Experience curves for power plant emission control technologies

Edward S. Rubin, Sonia Yeh and
David A. Hounshell

Department of Engineering and Public Policy,
Carnegie Mellon University,
Pittsburgh, PA 15213, USA
E-mail: rubin@cmu.edu

Margaret R. Taylor

Richard & Rhoda Goldman School of Public Policy,
University of California, Berkeley,
Berkeley, CA 94720, USA

Abstract: This paper examines past experience in controlling emissions of sulphur dioxide (SO_2) and nitrogen oxides (NO_x) from coal-fired electric power plants. In particular, we focus on US and worldwide experience with two major environmental control technologies: flue gas desulphurisation (FGD) systems for SO_2 control and selective catalytic reduction (SCR) systems for NO_x control. We quantitatively characterise historical trends in the deployment and costs of these technologies over the past 30 years, and use these data to develop quantitative 'experience curves' to characterise the rates of cost reduction as a function of cumulative installed capacity of each technology. We explore the key factors responsible for the observed trends, especially the development of regulatory policies for SO_2 and NO_x control and their implications for environmental control technology innovation. We further discuss some of the key technical innovations that have contributed to cost reductions over time. Finally, we discuss the relevance of these findings to other environmental issues of current interest, especially the outlook for technological progress in carbon capture and sequestration technologies applicable to fossil fuelled electric power plants.

Keywords: experience curves; learning by doing; flue gas desulphurisation (FGD); selective catalytic reduction (SCR); technology innovation; environmental technology; power plant emission control.

Reference to this paper should be made as follows: Rubin, E.S., Yeh, S., Hounshell, D.A. and Taylor, M.R. (2004) 'Experience curves for power plant emission control technologies', *Int. J. Energy Technology and Policy*, Vol. 2, No. 1/2, pp.52–69.

Biographical notes: Edward S. Rubin is the Alumni Professor of Environmental Engineering and Science; Professor, Engineering and Public Policy, and Mechanical Engineering; Director, Center for Energy and Environmental Studies, Carnegie Mellon University.

Sonia Yeh is a Post-Doctoral Fellow in the Department of Engineering and Public Policy, Carnegie Mellon University.

David A. Hounshell is Professor of Technology and Social Change; Professor of History, Social and Decision Sciences, and Engineering and Public Policy, Carnegie Mellon University.

Margaret R. Taylor is Assistant Professor of Public Policy at Richard & Rhoda Goldman School of Public Policy, University of California, Berkeley.

1 Introduction

The availability and cost of technology to control emissions of harmful air pollutants from electric power plants have been key factors in the development of environmental regulations and standards over the past several decades. Because over half of US electricity is generated from the combustion of coal, emissions from coal-fired power plants have been the subject of substantial scrutiny and attention. Today, power plant emissions are again the subject of intense study in the context of a new environmental problem – global climate change. Unlike the historical focus on pollutants directly linked to adverse human health effects (particulate matter, sulphur dioxide, nitrogen oxides and, most recently, mercury), the climate change issue centres primarily around emissions of carbon dioxide (CO_2), a greenhouse gas widely linked to global warming and climate change impacts. In looking prospectively at potential technological options for controlling power plant emissions of CO_2, historical experience in controlling other major pollutants can serve as a guide for expectations (and projections) of future cost trends for similar environmental technologies.

2 Study objectives

In this paper, we examine the historical development of two widely used emission control technologies now required on all new coal-fired power plants in the US and elsewhere. These technologies are flue gas desulphurisation (FGD) systems used to control SO_2 emissions, and selective catalytic reduction (SCR) systems used to control NO_x emissions. These two technologies are post-combustion control systems applied to the flue gas stream emanating from a coal-fired boiler or furnace. In contrast to other environmental control technologies that are applied either prior to or during combustion, FGD and SCR systems represent technologies having the highest pollutant removal efficiencies currently available for coal-burning plants. They are also the most expensive technologies for emission control, and for this reason, requirements for their use have been highly controversial.

The primary goals of this paper are to quantitatively characterise the historical trends in the cost of these technologies in the form of ‘experience curves’ and to explain the key factors responsible for observed trends. Towards this end, we trace the development of public policies for SO_2 and NO_x control and their implications for environmental control technology. We also examine some of the key technical innovations that have contributed to reductions in cost over time. At the conclusion of the paper, we discuss the relevance of these findings to other environmental issues of current interest, especially global climate change.

Because environmental quality is a public good, there are few if any private incentives to develop and install pollution control technology at power plants or other major emission sources. Thus, government actions play a key role by establishing policies or requirements that create markets for environmental technologies. We therefore begin with a brief review of the key regulatory developments that have influenced the use of FGD and SCR systems.

3 Regulatory requirements for SO_2 control

Although the earliest applications of FGD at coal-burning power plants can be traced back to the early 1930s in England, the modern era of environmental controls dates from the late 1960s and early 1970s. In the US, the 1970 Clean Air Act Amendments (CAAA) identified sulphur dioxide as one of the five 'criteria' air pollutants associated with adverse effects on human health and welfare. The principal sources of SO_2 at that time were (and continue to be) coal-burning power plants. When burned, the sulphur in coal is converted primarily to SO_2 and released to the atmosphere. The sulphur content of coals varies widely, from less than 0.5% to over 5% by weight, depending on coal type and source. In the early 1970s, the average sulphur content of coals burned at US power plants was approximately 2.5%.

In the US, environmental policies and regulations for controlling SO_2 emissions took two forms. For existing sources of SO_2 (primarily power plants), individual states were required to limit emissions to a level that would achieve and maintain the national ambient air quality standards (NAAQS) for SO_2 promulgated in 1971 by the newly created US Environmental Protection Agency (EPA). These standards applied to ground-level pollution concentrations and were intended to protect human health and welfare. The resulting set of state and local emission regulations allowed some power plants to continue emitting SO_2 with little or no emission controls, while at other locations moderate to severe restrictions were placed on SO_2 emissions.

For new power plants, SO_2 emission regulations were directly established by the EPA in the form of New Source Performance Standards (NSPS) requiring the use of 'best available control technology' (BACT). The first NSPS for coal-fired power plants, established in 1971, defined BACT as a performance-based standard limiting SO_2 emissions to 1.2 pounds per million Btu (lb/MBtu) of fuel energy input to the boiler. This emission standard corresponded to roughly a 75% reduction from the average emission rates at the time, but it allowed new plants to comply either by burning a sufficiently low-sulphur coal or by installing an FGD system while burning high-sulphur coals.

In 1979, a revised NSPS was promulgated that replaced the performance-based standard with a technology-based standard requiring all new coal-fired plants built after 1978 to employ a system of continuous emission reductions achieving between 70% and 90% SO_2 removal, with the percentage depending upon the sulphur content of the coal being burned. Given the set of pollution control technologies then available, this new standard effectively required the use of an FGD system on all new coal-fired plants. The lower removal efficiency limit applied to plants burning low-sulphur coals typical of those in the western US, while the higher limit of 90% removal applied to plants burning higher sulphur coals characteristic of the Midwest and Eastern US – then the dominant fuel sources for electric power generation.

Table 1 also lists the more recent SO_2 control requirements stemming from the 1990 amendments to the Clean Air Act. To address the problem of acid deposition, EPA established a national emission cap for SO_2 at a level of 9.8 million tons/yr, to be achieved by the year 2000. To achieve this limit, existing power plants were required to further reduce their SO_2 emissions by roughly 40% below their 1990 levels. Power plants could comply either by switching to cleaner (low-sulphur) fuels, by installing an FGD system, purchasing emission credits under a newly created emission trading scheme, or by some combination of these approaches.

Table 1 Major US regulations for SO_2 emissions from electric power plants

Year	*Regulation*	*Content*
1970	Clean air act amendments	Established national ambient air quality standards (NAAQS) for SO_2, affecting emissions from existing sources, and New Source Performance Standards (NSPS) for new plants >73 MWe. Emission limits were 1.2 lb SO_2/MBtu of fuel burned for coal units and 0.8 lb/MBtu for oil-fired units.
1977	Clean air act amendments	NSPS revised for coal-fired plants. Units built after 1978 must remove 70% to 90% of potential SO_2 emissions if actual emissions do not exceed 0.6 lb SO_2/MBtu, or >90% removal with no more than 1.2 lb SO_2/MBtu.
1990	Clean air act amendments: title IV, acid rain program	Reduce annual SO_2 emissions by 9.8 million tons/yr (Mt/y) below 1980 levels in two phases. Phase I (1995–2000): required 263 high-emitting units in 21 eastern and midwestern states to reduce total emissions by roughly 3.5 Mt/y beginning in 1995. Phase II (2000 and beyond) tightened these annual emission limits and set restrictions on smaller, lower-emitting plants fired by coal, oil, and gas. The program affects all new utility units and all existing generators with an output capacity of >25 MW. The Act established an emission allowance trading system with allowances allocated annually beginning in 1995 (one allowance = 1 ton SO_2/yr). The Act also set a permanent ceiling (or cap) of 8.95 million allowances/yr for allocation beginning January 1, 2000. Banking provisions and other incentives for early emission reductions were also established.

Outside the US, the most stringent controls on SO_2 emissions appeared in Japan and Germany. The first modern commercial-scale FGD systems were installed in Japanese power plants in the late 1960s. These units served as benchmarks for early FGD adoptions in the US. In 1984, in response to growing concerns about the destruction of German forests from acid rain, Germany enacted stringent new regulations requiring the installation of FGD systems on all large coal-fired plants already in service. Subsequently, other European nations also adopted regulations requiring FGD on coal-fired power plants.

4 Historical growth in FGD capacity

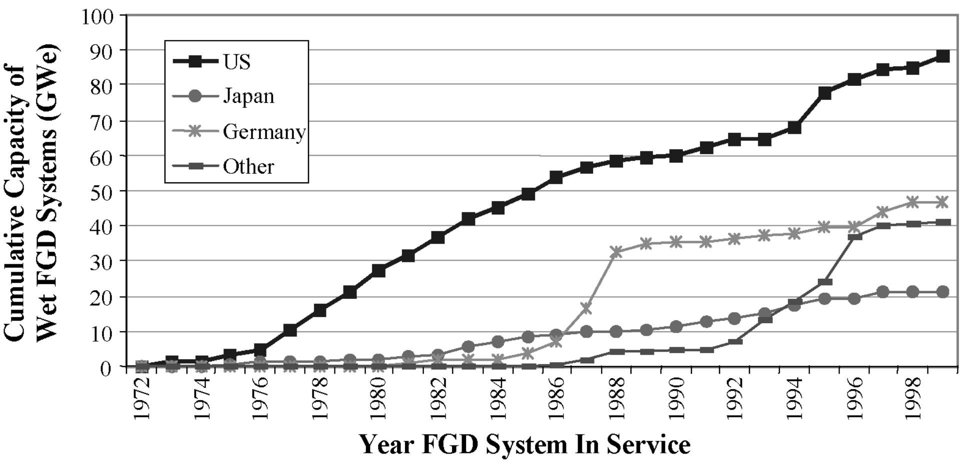
FGD systems (also known as scrubbers) encompass a variety of technologies that have been extensively described and discussed in the literature [1]. By far the most prevalent technology, accounting for approximately 86% of current world capacity, is the so-called 'wet' FGD systems employing limestone or lime as a chemical reagent. These systems can achieve the highest SO_2 removal efficiencies (historically around 90%, but today as high as 98% to 99%). However, the process generates a solid residue that must either be transformed into a useful by-product (such as gypsum) or disposed of as solid waste. The chemistry of SO_2 removal using limestone (slurried in water) with forced oxidation to produce gypsum can be described by the following overall reaction:

$$SO_2 + CaCO_3 + 2H_2O + \frac{1}{2}O_2 \rightarrow CO_2 + CaSO_4 \cdot 2H_2O \quad (1)$$

The so-called 'dry' FGD systems typically use lime (CaO) as the reagent in a spray dryer system that typically achieves lower SO_2 removal rates than a wet FGD system (historically about 70% to 80%, but today as high as 94%). Such systems were typically used to meet the less restrictive SO_2 removal requirements for low-sulphur coals allowed by the NSPS. Because of their limited applicability, lime spray dryers and other forms of dry SO_2 removal account for less than 8% of the total FGD market [1].

Figure 1 depicts the worldwide growth in FGD installations over the past three decades. The y-axis measures the total electrical capacity of power plants whose flue gases are treated with wet lime or limestone scrubbers. The onset of FGD use in each country corresponds to the time at which regulations were adopted that were sufficiently stringent so as to require or encourage the use of FGD as an emission control strategy. Figure 1 also shows that USA has dominated in the deployment of this technology. Today, approximately 30% (90 GW) of US coal-fired capacity is equipped with FGD systems, most of them wet limestone scrubbers.

Figure 1 Cumulative installed capacity of wet lime/limestone FGD systems in different countries



Source: [1,2]

The environmental policy initiatives responsible for the substantial growth in FGD use over the past three decades addressed not only emissions of SO_2 but other pollutants as well. In particular, power plant emissions of nitrogen oxides also came under control for the first time during this period.

5 Regulatory requirements for NO_x control

In addition to SO_2, the 1970 CAAA also identified nitrogen dioxide (NO_2) and ground-level ozone (O_3) as criteria that linked air pollutants to adverse human health effects. Both pollutants are formed by chemical reactions that occur in the atmosphere, although some NO_2 is also emitted directly from high-temperature combustion processes such as that occurring at power plants. Nitric oxide (NO) is formed in much greater quantities during combustion and is gradually oxidised to NO_2 once emitted to the atmosphere. The combination of NO and NO_2 – referred to as NO_x – also contributes to acid rain and (together with volatile organic compounds) the formation of ground-level ozone.

In the US, the control of NO_x emissions from power plants initially followed the same timetable and regulatory approach as for SO_2 (see Table 2). The key difference was the stringency of applicable requirements. Under the 1970 CAAA, existing power plants were largely unaffected by state-level requirements to achieve the NO_2 air quality standards. For new plants, the EPA New Source Performance Standards imposed only modest requirements that could be met at low cost using improved low-NO_x burners (LNB) for combustion. During the 1970s and 1980s, as SO_2 emission restrictions grew more stringent (and more costly), NO_x emission requirements for coal plants changed only slightly as LNB technology improved.

Table 2 Major US regulations for NO_x emissions from electric power plants

Year	*Regulation*	*Content*
1970	Clean air act amendments	Established national ambient air quality standards for NO_2 and New Source Performance Standards (NSPS) for new plants >73 MWe. NO_x limits were 0.7 lb NO_2/MBtu of fuel burned for coal units, 0.3 lb/MBtu for oil-fired units and 0.2 lb/MBtu for gas-fired units.
1977	Clean air act amendments	NSPS revised for coal-fired plants. New NO_x emission limits for units built after 1978 are 0.6 lb NO_2/MBtu (bituminous coal) and 0.5 lb/MBtu (sub-bituminous coal).
1990	Clean air act amendments	Two major portions of the CAA affecting power plant NO_x control are Title I (National Ambient Air Quality Standards), and Title IV (Acid Rain Control). Regulations stemming from 1990 amendments are discussed below.
1994	Title I: ozone transport commission (OTC) NO_x budget program	A regional NO_x emission control program in 12 northeastern states to help attain the health-related NAAQS for ground-level ozone. These reductions are in addition to previous state requirements that included the installation of reasonably available control technology. States committed to developing and adopting regulations to reduce region-wide NO_x emissions by 1999 with further reductions by 2003.

Table 2 Major US regulations for NO_x emissions from electric power plants (continued)

Year	*Regulation*	*Content*
1995	Title IV: US acid rain control program	A two-phased reduction in NO_x emissions from coal-fired power plants to control acid deposition. Phase I, finalised in 1995, sought to reduce NO_x emissions by over 400,000 tons/yr between 1996 and 1999 by requiring Reasonably Available Control Technology (RACT), as defined by USEPA for different types of boilers. Phase II tightened and extended these requirements to reduce NO_x emissions by over 2 Mt/yr beginning in 2000. The average RACT requirement was approximately 0.55 lb NO_2/MBtu.
1998	Title I: NO_x state implementation plan (SIP) call	EPA issues a rule requiring 22 states to revise their State Implementation Plan to further reduce NO_x emissions by 1.2 Mt/yr by 2007. The rule gives each affected state a NO_x emission budget. States have flexibility to determine how to reduce emissions to achieve the specified target.
1999	Title I: section 126 federal NO_x budget trading program	For states opting to meet the NO_x SIP Call requirements through a cap and trade program, EPA developed a model NO_x Budget Trading Program rule to facilitate cost-effective NO_x emission reductions from large stationary sources. The model rule includes provisions for applicability, allocations, monitoring, banking, penalties, trading protocols and program administration. States can modify certain provisions of the model rule. The allowance trading component provides incentives for units to over-control if the cost is less than the market price of NO_x allowances.

Because NO_x also contributes to acidic deposition, the acid rain provisions of the 1990 CAAA required many existing coal-fired plants to install 'reasonably available control technology' in the form of LNB and other combustion modifications. In 1994, however, EPA established much more stringent NO_x emission reduction requirements for existing power plants as part of a comprehensive regional strategy to attain the health-related NAAQS for ground-level ozone. These new requirements called for NO_x reductions averaging about 85%. An emission trading program akin to that for SO_2 also was established to help reduce compliance costs. Nonetheless, achieving these stringent NO_x reductions has required retrofitting many existing power plants with post-combustion SCR systems as well as LNB. A massive expansion in SCR installations is now underway in the US to meet the compliance deadline of 2004. A recent revision (1997) to the Federal NSPS for coal-burning plants also now requires a low level of NO_x emission currently achievable only with SCR systems in most cases.

In contrast to the US situation, the use of SCR in other industrialised countries began many years earlier in response to stricter NO_x emission limits. Japan first enacted strict requirements in the 1970s and pioneered the development of SCR technology for power plant applications. In the mid-1980s, Germany required the use of SCR systems on large coal-fired power plants as part of its acid rain control program. Subsequently, other European countries also began to adopt this technology. SCR systems also have been deployed at some power plants burning oil or natural gas, including gas turbine plants used for peak power generation.

6 Historical growth in SCR capacity

Like FGD systems, SCR is a post-combustion technology that employs a chemical reagent to remove NO_x from the flue gas stream. In this case, the reagent is ammonia (NH_3) injected into the flue gas stream exiting the boiler. NO_x is reduced to molecular nitrogen via two overall reactions:

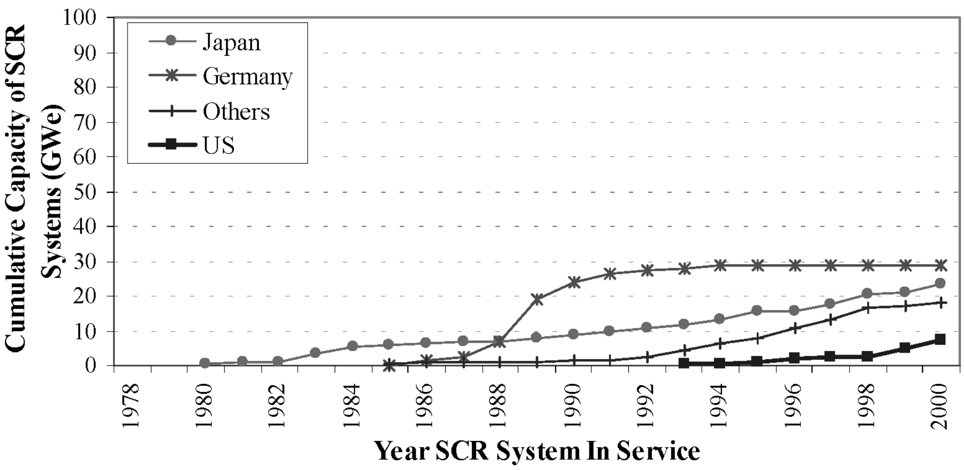
$$4NO + 4NH_3 + O_2 \rightarrow 4N_2 + 6H_2O \quad (2)$$

$$2NO_2 + 4NH_3 + O_2 \rightarrow 3N_2 + 6H_2O \quad (3)$$

To achieve high (80 to 90%) NO_x removal, a catalyst operating at high temperature is required. For this reason, an SCR system is typically located at the boiler exit upstream of the power plant's air preheater. The control of ammonia slip (excess NH_3 in the flue gas) is a secondary environmental impact of concern in SCR system design.

Figure 2 shows the historical trend in the worldwide growth of SCR capacity. As with FGD systems, the onset of growth reflects the stringency and timetable for NO_x reductions in different countries. The earliest use of SCR is seen in Japan beginning in the 1970s, followed by widespread adoption in Germany in the mid-1980s. The US has been the laggard in SCR use, with the first units on coal-fired plants installed only in 1993. However, US capacity of SCR systems is now expected to grow at least 100 GW by 2004 [3–5].

Figure 2 Cumulative installed capacity of SCR systems on coal-fired power plants in different countries. Adapted from [2]



The earliest installations of SCR systems on power plants in the US were at oil- and gas-fired plants (principally in California), where problems of operability and high cost are less severe than at coal-burning power plants. As of 1996, the total capacity of SCR systems on non-coal utility systems in the US was approximately 11.5 GW [6]. Data on non-coal systems in other countries are not readily available, but are believed to be small relative to coal-based applications.

7 Development of experience curves for FGD and SCR

A seminal paper by Wright [7] introduced the concept of a 'progress curve' to describe his finding that the average direct man-hours required to manufacture a given model of a Boeing aircraft systematically dropped with each unit produced. This phenomenon of 'learning by doing' has subsequently been studied and generalised to a wide variety of applications. Systematic reviews of this extensive literature can be found elsewhere [8–11]. Mathematically, most studies have used the simple non-linear function first proposed by Wright to describe the reduction in cost associated with increases in production:

$$y_i = ax_i^{-b} \tag{4}$$

where

y_i = time or cost to produce ith unit

x_i = cumulative production through period i

a = coefficient (constant)

b = learning rate exponent

According to this equation, each doubling of cumulative production results in a time or cost savings of $(1 - 2^{-b})$. The latter quantity is defined as the learning rate, while the quantity 2^{-b} is defined as the progress ratio.

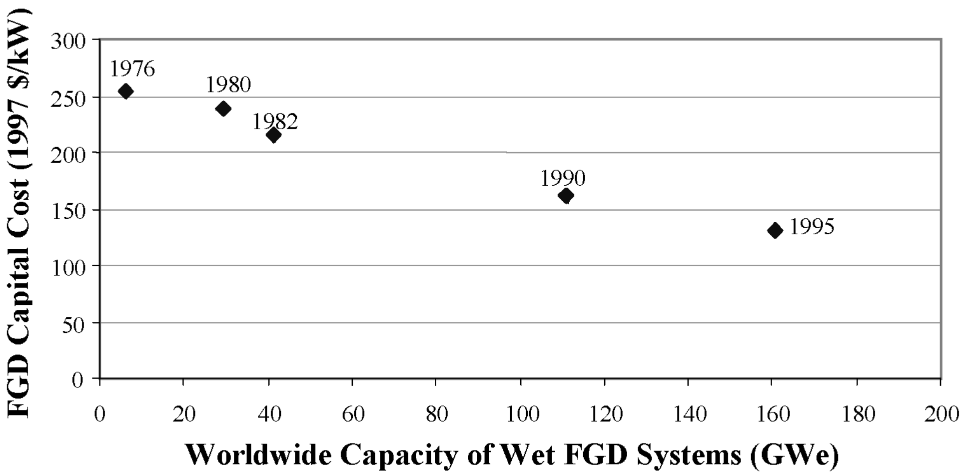
This concept of a learning curve has been extended to characterise the reductions in capital cost associated with the continued development and deployment of a wide variety of technologies, including energy technologies [12]. Known more generally as 'experience curves', the observed cost decreases in this case reflect not only the benefits of learning by doing, but also those derived from financial investments in research and development to improve the technology and its production. These investments are the key factor leading to new generations of a given technology that are not only lower in cost but often improved in other ways as well (e.g. more efficient or reliable than earlier models). Recent reviews of the literature on experience curves for energy-related technologies [12,13] found a range of learning rates varying from –14% to 34%, with most values between 4% and 30% and a median value of 16%. This is consistent with values reported earlier for many non-energy technologies [14]. Past studies, however, have focused mainly on products and technologies for which there are natural demands in a market economy, such as demands for lower-cost power generation systems. Little attention has been given to what we call environmental technologies, such as FGD and SCR systems, for which there are no significant demands in the absence of government actions requiring their use for environmental protection of the public at large. The development of experience curves for environmental technologies is thus the major focus of this paper.

7.1 Results for FGD systems

The deployment of FGD systems over the past several decades has been accompanied by measurable improvements in performance and reductions in the cost of this technology. The development of an experience curve to characterise FGD cost trends is not straightforward, however, because the cost of an FGD system depends on many site-specific power plant factors (such as plant size, age, emission limits, and fuel properties) that are not directly related to improvements in FGD technology per se. Thus, to obtain a more accurate picture of real FGD cost reductions, we used a series of historical cost studies performed over a period of years by the same organisations using a consistent set of design premises as the basis for FGD cost estimates. This allows us to characterise the cost of doing the same 'job' at different points in time. Systematic studies of FGD cost were performed by the Tennessee Valley Authority (TVA) during the 1970s and 1980s when FGD systems were first being installed at US coal-fired power plants [15,16]. Beginning in the mid-1980s, the Electric Power Research Institute (EPRI) conducted a similar series of studies for a variety of FGD processes [17–20]. Both the TVA and EPRI studies reflected contemporaneous designs and costs of FGD systems being installed at US power plants, and both organisations were highly regarded as authoritative sources in the SO_2 control industry [21].

Figure 3 shows the experience curve developed for FGD capital cost, adjusted for inflation using the Chemical Engineering construction cost index. All values are based on a standardised case of a wet limestone FGD system achieving 90% SO_2 removal at a 500 MW power plant burning a high-sulphur coal (3.5% S). To account for small changes in the design premises used in more recent studies (e.g., small changes in fuel sulphur content and plant size), reported cost results were also adjusted using a power plant computer model to account for the influence of these factors [22,23]. To develop an experience curve, the cumulative installed FGD capacity corresponding to each data point was taken to be one year prior to the publication date of each cost study so as to reflect the typical time lag between data collection and the presentation of results (typically at a widely attended industry conference). The x-axis values in Figure 3 reflect worldwide installations of FGD systems (primarily in the US, Germany, and Japan) in recognition of the international nature of markets and technology innovations in FGD systems [21].

Figure 3 Capital cost of a new wet limestone FGD system for a standardised coal-fired power plant (500 MWe, 3.5% sulphur coal, 90% SO_2 removal) as a function of cumulative worldwide capacity of FGD installations. Based on data from [1,15–17,19,20]

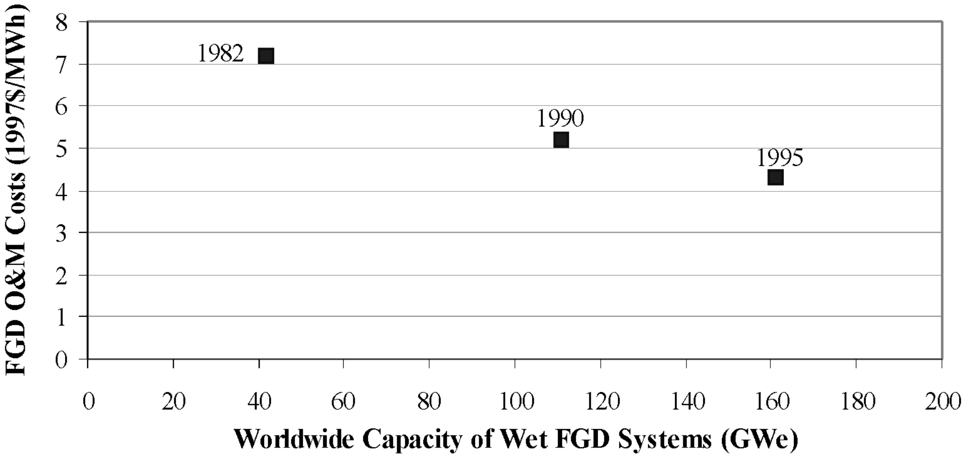


FGD capital costs exhibit significant declines over time as cumulative capacity increases. Many of the process improvements that contributed to lower costs (especially improved understanding and control of process chemistry, improved materials of construction, simplified absorber designs, and other factors that improved reliability) were the result of sustained R&D programs and inventive activity, as documented and described elsewhere [21]. Increased competition among FGD vendors may have also been a contributing factor. Such influences are difficult to discern in most studies of experience curves because the available data typically represent the costs to technology users (i.e., technology prices) rather than that to technology developers. In this study, however, a careful examination of the underlying technological changes over several decades [21] convinces us that the FGD cost reductions shown here primarily reflect the fruits of technology innovation. Later, we recast the data in Figure 3 into a conventional experience curve equation and compare it to results for SCR systems.

We do not attempt in this paper to develop an analogous experience curve for FGD operating and maintenance (O&M) costs, although there is clear evidence that these costs too have been reduced as a result of technology innovation and learning by doing. A systematic approach to quantifying such trends would require a retrospective study of each major element of O&M costs, including FGD reagent use, energy use, labour costs, maintenance costs, and by-product disposal costs. Most of the studies used in this paper to determine FGD capital cost also reported expected O&M costs, though in different degrees of detail. But unlike capital cost estimates, which can be (and were) verified against the actual cost of plants built at different points in time, projected O&M costs over the operating life of a system (typically several decades) cannot be readily verified until many years later. Thus, systematic design studies of the type used here reflect the trend in *expected* O&M costs for new plant designs, as opposed to actual experience. Nonetheless, such trends can be useful indicators of technological change since they do reflect and incorporate contemporaneous improvements in technology design as well as experience from learning by doing based on earlier designs.

Figure 4 shows the total projected O&M costs for several of the FGD design studies used earlier to quantify capital costs. An overall cost reduction of 40% is seen over a 13-year period. Many factors contributed to this reduction, including various process improvements (leading to reductions in reagent consumption, associated solid waste quantities, and process energy use), as well as reductions in operating labour and maintenance expenses. A companion analysis by Taylor [20] showed that labour costs alone exhibited a 20% learning rate at US power plants operating an FGD system for 12 years or more. While the relative importance of different O&M cost elements varies with plant design and operating conditions, reductions in such costs have clearly accompanied reductions in capital cost. The data in Figure 4 are used later to provide a rough estimate of the learning rate for O&M costs in the absence of more complete empirical data on changes in actual O&M costs for a given FGD application.

Figure 4 Annualised operating and maintenance (O&M) cost of a new wet limestone FGD system for a standardised coal-fired power plant (500 MWe, 3.5% sulphur coal, 90% SO_2 removal, 65% capacity factor) as a function of cumulative worldwide capacity of FGD installations. Based on data from [17,19,20]

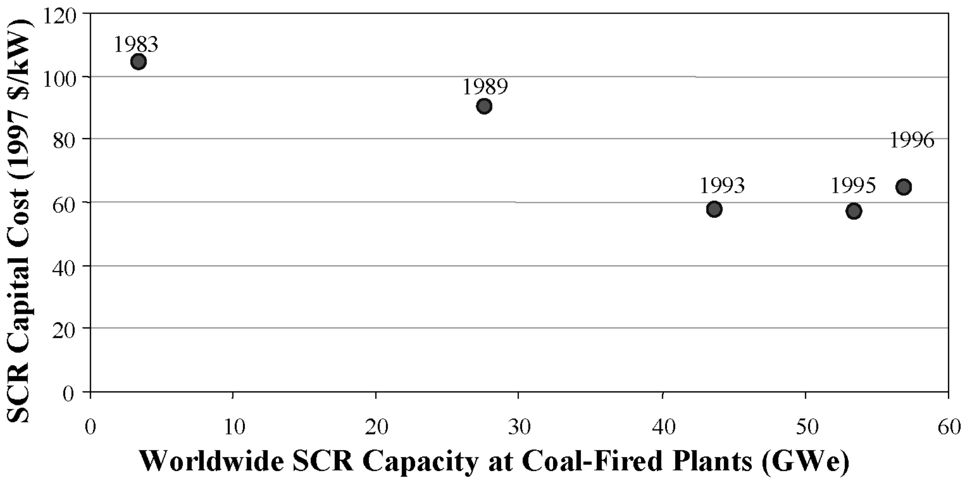


7.2 Results for SCR systems

Experience curves for SCR system capital cost were developed using the same methodology employed for FGD technology, namely the use of historical cost studies for new installations based on a standardised power plant design and NO_x removal efficiency. As before, a detailed computer model was used to adjust key design parameters to a consistent basis where necessary, and all results were converted to a common reporting year.

Figure 5 shows the resulting trend for SCR capital costs. Significant cost decreases have occurred as worldwide use of SCR systems has grown. Again, this trend reflects the effects of investments in R&D as well as learning by doing and other factors. Much of the decrease in capital cost is related to the initial cost of SCR catalyst, as SCR process improvements, coupled with improvements in catalyst manufacturing methods and competition among catalyst manufacturers, lowered both the total catalyst requirements and the unit cost of catalyst significantly. During the 1990s, for example, the unit price of SCR catalyst fell by a factor of two, when there was no systematic decline in the real prices of the principal metals, mainly vanadium and titanium, used for SCR catalysts [24].

Figure 5 Capital cost of a new SCR system for a standard coal-fired power plant (500 MWe, medium sulphur coal, 0.6 lb/MBtu inlet NO_x, 80% NO_x removal) as a function of cumulative worldwide capacity of coal-based SCR installations. Based on data from [25–28]

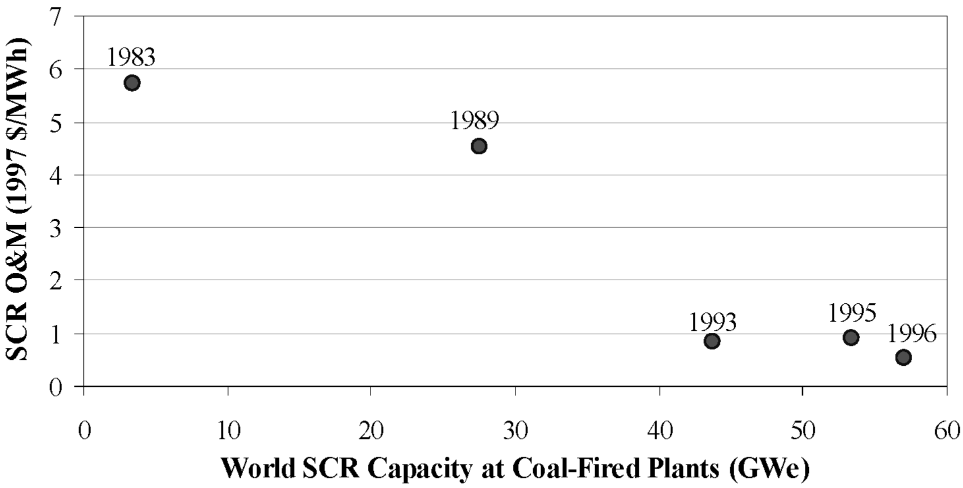


Another factor contributing to the decline in total capital cost was the lack of early experience with SCR in the US. Thus, there were great uncertainties in the early 1980s about the applicability and reliability of SCR for power plants burning US coals. A number of technical problems were anticipated because of the much higher sulphur content of US coals relative to those used in Japan and Germany, and such concerns were reflected in more conservative and more costly designs for US plants. Cumulative foreign experience and later applications with US coals subsequently demonstrated that less conservative (and less expensive) designs were indeed viable for US facilities.

The data in Figure 5 provided the basis for an SCR experience curve based on US coal-fired power plants. However, as with the FGD analysis, the relevant measure of cumulative production was taken to be the worldwide capacity of coal-based SCR installations to again reflect the global nature of markets and innovations in these environmental technologies. The potential contribution of SCR experience at oil- and gas-fired facilities is not reflected in these estimates, in part because of data limitations, and also because many of the designs and technical problems associated with coal-fired plants (such as high flyash loadings and trace contaminants that can poison SCR catalysts) do not apply in these cases. Nonetheless, to the extent that any spillover effects from these SCR markets have benefited coal-fired plants, the learning rates derived in this study would decline slightly as the experience base (cumulative capacity) is expanded.

As with FGD systems, the systematic design studies used to characterise SCR capital costs do not provide a rigorous basis for an experience curve for O&M costs, since these studies report expected costs rather than actual costs. Nonetheless, they are again instructive as they reflect changes in expectations based on contemporaneous process improvements and operating experience with earlier designs. Figure 6 shows the total expected annual O&M costs derived from several studies over a 13-year period, adjusted to a common basis. While several factors contribute to O&M cost, for SCR systems, the single dominant factor is the cost of replacement catalyst [22]. By the 1990s, the unit price of SCR catalyst had been reduced by half (as noted earlier), while at the same time, the expected catalyst lifetime (replacement interval) was more than four times longer than estimates of the early 1980s. Total catalyst quantities also had been moderately reduced as a result of SCR process improvements. The overall result was a sharp drop in expected annualised O&M costs, as seen in Figure 6. As the basis for an O&M cost experience curve, however, these data likely overestimate the true learning rate since the earliest estimates of catalyst lifetime and replacement cost were based primarily on manufacturers' guarantees at the time (typically a one-year catalyst life for US coal-fired plants) and very limited operating experience (mainly on Japanese power plants). Later cost projections were revised to reflect new process developments and experience that achieved significantly longer catalyst life. Thus, the O&M cost reduction of over 80% seen in Figure 6 represents the change in outlook for SCR costs over the past two decades. While further study is needed to quantify actual learning rates based on long-term experience at coal-fired power plants, the data in Figure 6 can be used to derive a rough estimate, as presented below.

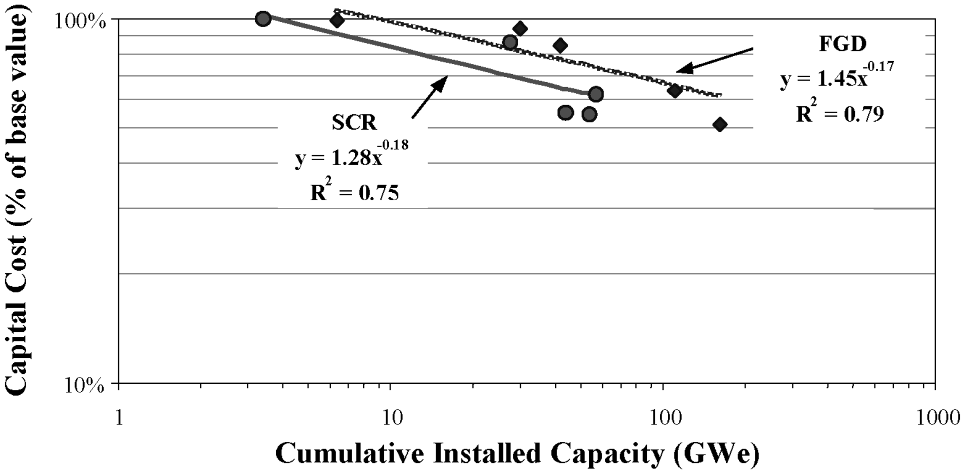
Figure 6 Annualised operating and maintenance (O&M) cost of a new SCR system for a standard coal-fired power plant (500 MWe, medium sulphur coal, 0.6 lb/MBtu inlet NO_x, 80% NO_x removal, 65% capacity factor) as a function of cumulative worldwide capacity of coal-based SCR installations. Based on data from [25–28]



8 Comparison of FGD and SCR experience curves

Figure 7 compares the capital cost experience curves derived in this study for FGD and SCR systems. The results shown earlier are normalised on the initial data point for each curve, and the log-linear relationship given by equation (3) is used to represent the experience curve. The resulting learning rates are 11% and 12% for the capital cost of FGD and SCR systems, respectively (corresponding to progress ratios of 0.89 and 0.88, respectively). These values are well within the range of learning rates found in the literature for a wide range of market-based technologies, as discussed earlier.

Figure 7 Capital cost experience curves for SCR and FGD systems. Based on equation (3) using data from Figures 3 and 5. The regression exponents correspond to learning rates 11% and 12% for FGD and SCR systems, respectively



Operating and maintenance (O&M) costs for these technologies have also significantly declined as a result of technology innovation and experience, but further study is needed to quantify these learning rates accurately. However, if the expected cost estimates in Figures 4 and 6 are used as surrogates for actual long-term O&M costs for technologies of different vintage, the implied learning rates (based on equation 3) would be 22% for FGD systems and 28% for SCR systems. These values too are typical of learning rates found in the literature for other technologies, though the value for SCR in particular is at best an upper bound, for reasons discussed earlier.

9 Implications for policy analysis

The data presented in this paper offer compelling evidence that the real cost of environmental control technologies employed at coal-fired power plants significantly declined once they were widely deployed in response to environmental policies that either required their use or made them economically attractive relative to other environmental control options. These findings are consistent with a large body of literature showing similar trends for a wide variety of market-based products and technologies.

A major implication of these findings is that environmental policy analysis that ignores technological change is likely to overestimate the true cost of future compliance with new environmental control requirements that are met using technologies that already exist commercially, but are not widely deployed or fully developed. In such cases, we believe the quantitative results presented here can serve as a guideline for how such costs might decline with increasing adoption under a sufficiently stringent policy regime. One case in point is the potential for CO_2 capture and sequestration technology to control greenhouse gas emissions (one of the leading options now being examined in climate policy studies). There are substantial technical similarities between current commercial technologies for CO_2 capture (such as chemical and physical absorption systems applicable to power plant gas streams) and the FGD and SCR gas treatment systems used for SO_2 capture and NO_x reduction. Thus, the experience curves derived in this paper might provide reasonable estimates for the rate of cost decline that might be expected if CO_2 capture systems were to be deployed at coal-based power plants as part of a future strategy to reduce greenhouse gas emissions. In this regard, preliminary results from an integrated assessment modelling study [29] indicate that the cost of achieving a climate stabilisation target is significantly lower when the learning rates derived in the present study are applied to CO_2 capture and storage systems for fossil fuel power plants.

Several methodological issues remain to be further explored in the context of modelling studies with relatively long time horizons, such as the 50- to 100-year time frames commonly used for climate change policy analysis. In particular, it is unlikely that the learning rates observed during the initial development and deployment of a new environmental technology (like CO_2 capture) can be sustained as the technology matures. Indeed, Klepper and Grady [30] found that a broad spectrum of technologies typically exhibits a declining rate of price reductions over long time periods. Thus, it is quite unlikely that the learning rates shown in Figure 5 for FGD and SCR systems will be sustained over periods of 50 to 100 years as cumulative capacity continues to grow. Rather, there will be a 'levelling off' in the rate of learning, typically after 30–40 years (based on the results of Klepper and Grady [30]). At some point, other technologies that accomplish the same goal – in this case, a given reduction of power plant SO_2 and NO_x emissions – may replace the environmental technologies currently in use, and marked cost reductions may resume. Pending the accumulation of longer-term data, parametric studies employing either a bounding assumption (such as no further cost decreases beyond a certain point) or more gradual rates of decline, such as those suggested by the data in Klepper and Grady [30], may be more appropriate for policy analyses extending over many decades. Such studies are planned as part of our continuing research in this area.

Another subject for future research is the relationship between cost trends and performance trends for environmental technologies. As noted earlier, for example, the SO_2 capture efficiency of FGD systems has continued to improve markedly over the past two decades. As a result, new plants frequently face more stringent control requirements commensurate with this improved technological capability. The overall cost trends associated with changing levels of regulatory stringency and environmental technology performance are beyond the scope of this paper, but are of significant interest and relevance to future environmental policy analysis.

10 Conclusion

Flue gas desulphurisation (FGD) systems and selective catalytic reduction (SCR) systems are the most widely used environmental technologies for high-efficiency removal of SO_2 and NO_x, respectively, at coal-fired electric power plants. These systems also are the most expensive environmental technologies employed at power plants worldwide. Nonetheless, substantial decreases in capital costs have been realised over the past several decades as a result of investments in R&D, learning by doing at power plant facilities, competition among equipment manufactures, and other factors. The combined effect of these activities has been represented in this paper by experience curves that quantify historical rates of cost decrease as a function of the cumulative installed capacity (the measure of experience) of FGD and SCR systems at coal-fired power plants. These rates were found to be similar to those of other energy-related and market-based technologies. The empirical data also show that widespread deployment of high-efficiency (but costly) environmental technologies like FGD and SCR systems requires the adoption of sufficiently stringent government regulations, policies, and other actions to create and sustain a market for these technologies. Given such policies, failure to account for the effects of technology innovation can lead to erroneous estimates of future compliance costs for new environmental initiatives.

Acknowledgements

This research was supported by the Office of Biological and Environmental Research, US Department of Energy, under Grant No. DE-FG02-00ER63037, and by the Center for Integrated Study of the Human Dimensions of Global Change under a cooperative agreement with the National Science Foundation (SBR-9521914) and Carnegie Mellon University.

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