Public Comments on Proposed Revisions to the Air Pollution Control Cost Manual
Section 5
Chapter 1: Wet and Dry Scrubbers for Acid Gas Control

Contents

List of Commenters

The EPA published a Notice of Data Availability (NODA) in the Federal Register on August 5, 2020 announcing and soliciting comments on updates to Section 5, Chapter 1 – Wet and Dry Scrubbers for Acid Gas Control (hereafter referred to as the "draft chapter"), of EPA's *Air Pollution Control Cost Manual (*hereafter referred to as the "Cost Manual"). The updated chapter provides technology descriptions and cost estimation methodologies for several different types of gas absorbers, including three types of flue gas desulfurization (FGD) systems and wet packed tower gas absorbers. Comments were received from members of public and several trade associations representing the electric power and industrial sectors. Table 1 lists the individuals and organizations that submitted comments. The full comments can be found in the docket for the Cost Manual update at https://www.regulations.gov/document/EPA-HQ-OAR-2015-0341-0081/comment. This document provides a summary of the comments and EPA's responses.

Table 1: Summary of Commenters and Their Affiliations

Document Control Number	Commenter Name	Commenter Affiliation
EPA-HQ-OAR-2015-0341-0083	C. Doyle	None
EPA-HQ-OAR-2015-0341-0084	Reed Hitchcock, Executive Vice President	Asphalt Roofing Manufacturers Association (ARMA)
EPA-HQ-OAR-2015-0341-0085*	Anonymous	None
EPA-HQ-OAR-2015-0341-0086	Paul Noe, Vice President, Public Policy	American Forest & Paper Association (AF&PA), American Fuel & Petrochemical Manufacturers (AFPM), American Wood Council (AWC) and Council of Industrial Boiler Owners
EPA-HQ-OAR-2015-0341-0087**	Rae E. Cronmiller	National Rural Electric Cooperative Association (NRECA)
EPA-HQ-OAR-2015-0341-0088**	Carolyn Slaughter, Director of Environmental Policy	American Public Power Association (APPA)
EPA-HQ-OAR-2015-0341-0089	Debra J. Jezouit, Tiffany Cheung and Baker Botts	Class of '85
EPA-HQ-OAR-2015-0341-0090**	John D. Kinsman, Senior Director	Edison Electric Institute (EEI), American Power Association and the National Rural Electric Cooperative Association

*Comments provided are not summarized in this document as they were outside the scope of the NODA and provided no specific remarks on the chapter revisions and provided no substantive information on the costs or application of wet and dry scrubbers.

** These commenters submitted comments prepared by J. Edward Cichanowicz and Michael C. Hein for the American Public Power Association, Edison Electric Institute and National Rural Electric Cooperative Association.

1.0 Introduction

1.1 General Comments

Commenter: C. Doyle
DCN: EPA-HQ-OAR-2015-0341-0083

<u>Comment</u>: The commenter supported the revisions made to the chapter. The commenter noted that the data presented shows the applicability and effectiveness of scrubbers for the control of SO_2 and supports the use of wet FGD scrubbers and dry scrubbers as an effective method to reduce SO_2 emissions by many U.S. industries. The commenter said the updated chapter will be beneficial because the revised chapter provides more insight into the costs for installing, maintaining, and operating acid gas absorbers that is helpful to the community and industry.

The commenter also supported EPA's decision to rename the chapter from "Wet Scrubbers for Acid Gas" to "Wet and Dry Scrubbers for Acid Gas."

<u>Response</u>: The EPA agrees with the commenter that the revised chapter will provide more assistance to the regulated community and the public in evaluating the costs and potential control effectiveness of wet and dry scrubbers. The revised chapter includes cost and performance data for dry scrubbers as well as updated information for wet scrubbers used to control SO_2. As we noted in the NODA, dry scrubbers were not covered in the previous versions of this chapter, but have been included in the revised chapter to reflect the full range of wet and dry FGD scrubbers currently in use in the U.S.

Commenter: American Public Power Association
ID: EPA-HQ-OAR-2015-0341-0088

<u>Comment</u>: The commenter expressed their support for the revisions and said the draft chapter provides a useful tool for estimating the capital and annual costs for installation, operation, and maintenance of wet flue gas desulfurization (WFGD) and dry scrubbers. The commenter said they supported the EPA's efforts to update the Cost Manual and said the Cost Manual should provide a consistent methodology for estimating costs. The commenter further noted that the Energy Information Agency's (EIA) 2020 annual outlook predicts 127 gigawatts of coal-fired generation will be operating in 2050 and said these coal-fired units will need to be retrofitted with wet or dry scrubber technology to meet the best available retrofit technology (BART) under the Regional Haze Program and the next 8-year Residual Risk and Technology Review under section 112 of Clean Air Act.

<u>Response</u>: The EPA agrees with the commenter that the revised chapter will be useful to both industry and state and federal regulators for identifying and evaluating the potential control options for facilities that emit acid gases. However, it should be noted that the cost methodologies described in the updated chapter are designed to provide study-level (that is, ±30% accuracy) capital and operating cost estimates. Selection of the most cost-effective control options in the context of various regulatory programs should be based on a detailed engineering study that uses cost quotations from control device vendors.

Commenter: Class of ‘85
ID: EPA-HQ-OAR-2015-0314-0089

Comment: The commenter supported the revisions to the chapter and said that periodic updates to the Cost Manual ensure that it includes the most recent and best available data for evaluating the performance and costs of control options.

Response: The EPA agrees with the commenter. Periodic updates to the Control Cost Manual are essential to incorporate new technologies, address advances in existing technologies, and update performance capabilities and costs. The EPA has already updated several other chapters over the last five years and is scheduled to complete the Control Cost Manual update over the next three to four years. For online copies of the chapters that have been updated and information on the schedule for future updates, please see EPA’s Cost Reports and Guidance For Air Pollution Regulations website at https://www.epa.gov/economic-and-cost-analysis-air-pollution-regulations/cost-reports-and-guidance-air-pollution.

Commenter: Class of ‘85
ID: EPA-HQ-OAR-2015-0314-0089

Comment: The commenter recommended the EPA clarify the updates to the draft chapter should not be used in place of site-specific analyses. The commenter said the Cost Manual provides cost estimation methodologies standardized for industry-level analyses that are “nominally accurate to within ± 30%.” Such standardization, the commenter asserted, means that the Cost Manual has limited value because it does not and cannot account for site-specific information. The commenter noted that the EPA has acknowledged that the Cost Manual allows for “customization by industrial sources to provide more accurate assessment of control cost sizing and cost.” The commenter said they appreciate EPA’s recognition of the practical limitations of the Cost Manual. Consistent with the current version of Section 1, Chapter 1, “Background” of the Cost Manual, the commenter requested EPA clarify the performance and cost analyses for acid gas controls are intended to serve as guidance and should not override site-specific studies that depart from the Cost Manual’s generalized analyses. The commenter noted that site-specific issues that should be considered when estimating control costs for gas absorbers include space limitations, size or performance constraints of other equipment or ancillary facilities, other pollution control equipment, and limitations on resources (e.g., such as water, even for dry scrubbers). The commenter said that these factors can affect the cost of acid gas scrubbers and recommended site-specific costs should supersede the more generic costs estimated using the methodologies presented in the draft chapter.

Response: The EPA agrees with the commenter that, where available, cost estimates developed using site-specific information can be more accurate than those based on the estimation methods presented in the Cost Manual. The cost methodologies described in the updated chapter are designed to provide study-level capital and operating cost estimates, which is consistent with the accuracy of estimates for the other chapters in the Cost Manual. Selection of the most cost-effective control option should ideally be based on a detailed engineering study that uses cost quotations from control device suppliers and takes into consideration any site-specific factors. The cost estimation methodologies should be used and relied upon when cost quotations from control device vendors are not available or, if available, not credible.

Commenter: Asphalt Roofing Manufacturers Association, American Forest & Paper Association (AF&PA), American Fuel & Petrochemical Manufacturers (AFPM), American Wood Council (AWC) and Council of Industrial Boiler Owners
ID: EPA-HQ-OAR-2015-0341-0084 and EPA-HQ-OAR-2015-0341-0086

Comment: Referencing Section 1.2.1.3, some commenters noted that the draft chapter states that dry sorbent injection (DSI) is not considered a typical add-on control technology. The commenters disagreed, stating DSI can be added in front of an existing fabric filter or electrostatic precipitator as a lower cost option to a wet FGD system for reducing acid gas emissions. The commenters state that industrial facilities would find it helpful to have a methodology for estimating the capital and operating costs for DSI systems. They further noted that Sargent and Lundy have developed a methodology for utility boilers. The commenters recommended the Sargent and Lundy methodology for DSI systems be included in the draft chapter.

One commenter recommended the EPA review comments they previously submitted for EPA's technology review for the Asphalt Processing and Asphalt Roofing Manufacturing Residual Risk and Technology Review (RTR) (see 85 FR 18926) that evaluated DSI for controlling hydrogen chloride (HCl) emitted from blowing stills at asphalt processing facilities that use chlorinated catalysts. The commenter disagreed with the HCl emissions reduction rate for DSI/FF systems presented in EPA's analysis developed as part of the RTR.

Response: EPA decided not to include DSI in this chapter in order to focus on wet and dry scrubbers, and not include other available acid gas and SO_2 control technologies. However, EPA plans to develop a new chapter that focuses on DSI for inclusion in the 7th edition of the Manual. Work on the new chapter is expected to begin later in 2021. For more information on the planned updates and schedule, please see the timeline for updating chapters published on our Website: https://www.epa.gov/sites/production/files/2021-01/documents/epaccmupdateschedule_jan2021vf.pdf.

1.2 General Comments on Cost Estimates

Commenter: American Forest & Paper Association (AF&PA), American Fuel & Petrochemical Manufacturers (AFPM), American Wood Council (AWC) and Council of Industrial Boiler Owners
ID: EPA-HQ-OAR-2015-0341-0086

Comment: In Section 1.2.5.4, the capital costs in the example assume the installation is completed using multiple lump sum contracts. The commenters said that costs for turnkey contracts, where the project price is fixed at the time a construction contract is signed, may be 10% to 15% higher than those calculated using the IPM equations.

Response: EPA agrees with the commenter that turnkey contracts where the price is fixed at the time a contract is signed may be more expensive where the vendor undertakes responsibility for the completion of the entire project, including any costs associated with unexpected delays and other unforeseen construction and operational problems. We also agree that the documentation for the IPM equations indicates they are based on lump-sum contracts rather than on turnkey contracts. Sargent and Lundy, who developed the IPM equations states in their documentation for their FGD scrubber calculations that a turnkey engineering procurement construction (EPC) contract would have capital costs of between 10 and 15% higher than estimated. However, we have not made any changes to the equations as they are developed based on multiple lump sum contracts and are intended to provide study-level cost estimates that can be used to compare the costs of different air pollution control and assess their cost effectiveness.

For wet FGD systems, we made the following changes to the second paragraph in Section 1.2.4.3, with new language in **bold**:

"The IPM **equations** estimate~~s~~ the purchased equipment cost and the direct and indirect installation costs ~~together~~ based on ~~data collected from several data sources, including wet FGD systems.~~ **cost data for multiple lump-sum contracts. Turnkey contracts where the price is fixed at the time the contract is signed and the contractor undertakes responsibility for the completion of the project, are generally 10 to 15% higher than multiple lump-sum contracts."**

We also added the following paragraph to the end of Section 1.1 (Introduction) for additional clarification:

"The cost methodologies presented provide study-level estimates of capital and annual costs, consistent with the accuracy of estimates for other control technologies included in the Cost Manual. These methodologies can be used to compare the approximate costs of different scrubber designs. Actual costs may differ from those estimated using these methodologies due to site-specific factors and type of contracting agreements. Where more accurate cost estimates are needed, we recommend capital and operating costs be determined based on detailed design specifications and extensive quotes from suppliers."

Commenter: Asphalt Roofing Manufacturers Association
DCN: EPA-HQ-OAR-2015-0341-0084

Comment: The commenter cited comments it previously submitted to EPA regarding the technology review for the proposed Asphalt Processing and Asphalt Roofing Manufacturing Residual Risk and Technology Review (RTR) (see 85 FR 18926)[1] in which the costs of wet scrubbers were evaluated for control of hydrogen chloride (HCl) emitted from blowing stills at asphalt processing facilities that use chlorinated catalysts. The commenter said that the cost methodology does not adequately account for certain site-specific engineering and other costs associated with cold (sub-freezing) weather design.

Response: EPA acknowledges that installation of wet scrubbers in regions that experience extreme temperatures is a factor that potentially could increase the capital and operating costs for some facilities. We have included a new chapter table (Table 1.1) that summarizes the advantages and disadvantages of using wet versus dry scrubbers in which we note that freezing is a concern for these systems. We also noted that additional capital costs and operating costs relative to other SO_2 control technologies is a disadvantage of using a wet scrubber system. However, we do not currently have data quantifying the additional capital and operating costs for wet scrubbers installed in areas where low winter temperatures are experienced.

[1] The reference to the Federal Register notice is not correct. The actual citation for this proposed RTR is 84 FR 18926 (May 2, 2019).

1.2.1 Allowance for Funds Used During Construction (AFUDC)

Commenter: Class of '85, American Public Power Association, Edison Electric Institute and National Rural Electric Cooperative Association
ID: EPA-HQ-OAR-2015-0314-0089, EPA-HQ-OAR-2015-0341-0087, EPA-HQ-OAR-2015-0341-0088, and EPA-HQ-OAR-2015-0341-0090

Comment: Commenters disagreed with how the indirect costs for engineering and construction management, labor adjustment for extended work shifts, and contractor profit and fees are calculated. The commenters stated that all indirect and AFUDC costs should be included in the calculation of total capital investment (TCI). The commenters disagreed with using the overnight cost method described in Section 1, Chapter 2 (Cost Estimation: Concepts and Methodology) of the Cost Manual for projects such as scrubbers, that take several years to plan, engineer, and install. The commenters said that excluding AFUDC and owner's costs for engineering, management, and procurement underestimates costs, particularly for projects that require significant financing and time to install. One commenter estimated that AFUDC can be between $30 to $60 million for scrubber installations that take more than a year to install. Other commenters said the owner's costs are typically 5 percent of total capital and AFUDC can be up to 10 percent of the entire project charge. The commenters said that excluding AFUDC and owner's costs for engineering, management and procurement may be appropriate for short-term, lower capital cost projects, but is not appropriate for longer-term projects that require high capital investment. The commenters said that these costs were not optional and that excluding them makes the control equipment appear more cost-effective and makes it impossible to compare costs for scrubbers with less costly, shorter-term control installations. The commenters also noted that Sargent & Lundy's methodology includes AFUDC costs.

The commenters recommended the EPA allow companies to include AFUDC and owner's costs when estimating TCI, especially for projects requiring significant capital and construction time. One commenter noted that for standard accounting and rate-making purposes, AFUDC is treated as part of capital costs and argued that including these costs would ensure better estimates of costs in future regulations, where it is essential the costs of controls are accurately evaluated to determine which control devices are feasible and cost-effective.

Response: The EPA disagrees with the commenter. This question is not one that is specific to cost estimation for wet and dry scrubbers, but is a question on the cost methodology employed for the entire Control Cost Manual. While AFUDC is a cost that is often included in the costs reported by a regulated utility to the regulatory body that sets its electric rates, the reporting of such a cost is not consistent with the Control Cost Manual's cost methodology, which estimates overnight capital costs. Overnight capital costs are expressed as base year dollars (2016 dollars, for instance, in this chapter) and estimated as if no interest is incurred during construction, or the construction occurs "overnight." Hence, AFUDC is not an allowable cost under this cost methodology. More information on the overnight cost estimation methodology can be found in the cost estimation methodology for the Control Cost Manual (Section 1, Chapter 2).

For owner's costs, those costs are often already part of the indirect installation costs that are to be calculated in the Control Cost Manual cost methodology. For example, start up and permitting costs, which are often considered as costs incurred by the owner in a typical EPC project that are not turnkey in nature, are items included in the indirect installation costs. Land is often included in owner's costs, and that is a separate item within the estimation of capital cost as defined in the Control Cost Manual's methodology. Thus, the inclusion of owner's costs in a capital cost estimate may double-count costs already accounted for in the Manual's cost methodology. Any inclusion of owner's costs in a cost estimate that is to follow this methodology must be carefully defined to avoid double-counting.

1.2.2 Taxes

Commenter: Class of '85, American Public Power Association, Edison Electric Institute and National Rural Electric Cooperative Association
ID: EPA-HQ-OAR-2015-0314-0089, EPA-HQ-OAR-2015-0341-0087, EPA-HQ-OAR-2015-0341-0088, and EPA-HQ-OAR-2015-0341-0090

Comment: Commenters disagreed with EPA's assumption that taxes should be zero. The commenters said that the costs in the proposed chapter should rely on the generally applicable methods of calculation presented by EPA in the Chapter "Cost Estimation: Concepts and Methodology". The commenter noted that the EPA recommends property taxes be calculated as 1% of total capital investment (TCI), overhead as 60% of the sum of labor costs and maintenance materials costs, insurance as 1% of total capital investment, and administrative charges as 2% of total capital investment. The commenters requested the draft chapter be revised so that it is consistent with the indirect cost calculation methodology provided in Section 1, Chapter 1 "Cost Estimation: Concepts and Methodology" of the Cost Manual.

Response: The estimate for property tax as 1% of TCI is only applicable if the purchase of land is required as part of the construction of the pollution control and is therefore not to be included in the TCI if no land purchase is necessary. The same is true for the inclusion of overhead, insurance, and administrative charges if these can be demonstrated to be necessary. The presumption of zero for these cost items in the capital cost estimates for wet and dry scrubbers is based on available information to the Agency, and we did not receive any information from this comment, or other comments, to contradict this presumption. This presumption of a cost of zero for these capital cost items is identical to that included in the methodology for estimating costs in the SCR and SNCR chapters in the Control Cost Manual. For wet packed tower scrubbers that are covered later in the chapter, these capital cost items may not be zero, and the standard factors for these cost items are included in the cost methodology for these controls.

1.2.3 Wastewater Treatment

Commenter: Asphalt Roofing Manufacturers Association, American Public Power Association, Edison Electric Institute and National Rural Electric Cooperative Association
ID: EPA-HQ-OAR-2015-0341-0084, EPA-HQ-OAR-2015-0341-0088, EPA-HQ-OAR-2015-0341-0087, EPA-HQ-OAR-2015-0341-0088, and EPA-HQ-OAR-2015-0341-0090

Comment: The commenters said the wastewater treatment capital and operating cost components (Equations 1.18 and 1.26) for wet FGD systems may underestimate cost. The commenters said the wastewater treatment costs appeared to be low compared to the costs cited in the 2019 ELG Supplemental Technical Development Document (see Technical Development Document for the Effluent Limitations

Guidelines and Standards for the Steam Electric Power Generating Point Source Category, EPA-821-R-15-00, September). Commenters said that wastewater treatment costs of $10.6 million estimated for a 500 MW unit is significantly below the cost projected using the 2019 EPA ELG Supplemental Technical Development Document for the same wastewater flow rate and unit generating capacity (see Sections 5.2.3 and 5.2.4. of the 2019 ELG Supplemental Technical Document). The commenter noted that the 2019 document describes the cost for two categories of wastewater treatment processes - chemical precipitation and biological treatment using low residence time reduction (LTRT). The capital cost for chemical pretreatment and LTRT ranges between $23-25M (million), depending on whether the solids separated are disposed on-site or off-site.

The commenters also said that the chapter does not indicate whether the costs presented in the draft chapter cover facilities participating in the Voluntary Incentive Program (VIP) for the treatment of flue gas desulfurization wastewater. The VIP was established in the Effluent Limitations Guidelines and Standards for the Steam Electric Power Generating Point Source Category (ELGs), which became effective on January 4, 2016.

One commenter cited comments they previously submitted to EPA for the technology review for the proposed Asphalt Processing and Asphalt Roofing Manufacturing Residual Risk and Technology Review (RTR) (see 85 FR 18926)[2] that evaluated wet scrubbers for control of hydrogen chloride (HCl) emitted from blowing stills at asphalt processing facilities equipped with chlorinated catalysts. The commenter disagreed with the wastewater disposal cost of $0.0054 per gallon used in the analysis because they believe it underestimates current costs for wastewater treatment and disposal. The commenter said that the cost estimate should have included costs for wastewater pre-treatment that would be needed before disposal to a publicly owned treatment works (POTW). The wastewater characteristics should be used to determine wastewater treatment requirements and disposal costs. For example, the scrubber wastewater will contain chlorides, have high alkalinity (pH) and solids which would not meet sewer discharge standards. The commenter said that on-site treatment would include pH neutralization and particle filtration, and possibly chemical treatment and dilution before disposal to a POTW. The commenter noted that other substances (e.g., oily condensed organic vapors) would further increase on-site treatment costs and could indicate the need for offsite wastewater disposal as hazardous waste. For this reason, the commenter said that costs for an on-site wastewater pre-treatment system (filtration, pH treatment, concentration, or dilution) or disposal as hazardous waste (due to high pH) should be included in the estimate of capital and operating costs for wet scrubbers used to control emissions from asphalt blowing stills.

Response: The EPA Office of Water published technology-based effluent limitations guidelines and standards (ELGs) for the steam electric power generating point source category in 2015 (see 80 FR 67837, November 3. 2015) that included ELGs for FGD wastewater discharged either directly to surface water or to a POTW (see 40 CFR part 243). The rule includes ELGs for both new sources (greenfield) and existing sources. As noted by the commenters, the EPA revised 2015 ELGs for FGD wastewater at existing plants in 2020 (see 85 FR 64650, October 13, 2020). Wastewater generated by wet FGD systems are subject to numeric effluent limitations on mercury, arsenic, selenium, and nitrate/nitrite as nitrogen. The final rule also includes a Voluntary Incentives Program that allows existing plants to adopt additional process changes and controls that achieve more stringent limitations on mercury, arsenic, selenium,

[2] The reference to the Federal Register notice is not correct. The actual citation for this proposed RTR is 84 FR 18926 (May 2, 2019).

nitrate/nitrite, bromide, and total dissolved solids. Plants that select the Voluntary Incentives Program have until December 31, 2028 to comply.

The ELGs for existing sources were based on chemical precipitation followed by biological treatment with filtration as a final polishing step. For the chemical precipitation pretreatment step, chemicals are added to help remove suspended and dissolved solids, particularly metals. The precipitated solids are then removed from solution by coagulation/flocculation, followed by clarification and/or filtration. The chemical precipitation uses a specific design that employs hydroxide precipitation, sulfide precipitation (organosulfide), and iron coprecipitation to remove suspended solids and to convert soluble metal ions to insoluble metal hydroxides or sulfides.

In the biological treatment step microorganisms are used to treat the FGD wastewater after it leaves the chemical precipitation processes. The 2015 rule focused on a high residence time biological reduction system that uses anoxic/anaerobic fixed-film bioreactors with a residence times of approximately 10 to 16 hours. For the 2020 amendments, EPA included in the revised ELGs for existing plants low hydraulic residence time reduction (LRTR) biological treatment, which is a biological treatment system that targets removal of selenium and nitrate/nitrite using fixed-film bioreactors in smaller, more compact reaction vessels than those used in the high residence time biological treatment system evaluated in the 2015 rule. The LRTR system is designed to operate with a shorter residence time (approximately 1 to 4 hours), while still removing significant volumes of selenium and nitrate/nitrite. The LRTR technology with chemical precipitation as a pretreatment stage and ultrafiltration as a polishing step was selected as the technology-basis for the revised ELGs for existing plants in the 2020 amendments.

For new plants and existing plants complying with the Voluntary Incentive Program, the ELGs were based on thermal evaporation that uses a falling-film evaporator (or brine concentrator). Following a softening pretreatment step, thermal evaporation systems produce a concentrated wastewater stream and a distillate stream, which reduce the volume of wastewater by 80 to 90 percent. The process also reduces the discharge of pollutants. The concentrated wastewater is usually further processed in a crystallizer, which produces a solid residue for landfill disposal and additional distillate that can be reused within the plant or discharged. These systems are designed to remove the broad spectrum of pollutants present in FGD wastewater to very low effluent concentrations.

As part of the 2020 final rulemaking, EPA collected capital and operating costs and prepared cost curves that relate the costs for chemical pre-treatment and the LRTR biological treatment system to the FGD wastewater flow rate. EPA updated the wastewater treatment cost in the draft scrubbers chapter to be consistent with the cost equations from the 2020 rulemaking.

The average FGD wastewater flow rate of 0.4 gpm/MW was used to develop new equations for estimating the capital and operating costs of the wastewater treatment system required to meet the ELG for an existing facility. For example, for a 500-MW unit, the wastewater treatment system would be designed to handle 200 gpm of FGD wastewater.

The FGD wastewater flow rate, F, is estimated as:

$$F = A \times 0.4 gpm/MW$$

For plants with onsite landfills, the capital costs for chemical pretreatment, LRTR biological treatment and ultrafiltration can be estimated using the following equation:

$$WWT_{cost} = (41.36\ F + 11{,}157{,}588) \times RF \times 0.898$$

The annual operating costs are estimated:

$$\text{Annual Wastewater Treatment Cost} = (4.847\ F + 479{,}023) \times 0.958 \times CF$$

For plants without onsite landfills, the capital costs for chemical pretreatment, LRTR biological treatment and ultrafiltration can be estimated using the following equation:

$$WWT_{cost} = (41.16\ F + 11{,}557{,}843) \times RF \times 0.898$$

The annual operating costs are estimated:

$$\text{Annual Wastewater Treatment Cost} = (6.3225\ F + 472{,}080) \times 0.958 \times CF$$

Where F is the maximum FGD wastewater flow rate and CF is the plant capacity factor, allowing for adjustment of the operating costs for utility boilers that are not operated year round.

The capital costs for the chemical pre-treatment include:

- Purchased Equipment Costs, including pumps, tanks and mixers, reactors, chemical feed systems, clarifiers, filter presses, sand filters, and pollutant monitoring and analysis (including a mercury analyzer).
- Direct Capital Costs, including purchased equipment (including fabricated equipment and process machinery), freight, installation, instrumentation, and controls (installed), piping (installed), electrical (installed), buildings (including services) and site preparation.
- Indirect Capital Costs, including engineering and supervision, construction expenses, contractor's fees, and contingency.

The capital costs for the biological treatment system include:

- Purchased Equipment Costs, including anoxic/anaerobic bioreactors, control skids, backwash skids, tanks, pumps, heat exchanger, pretreatment system (for denitrification at applicable plants), ultrafilter, chemical feed skids, and pollutant monitoring and analysis (including a mercury analyzer).
- Direct Costs, including purchased equipment (including fabricated equipment and process machinery), freight, instrumentation, and controls (installed), piping (installed), electrical (installed), buildings (including services), and site preparation.
- Indirect Costs, including engineering and supervision and contingency.

The capital cost equations for the biological treatment system assume the nitrate/nitrite concentrations of the FGD wastewater are less 50 mg/L. The annual operating costs include operating labor, maintenance materials and labor, chemicals, energy, sludge transportation and disposal.

In addition to updating the capital and operating costs for FGD wastewater treatment, we also added a new subsection to section 1.2.4.1 that discusses the types of pollutants, wastewater regulations and wastewater treatment methods for FGD wastewater.

Commenter: American Public Power Association, Edison Electric Institute and National Rural Electric Cooperative Association
DCN: EPA-HQ-OAR-2015-0341-0087, EPA-HQ-OAR-2015-0341-0088, and EPA-HQ-OAR-2015-0341-0090

Comment: The commenters recommended the EPA include the FGD wastewater treatment step in Figure 1.2 of the draft chapter.

Response: Figure 1.2 has been revised to replace "waste disposal" with "wastewater treatment & disposal".

1.2.4 Interest Rate

Commenter: Asphalt Roofing Manufacturers Association, Class of '85, American Public Power Association, Edison Electric Institute and National Rural Electric Cooperative Association
ID: EPA-HQ-OAR-2015-0341-0084, EPA-HQ-OAR-2015-0314-0089, EPA-HQ-OAR-2015-0341-0087, EPA-HQ-OAR-2015-0341-0088, and EPA-HQ-OAR-2015-0341-0090

Comment: The commenters disagreed with the interest rate used to calculate the capital recovery. The commenters said EPA should consider retaining the 7 percent annual interest rate to be consistent with other Chapters of the Cost Manual. They noted that 7 percent has historically been used by EPA in its control costs analyses. They said that although 4 percent may be consistent with present market conditions, it was inconsistent with the 7 percent as advised by Executive Order 18266 and with OMB guidance, which states that a 7% real discount rate should be used for base-case analyses of proposed investments and regulations. (see "Guidelines and Discount Rates for Benefit-Cost Analysis of Federal Programs," OMB Circular A-94 at 9 (Oct. 1992), https://www.whitehouse.gov/sites/whitehouse.gov/files/omb/circulars/A94/a094.pdf.)
The commenters agreed with OMB's explanation that:

"The 7 percent rate is an estimate of the average before-tax rate of return to private capital in the U.S. economy. It is a broad measure that reflects the returns to real estate and small business capital as a well as corporate capital. It approximates the opportunity cost of capital, and it is the appropriate discount rate whenever the main effect of a regulation is to displace or later the use of capital in the private sector."[3]

The commenters said that EPA had not explained why it had departed from the default 7% rate and that it was unclear why EPA used a lower interest rate. The commenter noted that the EPA has acknowledged that real discount rates are "riskless" and actual borrowing costs, which factor in entity- and project-specific risks, are typically higher. (*See* Sec. 1, Ch. 2 at 16-17. In fact, in its recently proposed regional haze state implementation plan ("SIP"), Texas "conservatively assumed that a constant 10% interest rate would be a reasonable 'mid-point' to use across all source categories" in assessing control costs. *See* Texas Proposed 2021 Regional Haze SIP Revision, App. B, at B-14, available at https://www.tceq.texas.gov/assets/public/implementation/air/sip/haze/2021RH_AppendixB_pro.pdf.)

[3] OMB Circular A-4 at 33 (Sept. 2003), available at https://www.whitehouse.gov/sites/whitehouse.gov/files/omb/circulars/A4/a-4.pdf (citing OMB Circular A-94).

Another commenter cited comments they previously submitted to EPA regarding the technology review for the proposed Asphalt Processing and Asphalt Roofing Manufacturing Residual Risk and Technology Review (RTR) (see 85 FR 18926)[4] that evaluated wet scrubbers for control of hydrogen chloride (HCl) emitted from blowing stills at asphalt processing facilities equipped with chlorinated catalysts. This commenter disagreed with the 4.75% interest rate used to calculate the capital costs, arguing that the rate was "overly optimistic." The commenter provided no assurance that the historically low interest rates in recent years would prevail in the future. The commenter recommended that EPA consider: 1) the interest that can be earned on the safest investments if there is no inflation; 2) a company's risk premium; and 3) inflation. These combined factors, the commenter said, would determine the cost of an individual company's corporate debt offerings. For example, the 20-year U.S. Treasury Bond rate is currently about 2.5 percent, and if a company's risk premium is 2.0% and the projected inflation rate is 2.5%, then total discount rate would be the sum of these (7.0%). The commenter said that a discount rate of 7.0% is more appropriate for evaluating the annualized costs of HCl emissions controls for asphalt plants. The commenters recommend the EPA use the default 7% rate to avoid underestimating costs, particularly for projects such as acid gas scrubbers that are more capital and time intensive.

Response: This issue is pertinent to the general cost methodology employed throughout the Control Cost Manual, not just this chapter. As stated in Section 1, Chapter 2 of the Cost Manual, the interest rate that is appropriate for annualizing capital cost is either the bank prime rate (currently 3.25%), which is an interest rate set by the Federal Reserve Board that fluctuates with the market for financial credit, or a firm-specific rate that reflects the rates of debt and equity for the firm owning the unit at issue if that firm can justify this alternative rate. The bank prime rate serves as a default if the firm can, or decides not to, provide an interest rate reflecting its rates for debt borrowing and/or equity. These rates are appropriate in the context of the cost methodology employed by the Control Cost Manual, for the capital expenditure for a control technology is a private cost (that is, a cost specific to the affected firm) rather than a social cost (that is, an estimate of the broader cost to society). The 7% rate mentioned by the commenters is a social discount rate recommended by US OMB in Circular A-4 (guidance for Executive Order 12866) for use in estimating the social cost of a regulatory action and is not appropriate for estimation of private cost, and an explanation for this position can be found in Section 1, Chapter 2 of the Cost Manual.

For clarity, we have added a footnote to section 1.2.4.6, Example Problem for a Wet FGD System, and section 1.2.5.7, Example Problem, of this chapter, explaining our use of the bank prime rate in the examples used in those sections. We have also added language to each of these Example Problems to indicate that these Examples are hypothetical in nature and do not reflect the data associated with an actual installation and operation of a control device.

1.3 Equipment Life

Commenter: Class of '85, American Forest & Paper Association (AF&PA), American Fuel & Petrochemical Manufacturers (AFPM), American Wood Council (AWC), Council of Industrial Boiler Owners, American Public Power Association, Edison Electric Institute and National Rural Electric Cooperative Association
ID: EPA-HQ-OAR-2015-0314-0089, EPA-HQ-OAR-2015-0341-0086, EPA-HQ-OAR-2015-0341-0087, EPA-HQ-OAR-2015-0341-0088, and EPA-HQ-OAR-2015-0341-0090

[4] The reference to the Federal Register notice is not correct. The actual citation for this proposed RTR is 84 FR 18926 (May 2, 2019).

Comment: Several commenters disagreed with using a 30-year equipment life for calculating the capital recovery factor. One commenter agreed that scrubbers are very durable and that in some applications they may operate for more than 30 years. However, several commenters noted that the equipment life was based on data drawn for utility units and said that life expectancies can be as low as 5 to 10 years for certain acid gas scrubbers installed on industrial processes. The commenter said that a 30-year lifetime is not appropriate for contemporary FGD applications and suggested a life of approximately 15 years would be more appropriate. Some commenters suggested that EPA revise the example cost calculations to include a more realistic lifetime of 15 or 20 years.

Some commenters agreed the typical equipment life range was 20 to 30 years, but noted that scrubber vendors do not typically guarantee equipment life. The commenters recommended the EPA emphasize in the draft chapter that source-specific details should be considered when determining equipment life and the default 30-year or greater scrubber equipment life may not apply to all applications. Some commenters noted that in the previous version of the Cost Manual, the calculations for the wet packed tower scrubber example used a 15-year life expectancy and 10% interest rate. The commenters said that the substantial change in scrubber life expectancy used in the example problem appeared to be based on utility data, which they argued may not be applicable to industrial applications. The commenters noted that the equipment life is an important parameter in calculating the annualized capital cost and urged the EPA to not specify a 30-year life for all acid gas scrubbers.

Commenters also noted that it is typical practice to rebuild instead of replacing some types of control devices. Commenters suggested the EPA clarify whether the equipment life is the number of years before the equipment is rebuilt or replaced. Some commenters said that a 30-year life may be accurate for some components, such as the absorber tower and ball mills, but would not be appropriate for components that require frequent rebuilding, such as spray headers and various components fabricated from fiberglass reinforced plastic (FRP).

Commenters also argued that EPA should base the capital recovery factor on the useful economic life of the equipment, rather than on how long certain FGD systems have operated. The commenters asked whether the equipment life should be the number of years the company depreciates its capital investment or the number of years over which the company will depreciate the equipment.

Response: We disagree with commenters that the 30-year equipment life used in the example problems is unreasonable. As we noted in section 1.1.5 of the draft chapter, as mentioned in several references including peer-reviewed literature, many scrubbers have operated for over 30 years. The 15-year equipment life in scrubber cost examples in previous versions of the Cost Manual was determined at a time in the mid-1990s when gas absorbers for pollution control had only begun in the 1970s. For the 7the Edition of the Cost Manual, the equipment life is defined as the operational life, not economic life. The equipment life is the expected design or operational life of the control equipment assuming the equipment is properly maintained and operated within its design specifications. The economic life is not appropriate to use for control equipment cost estimates in the context of the Cost Manual's cost methodology because economic life is based on factors that can vary considerably by firm and source.

2.0 Flue Gas Desulfurization Systems

2.1 General Comments

Commenter: Class of ’85, American Public Power Association, Edison Electric Institute and National Rural Electric Cooperative Association
ID: EPA-HQ-OAR-2015-0314-0089, EPA-HQ-OAR-2015-0341-0087, EPA-HQ-OAR-2015-0341-0088, and EPA-HQ-OAR-2015-0341-0090

Comment: The commenters agreed with EPA that SO_2 emission rates have declined since 2000 but said the trend may be attributable to operational changes, such as switching from operating at baseload to less-than-full capacity. Switching to a lower operating capacity would extend the residence time for SO_2 removal, which results in a higher liquid-to-gas ratio and may reduce SO_2 emissions. Additionally, the commenters said that many electric generating units also switched to burning coal with lower sulfur content in response to regulatory pressure over the last 20 years. The commenters recommended the draft chapter acknowledge the observed improvement in removal efficiency may be influenced by specific operational shifts, along with improved performance of the emission control design. The commenters noted that the capacity factor gradually decreased since 2005, particularly between 2015 and 2018.

The commenters said that Figure 1.1 does not account for the shift to burning coal with lower sulfur content. Specifically, the commenter noted that the figure does not account for the level of sulfur in the coal burned, which makes a unit with uncontrolled and controlled SO_2 emissions of 0.5 lb/MMBtu and 0.08 lb/MMBtu respectively (84 percent removal efficiency) appear to be better performing than a unit with uncontrolled and controlled SO_2 emissions of 5.0 lb/MMBtu and 0.10 lb/MMBtu respectively (98 percent removal efficiency). The commenter contends that some of the reduction in SO_2 emission rates observed from the year 2000 is due to changes in sulfur content coal, rather than improvements FGD performance. The commenter said that EPA’s analysis of FGD performance trends fails to account for the effect of declining consumption of higher-sulfur coal among FGD-equipped units.

Response: EPA agrees with the commenter’s remarks and has made the following changes shown in bold to section 1.2.2:

“The performance of FGD systems installed on power plants has improved ~~significantly~~ over the last 20 years **and many vendors have published SO_2 removal efficiencies of over 99 percent for new wet FGD systems, up to 95% for new SDA systems, and up to 98% for new dry FGD systems. [70, 71, 72, 73, 74 and 75].** Figure 1.1 shows the 12-month average emission rate for the top performing 50% and top performing 20% of wet limestone, wet lime and dry lime gas absorbers in 2000, 2005, 2010, 2015, and 2019. The average SO_2 emission rate for the top performing 50% of wet limestone FGD systems dropped from 0.22 pounds sulfur per million British Thermal Unit (lb/MMBtu) in 2000 to 0.04 lb/MMBtu in 2018. Similarly, the top performing 50% of wet lime FGD systems dropped from 0.21 lb/MMBtu in 2000 to 0.07 lb/MMBtu in 2018. Finally, the top performing 50% of dry lime FGD systems dropped from 0.14 lb/MMBtu in 2000 to 0.07 lb/MMBtu in 2018. **This decrease in SO_2 emission rates is likely attributable to a variety of factors including improvements in the design and operation of FGD systems and operational changes at some utilities switching to lower sulfur coal and operating at less than full capacity. Switching to lower operating capacity extends the residence time and results in a higher liquid-to-gas ratio, which increases SO_2 removal.** [19]”

[70] Babcock & Wilcox, product literature, available at https://www.babcock.com/en/technology/pollution-control/so2-acid-gases.
[71] GE Power, product literature for wet FGD, available at https://www.ge.com/power/steam/aqcs/sox-control-wfgd.

[72] GE Power, product literature for dry FGD systems, available at Dry Flue Gas Desulfurization | SOx Control | GE Steam Power.
[73] Marsulex Environmental Technologies, product literature for dry FGD systems, available at http://met.net/dry-fgd.aspx.
[74] LDX Solutions, product literature for wet scrubbers, available at https://www.ldxsolutions.com/technologies/wet-scrubbers/.
[75] LDX Solutions, product literature for DustexTM Circulating Dry Scrubber (CDS), available at https://www.ldxsolutions.com/circulating-dry-scrubber-cds/.

Commenter: Class of '85, American Public Power Association, Edison Electric Institute and National Rural Electric Cooperative Association
ID: EPA-HQ-OAR-2015-0314-0089, EPA-HQ-OAR-2015-0341-0087, EPA-HQ-OAR-2015-0341-0088, and EPA-HQ-OAR-2015-0341-0090

Comment: The commenters said that the term B_{MW} should be clarified. The EPA employs the term B_{MW} to describe both net and gross electric generating capacity. The embedded footnote and name assigned to this variable reference net generating capacity; however, the term B_{MW} is subsequently used as gross generating capacity in Equation 1.9 and examples in sections 1.2.4.6. and 1.2.5.7.

In determining the scrubber design parameters, the maximum heat input and heat rate factor (HRF) are calculated using the net plant heat rate (NPHR; in units of MMBtu/MWh). The NPHR is used to estimate maximum heat input "[i]f the boiler *produces* electricity," as well as for HRF, the "ratio of the actual heat rate of the boiler." The commenter said the descriptions of NPHR and HRF are inaccurate because boilers do not produce electricity. The commenter also disagrees with calculating the maximum heat input using the equation: *QB = BMW x NPHR*, where *BMW* is "boiler MW rating at full load capacity" (MWh). In addition to correcting the NPHR descriptions, the commenter suggested the EPA clarify whether NPHR is the "gross" or "net" electric generating capacity of the generating unit.

Response: EPA agrees with the commenters that additional clarification in needed. The IPM model uses the gross heat rate and the gross MW capacity. Since the net plant heat rate (NPHR) is not used in the cost equations, the discussion of NPHR presented in Section 1.2.3.1 is unnecessary and has been deleted from the final chapter. The heat rate factor (HRF) should be calculated using gross heat input rate. The discussion and equation in Section 1.2.3.3 (Heat Rate Factor) have been corrected in the final draft.

Commenter: American Public Power Association, Edison Electric Institute and National Rural Electric Cooperative Association
DCN: EPA-HQ-OAR-2015-0341-0087, EPA-HQ-OAR-2015-0341-0088, and EPA-HQ-OAR-2015-0341-0090

Comment: The commenter prepared their own evaluation of SO_2 emission rates using EPA data from the Clean Air Markets Division (CAMD) and found that their analysis "generally corroborates EPA's observations of SO_2 emission rates." However, the commenters said the SO_2 emission rate of 0.02 lbs/MBtu) was extremely low and sulfur removal to 99 percent extremely high. Commenters said the high sulfur removal values presented in Table 1.2 of the draft chapter could not be reproduced and disagreed with the method used to infer percent sulfur removal. The commenter disagreed with using EPA CAMD data and EIA coal composition from Form 923 as they are from different data sets. The commenters said that the EPA CAMD are hourly data subject to extensive quality assurance procedures, while EIA fuel data are monthly averages measured intermittently at different schedules that may provide misleading results. The commenters noted that this approach resulted in sulfur removal efficiencies higher than 99 percent for wet limestone and lime FGD, up to 95 percent for dry FGD SDA, and to 98 percent for dry FGD CDS. The commenter noted that CAMD allows deviance by 7.5 percent prior to recertification with RATA, but that the accuracy of EIA data was not defined. The commenter said that the high sulfur removal levels calculated may not be accurate as the 12-month averaging period could result in low SO_2 emission rates. The commenter cited a paper by Weilert[5] that shows reducing the averaging time to shorter periods results in higher SO_2 emission rates for both wet and dry FGD. The commenter said that Weilert's observation should be considered when evaluating FGD capability for shorter-term emission standards.

<u>Response</u>: The commenters are correct that the data source for the control efficiency and SO_2 emissions rates estimates is from the Clean Air Markets Program, which uses heat input data collected by EIA and SO_2 emissions data measured using continuous emission monitoring systems (CEMS) collected by EPA. We agree with the commenters that reducing the averaging time to shorter periods is likely to show periods in which SO_2 emissions rates are higher than those presented in Table 1.2. We also agree with the commenter that the coal heat input data may not be as accurate as the SO_2 emissions measurements. However, the data is subject to quality assurance checks by EIA and represents the best quality data currently available.

Commenter: American Public Power Association, Edison Electric Institute and National Rural Electric Cooperative Association
DCN: EPA-HQ-OAR-2015-0341-0087, EPA-HQ-OAR-2015-0341-0088, and EPA-HQ-OAR-2015-0341-0090

<u>Comment</u>: The commenters said they tried to reproduce the inventory data in Table 1.1 (now listed as Table 1.2 in the final chapter) but noted it was not possible to exactly replicate the table because EPA did not define the criteria used to select the reference inventory. Nevertheless, the commenters said their data, presented in the table below, is similar to the data presented in the Cost Manual. They said they identified all but 20 limestone-equipped wet FGD units, all lime-based processes, and all but 13 dry FGD processes. However, the commenter said that they identified almost four times as many CDS installation as EPA. The commenter said their data is based on a minimum capacity threshold of 25 MW; other factors affecting the operating status of a generating unit also likely contributed to the inability to replicate EPA's inventory. They noted that their analysis considered source categories of electric utility, cogeneration, and small power producers. They also said that twelve units were deleted from consideration including nine employing either limestone and/or lime reagent, and two SDA dry FGDs. Five units were designated as "operational" but reported no generation data for 2018 and six did not report firing coal. They said that these were removed from their inventory. With the exception of CDS installations, the commenter said the differences between their inventory and EPA's inventory are not significant and do not prevent evaluation of the SO_2 emission rate or sulfur removal. The table below compares the commenter's 2018 inventory of FGD equipment at coal-fired power stations with that included in Table 1.1 (now listed as Table 1.2 of the final chapter).

[5] Weilert, C. et. al., *Emissions Control Performance Achieved in Practice by Electric Utility Flue Gas Desulfurization Systems in the United States*, presentation to the 2010 Power Plant Air Pollutant Control symposium, paper #114.

FGD Design	Inventory by Commenters	Inventory: EPA Reported
Wet FGD		
Limestone	184	204
Lime	122	122
Sodium Reagent	12	11
Dual Alkali	5	4
Dry or Semi-Dry Lime FGD (SDA)	92	105
Fluidized Bed Limestone Injection	40	34
Dry Sorbent Injection	15	17
Circulating Dry Scrubber	25	8
Total	495	505

Response: EPA has updated the number of wet and dry FGDs systems currently installed on coal-fired power plants using 2019 data published by the Clean Air Markets Program. The revised table is included in the final chapter listed as Table 1.2. Overall, the 2019 data shows a decrease in FGD systems, which is likely due to closure of coal-fired plants. However, the number of wet FGD systems decreased by 37, while the number of dry FGD systems decreased by 4 units from 2018 to 2019.

Commenter: American Public Power Association, Edison Electric Institute and National Rural Electric Cooperative Association
DCN: EPA-HQ-OAR-2015-0341-0087, EPA-HQ-OAR-2015-0341-0088, and EPA-HQ-OAR-2015-0341-0090

Comment: The commenters referenced the costs discussed on page 13 of the draft chapter for the range and average cost for wet FGD, and semi-dry SDA and CDS equipment. The commenter said that the EIA cost data can be useful but should be used carefully because the data reported by owners and operators is inconsistent. The purpose of the EIA data, the commenter said, is to track expenditures in power generation technology, which is useful for planning, research and development, but not necessarily useful for estimating costs for a rulemaking or for quantifying the cost per ton ($/ton) of emission reduction. The commenters said that there is considerable variability in how owners and operators report the indirect or collateral costs attributable to the emission control system. The commenter noted that EIA recognize these uncertainties and quoted the following text from a January 16, 2020 private e-mail from EIA staff regarding the relative accuracy of reported costs:

"…. the respondents don't always follow the instructions and report the cost based on their judgment by what they understand as the "Total cost of the equipment". It is hard for us to determine the data accuracy unless the figures are completely out of range."

The commenters also noted that EIA stated in the e-mail that variances of 20 percent can go unnoticed. The commenters said that EIA cost data should be used cautiously and recommended the EPA remove the text on page 1-8 that applies averages of EIA cost data. The commenter said the data was misleading and incomplete. The commenter suggested the discussion should focus on how site conditions affect installed cost.

Response: EPA agrees with the commenter that reporting of information on costs can be inconsistent due to differences in reporter's interpretation of what costs should be included. However, the cost data in Section 1.2.1.2 is included to provide only a general guide to users of the range of costs for FGD systems and is not intended to be used for estimating costs or making any determinations regarding the selection of a particular control device. The data is provided for information purposes only.

2.2 General Comments on Cost Estimate Methodologies for FGD Systems

Commenter: Class of '85
DCN: EPA-HQ-OAR-2015-0314-0089

Comment: The commenter recommended the 2016-dollar values be adjusted to the most current values available. The commenter said the cost analyses is five years out of date. The commenter noted the EPA has acknowledged the impact of inflation on control cost prices, the need for timeliness in control equipment data, and the potential errors that can occur. The commenter said that adjusting the cost values to the most current information available would enhance the accuracy of the Cost Manual and minimize discrepancies between estimated and actual control costs.

Response: EPA disagrees with the commenters that the cost equations for FGD systems should be scaled to the most recent values. The cost equations for wet FGD systems, SDA and CDS are based on the methodology developed by Sargent & Lundy, LLC (S&L) for EPA's Clean Air Markets Division. The IPM is based on a statistical evaluation of cost data from various sources, including estimates for FGD systems from the "Analysis of MOG and LADCO's FGD and SCR Capacity and Cost Assumptions in the Evaluation of Proposed EGU 1 and EGU 2 Emission Controls" prepared for Midwest Ozone Group (MOG), data from the "Current Capital Cost and Cost-effectiveness of Power Plant Emissions Control Technologies" prepared by J. E. Cichanowicz for the Utility Air Regulatory Group (UARG) in 2010, 2007 to 2008 data published by G. W. Sharp in "Update: What's That Scrubber Going to Cost?" published in Power Magazine, March 2009, and unpublished from the S&L in-house database of wet FGD projects. Industry data from "Current Capital Cost and Cost-effectiveness of Power Plant Emissions Control Technologies" prepared by J.E. Cichanowicz for the Utility Air Regulatory Group (UARG) in 2012 to 2014 were used to update the algorithms. The IPM version 6 algorithms used in the draft chapter estimate the capital costs in 2016$. These costs are the most recent that are available to EPA for the reduction of air pollutant emissions by wet and dry scrubbers. To the extent that more recent cost year estimates are preferred, the costs can be escalated to current year dollars, using a cost index, such as the Chemical Engineering Plant Cost Index (CEPCI).

2.3 Retrofit Cost Factor

Commenter: American Public Power Association, Edison Electric Institute and National Rural Electric Cooperative Association
DCN: EPA-HQ-OAR-2015-0341-0087, EPA-HQ-OAR-2015-0341-0088, and EPA-HQ-OAR-2015-0341-0090

Comment: The commenters recommended the EPA include a description and examples of how site conditions affect the retrofit factor. The commenters noted that the EPA assumes that a typical wet or dry FGD retrofit represents a 30 percent premium over the installed cost for a new unit. However, the commenters stated that costs to retrofit a wet or dry scrubber are dependent on site-specific characteristics, such as site boundary access, site congestion, absorber duct layout and length, structural issues, and balance of plant. The commenters recommended the EPA include a discussion of site complexity, describing how site factors can be used to assess a retrofit cost.

The commenters compiled information on fourteen examples showing how site-specific characteristics impact retrofit installations of wet limestone, lime-based SDA, and lime-based CDS. The commenters said that the costs they provide are owner-reported costs derived from the report *Capital Cost and Cost-Effectiveness of Electric Utility Coal-Fired Power Plant Emissions Control Technologies: 2017 Update*, prepared by the Utility Air Regulatory Group in December 2017. The commenters said that the examples show a wide variety of reported capital cost that are compared to cost estimates using EPA's methodology. To fully critique the EPA methodology, many sites should be investigated, with EPA-basis costs compared to actual reported costs. The commenters said that the data shows a "default" retrofit factor of 1.3 (compared to a greenfield installation) is inadequate and that an alternative range should be provided addressing site-specific circumstances exist that result in higher costs. Key observations made by the commenters for the three categories of FGD are:

- Wet FGD. The commenters used Equation 1.13 and added owner's charge and an estimate for AFUDC for five wet FGD systems. The calculated costs were compared to the incurred cost reported by the facility. The results imply the retrofit factor should be approximately 1.6 for two facilities and 1.3 for two other facilities. The fifth facility was a greenfield unit, where the cost calculated using Equation 1.13 was greater than reported by the facility. These five sites, the commenters noted, show the retrofit factor compared to a new/greenfield construction can exceed 1.3.

Facility	**Site-Specific Factors**	**Reported Cost**	**Calculated Cost**	**Retrofit Factor Compared to New Construction**
Wet FGD Retrofit Projects				
Mississippi Power Daniel Station	(1) Site access for cranes constrained due to a boiler building, gas turbines and coal pile. (2) Relatively high density of process equipment, including a new stack for two coal conveyers. (3) 250 yards of ductwork and "substantial" induced draft fans required to transport flue gas.	$643/kW	$517/kW	1.61
Florida Progress Crystal River Station, Units 1 and 2	(1) Site access for cranes reasonable on three sides. (2) Site congestion made retrofit challenging due to existing stack and ESP. (3) Extensive ductwork, substantial induced draft fans and difficult structural issues (absorber ductwork had to be elevated over coal conveyor). (4) Costs savings due to installing two systems at the same site.	$662/kW	$520/kW	1.65
First Energy Sammis Units 6 and 7	(1) Site access for cranes is limited due to Ohio River and a state highway, existing plant equipment and maintenance roadway.	$414/KW for unit 6 $614/kW for unit 7	$537/kW	1.0 for unit 6 1.48 for unit 7

Facility	Site-Specific Factors	Reported Cost	Calculated Cost	Retrofit Factor Compared to New Construction
	(2) Relatively congested site due to compact arrangement of process equipment, including a new wet stack. (3) Extensive ductwork of 300 yards or more and "substantial" induced draft fans were needed to transport flue gas. Additional ductwork was needed for ancillary equipment. (4) Additional ductwork required for Unit 7 contributed to the higher costs, but other factors, such as reagent preparation and solid byproduct management, are likely responsible for the differences in costs between units 6 and 7.			
DTE Monroe Units 3 and 4	(1) Site access for cranes was constrained by adjacent units and process equipment. Units 3 and 4 could be accessed only from two sides. (2) Site was congested by other process equipment but there was room to locate the absorber near to the boiler so that extensive ductwork was not required. (3) A new auxiliary power supply was installed. (4) Costs likely lower for these two units due to cost savings for reagent preparation and byproduct handling equipment, which is used by four wet FGD systems.	\$470/kW	\$488/kW	1.28
Wet FGD Greenfield Projects				
Praire State Generating Plant	(1) Greenfield site with no limitations on site access. (2) FGD absorber arrangement and ductwork could be configured to minimize capital costs. (3) Installed two identical units and therefore benefited from costs savings in design, procurement and installation.	\$263/kW	\$348/kW	0.76

- Dry FGD SDA. The commenters compared the calculated costs for five dry SDA FGD systems with those reported by each facility. The commenters used Equation 1.37 and added the owner's charge and an estimate for AFUDC. The implied retrofit factor was 1.3 or lower for two facilities, 1.5 for one facility, and 1.6 or higher for two facilities. The commenters said these examples show the retrofit factor compared to a new/greenfield construction can be higher than 1.3 for some facilities.

Facility	Site-Specific Factors	Reported Cost	Calculated Cost	Retrofit Factor Compared to New Construction
SDA Retrofit Projects				
Alliant Columbia Unit 1	(1) Site access for cranes reasonable with two sides relatively unconstrained. Constrained on one side by a water body. (2) Relatively congested site due to need to maintain maintenance access. Also complicated by changes to underground utilities. (3) Extensive ductwork, elevated structures, improvements to gas handling capabilities and upgraded auxiliary power increased costs.	\$610/kW	\$500/kW	1.59
AEP Flint Creek Unit 1	(1) Site access for cranes was reasonable but constrained on one side by a coal yard. (2) SDA had to be displaced in a "sidecar" arrangement, with fabric filters located adjacent to the stack. (3) Some equipment had to elevated. (4) Additional costs for improving gas handling capabilities and upgrading auxiliary power distribution	\$711/kW	\$477/kW	1.94
MidAmerican George Neal Unit 3	(1) Good site access for cranes on two sides. Access on the other sides limited by existing equipment and adjacent river. (2) Relatively uncongested site with adequate site available for the SDA vessel and fabric filter adjacent to boiler. (3) Minimal costs for ductwork.	\$416/kW	\$489/kW	1.10
Interstate Power & Light Ottumwa	(1) Good site access for cranes on three sides. (2) Site was not congested. SDA and fabric filter could be installed next to the stack, with minimal ductwork and no need for elevated structures.	\$502/kW	\$432/kW	1.51
CMS Karn Units 1 and 2	(1) Limited site access due to existing equipment and cooling water channel. (2) Very congested site with no room for SDA vessel and fabric filter near stack. Equipment had to be located on the other side of the cooling water channel, which resulted in higher costs for ductwork, fans, etc. (3) Costs for unit 1 were higher due to more complex ductwork arrangement. Costs for unit 1 may have included costs for reagent preparation and storage equipment for both SDA units.	\$581/kW for unit 1 \$362/kW for unit 2	\$585/kW per unit	1.29 for Unit 1 0.62 for unit 2

- Dry FGD CDS. The commenters compared the calculated costs for four dry FGD CDS with those reported by the facilities. The commenters used Equation 1.37 and added owner's charge and an estimate for AFUDC. The costs for three units were consistent with the cost projections of the Equation 1.37 and showed the retrofit factor is between 1.3 to 1.4, consistent with EPA's assumption of a 30 percent retrofit premium. The fourth unit was located at a site that was easily accessible and uncontested. The costs for this fourth unit were consistent with an inferred retrofit factor of 1.05, less than EPA's assumed value of 1.3, where retrofit factor of 1 is a new/greenfield construction.

Facility	Site-Specific Factors	Reported Cost	Calculated Cost	Retrofit Factor Compared to New Construction
Circulating Dry Scrubber Retrofit Projects				
Alliant Lansing Unit 4	(1) Site access for cranes good with access on two sides. (2) Minimal site congestion.	$589/kW	$586/kW	1.3
Empire District Ashbury Unit 1	(1) Site access for cranes was good. (2) Minimal site congestion. (3) Costs for absorber ductwork and associated structural requirements were modest and the balance-of-plant issues were mostly for auxiliary power and gas handling capabilities. (4) The lower costs for this CDS retrofit could be attributable to lower financing charges available to municipalities and perhaps lower labor and indirect charges.	$516/kW	$641/kW	1.05
Minnesota Power Clay Boswell, Unit 4	(1) Access to the site is extremely limited. Cranes can access the site on only one side as existing equipment and a water body restrict access from other sides. (2) Site was moderately challenging due to limited space for CDS equipment. The compact arrangement, however, minimized the amount of ductwork and associated structural requirements.	$488/kW	$480/kW	1.3
NiSource Michigan City	(1) Plant is located adjacent to Lake Michigan. Site access issues presented significant challenges that increased some costs. Site access for cranes is limited on at least two sides by existing equipment. (2) Site congested by the location of the boilerhouse for Unit 12 and an adjacent generating unit. However, the commenters noted that the compact arrangement of equipment also helped lower some cost components.	$521/kW	$492/kW	1.4

The commenters said EPA should not ignore the impact of site conditions as these factors have a significant impact that "…transcends almost all other factors that determine installed FGD cost." The commenters recommended the EPA change the structure of the retrofit factor so that costs for units installed at sites with challenging site conditions can be better estimated. The commenters disagreed with using a default value that represents average value of prior retrofit installations and asserted that despite the large number of data sources used to develop the cost equations, the equations do not adequately address the effects of widely varying site conditions.

The commenters submitted the following table showing the five attributes of a generating unit site that should be considered in any site assessment.

Key Site Features Affecting Installed FGD Cost

Site Feature	Description	Example Case
Site Boundary Access	Ability to locate cranes near footprint for proposed process equipment.	3 of 4 peripheral boundaries merit low retrofit factor; 1 or 2 can merit high retrofit factor.
Site Congestion	High density of proposed and existing equipment complicates installation, access for manpower.	
Absorber Duct Layout and Length	Desired or available location of process equipment requires extended length of ductwork, support facilities.	Extended lengths of ductwork and subordinate facilities merits high retrofit factor; abbreviated lengths low retrofit factor.
Structural Issues	Support steel for extended ductwork, or elevated process equipment.	Significant lengths of ductwork or support columns for elevated process equipment merit a high retrofit factor; minimal steel requirements a low retrofit factor.
Balance-of-Plant Items	Upgrading gas handling equipment to sustain higher pressure drop; or reinforcement for implosion; of auxiliary power for support equipment.	High needs for BOP actions merit a high retrofit factor; low needs a low retrofit factor.

The commenters said that site boundary access defines how easily cranes and other heavy construction equipment can access site. The commenters said that if three of the four boundaries are open for equipment access, then the retrofit will be easier. For many sites, either adjacent generating units or a water body restrict access to one of more borders. Access to three boundaries, the commenters said, supports a lower retrofit factor, while a single boundary supports a higher retrofit factor.

The commenters said that site congestion is caused by existing boilers or environmental control equipment close to the footprint where FGD process equipment is proposed to be installed. The commenters noted that a congested site results in higher construction costs by requiring greater reliance on cranes to locate equipment. Also, a congested site limits access by work crews to critical areas that can establish the rate at which work is completed. The commenters recommended that sites with low congestion be assigned a low retrofit factor, while sites with high congestion be assigned a high retrofit factor.

The commenters noted that absorber duct layout and length of duct work also drive cost, not only for the routing of flue gas but all subordinate process streams, such as water, reagent preparation and transport, process water, byproducts of desulfurization, and process steam for units with reheaters. The commenters said that sites able to minimize absorber duct layout and length (e.g., those with compact equipment arrangements, should be assigned a low retrofit factor, while those retrofits requiring extensive lengths of ductwork and support equipment should be assigned a high retrofit factor.

The commenters also identified structural issues as another factor influencing the retrofit factor. They defined structural issues as the level of support required to secure ductwork and absorber towers, fabric filters, and foundations for reaction vessels and fans. In locations prone to hurricanes, the commenters noted, structural costs can be high, particularly for equipment located at significant elevation (typically due to a congested site). Also, existing underground facilities such as conduits for process water and power could have to be relocated to enable foundations for new equipment. The commenters recommended that sites requiring minimal structural considerations be assigned a low retrofit factor, while those with significant structural issues a high retrofit factor.

The commenters also identified balance-of-plant costs as impacting the costs of FGD retrofits for modifications where additional fan power to transmit gas from the boiler to the stack, changes to the stack to accommodate gas flow (particularly from wet FGD) effluent, and enhanced auxiliary power installed to support the ancillary equipment for reagent preparation and byproduct treatment. The commenters said that for wet FGD systems new stacks are frequently installed to provide a corrosion-resistant operation.

The commenters suggested EPA include a discussion of how various site features affect the installation cost and present examples to demonstrate the magnitude of the variance.

<u>Response</u>: EPA agrees with the commenters that costs for FGD systems installed at existing plants can be significantly impacted by site-specific characteristics. The reported costs for unit 2 at the CMS Karn plant is substantially lower than for other SDA retrofits. We agree with the commenters that the lower reported costs for the 2015 retrofit of unit 2 are likely because auxiliary equipment, such as sorbent preparation and storage, were constructed as part of the unit 1 retrofit in 2014.

We have added a new section 1.2.3.5 that discusses retrofit factors and the impacts site-specific characteristics may have on the selection of an appropriate retrofit factor for capital cost calculations, where 1.0 represents retrofit of average difficulty. Section 1.2.3.5 is added as follows:

"1.2.3.5 Retrofit Factor

Equipment and installation costs for FGD systems can vary significantly from site-to-site depending on site characteristics. For this reason, the capital cost equations in Section 1.2.4 for wet FGD systems and 1.2.5 for SDA systems include a retrofit (RF) factor that allows users to adjust the costs estimates, depending on the site-specific conditions and level of difficulty. An RF of 1 should be used to estimate costs for a project of average difficulty. For retrofits that are more complicated than average, a retrofit factor of greater than 1 can be used to estimate capital costs provided the reasons for using a higher retrofit factor are appropriate and fully documented. Similarly, new construction and retrofits of existing plants that are less complicated should use an RF less than 1. Each project should be evaluated to determine the appropriate value for RF. The capital costs for the control systems are calculated for multiple modules and then totaled. The cost for each module is calculated using a separate equation with its own RF. Thus, depending on the site-specific circumstances, different RFs may be used for different modules.

Factors that should be considered when evaluating the RF for retrofits include site congestion, site access and capacity of existing infrastructure. The amount of space available near the utility boiler can significantly impact the costs. Site congestion can be caused by existing generators, conveyors, and environmental control equipment. Costs will be higher if portions of the FGD system must be elevated or existing generators, control equipment, buildings and other infrastructure must be relocated to accommodate the FGD system. In some cases, site congestion results in the FGD system being installed further away from the boiler, resulting in extra costs for additional duct work and fans. Costs can also be impacted if ancillary equipment, such as wastewater treatment and absorbent storage and preparation areas, must be located further from the absorber. A congested site can also increase construction costs by requiring greater reliance on cranes to locate equipment and limiting access by construction workers.

Site access can impact installation costs if site is difficult for cranes and other heavy construction equipment to access the construction site. A retrofit for a plant that is bound on two or more sides by adjacent generating units, roadways, rivers, wetlands or other barriers will likely be more challenging, than sites where three of the four boundaries are open for equipment access.

The capacity, condition and location of existing infrastructure can also impact costs. Costs will be lower if existing equipment can be used. For example, new fans may not be needed where existing fans have adequate design margins. If the site has an existing FGD system, the existing ancillary units for absorbent storage and preparation equipment may be sufficient to support the new system. Similarly, if two FGD systems are planned to be installed at the same plant, costs may be reduced by installing a single wastewater treatment system capable of treating FGD wastewater for both absorbers.

Based on the information available in writing this chapter, the RF value should be between 0.7 and 1.3 for wet FGD systems and between 0.8 and 1.5 for dry FGD systems, depending on the level of difficulty. Costs for new construction are typically, though not for every instance, 20 to 30 percent less than for average retrofits for units of the same size and design. An RF of 0.77 is recommended for estimating capital costs for new construction. [3, 52, 53]"

[52] Cichanowicz, J.E., *Capital Cost and Cost-Effectiveness of Electric Utility Coal-Fired Power Plant Emissions Control Technologies: 2017 Update,* Utility Air Regulatory Group, December 2017.

[53] Cichanowicz, J.E and M.C. Hein, *Technical Comments on the Draft EPA Air Pollution Control Cost Manual Chapter Wet Scrubbers for Acid Gas Control, November 3, 2020.*

3.0 Wet FGD Systems

3.1 Design of Wet FGD Systems

Commenter: American Public Power Association, Edison Electric Institute and National Rural Electric Cooperative Association
DCN: EPA-HQ-OAR-2015-0341-0087, EPA-HQ-OAR-2015-0341-0088, and EPA-HQ-OAR-2015-0341-0090

Comment: In Section 1.2.1, Subsection 1.2.1.1, the commenters noted that the EPA stated that packed tower systems can offer SO_2 removal of 99.9 percent. The commenters said that there are very few packed tower FGD processes remaining in operation. The commenters said that the packing material promoted the formation of deposits that inhibited gas flow. The commenters also said that the term "pollutant-solvent" was unclear and that the EPA should clarify whether this term refers to SO_2 or another soluble species.

Response: EPA agrees with the commenter that scale formation in packed tower wet FGD systems can inhibit gas flow through the absorber vessel. We have revised section 1.2.1.1 as follows:

"**However, packed tower wet FGD systems are not widely used due to the potential for deposits of calcium sulfate and calcium chloride on the packing materials.**"

Commenter: American Public Power Association, Edison Electric Institute and National Rural Electric Cooperative Association
DCN: EPA-HQ-OAR-2015-0341-0087, EPA-HQ-OAR-2015-0341-0088, and EPA-HQ-OAR-2015-0341-0090

Comment: The commenter stated that the term "hydrated calcitic lime" is misleading because the material used for scrubbing is hydrated but is shipped to the plant as quicklime. The commenter noted that the quicklime is usually hydrated into a slurry via a wet ball mill.

Response: For clarification, EPA has made the following change to section 1.2.1.1:

"The wet lime FGD system uses hydrated ~~calcitic~~ lime, instead of limestone, in a countercurrent spray tower. **The lime is shipped to the plant as quicklime and hydrated to form the lime slurry using a wet ball mill.**"

Commenter: American Public Power Association, Edison Electric Institute and National Rural Electric Cooperative Association
DCN: EPA-HQ-OAR-2015-0341-0087, EPA-HQ-OAR-2015-0341-0088, and EPA-HQ-OAR-2015-0341-0090

<u>Comment</u>: Referring to Section 1.2.4.1, the commenters noted that the draft chapter sates that waste slurry is "…. generally sent to a reaction vessel where any remaining SO_2 reacts with the sorbent to produce calcium sulfite ($CaSO_3$) and calcium sulfate ($CaSO_4$). Spent sorbent from the reaction tank (called the slurry bleed) is dewatered and temporarily stored in a waste slurry pond for eventual disposal in a landfill. Alternatively, the calcium sulfate may be recovered and sold to wallboard manufacturers."

The commenters said that the waste slurry has already reacted with SO_2 and produced mostly calcium sulfite, if not oxidized, or calcium sulfate if oxidized. The commenters said that the second line appeared to refer to a special-purpose design that has been employed by two owners in the Southeastern U.S. that employed a bleed stream to a pond and dewatered naturally. The commenters said the liquid on top was directed to a pond and the solids disposed of in a landfill. Dewatering is usually accomplished using a vacuum belt. The liquid is returned to the FGD system as reclaimed water and calcium sulfate recovered and sold to wallboard manufactures.

<u>Response</u>: EPA has made the following changes to Section 1.2.4.1 based on the commenter's remarks:

"The waste ~~slurry collected in~~ **from** the absorber ~~is generally sent to a reaction vessel where any remaining SO_2 reacts with the sorbent to produce~~ ~~calcium sulfite ($CaSO_3$) and calcium sulfate ($CaSO_4$). Spent sorbent from the reaction tank~~ (called the slurry bleed) is **collected,** dewatered, ~~temporarily stored~~ **and transferred to an onsite or offsite** ~~in a waste slurry pond for eventual~~ disposal. ~~in a landfill.~~ Alternatively, the calcium sulfate may be recovered and sold to wallboard manufacturers. **Where calcium sulfate is recovered and sold to wallboard manufacturers, the solids are typically dewatered with a vacuum belt and the liquid returned to the FGD system as reclaimed water**. [3, 14]

4.0 Dry FGD Systems

4.1 Design of Dry FGD Systems

Commenter: Class of '85
ID: EPA-HQ-OAR-2015-0314-0089

<u>Comment</u>: The commenter said that EPA had not provided references for the following two statements regarding the control efficiencies of dry FGD systems: "[s]pray dryers can achieve SO_2 removal efficiencies up to 95%, depending on the type of coal burned." and "the Circulating Dry Scrubber (CDS), . . . can achieve over 98% reduction in SO_2 and other acid gases." The commenter disagreed with these statements. The commenter said total, overall SO_2 removal efficiency in units with circulating fluidized bed boilers using limestone as the bed material and with semi-dry FGD systems may achieve high control efficiencies but said these levels SO_2 removal efficiencies for spray Dry Absorbers (SDA) or CDS technology were not achievable. The commenter said the EPA should make available for public review the supporting data and analysis for these statements.

<u>Response</u>: The EPA disagrees with the commenter's statement that the control efficiencies provided in the draft chapter are too high. The removal efficiencies included in the draft chapter are based on reported emissions data and system equipment specifications published by vendors. For SDA systems, GE Power reports removal efficiencies of up to 95% for SO_2, HCl and HF for their latest designs. Babcock & Wilcox report removal efficiencies of up to 97% for SO_2 and 95% for HCl and HF. For CDS systems, GE Power, Babcock & Wilcox, Marsulex Environmental Technologies reports removal efficiencies of 98% for SO_2 and between 95 and 98% for HCl and HF. LDX Solutions claims their CDS system can achieve

99% SO_2 removal efficiency. The ranges of 85 to 95% for SDA systems and 95 to 98% for CDS systems provided in Table 1.3 of the draft chapter are based on SO_2 removal efficiency data for systems installed at U.S. coal-fired power plants and are consistent with the vendor information we collected for new SDA and CDS systems.

Commenter: American Forest & Paper Association (AF&PA), American Fuel & Petrochemical Manufacturers (AFPM), American Wood Council (AWC) and Council of Industrial Boiler Owners
ID: EPA-HQ-OAR-2015-0341-0086

<u>Comment</u>: The commenters recommended detailed technical data should be provided for semi-dry scrubbing systems, similar to the technical discussion provided for wet tower scrubbers. The commenters said that the description and technical discussions for dry and semi-dry scrubbers was "minimal" and recommended more detail be added, including more information on the performance characteristics of dry and semi-dry scrubbing systems. The commenters recommended EPA compile additional information on dry and semi-dry scrubbing systems. The commenters said that information on dry and semi-dry scrubbers is important both to the regulated community investigating control alternatives for their sources, and the regulators evaluating acid gas controls as part of an air permitting or regional emissions control effort.

<u>Response</u>: EPA added a new Section 1.1.4 to the chapter that describes the design of dry absorption equipment for control of acidic gases from combustion and industrial facilities. We also added a new table (Table 1.1) that compares wet and dry scrubbers and a discussion of the types of processes and industries they have been used.

Commenter: American Public Power Association, Edison Electric Institute and National Rural Electric Cooperative Association
DCN: EPA-HQ-OAR-2015-0341-0087, EPA-HQ-OAR-2015-0341-0088, and EPA-HQ-OAR-2015-0341-0090

<u>Comment</u>: The commenters disagreed with the statement "… for combustion sources that exceed 200 MW (2,000 MMbtu/hour), operators are more likely to install a wet FGD system." (page 1-35). The commenters said that this statement is not supported by the EPA FGD inventory that shows significant use of dry FGD. The commenters recommended EPA remove the observation that dry FGD systems are unlikely to be applied to generating units greater than 200 MW of capacity.

<u>Response</u>: EPA agrees with the commenters and has made the following revisions to the chapter:

"**In the past**, dry FGD systems ~~are~~ were typically installed on smaller boilers, furnaces and incinerators. **However, in recent years** ~~although~~ some newer dry FGD systems have been installed on combustion units larger than 500 MW (5,000 MMBtu/hour) burning bituminous and subbituminous coal. ~~However, for combustion sources that exceed 200 MW (2,000 MMbtu/hour), operators are more likely to install a wet FGD system.~~ Dry FGD systems typically have lower capital and operating costs and require less space than wet FGD systems, but generally use more expensive types of sorbent. [3, 16]"

Commenter: American Public Power Association, Edison Electric Institute and National Rural Electric Cooperative Association
DCN: EPA-HQ-OAR-2015-0341-0087, EPA-HQ-OAR-2015-0341-0088, and EPA-HQ-OAR-2015-0341-0090

Comment: The commenters said that section 1.2.1.2 should be revised to clarify that SDAs typically do not spray CaO into the absorber. Reagent received at the station is usually quicklime (CaO), which is subsequently hydrated into hydrated lime ($Ca(OH)_2$) before use. Plants typically receive quicklime rather than hydrated lime because the cost is lower.

Response: EPA agrees with the commenters and has made the following revisions to the chapter:

"Dry Lime FGD systems are also called Spray Dry Absorbers (SDA—sometimes called Semi-Dry Absorbers) and are gas absorbers in which a small amount of water is mixed with the sorbent. Lime (CaO) is usually the sorbent used in the spray drying process, **which is mixed with a small amount of water to produce** ~~but~~ hydrated lime ($Ca(OH)_2$) ~~is also used and can provide greater SO2 removal~~. Slurry consisting of **hydrated** lime and recycled solids is atomized **and** sprayed into the absorber. The SO_2 in the flue gas is absorbed into the slurry and reacts with the lime and fly ash alkali to form calcium salts."

4.3 Cost Estimate Methodology for SDA and CDS Systems

Commenter: American Public Power Association, Edison Electric Institute and National Rural Electric Cooperative Association
DCN: EPA-HQ-OAR-2015-0341-0087, EPA-HQ-OAR-2015-0341-0088, and EPA-HQ-OAR-2015-0341-0090

Comment: The commenters disagreed with using the same cost algorithm for both the SDA and CDS variants of dry FGD. The use of one relationship for two categories of process equipment, the commenters asserted, will produce misleading results. The commenters noted that CDS features abbreviated residence time and occupies a compact footprint compared to SDA.[6] The commenters recommended the EPA modify the cost-estimating relationship in Equation 1.41 to better reflect CDS equipment. The commenters disagreed that equation 1.41 (ABS_{Cost}) is applicable to both SDA and CDS systems. The commenters said they disagreed with this assumption for two reasons:

1. CDS technology employs equipment to fluidize alkali particles within a reactor, thus significant hardware is directed to supplying, controlling, and maintaining an alkali feed stream that can be suspended in the gas flow, and replenished as necessary. SDA components are markedly different from CDS, employing finely atomized spray of alkali within a reactor vessel. The CDS process equipment is smaller and the gas residence time within the CDS process is estimated to be 3-4 seconds, compared to 10-12 seconds for an SDA. (see *Circulating Dry Scrubbers: A New Wave in FGD,* Power Engineering, Issue 11 and Volume 115. November 1, 2011, available at https://www.power-eng.com/2011/11/01/circulating-dry-scrubbers-a-new-wave-in-fgd/).

[6] *Circulating Dry Scrubbers: A New Wave in FGD,* Power Engineering, Issue 11/Volume 115. Nov. 1, 2011. https://www.power-eng.com/2011/11/01/circulating-dry-scrubbers-a-new-wave-in-fgd/.

2. Table 2-2 in the draft chapter shows SDA installation exceed CDS by almost a factor of 4 with the first CDS installations not commercially operating until 2006. Consequently, SDA has far more operating experience, suggesting the cost basis could be more mature for U.S. utility applications.

<u>Response</u>: We agree with the commenters that the CDS and SDA systems are different in design and that the SDA systems have seen more wide application in the U.S. compared with CDS systems. The cost equations for SDA systems are based on the methodology developed by Sargent & Lundy, LLC (S&L) for EPA's Clean Air Markets Division that was subject to peer review. S&L has not yet developed algorithms for CDS systems. However, based on data available to the Agency, we believe the CDS FGD systems have installed costs that are comparable to SDA FGD systems even though there are differences in design.

Commenter: American Public Power Association, Edison Electric Institute and National Rural Electric Cooperative Association
DCN: EPA-HQ-OAR-2015-0341-0087, EPA-HQ-OAR-2015-0341-0088, and EPA-HQ-OAR-2015-0341-0090

<u>Comment</u>: The commenters recommended the EPA should segregate the cost relationships for a fabric filter from the costs of the process equipment (spray dryer absorber (SDA)/circulating dry scrubber (CDS)). The commenters said that costs of the fabric filter are significant and that the cost estimates could produce erroneous capital costs by not reflecting the relative content of coal sulfur and ash. The commenters said that the cost relationship should account for how coal constituents affect particulate matter and fabric filter design. The commenters noted that the cost relationship for ABS_{Cost} includes the fabric filter cost in addition to the SDA or CDS equipment. Combining the cost relationship for SDA/CDS with the fabric filter equipment introduces uncertainty related to coal composition. The commenters said that fabric filter design and cost is determined in part by the particulate loading rate, the air/cloth ratio, and the mechanism of filter cleaning. The commenters said that collapsing the costs for each of these individual components into one term introduces uncertainty into the projected costs. The ABS_{Cost} relationship as proposed does not reflect how the ratio of ash to sulfur content affects fabric filter design. As an example, the commenters noted that combustion unit fired with bituminous coal with sulfur content of 2 percent and 7-9 percent ash content would generate SO_2 waste at a rate of 16.1 tons/hour. When coal with a 7 percent ash content is used at full load, the commenters said, an additional 9.5 tons/hour SO_2 is generated. The ash content increases the total ash loading to over 25 tons/hour, which impacts fabric filter design. The commenters said that uncertainty in the fabric filer design is even higher for a subbituminous coal such as Powder River Basin (PRB) coal, which in many regions in the U.S. is the preferred application for dry FGD. A PRB coal with 1 percent sulfur content will generate 9 tons of sulfation products per hour, while a typical PRB ash content of 6 percent will result in an additional 8 tons/hour (accounting for 20 percent loss in the boiler hopper). The almost doubling of solid content entering the fabric filter, the commenters noted, will likely affect the design and capital and operating costs of the filter.

The commenters recommended the ABS_{Cost} relationship should be refined to separate the fabric filter from SO_2 removal process equipment and enable a change in the ratio of ash output to products of sulfation to be reflected in the fabric filter design (e.g., air/cloth ratio, or cleaning mechanic). The design and cost of the fabric filter could differ depending on the ratio of ash and sulfur content.

Response: While we appreciate the commenters' concerns, we are not able at this time to provide separate cost equations for the fabric filters used on SDA and CDS systems. Given the importance of having a fabric filter with a dry scrubber to obtain successful removal of SO_2, it is difficult to have separate cost equations for SDA and CDS distinct from fabric filters.

5.0 Wet Packed Tower Gas Absorbers and Application of Wet Scrubbers for Controlling Emissions from Industrial Facilities

Commenter: American Forest & Paper Association (AF&PA), American Fuel & Petrochemical Manufacturers (AFPM), American Wood Council (AWC) and Council of Industrial Boiler Owners ID: EPA-HQ-OAR-2015-0341-0086

Comment: The commenters stated that the technical and cost data for wet packed tower gas absorbers presented in Section 1.3 out-of-date. The commenters noted that the recent update to Section 1, Chapter 2 indicates that it is not appropriate to scale to current year dollars past 5 years. The commenters stated that since data presented in Section 1.3 was last updated in 1991, the data presented in the draft chapter is no longer useful. The commenters noted that the Cost Manual is an important resource for both regulators and the regulated community and urged the EPA update the cost data. The commenters argued that the use of inaccurate data for regulatory development will misrepresent the costs to industry of prospective regulatory actions.

The commenters recommended the EPA study of a variety of FGD and other acid gas scrubbing systems applied to industrial sources and suggested EPA review the RACT/BACT/LAER Clearinghouse to identify the variety of different industrial sources that have acid gas scrubbers and the range of applicable control efficiencies. The commenters also recommended the EPA collect up-to-date equipment cost data from control system and equipment vendors or engineering firms. The commenters said that they recognized that gathering, compiling, and maintaining current and accurate cost information on air pollution control system costs is a time-consuming and resource intensive endeavor and that current EPA budget and resource constraints may make such surveys difficult. The commenters encouraged the EPA to consider other alternatives, such hiring an architectural and engineering (A/E) firm to compile this information.

Response: We agree with the commenters that the cost data for the packed tower absorber is relatively old. EPA attempted to collect more current data on both costs and technology advances through extensive searches of various information sources, including databases (e.g., the EPA's RACT/BACT/LAER Clearinghouse), construction permits, journal articles, vendor information, EPA documents, and conference presentations. Despite these efforts, no additional cost data was identified that would allow us to develop new cost correlations. Although we agree with the commenter's remarks regarding the age of the data and the problems associated with scaling the data to current costs, the cost correlations included in the manual for packed tower scrubbers nevertheless represent the best data currently available to us. Although the data used to develop the cost correlations is dated, we concluded that this data was still useful for developing the study-level capital and operating cost estimates for which the Cost Manual is designed. Consequently, we have retained this data in the final chapter.

Commenter: American Forest & Paper Association (AF&PA), American Fuel & Petrochemical Manufacturers (AFPM), American Wood Council (AWC) and Council of Industrial Boiler Owners ID: EPA-HQ-OAR-2015-0341-0086

<u>Comment</u>: The commenters recommended detailed technical data should be provided for other wet scrubbing systems, similar to the technical discussion provided for wet tower scrubbers. The commenters recommended including discussions of some additional acid gas scrubbing technologies that they said may be more appropriate for certain industrial applications. The commenters said that several newer regenerable acid gas scrubbing technologies should be discussed, including ReACT, CanSolv and SolvR. They noted that these technologies have been deployed in different utility and industrial applications and suggested the chapter discuss non-packed tower and regenerative technologies. The commenters said that non-packed tower technologies are often used in the chemical industry.

<u>Response</u>: EPA agrees with the commenters that several companies market acid gas scrubber systems of various sizes specifically designed for industrial processes. We are not familiar with the ReACT system mentioned by the commenters. The CANSOLV SO_2 Scrubbing System was developed by Shell and is designed to control SO_2 emitted in various industrial processes, such as those generated by fluidized catalytic cracking units (FCCU), process heaters and boilers, sulfur plants, and spent acid regeneration units. The systems include a sulfur recovery unit that can convert the recovered sulfur into a marketable byproduct, such as sulfuric acid or liquefied SO_2. According to the vendor, the CANSOLV SO_2 Scrubbing System has been used to control emissions from a wide range of industries including oil refineries, metallurgical plants, fertilizer plants, chemical plants, steel plants, and cement.

SolvR is a similar system made by DuPont Technology that is also marketed as a control device for sulfuric acid plant tail gas and Claus SRU tail gas that can be combined with an integrated sulfur recovery/recycling processes to produce commercial grade liquefied SO_2, sulfuric acid or sulfur. The system is said to achieve SO_2 emission levels of 20 ppm or less. It also uses energy recovery techniques to reduce operating expenses. The system uses a sodium-based absorbent that forms aqueous sodium sulfate (Na_2SO_4), which can be discharged to a POTW, dried and transported as a solid waste to a municipal landfill.

We have added the following paragraph to the end of Section 1.1.2:

"Both wet and dry gas absorbers are commonly used to control SO_2, HCl, HF, HBr, HCN, HNO_3, H_2S, formic acid, chromic acid, and other acidic waste gases from large utility boilers, large industrial boilers, and a wide range of industrial processes. Gas absorbers have been used at refineries, fertilizer manufacturers, chemical plants (e.g., ethylene dichloride production), pulp and paper mills, cement and lime kilns, incinerators, glass furnaces, sulfuric acid plants, plating operations, steel pickling and metal smelters. Waste streams with flow rates ranging from 2,000 actual cubic feet per minute (acfm) to over 100,000 acfm can be treated with acid gas absorbers. Several vendors supply scrubbers of various sizes that are designed for specific industrial applications, such sulfur recovery units (SRUs), fluidized catalytic cracking units (FCCUs), sulfuric acid production plants, aluminum production, and other non-ferrous metal smelters. These systems typically achieve control efficiencies greater than 98%; however, the removal efficiency achieved can be lower for systems where the waste gas characteristics are variable (e.g., varying acid gas concentrations, flow rates, or temperature). Some systems controlling SO_2 emissions include

integrated sulfur recovery systems that produce commercial grade products, such as liquid SO_2, sulfuric acid and sulfur, that can be used onsite or sold."

Commenter: American Forest & Paper Association (AF&PA), American Fuel & Petrochemical Manufacturers (AFPM), American Wood Council (AWC) and Council of Industrial Boiler Owners ID: EPA-HQ-OAR-2015-0341-0086

Comment: The commenters said that many scrubbers are used to control other acid gases, such as HCl. The commenters suggested the EPA discuss design criteria for scrubbers used to control HCl, such as the differences in sorbents used to control each type of acid gas. The commenters also suggested the EPA present typical costs for the different types of sorbents that are used in acid gas scrubbing systems, along with their efficacy by pollutant in different types of applications.

Response: EPA added the following paragraphs to the end of section 1.1.3 discussing the different types of absorbents that can be used for controlling acid gases emitted by industrial processes.

"For certain industrial applications, wet scrubbers may use water to absorb acids such as HCl and H_2SO_4, resulting in wastewater comprising a weak acid solution that may be recovered for use elsewhere in the plant or sold as a by-product. However, scrubber efficiency is significantly improved if a strong alkali solution is used, such as sodium hydroxide (NaOH), sodium carbonate, calcium hydroxide, and magnesium hydroxide. For combustion sources, a lime or limestone slurry is typically used.

Wet scrubbers are used for a wide range of applications and typically achieve very high levels of pollutant removal. The scrubber design selected depends on the application. Spray towers are generally used in applications where the waste stream contains particulates, such as controlling SO2 emissions in flue gas from coal-fired boilers and HF emissions from aluminum production. Packed bed and tray towers are used to control HF, HCl, HBr, F_2, Cl_2, and SO_2 from incinerators, chemical processes, plating, and steel pickling. Wet scrubbers typically achieve removal efficiencies of between 95 and 99% for most industrial applications. For some industrial applications, two or more absorber vessels arranged in series and using different scrubbing solutions can be used to achieve high removal efficiencies for waste gases that contain multiple pollutants."

Commenter: American Forest & Paper Association (AF&PA), American Fuel & Petrochemical Manufacturers (AFPM), American Wood Council (AWC) and Council of Industrial Boiler Owners ID: EPA-HQ-OAR-2015-0341-0086

Comment: The commenters said the manual should include more information on acid gas scrubbing systems used by industrial sources. The commenters noted that acid gas scrubbers are used by industry to control a diverse range process and combustion sources of different sizes, flow rates, and pollutant loadings. The commenters argued that most of the examples and data presented are for utility boilers. The commenters recommended the EPA provide examples of industrial applications of acid gas scrubbers with the typical range of exhaust flow rate and the typical range of control efficiency for different types of sorbents. It is unreasonable to assume, the commenters said, that each type of scrubber can be installed on any type of equipment (e.g., a packed bed scrubber would not be installed on a large industrial boiler).

The commenters said that the equipment costs presented are not accurate or reliable for non-utility sources, particularly for regulatory development efforts and for evaluating control equipment for air permitting purposes. The commenters recommended the EPA collect information on equipment and operating costs specific to industrial applications.

The commenters said that the majority of the new and/or updated information presented is derived from coal-fired electric utility sources only. The commenters said that industrial sources that discharge acid gases range from small process units venting very low exhaust volumes (100 actual cubic feet per minute (acfm) or less) to large industrial sources, such as refinery units, incinerators, or industrial boilers that may be rated at up to 750 to 1,000 MMBtu/hour of heat input and exhaust 300,000 to 400,000 acfm. The commenters also noted that most industrial sources of acid gases are smaller in size and flow rate than the smallest utility boiler and have flow rates that typically fall between 10,000 and 100,000 acfm. The commenters stated that even the largest industrial combustion sources are much smaller than utility boilers. The commenters argued that cost data for utility boilers provides an inaccurate basis for estimating control costs for smaller industrial sources. The commenters also stated that it was not clear how industrial facilities would apply the scrubber cost calculations in Subchapter 1.2 since the inputs are in megawatts and the heat rate and the cost data are characterized in terms of dollars per megawatt.

The commenters provided the following cost information related to installing acid gas scrubbers on various types of process emissions sources with flow rates ranging from 2,000 to over 100,000 acfm. They noted that the capital costs for these scrubbers range from $3 million to over $50 million. They said that operating costs also vary widely but did not provide any cost data. The commenters said they were not able to apply the cost equations presented in the draft chapter because they use boiler megawatts, which do not apply to process equipment found at industrial facilities, such as refineries. The commenters said that they use engineering companies to design and install these scrubbers and recommended the EPA gather data from these vendors to develop cost algorithms for non-boiler sources.

The commenters said that they believed the information is accurate for coal-fired electric utility boilers, but not for industrial applications. They noted that coal-fired power plants are no longer a major source of new power capacity in the U.S. and most existing coal-fired power plants have been already retrofitted with scrubbers. The commenters said that a more detailed discussion of industrial acid gas scrubber applications would better serve the purposes of the Cost Manual. They also noted that there was not sufficient time allocated for responding to the NODA to conduct the necessary detailed survey for developing the capital and operating cost data and the life expectancy information for all of the types of industrial sources that use these scrubbing systems. The commenters said the chapter should emphasize the need for considering process- and site-specific details when applying a utility-based approach for determining the appropriate types of acid gas scrubbing systems for a specific source and for estimating control costs.

Response: EPA added a discussion of the types of processes and industries where wet and dry scrubbers may be used to control acid gases. We also added discussions of the types of sorbents used to control acid gases from industrial emission sources. See sections 1.1.2, 1.1.3, and 1.1.5 of the final chapter.

EPA attempted to collect additional cost information on the use of acid gas absorbers for industrial processes through extensive searches of various information sources, including databases (e.g., the EPA's RACT/BACT/LAER Clearinghouse), construction permits, journal articles, vendor information, EPA documents, and conference presentations. However, the data we collected was not sufficient to allow us to develop cost methodologies or design specifications specific to particular industrial applications.

Commenter: American Forest & Paper Association (AF&PA), American Fuel & Petrochemical Manufacturers (AFPM), American Wood Council (AWC) and Council of Industrial Boiler Owners DCN: EPA-HQ-OAR-2015-0341-0086

Comment: The commenters agreed the methodologies included in the chapter for estimating capital and operating costs for FGD systems were acceptable for FGD systems installed on utility boilers, but they disagreed that the methodologies could be applied to non-utility sources. The commenters said the methodologies were not reasonable or accurate for non-utility applications and that the approach taken by EPA ignored "an important aspect of the problem." The commenters referenced *Motor Vehicle Mfrs. Ass'n of the U.S., Inc. v. State Farm Mut. Auto. Ins. Co.*, 463 U.S. 29, 43 (1983) and recommended the EPA collect current information on equipment and operating cost for non-utility acid gas sources. The commenters said the methodologies presented in the draft chapter are not useful to non-utility sources because it does not provide accurate non-utility boiler scrubber cost estimates.

Response: EPA attempted to collect additional cost and technical information on the use of acid gas absorbers for industrial processes through extensive searches of various information sources, including databases (e.g., the EPA's Clearinghouse), construction permits, journal articles, vendor information, EPA documents, and conference presentations. However, the data we collected was not sufficient to allow us to develop cost methodologies or design specifications specific to industrial applications for this update. The data did not include any information to allow for correlation of costs to the size and operation of absorbers, which are necessary for methodologies to estimate capital and annual costs.

Commenter: American Forest & Paper Association (AF&PA), American Fuel & Petrochemical Manufacturers (AFPM), American Wood Council (AWC) and Council of Industrial Boiler Owners ID: EPA-HQ-OAR-2015-0341-0086

Comment: The commenters agreed with SO_2 removal and control efficiency information presented for utility boilers. However, the commenters said that similar control or removal efficiencies may not be able to achieve the same level of control for different types of waste combustors, industrial boilers, kilns, and other industrial processes. An industrial boiler firing a broad range of fuels (e.g., biomass, fossil fuel, sludge, process gas streams, etc.) or a waste combustor will exhibit substantial variability over time, not only for the acid gas loading in the exhaust gases, but for all of the other exhaust gas stream characteristics (e.g., volumetric flow rate, temperature, moisture content, oxygen level, etc.). The commenters noted that this variability can result in acid gas removal efficiencies that vary drastically from those of a scrubber application on a coal-fired utility boiler that runs at or near full load all the time. The commenters recommended the EPA collect more information on control efficiencies and SO_2 emission rates for a variety of industrial applications.

Response: EPA agrees with the commenters that scrubbers used to control waste gas streams that are highly variable in flow rate and composition are more challenging to control and may result lower control efficiencies. EPA has added the following sentence to the last paragraph in Section 1.1.2 of the final chapter:

"These systems typically achieve control efficiencies greater than 98%; however, the removal efficiency achieved can be lower for systems where the waste gas characteristics are variable (e.g., varying acid gas concentrations, flow rates, or temperature)."

6.0 Other Comments

Commenter: American Forest & Paper Association (AF&PA), American Fuel & Petrochemical Manufacturers (AFPM), American Wood Council (AWC) and Council of Industrial Boiler Owners ID: EPA-HQ-OAR-2015-0341-0086

Comment: The commenter suggested the EPA provide cost calculation spreadsheets reflecting the 2019 updates. The commenter noted that EPA has previously prepared spreadsheets for other chapters of the Cost Manual.

Response: The EPA is planning to prepare and publish on our website a new spreadsheet that will enable users to prepare study-level cost estimates, including capital costs (i.e., equipment and installation costs) and annual costs (i.e., operating and maintenance) for the wet and dry scrubbers presented in the revised chapter. The cost spreadsheet will be available at the time the chapter is final. Once complete, the spreadsheet will be available at: https://www.epa.gov/economic-and-cost-analysis-air-pollution-regulations/cost-reports-and-guidance-air-pollution.

Commenter: American Forest & Paper Association (AF&PA), American Fuel & Petrochemical Manufacturers (AFPM), American Wood Council (AWC) and Council of Industrial Boiler Owners ID: EPA-HQ-OAR-2015-0341-0086

Comment: The commenter noted that retrofitting a source with a wet scrubber sometimes requires replacing the exhaust stack. The commenter said that it would be helpful if EPA updated Section 2, Chapter 1 of the Cost Manual with up-to-date methodologies so that industry and other users could calculate better estimates for replacing ductwork and stacks of various types and sizes.

Response: The EPA agrees with the commenter that the cost approaches provided in Section 2 (Generic Equipment and Devices), Chapter 1 (Hoods, Ductwork and Stacks) should be updated. Work updating Chapter 1 is planned to begin in fiscal year 2023, provided resources are available. As with other updated Cost Manual chapters, the revised chapters will be made available for public comment through a NODA published in the Federal Register and the updated chapters will be posted to the EPA's website.

Commenter: Class of '85, American Public Power Association, Edison Electric Institute and National Rural Electric Cooperative Association
DCN: EPA-HQ-OAR-2015-0314-0089, EPA-HQ-OAR-2015-0341-0087, EPA-HQ-OAR-2015-0341-0088, and EPA-HQ-OAR-2015-0341-0090

Comment: The commenters said that the FGD process equipment is used to control mercury emissions and recommended a detailed discussion of the design, costs and operating requirements be added to the draft chapter. The commenters suggested a discussion of the role the oxidation-reduction potential (ORP) of FGD slurry plays in controlling Hg emissions be included. One commenter noted that studies have shown monitoring the ORP within an FGD process improves mercury capture by lowering mercury re-emission. (See ORP as a Predictor of WFGD Chemistry and Wastewater Treatment, Power Magazine, June 30, 2013)

Response: EPA agrees with the commenter that scrubbers are used to control mercury emissions. However, an exhaustive examination of application of scrubbers for mercury control is beyond the scope of the current chapter, which focuses on the costs and design of scrubbers for the control of acid gases and SO_2. We added the following paragraph to the end of Section 1.2.1.1:

"One benefit of wet FGD systems is their ability to also reduce mercury emissions from coal combustion by dissolving soluble mercury compounds (e.g., mercuric chloride). The level of mercury reduction depends on the mercury speciation, as flue gas from coal combustion contains varying percentages of three mercury species: particulate-bound, oxidized (Hg^{2+}), and elemental. The Hg^{2+} species is the only soluble form. Consequently, wet FGD systems are more effective at reducing mercury emissions where the fraction of Hg^{2+} in the waste gas stream is higher. The fraction of Hg^{2+} is generally higher in coal containing higher levels of chlorine, such as bituminous coal. Facilities may enhance mercury oxidation by directly injecting bromide or other halogens during combustion, mixing bromide with coal to produce refined coal; or using brominated activated carbon. Wet FGD systems that are used to control mercury as well as SO_2 generally have higher operating expenses due to costs for additives and additional monitoring of the oxidation/reduction potential necessary to optimize mercury removal. The control of mercury from coal combustion is complex due to mercury speciation and is generally achieved using of a combination of air pollution control techniques that are beyond the scope of this chapter. [49, 50, 51]"

[49] U.S. EPA, *Technical Development Document for the Effluent Limitations Guidelines and Standards for the Steam Electric Power Generating Point Source Category,* Office of Water, EPA-821-R-15-007, September 2015, available for download at https://www.epa.gov/sites/production/files/2015-10/documents/steam-electric-tdd_10-21-15.pdf.

[50] U.S. EPA, *Control of Mercury Emissions from Coal-fired Electric Utility Boilers,* Office of Research and Development, available for download at https://www3.epa.gov/airtoxics/utility/hgwhitepaperfinal.pdf#:~:text=Control%20of%20mercury%20emissions%20from%20coal-fired%20boilers%20is,2%2Bcompounds%20in%20wet%20flue%20gas%20desulfurization%20%28FGD%29%20systems.

[51] U.S. EPA, *Supplemental Technical Development Document for Proposed Revisions to the Effluent Limitations Guidelines and Standards for the Steam Electric Power Generating Point Source Category,* Office of Water, EPA-821-R-19-009, November 2019, available for download at https://www.epa.gov/sites/production/files/2019-11/documents/steam-electric-proposed-suppl-tdd_nov-2019.pdf.