific project under evaluation;"[70] however, references, such as the Control Cost Manual, "can be used by applicants if they do not have site-specific estimates already prepared."[71] The NSR Manual specifically includes "interest on working capital" in its example control technology cost estimate[72] and states that

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[68] U.S. Environmental Protection Agency Office of Air Quality Planning and Standards, *EPA Air Pollution Control Cost Manual*, Sixth Edition, EPA/452/B-02-001, January 2002, Section 1, Chapter 2, p. 2-20.

[69] Id., p 2-21.

[70] New Source Review (NSR) Workshop Manual, *Prevention of Significant Deterioration and Nonattainment Area Permitting*, draft October 1990, Appendix B, p. B-3.

[71] Ibid.

[72] Id., p. b.9 and b.11.

"[o]ther economic parameters (equipment life, cost of capital, etc.) should be consistent with estimates for other parts of the project.[73]

AFUDC is part of the capital expense that will be incurred with the installation of a large air pollution control system, and the accepted practice in the utility industry and by financial institutions is to treat AFUDC as a capitalized expenditure. Cost estimates prepared by engineering firms on behalf of clients typically include AFUDC, especially if the cost estimate will be used in a financial analysis or to develop project budgets and cash flows. AFUDC can represent a significant cost on large construction projects with long project durations, such as a WFGD project. For these reasons, I put AFUDC back into the WFGD control cost estimate.

It is also my opinion, that excluding AFUDC will skew the results of a cost-effectiveness evaluation towards high capital, long-duration projects, especially when comparing competing technologies with vastly different capital requirements and construction durations. For example, AFUDC for the Rush Island WFGD project totals approximately $115,433,000,[74] or almost 13% of the total project cost estimate, but only $1,419,000, or approximately 4.7% of the DSI system. By excluding AFUDC, Dr. Staudt underestimated the cost of WFGD at Rush Island and thus overstated WFGD cost-effectiveness.

4.1.2.2 Owner's Cost (including Property Tax and Corporate Overheads)

Dr. Staudt removed certain costs included as Owner's Costs in the 2010 Shaw Cost Estimate based on his assertion that these costs are "usually not included in a BACT cost analysis."[75] Specifically, Dr. Staudt removed "Corporate Overhead" costs ($37.72 million) from the cost estimate and reallocated property taxes ($22.93 million) from the capital cost estimate to an indirect annual cost of $5.8 million/year calculated at 1% of the total capital cost.[76]

[73] Id., p. b.11 (emphasis added).

[74] AMEREM_JES0000001, sheet AM-REM-00294505.

[75] Staudt Report, p. 44.

[76] AMEREM_JES0000001.xlsx, sheet Technology Cost_Cur_RI.

As discussed above, total capital investment is defined in the Control Cost Manual to include all expenditures incurred during the construction phase of the project, including direct costs, indirect costs, fuel and consumables expended during startup and testing, and other capitalized expenses. Nevertheless, Dr. Staudt removed these costs from the WFGD cost estimate, based on the assertion that corporate overhead or owner's costs are, in his experience, "usually not included in a BACT cost analysis."[77] Other than his own personal experience, Dr. Staudt provided no basis for this assertion.[78] Dr. Staudt's view is contrary to Appendix B of the NSR Manual, the methodology described in the Control Cost Manual, industry practice, and my own experience preparing cost effectiveness evaluations for the utility industry.

Corporate overhead, or owner's costs, include the project-related costs that Ameren would incur to purchase, engineer, manage, administer, and implement the WFGD construction project. These necessary costs include expenses such as internal labor and management costs, travel expenses, legal services, and builder's risk insurance. These costs clearly fall within the Control Cost Manual's definition of indirect costs. Owner's costs are also included in specific air pollution control examples in the Control Cost Manual, generally under the line item "Engineering & Home Office," and are calculated as a percentage of the total direct capital costs.[79]

Similarly, taxes on process equipment should be included as a capital cost, as applicable, on a case-by-case basis. In fact, the Capital Cost Manual states that total direct cost "includes purchased equipment cost, which in turn, is the sum of the base equipment cost (control device and auxiliaries), freight, instrumentation, and sales tax.[80] In this case, based on discussions with Ameren, the State of Missouri would impose a property tax on equipment purchased and delivered during the duration of the construction project. Based on equipment costs, Shaw estimated "Property Taxes & Permit Fees" of $22.9 million for the WFGD project.[81] This cost would be capitalized and amortized over the life of the project, and represents an indirect capital cost that should be included in the capital cost estimate.

[77] Staudt Report, p. 44.

[78] See, Staudt, Deposition, p. 164:17-167:11.

[79] See e.g., Control Cost Manual p. 2-44.

[80] Id., p. 2-26.

[81] See, AM-REM-00294505, p. AM-REM-00294538.

By arbitrarily removing these costs from the WFGD capital cost estimate, Dr. Staudt underestimated the total capital investment Ameren would incur to install WFGD controls on Rush Island Units 1 and 2, and thus overstated the cost-effectiveness of the WFGD control systems.

4.1.3 Support Facility Costs

Cost estimates prepared to support a BACT evaluation should include support facilities needed to successfully operate the control technology, assuming the support equipment or facility does not already exist at the plant or needs to be expanded or enhanced.[82] Support facilities needed to successfully operate a WFGD control system would include a new or expanded wastewater treatment system.

4.1.3.1 Wastewater Treatment Costs

The 2010 Shaw Cost Estimate upon which Dr. Staudt relied for his cost estimates was based on the assumption that a new physical/chemical wastewater treatment system would be sufficient for the wastewater discharges from a new Rush Island WFGD control system. The new wastewater treatment system was sized for the Powder River Basin (PRB) coal chloride purge stream to maintain 8,000 ppm chlorides in the absorber vessel, which required a design to treat up to 185 gpm for the PRB case.[83] Major components of the wastewater treatment system would include an equalization tank, clarifiers, multimedia filters, effluent tanks, sludge filter press, chemical storage and mixing equipment, and associated pumps, piping, and controls.[84]

In my opinion, permitting a new wastewater discharge from the Rush Island facility would likely result in stringent discharge limits, and that advanced wastewater treatment would likely be required to meet discharge limits imposed on a new wastewater discharge.

On November 3, 2015, EPA published a final Effluent Limitation Guideline (ELG) for the Steam Electric Power Generating Point Source Category.[85] Among other requirements, the Steam Electric ELG included

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[82] Control Cost Manual, p. 2-5.

[83] AM-REM-00195079, p. AM-REM-00195103.

[84] Ibid.

[85] 80 Fed. Reg. 67838, November 3, 2015.

discharge standards for FGD wastewater. FGD wastewater standards included mercury at 0.365 μg/L; selenium at 12 μg/L; and nitrate/nitrate 4.4 mg/L (30-day average). These discharge standards applied to all existing steam electric generating units greater than 50 MW. In addition, anti-circumvention provisions in the final rule required facilities to demonstrate compliance with the WFGD discharge standards prior to mixing with other wastewater streams in a combined outfall. Implementation of the federal Steam Electric ELG has been delayed to allow EPA to consider, and possibly propose, revised WFGD wastewater standards. Nonetheless, it remains likely that ELG standards will apply to new WFGD wastewater discharges.

Furthermore, a revised NPDES permit, or permit modification, would be required for a new WFGD bleed system wastewater discharge.[86] As noted in the May 2010 Shaw Report, starting August 30, 2008 all permit applications for new or expanded discharges will be required to follow the new Missouri Antidegradation Rule.[87] Missouri's Antidegradation rule requires applicants to identify the antidegradation review level that applies to their receiving water, determine existing water quality, assess and determine an appropriate extent of water quality degradation, identify and assess less-degrading or non-degrading alternatives, and identify important economic and social development to justify degradation.[88] Although discharge limits imposed on Rush Island as a result of the antidegradation assessment are unknown, it is my opinion that the antidegradation assessment will likely result in the imposition of stringent wastewater discharge limits or treatment requirements.

The extent of wastewater treatment required is a function of the characteristics of the wastewater and the applicable wastewater discharge limits. Based on discharge limits included in the Steam Electric ELG Rule and the Missouri Antidegradation requirement to identify less-degrading alternatives, it is reasonable to conclude that compliance with the Missouri rule, and possibly the revised and reinstated ELG Rule, would require both physical/chemical and biological treatment of FGD wastewater to meet the Hg, Se, and nitrate discharge standards. As an example, compliance with the Se and nitrate standards in the ELG Rule would

[86] BV2_0005747 at BV2_0005763

[87] AM-REM-00194950 at AM-REM-00195000

[88] Missouri Natural Resources, Division of Environmental Quality, Water Protection Program, *Missouri Antidegradation Implementation Procedure*, July 13, 2016, p. 10.

have required advanced treatment technologies such as biological treatment, and advanced biological wastewater treatment systems have been installed at some existing steam electric generating units equipped with WFGD to meet stringent discharge limits.[89]

A study published by the consulting firm CH2M Hill titled "FGD Technology Evaluation for Two Similar Power Plants Leads to Different Solution" described treating WFGD wastewater to comply with the water-quality based effluent limits in the Steam Electric ELG.[90] The study evaluated two zero-discharge alternatives (e.g., spray dryer and crystallizing evaporator) and a membrane bioreactor (MBR) biological treatment system to remove selenium and nitrates. Wastewater treatment system costs were developed for We Energies Pleasant Prairie and Oak Creek power plants. The Pleasant Prairie plant consists of two 594-MW PRB-fired units. The Oak Creek plant consists of six coal-fired units, with a total generating capacity of approximately 2,200 MW. Wastewater treatment costs were developed based on peak flows of 41 gpm and 400 gpm for the Pleasant Prairie and Oak Creek plants, respectively. Spray dryer zero-discharge control costs ranged between \$24 million (Pleasant Prairie) and \$69.3 million (Oak Creek). MBR treatment system costs ranged between \$21.9 million (Pleasant Prairie) and \$51.3 million (Oak Creek).

Costs presented in the CH2M Hill study are similar in magnitude to costs incurred by Public Service Company of New Hampshire (PSNH) to install a crystallizing evaporator treatment system at its Merrimack Station. In a report submitted to the Public Utilities Commission of New Hampshire, PSNH reported capital costs of \$36.4 million to install a crystallizing evaporator designed to treat wastewater flow of 65 gpm.[91]

Based on a design flow rate of 185 gpm, it is my opinion that Rush Island likely would incur an additional \$51 million in capital costs to install an advanced wastewater treatment system in connection with a WFGD control project. In addition, Rush Island likely would incur approximately \$2.86 million in annual O&M costs, a majority of which (approximately 80-90%) would be variable costs including treatment system

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[89] Robert Wylie et.al. *Duke Energy Carolina LLC's Strategy and Initial Experience of FGD Waste Water Treatment Systems*, International Water Conference, IWC-08-32, October 2008, San Antonio, Texas

[90] Krystal Perez et.al., FGD Technology Evaluation for Two Similar Power Plants Leads to Different Solution, International Water Conference, 2017, IWC-17-73, Florida, Table 9, p. 16.

[91] New Hampshire Clean Air Project Final Report, Prepared for: New Hampshire Public Utilities Commission, Jacobs Consultancy, September 10, 2012, p. 57.

chemicals and auxiliary power requirements.[92] These costs should be included in the evaluation of the cost-effectiveness of a retrofit WFGD system.

4.1.4 Actual Capital Cost for WFGD at Rush Island

I revised Dr. Staudt's WFGD cost estimate to correct the errors he made, in order to account for all of the actual costs that Ameren would incur to construct WFGD at Rush Island. Corrected capital costs are provided in Table 8. Column A in Table 8 shows my revised cost estimate including AFUDC, Corporate Overhead, Property Taxes, and Advanced Wastewater Treatment Costs, and using the escalation methodology described above to escalate costs from 2010$ to 2016$. Column B shows the estimated capital cost for the WFGD project escalated to December 2025, the control system in-service date, based on a project authorization date of January 1, 2021. Equipment, material, and labor cost were escalated to December 2025 assuming equipment and material costs escalate at an average rate of 1% per year based on a conservative evaluation of the Handy-Whitman indexes, and labor costs escalate at an average rate of 3% per year based on historic ENR labor cost escalation.

[92] Krystal Perez et.al , Table 9, based on bioreactor O&M costs at Oak Creek designed for 151-gpm average flow.

Table 8. Revised Capital Cost Estimate*

Parameter	(A) S&L WFGD Cost Estimate - $2016 ($1,000)	(B) S&L WFGD Cost Estimate - $2025 ($1,000)	S&L Remarks
Construction Contracts			
Direct Costs	$280,863	$333,262	44% labor/56% equipment
Construction Services	$80,424	$104,935	100% labor
Project Office Services	$57,129	$74,540	100% labor
Allowances	$12,958	$14,172	1% escalation/year
Fees and G&A	$40,845	$48,465	44% labor/56% equipment
Escalation	NA	NA	
Contractor Contingency	$40,721	$53,131	100% labor
Subtotal	$512,940	$628,506	
Owner's Cost			
Ameren Engineering	$23,253	$30,339	100% labor
Ameren Supervision	$15,769	$20,574	100% labor
Owner's Engineer	$12,899	$16,830	100% labor
Training and Procedures	$1,863	$2,431	100% labor
Spare Parts	$3,708	$4,056	100% materials/equipment
Property Tax	$22,932	$25,080	1% escalation/year
ACIP	$12,960	$14,174	1% escalation/year
Project Auditing	$950	$1,039	1% escalation/year
Permit Fees	$350	$383	1% escalation/year
FGD Studies	$4,797	$5,246	1% escalation/year
Subtotal	$99,481	$120,153	
Other Overheads			
LICARD			
Taxes			
AFUDC	$115,433	$126,247	1% escalation/year
Corporate Overheads	$44,089	$48,219	1% escalation/year
Subtotal	$159,522	$174,467	
Total Project Cost Less Contingency	$771,942	$923,126	
Contingency	$73,740	$88,181	
Advanced Wastewater Treatment	$51,000	$55,778	
Total Project Cost	$896,680	$1,067,090	

*Ken Snell Rush Island WFGD Cost Analysis.xlsx.

By using a cost index that was not representative of escalation in the utility industry, removing certain significant indirect capital costs, and failing to account for required WFGD wastewater treatment, it is my opinion that Dr. Staudt underestimated the total capital investment required for the WFGD project, including support facilities, by approximately $315 million (i.e., $581.8 million vs. $896.7 million 2016$). Dr. Staudt underestimated both the total capital cost and annualized capital costs of the WFGD project, and overstated the cost-effectiveness of the WFGD control system. Escalating these costs to an in-service date of December 2025, I estimate the total capital investment to be $1.067 billion.

4.2 Fixed and Variable Cost Estimate

In addition to the capital cost estimating items discussed above, Dr. Staudt incorrectly estimated auxiliary power requirements and costs for the WFGD control system.

4.2.1 WFGD Auxiliary Power Requirements

WFGD components generally include ball mills, recycle pumps, oxidation air compressors, vacuum belt filter pumps, booster ID fans, and other rotating equipment, all of which require large electric motors to operate. The power needed to operate this equipment, generally referred to as auxiliary power, is taken from the power plant's generating capacity. Auxiliary power requirements are calculated as the sum of the power needed to operate control system components (e.g., pumps, fans, motors, etc.).

Dr. Staudt estimated WFGD auxiliary power requirements by adjusting electrical load information provided in the 2009 Black & Veatch Technology Selection Report, ID Booster Fan Study.[93] Load information provided in the Black & Veatch report was based on a WFGD control system designed for IL-6 bituminous coal.[94] Dr. Staudt used the limestone consumption ratio (i.e., limestone consumption rate for PRB divided by the limestone consumption rate for IL-6) to adjust the auxiliary power loads for PRB operation.[95]

[93] AMEREM_JES0000001, sheets Electrical Load and ID Booster.

[94] BV2_0003012, pp. AME_BV002566 through AME_BV2002569.

[95] AMEREM_JES0000001, sheet Electrical Load.

I agree that using the limestone consumption ratio is a reasonably accurate approach for estimating electrical load requirements for the reagent preparation, FGD solids, and material handling areas; as these loads are generally proportional to limestone consumption. However, this approach provides an inaccurate estimate of load requirements associated with the WFGD absorber area, as load requirements for the absorber area, primarily made up of power required to operate the recycle pumps, are generally independent of the limestone consumption rate. A more appropriate method to adjust absorber electrical loads is to ratio the expected liquid-to-gas ratio (L/G) for the PRB and IL-6 operating conditions.

L/G refers to the volume ratio of limestone slurry to flue gas flow through the WFGD absorber, expressed as gallons of slurry per 1000 cubic feet (kacfm) of flue gas. The L/G ratio determines the amount of reagent available to react with SO_2, and is a function of the inlet SO_2 loading and SO_2 removal efficiency. WFGD absorbers designed for IL-6 will have a higher L/G ratio than an absorber designed for PRB due to the higher SO_2 removal efficiencies needed to achieve the target SO_2 emission rate. Based on Sargent & Lundy's experience designing WFGD control systems, L/G would be approximately 170 gpm/kacfm in an IL-6 application, compared to approximately 70 gpm/kacfm for PRB. Auxiliary load requirements for the WFGD absorber area should be adjusted based on the L/G ratio, rather than the limestone consumption rate.

Table 9 shows the adjustment in the WFGD absorber area load requirements, and the corresponding adjustment to the WFGD auxiliary power requirement.

Table 9. WFGD Auxiliary Power Requirements (Excluding ID Fan)

Parameter	Dr. Staudt Report	Corrected Power Consumption	Remarks
Reagent Preparation	169 hp	169 hp	No change. Adjusted based on limestone consumption ratio.
FGD Solids	119 hp	119 hp	
Material Handling	32 hp	32 hp	
BOP Systems	2,080 hp	2,080 hp	
Wastewater Treatment Equipment	400 hp	400 hp	Assumed no change.
Wet FGD Absorber Area (both units)	2,935 hp	8,244 hp	Adjusted based on ratio of L/Gs.
WFGD Absorber Common	1,225 hp	1,225 hp	Assumed no change.
Total Load (excluding ID Fan)	6,960 hp	12,268 hp	--

4.2.2 Auxiliary Power Costs

By using the limestone consumption rate to adjust all auxiliary power loads, Dr. Staudt underestimated auxiliary power requirement for a WFGD control system by 5,308 hp, or approximately 44% (excluding the ID booster fan). Underestimating auxiliary power requirements has a direct effect on auxiliary power costs and annual operating costs of a WFGD control system. In addition, Dr. Staudt incorrectly calculated auxiliary power costs by adding the incremental increase in ID fan power consumption in units of kW to the equipment power consumption in units of hp, and multiplying the sum by the power cost in units of dollars per kilowatt-hour ($/kWh).[96] The equipment power consumption should have been converted from hp to kW prior to multiplying by the power cost.

Revised auxiliary power costs are provided in Table 10.

[96] See Dr. Staudt Cost Analysis_20180302.xlsx, sheet Technology Cost_Cur_RI, cell D43

Table 10. Auxiliary Power Cost Comparison

Parameter	Dr. Staudt Report	Corrected Analysis
Equipment Load (excluding ID Fan)	6,960 hp	12,268 hp
Equipment Load (excluding ID Fan)	5,189 kW	9,147 kW
Incremental ID Fan Load(Note 1)	9,279 kW	9,279 kW
Total Load (kW)	14,468 kW	18,426 kW
Power Cost [97]	$30.00/MWh	$30.00/MWh
Capacity Factor	80.0%	75.0%
Total Power Cost – Both Units	$3,041,717	$3,631,727

Note 1: Converted the incremental ID fan load from 12,440 hp to kW based on 1.3406 hp/kW conversion factor.

By adjusting all power loads based on the limestone consumption ratio, Dr. Staudt underestimated auxiliary power costs for the WFGD control system by approximately $590,000 per year.

4.2.3 Net Plant Heat Rate Impacts

Auxiliary power needed to operate the WFGD control system will also have an adverse impact on the Net Plant Heat Rate (NPHR) of Rush Island Units 1 and 2. NPHR provides a measure of the quantity of fuel needed (based on MMBtu/hr heat input to the boiler) per net megawatt-hour (MWh) of electricity generate. Net generation is calculated by subtracting the auxiliary power load from the gross generation rate. The estimated impact to NPHR associated with WFGD on Rush Island Units 1 and 2 is shown in Table 11.

[97] Matthew I. Kahal, *Remedy Phase Expert Report of Matthew I. Kahal*, United States of America and the Sierra Club v. Ameren Missouri, Case No. 4:11 CV77 RWS, December 15, 2017, p. 20.

Table 11. Estimated Change in Heat Rate – Current vs. Post-Installation

Parameter	Current Operation[98]	Post-WFGD Installation
Gross Output (kW)	621,000	621,000
Auxiliary Power (kW)	50,922	60,135
Net Output (kW)	570,078	560,865
Heat Input (MMBtu/hr)	6,300	6,300
Net Plant Heat Rate (Btu/kW-net)	11,051	11,233

Notes:

1. Current auxiliary power requirements were estimated assuming 8.2% of gross output based on coal-fired steam electric generating unit without WFGD.
2. Post-WFGD auxiliary power requirement includes 9,213 kW /Unit for WFGD control (see Table 10).

Power needed to operate the WFGD control system will reduce NPHR of both Rush Island Units 1 and 2 by approximately 1.0%, from 11,051 Btu/kW-net to 11,233 Btu/kW-net. In other words, additional fuel has to be fired to achieve the same net electric power output, and emissions of all regulated air pollutants will increase on a lb/MWh basis. In addition, net output from the Rush Island generating station will decrease by approximately 18.4 MW (total both units) or approximately 121,000 MWh per year (assuming a 75% capacity factor). This power would have to be made up by operating the Rush Island units at a higher capacity factor, or from an alternative power generating source. As an example, a 100-MW generating source would have to operate approximately 1,210 hours to make up for the reduced output from Rush Island. Depending on the type of generating facility, this could actually result in an increase in regional air pollutant emissions.

4.3 WFGD Total Annual Costs

Adjustments to the capital cost estimates (Section 4.1) and the annual auxiliary power cost (Section 4.2.1) will affect the total annual cost of the WFGD control system used in a BACT analysis to evaluate economic impacts. Impacts to the total annual cost are shown in Table 12.

[98] BV2_0116857 at page 1362.

Table 12. Impacts on Total Annual Costs

Parameter	Staudt Current BACT Analysis (2016$)	S&L Adjustments (2016$)
Retrofit Capital, $1000(Note 1)	$581,788	$896,680
Capital Recovery Factor(Note 2)	0.0887	0.0944
Annualized Capital ($1000/yr)	$51,613	$84,640
Direct Annual Cost, $1000	$10,318	$10,318
Auxiliary Power Cost Adjustment, $1000(Note 3)	--	$590
Wastewater Treatment O&M Cost Adjustment, $1000 (Note 4)	--	$2,860
Indirect Annual Cost, $1000	$24,382	$24,382
Total Annualized Cost, $1000	$86,313	$122,790

Notes: (See, Ken Snell Rush Island WFGD Cost Analysis.xlsx)

1. S&L adjustments to the total capital cost estimate are summarized in Table 8.
2. The capital recovery factor used by Dr. Staudt was based on equipment life of 23 years and 7% interest rate (see See Dr. Staudt Cost Analysis_20180302.xlsx, sheet Technology Cost_Cur_RI). The capital recovery factor calculated by S&L based on an interest rate of 7% and an equipment life of 20 years based on a in-service date of 2025 and a retirement date of 2045 (see, Ameren Missouri's 2017 Integrated Resource Plan and Risk Analysis.pdf, page 2).
3. Auxiliary power cost adjustment shown in Table 10.
4. Wastewater Treatment O&M Cost adjustment shown in Section 4.1.3.1.

4.4 Other Technical Issues

In this section of my report I critique and comment on other technical conclusions and opinions offered by Dr. Staudt in his expert report. Specifically, I provide comments on Dr. Staudt's conclusions that: (1) that the incremental cost of increasing SO_2 removal from 93% to 94.3% will be approximately $240/ton on a unit firing PRB coal and equipped with WFGD; (2) that installing WFGD on Rush Island Units 1 and 2 will provide co-benefit mercury removal; (3) that his WFGD cost estimates (discussed in Section 4.1) were conservatively high because he did not adjust costs for the lower removal rates assumed in his report; and (4) his assumption that WFGD could be installed on Rush Island Units 1 and 2 within three years of a decision to proceed with the project.

4.4.1 WFGD SO_2 Control Efficiency and Incremental Cost-Effectiveness on PRB-Fired Steam Electric Generating Unit

Dr. Staudt provides a table summary of SO_2 removal efficiencies reported from eleven utility and/or industrial boilers to support his assertion that WFGD control systems can achieve removal efficiencies of 99% or more, and that the incremental cost of controlling SO_2 changes very little between 93% and 94.3%.[99] However, all of the units listed by Dr. Staudt in Table 2 of his report have inlet SO_2 emission concentrations significantly higher than SO_2 concentrations at Rush Island. Inlet SO_2 concentrations at the units cited by Dr. Staudt range from 1,300 ppm to as high as 5,740 ppm. These concentrations are equivalent to SO_2 concentrations in the flue gas of approximately 2.7 to more than 10.0 lb/MMBtu. By comparison, SO_2 concentrations in the Rush Island flue gas will range between 0.55 and 0.72 lb/MMBtu, or approximately 290 to 380 ppm. Removal efficiency is a function of inlet SO_2 loading, and higher removal efficiencies are more readily achieved with high inlet concentrations. Although WFGD is an effective SO_2 control technology, the removal efficiencies summarized in Table 2 of Dr. Staudt's Report are not representative of removal efficiencies achievable on a low-sulfur PRB-fired generating unit.

Dr. Staudt referenced Figure 11 in his report to support his assertion that "the incremental cost of controlling SO_2 over 90% changes very little between 93% and 94.3%."[100] The 93% and 94.3% removal efficiencies referenced by Dr. Staudt are the removal efficiencies Rush Island would have to achieve to attain controlled SO_2 emissions of 0.06 lb/MMBtu (Unit 1, from inlet rate of 0.86 lb/MMBtu) and 0.04 lb/MMBtu (Unit 2, from inlet rate of 0.70 lb/MMBtu). Even adjusting for the lower fuel sulfur content of PRB coal, Dr. Staudt concludes that the incremental cost of increasing SO_2 removal from 93% to 94.3% would be approximately $240/ton.[101] In my opinion, removal efficiencies shown in Figure 11 of his report are not representative of the removal efficiencies achievable on a unit firing low-sulfur PRB, like the Rush Island units, and the incremental cost-effectiveness curve shown in Figure 11 actually supports the conclusion that the incremental cost of SO_2 removal becomes significantly more expensive at controlled emission rates below approximately 0.06 lb/MMBtu.

[99] Staudt Report, p. 23.

[100] Id., p. 47.

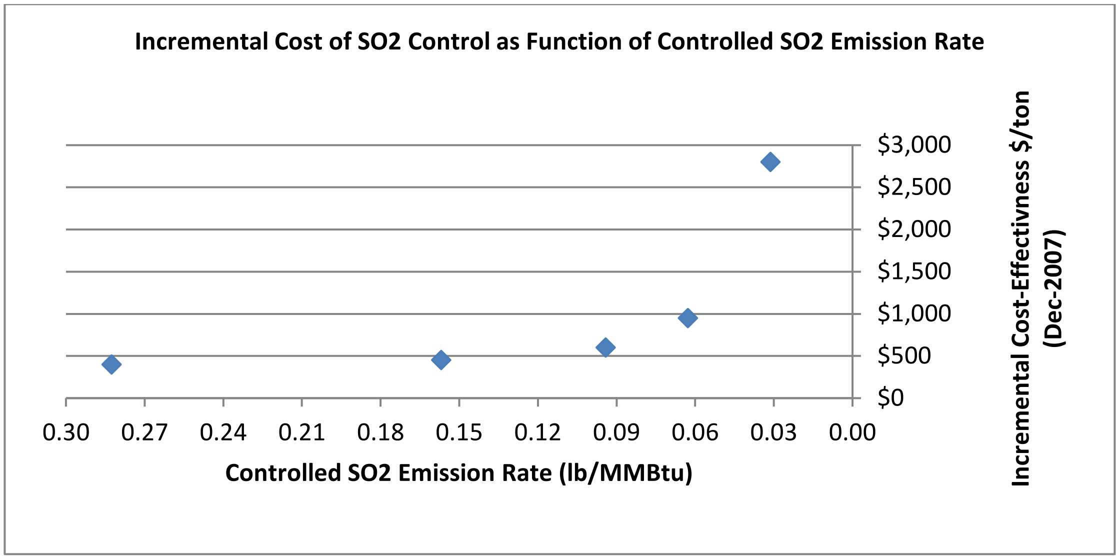
[101] Id., p. 48.

As Dr. Staudt notes in his report, removal efficiencies and the incremental cost-effectiveness curve shown in his Figure 11 were developed based on a unit firing Pittsburgh #8 bituminous coal with an uncontrolled SO_2 rate of 3.13 lb/MMBtu (i.e., 2.1% sulfur at heating value of 13,400 Btu/lb).[102] Removal efficiencies, shown along the y-axis of Figure 11 ranged between 91% and 99%, and were calculated based on an inlet rate of 3.13 lb/MMBtu, approximately four times the SO_2 emission rate being assumed by Staudt for Rush Island. Correlating these removal efficiencies to the incremental cost of SO_2 removal at Rush Island is misleading.

Figure 9 below shows the same incremental cost data from Figure 11 of Dr. Staudt's report as a function of the controlled SO_2 emission rate (lb/MMBtu). The data show a significant increase in the incremental cost of SO_2 removal below a controlled SO_2 emission rate of approximately 0.06 lb/MMBtu. An emission rate of 0.06 lb/MMBtu corresponds to a removal efficiency of 98% on a unit firing Pittsburgh #8 coal, and a removal efficiency of 93% on a unit firing low-sulfur PRB (at an inlet rate of 0.86 lb/MMBtu). Emission rates, which directly correspond to the concentration of SO_2 in the flue gas, should be used to evaluate incremental cost-effectiveness, especially on units firing significantly different types of coal. Data provided in Figure 11 of Dr. Staudt's report support the conclusion that SO_2 removal rapidly becomes less cost-effective below a controlled emission rate of approximately 0.06 lb/MMBtu.

[102] Id., p. 22.

Figure 9. Dr. Staudt Report (Figure 11) Incremental Cost Data



4.4.2 Co-Benefit Mercury Removal with WFGD on Rush Island Units 1 and 2 would be Minimal

Dr. Staudt used EPA's CUECOST worksheet to evaluate co-benefit mercury removal with WFGD at Rush Island Units 1 and 2.[103] Using fuel characteristics from a March 3, 2009 letter to Black & Veatch,[104] Dr. Staudt concluded that WFGD on Rush Island Units 1 and 2 would have the co-benefit of reducing mercury emissions from "about 7.69 lb/TBtu to about 5.88 lb/TBtu" or approximately 162 pounds per year with the addition of WFGD.[105] Dr. Staudt further opined that "wet FGD would also avoid the need for activated carbon for mercury control."[106] Based on my review of the approach Dr. Staudt used to estimate mercury emissions, and my understanding of mercury capture in a WFGD, it is my opinion that Dr. Staudt overestimated baseline mercury emissions at Rush Island Units 1 and 2. I also disagree with Dr. Staudt's conclusions that WFGD installed on Rush Island Units 1 and 2 will provide co-benefit mercury removal and that WFGD will avoid the need for activated carbon for mercury control.

[103] Id., p. 53.

[104] AM-REM-00280265 at p. 00280267.

[105] Staudt Report, p. 54.

[106] Id., p. 38.

To calculate baseline Hg emissions (i.e., without controls), Dr. Staudt used an average coal heating value of 8,318 Btu/lb and a mercury content of 0.08 ppm to calculate an uncontrolled Hg emission rate of 9.617 lb/TBtu, as shown in the following equation:

$$\frac{0.08\ lb\ Hg}{10^6\ lb\ coal} \times \frac{lb\ coal}{8{,}318\ Btu} \times \frac{10^{12} Btu}{TBtu} = 9.617\ lb\ Hg/TBtu$$

However, the heating value used in the equation was calculated on a "wet" basis[107] and the mercury concentration was reported on a dry basis.[108] Calculated on a dry basis, baseline Hg emissions would be 6.67 lb/TBtu, as show in the following equation (where, 0.2995 is the percent moisture in the coal):

$$\frac{0.08\ lb\ Hg}{10^6\ lb\ coal-dry} \times \frac{lb\ coal-wet}{8{,}318\ Btu} \times \frac{(1-0.2995) lb\ coal-dry}{lb\ coal-wet} \times \frac{10^{12} Btu}{TBtu} = 6.67\ lb\ Hg/TBtu$$

In my opinion, Dr. Staudt overestimated baseline Hg emissions from Rush Island Units 1 and 2 by approximately 44%, and overstated potential Hg co-benefit reductions with WFGD.

The CUECOST worksheets upon which Dr. Staudt relied to evaluate mercury control, with and without WFGD, simply assigned removal efficiencies calculated using EPRI co-benefit correlation equations.[109] EPRI developed the correlation equations based on EPA mercury emissions data from coal-fired steam electric generating units.[110] Correlation parameters developed by EPRI were based on fuel characteristics (fuel chlorine and SO_2 emission rate) grouped by air pollution controls.[111] For his evaluation Dr. Staudt used a fuel chlorine content of 100 ppm and uncontrolled SO_2 emission rate of 0.84 lb/MMBtu. Co-benefit mercury removal was calculated at 20.1% based on EPRI's cold-side ESP (ESPc) grouping, and 38.9% based on EPRI's ESPc+FGDw (wet FGD) grouping. In my opinion, the 93% increase in co-benefit mercury

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107 AMEREM_JES0000002, worksheet "Constants-CC" cell E33.

108 AM-REM-00280265 at AM-REM-00280267.

109 AMEREM_JES0000002, worksheet "Constants_CC" line B613.

110 EPRI, *An Assessment of Mercury Emissions from U.S. Coal-Fired Power Plants,* Technical Report 1000608, Final, October 2000, p. 1-2.

111 Id. p. 3-12.

removal with FGDw (i.e., from 20.1% to 38.9%) is not representative of co-benefit mercury removal with WFGD on a PRB-fired boiler.

Mercury capture in a WFGD is a function of mercury speciation in the flue gas. During the combustion process, mercury in the fuel is volatilized and converted to elemental mercury (Hg^0). As the flue gas cools, a portion of the Hg^0 will be oxidized to Hg^{++}, primarily mercuric chloride ($HgCl_2$).[112] The amount of oxidation is dependent on the flue gas temperature and flue gas composition, primarily the availability of chlorine.[113] Bituminous coals have higher concentrations of chlorine compared to subbituminous PRB; thus, mercury in bituminous coal-fired units tends to speciate toward oxidized mercury ($HgCl_2$), while mercury in low-chlorine PRB-fired units tends to speciate toward elemental mercury.[114] $HgCl_2$ is water-soluble and readily captured in WFGD control systems, while Hg^0 is not removed to any degree in a WFGD.

EPRI developed co-benefit correlations for several air pollution control system categories. The ESPc+FGDw category correlation included emissions data from units firing eastern bituminous, western subbituminous, and lignite coals.[115] The average coal mercury content for the ESPc+FGDw category was 12.1 lb/TBtu, significantly higher than the typical mercury content for subbituminous PRB coal.[116] Mercury speciation downstream of the ESPc ranged from approximately 20% Hg^0 on units firing high-chlorine coal, to more than 90% Hg^0 on units firing low-chlorine coal (i.e., less than 100 ppm).[117] Additional mercury removal across the FGDw was a function of mercury speciation at the FGDw inlet, with higher removal efficiencies achieved on units firing high-chlorine coal.[118] In fact, EPRI reported that regardless of the total mercury concentration at the FGDw inlet, "inlet and outlet average elemental levels are both about 5.4 lb/TBtu, indicating that elemental mercury is not absorbable in aqueous solutions."[119]

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[112] EPA, *Performance and Cost of Mercury Emission Control Technology Application on Electric Utility Boilers*, prepared by National Risk Management Research Laboratory, EPA-600-R-00-083, September 2000, p. 2.

[113] Ibid.

[114] EPRI Technical Report 1000608, October 2000, Figure 3-1 and Figure 4-5.

[115] Id., Table 3-2, p. 3-6.

[116] Id. p. 3-35.

[117] Id., Figure 3-13, p. 3-25.

[118] Id., Figure 3-24, p. 3-36.

[119] Id., p. 3-35.

The EPRI co-benefit correlation developed for the ESPc+FGDw category includes emissions data from bituminous, subbituminous, and lignite-fired units. Although the correlation equation may apply generally to the ESPc+FGDw category, it would not necessarily be representative of mercury removal on an individual PRB-fired unit. Rush Island Units 1 and 2 fire low-chlorine PRB subbituminous coal. Emissions data in the EPRI report show that more than 80% of the mercury in the flue gas at the ESPw inlet will be elemental mercury on units firing low-chlorine coal, and that WFGDs do not effectively capture elemental mercury.[120] For these reasons, it is my opinion that WFGD controls installed on Rush Island Units 1 and 2 would provide no co-benefit mercury control.

By relying solely on the EPRI co-benefit correlation equation, Dr. Staudt failed to account for Rush Island-specific fuel characteristics and flue gas mercury speciation. In my opinion, based on emissions data presented in the EPRI report, WFGD controls on Rush Island Units 1 and 2 would provide no co-benefit mercury removal, and would not avoid the need for activated carbon control for mercury as suggested by Dr. Staudt in his report. In his deposition, Dr. Staudt concurred with this conclusion, stating that WFGD would not, by itself, provide additional mercury control, and that a fuel additive would be needed to improve mercury oxidation.[121] Mercury controls available to Rush Island would include fuel additives to introduce additional halogen (chlorine or bromine) into the flue gas to support mercury oxidation and/or increased activated carbon injection (ACI) upstream of the ESP. The incremental increase in mercury control costs should be included in the overall cost-effectiveness analysis of WFGD at Rush Island.

4.4.3 Firing Lower-Sulfur PRB Coal would have no Significant Impact on Capital Costs and Converting WFGD System for IL-6 Coal would require Significant Modifications and Costs

Dr. Staudt asserts that his WFGD capital cost estimate was conservatively high because he did not adjust the 2010 Shaw WFGD costs for the lower removal rates assumed in his report.[122] It is my opinion that this assertion is inaccurate, as WFGD control system capital costs are primarily a function of fuel characteristics other than the fuel sulfur content.

[120] Id., Figure 3-13, p. 3-25 and Figure 3-24, p. 3-36.

[121] Staudt Deposition at 52:21-53:16.

[122] Staudt Report, pp. 50 and 58.

The 2010 Shaw cost estimate was based on a PRB design basis inlet SO_2 loading rate of 0.86 lb/MMBtu (typical) and 1.2 lb/MMBtu (maximum), while Dr. Staudt used a baseline of 0.70 lb/MMBtu to calculate annual emission reductions.[123, 124] In my opinion, changing the design basis inlet SO_2 loading rate to the WFGD control system from 0.70 to 0.86 lb/MMBtu would have no significant effect on control system sizing and capital costs, and Dr. Staudt's assertion that his WFGD capital cost estimate was conservatively high because he did not adjust for the lower removal rates is incorrect.

The design and sizing of an FGD control system generally consists of two major aspects: (1) the flue gas path and (2) the reagent/waste handling system. The flue gas path includes the absorber vessel, slurry spray headers and piping, duct work, foundations, support structures, and fans. On a WFGD, the reagent/waste handling system includes the limestone receiving and preparation, gypsum dewatering, and the solids handling systems. The sizing of the reagent/waste handling system is based on the amount of sulfur dioxide that will be removed from the flue gas; however, the required size of the flue gas path is a function of flue gas volume and is largely independent of the fuel sulfur content.

The primary design parameter for sizing a wet scrubber is flue gas flow rate. Flue gas flow rate is primarily a function of the heat input, fuel heating value, carbon content, and moisture. Fuel sulfur content has an insignificant effect on the volume of flue gas produced by combustion of subbituminous coal.[125] The wet scrubbers used as the basis for the 2010 Shaw Cost Estimate were sized to handle the quantity of flue gas that would be generated at full load heat input to the Rush Island units firing subbituminous PRB coal.[126]

The sulfur content of the fuel, and SO_2 loading to the absorber, does not affect the size (or cost) of the gas path portions of the WFGD system. Reducing the size of these systems based on fuel sulfur content would result in an undersized absorber system, unacceptably high flue gas velocities at the scrubber inlet, and insufficient liquid-to-gas contact time in the absorber. Reducing the size of the absorbers would also result

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[123] AM-REM-00194950 at AM-REM-00194954

[124] Staudt Report, p. 39.

[125] See, e.g., 40 CFR 75 Appendix F, Section 3.3.

[126] AM-REM-00194950 at AM-REM-00194954.

in additional pressure drop through the system, increased power requirements for the ID fan, and reduced net power generation.

While SO_2 loading to the scrubber does affect the size of the limestone preparation, dewatering, and solids handling systems, the capital costs associated with these systems are minimal compared to the capital costs associated with the flue gas path and absorber systems. In general, the gas path components of a WFGD control system account for more than 80% of the total capital cost of the system. For these reasons, it is my opinion that Dr. Staudt's assertion that capital costs should be adjusted for the lower removal rates is incorrect.

In addition, although Dr. Staudt does not suggest that Ameren would revert to using IL-6 coal at Rush Island for fuel cost savings, Ameren would incur significant costs to modify the WFGD control systems designed to treat PRB-generated flue gas to treat IL-6 generated flue gas. As described in the 2009 Shaw Report, the following components would need to be retrofitted or expanded to convert the Rush Island scrubbers from PRB coal to higher sulfur IL-6 bituminous coal:[127]

- Two additional absorber spray levels, including pumps, piping and spray headers to increase the overall L/G of the absorber vessels.
- An additional tray would need to be retrofit into each absorber vessel to increase overall collection efficiency of the absorber.
- New absorber bleed pumps, per unit, to replace the existing absorber bleed pumps.
- One additional dewatering vacuum belt filter to account for the additional waste production.
- Three oxidation air blowers to replace the existing oxidation air blowers to account for the larger demand.
- Two new primary and secondary hydroclones to replace the existing hydroclones.
- New filter feed pumps to replace the existing feed pumps.
- Additional processing equipment and tanks in the reagent preparation area to account for the increased reagent consumption (including two limestone silos, two sluice bowls, two rotary feeders, two slurry storage tanks, and four feed pumps).
- Additional wastewater treatment train to account for the increased chloride purge stream.

[127] AM-REM-00195079 at AM-REM-00195114.

- Additional electrical equipment to support induced draft (ID) fan motor retrofit.
- Distributed control system (DCS) modifications to incorporate controls of the new and modified equipment.

Shaw estimated the cost to covert the WFGD control systems for high sulfur coal at $22 million in 2009 dollars (material/equipment only).[128]

In addition to the WFGD control system upgrades that would be required, firing IL-6 at Rush Island would have additional balance of plant impacts. For example, as Dr. Staudt states in his deposition, firing IL-6 coal would likely increase NOx emissions from the boilers.[129] In its evaluation of converting the Rush Island units to fire IL-6, Shaw concluded that retrofit selective catalytic reduction (SCR) NO_X control systems would be needed on both units to mitigate for the higher NO_X emissions associated with firing IL-6 coal.[130] As part of the SCR retrofit project, two additional booster fans, per unit, would be needed to account for the additional pressure drop through the SCR.[131] Equipment and material costs for the retrofit SCR control systems were estimated at $67 million (2009 dollars).[132]

Other potential impacts associated with firing IL-6 would include higher chlorine content in bituminous coal, and potentially higher HCl emission rates, impacts to the WFGD wastewater treatment system, increased solid waste generation rates and disposal costs, and, as Dr. Staudt notes, potential impacts to the activated carbon mercury control system due to increased SO_3 concentrations in the flue gas.[133]

4.4.4 WFGD Construction Timeline

In his evaluation of excess emissions Dr. Staudt calculated emissions assuming WFGD controls could be installed on Rush Island Units 1 and 2 by the end of 2023, or approximately three years after a decision is

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[128] Id., at AM-REM-00195215.

[129] Staudt Deposition, p. 90.

[130] AM-REM-00195079 at AM-REM-00195082.

[131] Id., at AM-REM-00195115.

[132] Id., at AM-REM-00195301.

[133] Staudt Deposition, p. 95:17-96:5.

made to proceed with the project.[134] Dr. Staudt confirmed this assumption in his deposition, stating that the WFGD system could be in service three to four years from the decision to proceed date.[135] However, based on my experience with WFGD control projects designed, engineered, or installed by Sargent & Lundy, installation of WFGD control systems on Rush Island Units 1 and 2 would take approximately five years from the decision to proceed date. A project timeline of approximately five years is also consistent with the construction schedule shown in Figure 18 of Dr. Staudt's report, which shows approximately five and one-half years from project approval to commercial operation of the Rush Island WFGD control systems.[136]

Figure 10 below provides a simplified project schedule to install WFGD on a single unit. The major steps in a WFGD project, following a decision to proceed, include:

- The Owner must engage an architect-engineer (AE) to prepare conceptual designs and establish the design basis for the WFGD and ancillary systems. As an initial step, the AE would have to thoroughly review studies previously prepared by B&V and Shaw, and confirm that information and assumptions used for those studies, which would have been completed approximately 10 years earlier, remain valid.
- Once the design basis is established, specifications would be prepared for the WFGD equipment, including the reagent preparation system, absorber island, and by-product dewatering system. Although B&V/Shaw prepared specifications for the WFGD and balance-of-plant (BOP) equipment, the AE would be required to review plant operating data, review and update the specifications to industry-current standards, and ensure accuracy of the specifications prior to issuing for bid.
- In addition, specifications would be prepared for a new wet chimney and for an advanced wastewater treatment system. Construction of the wet chimney is typically awarded first, since the shell construction must precede construction of the WFGD absorber island.
- Environmental permit applications can be submitted following preliminary design and preparation of the equipment specifications. At a minimum, the WFGD project would require modification of the facility's Title V air permit and NPDES wastewater discharge permit, and, in my opinion, would likely require a New Source Review Prevention of Significant Deterioration (NSR/PSD) construction air permit. The requirement for an NSR/PSD permit is based on the assumption that the units would continue to operate at the same net output, but would fire additional coal to account for the additional auxiliary power load required to operate the WFGD; thus, mass emissions of other NSR-regulated pollutants

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[134] Staudt Report, p. 52.

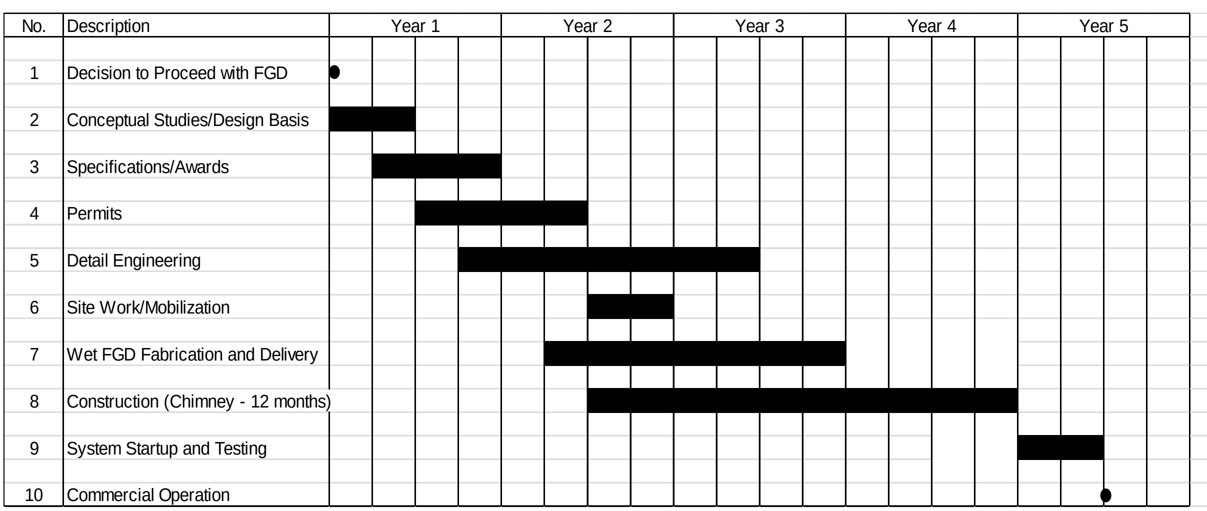
[135] Staudt Deposition, p. 183:11-184:7.

[136] Staudt Report, p. 39.

would increase on a ton-per-year basis. Permitting will likely take a minimum of 12 months, and construction will not be able to commence until permits are received.

- Equipment suppliers are typically given 10-12 weeks to prepare and submit a bid. The bid evaluation process typically takes 2-4 months depending on the number of technical and commercial exceptions taken by the bidders. The overall duration for specification preparation, bid submittal, bid evaluation, and final award takes a minimum of 9 months.
- Detailed engineering begins immediately upon award of the WFGD and chimney contracts. BOP engineering proceeds concurrently, and includes design of connecting ductwork, booster ID fan, foundations, structural steel, auxiliary power system, piping system with pipe-racks, etc.
- The AE will prepare a general work contract (GWC) specification upon completion of approximately 75% of the BOP engineering, and obtain a firm price bid on construction of WFGD and BOP equipment. This process takes approximately 4-5 months. Award of the GWC typically coincides with completion of the chimney shell such that other construction activities (e.g., absorber) can commence.
- Remaining WFGD and BOP construction activities typically take an additional 24-months.
- Commissioning of the WFGD subsystems (i.e., reagent preparation, gypsum dewatering, wastewater treatment, and byproduct disposal) starts as soon as construction is complete. Because there are multiple subsystems, commissioning typically takes approximately 3-4 month.
- Process tuning of the WFGD system, primarily the absorber system and the secondary dewatering system, typically takes an additional 3 months to complete due to the slow response of the various system parameters. Once the system is tuned and operating, a performance test takes place to ensure all performance guarantees are met. At this point, the WFGD is considered to be operational.

Figure 10. Typical Project Schedule for WFGD



As Dr. Staudt notes in his expert report, starting in 2008 Ameren commissioned a number of FGD conceptual studies and cost estimates.[137] Based on the results of these studies, on or around April 2010 Ameren made the decision to proceed with a more detailed evaluation of a WFGD system designed for PRB fuel only.[138] Technical feasibility studies and financial analyses prepared as part of the technology selection process would precede the decision to proceed date referenced in Figure 10. Therefore, the work done by Ameren prior to focusing on WFGD would not shorten the overall WFGD project schedule.

Once Ameren selected WFGD for further evaluation as a technology for SO_2 control on Rush Island Units 1 and 2, Ameren authorized the preparation of conceptual design studies, cost estimates, and preliminary construction and balance-of-plant specifications for the WFGD system. Construction specifications were prepared for the WFGD control system at Rush Island.[139] These specifications provide the design criteria and code requirements a general work contractor would follow to install foundations, structural steel, piping systems, electrical equipment, and similar systems associated with the WFGD control system, and to integrate the WFGD into the existing unit.[140] A mini-specification was also prepared for the WFGD system (i.e., absorber island) to obtain budgetary pricing from control system vendors.[141] Conceptual design studies and specification preparation are activities that would occur as part of Item No. 2 and the initial part of Item No. 3 shown in the schedule (i.e., during the initial 6-months of the WFGD project).

However, as I noted above, any AE engaged to restart the WFGD project would not rely on the previously prepared specifications, which would have been completed approximately 10-years earlier. Operating parameters, design parameters, code requirements, design assumptions, and equipment layouts and redundancy would all have to be reviewed, confirmed, and brought up to date. Previously prepared specifications would have to be revised to reflect current industry standards and codes, and to ensure accuracy of the specification prior to issuing for bid. In my opinion, having access to the previously prepared specifications may provide a benchmark against which design and operating parameters could be

[137] Staudt Report, p. 35.

[138] See, BV2_0065644

[139] See, BV2-0204942 and BV2-0205101.

[140] BV2-0204942.

[141] AM-REM-00194661.

confirmed, but would not reduce specification preparation time by any meaningful amount. Given the potential liabilities associated with the design, construction, and operation of a complex air pollution control system on a large coal-fired steam electric generating unit, the AE would thoroughly review and confirm all design and operating parameters and code requirements to ensure the specification reflects current industry standards.

5. Critique of Dr. Staudt's Analysis of SO_2 Control Technologies Available to Ameren's Labadie Station

In addition to evaluating retrofit control technologies available for Rush Island Units 1 and 2, Dr. Staudt evaluated a range of SO_2 control options for Ameren's Labadie Station. The Labadie Station, located approximately 30 miles west of St. Louis in Franklin County, Missouri, consists of four coal-fired steam-electric generating units. Each unit has a steam turbine generator with a summer capacity of approximately 594 MW and winter capacity of approximately 616 MW (Labadie Units 1-4). Each unit is equipped with electrostatic precipitators (ESPs) for particulate matter control and activated carbon injection (ACI) for mercury control.

SO_2 control options evaluated by Dr. Staudt included DFGD, WFGD, and DSI at two control levels (i.e., DSI at 50% control with the exiting ESPs and DSI at 70% control with retrofit fabric filter particulate control systems). Dr. Staudt evaluated the installation of retrofit SO_2 controls on Labadie Units 1-4 as a single project (i.e., assuming all four control units would be installed at the same time).[142] For the DFGD option, Dr. Staudt used costs from the 2009 Black &Veatch study, scaled to the associated megawatt output. WFGD costs developed by Dr. Staudt were based on the same studies used for the Rush Island BACT analysis (i.e., 2010 Shaw Cost Study), with the total capital cost adjusted for capacity and for the economies of scale associated with a larger total project.[143] Dr. Staudt used EPA's Integrated Planning Model (IPM) cost algorithms to establish a relative cost between different-sized WFGD retrofit projects and establish an

[142] Staudt Report, p. 64.

[143] Ibid.

"economies of scale" factor, ranging from one to four units.[144] Capital costs for the DSI options were generated directly from the IPM cost algorithms.

In my opinion, the approach used by Dr. Staudt results in inaccurate capital cost estimates for the installation of SO_2 controls on Labadie Units 1-4 for the following reasons:

1. Adjusting the Rush Island cost estimates based solely on capacity fails to take into consideration significant space constraints at Labadie and underestimates control system costs at Labadie Units 1-4.
2. The approach used by Dr. Staudt to account for economies of scale at Labadie is not accurate, as the IPM cost algorithms were developed based on an analysis of cost data for controls installed on individual units.
3. The IPM cost algorithms Dr. Staudt relied on to develop the DSI and FF capital cost estimates do not take into consideration site-specific constraints and do not provide unit-specific capital costs.

5.1 Using Rush Island WFGD and DFGD Cost Estimates as a Basis for Labadie Capital Cost Estimates Does Not Consider Space Constraints at the Station and Underestimates Retrofit Control System Costs

To generate capital costs for the DFGD and WFGD options, Dr. Staudt scaled costs developed for the Rush Island facility based on capacity (i.e., megawatts). Specifically, Dr. Staudt used costs from the 2009 Black &Veatch study for the DFGD option, and costs from the 2010 Shaw Cost Study for the WFGD option, adjusting both cost estimates by removing AFUDC, Corporate Overhead, and Property Taxes. In my opinion, due to significant space constraints at the Labadie Station, adjusting the Rush Island costs based solely on capacity fails to take into consideration significant space constraints at Labadie and underestimates control system costs.

As an initial comment, I incorporate comments from Section 4.1.2 of this report addressing the inclusion of certain indirect capital costs, including AFUDC, Corporate Overhead, and Property Taxes, into a cost estimate prepared to evaluate the relative cost-effectiveness of competing control technology options. For the reasons stated in Section 4.1.2 it is my opinion that these costs represent real costs that Ameren would incur to install control systems on Labadie Units 1-4, and are properly included in a control system cost

[144] Ibid.

estimate and cost-effectiveness evaluation. By arbitrarily removing these line items from the capital cost estimates, Dr. Staudt significantly underestimated WFGD and DFGD retrofit costs.

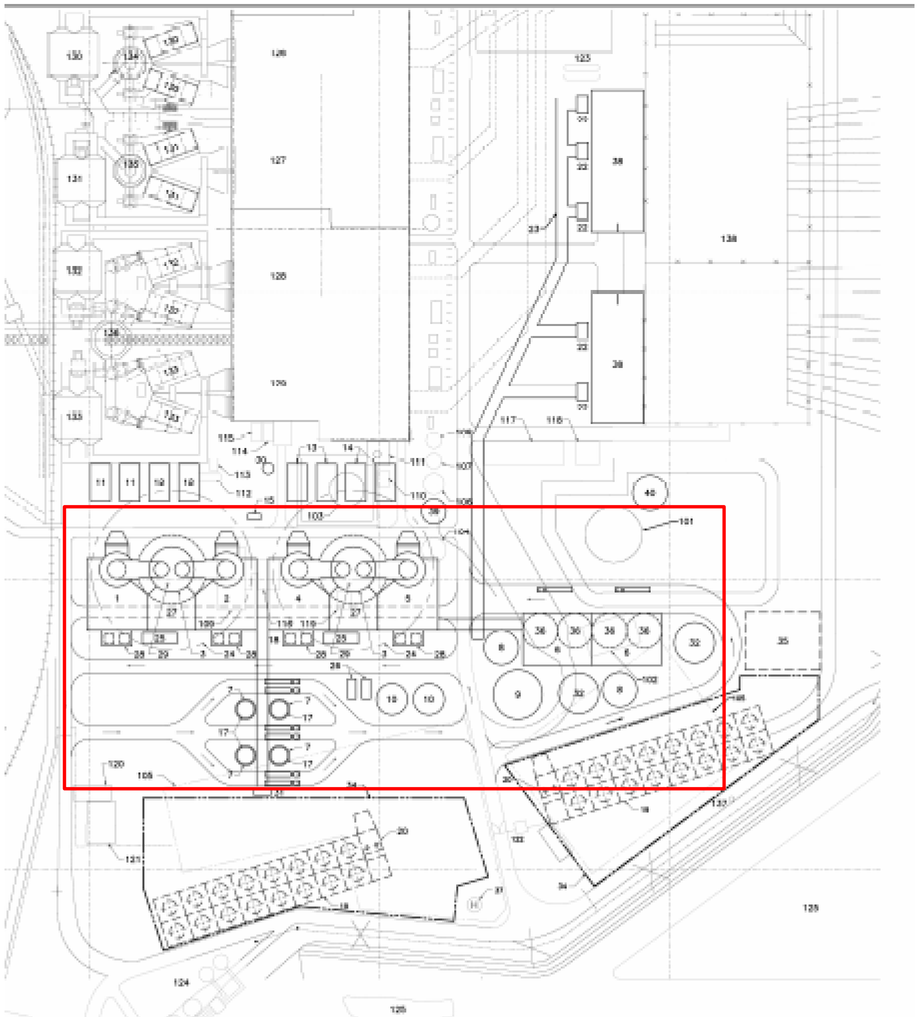
With respect to space constraints at the Labadie Station, Figure 24 in Dr. Staudt's report shows the location of Labadie Units 1-4, including the existing ESPs and exhaust stacks, but fails to show the significant site constraints surrounding the generating units. Figure 11 shows the location of the Labadie generating units in relation to existing features which limit expansion towards the north, east, and west. Labadie Units 1-4 are bordered to the north by the Missouri River, to the west by the facility's coal yard, and to the east by the existing boiler buildings.

Figure 11. Labadie Generating Station and Surrounding Area

Retrofit control systems could not be located in the vicinity of the existing ESPs and exhaust stacks. The only reasonably accessible location for the WFGD option would be to locate the absorber vessels south of the existing Unit 4 generating building, approximately 800 feet from the existing Unit 1 ESP. The location of the absorber vessels (outlined in red) and associated equipment is shown on the conceptual general arrangement drawings developed by Black & Veatch, shown in Figure 12.[145]

[145] BV2_0197934 at BV2_0198012 and BV2_0198013.

Figure 12. WFGD Conceptual Arrangement Drawing Labadie Units 1-4



Similarly, the DFGD reaction vessels and FF would have to be located south of the Unit 4 generator building, approximately 800 feet from the Unit 1 ESP. In addition, given the distance from the existing exhaust stacks to the new control system, the DFGD project would likely include new exhaust stacks located south of the Unit 4 building rather than redirecting the flue gas back to the existing stacks, adding significant costs to the DFGD system.

Conceptual general arrangement drawings for the retrofit WFGD controls at Labadie can be contrasted with the conceptual general arrangement drawings for control systems at Rush Island where the absorber vessels could be located adjacent to the existing ESPs.[146] Space constraints at the Labadie Station would require significant ductwork, require additional equipment demolition and relocation, and have a significant impact on both equipment and installation costs. Adjusting the Rush Island cost estimates based solely on capacity fails to account for these site-specific space constraints and underestimates retrofit control system costs at Labadie.

5.2 The Approach Used by Dr. Staudt to Account for Economies of Scale Associated with Installing Four WFGD Control Systems at Labadie is Based on an Inappropriate use of the EPA IPM Cost Algorithms

Dr. Staudt used EPA's IPM cost algorithms, developed by Sargent & Lundy, to establish a relative cost between different-sized WFGD projects at Labadie, ranging from one to four units.[147] The "Sargent & Lundy algorithm" identified in his report refers to cost algorithms developed by Sargent & Lundy to support EPA's IPM.[148] As the basis for his economies of scale adjustment, Dr. Staudt simply changed the unit size (i.e., 598 MW, 1,196 MW, and 2,392 MW) in the cost worksheet and compared total project cost on a $/kW basis. Based on this approach, Dr. Staudt concluded that, on a $/kW basis, WFGD on one unit would be roughly 20% more expensive than a wet scrubber on two units, which would be about 20% more expensive than WFGD on all four units.[149] For reasons discussed below, it is my opinion that this is an incorrect application of the IPM cost modules, and does not accurately reflect the economies of scale that may be realized on a larger project.

Cost algorithms developed by Sargent & Lundy for the IPM model were developed based on a least-squares curve-fit analysis of publically available cost data from control system retrofit projects.[150] Although the cost algorithms do reflect economies of scale that may be realized when installing controls on larger units,

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[146] BV2_0116857 at BV2_0118214.

[147] Staudt Report, p. 64.

[148] More specifically, Dr. Staudt references the "IPM Model – Updates to Cost and Performance for APC Technologies, Wet FGD Cost Development Methodology," dated March 2013.

[149] Staudt Report, p. 65.

[150] IPM Model – Updates to Cost and Performance for APC Technologies, Wet FGD Cost Development Methodology," dated March 2013., p. 1.

using the IPM cost algorithms to evaluate economies of scale for multiple units at a single facility is flawed for the following reasons:

1. The IPM cost algorithms are not set up to generate a cumulative cost for multiple units, but rather an order-of-magnitude cost for a typical project scope for a single unit.
2. By using a cumulative unit load (i.e., 2,392 MW instead of 4 x 598 MW units), total capital costs would be significantly underestimated and would not reflect the costs of installing multiple control system trains on multiple units rather than a single large control system.
3. This is particularly true for WFGD control systems, as the IPM model is set up to estimate capital costs based on a single absorber vessel. By using a cumulative unit load, the cost generated would be for a single absorber vessel treating flue gas from multiple units, which is not how the WFGD systems would be designed at Labadie.
4. The IPM cost algorithms are not designed to generate costs for units larger than approximately 1,000 MW as cost data used to develop the algorithms were based on historical industry pricing information, and very few control systems have been installed on individual units greater than approximately 1,000 MW.

Sargent & Lundy's IPM cost estimating methodology report notes that SO_2 reductions could be accomplished on small units (i.e., less than approximately 100 MW) by treating emissions in a single control system.[151] However, this approach has not been used in the power industry to treat flue gas from multiple large units, such as those at the Labadie Station. In cases where FGD controls are installed on multiple units at the same station, the control system would be designed with individual flue gas treatment equipment (i.e., absorber vessels and gas path equipment), and larger common support systems, such as reagent preparation and dewatering. Any potential economy-of-scale savings associated with installing multiple control systems at the same station would only apply to the common support systems.

Furthermore, installing a single large absorber vessel to treat multiple units would limit the overall turndown capability of the system, increase the risk that equipment failure would cause multiple units to de-rate or shutdown, and would be very challenging to control and operate due to changing operating conditions from multiple units. Increasing the total number of units relying on a single system would require a higher level of redundancy to ensure that equipment failures do not limit operation of multiple units. The need for increased redundancy would likely offset any economy of scale associated with the common support systems.

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[151] Ibid.

Capital costs calculated using a cumulative unit load would not reflect the costs of installing multiple control system trains on multiple units, and does not provide an accurate estimate of the economy of scale that may be realized when installing control systems on larger units.

5.3 Actual Capital Cost for WFGD at Labadie

I revised Dr. Staudt's WFGD cost estimate to include all indirect capital costs Ameren would incur to install WFGD on Labadie Units 1-4. For this evaluation, costs for these indirect capital cost line items were estimated based on the $/kW value from the Rush Island capital cost estimate (see, Column A of Table 8) multiplied by the Labadie generating rate of 2,390 MW. I also added back in the economies of scale discount Dr. Staudt assumed using the IPM cost ratios discussed in Section 5.2. Adjustments to Dr. Staudt's WFGD cost estimate for Labadie Units 1-4 are shown in in Table 13.[152]

Table 13. Comparison of Dr. Staudt and S&L WFGD Capital Cost Estimate at Labadie (2016$)

Line Item	Staudt Analysis (2016$)	S&L Adjustments (2016$)
Adjustment for Property Tax(Note 1)	--	$44,128
Adjustment for Corporate Overhead(Note 1)	--	$72,576
Adjustment for AFUDC(Note 1)	--	$222,130
Adjustment for Escalation(Note 1)	--	$132,841
Adjustment for Economies of Scale(Note 2)	--	$204,004
Retrofit WFGD Total Capital Cost, $1000	$929,352(Note 3)	$1,605,031

Notes:

1. Adjustments for Property Tax, Corporate Overhead, AFUDC, and Escalation were based on the $/kW costs generated for the Rush Island WFGD cost estimate (see, Column A of Table 8) multiplied by the total Labadie generating rate of 2,390 MW.
2. The adjustment for Dr. Staudt's calculation of an economies of scales savings was calculated by adding back in the 18% reduction assumed by Dr. Staut: ($929.352M/0.82) - $929.352M = $204M
3. Dr. Staudt's Cost Analysis_20180302.xlsx workbook applied the CECPI factor of 0.93 twice to his calculation spreadsheet (Rows D 41 and D22).

By removing certain indirect capital costs and incorrectly applying an economy of scale factor, it is my opinion that Dr. Staudt underestimated the total capital investment required to install WFGD controls on

[152] Ken Snell Cost Analysis_Labadie.xlsx workbook.

all four Labadie units, including support facilities, by at least $675.5 million (2016$). Furthermore, cost adjustments summarized in Table 13 do not include the unit specific scope items such as advanced wastewater treatment that will likely be required for the WFGD control system, nor do they include the extensive ductwork that would be required at Labadie due to site congestion. As an example, installing WFGD on Labadie Unit 1 would require approximately 800 feet of ductwork which would increase the cost of the WFGD control system by approximately $26 million. Even with these adjustments, the cost figure above is likely conservatively low. In any event, even expressed in 2016 dollars, the cost for WFGD at all four Labadie units would be at least $1.631 billion.

5.4 Using IPM Cost Algorithms to Generate Capital Costs for DSI does not account for Site-Specific Constraints

Dr. Staudt used the IPM cost algorithms to estimate capital costs of the DSI control options, including DSI at 50% control with the existing ESPs and DSI at 70% with retrofit FF control systems. The IPM cost algorithms were developed by Sargent & Lundy to support U.S. EPA's Clean Air Markets Division's (CAMD) work on the development of regulatory programs. The intended purpose of the IPM cost algorithms is to provide generic order-of-magnitude costs for various air-pollution control technologies that EPA can apply on a system wide analysis of the electric power generating industry. IPM-generated costs can be used to compare compliance alternatives on a system wide basis, but do not, and are not intended to, provide costs for any individual project.

By necessity, the IPM cost algorithms are designed to require minimal information that is available from publicly available sources. Given the limited number of unit-specific inputs needed to generate IPM costs, the algorithms do not take into consideration site-specific costs or constructability issues and limitations, and are not intended to estimate costs for a specific unit.

As noted in Sargent & Lundy's DSI control cost development methodology report, capital costs for DSI control are established based on an estimated sorbent feed rate.[153] The DSI IPM model calculates a sorbent feed rate based on a limited number of user input variables, including Unit Size (gross MW); Gross Heat

[153] S&L, *IPM Model – Updates to Cost and Performance for APC Technologies, Dry Sorbent Injection for SO_2 Control Cost Development Methodology,* Final, March 2013, p. 2.

Rate (Btu/kWh); Inlet SO_2 Design Rate (lb/MMBtu); and SO_2 Removal Efficiency (% within specified ranges).[154] However, as described in Section 3.1.2 of this report, the NS Ratio and sorbent feed rate needed to achieve a target SO_2 removal efficiency, can vary significantly from unit to unit, and must be determined based on demonstration tests conducted at site-specific operating conditions. Because IPM-generated costs are based on an assumed sorbent feed rate, actual control system costs could vary significantly, and should be determined based on unit-specific operating conditions.

Similarly, Dr. Staudt used Sargent & Lundy's IPM cost algorithm to calculate the capital cost of a retrofit fabric filter baghouse for the 70% DSI control option.[155] Dr. Staudt calculated a total capital cost of approximately $101.5 million per unit for the retrofit fabric filter systems.[156] However, again, Dr. Staudt arbitrarily removed AFUDC and Owner's Costs from the capital cost estimate, and escalated costs for 2012 to 2016 using the CEPC Index. I incorporate comments from Sections 4.1.1 and 4.1.2 to support my opinion that these costs should be included in a capital cost estimate for large retrofit air pollution control projects, and that the CEPC Index is not representative of cost escalation in the utility industry. Adjustments to Dr. Staudt's fabric filter cost estimate are shown in Table 14.[157]

Table 14. Comparison of Dr. Staudt and S&L DSI/FF Capital Cost Estimate at Labadie (2016$)

Parameter	Staudt Analysis (2016$)	S&L Adjustments (2016$)
Adjustment for Owner's Cost	--	$23,283
Adjustment for AFUDC	--	$48,894
Adjustment for Escalation	--	$79,706
Retrofit Capital, $1000	$431,484	$583,367

Finally, by using the IPM cost algorithms to calculate retrofit fabric filter costs, Dr. Staudt failed to account for significant site constraint issues at the Labadie Station. As discussed in Section 5.1, the retrofit fabric filter control systems would have to be located south of the existing Unit 4 generating building,

[154] Ibid.

[155] Staudt Report, p. 64.

[156] AMEREM_JES0000001, S&L algorithms worksheet, cell Z37.

[157] Ken Snell Cost Analysis_FGD Labadie.xlsx workbook.

approximately 800 feet from the existing Unit 1 ESP. It is also possible that new chimneys would be required at the location of the new fabric filters otherwise hundreds of feet of additional ductwork would be required to tie the fabric filters back into the existing chimneys. These site-specific constraints would significantly add to the cost of retrofit fabric filters at Labadie, and are not accounted for in the IPM cost algorithms, and are not included in the cost adjustments in Table 14.

By removing certain indirect capital costs, including AFUDC, Owner's Cost and applying an incorrect escalation, it is my opinion that Dr. Staudt underestimated the total capital investment required for the DSI with FF project, including support facilities, by at least $150,000,000.[158] The costs above do not include the unit specific scope items such as the extensive ductwork associated with locating the fabric filters south of the Unit 4 boiler building, potential fly ash handling system upgrades to handle the increase solids that would be collected in the ESP, nor do they include costs for new chimneys.

Dr. Staudt also underestimated the DSI only (without fabric filter) project, including supporting facilities by at least $20,000,000 as shown in Table 15 below.[159] Again, these costs below do not include unit specific scope items that could increase the cost beyond those shown in Table 15.

[158] Id.

[159] Id.

Table 15. Comparison of Dr. Staudt and S&L DSI Capital Cost Estimate at Labadie (2016$)

Parameter	Staudt Analysis (2016$)	S&L Adjustments (2016$)
Adjustment for Owner's Cost	--	$2,953
Adjustment for AFUDC	--	$6,201
Adjustment for Escalation	--	$10,109
Retrofit Capital, $1000	$54,723	$73,985

5.5 Dr. Staudt's Evaluation of SO_2 Control Options at Labadie Does Not Include Evaluation of Potential Non-Air Quality Collateral Environmental Impacts that Could Affect the Feasibility of Available SO_2 Control Options

Dr. Staudt's evaluation of SO_2 control technologies available to the Labadie Station was limited to an evaluation of control system costs and cost-effectiveness. However, all four SO_2 control systems covered in his evaluation (i.e., WFGD, DFGD, DSI/FF, and DSI) have significant non-air quality collateral environmental impacts that need to be evaluated on a case-by-case basis to ensure that installation and operation of the technology does not result in unacceptable collateral environmental impacts.

As discussed in Section 3.5, increased loading to the ESPs does not necessarily result in increased PM emissions, as the sodium-based sorbents tend to decrease PM resistivity and increase ESP collection efficiency. Nevertheless, these issues should be investigated more thoroughly when evaluating the technical feasibility of available control alternatives.

There are also potentially significant collateral environmental impacts associated with the WFGD and DFGD control options. For example, both control options have significant auxiliary power requirements. Increased auxiliary power requirements will adversely impact the net plant heat rate and reduce overall efficiency of the units. Emissions of other air pollutants, including NO_X, CO, VOC, PM, PM_{10}, and CO_2 will increase on a lb/MW-net basis.

Both FGD options also generate significant quantities of solid waste that must be properly managed and disposed. WFGD systems generate a calcium sulfate waste byproduct that must be properly managed. While most new WFGD systems utilize a forced oxidation system that results in a salable gypsum byproduct, if an adequate local gypsum market is not available, the gypsum byproduct will require proper disposal. Dry scrubbers are located upstream of the unit's particulate control device. DFGD solids mixed with fly ash will be captured in the particulate control device. The mixture of DFGD solids and fly ash is generally not salable; however, the material does not require dewatering and can be landfilled.

Both wet and dry FGD systems also require significant amounts of water. Assuming a water consumption rate of 1 gpm/MW,[160] WFGD installed on all four Labadie units would increase water requirements at the facility by approximately 1,006 million gallons per year (based on an 80% capacity factor). Water consumption with a dry system is approximately 20% less than the water requirements for a wet system; nevertheless, DFGD installed on all four Labadie units would increase water requirements at the facility by approximately 805 million gallons per year. WFGD control systems also generate a wastewater stream that must be treated and discharged. Water treatment requirements could be significant, and will result in increased wastewater discharges, and require modifications to the facility's NPDES wastewater discharge permit.

All of the potential collateral environmental impacts described above could add to the cost of and reduce the feasibility and practicality of potentially available control options for SO_2 control at Labadie.

[160] Reduction of Water Use in Wet FGD Systems _ netl.doe.gov

6. Information Required by Federal Rules of Civil Procedure

The information required by Federal Rules of Civil Procedure is provided below in the appendixes below.

6.1 Appendix A – Kenneth J. Snell CV

Education and Areas of Practice and Expertise:

John Marshall Law School, Chicago, IL
Juris Doctorate, cum laude
January 1994

University of Illinois at Chicago, Chicago, IL
B.S. Chemical Engineering, with honors
December 1984

University of Kansas, Lawrence, KS
B.A. Environmental Studies
January 1980

- National Environmental Policy Act
- Clean Air Act
- Clean Water Act
- Air Pollution Control Technologies, including NOx, SO_2, particulate matter, hazardous air pollutant, and greenhouse case control strategies
- Environmental Compliance and Enforcement
- Resource Conservation and Recovery Act
- Comprehensive Environmental Response, Compensation, and Liability Act (Superfund)
- Threatened and Endangered Species Act
- Complex Environmental Permitting

Expertise and experience in both the regulatory and technical aspects of:

- **Counseling clients on Clean Air Act compliance** at electric power generating facilities, including compliance auditing, Title V permitting and permit modifications, New Source Review (NSR) applicability assessments, Prevention of Significant Deterioration (PSD) major source permitting, air pollution control technology evaluations, control technology costs and cost-effectiveness evaluations, and strategic compliance planning.
- **Providing regulatory and technical support** to clients during the regulatory development process by drafting formal regulatory interpretations and policy analyses, drafting comments, responding to agency requests for information, providing oral/written testimony at public hearings, and providing support during the regulatory appeals process.
- **Preparing complex permit applications for major industrial projects,** including major source air permits, wastewater discharge permits, and solid waste management and disposal permits.
- **Developed and presented professional training courses** designed to introduce engineers and environmental professionals to the fundamentals of Environmental Law, Federal Environmental Regulations, Environmental Impact Statements, Administrative Law Procedures, Environmental Compliance, the Clean Air Act, Clean Water Act, and related regulations.

Professional Experience

2000 to Present Sargent & Lundy LLC, Chicago, IL
Senior Manager – Environmental Technologies and Licensing

- Mr. Snell is an environmental engineer and regulatory specialist with more than 30 years' experience in environmental permitting, compliance, and controls. Since joining Sargent & Lundy, Mr. Snell's work has focused on environmental issues affecting the electric power generating industry, including priority pollutant air emissions and emission control technologies, greenhouse gas emissions and control strategies, wastewater treatment and discharge permitting, solid waste management and disposal, and cooling water intake environmental impacts and intake technologies.

  Mr. Snell manages Sargent & Lundy's Environmental Technologies and Licensing group. In this capacity, he is responsible for directing a group of engineers and environmental specialists in the evaluation and implementation of federal and state regulatory initiatives, developing environmental compliance strategies, air pollution control technology assessments and cost-effectiveness evaluations, and control technology design and specifications. His responsibilities include reviewing existing and proposed power plant projects for compliance with the numerous environmental rules and regulations, and managing project teams in preliminary engineering and design of air pollution control retrofit projects, specification and procurement of control systems, and project implementation.

  Mr. Snell has prepared complex environmental permit applications for multiple projects, including New Source Review (NSR) construction air permit applications for new major stationary sources of air emissions, as well as major modifications to existing sources. He has prepared Best Available Control Technology (BACT) determinations for the control of NOx, SO_2, CO, PM/PM10/PM2.5, and VOC emissions from coal- and gas-fired electric generating units, as well as BACT determinations for the control of greenhouse gas (GHG) emissions fossil fuel based steam electric generating units.

  As the manager of Sargent & Lundy's Environmental Technology and Licensing Group, Mr. Snell's responsibilities include providing support and guidance to cross-functional project teams responsible for key project development functions including initial site assessment studies, due diligence evaluations, regulatory policy analyses, conceptual engineering and design, technology selection, permitting/licensing, and public outreach. Mr. Snell has assisted a number of clients develop and implement long-term compliance strategies; and advised clients and provided technical support during the regulatory review process, permitting process, enforcement proceedings, and permit appeals process.

1988 – 1999 Safety-Kleen Corp. Elgin, IL
Environmental Compliance Manager / Associate Environmental Counsel

- Prior to joining Sargent & Lundy, Mr. Snell was employed as an Environmental Manager and Associate Environmental Counsel for Safety-Kleen Corp., a leading hazardous waste management company. In this capacity, Mr. Snell was responsible for corporate legal matters primarily concentrating on developing environmental management systems to ensure compliance with the Resource Conservation and Recovery Act (RCRA) and Comprehensive Environmental Response, Compensation, and Liability Act (CERCLA). He prepared numerous RCRA Part-B permit applications for hazardous waste treatment, storage, and disposal

(TSD) facilities throughout the U.S., and implemented internal environmental auditing programs to ensure compliance with applicable hazardous waste management and disposal regulations. Other responsibilities included negotiating settlement agreements (Consent Orders and Administrative Orders) involving alleged violations of federal and state environmental regulations; drafting asset acquisition documents; and participating on Superfund potentially responsible party (PRP) defense groups and advising corporate management of potential off-site liabilities.

Selected Projects:

- **CPV Three Rivers Energy Center:** New nominal 1,200 MW combined-cycle generating facility (Illinois)

  Environmental permitting including, major source Prevention of Significant Deterioration (PSD) and non-attainment New Source Review permitting, Best Available Control Technology (BACT) and Lowest Achievable Emission Rate (LAER) control technology evaluations; greenhouse gas (GHG) BACT analysis, alternatives analysis, and support during the public review process.

- **Confidential Client:** NGCC Power Plant Siting Study

  Comprehensive siting study for a new nominal 800 MW natural gas combined-cycle facility located in the Midwest. Siting study included an evaluation of potential air quality impacts, availability of water resources, wastewater discharge impacts, social and Environmental Justice issues, and environmental permitting requirements.

- **J-Power Development USA Jackson Energy Center:** New nominal 1,200 MW NGCC generating facility (Illinois)

  Environmental permitting including major source PSD and non-attainment NSR permitting, BACT and LAER control technology evaluations, GHG BACT analysis, emission off-sets, alternatives analysis, and support during public review process

- **Entergy** – White Bluff Units 1 and 2 DFGD Study (Arkansas)

  Participated in the preliminary engineering and design of a retrofit DFGD control systems on White Bluff Units 1 and 2. Tasks included technology assessment and comparison of circulating dry scrubber (CDS) and spray dryer absorber (SDA) technologies; reviewing material balance and design criteria, and reviewing control system design specifications.

- **Confidential Client (**Existing Coal-Fired Power Plant) - Compliance Audit and Compliance Planning

  Comprehensive environmental compliance audit of an existing coal-fired electric generating facility, focusing on compliance with existing air regulations. Project included an evaluation of potential impacts from recently published environmental regulations, including the Cross State Air Pollution Rule, revised National Ambient Air Quality Standards (NAAQS), Effluent Limitation Guidelines, Coal Combustion Residuals Rule, and Clean Power Plan. Worked with the client to develop long-term strategic compliance plan.

- **Dynegy:** Zimmer Power Station (Ohio)

  Coordinated the preparation of a mercury discharge variance application for the Zimmer Power Station. Project included an evaluation of the Ohio Administrative Code to determine the appropriate regulatory mechanism for the variance request.

- **Basin Electric Power Cooperative -** Laramie River Generating Station (Wyoming)

  Prepared New Source Review (NSR) applicability determinations for the installation of nitrogen oxide (NOx) control technologies on existing coal-fired generating units, including emission impacts associated with selective catalytic reduction (SCR) and selective non-catalytic reduction (SNCR) controls. Participated in the preliminary engineering, design, and procurement of the SNCR control system.

- **Salt River Project:** Santan Generating Station Public Hearing (Arizona).

  Prepared and presented comprehensive NOx emission control technology evaluation for an existing natural gas combined-cycle generating station, and a provided testimony at public hearing required by the Arizona Corporation Commission.

- **Montana-Dakota Utilities:** Lewis & Clark Generating Station (Montana)

  Provided air permitting support for new 9 MW Reciprocating Internal Combustion Engine (RICE). Support included NSR applicability determination, control technology evaluation, and Title V Operating Permit modification.

- **Basin Electric Power Cooperative:** Lonesome Creek and Pioneer Generating Stations (North Dakota)

  Prepared the major source PSD air construction permit applications for two nominal 150 MW natural gas-fired electric generating stations located in North Dakota. Support included BACT evaluations, negotiating permit conditions, and providing oral testimony at public hearings before the North Dakota Department of Health and Environment.

- **Petra Nova:** Carbon Capture TPDES Permitting (Texas)

  Coordinated the preparation of a Texas Pollutant Discharge Elimination System (TPDES) permit application for the Petra Nova carbon dioxide (CO_2) capture project in Texas. Project included wastewater characterization, establishing discharge limits, and negotiating permit limits.

- **Portland General Electric** – Boardman Station FGD Study (Oregon)

  Participated in the preliminary engineering, design, and procurement of a dry sorbent injection (DSI) system for a 640 MW steam electric generating unit firing low-sulfur PRB coal. Tasks included developing a preliminary control technology evaluation and cost-effectiveness assessment; developing preliminary capital and O&M costs for the DSI system; and providing input to, and reviewing, the technical specification for the DSI system.

- **Regional Haze Rulemaking and Implementation – Various Clients**

  Provided technical and regulatory support to assist numerous clients with the development and implementation of their Regional Haze State Implementation Plans and/or Federal Implementation Plans. Support included a review of available nitrogen oxide (NOx) and sulfur dioxide (SO_2) control technologies, control technology effectiveness, costs, and preparation of facility-specific Best Available Retrofit Technology (BART) evaluations. Provided written comments on proposed rules and agency-generated technical support documents, as well as written and oral testimony at public hearings and during the appeals process. Provided regional haze rulemaking support for clients located in Wyoming, Arizona, New Mexico, Navajo Nation, Texas, Nebraska, Oklahoma, Louisiana, and Arkansas.

- **New Source Review Applicability Determinations – Various Clients**

  Prepared comprehensive New Source Review (NSR) evaluations for proposed modifications to existing major stationary emission sources to determine and document applicability of the NSR permitting regulations. Evaluations have been submitted for agency review in the states of Wyoming, Louisiana, Minnesota, Arkansas, Texas, Washington, and Utah.

- **American Electric Power:** Flint Creek, Northeastern, Pirkey, and Welsh Generating Stations - Permitting Support for Retrofit Air Pollution Control Technologies (Texas and Oklahoma)

  Provided environmental permitting support for the installation and operation of advanced air pollution control systems at the AEP generating stations listed above for compliance with the Mercury and Air Toxics Standard (MATS). Control technologies included fabric filter baghouses, electrostatic precipitator (ESP) to baghouse conversions, activated carbon injection, and dry sorbent injection.

- **NV Energy:** Reid Gardner and North Valmy Generating Stations - MATS Compliance Evaluations (Nevada)

  Prepared comprehensive MATS compliance evaluations for NV Energy's coal-fired generating stations, including an applicability evaluation and an assessment of air pollution control technologies available to control mercury, acid gas, and non-mercury trace metal emissions.

- **PacifiCorp:** Wyoming Generating Stations – MATS Compliance Evaluations and Technologies (Wyoming)

  Prepared comprehensive MATS compliance evaluations for PacifiCorp's coal-fired generating stations in Wyoming, including an applicability evaluation and an assessment of air pollution control technologies. Assisted in the design, specification, procurement, and installation of activated carbon injection (ACI) and fuel additive systems on four units.

- **Confidential Client:** Wind Powered Generation **-** Nominal 130 – 200 MW utility wind farm

  Provided regulatory and technical support for siting and permitting a new wind powered electric generating facility. Identified applicable federal, state and local permitting requirements, coordinated the preparation of numerous pre-construction environmental reviews and assessments, including Avian Impact Studies, Bat Impact Studies, Radar and Microwave Impact Studies, and Noise Impact Assessments.

Regulatory Support:

- Provided expert regulatory and technical support in the preparation of comments for three major Texas utilities on the Proposed Texas Regional Haze Federal Implementation Plan (82 Fed. Reg. 912, January 4, 2017, Docket: EPA-R06-OAR-2016-0611).
- Prepared comment addressing specific provisions of the Proposed Texas Regional Haze Federal Implementation Plan, prepared and submitted on behalf of Sargent & Lundy LLC (82 Fed. Reg. 912, Docket: EPA-R06-OAR-2016-0611), May 5, 2017.
- Declaration of Kenneth J. Snell in Support of Motion to Stay Final Rule of the U.S. Environmental Protection Agency by Entergy Arkansas, Inc. and the State of Arkansas, et al. v. U.S.EPA, U.S. Court of Appeals for the Eight Circuit, No. 17-1283 (Arkansas Regional Haze Federal Implementation Plan, 81 Fed. Reg. 66332).
- Provided expert technical and regulatory support on behalf of Basin Electric Power Cooperative to support client's comments on the Proposed Wyoming Regional Haze Federal Implementation Plan (77

Fed. Reg.58570, September 21, 2011, Docket No, EPA-R08-OAR-2012-0026). Provided oral testimony at a public hearing held by U.S.EPA regarding the proposed Regional Haze FIP, Casper, WY July 2013.

- Prepared Expert Report on behalf of Duke Energy (Cinergy Corp.), United State of America et al. v. Cinergy Corp, et al., U.S. District Court for the Southern District of Indiana, Civil Action No. IP99-1698 (New Source Review Enforcement Action).
- Provided expert technical and regulatory support on behalf of Public Service Company of New Mexico (PNM) to support client's appeal of the New Mexico Regional Haze Federal Implementation Plan (76 Fed. Reg. 52388, August 22, 2011, Docket No, EPA-R06-OAR-2010-0846), and negotiation of a Term Sheet Agreement between PNM, the State of New Mexico, and U.S.EPA (Tenth Circuit Court of Appeals, Nos. 11-9557 – 11-9567).
- Prepared comment addressing specific provisions of the Proposed Carbon Pollution Emission Guidelines for Existing Stationary Sources: Electric Utility Generating Units (Clean Power Plan), prepared and submitted on behalf of Sargent & Lundy LLC (79 Fed. Reg. 34830, Docket No. EPA-HQ-OAR-2013-0602), August 2014
- Provided expert regulatory and technical support on behalf of Basin Electric Power Cooperative to establish Settlement Agreement terms between Basin, the State of Wyoming, and U.S.EPA; In re: Wyoming et al. v. U.S.EPA, Tenth Circuit Court of Appeals, Nos. 14-9529, 14-9530, and 14-9534 (appeal of the Wyoming Regional Haze Federal Implementation Plan).
- Prepared technical evaluation of the feasibility, effectiveness, and costs of post-combustion selective catalytic reduction (SCR) NOx controls at Salt River Project's (SRP's) Coronado Generating Station to support client's challenge to the Arizona Regional Haze Federal Implementation Plan (77 Fed. Reg. 72512, December 5, 2012); client's Petition for Reconsideration (Docket No. EPA-R09-OAR-2012-0021); and to implement Consent Decree terms and conditions (United States of America v. Salt River Project Agricultural Improvement and Power District, U.S. District Court for the District of Arizona, Civil Action No. 2:08-cv-1479-JAT).
- Provided Declaration and Expert Report on behalf of Oklahoma Gas & Electric (OG&E) in its appeal of the Oklahoma Regional Haze Federal Implementation Plan (Oklahoma Industrial Energy Consumers and OG&E v. U.S. EPA, U.S. Court of Appeals for the Tenth Circuit, Nos. 12-9526 and 12-9527).
- Provided expert technical and regulatory support on behalf of Nebraska Public Power District (NPPD) in its preparation of comments on the Proposed Nebraska Regional Haze Federal Implementation Plan, (77 Fed. Reg. 12770, March 2, 2012, Docket No. EPA-R07-OAR-2012-0158).
- Provided expert testimony (written) before the Kentucky Public Utility Commissions on behalf of Big Rivers Electric Corporation, Environmental Compliance Study, February 2012.
- Prepared expert report and analysis of Basin Electric Power Cooperative's Dry Fork Station Power Plant; In the Matter of Basin Electric Power Cooperative Dry Fork Station, Air Permit CT-4631, Before the Environmental Quality Council of the State of Wyoming, June 2008 (Best Available Control Technology).
- Provided Expert Testimony; In Re: Roundup Power Project (Permit No. 3182-00) – Montana Environmental Information Center and Environmental Defense, Petitioners, before the Montana Board of Environmental Review, June 2003. (Issues included BACT controls for new coal-fired power plant, case-by-case MACT, and alternative generating technologies).

6.2 Appendix B – Kenneth J. Snell Publications List - Past 10 Years

> Panelist, Environmental Mega-Session – Compliance in a New Era, 19th Annual Electric Power Conference & Exhibition, April, 11, 2017, Chicago, IL. Session explored the strategies needed to effectively navigate the environmental regulations impacting the fossil fuel power industry, and likely scenarios for the future of Greenhouse Gas Emissions, Coal Combustion Residuals Rule, Effluent Limitation Guidelines, and other regulations.

> Sargent & Lundy LLC - Power Plant Fundamentals, *Introduction to Federal Environmental Laws and their Applicability to Electric Power Generating Industry*, (2012 – present):

- Fundamentals and Development of Federal Environmental Laws
- Introduction to the National Environmental Policy Act
  - Federal Actions and Environmental Impact Statements
- Introduction to the Clean Air Act
  - National Ambient Air Quality Standards
  - New Source Performance Standards
  - National Emission Standards for Hazardous Air Pollutants
  - New Source Review and Best Available Control Technologies
- Introduction to the Clean Water Act and Waters of the U.S.
  - Point Source Discharge
  - National Pollutant Discharge Elimination System

> K.J. Snell, *Fundamentals of the Administrative Procedures Act and the Environmental Rule-Making Process*, March 7, 2017

> Sargent & Lundy LLC webinar: *§316(b) Compliance Planning & Implementation*, prepared and presented by Kenneth Snell, August 2016

> Snell, K.J., *Greenhouse Gas Emission Limitations under the Clean Power Plan - Case Study of the Mass-Based and Rate-Based Compliance Options Under 40 CFR Part 62 (80 Fed. Reg. 64966),* December, 2015

> Sargent & Lundy LLC webinar: *EPA's Clean Power Plan – Planning for Compliance*, prepared and presented by Kenneth Snell October 2015

> Snell, K.J., *Understanding the Supreme Court's Ruling on the Mercury and Air Toxics Standard (MATS)*, June 29, 2015

> Snell, K.J., *Plantwide Applicability Limits and Greenhouse Gas Emissions*, Energy, Utility and Environment Conference (EUEC) 2014, Phoenix, AZ, February 3-5, 2014

> Snell, K.J., *Regional Haze Rule Update - 2014*, Energy, Utility and Environment Conference (EUEC) 2014, Phoenix, AZ, February 3-5, 2014

> Snell, K.J., *Consideration of CO_2 Emissions in a New Source Review Air Permit Application*, Power-Gen 2008, Orlando, FL, December 2-4, 2008

> Snell, K.J., *Consideration of Greenhouse Gas Emissions in a New Source Review Air Permit Application*, Electric Power Conference & Exhibition 2008, Baltimore, MD, May 5-8, 2008

> Snell, K.J., *Permitting New Coal-Powered Generation: Best Available Control Technologies – What Will Technology Support*, Electric Power Conference & Exhibition 2007, Rosemont, IL, May 1-3, 2007

6.3 Appendix C – Kenneth J. Snell Expert Witness Testimony Experience - Past 4 Years

> None

6.4 Appendix D – Documents Considered in Preparing this Expert Report

- ADA-Environmental Solutions, Inc., *TOXECON™ Retrofit for Multi-Pollutant Control on Three 90-MW Coal-Fired Boilers, Topical Report: Performance and Economic Assessment of Trona-Based SO_2/NO_X Removal at the Presque Isle Power Plant* (Aug. 25, 2008).
- Advatech Proposal for Rush Island AQCS (BV2_0105034).
- Alstom Power, *Results from ESP-upgrades, Including Control Systems*, (undated).
- AMEREM_JES0000001.
- AMEREM_JES0000002.
- Ameren – Rush Island – Unit 1 Inspection Report.
- Ameren – Rush Island – Unit 2 Inspection Report.
- Ameren Comments on Technology Selection Report Rush Island Plant (BV2_0103649).
- Ameren Missouri Rush Island and Labadie FGD Retrofit; Labadie Plant Draft System Study (BV2_0197934).
- Ameren Missouri, *2017 Integrated Resource Plan*.
- B&V Comment Log for Rush Island FGD Execution Plan & Report (AM-REM-00277956).
- B&V DRAFT FGD EPC Specification 01600 for Rush and Labadie (BV2_0204942).
- B&V DRAFT FGD EPC Specification 01600 for Rush and Labadie (BV2_0205101).
- B&V Phase I report, Rev. 1 (BV2_0003012).
- B&V Rush Island FGD Execution Plan & Report (BV2_0112682).
- B&V Rush Island FGD Execution Plan & Report Rev 1 (BV2_0116857).
- B&V Rush Island FGD Execution Plan & Report Rev 1 Project Flow Diagram (BV2_0065027).
- B&V Rush Island FGD Project Environmental Permitting Assessment (BV2_0005747).
- B&V Rush Island FGD Project Environmental Permitting Assessment Draft (BV2_00297218).
- Deposition of Christopher Stumpf and exhibits thereto (March 27, 2018).
- Deposition of Dr. James E. Staudt and exhibits thereto (March 1, 2018).
- Deposition of Ed Dimitry 30(b)(6) and exhibits thereto (May 1, 2013).
- Deposition of Gregory Macias 30(b)(6) and exhibits thereto (May 1, 2013).
- Deposition of James L. Williams 30(b)(6) and exhibits thereto (Nov. 7, 2017).
- Deposition of Matthew Kahal (Feb. 28, 2018).
- Deposition of Thomas P. Callahan and exhibits thereto (Nov. 8, 2017).

- E3-Handy-Whitman Northcentral Tables.xlsx.
- Effluent Limitations Guidelines and Standards for the Steam Electric Power Generating Point Source Category, 80 Fed. Reg. 67838 (Nov. 3, 2015) (to be codified at 40 CFR Part 423).
- ENR Tables.xlsx.
- EPA, *Performance and Cost of Mercury Emission Control Technology Application on Electric Utility Boilers*, prepared by National Risk Management Research Laboratory, EPA-600-R-00-083 (Sept. 2000).
- EPRI, *An Assessment of Mercury Emissions from U.S. Coal-Fired Power Plants*, Technical Report 1000608 (Oct. 2000).
- Expert Report of Dr. James E. Staudt, (Dec. 15, 2017, as amended March 7, 2018) (including work papers).
- Expert Report of Matthew I. Kahal (Dec. 15, 2017).
- Horn, J., *Upgrading Your ESP Performance*, Power Engineering (Mar. 16, 2015).
- Institute of Clean Air Companies (ICAC), *Dry Sorbent Injection for Acid Gas Control: Process Chemistry, Waste Disposal and Plant Operational Impacts* (July 2016) https://c.ymcdn.com/sites/icac.site-ym.com/resource/resmgr/white_papers/ICAC_Industrial_DSI_Ancillar.pdf.
- Institute of Clean Air Companies (ICAC), *Dry Sorbent Injection of Sodium Sorbents by Solvay Chemicals*, Emission Control and Measurement Workshop (March 24-25, 2010).
- Karl B. Schnelle, Jr. and Charles A. Brown, *Air Pollution Control Technology Handbook* (Florida: CRC Press, 2002).
- Krystal Perez et.al., *FGD Technology Evaluation for Two Similar Power Plants Leads to Different Solution*, International Water Conference, 2017, IWC-17-73, Florida.
- MDNR, Division of Environmental Quality, Water Protection Program, *Missouri Antidegradation Implementation Procedure* (July 13, 2016).
- *New Hampshire Clean Air Project Final Report, Prepared for: New Hampshire Public Utilities Commission*, Jacobs Consultancy (Sept. 10, 2012).
- New Source Review (NSR) Workshop Manual, *Prevention of Significant Deterioration and Nonattainment Area Permitting* (October 1990) https://www.epa.gov/sites/production/files/2015-07/documents/1990wman.pdf.
- *OAQPS, Control Cost Manual: Electrostatic Precipitators*, EPA/452/B-02-001 (September 1999).
- Project Plan for FGD Retrofit at Rush Island (AM-REM-00294505).
- Robert Mastropietro, *Fly Ash Resistivity with Injected Reagents and Predicted Impacts on Electrostatic Precipitators* (“Cottrell”).
- Robert Wylie et al., *Duke Energy Carolina LLC’s Strategy and Initial Experience of FGD Waste Water Treatment Systems*, International Water Conference, IWC-08-32 (Oct. 2008).
- Rush Island FGD Progress Overview (AM-REM-00289173).
- Rush Island Generating Station Dry Sorbent Injection Test Program Draft Report (Sept. 23, 2011) (AM-REM-00196411).
- Rush Island Generating Station Dry Sorbent Injection Test Program (AME-0167580).

- Rush Island Power Plant FGD Project Execution Plan and Report (BV2_0116857).
- Rush Island Units 1 & 2 PM 30 Day Rolling Average Data 2015 – 2017.xlsx.
- S&L, *IPM Model – Updates to Cost and Performance for APC Technologies, Dry Sorbent Injection for SO_2 Control Cost Development Methodology*, 2 (Mar. 2013).
- Sargent & Lundy (S&L), *IPM Model – Updates to Cost and Performance for APC Technologies, Wet FGD Cost Development Methodology* (Mar. 2013).
- *See* Yougen Kong and Michael Wood, *Dry Injection of Sodium Sorbents for Air Pollution Control*, environmental Engineer 21 (2011) https://epd.georgia.gov/air/sites/epd.georgia.gov.air/files/related_files/document/solvayarticle.pdf.
- Shaw 2010 Cost Estimate, AM-REM-00294538.
- Shaw Ameren UE Rush Island FGD Description of Plant in support of December 2009 Estimate (AM-REM-00195079).
- Shaw Ameren UE Rush Island FGD Project Final Report (AM-REM-00194950).
- Shaw Attachment 1 (AM-REM-00191197).
- Shaw Description of Plant (AM-REM-00195079).
- Shaw Final Report (AM-REM-00194950).
- U.S. Department of Energy (DOE)/National Energy Technology Laboratory (NETL), NETL-2002/1160, *Integrated Dry NO_X/SO_2 Emissions Control System – A DOE Assessment* (Oct. 2001) https://www.netl.doe.gov/File%20Library/Research/Coal/major%20demonstrations/cctdp/Round3/IntegDryNOxSO2/netl1160.pdf.
- U.S. Environmental Protection Agency, *Air Pollution Control Technology Fact Sheet*, EPA-452/F-03-034, https://www3.epa.gov/ttn/catc/dir1/ffdg.pdf.
- U.S. EPA, *ESP Design Parameters and Their Effects on Collection Efficiency*, 2.0-2/98.
- U.S. EPA, *Monitoring by Control Technique - Electrostatic Precipitators*, https://www.epa.gov/air-emissions-monitoring-knowledge-base/monitoring-control-technique-electrostatic-precipitators#box3.
- U.S. EPA, Office of Air Quality Planning and Standards, *EPA Air Pollution Control Cost Manual*, Sixth Edition, EPA/452/B-02-001 (January 2002).
- USR Group, Inc., *Reduction of Water Use in Wet Flue Gas Desulfurization Systems*, https://www.netl.doe.gov/research/coal/crosscutting/environmental-control/water-and-energy-interface/power-plant-water-management/water-reuse--recovery/reduction-of-water-use-in-wet-fgd-systems.
- WFGD Technology Selection FGD Evaluation Rush Island Plant (AM-REM-00280265).
- Whitman, Requardt and Associates, LLP , *Handy-Whitman Index of Public Utility Electricity Construction Costs*, ISSN 1092-955X (2017).
- William M. Vatavuk, *Air Pollution Control Escalate Equipment Costs*, “Chemical Engineering,” (December 1995) http://infohouse.p2ric.org/ref/27/26839.pdf.
- William M. Vatavuk, *Updating the CE Plant Cost Index*, “Chemical Engineering,” (January 2002).

6.5 Appendix E – Kenneth J. Snell Compensation Rate for this Proceeding

For my work on this proceeding, Sargent & Lundy is being compensated at a rate of $265/hour.

ATTACHMENT 1 FOLLOWS

SARGENT & LUNDY DSI EXPERIENCE SUMMARY PRESENTATION

Sargent & Lundy LLC

Dry Sorbent Injection Experience and Qualifications

SO_2 Mitigation	SO_3/HCl Mitigation
28 Units	41 Units
>15,100 MW	>19,700 MW

Dry Sorbent Injection – SO_2 Mitigation

Client	Station-Unit	MW	Technology	Scope	Operation
Associated Electric	Chamois 2	50	DSI	Testing/evaluation	2015
Associated Electric	New Madrid 1	600	DSI	Testing/evaluation	2015
Associated Electric	New Madrid 2	600	DSI	Testing/evaluation	2015
Associated Electric	Thomas Hill 1	180	DSI	Testing/evaluation	2015
Associated Electric	Thomas Hill 2	300	DSI	Testing/evaluation	2015
Associated Electric	Thomas Hill 3	730	DSI	Testing/evaluation	2015
AEP	Northeastern 3	500	DSI	Design	2015
Confidential	Midwest U.S. 1 unit	600	DSI	Design/evaluation	2015
Confidential	Midwest U.S. 1 unit	600	DSI	Design/evaluation	2015
Confidential	Midwest U.S. 1 unit	200	DSI	Design/evaluation	2015
Confidential	Midwest U.S. 1 unit	325	DSI	Design/evaluation	2015
Confidential	1 unit	580	DSI	Design	2015
Confidential	1 unit	580	DSI	Design	2015
Confidential	1 unit	700	DSI	Design	2015

Dry Sorbent Injection – SO_2 Mitigation, cont.

Client	Station-Unit	MW	Technology	Scope	Operation
Confidential	1 unit	700	DSI	Design	2015
Confidential	1 unit	700	DSI	Design	2015
OG&E	Muskogee 4	570	DSI	Evaluation	2015
OG&E	Muskogee 5	570	DSI	Evaluation	2015
OG&E	Muskogee 6	570	DSI	Evaluation	2015
OG&E	Sooner 1	570	DSI	Evaluation	2015
OG&E	Sooner 2	570	DSI	Evaluation	2015
OG&E	Sooner 3	550	DSI	Evaluation	2015
OG&E	Sooner 4	550	DSI	Evaluation	2015
NRG Energy	Big Cajun II 1	580	DSI	Specification	2015
Portland General Electric	Boardman 1	600	DSI	Design/testing/evaluation	2014
Dairyland Power Cooperative	Madgett 6	405	DSI	Design	2014
Midwest Generation	Powerton 5	850	DSI	Design	2013
Midwest Generation	Powerton 6	850	DSI	Design	2013

Dry Sorbent Injection – SO_3/HCl Mitigation

Client	Station-Unit	MW	Technology	Scope	Operation
Confidential	1 unit	250	DSI	Testing/evaluation	2015
Duke Energy	Allen 1	165	DSI	Evaluation	2015
Duke Energy	Allen 2	165	DSI	Evaluation	2015
Duke Energy	Allen 3	275	DSI	Evaluation	2015
Duke Energy	Allen 4	275	DSI	Evaluation	2015
Duke Energy	Allen 5	275	DSI	Evaluation	2015
Duke Energy	Cayuga 1	515	ACI + DSI	Design/evaluation	2015
Duke Energy	Cayuga 2	515	ACI + DSI	Design/evaluation	2015
GenOn	Conemaugh 1	900	DSI	Design/evaluation	2015
GenOn	Conemaugh 2	900	DSI	Design/evaluation	2015
LG&E/KU	Ghent 1	500	DSI	Evaluation	2015
LG&E/KU	Ghent 3	500	DSI	Evaluation	2015
LG&E/KU	Ghent 4	500	DSI	Evaluation	2015
LG&E/KU	Mill Creek 3	500	DSI	Evaluation	2015

Dry Sorbent Injection – SO_3/HCl Mitigation, cont.

Client	Station-Unit	MW	Technology	Scope	Operation
LG&E/KU	Mill Creek 4	400	DSI	Evaluation	2015
LG&E/KU	Trimble County 1	500	DSI	Evaluation	2015
NRG Energy	Big Cajun 1	600	ACI + DSI	Testing/evaluation	2015
NRG Energy	Big Cajun 3	600	ACI + DSI	Testing/evaluation	2015
Owensboro Municipal	Elmer Smith 1	150	DSI	Evaluation	2015
Owensboro Municipal	Elmer Smith 2	290	DSI	Specification and Evaluation	2015
Indianapolis Power & Light	Petersburg 1	230	DSI	Design/evaluation	2015
Indianapolis Power & Light	Petersburg 2	410	DSI	Design/evaluation	2015
Indianapolis Power & Light	Petersburg 3	510	DSI	Design/evaluation	2015
Indianapolis Power & Light	Petersburg 4	575	DSI	Design/evaluation	2015
Oklahoma Gas & Electric	Sooner 1	569	ACI + DSI	Specification	2015
Oklahoma Gas & Electric	Sooner 2	569	ACI + DSI	Specification	2015
Oklahoma Gas & Electric	Muskogee 4	569	ACI + DSI	Specification	2015
Oklahoma Gas & Electric	Muskogee 5	569	ACI + DSI	Specification	2015

Dry Sorbent Injection – SO_3/HCl Mitigation, cont.

Client	Station-Unit	MW	Technology	Scope	Operation
Oklahoma Gas & Electric	Muskogee 6	569	ACI + DSI	Specification	2015
NV Energy	North Valmy 1	275	DSI	OE and Testing/evaluation	2014
Cleco	Rodemacher 2	550	ACI + DSI	Design/evaluation	2014
Cleco	Dolet Hills	700	ACI + DSI	Design/evaluation	2014
Tampa Electric	Big Bend 1	450	Ammonia	Design	2010
AEP	Amos 1	815	DSI	Design	2009
AEP	Cardinal 2	615	DSI	Design	2009
Lakeland Electric	McInttosh 3	365	DSI	Design	2009
Tampa Electric	Big Bend 2	450	Ammonia	Design	2009
AEP	Cardinal 3	650	DSI	Design	2008
Tampa Electric	Big Bend 3	450	Ammonia	Design	2008
Tampa Electric	Big Bend 4	450	Ammonia	Design	2007
Duke Energy	East Bend 2	650	ACI + DSI	Evaluation	Delayed