CURRENT CAPITAL COST AND COST-EFFECTIVENESS OF POWER PLANT EMISSIONS CONTROL TECHNOLOGIES

Prepared by
J. Edward Cichanowicz

Prepared for
Utility Air Regulatory Group

January 2010

CURRENT CAPITAL COST AND COST-EFFECTIVENESS OF POWER PLANT EMISSIONS CONTROL TECHNOLOGIES

Section/Title Page No.

SECTION 1 Summary 1-1
SECTION 2 BACKGROUND 2-1
INTRODUCTION 2-1
RETROFIT OF CONTROL TECHNOLOGY 2-1
NEW GENERATING STATIONS 2-6
SECTION 3 MATERIAL AND LABOR ESCALATION 3-1
BASIC MATERIALS 3-1
LABOR 3-4
Labor Cost Escalation 3-4
Labor Pool Availability 3-5
SECTION 4 FACTORS AFFECTING CAPITAL COST ESTIMATES 4-1
CAPITAL COST ESTIMATING METHODOLOGY 4-1
SITE AND DESIGN FACTORS 4-3
SECTION 5 FLUE GAS DESULFURIZATION COSTS 5-1
FGD CAPITAL COST 5-1
Wet FGD 5-1
Dry FGD 5-2
OPERATING COST 5-4
SECTION 6 SCR NO_x COST 6-1
SCR CAPITAL COST 6-1
COST ESCALATION 6-1
OPERATING COST 6-5
SCR Catalyst 6-5
Reagent 6-6
Example Operating Cost 6-7
SECTION 7 CONCLUSIONS 7-1
SECTION 8 REFERENCES 8-1

LIST OF FIGURES

Figure 2-1. Historical and Projected Wet, Dry FGD Capacity: Installed MW by Year 2-3
Figure 2-2. Historical and Projected Wet, Dry FGD Capacity: Cumulative MW by Year 2-3
Figure 2-3. Historical and Projected SCR Capacity: Annual Installed Capacity (MW) 2-4
Figure 2-4. Historical and Projected SCR Capacity: Cumulative Installed SCR Capacity (MW) 2-4
Figure 2-5. Historical, Projected FGD and SCR Annual Capacity (MW) 2-5
Figure 2-6. Historical, Projected FGD and SCR Cumulative Capacity (MW) 2-5
Figure 3-1. Steel Mill Products Cost History 3-2
Figure 3-2. Iron Ore Cost Escalation 3-2
Figure 3-3. Price History Escalation: Nickel, Molybdenum, Copper, and Chromium 3-3
Figure 3-4. U.S. Bureau of Economic Analysis Finished Goods Capital Price Index 3-4
Figure 4-1. Graphic Depiction of Cost Elements 4-2
Figure 5-1. Wet FGD Process Equipment Cost: Various Sources 5-2
Figure 5-2. Dry FGD Process Equipment Cost: Various Sources 5-3
Figure 5-3. Range of Wet FGD Operating Costs for 500 MW Units 5-4
Figure 5-4. SO_2 Removal Cost per Ton ($/Ton), Year 2008 Basis 5-5
Figure 6-1. Capital Cost of SCR Process Equipment vs. Generating Capacity: 6-2
Figure 6-2. Increase in SCR Capital Cost Based on Four Time Periods (Three Increments) 6-2
Figure 6-3. Average Generating Capacity of Unit Retrofit with SCR vs. Installation Date 6-3
Figure 6-4. Site Layout for Associated Electric Cooperative's New Madrid Station, Units 1 and 2. (SCR reactors denoted within red circle) 6-4
Figure 6-5. Site Layout for Associated Electric Cooperative's Thomas Hill Station, Units 1 and 2. (SCR reactors denoted within red circle) 6-5
Figure 6-6. History of SCR Catalyst Prices: 1980- 2008 (2008 Dollar Basis) 6-6
Figure 6-7. NO_x Removal Cost per Ton ($/ton), Year 2008 Basis. 6-8

LIST OF TABLES

Table 4-1. Examples of Indirect Charges, Assumptions 4-2
Table 6-1. Key SCR Operating Cost Components: 500 MW Reference Plant ($150/kW Capital, 2008 Dollar Basis) 6-8

SECTION 1

SUMMARY

The utility industry faces numerous mandates to retrofit flue gas emission controls to existing power plants. For example, the Clean Air Interstate Rule (CAIR), Clean Air Visibility Rule (CAVR), and settlements with the Department of Justice over alleged NSR violations all require retrofit of control technology. In addition, the Hazardous Air Pollutant Maximum Achievable Control Technology (HAPs MACT) rule, and the increasingly stringent National Air Quality Standards (NAAQS) are anticipated to promote control technology application. Some of these mandates and consent decrees required equipment installation and operation before 2010, with provisions for additional controls. These additional control requirements could be for the second phase of CAIR – or the equivalent program that replaces it. The HAPs MACT rule could also require reductions of NO_x and SO_2 in the 2015 timeframe.

The demand for control equipment strained international and domestic supply chains until early 2008. Robust demand through 2007 for materials and labor to support expansion of petrochemical industries, urban infrastructure, and power generation in developing countries consumed much of the international supply. Exotic corrosion-resistant metals (such as C276 Hastolloy) were simply not available from many suppliers, almost regardless of price. As a consequence, capital cost escalated from approximately the time frame of 2000 through 2008 for flue gas desulfurization (FGD) and selective catalytic reduction (SCR) equipment, and shortages in material and labor forced construction delays. Some owners of small generating units – less than 250 MW – issued requests-for-proposals for FGD equipment for which no bids were offered – or limited bids received at a premium price. Even major utilities encountered limits, as some reported it was not possible to secure fixed price contracts on construction projects, assigning all risk to owners.

The recent moderation in the world economy has removed many of the supply barriers and eased cost escalation. The cost to retrofit FGD and SCR equipment is expected to moderate from peak levels observed in the last 24 months, but may not significantly decline. A key reason is the ever-increasing complexity of the host sites. As host units are older and of smaller generating capacity, there is less available space for control equipment. Frequently, convoluted and complex ductwork is required, increasing retrofit difficulty.

Capital cost for FGD escalated significantly from the 2004-2006 timeframe to the 2008-2010 timeframe. Over the four-year period between the approximate mid-point of these intervals (e.g., 2005 vs. 2009), FGD cost escalated at 19% above the inflation rate. Specifically, on an average basis, retrofit of wet FGD to a 500 MW in the 2004-2007 timeframe required $342/kW (2008 dollars). A unit of the same capacity retrofit with FGD in the 2008-2010 timeframe required $407/kW (2008 dollars). The difference equates to an escalation of approximately $16/kW per year. At this rate of escalation, an FGD process installed for a 2015 startup on a 500 MW unit will require about $470/kW (in 2008 dollars).

For a coal with sulfur content of 4 lbs/SO_2/MBtu, each increase in capital cost for wet FGD by $100/kW can increase the cost effectiveness of SO_2 removal by several hundred dollars per ton. At $400/kW, a typical 500 MW unit will expend about $600 to remove a ton of SO_2 from this coal. For PRB coal with 0.9 lbs SO_2/MBtu, each increase in FGD capital cost by $100/kW will increase SO_2 removal cost effectiveness by $500/ton. For this PRB coal, an SO_2 removal cost of up to $2,300/ton will be incurred for a $400/kW FGD capital cost.

Capital cost for SCR NO_x control has similarly escalated over the same time period. Data obtained for this paper show a large number of units that recently retrofit SCR incurred capital cost between $300-350/kW (in 2008 dollars). Catalyst unit price has remained low in the last 4-5 years, with new catalyst requiring a cost between $4,000-5,000/cubic meter. The cost of ammonia-based reagent, after peaking in 2007 at over $600/ton, is predicted to average about $400/ton through early 2010. Reagent cost after that time is uncertain, and historically linked to natural gas prices. For most applications, reagent has replaced catalyst supply as the largest SCR operating cost component.

For a typical 500 MW unit firing an eastern bituminous coal and producing NO_x at a rate of 0.38 lbs/MBtu, each $100/kW increase in SCR capital cost increases NO_x removal cost effectiveness by about $1,000/ton. The same unit equipped with a $300/kW SCR process would incur a NO_x removal cost-effectiveness of $3,500/ton. For a 500 MW unit firing PRB and producing NO_x at a rate of 0.20 lbs/MBtu, each $100/kW increase in SCR capital cost elevates NO_x removal cost effectiveness by $2,000/ton. A PRB-fired unit with a $300/kW SCR process would incur a NO_x removal cost-effectiveness of $6,500/ton.

In summary, the material and labor shortages witnessed during the 2007 and 2008 timeframe have abated. However, the cost to retrofit FGD and SCR equipment is anticipated to escalate, over the long-term, at about the same rate since the year 2000. The cost will be driven by the increasing complexity of smaller sites, at generally older units. Typically, large units with accessible, open sites have already been retrofit, as the most cost effective projects were first sought. These site–specific factors are anticipated to supersede the cost and availability of labor and components in determining installed equipment cost.

SECTION 2

BACKGROUND

INTRODUCTION

The cost to retrofit capital-intensive environmental controls to power stations rapidly escalated from the year 2000 through the end of 2009. In the U.S., several environmental mandates that stem from the 1990 Clean Air Act Amendments (CAAA) converged within the time span of only a few years. Since that time, the general slowdown in world-wide demand for chemical processing facilities, transportation, and urban infrastructure has diminished cost pressures for material and specialized construction labor. The relaxation in cost pressure was too late to moderate the installed FGD and SCR cost for units that planned to start-up in 2008 and 2009. Further contributing to the escalated cost for these units is an increase in the complexity of sites within which to retrofit equipment, as the units most amenable to retrofit were equipped first. As a consequence, although the price shocks of material and equipment observed in 2006 and 2007 have diminished, capital cost will continue to escalate due to more difficult retrofits.

On the supply side, the limit to construction schedule imposed by components such as rubber-lined slurry pumps, pulverization and reagent grinding equipment, and flue gas emission stacks has abated. Access to these components can still determine the schedule of a project, but availability is considerably improved since 2007.

RETROFIT OF CONTROL TECHNOLOGY

Retrofit of control technology to existing plants is mandated by several actions subsequent to the 1990 Clean Air Act Amendment: the Clean Air Interstate Rule (CAIR), regional haze initiatives such as the Clean Air Visibility Rule (CAVR), and increasingly stringent National Ambient Air Quality Standards (NAAQS). Further, settlements with EPA and the Department of Justice (DOJ) over alleged New Source Review (NSR) violations may affect plans for SO_2 and NO_x reduction, as well as the Hazardous Air Pollutant Maximum Achievable Control Technology (HAPs MACT) rule that is being developed. Each of these is further described as follows.

<u>Clean Air Interstate Rule (CAIR).</u> As initially promulgated, this two-phase program mandated reducing NO_x and SO_2 in an initial Phase 1 (2009 for NO_x and 2010 for SO_2), and a Phase 2 (2015 for both SO_2 and NO_x). The CAIR program was remanded but not vacated by the D.C. Circuit in December of 2008. However, the eventuality of more strict limits for SO_2 and NO_x emissions did not alter actions by most utility owners to install FGD and SCR.

<u>National Ambient Air Quality Standards (NAAQS).</u> Under the Clean Air Act, NAAQS are to be reviewed every 5 years. Recently those reviews have lead to more stringent standards. As EPA continues to review and revise the NAAQS, States with areas exceeding the standards are required to

develop State Implementation Plans (SIPs) to achieve compliance. In those SIPs, States have looked to power plants for further emission reductions.

Best Available Retrofit Technology (BART). BART requirements are part of the Clean Air Visibility Rule (CAVR). These federal regulations require all states to revise their State Implementation Plans (SIPs) to address visibility impairment in Mandatory Class I Federal Areas, which are specific national parks and wilderness areas across the country. Consequently, states may require retrofit of emissions controls to achieve "reasonable progress" toward eliminating manmade impairment of visibility in Mandatory Class I Federal Areas.

For example, the states of Illinois, Indiana, Michigan, and Wisconsin, through the Lake Michigan Air Directors Consortium are considering additional control measures for SO_2 and NO_x beyond CAIR. Regulatory agencies in other regions in the country such as the southeast (VISTAS) and far west (WRAP) are considering similar mandates. The extent and timing of these mandates is uncertain, but most proposed initiatives will require control equipment by the 2014 to 2018 time period.

Settlements Regarding Alleged NSR Violations. Allegations by the U.S. EPA that provisions of the CAAA regarding NSR were violated prompted several owners to agree to the installation of FGD and SCR controls on schedules that differ from those required to meet CAIR.

Retrofit of FGD and SCR to many coal-fired boilers is required to meet these existing and proposed mandates. Figures 2-1 to 2-6 depict the inventory of wet and dry FGD and SCR process equipment that has been either installed or announced to meet various regulatory mandates. Figure 2-1 shows the incremental annual addition of both wet and dry FGD in terms of generating capacity (MW) through 2012. The annual capacity added reaches about 20,000 MW in 2008, 2009, and 2010. Figure 2-2 presents the cumulative total installed since 2001, reaching almost 100,000 MW by the end of 2012. Cumulatively with the 95,000 MW installed prior to the year 2000, almost 200,000 MW of the U.S. coal-fired fleet will be equipped with FGD by 2012. All new units treat 100% of flue gas. Estimates for equipment installed beyond 2012 are uncertain and thus not shown.

Figure 2-3 shows the incremental generating capacity retrofit with SCR over the same time period. Since the peaks in 2002 to 2004, the capacity retrofit with SCR in each year has ranged between almost 4,000 and 10,000 MW. Figure 2-4 shows the cumulative capacity retrofit with SCR approaches 130,000 MW by 2012.

The ability of SCR and FGD to remove mercury (Hg) and other HAPs may also prompt their installation. Specifically, the "co-benefit" of Hg control, where oxidized Hg is removed as a consequence of SCR and wet FGD, is relevant to the anticipated HAPs MACT rule. This rule is expected to be proposed in 2011. The capacity projected to be equipped with both SCR and FGD is shown in Figures 2-5 and 2-6, showing the annual and cumulative totals, as designated by the first year of operation. Figure 2-6 shows almost 70,000 MW of capacity will be equipped with both SCR and FGD by 2012.

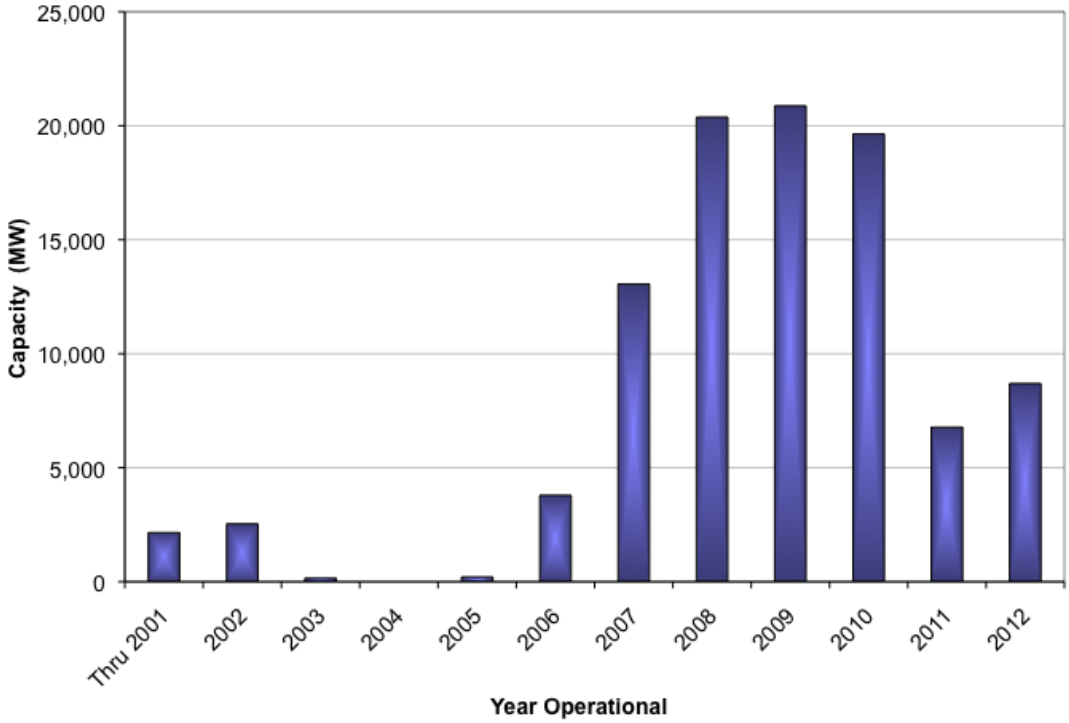


Figure 2-1. Historical and Projected Wet, Dry FGD Capacity: Installed MW by Year

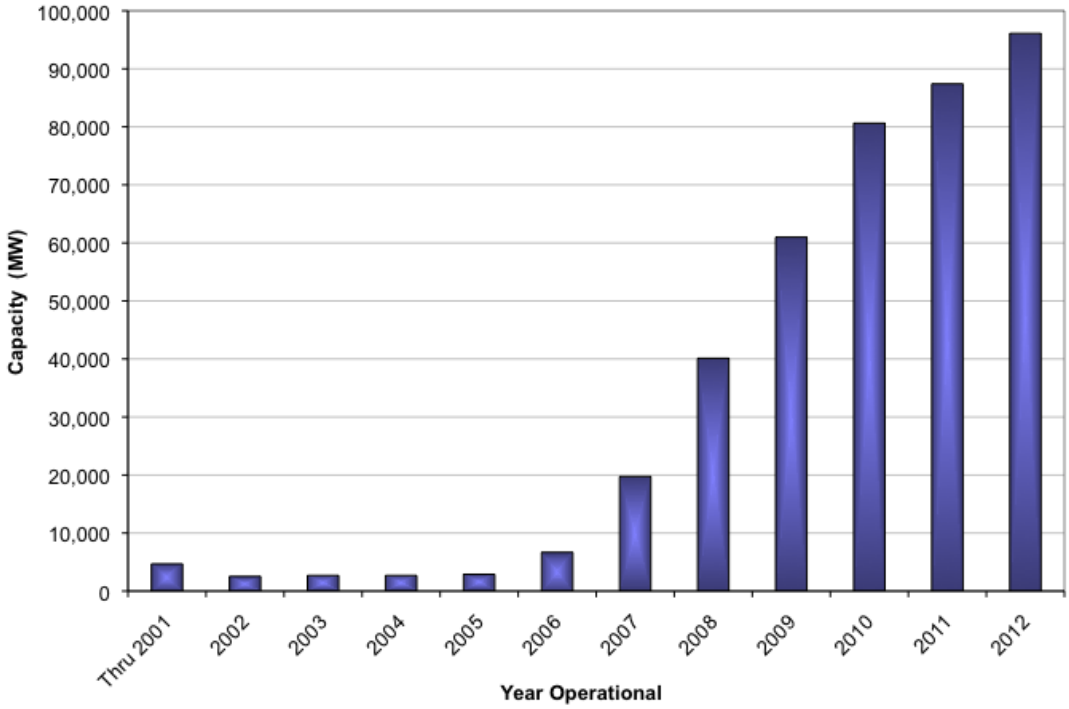


Figure 2-2. Historical and Projected Wet, Dry FGD Capacity: Cumulative MW by Year

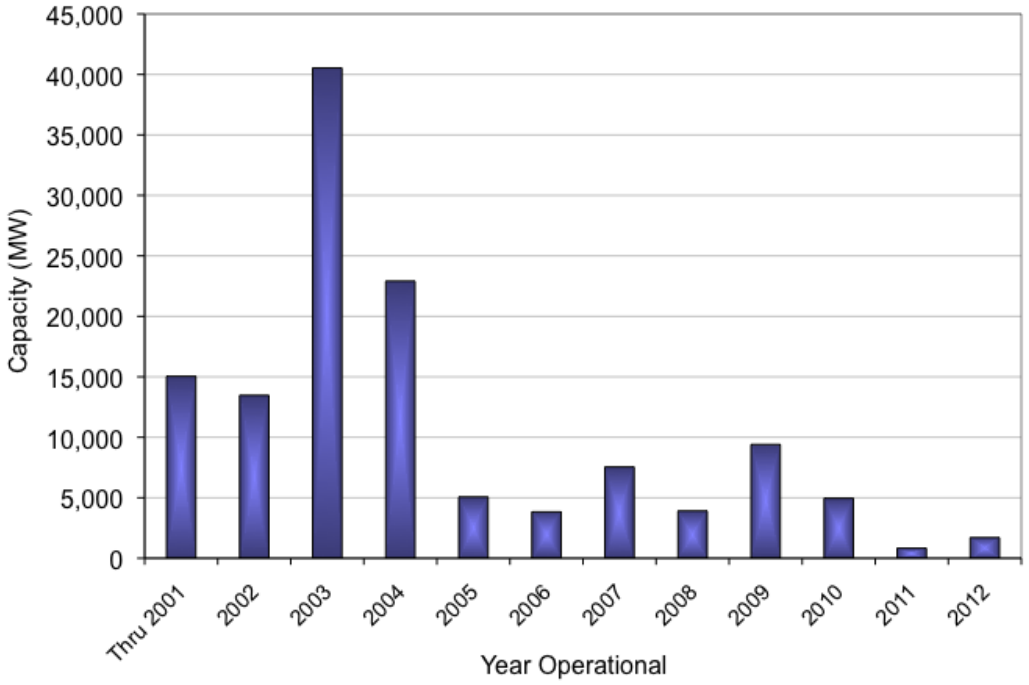


Figure 2-3. Historical and Projected SCR Capacity: Annual Installed Capacity (MW)

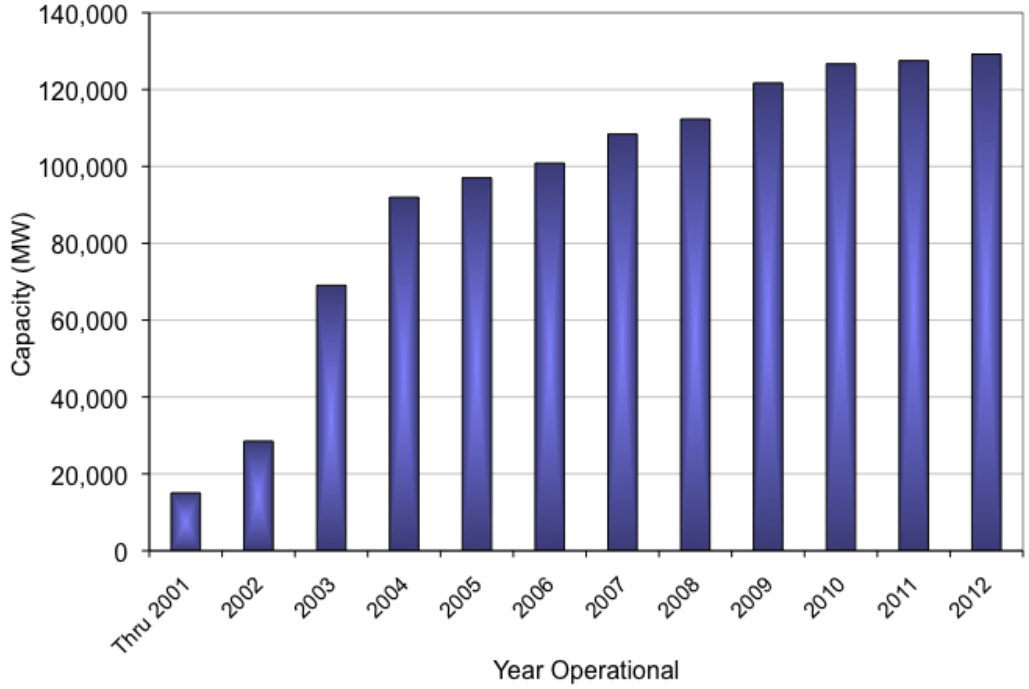


Figure 2-4. Historical and Projected SCR Capacity: Cumulative Installed SCR Capacity (MW)

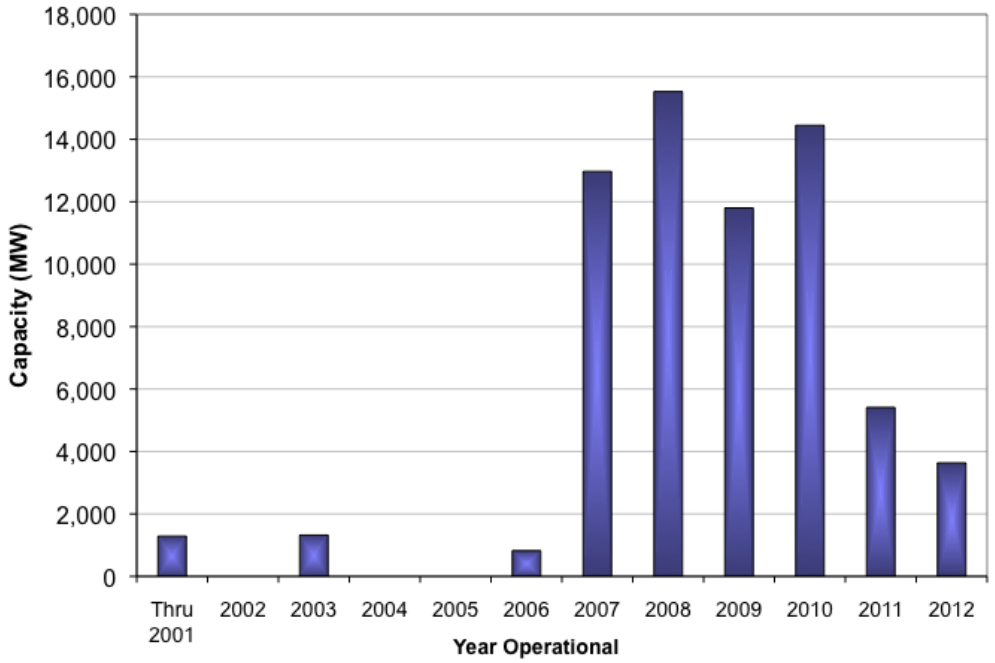


Figure 2-5. Historical, Projected FGD and SCR Annual Capacity (MW)

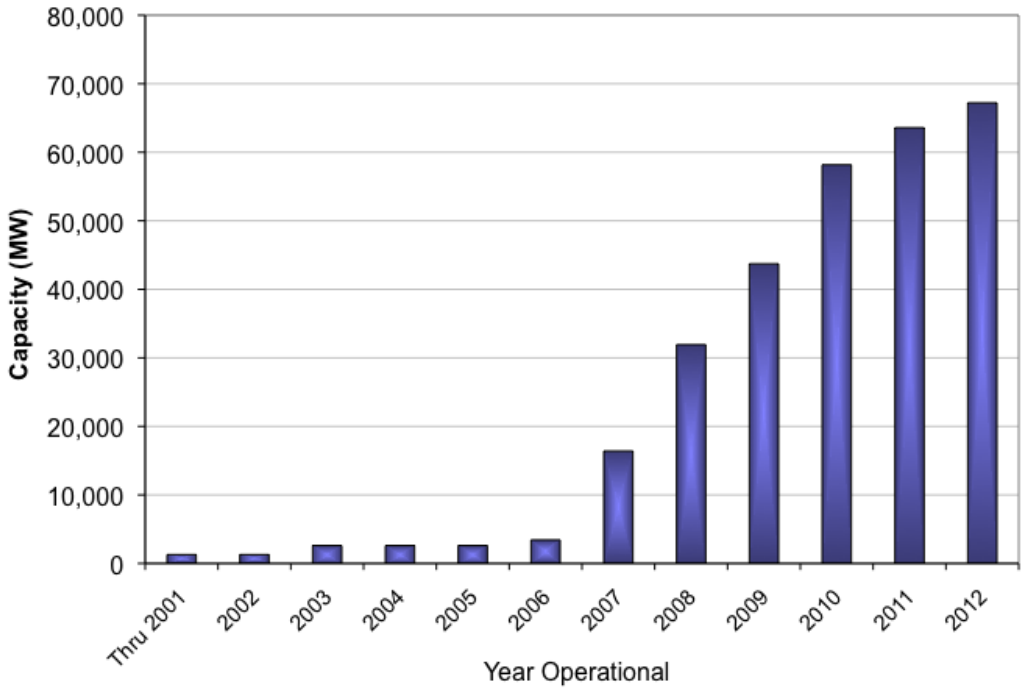


Figure 2-6. Historical, Projected FGD and SCR Cumulative Capacity (MW)

NEW GENERATING STATIONS

The number of new coal-fired units planned for operation between 2009 and 2020 has decreased notably in recent years. For example, in 2002 over 36,000 MW of capacity were scheduled to be installed by 2007, whereas only 12% of that amount (~4,500 MW) were actually completed (DOE, 2009). As of late 2009, approximately 15,000 MW of coal-fired capacity is under construction, with more than another 4,000 MW of capacity permitted. An additional 27,000 MW of new coal-fired generating capacity has been proposed for installation by 2018 (DOE, 2009). It is not clear how many of the proposed units will actually be built, as investment plans are subject to revision given the present economic climate and regulatory uncertainty regarding CO_2 regulation.

SECTION 3

MATERIAL AND LABOR ESCALATION

This section addresses the escalation of material and labor costs through 2008, the relaxation or normalization in prices since that time, and discusses possible impacts on equipment cost and construction schedule.

BASIC MATERIALS

Among the basic materials required for installation of environmental control technology and new generating equipment are iron ore, structural steel, copper for wire and cable, and elements such as nickel and molybdenum for exotic processed metals. These inputs, along with other construction materials and the cost and productivity of labor, determine the price of finished capital equipment. These materials are broadly available in the U.S. and throughout the world, but until mid-2008 experienced strong demand due to world-wide construction in process industries and infrastructure. Specifically, exotic corrosion-resistant metals (such as C276 Hastolloy) were simply not available from many suppliers, regardless of price. Further, several cases of substandard manufacturing quality were documented with certain international suppliers, ranging from failure of high pressure piping to poor castings that lead to catastrophic failures. The demand for these materials has relaxed, as have prices, mitigating but not completely eliminating both cost and quality concerns.

Figures 3-1 to 3-4 present price escalation data for selected materials over the last 10 years (with the exception of iron ore, for which data is only available over a three year period). These data, accessed either from the U.S. Bureau of Economic Analysis[1] (BEA) or a commercial source[2], reflect pricing from 1999 to present. These data show that prices for key commodities have relaxed from the 2008-era high marks, reverting for many materials to 2007 levels. Consequently, all commodity prices are lower than their 2008 peaks but most are not depressed.

Figure 3-1 presents BEA data for steel products, using 1982 prices as a base case. Figure 3-1 shows 2009 steel mill prices to be 60-70% of peak prices reported in the mid-2008, and at year-end returning to early 2007 and 2008 levels. Similarly, the price for iron ore (as traded at Hamersley, Australia) has relaxed from 2008 highs, and at the year-end of 2009, exceeds early 2008 levels (Figure 3-2).

The cost for special alloys used for wet FGD reaction vessels, and for high pressure, high temperature boiler components, has also relaxed from peak 2008 values. Specifically, key ingredients to corrosion-resistant and high-strength materials – nickel, molybdenum, and chromium – all experienced increased

---

[1] See U.S. Bureau of Economic Analysis, "Price Indices for Gross Domestic Product by Major Type of Product", revised December, 2009, http://www.bea.gov/national/nipaweb/SelectTable.asp?Selected=Y

[2] See www.Infomine.com

demand and higher prices up to 2008. Figure 3-3a presents price trends for molybdenum and nickel, showing that prices after escalating by a factor of 3 to 5, respectively, have relaxed to 2006 levels for nickel and to early 2004 levels for molybdenum. Figure 3-3b depicts a similar price trend for copper and chromium. Although the content of nickel, molybdenum, and chromium in finished steel products is small, cost escalation of this magnitude will affect final product cost.

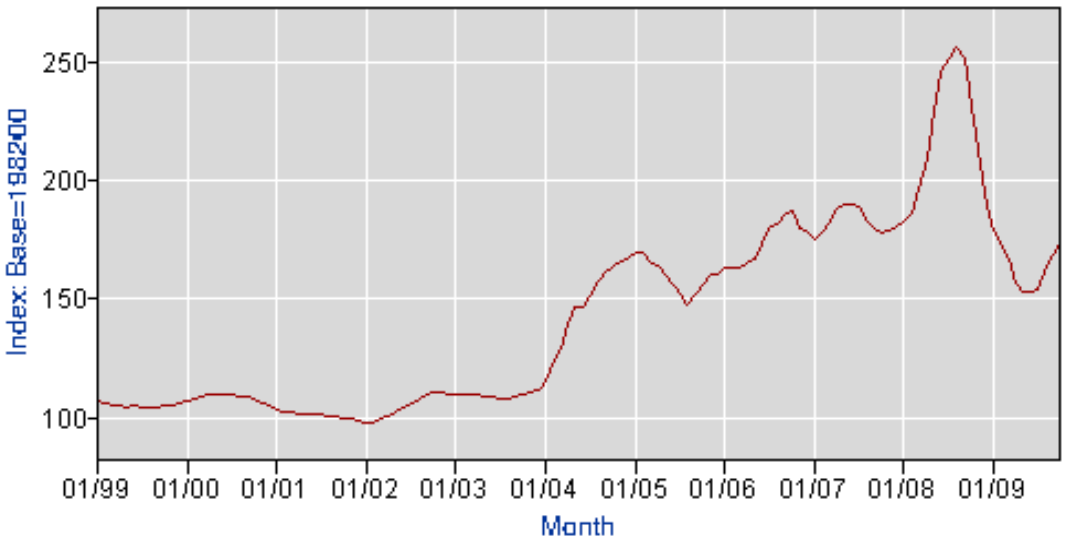


Figure 3-1. Steel Mill Products Cost History

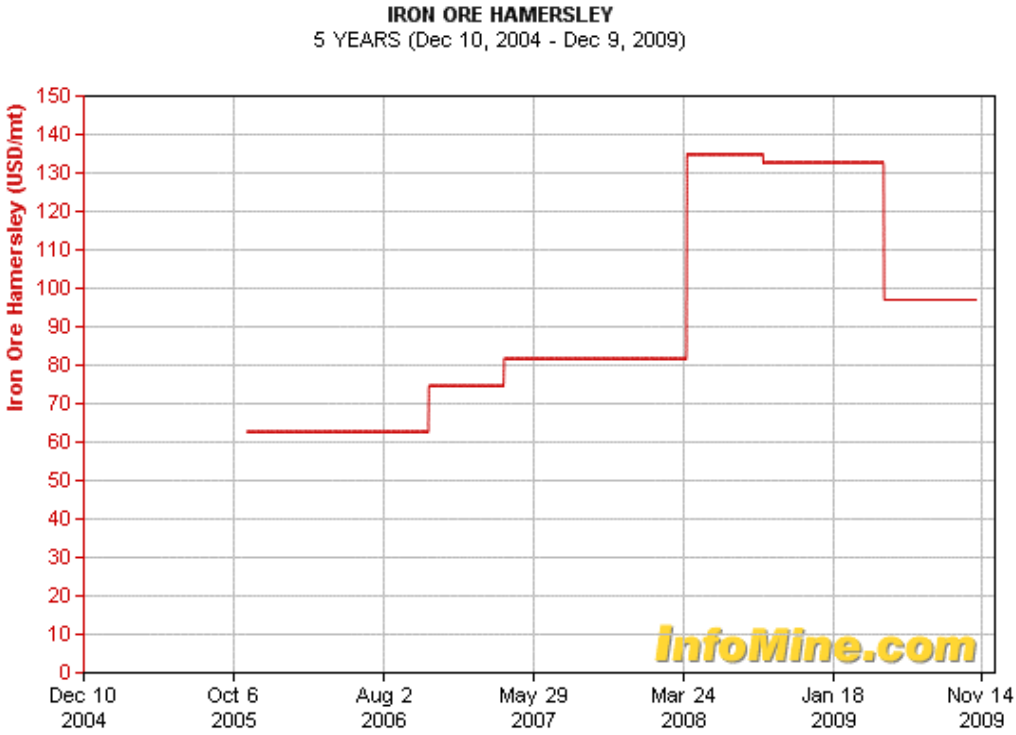
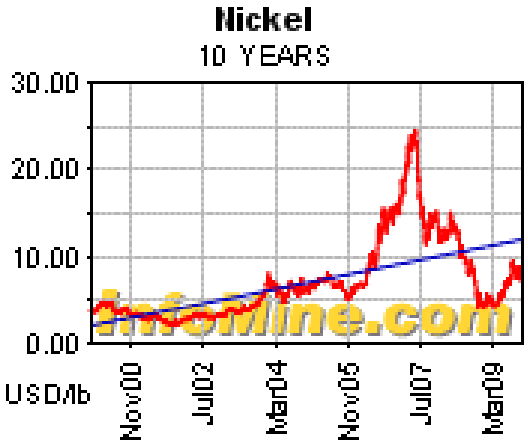
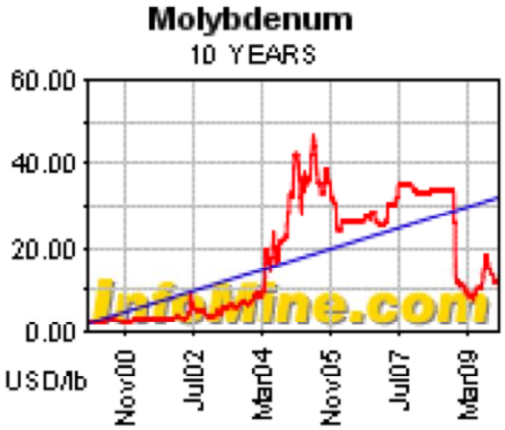
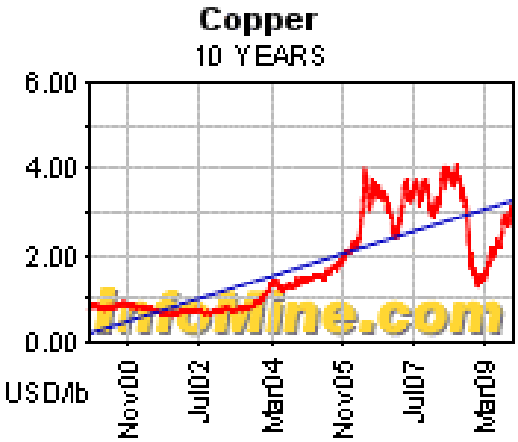


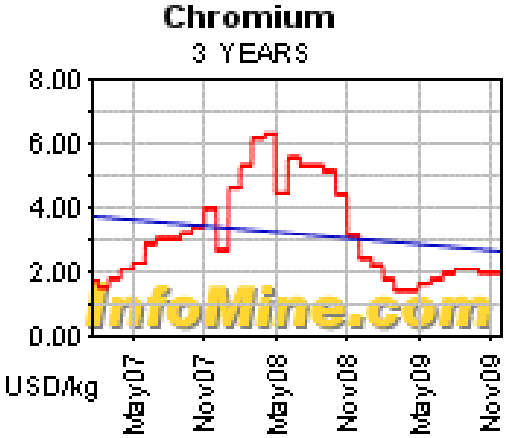
Figure 3-2. Iron Ore Cost Escalation





a. Molybdenum and Nickel Price History Escalation





b. Copper and Chromium Price History

Figure 3-3. Price History Escalation: Nickel, Molybdenum, Copper, and Chromium

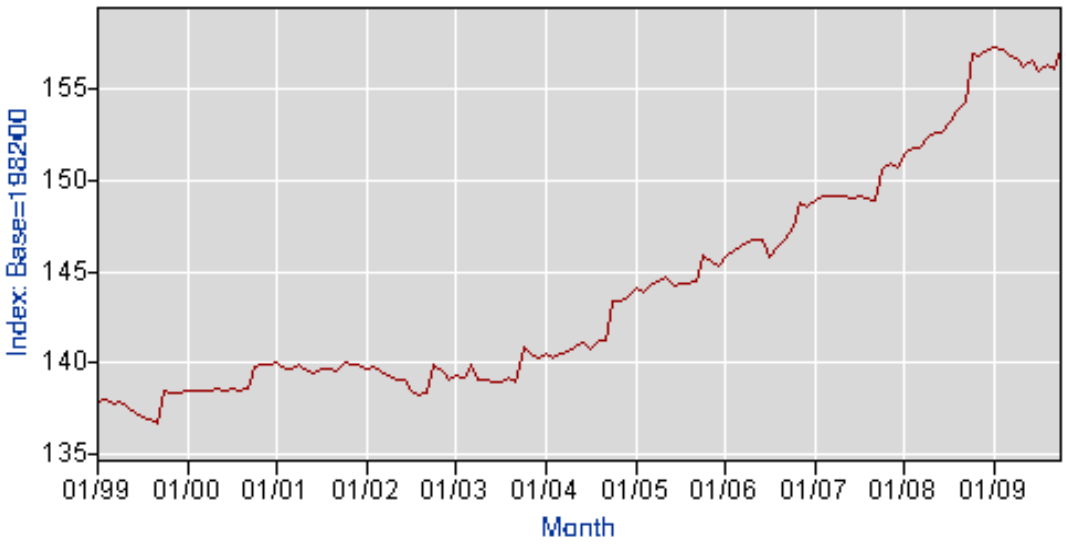


Figure 3-4. U.S. Bureau of Economic Analysis Finished Goods Capital Price Index

The delivered price of key finished goods and materials has also declined. However, finished equipment price declines are moderated because many inputs are manufactured goods, which require labor. These include components such as pumps, gas fans, valves, and steel plate fabricated from alloys. The delivered prices of these key components are reported to be lower by 10-20% compared to the peak 2007 and 2008 values (Gaikwaid, 2009; Erickson, 2009).

One indicator of the cost of industrial components is the BEA cost index of finished products. This index, as exhibited in Figure 3-4, shows that prices have relaxed only moderately from the 2008 highs.

Several key components or services no longer limit impose rate-limiting steps on project schedule. These include reagent preparation equipment, slurry recirculating pumps, agitator pumps, certain categories of forced and induced draft fans, and the stack. Perhaps most notable is the availability of material and personnel resources to fabricate and erect a stack. The limited number of stack erectors world-wide, coupled with the demand for new stacks for both retrofit of wet FGD and new generating units, has significantly elevated costs.

LABOR

The present cost trends and availability for qualified field labor are discussed in this section.

Labor Cost Escalation

Labor cost escalation experienced by the industry through 2007 was summarized by an architect/engineering firm involved in the construction of several new Midwestern plants (Black & Veatch, 2007). Through 2007, annual labor escalation was observed to be between 5.2 and 7.4% per year, averaging 6.2%.

Discussions with representatives of architectural/engineering firms and equipment suppliers, and public reports of pay scales indicate that despite the economic slowdown, labor rates are little changed since 2007. Modest increases (~2% annually) are noted in most but not all trades. This trend is

consistent with labor costs for general construction personnel increasing 2.1% from September 2008 to September 2009.[3] Labor rates are largely unchanged for the crafts with the most lengthy apprenticeship programs such as boilermakers, who are required for the heavy metal bending, forming, and erection duties required for SCR and FGD equipment. Labor rates for some crafts with less restrictive training (pipefitters, electricians) have slightly declined. Consequently, labor rates in 2007 and 2008 are likely representative of present-day costs, and modest escalation of nominally 2% annually can be anticipated.

The contribution of labor cost to future FGD or SCR retrofit projects is anticipated to increase due to greater site complexity which will require more skilled personnel. For example, early SCR retrofits required installation cost of 40-50% of the total project – with the remaining cost for process equipment acquisition and design. Not all installation cost is devoted to labor – cranes and other heavy equipment are required – but the labor component is large. Inevitably, escalating labor cost will translate into higher installed emission control equipment cost.

Labor Pool Availability

The availability of specialized labor required for SCR and FGD retrofit has modestly improved since the 2008 timeframe. Perhaps the most critical craft is "boilermakers" – the highly skilled metalworkers needed to fabricate the high pressure, high temperature steam piping and supply casings. Historically, this labor pool is restricted due to a lengthy apprenticeship that is necessary to assure quality fabrication.

The severe restrictions to the boilermaker labor pool incurred in 2007 and 2008 that limited SCR and FGD installation have subsided. The moderated demand allows project planners to construct a more productive schedule. For example, the ability to assign a work schedule of a "6 10's" (6 workdays per week, each 10 hours) is more feasible than in the 2007/2008 timeframe.

As noted previously, labor requirements for retrofit projects are anticipated to increase with greater complexity of host sites. Historically, wet FGD installation for a 500 MW unit requires from 600,000 to 900,000 man-hours of labor, depending on the design and site-specific conditions. The average value of 750,000 man-hours equates to 1,500 man-hours per MW of generating capacity. For SCR, an average of 500,000 hours is required for a 500 MW unit, which equates to 1,000 man-hours per MW of capacity.

In terms of construction schedule, installing FGD and SCR at a given site is assumed to require 36 and 28 months, respectively. It should be noted this schedule applies to the installation of a single control device at one unit; executing several of these projects in parallel can complicate logistics and significantly extend project duration. Although the demand for boilermaker man-hours required over the project duration is concentrated on the latter 2/3 of the schedule, key labor sources for all skill crafts must be arranged for well in advance of commencing construction.

<u>Labor Required for New Plant Construction</u>. In 2006, Black & Veatch estimated labor demand to construct the 80 GW of new plant capacity that at the time was either in construction, design, or permitting (Black & Veatch, 2006). In October of 2009, the Department of Energy National Energy

[3] See Table 5, "Natural Resources, Construction, and Maintenance", change registered in September 2009 versus September 2008, U.S. Bureau of Labor Statistics, www.bls.gov/news.release/eci.t05.htm

Technology Laboratory (NETL) revised the projected status of new coal-fired power plants either in construction, design, or permitting to be approximately 49 GW (NETL, 2009). From 2013 through 2016, the NETL predicts 21 GW of new coal-fired capacity will be installed. The revised workforce duty to support this construction, if executed in the field as projected, represents a large decrease from the 2006 projections. Given the uncertainty of new coal-fired plants in the "proposed" or "permitted" status, and the possibility of CO_2 limits, the workforce demand due to new coal-fired generation is anticipated to be slight.

Separate from coal-fired power stations, skilled craft labor will still be in demand, although not in short supply as in 2006 and 2007. The NETL projected 37 and 48 GW of natural gas-fired and wind generating capacity, respectively, to be installed between 2012 and 2016. The field labor to install these generating units is less than for coal-fired generation, but still expected to contribute to demand. Finally, many of these skilled labor trades will be in demand due to present economic stimulus actions.

In summary, the supply of skilled labor is not anticipated to limit project schedules, or excessively escalate cost to retrofit FGD and SCR NO_x control equipment. However, competition for skilled craft labor with other power generating projects and infrastructure improvements will exist, thus labor rates are not expected to change much from present values.

SECTION 4

FACTORS AFFECTING CAPITAL COST ESTIMATES

A review of factors affecting capital cost estimates is presented in this section. These involve the costing methodology and site-specific and engineering decisions.

CAPITAL COST ESTIMATING METHODOLOGY

Evaluating the capital cost of environmental controls requires a consistent accounting of costs. Both the costs directly incurred due to process equipment, and indirect costs imposed on plant and operations, must be accounted for. EPRI's Technical Assessment Guide (EPRI, 1993) provides a consistent methodology, and has served as a model by which DOE, EPA, and other organizations assess costs.

Figure 4-1 schematically depicts the key components of a capital cost estimate. The capital equipment directly purchased from the supplier, and installed by a construction contractor comprises the Total Process Capital. Several indirect charges consequential to these direct charges are incurred: (a) engineering design, (b) general facilities, (c) owners' costs, and (d) contingencies (usually both a process and a project). Contingencies are key planning cost elements that are usually absorbed as a project evolves. Indirect fees should be consistent when comparing costs from various suppliers. Table 4-1 presents typical ranges of values historically used by EPRI, DOE, and EPA. Together with the Total Process Capital, these indirect charges comprise the Total Plant Cost.

A second series of indirect charges is incurred based on project execution: fees for the prime contractor, and financing for the construction period. Adding these costs to the Total Plant Cost determines the Total Plant Investment.

Finally, the equipment and site must be equipped with spare parts, and a supply of reagents, chemicals, or fuels, prior to operation. These pre-production charges and inventory capital complete the Total Capital Requirement.

Ideally, evaluating capital costs would utilize similar charges as defined in Figure 4-1 and Table 4-1. Some but not all data presented in Section 6 have been developed on a consistent basis. However, most reported costs are derived from the same suppliers and A/E's that use similar assumptions. These costs are inevitably scrutinized by the public utilities commissions and thus eventually tested for reasonableness. Accordingly, comparing lump-sum costs has limits but can identify trends.

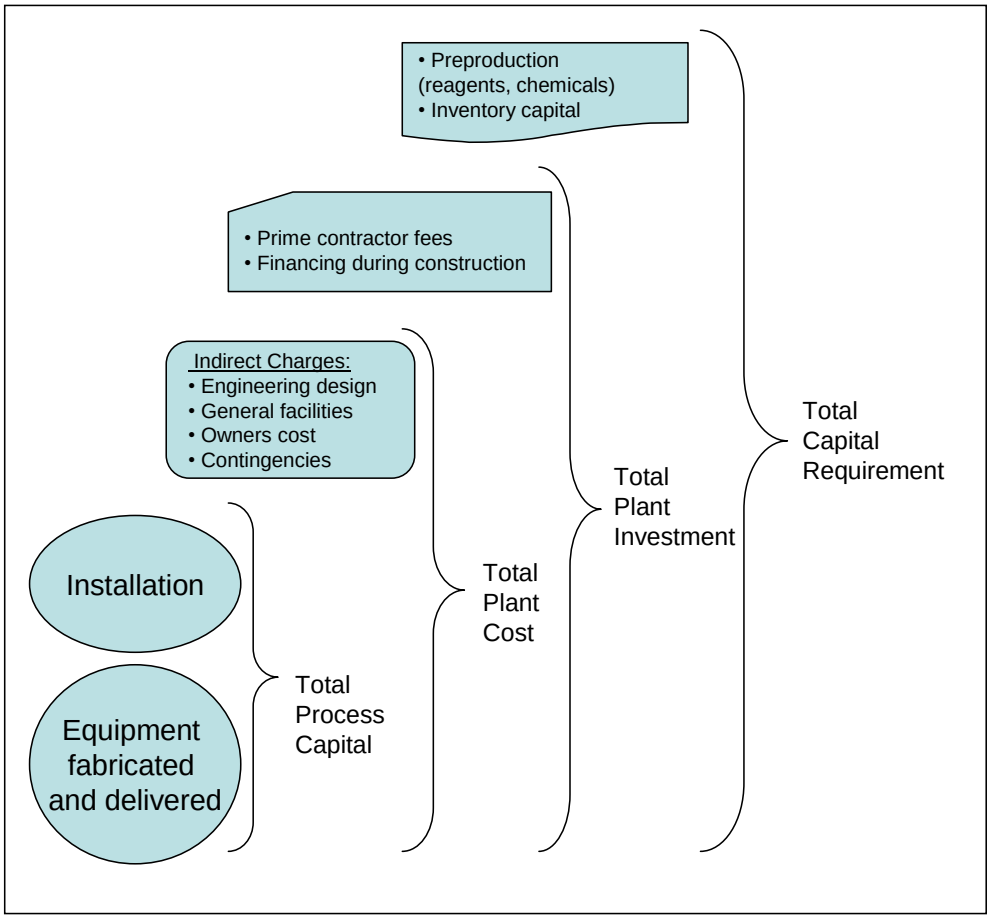


Figure 4-1. Graphic Depiction of Cost Elements

Table 4-1. Examples of Indirect Charges, Assumptions

Cost Element	Purpose	Range, % of Project Cost
Engineering	Establish design	7-15
General Facilities	Roads, buildings, shops, laboratories	2-5, based on process capital
Owner's Cost	Staff, management	5-10
Process Contingency	Uncertainty in process operation	5-10, for a mature process
Project Contingency	Uncertainty in site installation	5-10, if detailed engineering initially completed
Prime Contractor Fees	Business cost	2-8
AFDC	Financing during construction	5-10
Preproduction	Supply of parts, consumables	2, based on total process investment, plus 30 days fixed, variable O&M
Inventory Capital	Supply of consumables	Based on 30 day reagent, chemicals storage

SITE AND DESIGN FACTORS

Site characteristics and the operating philosophy, particularly the owner's tolerance for equipment outages, affect capital cost. These and other factors are responsible for variations in estimates of capital cost among projects.

The key site-specific factors that define capital cost are:

Fuel Composition. The fuel defines the volume of combustion products, content of particulates, SO_2, and NO_x production rates, and composition of fly ash. These characteristics drive process equipment cost. Most important is the volume of flue gas produced by fuel combustion. For example, PRB or other sub-bituminous coals can generate up to 30% greater volume flue gas to be treated, compared to an eastern bituminous coal, per unit generating capacity. For FGD, the amount of sulfur to be processed and the ultimate fate of the byproduct are factors. For SCR, the flue gas volume, the content and composition of ash, and trace elements in the fuel such as arsenic and phosphorous can determine reactor volume and catalyst layout.

Site Congestion and Retrofit Difficulty. Limited space for equipment location, access for construction, and access for labor will extend installation time. Generally, older units of smaller generating capacity will incur high costs due to limited access (as well as penalties due to economies-of-scale). Large generating units do not necessarily guarantee adequate space for equipment installation. Specifically, even though the area occupied by the plant will be larger, the opportunities for obstruction are greater.

Existing Site Auxiliary and Support Facilities. FGD and SCR process equipment demand auxiliary power, steam, and compressed air. The availability of these consumables at a site varies, and additional infrastructure to supply and distribute these consumables may be necessary. The most costly of these can be the requirement to provide new power distribution infrastructure including transformers, switchgear and/or "motor control centers". The escalation in price until 2008 of copper-derived electrical subsystems has contributed to cost increases; during periods of peak copper pricing electrical infrastructure escalated from 5-6% of an FGD budget to more than 10%.

Flue Gas Draft System Upgrades. The retrofit of environmental controls will change the static pressure within the ductwork, which may require upgrades to fans, new fan motors, upgraded electrical systems, and strengthening of ductwork, ESPs, and boiler walls. The upgrade and strengthening of ductwork and boiler walls is necessary to prevent collapse or implosion.

Waste Water Treatment Requirements. For wet FGD, the need to treat process discharge water varies depending on permitted limits. Zero-water discharge requirements can impose large costs on the entire FGD slurry treatment and dewatering systems, and may possibly interfere with FGD chemistry. For a suite of wet FGD process equipment installed in North Carolina, wastewater treatment facilities comprised a total of between 9 and 14% of the total capital cost.

Stack Rebuild or Replacement. Retrofit of wet FGD process equipment can require replacement or major rebuild of the stack. Flue gas treated by wet FGD poses corrosion and deposition potential, due to relatively low saturation temperature and content of SO_3. If space on-site is available, the least cost

solution sometimes involves a new stack rather than retrofitting corrosion-resistant liners to an existing stack. FGD installation can be limited by the availability of expertise and resources to erect a new stack.

Equipment Sparing and Redundancy Philosophy. The operating strategy of the owner, and the cost incurred for an FGD outage in terms of compliance margin and SO_2 allowances, determines the equipment sparing and redundancy strategy. General convention defines equipment that is "spare" as that stored in a warehouse and ready to install; equipment that is redundant is installed and ready to run. Operators with sufficient margin in meeting the SO_2 or NO_x cap, or for whom SO_2 or NO_x "allowances" are available, may choose to lower capital cost by minimizing redundant equipment. Conversely, operators for whom access to SO_2 or NO_x allowances is limited or costly may elect to invest in more spare equipment. Sparing philosophy can affect capital cost by 10-20%.

Materials of Construction. The materials required to resist corrosion and erosion, in an effort to obtain high reliability, elevate capital cost. Specifically, high alloy containing steels or rubber-lined absorber vessels or pumps are needed to increase reliability. Although lower grade materials can sometimes be used for certain piping applications, the ability of a fluid to corrode, erode, or otherwise compromise the reliability of piping must be considered when selecting construction materials. For wet FGD, the need to use higher alloy and lined equipment adds 10-20% to the project capital cost.

Capital versus Operating Cost. Many decisions revert to a tradeoff between capital and operating cost; capital savings derived can be at the expense of higher operating cost. For SCR, a key example is the catalyst layout – the number of initial and final layers of catalyst utilized. For example, a reactor layout of 2 initial layers and 1 spare layer (i.e., 2+1) will result in a lower capital but higher operating cost, compared to utilizing 3 initial layers and 1 spare layers (i.e., 3+1). The key difference is higher catalyst consumption over a long-term period.

Of these factors, perhaps the most important is site complexity. Plant sites where FGD and SCR are to be retrofit have become more complex for several reasons. First, the largest generating capacity, highest capacity factor units have already been equipped with FGD and SCR, leaving smaller and older units for future retrofit. The incurred capital cost per unit of generator output ($/kW basis) is disproportionately higher on these smaller units. Second, these units – being older – are located on sites of limited area and restricted access. Consequently, these sites may not be amenable to retrofit of control equipment, without relocating other components. The limited space also restricts labor productivity and extends construction time. As a consequence, for FGD, the absorber towers are located further from the unit, requiring longer ductwork runs.

SECTION 5

FLUE GAS DESULFURIZATION COSTS

This section presents capital and operating costs for wet and dry FGD process equipment.

FGD CAPITAL COST

The capital costs for both wet and dry FGD process equipment are discussed in this section.

Wet FGD

Figure 5-1 depicts installed capital cost as a function of generating capacity for wet limestone-based FGD. The units depicted all employ limestone reagent, forced oxidation treatment of byproduct, deliver at least 97% SO_2 removal, and are equipped with mist eliminators. The influence of design or operating conditions different from those stated will impact cost, especially due to variations in inlet SO_2 and the subsequent impact on solids byproduct handling equipment. In addition, some of the cost data are derived from two or more identical units installed at one site, and thus reflect an economy-of-scale for engineering and procurement. The cost reported in Figure 5-1 includes both contracted and staff engineering charges, and financing of construction.

Figure 5-1 depicts two curves, based on when the FGD process started commercial service. All costs are reported on a 2008-dollar basis. One curve (Curve A) represents units starting commercial operation after January 2008, and includes several units scheduled for a 2010 startup. This curve, based on 20 data points for the 2008-2010 startup dates, suggests a modest economy of scale with larger generating capacities, enabling lower unit cost. Figure 5-1 also shows a cost curve (Curve B) similarly based on 20 data points (not shown for simplicity) for units that began commercial operation between 2004-2007, relating capital cost and generating capacity. The “midpoint” of these latter cost data is 2005.

Comparing the two curves in Figure 5-1 shows capital cost increased from the 2004-2006 to the 2008-2010 timeframe. Specifically, Curve B shows wet FGD capital cost for a 500 MW unit retrofit in the 2004-2006 timeframe escalated from $342/kW to $407/kW – an increase of $65/kW over a mean time period of 4 years. The difference equates to an escalation of approximately $16/kW per year. At this rate of escalation, an FGD process installed for a 2015 startup on a 500 MW unit will require about $470/kW (in 2008 dollars).

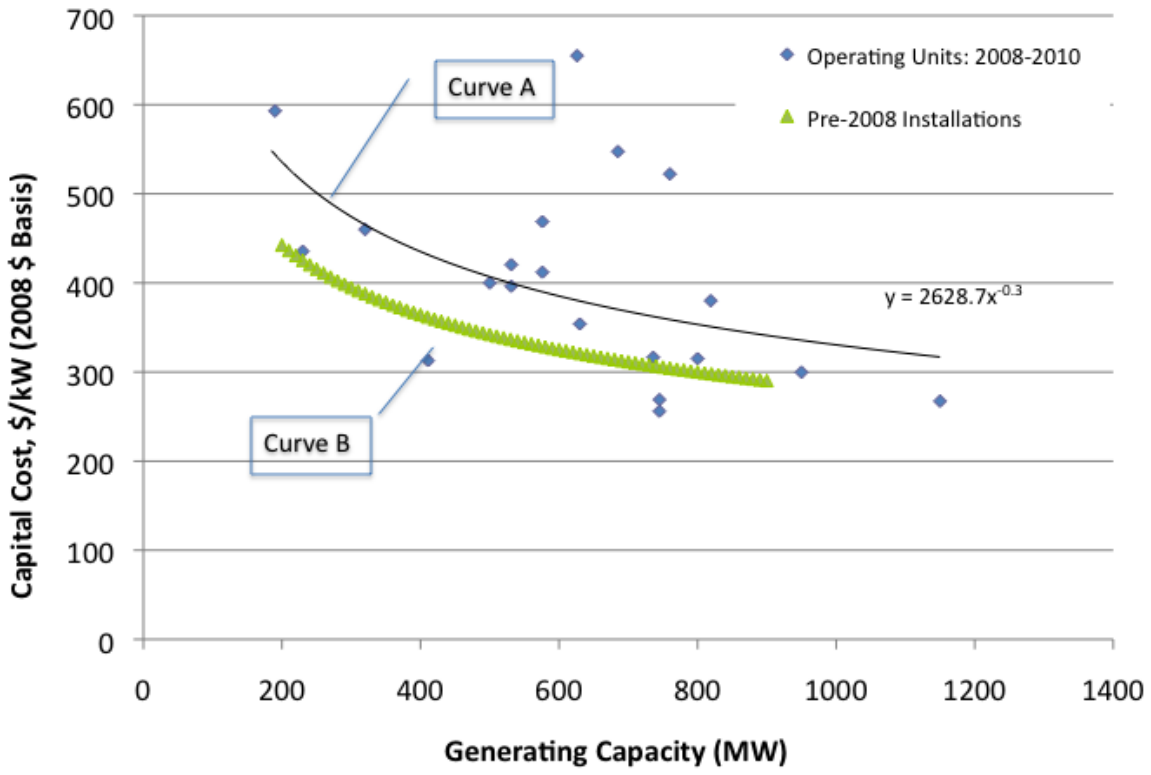


Figure 5-1. Wet FGD Process Equipment Cost: Various Sources

Dry FGD

Figure 5-2 depicts installed capital cost presented as a function of generating capacity, for dry lime-based FGD. The costs for all units with a lime-based spray dryer absorber (SDA) include a secondary fabric filter particulate collector. Most SDA equipment is designed for 93-95% SO_2 removal. For these designs, fly ash is removed in the existing particulate control device (an ESP in all cases), so ash handling and disposition is the same as prior to retrofit.

Figure 5-2 shows the estimated capital costs for eleven units evaluated for retrofit to a Midwestern utility operator. Similar to the case for wet FGD, these costs are expressed in 2008 dollars, and reflect a ready-to-operate FGD process accounting for all direct and indirect charges. For three dry FGD units that were actually constructed, the incurred costs are reported.

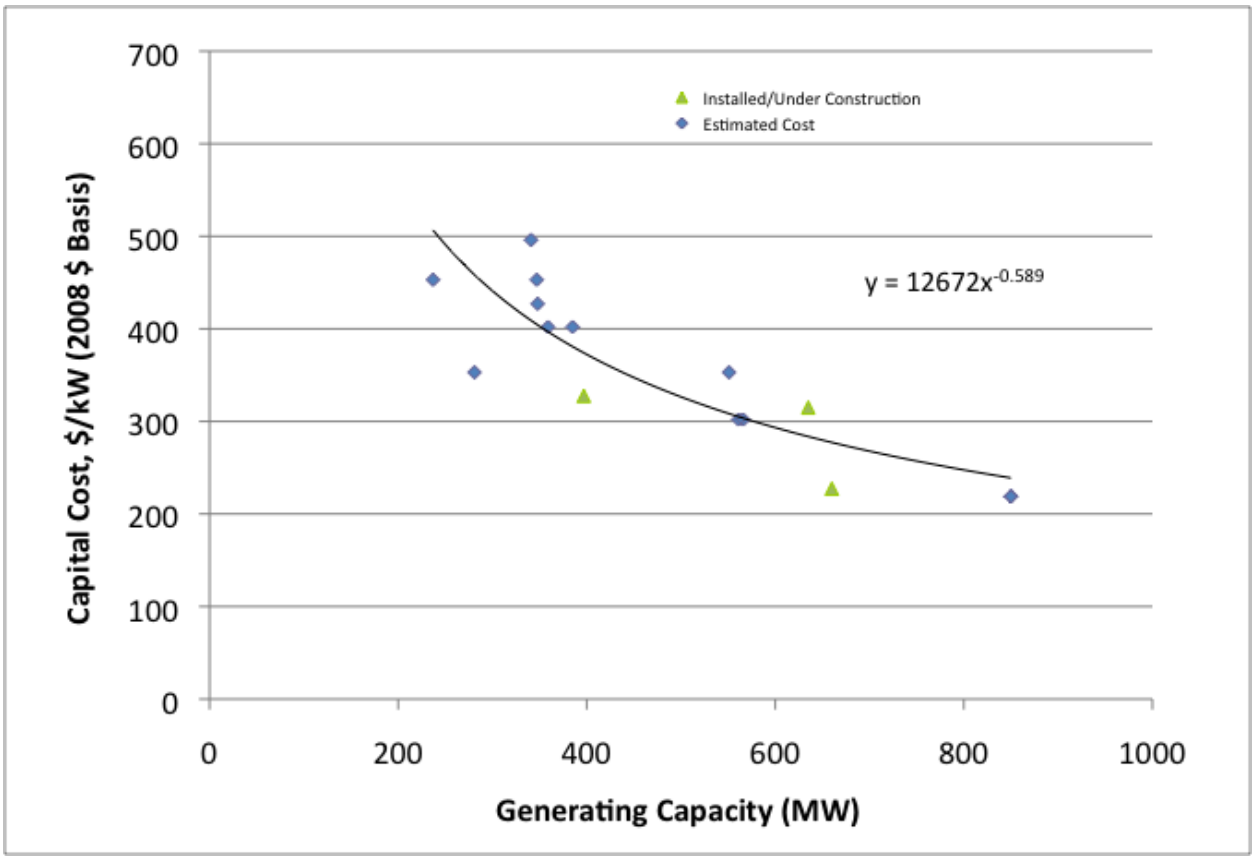


Figure 5-2. Dry FGD Process Equipment Cost: Various Sources

The dry FGD equipment costs reported do not suggest increases with time. However, the basic process equipment is the same as required for wet FGD, and escalation forces should be the same. Consequently, the same escalation rate of 19% over four years is assumed for dry FGD. These data suggest the capital cost of a 500 MW unit completed in late 2014 for process startup in 2015 would be approximately $385/kW.

Small units are particularly prone to escalated FGD cost, as fixed costs for items such as engineering and reagent preparation equipment are disproportionately borne by the limited plant output. An example of how capacity and market timing affects cost is presented by the case for PSHN Merrimack Units 1 and 2, where about $1,000/kW is projected for FGD to treat flue gas from both units. The site and market conditions are unique; so much that this value is not included in Figure 6-1. The small size of Units 1 and 2 (115 and 320 MW, respectively), the extensive ductwork to service both units, gas fan upgrades, enclosures for cold-weather maintenance, waste water treatment system, restricted site for equipment installation and construction, and strong market forces are responsible for the high cost. Notably, in 1993 Unit 2 was the first coal-fired generator in the U.S. retrofit with SCR. The conditions in 1993 under which the SCR reactor for Unit 2 was designed and installed featured aggressive pricing by early entrant suppliers, available materials and labor, and an accessible site. These conditions, which enabled Merrimack Unit 2 to acquire SCR for the lowest cost reported in the U.S., are the complete opposite for the acquisition of wet FGD.

OPERATING COST

Operating cost is defined in several ways – total operating cost per unit of capacity per year, normalized to power generated, or per unit of emission species removed.

Figure 5-3 is a reproduction of a graphic describing the range of various FGD operating cost components as presented at the November 2006 PowerGen conference (Sargent & Lundy, 2006). Figure 5-3 compares (for a 500 MW plant) the various contributors to total operating cost for a limestone-based wet FGD process, designed for 95-97% SO_2. Total O&M ranges from approximately \$15 to \$38/kW/yr, and is almost equally comprised of fixed and variable components. As noted in Figure 5-3, limestone reagent cost for this size of unit varies in direct proportion to the amount of sulfur in the coal. Other operating cost components directly related to sulfur content include operating and maintenance labor, and byproduct management.

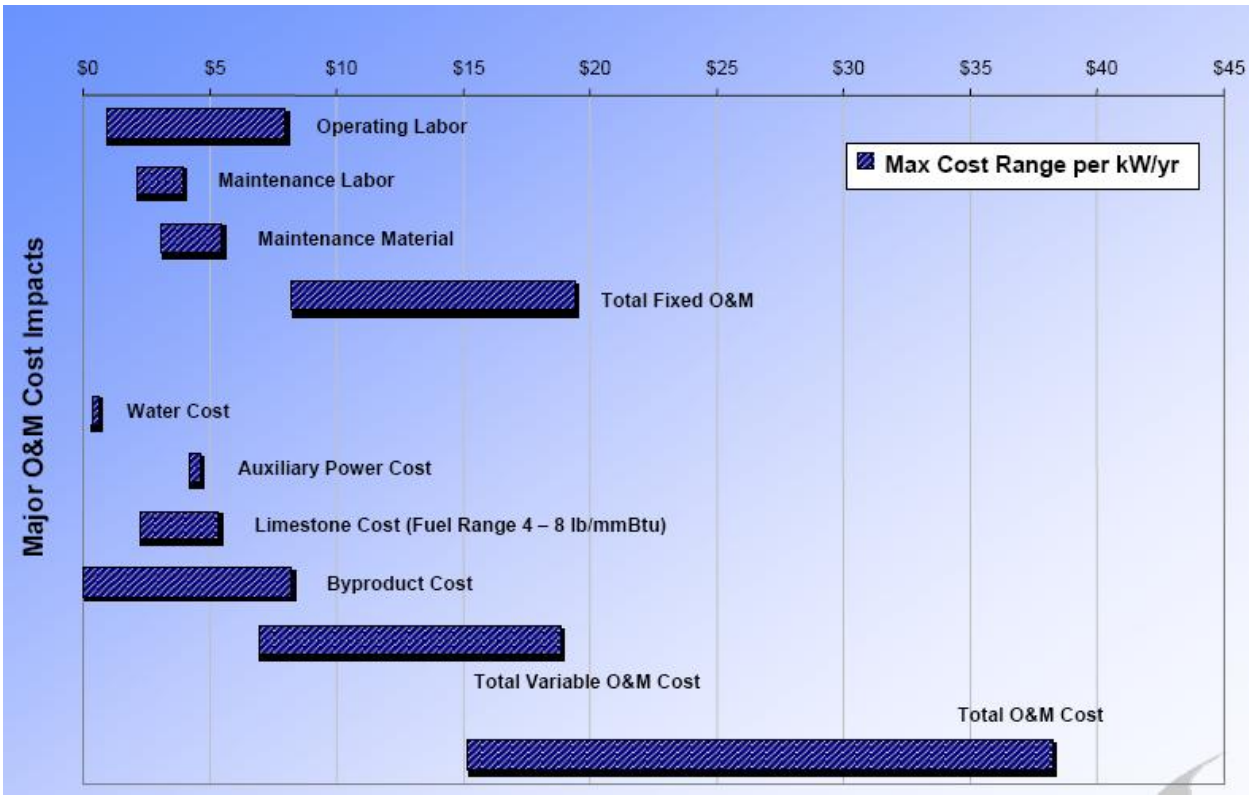


Figure 5-3. Range of Wet FGD Operating Costs for 500 MW Units (after Sargent & Lundy, 2006)

The capital cost ranges in Figures 5-1 and 5-2, when combined with operating costs escalated to a 2008 year basis, provide an indicator of FGD cost-effectiveness, or the cost per ton of SO_2 removed. Figure 5-4 presents the cost per ton of SO_2 removal for a hypothetical 500 MW unit, utilizing a limestone based forced oxidation process. Calculations are reported for coals such as PRB, with low sulfur content, and include Pennsylvania and Ohio coals with 2.6% and 3.4% sulfur content, respectively. These coals present an uncontrolled sulfur content of 0.90, 4.0, and 5.8 lbs SO_2/MBtu. Figure 5-4 presents results based operating costs similar to Figure 5-3, and calculated for the specific coal composition. It is possible that higher operating costs may be incurred that reflect higher labor rates

and other site-specific factors, such as reagent transportation. Figure 5-4 results also assume a 15-year book life (i.e., cost recovery period) and thus a capital recovery factor of 0.12.

For the Pennsylvania and Ohio coals, the unit cost of SO_2 removal is generally between $250 and $600/ton, exceeding $500/ton for the Pennsylvania coal when capital cost reaches $375/kW. Unit SO_2 removal cost approaches $500/ton for the Ohio coal as the capital cost exceeds $450/kW. For PRB coal, the same capital cost increase will elevate SO_2 removal cost from approximately $1,600 to $2,500/ton. The costs will change in proportion to the sulfur content of the fuel.

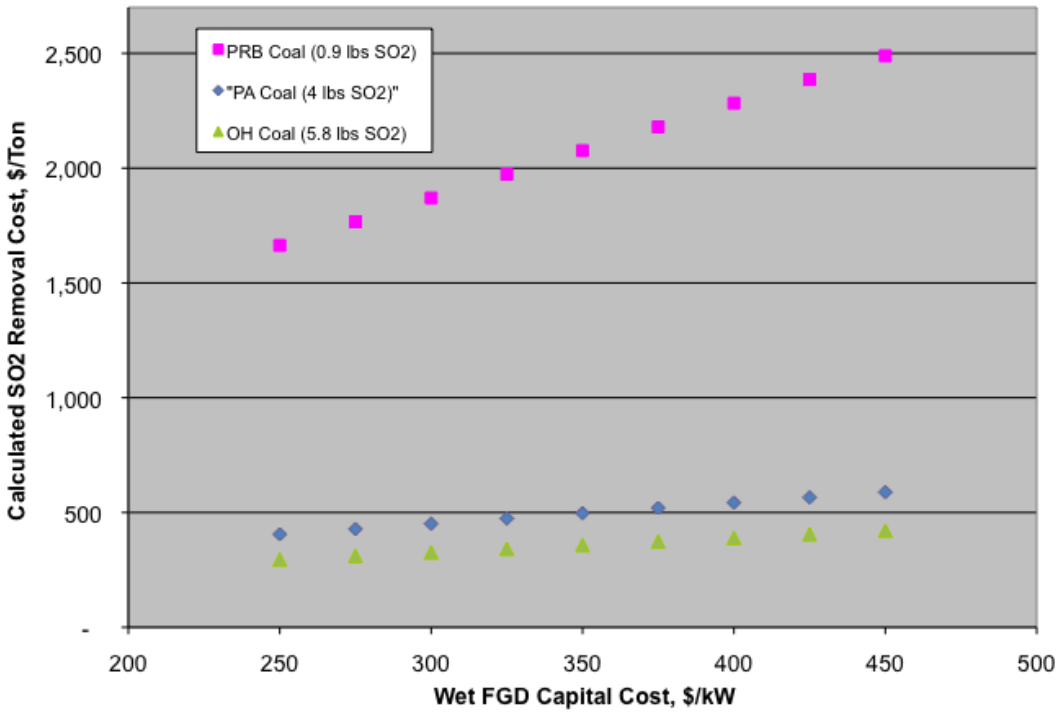


Figure 5-4. SO_2 Removal Cost per Ton ($/Ton), Year 2008 Basis

SECTION 6

SCR NO_x COST

This section presents capital and operating costs for SCR NO_x control.

SCR CAPITAL COST

Figure 6-1 summarizes the reported capital cost for over fifty SCR installations, some installed as early as 2000, and includes estimates for process equipment presently under construction. All costs are reported on the basis of 2008 dollars, include both staff engineering and owners' engineering charges, and financing charges (AFDC). Regarding process design, it should be cautioned that not all data represent comparable cases – the inlet NO_x removal, fuel type, outlet NO_x design level, number of catalyst layers, and reactor arrangement differ for most of the installations represented. However, the general trend in cost is believed to be an accurate reflection of the industry average.

Figure 6-1 reports cost incurred over four discrete time periods. These include the time periods for the years (a) pre-2000, reflecting the most early projects, (b) 2000-2002, reflecting the initial class of units installed prior to broad SIP-Call compliance, (c) 2003-2004, reflecting units installed during the height of the SIP-Call compliance, and (d) 2008-2010, reflecting units recently installed or presently under construction. A polynomial curve is fit to all data except that for the 2000-2002 timeframe, the latter excluded for graph clarity.

The data in Figure 6-1 reveal the cost penalty incurred by the smaller generating units is more acute for SCR retrofit to the most recent units; specifically, retrofitting SCR to the smallest units (<300 MW) compared to the largest units (>500 MW) incurs a relatively large cost penalty.

COST ESCALATION

The data presented in Figure 6-1 can be used to infer the escalation in cost experienced for the installed SCR process equipment over time. For each of the four time periods presented in Figure 6-1, the average installed capital cost was determined. Specifically, the average capital cost was determined for the units within each group. The difference in the average cost – all corrected to a 2008-dollar basis – suggests the cost escalation.

Figure 6-2 presents the difference in costs for the four periods, suggesting an escalation of $140/kW over the 12 year period, or about $12/kW per year. This trend can be anticipated to continue in to 2015, as the evolution to installing SCR at smaller, more complex sites continues.

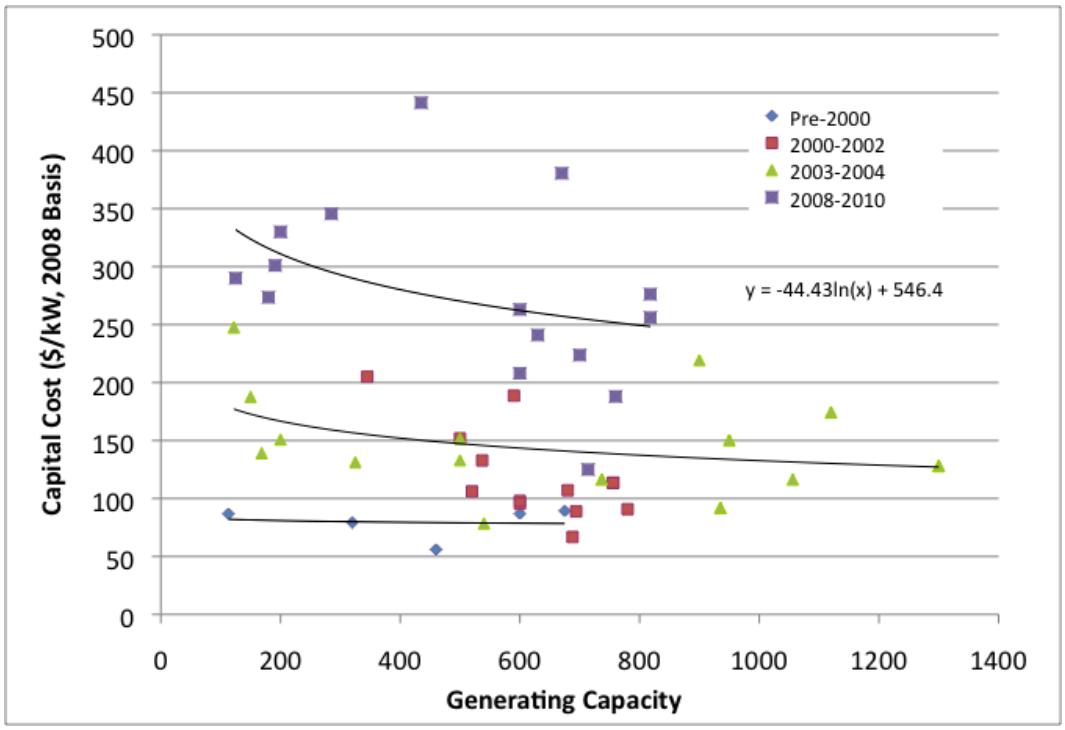


Figure 6-1. Capital Cost of SCR Process Equipment vs. Generating Capacity: Four Time Periods

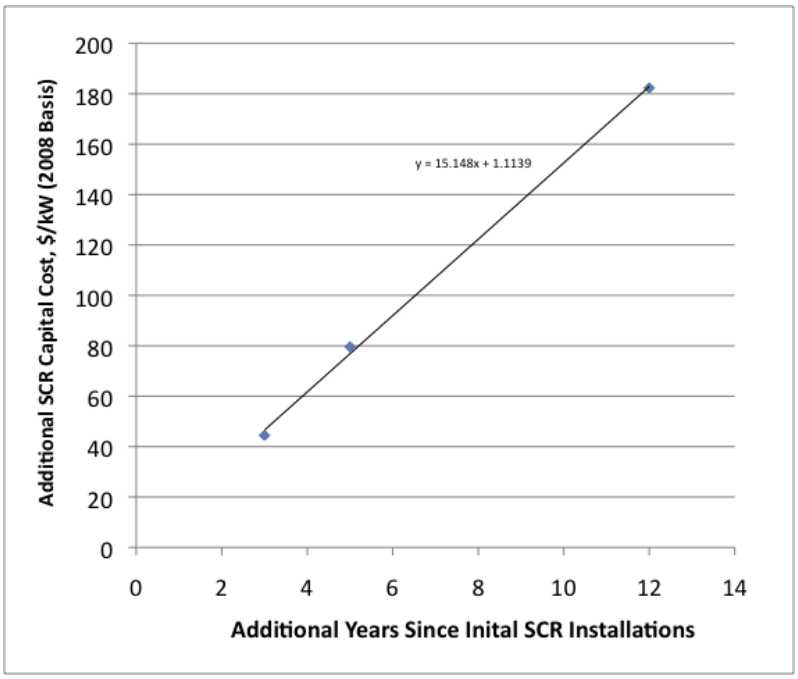


Figure 6-2. Increase in SCR Capital Cost Based on Four Time Periods (Three Increments)

Capital cost escalation of approximately $12/kW per year is apparent with SCR process equipment installed since 2000. In addition to the escalation in the basic cost of materials and labor, the complexity of the sites to which equipment is retrofit is believed to have increased. Although there is no index of site complexity that can be referenced, the average size of the generating unit retrofit has decreased. Specifically, Figure 6-3 presents the average generating capacity of the unit retrofit versus the startup year and shows a small but consistent decrease in the average generating capacity. This average capacity of units retrofit with SCR decreased from approximately 600 MW for the first wave of retrofits, to approximately 450 MW for those units deploying SCR in 2012.

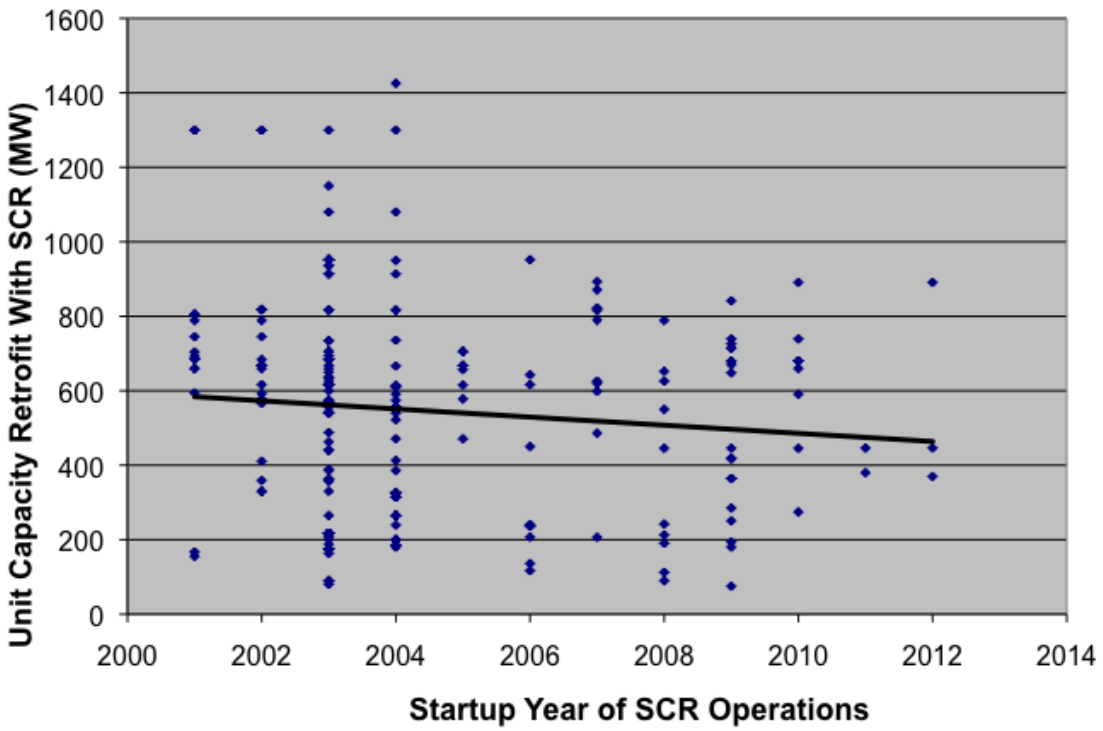


Figure 6-3. Average Generating Capacity of Unit Retrofit with SCR vs. Installation Date

An example of how the role of market forces and site characteristics affect SCR cost is demonstrated by the case of the Associated Electric Cooperative (AEC) SCR installations at the New Madrid and Thomas Hill generating stations.

AEC was as an early adopter of SCR in the U.S., specifically to the challenging case of cyclone boilers, fired by PRB coal. Units 1 and 2 of the New Madrid station retrofit SCR in 2001 and 2002, respectively. These units were designed and constructed by a leading engineering firm, and have proved to be capable designs. AEC was able to exploit market forces at the time – an evolving SCR market, with strong competition from numerous suppliers and service providers – and retrofit each 680 MW unit for less than $100/kW (2008 dollar basis). Figure 6-4 depicts the site and layout of the New Madrid SCR-equipped units, showing the available space for the SCR reactors.

Figure 6-4. Site Layout for Associated Electric Cooperative's New Madrid Station, Units 1 and 2. (SCR reactors denoted within red circle)

In 2008, AEC completed construction of three SCR reactors for each of Thomas Hill Units 1-3. Units 1 and 2 are cyclone boilers, fired by PRB, similar to New Madrid. The small generating capacity of these units (180 and 285 MW for Units 1 and 2, respectively), the limited space to locate the reactors, and restricted access all serve to elevate construction cost. Figure 6-5 depicts the site and layout of the Thomas Hill station, identifying the SCR reactors for Units 1 and 2.

AEC was not able to replicate the favorable market conditions encountered when the New Madrid units were built; notably the process supplier that provided attractive terms for New Madrid has withdrawn from the market. The demand for components, materials, and construction labor incurred during 2007 and 2008 timeframe exceeded that for the timeframe when the New Madrid units were constructed. As a consequence of these conditions, the capital cost to retrofit SCR for these units averages $300/kW – essentially three times the cost of New Madrid units. That an SCR-experienced owner such as AEC incurred these costs at Thomas Hill – while expending the same diligent effort as at New Madrid – demonstrates the strong role of market forces and site conditions in controlling technology costs.

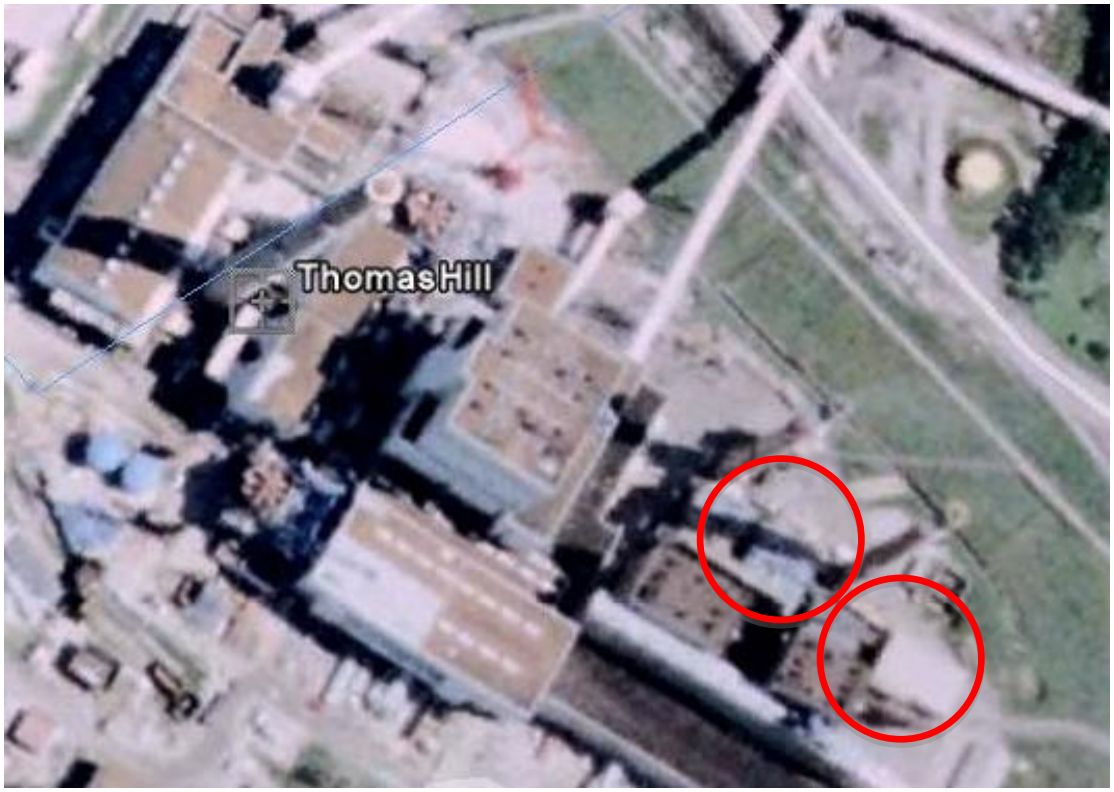


Figure 6-5. Site Layout for Associated Electric Cooperative's Thomas Hill Station, Units 1 and 2. (SCR reactors denoted within red circle)

OPERATING COST

Operating costs for SCR processes consist mostly of replacement catalyst and ammonia-based reagent. Each of these cost components has increased significantly in the last 10 years. In the early stages of SCR operation, catalyst replacement was the dominant component of operating cost. In the last ten years, a decrease in catalyst cost and escalating natural gas (and thus ammonia) prices have inverted this relationship, so that for most units reagent supply dominants operating cost. Fixed operating and maintenance costs are generally small compared to these two components, and typically are less than 1% of total capital, incurred annually.

Factors affecting catalyst and reagent supply and reagent cost are discussed subsequently.

SCR Catalyst

Historically, supply of catalyst comprised the largest operating component of SCR NO_x control. The unit cost of catalyst has greatly decreased since the early 1980s. Further, the ability to regenerate or rejuvenate catalyst for approximately 50% of new product price restrains price.

Figure 6-6 presents the unit price of catalyst since the early 1980s, corrected to a 2008-dollar basis, showing a decrease in unit price by a factor of five since the earliest commercial bids. The minimum price of near \$4,000/m^3 first occurred in 2005, and prices approximating this level continue today.

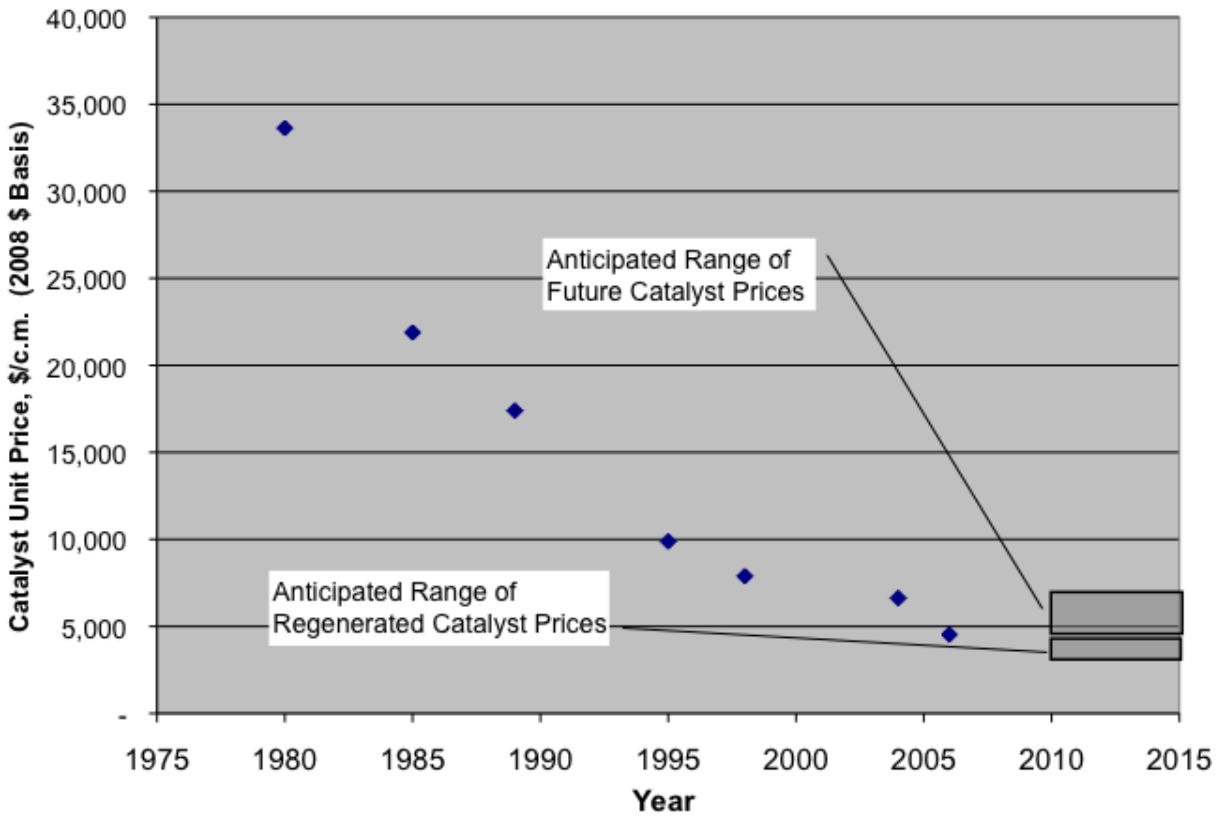


Figure 6-6. History of SCR Catalyst Prices: 1980- 2008 (2008 Dollar Basis)

Limited catalyst availability, requiring orders to be placed almost one year in advance, was observed in recent years as many operators prepared seasonal SCR reactors for annual operation, which included supplementing or replacing existing catalyst layer. However, catalyst prices remain in the approximate range of \$5,000-6,000/m^3 and are anticipated to remain in this range during the next 5 years.

The consequence of the catalyst price decrease is that catalyst procurement no longer dictates SCR cost as it has in the past. In fact, catalyst management decisions at present can exploit low prices to insure the reactor has adequate catalyst activity, to confine catalyst replacement to major outages, avoiding unit shutdown for the purpose of catalyst addition or exchange.

Reagent

Any savings in SCR operating cost due to catalyst price decreases have been offset by escalation in delivered price of ammonia-based reagent. SCR operators can choose from four types of ammonia-based reagent: anhydrous ammonia, aqueous ammonia of 19.5% NH_3 content or 29% NH_3 content, or urea. For the purposes of this discussion, anhydrous ammonia will be discussed as an example, recognizing that the alternative reagent forms are equally viable.

The cost of anhydrous ammonia is as much as 80-90% determined by the cost of natural gas feedstock. In late 2008, the cost for anhydrous ammonia for both agricultural and industrial uses jumped to well in excess of $600/ton for many suppliers. The moderation in natural gas prices and muted demand in the global economy has allowed ammonia reagent prices to relax from these 2008 highs. An industry report (CRU, 2009) predicts the price of anhydrous ammonia as-delivered to Tampa, Florida, to be approximately $300-350/ton for the early portion of 2010. This cost is consistent with a delivered cost to generating stations for anhydrous ammonia of $400/ton, the same as the level experienced in 2007.

Example Operating Cost

The operating and maintenance cost for an SCR process can be developed (for a hypothetical 500 MW unit), based on assumptions in Table 6-1 that define the conditions of operation. These are:

Fixed O&M. Spare parts and support for miscellaneous duties that must be executed regardless of unit operation are assumed to require 0.50% of process capital.

Catalyst Supply. Catalyst supply cost is determined by long-term purchases from which an annual-equivalent average can be calculated. The long-term purchases are dictated by catalyst addition to the empty spare layer, and replacement of existing layers. For an SCR reactor employing a 2+1 catalyst arrangement, an initial space velocity of 3,200 1/h, and a 16,000 hour period for an initial operating guarantee, the purchase of one layer for every 16,000-20,000 operating hours may be required, depending on the process design and fuel type. Operating experience through 2009 suggests this catalyst management strategy, typical of initial assumptions adopted by many operators, is proving to be a best-case scenario, and that greater volumes of catalyst are required, or more frequent catalyst changeout is needed.

Reagent Cost. The purchase of anhydrous ammonia for 90% NO_x removal from 0.35 lbs/MBtu, at 85% capacity factor, defines the reagent cost. A delivered price of $400/ton is assumed.

Auxiliary Power. Auxiliary power for an additional 6 inch water gauge (w.g.) flue gas pressure drop is assumed – 5 inch w.g. for the process flange-to-flange, and an additional 1 inch w.g. across the air heater.

Catalyst Cleaning. Sootblower consumption of 0.2% of the plant steam output is adopted; this steam is assigned a cost of $1/MBtu. Many new SCR installations employ acoustic horns for cleaning, which require less auxiliary power.

Operating Staff. The addition of one operator is assumed for maintenance of the above components. Also, a part time (25%) engineer to assess operation and evaluate data is assumed. The need to account for additional staff due to SCR is highly variable; some owners report additional operating or engineering staff is not added for these purposes. However, these assumptions are adopted to account for operations and staff duties that did not exist prior to SCR.

The capital cost observed in Figure 6-1, when combined with updated operating costs in Table 6-1, provides an indicator of SCR cost-effectiveness, or the cost per ton of NO_x removed. Figure 6-7 presents the cost per ton of NO_x removal for a hypothetical 500 MW unit, utilizing a 2+1 catalyst arrangement, with an initial NO_x input of 0.38 lbs/MBtu, as a function of SCR capital cost.

Calculations are reported for an eastern bituminous coal with approximately 0.38 lb/MBtu furnace NO_x exit, and a PRB-fired unit assumed to produce 0.20 lb/MBtu. Results presented in Figure 6-7 for the eastern bituminous coal employ operating cost in Table 6-1, while calculations for PRB coal employ lower cost for reagent use and catalyst consistent with lower inlet NO_x. Figure 6-7 results also assume a 15-year book life (i.e., cost recovery period) and thus a capital recovery factor of 0.12.

Table 6-1. Key SCR Operating Cost Components: 500 MW Reference Plant ($150/kW Capital, 2008 Dollar Basis)

Operating Cost Component	Basis	Annual Cost for 500 MW ($/yr)	Annual Cost for 500 MW (mills/kWh)
Fixed O&M	0.5% of Process Capital	150,000	0.04
Labor	Operators/Part-time Engineer	125,000	0.03
Fuel Cost	Auxiliary Steam	100,000	0.02
Reagent	90% NO_x removal (from 0.38 lb/MBtu)	885,000	0.25
Auxiliary power	6 in. w.g. total @ $20/MWh	265,000	0.07
Catalyst Supply	16,000 hr guarantee for 2+1 reactor	675,000	0.15
Total		2,200,000	0.59

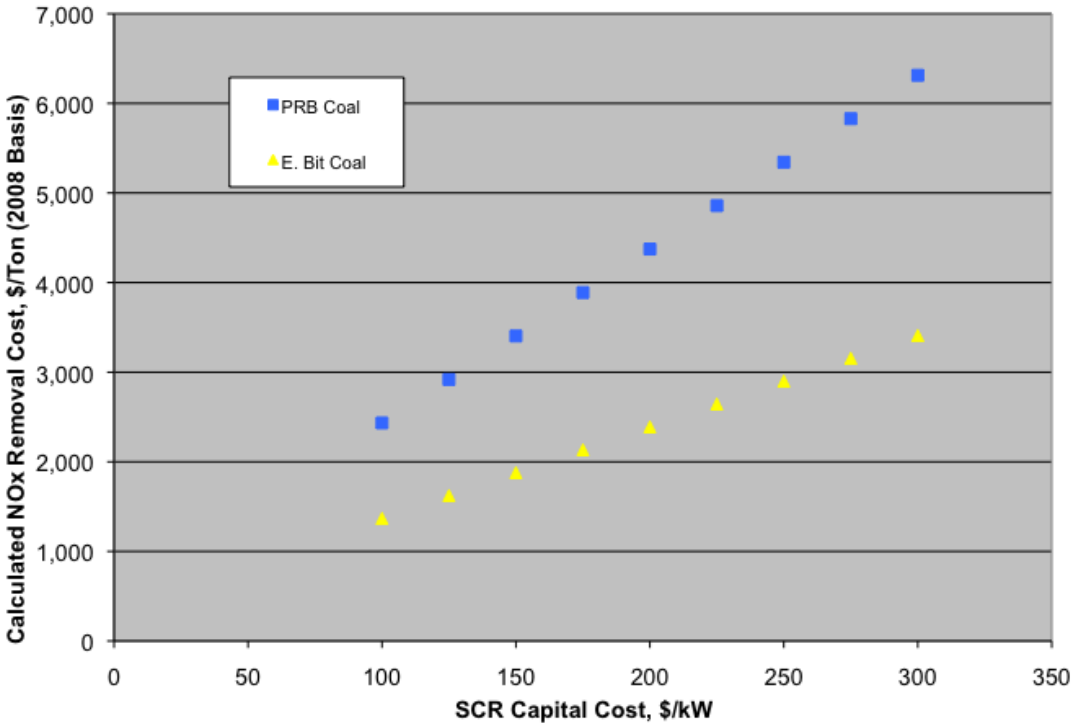


Figure 6-7. NO_x Removal Cost per Ton ($/ton), Year 2008 Basis.

For the eastern bituminous coal, an increase in capital cost from $100/kW to $300/kW elevates the cost of NO_x removal from $1,200 to more than $3,200/ton. For the PRB coal, with lower inlet NO_x rate and lower operating costs, the same capital cost increase elevates NO_x removal cost from approximately $2,300 to more than $6,000/ton. The costs will change in proportion to the boiler NO_x generated.

SECTION 7

CONCLUSIONS

The escalation in cost to acquire and retrofit environmental control equipment has moderated from the rates in 2007 and 2008. Two factors are responsible for this outcome. First, the moderated demand for goods in response to a slower world-wide economy has lowered prices for most components of finished goods. Delivered prices for some goods are unchanged, while others are reduced by 10-20% from the 2007 and 2008 highs.

Second, the skilled labor pool for which shortages in 2007 and 2008 limited the rate of project completion is in less demand. For most skilled trades, labor prices have not decreased, but continue to escalate at modest rates of 1-2% annually. The productivity in deploying this labor will likely be higher, due to the improved skill and experience of the average available worker.

The capital cost of retrofitting either wet FGD or SCR increased over the recent 4-year period, from about 2005 through 2009, and specifically for a 500 MW plant, by approximately $50-65/kW. This same rate of cost escalation is anticipated to continue for the next 4-6 years, elevating the cost of equipment installed in 2014 and 2015 for a CAIR Phase 2 mandate and the anticipated HAPs MACT rule.

Two reasons suggest why installed cost will continue to escalate despite the world-wide economic slowdown. First, the $50-65/kW increase represents an average since approximately 2005; price and schedule pressures existed prior to the 2007 and 2008 increases. In 2009, material prices have moderated but not significantly, while labor escalation continues.

Second, the remaining units to be retrofit feature more complicated sites. These units are smaller in generating capacity, and frequently represent single-unit installations that cannot share common facilities, such as reagent preparation, byproduct handling and storage, and a wet stack. Further, the layout of the host sites will be more compact, with greater interference from existing equipment, requiring a more complex and labor-intensive design.

SECTION 8

REFERENCES

Reference	Author
Black & Veatch, 2006	Black & Veatch, "Building New Baseload Generation in The Midwest", presentation to MMEA, April 11, 2006.
CRU, 2009	CRU, "Ammonia Short-Term Forecast and Review", Volume 02, Issue 12, November 5, 2009.
Cichanowicz, 2004	Cichanowicz, J.E., "Why are SCR Costs Still Rising", Power Magazine, April 2004.
DOE, 2009	U.S. Department of Energy, 'Tracking New Coal-Fired Power Stations", National Energy Technology Laboratory, Office of Systems Analyses and Planning, October 8, 2009.
EPRI, 1993	EPRI Technical Assessment Guide, "Electricity Supply – 1993," EPRI TR-102275-V1R7, June 1993.
Erickson, 2009	Erickson, Clay, "Personal Communication", December 8, 2009.
Gaikwad, 2009	Gaikwad, Rajendra, Personal Communication", December 8, 2009.
Hoskins, 2003	Hoskins, B., et al., "Uniqueness of SCR Retrofits Translates Into Broad Cost Variations", Power Engineering, May 2003.
Katzberger, 2007	Katzberger, S., et al., "Impact of a Resource-Constrained FGD Market", Electric Power 2007 Conference and Exhibition, May 1-4, 2007, Chicago, IL.
Marano, 2006	Marano, M., et al., "Estimating SCR Installation Costs", Power, January/February 2006.
NCDENR, 2009	North Carolina Department of Environment and Natural Resources, "Implementation of the Clean Smokestacks Act", June 1, 2009.
NETL, 2009	National Technology Energy Laboratory, "Tracking New Coal-Fired Power Plants", Office of Systems Analyses and Planning, October 8, 2009.
Sargent & Lundy, 2006	Sargent & Lundy, "The Real Cost of Wet FGD Retrofit Projects", presentation to Power-Gen, November 2007, Orlando, FL.