Public Comments on the Proposed Revisions to Section 4.2 Chapter 1 (SNCR) of the Control Cost Manual

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1.0   General Comments on the Selective Non-Catalytic Reduction Chapter

Commenter: Sierra Club and National Parks Conservation Association

DCN: EPA-HQ-OAR-2015-0341-0025

<u>**Comment:**</u> The 7% interest rate is too high. The EPA should reduce the interest rate to better align with current economic conditions. The Office of Management and Budget's (OMB) Circular A4 prescribes the use of both 3% and 7% discount rates, with 7% being appropriate only when a regulatory requirement would starve other productive investments of capital. For measures that affect consumption more than capital allocation, OMB suggested a 3% real rate, based on "the real rate of return on long-term government debt." The EPA did not address which category better describes the effects of the vast majority of sources that would be considered for installation of SNCR. For most of the thermal generation in the United States, the costs of pollution controls would flow through to consumers in rates, resulting in "higher consumer prices". OMB Circular A-4 suggests that a 3% discount rate would be applicable because the cost of the emissions controls do not compete with other projects for capital, since the costs will be recovered through non-bypassable cost-of-service regulation or contract terms, with a high level of certainty, allowing the owner to continue raising capital for other projects, including projects in competitive markets. With the right to cost recovery from captive load, there is no practical limit on the ability of firms to raise capital. Thus, the conditions that would justify the use of OMB's higher 7% rate do not apply to most power plants.

The commenters provided some historical and current data on bond rates, approved rates of return on equity and inflation rates. They concluded that the current average nominal rate for corporate bonds is about 2.3% in real terms. The commenters also noted that the return on long-term government debt has fallen since 1992, which average being 2.8% for 10, 20 and 30-year bonds. The rates for 1992 and 2015 are shown in Table 1.

The commenters stated OMB's Circular No. A-94, Appendix C, Revised December 2014 recommends real rates for 2015 be used "for cost-effectiveness, lease purchase, and related analyses."

Table 1: OMB Real Interest Rates for Cost-Effectiveness Analysis, 1992 and 2015

Period (years)	1992	2015	Change
3	2.7%	0.1%	2.6%
5	3.1%	0.4%	2.7%
7	3.3%	0.7%	2.6%
10	3.6%	0.9%	2.7%
20		1.2%	
30	3.8%	1.4%	2.4%

The 2015 update does not propose the use of a higher discount or interest rate for any purpose, and says "These real rates are to be used for discounting constant-dollar flows, as is often required in cost-effectiveness analysis." There is no longer any basis for the use of a 7% interest rate. The 7% rate does not apply to most power-generation facilities, and the OMB no longer advocates for the use of a real rate over 1.4%. The EPA may wish to use the 3% real rate for examples (since the real discount rate will vary over time), but it should specify that the OMB's current guidance should be followed. The rate may differ, depending on the anticipated life of the control system.

According to Section 2.4.2 of the existing Control Cost Manual, alternate interests are allowed, which encouraged analysts to use a wide range of definitions of interest rates, many of which have little relationship to the cost of financing an environmental improvement. Rather than using the OMB-specified real interest rates for all projects, it should tighten up the discussion and specify the following:

First, this exemption is limited to projects that will affect the use of capital, but will not flow through to consumer prices by means of cost-of-service regulation or contracts. The OMB guidance is clear that projects that will affect consumer prices should use the rates in Table 1, updated to the year in which the analysis is conducted.

Second, the relevant rates are limited to "the business' current borrowing rate," which may be approximated by "the current prime rate," or the cost of new debt, given the firm's current credit rating and the anticipated life of the project, minus the inflation rate implied by the difference between nominal and real returns on Treasury securities of similar maturity. For example, current corporate bond yields for 10 to 30 years (which would be typical of the expected life of most SNCR installations) are shown in Table 2.

Table 2: Recent Nominal Yields for Corporate Bonds

	Maturity		
Rating	10	20	30
AAA	2.85%	3.87%	4.15%
AA	3.31%	4.05%	
A	3.44%	4.29%	
Baa			5.20%
Sources: Yahoo! Finance and St. Louis Federal Reserve			

The inflation implicit for each duration in the OMB's latest update is shown in Table 3.

Table 3: 2015 Nominal and Real Treasury Rates and Implied Inflation

Maturity	Nominal	Real	Inflation
3	1.7%	0.1%	1.6%
5	2.2%	0.4%	1.8%
7	2.5%	0.7%	1.8%
10	2.8%	0.9%	1.9%
20	3.1%	1.2%	1.9%
30	3.4%	1.4%	2.0%

Netting these inflation rates out of current bond rates produces these values in Table 4.

Table 4: Real Corporate Bond Rates

	Maturity		
	10	20	30
Inflation	1.9%	1.9%	2.0%
AAA	0.9%	2.0%	2.1%
AA	1.4%	2.1%	
A	1.5%	2.4%	
Baa			3.2%

Third, for publically-owned utilities (municipal, state, and other special governmental units), environmental equipment would be financed with tax-exempt securities. Other entities may be able to access tax-exempt pollution-control financing through state or local agencies. In these cases, the appropriate private interest rate is the municipal bond rate, net of inflation. Table 5 summarizes the nominal municipal bond rates available from the St. Louis Federal Reserve, as well as the corresponding real rates, computed as described in connection with Table 4.

Table 5: Municipal Rates, Nominal and Real

	Nominal Return		Real Return	
Rating	10	20	10	20
AAA	2.2%	3.1%	0.3%	1.2%
AA	2.4%	3.4%	0.5%	1.5%
A	3.2%	3.9%	1.3%	2.0%

Finally, the EPA should require that the borrowing rates be computed from the relevant credit quality and anticipated equipment life. Owners that have previously received tax-exempt financing for pollution controls (for the owner, predecessor firms, or affiliates) in the same state should be assumed to still have such access, unless the owner can demonstrate that such

financing is no longer available due to changes in law or policy. In situations in which the owner's credit status is difficult to determine, and only in those situations, the cost of financing should be estimated from information about the firm's recent costs of new debt or similar indicators.

Response: Section 1, chapter 2 of the Cost Manual states that a social interest rate of 7% should be used instead of the nominal and real interest rates. The revisions to OMB Circular No. A-94, Appendix C (Revised December 2014) identified by the commenter changed the nominal and real interest rates for treasury notes and bonds, but did not revise the social interest rate, which remains at 7%. We used this 7-percent interest rate in calculating the capital recovery factor (CRF). This factor is important to estimating the annualized cost of capital, as the commenter has noted. For cost analyses related to government regulations, an appropriate ''social'' interest (discount) rate should be used, not the source's actual rate of borrowing. This is stated and explained in OMB Circular A–4 (dated September 17, 2003), which provides Federal agencies guidance on developing regulatory analyses, and that reiterates the guidance found in the earlier Circular A–94:

> As a default position, OMB Circular A–94 states that a real [inflation-adjusted] discount rate of 7 percent should be used as a base-case for regulatory analysis. The 7 percent rate is an estimate of the average before-tax rate of return to private capital in the U.S. economy, based on historical data. It is a broad measure that reflects the returns to real estate and small business capital as 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 alter the use of capital in the private sector.

> The yearly updates to OMB Circular A-94 to which the commenter refers, are indeed to Appendix C. However, as the letter that transmits this yearly update explains: "The rates presented in Appendix C do not apply to regulatory analysis or benefit-cost analysis of public investment. They are to be used for lease-purchase and cost-effectiveness analysis, as specified in the Circular." We note that the reference to "cost-effectiveness analysis" here does not refer to that used in cost estimation as shown for this Cost Manual chapter and other chapters, but rather to the analysis of programs requiring the expenditure of federal funds.

Commenter: Sierra Club and National Parks Conservation Association
DCN: EPA-HQ-OAR-2015-0341-0025
Comment: The proposed cost analysis section indicates that the proposed methodology "provides a tool to estimate study-level costs," concluding "[a]ctual selection of the most cost-effective option should be based on a detailed engineering study and cost quotations from the system suppliers." This approach appears to eliminate the possibility of a consistent and transparent methodology. These "detailed engineering studies and cost quotations from system suppliers" are generally based on confidential, opaque vendor quotes. The CCM should rather be requiring cost estimates based on fundamental engineering principals that are transparent.

Further, it is not clear how this approach would work. Would the permitting agency first prepare a cost estimate based on the appropriate chapter of the CCM and then submit it to the applicant to confirm with a vendor quotation? Or would the permitting agency obtain vendor quotes? Or would the applicant submit the cost analysis, based on vendor quotes, and the agency review it, using the Cost Manual method?   This approach is problematic for the following reasons:

- Vendor quotes are not transparent. They do not follow the overnight costing method and use many contingencies and cost adders that are not allowed under the CCM, (e.g., owners cost and AFUDC), so they may greatly overestimate overnight costs. The quotes are usually either CBI, or not supported. Thus, there is no way to break out invalid costs and convert the estimate to one that complies with the CCM methodology.
- Vendors will generally not provide cost quotes to parties who are not potential purchasers of the equipment, (e.g., permitting agencies). Further, vendors are pressured by their clients not to cooperate with permitting agencies.
- Vendor quotes are generally submitted to the agency as CBI, preventing any meaningful review by the agency and/or the public.
- Applicants who supply "detailed engineering studies" to permitting agencies have every incentive to increase the costs to eliminate control options, which permit agencies have no way to verify. Thus, this requirement effectively guts the ability of a permitting agency to independently estimate costs and verify costs provided by applicants. This requirement should be eliminated.

EPA should develop a cost model based on fundamental engineering principles, rather than adopting the opaque, regression-equation based algorithms developed by Sargent and Lundy.

Response: As we noted in Chapter 1 (Selective Noncatalyic Reduction), the cost methodology described is designed to provide study-level capital and operating cost estimates. Selection of the most cost-effective option for a control device should be based on a detailed engineering study and cost quotations from system suppliers. For cost analyses conducted under the authority of the Regional Haze program, such as for Best Available Retrofit Technology (BART) and reasonable progress determinations, Reasonably Available Control Technology (RACT) determinations, and Best Available Control Technology (BACT) determinations, detailed itemized costs with appropriate documentation must be prepared for each control technology and reviewed by Agency staff to ensure the costs provided are complete, correctly calculated, and supported by the documentation. In addition, we note that the Sargent and Lundy cost estimation memoranda have undergone peer review and have been reviewed by the public during their use in multiple EPA rulemakings since costs algorithms and data from these memorandas have been included in the IPM.

Commenter: Coalition of the American Chemistry Council, American Forest & Paper Association, American Fuel & Petrochemical Manufactures, American Wood Council, Brick Industry Association, and Council of Industrial Boiler Owners.
DCN: EPA-HQ-OAR-2015-0341-0022-A1
Comment: We believe EPA's efforts would be advanced if the draft document provided greater discussion on instances where control technology is less effective, even ineffective, on certain types of sources, sizes, or applications. For example, neither technology would be applicable to an industrial source like a direct-fired brick kiln. This type of discussion will provide clarity in understanding the practical limits of SNCR as control strategies are being evaluated for various regulatory purposes.

The introduction to Chapter 1 discusses the expected performance of SNCR on various types and sizes of combustion units. EPA states that SNCR efficiencies vary over a wide range, but more discussion of the factors that affect performance and information about situations where SNCR cannot be effectively applied should be provided. Although the document states SNCR has been applied to many different types of sources, the majority of the chapter focuses on its application to large utility boilers, which have heat inputs greater than all but the very largest industrial units.

There are a number of source types for which SNCR is not practical or feasible. Due to the nature of the flue gas path, package boilers do not have a suitable location in the proper temperature range for successful reagent injection. Many types of industrial process heaters also cannot accommodate SNCR due to the lack of a suitable temperature zone for reagent injection, and/or fluctuating operation. Although SNCR has been applied to cement kilns, it is not suitable for all types of kilns due to the design/temperature limitations of the equipment, or the potential impact of injected chemicals on the product. For example, a brick kiln is a direct-fired unit with carefully balanced air flow and fire zones around the product. Those process conditions, along with specific additives or coatings create the color and other characteristics of the final product. The introduction nozzles to inject reagent, using air as the carrier gas would have an impact on the final aesthetics of the product.

Response: We agree that SNCR controls may not be feasible for all units due to site-specific operating and design characteristics. Since there are many factors that impact whether SNCR is feasible for a given unit, we believe it would be impractical to include a list of all situations where SNCR is not feasible. As we noted in the response to the previous comment, for the purposes of BART, RACT and BACT analyses, each unit must be assessed on an individual basis to determine which control technologies are feasible. These determinations are made based on the limitations of the technology available at the time of the review and hence take into consideration new innovations and changes to control technology. However, we agree with the commenter that some general guidance on when SNCR is an appropriate control device may be helpful to some users. Rather than list specific industries, we have added the following general guidance to Section 1.1 on when SNCR is appropriate:

"SNCR is only effective in a relatively high, narrow temperature range and therefore is not suitable for all applications. The site-specific operating and design characteristics of the emission

unit must be evaluated on a case-by-case basis to determine whether SNCR is feasible. Several factors determine whether SNCR is an appropriate control for a source, including temperature, residence time, feasibility of installing reagent injection ports, and the NO_x concentration. SNCR is not suitable for sources where the residence time is too short, temperatures are too low, NO_x concentrations are low, the reagent would contaminate the product, or no suitable location exists for installing reagent injection ports. For example, SNCR is generally not used for gas turbines because low NO_x concentrations in the flue gas make SNCR less efficient than other available control methods [2]. Sources with stable temperatures of 1550°F to 1950°F, uncontrolled NO_x emissions above 200 ppm, and residence times of 1 second are generally well suited to SNCR and attain the highest levels of NO_x control."

Commenter: Coalition of the American Chemistry Council, American Forest & Paper Association, American Fuel & Petrochemical Manufactures, American Wood Council, Brick Industry Association, and Council of Industrial Boiler Owners.
DCN: EPA-HQ-OAR-2015-0341-0022-A1
<u>**Comment:**</u> We request that the agency place more emphasis on assessing the operating costs associated with this control equipment. Operating costs for SNCR can be significant and can vary significantly depending on the source, service, and capacity, and should therefore be included in any assessment of cost-effectiveness of pollution control equipment.

Response: The chapter for SNCR include detailed methodologies for estimating operating costs. We agree with the commenter that operating costs can be a significant portion of the total costs and should be included when assessing the cost-effectiveness of pollution control equipment. The equipment and installation costs for SNCR are relatively low when compared with other technologies (e.g., SCR) and most of the costs for SNCR are operating expenses. As we noted in Section 1.1 of the draft Cost Manual chapter, a typical breakdown of annual costs is 25% for capital costs and 75% for operating expense. The primary operating expense is for the purchase of NOx reduction reagent. For these reasons, we agree with the commenter that operating costs must be considered in any assessment of cost-effectiveness. Since the quantity of reagent used can vary from one emission unit to another based on the amount uncontrolled NOx emissions in the flue gas and level of control required, we further note that the methodology for estimating operating costs uses site-specific information regarding the NOx emission levels and NOx destruction efficiency.

Commenter: American Petroleum Institute (API)
DCN: EPA-HQ-OAR-2015-0341-0020-A1
<u>**Comment:**</u> The chapter should be renamed and the content clarified to make it clear the chapter only applies to SNCR installations on Boilers ≥25 MW. The cost estimating sections only deal with boilers of ≥25 MW and unlike the existing Control Cost Manual Chapters that are being updated do not use any of the introductory material, process descriptions or design parameter discussions from the first part of each Chapter. Rather, the cost estimating equations for utility boilers are taken from a separate EPA evaluation of the electric utility industry and the cost estimating equations for industrial boilers are derived from the utility boiler equations assuming

costs are the same for utility boilers and industrial boilers with equivalent heat inputs. The derivation of the cost estimating procedures for utility boilers is not explained in the draft Chapter, but is available, in limited detail, on EPA's electric utility website.

The procedures in the chapter are used in making critical regulatory decisions, since EPA requires or encourages use of the Control Cost Manual when making certain regulatory decisions, such as whether a control technology represents Best Available Retrofit Technology (BART) for a particular combustion source. Thus, it is critical that the applicability of these Chapters be clearly identified. Since the draft Chapter title and the introductory material do not suggest any limits to the applicability of the Chapter, API recommends that the Chapter title be changed to reflect the fact that the chapter only addresses cost estimating for boilers ≥25 MW.

The introductory material, process descriptions and design parameter discussions in the draft chapter are ambiguous regarding equipment applicability and could be interpreted to apply to any SNCR system on any type of equipment, even though the information is only based on installation of such facilities on utility boilers and the chapter only applies the information to boilers. Broad applicability of the introductory material, process descriptions and design parameter discussions is suggested. While API agrees that these general discussions might allow for rough estimates of costs for installations on non-boiler types of equipment, the information does not indicate how to adjust for differences in equipment design or exhaust gas properties between equipment types or the significant differences in SNCR system construction approaches needed to deal with those differences. For instance:

- SNCR sizing, location, catalyst type, etc., will also vary between equipment types and even from unit to unit of the same type due to the differences in their designs, temperature profiles, heat densities, etc.
- Costs can also be significantly impacted by the level and form of the NOx limitation and how that limit is applied during periods of startup and shutdown, since additional facilities (e.g. catalyst and reagent volume) may be needed to achieve a particularly low emission limit or to address variability.

API applauds the places in these introductory discussions where the differences between utility boilers and other equipment types are mentioned, but we request that these be strengthened and it be made clearer that project specific estimates, not use of the Control Cost Manual equations, are necessary for determining the cost of applying SNCR to non-boiler installations and to installations on boilers of <25 MW capacity.

Response: While we agree there are some differences between utility and industrial boilers, we believe these differences are not substantial for purposes of treatment in the Cost Manual and that the IPM model is a reasonable and appropriate approach to estimating study-level costs for industrial boilers. As we noted in the SNCR chapter, and in the current cost methodology in the Cost Manual, study-level estimates by their nature incorporate approximations that result in cost estimates that have an accuracy of ±30 percent. Where accurate cost estimates are needed, we

recommend capital and operating costs be determined based on detailed design specifications and quotes from suppliers.

We also disagree that the SNCR chapter should be renamed or otherwise revised to indicate the chapter applies only to boilers greater than 25 MW. The SNCR chapter includes design and cost data for installation of SNCRs that is of general applicability to combustion and process units of any type or size.

Commenter: Coalition of the American Chemistry Council, American Forest & Paper Association, American Fuel & Petrochemical Manufactures, American Wood Council, Brick Industry Association, and Council of Industrial Boiler Owners.
DCN: EPA-HQ-OAR-2015-0341-0022-A1
<u>**Comment:**</u> We feel that the present draft relies too heavily on utility-related combustion units as the basis for control appropriateness, effectiveness, and underlying costs. As we discuss below, there can be significant differences between utility and industrial combustion sources that precludes generalizing emission controls across all types, sizes, and applications. Indeed, the variety of sources and operating characteristics requires a case-specific analysis to pollution control, more than a general "one size fits all" manual. We believe the complexity involved in an analysis of this type obligates EPA to address issues from a very general perspective, as increasing the granularity of the manual only serves to highlight the disparity between sources when applying pollution control.

Response: For the response to this comment, please see the response to the previous comment.

1.1   Introduction

Commenter: Utility Air Regulatory Group and Edison Electric Institute (EEI)
DCN: EPA-HQ-OAR-2015-0341-0026-A2 and EPA-HQ-OAR-2015-0341-0024
<u>**Comment:**</u> UARG notes that a NOx removal rate of 35 percent is generally the maximum level feasible for coal-fired EGU applications of SNCR. The feasible rate of removal depends on numerous factors, including the initial NOx level, boiler size, gas temperature distribution, and the acceptable level of residual ammonia ("NH_3"). Higher levels of NOx reduction through SNCR are only feasible on a site-specific basis where each of these factors heavily favors greater reduction.

Achieving SNCR NO_x reduction greater than 35% from large commercial utility steam generators is very rare, and should not be considered routine commercial practice. There are numerous factors that determine the achievable NO_x reduction by SNCR – the initial NO_x level to be treated; the physical size of the boiler and distances over which reagent is to be injected and dispersed; the gas temperature distribution within the boiler and how it changes with load; the acceptable level of residual NH_3 generated by the process; and fuel type. The potential migration of unit operating capacity factors to highly variable and mostly lower operating capacity can exacerbate this limit to NO_x reduction.

The NOx reduction capability of SNCR strongly depends on the level of residual NH_3 that can be tolerated in the gas stream. EPA in Chapter 1 (Figure 1.1a) presents NOx removal data per unit generating capacity, with most data suggesting the achievable NOx removal of 20-35% from inlet values. The maximum level of achievable NOx reduction using SNCR is about 35% of inlet values. There are numerous factors that affect the achievable level of NOx reduction from SNCR, such as:

- The initial level of NOx. As shown in Figure 1-1c of draft SNCR Chapter 1, a moderate correlation exists between initial NOx content and the achievable NOx removal.

- Size of Boiler. Higher NOx control requires rapid and uniform mixing of reagent within the boiler, and larger physical distances over which to effect uniform mixing presents a challenge.

- Gas Temperature Distribution. The relatively narrow window of gas temperature suitable for SNCR reactions (~1,700 -1,900°F, per Figure 1.4 of Draft SNCR Chapter 1) will rapidly migrate within the boiler with operating conditions and load, and complicate dispersing the reagent within the desired range of temperature.

- Acceptable Level of Residual NH_3. SNCR NOx reduction is directly proportional to the amount of residual NH_3 that can be tolerated, which is typically about 5 ppm. Higher tolerable levels of residual NH_3 can increase the achievable NOx reduction but can induce operating problems, such as ammonium sulfate and bisulfate deposits in the air heater or excessive levels of ammonia in the collected ash.

Achieving NOx reduction of more than 35% is only possible under conditions in which almost all of the preceding factors favor high removal – a high initial level of NOx; relatively small boiler size; uniform gas temperature overall operating modes; and relatively high level of residual NH_3. As the industry evolves to operating scenarios that require significant and "deep" cycling on coal-fired units, gas temperatures within the boiler will become highly variable, challenging the ability to obtain high NOx removal.

Response: We agree with the commenter that SNCR control efficiency can vary considerably between units. Factors such as the temperature profile, residence time, degree of mixing, uncontrolled NOx level, type and amount of reagent injected, allowed ammonia slip, and presence of other compounds in the flue gas (e.g., carbon monoxide, sulfur dioxide, hydrogen, etc.) are known to impact the control efficiency. For additional information on how each of these factors impact SNCR operation and efficiency, please see section 1.2.3 for additional information. While we agree that Figure 1a shows that many SNCR systems installed on utility boilers achieve NOx reduction efficiencies of 20 and 35 percent, we note that Figure 1.1a also shows some SNCR systems are able to achieve higher NOx removal efficiencies. We also note

that Figure 1a shows efficiencies of smaller utility boilers are comparable to those of larger units. We agree that changes in load can impact NOx reduction efficiency by both changing the temperature profile and the inlet NOx concentration. As we noted in Section 1.2.3, variations in flue gas temperature, dimensions of the boiler gas path, and volumetric flow rate of the exhaust gas make the design and operation of SNCR more difficult. Since these factors are not always ideal for all combustion units, some variability in NOx reduction efficiency will occur. While we agree changing loads and fuel conditions can impact performance of SNCR, we note that computational fluid dynamics modeling and use of multiple levels of reagent injection points have been used to alleviate their impact. The SNCR design must be optimized to obtain the maximum NOx reduction possible for each individual combustion unit based on its specific design and operating characteristics.

Commenter: Institute of Clean Air Companies (ICAC)
DCN: EPA-HQ-OAR-2015-0341-0021-A1
Comment: The introduction to Chapter 1 discusses the expected performance of SNCR on various types and sizes of units. SNCR as a process is highly dependent on various operating conditions including baseline NOx, temperature, furnace CO, residence time, furnace geometry and corresponding injector coverage and allowable ammonia slip. These are major factors and lead to a wide range of potential removal efficiencies. The performance of the SNCR systems are more defined by the NOx reduction needs of the units and the allowable ammonia slip for a given process and boiler type.

Response: We agree with the commenter's remarks regarding the performance of SNCR systems. Please also see our response to the comment above.

Commenter: American Petroleum Institute (API)
DCN: EPA-HQ-OAR-2015-0341-0020-A1
Comment: On page 1-8 of draft Chapter 1, general cost information from published studies is provided for installing SNCR on utility boilers and industrial boilers. However, this information is inconsistent with the information presented at the beginning of the cost estimating section on page 1-40. For instance, on page 1-8 it is indicated that costs for utility boiler installations range from $5-20 per kW, while on page 1-40 the costs are reported to be $4-44 per kW. While there is a slight difference in the years of the costs, it would seem appropriate to cite both in both places or to be silent and rely on the cost equations.

Response: The costs included on page 1-7 are based on the White Paper on Selective Non-Catalytic Reduction (SNCR) for Controlling NO_x Emissions, which was published by the Institute of Clean Air Companies, Inc. (ICAC) in February 2008. The paper does not cite a source for the $5-20 per kW capital cost range. However, the capital cost ranges included on page 1-40 are from data reported by utilities to the North Carolina Department of Environment and Natural Resources and show the actual capital costs for SNCRs installed between 2005 and 2007. Therefore, the capital costs cited on page 1-40, which are based on actual data submitted by utility companies, represent the most accurate values currently available. We have added the

North Carolina data to Table 1.3 and corrected the summary of costs stated on page 1-7 as follows:

"In addition, the installed capital cost of SNCR applications ranged from $4-44/kWe (kilowatt) for power generation units based on data for 2005-2007 [49]."

Commenter: Portland Cement Association
DCN: EPA-HQ-OAR-2015-0341-0023-A1
Comment: Approximately sixty seven percent (67%)[1] of the cement kilns in the United States are equipped or will be equipped with SNCR to reduce the emissions of oxides of nitrogen (NOx) as the result of permitting actions or changes to regulatory requirements (*e.g.*, changes for visibility protection/improvement and ozone reduction.) As noted in Chapter 1 of the Cost Manual, the control efficiencies achieved by SNCR systems are variable and relate to site-specific conditions, including but not limited to NOx emissions concentrations prior to ammonia/urea injection and kiln type. In general, achieved control efficiencies are higher than initial predictions, and in a few instances can approach the lower range of efficiency that would be anticipated from use of SCR in cement kiln system applications. Further, SNCR operates more reliably and continuously than SCR. SNCR does not require a thermal bypass, which is required by SCR systems to protect the catalyst from high and low temperature conditions and is used in the manual cleaning of the catalyst. The SCR bypass reduces the overall availability of the control systems in cement kilns. In short, SNCR remains a superior option when comparing the two systems.

Response: The EPA thanks the commenter for their input. The EPA agrees with the commenter that SNCR has been widely implemented for controlling NOx emissions from cement kilns in the U.S. We also agree with the commenter that the control efficiency achieved with SNCR systems varies due to site-specific conditions, including the concentration of NOx in the inlet and the kiln type. We also agree with the commenter that SNCR systems do not require a thermal by-pass. However, we disagree that SNCR is a superior option for NOx control. Although SCR has not been widely implemented in the cement industry, we note that SCR systems have higher control efficiencies than SNCR and have been widely used in other sectors. While we agree with the commenter that there are differences between SNCR and SCR, the Manual is not intended to promote one control technology over another. Instead, the goals of the Manual are to identify and describe the available pollution control technologies, and provide methodologies for estimating the installation and operating costs.

Commenter: Portland Cement Association
DCN: EPA-HQ-OAR-2015-0341-0023-A1
Comment: Capital investments for SNCR for cement kilns are relatively consistent regardless of kiln type or production capacity, and based on industry experience, the expenses range from approximately $1.5 to $2M. Capital costs for SNCR systems at precalciner kilns typically range

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[1] Data collected in an August 2015 PCA member survey (70% of active kilns reporting) indicated that 67% of active kilns either have or will have installed SNCR systems by 2017.

from \$1 to \$2 per ton clinker (T_c). Older, long-wet or long-dry, kilns have lower production capacity than precalciner kilns and a similar capital cost for the installation of SNCR resulting in higher capital costs for SNCR per ton of clinker capacity.

The Cost Manual should recognize that operating costs for SNCR systems can vary significantly from cement plant to plant. SNCR operating costs largely are driven by NOx concentrations, and thus tons of NOx to be controlled. Accordingly costs will vary based on kiln type, kiln feed burnability, cement type, and the type and injection locations for fuel in the specific kiln system. In the "Alternative Control Techniques Document Update – NO_x Emissions from New Cement Kilns" published in November 2007, Table 2-1 provides ranges for uncontrolled NOx emissions for different kiln types. For example precalciner kiln uncontrolled NO_x emissions range from 0.9-7 lb/T_c and long-wet kilns range from 3.6-19.5 lb/T_c. Burnability is the relative ease or difficulty of converting kiln feed to quality clinker, in other words, the amount of fuel required to convert kiln feed to quality clinker. Additional fuel equates to higher NO_x emissions. Different clinker types require changes to the composition of the kiln feed and changes to the burnability. When a portion of the fuel is combusted in a reducing zone, such as mid-kiln firing of tires, or at lower temperatures, such as in a calciner rather than the main kiln burner, lower NOx emissions result.

Response: The EPA agrees with the commenters statements and has added the following paragraph to Section 1.1:

"For cement kilns, the capital costs for SNCR systems range from \$1.5 to \$2 million and are relatively consistent regardless of the type and production capacity of the kiln [59]. Because of their lower production capacities, the capital costs per ton of clinker produced are generally higher for long-wet and long-dry kilns than for preheater/precalciner kilns. One source reported the capital costs for precalciner kilns to be \$1 to \$2 per ton of clinker produced [59]. As for other emission units, SNCR operating costs for cement kilns vary by the level of uncontrolled NO_x emissions and the desired level of NOx control. The higher the uncontrolled NO_x emissions and lower the desired NOx outlet emissions, the greater the quantity of reagent used and hence, higher the operating cost. The NOx emissions differ by kiln type, raw material composition, type of cement produced, fuel type, and fuel injection location [17]."

Commenter: Portland Cement Association
DCN: EPA-HQ-OAR-2015-0341-0023-A1
Comment: The commenter recommended the following edit (shown in red) to paragraph 2 on page 1-1:

"…CO and O_2 concentrations all affect the reduction efficiency of the SNCR[2]."

Response: The EPA thanks the commenter for their input. The requested insert is present in the draft chapter as posted in the docket. Thus, no change is needed based on this comment.

Commenter: Portland Cement Association
DCN: EPA-HQ-OAR-2015-0341-0023-A1
<u>**Comment:**</u> The commenter recommended the following text be added to section 1.1:

"Kiln type, design, raw material burnability, and the type of cement produced by the kiln impact uncontrolled NO_x emissions rates. Kiln type and design also impact the degree of difficulty encountered when installing SNCR injection systems on cement kilns. Typically cement kilns in the U.S. utilize 19% aqueous ammonia as the reagent. Preheater and precalciner kilns are relatively simple SNCR installations. Long wet and dry kiln SNCR installations require different SNCR installations than preheater or precalciner kilns. There are two types of SNCR systems that have been utilized on long kilns. The first requires the installation of a rotary valve at the feed end of the kiln and require the reagent piping to pass in and out of the kiln wall in order to reach the optimum temperature zone within the rotating kiln. The second is the Cadence™ system which consists of a manifold affixed to the kiln with a slight opening through which a fixed ammonia pipe continuously feeds ammonia reagent at a fixed rate.

In general, control efficiencies when utilizing SNCR on cement kilns have improved and in some cases are higher than projected. SNCR systems on cement kilns are reliable control systems. The combination of improved control efficiency for SNCR and high availability, when compared to SCR systems, results in overall control efficiencies approaching those for SCR at significantly lower capital costs and maintenance expenditures."

<u>**Response:**</u> We agree with the commenter that the type of kiln, raw material composition, and type of cement produced impact NOx emission rates from cement kilns. We also agree with the commenter that SNCR is easier to install on preheater/precalciner kilns than on long wet and dry kilns. In preheater/precalciner kilns the SNCR injection ports can be installed in the combustion zone in the calciner, the oxidation zone of the upper air inlet before the deflection chamber, or in the area after the mixing chamber before the inlet to the bottom cyclone. In a long kiln, the appropriate temperature window is in the middle of the kiln and because of the rotating nature of a long kiln, injection of ammonia- or urea-based reagents is technically more difficult. The technology developed for mid-kiln firing that allows injection of material once during each kiln revolution was thought to be impractical for SNCR. However, tests on wet kilns in France suggest that injection of urea into long-wet kilns may be possible if mixing is induced and volatilization or decomposition of the urea is delayed by inserting it in a solid form in a carrier such as a tire. As the commenter noted, mixing in rotary kilns can be improved using systems such as the Cadence™ system, which injects air and reagent into the rotary kiln.

The following text was incorporated into section 1.1:

"For cement kilns, the kiln type, design, raw material composition, and the type of cement produced by the kiln impact uncontrolled NOx emissions rates. Kiln type and design also impact the degree of difficulty encountered when installing SNCR injection systems on cement kilns. Preheater and precalciner kilns are relatively simple SNCR installations. In preheater/precalciner kiln design, the SNCR injection ports can be installed in the combustion zone in the calciner, the

oxidation zone of the upper air inlet before the deflection chamber, or in the area after the mixing chamber before the inlet to the bottom cyclone. In the long wet and dry kiln designs, the appropriate temperature window is in the middle of a kiln. Because of the rotating nature of a long kiln, continuous injection of ammonia- or urea-based reagents is technically more difficult and the technology developed for mid-kiln firing that allows injection of material once during each kiln revolution was thought to be impractical for SNCR. However, tests on wet kilns in France showed that injection of urea into long wet kilns was possible if mixing is induced and volatilization or decomposition of the urea is delayed by inserting it in a solid form in a carrier such as a tire [17]. According to one source, SNCR systems for long kilns may use one of two designs. The first requires the installation of a rotary valve at the feed end of the kiln and require the reagent piping to pass in and out of the kiln wall in order to reach the optimum temperature zone within the rotating kiln. The second is the Cadence™ system, which consists of a manifold fixed to the kiln with a small opening through which ammonia reagent is continuously fed at a fixed rate."

Commenter: Coalition of the American Chemistry Council, American Forest & Paper Association, American Fuel & Petrochemical Manufactures, American Wood Council, Brick Industry Association, and Council of Industrial Boiler Owners.
DCN: EPA-HQ-OAR-2015-0341-0022-A1
Comment: Page 1-3 states that SNCR is used at pulp and paper process units; but this is not correct. In the early 1990's, a 2-week SNCR trial was run on a recovery furnace at a Swedish mill, but the equipment was decommissioned shortly thereafter.[2] Although SNCR is in use on some industrial boilers at forest products facilities, we do not know of any pulp and paper mill process equipment currently using SNCR, and the long term effects of operating SNCR on a chemical recovery furnace are unknown.

Response: We agree with the commenter's remarks and have made the following revisions to page 1-3:
"SNCR is now used beyond the electric power industry, and is currently being used to control NO_x emissions from a multitude of combustion sources, including industrial boilers, electric utility steam generators, thermal incinerators, cement kilns, pulp and paper power boilers, steel industry process units, refinery process units, and municipal solid waste energy recovery facilities [1, 2, 3]."

Commenter: Coalition of the American Chemistry Council, American Forest & Paper Association, American Fuel & Petrochemical Manufactures, American Wood Council, Brick Industry Association, and Council of Industrial Boiler Owners.
DCN: EPA-HQ-OAR-2015-0341-0022-A1
Comment: Industrial combustion units are a very diverse group, and are mostly one-of-a-kind applications. Any control technology feasibility analysis will be site-specific, and consider an

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[2] See NCASI Special Report 03-06, Effect Of Kraft Recovery Furnace Operations On Nox Emissions: Literature Review and Summary of Industry Experience, October 2003.

individual unit's age, retrofit difficulty factor, temperature profile, design, outlet conditions, load variability, capacity factor, fuels, and current pollution control systems. Some units are good candidates for application of SNCR, while others are not. Industrial boilers operate at greater turndown ratios than utility boilers and do not maintain sufficient temperature at low loads to sustain the necessary SNCR reactions. Industrial boilers can also experience more frequent and more dramatic load swings than utility boilers, resulting in rapid changes in the temperature at a given point in the flue gas path, thus limiting the ability to adequately control the point of reagent injection while maintaining the appropriate NOx emissions and ammonia slip.

Response: We agree that all control technology analysis should recognize that site-specific attributes are important to consider and that SNCR may not be feasible for all units. The second paragraph in the introduction to the chapter indicates that SNCR reduction efficiencies vary over a wide range, and lists a number of factors that affect the achievable reduction. These factors are discussed in greater detail in section 1.2.3. For further clarification, we have added the following text to section 1.1:

"Factors such as the temperature, residence time, reagent distribution in the flue gas, and CO/O_2 concentrations may be affected by the age, design, load variability, and capacity factor of the combustion unit. Fuel type and composition can also affect these parameters. However information on these characteristics is not available for the units profiled in Tables 1.1 and 1.2 and Figures 1.1a, 1.1b, and 1.1c. However, we note that some SNCR systems are designed with reagent injection ports at different locations to address changes in the temperature profile due changes in fuel type and load."

We also agree that low load operation can impact SNCR operation. However, we note that some SNCR systems are designed with reagent injection ports at different locations to address changes in the temperature profile due to changes in fuel type and load. We have added the following paragraph to the discussion of temperature in section 1.2.3:

"Combustion units operated at low load or with different fuels may result in changes in the temperature profile in the combustion unit. In some cases, temperatures may be below the optimum required for achieving NOx reductions. To address this concern, some SNCR systems are designed with multi-level reagent injection locations, temperature sensors, and automatic controls to allow switching between injection ports. These systems ensure that reagent is always injected at the location with the optimum temperature for NOx reduction."

Commenter: Institute of Clean Air Companies (ICAC)
DCN: EPA-HQ-OAR-2015-0341-0021-A1
Comment: Table 1.2 should be modified. Utility and coal fired boilers should not be considered separate categories. Similarly, MSW and MW should also be combined. The comparisons in Table 1.2 could be misleading.

Response: The EPA agrees. Table 1.2 has been revised such that the data for utility and coal-fired boilers and the data for MSW and MW have been combined into single categories.

Commenter: Institute of Clean Air Companies (ICAC)
DCN: EPA-HQ-OAR-2015-0341-0021-A1
Comment: If Figures 1.1a and 1.1b represent a variety of projects, then the coverage and distribution issues are part of the individual performance levels. Large units typically have less than optimal coverage, which can reduce performance compared to smaller units. The variety of data points in Figures 1.1a and 1.1b most likely include different ammonia slip values for the various projects. It is very unlikely that all performance for the various cases use the same allowable ammonia slip, and this is a critical parameter to define when comparing SNCR performance on different sized units. Industrial applications often allow a minimum of 10 ppmv slip, with many installations having slip limitations of 20 ppm or higher. For the curve to be more meaningful, the data should be grouped according to ammonia slip levels. In addition, the characterization that ammonia as reagent performs better than urea has more to do with performance of ammonia based systems on fluidized bed boilers, which often have higher ammonia slip limits. Ammonia applicability is limited based on furnace coverage and temperature window limitations, and urea reagent provides maximum reagent flexibility. It is also important to note that urea has a higher effective temperature window and a higher allowable urea release point, and that there are no ammonia SNCR systems on utility boilers.

There is a misperception about SNCR and the ability to perform over a wide boiler range. SNCR systems are designed using multiple levels of injection to accommodate quick changes in boiler load. The SNCR systems are designed to allow for injection in the optimal temperature window, which changes based on boiler load. Systems can accommodate 25% to 100% MCR load, and the control systems typically use boiler load as the feed forward signal. The proper injection locations can be designed into a system based on boiler load and temperatures. Systems need to be operated in automatic mode with multiple levels of injectors. Several customers in the early 1990s installed systems without automatic load following capability and cutback on the number of injectors. The systems were designed to manually change injectors from one level to another as a basis for operation. The resulting performance was not indicative of SNCR technology and its capabilities.

Response: We agree with the commenter that the data in Figures 1a and 1b represents NOx efficiencies achieved with different levels of ammonia slip. While we agree that it would be useful to show the NOx reduction efficiencies grouped by ammonia slip level, we do not have the data to make this revision. We also agree with the commenter that SNCR systems can accommodate changes in load using systems with multiple levels of reagent injection points, temperature monitors, and control systems. With regard to the comments concerning the use of reagent injectors at multiple levels, see the response to the previous comment for discussion of this issue and for the additional text we included in Section 1.2.3.

1.2   Process Description

Commenter: Portland Cement Association
DCN: EPA-HQ-OAR-2015-0341-0023-A1
Comment: The commenter recommended the text in section 1.2 be revised as follows:

"Single- and multi-level injection systems for boiler SNCR installations can be effective for NO_x reduction. Using different injector configurations can increase efficiency and reduce capital and operating costs. Several new approaches are currently being used in addition to conventional SNCR installations, including SNCR Trim, Rich Reagent Injection, NO_xSTAR, and ROTAMIX."

Response: The EPA disagrees with the change recommended by the commenter. Both single and multi-level injection systems have been found to be effective in controlling NO_x emissions from other sources, including cement kilns. For example, an SNCR system at the Slite cement plant in Sweden reportedly reduced NOx emissions to about 1lb per ton of clinker using an SNCR with 12 injection points at multiple levels.[3]

1.2.1   Reduction Chemistry

Commenter: Institute of Clean Air Companies (ICAC)
DCN: EPA-HQ-OAR-2015-0341-0021-A1
Comment: On page 1-12, the statement that the primary byproduct formed in SNCR systems is nitrous oxide (N_2O) is not accurate. The data referenced were published in 1993 prior to the understanding that elevated N_2O levels in flue gas samples were an artifact of the sampling and analytical methodology in use at the time. These results were later disproven after the advent of continuous N_2O emissions analyzers, which showed that N_2O formation in SNCR systems was not significant.

Response: We have not identified any studies that support the commenter's statement. However, more recent studies have documented the formation of N_2O. For example, research conducted in Europe indicate a N_2O stack concentration range of between 20 and 60 mg/m^3, with higher levels for those situations where a higher NOx removal is required. If the systems is properly optimized, conversion rates with ammonia can be easily reduced to below 2%, while with urea this can be reduced to about10%. Their research also indicate N_2O formation increases when the temperature in the section where the reactant is introduced falls below 850 – 900°C.[4, 5] Therefore, for the final chapter, EPA retained the statement that N_2O is a byproduct of SNCR systems.

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[3] Horton, J., Linero, A. and Miller, F.M., *Use of SNCR to Control Emissions of Oxides of Nitrogen from Cement Plants,* IEEE, 2006
[4] European Commission (2006). "Reference document on Best Available Techniques for Waste Incineration". Brief on Waste Incineration, August 2006.
[5] Grosso, M. and Rigamonti, L. Politecnico di Milano – DIIAR – Environmental section. *Experimental Assessment of N₂O Emissions From Waste Incineration: the Role of NOx Control Technology. Available at http://www.iswa.org/uploads/tx_iswaknowledgebase/3-311paper_long.pdf.*
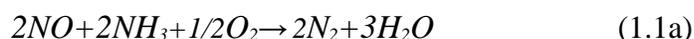
Commenter: Arizona Public Service Company (APS)
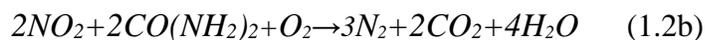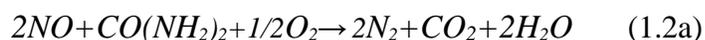**DCN: EPA-HQ-OAR-2015-0341-0028-A1**
Comment: Page 1-11, section 1.2.1: This section should note that although NO_x is mostly NO, NO_x is calculated as NO_2 for emissions purposes. Therefore, the major NO_2 reactions should also be included here.

Response: The EPA has added the following equations showing the reaction of NO_2 with ammonia and urea to section 1.2.1 and renumbered equations 1.1 and 1.2 as 1.1a and 1.2a, respectively. Hence, the section now reads as follows:

"Since NOx includes both NO and NO_2, the overall reactions with urea and ammonia are as follows:

$$2NO+2NH_3+1/2O_2 \rightarrow 2N_2+3H_2O \qquad (1.1a)$$

$$2NO_2+4NH_3+O_2 \rightarrow 3N_2+6H_2O \qquad (1.1b)$$

The urea reaction equations for NO and NO_2 are:

$$2NO+CO(NH_2)_2+1/2O_2 \rightarrow 2N_2+CO_2+2H_2O \qquad (1.2a)$$

$$2NO_2+2CO(NH_2)_2+O_2 \rightarrow 3N_2+2CO_2+4H_2O \qquad (1.2b)$$

Equations 1.1a and 1.2a are the predominant reactions because the 90 to 95% of NO_x in flue gas from combustion units is NO. The reaction occurs as a two-step process in which the ammonia reacts with available hydroxyl radicals to form amine radicals and water [17]

$$NH_3+OH \rightarrow NH_2+H_2O$$
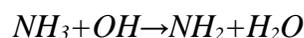
The amine radicals combine with nitrogen oxides to form nitrogen and water:

$$NH_2+NO \rightarrow N_2+H_2O"$$
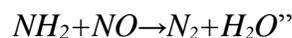
1.2.2 SNCR Process Description

Commenter: Institute of Clean Air Companies (ICAC)
DCN: EPA-HQ-OAR-2015-0341-0021-A1
Comment: On Page 1-13, Section 1.2.2, 19% ammonia solution is the most common concentration used when it comes to aqueous ammonia. Concentrations higher than 19% often have Department of Transportation restrictions.

Response: The EPA agrees with the commenter that a 19% aqueous ammonia solution is a commonly used reagent for SNCR. Table 1.4 has been revised to indicate that 19% aqueous ammonia solution is commonly used. Section 1.2.2 has been revised as shown below:

"Ammonia can be supplied in either aqueous or anhydrous form. Anhydrous ammonia is a gas at normal atmospheric temperature and must be transported and stored under pressure, which presents safety issues and increases transportation cost [23]. Aqueous ammonia is generally transported and stored at a concentration of 29.4% ammonia in water. At concentrations above 28%, storage of ammonia may require a permit; therefore, some applications of SNCR use aqueous ammonia solutions of 19% [29]. For example, most U.S. cement plants use a solution of 19-20% aqueous ammonia reagent, while some cement plants in Europe use 25% ammonia solutions [17, 60]. Decreasing the concentration, however, increases the required storage volume and associated transportation costs. Ammonia may be injected either as a vapor or as an aqueous solution." [6],[7]

Commenter: Portland Cement Association
DCN: EPA-HQ-OAR-2015-0341-0023-A1
Comment: The commenter recommended the text in section 1.2.2 be revised as follows:

"Ammonia can be supplied in either aqueous or anhydrous form. Anhydrous ammonia is a gas at normal atmospheric temperature and must be transported and stored under pressure, which presents safety issues and increases transportation cost [23]. Aqueous ammonia is generally transported and stored at a concentration of 29.4% ammonia in water. At concentrations above 28%, storage of ammonia may require a permit; therefore, some recent boiler applications of SNCR are using a 19% solution [29]. U.S. cement plants also typically utilize a 19% aqueous ammonia solutions for the SNCR reagent. Decreasing the concentration, however, increases the required storage volume and associated transportation costs. Ammonia is generally injected as a vapor. Providing sufficient ammonia vapor to the injectors requires a vaporizer, even though the 29.4% solution has substantial vapor pressure at normal air temperatures. The injection system equipment for vapor systems is more complicated and expensive than equipment for aqueous systems (see Section 1.2.4, SNCR System)."

Response: The EPA agrees with the commenter that aqueous ammonia solutions are commonly used. See the revisions to section 1.2.2 shown in the response to the previous comment.

1.2.3 SNCR Performance Parameters

Commenter: Coalition of the American Chemistry Council, American Forest & Paper Association, American Fuel & Petrochemical Manufactures, American Wood Council, Brick Industry Association, and Council of Industrial Boiler Owners.
DCN: EPA-HQ-OAR-2015-0341-0022-A1
Comment: The figures presented in Chapter 1 (including 1.1, 1.4, 1.5, 1.6, 1.7, and 1.8) show significant differences in the maximum NOx reduction efficiency achievable with SNCR,

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[6] U.S. EPA, *Alternative Control Techniques Document Update – NO$_x$ Emissions from New Cement Kilns,* EPA-453/R-07-006, November 2007.
[7] Miljö, Petro, *NOx Lower than 200 mg/Nm^3?* International Cement Review, February 2011.

ranging anywhere from 35% to 95% (in Figures 1.4 and 1.5). A number these figures do not appear to be referenced, which makes it impossible to determine the types of emission sources to which the results refer. This ambiguity results in uncertainty about the appropriate removal efficiencies for use in estimating SNCR performance for a particular application.

Response: Figures 1.1a and 1.1b show NO_x reduction efficiencies for various sizes of utility and industrial boilers, respectively. Figure 1.1c shows NO_x reduction efficiencies versus NO_x inlet concentrations for coal fired EGUs. Figures 1.4 through 1.8 are graphical representations that are designed to show the effect of various factors on SNCR control efficiency. The actual NO_x reduction efficiencies for a given SNCR system will vary from one unit to another based on several factors, including the design of the combustion unit, temperature range, residence time, and the composition of the flue gas. To clarify that these figures are intended as only graphical illustrations and should not be used to estimate NO_x reduction efficiencies for a particular SNCR unit, we have replaced the values on the y-axis with an arrow to delineate increasing NOx efficiency.

Commenter: Institute of Clean Air Companies (ICAC)
DCN: EPA-HQ-OAR-2015-0341-0021-A1

Comment: Section 1.2.3 discusses the design factors and their impact on SNCR performance. CO and O_2 levels should be added to the list based on their impact on performance. High CO levels will lower the temperature range in which SNCR is effective.

Response: We agree with the commenter that CO and O_2 levels impact SNCR performance and have added CO and O_2 concentrations to the discussion of design and operational factors. As noted by the commenter and shown in various studies, the CO and O_2 concentrations impact the temperature at which NO_x reduction occurs. We have therefore added the following additional explanation to the Section 1.2.3:

"High CO concentrations have been shown to lower the optimum reaction temperature, widen the temperature window, and reduce the NO_x control efficiency.[8, 9, 10, 11, 12] Researchers believe this occurs because CO competes for the hydroxyl free radicals that are required for NO to be converted to N_2. Researchers also note that CO effects may be compounded in systems using urea because CO is generated during urea dissociation. Since oxygen is needed to generate the hydroxyl free radicals, flue gas with high CO concentrations and low O_2 concentrations will reduce the NO_x control efficiency. However, some studies have shown that increasing the O_2

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[8] Suhlmann, J., Rotzoll, G., *Experimental Characterization of the Influence of CO on the High Temperature Reduction of NO by NH₃,* Fuel, 72, 1993.

[9] Caton, J.A., Siebers, D.L., *Comparison of Nitric Oxide Removal by Cyanuric Acid and By Ammonia,* Combustion Science Technology, 65, 1989.

[10] Alzueta, M.U., Rojel, H., Kristensen, P.G., Glarborg, P., Dam-Johansen, K., *Laboratory Study of the CO/NH₃/NO/O₂ System: Implications for Hybrid Reburn/SNCR Strategies,* Energy Fuels, 11, 1997.

[11] Bae, S.W., Roh, S.A. and Kim, S.D., *NO Removal By Reducing Agents and Additives in the Selective Non-catalytic Reduction (SNCR) Process,* Chemosphere, 65, 2006.

[12] Institute of Clean Air Companies, Inc., *White Paper: Selective Non-Catalytic Reduction (SNCR) for Controlling NOx Emissions,* February 2008.

concentration above 2.4% can promote NO_x reduction by providing sufficient hydroxyl free radicals for the NO to N_2 reaction. Higher oxygen levels also promote the conversion of CO to CO_2, which is believed to create localized areas of high temperature due to the release of heat from CO_2 formation.[13]"

Commenter: Institute of Clean Air Companies (ICAC)
DCN: EPA-HQ-OAR-2015-0341-0021-A1
<u>Comment:</u> On Page 1-19, there is a discussion on ammonia slip from SNCR. Utility units typically have ammonia slip limits of 5 to 10 ppmv. The fuel sulfur content can be the limitation, with 5 ppm being the limit required for higher sulfur fuel applications. Industrial units have historically been given much wider allowable range, with some applications having permit limits of 20 ppmv or larger.

<u>Response:</u> We thank the commenter for this comment, and have incorporated this information into the chapter as follows.

"Limits on acceptable ammonia slip, imposed by either regulatory limits or design requirements, place constraints on SNCR performance. For example, some utilities have ammonia slip limits of 5 to 10 ppmv. Injection of urea at higher NSR values can improve NO_x reduction, but may also increase ammonia slip. The sulfur content of the fuel can also restrict the amount of ammonia injected due to the formation of ammonium sulfate and bisulfate salts that can deposit on air heater surfaces and cause plugging and reduced efficiency. Combustion units that burn fuels with high sulfur contents are generally limited to ammonia slip levels of 5 ppm to help minimize the formation of ammonium sulfate and bisulfate."

Commenter: Arizona Public Service Company (APS)
DCN: EPA-HQ-OAR-2015-0341-0028-A1
<u>Comment:</u> Page 1-19, Ammonia Slip: The chapter states that increased NSR may increase ammonia slip. It should say it will increase ammonia slip.

Response: EPA disagrees with the commenter that higher NSR values will always result in increased ammonia slip. As discussed in the Cost Manual, several factors impact ammonia slip, including how well the reagent is mixed, the residence time, the temperature, the NO_x, sulfur dioxide, carbon monoxide and oxygen concentrations in the flue gas, and the rates of competing chemical reactions.

Commenter: Institute of Clean Air Companies (ICAC) and the Coalition of the American Chemistry Council, American Forest & Paper Association, American Fuel & Petrochemical Manufactures, American Wood Council, Brick Industry Association, and Council of Industrial Boiler Owners.
DCN: EPA-HQ-OAR-2015-0341-0021-A1 and EPA-HQ-OAR-2015-0341-0022-A1

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[13] Horton, J., Linero, A., and Miller, F.M., *Use of SNCR to Control Emissions of Oxides of Nitrogen From Cement Plants,* IEEE, 2006.

Comment: Figure 1.6 (for which a reference is not provided) is not accurate. It indicates that a NO_x reduction efficiency of 20% is feasible for a unit with an inlet NO_x concentration of 30 ppm, but this is not true in practical applications. The chemical kinetics limit the effectiveness of the reduction reaction at low inlet concentrations. The figure also suggests that the reduction efficiency increases as the temperature drops below 1600°F. However, in reality, most of the ammonia will pass unreacted through the unit at temperatures below 1600°F.

Response: Figure 1.6 provides NO_x reduction efficiency data for urea injection for temperatures above 1600°F. We agree with the commenter that kinetics limit the effectiveness of the NO_x reduction reaction at low NO_x concentrations. The data shown in Figure 1.6 is based on a pilot-scale study conducted by Dr. Lawrence Muzio[14,15] using urea. The figure is provided only as an example to illustrate how the inlet NO_x concentration effects control efficiency. Actual control efficiencies in commercial applications are likely to differ from those shown in the figure due to site-specific factors, such as degree of mixing, residence time, type and quantity of reagent used, and carbon monoxide concentrations. However, the trends shown in the figure are expected to be comparable to those experienced in commercial applications.

Commenter: Portland Cement Association
DCN: EPA-HQ-OAR-2015-0341-0023-A1
Comment: The commenter recommended the text in section 1.2.3 be revised as follows:

"Ammonia in the flue gas stream has several negative impacts. As shown in Table 1.4, ammonia has a detectable odor at levels of 5 ppm or greater and poses a health concern at levels of 25 ppm or greater. It can cause a stack plume visibility problem by the formation of ammonium chlorides, which occur when burning fuels containing chlorine compounds. Furthermore, ammonium bisulfate and ammonium sulfate form when burning sulfur-containing fuels or when cement kiln raw materials contain pyritic sulfur. Ammonia-sulfur salts can plug, foul, and corrode downstream equipment such as air heaters, ducts, and fans. Lastly, the ability to sell the fly ash as a secondary product is affected by its ammonia concentration. Ammonia slip impacts are discussed further later in this chapter in Section 1.2.5, Other Considerations."

Response: The EPA agrees with the commenter that raw materials that contain pyritic sulfur used in cement kilns can be another source of sulfur. SO_2 can be as much as two orders of magnitude greater when pyritic sulfur is present in raw materials and will react with unreacted ammonia from the SNCR process or from raw materials to produce ammonium bisulfate, ammonium sulfate, and ammonium bisulfite.[16] We have made the recommended revisions to Section 1.2.3.

Commenter: Arizona Public Service Company (APS)
DCN: EPA-HQ-OAR-2015-0341-0028-A1

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[14] See https://web.anl.gov/PCS/acsfuel/preprint%20archive/Files/38_2_DENVER_03-93_0699.pdf.

[15] Muzio, L.J. and Arand, J.K., *Homogeneous Gas Phase Decomposition of Oxides of Nitrogen,* Electric Power Research Institute Report, EPRI 461-1, July 1976.

[16] U.S. EPA, Office of Air Quality Planning and Standards, *Alternative Control Techniques Document Update – NOx Emissions from New Cement Kilns,* EPA-453/R-07-006, November 2007.

Comment: Page 1-17, Normalized Stoichiometric Ratio: The chapter should note that NO_2, which is typically about five percent of the total NO_x, requires about two moles of ammonia for conversion. Also, because certain low NO_x burners can produce higher percentages of NO_2, the five percent cannot always be assumed.

Response: The EPA agrees with the commenter that NO_2 theoretically requires 2 moles of ammonia to each mole of NO_2. We have revised the discussion of the normalized Stoichiometric ratio as follows:

" . . . Theoretically, based on reaction equations 1.1(a) and (b) and 1.2(a) and (b), two moles of NO can be removed with one mole of urea or two moles of ammonia and one mole of NO_2 requires one mole of urea and two moles of ammonia. Since NO_x is mostly comprised of NO (approximately 95%), the theoretical NSR for NO_x is close to one mole of ammonia per mole of NO_x and 0.5 moles of urea per mole of NO_x. In practice, more than the theoretical amount of reagent needs to be injected into the boiler flue gas to obtain a specific level of NO_x reduction. .. ."

Commenter: Portland Cement Association
DCN: EPA-HQ-OAR-2015-0341-0023-A1
Comment: The commenter recommended the following text be added to section 1.2.3:

"Raw materials at some cement kilns contain constituents that when heated release ammonia to the kiln gas stream. This raw material related ammonia can result in ammonia emissions significantly higher (values of 80 ppm or greater) than the typical ammonia slip from SNCR (10 ppm or less). Therefore, for cement kilns it is important to understand the rate of raw material derived ammonia emissions before designing SNCR control systems and establishing limits on ammonia slip. The ammonia derived from raw materials will not reduce NO_x emissions as it is released at the top of the preheater tower or the back end of the long kiln where temperatures are below the appropriate temperature range for the ammonia to react with NO_x."

Response: The EPA agrees that raw materials used at some cement kilns result in ammonia emissions that should be taken into account when designing an SNCR control system. However, we have been unable to confirm the commenter's statements regarding the level of ammonia emissions from raw materials and that ammonia derived from raw materials does not react with NO_x. Therefore, we have included the following text in section 1.2.3 of the final version of the Chapter:

"Raw materials at some cement kilns contain constituents that when heated release ammonia to the kiln gas stream. Therefore, for cement kilns it is important to understand the rate of raw material derived ammonia emissions before designing SNCR control systems and establishing limits on ammonia slip."

Commenter: Arizona Public Service Company (APS)

DCN: EPA-HQ-OAR-2015-0341-0028-A1

Comment: Page 1-20, Section 1.2.3: The cost for ammonia monitoring appears to be based only on the incremental cost of the instrumentation and does not take into consideration the complete monitoring system. The chapter should be clear as to what equipment is included in this cost estimate.

Response: The costs cited in section 1.2.3 are the purchase costs for the ammonia monitoring instrument and do not include any other costs for any ancillary equipment or installation. Note that capital and operating costs for monitoring systems must be estimated separately using the methodology presented in Section 2, Chapter 4 (Generic Equipment and Devices) of the Cost Manual. The following changes were made for clarification:

"The cost to purchase one ammonia slip monitoring instrument is estimated to be $40,000 for a single measurement point and up to $70,000 ~~in capital cost~~ for three measurement points."

Commenter: Institute of Clean Air Companies (ICAC)
DCN: EPA-HQ-OAR-2015-0341-0021-A1
Comment: On Page 1-26, the statement in Section 1.2.5 conflicts with Page 1-7. The only real area of costs savings for a new unit include boiler penetrations being built into a new unit, compared to the additional cost to retrofit boilers to install ports in the field. The equipment installation and fabrication are largely unaffected when evaluating new unit installations compared to retrofits.

Response: The EPA thanks the commenter for their input. We agree with the commenter that the costs of installing SCRs on new units is slightly less than for retrofits. One study indicates that capital costs for new units are generally between 9 to 23 percent less than comparably sized SCR retrofits. To account for the differences in costs between new and retrofit SCR installations, we have revised the methodology for estimating capital costs in Section 1.4.1. The revised total capital investment (TCI) equations include a retrofit factor (RF). The equations in Section 1.4 are those developed by EPA's CAMD for the IPM. The IPM is based primarily on costs for retrofitting SCRs to existing boilers. Hence, a retrofit factor of 1 is used for SCR retrofits. For new units, a retrofit factor of 0.84 is used since the costs for new units is on average 16 percent less than for retrofits.

We disagree with the commenter's statement that the discussion in Section 1.2.5 conflicts with that on page 1-7. On page 1-7 we noted that the costing algorithms were based on retrofit applications of SNCR to existing coal-fired utility boilers and acknowledge that we have limited information regarding SNCR costs for new installations but would expect the costs to be slightly lower than those for retrofits. In Section 1.2.5, we indicate that the capital costs estimated using the methodology provided in the Cost Manual are for retrofit SNCRs. We also again acknowledged the limited cost information available and provided some information from the early 1990s that suggests costs of retrofit installations ranged from 10-30% higher than for new installations. We agree with the commenter's statement that equipment costs would be the same between new and retrofit SNCRs and note that the only additional costs would be for relocating watertubes, removing asbestos, or moving ductwork or other equipment to make space for the

SCNR equipment. As we noted on page 1-7, we consider the method for estimating capital costs to be applicable to both new and retrofit SNCRs for the purposes of a study-level cost estimate, which has an accuracy of ±30%.

Commenter: Coalition of the American Chemistry Council, American Forest & Paper Association, American Fuel & Petrochemical Manufactures, American Wood Council, Brick Industry Association, and Council of Industrial Boiler Owners.
DCN: EPA-HQ-OAR-2015-0341-0022-A1
<u>**Comment:**</u> It is not accurate to state that "ammonia slip results from operational settings" (see Page 1-18). While ammonia slip will increase as the reagent injection rate increases, slip may also be a result of poor injection system design or maintenance that produces a poor distribution of the reagent in the duct.

<u>**Response:**</u> Amount of ammonia slip is impacted by many factors, including mixing, residence time, NO_x inlet concentration, temperature, level of CO and sulfur in the exhaust gas, and rate of reagent injection. We agree the commenter that ammonia injection systems with poor distribution of reagent would have lower NO_x reduction efficiency and potentially higher levels of ammonia slip than SNCR systems with well-designed and maintained injection systems operated with the same ammonia injection rate. In addition, a higher reagent injection rate would be necessary to achieve the same level of NO_x reduction as achieved by a system with a well-designed and maintained injection system to overcome the system's inherent limitations. Ammonia slip differs from one system to another, based on each systems limitations. Although the level of ammonia slip will differ from one unit to the next, for any individual unit the ammonia slip is based on the ammonia injection rate – an operational setting. For clarification, we have made the following revisions to the discussion of ammonia slip in Section 1.2.3:

"Ammonia slip results from excess reagent injection to overcome inherent natural system limitations to obtain the desired level of NO_x reduction. Although the level of ammonia slip will differ from one unit to the next based on the limitations inherent to each system, for any individual SNCR, the NO_x reduction <u>and</u> ammonia slip are established by the reagent injection rate – an operational setting that can be adjusted based on the desired NOx reduction and allowed ammonia slip."

1.2.4   Other Considerations

Commenter: Portland Cement Association
DCN: EPA-HQ-OAR-2015-0341-0023-A1
<u>**Comment:**</u> The commenter recommended the following be added to Table 1.5: Urea-based SNCR System Equipment, in section 1.2.4:

Rotary valve installation or Cadence™ manifold system	For long wet or dry cement kilns only

Response: We agree with the commenter that additional equipment is needed for installation of SNCR on long-wet and -dry cement kilns. We have revised Table 1.5 as shown below:

Air compressor Distribution modules (1 to 5 modules)	Rotary type (including long wet and dry cement kilns) Urea solution distribution module consisting of,
	• Valved connections for urea and atomizing air (e.g., Cadence™ system),
	• Isolation valve and a pressure control valve for the air/urea supply to each injector,
	• Pressure indicator for air/urea supply to each injector,
	• Flow indicator for urea supply to each injector

Commenter: Institute of Clean Air Companies (ICAC)
DCN: EPA-HQ-OAR-2015-0341-0021-A1
Comment: Commenter noted that Section 1.2.4 provided a good general description of an SNCR but noted that SNCR manufacturers may use different configurations. The commenter also noted that Page 1-20 refers to ammonia as being injected as a vapor. While that is true for anhydrous ammonia based systems, most aqueous ammonia based systems inject a liquid into the flue gas. The commenter made the following recommendations for changes to Section 1.2.4:

"There were two original basic designs for the application of SNCR. The first was an ammonia based system known as Thermal DeNOx that was developed and patented by Exxon Research and Engineering Company in 1975. The second system was developed and patented by the Electric Power Research Institute (EPRI) in 1980. It is a urea-based process known by the trade name NOx OUT. The technology was originally licensed to Fuel Tech, which held several additional patents that claimed improvements and enhancements to the basic process. Since that time, there have been a number of variations and improvements to the urea SNCR process, which are noted in Section 1.2.

These steps are common to both urea and ammonia SNCR; however, the design and equipment specifications for the two systems are different, because anhydrous ammonia-based systems use the injection of vapor while urea is injected as an aqueous solution. Aqueous ammonia based SNCR systems are very similar to aqueous urea systems in terms of the overall system approach of injecting solution, and therefore are similar in terms of equipment. Anhydrous and aqueous ammonia based systems can be effective on units where the injection temperatures are in the range of 1600 – 1800°F. However, urea is typically used in large boiler applications of SNCR because it is safer to store, has better dispersion properties, and can use urea droplet evaporation for effective injection at much higher temperatures found in utility furnace applications. Ammonia-based systems have been effective on industrial boilers and some fluidized bed utility boilers, but urea is the dominant reagent for utility furnace applications. . . ."

The reagent injection systems used for anhydrous ammonia-based systems are generally more complicated and expensive than those used in urea-based systems [29]. These systems inject gas-phase ammonia rather than an aqueous solution. For this reason, anhydrous ammonia-based systems often use high-energy lance systems with multiple injectors. The lances are placed in a grid formation across the width and height of the boiler passes."

Response: In general, we agree with the commenter's recommended revisions to Section 1.2.4 and have made the revisions shown below based on their comments. We did not include the sentence regarding the temperature range for ammonia-based systems since temperature is already discussed in detail in Section 1.2.3. Also, the upper temperature range of 1800 ºF recommended by the commenter does not agree with other sources who indicate ammonia may be used up to temperatures of around 2000ºF.[17,18, 19]

The following changes were made to Section 1.2.4:

"Two basic designs for the application of SNCR were developed in the 1970s and early 1980s. The first was an ammonia based system known as Thermal DeNO$_x$ that was developed and patented by Exxon Research and Engineering Company in 1975 [69, 70]. The second was a urea-based system known as NOx OUT that was developed and patented by the Electric Power Research Institute (EPRI) in 1980 and subsequently licensed to Fuel Tech [71, 72]. Since that time, there have been a number of variations and improvements to the urea SNCR process, which are noted in Section 1.2. . . ."

"These steps are common to both urea and ammonia SNCR applications; however, the design and equipment specifications for SNCR systems may vary. For example, SNCR systems using anhydrous ammonia inject the reagent as a vapor, while systems using aqueous ammonia solutions and urea-typically inject the reagent as an aqueous solution. Urea is typically used in large boiler applications of SNCR because it is safer to store, has better dispersion properties, and can use droplet evaporation for effective injection at the higher temperatures found in utility furnaces. However, ammonia-based systems are used on industrial boilers, fluidized bed utility boilers, and cement kilns. . . .

The reagent injection systems used for anhydrous ammonia-based systems are generally more complicated and expensive than those used in aqueous ammonia- and urea-based systems [29]. These systems inject gas-phase ammonia rather than an aqueous solution. For this reason, anhydrous ammonia-based systems often use high-energy lance systems with multiple injectors. The lances are placed in a grid formation across the width and height of the boiler passes."

Commenter: Institute of Clean Air Companies (ICAC)
DCN: EPA-HQ-OAR-2015-0341-0021-A1
Comment: On Page 1-24, last 2nd paragraph at bottom, 3rd sentence. Authors state "Wall injectors are used in smaller boilers and urea based systems." This is not completely accurate,

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[17] Von Der Heide, Bern. *SNCR Process – Best Available Technology for NOx Reduction in Waste to Energy Plants,"* Presented at POWER-GEN Europe, Milan, June 2008 (http://www.ms-umwelt.de/english/downloads/SNCR-Best_Available_Technology_for_NOx_Reduction_in_Waste_To_Energy_Plants.pdf, accessed January 12, 2016).
[18] Process Combustion Corporation product literature (http://www.pcc-sterling.com/products/thermal-oxidizers/scr-sncr/).
[19] Lee, G.W., B.H. Shon, J.G. Yoo, J.H. Jung, and K.J. Oh, *The Influence of Mixing Between NH$_3$ and NO for De-NOx Reaction in the SNCR Process,* Journal of Industrial and Engineering Chemistry, July 2008.

since wall injectors have been used in both smaller and large boilers. The commenter also suggested the following sentence be added to the end of this paragraph:

"Wall injectors can either use air or mechanical atomization prior to injection."

Response: We agree with the commenter's recommendation and have made the following revisions to Section 1.2.4.

"Wall injectors are attached to the inner wall of the boiler at specified locations. There is generally one nozzle for each injector location. They may be used in small or large combustion units. Smaller boilers and urea based systems, where short-range injection is sufficient to mix the reagent with the flue gas, may be equipped only with wall injectors. In larger boilers, wall injectors are often used in combination with lance injectors to improve reagent coverage near the walls. They have a longer operating life than lance injectors because they are not directly exposed to hot flue gas. Wall injectors may use air or mechanical atomization prior to reagent injection."

Commenter: Portland Cement Association
DCN: EPA-HQ-OAR-2015-0341-0023-A1
Comment: The commenter recommended the text in section 1.2.4 be revised as follows:

"These steps are common to both urea and ammonia boiler SNCR; however, the design and equipment specifications for the two systems are different, because ammonia is injected as a vapor while urea is injected as an aqueous solution. Urea is typically used in large boiler applications of SNCR because it is safer to store and has better dispersion properties. A discussion of the SNCR equipment is given below. Note that for long wet and dry cement kilns the SNCR will require either the installation of a rotary valve at the end of the rotary kiln or the Cadence™ manifold system onto the kiln. Figure 1.9 presents a simplified system flow schematic and Table 1.5 lists the equipment requirements for urea-based boiler SNCR."

Response: We agree that SNCR systems installed on long-dry and -wet cement kilns require the equipment mentioned by the commenter. However, we note that they are not required for SNCR systems installed on preheater/precalciner kilns. For clarification, we have made the following changes to section 1.2.4:

"For long wet and dry cement kilns the SNCR will require either the installation of a rotary valve at the end of the rotary kiln or a Cadence™ manifold system because the reagent must be injected into the rotary kiln. These are not required for SNCR systems installed on preheater/precalciner cement kilns because the injection ports can be installed in the combustion zone in the calciner, the oxidation zone of the upper air inlet before the deflection chamber, or in the area after the mixing chamber before the inlet to the bottom cyclone [17]."

1.2.5   Other Considerations

Commenter: Arizona Public Service Company (APS)
DCN: EPA-HQ-OAR-2015-0341-0028-A1
Comment: Page 1-27, Additives/Enhancers: The chapter states "enhancer formulations are generally proprietary." If there are any known chemicals, they should be listed.

Response: Since the early 1990s, the co-injection of hydrogen with ammonia has been known to lower the effective temperature window to about 700 °C (1300 °F).[20,21] There are also several studies evaluating the effect of additives on optimum temperatures, the temperature window, and NOx control efficiency. Additives studied include carbon monoxide, glycerol, methyl acetate, phenol, succinic acid, propylaldehyde, diethyl ether, hydrogen peroxide, and several alcohols (e.g., methanol, ethanol, toluene, ethylene glycol, and phenol). Additives such as ammonium carbonate, ethanol, methanol, toluene, phenol, and ethylene glycol are reported to decrease the optimum reaction temperature by up to 180°C; however, many these additives have been shown to reduce NOx reduction efficiency. [22, 23] One study found that urea mixed with ethylene glycol or glycerol can widen the temperature range from the low 800°C to high 1200°C with a NOx removal efficiency of greater than 45%.[24] We do not know which, if any, of these additives are being used in commercial applications.

For clarification, we have added the following paragraph to the discussion of additives/enhancers in section 1.2.5:

"The co-injection of hydrogen with ammonia has been known since the early 1990s to lower the effective temperature window to about 700 °C (1300 °F) [66]. There are also several studies evaluating the effect of other additives, including carbon monoxide, glycerol, methyl acetate, phenol, succinic acid, propylaldehyde, diethyl ether, hydrogen peroxide, and several alcohols (e.g., methanol, ethanol, toluene, ethylene glycol, and phenol. Studies have demonstrated that additives such as ammonium carbonate, ethanol, methanol, toluene, phenol, and ethylene glycol can decrease the optimum reaction temperature by up to 180°C. However, many these additives have also been shown to reduce NO_x reduction efficiency [67, 68]. One study found that urea mixed with ethylene glycol or glycerol can widen the temperature range from the low 800°C to high 1200°C with a NO_x removal efficiency of greater than 45% [67]. However, there are no known commercial applications of these additives known."

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[20] See http://www.hamonusa.com/hamonresearchcottrell/products/nox.
[21] Haas, G.A. Selective Noncatalytic Reduction (SNCR): Experience with the Exxon Thermal DeNox Process. Presented at the NOx Control V Conference. Council of Industrial Boiler Owners. Long Beach, CA. February 10-11, 1992.
[22] Javed, M.T., W. Nimmo, A. Mahmood, and N. Irfan, *Effect of Oxygenated Liquid Additives on the Urea Based SNCR Process,* Journal of Environmental Management, 910, 2009.
[23] Bae, S.B., S.A. Roh, S.D. Kim, *NO Removal by Reducing Agents and Additives in the Selective Non-Catalytic Reduction (SNCR) Process*, Chemosphere, 65, 2006.

Commenter: Portland Cement Association
DCN: EPA-HQ-OAR-2015-0341-0023-A1
Comment: The commenter recommended the following be added to the discussion on "injection locations" in section 1.2.4:

"Generally in preheater and precalciner cement kiln applications, pilot tests utilizing several reagent injection nozzle locations are performed to establish the optimum location(s) for reagent injection."

Response: The EPA agrees that the exact location and number of injection points differ from one system to another and can be optimized through testing. We note that pilot tests have been conducted at several cement kilns prior to final installation of the SNCR.[24] The following revisions have been made to Section 1.2.4:

"Pilot testing using several reagent injection locations may be used to establish the optimum location(s) for reagent injection. Pilot testing has been used in preheater and precalciner cement kilns."[25]

1.2.6   New SNCR Approaches

Commenter: Institute of Clean Air Companies (ICAC)
DCN: EPA-HQ-OAR-2015-0341-0021-A1
Comment: On Page 1-26, the last paragraph states that Rotamix has to be installed together with Rotating Over-Fire Air (ROFA). This is not true since Rotamix can be installed as a standalone technology. On Page 1-29, the Rotamix costs in this section are outdated. Recent installations show capital costs of $15-$20/kw for a 250 MW boiler and $10$15/kw for a 350 MW boiler and larger.

Response: EPA thanks the commenters for their input. We have made the following revisions based on these comments:

"The Rotamix® technology introduces urea or ammonia in the upper furnace, typically in conjunction with a form of boosted (i.e., high pressure) overfire air called rotating opposed fired air (ROFA), although Rotamix® can also be installed as a standalone unit."

"Together, ROFA and Rotamix can achieve 60–80+% total NOx reduction. In 2010, the capital of costs were reported to be $24-32/kW for a 250 MW boiler and $40-55/kW for a 150 MW boiler. Data obtained in 2015 from manufacturers show capital costs of $15-$20/kW for a 250 MW boiler and $10-$15/kW for a 350 MW boiler and larger [65]."

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[24] U.S. EPA, *Alternative Control Techniques Document Update – NO$_x$ Emissions from New Cement Kilns,* EPA-453/R-07-006, November 2007.
[25] U.S. EPA, *Alternative Control Techniques Document Update – NO$_x$ Emissions from New Cement Kilns,* EPA-453/R-07-006, November 2007.

Commenter: Institute of Clean Air Companies (ICAC)
DCN: EPA-HQ-OAR-2015-0341-0021-A1
Comment: Page 1-27 includes references NOxSTAR as an SNCR technology. However, since there are no commercial installations of this technology, the reference should be deleted.

Response: The hydrocarbon-enhanced SNCR technology (known commercially as NOxStar) was demonstrated at the Tennessee Valley Authority's (TVA) Kingston Power Station Unit 9 (a coal-fired 200 MW boiler) in 2002 and was subsequently installed at TVA's Colbert Station Unit 4 in 2003 on a coal-fired 192 MW boiler.[26] We note that TVA plans to close the Colbert Station plant by Spring 2016.[27, 28] The EPA knows of no other plants where NOxSTAR has been installed. However, since NOxSTAR was used commercially between 2003 and the present, we consider NOxSTAR to be a demonstrated technology that should be included in the Cost Manual.

1.3   Design Parameters

1.3.1   Design Parameters for Study-Level Estimates

Commenter: Arizona Public Service Company (APS)
DCN: EPA-HQ-OAR-2015-0341-0028-A1
Comment: Page 1-32, System Capacity Factor: The CF_{SNCR} factor should also take into account start-ups and shut-downs when the temperature is too low for ammonia injection to be effective.

Response: The EPA disagrees with the commenter that the CF_{SNCR} factor should be adjusted for start-ups and shut-downs. The SNCR capacity factor, CF_{SNCR}, is simply the ratio of the theoretical number of days the SNCR could operate to the total number of days per year (i.e., 365 days). This factor is used to account for SNCRs that operate only during the ozone season. The total system capacity factor, CF_{total}, is the estimate of the fraction of time during which the SNCR would be expected to operate and is calculated by multiplying the CF_{SNCR} by the ratio of actual annual fuel burned to maximum annual fuel that could be burned in the combustion unit. The total system capacity factor, CF_{total}, is then used to calculate the estimated SNCR operating time, t_{op}, by multiplying CF_{total} by 8,760 hours/year, as shown in Equation 1.40. The estimated operating time is used to calculate estimated costs, such as estimated annual cost of reagent in Equation 1.39. Hence, to correct the estimated costs for start-up/shutdown periods when the temperature is too low for the reagent to be effective, the number of operating hours during which reagent is not injected would be subtracted from the value of t_{op} calculated in Equation

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[26] Morris, Keith and Scott Affelt, *NOxSTAR Rises in the South,* Modern Power Systems, volume 23, issue 11, November 2003.
[27] See http://www.timesfreepress.com/news/local/story/2013/nov/14/tva-shifts-more-gas-less-goal/124144/ (accessed October 21, 2015).
[28] See http://www.timesfreepress.com/news/local/story/2015/may/08/tvshut-down-widows-creek-coal-plant/303100/ (accessed October 21, 2015).

1.40. However, for most facilities this adjustment would be small and have negligible impact on annual operating costs.

Commenter: Institute of Clean Air Companies (ICAC)
DCN: EPA-HQ-OAR-2015-0341-0021-A1
Comment: On Page 1-36, Figure 1.10 presents data showing dramatic increases in predicted Normalized Stoichiometric Ratio (NSR) to achieve a desired NOx reduction as the uncontrolled NOx emissions decrease, and would appear to suggest that ammonia slip levels will become prohibitive at inlet NOx concentrations below 0.5 lb/MMBtu. This is not accurate based on recent practical experience; the reference for this figure is dated 1998. ICAC can offer more recent data upon request. ICAC recommended the urea percent utilization from page 4 of the final version of the "IPM Model Updates to Cost and Performance for APC Technologies SNCR Cost Development Methodology" (dated March 2013) be used to estimate urea utilization. ICAC stated that the IPM percent utilization provides a good estimating tool for urea utilization. However, they also noted there are a number of parameters which effect actual utilization, including boiler geometry, furnace temperatures, residence time, and combustion conditions. An estimate on a case by case basis by an experienced technology provides is suggested to estimate NSR.

Response: The IPM suggested 15% urea utilization be used for NO_x inlet concentrations of equal to or less than 0.3 lb/MMBtu and 25% urea utilization be used for NO_x inlet concentrations above 0.3 lb/MMBtu. As shown in the following table, when the IPM values are compared with the percent reagent utilization predicted by Equation 1.17, the predicted percent utilization values are higher than the IPM values at all NO_x inlet rates. The higher the reagent utilization the lower the ammonia slip. Hence, Equation 1.17 predicts lower levels of ammonia slip at all NO_x inlet levels than the IPM values recommended by the commenter.

	% Utilization for Different NOx Inlet Levels			
	NOxin = 0.2 lb/MMBtu	NOxin = 0.3 lb/MMBtu	NOxin = 0.5 lb/MMBtu	NOxin = 1.0 lb/MMBtu
Predicted utilization using Equations 1.16 and 1.17 in current Manual	18.2%	23.1%	29.4%	37.0%
IPM Model	15%	15%	25%	25%

However, we note that Equation 1.17 is based on a limited data set in which the NO_x inlet value ranges from 0.45 to 1.4 lb/MMBtu. Given the limited data available, we cannot confirm the accuracy of Equation 1.17 for values outside of the 0.45 to 1.4 lb/MMBtu range. We have therefore revised Figure 1.10 to show the predicted NSR values for NOx inlet concentrations between 0.4 and 1.4 lb/MMBtu, rather than the broader range of 0.2 to 2.0 lb/MMBtu.

Commenter: Coalition of the American Chemistry Council, American Forest & Paper Association, American Fuel & Petrochemical Manufactures, American Wood Council, Brick Industry Association, and Council of Industrial Boiler Owners.
DCN: EPA-HQ-OAR-2015-0341-0022-A1
<u>**Comment:**</u>

Response: This comment is identical to the comment above. Please see the response to the previous comment submitted by ICAC.

Commenter: Arizona Public Service Company (APS)
DCN: EPA-HQ-OAR-2015-0341-0028-A1
<u>**Comment:**</u> Page 1-38, Section 1.3.1: The tank volume should be based on maximum hourly heat input rather than the maximum annual heat input rate.

Response: The reagent volume (q_{sol}) is calculated using the maximum hourly heat input rate (Q_B in Equation 1.18). The tank size calculated in Equation 1.21 calculates the maximum tank size based on the reagent volume (q_{sol}), assuming the SNCR operates at the maximum rate for 24 hours a day for $t_{storage}$ days. Hence, we agree with the commenter that the tank volume is based on the maximum hourly heat input rate. Therefore, we have deleted the following sentence from the last paragraph of Section 1.3.1:

"Note that the tank volume is typically based on the maximum annual input rate, so the capacity factor is not included in Equation 1.21."

1.3.2   Design Parameters for Detailed/Performance Specifications

Commenter: Institute of Clean Air Companies (ICAC)
DCN: EPA-HQ-OAR-2015-0341-0021-A1
<u>**Comment:**</u> On Page 1-39, the section discussing which parameters are needed to define an ammonia slip guarantee should include the location of where the ammonia slip will be measured, which is typically at the stack or at the economizer outlet.

Response: The EPA agrees with the commenter and has made the following revisions to Section 1.3.2 – Cost Estimates Based On Performance Specifications:

"Guaranteed and expected NH_3 slip, ppm and location where the slip will be measured (other conditions such as dry basis, percent O_2, per the air permit."

1.4   Cost Analysis

Commenter: Institute of Clean Air Companies (ICAC)
DCN: EPA-HQ-OAR-2015-0341-0021-A1
<u>**Comment:**</u> Section 1.4 references NOxOUT, which is one specific type of SNCR technology. A more generic reference should be utilized.

Response: The references in Section 1.4 to "NOx$_{out}$" refer to the NOx emission limit at the stack outlet and not to the trade name "NOx OUT" for the urea-based SNCR system developed by Electric Power Research Institute (EPRI). To avoid future confusion, we have revised the text in section 1.4 by replacing "NOx$_{out}$" with the phrase "NOx levels at the stack outlet."

Commenter: Coalition of the American Chemistry Council, American Forest & Paper Association, American Fuel & Petrochemical Manufactures, American Wood Council, Brick Industry Association, and Council of Industrial Boiler Owners.
DCN: EPA-HQ-OAR-2015-0341-0022-A1
Comment: Page 1-25 states that retrofit costs increase sharply for smaller boilers (<50MW). However, in the cost analysis section on Page 1-40, it states that "the capital cost equations are applicable to utility boilers with full load capacities that are greater than or equal to 25MW." The statement on Page 1-25 correctly matches our own experience, so the cost equation should include a factor that accounts for the higher costs associated with the retrofit of smaller units.

Response: We disagree with the commenters that an additional factor is needed to estimate costs for small units. The current methodology uses a power function that results in much higher costs for smaller units. The table below shows the estimated costs calculated for different sized systems using the same inlet NOx and reduction as in the example in section 5.1. As shown in the table, the $/KW for the 25 MW boiler is significantly and reasonably higher than the cost estimated for the 500 MW unit.

Boiler, MW	TCI, million $	$/KW
25	3.0	120
50	4.0	81
120	5.9	49
150	6.5	44
200	7.4	37
500	11.1	22

In addition, the S&L SNCR cost memorandum states that "the rapid rise in project costs at the lower end of the MW range is due primarily to economies of scale." Thus, the higher costs of retrofitting smaller SNCRs is accounted for in the cost approach included in this Control Cost Manual chapter.

Commenter: Coalition of the American Chemistry Council, American Forest & Paper Association, American Fuel & Petrochemical Manufactures, American Wood Council, Brick Industry Association, and Council of Industrial Boiler Owners.
DCN: EPA-HQ-OAR-2015-0341-0022-A1
Comment: Page 1-40 states that the capital cost equations are applicable to utility boilers with full load capacities greater than or equal to 25 MW. This is appropriate, as there are almost no utility boilers in operation that are smaller than 25 MW. Using the factor provided to convert

from MW to MMBtu/hr places this minimum heat input value at 250 MMBtu/hr. This is consistent with the cost equations in Section 1.4.1.2, which state that they are applicable to units >250 MMBtu/hr. However, industrial units of this size represent a small fraction of the total population of industrial fired equipment. This is a significant gap in the usefulness of this chapter of the Cost Control Manual.

Response: We agree with the commenter that the model is intended to provide reliable, study-level cost estimates for units above 25 MW; however, we note that the cost methodology can be used to estimate costs for units smaller than 25 MW with the understanding that the costs estimates are likely of lesser accuracy and may be less reliable for units that are significantly smaller than 25 MW.

Commenter: Coalition of the American Chemistry Council, American Forest & Paper Association, American Fuel & Petrochemical Manufactures, American Wood Council, Brick Industry Association, and Council of Industrial Boiler Owners.
DCN: EPA-HQ-OAR-2015-0341-0022-A1
Comment: Page 1-40 states that the capital cost estimates are sufficient for reductions of 25% for pulverized coal and 50% for fluidized bed boilers. However, capital cost correlates more closely to the operating range over which the boiler must be controlled because a boiler that operates at variable loads will require more injection levels than one that operates at a constant load. Removal efficiency correlates more closely with annual costs for reagent.

Response: The NO_x removal efficiencies reflects recent quotes for SNCR costs and related information collected from 2009 to 2012, and are averages of removal efficiencies consistent with quotes from Sargent & Lundy's data base that serves as a major foundation for the SNCR information within the chapter. The commenter's point has some validity, but this does not render inaccurate the removal efficiencies in the chapter.

Commenter: Coalition of the American Chemistry Council, American Forest & Paper Association, American Fuel & Petrochemical Manufactures, American Wood Council, Brick Industry Association, and Council of Industrial Boiler Owners.
DCN: EPA-HQ-OAR-2015-0341-0022-A1
Comment: Page 1-40 indicates that the costing methodology was developed to estimate capital costs in 2012 dollars. The methodology should be updated to reflect the year in which the chapter revision will be finalized (e.g.., 2015 or 2016).

Response: We disagree with the commenter that capital costs included in the Cost Manual should be converted to the current year. There is no need to scale annual costs, and this has not been our historical convention. For operating costs, the appropriate inputs for the current cost year of interest should be used, i.e., current labor costs, reagent costs, utility cost, and catalyst replacement cost. The maintenance costs would already be scaled appropriately based on escalation of the capital costs to the appropriate cost year (i.e., maintenance costs are a percentage of TCI). The EPA recommends the use of a well demonstrated cost index, such as the

Chemical Engineering Plant Cost Index (CEPCI), for converting costs from one year to another year.

1.4.1   Total Capital Investment

Commenter: Institute of Clean Air Companies (ICAC)
DCN: EPA-HQ-OAR-2015-0341-0021-A1
<u>Comment:</u> On Page 1-41, the 2nd paragraph states that "Thus, the procedure described in this document assumes the costs for industrial boilers are essentially the same as for utility boilers for the same design heat input." The costs of SNCR applied to industrial boiler are often less than for the same size utility boiler. This is based on lower equipment costs due to a narrower boiler load operating range which results in the need for fewer injectors and also from a higher allowable ammonia slip which can reduce the complexity of the system controls.

<u>Response:</u> The EPA thanks the commenter for their input. We have revised section 1.4.1 as follows:

"In addition, costs for different size categories of industrial boilers have been included in this SNCR section. IPM v5.13 does not contain cost procedures for industrial boilers; however, based on analysis of data in Table 1.3, costs for industrial boilers (in the 100 MMBtu/hr to 1000 MMBtu/hr range) appear to range between significantly less than costs for utility boilers to essentially the same as the cost for utility boilers. The procedure described in this document assumes the costs for industrial boilers are essentially the same as for utility boilers for the same design heat input. On average, this costing approach may result in a slight overestimate of costs for industrial boilers. The equipment costs of installing SNCRs on industrial boilers may be less than the costs for installing an SNCR on the same size utility boiler because (1) the narrower load operating range for boilers requires fewer injectors; and (2) higher allowable ammonia slip for some industrial boilers reduces the complexity of system controls."

Commenter: Institute of Clean Air Companies (ICAC)
DCN: EPA-HQ-OAR-2015-0341-0021-A1
<u>Comment:</u> On Page 1-41, additional information is required as to the reason for an elevation factor. The unit size and the operating range factor are the primary factors that affect system costs, and the elevation factor as stated is not accurate.

<u>Response:</u> The elevation factor is included to adjust for any changes that may be needed to accommodate SNCR systems at higher elevations, such as larger ducts and additional injection points.

Commenter: Institute of Clean Air Companies (ICAC)
DCN: EPA-HQ-OAR-2015-0341-0021-A1
<u>Comment:</u> The implication that BOP costs include fans and chimneys are not correct for SNCR. That type of equipment has no relevance to SNCR technology.

Response: We agree with the commenter that BOP costs would not include fans or chimneys. We have revised the BOP discussion on pages 1-44 through 1-48 as follows:

"The BOP costs include cost items such as piping, water treatment for dilution water, ductwork, auxiliary power modifications, and other electrical and site upgrades that are typically necessary as part of the installation of the SNCR unit."

Commenter: American Petroleum Institute (API) and Institute of Clean Air Companies (ICAC)
DCN: EPA-HQ-OAR-2015-0341-0020-A1 and EPA-HQ-OAR-2015-0341-0021-A1
<u>Comment:</u> Chapter 1, pages 1-43 through 1-47
The paragraphs introducing the SNCR and BOP cost equations on these pages cite reference 27 as their source, but that reference has to do with ammonium hydroxide and does not appear to be the correct reference for these paragraphs.

Response: The EPA agrees with the commenter that reference 27 cited in section 1.4.1 is incorrect. The references on pages 1-43 through 1-47 have been corrected to cite reference 8.

Commenter: Institute of Clean Air Companies (ICAC)
DCN: EPA-HQ-OAR-2015-0341-0021-A1
<u>Comment:</u> In Section 1.4.1.1.1 and throughout the section that contains the SNCR cost formulas, the 1.3 factor is used with no stated reason for the factor. ICAC strongly disagrees with the overall cost model approach given the standardized nature of the approach, and the lack of definition of the 1.3 factor. The IPM cost model previously used by EPA, defines specific contingency factors, and a similar justification seems to be in order for this Manual.

Response: The "1.3" factor is used to adjust the TCI for estimated engineering and construction management costs, contractor fees, etc. For clarification, the following revisions were made to the paragraph below Equation 1.23:

"The TCI calculation shown in equation 1.23 includes a factor of 1.3 to estimate engineering and construction management costs, installation, labor adjustment for the SNCR, and contractor profit and fees."

Commenter: American Petroleum Institute (API)
DCN: EPA-HQ-OAR-2015-0341-0020-A1
<u>Comment:</u> The 1.3 Factor in the Cost Estimating TCI Equations Should be at least 1.4.

The cost equations presented in these Chapters for estimating TCI generally include a 1.3 multiplier. The explanation for this multiplier is provided on page 2-57 of draft Chapter 2, stating "This TCI calculation includes a factor of 1.3 to estimate engineering and construction management costs, labor adjustment for installation (e.g., per diem and premium for work shifts of 10 hr.), and contractor profit and fees." While this factor is also used in some of the TCI

equations in draft Chapter 1, no explanation is provided there and API recommends that such an explanation be included in the final Chapter 1.

Further detail is provided in the electric utility integrated planning model (IPM) documents. On page 3 of the SNCR document[9] and page 3 of the SCR document[29], the following breakdown is provided.

- Engineering and construction management costs at 10% of the [total base module installed] cost;
- Labor adjustment for 6 x 10 hour shift premium, per diem, etc., at 10% of the [total base module installed] cost; and
- Contractor profit and fees at 10% of the [total base module installed] cost.

Our members report that engineering costs for these type projects typically range from 10-40%. For project management costs, our members' report 20-40+%. Thus, the minimum engineering and project management cost should be estimated at 30%, rather than 10%. The 10% EPA allows for contractor profit appears to be reasonable, based on limited member input. Contractor wage and shift adjustments, would typically be included in the installation cost factors and thus be included in the base cost estimate. Thus, API believes the factor used to reflect these categories of costs should be set at least 40% (10% for engineering, 20% for project management, and 10% for contractor profit and other installation related costs). If the installation cost factors used in the IPM did not include 10-hour, 6 day wages, per diem, etc., the additional 10% included in the IPM work is appropriate and the TCCI equations should use a 1.5 factor, rather than 1.3 or 1.4.

Response: The "1.3 factor" comes from the IPM model and is based on input from industry. The IPM is revised periodically to incorporate new data and each version of the model is subject to a peer review process prior to being finalized. In addition, the IPM is often revised in response to public comments on EPA rulemakings in which the model was used. As noted above, we have revised the text in section 1.4.1 to clarify that this factor is used to adjust the TCI for costs engineering and construction management costs, labor adjustment, and contractor profit and fees. We disagree with the commenter's recommendation that the factor be raised to 1.4 to allow for 10% engineering, 20% project management, and 10% contractor profit. While these costs may be higher for retrofit projects with more challenging site-specific issues, we consider the "1.3 factor" included in the IPM model to be a reasonable estimate of costs. We also disagree with raising the factor to 1.5 to allow for an additional 10% for a 10 hour, 6-day per diem for installation. The SNCR base cost is the installed cost that already includes the costs for all equipment, installation, buildings, foundations, electrical, water treatment, and retrofit difficulty associated with SNCR installations.

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[29] Sargent and Lundy Report to Systems Research and Applications Corporation, *IPM Model – Updates to Cost and Performance for APC Technologies, SCR Cost Development Methodology, Final Report*, March 2013.

Commenter: American Petroleum Institute (API)
DCN: EPA-HQ-OAR-2015-0341-0020-A1
Comment: The 1.3 factor does not appear in all the Chapter 1 and 2 TCI equations. This factor reflects real costs and EPA should demonstrate that those costs are included in the equations where the factor is not explicitly shown.

Response: The 1.3 factor is included in all the TCI equations in section 1.4.4 and in the cost estimation example included in section 1.5.2. Note that the factor is applied to the equation that sums the equipment costs for all applicable "base modules" rather than to each of the base module equations.

Commenter: Arizona Public Service Company (APS)
DCN: EPA-HQ-OAR-2015-0341-0028-A1
Comment: Page 1-44, Section 1.4.1.1: Balance of Plant Costs: It should be noted that if actual balance of plant requirements are known, the balance of plant costs can be determined with considerably more accuracy.

Response: The EPA agrees with the commenter that where actual costs are known, they should be used to calculate TCI. However, we note that all actual costs, including SNCR costs, balance of plant costs, and air pre-heater costs, should be used if known. As we noted in the introduction to section 1.4, the cost methodology included in this chapter provides a tool for estimating study-level SNCR capital and annual costs. Selection of the most cost-effective control option should be based on a detailed engineering study and cost quotations from SNCR suppliers.

Commenter: Institute of Clean Air Companies (ICAC)
DCN: EPA-HQ-OAR-2015-0341-0021-A1
Comment: The Balance of Plant (BOP) cost factor is based on a formula, however, no data to correlate the formula is provided. ICAC believes that the formula produces an extremely high value for BOP costs. Unless actual data can be referenced, the BOP calculation should be adjusted. The BOP values are significantly higher than the curve in Figure 1.2, where actual installation data is provided to establish the curve.

Response: Industrial boilers, such as those with data included in Figure 1.2 of the chapter, are typically significantly smaller in size than utility boilers, and thus occupy smaller footprints with less spatial volume. This allows close interfacing of the SNCR system to existing plant equipment; consequently, new pipe runs and ductwork, pipe supports, additional wiring, cable trays, structural support issues, civil site work, etc, result in lower BOP costs at industrial units. The typical utility boiler with its significantly higher NO_x emissions, greater capacity, and larger size equipment requires larger equipment, longer pipe runs, more cable wire, more extensive site upgrade work, etc., which results in higher BOP costs.

Commenter: American Petroleum Institute (API)
DCN: EPA-HQ-OAR-2015-0341-0020-A1
<u>Comment</u>: *Chapter 1, page 1-47, first paragraph: The first paragraph is as follows:*

<u>Industrial, oil- and gas-fired units ≥250 MMBTU/hr.</u> The capital cost equation for industrial oil- and gas-fired boilers ≥1,000 MMBTU/hr. is based on the utility boiler equations. The capital cost equation for oil- and gas-fired units is as follows:

It is clear from the header that this paragraph deals with units ≥250 MMBTU/hr. units. Thus, the "≥1000 MMBTU/hr." in the first sentence should be "≥250 MMBTU/hr."

Response: The heat input for industrial oil and gas-fired boilers has been corrected.

"<u>Industrial, oil- and gas-fired units ≥250 MMBTU/hr.</u> The capital cost equation for industrial oil- and gas-fired boilers ≥250 MMBTU/hr. is based on the utility boiler equations."

Commenter: Institute of Clean Air Companies (ICAC) and Coalition of the American Chemistry Council, American Forest & Paper Association, American Fuel & Petrochemical Manufactures, American Wood Council, Brick Industry Association, and Council of Industrial Boiler Owners.
DCN: EPA-HQ-OAR-2015-0341-0021-A1 and EPA-HQ-OAR-2015-0341-0022-A1
<u>Comment:</u> The equations for air heater costs modifications are based on the assumption that air heater modifications to manage corrosion and deposition associated with the presence of SO_3 will be accomplished by replacing baskets with ceramic coated material. This is only applicable to units equipped with Ljungstrom rotating-type air heaters, and it not appropriate for other gas-to-gas air heater designs.

The basic idea that a given sulfur level, which in turn becomes an SO_2 and ultimately an SO_3 issue, will result in additional system costs must be questioned. Most high sulfur applications do not require air heater modifications since ammonia slip is limited to 5 ppmv at the economizer outlet in most SNCR installations. High sulfur fuel conditions can minimize operating costs through reduced ammonia injection levels, and the lower ammonia slip will affect SNCR performance. Most SO_2 and SO_3 related issues are mitigated through tight controls on ammonia slip.

Where air heater issues are present due to ammonia slip and SO_3, the addition of sonic horns can mitigate potential issues through improved cleaning. This option combined with soot blowers should also be considered as a separate option for high sulfur applications. These items are typically low in capital cost and a single cost model that also includes air heater changes will dominate the cost calculation.

Response: The EPA agrees with the commenters that controlling ammonia slip levels can help avoid air heater fouling by minimizing the amount of ammonium salts formed. We also agree that Ljungstrom rotating-type air heaters are likely to be more severally impacted by fouling than other preheater designs as the deposition of ammonia salts tends to restrict air flow, causing an

increase in pressure drop. Although tubular air heaters have relatively large passages for gas compared to Ljungstrom air heaters, they are still impacted by fouling. In tubular air heaters, salt deposition tends to decrease the heat transfer process. We agree that sonic horns and soot blowers may be used to mitigate problems caused by ammonia salt deposition. However, based on information collected from industry, air heater modifications are generally required when the level of SO_2 is above 3 lb/MMBtu. Since fouling of air heaters can occur when high sulfur fuels are burned, it is appropriate the methodology allows a cost adjustment to be made to account air heater modification costs.

Commenter: Institute of Clean Air Companies (ICAC) and Coalition of the American Chemistry Council, American Forest & Paper Association, American Fuel & Petrochemical Manufactures, American Wood Council, Brick Industry Association, and Council of Industrial Boiler Owners.
DCN: EPA-HQ-OAR-2015-0341-0022-A1 and EPA-HQ-OAR-2015-0341-0021-A1
<u>**Comment:**</u> The costing equations include the possibility for air preheater (APH) modifications for SO_3 control when high-sulfur coal is burned. On page 1-44, equation 1.25, the air heater factor (AHF) is defined as 1 if "the SO_2 content of the coal is $\geq$ 3 lb/MMBtu" and zero if below. The coal does not contain SO_2; it contains sulfur, which is oxidized to form SO_2 and SO_3. It is not clear whether the choice of factor should be based on the sulfur content of the coal or the maximum equivalent SO_2 emission rate expected. Flue gas SO_3 concentration and the air heater outlet temperature affect air heater corrosion. The concentration of SO_3 and the amount of ammonia slip present in the flue gas affect air heater deposition. The threshold provided is arbitrary and does not accurately capture the potential for either air heater corrosion or deposition of ammonium bisulfate on the air heater baskets or other downstream equipment. In addition, the cost equations do not include APH costs for other types of combustion units, but high-sulfur fuel oils can also result in elevated flue gas SO_3 concentrations that lead to ammonium bisulfate deposition in the presence of ammonia slip.

Response: In accordance with the IPM, the threshold for determining whether an air preheater (APH) modification is required is based on the SO_2 emission rate. The costs of a preheater should be included for fuels that generate $\geq$ 3 lb/MMBtu SO_2. The IPM allows the air preheater costs to be adjusted for fuel type affects when sulfuric acid or ammonium bisulfate deposition poses a problem. Based on information collected from industry, air heater modifications are generally required and additional costs incurred when the level of SO_2 is above 3 lb/MMBtu. The 3 lb/MMBtu threshold for coal was based on input from industry and was not considered necessary for oil combustion since most fuel oil burned have lower sulfur content to comply with other air regulations. Since the IPM is revised periodically to incorporate new data and each version of the model is subject to a rigorous peer review process prior to being finalized, we consider the model to represent the best approach based on currently available information.

Commenter: Coalition of the American Chemistry Council, American Forest & Paper Association, American Fuel & Petrochemical Manufactures, American Wood Council, Brick Industry Association, and Council of Industrial Boiler Owners.

DCN: EPA-HQ-OAR-2015-0341-0022-A1

Comment: The costing algorithms in this report are based on retrofit applications of SNCR to coal fired utility boilers (see Page 1-7). Industrial combustion units (which may be either direct- or indirect-fired) operate quite differently and are of smaller size than coal-fired utility boilers; Table 1.3 demonstrates that the cost can vary widely by application. Page 1-41 references Table 1.3, and states that the costs for industrial boilers in the 100-1000 MMBtu/hr range are 'significantly less than' or 'essentially the same as' the cost for utility boilers. We dispute this assertion, as it is contradicted by EPA's own data. Page 1-8 indicates the cost for power generation applications is $5-20/kW. This translates to $5,000-20,000/MW, and using a factor of 10 MMBtu/hr per MW converts to $500-2,000/MMBtu/hr. However, data in Figure 1.2 shows industrial boiler costs starting at $2,000/MMBtu/hr for large units and increasing to over $5,000 for units under 200 MMBtu/hr. Therefore, the cost to apply SNCR to industrial boilers is shown to be significantly <u>higher</u> than that for utility boilers, in contrast to the statement on page 1-41. Our experience has shown that in cases where the application of SNCR to an industrial boiler is technically feasible, the cost is routinely higher than $2,000/MMBtu/hr. For example, the cost for the controls and instrumentation (including NOx and ammonia analyzers) are essentially the same for both large and small units, so they represent a larger fraction of the total cost of an installation on a smaller unit.

Response: We have revised the capital costs on p. 1-8 to $4-44/kW based on updated information available to EPA as presented in a previous comment in this RTC document. IPM S&L cost equations accounts for all operating and maintenance (O&M) costs, and this includes the cost of reagent for operating an SNCR. SNCR requires excess reagent injection to accomplish a significant reduction potential; consequently, the SNCR application for utility and industrial boilers results in relatively high O&M costs compared to other types of NO_x controls (combustion or SCR, for instance). Regarding NO_x analyzer and instrumentation costs, while it is true the instrumentation and analyzers for NO_x and ammonia are functionally identical, the utility sector requirements for monitoring and reporting emissions data must follow the requirements of 40 CFR Part 75. This regulation rigorously stipulates certification requirements, electronic data reporting formats, data reporting systems, on-going quality assurance tests, and verification protocols to ensure accurate emissions data reporting. While the base instrumentation for measuring pollutants utilizes the same technology, the Part 75 implementation requirements for EGUs requires more resources than simply installing a sensor to measure a pollutant.

Commenter: American Petroleum Institute (API)
DCN: EPA-HQ-OAR-2015-0341-0020-A1
Comment: *Equation 1-35 Should Be Deleted and, If Not Deleted, It Should be Validated.*

Equation 1-35 is recommended to estimate the cost for new or retrofitted SNCR on oil- or gas fired industrial boilers >250 MMBTU/hr., as follows:

$$SNCR_{Cost} = 147,000 \times \left(\frac{Q_B}{NPHR} \times HRF \right)^{0.42}$$

Where:

       SNCRCost = SNCR unit costs, $
       147,000 = constant in the equation
       QB = maximum heat rate input to the boiler, MMBTU/hr.
       NPHR. = net plant heat rate, MMBTU/MWh (use 11 for oil-fired units and 8.2 for
       gas fired units, if actual values are not available) *HR.F* = heat rate factor.

Other than converting from a MW to a MMBTU basis, this equation is the same as provided for utility oil- and gas-fired boilers. No basis is provided for assuming utility boiler information applies to industrial boilers, nor is any information provided on how the dollars per MW factor and scaling factor were derived for utility boilers. API recommends EPA justify the basis for the 147,000 value and justify the 0.42 power relationship for utility boilers and the extension of those values to the typically smaller industrial oil- and gas-fired boilers.

Relative to the conversion of the utility boiler data to industrial boilers, in draft Chapter 2 EPA used a different MMBTU/MW factor for industrial oil-fired boilers and for industrial gas-fired boilers. Draft Chapter 1 used the same conversion factor for the two types of industrial boilers. For consistency, API recommends the conversion from MW to MMBTU be done the same way in both Chapters.

Response: The available information regarding SNCR cost retrofit data on oil and gas-fired industrial boilers is very limited to establish a capital cost estimate equation with reasonable variability and a study-level accuracy. The best information available for such data exists within the utility sector, in which multiple installations for a range of boiler sizes yields information indicative of technological effectiveness and provides some degree of robust cost data. The Agency provides this capital cost equation to allow users to generate estimates with reasonable variability and study-level accuracy associated with deployment for the industrial sector. An owner, whether of an utility or industrial boiler, should obtain multiple vendor estimates for control measure installation given the uniqueness of their facility configuration and operating conditions in order to establish budgetary requirements since these factors significantly affect capital cost.

Commenter: American Petroleum Institute (API)
DCN: EPA-HQ-OAR-2015-0341-0020-A1
Comment: Equation 1-36 Should Be Deleted and, If Not Deleted, It Should be Validated. Equation 1-36 estimates the Balance of Plant (BOP) costs for installing SNCR on oil- and gas fired industrial boilers >250 MMBTU/hr., as follows:

$$BOP_{Cost} = 213,000 \times \left(\frac{Q_B}{NPHR}\right)^{0.33} \times \left(NO_x\,\text{Removed/hr}\right)^{0.12}$$

Where:

   BPC = Balance of plant, $
   213,000 = constant in the equation
   $NOx\,Removed/hr.$ = hourly mass of NOx removed by the SNCR system, lb./hr.

BOP costs are explained on page 1-47 to include cost items such as ID and booster fans, new wet chimneys, siting, piping, ductwork, auxiliary power modifications, and other electrical and site upgrades that are typically necessary as part of the installation of the SNCR unit. No explanation is provided as to how any of the equation factors were derived or relate to those types of costs. Nor is the extension of these factors from utility boilers to industrial boilers justified.

Furthermore, none of these items identified as being included in the BOP cost would seem to be a function of NOx removal and thus it is unclear why a NOx factor is included in Equation 136. NOx removal would be a factor in sizing the SNCR reagent system, but that cost would belong in the SNCR equipment cost, not in the BOP cost. In fact, in their description of the derivation of the SNCR cost equations[30] for the IPM 5.13 model, Sargent and Lundy clearly identify the NOx removal as an SNCR system sizing variable, though it is not included as a variable in the SNCR cost equations in this draft.

Furthermore, the equation as drafted is unbalanced, with the left side being in dollars and the right side being in $-lb. NOx/hr. removed. If such a NOx scaling factor is indeed required, it should be a ratio to the NOx removal corresponding to the base rate for the $213,000/MMBTU/hr. factor, so the pound/hour units cancel. API recommend this equation be deleted along with the entire industrial oil- and gas-fired boiler cost section. If it is not deleted, the factors and scaling factors should be explained, justified, and corrected where necessary.

Response: The available information regarding SNCR cost retrofit data on oil and gas-fired industrial boilers is very limited to establish a capital cost estimate equation with reasonable variability and a study-level accuracy. The best information available for such data exists within the utility sector, in which multiple installations for a range of boiler sizes yields information indicative of technological effectiveness and provides some degree of robust cost data. The Agency provides this equation to estimate SNCR balance of plant costs to allow users to generate estimates with reasonable variability and study-level accuracy associated with deployment for the industrial sector. An owner, whether of an utility or industrial boiler, should obtain multiple vendor estimates for control measure installation given the uniqueness of their facility configuration and operating conditions in order to establish budgetary requirements since these factors significantly affect balance of plant cost. Regarding the unbalanced nature of the equation, unitary consistency across the equal sign (=) holds for scientific equations describing

laws of nature (ex.: force (Fg_c) = mass * acceleration (ma)) since these equations are universal. Empirical equations such as for balance of plant cost, by their very nature, correlate one set of data to another set of data to establish a relationship between two different measurable metrics and do not require unit consistency.

1.4.2   Total Annual Costs

Commenter: American Petroleum Institute (API)
DCN: EPA-HQ-OAR-2015-0341-0020-A1
<u>**Comment:**</u> The Installation and Annual Costs for Continuous Monitors Should be Included in the Cost Estimates.

SCR and SNCR installations require continuous NOx, O_2 (and possibly CO), and sometimes NH_3 slip monitors to demonstrate continuous compliance. Few industrial boilers already have such instrumentation prior to SCR or SNCR addition, since compliance for NOx limits for equipment without add-on NOx controls is typically demonstrated through a performance test. Thus, continuous NOx, O_2 and/or CO monitor costs are rightfully project costs, along with a slip monitor in some cases[31]. The capital costs and the ongoing maintenance costs for such monitors are significant, yet the descriptive information in these Chapters and the electric utility industry basis on which these Chapters rely, do not indicate that the costs associated with these monitors are included. In fact, for SNCR and smaller SCR installations the costs for monitoring can be a significant portion of the total project cost. Our members indicate the costs for these monitors can reach and exceed $500,000. This exceeds typical EPA estimates,[32] because a new analyzer shelter, access platforms, and additional or upgraded electrical and instrumentation and data systems are often required.

Because continuous emission monitors are complex and are subject to significant regulatory requirements, at least two hours per day of instrument upkeep and QA/QC is required along with quarterly or annual Relative Accuracy testing for these continuous monitors. Continuous monitor upkeep to regulatory standards involves considerably more than the 0.5% of monitor cost that EPA assigns for maintenance of SCRs and 1.5% of monitor cost that is assigned to SNCR maintenance in the drafts.

Response: The EPA agrees with the commenter that continuous emission monitors are necessary for SNCRs. However, we note that costs for installing and operating monitoring equipment are

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[31] Since ammonia slip is not usually expected to change quickly, it is often monitored using Stain tube monitoring. In such cases, the NOx monitor would have to measure both SCR inlet and outlet concentrations to allow calculation of the required ammonia rate. Such dual NOx units are higher cost than single outlet NOx monitors, because of the additional sampling system, switching hardware, and additional platforming and electronics needed.

[32] For instance, on page 2-18 of the draft Chapter 2, it is stated that "The capital cost for one ammonia slip monitoring instrument is estimated to be $40,000 for a single measurement point and up to $70,000 in capital cost for three measurement points [54]." With structural, utility, indirect and other required ancillary costs added, the actual cost of this one monitor will be much higher and have a substantial impact on the total project cost for industrial boilers.

covered in Section 2, Chapter 4 (Monitors) of the Cost Manual. The costs of installing and operating continuous emissions monitors should be calculated separately, in accordance with the methods specified in Section 2, Chapter 4.

Commenter: Coalition of the American Chemistry Council, American Forest & Paper Association, American Fuel & Petrochemical Manufactures, American Wood Council, Brick Industry Association, and Council of Industrial Boiler Owners.
DCN: EPA-HQ-OAR-2015-0341-0022-A1
Comment: Page 1-52 does not include property tax or insurance cost in the indirect annual cost estimate. We would like to note that the entire cost of these projects is not always exempt from property tax. In addition, a site may acquire insurance to cover the downtime necessary to install the pollution control project. Smaller companies that are not self-insured may purchase insurance specifically for a pollution control installation project. This page also states that additional labor is not required to operate the SNCR system. However, additional labor could be needed to operate and maintain the additional instrumentation and monitoring systems required. Costs of installing, testing, maintaining, and operating additional monitoring equipment (e.g., NOx and ammonia analyzers) are not insignificant.

Response: The methodology used in the Cost Manual for making study-level cost estimates is described in Section 1, Chapter 2, Cost Estimation: Concepts and Methodology. The cost estimating methodology included in the Cost Manual is primarily targeted toward study-level estimates that have an accuracy of ±30 percent. In this methodology, the total annual cost is the sum of direct costs and indirect costs minus any recovery credits. As indicated in the Section 1, Chapter 2, the indirect costs may include the overhead, property taxes, insurance, administrative charges and capital recovery. In addition, costs associated with monitoring equipment are not included in the cost estimates, consistent with how such costs are treated in other chapters of the Cost Manual. For more information on monitoring costs, please consult the monitoring chapter of the Cost Manual.

Commenter: Institute of Clean Air Companies (ICAC)
DCN: EPA-HQ-OAR-2015-0341-0021-A1
Comment: Operating Costs. The maintenance costs as a percentage of the TCI are overstated due to an extremely high TCI calculation. With a more representable TCI, the calculated value for maintenance costs would be reasonable.

Response: We disagree that the TCI values are not representative of the capital costs for SNCR. The TCI data are based on actual costs. The IPM is a well-established model that uses actual data from the electric power sector. Since the IPM model is revised periodically to incorporate new data and each version of the model is subject to a peer review process prior to being finalized, we consider the model to represent the best approach to calculating costs based on currently available information.

Comments on the Expected Equipment Life:

Commenter: Institute of Clean Air Companies (ICAC)
DCN: EPA-HQ-OAR-2015-0341-0021-A1
Comment: A number of SNCR systems have been in operation since before 1995. When SNCR components and piping systems are constructed using stainless steel, a 20 year design life has been demonstrated. A design life range of 15-25 years is often specified and is the expected life of an SNCR system.

Response: We thank the commenters for their input. As we noted in the draft Cost Manual chapter, data collected from three petroleum refiners also estimated SNCR life at between 15 and 25 years. We agree with the commenter that 20 years is a reasonable estimate of the expected lifetime of an SNCR and have stated this in the draft Cost Manual chapter.

Commenter: Arizona Public Service Company (APS)
DCN: EPA-HQ-OAR-2015-0341-0028-A1
Comment: A reasonable estimate of SNCR equipment life is 20 years. Even if the SNCR equipment could last longer, environmental equipment is often upgraded or replaced with new technology before it has reached the end of its useful life. For SNCR, that useful life could be even shorter than 20 years. For internal economics, we use 20 years or less if we have a specific reason to believe it would be retired sooner. Also, the accounting depreciation life for this equipment is 20 years.

Response: The EPA agrees with the commenter that a 20 year equipment life is a reasonable estimate for SNCR systems. Please see the response to the first comment in this section for additional information.

Commenter: Portland Cement Association
DCN: EPA-HQ-OAR-2015-0341-0023-A1
Comment: Industry experience suggests that an equipment life of 15 years or more is reasonable for the major components such as the storage tanks. However, pumps and other equipment require maintenance and/or replacement much more frequently leading to a shorter operational life.

Response: While some equipment, such as pumps, will require maintenance and perhaps even need to be replaced, all of the major components for an SNCR system, such as storage tanks, piping, and injection ports, should be sufficiently durable to last for at least 20 years. Please see the response to the first comment in this section for additional information.

Commenter: Coalition of the American Chemistry Council, American Forest & Paper Association, American Fuel & Petrochemical Manufactures, American Wood Council, Brick Industry Association, and Council of Industrial Boiler Owners.
DCN: EPA-HQ-OAR-2015-0341-0022-A1
Comment: EPA has requested comment on a reasonable estimate of equipment life. Based on our members' experience, a reasonable estimate of SNCR equipment life is 10 to 20 years.

Response: The EPA thanks the commenter for their input. Please see the response to the first comment in this section for additional information.

Commenter: Coalition of the American Chemistry Council, American Forest & Paper Association, American Fuel & Petrochemical Manufactures, American Wood Council, Brick Industry Association, and Council of Industrial Boiler Owners.
DCN: EPA-HQ-OAR-2015-0341-0022-A1
Comment: The factors used by EPA to calculate capital recovery cost grossly underestimate the annualized costs of installing SNCR. The text on page 1-52 states that "[c]apital recovery cost is based on the anticipated equipment lifetime and the annual interest rate employed." Any estimate based on these two factors alone is completely deficient, yet these are the only factors used by EPA in the equation for the capital recovery factor provided on page 1-53. The capital recovery factor should account for not only interest rates, but should also include return on equity, depreciation, inflation, and risk. The use of these factors is standard practice, as in Alstom*, Clean Combustion Technologies* 125 (Carl Bozzuto ed., 2009). In addition, the Federal government generally recognizes that cost estimates need to be based on much more than just equipment lifetime and annual interest. For example, cost estimates made by the Department of Energy routinely take into account the cost of equity, risk, the cost of debt, and the proportion of debt to equity in financing a capital project. *See, e.g.*, Technical Support Document, Energy Conservation Program: Energy Conservation Standards for Packaged Terminal Air Conditioners and Packaged Terminal Heat Pumps, EERE-2012-BT-STD-0029-0040, at 8-20 to 8-22 (June 2015).

Response: The methodology used in the SNCR chapter to calculate the capital recovery cost is based on the methodology outlined in in Section 1, Chapter 2, Cost Estimation: Concepts and Methodology. This methodology is used as the basis for preparing the cost estimate methods for all of the pollution control equipment included in the cost manual. This methodology estimates real, not nominal (or including inflation) costs, and is a standard methodology for estimating equivalent uniform annual costs (EUAC) as stated in Section 1, Chapter 2 of the Cost Manual. The approach is primarily targeted toward study-level estimates that have an accuracy of ±30 percent and allows for a consistent and systematic approach to estimating costs. By using the same basic methodology for all control equipment, the costs estimates can be used to compare the relative cost effectiveness of each system.

1.5   Example Problem

No comments

1.5.1   Design Parameter Example

Commenter: Institute of Clean Air Companies (ICAC)
DCN: EPA-HQ-OAR-2015-0341-0021-A1
Comment: Examples on page 1-56. The constant in the second equation "0.35" should not be in this equation. The mistake made the reagent flow very low and the correct value should be 438 lb/hour, instead of 154. Due to the error in the second equation, the flow calculated in the third equation should be 877 lb/hour, instead of 307 lb/hour. All solutions flow, tank size, and operating cost calculated in this example should be updated.

Response: The EPA agrees with the commenter that the NOx reduction efficiency (i.e., 0.35) should be deleted from the equation on page 1-56 and the calculated flow, tank size, and costs should be revised to correct the error in the calculated reagent flow rate. The NSR indicates the actual amount of reagent needed to achieve the targeted NO_x reduction based on the uncontrolled NO_x emissions (NOx_{in}). Since the NSR in the example was 1.22, this means that 1.22 moles of reagent are required for each mole of uncontrolled NO_x. The same error was also found in Equation 1.18 on page 1-37. Equation 1.18 and the example provided in section 1.5.1 have been updated.

1.5.2   Cost Estimation Example

Commenter: Institute of Clean Air Companies (ICAC)
DCN: EPA-HQ-OAR-2015-0341-0021-A1
Comment: ICAC believes that the following excerpt from Page 1-7 is a much more accurate indication of SNCR technology costs:

> Based on applications in operation, capital costs for SNCR installations are generally low due to the small amount of capital equipment required, and the cost per unit of output decreases as the size of the source increases. For example, Figure 1.2 shows the installed capital cost of SNCR technology for industrial boilers, on a $/MMBtu/hr basis, decreases as the size of the boiler (and therefore the gross heat input in MMBtu/hr) increases. In addition, the installed capital cost of SNCR applications ranged from $5–20/kWe (kilowatt) in $2008 for power generation units. The installed cost represents the cost of the capital equipment plus the associated installation expenses, but does not include the operation, maintenance, or reagent costs. Table 1.3 contains a summary of average capital costs for SNCR applications on various size units in several source categories.

The above reference appears to be ignored using the proposed cost model. The example in Section 1.5.2 calculates SNCR plus Balance of Plant (BOP) costs at $38/kWe for a 120MW unit, with the undefined 1.3 factor driving the cost to $49/kWe. For industrial units, Figure 1.2 is a much more accurate representation for the stated size range than the proposed cost formula.

In addition, Figure 1.2 for industrial units below 250 MMBtu/hr should be used as the basis for the technology cost evaluation. EPA has not proposed any sort of new cost formula for industrial units in that size range.

It is important to note that SNCR system costs are closely related to the boiler load range over which the SNCR system will operate. A wide load range of 25 or 30%MCR to 100%MCR may require multiple levels of injectors which affects the size and system capacity of the overall SNCR systems.

Response: See section 1.4 for responses to comments on the equations used to estimate TCI.

Commenter: Coalition of the American Chemistry Council, American Forest & Paper Association, American Fuel & Petrochemical Manufactures, American Wood Council, Brick Industry Association, and Council of Industrial Boiler Owners.
DCN: EPA-HQ-OAR-2015-0341-0022-A1
Comment: Much technical work has been done to understand the mechanisms that influence the control of NOx emissions since these chapters were first published in October 2000 and entire technical conferences have recently been devoted to the control of NOx emissions. For example, the annual Reinhold Environmental NOx-Combustion Roundtable conference (see www.reinholdenvironmental.com). NOx emissions control is also covered at the annual Energy, Utility, and Environment Conference (EUEC), the CIBO Industrial Emissions Control Technology Conference, and the A&WMA Power Plant Pollutant Control "MEGA" Symposium. EPA should review the most recent information available and update its analysis and its list of technical references.

Response: The EPA thanks the commenter for their input. The EPA has reviewed the current literature and updated the Manual based on the best information available.

1.6   Other Comments

Comments on Inclusion of a Contingency Cost

Commenter: Arizona Public Service Company (APS)
DCN: EPA-HQ-OAR-2015-0341-0028-A1
Comment: The contingency cost for EPA's capital cost estimating procedure should be 50 percent. In cases where access issues are known, the contingency could be reduced to 25 to 35 percent.

Response: The capital cost procedure in the Sargent and Lundy SNCR cost memorandum of March 2013 reflects contingency consistent with a process contingency of 5-10 percent and a project contingency of 15 percent. These percentages are adequate to capture such cost elements as inadequacies in estimating methods for process and project installation, and the degree of maturity of the technology. These percentages are also consistent with percentage estimates recommended by the Association for the Advancement of Cost Engineering International (AACEI) and are consistent with recommended percentages used by EPRI and DOE. Given the maturity of SNCR technology, these relatively low process and project contingencies are appropriate.

Commenter: Utility Air Regulatory Group and Edison Electric Institute (EEI)
DCN: EPA-HQ-OAR-2015-0341-0026-A2 and EPA-HQ-OAR-2015-0341-0024
<u>Comment:</u> As to SNCR capital cost, UARG notes that the cost estimation methodology in the Draft SNCR Chapter does not account for site-specific physical features or layout. Accordingly, EPA should assign a contingency value of ± 50 percent when estimating capital cost for SNCR. *Id.* at 6-2.

Response: The capital cost procedure in the Sargent and Lundy SNCR cost memorandum of March 2013 reflects contingency consistent with a process contingency of 5-10 percent and a project contingency of 15 percent. These percentages are adequate to capture such cost elements as inadequacies in estimating methods for process and project installation, and the degree of maturity of the technology. These percentages are also consistent with percentage estimates recommended by the Association for the Advancement of Cost Engineering International (AACEI) and are consistent with recommended percentages used by EPRI and DOE. Given the maturity of SNCR technology, these relatively low process and project contingencies are appropriate.

Commenter: Utility Air Regulatory Group and Edison Electric Institute (EEI)
DCN: EPA-HQ-OAR-2015-0341-0026-A2 and EPA-HQ-OAR-2015-0341-0024
<u>Comment:</u> EPA correctly notes that the bulk of incurred operating cost for SNCR is due to the cost of procuring and utilizing urea reagent. As a consequence, the capital cost of SNCR is not a strong factor in defining the cost effectiveness of SNCR as an option. The cost relationship offered by EPA should be assigned a contingency consistent with other cost-estimating methods that use only process data (and not site-specific physical constraints), and that is ± 50%.

Response: The capital cost procedure in the Sargent and Lundy SNCR cost memorandum of March 2013 reflects contingency consistent with a process contingency of 5-10 percent and a project contingency of 15 percent. These percentages are adequate to capture such cost elements as inadequacies in estimating methods for process and project installation, and the degree of maturity of the technology. These percentages are also consistent with percentage estimates recommended by the Association for the Advancement of Cost Engineering International (AACEI) and are consistent with recommended percentages used by EPRI and DOE. Given the maturity of SNCR technology, these relatively low process and project contingencies are appropriate.

Commenter: American Petroleum Institute (API)
DCN: EPA-HQ-OAR-2015-0341-0020-A1
Comment: A Contingency of at Least 30% should be Included in All of the Chapter 1 and 2
Total Capital Investment (TCI) Cost Estimates.

On page 33517 of the Notice of Data Availability EPA requests comment on "What is a
reasonable estimate of contingency, whether it be for one or more types, for [SCR and SNCR]?"
No contingency appears to be included in the estimates in these drafts[33], though a 5% process
contingency is applied to the installation costs and a 15% project contingency is applied to the
overall project cost in the two current versions of these Chapters.

Contingency factors are required for all project cost estimates, since direct estimates, particularly
those based on only rough screening quality information, cannot anticipate every project need or
impact. For instance, every potential siting and installation issue, every required upgrade to
electrical, instrument or other utility services, every labor cost variation, every weather effect,
etc. cannot be predicted in a screening quality estimate. Typically, project contingency factors
use by the petroleum industry start quite high (e.g., 30-50%) and are reduced as project detail
improves. However, even for projects with detailed process designs, project contingencies of at
least 10-20% are still required (depending on company practice and experience). API members
indicate that 30 – 50% is the amount of contingency typically required for screening estimates,
such as those developed through the Control Cost Manual. Thus, API recommends a project
contingency of at least 30% to improve the probability that the SCR or SCNR installation under
consideration can actually be installed for the estimated cost.

In these draft Chapters, the cost estimates for boilers ≥25 MW are based on averages of utility
coal-fired boiler historical data, rather than being developed from process data that would allow
sizing the major equipment as a starting point for a traditional screening cost estimate. None-
the-less, there still is considerable concern over these estimates and contingency is still needed.
Factors of concern that must be addressed by adding a contingency factor include:

- The accuracy of the underlying cost information. Reports of costs for installed projects
tend to be incomplete, because project accounting systems are segmented and often do
not count all indirect costs, costs charged to on-going operations (such as required utility
upgrades and equipment preparation costs), outage costs, etc. Retrospective reviews may
also fail to include costs from ancillary facilities managed as a separate contract or
project or that is classified as maintenance, even though it is required for the project.
Specific equipment that is often missed in such look-back reviews include the monitors
discussed in Comment II.4, upgrades to existing ID fans and their electrical supply, the

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[33] It is possible that a contingency factor of 20% was included in some of the utility boiler cost estimates that make up a portion of the basis for
the $/kW factors in each cost equations in these drafts, since that contingency factor is used in EPA's Coal Utility Environmental Cost program
from which some of the raw data underlying the equations may have been drawn. But the raw data and the basis for that data for the Integrated
Planning Model for the electrical power industry that is the basis for these cost factors is not provided in the record.

cost of an SCR bypass (often needed on startup and for emergencies), and incremental additions to the DCS, instrument air, and other general plant facilities.

- The data on utility boilers may not be representative of smaller industrial boilers. Utility boilers typically are 100 MW or larger, while industrial boilers are typically smaller than 100 MW. Further, as discussed elsewhere, industrial boilers are of different designs than utility boilers and often have different operating and siting issues. Sargent and Lundy[34] indicate the costs for both SCR and SNCR increase rapidly for utility boilers under 100MW (about 1100 MMBTU/hr. for oil-fired units and 820 MMBTU/hr. for gas-fired boilers) and, thus, the cost curves they derived primarily from larger utility boilers may be particularly questionable for smaller industrial boilers.

- The likely increased complexity and cost associated with future SCR and SNCR installations because of having retrofitted the easier installations first. Typically, control requirements first apply to equipment that can be most readily retrofitted and later to more difficult to retrofit equipment. Thus, it is reasonable to expect that data from the 1990s and 2000s, would understate the costs for installations in the 2010+ timeframe.

As a result of these concerns a significant contingency is clearly necessary when estimating industrial boiler costs when they are based on average historical cost data. Average cost data might be usable for developing national averages, but not for making cost benefit decisions for individual combustion device NOx controls. Since the boiler cost equations in the draft Control Cost Manual Chapters are based on average information, a contingency adjustment is necessary to assure the cost estimated for an individual project is valid and the cost benefit of a potential control decision is properly evaluated.

Based on company practices for screening quality estimates[35] and the factors discussed above, API recommends a contingency of at least 30% be applied to industrial boiler estimates derived from the draft cost estimating equations, should those estimates be included in the final publication of these Chapters. Such a contingency factor is consistent with the statements in the drafts on the estimated accuracy of these equations. For instance, on page 1-7 of the draft Chapter 1 it is stated "The cost methodology incorporates certain approximations; consequently, it should be applied to develop study-level accuracy (±30%) cost estimates for

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[34] Sargent and Lundy Report to Systems Research and Applications Corporation, *IPM Model – Updates to Cost and Performance for APC Technologies, SCR Cost Development Methodology, Final Report*, March 2013.

[35] In fact, these estimates would be less accurate than typical industry screening quality estimates, since industry estimates would be based on knowledge of the site where the facility would be located and include be based on some site specific information (e.g., whether the boiler is natural draft or induced draft and site specific construction rates and overheads). [9] Sargent and Lundy Report to Systems Research and Applications Corporation, *IPM Model – Updates to Cost and Performance for APC Technologies, SNCR Cost Development Methodology, Final Report*, March 2013.

SNCR applications." A similar statement is made on page 2-2 of draft Chapter 2 relative to the SCR cost estimates.

Response: The capital cost procedure in the Sargent and Lundy SNCR cost memorandum of March 2013 reflects contingency consistent with a process contingency of 5-10 percent and a project contingency of 10 percent. These percentages are adequate to capture such cost elements as inadequacies in estimating methods for process and project installation, and the degree of maturity of the technology. These percentages are also consistent with percentage estimates recommended by the Association for the Advancement of Cost Engineering International (AACEI) and are consistent with recommended percentages used by EPRI and DOE. Given the maturity of SNCR technology, these relatively low process and project contingencies are appropriate.

Commenter: Portland Cement Association
DCN: EPA-HQ-OAR-2015-0341-0023-A1
Comment: PCA believes that 20% represents a reasonable minimum contingency. See U.S. EPA "NOx Control Technologies for the Cement Industry: Final Report", September 2000, Section 6.1.2 (stating that a 20% contingency is appropriate for cost estimation).

Response: The capital cost procedure in the Sargent and Lundy SNCR cost memorandum of March 2013 reflects contingency consistent with a process contingency of 5-10 percent and a project contingency of 10 percent. These percentages are adequate to capture such cost elements as inadequacies in estimating methods for process and project installation, and the degree of maturity of the technology. These percentages are also consistent with percentage estimates recommended by the Association for the Advancement of Cost Engineering International (AACEI) and are consistent with recommended percentages used by EPRI and DOE. Given the maturity of SNCR technology, these relatively low process and project contingencies are appropriate.

Commenter: San Joaquin Valley Air Pollution Control District
DCN: EPA-HQ-OAR-2015-0341-0027-A2
Comment: In response to EPA's question as to what a reasonable estimate of contingency is, whether it be for one or more types of contingency, the District recommends adding a contingency factor in the total capital investment costs for SNCR and SCR installation and retrofit. More specifically, the District recommends maintaining the process contingency between 5-10% due to uncertainty in the process operation and a project contingency of 15% due to uncertainty in project installation. These assumptions are based on 2010 information prepared for the Utility Air Regulatory Group's report titled "Current Cost and Cost-Effectiveness of Power Plant Emissions Control Technologies (http://www.publicpower.org/files/pdfs/uargscr_fgdfinal.pdf).

Response: The capital cost procedure in the Sargent and Lundy SNCR cost memorandum of March 2013 reflects contingency consistent with a process contingency of 5-10 percent and a project contingency of 10 percent. These percentages are adequate to capture such cost elements as inadequacies in estimating methods for process and project installation, and the degree of maturity of the technology. These percentages are also consistent with percentage estimates

recommended by the Association for the Advancement of Cost Engineering International (AACEI) and are consistent with recommended percentages used by EPRI and DOE. Given the maturity of SNCR technology, these relatively low process and project contingencies are appropriate.

Commenter: Coalition of the American Chemistry Council, American Forest & Paper Association, American Fuel & Petrochemical Manufactures, American Wood Council, Brick Industry Association, and Council of Industrial Boiler Owners.
DCN: EPA-HQ-OAR-2015-0341-0022-A1
Comment: EPA did not include an estimate of contingency factor in the draft chapter but asked for comment on a reasonable estimate of contingency factor. A contingency factor is appropriate to include, especially in retrofit applications. Based on our members' experience, a reasonable contingency factor would be in the range of 10 to 15 percent, or even higher depending on the site-specific conditions.

Response: The capital cost procedure in the Sargent and Lundy SNCR cost memorandum of March 2013 reflects contingency consistent with a process contingency of 5-10 percent and a project contingency of 15 percent These percentages are adequate to capture such cost elements as inadequacies in estimating methods for process and project installation, and the degree of maturity of the technology. These percentages are also consistent with percentage estimates recommended by the Association for the Advancement of Cost Engineering International (AACEI) and are consistent with recommended percentages used by EPRI and DOE. Given the maturity of SNCR technology, these relatively low process and project contingencies are appropriate.

Other General Comments

Commenter: Portland Cement Association
DCN: EPA-HQ-OAR-2015-0341-0023-A1
Comment: How do the costs of SNCR installation and operation differ between the electric power sector and industrial sources?

The installation costs for SNCR for electric power decrease on a per unit basis as the size of the unit increases. For cement, the type of the kiln and its production rate impact the installation costs. For example, the installation costs for preheater and precalciner kilns are generally similar regardless of the production rate unless additional storage capacity is needed. In contrast, the installation costs are higher for long-wet and dry kilns due to the need to install a rotary valve and piping on the rotating kiln or to install the Cadence™ system. The long kilns typically have significantly lower production rates which result in higher installation costs per ton of clinker capacity.

Operating costs are driven by the NOx emissions rate and the control efficiency desired/required and the resulting quantities of reagent required. Kiln type, clinker type, kiln feed burnability, and fuels types and injection locations impact the uncontrolled NOx emissions rates for kilns. Thus,

uncontrolled emissions rates for cement kilns can vary significantly from rates of less than 2 lb NO_x/T_c for a precalciner kiln to rates in the 10-19 lb NO_x/T_c for long-wet kilns.

Response: The EPA thanks the commenter for their input. We agree with the commenter that the installation costs would likely be higher for SNCR systems installed on long wet and dry cement kilns because the reagent must be injected in the rotary furnace. We also agree with the commenter that long kilns generally have lower production rates and hence the installation costs for SNCR would be higher on a dollar per ton of clinker production capacity basis. We also agree that the reagent costs are a significant portion of the operating costs for SNCR systems. As the commenter notes, the amount of reagent used is dependent on several site-specific factors and can vary significantly depending on the type of kiln, the composition of the raw materials, types of fuels used, and the level of control required.

Commenter: Arizona Public Service Company (APS)
DCN: EPA-HQ-OAR-2015-0341-0028-A1
<u>**Comment:**</u> There should not be an appreciable difference in the capital costs between utility and industrial SNCR; however, the operations and maintenance can be different due to differences in the start-up/shut-down cycles. Because industrial boilers are only handling their own load they may run steadier. Utility boiler operation is subject to customer demand and thus could cycle more frequently.

Response: The EPA thanks the commenter for their input.