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EXPERIENCE CURVES FOR ENVIRONMENTAL TECHNOLOGY AND THEIR RELATIONSHIP TO GOVERNMENT ACTIONS

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ABSTRACT

We seek to improve the ability of integrated assessment models (IA) to incorporate changes in CO₂ capture and sequestration (CCS) technology cost and performance over time. This paper presents results of new research that examines past experience in controlling other major power plant emissions that might serve as a reasonable guide to future rates of technological progress in CCS systems. In particular, we focus on U.S. and worldwide experience with sulfur dioxide (SO₂) and nitrogen oxide (NO_x) control technologies over the past 30 years.

INTRODUCTION

Large-scale energy-economic models used to study global climate change and carbon management options often ignore the impacts of environmental technology innovation and diffusion, or they use simple representations such as exogenously-specified (often arbitrary) rates of change in cost or efficiency over time. The predicted impacts of proposed policy measures can depend critically upon these assumptions. Thus, better methods are needed to model technological change and its relationship to government policy. This is especially true for CO₂ capture and sequestration (CCS) technology, an important new class of environmental technology with the potential to allow continued use of fossil fuels without significant greenhouse gas emissions to the atmosphere. Research efforts are underway worldwide to develop this technology and evaluate its effectiveness. Large-scale energy-economic and integrated assessment models also are being used to evaluate the potential of CCS in competition with other options for CO₂ control.

We seek to improve the ability of such models to represent and quantify the changes in CCS technology cost and performance over time as a function of pertinent variables, including the effects of alternative government actions or policies. Toward this end, this paper presents results of new research that examines past experience in controlling other major power plant emissions that might serve as a reasonable guide to future rates of technological progress in CO₂ capture and sequestration systems. In particular, we focus on U.S. and worldwide experience with sulfur dioxide (SO₂) and nitrogen oxide (NO_x) control technology over the past 30 years, seeking answers to the following related questions: (1) how did the deployment, performance, and cost of these environmental technologies change over time? And, (2) how were these changes and technological innovations related to government actions and policies?

DEVELOPMENT OF EXPERIENCE CURVES

Two widely used emission control technologies at coal-fired power plants are flue gas desulfurization (FGD) systems used to control SO₂ emissions and selective catalytic reduction (SCR) systems used to control NO_x emissions. Both technologies are post-combustion control systems applied to the flue gas stream emanating from a coal-fired boiler or furnace. In contrast to environmental controls that are applied either prior to or during combustion, FGD and SCR systems represent the technologies having the highest pollutant removal efficiencies currently available for coal-burning plants. They are also the most expensive technologies for emissions control, and for this reason requirements for their use have been highly controversial.

Historical Deployment of FGD Systems. 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 the world market, are so-called "wet" FGD systems employing limestone or lime as a chemical reagent. These systems can achieve the highest SO₂ removal efficiencies (historically around 90%, but today as high as 98 to 99%), but they generate a solid residue that must either be transformed into a useful byproduct (gypsum) or disposed as a solid waste. So-called "dry" FGD systems typically use lime as the reagent in a spray dryer system that is less efficient than wet FGD systems but adequate to achieve the less restrictive SO₂ removal requirements for low-sulfur coals allowed by the New Source Performance Standards (NSPS). Because of their limited applicability, lime spray dryers and other forms of dry SO₂ removal account for less than eight percent of the total FGD market [1].

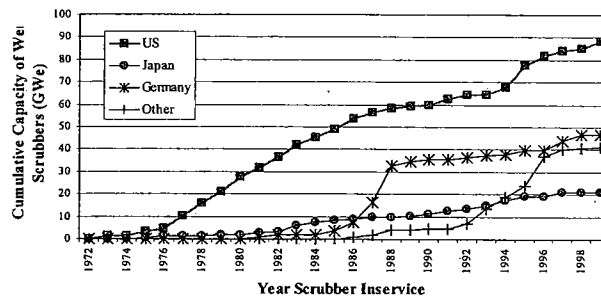


Figure 1. Cumulative installed GWe capacity of wet scrubbers using lime or limestone as the reagent in the U.S., Japan, Germany, and the rest of the world. Years after 1993 were under construction or firmly planned as of 1994.

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. Figure 1 also shows that the United States has led in the deployment of this technology. Today, approximately 30 percent (80,000 MW) of U.S. coal-fired capacity is equipped with FGD systems, most of which are wet scrubbers.

Relationship to SO₂ Control Requirements. The onset and growth of FGD use in each country reflects the adoption of national (and in some cases international) regulations that were sufficiently stringent so as to require or encourage the use of FGD as an emissions control strategy. In the United States, stringent requirements for SO₂ control can be traced to the Clean Air Act Amendments (CAAA) of 1970 and 1977. Many existing power plants chose to retrofit FGD systems in order to meet state and local emission regulations designed to achieve the national ambient air quality standards for SO₂ established under the 1970 CAAA. For new power plants, federal New Source Performance Standards (NSPS) set by the U.S. Environmental Protection Agency (EPA) required 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 SO₂ 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 percent reduction from the average emission rates at the time, but allowed new plants to comply either by burning a sufficiently low sulfur coal, or by installing an FGD system while burning high-sulfur 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 percent SO₂ removal, with the percentage depending upon the sulfur content of the coal being burned. Effectively, this meant the use of an FGD system on all new coal-fired plants. The lower removal efficiency limit applied to plants burning low sulfur coals typical of those in the western United States, while the higher limit of 90 percent removal applied to plants burning higher sulfur coals characteristic of the Midwest and eastern U.S. More recently, the 1990 CAAA established a national emissions cap for SO₂ to address the problem of acid deposition. To achieve this limit, existing power plants were required to further reduce their SO₂ emissions by roughly 40 percent below their 1990 levels. Power plants could comply in a variety of ways (including emissions trading), but owners of some plants chose to install FGD systems. In other countries, stringent controls on SO₂ emissions were implemented initially in Japan and later in Germany. The first modern utility-scale FGD systems were installed on Japanese power plants in the late 1960s and served as benchmarks for early FGD adoptions in the United States. In 1983, 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.

Resulting Trend in FGD Cost. The deployment of FGD systems over the past several decades has been accompanied by improvements in performance and reductions in the cost of this technology. We use the concept of an "experience curve" (often called a learning curve) to characterize these reductions in cost. Such curves have been discussed extensively in the literature for a wide range of technologies, including energy technologies [2-6]. Cost reductions are typically described by an equation of the form: $y_i = ax_i^{-b}$, where y_i = cost to produce the i th unit, x_i = cumulative production through period i , b = learning rate exponent, and a = coefficient (constant). According to this equation, each doubling of cumulative production results in a cost savings of $(1 - 2^{-b})$, which is defined as the learning rate, while the quantity 2^{-b} is defined as the progress ratio. These cost reductions reflect not only the benefits of learning by doing at existing facilities, but also the benefits derived from investments in research and development that produce new knowledge and generations of a technology. The development of an experience curve for FGD systems is not straightforward because many of the factors that influence cost are not directly related to improvements in the FGD technology [7]. To obtain a more accurate picture of real FGD cost reductions, we use a series of studies performed by the same organizations over a period of years using a consistent set of design premises as the basis for FGD cost estimates. These studies reflect the contemporaneous designs and costs of FGD systems installed at U.S. power plants.

Figure 2 shows the experience curve developed for FGD capital cost. All costs are adjusted to a common basis for a standardized 500 MW power plant burning a high sulfur coal (3.5 % S) with a wet limestone FGD system achieving 90 percent SO₂ removal. Total capital cost shows a significant decline over time. 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 [7]. Increased competition among FGD vendors also may have been a contributing factor. Such influences are difficult to discern in most studies of experience curves because the available data typically represent the cost to technology users (i.e., technology prices) rather than the cost to technology developers.

However, a careful look at the underlying technological changes over several decades indicates that the FGD cost reductions shown here primarily reflect the fruits of technology innovation.

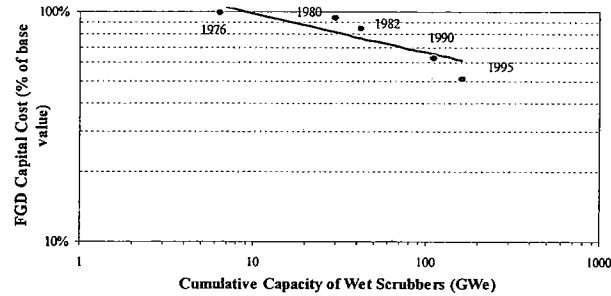


Figure 2. FGD capital costs for a std. 500 MWe plant with 3.5% S coal vs. cumulative installed FGD capacity worldwide. . All data points normalized on an initial (1976) value of \$254/kW (in constant 1997\$).

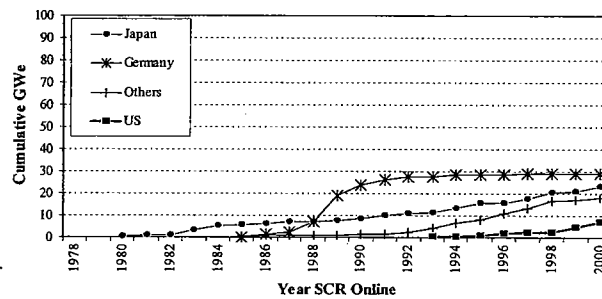


Figure 3. Cumulative installed capacity of SCR systems on coal-fired power plants from 1980 to 2000.

Historical Deployment of SCR Systems. Figure 3 shows the historical trend in the worldwide growth of SCR capacity. Here, the earliest use of SCR is seen in Japan beginning in the 1970s, followed by widespread adoption in Germany in the mid-1980s. The U.S. has been the laggard in SCR use, with the first units on coal-fired plants installed only in 1993. Over the next few years, however, U.S. capacity of SCR systems is expected to grow significantly in response to recently enacted NO_x control regulations. SCR systems also have been installed on electric power plants burning oil and natural gas since these systems also produce NO_x during combustion. The total capacity of SCR systems on non-coal utility systems for U.S. power plants was approximately 11.5 GW in 1996 [8], most of which was installed only in the last decade.

Relationship to NO_x Control Requirements. As with FGD systems, the onset of growth in SCR capacity reflects the stringency and timetable for NO_x regulations in different countries. In the United States, the control of power plant NO_x emissions initially followed the same timetable and regulatory approach as for SO_2 , beginning with the 1970 CAAA and 1971 NSPS. The key difference was in the stringency of applicable requirements. Under the 1970 CAAA, existing power plants were largely unaffected by state-level requirements to achieve NO_2 air quality standards. For new sources, the EPA performance standards imposed only modest requirements that could be met at low cost using low- NO_x burners (LNB) for combustion. As SO_2 emission restrictions grew more stringent (and more costly) during the 1970s and 1980s, NO_x emission requirements for coal plants did not change appreciably until the 1990s.

The acid rain provisions of the 1990 CAAA required many existing coal-fired plants to install "reasonably available control technology" in the form of low-NO_x burners and other combustion modifications. In 1994, EPA established much more stringent emission reduction requirements (averaging about 85 percent) for existing power plants as part of a regional strategy to attain the health-related air quality standards for ground-level ozone. Achieving these stringent NO_x reductions requires retrofitting SCR systems at many existing power plants. A massive expansion in SCR installations is thus now underway in the United States. A 1997 revision to the Federal NSPS also now requires a high level of NO_x control that is currently achievable only with SCR systems in most cases. In contrast to the U.S. situation, the use of SCR in other industrialized countries began many years ago 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, as seen in Figure 3.

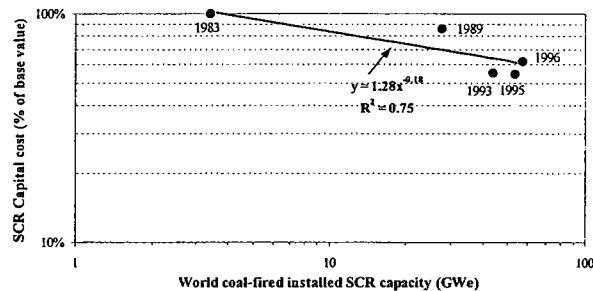


Figure 4. SCR capital cost improvement for a standard coal-fired power plant (500 MWe, 80% NO_x removal) vs. cumulative installed capacity. All data points normalized on an initial (1983) value of \$105/kW (in constant 1997\$).

Resulting Trend in SCR Cost. Experience curves for SCR systems were developed using the same methodology used for FGD technology. Figure 4 shows the resulting trend for capital cost. Again, these data reflect the effects of investments in R&D as well as learning by doing and other factors. SCR process improvements have substantially lengthened the average catalyst lifetime, while improvements in catalyst manufacturing methods, as well as competition among catalyst manufacturers, simultaneously lowered catalyst prices by 50 percent over a recent ten-year period. During this time there was no systematic change in the real price of the principal metals, mainly vanadium and titanium, used for SCR catalysts [9].

APPLICATION TO INTEGRATED ASSESSMENTS MODELS

The resulting learning rates of 11% and 12% for FGD and SCR systems, respectively, are similar not only to each other, but also to the average learning rates found in other studies for a wide range of market-based technologies [4, 10]. We believe the quantitative results presented here can provide useful guidelines for assessing the influence of technological change on future compliance costs for new environmental control requirements for coal-based power plants. In this context, our preliminary experience curve for FGD systems was used as a surrogate for the rate of capital cost decline that might be expected if CO₂ capture and storage (CCS) systems were deployed at power plants as part of a future strategy to reduce greenhouse gas emissions. Preliminary results from an integrated assessment modeling study carried out by researchers at IIASA [11] indicated that the cost of achieving a climate stabilization target was significantly lowered when the historical learning rate for SO₂ capture systems was applied to CCS systems for fossil fuel power plants. Several methodological issues remain to be further explored in the context of modeling studies with long

time horizons such as the 50- to 100-year time frames commonly used for climate policy analysis. In particular, it is unlikely that the learning rates observed during the initial development and deployment of a new environmental technology (like CO₂ capture) will be sustained indefinitely as the technology matures [12]. Future studies will explore this and other issues as part of our continuing research in this area.

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