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Report to the Chairman, Subcommittee on Energy and Power, Committee on Energy and Commerce, House of Representatives

May 1990

FOSSIL FUELS

Outlook for Utilities' Potential Use of Clean Coal Technologies

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GAO/RCED-90-165

GAO

United States
General Accounting Office
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Resources, Community, and
Economic Development Division

B-239607

May 24, 1990

The Honorable Philip R. Sharp
Chairman, Subcommittee on Energy
and Power
Committee on Energy and Commerce
House of Representatives

Dear Mr. Chairman:

As you requested, this report presents information on the extent to which electric utilities plan to use clean coal technologies on their coal-fired power generating units and how such technologies could contribute to reducing acid rain. It also provides utilities' perspectives on how they might react to different emission reduction requirements and compliance dates. The preliminary results of our review were presented in our Statement for the Record (GAO/T-RCED-90-3) submitted for your Subcommittee's October 18, 1989, hearing on acid rain control provisions of the administration's proposal to amend the Clean Air Act. We also testified on our preliminary results on March 28, 1990, before the Subcommittee on Economic Stabilization, House Committee on Banking, Finance and Urban Affairs (GAO/T-RCED-90-56).

As arranged with your office, we plan to distribute copies of this report to the Secretary of Energy and other interested parties and to make copies available to others upon request.

Please call me at (202) 275-1441 if you have any questions about this report. Major contributors are listed in appendix VI.

Sincerely yours,

Victor S. Rezendes
Director, Energy Issues

Executive Summary

Purpose

About 20 million tons of sulfur dioxide (SO_2) emissions and about 20 million tons of nitrogen oxides (NO_x) emissions are released into the atmosphere in the United States every year, contributing to the formation of acid rain. Electric utilities burning fossil fuels—primarily coal—account for about two-thirds of the nation's SO_2 emissions and about one-third of the NO_x emissions. Continuing congressional debate has focused on acid rain control proposals that would require many utilities to significantly reduce powerplant emissions by specific deadlines. At the same time, Congress has authorized the Department of Energy (DOE) to institute a $2.75-billion Clean Coal Technology Program to share in the cost of industry projects demonstrating emerging clean coal technologies that show promise of reducing SO_2 and NO_x emissions.

Concerned about the relationship between DOE's program and acid rain control proposals, the Chairman, Subcommittee on Energy and Power, House Committee on Energy and Commerce, requested GAO to examine (1) the extent to which electric utilities plan to use clean coal technologies on their power generating units and (2) how such technologies could contribute to reducing acid rain. Using a questionnaire, GAO requested information on utilities' plans to use these technologies at a random sample of the nation's fossil-fueled power generating units with 75-megawatt or greater capacity—and the extent that they would use such technologies at these units to meet four acid rain control scenarios that GAO developed.

Background

GAO considered acid rain control bills in the 100th Congress in developing its scenarios. The scenarios included both moderate and stringent SO_2 and NO_x emission reduction requirements by 1997 and 2004 compliance dates. GAO's scenarios are generally more stringent than the emission requirements in the Senate and House bills recently approved to amend the Clean Air Act.

GAO received responses for 94 percent of the sampled generating units. Because utilities were primarily interested in the technologies for their coal-fired units, this report discusses responses for coal-fired units only. The results have been applied to the universe of coal-fired units and associated utilities from which the sample was drawn.

Results in Brief

Respondents to GAO's questionnaire indicated that enactment of acid rain legislation would provide a major impetus for considering using clean coal technologies. Utilities plan to use the technologies at only 5 percent of their coal-fired units. However, should acid rain controls be mandated, they would consider such technologies for as many as 50 percent of their coal-fired units to reduce SO_2 emissions and 75 percent of their units to reduce NO_x emissions. Utilities indicated that their willingness to consider specific technologies depends on the severity of emission reduction requirements, target dates for compliance, future power generation requirements, their confidence in the technologies, and cost considerations. Generally, the more stringent the requirements and the more lead time to comply, the more clean coal technologies were considered viable options. They also indicated that they would favor other options—such as switching to low-sulfur coal—in three of the four scenarios to achieve SO_2 emission reduction requirements. However, not all coal-fired units would need to reduce emissions because up to 21 percent already meet one or more of the scenarios.

Despite their potential, clean coal technologies may not contribute much to the reduction of acid rain-causing emissions during the next 15 years. Uncertainty about the commercial availability of the new technologies is a key factor in determining when they could be widely deployed. Many are expected to be commercially available between the mid-1990s and 2000, but this time frame could be optimistic based on the problems and delays under the Clean Coal Technology Program in formalizing agreements with project sponsors and getting demonstrations underway. Even after the technologies are commercially available, utilities will likely test them on one unit before installing them on others, and lead time will be needed for ordering and manufacturing the technologies. Thus, it could take another 5 to 10 years beyond the date of commercial availability for the technologies to be widely deployed. Once they are proven and widely deployed, however, they could play a major role in combating acid rain.

Principal Findings

Technology Use Depends on Requirements

GAO's survey showed that utilities plan to use clean coal technologies at only 5 percent of their existing coal-fired units by the year 2010. However, should acid rain control requirements be mandated, utilities would give much greater consideration to using these technologies. Some units may not be affected because from 16 to 21 percent meet the SO_2 scenarios, and from 6 to 18 percent meet the NO_x scenarios.

Utilities' interest in clean coal technologies to meet SO_2 emission requirements seemed to be linked more to the time frames for compliance than the level of reductions to be met. For example, utilities would consider using the technologies to achieve SO_2 reductions at up to 51 percent of their coal-fired units under a 2004 compliance date, but only at up to 25 percent of their units under a 1997 deadline. However, many utilities would also consider conventional options and technologies, such as switching to low-sulfur coal (at up to 46 percent of their units) and installing conventional flue gas scrubbers (at up to 35 percent of their units) to meet GAO's scenarios for reducing SO_2 emissions.

Utilities' interest in clean coal technologies for NO_x control was more directly related to the severity of emission requirements than to the timing of compliance dates. Utilities would consider such technologies to reduce NO_x emissions at up to 57 percent of their coal-fired units under the moderate emission reduction scenarios and at up to 77 percent of their units under the stringent scenarios. This may stem from some utilities' high level of confidence in the potential application of some of the NO_x reduction technologies currently being pursued by industry.

Demonstration Projects Behind Schedule

Although DOE and the coal industry believe clean coal technologies may be less costly and environmentally superior to conventional technologies, the new technologies have not been successfully demonstrated on a commercial scale. Utilities have expressed concerns about the technical feasibility and cost effectiveness of many of the technologies and whether they will be able to achieve expected emission reductions.

According to utility and coal industry estimates, the new technologies should be demonstrated and available for commercial order between 1995 and 2000. These estimates generally assume that DOE's Clean Coal Technology Program will be fully funded and that the demonstration projects will be completed successfully and on schedule. However, some demonstration projects under DOE's program are behind schedule.

DOE has conducted three solicitations (rounds) for project proposals under its program and has two more planned. As of April 30, 1990, cooperative agreements had been completed for 19 of the 38 projects in the program, but only 3 projects had progressed to the demonstration phase. In March 1989, GAO reported that DOE experienced major delays in negotiating agreements with round-one project sponsors, and three projects withdrew from the program because of sponsors' difficulties in completing project financing and other business arrangements. GAO's follow-up work showed that these problems have continued under round two of the program. DOE has recently taken steps to shorten the process.

GAO also reported that seven funded round-one projects were experiencing coordination, equipment, and financing problems that caused delays in completing project phases and extensions of some completion dates—which could delay the successful demonstration of some technologies. Two funded projects dropped from the program in June 1989 and January 1990 because of financing problems. In March 1990 GAO reported that over half of the round-two projects were rated weak by DOE in their potential to reduce nationwide emissions. GAO suggested that the Congress consider delaying the final two rounds of projects until DOE obtains more results from demonstration projects already in the program. This would allow DOE to target the remaining program funds to the more promising technologies.

5 to 10 Years Needed to Deploy Technologies

According to DOE and utility and coal industry estimates, it may take 5 to 10 years for clean coal technologies to penetrate the market once they are proven and available for commercial order. This time span is needed for utilities to develop confidence in the new technologies and to provide the necessary lead time for ordering, designing, manufacturing, obtaining, and installing the technologies. Utilities' willingness to invest in the new technologies could also be influenced by their concerns about whether they will be allowed to recover their investment costs.

Recommendations

GAO is not making recommendations. However, the information in this report should be useful during congressional deliberations on acid rain control proposals in providing some perspective on how utilities might react to different emission reduction requirements and compliance dates.

Agency Comments

GAO discussed the information in this report with DOE officials and incorporated their comments where appropriate. They generally agreed with the accuracy of the information presented relating to the Clean Coal Technology Program. However, as requested by the Chairman's office, GAO did not obtain official agency comments on a draft of this report.

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Abbreviations

CCT	Clean Coal Technology
DOE	Department of Energy
EPA	Environmental Protection Agency
GAO	General Accounting Office
NO_x	nitrogen oxides
NSPS	New Source Performance Standards
PSD	Prevention of Significant Deterioration
SO_2	sulfur dioxide

Introduction

About 20 million tons of sulfur dioxide (SO_2) emissions and about 20 million tons of nitrogen oxides (NO_x) emissions are released into the atmosphere in the United States every year. These pollutants contribute to the formation of acid rain. Although there has been a decrease in SO_2 emissions since the 1970s, electric utilities burning fossil fuels account for about two-thirds of the nation's SO_2 emissions. The combustion of automotive fuels accounts for the largest share of NO_x emissions, but the utility sector NO_x emissions increased by 40 percent from 1970 to 1983 and accounts for about one-third of NO_x emissions.

Clean coal technologies are a family of emerging technologies that are expected to reduce SO_2 and NO_x emissions resulting from coal combustion. Many of these technologies will have industrial applications, but their main contribution to emissions reductions will be at coal-fired generators operated by electric utilities.

The Problem of Acid Rain and the Electric Utility Industry

Sulfur dioxide and nitrogen oxides undergo chemical changes in the atmosphere that convert them to their acidic forms. These acidic compounds are then returned to earth in rain or snow and as dry particles or gases, called acid rain. While the effects of acid rain have yet to be fully quantified, there is concern that it may be potentially harmful to the environment. For example, it is believed that acid rain may be damaging lakes and streams and causing the loss of gamefish and other species. A cause and effect relationship has not been proven between acid rain and forest damage, but growth decline and premature tree death have been documented in some areas where acid rain is present. Another concern is that building materials (marble, limestone, paints, and galvanized steel) can be eroded by exposure to acid rain. Finally, although acid rain has no known direct effect on human health, there is concern that acid rain can increase the levels of dissolved metals, such as lead and mercury, in water.

The Department of Energy (DOE), electric utilities, and the coal industry see the adoption of clean coal technologies as a way for utilities to achieve long-term reductions in emissions that contribute to acid rain. Current technology—basically, conventional flue gas scrubbers—[1] effectively removes SO_2 emissions but is costly, labor intensive, and creates waste-handling problems. Switching to natural gas or lower-sulfur

[1]Conventional flue gas scrubbing describes a number of processes for capturing sulfur dioxide. Basically, the utility's flue gas is exposed to a wet lime or limestone compound which reacts with the sulfur in the gas, leaving the cleaned gas to be expelled through the smokestack.

coal may be a low-cost option for some utilities to reduce SO_2 emissions, but if done on a wide scale, it could have an adverse economic effect in areas that mine high-sulfur coal. Proponents of clean coal technologies consider these technologies to be the best hope for achieving significant emission reductions in the utility industry and for ensuring a continuing market for our nation's high-sulfur coal.

The Clean Coal Technology Program

In 1984, the Congress set aside $750 million in the Energy Security Reserve Fund to establish DOE's Clean Coal Technology (CCT) Program. The purpose of this government and industry cost-sharing program is to assist industry in accelerating the commercialization of new clean coal technologies by demonstrating that they burn coal more cleanly, efficiently, and cost-effectively than current technologies. Under the program, DOE can fund up to 50 percent of the cost of each project selected for assistance. Industry and other nonfederal sources are expected to provide the balance of project financing.

In December 1985, the Congress authorized DOE to use $400 million from the Energy Security Reserve Fund for the first solicitation, or round one, of the program. DOE issued the first solicitation for project proposals in February 1986 and has 10 projects in the program from that solicitation. The objective of round one was to demonstrate the feasibility and commercial application of a broad slate of clean coal technologies to enhance the use of coal for all market applications. We issued two reports[2] and testified twice[3] on round one of the program.

In March 1987, the administration announced plans to expand the CCT Program on the basis of a January 1986 joint report by special U.S. and Canadian envoys that made several recommendations to reduce environmental problems associated with U.S. and Canadian transboundary acid rain.[4] Among other things, the envoys' report recommended that the United States implement a 5-year, $5-billion commercial demonstration program in which the federal government and industry would each provide $2.5 billion to advance clean coal technologies that would be needed for future acid rain control programs. The administration endorsed this

[2] Fossil Fuels: Commercializing Clean Coal Technologies (GAO/RCED-89-80, Mar. 29, 1989) and Fossil Fuels: Status of DOE-Funded Clean Coal Technology Projects as of March 15, 1989 (GAO/RCED-89-166FS, June 29, 1989).

[3] Views on DOE's Clean Coal Technology Program (GAO/T-RCED-88-47, June 22, 1988) and Status of DOE-Funded Clean Coal Technology Projects (GAO/T-RCED-89-25, Apr. 13, 1989).

[4] Joint Report of the Special Envoys on Acid Rain (Jan. 1986).

recommendation by requesting $2.5 billion over a 5-year period to demonstrate new clean coal technologies. The administration also announced that future demonstration projects would be selected, where possible, to reduce acid rain-causing emissions from fossil fuel-burning facilities.

DOE issued its second solicitation for project proposals in February 1988 and selected 16 projects in September 1988 from the 55 proposals received. (One of the 16 projects subsequently withdrew from the program.) Following the recommendations of the joint U.S.-Canadian envoys' report, the objective of the round-two CCT Program was to select projects that would demonstrate innovative clean coal technologies that are (1) capable of being commercialized in the 1990s, (2) more cost-effective than current technologies, and (3) capable of achieving significant reductions of SO_2 and NO_x emissions from existing coal-burning facilities. We reported on the round-two selection process in March 1990.[5]

The third solicitation was conducted in May 1989, and 13 projects were selected in December 1989 from the 48 proposals received. As of April 30, 1990, DOE and project sponsors had completed cooperative agreements for 19 of the 38 projects in the CCT Program. DOE expects to complete the cooperative agreements for the 6 other round-one and-two projects by July 1990 and the 13 round-three projects by December 1990.

The Congress has appropriated a total of $2.75 billion for the five rounds of projects planned for the CCT Program ($400 million for round one, $575 million each for rounds two and three, and $600 million each for rounds four and five). The Department of Interior and Related Agencies Appropriations Act, Pub. L. No. 101-121, 103 Stat. 701 (1989) directs DOE to issue the fourth solicitation for project proposals by June 1, 1990, and the fifth (final) solicitation by September 1, 1991. It also directs DOE to select the round-four projects by February 1, 1991 and the round-five projects by May 1, 1992.

[5] Fossil Fuels: Pace And Focus of the Clean Coal Technology Program Need to Be Assessed (GAO/RCED-90-67, Mar. 19, 1990).

Proposed Acid Rain Control Legislation and Clean Coal Technology

Legislation to combat acid rain-causing emissions from power plants and other sources has been a key issue of debate in congressional efforts to amend the Clean Air Act. Numerous acid rain control bills were considered in the 100th Congress, and several have been introduced in the 101st Congress. In July 1989, the administration proposed amendments to the Clean Air Act that would require annual reductions of SO_2 emissions from fossil-fueled generators by about 10 million tons below 1980 levels and annual NO_x emissions by 2 million tons below projected 2000 levels by December 31, 2000. Several hearings have been held in both the House and Senate on the administration's proposal and other acid rain control bills.

Acid rain control proposals share a common goal with clean coal technologies—the reduction of hazardous emissions into the atmosphere. However, the extent that clean coal technologies would contribute to emissions reductions, if acid rain control legislation were passed, is an open question. These are developmental technologies, and uncertainties remain as to (1) when they will be available, (2) whether they will be as effective as expected, (3) whether acid rain control legislation would promote or delay their development, and (4) how many utilities would use them if legislation is enacted.

Objectives, Scope, and Methodology

Concerned about the relationship between the CCT Program and potential acid rain control legislation and the effectiveness of DOE's strategy in demonstrating technologies that will reduce SO_2 and NO_x emissions, the Chairman, Subcommittee on Energy and Power, House Committee on Energy and Commerce, requested that we examine (1) the extent to which electric utilities plan to use clean coal technologies, and (2) how such technologies could contribute to reducing acid rain.

To assess the likelihood that utilities will use clean coal technologies, we developed a comprehensive questionnaire to collect information on (1) utilities' current plans to use clean coal technologies on specific power generating units and (2) the options that would be considered for these units if acid rain controls were mandated. We also asked utilities to identify incentives that would encourage them to invest in clean coal technologies.

To determine how utilities might react to acid rain control requirements, we included four hypothetical SO_2 and NO_x emission reduction scenarios in our questionnaire. We considered the acid rain control bills in the 100th Congress in developing the scenarios. The scenarios included both moderate and more stringent emission reductions by 1997 and 2004 compliance dates. Our scenarios, which are summarized in table 1.1, asked utilities to indicate what options they would consider at specific generating units to reduce their systemwide SO_2 and NO_x emissions by a specified percent below 1980 levels or to a target level stated in pounds per million British thermal units (lbs./MMBtus)--whichever requirement would be less stringent.

Table 1.1: Questionnaire Scenarios for Acid Rain Control Requirements

Scenario	Compliance date	Emission reduction requirement[a] Sulfur dioxide	Emission reduction requirement[a] Nitrogen oxide
1 Near-term moderate	1997	35% or to 1.0 lbs./MMBtus	25% or to 0.6 lbs./MMBtus
2 Near-term stringent	1997	75% or to 0.8 lbs./MMBtus	50% or to 0.4 lbs./MMBtus
3 Long-term moderate	2004	35% or to 1.0 lbs./MMBtus	25% or to 0.6 lbs./MMBtus
4 Long-term stringent	2004	75% or to 0.8 lbs./MMBtus	50% or to 0.4 lbs./MMBtus

[a]The percentages refer to the extent that emissions would need to be reduced below 1980 levels.

We distributed our questionnaire to utilities several months before the current administration announced its acid rain control proposal. Our scenarios for SO_2 emission reductions are more stringent than the administration's proposal, which essentially would require utilities to reduce SO_2 emissions from fossil fuel-fired steam electric generating units to 2.5 lbs./MMBtus after December 31, 1995, and to 1.2 lbs./MMBtus after December 31, 2000. The administration's proposal does not specify NO_x emission limits for generating units but would require the Administrator, EPA, to establish NO_x emission rates for utilities' coal-fired steam electric generating units to meet after December 31, 2000. The administration's proposal would also grant a 3-year extension (until December 31, 2003) for generating units that will be repowered with a qualifying clean coal technology to comply with emission requirements. Our scenario 3 is the closest to matching the administration's proposed SO_2 emission reduction requirement.[6]

We obtained technical assistance from DOE, the Environmental Protection Agency (EPA), two utility industry groups, and an environmental organization in developing our questionnaire and visited several utilities

[6]In April 1990, the Senate approved amendments to the Clean Air Act (S. 1630, 101st Cong., 2d Sess.), which contained emission reduction requirements that are generally consistent with the administration's proposal. The emission requirements in the bill that the House approved on May 23, 1990, are also generally consistent with the administration's proposal.

to test the clarity of our questions. We reviewed literature on clean coal technologies and consulted DOE in identifying the following categories of clean coal technologies for utilities to consider in responding to our questionnaire:

- coal cleaning and upgrading,
- advanced flue gas desulfurization,
- sorbent injection,
- low-NO_x combustion,
- post-combustion NO_x control,
- gas cofiring/reburning,
- combined SO_2/NO_x control,
- atmospheric fluidized-bed combustion,
- pressurized fluidized-bed combustion,
- slagging combustion, and
- integrated gasification, combined cycle.

(These technologies are described in app. I.)

For our questionnaire survey, we randomly sampled 480 of the nation's 1,503 fossil-fueled generating units that have at least 75 megawatts of generating capacity. The 1,503 units are operated by 190 utilities. Our sampled units included 307 coal-fired, 99 gas-fired, and 74 oil-fired generating units operated by 138 utilities. We used a stratified sampling design to ensure that all of the utilities with a large number of units would be sampled, with a maximum of five units randomly selected for any one utility. (Our sampling methodology is discussed in more detail in app. II.)

In January 1989, we sent our questionnaire (app. III) to the utilities that operated the sampled units. We received responses from 130 utilities, which provided us information on 94 percent of the sampled units. The responses showed that utilities would consider clean coal technologies primarily for coal-fired units. Therefore, this report discusses our survey results for coal-fired units only. We received information from 99 utilities on 291 (94 percent) of the 307 coal-fired units in our sample. These responses have been analyzed to develop estimates for the 876 coal-fired units and 150 associated utilities in the universe from which the sample was drawn.

To supplement the questionnaire data, we visited four utilities that have actively pursued clean coal technologies to discuss their experiences and interest in the technologies. We also met with DOE and EPA officials and representatives of environmental groups, including the National Resources Defense Council and Greenpeace, to discuss the potential use of the technologies for reducing acid rain-causing emissions at power plants and to obtain their perspectives on other issues.

Our work was performed from June 1988 through December 1989 in accordance with generally accepted government auditing standards. We discussed the information in this report with DOE officials and incorporated their comments where appropriate. They generally agreed with the accuracy of the information presented relating to the CCT Program. However, as the Chairman's office requested, we did not obtain official agency comments on a draft of this report.

Few Utilities Plan to Use Clean Coal Technologies, but Many Would Consider Them to Meet Acid Rain Control Mandates

Our questionnaire survey revealed that few utilities currently have plans to use clean coal technologies at their existing power generating units to reduce emissions—or in building new power generation facilities to meet future demand growth for electricity. However, should there be a requirement to meet acid rain control mandates, utilities would consider adopting clean coal technologies for as many as 50 to 75 percent of their coal-fired power generating units. The utilities' willingness to consider specific technologies depends on such factors as the severity of required emission reductions, the target dates for compliance, the utilities' present and future power generation requirements, and cost considerations. Utilities indicated that they would also weigh the feasibility of other options, such as using conventional flue gas scrubbing technology or switching to low-sulfur coal, to meet acid rain controls. Some coal-fired units may not be affected by acid rain control requirements because about 16 to 21 percent would already meet our SO_2 emission reduction scenarios and about 6 to 18 percent would meet our NO_x emission reduction scenarios.

Acid Rain Controls Would Increase Interest in Clean Coal Technologies

Information provided in response to our questionnaire indicated that utilities have plans to use clean coal technologies at only about 5 percent of their existing coal-fired generating units by the year 2010.[1] Some of the technologies to be used on these units included low-NO_x combustion, gas cofiring, advanced flue gas desulfurization, sorbent injection, and combined SO_2/NO_x control.

We asked the utilities in our questionnaire survey whether they had explored emission control options for the generating units in our sample should acid rain control legislation be enacted. We asked those that had explored such options to indicate what options they would most seriously consider at the sampled units to meet the SO_2 and NO_x emission requirements under each of our scenarios. Our questionnaire listed clean coal technologies as one of the options for reducing emissions. Some of the other options included using conventional technologies to meet the requirements, switching to low-sulfur coal, retiring the unit, or taking no action at the sampled unit if the utility's system already met our scenario emission limits.

Our analysis of questionnaire responses showed that utilities have explored emission control options at at least 80 percent of their coal-

[1]This estimate could range from 2.4 to 7.2 percent (see app. II).

fired units.[2] It also showed that many utilities would consider the future use of clean coal technologies if they were required to meet acid rain control requirements. Under our acid rain control scenarios, utilities would consider using clean coal technologies at as many as half of their coal-fired units to meet SO_2 emission limits and at as many as three-fourths of their coal-fired units to meet NO_x emission limits. However, clean coal technologies were not the most frequently considered options to meet acid rain control requirements in three of our four SO_2 emission reduction scenarios. It should also be noted that in responding to our scenarios, utilities indicated options they would seriously consider, but their responses did not represent firm plans or commitments to use clean coal technologies or other options.

Options That Would Be Considered to Meet SO_2 Scenarios

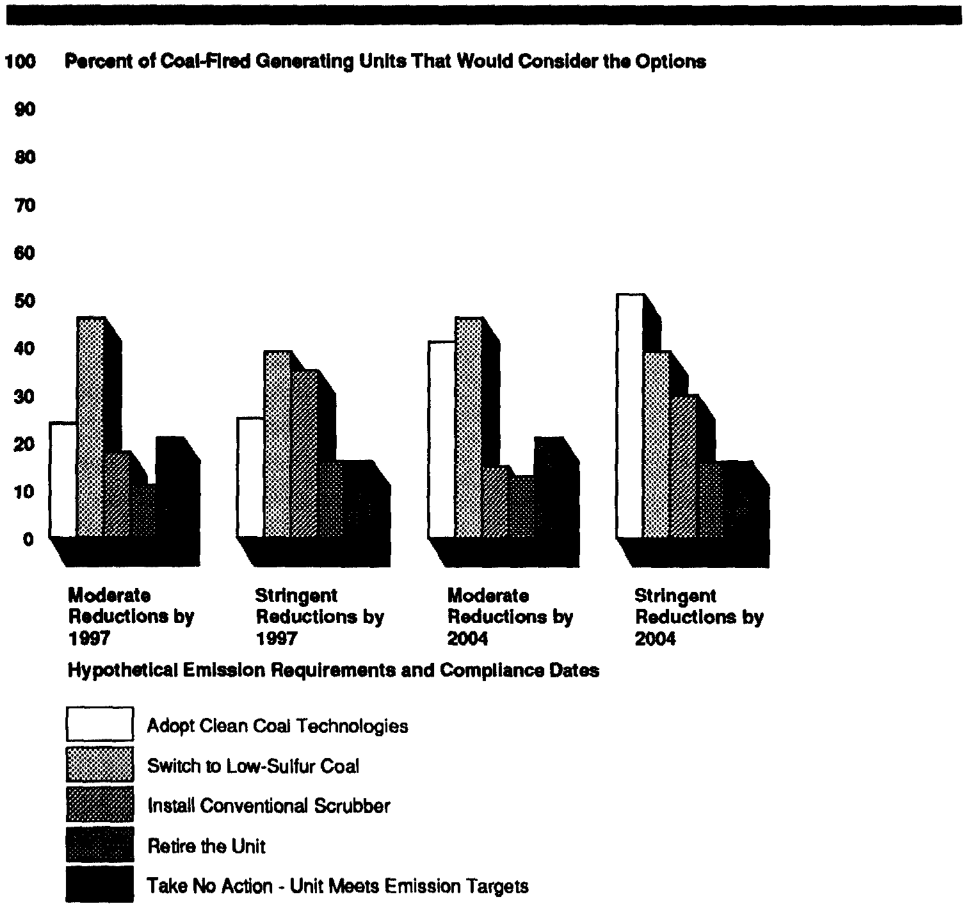
Not all utilities would need to take action to reduce SO_2 emissions under our scenarios. Questionnaire results indicate that about 21 percent of utilities' coal-fired units would already comply under our moderate SO_2 emission reduction scenarios, and about 16 percent would comply under our more stringent scenarios.

As shown in figure 2.1, for those units where action would be considered, switching to low-sulfur coal was the most often cited method of meeting the SO_2 emission reduction requirements in three of our four scenarios. Utilities would consider switching to low-sulfur coal at 46 percent of their coal-fired units under both of the moderate emission reduction scenarios, and at 39 percent of their units under both of the stringent scenarios.

Only in our scenario of meeting stringent requirements by 2004 would utilities choose clean coal technologies more often than other options. Questionnaire results indicate that compared to conventional options, clean coal technologies would be utilities' second most frequently chosen option to meet moderate reduction requirements for both 1997 and 2004 compliance dates, and third most frequently chosen option to meet stringent requirements by a 1997 deadline. Given this latter scenario, utilities indicated that they would switch to low-sulfur coal or use conventional scrubber technology more often than using clean coal technologies.

[2] This estimate could range from 76.5 to 85 percent (see app. II).

Figure 2.1: Utility Responses to Sulfur Dioxide Emission Reduction Options



For those utilities indicating an interest in using clean coal technologies to meet SO_2 emission requirements, the interest seemed to be linked more to the time frames for compliance than the level of reductions to be met. For example, our analysis showed that utilities would consider clean coal technologies for 41 and 51 percent of their coal-fired units under a 2004 compliance deadline, but only for 24 and 25 percent of their units under a 1997 compliance deadline. This suggests that utilities would be more apt to use clean coal technologies to meet SO_2 emission control mandates if they were given a longer time frame for compliance. The technologies most frequently cited as options for reducing SO_2 emissions were sorbent injection, advanced flue gas desulfurization, coal cleaning and upgrading, and combined SO_2/NO_x control. The level of interest in such technologies was not concentrated in any age group or size of generating units.

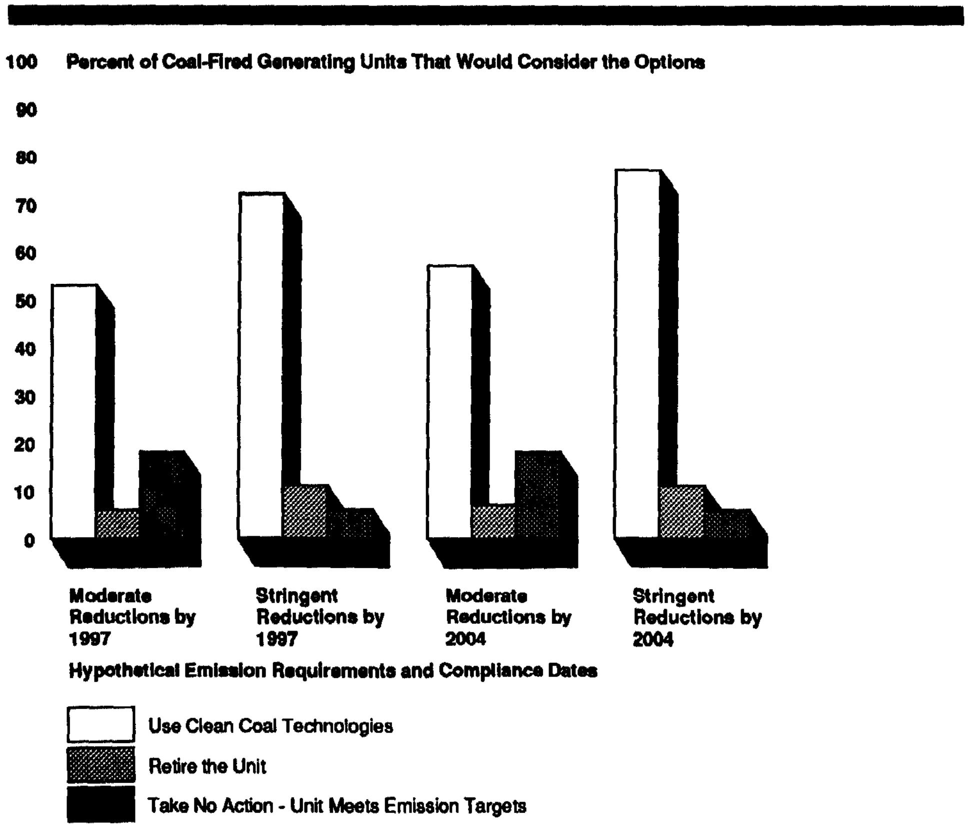
Our survey results also indicated that utilities would consider the use of conventional technologies to meet SO_2 emission requirements. For example, utilities would consider installing conventional scrubber technology at 18 and 15 percent of their coal-fired units under the 1997 and 2004 moderate emission reduction scenarios and at 35 and 30 percent of their units under the 1997 and 2004 stringent scenarios. (App. IV includes more information on our estimates of the extent that utilities' coal-fired units would be considered for various options to achieve the SO_2 emission requirements in each of our acid rain control scenarios.)

Officials at one of the utilities we visited have testified that acid rain control legislation could influence some utilities to abandon clean coal technology demonstration efforts and redirect funds that otherwise would have been used for such technologies to investments in conventional processes in order to meet SO_2 emission reduction requirements. On the other hand, an official from an environmental organization told us that acid rain control legislation could encourage some utilities to invest in clean coal technologies because they would have added incentive to explore all possible options for meeting SO_2 emission reduction requirements.

Options That Would Be Considered to Meet NO_x Scenarios

Our questionnaire responses showed that the extent of the utilities' interest in clean coal technologies to control NO_x emissions was more directly related to the severity of targeted reductions than to the timing of the compliance dates. As shown in figure 2.2, utilities would consider using clean coal technologies to reduce NO_x emissions at 53 percent of their coal-fired units under the moderate, near-term scenario and at 57 percent of their units under the moderate, long-term scenario. Given more stringent reduction goals, however, utilities would consider such technologies to reduce NO_x emissions at 72 percent of their units under the near-term scenario and 77 percent of their units under the long-term scenario. The questionnaire results indicate that about 18 percent of utilities' coal-fired units would already comply with the moderate NO_x emission reduction scenarios, and 6 percent would meet the stringent scenarios.

Figure 2.2: Utility Responses to Nitrogen Oxide Emission Reduction Options



Low-NO_x combustion technology was by far the most frequently considered clean coal technology for reducing NO_x emissions. Other clean coal technologies that utilities considered were post-combustion NO_x control, gas cofiring/reburning, and combined SO_2/NO_x control. (App. V includes more information on our estimates of the extent that utilities' coal-fired units would be considered for various options to achieve the NO_x emission requirements in each of our acid rain control scenarios.)

Low-NO_x combustion is not really a single technology, but rather a variety of applications of related technologies—for example, low-NO_x burners and over-fire air, used independently or in combination. Questionnaire responses and discussions with utility officials revealed that some utilities consider certain low-NO_x combustion applications to be currently available conventional technology, at least on newly constructed boilers. Some utilities even indicated they would consider low-NO_x combustion a clean coal technology when applied to one of their units, while another application at a different unit would be considered a conventional technology. Also, more than for any other clean coal technology, utilities cited a high level of confidence in low-NO_x combustion as a reason for considering the technology for emission reduction. Some utility representatives indicated that this high confidence in low-NO_x combustion was based on their experience with using the technology on some boilers.

Potential Use of Clean Coal Technologies to Meet Increased Demand for Electricity

We asked the utilities in our questionnaire survey whether they expected to experience demand growth by the year 2000 and, if so, how they would meet that growth. Nearly all of the utilities indicated that they did expect some increase in the demand for electricity; however, the use of clean coal technologies was not the most often cited option in expanding their capacity to help meet this growth.

Table 2.1 shows the options we asked utilities to consider in answering this question. As indicated, 70 percent of the utilities with coal-fired units would be likely to rely on demand management and/or conservation to meet demand growth—this was the most frequently checked option. The second and third most frequently checked options were to purchase power from a domestic provider and to build a new oil- or gas-fired unit. Building a new coal-fired unit using clean coal technology would be considered by 45 percent of the utilities and was the fourth most cited option. Twenty percent of the utilities would consider using clean coal technologies to increase capacity at existing units. (Some clean coal technologies are designed to replace a major portion of an existing plant, such as a boiler, with new power-generating equipment to extend the plant's life, increase its capacity, and reduce its emissions.)

Table 2.1: Options That Utilities With Coal-Fired Units Would Consider to Meet Demand Growth

Option	Percent of utilities that would consider option[a]
Rely on demand management and/or conservation	70
Purchase power from a domestic provider	68
Build a new oil- or gas-fired unit	60
Build a new coal-fired unit using clean coal technology	45
Increase output at existing unit(s) that are operating below capacity	43
Increase capacity at existing units by means other than clean coal technology	33
Purchase power from a foreign supplier	21
Build a new coal-fired unit without clean coal technology	20
Use clean coal technology to increase capacity at existing unit(s)	20

[a]The total exceeds 100 percent because many utilities indicated that they would consider more than one option. The numbers represent the percent of utilities that would be "very likely" or "fairly likely" to consider these options. The maximum sampling error is 6 percent.

Although our questionnaire did not ask utilities to indicate why they would consider certain options over others in meeting demand growth, officials at some of the utilities we visited said that they expected demand growth in the next decade to be generally in the form of peaking demand (temporary periods of high demand) that would generally be met by purchasing power, construction of additional gas-fired turbines, and greater utilization of existing facilities. They indicated that there would be little need for construction of new coal-fired base-load capacity until after the year 2000.

A June 1989 DOE report also concluded that there may be only limited need for construction of new coal-fired power plants through the year 2000.[3] The report cited excess nuclear- and coal-fired generating capacity, high capital costs of new plant construction, and relatively slow growth in electric power demand as reasons for this forecast. The DOE report indicated that, instead of constructing new coal-fired power plants, utilities are expected to meet demand growth by increasing use of existing plant capacity, purchasing electric power from non-utility sources, constructing gas-fired units, and refurbishing aging units to extend their working lives. An August 1987 DOE report also indicated that some utilities are planning to operate their older generating units beyond the normal retirement date and to bring an increasing number of

[3]Annual Outlook for U.S. Electric Power 1989 (DOE/Energy Information Administration, June 26, 1989).

gas turbines on line within the next decade.[4] Other options include energy conservation and better load management.

According to the DOE reports, these strategies would enable utilities to meet moderate or temporary demand increases with limited capital investment. For example, gas-fired units can be installed in relatively small increments of power and can be cost-effective even when operated intermittently. In contrast, the large scale and high capital cost of conventional coal-fired units makes them cost-effective only for continuous power generation.

Conclusions

Our questionnaire responses show that while few utilities have current plans to use clean coal technologies, as many as one-half to three-fourths of the utilities would consider using them on their coal-fired units to meet acid rain control mandates. Presently, utilities would be more inclined to use clean coal technologies to meet NO_x emission requirements than SO_2 requirements. Given additional time to meet acid rain control mandates, utilities would probably make greater use of the technologies to meet SO_2 emission requirements. This appears to stem from utilities' high level of confidence in low-NO_x combustion, one of the clean coal technology options for NO_x reduction, and utilities' understanding that clean coal technologies for SO_2 reduction are not yet proven but may be available in time to meet the long-term scenario requirements.

In addition to potential acid rain legislation, increasing demand for power might stimulate the adoption of clean coal technologies in repowering applications and new construction. However, our questionnaire responses indicate that utilities do not view clean coal technology as a primary tool for meeting increased demand in the near future.

While the results of our questionnaire indicate that enactment of acid rain legislation will encourage utilities to consider clean coal technologies, they should not be considered as indicative of the extent to which clean coal technologies or other conventional emission control options would be actually used at utilities' coal-fired generating units. In responding to our questionnaire, utilities identified clean coal technologies and other options they would consider in response to our emission control scenarios, but their responses did not necessarily represent firm

[4] Inventory of Power Plants in the United States 1986 (DOE/Energy Information Administration, Aug. 11, 1987).

plans—nor a definite commitment—to use the technologies and other options. Furthermore, many other factors will affect how widely the technologies are actually adopted. As discussed in chapter 3, clean coal technologies have not been adequately demonstrated and may not be commercially available in time to meet the utilities' needs.

Clean Coal Technologies Are Unlikely to Contribute Significantly to Acid Rain Reduction in the Next 15 Years

Although acid rain control legislation may encourage utilities to give much more consideration to using clean coal technologies, uncertainty about their commercial availability—which is contingent upon successful demonstrations—is a key factor in determining when the technologies could be widely deployed. Many of the emerging technologies may be commercially available between the mid-1990s and 2000, however, it may take another 5 to 10 years beyond the date of commercial readiness for the technologies to penetrate the market. Consequently, at their current pace of development and anticipated time tables for widespread deployment, emerging clean coal technologies will probably not contribute significantly to the reduction of acid rain-causing emissions during the next 15 years. Utilities' willingness to invest in clean coal technologies could also be influenced by their concerns about whether they will be able to recover the technologies' costs and about what emissions standards the technologies will need to achieve.

Technologies Need to Be Successfully Demonstrated

Although DOE and the coal industry believe emerging clean coal technologies offer the promise of being both less costly and environmentally superior to conventional technologies, the new technologies have generally not been successfully demonstrated on a commercial scale. Several of the utilities we visited expressed concerns about the technical feasibility and cost effectiveness of many of the new technologies and about whether they will be able to achieve expected emission reductions.

Industry spokesmen and reports have stated that a technology is not successfully demonstrated until it has undergone multiple commercial demonstrations addressing a wide range of boiler designs, fuel types, and other operating variables. According to industry officials, potential users of the technologies need a base of information and experience, gained through multiple demonstrations, upon which to judge costs, efficiency, reliability, and other issues when comparing clean coal technologies with conventional alternatives for reducing emissions. In this regard, about 41 percent of the utilities with coal-fired units in our questionnaire survey indicated that having multiple demonstrations of the technologies that seemed most promising was the best way to promote the commercialization of clean coal technologies.

According to utility and coal industry estimates, the new technologies are expected to be available for commercial order between 1995 and 2000. The less complex technologies, such as sorbent injection, are expected by the mid-1990s, and the more complex technologies, such as pressurized fluidized-bed combustion, are expected by 2000. These estimates generally assume that DOE's CCT Program, which is a major effort to expedite the demonstration of clean coal technologies on a commercial scale, will be fully funded and that the selected demonstration projects will be completed successfully and on schedule.

As of April 30, 1990, 38 projects were in the CCT Program, including 16 that were being funded under cooperative agreements, 3 that were awaiting the completion of a 30-day congressional review period before their cooperative agreements could take effect, and 19 that were in various phases of DOE's process for formalizing cooperative agreements with the project sponsors. Only 3 of the funded projects had progressed to the demonstration (operation) phase and none were completed.

In our March 1989 report on the CCT Program, we pointed out that DOE experienced difficulties in negotiating cooperative agreements with round-one project sponsors, which delayed completing agreements for five projects by up to 9 months and resulted in the termination of negotiations for three projects.[1] The delays were primarily attributable to the time it took to resolve sponsors' problems with project financing and other business arrangements, including proprietary data rights. Recently, a round-one replacement project was withdrawn from the program because of the sponsor's problems in completing agreements with project participants. DOE has also experienced delays of 4 to 6 months in completing round-two agreements, and one project withdrew because of financing and other problems. In December 1989, the Secretary of Energy directed DOE to streamline its review and approval process for completing cooperative agreements. The Secretary stated that the Department's goal was to have the agreements completed within 1 year after a project is selected.

Our March 1989 report and April 1989 testimony on the CCT program also pointed out that seven of the nine funded round-one projects were experiencing coordination, equipment, and financing problems that caused delays in completing project phases, cost overruns, and proposed project modifications.[2] We stated that DOE had extended the demonstration completion date for two of the projects and expected to extend the demonstrations of other funded projects that were behind schedule.

[1] Fossil Fuels: Commercializing Clean Coal Technologies (GAO/RCED-89-80, Mar. 29, 1989).

[2] Status of DOE-Funded Clean Coal Technology Projects (GAO/T-RCED-89-25, Apr. 13, 1989).

These problems could delay the successful demonstration of the technologies. In fact, two of the funded round-one projects dropped from the program (in June 1989 and January 1990) because of financing problems. Therefore, industry estimates of the time frame when the new technologies should be commercially available may be optimistic for some technologies.

Also, although the objective of the round-two CCT Program was to place greater emphasis on demonstrating technologies that are capable of achieving significant reductions of SO_2 and/or NO_x emissions, some of the round-two demonstration technologies may have limited potential for reducing nationwide acid rain-causing emissions. Our March 1990 report pointed out that 9 of the 16 round-two projects are to demonstrate technologies that were rated weak by DOE's evaluation Board in their potential to reduce nationwide SO_2 and/or NO_x emissions when used at existing coal-burning facilities.[3] Given the current status of the projects in the CCT Program, and in view of the nation's current budget constraints, we suggested that the Congress may want to have DOE delay the final two rounds of the program until it obtains additional demonstration results from projects already in the program. This would allow DOE to target the remaining $1 billion that has already been appropriated for rounds four and five of the program to the more promising technologies and help ensure that program funds are used effectively and efficiently.

Widespread Deployment May Take 5 to 10 Years After Technologies Are Proven

Clean coal technologies would need to be widely deployed in order to achieve significant reductions in nationwide emissions from coal-fired generating units. According to DOE and utility and coal industry estimates, it may take 5 to 10 years or more for the technologies to penetrate the market once they are proven and available for commercial order. This time span is needed for utilities to develop confidence in the new technologies and to provide the necessary lead time for ordering, designing, manufacturing, obtaining, and installing the technologies.

Utilities are apt to move cautiously in applying the new technologies. For example, according to industry officials and reports, utilities will likely test the performance of a successfully demonstrated technology on a single unit before installing it on other units. Utilities will also need time to obtain the necessary state and federal permits and regulatory

[3]Fossil Fuels: Pace And Focus of the Clean Coal Technology Program Need to Be Assessed (GAO/RCED-90-67, Mar. 19, 1990).

approvals at the powerplant sites where the new technologies will be used.

The demand for the new technologies will also affect their future market penetration. Currently, utilities' emission control options are limited to conventional processes, including flue gas scrubbing, coal switching, and coal cleaning. Although these processes have limitations, they offer advantages to the user that clean coal technologies cannot yet offer—they are commercially tested and available, and they can reduce emissions. Once clean coal technologies are available for commercial order, utilities will have a broader range of emission control and power generation options to choose from, but the demand for the technologies will be based on their efficiency and reliability, cost effectiveness, and emission reduction capability in comparison with conventional options.

Other Concerns That Could Affect Utilities' Willingness to Invest in Clean Coal Technologies

Utilities are concerned about whether they will be allowed to recover the costs of emerging clean coal technologies and what emission standards the technologies will need to achieve.

Uncertainty of Cost and Cost Recovery

Although DOE expects that the installation and operating costs for clean coal technologies generally will be lower than conventional options, the costs of the new technologies have not yet been determined. This places a utility that chooses to use a clean coal technology at greater risk than one that decides on a conventional technology or option that has more established and predictable costs. The importance to utilities of choosing the lowest-cost option was reflected in their responses to our questionnaire survey. About one-half of the respondents with coal-fired units indicated that lower capital, operating, and maintenance costs would be primary reasons to invest in clean coal technologies over conventional alternatives. Officials at one of the utilities we visited said that they would consider all available options but would only select a clean coal technology if it was shown to be the lowest-cost option.

Utilities are also concerned about the uncertainty of recovering investment in clean coal technologies. A utility's decision to invest in a clean coal technology would need to satisfy the same criteria as any other investment in the generating plant for the public utility commission to authorize the utility to recover the cost of bringing the new technology on line. The utility would need to show that such investment was a prudent and cost-effective decision. Some utility officials we met with expressed concern that utilities planning to use emerging innovative clean coal technologies in place of conventional technologies face a greater risk that their costs may not be approved for recovery. One official believed that utilities demonstrating innovative clean coal technologies should be allowed to receive an incentive rate of return on their investment that would be more commensurate with the higher risk taken for using unproven technologies in place of conventional technologies to reduce emissions.

Only a few states have developed specific incentives to allow utilities to recover demonstration costs for clean coal technologies, and none has specifically approved a cost recovery policy for commercial applications of the technologies. At least two states (Florida and Ohio) have devised programs to allow for an accelerated recovery of demonstration costs. Indiana has passed a law that allows utilities engaged in clean coal technology demonstration projects to obtain preapproval of the prudency of expenditures and to qualify for accelerated depreciation and recovery of preconstruction costs, among other things. About 27 percent of the utilities with coal-fired units in our questionnaire survey indicated that increased flexibility by public utility commissions on cost recovery would be an incentive to invest in clean coal technologies.

Concerns About Applicable Emission Standards

Utilities are also concerned about the emission standards that existing generating units will be required to meet if they install clean coal technologies on the units and about whether the new technologies will be able to achieve the required standards.

EPA regulations require that fossil fuel-fired steam generating units of more than 73 megawatts that began construction after August 17, 1971, must meet New Source Performance Standards (NSPS) for controlling emissions.[4] Generating units that began construction before that date are exempt from these standards but may become liable for meeting them if the units are modified. Generally, an exempt unit must meet NSPS

[4]New Source Performance Standards were established by EPA under the Clean Air Act Amendments of 1970, Pub. L. No. 91-604, 84 Stat. 1676 (1970). Pursuant to the Clean Air Act Amendments of 1977, Pub. L. No. 95-95, 91 Stat. 685 (1977), EPA promulgated more stringent regulations for fossil fuel-fired steam generating units of more than 73 megawatts that began construction after September 18, 1978.

if the unit's physical structure or operation is changed and results in increased emissions, or if a substantial portion of the unit is replaced at a cost that exceeds 50 percent of the cost of building a comparable new unit.

According to utility industry spokesmen, utilities are concerned that EPA may require previously-exempt generating units to meet NSPS and/or the emissions limitation requirements of the Prevention of Significant Deterioration (PSD) Program if the units are modified to demonstrate clean coal technologies.[5] Although DOE has reported that emerging clean coal technologies offer the promise of being environmentally superior to conventional technologies, utilities are concerned that some technologies may not be able to achieve NSPS and PSD requirements.

This concern over modifying existing units has been heightened by an October 14, 1988, EPA determination that the Wisconsin Electric Power Company would have to meet NSPS and PSD limitations at several units it planned to refurbish. Although this case does not involve clean coal technology, the utility industry views it as a potential precedent for requiring existing units refurbished with clean coal technologies to meet NSPS and PSD limitations. According to DOE and utility industry spokesmen, this concern could discourage some utilities from participating in the CCT Program or demonstrating clean coal technologies without federal assistance. DOE advised a congressional subcommittee in August 1989 that several industrial participants in the CCT Program had indicated that they would abandon their demonstration projects if it appeared that their efforts would become subject to NSPS and PSD requirements. According to DOE, uncertainty over the outcome of this case contributed to a first-round project being withdrawn from the CCT Program.

The Wisconsin Electric Power Company appealed EPA's ruling, and on January 19, 1990, a federal appeals court affirmed EPA's decision that the company's powerplant in question was subject to NSPS. The court also held that EPA had not properly supported its decision to impose PSD requirements on the units in question. The case was returned to EPA for further consideration.

[5]The PSD Program, which was established pursuant to the 1977 amendments to the Clean Air Act, can impose more stringent emission limitations on newly constructed or modified generating units than NSPS to prevent the deterioration of air quality.

EPA granted an exemption from NSPS and PSD requirements in February 1989 for a powerplant unit demonstrating a clean coal technology and has indicated that it will continue to consider such exemptions on a case-by-case basis. However, the utility industry is concerned that generating units that are modified to demonstrate clean coal technologies will be subject to the more stringent emission standards after the demonstrations end, even if the technologies are removed. There is also concern that the EPA exemption does not protect a utility from legal action that private citizens might take under the Clean Air Act if emission levels should increase at the generating unit during or after the demonstration. The administration's proposal to amend the Clean Air Act includes provisions that would exempt clean coal technology demonstration projects from meeting NSPS and PSD requirements as long as emission levels do not increase above the generating unit's predemonstration emission level.

Utility officials are also concerned about whether clean coal technologies used in new plant construction will be able to achieve NSPS or, if applicable, the best available control technology emission requirements of the PSD program. In addition, since the new technologies are still being developed, there is uncertainty as to what technologies will be used to establish the best available control technology emission requirements.

Officials at a utility that had plans to demonstrate a clean coal technology on an existing generating unit told us that they experienced difficulties in negotiating emission levels that the unit would be required to attain. They said that the state and federal environmental agencies attempted to apply the best available control technology emission requirements of the PSD program to this unit, but the utility argued that the technology was experimental and there was no similar technology to use as a basis for establishing more stringent emission levels than those required under NSPS. According to these officials, before this issue was resolved, the utility cancelled its demonstration plans because of financial reasons. This demonstration proposal had been selected as an alternate project under round one of DOE's CCT Program.

Utilities' Views on Incentives for Using New Technologies

We asked the utilities in our questionnaire survey to identify up to three incentives from a list of choices that we provided that would most encourage them to invest in a clean coal technology. The incentives that were indicated most often involved cost considerations, as shown in table 3.1.

Table 3.1: Incentives That Would Most Encourage Utilities With Coal-Fired Units to Invest in Clean Coal Technologies

Incentive	Percent of utilities that would be motivated by incentive[a]
Lower capital costs than conventional technologies	53
Lower operating and maintenance costs than conventional technologies	42
Extended compliance dates, if acid rain control legislation is enacted, for utilities using clean coal technology	35
Relaxed emission reduction targets, if acid rain control legislation is enacted, for utilities using clean coal technology	30
Public utility commission flexibility on cost recovery	27
Additional commercial demonstrations	21
Tax credits	17
Less stringent NSPS standards for utilities using clean coal technology	14
Government cost-sharing	13
Government grants	10
Other	7

[a]The total exceeds 100 percent because utilities were asked to select up to three incentives. The maximum sampling error is 6 percent.

Next to lower capital, operating, and maintenance costs, utilities indicated that favorable treatment for using clean coal technologies to meet acid rain control requirements and for recovering costs would enhance the likelihood that they would invest in a new technology. As previously mentioned, the administration's acid rain control proposal provides a 3-year extension to meet emission requirements for generating units that will be repowered with a qualifying clean coal technology. The administration's proposal also includes other regulatory incentives to promote the development and use of clean coal technologies that limit power plant emissions.

About 21 percent of the utilities would be encouraged to invest by more commercial-scale demonstrations of the technologies. Only 14 percent would be encouraged by less stringent NSPS standards. A few utilities indicated that direct government financial assistance in the form of grants, cost-sharing, or tax credits would provide added incentive for them to invest in a clean coal technology.

Views of DOE Officials

In commenting on the results of our review, DOE officials said that the emissions trading concept in the proposed legislation to amend the Clean Air Act would provide an economic incentive for some utilities to reduce their powerplants' emissions as much as possible below the limitations by using the cleanest technologies available so that they could accumulate emission credits that could be used to expand their systemwide capacity or to sell to other utilities that may not be able to meet emission limitations. The officials indicated that the emissions trading concept could provide an additional incentive for utilities to adopt clean coal technologies and that if the utilities had known about this concept before completing our questionnaire, some may have responded differently to the options they would consider for reducing their emissions.

Conclusions

Emerging clean coal technologies have not been proven successful on a commercial scale. As a result, their technical feasibility, cost effectiveness, and emission control capability relative to conventional options have not been established. Although industry estimates indicate that many of the new technologies should be proven and available for commercial order by the mid- to late-1990s, this time frame could be somewhat optimistic based on the problems and delays experienced under DOE's CCT Program in formalizing cooperative financial assistance agreements with project sponsors and completing funded demonstration project phases. Five projects under the CCT Program were withdrawn during the cooperative agreement formalization process, and two of the funded demonstration projects were dropped from the program because of financing and other problems.

Utilities' decisions to invest in emerging clean coal technologies will depend in large part on their confidence in how the new technologies will compare to conventional technologies and other options, whether they will be able to recover their investment costs, and the emission standards they will be required to meet.

Because of the time needed for demonstration and deployment, emerging clean coal technologies may play only a limited role in reducing acid rain-causing emissions from coal-burning power plants in the next 15 years. However, once the new technologies are successfully demonstrated and widely deployed, they could play a major role in addressing the acid rain problem.

Description of Clean Coal Technologies

This appendix provides a brief description of emerging clean coal technologies.

Coal Cleaning and Upgrading

Coal-preparation and-cleaning processes upgrade the fuel by removing sulfur from coal before the coal reaches the boiler. Physical and chemical cleaning are the two most common means of coal upgrading. Physical cleaning removes a portion of the ash and sulfur, and chemical cleaning is needed to remove organically bound sulfur and inorganically combined sulfur. The extent to which the ash and sulfur can be reduced depends on the characteristics of the coal and the way it is processed.

The benefits of coal cleaning and upgrading go beyond emission reductions. In some cases, the lowered sulfur and ash reduces scrubbing and waste disposal costs and mitigates the accumulation of ash in the boiler. The enhanced heating value and improved consistency benefit boiler operation and performance.

Advanced Flue Gas Desulfurization (Scrubbing)

Advanced flue gas desulfurization technologies are designed to remedy many of the problems associated with conventional scrubbers. With conventional scrubbers, sulfur oxides are removed from flue gas by "scrubbing" the gas with an alkaline slurry. The advanced technologies include a process that has the potential to produce a salable byproduct rather than waste sludge and another process that, in addition to SO_2 reductions, achieves NO_x reductions.

Sorbent Injection

Sorbent injection includes a variety of proposed technologies for injecting dry sorbents[1] into the furnace or into flue gas ducts to remove sulfur dioxide. Dry sorbent processes are expected to be less costly than scrubbers.

The limestone injection multistage burner is expected to reduce sulfur dioxide by injecting dry limestone sorbent into the boiler above the burners. The calcium sulfate that forms travels through the boiler and is removed along with the fly ash in the existing particulate removal equipment. NO_x formation is controlled by staged combustion.

[1]Sorbents are chemical compounds which are used to react with pollutants to form a solid which is then removed from the system.

In-duct sorbent injection avoids the corrosion problems associated with furnace sorbent injection because it bypasses the furnace. A dry sorbent is injected into the flue gas where it combines with sulfur dioxide to be captured in the removal equipment.

Low-NO_x Combustion

Low-NO_x combustion involves redesigning burners or rearranging air flow through the furnace to reduce flame temperature, which reduces the formation of nitrogen oxides.

Two low-NO_x combustion techniques, low-NO_x burners and over-fire air, can be used independently or in combination. Low-NO_x burners reduce NO_x emissions by promoting a more gradual mixing of fuel and air to reduce flame temperature, and they use a richer fuel-air mixture to reduce oxidation of nitrogen in the fuel. Over-fire air reduces NO_x formation by removing some of the excess air from the burner flame zone and reintroduces it later in the combustion area, away from the high temperature flames.

Other low NO_x combustion techniques include fuel reburning and fuel biasing (readjusting the fuel mixture to different sections of the furnace to control NO_x formation).

Post-Combustion NO_x Control

Post-combustion NO_x control may potentially achieve greater NO_x emission reductions than low-NO_x combustion. The two primary approaches in this category are selective noncatalytic reduction and selective catalytic reduction.

Selective noncatalytic reduction involves injection of nitrogen compounds into the flue gas, which causes NO_x to be reduced to water and nitrogen. The selective catalytic reduction process is similar except that reactions take place in the presence of a catalyst. Selective catalytic reduction promises greater NO_x reductions than selective noncatalytic reduction but at greater cost.

Gas Cofiring/ Reburning

Gas cofiring and reburning refer to processes that inject natural gas into the furnace to reduce SO_2 or NO_x emissions.

In cofiring applications, natural gas is injected into the furnace along with pulverized coal, permitting a reduction in SO_2 emissions to the extent that less coal is being burned. Application of the technology is dependent upon the type of boiler in place and requires additional controls and maintenance.

In gas reburning, fuel is bypassed around the main combustion zone and injected above the main burners to form a reducing zone in which NO_x is converted to reduced nitrogen compounds. About 15 to 20 percent of the fuel is injected into this reburning zone.

Combined SO_2/NO_x Control

Several approaches to combined SO_2/NO_x control gas cleanup have been proposed. One approach would combine SO_2 and NO_x removal by injecting a sorbent into the flue gas to reduce SO_2 and injecting ammonia into the boiler to control NO_x formation.

In another approach, heated flue gas and a small amount of ammonia would be combined in a reactor, converting the NO_x to nitrogen and water vapor. The gas would then pass through additional processes in which SO_2 is ultimately converted into a saleable sulfuric acid by-product. Because no sorbents are used, no waste by-products would be formed.

Atmospheric Fluidized-Bed Combustion

In atmospheric fluidized-bed combustion, pulverized coal is combined with a sorbent in a heated bed. The bed is fluidized—or held in suspension—by injecting air, causing the mixture to agitate much like a boiling fluid. During combustion, the coal reacts with the sorbent to reduce SO_2 emissions, and the low operating temperature reduces NO_x formation.

Pressurized Fluidized-Bed Combustion

Another approach to fluidized-bed combustion technology is pressurization of the furnace. Performing much like a pressure cooker, pressurized fluidized-bed combustion produces steam more efficiently than an atmospheric fluidized-bed combustion unit. The pressurized system operates at higher pressures and therefore can be much more compact than the atmospheric system. Pressurized fluidized-bed combustion, which operates in a combined cycle configuration—using both a steam turbine and a combustion turbine—offers the potential for greater fuel efficiency.

Slagging Combustion

Slagging combustion technology uses cylindrical cyclone combustors that are mounted on the furnace, replacing conventional burners. The combustor mixes coal, sorbent (limestone), and air; provides ignition;

and removes ash before discharging the combustion products to the boiler. Sulfur oxides are controlled by limestone injection into the combustor, and NO_x is controlled by staged combustion.

Integrated Gasification, Combined Cycle

The integrated gasification, combined cycle process centers around two elements. First is a gasification plant which converts coal into combustible gas; other equipment purifies the gas. Second is a combined-cycle power plant in which the gas fuels a combustion turbine whose hot exhaust gases are used to generate steam which drives a steam turbine.

Sampling Methodology

For our questionnaire survey, we collected information on utilities' current plans to use clean coal technologies on specific fossil fuel-fired generating units and the options they would consider for these units to meet the SO_2 and NO_x emission reduction requirements of our four acid rain control scenarios. Our sampling approach enabled us to apply the results of our questionnaire responses to the universe of generating units and associated utilities from which the sample was drawn. This appendix describes how we selected our sample of utilities and generating units to include in our questionnaire survey.

Working with the Energy Information Administration's computer-generated 1987 Annual Electric Generator Report, we identified 1,503 fossil-fueled (coal-, gas-, and oil-fired) generating units in the United States that have a name plate capacity of at least 75 megawatts. The 1,503 units were operated by 190 utilities. We limited our questionnaire survey to generating units with at least 75-megawatt capacity because the larger units would be more likely to use clean coal technologies.

To select our sample generating units, we first identified three groups, or universes, of utilities—those with coal-fired units, those with gas-fired units, and those with oil-fired units. Utilities that used more than one of these types of fuel were included in more than one universe. We then used a stratified two-stage cluster sampling methodology to select 138 of the 190 utilities and 480 of the 1,503 fossil-fueled generating units to include in our questionnaire survey. The 480 units included 307 coal-fired units, 99 gas-fired units, and 74 oil-fired units.

For example, to sample 307 of the 876 coal-fired generating units in our universe, we first identified 150 utilities that had one or more coal-fired units. We then divided this universe into two groups, or strata. The first stratum consisted of utilities that had many (nine or more) coal-fired units, and the second stratum consisted of utilities that had fewer (eight or less) coal-fired units. We selected all of the utilities in the first stratum (41 out of 41) and then randomly selected two to five generating units for each of these utilities. We confined our sample to no more than five units per utility to limit the utility's work in responding to our questionnaire. We randomly selected utilities in the second stratum (65 out of 109) and then randomly selected one to four generating units for each of the 65 selected utilities. We followed a similar procedure in selecting utilities with gas- and oil-fired generating units and in selecting units operated by those utilities to include in our questionnaire survey.

A comparison of the total number of utilities and generating units in each stratum and the number included in our sample from each stratum are shown in table II.1.

Table II.1: Total Number of Utilities and Generating Units in Each Stratum of GAO's Sample and the Number Sampled

	Number of utilities		Number of generating units	
Stratum	**in stratum**	**sampled**	**in stratum**	**sampled**
Coal (9 or more units)	41	41	532	158
Coal (1 to 8 units)	109	65	344	149
Oil (5 or more units)	14	14	112	43
Oil (1 to 4 units)	34	20	70	31
Gas (8 or more units)	21	21	320	64
Gas (1 to 7 units)	45	20	125	35
Total	[a]	[a]	**1,503**	**480**

[a]These numbers total more than 190 and 138 because utilities that used more than one type of fuel were included in more than one stratum.

We received responses from 130 (93 percent) of the 138 utilities that were mailed a questionnaire. The responses included information on 450 (94 percent) of the 480 generating units in our sample.

Although oil- or gas-fired generating units can benefit from some clean coal technologies, our questionnaire survey indicated that utilities would be primarily interested in the technologies for their coal-fired units. We have therefore focused the discussion of our questionnaire survey in this report on utilities' responses for coal-fired units. We received information from 99 utilities on 291 (94 percent) of the 307 coal-fired units in our sample. The responses were analyzed to develop estimates for the universe of 75-megawatt-and-larger coal-fired generating units and associated utilities from which the sample was drawn.

Because we reviewed a statistical sample of coal-fired generating units, each estimate developed from the sample has a measurable precision, or sampling error. The sampling error is the maximum amount by which the estimate obtained from a statistical sample can be expected to differ from the true value we are estimating. Statistical estimates were developed at the 95- percent confidence level and are shown with the lower and upper confidence limits (see app. IV and V). This means that 19 out of 20 times the sampling procedure we used would produce a confidence interval containing the true value of the characteristic we are estimating.

Copy of GAO's Questionnaire Sent to Utilities

United States General Accounting Office

Survey of Utilities' Views of Clean Coal Technologies

INTRODUCTION

The U.S. General Accounting Office (GAO), an agency which conducts studies for the Congress, is surveying utilities to obtain their views about clean coal technologies. The Subcommittee on Energy and Power, House Committee on Energy and Commerce, asked us to determine the extent to which utilities would consider using clean coal technologies with and without acid rain control legislation. We are also interested in obtaining utilities' perspectives on demand growth and incentives for commercializing clean coal technologies.

We are collecting information from utilities on possible plans for using clean coal technologies on selected coal-, gas-, and oil-burning units. The unit we have selected at your utility is:

(PLACE UNIT LABEL HERE)

Part 1 of this questionnaire specifically addresses the unit identified on the label below; parts 2 and 3 require responses for your entire system.

All answers from individual utilities will be kept confidential. Your responses will be combined with those of other utilities and reported in summary form. No individual utility's responses will be identified.

Please return the completed questionnaire in the enclosed self-addressed, postage-paid envelope. Mailing your reply within 2 weeks of receipt will help us avoid costly follow-up mailings. If the envelope has been misplaced, please mail the completed questionnaire to:

Carole Buncher
U. S. General Accounting Office
10 West Jackson Boulevard
Fifth floor
Chicago, Illinois 60604

If you have questions about the survey, please call Ms. Buncher or Daniel Feehan at (312) 353-0514. Thank you for your cooperation.

1

CLEAN COAL TECHNOLOGIES

For the purposes of this questionnaire, we are defining clean coal technologies as emerging technologies designed to reduce emissions of sulfur dioxide (SO2) and/or nitrogen oxides (NOx) from fossil-fuel-fired units. As you complete the questionnaire, consider the following as clean coal technologies.

- Coal cleaning and upgrading (e.g., ultrafine and advanced flotation, physical, and chemical)
- Advanced FGD (e.g., "dry" scrubbers and scrubbers with regenerable sorbent)
- Sorbent injection
- Low-NOx combustion
- Post-combustion NOx control
- Gas cofiring/reburning
- Combined SO2/NOx control
- Atmospheric fluidized bed combustion
- Pressurized fluidized bed combustion
- Slagging combustion
- Integrated gasification, combined cycle

2

PART 1.1: Background information for the unit identified on page 1

1. Nameplate capacity (in MW)

   ________MW 1(9-12)

2. Year of initial operation

   19____ (13-14)

3. Type of fuel principally used *(Check one)* (15)

   1. ☐ Bituminous coal
   2. ☐ Subbituminous coal
   3. ☐ Lignite coal
   4. ☐ Anthracite coal
   5. ☐ Natural gas
   6. ☐ Oil - distillate
   7. ☐ Oil - residual
   8. ☐ Dual-fired
   9. ☐ Other (*Please specify*)

4. Average sulfur content of principal fuel

   ________lbs SO2/MMBtu (16-19)

5. Is the unit equipped with a SO2 and/or NOx emission control device? *(Check one)* (20)

   1. ☐ SO2 control only
   2. ☐ NOx control only
   3. ☐ SO2 *and* NOx controls
   4. ☐ Neither SO2 nor NOx controls

3

Part 1.2: Your utility's current plans on clean coal technology use for this unit

6. Is your utility currently planning to use a clean coal technology before the year 2010 for the unit identified on page 1? *(Check one)* (21)

   1. ☐ Yes
   2. ☐ No ——→ *Skip to Page 6*
   3. ☐ Uncertain ——→ *Skip to Page 6*

7. Which of the following clean coal technology(ies) is your utility planning to use on this unit? For the technology(ies) your utility is planning for this unit please enter the year your utility plans to bring it into service. *(Check "no" or "yes" for each technology; for each technology you check "yes", enter year)* 2(9-68)

TECHNOLOGIES	Use technology No (1)	Yes (2)	Year (3)
1. Coal cleaning and upgrading			
2. Advanced FGD			
3. Sorbent injection			
4. Low-NOx combustion			
5. Post-combustion NOx control			
6. Gas cofiring/reburning			
7. Combined SO2/NOx control			
8. Atmospheric fluidized bed combustion			
9. Pressurized fluidized bed combustion			
10. Slagging combustion			
11. Integrated gasification, combined cycle			
12. Other (*Please specify*)			

8. Does your utility have officially approved plans to use (any of) the clean coal technology(ies) checked in question 7 above? *(Check one)* (69)

   1. ☐ Yes
   2. ☐ No

4

9. How much of a role, if any, have each of the following factors played in your utility's plans to use the clean coal technology(ies)? (*Check one for each factor*) 3(9-24)

FACTORS	Very great role (1)	Great role (2)	Moderate role (3)	Some role (4)	Little or no role (5)
1. Additional capacity needed					
2. Current federal environmental regulations					
3. Anticipated federal acid rain control legislation					
4. State environmental regulations					
5. Land and space characteristics					
6. Age or condition of current boiler require replacement					
7. Size of boiler					
8. Fuel costs					
9. Required outages for installation can be accommodated					
10. Low operating and maintenance costs					
11. Low capital costs					
12. Benefits (e.g., financial, learning curve, etc.) of serving as a host site for a demonstration project					
13. Waste management					
14. High level of confidence in technology					
15. Capital availability					
16. Other *(Please specify)*					

5

PART 1.3: Effect of acid rain control legislation on the market penetration potential of clean coal technologies

A number of bills were introduced in the 100th Congress that would have required utilities to reduce SO2 and NOx emissions. Some of these bills provided for phased-in compliance dates, bubbling, etc. GAO has designed four hypothetical acid rain control scenarios based on those bills. However, our scenarios do not provide for phasing in or bubbling because they have been simplified for purposes of analysis. Some of the questions in this section are based on these scenarios, which are as follows.

- *Scenario 1:* Utilities are required to reduce systemwide SO2 emissions by 35 percent and NOx emissions by 25 percent from 1980 levels or to a floor of 1.0 lb/MMBtu for SO2 and 0.6 lb/MMBtu for NOx--whichever approach is less stringent--by the year 1997.

- *Scenario 2:* Utilities are required to reduce systemwide SO2 emissions by 75 percent and NOx emissions by 50 percent from 1980 levels or to a floor of 0.8 lb/MMBtu for SO2 and 0.4 lb/MMBtu for NOx--whichever approach is less stringent--by the year 1997.

- *Scenario 3:* Utilities are required to reduce systemwide SO2 emissions by 35 percent and NOx emissions by 25 percent from 1980 levels or to a floor of 1.0 lb/MMBtu for SO2 and 0.6 lb/MMBtu for NOx--whichever approach is less stringent--by the year 2004.

- *Scenario 4:* Utilities are required to reduce systemwide SO2 emissions by 75 percent and NOx emissions by 50 percent from 1980 levels or to a floor of 0.8 lb/MMBtu for SO2 and 0.4 lb/MMBtu for NOx--whichever approach is less stringent--by the year 2004.

For each question that refers to the scenarios, the scenarios will be duplicated in table form as follows for easy reference:

Utilities required to make the following systemwide reductions from 1980 levels

Scenario	*SO2*	*NOx*	*Deadline*
1	35% or to 1.0 lb/MMBtu	25% or to 0.6 lb/MMBtu	1997
2	75% or to 0.8 lb/MMBtu	50% or to 0.4 lb/MMBtu	1997
3	35% or to 1.0 lb/MMBtu	25% or to 0.6 lb/MMBtu	2004
4	75% or to 0.8 lb/MMBtu	50% or to 0.4 lb/MMBtu	2004

The responses you provide to the questions in Part 1.3 should apply only to the unit identified on page 1 of this survey. However, in responding to the questions, you may need to consider your systemwide plans.

10. Has your utility explored emission control options, that may affect this unit, for meeting the requirements of acid rain control legislation, should it be enacted? *(Check one)* (25)

1. ☐ Yes
2. ☐ No ⟶ *Skip to page 11*

6

11. For each scenario, what option(s), if any, would your utility most seriously consider employing on this unit to meet the SO2 and NOx requirements? *(Check at least one option for achieving SO2 reductions and at least one option for achieving NOx reductions under each scenario)* 4(9-88) 5(9-88)

Utilities required to make the following systemwide reductions from 1980 levels

Scenario	*SO2*	*NOx*	*Deadline*
1	35% or to 1.0 lb/MMBtu	25% or to 0.6 lb/MMBtu	1997
2	75% or to 0.8 lb/MMBtu	50% or to 0.4 lb/MMBtu	1997
3	35% or to 1.0 lb/MMBtu	25% or to 0.6 lb/MMBtu	2004
4	75% or to 0.8 lb/MMBtu	50% or to 0.4 lb/MMBtu	2004

	Scenario 1		Scenario 2		Scenario 3		Scenario 4	
OPTIONS	SO2	NOx	SO2	NOx	SO2	NOx	SO2	NOx
1. Take no action at this unit or any other unit as system already meets floor(s) established in the scenario								
2. Take no action at this unit, but instead reduce emissions elsewhere								
3. Install a conventional scrubber								
4. Switch to low-sulfur coal								
5. Switch fuel type (e.g., from coal to gas or oil)								
6. Use a clean coal technology								
7. Retire the unit								
8. Rely on demand-side management/conservation								
9. Change duty cycling								
10. Other *(Please specify)*								

NOTE: If your utility is not seriously considering using a clean coal technology on this unit (i.e., did not check option 6 in any columns), ***SKIP TO QUESTION 15***

7

12. **If you indicated in the preceding question that your utility would seriously consider using at least one clean coal technology, please indicate below *which* clean coal technology(ies) that is.** ***(For each scenario for which you checked option 6 in the preceding question, check that technology(ies) which your utility would most seriously consider using)***

6(9-112)
7(9-112)

Utilities required to make the following systemwide reductions from 1980 levels

Scenario	*SO2*	*NOx*	*Deadline*
1	35% or to 1.0 lb/MMBtu	25% or to 0.6 lb/MMBtu	1997
2	75% or to 0.8 lb/MMBtu	50% or to 0.4 lb/MMBtu	1997
3	35% or to 1.0 lb/MMBtu	25% or to 0.6 lb/MMBtu	2004
4	75% or to 0.8 lb/MMBtu	50% or to 0.4 lb/MMBtu	2004

	Scenario 1		Scenario 2		Scenario 3		Scenario 4	
TECHNOLOGIES	SO2	NOx	SO2	NOx	SO2	NOx	SO2	NOx
1. Coal cleaning and upgrading								
2. Advanced FGD								
3. Sorbent injection								
4. Low-NOx combustion								
5. Post-combustion NOx control								
6. Gas cofiring/reburning								
7. Combined SO2/NOx control								
8. Atmospheric fluidized bed combustion								
9. Pressurized fluidized bed combustion								
10. Slagging combustion								
11. Integrated gasification, combined cycle								
12. Other *(Please specify)*								
13. N/A; would not use a clean coal technology under this scenario								

8

13. **Please indicate the primary reason(s) that your utility would seriously consider using the technology(ies) you indicated in the preceding question. (*Check* no more than three in each column)** 8(9-136)

9(9-136)

Utilities required to make the following systemwide reductions from 1980 levels

Scenario	*SO2*	*NOx*	*Deadline*
1	35% or to 1.0 lb/MMBtu	25% or to 0.6 lb/MMBtu	1997
2	75% or to 0.8 lb/MMBtu	50% or to 0.4 lb/MMBtu	1997
3	35% or to 1.0 lb/MMBtu	25% or to 0.6 lb/MMBtu	2004
4	75% or to 0.8 lb/MMBtu	50% or to 0.4 lb/MMBtu	2004

	Scenario 1		Scenario 2		Scenario 3		Scenario 4	
REASONS	SO2	NOx	SO2	NOx	SO2	NOx	SO2	NOx
1. Additional capacity needed								
2. Current federal environmental regulations								
3. Anticipated federal acid rain control legislation								
4. State environmental regulations								
5. Land and space characteristics								
6. Age or condition of current boiler require replacement								
7. Size of current boiler								
8. Fuel costs								
9. Required outages for installation can be accommodated								
10. Low operating and maintenance costs								
11. Low capital costs								
12. Benefits (e.g., financial, learning curve, etc.) of serving as a host site for a demonstration project								
13. Waste management								
14. High level of confidence in technology								
15. Capital availability								
16. Other *(Please specify)*								

9

14. Will using a clean coal technology require your utility to make operational changes (e.g., switch fuel type)? If so, briefly explain. 10(9)

(SKIP TO NEXT PAGE)

15. Briefly explain why your utility would not seriously consider using a clean coal technology under any of the scenarios. (10)

10

PART 2: Systemwide perspective on demand growth

16. Will your utility, as a whole, likely experience demand growth by the year 2000? *(Check one)* (11)

1. ☐ Yes
2. ☐ No ——→ *Skip to next page*
3. ☐ Don't know ——→ *Skip to next page*

17. How much of an increase in peak, base, and cycling demand will your utility require by the year 2000? *(If you expect no increase in a category(ies), enter 0)*

__________MW peak

__________MW base

__________MW cycling (12-32)

18. How likely or unlikely is it that your utility would use the following methods to meet demand growth in your system? *(Check one for each method)* (33-43)

METHODS	Very likely (1)	Fairly likely (2)	Fairly unlikely (3)	Very unlikely (4)
1. Build a new coal-fired unit using clean coal technology				
2. Build a new coal-fired unit without clean coal technology				
3. Build a new oil- or gas-fired unit				
4. Build a new non-fossil-fired unit				
5. Use clean coal technology to increase capacity at an existing unit(s)				
6. Increase capacity at an existing unit(s) by means other than clean coal technology				
7. Purchase power from a domestic provider				
8. Purchase imported power				
9. Rely on demand-side management/conservation				
10. Increase output at existing unit(s)				
11. Other *(Please specify)*				

11

PART 3: Systemwide perspective on commercializing clean coal technologies

19. Which of the following incentives, if any, would most enhance the likelihood that your utility would invest in a clean coal technology? (*Check* no more than *three*)

(44-62)

1. ☐ Extended compliance date, assuming acid rain legislation is enacted, for utilities willing to use clean coal technology
2. ☐ Relaxed emission reduction targets, assuming acid rain legislation is enacted, for utilities willing to use clean coal technology
3. ☐ Tax credits
4. ☐ Federally established price and loan guarantees
5. ☐ Government grants
6. ☐ Cost sharing with government
7. ☐ Less stringent new source performance standards for utilities willing to use clean coal technology
8. ☐ Increased flexibility by public utility commissions on cost recovery and prudency
9. ☐ Additional commercial demonstrations
10. ☐ Lower capital costs than that of conventional technologies
11. ☐ Lower operating and maintenance costs than that of conventional technologies
12. ☐ Demonstrated short construction lead times
13. ☐ Other *(Please specify)*
14. ☐ None of the above

20. What does your utility consider as the best ways to commercialize clean coal technologies? (*Check* no more than *three*)

(63-70)

1. ☐ Continue DOE's Clean Coal Technology Program (CCTP) as currently implemented
2. ☐ Redirect DOE's CCTP to emphasize multiple demonstrations of technologies that seem most promising
3. ☐ Redirect DOE's CCTP to emphasize retrofit technologies
4. ☐ Redirect DOE's CCTP to emphasize repowering technologies
5. ☐ Redirect DOE's CCTP to emphasize NOx-control technologies
6. ☐ Legislate emission reduction target levels and compliance dates that are compatible with the availability and capability of clean coal technology
7. ☐ Charge emitters for exceeding established SO2 and NOX emission levels
8. ☐ Other *(Please specify)*

21. If acid rain control legislation is enacted, which approach would your utility consider to be more conducive to commercializing clean coal technologies? *(Check one)*

(71)

1. ☐ Requiring emission reductions to be accomplished *in phases*
2. ☐ Requiring emission reductions to be accomplished *by a single deadline*
3. ☐ Both approaches equally conducive

12

22. Thank you for your cooperation. If you have additional comments the topics covered please feel free to write them here. (72)

If you would like to elaborate on the topics covered in this questionnaire, please provide your name and telephone number:

Name:______________________________

Telephone: (______)____________________

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Options That Would Be Considered at Coal-Fired Units to Achieve SO_2 Reductions Under GAO's Scenarios

Scenario 1[a]

Option	Percent of units for which option would be considered: Estimate	95% confidence limits: Lower	95% confidence limits: Upper
Use clean coal technologies[b]	24	17	31
Sorbent injection	18	10	25
Coal cleaning and upgrading	9	3	14
Advanced flue gas desulfurization	7	2	11
Gas cofiring/reburning	5	1	9
Use conventional technologies			
Switch to low-sulfur coal	46	39	53
Install a conventional scrubber	18	12	24
Switch type of fuel	5	1	8
Other options			
Take no action at this unit but reduce emissions elsewhere	34	27	41
Take no action at this unit as system already meets scenario	21	15	28
Retire the unit	11	5	17

Note: Based on questionnaire responses, we estimate that utilities have explored emission control options for 699 of their coal-fired units. The percentages in this appendix relate to these units.

[a]Under this near-term, moderate scenario, utilities would be required to reduce their systemwide SO_2 emissions by 35 percent below 1980 levels or to 1.0 lbs./MMBtus—whichever would be less stringent—by a 1997 compliance date.

[b]We are unable to provide meaningful estimates for combined SO_2/NO_x control and atmospheric fluidized-bed combustion technologies because only a few utilities selected them as options.

Scenario 2[a]			
	Percent of units for which option would be considered		
		95% confidence limits	
Option	**Estimate**	**Lower**	**Upper**
Use clean coal technologies[b]	25	18	32
Sorbent injection	17	10	24
Advanced flue gas desulfurization	11	6	16
Coal cleaning and upgrading	9	4	15
Combined SO_2/NO_x control	8	3	13
Gas cofiring/reburning	5	1	9
Use conventional technologies			
Switch to low-sulfur coal	39	31	47
Install a conventional scrubber	35	28	42
Switch type of fuel	7	2	12
Other options			
Take no action at this unit but reduce emissions elsewhere	19	13	26
Take no action at this unit as system already meets scenario	16	10	22
Retire the unit	16	9	22

[a]Under this near-term, stringent scenario, utilities would be required to reduce their systemwide SO_2 emissions by 75 percent below 1980 levels or to 0.8 lbs./MMBtus—whichever would be less stringent—by a 1997 compliance date.

[b]We are unable to provide meaningful estimates for atmospheric fluidized-bed combustion and pressurized fluidized-bed combustion technologies because only a few utilities selected them as options they would consider.

Scenario 3[a]

Option	Percent of units for which option would be considered: Estimate	95% confidence limits: Lower	95% confidence limits: Upper
Use clean coal technologies[b]	41	33	48
Sorbent injection	34	25	42
Advanced flue gas desulfurization	21	12	29
Coal cleaning and upgrading	13	6	19
Combined SO_2/NO_x control	10	4	16
Atmospheric fluidized-bed combustion	6	1	11
Slagging combustion	6	1	11
Gas cofiring/reburning	5	1	9
Pressurized fluidized-bed combustion	5	1	9
Use conventional technologies			
Switch to low-sulfur coal	46	39	53
Install a conventional scrubber	15	9	21
Switch type of fuel	5	1	9
Other options			
Take no action at this unit but reduce emissions elsewhere	37	30	44
Take no action at this unit as system already meets scenario	21	15	28
Retire the unit	13	7	20

[a]Under this long-term, moderate scenario, utilities would be required to reduce their systemwide SO_2 emissions by 35 percent below 1980 levels or to 1.0 lbs./MMBtus—whichever would be less stringent—by a 2004 compliance date.

[b]We are unable to provide a meaningful estimate for integrated gasification, combined cycle technology because only a few utilities selected it as an option they would consider.

Scenario 4[a]

Option	Percent of units for which option would be considered		
		95% confidence limits	
	Estimate	Lower	Upper
Use clean coal technologies[b]	51	43	59
Advanced flue gas desulfurization	32	24	41
Sorbent injection	32	23	41
Combined SO_2/NO_x control	14	7	20
Coal cleaning and upgrading	14	7	20
Pressurized fluidized-bed combustion	9	4	15
Atmospheric fluidized-bed combustion	8	3	13
Slagging combustion	6	1	12
Integrated gasification, combined cycle	5	0	9
Use conventional technologies			
Switch to low-sulfur coal	39	32	47
Install a conventional scrubber	30	24	36
Switch type of fuel	7	2	11
Other options			
Take no action at this unit but reduce emissions elsewhere	22	16	29
Retire the unit	16	10	23
Take no action at this unit as system already meets scenario	16	10	22

[a]Under this long-term, stringent scenario, utilities would be required to reduce their systemwide SO_2 emissions by 75 percent below 1980 levels or to 0.8 lbs./MMBtus—whichever would be less stringent—by a 2004 compliance date.

[b]We are unable to provide a meaningful estimate for gas cofiring/reburning technology because only a few utilities selected it as an option they would consider.

Options That Would Be Considered at Coal-Fired Units to Achieve NO_x Reductions Under GAO's Scenarios

Scenario 1[a]

Option	Percent of units for which option would be considered: Estimate	95% confidence limits: Lower	95% confidence limits: Upper
Use clean coal technologies[b]	53	43	63
Low-NO_x combustion	44	36	52
Post-combustion NO_x control	12	4	19
Gas cofiring/reburning	6	2	10
Other options			
Take no action at this unit but reduce emissions elsewhere	22	16	29
Take no action at this unit as system already meets scenario	18	12	24
Retire the unit	6	1	10

Note: Based on questionnaire responses, we estimate that utilities have explored emission control options for 699 of their coal-fired units. The percentages in this appendix relate to these units.

[a]Under this near-term, moderate scenario, utilities would be required to reduce their systemwide NO_x emissions by 25 percent below 1980 levels or to 0.6 lbs./MMBtus—whichever would be less stringent—by a 1997 compliance date.

[b]We are unable to provide meaningful estimates for combined SO_2/NO_x control, slagging combustion, atmospheric fluidized-bed combustion, and sorbent injection technologies because only a few utilities selected them as options they would consider.

Scenario 2[a]

Option	Percent of units for which option would be considered: Estimate	95% confidence limits: Lower	95% confidence limits: Upper
Use clean coal technologies[b]	72	65	78
Low-NO_x combustion	61	54	67
Post-combustion NO_x control	21	13	30
Gas cofiring/reburning	12	6	17
Combined SO_2/NO_x control	8	3	12
Other options			
Retire the unit	11	5	17
Take no action at this unit but reduce emissions elsewhere	10	6	13
Take no action at this unit as system already meets scenario	6	2	11

[a]Under this near-term, stringent scenario, utilities would be required to reduce their systemwide NO_x emissions by 50 percent below 1980 levels or to 0.4 lbs./MMBtus—whichever would be less stringent—by a 1997 compliance date.

[b]We are unable to provide meaningful estimates for slagging combustion, atmospheric fluidized-bed combustion, and sorbent injection technologies because only a few utilities selected them as options they would consider.

Scenario 3[a]			
	Percent of units for which option would be considered		
		95% confidence limits	
Option	**Estimate**	**Lower**	**Upper**
Use clean coal technologies[b]	57	48	67
Low-NO_x combustion	47	39	56
Post-combustion NO_x control	17	8	25
Combined SO_2/NO_x control	8	2	14
Gas cofiring/reburning	6	2	10
Other options			
Take no action at this unit but reduce emissions elsewhere	23	16	30
Take no action at this unit as system already meets scenario	18	12	24
Retire the unit	7	2	12

[a]Under this long-term, moderate scenario, utilities would be required to reduce their systemwide NO_x emissions by 25 percent below 1980 levels or to 0.6 lbs./MMBtus—whichever would be less stringent—by a 2004 compliance date.

[b]We are unable to provide meaningful estimates for slagging combustion, atmospheric fluidized-bed combustion, pressurized fluidized-bed combustion, and integrated gasification, combined cycle technologies because only a few utilities selected them as options they would consider.

Scenario 4[a]

Option	Percent of units for which option would be considered: Estimate	95% confidence limits: Lower	95% confidence limits: Upper
Use clean coal technologies[b]	77	71	83
Low-NO_x combustion	62	56	69
Post-combustion NO_x control	30	21	38
Combined SO_2/NO_x control	14	8	21
Gas cofiring/reburning	11	6	17
Pressurized fluidized-bed combustion	5	1	9
Other options			
Take no action at this unit but reduce emissions elsewhere	12	7	16
Retire the unit	11	5	16
Take no action at this unit as system already meets scenario	6	2	11

[a]Under this long-term, stringent scenario, utilities would be required to reduce their systemwide NO_x emissions by 50 percent below 1980 levels or to 0.4 lbs./MMBtus—whichever would be less stringent—by a 2004 compliance date.

[b]We are unable to provide meaningful estimates for slagging combustion, atmospheric fluidized-bed combustion, and integrated gasification, combined cycle technologies because only a few utilities selected them as options they would consider.

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