Design and Cost Estimating Procedures for SCR and SNCR Retrofits on Gas- and Oil-Fired Boilers

Technical Report

Design and Cost Estimating Procedures for SCR and SNCR Retrofits on Gas- and Oil-Fired Boilers

1004123

Final Report, September 2002

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This report describes research sponsored by EPRI.

The report is a corporate document that should be cited in the literature in the following manner:

Design and Cost Estimating Procedures for SCR and SNCR Retrofits on Gas- and Oil-Fired Boilers, EPRI, Palo Alto, CA: 2002. 1004123.

REPORT SUMMARY

Utility companies have been reevaluating the feasibility of selective catalytic reduction (SCR) and selective non-catalytic reduction (SNCR) retrofits in order to meet increasingly stringent NO_x emission limits. This report describes two EPRI-developed models for helping utility companies screen the cost effectiveness of SCR and SNCR technologies for application at specific gas- and oil-fired boiler sites.

Background

SNCR and SCR technologies have historically been considered "approaches of last resort" for utility boiler NO_x control because of their relatively high operating costs and, particularly in the case of SCR, high capital costs. SCR and SNCR have commonly been evaluated under the assumption that lower-cost NO_x control techniques—such as low-NO_x burner modifications and flue gas recirculation—would first be fully exploited. This approach to post-combustion NO_x control remains appropriate in many applications, as lower NO_x emissions from the burner zone of the boiler will translate into lower operating costs for SCR and SNCR. Today, however, it is not uncommon for SCR and SNCR to be evaluated along with new combustion NO_x controls to determine an optimum combination of combustion and post-combustion NO_x controls for a given site.

Objective

To develop cost estimating models that will support utility companies in evaluating NO_x compliance options involving SCR and SNCR technologies.

Approach

EPRI developed SCR and SNCR cost models and tested them using design and operating data provided by EPRI-member companies. In formulating these models, EPRI identified and incorporated major design and operating factors that impact cost and would likely be considered in utility retrofit projects. Empirical correlations, engineering estimates, and assumptions have been used where necessary.

Results

This report describes in detail the SCR and SNCR cost models, including key formulas, input parameters, and output values. Model results are presented in terms of capital cost, operating and maintenance costs, and cost effectiveness ($/ton NO_x removed). The report also describes results of intermediate calculations, producing a very "transparent" model that can be scrutinized by the user and used to evaluate tradeoffs or optimize desired parameters by trial and error calculations. The accuracy of cost estimating procedures of this nature is subject to many site-specific technical and economic factors. In general, however, the cost output of the models should be

considered accurate to approximately +/- 20% and thus suitable for use in preliminary screening and budgeting studies.

EPRI Perspective

Both models provide a comprehensive computational procedure for estimating the capital cost of SCR and SNCR retrofit systems on gas- and oil-fired boilers. In the SCR Cost Model, the overall approach consists of first determining the fundamental design and gas treatment conditions of the SCR catalyst, which satisfy the specified SCR emissions and performance requirements. Once the user defines the catalyst conditions, the model then "builds" a retrofit SCR system consistent with the specific boiler characteristics. After specifying and sizing the SCR components, the model estimates component costs using a variety of empirical cost algorithms and cost factors. The SNCR Cost Model estimates the cost of retrofitting SNCR for purposes of incremental NO_x reduction. In such applications ("SNCR Trim"), the SNCR system is typically designed to achieve maximum NO_x reductions in the range of 20 to 30%, while minimizing capital costs by limiting the reagent injection system to a single level of injectors. Additional EPRI resources recommended for use in conjunction with this document include Guidelines for Induced Flue Gas Recirculation—Volume 2: Roadmap for Application of IFGR, (1000450) and Retrofit NO_x Control Guidelines for Gas- and Oil-Fired Boilers Version 2.0 (TR-108181). Recent case studies for application of SCR and SNCR systems include Pacific Gas and Electric Company's Advanced SCR Pilot Plant (TR-108525) and Evaluation of an SNCR Trim System on a 185 MW Tangential Design Coal-Fired Utility Boiler (1006951).

Keywords

Selective Catalytic Reduction
Selective Non-Catalytic Reduction
NO_x Control Technologies
Cost Estimating Models
NO_x Compliance Options
Gas- and Oil-Fired Boilers

ABSTRACT

As NO_x emission limits become more stringent, utilities have reevaluated the feasibility of selective catalytic reduction (SCR) and selective non-catalytic reduction (SNCR) retrofits in order to meet regulatory mandates. To help utilities in this process, EPRI has developed two cost estimating models for screening SCR and SNCR compliance options for application to gas- and oil-fired boilers. The models incorporate major design and operating factors that impact cost and would likely be considered in utility retrofit projects. Model results are presented in terms of capital cost, operating and maintenance costs, and cost effectiveness ($/ton NO_x removed). While the accuracy of cost estimating procedures is subject to many site-specific technical and economic factors, in general, the cost output of the models should be considered accurate to approximately +/- 20% and thus suitable for use in preliminary screening and budgeting studies. EPRI has tested both cost models using design and operating data provided by EPRI-member companies.

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1 INTRODUCTION

Role of SCR and SNCR in NOx Reduction Strategy

Selective Catalytic Reduction (SCR) and Selective Non-Catalytic Reduction (SNCR), and certain "hybrid" combinations of SCR and SNCR, are regarded as commercially proven, post-combustion NOx emission controls for retrofit to gas- and oil-fired power plants. These technologies have historically been considered "approaches of last resort" for utility boiler NOx control because of their relatively high operating costs and, particularly in the case of SCR, high capital cost. Recently, utility companies have been forced to evaluate the feasibility of SCR and SNCR, or to commit to retrofitting these technologies, in order to meet increasingly stringent NOx emission limits.

SCR and SNCR have commonly been evaluated under the assumption that lower-cost NOx control techniques, such as low-NOx burner modifications and flue gas recirculation, would first be fully exploited. This approach to post-combustion NOx control remains appropriate in many applications, as lower NOx emissions from the burner zone of the boiler will translate into lower operating costs for SCR and SNCR. It is not uncommon, however, for SCR and SNCR to be evaluated along with new combustion NOx controls to determine an optimum combination of combustion and post-combustion NOx control for a given site. Such analyses are increasingly required as previously uncontrolled boilers (or boilers with minimal control) are subject to stringent NOx limits. New NOx emission limits in many parts of the country cannot be met with combustion modifications alone, thus requiring more complex system-wide NOx compliance strategies. As the cost and performance of SCR and SNCR have become more predictable, many utility companies have recognized a potential role of SCR (or SNCR), if optimally applied in combination with other NOx controls.

NOx regulations have not only become more stringent in many parts of the country, but have also incorporated system-wide NOx emissions tonnage caps during the ozone season, or have been linked to unit efficiencies with emissions limited to specific levels in lb/MW-hr. As a result, compliance planning cannot just focus on full load NOx emission rates, but must also consider emissions over the entire load range. In this context, the need for incremental, low-cost NOx reduction or "NOx trim" takes on an increased importance. Scenarios that might require a low capital cost approach for NOx trimming include [1]:

- Reduce NOx emissions at low load due to an increase in emissions from high excess air operation for steam temperature control,
- Reduced NOx on high capacity unit(s) to avoid or minimize purchase of NOx credits or unit derate to maintain emissions within a system wide cap, and

- Generate NOx credits from early implementation, with the goal of deferring implementation of capital-intensive NOx control technologies pending further definition of deregulation impacts, or supporting phased installation of SCR systems.

A simplified retrofit design of SNCR technology can potentially address each of these scenarios. The approach would be to minimize the retrofit capital requirement, while sacrificing operational flexibility or accepting somewhat higher operating costs or lower NOx reduction efficiency. For example, a relatively cheap SNCR system with a single level of furnace injectors might be designed to target a specific operating mode as opposed to targeting a broad range of operation requiring multiple levels of injectors. Southern California Edison adopted such an approach in the early 1990s as part of their compliance plan for meeting a phased NOx compliance regulation. The low-capital-cost SNCR systems achieved moderate NOx reductions (20 to 30%) for several years while SCR systems were being built and implemented. Ultimately, the SCR systems provided NOx emission compliance and many of the low-cost SNCR systems were then retired from service.

EPRI SCR and SNCR Cost Models

To support utility companies in evaluating NOx compliance options involving SCR and SNCR, cost estimating models for these technologies were developed by EPRI [1,2]. These models, the subject of this report, are intended to help utility companies screen SCR and SNCR technologies for specific utility boiler sites and NOx control requirements.

The models are described in detail in the following sections, including key formulas, input parameters, and output values. Results are presented in terms of capital cost, operating and maintenance costs, and cost effectiveness ($/ton). The results of intermediate calculations are also described, producing a very "transparent" model that can be scrutinized by the user and used to evaluate tradeoffs or optimize desired parameters by trial and error calculations.

The cost models have been developed and tested using design and operating data provided by EPRI member companies. In developing these models, EPRI has identified and incorporated major design and operating factors, which impact cost and would likely be considered in utility retrofit projects. Empirical correlations, engineering estimates and assumptions have been used where necessary. The accuracy of cost estimating procedures of this nature is subject to many site-specific technical and economic factors. In general, the cost output of the models should be considered to be accurate to approximately +/- 20% and, thus, are suitable for use in preliminary screening and budgeting studies.

Other EPRI Resources

Additional EPRI resources that are recommended for use in conjunction with this document include:

Guidelines for Induced Flue Gas Recirculation – Volume 2: Roadmap for Application of IFGR, EPRI, Palo Alto, CA, 2002. 1000450.

Retrofit NOx Control Guidelines for Gas- and Oil-Fired Boilers Version 2.0, EPRI, Palo Alto, CA. 1997. TR-108181.

Retrofit NOx Control Guidelines for Gas- and Oil-Fired Boilers, EPRI, Palo Alto, CA. 1993. TR-102413.

Pacific Gas and Electric Company's Advanced SCR Pilot Plant, EPRI, Palo Alto, CA. 1997. TR-108525.

EPRI SCR Pilot Program: Niagara Mohawk Oswego Station, EPRI, Palo Alto, CA. 1995. TR-105327.

Guidelines for the Fluid Dynamic Design of Power Plant Ducts, EPRI, Palo Alto, CA. 1998. TR-109380.

Evaluation of an SNCR Trim System on a 185 MW Tangential Design Coal-Fired Utility Boiler, EPRI, Palo Alto, CA. 2002. 1006951.

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SCR DESIGN AND COST ESTIMATING PROCEDURE

This section of the report describes the structure and use of the computational procedure (herein referred to as the SCR Cost Model) for estimating the cost of retrofit Selective Catalytic Reduction (SCR) systems on gas- and oil-fired boilers. The overall approach consists of first determining the fundamental design and gas treatment conditions of the SCR catalyst, which satisfy the specified SCR emissions and performance requirements. Once the catalyst conditions are defined, the model then "builds" a retrofit SCR system that is consistent with the specific characteristics of the retrofit boiler. After the SCR components are specified and sized, component costs are estimated using a variety of empirical cost algorithms and cost factors.

SCR Process

The following subsections describe how the SCR Cost Model defines the SCR catalyst parameters, operating conditions, and performance predictions that are used in subsequent sections to determine retrofit components and cost. This description assumes that the reader has a basic understanding of SCR technology. General descriptions of SCR technology and more details on SCR concepts, design, and operation can be found in *Retrofit NOx Control Guidelines for Gas- and Oil-Fired Boilers Version 2.0,* EPRI, Palo Alto, CA. (TR-108181, 1997) and in other resources listed in the previous section.

Selection of Catalyst Pitch

SCR catalyst is commonly supplied in modules with a grid or "honeycomb" design consisting of numerous parallel flow paths or cells. Such a design is assumed for the SCR Cost Model. These grid-type catalysts are manufactured with various cell sizes. A measure of the cell size is the catalyst "pitch," defined as the width of one cell opening plus the thickness of the cell wall. Pitch values in the range of 3 mm to 5 mm are typically specified for clean gas applications, while a larger pitch (e.g., 6 mm to 7 mm) is required for high-ash oil applications.

While pitch defines the fundamental geometry of the catalyst, the term "space velocity" defines the gas treatment flow conditions. Space velocity is defined as the volume of flue gas at standard conditions treated per hour (ft^3/hr at 60°F) divided by a unit volume of catalyst (ft^3). For a specific catalyst composition and geometry (i.e., pitch), a smaller value of space velocity indicates a larger catalyst volume, increased pressure drop, higher reactive surface area of catalyst, and higher NOx reduction potential. Pitch and space velocity are primary considerations for catalyst design and selection.

From the standpoint of SCR design and operation, a trade-off exists between catalyst pitch size, system pressure drop, and NOx reduction performance. One assessment, based on an evaluation of different catalyst pitch sizes at a constant pressure drop (2-inches water), showed that increasingly smaller pitch catalysts will eventually inhibit NOx reduction performance, while larger pitch catalysts require increasingly more catalyst volume for the same level of NOx performance. As a result, significant cost benefit can be realized through optimization of pitch and space velocity. The SCR Cost Model facilitates optimization by selecting a recommended catalyst pitch size based on fuel type, and allowing the user to iterate on catalyst volume until other SCR performance criteria are met.

For oil-fired applications, sulfur content of the fuel typically limits the catalyst activity that can be utilized due to conversion (oxidation) of SO_2 to SO_3 across the catalyst and the resulting increase in corrosion of downstream equipment. To minimize SO_3 conversion and to reduce the potential for catalyst pluggage from oil ash, a catalyst with a larger pitch and lower catalytic activity may be required. Recent contacts with catalyst vendors, indicated that for gas/oil-fired boilers with less than 100 to 200 hours of oil burning per year, the oil firing will have no significant impact on the catalyst selection process (the primary effect will be a reduction in estimated catalyst life). In such instances, the catalyst could be selected based upon criteria for 100% gas firing. For boilers with more than 100 to 200 operating hours on fuel oil, SCR catalyst with higher pitch is usually selected. The SCR cost model distinguishes between three fuel scenarios and recommends the following catalyst pitch sizes:

Table 2-1
SCR Catalyst Pitch for Different Fuel Scenarios

Fuel Scenario	Catalyst Pitch (mm)
Natural gas only or less than 200 hours per year No. 2 fuel oil.	3.2
Natural gas and more than 200 hours per year No. 2 fuel oil.	3.9
Natural gas and/or No. 6 fuel oil.	5.6

For each of the above scenarios, a catalyst cell wall thickness of 0.6 mm is assumed for purposes of calculating catalyst flow area and space velocity.

Emissions Reduction Performance

A simplified procedure is used for estimating SCR emissions performance, based on curve fits of predicted NO conversion rates [3] for the three catalyst pitch sizes identified in Table 2-1. The NO conversion rate is a function of the catalyst space velocity and flue gas temperature. Thus, the procedure utilized in the SCR Cost Model for estimating the catalyst system performance involves the following steps:

- Calculation of the flue gas flow rate and duct velocity.
- Determination of the catalyst space velocity for a target system pressure drop and specified catalyst pitch size.
- Calculation of the NO conversion and ammonia slip level.

The following sub-sections summarize the calculations associated with each of the above steps.

Flue Gas Flow Rate and Duct Velocity

The total boiler flue gas flow rate (wet standard conditions) is calculated from the specified boiler load and heat rate as follows:

Flue Gas Flow Rate (wscf/hr) = Unit Size (MW) * 1000 (kW/MW) * Heat Rate (Btu/kWh) * F_w (wscf/MBtu) * MBtu/10^6

Where, F_w = EPA F-factor (10,610 for gas or 10,320 for oil)

The flue gas velocity entering the catalyst is then computed based on the SCR reactor inlet dimensions. The user-specified values for reactor width and depth, and the number of reactors, are used to determine total reactor flow area. An inlet flow area aspect ratio of 2.0 is assumed (i.e., width = 2 x depth). The values used must be consistent with the desired SCR reactor configuration (e.g., in-duct, expanded duct, or separate reactor configuration).

Duct Velocity (acf/s) = Flue Gas Flow Rate (wscf/hr) * hr/3600 sec / [Duct Width (ft) * Duct Depth (ft) * No. of Reactors] * [1/(0.999-(0.04976 * O_2)) * (460 + T_{fg})/520] (acf/wcf)

Where, O_2 (% wet) = excess oxygen at SCR inlet
T_{fg} (F) = temperature of flue gas at SCR inlet (F)
Duct Width (ft) = 2 * Duct Depth (ft)

In general, the duct width and depth are selected so as to yield a SCR reactor flue gas velocity of nominally 15 ft/s. The generic layout of an SCR retrofit installation in Figure 2-1 shows the dimensions of the catalyst, reactor housing, and ductwork used in the SCR Cost Model. These dimensions are referred to in the above equation and in subsequent calculations below.

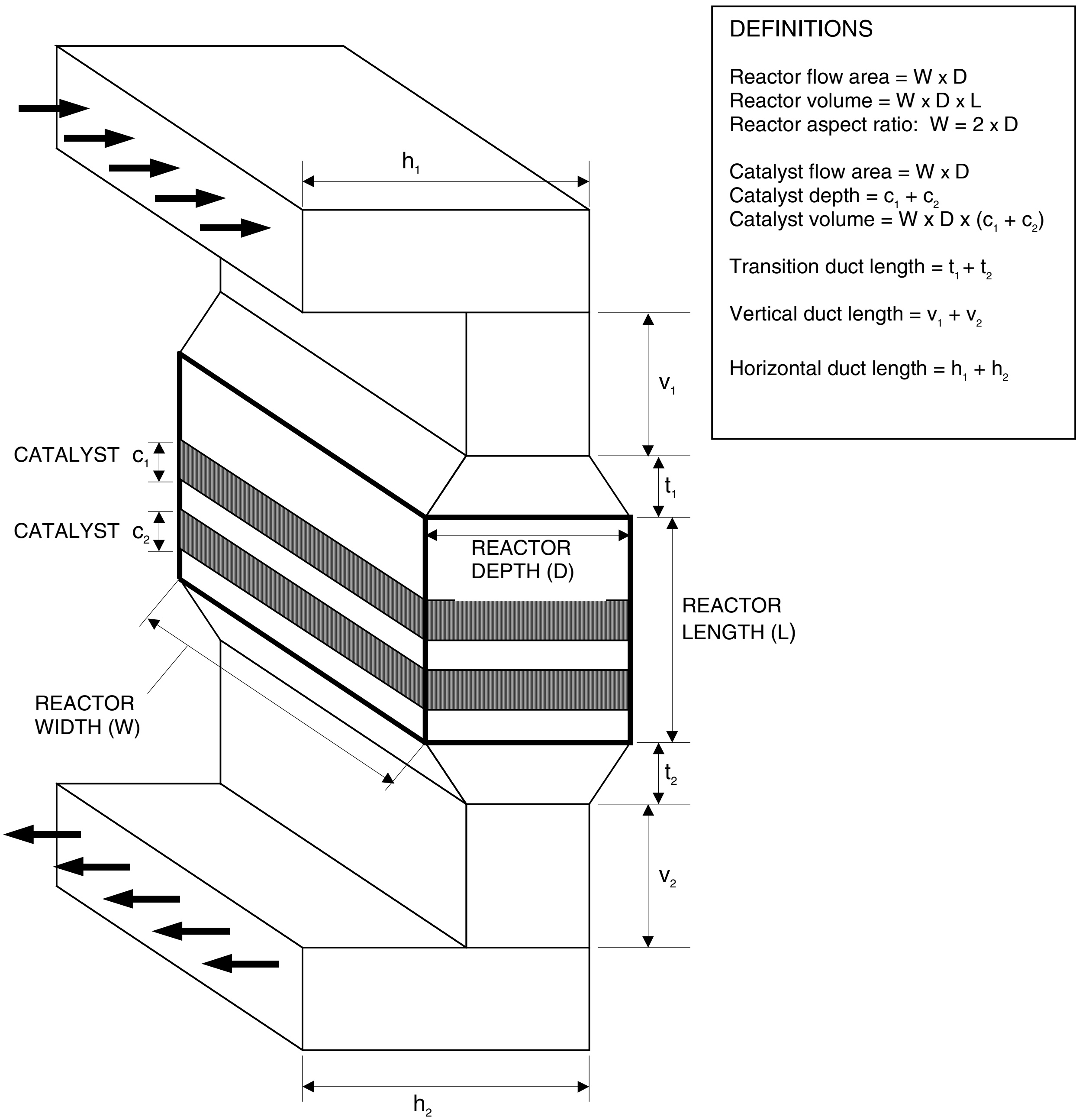

Figure 2-1
SCR Reactor Dimensions

Catalyst Pressure Drop and Space Velocity

The amount of catalyst that can be installed within the ductwork is often limited by the available system pressure drop. The pressure drop associated with a given catalyst is a function of the duct velocity at the reactor inlet, catalyst pitch, and catalyst depth. An estimate of the pressure drop across the catalyst is made from the following formula for laminar flow in a channel:

Catalyst Pressure Drop (i.w.g.) = 32 * μ * L * V / d^2_{eff} (26.12/(g_c * 144)

Where: μ (lbm/ft-s) = flue gas viscosity = ((0.0013 * T_{fg} (F))+1.256)*10^{-5}
T_{fg} (F) = temperature of flue gas at SCR inlet
L(ft) = catalyst length (dimension of catalyst in direction of flow)
V (ft/s) = flue gas velocity in catalyst = duct velocity / % catalyst open area/100
d_{eff} (ft) = catalyst effective diameter = (pitch – wall thickness)
g_c = 32.17 ft-lbm/lb_f s^2

It should be noted that the above procedure does not account for the head loss due to SCR reactor inlet and outlet changes in flue gas velocity. As ductwork designs and associated head losses are site specific, these losses may be estimated at 0.5 i.w.g. Alternatively, the user may reference *Guidelines for the Fluid Dynamic Design of Power Plant Ducts* (TR-109380, 1998) for procedures that quantify head losses as a function of duct design.

The determination of the catalyst space velocity then becomes an iterative process to establish a catalyst volume (e.g., depth for a previously-specified reactor cross sectional area) that yields a target pressure drop for a specified catalyst pitch. The catalyst space velocity is calculated according to the following equation:

Catalyst Space Velocity (1/hr) = (Flue Gas Volumetric Flow Rate (wscf/hr) /
[Catalyst Depth (ft) * Reactor Width (ft) * Reactor depth (ft) * No. of Reactors]

Once a catalyst space velocity has been calculated for a specified pressure drop across the catalyst, an estimate of the NOx reduction potential can then be made as a function of the allowable ammonia slip.

NO Conversion and Ammonia Slip Calculation

The overall SCR NOx conversion (NOx reduction) is defined by the known NOx concentration at the inlet to the SCR reactor and the desired outlet NOx concentration specified by the user:

Specified NOx Conversion (%) = (NOx inlet – NOx outlet)/NOx inlet

The units of NOx may be ppmv or lb/MBtu. To confirm that the SCR catalyst length and space velocity determined above is sufficient to provide the required NOx conversion, the model produces a calculated NOx conversion for comparison. The calculated value is based on the observations that the NO oxidation reaction occurring in the SCR process is “first order” with respect to NO concentration and is independent of ammonia concentration. As a result, a relatively simple mathematical model can be devised on first principles to estimate the NO reduction for a given catalyst pitch size and flue gas temperature. The reaction rate constant used in the model was developed from field data obtained from the advanced SCR pilot plant work conducted at Morro Bay [4]. For estimation purposes, NO conversion models were developed for the three catalyst pitch sizes (3.2 mm, 3.9 mm, and 5.6 mm) over a range of catalyst space velocity and flue gas temperature (e.g., 500 – 750°F). The results were subsequently curve fit as a function of the space velocity, and are presented below:

Table 2-2
NO Conversion Formulas

Catalyst Pitch (mm)	NO Conversion (%)
3.2	$[11.688-.001475 * SV^{0.5} * \ln(SV)]^2 * (1.363-9.27/T^{0.5})$
3.9	$[11.52-0.0015836\ SV^{0.5} * \ln(SV)]^2 * (1.363-9.27/T^{0.5})$
5.6	$[1/(0.0079+2.9465*10^{-8}*SV*\ln(SV))]*(1.363-9.27/T^{0.5})$

In the above formulas,

SV (1/h) = catalyst space velocity
T (F) = temperature of flue gas at SCR inlet

Once the calculated NO conversion is determined from the appropriate equation above and verified to be consistent with the required NOx conversion, the ammonia slip can then be computed for the corresponding ammonia injection normalized stoichiometric ratio (NSR). Should the target NOx reduction not be achievable within constraints imposed by the selected reactor dimensions and allowable pressure drop, the process can be repeated with a larger reactor size and reduced flue gas velocity.

The NSR value is estimated based on the specified NOx conversion. The table below provides general guidelines for selecting a value of NSR for various ranges of NOx conversion.

Table 2-3
Guideline for Estimating NSR Required to Achieve Specified NOx Conversion

Range of NOx Conversion (%)	Assumed NSR
< 50 to 70	NSR = % NOx Conversion / 100
70 to 90	NSR = % NOx Conversion * 1.05 / 100
90 to 95	NSR = % NOx Conversion * 1.10 / 100

The NSR is used to calculate the amount of ammonia injected upstream of the SCR reactor to achieve the specified NOx conversion for the corresponding inlet NOx concentration. The calculation of inlet ammonia concentration must take into account the presence of both NO and NO_2 in the flue gas entering the SCR reactor. The importance of this is that that the NSR for a given concentration of NOx at the inlet to the SCR will be different depending on the relative proportions of NO and NO_2 that comprise the NOx. For example, a flue gas with 35 ppm NOx, of which 7 ppm is NO_2, would have a true NSR of 0.84 as compared to a NSR of 0.9 based on all 35 ppm being NO. The SCR Cost Model assumes that the specified NOx inlet concentration is composed of 95% NO and 5% NO_2. Using the NSR and values of NO (ppmv) and NO_2 (ppmv), the concentration of ammonia at the inlet to the SCR reactor is calculated as follows:

Inlet Ammonia Concentration NH_3 (ppmv) = NSR * (NO + 1.33 * NO_2)

The inlet ammonia concentration, based on an NSR that is less than or equal to one, and NO conversion values calculated above are then used to calculate the concentration of unreacted ammonia at the exit of the SCR reactor (i.e., ammonia slip):

Ammonia Slip NH_3 (ppmv) = (1 – NO Conversion %) * Inlet Ammonia Concentration NH_3 (ppmv)

If the ammonia slip is higher than the target value, it may be necessary to increase the quantity of catalyst and/or reduce the space velocity. The catalyst depth, and/or the dimensions of the SCR reactor inlet, may also be adjusted by trial and error as required, making sure that other performance criteria (e.g., pressure drop) are met.

Based on the amount of catalyst, the ammonia requirement and other process parameters determined above, the SCR Cost Model sizes the SCR system components and computes associated capital and O&M costs as described below.

Impact of Flue Gas Recirculation

For boilers equipped with flue gas recirculation, it is important to design the ammonia injection grid (AIG) to minimize ammonia that is recirculated to the windbox. Recirculated ammonia will increase the NOx formed in the boiler and will require increased SCR ammonia consumption to makeup for the lost ammonia as well as to respond to higher inlet NOx concentration. One assessment [5] indicates that as much as 20% additional NOx (7 ppm increase from a 35 ppm baseline) can result from injected ammonia being entrained into FGR flows to the windbox. The SCR cost model does not account for recirculated ammonia that may be associated with flue gas recirculation and assumes that the AIG will be designed to minimize such occurrences.

Boilers equipped with Induced Flue Gas Recirculation (IFGR) will experience increasingly higher volumetric flow rates of flue gas through the SCR reactor as the IFGR rate is increased. The model does not explicitly handle this situation and users must adjust the gas flow rate through the catalyst to account for the specific IFGR rate. Boilers equipped with conventional (forced) FGR will ordinarily not experience a change in flue gas flow through the SCR catalyst since the flue gas extraction point is upstream of the SCR reactor.

Retrofit SCR System Design

The SCR Cost Model defines the physical characteristics of a stand-alone SCR reactor with support equipment. The procedure adopted within the SCR Cost Model for each of the following components is described below.

- Reagent storage
- Catalyst
- Reactor housing
- Ductwork and insulation

- Structural steel
- Other capital equipment items

Each component is discussed first in terms of how its quantity or size is estimated. The next section then describes the algorithms for estimating the capital cost associated with each component.

Reagent Storage

The reagent storage equipment is characterized by the storage volume, which is based on the computed SCR ammonia requirement, reagent selection (aqueous versus anhydrous ammonia), and number of days of on-site storage specified by the user. The ammonia requirement (lb/hr) is calculated according to the following equation:

$$NH_3 \text{ Requirement (lb/hr)} = \text{NOx (lb/MBtu)} * \text{Heat Input (MBtu/hr)} * \text{NSR} * 17/46$$

The calculation of ammonia storage volume is then performed as outlined in Table 2-4.

Table 2-4
Calculation of Reagent Storage Volume

Reagent	Storage Volume (gal)
Anhydrous Ammonia	NH_3 Requirement (lb/hr) * No. days storage * 5.271
Aqueous Ammonia	NH_3 Requirement (lb/hr)/ NH_3% by Weight * No. days storage * 3.575

The above storage volume requirements include a 20% void volume for anhydrous ammonia, and a 10% void volume for aqueous ammonia. These void volumes are required by code to allow for expansion of the ammonia as ambient temperature increases.

Catalyst

The catalyst is characterized by the volume of catalyst determined previously to provide a specified NOx reduction within acceptable limits of ammonia slip and pressure drop.

$$\text{Catalyst Volume (ft}^3\text{)} = \text{Reactor Width (ft)} * \text{Reactor Depth (ft)} * \text{Catalyst Depth (ft)} * \text{No. of Reactors}$$

The catalyst depth is divided into one or more catalyst layers for purposes of calculating the reactor dimensions below. A maximum depth of 3 feet (1 meter) is assumed for each layer. The number of layers is calculated by dividing the total catalyst depth by 3 and rounding to the next highest integer. Accordingly, the total catalyst depth must exceed 3 feet (1 meter) before a second catalyst layer is added, exceed 6 feet (2 meters) before a third layer is added, and so forth.

Reactor Housing

The reactor housing is characterized by its surface area. To calculate the surface area of a conventional stand-alone SCR reactor housing, the flue gas flow rate (wscfh) is converted from standard to actual flow conditions (acfm), based on the indicated economizer outlet temperature. The cross-sectional area is then estimated by dividing acfm by the velocity of the flue gas entering the reactor. Once the cross sectional area is determined, the dimensions of the reactor housing normal to flow (width and depth) are calculated based on an assumed 2:1 aspect ratio.

The dimension of the reactor housing in the direction of flow (length) is then determined on the basis of the required number of catalyst layers. The overall length of the reactor is defined on the basis of 10 feet (3 meters) for the first catalyst layer plus 5 feet (1.6 meters) for each additional layer. The surface area of the reactor housing is then computed by multiplying the perimeter times the length. Refer to Figure 2-1 for definitions of reactor dimensions.

Table 2-5
Steps in Calculation of SCR Reactor Housing Surface Area

Item	Calculation
Actual Flow Rate (acfm)	wscfh * (flue gas temp + 460)/(520*60)
Reactor Cross Sectional Area (CSA - ft^2)	acfm/(velocity ft/s * 60)
Reactor Depth (ft)	$(CSA/2)^{0.5}$
Reactor Width (ft)	2 * reactor depth
Length of Reactor (ft)	10 + (No. catalyst layers * 5)
Surface Area of Reactor (ft^2)	2 * (Depth + Width) * Length

Ductwork and Insulation

The ductwork is sized to provide flue gas velocities of 60 ft/s. A 2-to-1 aspect ratio is assumed for ductwork dimensions normal to flow. The calculations of ductwork lengths required to connect the SCR reactor to existing flue gas ducts are summarized in the table below. Refer to Figure 2-1 for identification of duct elements.

Table 2-6
Steps in Calculation of Ductwork Length

Item	Calculation
SCR inlet/outlet transition ductwork added to reactor height (ft)	Sqrt(acfm) / 42.4
Horizontal connecting duct length (ft)	2 * reactor depth
Vertical connecting duct length (ft)	Reactor length (Table 2-5) + SCR inlet/outlet transition duct
Transition ductwork Surface Area (ft^2 per transition)	(horizontal + vertical duct length) * 0.707 * sqrt(acfm) * 1.25
Total Ductwork Surface Area (ft^2)	Transition ductwork (ft^2) * 2 * (No. of reactors)
Expansion Joints (ft)	Sqrt(acfm) * .0118 * 6 * 3 * 2 * (No. of reactors)
Insulation	(accounted for in ductwork cost per ft^2)

Structural Steel

The quantity of structural steel for the SCR retrofit is estimated using the formulas summarized in the table below. Catalyst weight is estimated at 20.5 pounds per cubic foot, with the catalyst support steel estimated at 30% of the catalyst weight. Estimates of reactor and ductwork weights are based on the respective surface areas, and a weight of 10.2 lb/ft^2 (based on ¼-inch steel plate) plus 8 lb/ft^2 for insulation (4-inch (10 cm) mineral wool) with lagging. The total supported equipment weight is then summed, and the structural steel requirement is estimated at 50% of this value.

Table 2-7
Steps in Calculation of Structural Steel

Item	Calculation
Equipment Weight (tons):	
- Weight of catalyst	Catalyst volume * 20.5 / 2,000
- Weight of catalyst support steel	0.3 * catalyst weight
- Weight of SCR reactor	(reactor surface area) * (10.2 + 8) / 2,000 * (No. of reactors)
- Weight of ductwork + insulation (reactor inlet and outlet)	(ductwork surface area) + (10.2 + 8) / 2,000 * 2 * (No. of reactors)
Total Supported Equipment Weight (tons)	Sum of Above
Structural Steel Requirement (tons)	0.5 * (total supported equipment weight)

Other Capital Equipment Items

Other system components not explicitly sized but included in the estimated costs via indirect calculation (e.g., scaled from boiler generating capacity) are listed below. The procedures used to estimate their cost are described in the following subsection.

- SCR reagent pumping and injection
- Sootblowers (required for SCR systems operating with #6 fuel oil)
- Asbestos removal (user input cost and required surface area for removal)
- Instrumentation and controls work
- FD fan upgrades (user input option dependent upon current fan conditions and capacity)
- Electrical equipment

SCR Cost Estimate

Capital Cost

The capital cost calculation for a retrofit SCR system is detailed in the table below. Where applicable, algorithms developed from EPRI's UMBRELLA cost estimating software [6] have been applied or modified for gas/oil boiler conditions.

Table 2-8
SCR Capital Cost Components

SCR Component	Capital Cost Calculation ($)
Reagent Storage	Anhydrous NH_3: Storage Volume (gal) * 4.80 + 106,000 Aqueous NH_3: Storage Volume (gal) * 0.75 + 80,750
Ammonia Vaporizer	Ammonia Requirement (lb/hr) * 300 + 50,000
Reagent Storage and Handling	Sum of above two components
Flow Control & Injection System	[Ammonia Requirement (lb/hr) * 360 + 126,000] + [Unit Size (MWg) * 1000]
Catalyst Material	Catalyst Volume (ft^3) * Catalyst Unit Cost ($/$ft^3$)
Reactor Housing	Reactor Surface Area (ft^2) * (No. of Reactors) * $35/ ft^2
Catalyst Sootblowers (for #6 oil operation)	Reactor Width (ft) / 12 * 4 * 15000 * (No. of Reactors)
Ductwork/Insulation	Ductwork Surface area * $35/ ft^2
Asbestos Removal (if required)	Affected Surface Area (ft^2) * $400/$ft^2$
Structural Steel	Structural Steel Requirement (tons) * $3,000/ton
Instrumentation and Control	$1/kW * Unit Size (MWg) * 1000
FD Fan Upgrade (if required)	Low-Cost: $3.5/kW * Unit Size (MWg) * 1000 High-Cost: $7.5/kW * Unit Size (MWg) * 1000
Electrical Equipment	$1/kW * Unit Size (MWg) * 1000
Construction	- see below -
Other Major Site Factors	(User Specified $)
Total Process Capital (TPC)	Sum of Above Components ($)
Indirects and Mark-up	15% of TPC
Contingency	12.5% of TPC
Engineering	17.5% of TPC
Total Capital Cost	Sum of TPC, Indirects, Contingency, and Engineering

NOTE: Underlined items in above table indicate user-specified cost factors.

Reagent Storage and Handling Capital Cost

The reagent storage cost formulas were developed from information provided by a reagent supplier. As mentioned above, the storage volume and corresponding capital cost include a 20% void volume for anhydrous ammonia, and a 10% void volume for aqueous ammonia. The vaporizer cost was based on EPRI member input.

Flow Control and Injection

These costs include the ammonia pumping skid, ammonia piping to the duct, and the injection grid. The latter is based on a cost of $1/kW.

Catalyst Material

The catalyst material cost is simply the multiplication of the required catalyst volume -- calculated to provide a specified NOx reduction within acceptable bounds of ammonia slip and pressure drop -- by the unit catalyst cost ($\$/ft^3$). A "default" unit cost of $\$400/ft^3$ is recommended, unless a site-specific market cost is available.

Reactor Housing

The cost of the reactor housing is directly proportional to its surface area. The cost of the reactor housing material is obtained by multiplying the reactor surface area by an estimated $\$35/ft^2$ for 1/4-inch (0.6 cm) steel plate with 4-inch (10 cm) mineral wool insulation and lagging.

Catalyst Sootblowers

It is assumed that SCR systems operating with #6 fuel oil firing will require sootblowers to remove oil ash deposition on catalyst surfaces in order to maintain catalyst activity and pressure drop. The recommended sootblower retrofit cost is a function of the reactor width, number of catalyst layers, and the number of reactors. It should be noted that actual sootblower requirements would depend on fuel composition (e.g., actual ash content) and duration of oil burns if also firing gas.

Ductwork/Insulation

The ductwork and insulation costs are for a stand alone reactor with inlet and outlet ductwork sized to provide flue gas velocities of 60 ft/s. Cost of the ductwork and insulation is the total ductwork surface area (ft^2) multiplied by $\$35/ft^2$.

Asbestos Removal

Asbestos abatement cost is calculated by multiplying a user-specified affected surface area (ft^2) by an asbestos removal cost factor ($\$/ft^2$). A "default" asbestos removal cost factor of $\$400/ft^2$ is recommended, based on utility company experience. A site-specific cost factor may be substituted, if available.

Structural Steel

The total weight of structural steel (tons) determined in the previous subsection is multiplied by a cost factor of \$3,000/ton to determine the cost of structural steel.

Instrumentation and Control

An instrumentation and control (I&C) cost of \$1/kW is generally representative of industry experience. Depending on the scope of modification or replacement of instrumentation and controls, this user-specified value may be adjusted.

FD Fan Upgrade

Two FD fan upgrade options are specified in the cost model. A low-cost upgrade (\$3.5/kW) corresponds to a minimal modification of the FD fans, which would typically include re-tipping fan blades, rewinding the motors, and modifying the fan foundations. A high-cost upgrade (\$7.5/kW) corresponds to more extensive modifications such as rotor and/or motor replacement and conversion to variable-speed drive.

Electrical Equipment

An electrical equipment cost of \$1/kW is considered representative of industry experience. Depending on the scope of electrical work, this user-specified value may be adjusted. The extent of electrical rerouting due to new footings, ductwork, or foundations is a major retrofit consideration that will impact this cost.

Construction

The procedure for estimating construction costs is summarized in the following table. It is assumed that the construction costs consist mainly of labor for demolition and installation. The procedure includes estimates of construction labor for major SCR system components and multiplication of these hours by various cost factors, as indicated.

Table 2-9
Construction Cost Calculation

Construction Cost Component	Construction Cost Calculation ($)
Ammonia Storage and Handling System Installation Labor (hrs)	1,000 hrs
Catalyst Installation Labor (hrs)	Catalyst Weight (tons) * 24 hrs/ton
Reactor Housing Installation Labor (hrs)	[Catalyst Support Steel (tons) + Reactor Weight (tons)] * 80 hrs/ton
Ductwork Steel Installation Labor (hrs)	Ductwork & Insulation Weight (tons) * (10.2/18.2) * 70 hrs/ton
Insulation & Lagging Installation Labor (hrs)	[Reactor Surface Area (ft^2) + Ductwork Surface Area (ft^2)] * 0.75 hrs/ft^2
Structural Steel Installation Labor (hrs)	Structural Steel Weight (tons) * 20 hrs/ton
Total Construction Labor (hrs)	Sum of above
Wage Rate ($/hr)	$54.60/hr
Non-Electrical Labor Cost ($)	Total Construction Labor (hrs) * Wage Rate ($/hr) * 1.2 * Retrofit Difficulty Factor
Electrical Labor Cost ($)	[I&C Capital Cost ($) + FD Fan Upgrade Cost ($)] * 0.4 * Retrofit Difficulty Factor
Total Labor	Non-Electrical Labor Cost ($) + Electrical Labor Cost ($)

NOTE: Underlined items in above table are recommended based on utility experience, but may be modified for specific sites. Adjust the Retrofit Difficulty Factor as explained in the text.

The retrofit difficulty factor in the above formulas is subjective and generally hard to quantify for a specific retrofit project. It is recommended that this factor be determined by trial-an-error. Utility experience indicates that the total construction costs for SCR retrofits on gas-fired boilers represent approximately 40% of the Total Capital Requirement (TCR). Therefore, it is recommended that the retrofit difficulty factor be treated as a variable input in the cost model and adjusted until the computed construction costs are 40% of the TCR. This approach, in effect, eliminates the uncertainty in defining the retrofit difficulty factor, while still providing a breakdown of the construction component costs.

Other Major Site Factors

The user may specify costs for significant items not accounted for in the above calculations. Such items may include relocation of air heater(s) and fan(s), and economizer bypass for SCR temperature control.

Indirects and Mark-Up

The user specifies a percentage of the TCR to account for project indirect costs, taxes, and markups. A value of 15% is recommended, unless a project-specific value is known.

Contingency

Project contingency accounts for miscellaneous known or undefined costs that may include project mobilization, equipment rental, scaffolding, flow modeling and testing, permitting, and startup and commissioning. A value of 15% of TCR is recommended, unless a project-specific value is specified.

Engineering

Based on utility experience, a value of 17.5% of TCR is recommended.

O&M, Annualized, and Seasonal Costs

The O&M costs consist of the cost components shown in the table below, along with the corresponding estimating procedure. The unit capacity factor present in some of the calculations is varied by the user to reflect the time period for the cost analysis. For example, an annual capacity factor is used to compute annual O&M costs, whereas a capacity factor for the ozone season is used when estimating the O&M costs for the ozone season. The time period (hrs/yr) for specific calculations are also adjusted to reflect annual or ozone season.

Table 2-10
O&M Cost and Annualized (or Seasonal) Cost Estimating Procedure

Cost Component	Cost Calculation
Ammonia Reagent ($)	Ammonia Requirement (lb/hr) * Time Period (hrs) * Capacity Factor(%) / 100 * Ammonia Cost ($/dry ton) / 2000 lb/ton
Ammonia Injection Grid Tuning and Ammonia Slip Testing ($)	$50,000 (Optional)
Catalyst Cost ($)	Catalyst Capital Cost ($) * Time Period (hrs) * Capacity Factor(%) / 100 / Catalyst Guarantee Life (hrs)
Energy Cost ($)	Power Consumption (kW, Table 2-11)* Time Period (hrs)* Capacity Factor (%) / 100* Energy Cost ($/kWh)
Maintenance Labor & Material ($)	0.10 * [Ammonia Storage & Handling Capital Cost ($) + Flow Control & Injection Capital Costs ($)] + 0.20 * I&C Capital Costs ($)
Annual (or Seasonal) O&M Cost ($)	Sum of Above
Annualized Capital Cost ($)	Total Capital Cost ($) * Annualized Cost of Capital (%) / 100
Total Annual (or Seasonal) Cost ($)	Annual O&M Cost ($) + Annualized Capital Cost ($)
Cost Effectiveness ($/ton of NOx Removed)	[Total Annual (or Seasonal) Cost ($)] / [NOx Reduction (tons/year or tons/season – See below)]

NOTE: Underlined items in above table are user-specifiable. A catalyst guarantee life of 24,000 hours is recommended in the absence of site-specific vendor guarantees.

The annual (or seasonal) NOx reduction in tons, used in the above table, is calculated as follows:

> NOx Reduction (tons) = Inlet NOx (lb/MBtu) * Boiler Heat Input (MBtu/hr) / 2000 lb/ton * Time Period (hours) * Capacity Factor for Time Period (%) / 100 * NOx Removal Efficiency (%) / 100

The power consumption used to calculate the cost of power is estimated using the formulas in the following table.

Table 2-11
Power Consumption Estimate

Power Consumption Component	Power Consumption Calculation (kW)
ID Fans (kW)	Flue Gas Flow (acfm) * SCR System Pressure Drop (i.w.g.) / 6350 / 0.7 * 0.746
Reagent Vaporizer (kW)	Ammonia Requirement (lb/hr) / 2000 * 0.5 * 2000
Auxiliary Power (kW)	User specified kW
Total Power Consumption (kW)	Sum of Above (kW)

The capacity factor method used above to calculate annual or seasonal costs is commonly used in economic estimating procedures. In this approach, certain variables are based on boiler full load conditions. The potential load-dependence of these variables is neglected for simplicity. For example, the cost model does not take into account the variability in SCR process variables (e.g., NSR and pressure drop) or NOx inlet concentration (lb/MBtu) as a function of load. This results in inherent inaccuracies in the cost model, but such inaccuracies are consistent with the preliminary cost-screening objectives of the model.

Summary of Model Input Data

The following table summarizes the minimum input data required for the SCR Cost Model. Certain parameters not listed in the table are user-specifiable, but recommended "default" values presented in preceding subsections will generally be suitable for cost estimating purposes.

Table 2-12
Summary of Input Data

Input Variable	Units	Comment
Unit Size	MW (gross)	
Heat Rate	Btu/kWh	
Fuel Option	(1) 100% gas or less than 200 hours per year low sulfur #2 oil; (2) Natural gas and greater than 200 hours per year low sulfur #2 oil; or (3) Natural gas and/or #6 fuel oil	Fuel selection determines catalyst pitch size, catalyst activity, and requirement of catalyst sootblowers
Excess Oxygen at SCR Inlet	%, wet basis	
Reactor Depth	ft	Iterate on this parameter until desired duct velocity is obtained. Refer to Figure 2-1 for depiction of Depth.
Flue Gas Temperature	Deg-F	Temperature at SCR inlet
Total Catalyst Depth	ft	Iterate on catalyst depth until target NO conversion, pressure drop, and ammonia slip are met
SCR Inlet NOx	Lb/MBtu	
Design SCR Outlet NOx	Lb/MBtu	
Asbestos Abatement	Yes or No	
Surface Area Requiring Asbestos Removal	ft^2	
Asbestos Removal Cost	$/ ft^2	$400/$ft^2$ recommended
Low-Cost FD Fan Upgrade Required	Yes or No	
High-Cost (Complete) FD Fan Upgrade Required	Yes or No	
Number of SCR Reactors per boiler	_	Typically "1" or "2"
Ammonia Injection Normalized Stoichiometric Ratio (NSR)	_	Refer to text for guidelines on estimating NSR
Number of Ammonia On-Site Storage Days	_	Typically 7 days
Type of Ammonia Reagent	(1) Anhydrous Ammonia or (2) Aqueous Ammonia	
Catalyst Unit Cost	$/$ft^3$	Suggested value is $400/$ft^3$
Retrofit Difficulty Factor	_	Iterate on this parameter until construction costs equal 40% of total capital requirement
Wage Rate	$/hr	
Capacity Factor (annual)	%	
Capacity Factor (seasonal)	%	Required if seasonal cost estimate is sought (e.g., ozone season)
Ammonia Cost	$/dry ton	$350/dry ton typical cost
Energy Cost	$/kWh	
Annualized Cost of Capital	%	12% "default" value

Comparison of Model Predictions and Commercial Estimates

As indicated previously, the SCR Cost Model incorporates information from various engineering estimates of retrofit SCR systems provided by EPRI members. The development of the model evolved as member information and recommendations were evaluated and revisions to the model were tested against architectural and engineer (A&E) cost estimates and criteria. During this period, model cost estimates were made for several retrofit projects that were in preliminary (e.g., "Level 1") design stages. Both A&E and model cost estimates changed as the project scopes became more defined and as the model was refined. The estimated costs varied considerably over time, emphasizing the fact that actual project cost estimates vary during the initial phases of a project. Some A&E cost estimates decreased over this time by approximately 15%, while model predictions increased by 30% to 50% as retrofit scope was clarified and cost estimating procedures were modified.

The final version of the SCR Cost Model was used to predict the costs of two retrofit SCR projects, which had progressed to final design or initial construction. The predicted costs were compared to the A&E cost estimates, which at this stage in the projects were considered very well defined ("Level 2" or "Level 3" estimates). The major characteristics of each project (denoted as Unit A and Unit B) are summarized in Table 2-13.

Table 2-13
Project Case Studies for Retrofit SCR Cost Comparisons

Project Characteristic	Unit A	Unit B
Unit Size (MW gross)	770	132
Fuel	Gas; #2 oil backup	Gas
No. SCR Reactors	2	2
FD Fan Upgrade	Yes	No
Asbestos Removal	No	No
SCR Inlet NOx (lb/MBtu)	0.17	0.09
Design NOx Removal (%)	90	90

The SCR Cost Model predictions and A&E cost estimates for the two projects are summarized in Tables 2-14 and 2-15. In each project, the model predictions are broken out into cost elements for comparison with corresponding cost categories used in the A&E estimates.

For each project, the SCR Cost Model predicted a higher cost that the A&E estimate. This is not believed to be a generic tendency of the model. More importantly, the model results are in good agreement with the A&E estimates. The latter are lower than the model predictions by 23% and 18% as shown in the tables. These differences are reasonably expected, considering the complexity of the model and the SCR retrofit projects. Moreover, the close agreements indicate that the model is suitable for performing preliminary (e.g., "Level 1") economic analyses with nominal 20% accuracy, as intended.

Table 2-14
Unit A – Comparison of SCR Cost Model and A&E Cost Estimate

Acct	Item	Differential	A&E Cost, $ 05-Sep-2001	SCR Model, $	SCR Model, $ Breakdown	SCR Model Cost Item
100	**Demolition and Modifications**	-10.7%	2,394,800	3,080,000	3,080,000	Demolition @ $4/kW
	Demo existing ductwork					
	Piping relocation					
	Economizer modifications					
	Mech equip and utility relocation					
	Electrical demolition					
	New cable, cable tray, and junction boxes					
126	Boiler Reinforcement		387,000			
200	**Ductwork and SCR Reactor**	22.7%	7,707,600	5,959,002		
	Gas ductwork from econ outlet to SCR				180,120	Reactor Housing
	SCR reactor				4,299,447	Ductwork/Insulation
	Gas ductwork between SCR & air heater				1,479,435	Structural Steel
	Structural support steel for all ductwork					
400	**Mechanical Equipment**	6.1%	4,092,300	3,935,058		
	FD Fan modification				321,981	Reagent Storage & Handling
	Aqueous ammonia system				1,052,931	Flow Control & Injection system
	Catalyst				2,560,146	Catalyst
	Demolition assoc. with FD fan motors & drives		100,000			
500	**Civil Structural**	-21.5%	950,400	1,155,000	1,155,000	@1.5/kW
	Piling and foundation for ductwork and supports					
	Misc. civil/foundation work					
600	**SCR Electrical**	35.1%	5,340,000	3,465,000		
	SCR electrical equip, fixtures, and cable					
	Motors and adj speed drives				2,695,000	FD Fan Upgrades
	Electrical				770,000	Electrical equipment
	FD fan and installation					
	Electrical testing					
700	**Instrumentation**	-22.6%	627,900	770,000		
	Instrumentation equipment				770,000	I&C
	DCS control system interfacing					
	NOx analyzers					
	O2 monitoring					
	Instruments and transmitters					
	Fdwtr flow straightener					
	Fan annunciator					
	Instrumentation testing					
800	**Misc Construction Costs**	-157.8%	5,760,000	14,850,000		Construction
	mobilization					
	eqpt rental (including cranes)					
	misc permits					
	start-up					
	additional overtime labor costs					
	spare parts		500,000			
900	**Indirect Costs**					
	Owner's cost/sales tax	-9.7%	3,026,000	3,320,000		Indirects & Mark-ups
	Engineering	-8.9%	2,856,200	3,320,000		Engineering
	Field Services		193,800			
	Contingency	-22.3%	2,714,300	3,320,000		Contingency
	Total	-17.8%	36,650,300	43,174,060		

Table 2-15
Unit B – Comparison of SCR Cost Model and A&E Cost Estimate

A&E Cost Item	Differential		A&E Cost, $	SCR Model,$	Model Cost Item
			11-Mar-2002		
Major Equipment (purchase)		2,841,369			
Major Equipment (installation-material)		40,704			
Construction Management/Indirects		40,441			
Construction Equipment		130,249			
Subtotal 1	-24.5%		3,052,762	3,800,006	Category 1 (see box below)
Sitework and Concrete		31,606			
Piping		191,413			
			223,018	396,000	Civil & Structural
Structural Steel			95,098	634,818	Structural Steel
Electrical			91,017	264,000	Electrical Equipment
Instrumentation			99,035	264,000	I&C
Construction Field Labor		754,919			
Construction Management/Tech Support		678,078			
Labor - Major Equipment Install		538,422			
Labor - Sitework and concrete		138,529			
Labor - Structural Steel		86,656			
Labor - Piping		321,287			
Labor - Electrical		201,783			
Labor - Instrumentation		122,011			
Construction Subtotal	-24.1%		2,841,685	3,525,494	Construction
Subtotal 2	-51.8%		3,349,854	5,084,312	
Engineering & Design			1,690,918	888,432	
Indirects & Mark-ups				888,432	
Contingency			1,303,183	888,432	
Subtotal 3	11.0%		2,994,101	2,665,296	
Total (Subtotals 1 + 2 + 3)	-22.9%		9,396,717	11,549,614	
Multiplier	1.3911				

Category 1	SCR Model, $
Reagent Storage & Handling	302,232
Flow Control & Injection System	552,772
Catalyst	930,240
Reactor Housing	155,344
Ductwork & Insulation	1,859,418
	3,800,006

3
SNCR DESIGN AND COST ESTIMATING PROCEDURE

This section of the report describes the structure and use of the computational procedure (herein referred to as the SNCR Cost Model) for estimating the capital cost of retrofit Selective Non-Catalytic Reduction (SNCR) systems on gas and oil fired boilers. As described below, the SNCR Cost Model is designed to estimate the cost of retrofitting SNCR for purposes of incremental NOx reduction. In such applications ("SNCR Trim"), the SNCR system is typically designed to achieve maximum NOx reductions in the range of 20 to 30%, while minimizing capital costs by limiting the reagent injection system to a single level of injectors. This approach is tailored to those units that are base loaded or brought on-line for peaking capacity requirements.

SNCR Design Overview

SNCR involves the injection of a nitrogen-containing chemical reagent (reducing agent) into the furnace after the combustion zone where the temperature is in the range of 1600–2100°F (870–1100°C). In this temperature range, the reducing agent reacts selectively with NOx in the presence of oxygen, forming primarily molecular nitrogen (N_2) and water (H_2O). A number of reducing agents have been investigated and used for SNCR, with the most common reagents being urea and anhydrous or aqueous ammonia. In order to minimize the overall capital requirement as described below, urea is recommended for SNCR Trim and is the assumed reagent in the SNCR Cost Model. More detailed information on SNCR can be found in EPRI's *SNCR Feasibility and Economic Evaluation Guidelines for Fossil-Fired Utility Boilers* (TR-103885, May 1994) and *State-of-the-Art Assessment of SNCR Technology* (TR-102414, September 1993).

SNCR performance is not just a function of the reducing agent and process chemistry, but also of furnace parameters including flue gas stratification, flue gas temperature, and CO levels at the point of reagent injection. SNCR design and operation frequently entail tradeoffs between acceptable ammonia emissions and achievable levels of NOx reduction. When an SNCR system is combined with low-NOx combustion modifications (e.g., low-NOx burners, overfire air, burners-out-of-service, flue gas recirculation, and reburning), the potential changes in flue gas parameters that accompany these modifications – and their impact on SNCR performance – must be considered. A recent computational fluid dynamics (CFD) analysis of an overfire air system proposed for retrofit upstream of an existing SNCR system indicated that the NOx reduction capability provided by the SNCR system would be cut significantly, due to a greater than twofold increase in predicted CO levels entering the SNCR injection zone.

The design of the urea injection system also has an important impact on SNCR performance in terms of NOx reduction and emissions of unreacted ammonia. When maximum SNCR performance is required, multiple levels of injectors are commonly used to facilitate boiler load following as the optimum flue gas temperature window moves within the furnace. Various “high energy” injection systems, designed to provide rapid and complete mixing of reducing agent with the flue gas via high-pressure atomization or other means are also employed to maximize performance. To minimize capital cost for SNCR Trim, however, a single level of injectors is assumed in the SNCR Cost Model with corresponding decreases in NOx reduction efficiency as detailed below. In addition, relatively unsophisticated, less expensive “low-energy” injector designs are assumed.

Urea is typically used with low-energy injection systems due to its ability to tailor the chemical release point within the boiler through changes in the injection water dilution ratio and/or atomization properties (e.g., injector drop size). The turbulence of the flue gas provides reagent mixing prior to entering the boiler convective passages. Reagent injection on the high-temperature side of the SNCR temperature window minimizes ammonia slip, although frequently at the expense of higher reagent and consumption rates (low utilization). Low-energy injection systems are broadly applicable, and are especially economically competitive on units requiring less than 30% NOx reduction, small units (<200 MW), or units with capacity factors of less than 50%.

NOx Reduction and Ammonia Slip

Because of the many factors that affect the performance of SNCR systems, a wide range of NOx reduction results have been reported (20–50%), as well as a range of ammonia (NH_3) emissions “slip” (5–150 ppm at a N/NO injection ratio of 2:1). The variability in performance with SNCR Trim, however, will tend to be less since it is typically applied over a relatively narrow range of unit operating conditions and/or the design NOx reduction is relatively low. Nevertheless, the maximum NOx reduction attainable will generally still be constrained by an NH_3 slip limit typically imposed by the boiler operating permit.

The interdependence between ammonia slip and achievable NOx reduction is illustrated in the following empirical equations, which are used in the SNCR Cost Model to determine the NOx reduction for a specified ammonia slip.

$$\text{NSR} = -0.056 + 0.3707 * (\text{ammonia slip ppmv})^{0.5}$$

$$\text{NOx Reduction (\%)} = 69.6 - 72.428 * e^{-\text{NSR}} - 10$$

NSR represents the “normalized stoichiometric ratio” of reducing agent to NOx in the flue gas. These equations are based on curve fits of data from short-term field tests of SNCR under controlled full-scale operating conditions. To apply the equations, the user specifies the permissible ammonia slip in the first equation, which determines the NSR. The calculated NSR is then entered into the second equation to determine NOx reduction efficiency.

The above equation used to calculate NOx reduction reflects the performance limitations associated with a single level of furnace injectors assumed for SNCR Trim. Specifically, a review of test data from several SNCR demonstrations indicates a 10% lower NOx reduction with single-level injection systems compared to multi-level injection systems. This accounts for the minus 10% term in the NOx reduction equation above.

Estimation Procedure for SNCR Trim Capital Costs

The capital cost of a traditional SNCR system typically varies between $10/kW and $20/kW. The lower end of the cost range generally applies to low-energy injection systems with wall injectors. The high end of the range generally corresponds to high-energy injection systems with multiple lances. Capital costs for SNCR Trim are estimated to range from $4 - $8/kW. The basis for the capital cost estimate for SNCR Trim is provided in Table 3-1. The principle factors influencing the $/kW capital cost of a SNCR Trim system are the baseline NOx level and operating capacity factor, due to their direct influence on the reagent storage capacity requirements.

Table 3-1
SNCR Capital Cost Components

Capital Cost Component	Cost Calculation ($)
Modeling	$75,000 fixed cost for boiler/injector flow modeling.
Testing	$125,000 fixed cost. Includes boiler temperature characterization and SNCR system start-up and optimization.
Reagent Storage (RS)	Urea reagent storage cost is a linear function of the initial NOx level and NSR. See cost calculation for Reagent Storage in text.
Injection System (IS)	Injection system cost is a function of the unit size, number of wall injectors and/or lance injectors, and base reagent. See cost calculation for Injection System in text.
Compressors (C)	Compressor cost is a function of the wet flue gas flow rate. See cost calculation for Compressors in text.
Installation	75% of (RS+IS+C)
Total Process Capital (TPC)	Sum of above costs
Process Contingency	5% of TPC (excluding modeling and testing)
Project Contingency	10% of TPC (excluding modeling and testing)
Engineering	20% of TPC (excluding modeling and testing)
Total Capital Cost ($)	Sum of TPC, contingencies, and engineering

Details on the approach for estimating the capital cost for reagent storage, injection system, and compressors are provided in the subsections below.

Reagent Storage Capital Cost

The urea reagent storage cost is a linear function of the initial NOx level and the specified NSR. The initial NOx level (i.e., the NOx emission rate in lb/hr prior to the application of SNCR Trim) is calculated according to the following equation:

NOx (lb/hr) = NOx (lb/MBtu) * Unit Size (MW) * 1000 kW/MW * Heat Rate (Btu/kWh) / 10^6

The reagent consumption is then calculated from the initial NOx level and NSR according to the following equation:

Reagent Use (lb/hr) = NOx (lb/hr) * 0.022 lbmole NOx/lb NOx * NSR (mole N/mole NOx) * reagent-nitrogen ratio (mole reagent/mole N) * reagent molecular weight (lb/lbmole reagent)

The NSR is obtained from formulas in the preceding subsection to satisfy specified ammonia slip and NOx reduction requirements. The reagent-nitrogen molar ratio and molecular weight are based on the specific composition of the chemical reducing agent selected. For urea, these values are 0.5 mole urea/mole N, and 60 lb urea/lb mole reagent, respectively.

The reagent storage cost is calculated according to the following equation, assuming the reagent is stored as a 50% water-urea solution:

Reagent Storage Capital Cost ($) = [Urea 50% Solution Reagent Use (lb/hr) * Days Storage * 2.807 * $2.14/gal] + $68,400

The factor of 2.807 in the above equation is based upon ((24 hrs/day * 1 gal reagent/9.5 lbs urea)/0.90), with the 0.90 denominator representing a 10% tank void fraction. The reagent storage cost factor ($2.14/gallon) developed for aqueous ammonia, based upon material and installation cost for 35,000 gallon tank capacities, is assumed to be applicable to urea solutions. The $68,400 constant factor is based on a previous A&E study that took into account safety and general handling requirements for urea beyond tank storage.

Injection System

The reagent injection system cost is estimated as a function of the unit width, assuming that a single elevation of wall injectors are spaced approximately five feet apart on a single furnace wall. An individual wall injector cost factor is estimated at $12,500 per injector. The sum of the wall injector costs are added to an incremental base cost of $150,000, yielding the following equation:

Injection System Cost = [Boiler Width (ft) * 0.22 * $12,500] + $150,000

Compressors

It is assumed that the reagent injectors utilize compressed air for reagent atomization and dispersion. The capital cost associated with increased plant compressed air capacity is a function of the wet flue gas flow rate. The wet flue gas flow rate calculation is based on the fuel F-factor and boiler heat input according to the equation:

Flue Gas Flow Rate (wscfm) = F-Factor (wscf/MBtu) * Heat Input (MBtu/hr)/60 * 1.1

where the F-Factor for natural gas is 10,610 wscf/10^6 Btu for zero excess air, and the 1.1 excess air factor corrects the flue gas to an assumed 2% operating excess oxygen level. The F-Factor and excess air factor may be adjusted as necessary for the specific fuel composition and excess oxygen level.

The compressor capital cost for a low-energy urea injection system is then calculated from the following equation:

Compressor Cost ($)= [92.5 + (1.55*$10^{-5}$ * Flue Gas Flow Rate (wscfm))] * 1000

This capital cost assumes that the existing plant compressed air capacity is increased to provide the needs of the SNCR Trim. If the existing plant compressed air capacity is sufficient to carry the additional load required for the reagent injectors, then this cost may be reduced or neglected as appropriate. The compressed air requirement for SNCR Trim applications may be estimated at an air to liquid mass ratio of 0.10, assuming a dilute 5% urea solution is injected into the boiler. For a 338 MW boiler with NOx emissions of 0.10 lb/MBtu, this translates to nominally 20 acfm of 90 psig compressed air.

Example Calculation

An example application of SNCR Trim has been prepared for a 338 MW gas-fired boiler operating with 3% excess oxygen and equipped with NOx combustion controls (overfire air and windbox flue gas recirculation) producing an initial NOx emission level of 80 ppmv, or approximately 0.10 lb/MBtu.

As shown in Table 3-2, the NOx reduction potential is a strong function of the allowable ammonia slip. At 5 ppmv ammonia slip, a NOx reduction of 26% is estimated, while at 10 ppmv ammonia slip, the NOx reduction potential is estimated to increase to 36%.

Table 3-2
Estimate of NSR, NOx Reduction Potential, and Urea Consumption for Two Levels of Ammonia Slip

Parameter	5 ppmv NH_3 Slip	10 ppmv NH_3 Slip
NSR	0.77	1.12
ΔNOx	26%	36%
Urea Use	190 lb/hr	275 lb/hr

Assuming a unit heat rate of 11,000 Btu/kWh, the full load baseline NOx emission rate of 0.10 lb/MBtu (80 ppmv) equates to a NOx emission rate of 372 lb NOx/hr. For urea reagent, the reagent consumption is calculated to be between 190 - 275 lb urea/hr, depending upon the NSR injection rate (0.77 versus 1.12 in Table 3-2). The reagent storage cost is then scaled off of the reagent use requirement. Based on the largest calculated urea usage rate (275 lb/hr), the computed reagent storage cost is estimated at $80,000.

The injection system is scaled on the basis of the boiler width. For the example boiler, which is 54 feet wide by 28 feet deep, the injection system is estimated to cost $300,000.

Finally, compressors to supply atomization air to the injection system are scaled on the basis of the flue gas flow rate. Based on the unit heat rate of 11,000 Btu/kWh heat rate, the calculated flue gas flow rate is nominally 725,000 wscfm. The compressor cost for atomization air is then estimated at $105,000. As indicated above, this incremental cost is optional, depending upon spare compressor capacity at the subject unit.

A summary of the cost components is provided in Table 3-3. As indicated, the total estimated retrofit cost is nominally $4/kW.

Table 3-3
Summary of Capital Cost Components for Retrofit of SNCR Trim on a 338 MW Gas-Fired Boiler

Component	Estimated Capital Cost	Percent of Total
Modeling	$75,000	5.5%
Testing	$125,000	9.2%
Reagent Storage	$80,000	5.9%
Injection System	$300,000	22.1%
Compressors	$105,000	7.7%
Installation	$372,000	27.3%
Total Process Capital	$1,057,000	77.7%
Contingency	$130,000	9.6%
Engineering	$173,000	12.7%
Total Capital Cost	$1,360,000	100.0%
$/kW Capital Cost	($4.02/kW)	

The cost effectiveness of SNCR Trim ($/ton of NOx removed) may be calculated following similar procedures outlined for SCR in the previous chapter. The annual or seasonal NOx reduction in tons is calculated from the inlet NOx emissions (lb NOx/hr), NOx reduction, and number of operating hours. The annualized cost ($) includes the sum of annual (or seasonal) O&M costs and annualized capital cost. The annual O&M cost may be simplified by equating it to the annual (or seasonal) reagent cost, neglecting other costs such as energy consumption for reagent water evaporation, air compressor costs, etc.

For the above example, the cost effectiveness for an ozone season is calculated to be on the order of $2,300/ton NOx removed for 26% NOx reduction with an NSR of 0.77, and $1,850/ton NOx removed for 36% NOx reduction with an NSR of 1.12. These estimates are based on 12.5% capital cost recovery factor, an 1825-hour ozone season, 50% capacity factor, and delivered urea cost of $0.60/gallon.

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