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Chapter 1

Selective Noncatalytic Reduction

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1. SELECTIVE NONCATALYTIC REDUCTION

1.1 Introduction

Selective noncatalytic reduction (SNCR) is a post combustion emissions control technology for reducing NO_x by injecting an ammonia type reactant into the furnace at a properly determined location. This technology is often used for mitigating NO_x emissions since it requires a relatively low capital expense for installation, albeit with relatively higher operating costs. Japan originally developed SNCR for oil and gas units in the 1970s; Western Europe followed by applying the science to coal fired units in the late 1980s and the U.S electric power sector began installations on coal plants in the early 1990s. More than 45 gigawatts of coal-fired power capacity in the U.S. now have SNCR.[1] 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]. It is being used on industrial boilers covering a wide range of sizes from <50 MMBtu/hr to more than 800 MMBtu/hr [2]. SNCR is also being used on a wide range of sizes of utility boilers from <50 MW to more than 900 MW. More than half of utility boilers with SNCR are relatively small (<50 – 200 MW) but about 24 percent are larger than 300 MW.[1] Over 70 percent of the utility boilers using SNCR burn coal as the primary fuel and most of the others burn biomass, but the other types of combustion sources are burning a wide range of materials [2].[1] SNCR can be applied as a standalone NO_x control or with other technologies such as combustion controls. The SNCR system can be designed for seasonal or year-round operations.

Reported SNCR reduction efficiencies vary over a wide range. Temperature, residence time, type of NO_x reducing reagent, reagent injection rate, uncontrolled NO_x level, distribution of the reagent in the flue gas, and CO and O_2 concentrations all affect the reduction efficiency of the SNCR [2]. Tables 1.1 and 1.2 and Figures 1.1a, 1.1b, and 1.1c summarize emission reductions for SNCR applications in a variety of industries [2]. Findings based on review of these data are as follows:

- Although installation of urea-based systems is more common than ammonia-based deployments, operating data reveal higher NO_x reductions occur with ammonia reagent. Table 1.1 shows the median (as a measure of average) reductions for urea-based SNCR systems in various industry source categories range from 25 to 60 percent, while median reductions for ammonia-based SNCR systems range from 61 to 65 percent. Note that most of the boilers with ammonia-based SNCR systems that are fired with solid fuels are fired with wood or municipal solid waste. Figure 1.1b shows nearly all ammonia-based systems have reduction efficiencies greater than 40 percent, while several urea-based systems have lower reduction efficiencies.

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[1] Spreadsheet of information provided to EPA's Clean Air Market Division from query of SNL Energy data on 1/22/2015.

Table 1.1: Summary of NO_x Reduction Efficiencies Obtained Using SNCR on Different Types of Boilers in the U.S. [2]

Type of source category	Fuel	NO_x reduction reagent	Average boiler size	Median NO_x reduction (%)
Electric utility	Coal	Urea	320 MW	25
Co-generation	Primarily wood, some coal, biomass, and tires	Urea	360 MMBtu/hr	50
Pulp & paper (P&P)	Primarily bark and wood waste, supplemented with a variety of other fuels	Urea	410 MMBtu/hr	50
Municipal waste combustion (MWC)	Municipal solid waste (MSW)	Urea	270 MMBtu/hr	37
Refinery CO boilers	Typically refinery fuel gas	Urea	320 MMBtu/hr	60
Miscellaneous combustion units	Primarily wood, MSW, or coal	Ammonia	400 MMBtu/hr	65
Miscellaneous combustion units	Primarily crude oil or gas	Ammonia	110 MMBtu/hr	61

Table 1.2: SNCR NO_x Reduction Efficiency by Industry and Reagent Type [2, 4]

Industry and Units	**% Reduction**	
	Ammonia-Based	**Urea-Based**
Cement Kilns	12-77	25–90
Chemical Industry	NA[a]	35–80
Circulating Fluidized and Bubbling Bed Boilers	76–80	NA
Coal, Wood and Tire Fired Industrial and IPP/Co-Generations Boilers	NA	20–75
Coal-Fired Boilers	38–83	20–66
Gas- and Oil-Fired Industrial Boilers	30–75	NA
Glass Melting Furnaces	51–70	NA
Steel Products Industry	NA	42.9–90
Municipal Waste Combustors	45-70	16–87
Oil- and Gas-Fired Heaters	45–76	NA
Process Units	NA	40–85
Pulp and Paper Industry	NA	20–62
Refinery Process Units and Industrial Boilers	NA	20–75
Stoker-Fired and Pulverized Coal-Fired Boilers	50–83	NA
Stoker-Fired Wood-Fueled Boilers	40–75	NA
Vapor, Sludge and Hazardous Waste Incinerators	65–91	NA

[a] NA means not available.

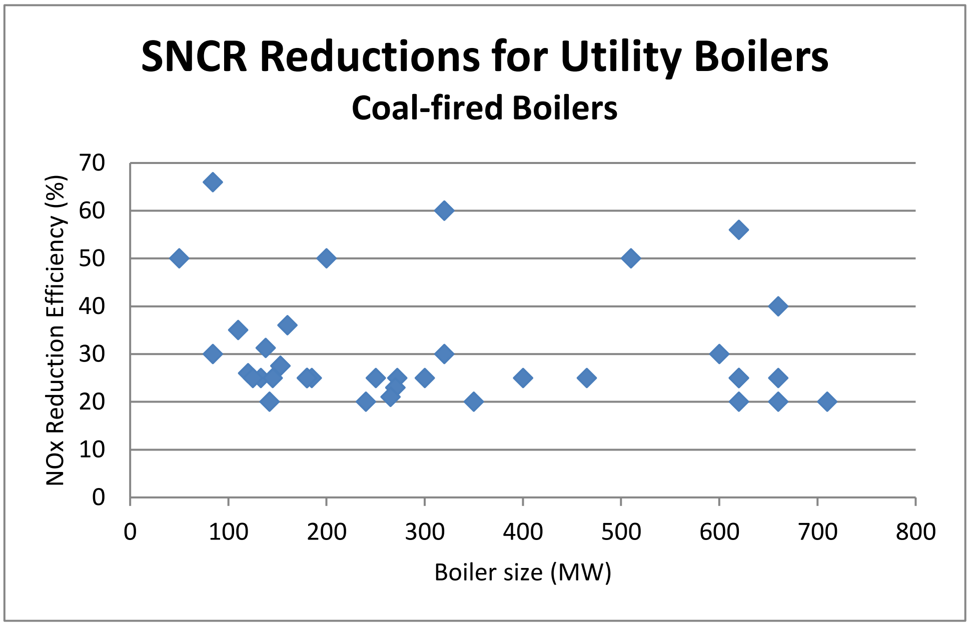

Figure 1.1a: SNCR NO_x Reduction Efficiency for Various Utility Boiler Sizes [2]

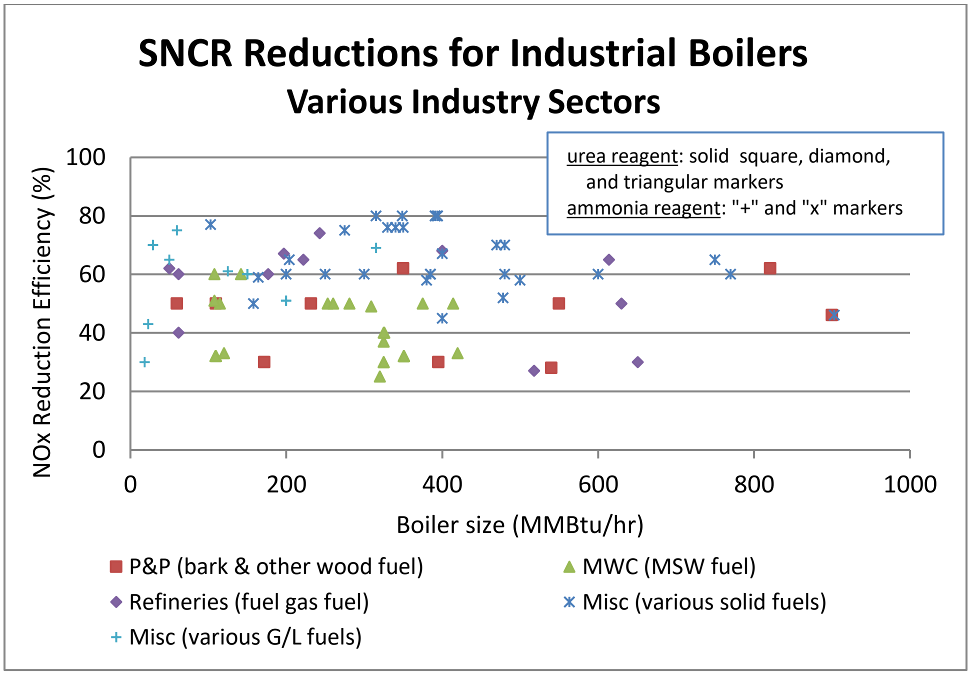

Figure 1.1b: SNCR NO_x Reduction Efficiency for Boilers in Various Industry Sectors [2]

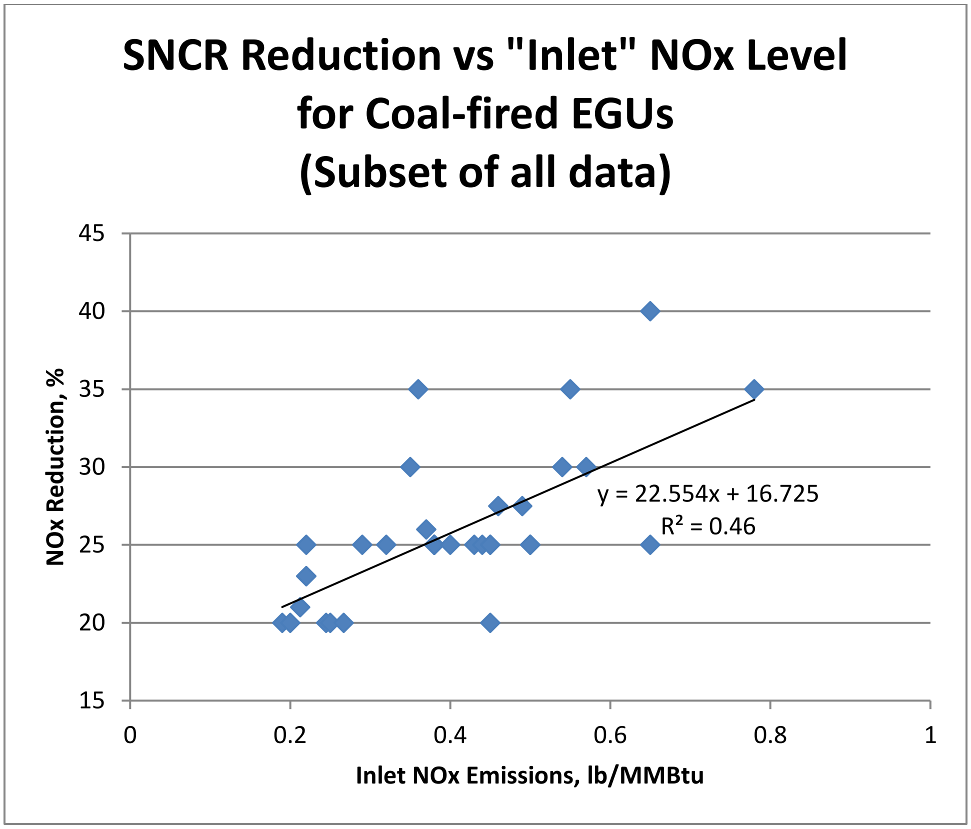

Figure 1.1c: SNCR NO_x Reduction Efficiency Versus Baseline NO_x Levels for Coal-fired Utility Boilers [2]

- Figure 1.1a shows the efficiencies for utility boilers range from 20 percent to over 60 percent with most between 20 percent and 35 percent. Figure 1.1a also shows the efficiencies for the larger utility boilers are comparable to those for smaller utility boilers.

- Although there is significant scatter, Figure 1.1c shows a trend of increasing reductions with increasing baseline NO_x levels for utility boilers. Specifically, the reductions range from 20 percent when the baseline NO_x concentration is about 0.2 lb/MMBtu to 35 percent when the baseline NO_x concentration is about 0.8 lb/MMBtu. This plot excludes 4 data points that had baseline NO_x concentration over 1 lb/MMBtu and 5 additional data points with reductions over 50 percent because such conditions are significantly outside the range of the other available data. Similar plots for boilers in other industry source categories showed no trends.

- Data indicates average reductions for industrial boilers surpass average reductions for utility boilers (see Table 1.1, Fig. 1.1a, and Fig. 1.1b). Figure 1.1b shows reductions for industrial boilers range from about 25 percent to 80 percent, which is a slightly higher range than for coal-fired utility boilers in Figure 1.1a. Table 1.1 shows the median reductions for industrial boilers equipped with urea-based SNCR in various industry source categories range from 37 percent to 60 percent, while the median reduction for utility boilers is 25 percent.

- Table 1.2 presents the range of reductions for numerous source categories. It also includes data for facilities outside the U.S. For most source categories, the range bounds are represented by facilities in the U.S. However, most of the reductions over 80 percent are for facilities outside the U.S. The only exception is the Steel Products Industry[2] where the greatest reduction of 90 percent is at a U.S. facility.

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, 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.

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.

Available information from 7 Best Available Retrofit Technology (BART) analyses in which SNCR was designated as BART for 11 cement kilns indicates estimated NO_x reductions for SNCR systems that are between 35 percent and 58 percent with a median reduction of 40 percent [5]. Two of these kilns have proposed BART emission limits--one at 5.5 lb NO_x/ton clinker and the other at 8.0 lb NO_x/ton of clinker. Also, SNCR was determined as BART in 2014 for a lime kiln in Arizona. NO_x reductions of 50 percent were estimated for the SNCR application, and the final BART emission limits were 3.81 lb NO_x/ton of clinker for one kiln and other at 2.61 lb NO_x/ton of clinker for the other, with a combined limit of 3.27 lb NO_x/ton of clinker on a 30-day rolling average [6].

For cement kilns, the kiln type, design, raw material composition, and the type of cement produced 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. 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 [7]. 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,

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[2] In the referenced study, this source category is called the “Industrial/Steel Industry”.

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 tires [8]. 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 [9].

SNCR utilizes ammonia or urea as a NO_x reduction reagent. An information collection request for data from electric utilities indicated that based on 132 SNCR units, approximately 67% (or 88 units) used urea and 33% (44 units) used ammonia; of those units listed as using urea, 11 units indicated use of urea to ammonia conversion [10].

The mechanical equipment associated with an SNCR system is simple compared to an SCR, semi-dry FGD, or wet scrubber and thereby requires lower capital costs ($/mmBtu/hr basis). Installation of SNCR equipment requires minimum downtime. Although simple in concept, it is challenging in practice to design an SNCR system that is reliable, economical, and simple to control and that meets other technical, environmental, and regulatory criteria. Practical application of SNCR is limited by the boiler design and operating conditions.

The costing algorithms in this report are based on retrofit applications of SNCR to existing coal-fired utility boilers [11]. In the 1990's there was little difference between the cost of SNCR retrofit of an existing boiler and SNCR installation on a new boiler [12]. Over the years SNCR has begun to be applied to existing sites that are more difficult to retrofit which means the gap between average retrofit and new installation costs may be greater than it used to be, but it is not expected to be substantial. Therefore, the cost estimating procedure in this report is suitable for both retrofit and new boiler applications of SNCR on all types of coal-fired electric utilities and large industrial boilers. For other sources, this methodology is somewhat less applicable, and calculations should be developed more specific to the source being controlled. The cost methodology incorporates certain approximations; consequently, it should be applied to develop study-level accuracy (+-30%) cost estimates for SNCR applications.

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 $4-44/kWe (kilowatt) for power generation units based on data for 2005-2007 [13]. 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 [1]. Table 1.3 contains a summary of average capital costs for SNCR applications on various size units in several source categories.

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 [9]. 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 [9]. As for other emission units, SNCR operating costs for cement kilns vary by the desired level of uncontrolled NO_x emissions. The higher the uncontrolled NO_x emissions and lower the desired NO_x outlet emissions, the greater the quantity of reagent used and hence, higher the operating cost. The NO_x emissions differ by kiln type, raw material composition, type of cement produced, fuel type, and fuel injection location [8].

Most of the cost of using SNCR is operating expense. A typical breakdown of annual costs for utilities is 25% for capital recovery and 75% for operating expense [2]. The primary operating expense is for the NO_x reduction reagent. Thus, the total annual costs vary directly with the NO_x reduction requirements. For industrial boilers, typical cost effectiveness values for annual operation of SNCR are less than \$3,000 per ton of NO_x removed, and typical cost effectiveness values for ozone season operation are less than \$4,000 per ton of NO_x removed [1].[3]

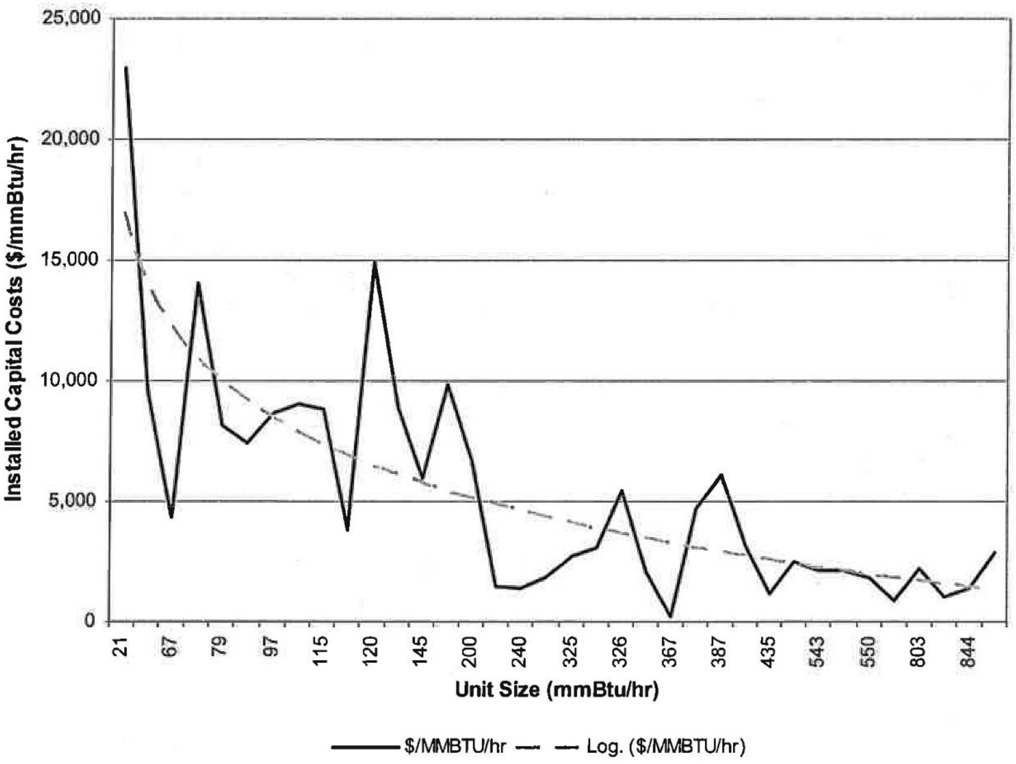

Figure 1.2: Actual SNCR Installed Capital Costs on Industrial Sources
Used with permission from ICAC [1]

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[3] The cited study reported cost-effectiveness values for more than 30 boilers. However, the study did not report the year to which costs were normalized or the applicable year dollars for the individual values.

Table 1.3: Summary of SNCR Cost Data

Source Category	Unit Size	Fuel Type	Capital Cost: average (range)a	$ Year	Reference
Electric Generating Units	NA	Coal	NA ($10–$20/kW) [R]	2005$[b]	[14]
	NA	NA	NA ($5-$20/kW)	2008$[b]	[2]
	NA	NA	NA ($10-$30/kW)	2006$[b]	[15]
	NA	NA	NA ($4-44/KW)	2005-2007	[13]
Industrial-Commercial Boilers	>100 MMBtu/hr	NA	NA ($900–$2,500/MMBtu/hr or $9,000-$25,000/MW)	2006$	[16]
	21–844 MMBtu/hr	NA	See Figure 1.2	2006$[b]	[2, 17]
	89–285 MMBtu/hr	Wood	NA ($0.924–$1.786 million)	2006$[b]	[17]
	>250 MMBtu/hr	NA	NA ($0.5-$1.0 million)	2000$[b]	[18]
	100–1,000 MMBtu/hr	Coal	NA ($2,600–$5,300/MMBtu/hr) [R]	1999$	[19]
	100–1,000 MMBtu/hr	Gas	NA ($2,100–$4,200/MMBtu/hr) [R]	1999$	[19]
	100–1,000 MMBtu/hr	Oil	NA ($2,000–$4,100/MMBtu/hr) [R]	1999$	[19]
	350 MMBtu/hr	Gas and paper sludge	NA ($0.775 million) [N] [$0.50-0.75 million][e]	1997$	[18]
	155 MMBtu/hr	Medium Density Fiberboard waste and wood waste	NA ($0.24 million) [N]	1996$	[18]
	900 MMBtu/hr	Wood	NA ($1.1 million)	1999$[b]	[18]
	475 MMBtu/hr	Wood	NA ($0.70 million)	1999$[b]	[18]
	300 MMBtu/hr	Wood	NA ($0.60 million)	1999$[b]	[18]
	245 MMBtu/hr	Wood	NA ($0.39 million)	1999$[b]	[18]
Portland Cement	1.095 million short tpy clinker	NA	NA ($1.154 million or $1.05 per short ton clinker) [N]	2011$[b]	[20]
	1.09 million short tpy clinker	NA	NA ($2.3 million or $2.1 per short ton clinker) [R]	2006$[b]	[8, 21]
	1.13 million short tpy clinker	NA	NA ($2.3 million or $2.0 per short ton clinker) [R]	2006$[b]	[8, 21]
	2.16 million short tpy clinker	NA	NA ($2.3 million or $1.1 per short ton clinker) [R]	2006$[b]	[8, 21]
	1.4 million short tpy clinker	NA	NA ($1.153 million or $0.8 per short ton clinker)	2004$	[22]
	NA	NA	NA ($1.4 million) [N]	2003$	[23]

Source Category	Unit Size	Fuel Type	Capital Cost: average (range)a	$ Year	Reference
	<150 ton/hr (precalciner kiln)	NA	NA ($0.40–$0.80 million)[e]	1999$[b]	[18]
	100 ton/hr (precalciner kiln)	NA	NA ($0.08/ton clinker or $0.90 million)	1994$[b]	[18]
	0.3 million short tpy clinker (wet kiln)	NA	NA ($1.4 million or $4.7 per short ton clinker) [R]	2006$[b]	[8, 24]
	0.320 million short tpy clinker (wet kiln)	NA	NA ($1.2 million to $1.4 million or $3.8 to 4.4 per short ton clinker)	2006$[b]	[8, 21]
Petroleum Refinery–Process Heater	350 MMBtu/hr	Gas/refinery fuel gas or refinery oil	NA ($0.706–$2.59 million) [R][d]	2004$[c]	[25]
Petroleum Refinery–Boiler	650 MMBtu/hr	Gas or refinery fuel gas	NA ($1.31–$4.80 million) [R][d]	2004$[c]	[25]
Pulp and Paper–Boilers	300,000 lb/hr	Wood or wood/coal/oil	NA ($1.5 million) [R]	2004$[b]	[14]

[a] Costs are for both new SNCR and retrofit SNCR, unless otherwise noted. [R] indicates costs are for retrofit only. [N] indicates costs are for new only, NA indicates the data are not available.

[b] Year of reference.

[c] Year analysis was conducted (assumed vendor contacts were made that year).

[d] Costs are for SNCR only, that is part of combination control including LNB plus SNCR.

[e] Cost does not include installation cost; installation would add 20–30% to the cost shown here.

1.2 Process Description

The basis of SNCR technology is a non-catalyzed chemical reaction utilizing an ammonia based reagent (such as urea or ammonia) for reducing NO_x into nitrogen (N_2) and water (H_2O) by injecting this reagent into the post combustion gas stream at temperatures ranging from 1600-2400°F (870–1320°C) [26]. The reagent can react with a number of flue gas components. However, the NO_x reduction reaction is favored over other chemical reaction processes for a specific temperature range and in the presence of oxygen; therefore, it is considered a selective chemical process.

The conventional SNCR process occurs within the combustion unit, which acts as the reaction chamber. Figure 1.3 shows a conventional SNCR process schematic for an electric power boiler with injection nozzles mounted through the wall and penetrating the combustion unit. The injection nozzles are located in the post-combustion area in the upper area of the furnace near the convective passes. The injection causes mixing of the reagent and flue gas. The heat of the boiler provides the energy for the reduction reaction. The NO_x molecules are reduced and the reacted flue gas then passes out of the boiler. More details on the SNCR process and equipment are provided in the following sections.

Single- and multi-level injection systems for 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.

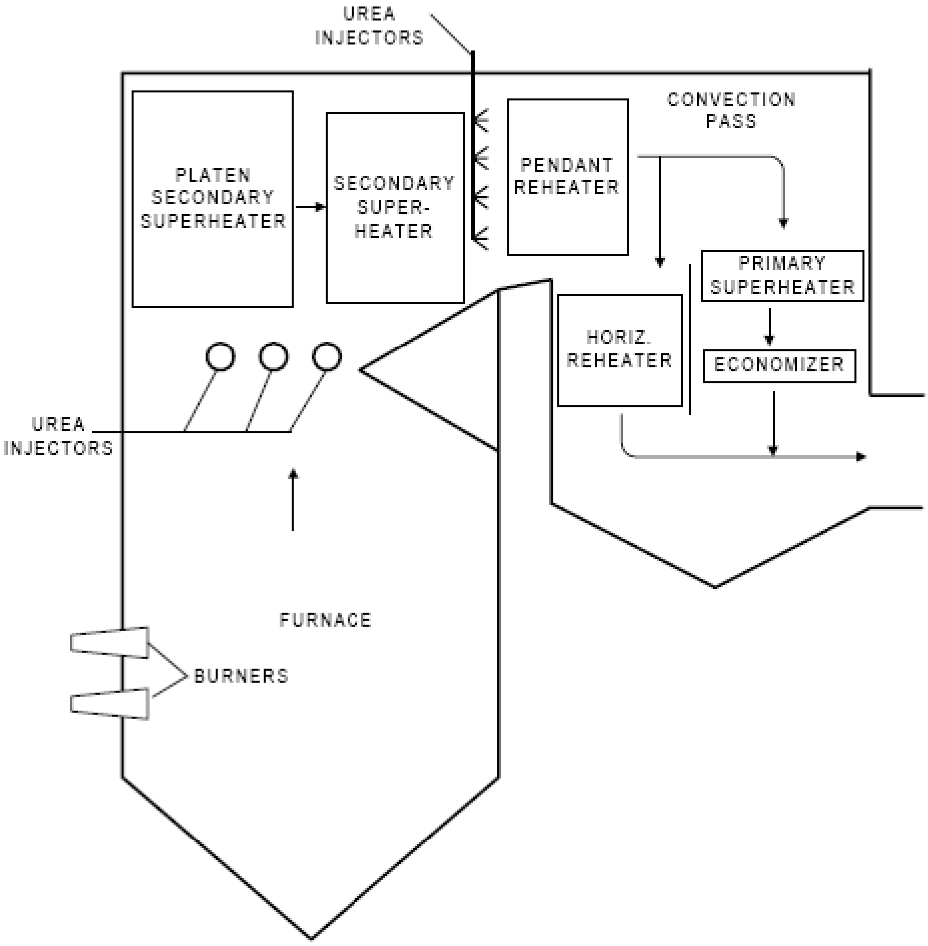

Figure 1.3: Boiler Gas Path Configuration

1.2.1 Reduction Chemistry

SNCR is a relatively simple chemical process. The process begins with an ammonia-based reagent, ammonia (NH_3) or urea [$CO(NH_2)_2$], being vaporized either before injection by a vaporizer or after injection by the heat of the boiler. Within the appropriate temperature range, the gas-phase urea or ammonia then decomposes into free radicals including NH_3 and NH_2. After a series of reactions, the ammonia radicals come into contact with the NO_x and reduce it to N_2 and H_2O.

Since NO_x 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:

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

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

$NH_3+OH\rightarrow NH_2+H_2O$

The amine radicals combine with nitrogen oxides to form nitrogen and water [8]:

$NH_2+NO\rightarrow N_2+H_2O$”

The primary byproduct formed in either ammonia- or urea-based SNCR systems is nitrous oxide (N_2O). N_2O is an ozone depleter and greenhouse gas.[4] Urea-based reduction generates significantly more N_2O than ammonia-based systems; up to 30% of the NO_x can be transformed into N_2O [12, 27]. In one study, N_2O emissions were measured at 0 to 7 µmol/mol in ammonia-based SNCR, and as high as 27.8 µmol/mol in urea-based SNCR [28]. The amount of N_2O formed depends on the reagent feed rate and temperature, and increased N_2O formation correlates with increased NO_x reductions [27, 29]. Proprietary additives are available for the urea-based SNCR process to reduce the formation of N_2O [12].

1.2.2 Reagents

Reagent costs currently account for a large portion of the annual operating expenses associated with this technology, and this portion has been growing over time. Ammonia is generally less expensive than urea since urea is derived from ammonia. However, the choice of reagent is based not only on cost but also on physical properties and operational considerations. The properties of urea and ammonia in aqueous solutions are shown in Table 1.4.

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[4] EPA issued a final rule on November 29, 2013 as part of a notice of data availability concerning the Mandatory Greenhouse Gas Rule that indicates the global warming potential (GWP) of N_2O is 298. The November 29, 2013 notice can be found in the Federal Register at http://www.gpo.gov/fdsys/pkg/FR-2013-11-29/pdf/2013-27996.pdf .

Table 1.4: Urea and Ammonia Reagent Properties [30]

Property	Urea Solution	Aqueous Ammonia
Chemical formula	$CO(NH_2)_2$	NH_3
Molecular Weight of reagent	60.06	17.03
Liquid or gas at normal air temperature	Liquid	Liquid
Concentration of reagent normally supplied	50% by weight	19.0% by weight
Ratio of NH_3 to solution	28.3% by weight of NH_3	19.0% by weight of NH_3
Density of solution @ 60°F	71 lb/ft^3	58 lb/ft^3 (56 lb/ft^3 for 29.4%)
Vapor pressure @ 80°F	<1 psia	14.8 psia [31]
Crystallization temperature	64°F	−110°F
Flammability limits in air	Non-flammable	Lower explosion limit = 16% NH_3 by volume Upper explosion limit = 25% NH_3 by volume.
Threshold limit value (health effects)	Not specified	25 ppm
Odor	Slight (ammonia-like)	Pungent odor @ 5 ppm or more
Acceptable materials for storage	Plastic, steel, or stainless steel (no copper or copper- based alloys or zinc/aluminum fittings)	Steel tank, capable of handling at least 25 psig pressure (no copper or copper-based alloys, etc.)

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 [26]. 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% [32]. 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 [8, 33]. 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. 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).

Urea is generally stored in a 50% aqueous solution [2, 32]. At this concentration, the urea solution must be heated and circulated in cold climates due to its low freezing point, 64°F (18°C). Higher concentrations of urea solutions are available that decrease the storage volume but require extensive heating to prevent freezing. Urea is injected into the boiler as an aqueous solution and vaporized by the heat of the boiler. Urea can also be transported in pellet form, which minimizes transportation requirements, or can be transported at a higher concentration, which reduces the transportation cost due to the lower weight and volume of the solution. However, to produce aqueous urea for use in the SNCR system, the urea must then be mixed with water at the facility to dilute it to the 50% aqueous solution [26]. For urea pellets, this dissolving, diluting, and mixing process is generally cost prohibitive except for remote sites, large facilities, or facilities where chemical mixing processes are already being performed, due to the additional capital requirements associated with this process [26, 34]. Urea solutions become more cost effective as the transported concentrations increase; the cost to transport a 70% solution by rail to a third-party facility is 65% less than the cost to transport a 50% urea solution and is 58% less than the cost to transport a 60% urea solution [26].

Urea-based systems have several advantages over ammonia-based systems. Urea is a nontoxic, less volatile liquid that can be stored and handled more safely than ammonia. Urea solution droplets can penetrate farther into the flue gas when injected into the boiler. This enhances mixing with the flue gas, which is difficult on large boilers [32]. Because of these advantages, urea is more commonly used than ammonia in large boiler applications of SNCR systems.

Generally, anhydrous ammonia, which is typically used in conventional SNCR, is the least costly reagent, with a nominal cost one-half that of 50% urea. A 29.4% aqueous ammonia solution costs 150% more than anhydrous ammonia, and 70% urea costs 175% more than anhydrous ammonia. However, the reagent characteristics associated with ammonia and urea must also be taken into consideration. At any level of dilution, ammonia will flash evaporate upon contact with flue gas; therefore, a physical distribution grid must be used, or in some instances, an alternative high-energy lance injection system, such as the NO_xSTAR or Rotamix, must be used. These alternative SNCR technologies are discussed in Section 1.2.6 below. These injection systems increase the overall capital cost, countering some of the cost savings associated with dilution of anhydrous ammonia. Although urea is a more costly reagent, the vapor pressure of urea is much lower than that of ammonia. Because urea is most efficiently introduced into the system as a droplet, allowing for additional mixing with the flue gas and tailoring of the release location, it is also a more flexible process than ammonia injection and is also typically more cost efficient over time. In general, the use of 70% urea solution shipped by rail and diluted to 50% onsite results in the lowest cost SNCR process for most applications, with a savings of 20% compared to delivered cost of a 50% urea solution [26].

1.2.3 SNCR Performance Parameters

The design and operational factors affecting NO_x reduction are:

- Reaction temperature (sp.: furnace temp)
- Residence time (reagent injection location)
- Degree of mixing
- Uncontrolled NO_x concentration (starting NO_x)
- Ratio of injected reagent to uncontrolled NO_x (amount of reagent injected); and
- Ammonia slip (which is strongly influenced by the ratio of injected reagent to uncontrolled NO_x)

Figures 1.4 through 1.8 in this section present graphical representations of the effect of these factors on SNCR reductions. The plots are intended to illustrate trends and relative effects of the factors as discussed in the text, but they are not based on test data.

Temperature

The NO_x reduction reaction occurs within a specific temperature range for a selected reagent - at lower temperatures, the reaction kinetics are slow: at higher temperatures, the reagent oxidizes and additional NO_x is generated. Figure 1.4 shows the NO_x reduction efficiency for urea and ammonia at various boiler temperatures. For ammonia, the optimum temperature range is 1600–2000°F (870–1100°C), with peak removal usually occurring at 1750°F (950°C) [26, 32]. For urea, the optimum temperature range is 1650–2100°F (900°–1150°C), with peak removal typically occurring at 1850°F (1010°C) [26, 32].

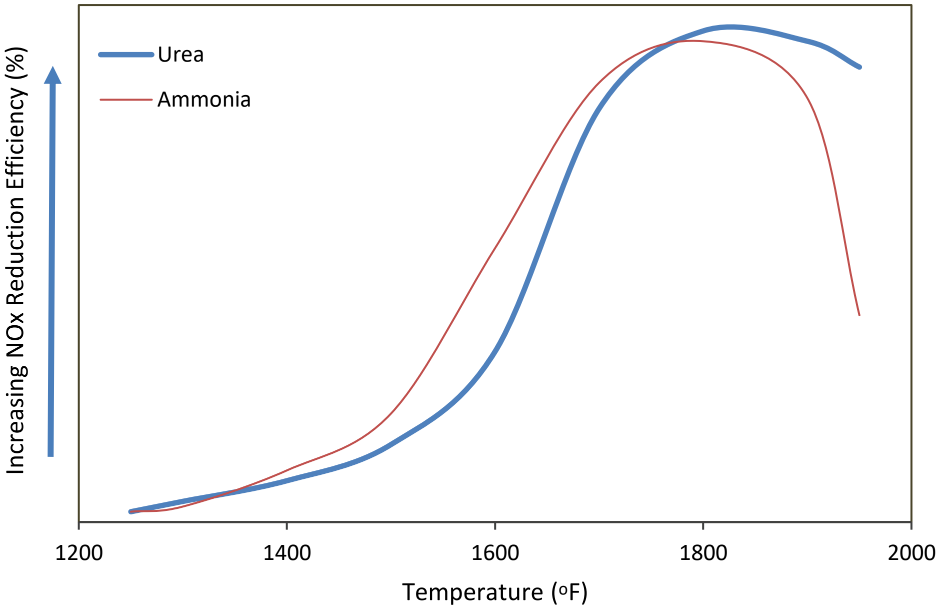

Figure 1.4: Effect of Temperature on NO_x Reduction

During the engineering phase, designers locate the injection points based on: the furnace operating conditions, the owner-elected reagent (urea or ammonia), and reaction rate curves (similar to those above) to optimize reagent consumption for a pre-determined NO_x reduction rate. Typically, the reagent is injected between the boiler superheater and reheater or the radiant and convective regions, where the appropriate temperature range is typically available [32]. Proper placement of the injection ports results in higher NO_x reduction efficiency.

Flue gas temperature within the boiler depends on the boiler design and operating conditions, which are established to meet steam generation requirements – these design parameters are not always ideal conditions for SNCR. Flue gas temperatures in the upper furnace through the convective pass may vary by ±300°F (150°C) from one boiler to the next [32]. In addition, fluctuations in the boiler load profile affect the temperature within the boiler. At lower load profiles, the temperature within the boiler is lower. Variations in the flue gas temperature make the design and operation of an SNCR system more difficult.

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 NO_x 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 NO_x reduction.

Residence Time

By definition, residence time is the amount of time the reactants are present within a chemical reactor. The longer the residence time, the greater conversion achieved. The upper area of the furnace is the reaction area for the SNCR process with flue gas velocity determining residence time within this fixed area; however, boiler design establishes flue gas velocity. Increasing the residence time available for mass transfer and chemical reactions generally increases the NO_x removal. In addition, as the temperature window for the reaction is lowered, greater residence time is required to achieve the same NO_x reduction level. Residence time can vary from 0.001 to 10 seconds [32]. However, the gain in performance for residence times greater than 0.5 seconds is generally minimal, and performance degradation is observed for residence times less than 0.2 seconds [12, 26]. Figure 1.5 shows the effect of residence time and temperature on NO_x reduction.

The amount of residence time depends on the dimensions of the boiler gas path and the volumetric flow rate. These design parameters are optimized for steam generation and prevent watertube erosion. Consequently, the residence time in the boiler is not always ideal for the SNCR process.

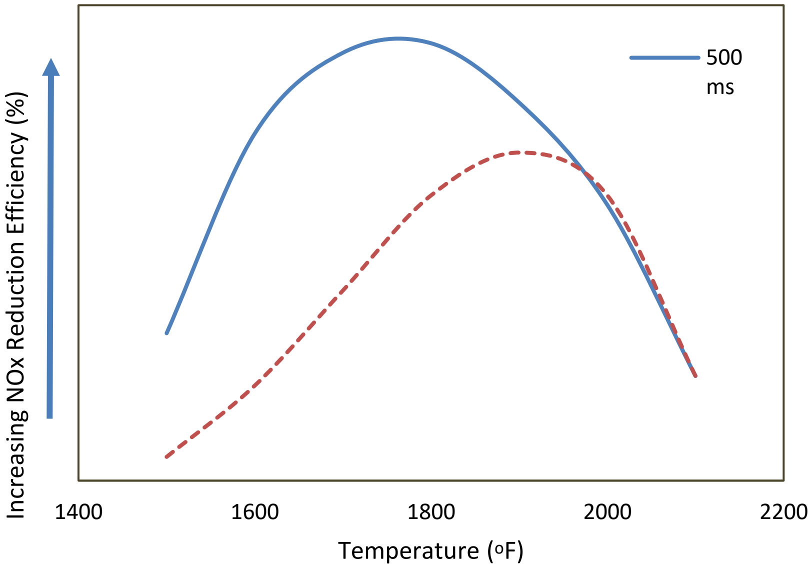

Figure 1.5: Effect of Residence Time on NO_x Reduction

Degree of Mixing

For optimal reaction rates and decreased reagent consumption, the reagent is properly mixed with the flue gas via a multi-point injection grid situated within the furnace. The mixing requirements are unit specific and depend on the air flow profiles through the furnace [32]. Mixing is performed by the injection system. The injectors atomize the reagent and control the spray angle, velocity, and direction of the injected reagent. These systems are boiler and reagent specific. Numeric modeling of the flue gas and reagent flow optimizes the design of the injection system (see Section 1.2.5, Other Considerations).

To assist in dispersion of aqueous urea, the reagent is atomized into droplets by specially designed nozzles that optimize the droplet size and distribution. Evaporation time and trajectory are a function of the diameter of the droplet. Larger droplets have more momentum and penetrate farther into the flue gas stream; however, they require a longer time to volatilize, increasing the required residence time [32].

Inadequate mixing results in insufficient NO_x reduction. Mixing patterns can be improved by several methods:

- Increase the energy imparted to the droplets;
- Increase the number of injectors;
- Increase the number of injection zones; and
- Modify the atomizer nozzle design to improve the solution droplet size, distribution, spray angle, and direction.

Uncontrolled NO_x

The concentration of the reactants also affects the reaction rate of the NO_x reduction process. The reaction kinetics decrease as the concentration of reactants decreases. This is due to thermodynamic considerations that limit the reduction process at low NO_x concentrations [32]. For lower NO_x inlet concentrations, the optimum temperature for the reaction is lower; hence, the percent NO_x reduction is lower. Figure 1.6 shows the NO_x reduction efficiency as a function of temperature for several uncontrolled NO_x levels.

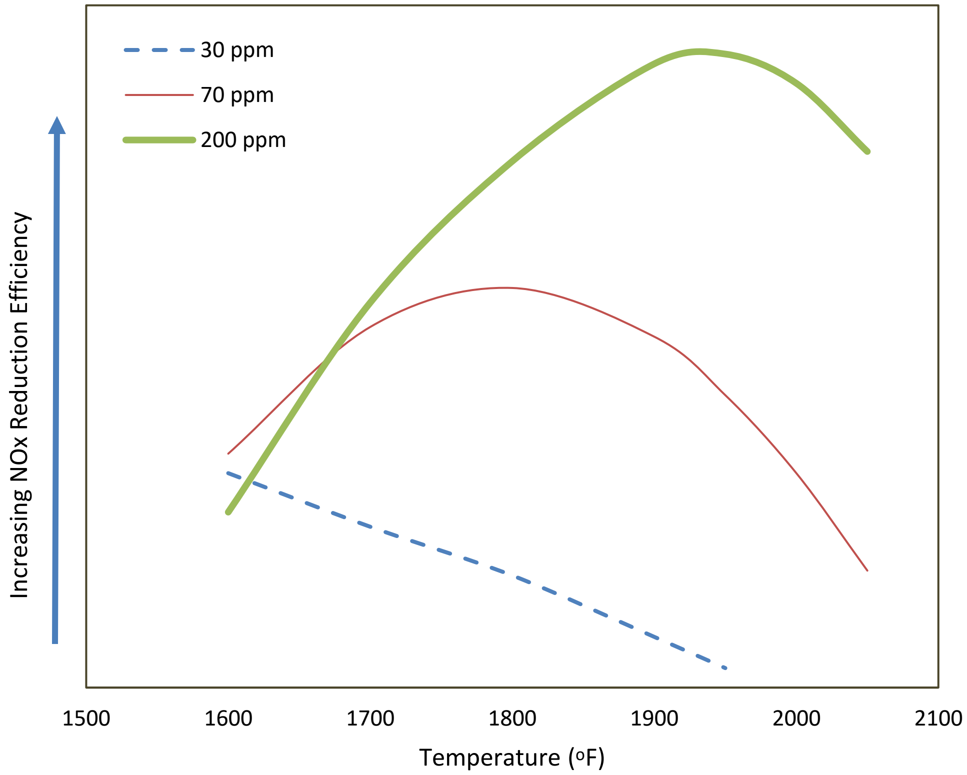

Figure 1.6: Effect of Uncontrolled NO_x Level on NO_x Reduction Efficiency

Normalized Stoichiometric Ratio

The normalized stoichiometric ratio (NSR) defines the amount of reagent needed to achieve the targeted NO_x reduction. 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. This is due to the complexity of the actual chemical reactions involving NO_x and injected reagent and mixing limitations between reagent and flue gas (rate kinetics). Typical NSR values are between 0.5 and 3 moles of ammonia per mole of NO_x [12]. Because capital and operating costs depend on the quantity of reagent consumed, determining the appropriate NSR is critical. The factors that influence the value of NSR include the following:

- Percent NO_x reduction;
- Uncontrolled NO_x concentration in the flue gases;
- Temperature and residence time available for the NO_x reduction reactions;
- Extent of mixing achievable in the boiler;
- Allowable ammonia slip; and
- Rates of competing chemical reactions.

Section 1.3, Design Parameters, provides further discussion of these influences and a method for estimating the NSR.

Figure 1.7 shows the NO_x reduction as a function of the NSR. Note that as the NSR increases, the NO_x reduction increases. However, as the NSR increases, the increment of NO_x reduction decreases exponentially. Rate kinetics limit the possible NO_x reduction to much less than the theoretical value. Increasing the quantity of reagent does not significantly increase the NO_x reduction for NSR values over 2.0.

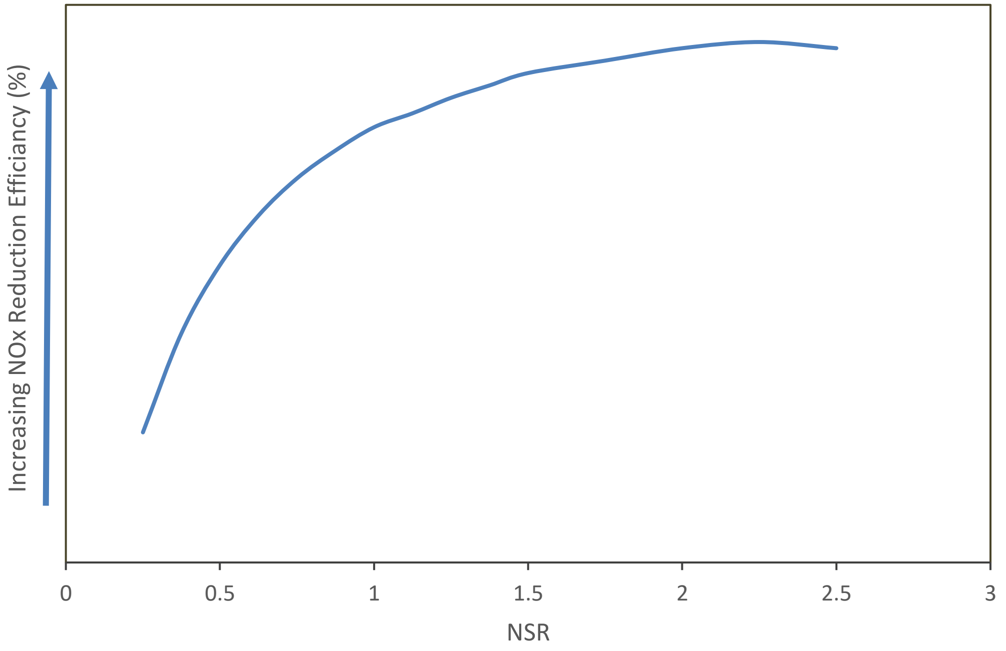

Figure 1.7: Effect of NSR on NO_x Reduction

Ammonia Slip

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 and ammonia slip are established by the reagent injection rate – an operational setting that can be adjusted based on the desired NO_x reduction and allowed ammonia slip. Typical NSR values require significantly more reagent to be injected in practice than is required by the theoretical stoichiometric ratio. Figure 1.8 shows an example of the NO_x reduction efficiency that can be achieved for an uncontrolled NO_x level of 120 parts per million (ppm) and various ammonia slip levels.

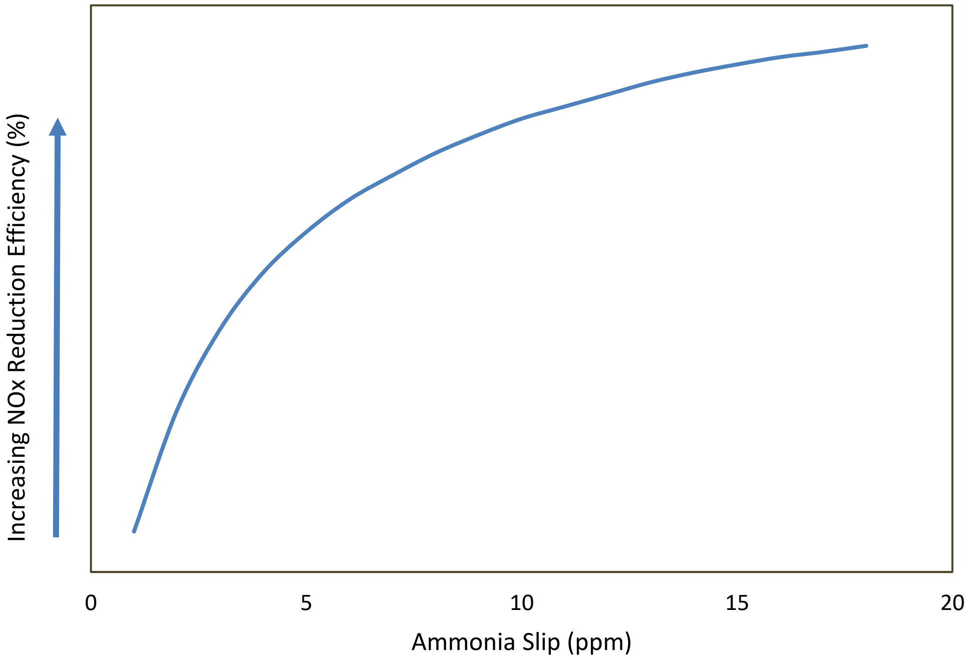

Figure 1.8: NO$_x$ Reduction for Various Ammonia Slip Levels

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.

Limits on acceptable ammonia slip, imposed by either regulatory limits or design requirements, place constraints on SNCR performance. For example, utilities typically 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. In addition, variation in the temperature profile of the boiler during operations can increase ammonia slip. In general, current SNCR systems control ammonia slip between 2 and 10 ppm [35]. Ammonia slip monitoring instruments are commercially available and are in place and operating at a number of coal-fired units. Facilities typically install ammonia slip monitors between the SNCR and the air heater and may measure at one or several points. These systems monitor ammonia slip and help the unit maintain slip levels of 2–3 ppmv or less. 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 for three measurement points [36]. Ammonia slip can also be controlled by establishing a feedback control loop to adjust the reagent injection feed rate according to the ammonia slip level measured by the monitor [26]. Another method of quantifying ammonia slip is to determine the ammonia concentration in collected fly ash.

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 ammonia slip limits.

Carbon Monoxide

High CO concentrations have been shown to lower the optimum reaction temperature, widen the temperature window, and reduce the NO_x control efficiency [2, 37, 38, 39, and 40]. 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 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 [4].

1.2.4 SNCR System

Two basic designs for the application of SNCR were developed in the 1970s and early 1980s [41, 42]. 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. 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 [43, 44]. Since that time, there have been a number of variations and improvements to the urea SNCR process, which are noted in Section 1.2.

An SNCR system has four basic steps to accomplish:

- Receiving and storing the reagent;
- Diluting, metering, and mixing the reagent;
- Injecting diluted reagent at appropriate locations in the boiler; and
- Mixing the reagent with flue gas.

These steps are common to both urea and ammonia SNCR applications; however, the design and equipment specifications for SNCR systems may differ. 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, some fluidized-bed utility boilers, and cement kilns.

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 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 [8].

A discussion of the SNCR equipment is given below. Figure 1.9 presents a simplified system flow schematic and Table 1.5 lists the equipment requirements for urea-based SNCR.

Urea-based systems typically employ a modular design to allow for boiler-specific design requirements while minimizing capital costs. Modular shop assembly of pumps, valves, internal piping, instruments, and controls reduces field installation time and related costs while providing flexibility for future expansion [32]. The components are assembled into functional units and mounted on stainless steel skid modules. These modules can then be transported to the site and installed directly. The skid modules shown in Figure 1.9 will be discussed further in the next sections.

It is typical for large industrial sources employing urea-based SNCR systems to store 10,000–20,000 gallons per tank to maintain sufficient volume for 1–3 weeks of SNCR operations. A closed top, flat bottom, vertical tank is used for urea storage. These tanks are usually constructed of fiber-reinforced polyester and have a corrosion barrier coating on the inside made of premium-grade vinyl ester resin. The tanks are equipped with level and temperature indicators; a manway, vent, and access ladder; and other appurtenances. The applicability of heat tracing, insulation, and seismic design criteria are determined based on site-specific conditions. The tank should be mounted on a concrete pad and surrounded by a spill containment structure such as a dike.

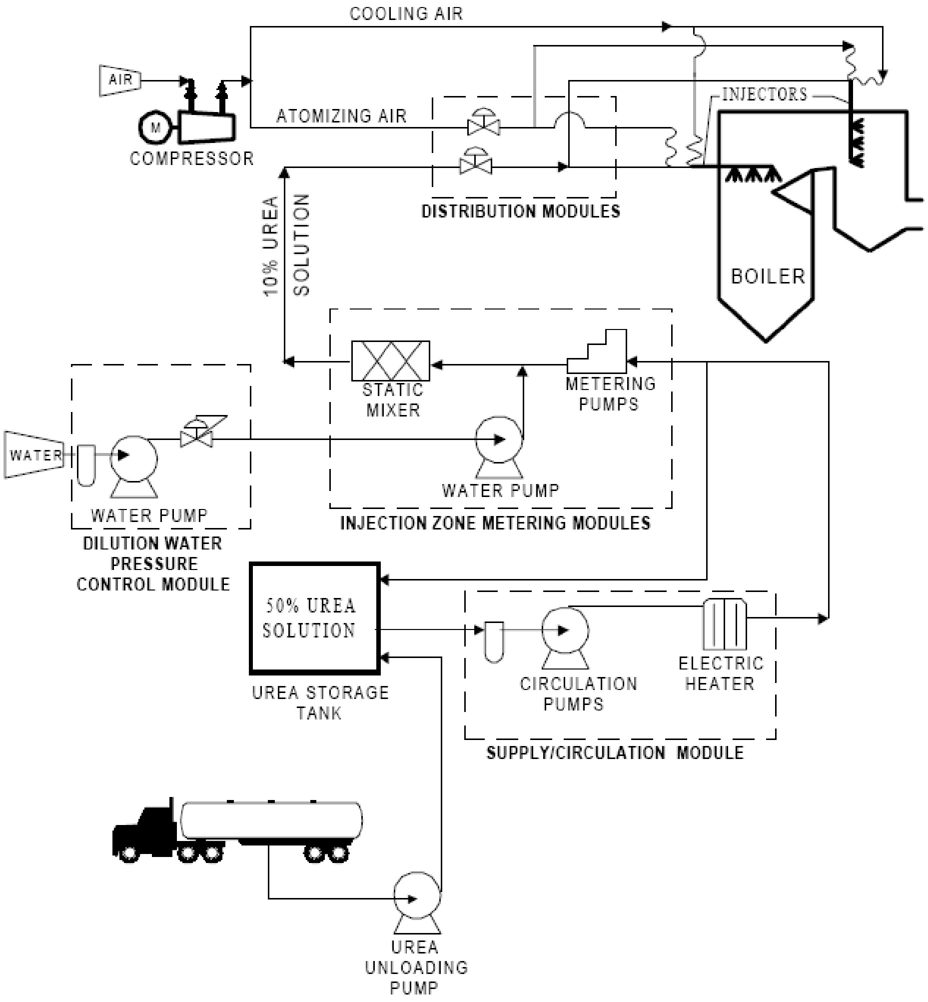

Figure 1.9: Urea SNCR Process Flow Diagram [32]

Table 1.5: Urea-Based SNCR System Equipment

Item	Description/Size
Urea unloading skid	Centrifugal pumps with hoses to connect to rail tank car or truck
Urea storage tanks	Vertical, insulated fiberglass reinforced plastic (1 or more tanks) (vinyl ester resin) tank, atmospheric pressure design, and equipped with a vent, caged ladder, manway, and heating pads
Circulation module	Skid-mounted circulation module consisting of • Circulation pumps, • Electric heaters, • Insulated/heat traced piping, • Isolation valves for pumps and heaters, and • Instrumentation for flow, pressure, temperature, and a control panel

Item	Description/Size
Injection zone metering (IZM) modules (1 to 5 modules)	Skid mounted metering modules consisting of • Metering pumps, hydraulic diaphragm type equipped with a variable speed motor drive, • Water booster pumps, turbine type, • Insulated/heat traced piping, • Isolation and control valves for pumps, • Instrumentation for flow, pressure, temperature, and a control panel
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^{TM} 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
Injectors (4 to 12 per distribution module)	Wall-type: Dual-fluid type wall injector, with modules, furnace wall panels, and hoses for air and urea supplies Lance-type: Dual-fluid type lance injector, with furnace wall panels, and hoses for air and urea supplies
Piping	Between urea unloading skid and urea tank; urea tank and circulation module; and circulation module and IZM modules(s). Insulate/heat traced piping, stainless steel
Piping	Between IZM module(s) and distribution modules. Insulated/heat traced tubing, stainless steel
Tubing	Between distribution modules and injectors. Insulated/heat traced tubing, stainless steel
Dilution water piping	Insulated/heat traced piping, carbon steel, with isolation and pressure reducing valves
Miscellaneous piping	Piping/tubing and valves for flushing water, atomizing air, and control air
Piping supports	Structural support steel, including a pipe bridge, for supporting all piping and oxygen in the flue gas and providing a feedback signal for urea injection control
Economizer outlet emission monitors	Monitors NO_x and O_2 in the flue gas and provides a feedback signal for urea injection control
Instrumentation and controls	Instrumentation and standalone, microprocessor-based controls for the SNCR system with feedback from the plant controls for the unit load, NO_x emissions, etc.
Enclosures	Pre-engineered, heated and ventilated enclosure for the circulation and metering skids
Foundations	Foundations and containment walls for the tank and equipment skids, enclosure, and piping support steel, as required
Platforms/stairways	Platform/stairway modifications and additions for access to injectors
Asbestos removal	Asbestos removal and reinsulation for a retrofit installation

Circulation Module

The circulation module maintains continuous circulation of the stored urea and supplies high-flow, high-pressure urea to the injection system. The circulation module pumps the urea from the storage tank to the components on the module. The urea solution is filtered to avoid clogging of the injectors and heated to prevent the solution from freezing. The urea is then returned to the tank or sent to the injection system. The module also provides a local/remote control and monitoring station for the storage tank and circulation system. This module contains multistage stainless-steel centrifugal pumps, inline duplex strainers, electric heaters, and instrumentation and controls for reagent pressure, flow, temperature, and quantity [32].

Diluting, Metering, and Mixing of the Reagent

Dilution Water Pressure Control Module

The dilution water pressure control module provides filtered plant water at the proper pressure for reagent dilution. The plant water is filtered to less than 50 milligrams per liter (mg/L) of suspended solids and low dissolved solids. The dilution water pressure module typically consists of two full-flow multistage stainless-steel centrifugal pumps, an inline duplex strainer, pressure control valves, and the required pressure/flow instrumentation. Through the use of backpressure controllers and multistage pumps, this system maintains a constant supply of dilution water, at the design pressure, in response to the changing SNCR process demand signals [32]. The 50% solution from storage is diluted for injection, typically to either 5% or 10% [11, 32].

Injection Zone Metering Module

The injection zone metering (IZM) module meters and controls the reagent concentration and flow to each zone of injection in the boiler. The aqueous urea generally requires dilution before injection to achieve the correct NSR between the reagent and flue gas NO_x. The reagent is diluted using filtered plant water from the dilution water pressure module. Each IZM module includes a chemical metering pump, a water pump, an inline static mixer, a local control panel, zone isolation valves, and magnetic flow meters and control valves for chemicals and water. The module design generally incorporates independent chemical flow and zone pressure valves, which respond to signals from the control systems, the master control module, and the local programmable logic controller. Through the control system, the module adjusts solution flow rates and activates or deactivates injection zones in response to changes in outlet NO_x concentration, boiler load, or fuel quality. Urea-based SNCR systems typically employ one to five IZM modules, depending on the boiler size and configuration, the uncontrolled NO_x concentration, and the desired NO_x removal efficiency. Several IZM modules can be combined onto one skid-mounted system [32].

Injecting of Diluted Reagent at Appropriate Locations in the Boiler

Reagent Distribution Module

The mixed and diluted urea solution is transported from the IZM to the distribution modules, which are typically located adjacent the boiler. The distribution modules control the flow of the solution to each injector. Each of the distribution modules consists of flow meters, balancing valves, and regulators connected to an automatic control system. The control system accurately controls and displays the reagent and atomizing air or steam flow to each injector. The modules also include manual ball valves, gauges, and stainless-steel tubing to adequately control the urea injection process. One distribution module for each IZM module provides reagent to multiple injectors [32].

Injection Locations

The urea solution flows from a given distribution module to a set of injectors. For large boiler applications, multiple injectors are located within several different zones of the boiler and can be operated independently or in groups (sub-zones) via the IZM. Controlling the amount and location of reagent injection gives the system flexibility to respond to variation in the boiler operating conditions and to maintain ammonia slip levels.

The number and location of the zones is determined by the temperature and flow patterns of the boiler. The locations are optimized using numeric modeling of flow and chemical reactions (see Section 1.2.5, Other Considerations). Typical designs employ 1–5 injection zones with 4–12 injectors per zone [32]. Injectors are located in open areas of the boiler, such as the region between the superheater and reheater sections. Figure 1.3 illustrates this configuration. For SNCR retrofit of existing boilers, optimal locations for injectors may be occupied by boiler equipment such as the watertubes. Removal or relocation of this equipment increases the installation costs. Installation in suboptimal boiler areas decreases the NO_x reduction efficiency that can be achieved by the system while maintaining the required ammonia slip level.

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 [8].

Mixing of the Reagent with Flue Gas and Reduction of NO_x

Injectors

The injectors assist in dispersion and mixing of the reagent with the flue gas. There are two types of injectors, wall and lance:

- 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 in which 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.
- Lance injectors consist of a small pipe that protrudes from the boiler wall into the flue gas pathway. Nozzles are located along the pipe directly in the flue gas pathway. Lance injectors are used for ammonia gas systems and in large boilers where mixing of the flue gas and reagent is more difficult. In some designs, the lance extends across the entire width of the boiler pass. Lance injectors can be single- or multi-nozzle designs.

> Multinozzle lances are a more complicated design; therefore, they are more expensive than single-nozzle lance or wall injectors [32].

SNCR systems may employ one or both types of injectors.

Injectors are subject to high temperatures and to flue gas impingement, which cause erosion, corrosion, and structural integrity degradation. Therefore, injectors are generally constructed of stainless steel and designed to be replaceable. In addition, injectors are often cooled with air, steam, or water. Lance injectors and some wall injectors are also designed to be retractable when not in use. This minimizes their exposure to the hot flue gas when the SNCR system is not being operated because of seasonal operations, boiler startup or shutdown, or other operational reasons.

The reagent is injected under pressure and atomized by specially designed nozzle tips to create droplets of the optimum size and distribution. The spray angle and velocity of the injection control the trajectory of the reagent. Urea systems often inject a carrier fluid, typically air or steam, along with the urea through a dual-fluid atomizer nozzle. The reagent can be injected with a low- or high-energy system. A low-energy system uses little or no pressurized air while a high-energy system uses large amounts of compressed air or steam to inject and vigorously mix the solution with the flue gas. Lance injectors in large boilers typically use high-energy systems. High-energy systems are more expensive to build and operate because they require a larger compressor and a more robust injection system and consume more electric power.

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 [32]. 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.

1.2.5 Other Considerations

Retrofit

The difficulty of SNCR retrofit on existing large coal-fired boilers is considered to be minimal. The primary concern is adequate wall space within the boiler for installation of injectors. The injectors are installed in the upper regions of the boiler, the boiler radiant cavity, and the convective cavity. Existing watertubes and asbestos may need to be moved or removed from the boiler housing. In addition, adequate space adjacent to the boiler must be available for the distribution system equipment and for performing maintenance. This may require modification or relocation of other boiler equipment, such as ductwork. The methodology presented in section 1.4 estimates SNCR capital costs that model actual costs for typical SNCR retrofits at existing boilers. The estimated costs on a $/kW basis increase sharply for small boilers (<50 MW) due to both economies of scale and to account for the more difficult installation conditions that are often encountered for the small boilers. As such, estimates based on this methodology typically should not include an additional retrofit factor for existing boilers. Little data are available regarding the cost of new installations versus retrofits. One study suggested retrofit installation of the SNCR system generally calls for additional expenditures in the range of 10–30% of the SNCR system cost [12], a minimal increase. Based on this study, costs for installation at new facilities may be 9 to 23 percent lower than the costs for retrofits at existing sources.

Ammonium Sulfate Deposition and Fly Ash Considerations

Sulfur trioxide (SO_3) forms during the combustion of fuels that contain sulfur. It reacts with ammonia in the flue gas downstream of the boiler (ammonia slip) to form ammonium bisulfate and ammonium sulfate. The amount formed depends on the sulfur content of the fuel and the amount of ammonia slip. Ammonia-sulfur salts can plug, foul, and corrode downstream equipment such as the air heater, ducts, and fans. Depending on the rate of ammonia-sulfur salt deposition on downstream equipment, more frequent acid washing of this equipment may be warranted. Increased acid washing generates additional wastewater that must be disposed of or treated by the plant. Ammonia slip limits are generally imposed as part of the design requirements to avoid impacts on downstream equipment.

Ammonia sulfates also deposit on the fly ash that is collected by particulate removal equipment. The ammonia sulfates are stable until introduced into an aqueous environment with an elevated pH level. Under these conditions, ammonia gas can be released into the atmosphere. This results in an odor problem or, in extreme instances, a health and safety concern. Plants that burn alkali coal or mix the fly ash with alkali materials can have fly ash with high pH. In general, fly ash is either disposed of as waste or sold as a byproduct for use in processes such as concrete admixture. Ammonia content in the fly ash greater than 5 ppm can result in off-gassing, which would impact the ability to sell the ash as a byproduct and the storage and disposal of the ash by landfill [12, 45].

Ammonia slip mitigation (ASM) technology exists to treat fly ash that is contaminated with ammonia. The technology consists of blending a chemical oxidizer such as calcium hypochlorite with the dry fly ash. When combined with water the calcium hypochlorite reacts with some of the ammonia in solution to form chloramines. Overtreatment, however, can result in the release of chlorine gas when the fly ash is mixed with water. Treatment for typical operating conditions has reportedly reduced ammonia levels by roughly 30 to 50 percent. The total annual cost for one electricity generating unit was estimated to be $5.61 per ton of ash treated [45].

Computational Fluid Dynamics (CFD) and Chemical Kinetic Modeling

Each boiler unit has a unique temperature and flow gradient with areas of high flow and stagnation. In addition, temperature and flow profiles vary according to the load capacity under which the boiler is operating. A mathematical model is developed to describe this stratification and variation of important species such as NO_x and SO_3 in the flow stream. To develop the model, the flue gas temperature and velocity within the boiler are measured at many locations. These measurements are used in a CFD model for the convective passes of the boiler. The model predicts the temperature and gas flow within the boiler for various operating conditions and injection scenarios.

The residence times and temperatures predicted by the CFD model are input into a chemical kinetic model, which defines the chemical reactions associated with the SNCR process in the boiler. Analysis of the fuel and flue gas constituents is required to develop this model. The model predicts the reactions and rates of reactions within the boiler in order to estimate the NO_x reduction along the flue gas pathway.

Modeling such as this optimizes the SNCR design for the boiler of concern to obtain the maximum NO_x reduction within acceptable ammonia slip limits. It determines design parameters such as the NSR, injector locations, and optimum droplet size and distribution. In general, SNCR vendors obtain the required measurements and develop the models. The cost of model development is generally included in the purchased equipment cost for SNCR [32].

Additives/Enhancers

Additives to the reagents are called enhancers and can be used to lower the temperature range at which the NO_x reduction reaction occurs. During low-load operation, the location of the optimum temperature region shifts upstream within the boiler. This shift requires the injection point of the reagent to be moved upstream. The use of an enhancer reduces the need for additional injection locations, which are required to compensate for variable load operation. Fewer injection locations decrease capital costs and the need for modifications to the boiler. In addition, the larger temperature range available with enhancers increases the available residence time for the reduction reaction, further reducing NO_x emissions. Additional reagent is injected with the enhancer to maintain the same NO_x reduction efficiency because some of the reagent reacts with the enhancer as opposed to the NO_x. This can increase the reagent usage by up to 10%. In addition, enhancers can result in increased levels of CO and N_2O in the stack effluent. Enhancers require additional storage, distribution, and control system equipment. Enhancer formulations are generally proprietary [12].

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) [46].[5] There are also several studies evaluating the effect of other additives, including carbon monoxide, glycerol, methyl acetate, phenol, succinic acid, propionaldehyde, 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 [40, 47]. 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% [47]. However, there are no known commercial applications of these additives.

Energy Consumption

An SNCR process reduces the thermal efficiency of a boiler. The reduction reaction uses thermal energy from the boiler, which decreases the energy available for power or heat generation. As a result, additional energy is required for the boiler to maintain the same steam output. Pretreatment and injection equipment, pumps, compressors, and control systems, also require electricity. This increased usage of fuel and electricity increases the annual costs required

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[5] See http://www.hamonusa.com/hamonresearchcottrell/products/nox.

to operate the boiler [29]. Section 1.4.2, Total Annual Costs, presents a method for estimating the additional fuel and electricity usage.

1.2.6 New SNCR Approaches

Several advances to conventional SNCR technology have been made. The alternative approaches include systems such as SNCR Trim, Rich Reagent Injection (RRI), NO_xSTAR and ROTAMIX. These systems use different injector configurations to improve efficiency and reduce costs. The costs presented in this discussion are from 2004 to 2006 and thus should not be considered current. However, it is expected that the trends or ranking have not changed.

SNCR Trim

The SNCR Trim technology is a simple, low-cost, low-energy single-level injection system with injectors located approximately five feet apart along the front wall of the upper furnace. By using upper furnace injection, the droplet trajectory can be optimized for penetration into the bulk turbulent mixing in the furnace. SNCR Trim has been applied to more than 21 coal-fired utility boilers and has been demonstrated for utility boilers ranging from 35 to 720 MW. Typical NO_x reductions of 25–35% are achieved. Capital costs for SNCR Trim installations are typically projected to be half what would be incurred for a conventional SNCR in the same application, approximately $5-10/kW for a single level of injectors [26].

Rich reagent injection

RRI involves the injection of urea or ammonia into a high-temperature, fuel-rich environment with a residence time of 0.5–1 seconds. The efficiency of RRI depends on the extent of overall mixing and is typically in the range of 30-40% NO_x reduction. Ammonia slip with the RRI process is minimal because any unreacted urea or ammonia is oxidized to nitrogen oxide (NO) in the upper furnace. RRI has been demonstrated to achieve 30% NO_x reductions in two existing cyclone-fired boilers with overfire air. For a 500-MW cyclone boiler with a single level of injectors, the capital cost for RRI alone is approximately $8-12/kW. RRI can be combined with SNCR Trim to achieve an overall NO_x reduction efficiency of 55% when operated during ozone season, for an additional capital cost of $4/kW and an overall cost effectiveness of $1,447 per ton of NO_x removed [26].

NO_xSTAR

NO_xSTAR uses an injection grid to provide NO_x control by injecting ammonia and a hydrocarbon into a utility boiler within the flue gas path at a temperature in the range of 1800–2000°F (980–1090°C). The hydrocarbon serves to reduce the ammonia slip, enabling higher reagent injection rates, resulting in NO_x reductions twice as high as could be achieved with conventional SNCR. Full-scale demonstrations have achieved 45–50% NO_x reduction on a long-term basis, although reductions as high as 70–80% are probably attainable for some applications. In particular, applications with higher flue gas temperatures will see a greater NO_x reduction and lower hydrocarbon usage requirements. Capital costs for the NO_xSTAR system are high, ranging from $60–75/kW; however, for higher NO_x baseline concentrations, the removal efficiency can prove cost effective [26].

Rotamix®

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. ROFA is a patented process in which the rising combustion gases through the furnace (or bulk flow in a fluidized bed combustor) are set in rotation, using custom-designed, asymmetrically-placed air nozzles. ROFA consists of a boost fan, insulated ductwork, modulated dampers, air nozzles, and a control system. Like typical overfire air systems, ROFA stages the primary combustion zone to burn overall fuel rich. The remaining excess secondary air is added through the ROFA injection nozzles high in the furnace to complete burnout. In a combined ROFA/Rotamix system, a NO_x reducing reagent is introduced downstream of the ROFA injection nozzles into a well distributed, turbulent zone that allows for the effective mixing of the NO_x reducing reagent with the combustion gases. Although many of the early installations used ammonia as the NO_x reducing reagent, urea is now the preferred reagent (particularly for large boilers) because it vaporizes more slowly than water and has a broader reaction window than ammonia.

The Rotamix system consists of a small ambient-air Rotamix fan placed on deck. On grade is the reagent delivery system, including: reagent storage tank, reagent pump skid, dilution water pump skid, and humidification water pump skid. The delivery lines supply pressurized water and reagent to the Rotamix cabinet, located near the Rotamix injector boxes at the upper furnace. The water and reagent are mixed inside the Rotamix cabinet and are delivered to individual injectors. A humidification cabinet, located beside the Rotamix cabinet, provides humidification to the Rotamix air nozzles to condition the air flow to optimize chemical utilization. The Rotamix injectors use air-boosted nozzles and thus less water than conventional SNCR reagent injectors. The locations of both the ROFA and Rotamix ports are determined from CFR modeling and field test data.

As of early 2010, Rotamix was installed on 24 boilers in the US. All but 3 of the 24 installations also include ROFA. Boiler capacities range from 17 MW to 570 MW, and 3 of the boilers (13 percent) are larger than 260 MW. Half of the current installations are on tangential-fired boilers; most of the others are on wall-fired boilers, but there is also a grate unit and small wood fired bubbling fluidized bed combustor. All of the boilers fire coal, except for one small wood-fired combustor and another that burns landfill gas. Together, ROFA and Rotamix can achieve 60–80+% total NO_x reduction. In 2010, the capital 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 [48]. Reductions for Rotamix alone are reported to be 25 to 40 percent. Cost effectiveness for one facility was reported at $550/ton of NO_x reduced, but this facility had relatively high baseline emissions of about 0.6 lb/MMBtu. In general, the cost effectiveness of combined ROFA and Rotamix technology is likely to be higher [26, 49, 50, 51, 52, 53].

Hybrid SNCR/SCR

SNCR and SCR may be combined in a "hybrid" manner by installing a small layer of SCR catalyst in ductwork downstream of the SNCR system. Such a system can achieve a higher

NO_x reduction than is possible with SNCR only but at lower capital cost than with a full SCR system. A hybrid system also can achieve better reagent utilization than an SNCR system because the SNCR reagent can be injected into cooler temperatures (i.e., adjusting the placement of injectors in the boiler) than in a stand-alone SNCR system. This increases the NO_x reduction achieved with SNCR while also increasing ammonia slip. The ammonia slip then provides reagent to a relatively small SCR that reduces ammonia while also achieving additional NO_x reductions [54, 55].

Hybrid technology has been evaluated extensively in modeling and pilot-scale studies [55, 56, 57, 58]. Commercial applications in the U.S., however, have been rare. At least three coal-fired utility boilers have been equipped with hybrid technology for demonstrations or short-term commercial operation, though none are still operating [15, 55]. As of 2005, two hybrid systems were operating in the steel industry [55]. In the early 1990's a gas-fired utility boiler also was equipped with a hybrid system [56].

Hybrid systems on two coal-fired utility boilers have achieved reductions up to more than 90 percent, depending on operating conditions; for example, performance is better at low load than at high load [15, 59]. A gas-fired utility boiler equipped with a hybrid system also achieved reductions up to 90 percent [56]. On other utility boilers, hybrid systems have achieved or been designed to achieve reductions between 40 percent and 75 percent [15, 55].

Capital costs for a hybrid system that was installed on a 107 MW coal-fired utility boiler were about $114/kW in 2005 dollars [54]. In 2006, capital costs for hybrid systems were estimated to be $35/kW to $80/kW, while SCR capital costs were estimated to be $70/kW to $200/kW, and SNCR capital costs were estimated to be $10/kW to $30/kW [15].

1.3 Design Parameters

SNCR system design is a proprietary technology. Extensive details of the theory and correlations that can be used to estimate design parameters such as the required NSR are not published in the technical literature [60]. Furthermore, the design is highly site-specific. In light of these complexities, SNCR system design is generally undertaken by providing all of the plant- and boiler-specific data to the SNCR system supplier, who specifies the required NSR and other design parameters based on prior experience and computational fluid dynamics and chemical kinetic modeling [32].

The procedure given below in Section 1.3.1, Design Parameters for Study-Level Estimates, is a step-by-step approach to estimate design parameters based on a procedure developed in the draft U.S. Environmental Protection Agency (EPA) report *Selective Noncatalytic Reduction for* NO_x *Control on Coal-fired Boilers* [32]. This procedure assumes that SNCR system size and cost are based on three main parameters: the boiler size or heat input, the required level of NO_x reduction, and the reagent consumption. Data requirements for obtaining vendor cost estimates based on design specifications or performance specifications are outlined in Section 1.3.2.

1.3.1 Design Parameters for Study-Level Estimates

Boiler Heat Input

The methodology presented in Reference [32] is the maximum potential heat released by the boiler or heat input rate, Q_B, expressed as MMBtu/hr. It is obtained from the higher heating value, *HHV*, of the fuel in Btu per pound (Btu/lb) multiplied by the maximum fuel consumption rate in pounds per hour (lb/hr):

$$Q_B = HHV \times \dot{m}_{fuel} \times \frac{1}{10^6} \tag{1.3}$$

Where:

Q_B = maximum heat rate input to the boiler, MMBtu/hr
HHV = higher heating value of the fuel, Btu/lb
$\dot{m}_{fuel}$ = maximum fuel consumption rate of the boiler, lb/hr
$1/10^6$ = conversion factor of 1 MMBtu/10^6 Btu.

Table 1.6 provides the HHV for various coals.

Table 1.6: Higher Heating Values for Various Coals

Type of Coal	Energy Content (Btu/lb)
Lignite	5,000–7,500
Subbituminous	8,000–10,000
Bituminous	11,000–15,000
Anthracite	14,000

If the boiler produces electricity, then its maximum heat input can be estimated using the boiler net plant heat rate, *NPHR* in MMBtu per Megawatt-hour (MMBtu/MWh):

$$Q_B = B_{mw} \times NPHR \tag{1.4}$$

Where:

B_{MW} = boiler MW rating at full load capacity, MWh
$NPHR$ = net plant heat rate, MMBtu/MW.

Note that if *NPHR* is not known (e.g., a cogeneration unit), a conversion value for coal of 10,000 Btu/kWh (or 10 MMBtu/MWh) can be used as a reasonable estimate; a conversion value for petroleum of 11,000 Btu/kWh (11 MMBtu/MWh) and for natural gas of 8,200 Btu/kWh

(8.2 MMBtu/MWh) can be used [61].[6] Using this value, the heat input rate, Q_B, for a coal-fired unit is:

$$Q_B = B_{MW} \times 10 \tag{1.5}$$

Where:

10 = estimated NPHR for coal, MMBtu/MWh.

Heat Rate Factor

The heat rate factor (HRF) is the ratio of actual heat rate of the boiler, in terms of the boiler NPHR in MMBtu/MWh, compared to a typical heat rate of 10 MMBtu/MWh. The developers of the cost estimation methodology presented in section 1.4.1 determined that using this ratio in the equation for capital costs helped account for observed differences in actual costs for different coal-fired boilers. To maintain consistency with that approach, the same ratio (i.e., with 10 in the denominator) also has been used in the equations for oil and gas fired boilers in section 1.4.1. The NPHR is simply the amount of fuel energy that a boiler consumes to generate 1 MWh of electricity and is determined based on measurements of the electricity generation and fuel consumption over the same period of time. As noted above, if the NPHR is not known for a particular boiler, use 10 MMBtu/MWh.

$$HRF = \frac{NPHR}{10} \tag{1.6}$$

Where:

HRF = Heat rate factor
$NPHR$ = net plant heat rate of the system to be costed, MMBtu/MWh
10 = in MMBtu/MWh, is the NPHR that is the basis of the SNCR base module capital cost.

System Capacity Factor

The total system capacity factor, CF_{total}, is a measure of the average annual use of the boiler in conjunction with the SNCR system. CF_{total} is given by:

$$CF_{total} = CF_{plant} \times CF_{SNCR} \tag{1.7}$$

Where:

CF_{total} = total system capacity factor
CF_{plant} = boiler capacity, which is the ratio of the actual quantity of fuel burned annually to the potential maximum quantity of fuel burned annually

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[6] In recent years (2003 to 2010), the average NPHR for coal has increased slightly (likely due to aging of equipment), and the average NPHR for natural gas has decreased slightly (likely due to the increased use of natural gas fuel and the installation of new equipment).

$CF_{SNCR,}$ = SNCR system capacity factor, which is the ratio of the actual days of SNCR operation annually to the total number of days per year (i.e., 365 days).

For utility boilers, the capacity factor of the boiler, $CF_{plant,}$ is the ratio of actual quantity of fuel burned annually to the potential maximum quantity of fuel burned annually in pounds (lbs), as shown in Equation 1.8a:

$$CF_{plant} = \frac{B_{output}}{(B_{MW} \times 8760)} \tag{1.8a}$$

Where:

B_{MW} = boiler MW rating at full load capacity, MWh
B_{output} = annual actual MW output, MW/year.

Alternatively, for industrial and utility boilers, the capacity factor of the boiler, $CF_{plant,}$ can be calculated as the ratio of actual quantity of fuel burned annually to the potential maximum quantity of fuel burned annually in pounds (lbs), as shown in Equation 1.8b:

$$CF_{plant} = \frac{actualannu\ al\ m_{fuel}}{maximum\ \ annual\ \ m_{fuel}} \tag{1.8b}$$

Where:

actual annual m_{fuel} = annual actual fuel consumption rate of the boiler, lb
maximum annual m_{fuel} = annual maximum fuel consumption rate of the boiler, lb.

SNCR can be operated year-round or only during the specified ozone season (usually 5 months in length). The capacity factor for the SNCR system, $CF_{SNCR,}$ is the ratio of the actual number of SNCR operating days, $t_{SNCR,}$ to the total number of days per year, 365 days:

$$CF_{SNCR} = \frac{t_{SNCR}}{365} \tag{1.9}$$

Where:

$t_{SNCR,}$ = actual days of SNCR operation annually, days
365 = number of days in a year, days.

Uncontrolled NO_x and Stack NO_x

Uncontrolled NO_x, represented as NO_{xin}, is the NO_x emission level in the flue gas exit stream from a boiler prior to the SNCR system. Note that NO_{xin} also accounts for combustion controls if the boiler is equipped with such controls. The uncontrolled NO_x emission level, obtained from analyzing the boiler flue gas stream, is generally given in lb/MMBtu of NO_2 [62].

The stack NO_x, represented as NO_{xout}, is the required NO_x emission limit at the stack outlet. It is generally set by regulatory limits and also given in lb/MMBtu of NO_2.

NO_x Removal Efficiency

The NO_x removal efficiency, represented as η_{NOx}, is determined from the uncontrolled NO_x level of the boiler at maximum heat input rate, CF_{plant} = 1.0, and the required stack emission limit using the following equation:

$$\eta_{NO_x} = \frac{NO_{x_{in}} - NO_{x_{out}}}{NO_{x_{in}}} \tag{1.10}$$

Where:

η_{NOx} = NO_x removal efficiency, fraction
NO_{xin} = uncontrolled NO_x level from the boiler, i.e., inlet NO_x rate to the SNCR, lb/MMBtu (at maximum heat input rate, CF_{plant} = 1.0)
NO_{xout} = outlet NO_x rate from the SNCR, lb/MMBtu.

NO_x Removal Rates

The tons of NO_x removed annually are:

$$NO_x\ Removed/yr = NO_{xin}\ \eta_{NOx}\ Q_B\ t_{op}/\ 2{,}000 \tag{1.11}$$

Where:

NO_x *Removed/yr* = annual mass of NO_x removed by the SNCR, tons/yr
Q_B = maximum potential heat input rate of the boiler, MMBtu/hr
t_{op} = operating time per year (CF_{total} x 8760), hr/yr
2000 = conversion factor for lb/ton.

The pounds of NO_x removed per hour (lb/hr) are:

$$NO_x\ Removed/hr = NO_{xin}\ \eta_{NOx}\ Q_B \tag{1.12}$$

Where:

NO_x *Removed/hr* = hourly mass of NO_x removed by the SNCR, lb/hr
NO_{xin} = uncontrolled NO_x of the boiler, lb/MMBtu (at maximum heat input rate, CF_{plant} = 1.0)
η_{NOx} = NO_x removal efficiency of the SNCR, expressed as a fraction
Q_B = heat input rate, MMBtu/hr.

Normalized Stoichiometric Ratio

The normalized stoichiometric ratio, *NSR*, indicates the actual amount of reagent needed to achieve the targeted NO_x reduction. The actual quantity of reagent is greater than the theoretical quantity due to reaction kinetics (see Section 1.2.3, Performance Parameters). *NSR* is defined as:

$$NSR = \frac{moles\ \ of\ \ equivalent\ \ NH_3\ injected}{moles\ \ of\ \ uncontroll\ ed\ \ NO_x} \tag{1.13}$$

For estimating purposes, the moles of NO_x are equivalent to the moles of NO_2. Note that the moles of equivalent NH_3 in Equation 1.13 are the moles of NH_2 that will be released from the reagent.

The actual stoichiometric ratio, *ASR,* is defined as:

$$ASR = \frac{moles\ \ of\ \ reagent\ \ injected}{moles\ \ of\ \ uncontroll\ ed\ \ NO_x} \tag{1.14}$$

ASR can also be calculated from the *NSR* using the following equation:

$$ASR = \frac{NSR}{SR_T} \tag{1.15}$$

Where SR_T is the theoretical stoichiometric ratio, the ratio of equivalent moles of NH_3 per mole of reagent injected. From the chemical formulas for ammonia (NH_3) and urea [$CO(NH_2)_2$] given in the reaction Equations 1.1 and 1.2, SR_T is 1 for ammonia and 2 for urea.

Reagent utilization is the ratio of moles of reagent reacted to the moles injected. This indicates how much reagent is being reacted versus how much reagent is passing through as ammonia slip. Utilization of reagent can be calculated from *NSR* and the NO_x reduction efficiency as follows:

$$Utilizatio\ n = \frac{\eta_{NO_x}}{NSR} \tag{1.16}$$

The derivation for this equation is presented in Reference [24].

Methods for estimating *NSR* are considered proprietary. A simplified *NSR* estimation procedure was developed by The Cadmus Group, Bechtel Power, Inc., and SAIC in the EPA draft report, *Selective Noncatalytic Reduction for NO_x Control on Coal-fired Boilers* [32]. This procedure was developed using linear regression and *NSR* data from References [62] and [63]. The values of *NSR* derived using this approach should not be used for equipment design or guarantee purposes.

The *NSR* estimation equation is valid from 0 to 50% NO_x reduction [32]. The equation used to estimate *NSR* for urea reagent is where NO_{xin} is given in lb/MMBtu.

$$NSR = \frac{[2\,NO_{X_{in}} + 0.7]\eta_{NO_x}}{NO_{x_{in}}} \tag{1.17}$$

Figure 1.10 provides a graphical representation of this *NSR* estimation method. Generally, the value of *NSR* ranges from 0.5 to 2.0 in industrial and utility boilers with utilization ranging from 25 to 50%.

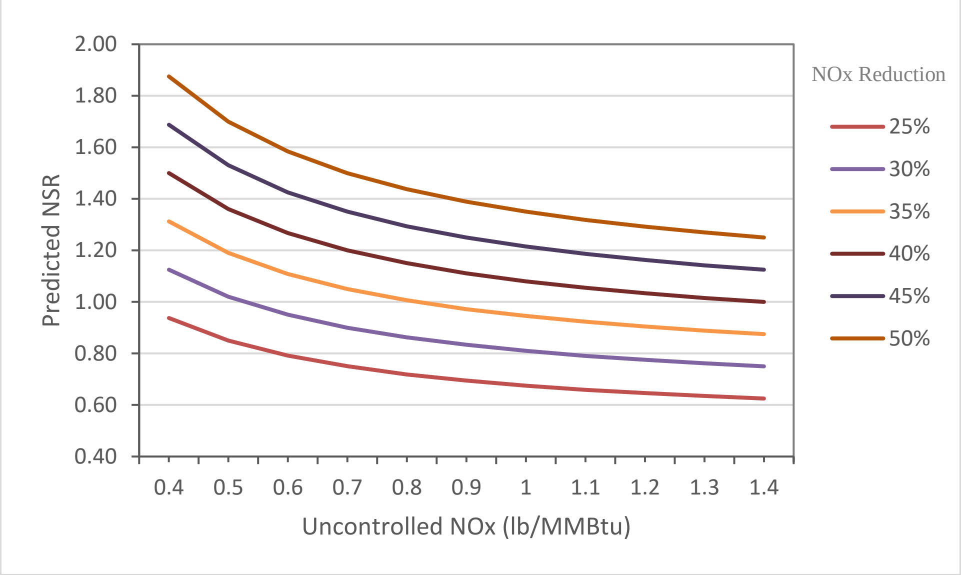

Figure 1.10: Approximate NSR Estimation for Urea [32]

In a design developed by a system supplier, *NSR* would be adjusted to account for several parameters that are not included in the *NSR* estimation equation. The following parameters are used by the system supplier to more accurately predict *NSR* for a given boiler:

- Reaction temperature range available within the boiler superheater (radiative and convective section) and primary reheater (convective section or cavity) region. If the required temperature window occurs in the radiant section of the boiler, *NSR* could decrease. However, if the temperature window occurs in the convective section, *NSR* may increase.
- Residence time available in the desirable temperature range. The required *NSR* decreases as the available residence time increases.
- Degree of mixing between the injected chemical and the flue gases. *NSR* decreases as the degree of mixing increases.
- Ammonia slip vs. required NO_x reduction. Tighter constraints on ammonia slip would dictate lower *NSR*s, thereby limiting the achievable NO_x reduction. In addition, ASM equipment may need to be installed as ammonia slip constraints become tighter.

Estimating Reagent Consumption and Tank Size

Once *NSR* is estimated, the rate of reagent consumption or mass flow rate of the reagent, $\dot{m}_{reagent}$ expressed as lb/hr, can be calculated using:

$$\dot{m}_{reagent} = \frac{NO_{x_{in}} \times Q_B \times NSR \times M_{reagent}}{M_{NO_x} \times SR_T} \tag{1.18}$$

Where:

$\dot{m}_{reagent}$ = mass flow rate, or consumption rate, of the reagent, lb/hr
$M_{reagent}$ = the molecular weight of the reagent (60.06 grams per mole [g/mole] for urea, 17.03 g/mole for ammonia)
M_{NOx} = the molecular weight of NO_2 (46.01 g/mole).

In this equation, the molecular weight of NO_2 is used because the NO_x emissions, NO_{xin}, are given in lb/MMBtu of NO_2. As stated previously, SR_T is the ratio of equivalent moles of NH_3 per mole of reagent (1 for ammonia and 2 for urea).

For urea or ammonia, the mass flow rate of the aqueous reagent solution is given by:

$$\dot{m}_{sol} = \frac{\dot{m}_{reagent}}{C_{sol}} \tag{1.19}$$

Where:

$\dot{m}_{sol}$ = mass flow rate of the aqueous reagent solution, lb/hr
C_{sol} = the concentration of the aqueous reagent solution, by weight fraction.

The solution volume flow rate q_{sol}, generally expressed as gallons per hour (gph), is given by:

$$q_{sol} = \frac{\dot{m}_{sol}}{\rho_{sol}} \times 7.4805 \tag{1.20}$$

Where:

q_{sol} = solution volume flow rate, gph
ρ_{sol} = the density of the aqueous reagent solution, lb/ft^3
7.4805 = conversion factor of 7.4805 gal/1 ft^3.

The density is 71.0 lb/ft^3 for 50% urea and 56 lb/ft^3 for 29% ammonia.

The total volume stored in the tank, or tanks, is based on the volume that the SNCR system requires to operate for a specified number of days. The volume stored onsite for the number of operating days, $t_{storage}$, is:

$$Vol_{\tan k} = q_{sol} \times t_{storage} \times 24 \tag{1.21}$$

Where:

Vol_{tank} = total volume of aqueous solution stored in the tank(s), gallons (gal)
$t_{storage}$ = number of operating days the SNCR is required to operate between solution delivery, days
24 = conversion factor of 24 hr/1 day.

Note that the tank volume is typically based on the maximum annual heat input rate, so the capacity factor is not included in Equation 1.21. A common onsite storage requirement is for 14 days (or 1–3 weeks) of SNCR operation.

1.3.2 Design Parameters for Detailed/Performance Specifications

Cost Estimates Based on Detailed Specifications

This subsection describes the information that must be assembled and furnished to a supplier to prepare design specifications, particularly the component information with the greatest influence on system cost. SNCR capital and operating costs can be estimated if the major cost items are identified and the system is defined in adequate detail [32]. The following data are provided to the system supplier for SNCR system design:

- The boiler capacity in terms of heat input rate (MMBtu/hr);
- Boiler capacity profile – percent of time the boiler operates at a given heat input rate;
- Type of combustion unit – dry/wet bottom boiler, wall-fired, tangentially fired, cyclone fired, other (e.g., stoker fired); year built; and manufacturer;
- Boiler dimensions – sectional side view, sectional front view, plan section through furnace (width × depth), furnace height (floor to furnace exit), firing zone height, sections through radiant and connective heat transfer cavities (zones), other unique features (e.g., division wall/panels) in the furnace or backpass;
- Locations of boiler furnace overfire air ports;
- Locations and sizes of boiler observation ports, temperature probe ports, soot blower openings, and other locations for potential new ports;
- Air preheater design and operational data, including soot blower data;
- Fuel data – proximate and ultimate analyses and *HHV* for primary and secondary fuels;
- Fuel firing rates at full and partial loads (e.g., 100%, 70%, and 30%);
- Test data or combustion calculations – flue gas flow rate at design or actual conditions; excess air rate at full and partial loads; flue gas composition including O_2, NO_x, CO, SO_2, and HCl;
- Flue gas temperature profile from furnace exit to economizer (i.e., where temperature drops to about 1400°F [760°C]) at various loads;

- Flue gas residence time – available flue gas residence time in the upper furnace and convective pass within the temperature window for urea at various loads;
- Existing or planned uncontrolled NO_x and CO emission data in ppm or lb/MMBtu without the proposed SNCR system, including any change in emissions related to other installed or planned technologies (e.g., LNB, gas recirculation). This should be specified for boiler operations at full load and selected partial loads;
- Minimum expected NO_x reduction or permit requirement for stack NO_x emission level (ppm or lb/MMBtu). This should be specified for boiler operations at full load and selected partial loads; and
- Allowable byproduct emission rates for regulated emissions such as ammonia.

The boiler supplier/manufacturer can furnish most of this information for existing or planned new units. For fuel data, the designer needs typical or design values, as well as the expected range. To define the temperature and flue gas velocity profiles in existing boilers, it is preferable to obtain actual measurements.

To obtain a representative cost quotation from an SNCR system supplier, the request should contain sufficient details to minimize design assumptions by the supplier. The request for quotation should include the technical specifications, as well as commercial terms and conditions.

Two important parts of the specification are work included in the scope of the supplier and work not included (i.e., work performed by the owner/operator). The more precise and detailed the specification of the work, the more accurate the overall system design and cost. For a turnkey scope (design, supply, and erect all equipment, and demonstrate commercial operation while meeting all performance criteria), the excluded work is minimal.

Cost Estimates Based on Performance Specifications

Preparation of detailed specifications involves significant time and effort (for both owner and supplier) and is not critical for study-level cost estimates. To simplify the process, a performance specification approach may be used in the request for quotation. In this approach, the basic required plant and fuel data are provided along with the required SNCR system performance requirements, excluding equipment-related details (e.g., materials of construction, equipment redundancy, and level of instrumentation and controls) [32].

The performance specification should include a description of the system and components in enough detail to understand the type and quality of system proposed by the supplier. A cost breakdown of major components and subsystems also should be obtained from the supplier to enable independent assessment, deletion, or addition, and to compare other bids on an equitable basis. The SNCR performance specification typically should request the following items regarding NO_x emission control performance, chemical consumption, and other consumption rates at full and partial loads:

- Guaranteed and expected NO_x emission rates in units of lb/MMBtu and lb/hr with averaging period as defined in the air quality permit of the facility;

- 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);
- Other emission limits as specified (or anticipated) in the permit;
- NSR proposed to achieve the required NO_x reduction;
- Guaranteed and expected reagent consumption rate;
- Guaranteed and expected dilution air, steam, or water consumption rate;
- Atomizing and cooling air (or steam) pressure and consumption rate; and
- Guaranteed and expected electrical power consumption.

1.4 Cost Analysis

The presence of different boiler configurations, fuel use, and various site-specific conditions produces variability in the cost and cost-effectiveness of SNCR. For utility boilers with capacity of 100 MW, the capital cost ranges from $35 to $44/kW, for 400 MW boilers the capital cost ranges from $9 to $13/kW, and for 700 MW boilers ranges from $4 to $7/kW [13].[7] For industrial boilers, cost data are provided in Table 1.3. For coal-fired industrial boilers of 100 to 1,000 MMBtu/hr, the capital cost ranges from $2,600 to $5,300/MMBtu/hr, and for gas and oil-fired industrial boilers, ranges from $2,000 to $4,200/MMBtu/hr [19].

The cost estimating methodology presented here provides a tool to estimate study-level SNCR capital and annual costs. Actual selection of the most cost-effective option should be based on a detailed engineering study and cost quotations from system suppliers. The costing methodology was developed to estimate capital costs in 2016 dollars (2016$).

The capital cost equations are based on the EPA Clean Air Markets Division (CAMD) Integrated Planning Model [11]. In the costing method for SNCR from the IPM, the purchased equipment cost, the direct installation cost, and the indirect installation cost are estimated together. This methodology is somewhat different from the *EPA Air Pollution Control Cost Manual* methodology, which estimates equipment costs and installation costs separately.

The capital cost equations are applicable to utility boilers with full load capacities greater than or equal to (≥) 25 MW. The capital costs estimated by the equation represent typical costs for retrofits at existing boilers, however, these equations are appropriate for both new units and retrofit units [11]. The cost equations are sufficient for NO_{xout} emission reductions of 25% for Pulverized Coal and 50% for Fluidized Bed [11]. The SNCR system design used for the cost estimate is a urea-based system. An ammonia-based system would have different storage, distribution, and injection equipment costs. Allowed ammonia slip for the SNCR system ranges from 2–10 ppm [32].

Capital cost equations are provided for coal-fired units. Capital cost equations are provided for fluidized bed (FB) boiler units and for other boiler types (i.e., non-FB boiler units such as cyclone, wall-fired, tangential-fired, etc.). In general, SNCR units for FB boilers are less expensive than for other boiler types. The cost equations are sufficient for NO_{xout} emission levels as low as 0.08 lb/MMBtu for FB and 0.1 lb/MMBtu for nonFB [11]. The cost equations are

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[7] Cost years for these data range from 2005 to 2007.

applicable to retrofit of SNCR on existing boilers. The cost estimating procedure, however, is suitable for retrofit or new boiler applications of SNCR on all types of coal-fired electric utilities and large industrial boilers. The increased cost due to retrofit is minimal; approximately 10–30% of the cost of SNCR applied to a new boiler [12].

1.4.1 Total Capital Investment

Total capital investment (TCI) includes direct and indirect costs associated with purchasing and installing SNCR equipment. Costs include the equipment cost for the SNCR system itself, the cost of auxiliary equipment, direct and indirect installation costs, additional costs due to installation, costs for buildings and site preparation, offsite facilities, land, and working capital. In general, SNCR does not require buildings, site preparation, offsite facilities, land, or working capital. A more detailed discussion of capital costs can be found in Section 1, Chapter 2 of this Manual. The total project cost or TCI for the SNCR is based on the approach used by EPA CAMD in the Integrated Planning Model version 6 (IPM v6) [11], and this approach includes both the direct capital costs and the indirect capital costs for coal-fired utility boilers. Cost estimates are available for different size categories of coal-fired utility boilers. Costs for oil- and gas-fired utility boilers have also been included in this SNCR section. While the IPM v6 approach does not include capital cost equations for utility oil- and gas-fired units, it was assumed that the costs for utility oil- and gas-fired units are slightly less than costs for FB coal-fired units.[8] For oil- and gas-fired units, the appropriate NPHR value for oil (average value of 11 MMBtu/MWh) and for natural gas (average 8.2 MMBtu/MWh) should be used. Cost estimates are available for different size categories utility oil- and gas-fired units. Since the IPM is based primarily on data for retrofits and retrofits are typically 9 to 23 percent more than for new units of the same size and design, we have included a retrofit factor in the TCI equations [12]. A retrofit factor of 0.84 should be used for new construction and a retrofit factor of 1 should be used for SNCR retrofits to existing boilers, where the retrofit is of an average level of difficulty.

In addition, costs for different size categories of industrial boilers[9] have been included in this SNCR section. IPM v6 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.

The SNCR costs are impacted by the unit's elevation with respect to sea level. These cost calculations have been developed for SNCR systems located within 500 feet of sea level. For

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[8] When using the IPM v3 procedures, capital costs for non-fluidized bed coal-fired boilers were approximately 1.5 times higher than the costs for oil- and gas-fired boilers. The procedure described here maintains approximately the same ratio.

[9] By "industrial," the reference is to industrial, commercial, and institutional (or ICI) boilers.

SNCR systems located at higher elevations, the base cost should be increased based on the ratio of the atmospheric pressure between sea level and the location of the system, i.e., atmospheric pressure at sea level divided by atmospheric pressure at elevation of unit, as shown in Equation 1.22. [11]

$$ELEVF = \frac{P_0}{P_{ELEV}} \tag{1.22}$$

Where:

$ELEVF$ = elevation factor
P_0 = atmospheric pressure at sea level, 14.7 pounds per square inch absolute (psia)
P_{ELEV} = atmospheric pressure at elevation of the unit, psia.

The P_{ELEV} can be calculated using the following equation [64]:

$$P_{ELEV} = 2116 \times \left[\frac{59 - (0.00356 \times h) + 459.7}{518.6}\right]^{5.256} \times \frac{1}{144} \tag{1.23}$$

Where:

P_{ELEV} = atmospheric pressure at elevation of the unit, psia
h = altitude, feet.

1.4.1.1 Utility Boilers, Coal-fired Units

Utility, coal-fired units ≥25 MW. The capital cost equation for coal-fired units ≥25 MW is as follows:

$$TCI = 1.3 \times \left(SNCR_{Cost} + APH_{Cost} + BOP_{Cost}\right) \tag{1.24}$$

Where:

TCI = total capital investment for a SNCR on a boiler, \$
$SNCR_{Cost}$ = cost of the SNCR, \$
APH_{Cost} = air pre-heater cost, \$
BOP_{Cost} = balance of plant costs, \$.

The TCI calculation shown in Equation 1.25 includes a factor of 1.3 to estimate engineering and construction management costs, installation, labor adjustment for the SNCR, and contractor profit and fees. The owner’s costs (for owner activities related to engineering, management, and procurement) and costs such as allowance for funds used during construction (AFUDC) are capital cost items that are not included in the EPA Control Cost Manual methodology and are inconsistent with the overnight cost method[10] that is a basis for the Control Cost Manual methodology, and thus are not included in the TCI estimates in this section or in other Control Cost Manual chapters.

SNCR costs, utility, coal-fired units ≥25 MW. The capital costs for the SNCR base unit includes costs for the injectors, blowers, distributive control system (DCS), and the reagent system [11]. The SNCR costs are calculated as follows:

$$SNCR_{Cost} = 220{,}000 \times \left(B_{MW} \times HRF\right)^{0.42} \times CoalF \times BTF \times ELEVF \times RF \tag{1.25}$$

Where:

$SNCR_{Cost}$ = SNCR unit costs, \$
220,000 = constant in the equation
BTF = boiler type factor (BTF=1 if non-FB boiler; BTF=0.75 for FB boiler)
B_{MW} = boiler MW rating at full load capacity for the unit being costed, MW
HRF = heat rate factor
$CoalF$ = coal factor (CoalF=1 if bituminous; CoalF=1.05 if PRB; CoalF=1.07 if Lignite)
$ELEVF$ = elevation factor (calculated using Equation 1.22 if plant is located above 500 feet above sea level; ELEVF = 1 for plants located at or below 500 ft above sea level)
RF = retrofit factor (RF = 0.84 for new construction; RF = 1 for retrofits with average level of difficulty).

The boiler type factor, BTF, is based on the type of boiler unit. Boiler types may be fluidized bed or non-fluidized bed. Non-FB units include cyclone, tangentially-fired, wall-fired boiler units. Fluidized bed units include circulating, bubbling, atmospheric, and pressurized units. The BTF is 1 for non-FB boilers and is 0.75 for FB boilers. The CoalF is 1 for bituminous coal, 1.05 for powder river basin (PRB) coal and 1.07 for lignite coal.

Air Pre-Heater Modification costs, utility, coal-fired units ≥25 MW. Air pre-heater modification costs are included only where SO_3 control is necessary. An air pre-heater modification is necessary for the control of SO_3 for boilers that burn bituminous coal where the SO_2 content of the coal is 3 lb/MMBtu or greater. If other coal types are used, then no air pre-heater modification is needed. The air pre-heater modification costs are calculated as follows:

$$APH_{Cost} = 69{,}000 \times \left(B_{MW} \times HRF \times CoalF\right)^{0.78} \times AHF \times RF \tag{1.26}$$

Where:

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[10] The overnight cost estimation method presumes costs are incurred as if the project in question incurred no interest during construction,or was built "overnight." Another description of this method is the present value of cost that would have to be paid as a lump sum up front to completely pay for a construction project. For more information, see "Conducting Technical and Economic Evaluations – As Applied for the Process and Utility Industries," Recommended Practice 16R-90, American Association of Cost Engineering International. April, 1991.

APH_{Cost} = Air pre-heater cost, $
69,000 = constant in the equation
AHF = air heater factor (AHF=1 if bituminous coal and $SO_2 \geq 3$ lb/MMBtu; if not true, AHF=0)
RF = retrofit factor (RF = 0.84 for new construction; RF = 1 for retrofits with average level of difficulty).

The AHF is 1 for bituminous coal and where the SO_2 content of the coal is 3 lb/MMBtu or greater. If the boiler burns other coal types, then the AHF is 0 and this term drops out of the overall $SNCR_{Cost}$ equation.

Balance of plant (BOP) costs, utility, coal-fired units ≥25 MW. 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 [11]. The BOP costs are calculated as follows:

$$BOP_{Cost} = 320{,}000 \times \left(B_{MW}\right)^{0.33} \times \left(NO_x \text{Removed/hr}\right)^{0.12} \times BTF \times RF \tag{1.27}$$

Where:

BOP_{Cost} = Balance of plant costs, $
320,000 = constant in the equation
NO_x *Removed/hr* = hourly mass of NO_x removed by the SNCR system, lb/hr
RF = retrofit factor (RF = 0.84 for new construction; RF = 1 for retrofits with average level of difficulty).

1.4.1.2 Utility boilers, Oil- and gas-fired units

Utility, oil- and gas-fired units ≥25 MW. The capital cost equation for oil- and gas-fired boilers ≥100 MW is based on the utility boiler equations for fluidized bed boilers. Because oil and natural gas are the fuel inputs and not coal, it is assumed that no modifications are needed for the air pre-heater. The capital cost equation for oil- and gas-fired units is as follows:

$$TCI = 1.3 \times \left(SNCR_{Cost} + BOP_{Cost}\right) \tag{1.28}$$

Where:

TCI = total capital investment for a SNCR on a boiler, $
$SNCR_{Cost}$ = cost of the SNCR, $
BOP_{Cost} = balance of plant costs, $.

This TCI includes engineering and construction management costs, installation, labor adjustment for the SNCR, and contractor profit and fees.

SNCR costs, utility oil- and gas-fired units ≥25 MW. The capital costs for the SNCR base unit includes costs for the injectors, blowers, distributive control system (DCS), and the reagent system [11]. The SNCR costs are calculated as follows:

$$SNCR_{Cost} = 147{,}000 \times \left(B_{MW} \times HRF\right)^{0.42} \times ELEVF \times RF \tag{1.29}$$

Where:

$SNCR_{Cost}$ = SNCR unit costs, $
147,000 = constant in the equation
B_{MW} = boiler MW rating at full load capacity for the unit being costed, MW
HRF = heat rate factor
$ELEVF$ = elevation factor (calculated using Equation 1.22 if plant is located above 500 feet above sea level; ELEVF = 1 for plants located at or below 500 feet above sea level)
RF = retrofit factor (RF = 0.84 for new construction; RF = 1 for retrofits with average level of difficulty).

<u>Balance of plant (BOP) costs, utility oil- and gas-fired units ≥25 MW</u>. 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 [11]. The BOP costs are calculated as follows:

$$BOP_{Cost} = 213{,}000 \times \left(B_{MW}\right)^{0.33} \times \left(NO_x\ \mathrm{Re}\,moved\ / \ hr\right)^{0.12} \times RF \tag{1.30}$$

Where:

BOP_{Cost} = Balance of plant costs, $
213,000 = constant in the equation
NO_x *Removed/hr* = hourly mass of NO_x removed by the SNCR system, lb/hr
RF = retrofit factor (RF = 0.84 for new construction; RF = 1 for retrofits with average level of difficulty).

1.4.1.3 Industrial Boilers, Coal-fired Units

<u>Industrial, coal-fired units ≥250 MMBtu/hr</u>. The capital cost equation for industrial coal-fired boilers ≥250 MMBtu/hr is as follows:

$$TCI = 1.3 \times \left(SNCR_{Cost} + APH_{Cost} + BOP_{Cost}\right) \tag{1.31}$$

Where:

TCI = total capital investment for a SNCR on a boiler, $
$SNCR_{Cost}$ = cost of the SNCR, $
APH_{Cost} = air pre-heater cost, $
BOP_{Cost} = balance of plant costs, $.

This TCI includes engineering and construction management costs, installation, labor adjustment for the SNCR, and contractor profit and fees.

SNCR costs, industrial, coal-fired units ≥250 MMBtu/hr. The capital costs for the SNCR base unit includes costs for the injectors, blowers, distributive control system (DCS), and the reagent system [11]. The SNCR costs are calculated as follows:

$$SNCR_{Cost} = 220{,}000 \times \left(0.1 \times Q_B \times HRF\right)^{0.42} \times CoalF \times BTF \times ELEVF \times RF \qquad (1.32)$$

Where:

$SNCR_{Cost}$ = SNCR unit costs, $

220,000 = constant in the equation

Q_B = maximum heat rate input to the boiler, MMBtu/hr

HRF = heat rate factor

$CoalF$ = coal factor (CoalF=1 if bituminous; CoalF=1.05 if PRB; CoalF=1.07 if Lignite)

BTF = boiler type factor (BTF=1 if non-FB boiler; BTF=0.75 for FB boiler)

$ELEVF$ = elevation factor (calculated using Equation 1.22 if plant is located above 500 feet above sea level; ELEVF = 1 for plants located at or below 500 feet above sea level)

RF = retrofit factor (RF= 0.84 for new construction; RF = 1 for retrofits with average level of difficulty).

The boiler type factor, BTF, is based on the type of boiler unit. Boiler types may be fluidized bed or non-fluidized bed. Non-FB units include cyclone, tangentially-fired, wall-fired boiler units. Fluidized bed units include circulating, bubbling, atmospheric, and pressurized units. The BTF is 1 for non-FB boilers and is 0.75 for FB boilers. The CoalF is 1 for bituminous coal, 1.05 for powder river basin (PRB) coal, and 1.07 for lignite coal.

Air Pre-Heater Modification costs, industrial, coal-fired units ≥250 MMBtu/hr. Air pre-heater modification costs are included only where SO_3 control is necessary. An air pre-heater modification is necessary for the control of SO_3 for boilers that burn bituminous coal where the SO_2 content of the coal is 3 lb/MMBtu or greater. If other coal types are used, then no air pre-heater modification is needed. The air pre-heater modification costs are calculated as follows:

$$APH_{Cost} = 69{,}000 \times \left(0.1 \times Q_B \times HRF \times CoalF\right)^{0.78} \times AHF \times RF \qquad (1.33)$$

Where:

APH_{Cost} = Air pre-heater cost, $

69,000 = constant in the equation

AHF = air heater factor (AHF=1 if bituminous coal and SO_2 ≥3 lb/MMBtu; if not true, AHF=0)

RF = retrofit factor (RF = 0.84 for new construction; RF = 1 for retrofits with average level of difficulty).

The AHF is 1 for bituminous coal and where the SO_2 content of the coal is 3 lb/MMBtu or greater. If the boiler burns other coal types, then the AHF is 0 and this term drops out of the overall $SNCR_{Cost}$ equation.

Balance of plant (BOP) costs, industrial, coal-fired units ≥250 MMBtu/hr. 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 [11]. The BOP costs are calculated as follows:

$$BOP_{Cost} = 320{,}000 \times \left(0.1 \times Q_B\right)^{0.33} \times \left(NO_x \text{Removed/hr}\right)^{0.12} \times BTF \times RF \qquad (1.34)$$

Where:

BOP_{Cost} = Balance of plant costs, \$
320,000 = constant in the equation
NO_x *Removed/hr* = hourly mass of NO_x removed by the SNCR system, lb/hr
RF = retrofit factor (RF = 0.84 for new construction; RF = 1 for retrofits with average level of difficulty).

1.4.1.4 Industrial Boilers, Oil- and Gas-fired Units

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

$$TCI = 1.3 \times \left(SNCR_{Cost} + BOP_{Cost}\right) \qquad (1.35)$$

Where:

TCI = total capital investment for a SNCR on a boiler, \$
$SNCR_{Cost}$ = cost of the SNCR, \$
BP_{Cost} = balance of plant costs, \$.

This TCI includes engineering and construction management costs, installation, labor adjustment for the SNCR, and contractor profit and fees.

SNCR costs, industrial, oil- and gas-fired units ≥250 MMBtu/hr. The capital costs for the SNCR base unit includes costs for the injectors, blowers, distributive control system (DCS), and the reagent system [11]. The SNCR costs are calculated as follows:

$$SNCR_{Cost} = 147{,}000 \times \left(\frac{Q_B}{NPHR} \times HRF\right)^{0.42} \times ELEVF \times RF \qquad (1.36)$$

Where:

$SNCR_{Cost}$ = SNCR unit costs, \$

147,000 = constant in the equation
Q_B = 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)
HRF = heat rate factor
$ELEVF$ = elevation factor (calculated using Equation 1.22 if plant is located above 500 feet above sea level; ELEVF = 1 for plants located at or below 500 feet above sea level)
RF = retrofit factor (RF = 0.84 for new construction; RF = 1 for retrofits with average level of difficulty).

Balance of plant (BOP) costs, industrial, oil- and gas-fired units ≥250 MMBtu/hr. 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 [11]. The BOP costs are calculated as follows:

$$BOP_{Cost} = 213{,}000 \times \left(\frac{Q_B}{NPHR}\right)^{0.33} \times \left(NO_x \text{Removed/hr}\right)^{0.12} \times RF \tag{1.37}$$

Where:

BPC = Balance of plant, \$
213,000 = constant in the equation
NO_x *Removed/hr* = hourly mass of NO_x removed by the SNCR system, lb/hr
RF = retrofit factor (RF = 0.84 for new construction; RF = 1 for retrofits with average level of difficulty).

1.4.2 Total Annual Costs

Total annual costs (TAC) consist of direct costs, indirect costs, and recovery credits. Direct annual costs are those associated or proportional to the quantity of waste gas processed by the control system. Indirect (fixed) annual costs are independent of the operation of the control system and would be incurred even if it were shut down. No byproduct recovery credits are included because there are no salvageable byproducts generated from the SNCR [24]. Each of these costs is discussed in the sections below. A more detailed discussion of annual costs can be found in Section 1, Chapter 2 of this Cost Manual.

Design parameters are estimated using the maximum annual heat input rate of the boiler to ensure adequate sizing of the SNCR system. Annual costs are calculated using the average heat input rate of the boiler and SNCR system using CF_{total}. This ensures that annual costs are based on the actual operating conditions rather than the design case.

Direct Annual Costs

Direct annual costs (*DAC*) include variable and semivariable costs. Variable direct annual costs account for purchase of reagent, utilities (electrical power and water), and any additional coal and ash disposal resulting from the operation of the SNCR. Semivariable direct annual costs include operating and supervisory labor and maintenance (labor and materials). These costs are discussed individually below.

$$DAC = \begin{pmatrix} Annual \\ Maintenanc\ e \\ Cost \end{pmatrix} + \begin{pmatrix} Annual \\ Reagent \\ Cost \end{pmatrix} + \begin{pmatrix} Annual \\ Electricit\ y \\ Cost \end{pmatrix} + \begin{pmatrix} Annual \\ Water \\ Cost \end{pmatrix} + \begin{pmatrix} Annual \\ Coal \\ Cost \end{pmatrix} + \begin{pmatrix} Annual \\ Ash \\ Cost \end{pmatrix} \tag{1.38}$$

<u>Operating and Supervisory Labor</u>

In general, no additional personnel are required to operate or maintain the SNCR equipment for large industrial facilities. Therefore, the cost of operating or supervisory labor is assumed to be negligible.

<u>Maintenance</u>

The annual maintenance labor and material cost, including nozzle tip replacement for the injectors, is assumed to be 1.5% of the *TCI* in dollars. This is a fairly standard percentage for maintenance on control devices, but for SNCR it may be conservative (i.e., overstate the cost) because one study indicates that a lower percentage is reasonable [11]. The equation for annual maintenance cost in $/hr, *AMC,* is given by:

$$\textit{Annual maintenance cost} = 0.015 \times TCI \tag{1.39}$$

<u>Reagent Consumption</u>

The annual cost of reagent purchase in $/yr is estimated using the aqueous reagent volume flow rate in gallons per hour (gph,) q_{sol} , and the total operating time, t_{op}, in hours, and $Cost_{reag}$ is the cost of reagent in dollars per gallon ($/gal):

$$\textit{Annual reagent cost} = q_{sol} \times Cost_{reag} \times t_{op} \tag{1.40}$$

The operating time per year, t_{op}, is estimated using the capacity factor, CF_{total}:

$$t_{op} = CF_{total} \times 8{,}760\ \frac{hr}{yr} \tag{1.41}$$

For pelletized urea or anhydrous ammonia, the $\dot{m}_{\text{reagent}}$ calculation would need to be adjusted according to the cost of the reagent and Equation 1.18 above; however, since these are not the least costly reagent choices, these costs are not addressed here.

<u>Utilities</u>

The electrical power consumption, *P*, in kilowatts (kW) estimated for SNCR operations is derived in Appendix B of the draft EPA report, *Selective Noncatalytic Reduction for* NO_x

Control on Coal-fired Boilers [32]. It is based on a linear regression of electrical power consumption data correlated to the uncontrolled NO_x emission level in lb/MMBtu, NO_{xin}, the NSR and the boiler heat input in MMBtu/hr, Q_B:

$$P = \frac{0.47 \times NO_{x_{in}} \times NSR \times Q_B}{NPHR} \tag{1.42}$$

Where:

P = electrical power consumption of the SNCR, kW
0.47 = constant in the equation
$NPHR$ = net plant heat rate, MMBtu/MWh.

Using the estimated power consumption, P, the annual cost of electricity is estimated from the following equation:

$$\text{Annual electricity cost} = P \times Cost_{elect} \times t_{op} \tag{1.43}$$

Where:

$Cost_{elect}$ = cost of electricity in dollars per kWh (\$/kWh).

Water Consumption

The volumetric flowrate of water for diluting the urea is calculated from the aqueous urea mass flow rate in lb/hr and the concentration of the aqueous urea during storage, $C_{urea\ sol\ stored}$ and the average percent concentration of the injected urea, $C_{urea\ sol\ inj}$. The flowrate, q_{water}, in gallons per hour (gph) is:

$$q_{water} = \frac{\dot{m}_{sol}}{\rho_{water}} \left(\frac{C_{urea\ sol_{stored}}}{C_{urea\ sol_{inj}}} - 1 \right) \tag{1.44}$$

Where:

q_{water} = flowrate of water necessary for diluting the reagent solution, gph
ρ_{water} = the density of water, 8.345 lb/gal
$C_{urea\ sol\ stored}$ = concentration of the aqueous solution as stored, weight fraction
$C_{urea\ sol\ inj}$. = concentration of the aqueous solution as injected, weight fraction.

For urea dilution from a 50% solution to a 10% solution, Equation 1.44 becomes:

$$q_{water} = \frac{4\ \dot{m}_{sol}}{\rho_{water}} \tag{1.45}$$

Using this estimate for the volume flow rate of water (gph), the annual cost of water consumption in $/yr is given by:

$$Annual\ water\ cost = q_{water} \times Cost_{water} \times t_{op} \tag{1.46}$$

where $Cost_{water}$ is the cost of water in dollars per gallon ($/gal) and t_{op} is given by Equation 1.43.

Additional Fuel to Vaporize Water in Reagent Solution

The additional fuel required as a result of the heat used to evaporate the water in the injected solution (water in the stored urea solution and the dilution water) is estimated using the following equation:

$$\Delta Fuel = Hv \times \dot{m}_{reagent} \times \left(\frac{1}{C_{urea\ sol_{inj}}} - 1 \right) \tag{1.47}$$

Where:

$\Delta Fuel$ = fuel required to evaporate the injected solution water, Btu/hr
H_v = the heat of vaporization of water, Btu/lb.

$C_{urea\ sol\ inj}$ is the percent concentration of the injected aqueous urea agent and $\dot{m}_{reagent}$ is the mass flowrate in lb/hr. The approximate H_v at 310°F (150°C) is 900 BTU/lb, which is a representative temperature for flue gas exiting the air heater.

Although the water from the urea solution is evaporated in the furnace at higher temperatures (due to urea injection in the furnace zones at over 1500°F [820°C]), the temperature at the air heater exit is used because it is the thermodynamic end point of the combustion process. The quantity of fuel burned in the boiler depends on the boiler efficiency, which in turn depends on the air heater exit temperature and the moisture in the air heater exit gas. The boiler is fired to maintain the required steam flow (e.g., for the steam turbine). Because the water from the urea solution evaporates in the boiler, the boiler efficiency decreases. Consequently, more fuel needs to be burned to maintain the required steam flow.

With urea as the reagent, injected as a 10% solution and H_V = 900 Btu/lb, Equation 1.47 in MMBtu per hour becomes:

$$\Delta Fuel \left(\frac{MMBtu}{hr} \right) = \frac{900 \left(\frac{Btu}{lb} \right) \times \dot{m}_{reagent} \left(\frac{lb}{hr} \right) \times 9}{10^6 \left(\frac{Btu}{MMBtu} \right)} \tag{1.48}$$

The cost of the additional fuel in $/yr required to maintain the same boiler steam output is:

$$Annual\ \Delta Fuel\ cost = \Delta Fuel \times Cost_{fuel} \times t_{op} \tag{1.49}$$

Where:

$Annual\ \Delta Fuel\ cost$ = annual cost of the fuel required to evaporate the water in the injected aqueous solution, $

$Cost_{fuel}$ = the cost of fuel, $/MMBtu.

Coal Ash Disposal

For a coal-fired boiler, additional ash is generated from burning the additional coal to vaporize water in the reagent solution. This ash must be disposed of or sold as byproduct. This cost methodology assumes that the ash is disposed of. The estimated additional ash to be disposed of in lb/hr is given by:

$$\Delta Ash = \frac{\Delta Fuel\ \times ash\ \ product}{HHV} \times 10^{6} \tag{1.50}$$

Where:

ΔAsh = mass of ash product that is generated and must be disposed, lb/hr

$ash\ product$ = the fraction of ash produced from the coal burned

10^6 = conversion factor of 10^6 Btu/1 MMBtu.

The ash product is the fraction of ash produced as a byproduct of burning a given type of coal. The *HH*V is given in Table 1.6.

The cost of additional ash disposal due to the additional fuel usage is given by:

$$Annual\ \Delta Ash\ cost = \Delta Ash \times Cost_{ash} \times t_{op}\ x\ (1\ /\ 2000) \tag{1.51}$$

Where:

$Annual\ \Delta Ash\ cost$ = annual cost to dispose of the ash generated, $

$Cost_{ash}$ = the cost of ash disposal, $/ton

2000 = conversion factor of 2,000 lb/ 1 ton.

Indirect Annual Costs

In general, indirect annual costs (fixed costs) include the capital recovery, property taxes, insurance, administrative charges, and overhead. Capital recovery is based on the anticipated equipment lifetime and the annual interest rate employed.[11] As mentioned earlier in this chapter, SNCR control systems began to be installed in Japan the late 1980's. Based on data EPA collected from electric utility manufacturers, at least 11 of approximately 190 SNCR systems on utility boilers in the U.S. were installed before January 1993 [10]. In responses to another ICR, 3

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[11] The interest rate recommended by EPA can vary by firm or industry, but the bank prime rate is a default rate that can be used for annualization of capital costs. This interest rate is 5.25 to 5.5 percent as of January 2019. For more information, please consult the cost estimation chapter of this Control Cost Manual (Section 1, Chapter 2).

petroleum refiners estimated SNCR life at between 15 and 25 years [3]. Thus, an equipment lifetime of 20 years is assumed for the SNCR system in this analysis. (The remaining life of the controlled unit may also be a determining factor).

In many cases property taxes do not apply to capital improvements such as air pollution control equipment; therefore, for this analysis, taxes are assumed to be zero [65]. The cost of overhead for an SNCR system is also considered to be zero. An SNCR system is not viewed as risk-increasing hardware (e.g., a high energy device such as a turbine). Consequently, insurance on an SNCR system is on the order of a few cents per thousand dollars annually [65]. Finally, there are two categories of overhead, payroll and plant. Payroll overhead includes expenses related to labor employed in operation and maintenance of hardware; whereas plant overhead accounts for items such as plant protection, control laboratories, and parking areas. Because this procedure assumes that no additional labor is needed to operate an SNCR system, payroll overhead is zero and plant overhead is considered negligible.

Using these assumptions, indirect annual costs in \$/yr, *IDAC*, consist of both administrative charges and capital recovery, which can be expressed as:

$$IDAC = AC + CR \tag{1.52}$$

Where *AC* represents the administrative charges and CT represents the capital recovery cost. Administrative charges may be calculated as:

$$AC = 0.03 \times \text{Annual maintenance cost} \tag{1.53}$$

Capital recovery is estimated as:

$$CR = CRF \times TCI \tag{1.54}$$

Where TCI is the total capital investment in dollars and CRF is the capital recovery factor. Capital recovery factor was defined in Section 1 as:

$$CRF = \frac{i\,(1+i)^n}{(1+i)^n - 1} \tag{1.55}$$

Where *i* is the assumed interest rate and *n* is the equipment life of the SNCR system.

Total Annual Cost

The total annual cost, *TAC,* for owning and operating an SNCR system is the sum of direct and indirect annual costs as given in the following equation:

$$TAC = DAC + IDAC \tag{1.56}$$

Cost Effectiveness

The cost in dollars per ton of NO_x removed per year, is:

$$Cost\ Effectiveness = \frac{TAC}{NO_x\ Removed\ /\ yr} \tag{1.57}$$

Where:

Cost Effectiveness = the cost effectiveness, \$/ton
NO_x *Removed/yr* = annual mass of NO_x removed by the SNCR, ton/yr.

1.5 Example Problem

An example problem, which calculates both the design parameters and capital and annual costs, is presented below. The design basis is a retrofit SNCR system being applied to a 120 MW, wall-fired, utility boiler firing bituminous coal. The following assumptions are made to perform the calculations:

Fuel High Heating Value, *HHV*	12,000 Btu/lb
Maximum Fuel Consumption Rate, $\dot{m}_{fuel}$	1.0×10^5 lb/hr
Heat Rate, *NPHR*	10.0 MMBtu/MWh
Average Annual Fuel Consumption, *actual* $\dot{m}_{fuel}$	4.38×10^8 lb
Number of SNCR operating days, t_{SNCR}	155 days
Uncontrolled NO_x Emission Level, NO_{xin}	0.46 lb/MMBtu
Required Controlled NO_x Emission Level, NO_{xout}	0.30 lb/MMBtu
Sulfur content of coal, $S_{content}$	<3 lb SO_2/MMBtu
Percent Fuel Ash Weight, *ash product*	7.5%
Stored Urea Concentration, $C_{urea\ sol\ stored}$	50% urea solution
Injected Urea Concentration, $C_{urea\ sol\ inj}$	10% urea solution
Number of Days of Storage for Urea, $t_{storage}$	14 days
RF	1

In addition to these assumptions, the estimated economic factors for the cost calculations are:

Cost Year	2016
Equipment Life	20 years
Annual Interest Rate	5.5%
Coal Cost, Bituminous[12] [66]	\$2.40/MMBtu
Ash Disposal Cost [67]	\$48.8/ton
50% Urea Solution Cost [11][13]	\$1.66/gal

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[12] This value represents the 2016 coal price.

[13] The electricity and reagent unit costs used in this example are based on data for 2016. These values are provided here for demonstration purposes only. When estimating direct annual operating costs, the current price of these commodities reflecting the year in which the cost estimate is made should be used. Reagent prices can be obtained from vendors. Industrial plants should use the electricity price from their latest utility bill, while electricity generators should use the busbar rate.

Water Consumption Cost [68]	\$0.00417/gal[14]
Electricity Cost [69][13]	\$0.0361/kWh

1.5.1 Design Parameter Example[15]

The boiler annual heat input rate, Q_B, is calculated from the *HHV* for bituminous coal given in Table 1.6 and the maximum fuel consumption rate, $\dot{m}_{fuel}$ using Equation 1.3:

$$Q_B = \frac{12{,}000\ \frac{Btu}{lb} \times 100{,}000\ \frac{lb}{hr}}{10^6\ \frac{Btu}{MMBtu}} = 1{,}200\ \frac{MMBtu}{hr}$$

The plant capacity factor is calculated from the maximum and annual average fuel consumption using Equation 1.8:

$$CF_{plant} = \frac{4.38 \times 10^8\ lb}{1 \times 10^5 \left(\frac{lb}{hr}\right) \times 8{,}760 \left(\frac{hr}{yr}\right)} = 0.5 = 50\%$$

The SNCR system capacity factor is calculated from the months of SNCR operation, which is assumed to be only for the ozone season (5 months in this example), using Equation 1.9:

$$CF_{SNCR} = \frac{155\ days}{365\ days} = 0.42 = 42\%$$

The total capacity factor including both plant and SNCR capacity factors is calculated using Equation 1.7:

$$CF_{total} = 0.5 \times 0.42 = 0.21 = 21\%$$

The total operating time per year of the SNCR is calculated using Equation 1.43:

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[14] The water rate is based on industrial water rates for users with greater than 10,000,000 gal monthly usage who purchase water from a municipality. Industrial users that have their own water source or supply with likely have lower water rates [68]. The 2016 value for water costs was estimated based on the 2013 water rate published by Black & Veatch and assuming an annual increase in costs of 6 percent. The annual increase of 6 percent is consistent with the compound annual increase in typical water bills reported to Black & Veatch between 2001 and 2013 [68].

[15] Note: Results of all parameter calculations are shown rounded to an acceptable number of significant figures. However, the full, unrounded value is used in subsequent parameter and cost calculations that use the parameter as an input. Thus, the results shown for subsequent calculations often differ from what would be calculated using the shown rounded inputs. The use of extra significant figures in the subsequent calculations does not imply greater accuracy of the numbers.

$$t_{op} = 0.21 \times 8{,}760 \ \frac{hr}{yr} = 1{,}860 \ \frac{hr}{yr}$$

The NO_x removal efficiency, η_{NOx}, is calculated from the inlet NO_x emission level and the required stack NO_x emission level using Equation 1.10:

$$\eta_{NO_x} = \frac{0.46 \ \frac{lb}{MMBtu} - 0.30 \ \frac{lb}{MMBtu}}{0.46 \ \frac{lb}{MMBtu}} = 0.35 = 35\%$$

The NO_x removed per hour (lb/hr) is calculated from the inlet NO_x emission level, the NO_x removal efficiency, and the maximum heat rate to the boiler using Equation 1.12:

$$NO_x \ \mathrm{Re}\,moved \ / \ hr = 0.46 \ \frac{lb}{MMBtu} \times 0.35 \times 1{,}200 \ \frac{MMBtu}{lb} = 192 \ \frac{lb}{hr}$$

The equation derived in Reference [32] is used to estimate *NSR* for the SNCR system. The estimate is given by using Equation 1.13 (or Equation 1.17 for urea systems):

$$NSR = \frac{\left[\left(2 \times 0.46 \ \frac{lb}{MMBtu}\right) + 0.7\right] \times 0.35}{0.46 \ \frac{lb}{MMBtu}} = 1.22$$

The reagent utilization can then be calculated based on the required NO_x removal efficiency and NSR value using Equation 1.16:

$$Utilizatio \ n = \frac{0.35}{1.22} = 0.29 = 29\%$$

The value of the NSR indicates that 1.22 moles of NH_3 are required per mole of uncontrolled NO_x to reduce the NO_x level by 35%. This translates to a reagent utilization of 0.29, the ratio of moles of reagent reacted to the moles injected. This indicates that 29% of the injected reagent is being utilized for NO_x removal. The remainder of the reagent is being destroyed or passing through as ammonia slip.

The mass flow rate of the reagent is calculated using the molecular weight of the reagent, 60.06 g/mole and NO_2, 46.01 g/mole and the SR_T for urea, 2. For an *NSR* of 1.22, the reagent mass flow rate is given by Equation 1.18:

$$\dot{m}_{reagent} = \frac{0.46 \ \frac{lb}{MMBtu} \times 1{,}200 \ \frac{MMBtu}{hr} \times 1.22 \times 60.06 \ \frac{g}{mole}}{2 \times 46.01 \ \frac{g}{mole}} = 440 \ \frac{lb}{hr}$$

The flow rate of the diluted solution, where the concentration of the aqueous solution is 50% urea, is given by Equation 1.19:

$$\dot{m}_{sol} = \frac{440\,\frac{lb}{hr}}{0.50} = 880\,\frac{lb}{hr}$$

The solution volume flow rate can then be calculated where ρ is the density of the aqueous reagent solution, 71.0 lb/ft^3 for 50% aqueous urea solution at 60°F Equation 1.20.

$$q_{sol} = \frac{880\,\frac{lb}{hr} \times 7.481\,\frac{gal}{ft^3}}{71.0\,\frac{lb}{ft^3}} = 92.6\,gallons\ /\,hr\,(gph)$$

The total volume stored in the tank, or tanks, is based on the volume that the SNCR system requires for 14 days of operation. The onsite storage requirement is given by Equation 1.21:

$$V_{\tan k} = 92.6\,gph \times 14\ days \times \frac{24\,hr}{day} = 31{,}200\,gal$$

The onsite storage requirement for urea is 31,200 gallons per 14 days (rounded to the nearest 100 gallons). This shows that for the example boiler (1,200 MMBtu/hr design, 50% actual loading, and 35% NO$_x$ removal efficiency), the volume of urea solution required to operate an SNCR system for 155 days during the ozone season is approximately 344,500 gallons.

An estimate for power consumption is given by Equation 1.42:

$$P = \frac{0.47 \times 0.46\,\frac{lb}{MMBtu} \times 1.22 \times 1{,}200\,\frac{MMBtu}{hr}}{10} = 31.7\,kW$$

Water consumption, assuming a 50% urea solution stored and a 10% urea solution injected, is calculated using Equation 1.44:

$$q_{water} = \frac{880\,\frac{lb}{hr}}{8.345\,\frac{lb}{gal}} \times \left(\frac{0.5}{0.10} - 1\right) = 421\,gph$$

The estimated additional coal consumption and ash disposal required to maintain the same net heat output are given by Equations 1.48 and 1.50, respectively:

$$\Delta Fuel = \frac{440\,\frac{lb}{hr} \times 900\,\frac{Btu}{lb}}{10^{6}\,\frac{Btu}{MMBtu}} \times \left(\frac{1}{0.10} - 1\right) = 3.56\,\frac{MMBtu}{hr}$$

$$\Delta Ash = \frac{3.56\,\frac{MMBtu}{hr} \times 0.075 \times 10^{6}\,\frac{Btu}{MMBtu}}{12{,}000\,\frac{Btu}{lb}} = 22.3\,\frac{lb}{hr}$$

1.5.2 Cost Estimation Example

Once the SNCR system is sized, the capital and annual costs for the SNCR system can be estimated. The total capital investment costs are estimated using Equation 1.24:

$$TCI = 1.3 \times \left(SNCR_{Cost} + APH_{Cost} + BOP_{Cost}\right)$$

The SNCR capital costs are estimated using Equation 1.25:

$$SNCR_{Cost} = 220{,}000 \times \left(B_{MW} \times HRF\right)^{0.42} \times CoalF \times BTF \times ELEVF \times RF$$

$$SNCR_{Cost} = 220{,}000 \times (120 \times 1)^{0.42} \times 1 \times 1 \times 1 \times 1 = \$1{,}643{,}156$$

The sulfur content is assumed to be low enough that the SO_2 emission rate is less than 3 lb/MMBtu; thus, as described in the discussion accompanying Equation 1.26, no air preheater modifications are needed:

$$APH_{Cost} = 69{,}000 \times \left(B_{MW} \times HRF \times CoalF\right)^{0.78} \times AHF \times RF$$

$$APH_{Cost} = 57{,}960 \times (120 \times 1 \times 1)^{0.78} \times 0 \times 1 = 0$$

The BOP_{Cost} can be calculated using Equation 1.27:

$$BOP_{Cost} = 320{,}000 \times \left(B_{MW}\right)^{0.33} \times \left(NO_x \text{Removed/hr}\right)^{0.12} \times BTF \times RF$$

$$BOP_{Cost} = 320{,}000 \times (120)^{0.33} \times (192)^{0.12} \times 1 \times 1 = \$2{,}919{,}281$$

The total capital investment can be calculated using the values above:

$$TCI = 1.3 \times \left(SNCR_{Cost} + APH_{Cost} + BOP_{Cost}\right)$$

$$TCI = 1.3 \times \left(\$1{,}643{,}156 + 0 + \$2{,}919{,}281\right) = \$5{,}931{,}168$$

The SNCR system is assumed to operate for 5 months of the year with a boiler loading of 50%, resulting in a total capacity factor of 21%. The annual variable costs are given by Equations 1.39, 1.40, 1.43, 1.46, 1.49 and 1.51, respectively:

$$\textit{Annual maintenance cost} = 0.015 \times \$5{,}931{,}168 = \frac{\$88{,}968}{yr}$$

$$\textit{Annual reagent cost} = 92.6\,gph \times 1.66\,\frac{\$}{gal} \times \left[1{,}860\,\frac{hr}{yr}\right] = \frac{\$285{,}973}{yr}$$

$$\textit{Annual electricity cost} = 31.7\ kW \times 0.0361\,\frac{\$}{kW}\left[1{,}860\,\frac{hr}{yr}\right] = \frac{\$2{,}125}{yr}$$

$$\textit{Annual water cost} = 421\,gph \times 0.00417\,\frac{\$}{gal} \times \left[1{,}860\,\frac{hr}{yr}\right] = \frac{\$3{,}268}{yr}$$

$$\textit{Annual}\ \ \Delta\textit{Fuel}\ \ \text{cost} = 3.56\,\frac{MMBtu}{hr} \times 2.40\,\frac{\$}{MMBtu} \times \left[1{,}860\,\frac{hr}{yr}\right] = \frac{\$15{,}893}{yr}$$

$$\textit{Annual}\ \ \Delta\textit{Ash}\ \ cost = \frac{22.3\,\frac{lb}{hr} \times 48.8\,\frac{\$}{ton} \times \left[1{,}860\,\frac{hr}{yr}\right]}{2{,}000\,\frac{lb}{ton}} = \frac{\$1{,}010}{yr}$$

The total direct annual cost (DAC), the sum of the cost of the maintenance, reagent, electricity, water, coal and ash disposal, is given by the sum of the annual costs, using Equation 1.38:

$$DAC = \frac{\$88{,}968}{yr} + \frac{\$285{,}793}{yr} + \frac{\$2{,}125}{yr} + \frac{\$3{,}268}{yr} + \frac{\$15{,}893}{yr} + \frac{\$1{,}010}{yr} = \frac{\$397{,}237}{yr}$$

As discussed in section 1.4.2, property taxes and overhead are both assumed to be zero, and insurance costs are assumed to be negligible. Thus, administrative charges and capital recovery are the only components of indirect annual costs estimated in this analysis. Administrative charges are calculated using Equation 1.53 as:

$$AC = 0.03 \times 88{,}968 = \$2{,}669/\text{yr}$$

The capital recovery factor, CRF, is defined in Equation 1.55 as:

$$CRF = \frac{0.055\ (1 + 0.055)^{20}}{(1 + 0.055)^{20} - 1} = 0.0837$$

and the capital recovery is calculated using Equation 1.54 as:

$$CR = 0.0837 \times \$5{,}931{,}168 = \$496{,}439/\text{yr}$$

The total indirect annual costs (IDAC) are calculated in Equation 1.52:

$$IDAC = \$2{,}669 + \$496{,}439 = \frac{\$499{,}108}{yr}$$

The total annual cost is the sum of the direct annual and indirect annual costs given in Equation 1.54:

$$TAC = \frac{\$397{,}237}{yr} + \frac{\$499{,}108}{yr} = \frac{\$896{,}345}{yr}$$

The total amount of NO_x removed can be calculated using Equation 1.11:

$$NO_x\ Removed\ /\ yr = \frac{0.46\,\frac{lb}{MMBtu} \times 0.35 \times 1{,}200\,\frac{MMBtu}{hr} \times \left[1{,}860\,\frac{hr}{yr}\right]}{2{,}000\,\frac{lb}{ton}} = 178.6\,\frac{tons}{yr}$$

And the annual cost in terms of NO_x removed, or cost effectiveness, is calculated using Equation 1.57:

$$\boldsymbol{AnnualCostEffectiveness = \frac{\$876{,}345}{178.6\ tons} = \frac{\$5{,}020}{ton}}$$

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