

Section 4

NO_x Controls

Section 4.2

NO_x Post- Combustion

Introduction

Nitrogen oxides (NO_x) are gaseous pollutants that are primarily formed through combustion process. While flue gas is within the combustion unit, about 95% of the NO_x exists in the form of nitric oxide (NO). The balance is nitrogen dioxide (NO_2), which is unstable at high temperatures. Once the flue gas is emitted into the atmosphere, most of the NO_x is ultimately converted to NO_2 . NO_x in the atmosphere reacts in the presence of sunlight to form ozone (O_3), one of the criteria pollutants for which health-based National Ambient Air Quality Standards have been established. Since ozone formation requires sunlight and high temperatures, ozone formation is greatest in summer months.

NO_x is generated in one of three forms; fuel NO_x , thermal NO_x , and prompt NO_x . Fuel NO_x is produced by oxidation of nitrogen in the fuel source. Combustion of fuels with high nitrogen content such as coal and residual oils produces greater amounts of NO_x than those with low nitrogen content such as distillate oil and natural gas. Thermal NO_x is formed by the fixation of molecular nitrogen and oxygen at temperatures greater than 3600°F (2000°C). Prompt NO_x forms from the oxidation of hydrocarbon radicals near the combustion flame and produces an insignificant amount of NO_x .

Selective Noncatalytic Reduction (SNCR) and Selective Catalytic Reduction (SCR) are post-combustion control technologies based on the chemical reduction of nitrogen oxides (NO_x) into molecular nitrogen (N_2) and water vapor (H_2O). The primary difference between the two technologies is that SCR utilizes a catalyst to increase the NO_x removal efficiency, which allows the process to occur at lower temperatures. The technologies can be used separately or in combination with other NO_x combustion control technologies such as low NO_x burners (LNB) and natural gas reburn (NGR). SNCR and SCR can be designed to provide NO_x reductions year-round or only during summer months, when ozone concerns are greatest.

This section presents design specifications and a costing methodology for SNCR and SCR applications for large industrial boilers (greater than 250 MMBtu/hr). Its primary purpose is to provide study-level cost estimates. These estimates can be used to compare the approximate costs of SNCR, SCR, and alternative NO_x control technologies. The costing methodologies are based on cost estimations for SNCR and SCR applications to utility boilers, which were developed by the Office of Research and Development (ORD), U.S. Environmental Protection Agency (EPA), Research Triangle Park, NC.

As a prelude to the cost methodology, the section describes the process chemistry, performance parameters, and system components of SNCR and SCR. In addition, impacts to the boiler performance and facility operations resulting from the installation of SNCR and SCR are presented. The section also estimates important underlying design parameters including the normalized stoichiometric ratio, catalyst volume, and reagent consumption. Lastly, it presents

assumptions and equations for estimating capital costs, annual operation and maintenance costs, and annualized costs. SNCR and SCR are discussed in separate chapters, however, the chapter on SCR builds on the concepts discussed in the SNCR chapter.

Information on key aspects of the design of SNCR and SCR systems is considered proprietary by vendors, including methods for estimating certain design parameters and costs. This information is not available to develop cost methodologies for SNCR and SCR. In order to obtain estimates of the proprietary design parameters and costs, it is necessary to develop mathematical correlations from available data using regression and curve fitting techniques. These expressions are derived in EPA reports prepared by The Cadmus Group, Bechtel Power, Inc. and SAIC in SNCR and SCR References [1, 2 and 3] from documented comprehensive SNCR and SCR performance data and costs based on quotations provided by suppliers and facilities.

Chapter 1

Selective Noncatalytic Reduction

Daniel C. Mussatti
Innovative Strategies and Economics Group
Air Quality Strategies and Standards Division
Office of Air Quality Planning and Standards
U.S. Environmental Protection Agency
Research Triangle Park, NC 27711

Dr. Ravi Srivastava
Office of Research and Development
U.S. Environmental Protection Agency
Research Triangle Park, NC 27711

Paula M. Hemmer and
Randy Strait
E. H. Pechan & Associates, Inc.
3622 Lyckan Parkway, Suite 2002
Durham, NC 27707

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1.1 Introduction

SNCR is currently being used for NO_x emission control on industrial boilers, electric utility steam generators, thermal incinerators, and municipal solid waste energy recovery facilities. Its use on utility boilers has generally been limited to units with output of less than 3,100 MMBtu, but large-scale applications of SNCR have been successfully tested such as Cardinal Plant Unit 1, a 600 MW (5,700 MMBtu/hr) utility boiler located in Brilliant, Ohio [11]. SNCR can be applied as a stand-alone NO_x control or with other technologies such as combustion controls. The SNCR system can be designed for seasonal or year-round operations.

SNCR can achieve NO_x reduction efficiencies of up to 75 percent (%) in selected short-term demonstrations [5]. In typical field applications, however, it provides 30% to 50% NO_x reduction. Reductions of up to 65% have been reported for some field applications of SNCR in tandem with combustion control equipment such as low NO_x burners (LNB) [11]. SNCR systems applied to large combustion units (greater than 3,000 MMBtu/hr) typically have lower NO_x reduction efficiencies (less than 40%), due to mixing limitations [11]. Figure 1.1 presents the NO_x reduction efficiency of SNCR for various utility boiler sizes.

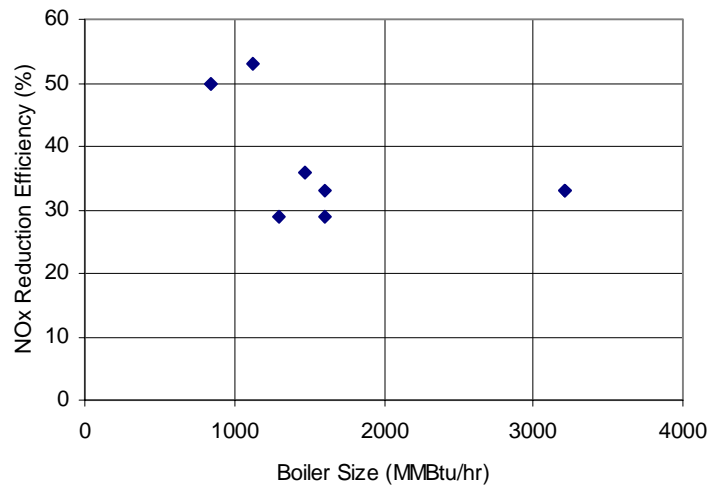


Figure 1.1: SNCR NO_x Reduction Efficiency for Various Boiler Sizes [8]

The hardware associated with an SNCR installation is relatively simple and readily available. Consequently, SNCR applications tend to have low capital costs compared to LNB and SCR. Installation of SNCR equipment requires minimum downtime. Though simple in concept, it is challenging in practice to design an SNCR system that is reliable, economical, simple to control, and 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, dry bottom, wall-fired and tangential, balanced draft boilers. There is little difference between the cost of SNCR retrofit of an existing boiler and SNCR installation on a new boiler [10]. Therefore, the cost estimating procedure is suitable for retrofit or new boiler applications of SNCR on all types of coal-fired electric utilities and large industrial boilers.

1.2 Process Description

SNCR is based on the chemical reduction of the NO_x molecule into molecular nitrogen (N_2) and water vapor (H_2O). A nitrogen based reducing agent (reagent), such as ammonia or urea, is injected into the post combustion flue gas. 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 SNCR process occurs within the combustion unit which acts as the reaction chamber. Figure 1.2 shows a schematic of a boiler interior with SNCR. Reagent is injected into the flue gas through nozzles mounted on the wall of the combustion unit. The injection nozzles are generally located in the post-combustion area, the upper area of the furnace and 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 detail on the SNCR process and equipment is provided in the following sections.

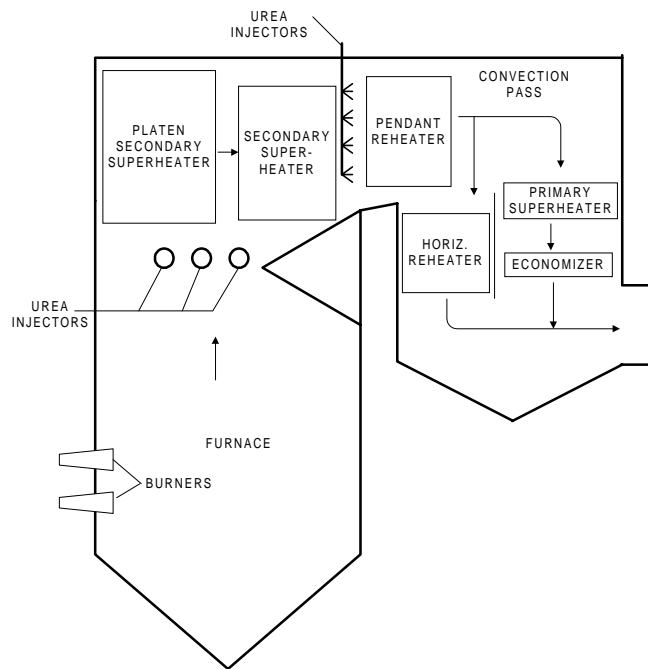
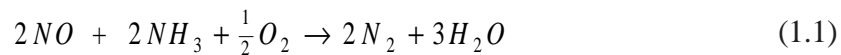


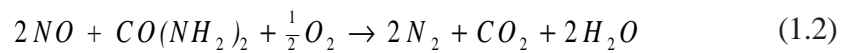
Figure 1.2: Boiler Gas Path Configuration

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 ($\text{CO}(\text{NH}_2)_2$), 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 . The global representation of these reactions is given below for both urea and ammonia. Note that the NO_x is represented as NO since it is the predominant form of NO_x within the boiler. The ammonia reaction equation is given by:



The reaction for urea is given by:



The primary byproduct formed during either ammonia or urea SNCR is nitrous oxide (N_2O). N_2O is an ozone depletor and a greenhouse gas but is currently not regulated. 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 . Proprietary additives are available for the urea-based SNCR process to reduce the formation of N_2O . [10]

1.2.2 Reagents

Both ammonia and urea have been successfully employed as reagents. The cost of the reagent is a large portion of the annual costs of operating an SNCR system. Ammonia is generally less expensive than urea. However, the choice of reagent is based not only on cost but on physical properties and operational considerations. The properties of urea and ammonia in aqueous solutions are shown in Table 1.1.

Ammonia can be utilized in either aqueous or anhydrous form. Anhydrous ammonia is a gas at normal atmospheric temperature. It must be transported and stored under pressure which presents safety issues. Aqueous ammonia is generally transported and stored at a concentration of 29.4% ammonia in water. At concentrations above 28%, storage of ammonia may require a permit, therefore some recent applications of SNCR are using a 19% solution [1]. Decreasing the concentration, however, increases the required storage volume. Ammonia is generally injected as a vapor. Providing sufficient ammonia vapor to the injectors requires a vaporizer, even though the 29.4% solution has substantial vapor pressure at normal air temperatures. The injection system equipment for vapor systems is more complicated and expensive than equipment for aqueous systems (see Section 1.2.4 SNCR System)

Table 1.1: Urea and Ammonia Reagent Properties, [6]

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	29.4% by weight
Ratio of NH ₃ to solution	28.3% by weight of NH ₃	29.4% by weight of NH ₃
Density of solution @ 60° F	71 lb/ft ³	56 lb/ft ³ (58 lb/ft ³ for 19%)
Vapor pressure @ 80° F	< 1 psia	13.9 psia [8]
Crystallization temperature	64° F	- 110° F
Flamability 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.)

Urea is generally utilized in a 50% aqueous solution [1]. At this concentration, the urea solution must be heated and circulated in cold climates due to its low freezing point, 17.8EC (64EF). Higher-concentrations of urea solutions are available which 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. However, to produce aqueous urea for use in the SNCR system, the urea must then be mixed with water at the facility. This mixing process is generally cost prohibitive except for remote sites, large facilities, or facilities where chemical mixing processes are already being performed [13].

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 [1]. Because of these advantages, urea is more commonly used than ammonia in large boiler applications of SNCR systems.

1.2.3 SNCR Performance Parameters

The rate of the reduction reaction determines the amount of NO_x removed from the flue gas. The important design and operational factors that affect the reduction of NO_x by an SNCR system include:

- Reaction temperature range;
- Residence time available in the optimum temperature range;
- Degree of mixing between the injected reagent and the combustion gases
- Uncontrolled NO_x concentration level;
- Molar ratio of injected reagent to uncontrolled NO_x ; and
- Ammonia slip.

Temperature

The NO_x reduction reaction occurs within a specific temperature range where adequate heat is available to drive the reaction. At lower temperatures the reaction kinetics are slow and ammonia passes through the boiler (ammonia slip). At higher temperatures the reagent oxidizes and additional NO_x is generated. The temperature window is dependant on the reagent utilized. Figure 1.3 shows the NO_x reduction efficiency for urea and ammonia SNCR at various boiler temperatures. For ammonia, the optimum temperature is from 870EC to 1100EC (1,600EF to

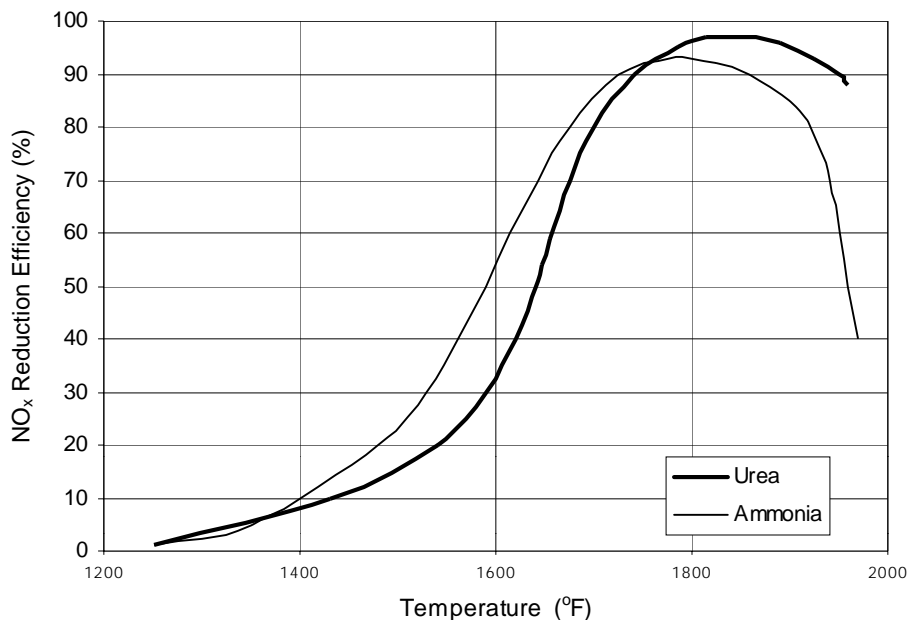


Figure 1.3: Effect of Temperature on NO_x Reduction

2,000EF) [1]. Its optimum temperature range can be reduced by injecting hydrogen gas with the ammonia. For urea, the optimum temperature range is between 900EC to 1150EC (1,650EF to 2,100EF) [1]. Additives to the urea reagent may be used to widen the effective temperature window. These additives are generally proprietary (see Section 1.2.4 Other Considerations).

The reagent is injected into the boiler in regions where the combustion gas temperature is within the specified range. Since reaction temperatures are high, the injection takes place in the boiler itself. In general, the reagent is injected within the boiler superheater and reheater radiant and convective regions, where the appropriate temperature range is typically available [1]. 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. These are generally set to meet steam generation requirements and are not always ideal for the SNCR process. Flue gas temperatures in the upper furnace through the convective pass may vary by ±150EC (300EF) from one boiler to the next [1]. 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.

Residence Time

Residence time is the amount of time the reactants are present within the chemical reactor, the upper area of the furnace and convective passes. Before the reactants exit the boiler, all the steps in the SNCR process must be complete, including:

- Mixing of the injected urea with the flue gas;
- Evaporation of water;
- Decomposition of urea to NH₃;
- Decomposition of NH₃ to NH₂ and free radicals; and
- NO_x reduction reaction chemistry.

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 [1]. However, the gain in performance for residence times greater than 0.5 seconds is generally minimal [10]. Figure 1.4 shows the effect of residence time and temperature on NO_x reduction.

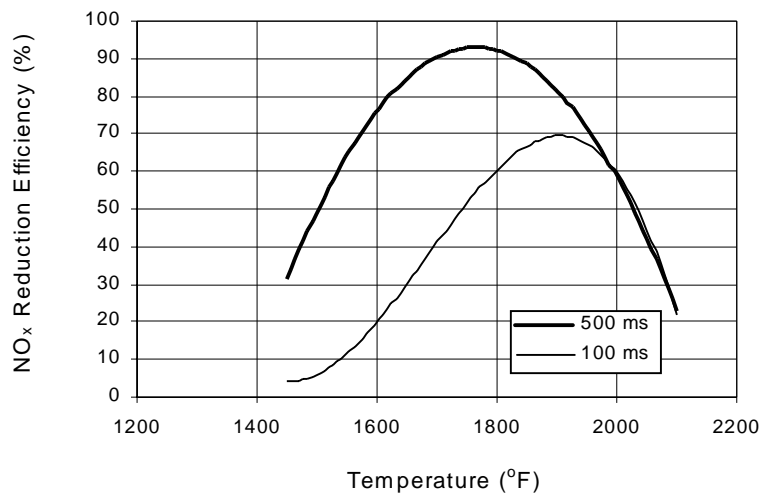


Figure 1.4: Effect of Residence Time on NO_x Reduction

The amount of residence time depends on the dimensions of the boiler gas path and the volumetric flow rate of the flue gas along the boiler gas path. These design parameters are optimized for boiler operations, not the SNCR process. The boiler residence time is set to meet steam generation requirements while maintaining a flue gas velocity to prevent erosion of the watertubes in the boiler. Because of these boiler design requirements, the residence time in the boiler is not always ideal for the SNCR process.

Degree of Mixing

For the reduction reaction to take place, the reagent must be dispersed and mixed throughout the flue gas. The dispersion must occur rapidly due to the volatility of ammonia. The mixing requirements are generally boiler specific and dependant on the air flow profiles through the boiler [1]. Areas of stagnation or high flow must be accommodated. Dispersion and mixing of the reagent and flue gas is more difficult on large boilers due to their size and flow patterns.

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 which 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. [1]

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 which limit the reduction process at low NO_x concentrations [1]. For lower NO_x inlet concentrations, the optimum temperature for the reaction is lower, hence, the percent NO_x reduction is lower. Figure 1.5 shows the NO_x reduction efficiency as a function of temperature for several uncontrolled NO_x levels.

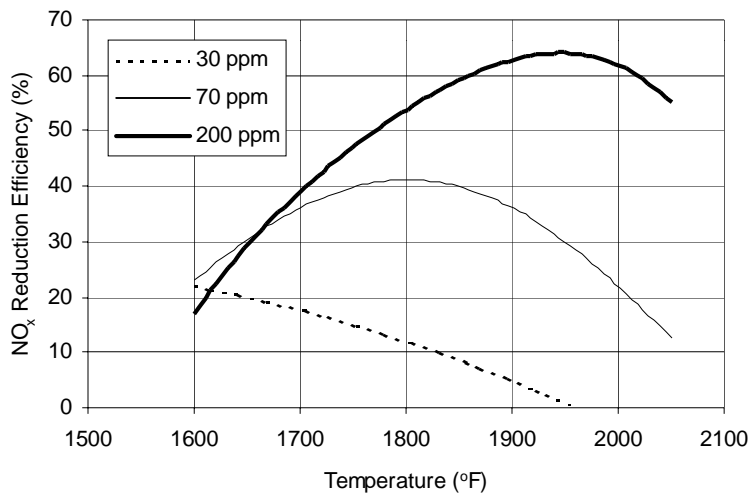


Figure 1.5: Effect of Uncontrolled NO_x Level on NO_x Reduction Efficiency

Normalized Stoichiometric Ratio

The Normalized Stoichiometric Ratio (NSR) defines the amount of reagent needed to achieve the targeted NO_x reduction. Based on reaction equations (1.1) and (1.2), theoretically two moles of NO_x can be removed with one mole of urea or two moles of ammonia. 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 to 3 moles of ammonia per mole of NO_x [10]. 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:

- 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 4-1.1.3 Design Parameters provides further discussion of these influences and a method for estimating the NSR.

Figure 1.6 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.

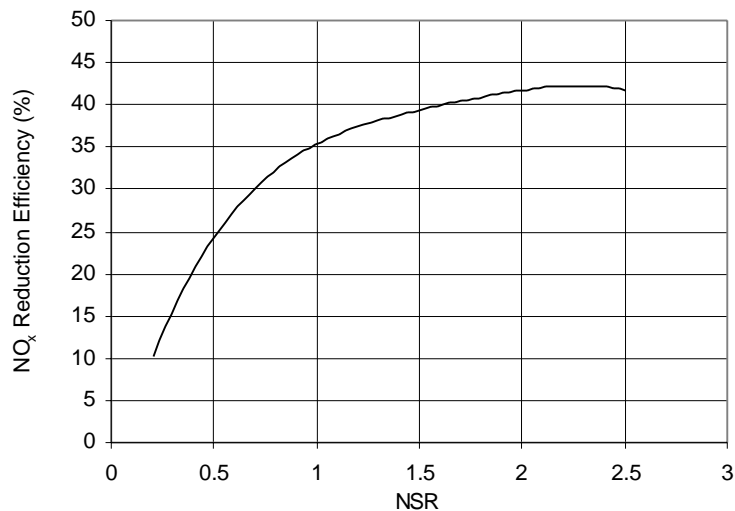


Figure 1.6: Effect of NSR on NO_x Reduction

Ammonia Slip

Typical NSR values require significantly more reagent to be injected in practice than required by the theoretical stoichiometric ratio. In addition, the amount of NO_x removed is generally much less than the amount of uncontrolled NO_x . This leaves a large portion of the injected reagent unreacted. Most of the excess reagent used in the process is destroyed through other chemical reactions. However, a small portion remains in the flue gas as ammonia slip. Figure 1.7 shows an example of the NO_x reduction efficiency which can be achieved for an uncontrolled NO_x level of 120 ppm and various ammonia slip levels.

Ammonia in the flue gas stream has several negative impacts. As shown in Table 1.1, 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. Ammonia-sulfur salts can plug, foul, and corrode downstream equipment such as air heater, 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 in Section 4-1.1.2.4 Other Considerations.

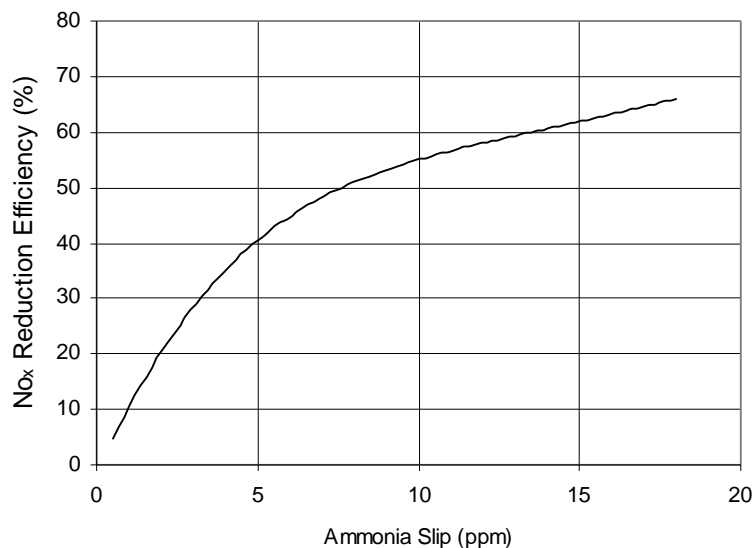


Figure 1.7: NO_x Reduction for Various Ammonia Slip Levels

Limits on acceptable ammonia slip, imposed by either regulatory limits or by design requirements, place constraints on SNCR performance. Injection of urea at higher NSR values can improve NO_x reduction, but may also increase ammonia slip. 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 5 to 10 parts per million (ppm) [12]. Instrumentation for monitoring ammonia slip is currently being developed but not commercially available [11]. One method to quantify ammonia slip is to determine the ammonia concentration in collected fly ash .

1.2.4 SNCR System

There are two basic designs for the application of SNCR. The first is an ammonia based system known as Thermal DeNO_x® that was developed and patented by Exxon Research and Engineering Company in 1975. The second system was developed and patented by The Electric Power Research Institute (EPRI) in 1980. It is a urea-based process known by the trade name NO_x OUT®. The technology was licensed to Fuel Tech, which holds several additional patents that claim improvements and enhancements to the basic process. Fuel Tech has several sub-licensees authorized to supply and install SNCR technology in several industrial sectors.

An SNCR system has four basic steps to accomplish:

- Receiving and storage of the reagent;
- Metering, dilution, and mixing of the reagent;
- Injection of diluted reagent at appropriate locations in the boiler; and
- Mixing of the reagent with flue gas.

These steps are common to both urea and ammonia SNCR. However, the design and equipment specifications for the two systems are different, since ammonia is injected as a vapor while urea is injected as an aqueous solution. Urea is typically used in large boiler applications of SNCR because it is safer to store and has better dispersion properties. A discussion of the SNCR equipment is given below. Figure 1.8 presents a simplified system flow schematic and Table 1.2 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 shops assembly of pumps, valves, internal piping, instruments, and controls reduces field installation time and related costs while providing flexibility for future expansion [1]. 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 1.8 will be discussed further in the next sections.

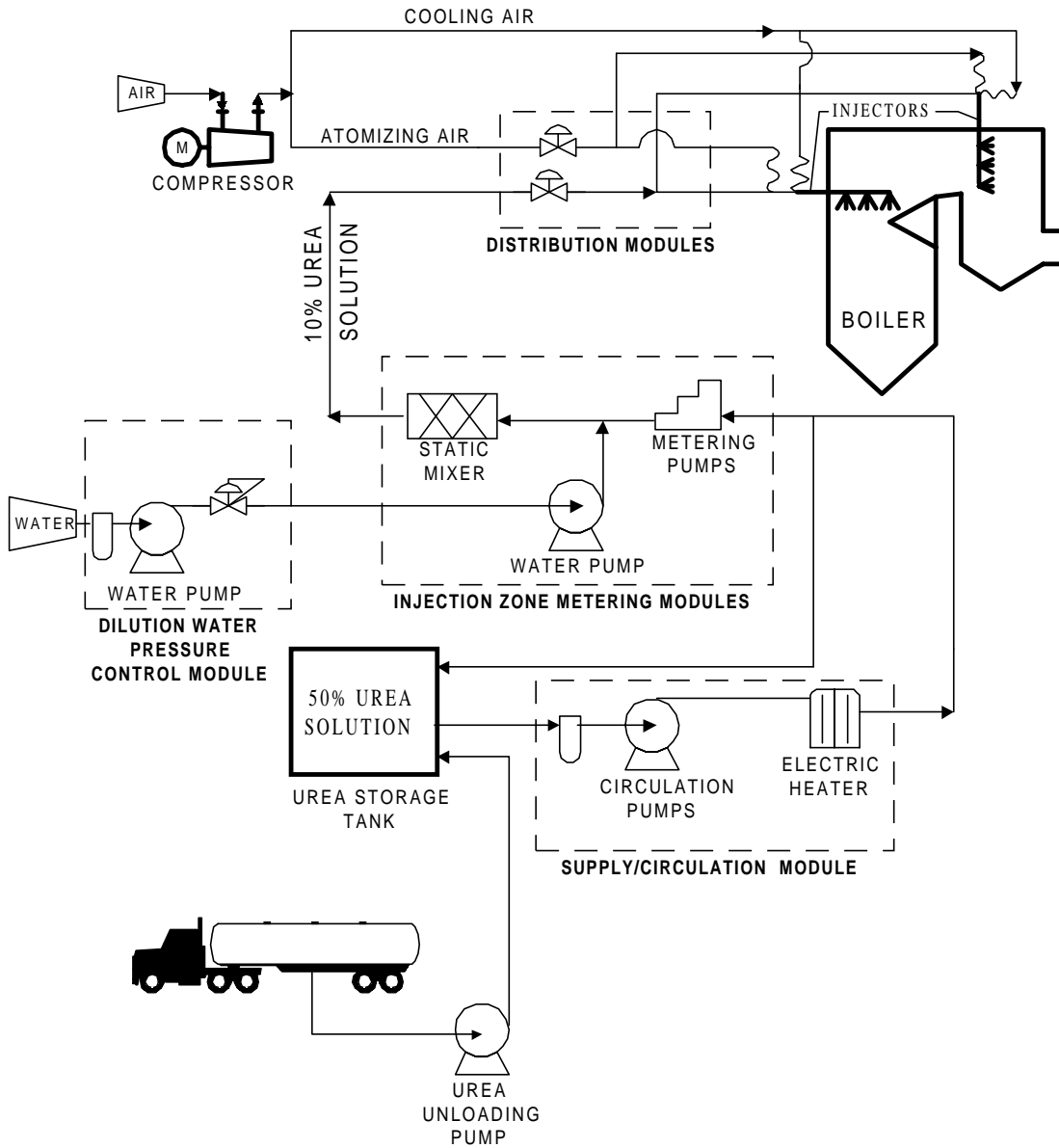


Figure 1.8: Urea SNCR Process Flow Diagram

Table 1.2: 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: <ul style="list-style-type: none"> - Circulation pumps, - Electric heaters, - Insulated/heat traced piping - Isolation valves for pumps and heaters, - Instrumentation for flow, pressure, temperature, and a control panel
Injection zone metering (IAM) modules (1 to 5 modules)	Skid mounted metering modules consisting of: <ul style="list-style-type: none"> - 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 Urea solution distribution module consisting of: <ul style="list-style-type: none"> - Valved connections for urea and atomizing air, - 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)	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 module(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
Economizer outlet emission monitors	Monitor NO and O in the flue gas and provide a feedback signal for urea injection control
Instrumentation and controls	Instrumentation and stand-alone, microprocessor-based controls for the SNCR system with feedback from the plant controls for the unit load, NO 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 re-insulation, for a retrofit installation

from 10,000 to 20,000 gallons per tank to maintain sufficient volume for 1 to 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.

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, in-line duplex strainers, electric heaters, and instrumentation and controls for reagent pressure, flow, temperature, and quantity. [1]

Dilution, metering, and mixing of the reagent

Dilution Water Pressure Control Module

The dilution water pressure (DWP) 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 DWP typically consists of two full-flow multistage stainless steel centrifugal pumps, an in-line 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. [1]

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 DWP module. Each IZM module includes a chemical metering pump, a water pump, an in-line 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 local programmable logic controller (PLC). 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, configuration, the uncontrolled NO_x concentration, and desired NO_x removal efficiency. Several IZM modules can be combined onto one skid-mounted system. [1]

Injection 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. There is one distribution module for each IZM module providing reagent to multiple injectors. [1]

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 between one and five injection zones with 4 to 12 injectors per zone [1]. Injectors are located in open areas of the boiler such as the region between the superheater and reheater sections. Figure 1.2 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 sub-optimal boiler areas decreases the NO_x reduction efficiency which can be achieved by the system while maintaining the required ammonia slip level.

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. Wall injectors are used in smaller boilers and urea based systems, where short-range injection is sufficient to mix the reagent with the flue gas. They have a longer operating life than lance injectors since they are not directly exposed to hot flue gas.

Lance injectors consist of a small pipe which 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. Multi-nozzle lances are more complicated design, therefore, they are more expensive than single-nozzle lance or wall injectors [1].

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 energy 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 since they require a larger compressor, a more robust injection system, and consume more electric power.

The reagent injection systems used for ammonia-based systems are generally more complicated and expensive than those used in urea-based systems [1]. These systems inject gas phase ammonia rather than an aqueous solution. For this reason, 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 convective cavity. Movement and/or removal of existing watertubes and asbestos from the boiler housing may be required. 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. Retrofit installation of the SNCR system generally calls for additional expenditures in the range of 10% to 30% of the SNCR system cost. [10]

Ammonium Sulfate Deposition

Sulfur trioxide (SO_3) forms during the combustion of fuels which 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 which must be disposed 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 a elevated pH levels. Under these conditions, ammonia gas can release 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 salability of the ash as a byproduct and the storage and disposal of the ash by landfill. [10]

Computational Fluid Dynamics 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 computational fluid dynamics (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 (CKM). CKM defines the chemical reactions associated with the SNCR process in the boiler. Analysis of the fuel and flue gas constituents are 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 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. [1]

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 since 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. The increase in annual cost from the usage of additional reagent and enhancer can be significant. Enhancer formulations are generally proprietary. [10]

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. Pre-treatment and injection equipment, pumps, compressors, and control systems, also require electricity. This increased usage of fuel and electricity increases the annual costs required to operate the boiler [1]. Section 1.4.2 Total Annual Costs presents a method for estimating the additional fuel and electricity usage.

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 [5]. 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. [1]

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 EPA report Selective Noncatalytic Reduction for NO_x Control on Coal-fired Boilers [1]. This procedure assumes 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 primary cost estimation parameter in the methodology presented in Reference [1] is the maximum potential heat released by the boiler or heat input rate, Q_B , expressed as million British thermal units per hour (MMBtu/hr). It is obtained from the high 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),

$$Q_B = HHV \dot{m}_{fuel} \quad (1.3)$$

where Table 1.3 gives the HHV for various coals and a conversion of 10^{-6} MMBtu/Btu is required.

Table 1.3: High Heating Values for Various Coals

Type of Coal	Energy Content (Btu/ lb)
Lignite	5000-7500
Subbituminous	8000-10,000
Bituminous	11,000 - 15,000
Anthracite	14,000

If the boiler produces electricity, then its heat input can be estimated using the boiler net plant heat rate, $NPHR$ in Btu per kilowatt-hour (Btu/kWh):

$$Q_B = B_{MW} NPHR \quad (1.4)$$

where B_{MW} is the boiler megawatt (MW) rating at full load capacity. Note that if $NPHR$ is not known (e.g., a cogeneration unit), a value of 9,500 Btu/kWh can be used as a reasonable estimate conversions of 1,000 kW/MW and 10^{-6} MMBtu/Btu are required. Using this value, the heat input rate, Q_B , is:

$$Q_B \left(\frac{MMBtu}{hr} \right) = 95 \left(\frac{MMBtu}{MWh} \right)_{MW} (MW) \quad (1.5)$$

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:

$$CF_{total} = CF_{plant} \times CF_{SNCR} \quad (1.6)$$

For industrial 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). CF_{plant} is given by:

$$CF_{plant} = \frac{\text{actual } m_{fuel}}{\text{maximum } m_{fuel}} \quad (1.7)$$

SNCR can be operated year-round or only during the specified ozone season. 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:

$$CF_{SNCR} = \frac{t_{SNCR}}{365 \text{ days}} \quad (1.8)$$

Uncontrolled NO_x and Stack NO_x

Uncontrolled NO_x, represented as $NO_{x_{in}}$, is the NO_x concentration in the flue gas after any reductions provided by combustion controls, but prior to the SNCR system. The uncontrolled NO_x concentration, obtained from analyzing the boiler flue gas stream, is generally given in pounds per MMBtu (lb/MMBtu) of NO₂ [2].

The stack NO_x, represented as $NO_{x_{out}}$ is the required NO_x emission limit at the stack outlet. It is generally set by the plant or regulatory limits and also given in pounds per MMBtu (lb/MMBtu) of NO₂.

NO_x Removal Efficiency

The NO_x removal efficiency, represented as η_{NO_x} , 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:

$$\eta_{NO_x} = \frac{NO_{x_{in}} - NO_{x_{out}}}{NO_{x_{in}}} \quad (1.9)$$

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). The *NSR* is defined as:

$$NSR = \frac{\text{moles of equivalent } NH_3 \text{ injected}}{\text{moles of uncontrolled } NO_x} \quad (1.10)$$

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 (1.10) are the moles of NH_2 that will be released from the reagent.

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

$$ASR = \frac{\text{moles of reagent injected}}{\text{moles of uncontrolled } NO_x} \quad (1.11)$$

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

$$ASR = \frac{NSR}{SR_T} \quad (1.12)$$

where SR_T is the ratio of equivalent moles of NH_3 per mole of reagent injected. From the chemical formula 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 the *NSR* and the NO_x reduction efficiency as follows:

$$Utilization = \frac{\eta_{NO_x}}{NSR} \quad (1.13)$$

The derivation for this equation is presented in Reference [1].

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 [1]. This procedure was developed using linear regression and *NSR* data from References [2] and [3]. 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 percent NO_x reduction [1]. The equation used to estimate the NSR for urea reagent is where No_{iu} is given in lb/MMBtu.

$$NSR = \frac{[2NO_{x_{in}} + 0.7] \eta_{NO_x}}{NO_{x_{in}}} \quad (1.14)$$

Figure 1.8 provides a graphical representation of this NSR estimation method. Generally, the value of the NSR ranges between 0.5 and 2.0 in industrial and utility boilers with utilization ranging between 25 and 50 percent.

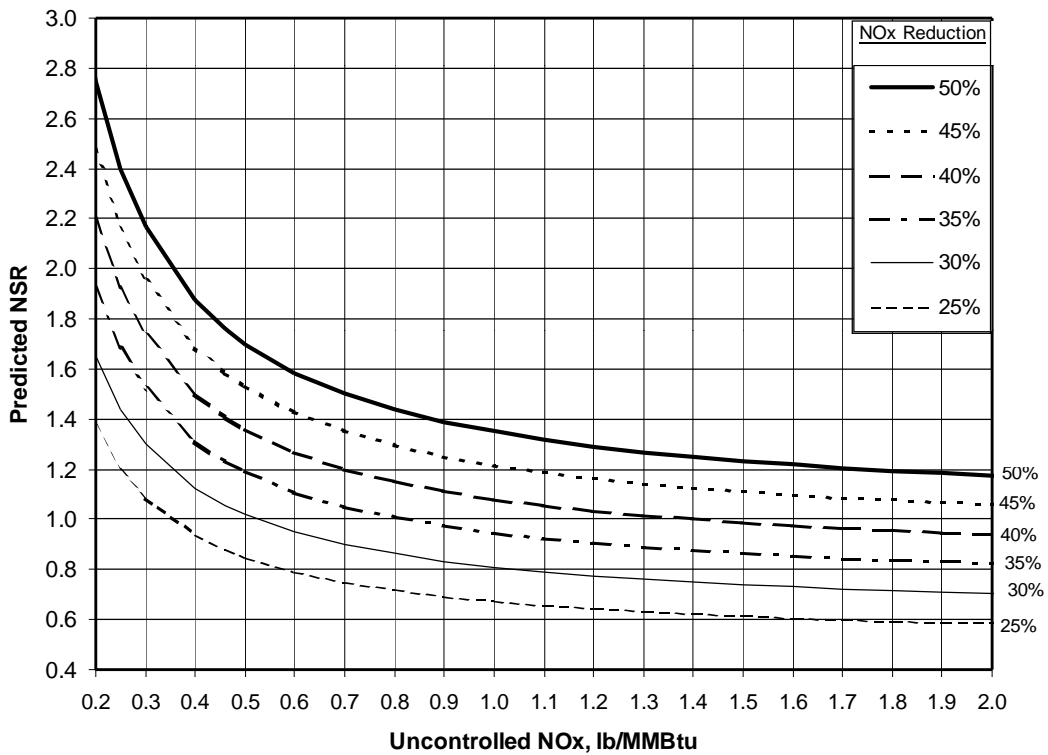


Figure 1.8: Approximate NSR Estimation for Urea

In a design developed by a system supplier, the 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 the 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, the NSR could decrease. However, if the temperature window occurs in the convective section, the 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. The NSR decreases as the degree of mixing increases.

Ammonia slip vs required NO_x reduction. Tighter constraints on ammonia slip would dictate lower NSRs, thereby limiting the achievable NO_x reduction.

Estimating Reagent Consumption and Tank Size

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

$$\dot{m}_{reagent} = \frac{NO_{x,in} Q_B \eta_{NO_x} NSR M_{reagent}}{M_{NO_x} SR_T} \quad (1.15)$$

where the $M_{reagent}$ is the molecular weight of the reagent (60.06 grams per mole for urea, 17.07 grams per mole for ammonia) and M_{NO_x} is the molecular weight of NO₂ (46.01 grams per mole). The molecular weight of NO₂ is used because the NO_x emissions, $NO_{x,in}$, are given in lb/MMBtu of NO₂. As stated previously, SR_T is the ratio of equivalent moles of NH₃ 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:

$$\dot{m}_{sol} = \frac{\dot{m}_{reagent}}{C_{sol}} \quad (1.16)$$

where C_{sol} is the concentration of the aqueous reagent solution by weight.

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

$$q_{sol} = \frac{\dot{m}_{sol}}{\rho_{sol}} \quad (1.17)$$

where ρ_{sol} is the density of the aqueous reagent solution in lb/ft^3 . A conversion of $7.4805 \text{ gal}/\text{ft}^3$ is required to correct the units. given in Table 1.1, $71.0 \text{ lb}/\text{ft}^3$ for 50% urea and $56 \text{ lb}/\text{ft}^3$ for 29% ammonia.

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

$$V_{tank} = q_{sol} t_{storage} \quad (1.18)$$

where V_{tank} is in gallons, q_{sol} is in gph and a conversion of 24 hr/day is required.

Note that the tank volume is typically based on the maximum annual heat input rate, so the capacity factor is not included in Equation 1.18. A common on site storage requirement is for 14 days of SNCR operation.

1.3.2 Design Parameters for Detailed/Performance Specifications

Cost Estimates Based on Detailed Specifications

This subsection is included to describe the information that must be assembled and furnished to a supplier to prepare design specifications, particularly that 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, [1]. 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 convective heat transfer cavities (zones); other unique features, e.g., division wall/panels, etc., in the furnace or backpass;
- Locations of boiler furnace overfire air ports;
- Locations and sizes of boiler observation ports, temperature probe ports, sootblower openings, and other locations for potential new ports;
- Air preheater design and operational data, including sootblower data;
- Fuel Data – proximate and ultimate analyses and high heating value (HHV) for primary and secondary fuels;
- Fuel firing rates at full and partial loads (e.g., 100 percent, 70 percent, and 30 percent);
- 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 O₂, NO_x, CO, SO₂, and HCl;
- Flue gas temperature profile from furnace exit to economizer (i.e., where temperature drops to about 1,400°F) 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., low-NO_x burner, 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 and nitrous oxide.

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 (RFQ) 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 budgetary cost estimates. To simplify the process, a performance specification approach may be used in the RFQ. 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) [1].

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 (other conditions such as dry basis, percent O_2 , per the air permit);
- Guaranteed and expected N_2O emissions (guarantees needed if it is a permit condition);

- Other emission limits as specified (or anticipated) in the permit.
- Normalized stoichiometric ratio (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 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 costs are presented in 1998 dollars.

The cost estimating equations presented in this section are based on equations developed in the draft EPA report *Selective Nuncatalytic Reduction for NO_x Control on Coal-fired Boilers* [1]. These equations follow the costing methodology used by the Electric Power Research Institute (EPRI) [7]. In the EPRI method, both the purchased equipment cost (PEC) and direct installation cost are estimated together. This methodology is different from the EPA Air Pollution Control Cost Manual methodology, which estimates equipment costs and installation costs separately. Due to the limited availability of equipment cost data and installation cost data, the equations for SNCR capital costs were not reformulated.

The capital and annual cost equations were developed for coal-fired wall and tangential utility and industrial boilers with heat input rates ranging from 250 MMBtu/hr to 6000 MMBtu/hr. The SNCR system design used for the cost estimate is an **urea-based system**. An ammonia-based system would have different storage, distribution and injection equipment costs. The cost equations are sufficient for NO_x reduction efficiencies up to 50%. Allowed ammonia slip for the SNCR system ranges from 2 to 10 ppm. [1]

The cost equations are 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 approximately 10% to 30% of the cost of SNCR applied to a new boiler [10].

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 (EC) for the SNCR system itself, the cost of auxiliary equipment, direct and indirect installation costs, additional costs due to installation such as asbestos removal, costs for buildings and site preparation, offsite facilities, land, and working capital. In general, SNCR does not require buildings, site preparation, offsite facilities, land, and working capital. A more detailed discussion of capital costs can be found in Section 1, Chapter 2 of this Manual.

Direct Capital Costs

The direct capital cost equation developed in Reference [1] is based on data for one representative boiler. This data is used to develop an equation for the boiler size range of interest by applying a scaling methodology from the EPRI Technical Assistance Guide (TAG) [3]. The equation assumes that performance parameters vary in direct proportion to the boiler size. The costs are adjusted to 1998 dollars using the Chemical Engineering Cost Index.

The direct capital cost estimate includes PEC such as SNCR system equipment, instrumentation, sales tax and freight. This includes costs associated with field measurements, numerical modeling and system design. It also includes direct installation costs such as auxiliary equipment (e.g., ductwork, compressor), foundations and supports, handling and erection, electrical, piping, insulation and painting. In addition costs such as asbestos removal are included. Table 1.2 presents a list of the equipment and installation requirements for a urea-based SNCR system.

The direct capital cost equation is a function of both boiler heat input rate QB in MMBtu/hr, and the NO_x removal efficiency η_{NO_x} . The boiler heat input rate indicates the size of the boiler and the flue gas flow rate, which directly influence the size of the SNCR system. The NO_x removal efficiency effects both the required urea flow rate and associated urea-related equipment. Increases in the NO_x removal efficiency will require higher urea flow rates and increase the size and/or number of the urea related equipment such as storage tanks. The equation for direct capital cost (DC) of urea-based SNCR in dollars is:

$$DC(\$) = \frac{\$950}{MMBtu} Q_B \left(\frac{MMBtu}{hr} \right) \left(\frac{2375 \frac{MMBtu}{hr}}{Q_B \left(\frac{MMBtu}{hr} \right)} \right)^{0.577} (0.66 + 0.85\eta_{NO_x}) \quad (1.19)$$

where 950 \$/(MMBtu/hr) is the direct capital cost for a 2375 MMBtu/hr boiler at 40% NO_x removal efficiency [1].

Indirect Capital Costs

Indirect installation costs include costs such as; construction and contractor fees, startup and testing, inventory capital, and any process and project contingency costs. As explained in the Manual Section 1 Introduction, average values of indirect installation factors are applied to the direct capital cost estimate to obtain values for indirect installation costs. These costs are estimated as a percentage of the TCI. The equations for indirect installation costs are presented in Table 1.4.

Table 1.4: Capital Cost Factors for an SNCR Application

Description	Data or Formula
Boiler Size (MMBtu/hr)	Q_B
NO _x Removal Efficiency	n_{NO_x}
Cost Year	1998
Total Direct Capital Costs (\$)	$DC(\$) = \frac{\$950}{\text{MMBtu/hr}} Q_B \left(\frac{2375 \frac{\text{MMBtu}}{\text{hr}}}{Q_B} \right)^{0.577} \left(0.66 + 0.85 \eta_{NO_x} \right)$
Indirect Installation Costs	
General Facilities (\$)	0.05 A
Engineering and Home Office Fees (\$)	0.10 x A
Process Contingency (\$)	0.05 x A
Total Indirect Installation Costs (\$)	$B = A \times (0.05 + 0.1 + 0.05)$
Project Contingency (\$)	$C = 0.15 \times (A + B)$
Total Plant Cost (\$)	$D = A + B + C$
Allowance for Funds During Construction (\$)	$E = 0$ (Assumed for SNCR)
Royalty Allowance (\$)	$F = 0$ (Assumed for SNCR)
Preproduction Cost (\$)	$G = 0.02 \times (D + E)$
Inventory Capital* (\$)	$H = Vol_{reagent} (gal) \times Cost_{reagent} (\$/gal)$
Initial Catalyst and Chemicals (\$)	$I = 0$ (Assumed for SNCR)
Total Capital Investment (TCI) (\$)	$TCI = D + E + F + G + H + I$

* Cost for urea stored at site, i.e., the first fill of the reagent tanks

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 product 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 [1]. Each of these costs is discussed in the sections below. A more detailed discussion of capital costs can be found in Section 1, Chapter 2 of this 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).

$$DAC = \left(\begin{array}{c} \text{Annual} \\ \text{Maintenance} \\ \text{Cost} \end{array} \right) + \left(\begin{array}{c} \text{Annual} \\ \text{Reagent} \\ \text{Cost} \end{array} \right) + \left(\begin{array}{c} \text{Annual} \\ \text{Electricity} \\ \text{Cost} \end{array} \right) + \left(\begin{array}{c} \text{Annual} \\ \text{Water} \\ \text{Cost} \end{array} \right) + \left(\begin{array}{c} \text{Annual} \\ \text{Coal} \\ \text{Cost} \end{array} \right) + \left(\begin{array}{c} \text{Annual} \\ \text{Ash} \\ \text{Cost} \end{array} \right) \quad (1.20)$$

Operating and Supervisory Labor

In general, no additional personnel is 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.

Maintenance

The annual maintenance labor and material cost, including nozzle tip replacement for the injectors, is assumed to be 1.5% of the Total Capital Investment, TCI , in dollars. The equation is for annual maintenance cost in \$/hr, AMC , given by:

$$\text{Annual maintenance cost} = 0.015 \text{ } TCI \quad (1.21)$$

Reagent Consumption

The annual cost of reagent purchase in \$/yr is estimated using the aqueous reagent volume flow rate in gph q_{sol} , the total operating time t_{op} in hours.

$$Annual\ reagent\ cost = q_{sol} Cost_{reag} t_{op} \quad (1.22)$$

where $Cost_{reag}$ is the cost of reagent in dollars per gallon (\$/gal) and t_{op} in hours can be calculated using the total capacity fuel or CF_{total} :

$$t_{op} = CF_{total} 8760 \frac{hr}{yr} \quad (1.22a)$$

Utilities

The electrical power consumption 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 [1]. It is based on linear regression of electrical power consumption data correlated to the uncontrolled NO_x concentration in lb/MMBtu, NO_{xin} , the *NSR* and the boiler heat input in MMBtu/hr, Q_B .

$$P = \frac{0.47 NO_{xin} NSR Q_B}{9.5} \quad (1.23)$$

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

$$Annual\ electricity\ cost = P Cost_{elect} t_{op} \quad (1.24)$$

where $Cost_{elect}$ is the cost of electricity in dollars per kW (\$/kw) and t_{op} is defined in equation 1.22a.

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:

$$q_{water} = \frac{\dot{m}_{sol}}{\rho_{water}} \left(\frac{C_{urea\ sol\ stored}}{C_{urea\ sol\ inj}} - 1 \right) \quad (1.25)$$

where ρ_{water} is the density of water, 8.345 lb/gal. For urea dilution from a 50% solution to a 10% solution, Equation (1.25) becomes:

$$q_{water} = \frac{4 \dot{m}_{sol}}{\rho_{water}} \quad (1.26)$$

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

$$Annual\ water\ cost = q_{water} Cost_{water} t_{op} \quad (1.27)$$

where $Cost_{water}$ is the cost of water in dollars per gallon (\$/gal) and t_{op} is given by equation 1.22a.

Coal and Ash

The additional coal 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:

$$\Delta C_{coal} \left(\frac{Btu}{hr} \right) = H_v \left(\frac{Btu}{lb} \right) \times \dot{m}_{reagent} \left(\frac{lb}{hr} \right) \times \left(\frac{1}{C_{urea\ sol\ inj}} - 1 \right) \quad (1.28)$$

where $C_{urea\ sol\ inj}$ is the percent concentration of the injected aqueous urea agent and $\dot{m}_{reagent}$ is the mass flowrate in lb/hr. H_v , the approximate heat of vaporization of water at 310°F, 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 1,500 °F), 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 $H_V = 900$ lb/Btu, Equation (1.28) in MMBtu per hour becomes:

$$\Delta C_{Coal} \left(\frac{MMBtu}{hr} \right) = \frac{900 \left(\frac{Btu}{lb} \right) \dot{m}_{reagent} \left(\frac{lb}{hr} \right) 9}{10^6 \left(\frac{Btu}{MMBtu} \right)} \quad (1.29)$$

As a result of burning additional coal, additional ash is generated. This ash must be disposed or sold as byproduct. This cost methodology assumes that the ash is disposed. The estimated additional ash to be disposed in lb/hr is given by:

$$\Delta A_{sh} = \frac{\Delta C_{Coal} \text{ ash product}}{HHV} \quad (1.30)$$

where *ash product* is the fraction of ash produced as a byproduct of burning a given type of coal to and *HHV* is the high heating value of the coal in Btu/lb as given in Table 1.3.

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

$$Annual \Delta C_{Coal} \text{ cost} = \Delta C_{Coal} Cost_{coal} t_{op} \quad (1.31)$$

where $Cost_{coal}$ is the cost of coal in dollars per MMBtu (\$/MMBtu) Coal is in lb/hr, and t_{op} is given in equation 1.22a.

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

$$Annual \Delta Ash \ cost = \Delta Ash \ Cost_{ash} \ t_{op} \quad (1.32)$$

where $Cost_{ash}$ is the cost of ash disposal in dollars per ton (\$/ton). Ash is in lb/hr and t_{op} is given equation 1.22a. A conversion of 2,000 lb per ton is required to convert \$/ton to \$/lb.

Indirect Annual Costs

In general, indirect annual costs (fixed costs) include the capital recovery cost, property taxes, insurance, administrative charges, and overhead. Capital recovery cost is based on the anticipated equipment lifetime and the annual interest rate employed. An economic lifetime of 20 years is assumed for the SNCR system. (The remaining life of the boiler 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 [9]. The cost of overhead for an SNCR system is also considered to be zero. An SCR 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 pennies per thousand dollars annually [9]. The administrative charges, covering sales, research and development, accounting, and other home office expenses, incurred in operation of an SNCR system are not significant for the cost estimation procedure presented here. 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, $IDAC$, can be expressed as:

$$IDAC = CRF \ TCI \quad (1.33)$$

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:

$$CRF = \frac{i(1+i)^n}{(1+i)^n - 1} \quad (1.34)$$

where i is the assumed interest rate and n is the economic 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:

$$TAC = DC + IDAC \quad (1.35)$$

The tons of NO_x removed annually are:

$$NO_x \text{ Removed} = NO_{x_{in}} \eta_{NO_x} Q_B t_{op} \quad (1.36)$$

where NO_x is given as lb/MMBtu, Q_B as MMBtu/hr and t_{op} in hours and a conversion of 2,000 lb/ton^{kin} is required.

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

$$Cost \text{ Efficiency} = \frac{TAC}{NO_x \text{ Removed}} \quad (1.37)$$

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 1000 MMBtu/hr, wall-fired, industrial boiler firing subbituminous coal. The following assumptions are made to perform the calculations:

Fuel High Heating Value	10,000 Btu/lb
Maximum Fuel Consumption Rate	1.0×10^5 lb/hr
Average Annual Fuel Consumption	4.38×10^8 lb
Number of SNCR operating days	155 days
Uncontrolled NO _x Concentration	0.46 lb/MMBtu
Required Controlled NO _x Concentration	0.30 lb/MMBtu
Percent Fuel Ash Weight	7.5%
Stored Urea Concentration	50% urea solution
Injected Urea Concentration	10% urea solution
Number of Days of Storage for Urea	14 days

In addition to these assumptions, the estimated economic factors required to perform the calculations are taken from References [2] and [3]. These estimates are:

Cost Year	December, 1998
Equipment Life	20 years
Annual Interest Rate	7%
Coal Cost, Eastern Bituminous	1.60 \$/MMBtu
Ash Disposal Cost	11.28 \$/ton
50% Urea Solution Cost	0.85 \$/gal
Water Consumption Cost	0.0004 \$/gal

1.5.1 Design Parameter Example

The boiler annual heat input rate, Q_B , is calculated from the High Heating Value for subbituminous coal given in Table 1.3 and the maximum fuel consumption rate, \dot{m}_{fuel} :

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

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

$$CF_{plant} = \frac{4.38 \times 10^8 \text{ lb}}{1 \times 10^5 \left(\frac{lb}{hr} \right) \times 8760 \frac{hr}{yr}} = 0.5 = 50\%$$

The SNCR system capacity factor is calculated from the months of SNCR operation, 5 months:

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

The total capacity factor including both plant and SNCR capacity factors is given by:

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

The NO_x removal efficiency, η_{NO_x} , is calculated from the inlet NO_x concentration and the required stack NO_x concentration:

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

The equation derived in Reference [1] is used to estimate the NSR for the SNCR system. The estimate is given by:

$$NSR = \frac{\left[\left(2 \times 0.46 \frac{lb}{MMBtu} \right) + 0.7 \right] \times 0.35}{0.46 \frac{lb}{MMBtu}} = 1.23$$

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

$$Utilization = \frac{0.35}{1.23} = 0.28 = 28\%$$

The value of the the NSR indicates that 1.23 moles of NH₃ are required per mole of uncontrolled NO_x to reduce the NO_x level by 35%. This translates to a reagent utilization of 0.28, the ratio of moles of reagent reacted to the moles injected. This indicates that 28% 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 NO₂, 46.01g/mole and the SR_T for urea, 2. For an NSR of 1.23, the reagent mass flow rate is given by:

$$\dot{m}_{reagent} = \frac{0.46 \frac{lb}{MMBtu} \times 1000 \frac{MMBtu}{hr} \times 0.35 \times 1.23 \times 60.06 \frac{g}{mole}}{2 \times 46.01 \frac{g}{mole}} = 130 \frac{lb}{hr}$$

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

$$\dot{m}_{sol} = \frac{130 \frac{lb}{hr}}{0.50} = 260 \frac{lb}{hr}$$

The solution volume flow rate can then be calculated where ρ is the density of the aqueous reagent solution, 71.0 lb/ft³ for 50% aqueous urea solution at 60 °F.

$$q_{sol} = \frac{260 \frac{lb}{hr} \times 7.481 \frac{gal}{ft^3}}{71.0 \frac{lb}{ft^3}} = 27 \text{ gph}$$

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 on site storage requirement is given by:

$$Volume_{tank} = 27 \text{ gph} \times 14 \text{ days} \times \frac{24 \text{ hr}}{\text{day}} = 9072 \text{ gal}$$

The on site storage requirement for urea is 9,072 gallons per 14 days. This shows that for a large boiler, 1000 MMBtu/hr with 35% NO_x removal efficiency the volume of urea required to operate an SNCR system for 155 days during summer months is approximately 10,500 gallons.

An estimates for power consumption is given by:

$$Power = \frac{0.47 \times 0.46 \frac{lb}{MMBtu} \times 1000 \frac{MMBtu}{hr}}{9.5} = 23 \text{ kW}$$

Water consumption, assuming a 50% urea solution stored and a 10% urea solution injected, is:

$$q_{\text{water}} = \frac{260 \frac{lb}{hr}}{8.345 \frac{lb}{gal}} \times \left(\frac{0.5}{0.10} - 1 \right) = 125 \text{ gph}$$

The estimated additional coal and ash required to maintain the same net heat output are given by:

$$\Delta Coal = \frac{260 \frac{lb}{hr} \times 900 \frac{Btu}{lb}}{10^6 \frac{Btu}{MMBtu}} \times \left(\frac{1}{0.10} - 1 \right) = 2 \frac{MMBtu}{hr}$$

$$\Delta Ash = \frac{2 \frac{MMBtu}{hr} \times 0.077 \times 10^6 \frac{Btu}{MMBtu}}{10,000 \frac{Btu}{lb}} = 15 \frac{lb}{hr}$$

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 direct capital costs are estimated using:

$$DC = \frac{\$950}{MMBtu} \times 1000 \left(\frac{MMBtu}{hr} \right) \times \left(\frac{2375 \frac{MMBtu}{hr}}{1000 \frac{MMBtu}{hr}} \right)^{0.577} \times [0.66 + (0.85 \times 0.35)] = \$1,498,152$$

Indirect capital costs are estimated from the direct capital costs using the following equations:

Indirect Installation Costs	
General Facilities (\$)	$\$1,498,152 \times 0.05 = \$74,908$
Engineering and Home Office Fees (\$)	$\$1,498,152 \times 0.10 = \$149,815$
Process Contingency (\$)	$\$1,498,152 \times 0.05 = \$74,908$
Total Indirect Installation Costs (\$)	$\$74,908 + \$149,815 + \$74,908 = \$299,630$
Project Contingency (\$)	$(\$1,498,152 + \$299,630) \times 0.15 = \$269,667$
Total Plant Cost (\$)	$\$149,815 + \$299,630 + \$269,667 = \$719,112$
Preproduction Cost (\$)	$\$719,112 \times 0.02 = \$143,82$
Inventory Capital* (\$)	$9072 \text{ gal} \times 0.85 \text{ \$ / gal} = \$7,711$
Total Capital Investment (TCI) (\$)	$\$719,112 + \$143,82 + \$7,711 = \$741,205$

Annual costs are based on the economic factors listed above. In addition, the SNCR system is assumed to operate for 5 months of the year with a boiler loading of 65%, resulting in a total capacity factor of 27%. The annual variable costs are given by:

$$\text{Annual maintenance cost} = 0.015 \times \$741,205 = \frac{\$11,118}{\text{yr}}$$

$$\text{Annual reagent cost} = 27 \text{ gph} \times 0.85 \frac{\$}{\text{gal}} \times \left[0.21 \times 8760 \frac{\text{hr}}{\text{yr}} \right] = \frac{\$42,218}{\text{yr}}$$

$$\text{Annual electricity cost} = 23 \text{ kW} \times 0.05 \frac{\$}{\text{kW}} \left[0.21 \times 8760 \frac{\text{hr}}{\text{yr}} \right] = \frac{\$2,115}{\text{yr}}$$

$$\text{Annual water cost} = 125 \text{ gph} \times 0.0004 \frac{\$}{\text{gal}} \times \left[0.21 \times 8760 \frac{\text{hr}}{\text{yr}} \right] = \frac{\$92}{\text{yr}}$$

$$\text{Annual } \Delta \text{Coal cost} = 2 \frac{\text{MMBtu}}{\text{hr}} \times 1.60 \frac{\$}{\text{MMBtu}} \times \left[0.21 \times 8760 \frac{\text{hr}}{\text{yr}} \right] = \frac{\$5,887}{\text{yr}}$$

$$\text{Annual } \Delta \text{Ash cost} = \frac{15 \frac{\text{lb}}{\text{hr}} \times 11.28 \frac{\$}{\text{ton}} \times \left[0.21 \times 8760 \frac{\text{hr}}{\text{yr}} \right]}{2,000 \frac{\text{lb}}{\text{ton}}} = \frac{\$156}{\text{yr}}$$

The total variable direct annual cost, the sum of the cost of the reagent, electricity, water, coal and ash, is given by:

$$Total\ Variable\ Cost = (42,218 + 2,115 + 92 + 5,887 + 156) \frac{\$}{yr} = \frac{\$50,468}{yr}$$

and the total direct annual cost is given by the sum of the maintenance and variable cost:

$$Total\ Direct\ Annual\ Cost\ (DAC) = \frac{\$31,748}{yr} + \frac{\$50,468}{yr} = \frac{\$82,216}{yr}$$

Total indirect annual costs assumes that the property tax factor, F_{tax} , and the overhead factor, F_{ovhd} , are both zero. The capital recovery factor, CRF, is defined by:

$$CRF = \frac{0.07 (1+0.07)^{20}}{(1+0.07)^{20} - 1} = 0.09439$$

and the indirect annual costs (IDAC) are calculated by:

$$IDAC = 0.09439 \times \$741,205 = \frac{\$69,962}{yr}$$

The total annual cost is the sum of the direct annual and indirect annual costs given by:

$$TAC = \frac{\$82,216}{yr} + \frac{\$69,962}{yr} = \frac{\$152,178}{yr}$$

The annual cost in terms of NO_x removed can be calculated using the total annual cost and the tons of NO_x removed annually by:

$$NO_x\ Removed = \frac{0.46 \frac{lb}{MMbtu} \times 0.35 \times 1000 \frac{MMbtu}{hr} \left[0.21 \times 8670 \frac{hr}{yr} \right]}{2000 \frac{lb}{ton}} = 147\ tons$$

and

$$NO_x\ Removed = \frac{0.46 \frac{lb}{MMbtu} \times 0.35 \times 1000 \frac{MMbtu}{hr} \left[0.21 \times 8670 \frac{hr}{yr} \right]}{2000 \frac{lb}{ton}} = 147\ tons$$

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(Please read Instructions on reverse before completing)

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