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FLUE GAS DESULFURIZATION AND ITS ALTERNATIVES: THE STATE OF THE ART

by

Arthur P. Hurter, Jr.

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ARGONNE NATIONAL LABORATORY

ENERGY AND ENVIRONMENTAL SYSTEMS DIVISION

MASTER

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N O T E

This report is basically a technology characterization for flue gas desulfurization (FGD). An engineering economic model is developed for estimating the cost to an electric utility for utilizing FGD devices. Capital, operating, and maintenance costs are considered in the methodology. This work contributes to a regional study of control options for electric utilities and other regional study activities being pursued by Argonne National Laboratory.

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LIST OF ABBREVIATIONS USED
(singular or plural)

bpd	barrels per day
bpsd	barrels per stream day
Btu	British thermal unit
Btu/lb	British thermal unit per pound
MBtu	million British thermal units
¢Mbtu	cents per MBtu
$Mbtu	dollars per MBtu
FOB	free on board
hp	horsepower
K	thousand
kw	kilowatt
kw-hr	kilowatt-hour
M	million
Mw	megawatt
Mwe	megawatt electric
ppm	parts per million
psi	pounds per square inch
psia	pounds per square inch absolute
psig	pounds per square inch gauge
scf	standard cubic feet
scfm	standard cubic feet per minute
Mscfm	million standard cubic feet per minute
tpy	tons per year

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ABSTRACT

This report is addressed to the use by power companies of fossil fuel for the production of electric energy, thus creating the largest contributing source of sulfur dioxide pollution. The practice of emitting sulfur dioxide cannot be continued if the ambient air quality standards, as promulgated by the Clean Air Act of the U.S. Environmental Protection Agency, are to be met.

Among several, three alternative methodologies for handling the burning of fossil fuel so as to meet these standards are considered in detail. The power companies can switch to low sulfur coal; they can perhaps use tall stacks to disperse the sulfur dioxide emissions and intermittent control when adverse meteorological conditions make dispersion unsuitable; or they can remove the sulfur dioxide created by the burning of high sulfur coal from the flue gases before they are released to the atmosphere. It is with flue gas desulfurization (FGD) that this report is principally concerned, predicated upon a background of data estimations on the availability and related costs of using low sulfur coal.

SUMMARY

Data concerned with energy and pollution are necessarily treated as gross estimates. The work contained in this report attempts to provide a variety of opinions concerning estimates on pollution control costs and on availability and costs of high- and low-sulfur coal, what we consider to be the most likely values, recognizing that wide variation may be possible.

The Clean Air Act, as amended (1971), calls for the ambient air quality to be 0.03 parts per million (ppm) of sulfur dioxide as an annual mean of 24-hour averages and 0.5 ppm on a 3-hour basis. Sulfur dioxide is apparently injurious to vegetation when the 24-hour average falls between

0.025 and 0.04 ppm over a long period of time. Health effects for humans begin to become apparent when the concentration approaches 0.11 ppm for 3-4 days or 0.04 ppm as an annual mean of 24-hour averages.

The practice of emitting sulfur dioxide cannot be continued if the ambient air quality standards are to be met. Since the burning of fossil fuels for the production of electric energy is by far the largest contributing source of sulfur dioxide pollution, it is with respect to the use of fossil fuels by power companies and the control of sulfur dioxide emissions that this report is addressed.

Power companies, if they are to satisfy the ambient air quality standards, have a choice of several alternative methodologies for handling the use of fossil fuel, of which three are considered in some detail. They can switch to low sulfur coal; they can remove the sulfur dioxide created by the burning of high sulfur coal from the flue gases, using flue gas desulfurization (FGD), before they are released to the atmosphere; or they can perhaps meet the ambient air quality standards by using tall stacks to disperse the sulfur dioxide and intermittent control when adverse meteorological conditions make it impossible to meet the air quality standards through dispersion.

Based on rough estimates of Eastern and Western U.S. supplies, the total supply of low sulfur coal by 1980 could rise as high as 550 million tons/yr. This is about equal to the current consumption of both high- and low- sulfur coals combined. Since power generation using fossil fuel is expected to increase between now and 1980, it is expected that high sulfur coal will be used for power generation in 1980.

Although there are conflicting estimates, it is apparent that Eastern low sulfur coal can be increased in rate of production only to a relatively modest extent. Approximately 25 million tons/yr of additional Eastern low sulfur coal could be produced. The price FOB mine will be approximately 33¢/MBtu. Shipping charges throughout the East would then have to be added to that.

Low sulfur Western coal has a heating value of 8000-8700 Btu/lb, in contrast to the Midwestern coal's heating value of 12,000 Btu/lb. The Western coal is much lower in sulfur content, usually between 0.55 and 0.77% sulfur by weight. Only Western coal that can be stripmined is considered economically feasible, and only it is considered under the general heading "Western coal." It is estimated that stripmined low sulfur Western coal in 1973 cost $2.25/ ton, which is equivalent to between 13 and 15¢/MBtu. It is estimated, also, that if a very rapid expansion in the amount produced each year is necessary, these costs could rise to 40¢/MBtu by 1980. However, considerable expansion over present levels of production without depletion (that is, without the necessity of removing an excessively increasing overburden) is possible. In 1973 and in 1973 prices, the delivered cost of Western coal to Chicago was 64¢/MBtu, or approximately $11.20/ton. Further estimations are that Western coal traffic to the Midwest could expand to equal 200,000 tons/yr -- anything beyond that would require an increase in the price, or delivered costs, above an amount in the order of 64¢/MBtu; if the demand were such that 300,000 tons/ yr were required in the Midwest by 1980, the price could rise to $1.28/MBtu, primarily because of the bottlenecks caused by this rapid expansion in mine output and in transportation capacity.

In the Midwest, most of the coal will have to be deepmined. In deep-mining, the recently passed Mine Safety Act will substantially increase costs over the next few years, and has already substantially increased them. Coal mined in the Midwest and delivered to the Chicago area in 1973 is estimated as costing, at most, 42¢/MBtu, and many deliveries have been made at lower cost. There is no conceivable shortage of this kind of coal, nor of transportation facilities for it.

By way of direct comparison, in December of 1973 utilities in Illinois paid an average of 62.8¢/MBtu for Western coal; while at the same time they were paying 31.4¢/MBtu for local coal -- both delivered to approximately the Chicago area. In spite of the differential in prices, Western coal has been shipped to Illinois. During 1973, over 7 million tons were purchased at approximately 64¢/MBtu. This purchase represented 22% of all the coal used in Illinois for electric power generation.

It has been predicted that the 1980 demand for coal on a nationwide basis will be in the 700-800/million-ton range. Of that, it is expected that the total supply of low sulfur coal from the East and the West would approach 550 million tons per year. By way of comparison, we have estimates that the costs of using FGD systems range between 30 and 85¢/MBtu. This range can be translated, using a heat rate of 10,000 Btu/kw-hr, into roughly 3-8.5 mills/kw-hr. If the costs of local coal delivered to Chicago are in the range of 40-45¢/MBtu while the costs of Western coal delivered to the Chicago area are in the range of 65-70¢/MBtu, the cost margin for FGD systems, in order to be competitive, is toward the low range, that is, 3 mills/kw-hr.

In addition to the direct costs of using low sulfur coal, there are two other kinds of costs that should be considered. First, the bulk of the fossil fuel power generating plants in the Midwest were designed for use with Midwestern coal, and there will be changeover costs due to the differences in heating value, moisture, and ash content between the local coal and the Western coal. The extensive use of the low sulfur coal with its lower heating value could have some adverse effects upon the reserve generating capacity of the power system.

A second, indirect effect, which may be the most important effect of all, is the dramatic change that a massive changeover from Midwestern to Western coal would have on the economies of both of these coalmining regions.

Turning now to the costs of FGD systems, we must point out that there are two kinds of cost estimates appearing in the literature. One cost estimate is based on experiences with FGD systems to date, and represents not only the costs of the equipment and its operation, but also some developmental costs, since these installations are still in a formative stage. A second set of cost estimates is based on the presumption that FGD systems will become common and that, after many have been done, the developmental costs will be netted out and the true operating and capital costs will remain.

Preliminary evidence related to the TVA Widows Creek unit indicates that almost two-thirds of the total annualized costs of operating an FGD system are due to the capital costs. Therefore, an increase in annual plant load factor will lead to the distribution of the fixed portion of annual costs over a larger number of output units, and the operating costs on a kw-hr basis will fall dramatically as the number of electrical units produced increases. Thus, in terms of the operation of a given plant, there are what may be called short-term economies of scale in the use of FGD systems.

There seems to be considerable evidence from a variety of different sources to indicate that there are no substantial differences in the cost of using the various kinds of FGD systems normally considered. As the design of scrubbers is limited by technological considerations to a maximum volume of gas that can be handled, the scrubbers will undoubtedly be constructed in a modular fashion, with each module handling the flow associated with an approximately 150-Mw plant. This limits the long-term economies of scale in the development of FGD systems, but, nevertheless, some of these economies are in evidence. However, it is apparent that annualized costs are a strong function of plant parameters, such as size, load factor, and sulfur content. The rather extensive range of estimated possible costs, when using the engineering-economic basis for developing these costs, is between 1.1 and 7.7 mills/kw-hr. This is the range of costs for a single kind of process; for example, limestone scrubbing, when the parameters are changed throughout their range. This range is particularly important since it far exceeds the range of differences between types of processes when all of the parameters are considered at their normal or most likely, levels.

The engineering-economic analysis of scrubber activities performed in October, 1972, indicates a cost range of 2.22-2.46 mills/kw-hr, or a capital cost range of $34.60-$46.00/kw. These are the costs from a variety of different processes, including limestone scrubbing, lime scrubbing, magnesium oxide scrubbing with regeneration, alkali scrubbing with thermal regeneration, and alkali scrubbing with electrolytic regeneration. In each case, the most likely values of the parameters were used in computing the costs.

Annualized costs for waste disposal, a difficult problem, ranged from $1.00-$7.00/ton, and $3.00/ton was used. A value of $15.00/ton for sulfur, or for the sulfur content of sulfuric acid as resale, was used.

It was estimated that 25% of the coal- and oil-fired capacity could be retrofit at a cost of 1.3-1.8 mills/kw-hr. An additional 25% could be retrofit at a cost ranging 1.8-2.0 mills/kw-hr. It must be recalled that these particular estimates, based on the engineering-economic analysis were made in 1972. With reference to the costs of low sulfur coal, it should be noted that 2 mills/kw-hr would be approximately 20¢/MBtu. If local high sulfur coal is available at 40¢/MBtu, then adding a 20¢/MBtu premium for the use of FGD is a total equivalent cost of 60¢/MBtu for the fuel, which is close to the 64¢/MBtu-delivered as reported earlier for low sulfur Western coal. Recall that the latter figure does not include annualized costs associated with the switch to low sulfur coal.

Several other sources of cost estimates place the range for different forms of flue gas scrubbing at 1.1-3.0 mills/kw-hr, with the increment for the use of low sulfur fuel in the range of 2-6 mills/kw-hr.

Updated estimates on the costs of FGD systems purporting to take account of recent and expected inflation put the costs at 5.75-7.3 mills/kw-hr. These estimates appear the more reasonable for use at this time.

According to estimates from the Environmental Protection Agency (EPA), the 1972 average national consumer costs for power were about 17.8 mills/kw-hr; while, as we have already seen, the 1972 average cost of FGD (at least, as seen by the EPA) is about 2 mills/kw-hr. On the basis of these figures, EPA estimates that consumer costs for electricity could rise by 18% through the wide-scale adoption of FGD systems. Of course, the increase in cost will be larger for consumers who happen to live within areas that generate power almost exclusively through the burning of coal.

When turning to the diversity of cost estimates that appear in the literature, it must be kept in mind that actual operating experience with FGD systems is very limited indeed. Consequently, the numbers presented are estimates, and nothing more. The following capital costs on a per kilowatt basis were presented in the literature. This listing will give an idea of the range and frequency of different levels: \$62.00, \$57.00, \$66.00, \$52.00, \$75.00, \$62.00, \$108.00, \$83.00, \$35.00, \$45.00, \$35.00, \$30.00, \$50.00, \$45.00, \$65.00, \$30.00, \$70.00, \$60.00, \$100.00, \$40.00, \$50.00, \$40.00, \$80.00. On an annualized cost basis, the following figures in mills/kw-hr were reported: 4, 1.4, 3.7, 2.1, 10, 2.7, 2, 1.1, 3. Some of these cost estimates are for new plants, and others are for retrofit. Some include the cost of sludge disposal, and others do not.

The rate of installation of FGD systems depends upon the demand for such systems generated by the power generating companies and the availability of the supply of such systems provided by vendors. The cumulative need, based upon the air quality standards, for FGD will be about 66,000 Mw by the end of 1975, 73,000 Mw by the end of 1977, and 90,000 Mw by the end of 1980. These projections depend upon the simultaneous projections of the availability of low sulfur coal and are to be interpreted as most probable figures. For a given availability of low sulfur coal, the capacity fitted with scrubbers reported above is deemed (by EPA) necessary to meet the air quality standards.

A key factor in determining the rate at which FGD systems could be installed is the length of time an installation takes. A vendor may state that four systems could be installed at a time; but, if each system takes four years to install, then he is able, on the average, to install only one a year. Experience to date indicates that a system installation takes 27-36 months. In 1976 vendor capacity is estimated at about 10,000 Mw to 23,000 Mw, depending upon which estimate is used. In 1977, the capacity is estimated at about 25,000 Mw to 50,000 Mw. These figures are the cumulative capacity that would be fitted by the dates in question. By 1978, it is estimated that vendors could have supplied 50,000-80,000 Mw of FGD systems, and, significantly, the need by then is estimated at only 75,000 Mw.

Although present installation of FGD systems seems to be limited by the demand by users for the systems, the vendor capacity is expected to grow at a rapid rate in anticipation of enforcement of the Clean Air Act; so that in the relatively short time up to, say, 1979 vendor capacity will equal or exceed the needed capacity. Since demand is presently the limiting factor so far as installation of systems is concerned, it is unlikely that all the potential under-capacity will be used up in the years immediately following. A major determinant of this market will be the vigor with which the state and the federal environment protection agencies push the sulfur oxide compliance requirements, especially in the form of emission limitations. The combination of an energy shortage, inflation and recession have prompted the Ford Administration to postpone some aspects of the Clean Air Act that were to take effect in May 1975. Future enforcement policies and the future of FGD systems are not clear at this writing. After all the time and energy expended on the installations and development of FGD systems, fewer than ten systems are actually in operation at the present time. Furthermore, many installations of various types have been tried and discarded.

Nevertheless, the final report of the Sulfur Oxide Control Technology Assessment Panel (SOCTAP) states that technology does not appear to be a limiting factor in utilization of stack gas cleaning. "The SOCTAP task force believes that the required high reliability of FGD systems will be achieved with the early resolution of a number of engineering problems for which specified solutions have already been developed and demonstrated at one or another location." The optimism of the SOCTAP report does not appear to have been borne out.

The EPA, leading the SOCTAP panel, feels that, at least, lime-limestone scrubbing systems are ready for commercial applications. They are supported in this contention by various vendors who feel that several of their systems are commercially feasible. By and large, the power companies dissent.

One form of evidence on this question would be the reliability data from operating scrubbing units. Reliability data were sought from seven plants that, in one way or another, were considered to be in operation. None of the plants had enough operating experience, during which time the scrubbers actually operated, to provide figures, except for the Commonwealth Edison Will County plant. The Will County plant used two scrubbers designed to operate in parallel and to take the entire flue gas output. In 1972, one scrubber was available 32% of the time; the second, 26% of the time; and the two together, 8% of the time. The availability figures fell to 27% for the first scrubber, 5% for the second, and less than 1% for the two combined during 1973. At the last available notice, the scrubbers are both now shut down.

An interview study of "experts" made by Battelle in the spring of 1973 indicates that there is little difference among the various individual processes in terms of expected reliabilities. A 90% onstream or availability factor for closed cycle, stack gas treatment process on a 100-Mw or greater, coal-fired utility plant in the United States will not be available until 1976 at the earliest. One-third of the respondents in the Battelle survey felt that none of the major processes would achieve 90% availability until after 1980.

In contrast to the views and evidence on reliability, the EPA feels that the various sets of hearings have established that lime-limestone scrubbing and Wellman-Lord scrubbing are both demonstrated and reliable. The EPA feels that, of the 75% of existing fossil-fuel power plants that could be retrofitted, approximately 50% of these have sufficient onsite sludge storage space. In other words, these plants have no technological reason for not adopting the FGD systems in the immediate future.

The availability and technological feasibility of using FGD systems is certainly a matter open for debate in the immediate future. The question then remains as to how it might be possible to meet the requirements of the Clean Air Act without using FGD, recognizing that not enough low sulfur Western coal can be made available for use by all coal-fired power plants.

The British have had a successful experience with the use of tall stacks. Tall stacks simply disperse the emissions over a broader area, permitting the ambient air quality standards to be met, even though the emission restrictions are violated. The EPA, while permitting the use of dispersion techniques as a temporary expedient, does not accept them as a permanent solution to the sulfur dioxide control problem. In order to give some perspective on this question, it is important to notice that if all air pollution generated by U.S. power companies were evenly dispersed over this country, the sulfur dioxide concentration would be only 6 parts per billion. This is, of course, well below the ambient air quality standards, but there is no guarantee of even dispersion. Tall stacks have been employed by some U.S. power companies and have been successful in meeting the air quality standards. The use of tall stacks and intermittent control may be the only way in which the Clean Air Standards can be met in 1975. The use of tall stacks with intermittent control for conditions of adverse meteorological status can be used, according to the EPA, on a temporary basis. It is not clear what "temporary" means, but it seems reasonable to interpret the stand of the EPA to mean "until an FGD system can be installed." A broader interpretation of "temporary" might be very useful. It might be economically and environmentally efficient to permit the use of tall stacks and intermittent control to achieve the air quality standards in 1975 and to permit the continued use of tall stacks and intermittent control until such time as coal gasification or liquefaction becomes available. In other words, if FGD continues to be technologically troublesome, it may be that the best long-term strategy is to simply ignore it and to use tall stacks with intermittent control until the newer technologies of coal gasification become available in the late 1980s. The ultimate decision should be based on the health effects from violation of the standards.

In addition to the advantages of a short implementation period, tall stacks seem to be much more economical than scrubbers. The strong argument in favor of the use of tall stacks and intermittent control programs is that they do permit meeting the ambient air quality standards that the EPA itself has found sufficient to protect the public health and welfare from any known or anticipated adverse effects of sulfur dioxide. Further, the use of tall stacks with intermittent control and/or low sulfur coal on an intermittent basis would reduce the frequency of required generation reductions in any plant. The use of tall stacks would have the advantage of permitting the continued use of coal mined locally. Furthermore, a fixed emissions standard, unless it is applied at a level even below the new source performance standard, may not ensure that ambient sulfur dioxide standards are not exceeded at times, due to particular meteorological conditions. At other times, under more favorable meteorological conditions, the fixed emissions standards may be overly restrictive in terms of the ambient air quality standards.

Apparently, the Lurgi process for low Btu gasification of coal has several potential advantages and great hopes are held for its future. Used in combined cycle plants, that is, gas turbines along with steam turbines, the process could ultimately convert high sulfur coals to electricity at higher thermal efficiency and with less pollution than any other system. This state of efficiency might be achieved while lowering the investment in $/kw compared to conventional coal-burning plants. Some preliminary cost estimates show that the Lurgi process could be developed to generate electricity at incremental costs of 7-7.5 mills/kw-hr, which is not far from the newest cost estimates for the FGD systems. These costs refer to retrofitting the low Btu gasification systems on old plants. The low Btu gasification alternative seems to be most applicable to large base-loaded plants, because the gasification facilities are not as amenable to load changes as an oil-fired plant. The gasification and liquefaction processes do not generate the disposal problem that is associated with throw-away FGD systems.

An independent estimate of the costs of some alternatives indicates that high Btu gas would cost in the order of $1.20-$1.50/MBtu in 1973 dollars; while stack gas cleanup (FGD) would cost $0.85-$0.95/MBtu, and low Btu gas would cost $0.70-$0.85/MBtu.

Although the costs are comparable, Commonwealth Edison considers that low Btu gas as a fuel supply possesses several advantages over stack gas scrubbing. The two most important are: first, the low Btu gas supply, using the pressure gasifier, can generate a net excess of electric power through the use of an unfired expander turbine, contrasting with the stack gas emission process, which has a parasitic drain of 5-10% of the power generated; second, the gas purification processing in the gas supply system works to remove hydrogen sulfide, for which technology exists, instead of sulfur dioxide -- further, it has to work on less than 5% of the volume of gases that would be processed in a stack gas scrubbing system.

For new, integrated plants, the expected capital cost of a large-scale gasification process is about $80/kw, compared with a stack gas scrubbing process at $70/kw. The gasification process allows equipment elsewhere in the plant to be eliminated, which would more than offset this cost differential. The total, net capital cost differential could be as much as $30/kw in favor of gasification. The total cost of power from a fossil-fired steam generating plant could be 0.5-1.5 mills/kw-hr lower with low Btu gas, as compared to using high sulfur coal and stack gas scrubbing.

Capabilities of these processes to supply U.S. needs can be estimated as follows: High Btu natural gas is assumed to be produced in plants having a production capacity of 250 million cu ft/day, consuming 16,000 tons of bituminous coal daily. One hundred such plants would produce only one-third of the current gas needs. but would consume all the coal now being mined in the United States. One hundred synthetic crude plants, generating the same heating value as the synthetic gas plant, would produce only about one-quarter of the country's current 15 million-bbl daily consumption. It would consume approximately the same amount of coal as the gas plant. These considerations add further weight to the emphasis on the low Btu plant.

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INTRODUCTION

The Federal Environmental Protection Agency under the mandate of the "Clean Air Act", 77 Stat. 392, as amended, 42 U.S.C. ПП 1857-1857K (1970; Supp. 1971) established the following national ambient air quality standards for sulfur dioxide:

<u>Primary</u>

Annual arithmetic mean	80 $\mu g/m^3$ or (0.03 ppm)
Maximum 3-hour concentration not to be exceeded more than once annually	365 $\mu g/m^3$ or (0.14 ppm)

<u>Secondary</u>

Maximum 3-hour concentration not to be exceeded more than once annually	1,300 $\mu g/m^3$ or (0.05 ppm)

These standards were to be met no later than May 31, 1975.

Although the setting of standards for ambient air quality is a complicated mix of politics, science, and economics, there is some evidence to indicate that concentrations of SO_2 greater than 0.7 ppm for a 1-hr period, 0.18 ppm for an 8-hr period, or 0.05 ppm for an annual average can be injurious to vegetation.[2,3] Adverse health effects have been noted when the average SO_2 concentration exceeded 0.11 ppm for 3 or 4 days or when the annual mean level SO_2 exceeded 0.04 ppm.[4]

The date by which the standards are to be met seems to have been chosen arbitrarily. Questions about the date by which the standards are to be met may be purely academic at this point. It appears impossible for most power companies to comply with the standards as translated into <u>emission restrictions</u> by May 31, 1975, while maintaining adequate service to their customers. It might be possible for many power plants to meet the <u>ambient air quality standards</u> in their region through dispersal techniques. The economic and environmental significance of the date selected in the Clean Air Act and the economic and environmental consequences of altering the date must be evaluated -- but not in this report. Indeed, the Ford Administration has suggested postponement of the deadline until 1977.

In the Meuse Valley, Belgium, in 1930 a meteorological episode contributed to 60 deaths among mostly the elderly or cardiac patients. The SO_2 level was estimated at 10 to 40 ppm. In the Donora, Pennsylvania, episode in 1948, 20 deaths among old and cardiac patients occurred, while SO_2 levels reached 0.5 to 2.0 ppm. In addition, heavy fog and SO_3 mist, along with particulates, were in the air. In the famous London episode of 1952 there were 4000 deaths. There, the peak SO_2 concentration was 1.34 ppm and high humidity prevailed.[2]

By way of comparison the sulfur dioxide levels in downtown Chicago have varied through the years in the following manner:[5] 1967 - 0.078 ppm, 1968 - 0.053 ppm, 1969 - 0.054 ppm, 1970 - 0.051 ppm, 1971 - 0.027 ppm, and 1972 - 0.036 ppm. These annual arithmetic means are to be compared to the standard of 0.03 ppm. The reduction noticed since 1967 is attributed to reduced use of high sulfur fuels. The average <u>winter</u> time concentration of SO_2 in Chicago in 1937 was 0.4 ppm.[5]

The source of the major portions of the SO_2 emissions is revealed by the following 1969 worldwide data measured in millions of tons:[5] coal - 102, gasoline and light oil - 2, residual oil - 20, refining - 6, nonferrous metals - 16, industrial H_2S measured in SO_2 equivalents - 6. Total annual man-made emissions in 1969, 152×10^6 tons. Natural emissions of SO_2 or equivalents, include marine H_2S - 60, land H_2S - 140 for a total from natural sources of 200×10^6 tons. In the U.S. in 1969: motor vehicles - 0.2, aircraft - 0.1, railroads - 0.2, vessels - 0.3, non-highway use of motor fuels - 0.2, for a total from transportation of 1.1×10^6 tons in 1969. Fuel combustion from stationary sources 24.4, with coal accounting for 19.8 and fuel oil for 4.6. Industrial processes, combined, accounted for 7.5, for a total of 33.4×10^5 tons/yr. Clearly, the burning of coal is the major man-made source of SO_2 emissions, and it seems reasonable that initial anti-SO_2 pollution efforts be directed toward coal-burning enterprises. The dominant use of coal in the U.S. is for the generation of electric power by public utility companies.

In general, the ambient air quality standards have been translated into emission standards for power plants. In December 1971, the EPA issued new standards for stationary sources. For large new power plants the limit is 1.2 lb SO_2/MBtu. This standard can be achieved by burning 3% S fuel with 75% of the sulfur removed or, equivalently, by burning 1% S coal.[4]

The Clean Air Act specified ambient air quality standards. They have been interpreted by many enforcement entities as a mandate to impose emission limitations on electric utility plants. The question of whether a scheme that would comply with air quality standards but not with emission restrictions is a satisfactory long-term solution is being hotly debated today.

What alternatives are "available" to the utilities as a means of complying with the air quality standards of the "Clean Air Act"? The usual list includes:

1. Use of low sulfur coal,
2. Use of low sulfur oil or gas,
3. Use of nuclear energy,
4. Removing the sulfur from high sulfur coal via gasification or liquefaction,
5. Removing the physically bound sulfur from coal by gravitational methods (washing),
6. Removal of SO_2 from stack gases after burning. (The Flue Gas Desulfurization -- FGD),
7. The use of tall stacks with intermittent control, for periods of adverse weather, either in the form of curtailed operation or operation using low sulfur fuel or both, and
8. Continue operation as-is with payment of resulting fines.

Several of these alternatives can be disposed of quickly. The energy shortage with respect to petroleum products rules out the second alternative as a general solution. The use of nuclear energy as a proportion of the whole in power plant generation, is scheduled to increase dramatically in the near future. However, coal is projected to remain a major energy source for power generation into the forseeable future. It is conceivable that the power companies may accelerate their shift toward nuclear fuel if the SO_2 emission requirements cannot be met economically with coal. Of course, there are some real and imagined threats to the environment from the use of nuclear fuel, which may prove as intractable as sulfur removal from coal. Nevertheless, the potential capability of the power industry to accelerate its switch to nuclear energy bears investigation -- but it will not be covered in this report. Unless some form of sulfur tax with a value approaching the social cost of SO_2 pollution is instituted, alternative 8, by itself cannot be used.

A great deal has been written recently about the removal of sulfur from coal prior to its combustion. Coal gasification and coal liquefaction techniques are considered very promising by many people. However, except for a few low Btu gasification operations, no one expects that these processes will produce commercially useful quantities of fuel before 1985 (refer to the final section of this report). In addition, there is some feeling that the output of these processes will have to be used to replace petroleum and will not generally be available for power plants until well beyond 1985. The availability of these processes to supply clean fuel to the electric utility industry should be investigated. For example, if it were reasonable to expect substantial supplies by 1985, it may be economically and environmentally sound to make use of "temporary" control methods between 1975 and 1985, expecting the combination of increased reliance on nuclear fuel and on clean fuel from coal to provide the long-term solution to the SO_2 problem. Support for the contention that coal gasification or liquefaction are most promising for conversion of coal to clean fuel but that they will not be an applied technology until the 1980s, comes from Babcock and Wilcox.[6] EPA agrees with the forecast on the availability of coal gasification or liquefaction.[7]

Alternative 5 is in use today. Coal has two forms of sulfur, organically bonded and physically bonded. Processes included under alternative 4 remove both kinds. Crushing and "washing" coal may remove most of the physically held sulfur. Unfortunately, for most coals, the organic sulfur makes up the bulk of sulfur in the coal. Consequently, this alternative is not a feasible means of achieving the SO_2 emission standards in most cases.

For example, approximately 75% of the coal burned in TVA steam plants is obtained under coal contracts from Midwestern coal fields, mostly from the western Kentucky fields. The sulfur content of this coal ranges from 3.5 to 5%. The sulfur reduction potential of these coals has been tested by U.S. Bureau of Mines and the results published in USBM Report of Investigation 7633 - "Sulfur Reduction Potential of the Coals of the U.S." This report shows that the major coal seams of western Kentucky -- No. 9, No. 11, and No. 12 seams -- have an organic sulfur content of 2%. The theoretical minimum sulfur contents were in the range of 2.4 to 3.4%. To obtain these "low" sulfur values, from 33 to 90% of the raw coal would have to be discarded. With commercially available equipment, a sulfur level of 3 to 3.8% is expected to be the lowest sulfur coal that can be produced from these seams.[8] This is not, by itself, adequate to meet the emission standards.

The remaining "alternatives": 1. the use of low sulfur fuel, 6. removal of SO_2 from stack gases after combustion, and 7. the use of tall stacks with intermittent control will be considered in some detail with special emphasis on 6. A section of the report will be devoted to each. The sections will cover the general availability, reliability and cost of each alternative. A final section provides preliminary information on processes with commercially available dates of 1980 or beyond.

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THE USE OF LOW SULFUR COAL

The price and availability of coal depends on three categories of factors: (1) the cost of producing coal at the mine as it varies with the rate of output (sometimes called the supply function), (2) the cost of transporting the coal from the mine to the utility, and (3) the imperfectly competitive market in which the suppliers, purchasers, and transporters operate.

The third factor is the most difficult to deal with. For example, when Western coal is shipped to the Midwest, it competes with low sulfur Eastern coal, high sulfur Midwestern coal used with FGD systems, and other alternatives. Suppose the cost of producing the Western coal is X($/ton) and the cost of transporting it is Y($/ton); then a lowerbound on the delivered price is X + Y. The upperbound may be estimated as the delivered price of the next lowest cost alternative to the utility, assuming no restriction on supply. In the following, the emphasis is on estimation of the lowerbound.

The potential supply of coal at various prices consists of Eastern low sulfur coal, Western stripmined coal, and Eastern or Midwestern high sulfur coal. As pointed out in Ref. 9, "The supplies of coal are predicted with the assumption of an entirely new industry -- stripmining in southeastern Montana. These estimates are imprecise because of poor data in all energy industries; particularly in coal, where there is no industry at all in Montana at the present time."

In 1969, the electric utilities consumed 259 million tons of coal, with a sulfur content exceeding 1%. To meet air quality regulations, through substitution, demand for Western coal could reach 200 million tons/yr by the mid-1970s. In 1972 the Western states produced 55 millions tons. By 1985 the demand for Western coal may have climbed to 300 to 350 million tons annually, meaning that the Western mines would have to increase production by 15% each year from 1972 on to meet the demand by 1985.

These projections may be considered as part of the demand for low sulfur coal or for coal energy that can be burned within environmental regulations. There is some low sulfur coal available in the East and the Midwest. Stripmining will be limited in Appalachia, and the flatter sections of Illinois and Indiana do not appear to have large amounts of strippable coal resources.[1,9] Thus, any substantial expansion of coal production in the

East or the Midwest will have to rely on underground mining. For underground mining, the relatively new mine safety acts have already substantially increased production costs. There seems to be no doubt that there will be significant increases in hourly-wage costs over the next decade. During the same period, the most optimistic experts predict that labor productivity will stay about the level achieved in 1972. Since the inception of the Mine Safety Act, labor productivity has been declining. A daily wage of $150 is predicted for 1985.[9] Productivity is estimated at 20 tons per man day.

EASTERN LOW SULFUR COAL - AVAILABILITY AND COST

The supply of Eastern low sulfur coal is estimated to remain at its current annual output of 200-250 million tons. A 1967 Bureau of Mines survey cited 4.5 billion tons of recoverable reserves in the East, with less than 1% sulfur, currently being held by producers of more than 100,000 tpy. Assuming a mine life of 20 years, this could support production of only 225 million tpy or only 25 million tpy more than the present rate. Gordon[9] estimates that the costs of this coal, at the mine, have reached 33¢/MBtu. With labor costs expected to rise substantially over the next decade, this cost is expected to rise until, in Gordon's terms the price has reached the fuel oil equivalent (Btu/bbl of oil/Btu/ton of coal) of $7.00/bbl by 1980, in 1973 dollars.

The availability figures developed by Gordon[9] should be compared to those quoted from Ref. 8. A study (Survey of Coal Availability by Sulfur Content, MTR-6086, May 1972) done by MITRE Corp. for EPA indicated that in the Southern Appalachian region, there were over 37 billion tons of coal resources with sulfur content of 0.7% or less, with over 4 billion tons classed as recoverable reserves. A more recent MITRE study (Availability and Requirements of Stationary-Source Fossil Fuels - 1975 and 1977, MTR-6221, August 1972) indicates that in the Eastern coal fields area there are extremely limited reserves of coal containing 1.6% sulfur or less, which are held by operating mining companies but which are neither captive nor already committed to other markets. In contrast, the United Mine Workers have stated that existing Eastern mines could produce an additional 70 million tpy of "low" sulfur fuel in the immediate future.[6] The evidence seems to support Gordon's figures as the more realistic. Gordon[9] admits that the Bureau of Mines figures on which his estimates are based are underestimates since they exclude reserves held by land companies and smaller producers.

WESTERN LOW SULFUR COAL - AVAILABILITY AND COST

Turning to Western coal, it must be noted that the coal from Wyoming and Montana is subbituminous with a low heat content (8000 to 8700 Btu/lb as compared with 12,000 Btu/lb for Midwestern coal) and is extremely high in moisture content ranging from 26 to 30%. Of the known bituminous coal reserves in the Rocky Mountain states 54% is located in Colorado, 25% in Utah, 11% in Wyoming, 9% in New Mexico, and 2% in Montana. Whereas in Montana and Wyoming coal can usually be stripmined, in Colorado only a small portion of it can be mined in this way.

Regarding the availability and cost of Western coal, the Adelman report[1] relies on a Bureau of Mines Circular.[10] The circular states that the costs of mining in Wyoming and Montana (Powder River Basin) are $2.25/ton, exclusive of royalties and state taxes and assuming a 15% annual discount factor. This cost translates into 13.2¢/MBtu at 8500 Btu/lb. Assuming reclamation costs of $5,000/acre[10] and a coal-seam thickness of 10 feet, costs of reclamation are $0.28/ton or 1.6¢/MBtu.

As coal is used up it is natural to question whether depletion will lead to higher costs as represented by higher overburden ratios. The Bureau of Mines Circular No. 8531 estimates that 13.6 billion tons could be extracted using stripmining techniques without increasing the present overburden. Again, assuming a mine life of 20 years this represents an output of 680 million tpy before depletion makes it necessary to mine with higher overburden. Productivity of labor is expected to remain constant at its present level,[1] which already represents a substantial improvement over the productivity of the 1960s. Wage rates are expected to increase. With projected modest annual increases of 5% to 1980, costs are expected to be $2.68/ton or $0.158/MBtu in 1973 dollars. These costs are not expected to rise further with output and depletion until the annual output of Western coal approaches the 680 million tpy level.

Gordon states that close examination of Western strippable coal reserves suggests that the amounts are far too small to justify the extravagent claims made in the popular press concerning reliance on Western coal. "In short, known strippable coal reserves are by themselves grossly inadequate to supply the United States with its fuel. The case for heavy reliance on coal must rest on the discovery of more strippable reserves or very sharp rises in the costs of other fuels."[9]

Assuming Gordon is correct, it is then natural to question our earlier statement that output from the Western mines could be substantially increased without major cost increases due to depletion of reserves over the next 20 years. The resolution of this potential conflict lies in the magnitudes of the production figures. Actual production, as of 1971, compared with the available reserves was very low. For example, Wyoming has 13.971 billion tons of strippable reserves,[9] while only 7.9 million tons were mined in 1971. At this rate the reserves would last over 1700 years. Thus, it may be possible to make very substantial increases in the present rates of production at no increase in costs related to depletion and, at the same time, not be possible to rely completely on Western coal for fuel. The cost figures given earlier assume a rather orderly increase in output. Coal and electric utility sources[1] expect FOB mine costs in the West to rise to at least 20 to 25¢/MBtu mainly because of the anticipated rapid rate of expansion. In other words the present price of 15¢/MBtu is the result of a gradual buildup by existing mines to their peak output levels. This gradual pace will not be available to the newer mines. The rapid rate of expansion will also promote at least temporary cost increases related to shortages of men and equipment. Recently announced contracts have been in this price range of 15¢/MBtu. Some have conjectured that the present sales were made at bargain rates to attract new customers (refer to Table 1).

Costs of reclamation are currently estimated at the \$4000-to-\$5600/acre-level as cited in <u>Final Environmental Statement, Proposed Plan of Mining and Reclamation for the Big Sky Mine</u>, Peabody Coal Company, Coal Lease No. ML5965, Coal Strip, Montana. But there is concerted opposition to stripmining and a move to make reclamation mean replacing destroyed vegetation with exactly the same kind of vegetation. In the arid, windy regions of the West this kind of reclamation may be extremely expensive -- presumably, in regions where it is deemed impossible, stripmining would be banned. Thus, the reclamation costs built into the coal cost estimates cited above must be considered a lower estimate for regions such as these.

Naturally, transportation costs for Western coal are very important Existing rates average 7.5 mills/ton-mile. Using a cost of \$0.15/MBtu for the coal, this results in a delivered cost to a market at Chicago of $0.64/MBtu or approximately $11.2/ton. According to the Adelman report[1] some new plants are using transport costs in the 5 to 5.5 mill/ton-mile range. New coal-fired plants have a potential advantage over existing plants. They can bargain with railroads using the threat of moving their planned plant to a new location and becoming customers of a competitor railroad. This advantage is limited because a single railroad provides service to most of the coal-producing Western country. Lower rates per ton-mile might prevail for new mining capacity in the next five years; but pressure for higher rates to offset increased wage and fuel costs may be expected to nullify the benefits of low incentive rates, especially on long hauls to the Midwest. The same may be said for the cost reductions achieved from economies of scale obtained through the use of technological improvements like unit trains and new loading and unloading procedures.

A trainload of coal normally contains about 13,000 tons. Depending upon distances and speeds, total annual deliveries of 1 to 3 million tons could be made by a single train entirely devoted to this service. Gordon[9] estimates that plants consume 2.5 tons of coal/yr for every kilowatt of capacity. A 500-Mw plant would, therefore, fully occupy one such train. Potential transportation bottlenecks include limitations on the supply of hopper cars and track necessary to haul large amounts of Western coal to the Midwest. It is likely that by 1980 enough cars could be produced and enough immediate policy changes could be made to allow a larger outflow of coal traffic.[1] There are limits to this process but at present no one knows what those limits are. Prevailing opinion seems to be that with no appreciable increase in cost, the traffic could be expanded to more than 200 million tons/yr. Beyond that, say to 300 million tons/yr, Gordon[9] estimates that the cost would rise by 1980 to 128¢/MBtu delivered to Chicago and measured in 1973 dollars. This is approximately $22.4/ton.

The extra increase would be attributable to bottlenecks in transportation and mining caused by equipment and, possibly, labor shortages. For example, at the present time the mining machinery industry produces enough machinery to add 15 million tons/yr to production capacity. With no scaleup, an additional 90 million tons of equipment capacity could be provided. Thus, more production could be achieved without substantially higher costs for capital equipment.

Sometimes reclamation efforts take the form of taxes. A typical bill considered by the House Interior Committee would tax Western strip-mining at \$2.50/ton to provide a fund for reclaiming land. This would double the mine-mouth cost of coal to 30¢/MBtu. A moratorium on the leasing of lands for stripmining may also create a future bottleneck to output expansion.

COST COMPARISONS OF LOW SULFUR AND HIGH SULFUR COAL

Major[11] has also studied coal costs. On a national basis, the cost of coal FOB mine has risen from 19¢/MBtu in 1969 to 31¢/MBtu in 1973. The average delivered price has also risen rapidly. The average FOB price for coals produced in the Midwest (Minn., Iowa, Mo., Wisc., Ill., Ind., Ky., Ohio, Mich.) ranged from \$4.86/ton in Iowa to \$6.81/ton in Kentucky. Maximum transport cost of Midwest coal delivered to points in the Midwest is \$2.00/ton making a range of delivered prices in the \$6.86 to \$8.81/ton range. Since this coal has a heat content of 10,000 to 11,000 Btu/lb, the maximum delivered cost should be 42¢/MBtu. As Major points out, many local coals are delivered for less.

Major's[11] estimates of the costs of using Western coal in Chicago are consistent with those reported on in Refs. 1 and 9. The estimates in Ref. 11 for the beginning of 1974 approach the estimates in Ref. 1 for 1980. Major[11] reports that Western coal FOB mine is \$3.74/ton from Wyoming and \$2.03/ton from Montana, the two major suppliers of Western coal to the Midwest. The combination of long shipping distances and a lower heat content (8500 Btu/lb) makes the cost of Western coal delivered to Indiana or Illinois almost twice as high as local coal. Utilities in Illinois in Dec. 1973 paid an average of 62.76¢/MBtu for Western coal. For the same period, Illinois utilities paid 31.38¢/MBtu for local coal (refer to Table 1).

The low heat content of the subbituminous Western coal makes its ability to meet the metropolitan requirements in Illinois of 1% S (for 11,000 Btu/lb coal) for older and .6% for new plants questionable. For example, one pound of coal from the Midwest yields heat energy equivalent to 1.3 lb of Western coal. Thus, 1% S Midwestern coal is equivalent to .77% S Western coal. A substantial proportion of the Western coals have .5 to .7% S.

Starting in 1972, Western coal has been shipped to Illinois. In tl final six months of 1972, Illinois utility companies received 1.85 million tons of low sulfur coal or about 25% of their total coal requirements from the West at an average delivered price of 62.55¢/MBtu. During 1973, 7.11 million tons were purchased at 64.52¢/MBtu. This purchase represented 22% of all coal used. During 1972 and 1973, average coal prices for utilities rose steadily from 35.6¢/MBtu in 1971 to 50.4¢/MBtu in 1972 and 52.5¢/MBtu in 1973. Available data on costs are summarized in Table 1.

Based on rough estimates of Eastern and Western supplies, the total supply of low sulfur coal in 1980 could rise as high as 550 million tpy, which is about equal to current production of high- and low-sulfur coal combined. These estimates suggest that high sulfur coal will continue to be used in 1980. At a price of 68¢/MBtu delivered in Chicago for low sulfur coal, perhaps the current output rate of 350 million tpy of high sulfur coal can be maintained.[1] The 1980 demand for coal will be the 700-800 million-ton range. This demand is expected to be met by the projected normal growth of the industry. The Adelman report[1] additionally states that the costs of using FGD systems (the subject of the next section) are in the range of 30 to 85¢/MBtu (roughly 3 to 9 mills/kw-hr) for retrofitting existing plants. At the higher range, FGD could not compete with low sulfur coal despite the high transport cost of the latter. The high liklihood of substantial increases in costs associated with deepmined coal expected by 1980 may make the use of Western stripmined coal seem more attractive than the table indicates.

When a comparison between the use of Midwestern high sulfur coal in the Midwest and the use of low sulfur Western coal in the Midwest is made, two previously mentioned sources of costs must be considered. Since the coal-fired utility plants now operating in the Midwest were designed for the use of local coals, there will be a changeover cost. Further, since the Western coal has a lower heat content, the capacity of the plant undergoing the changeover will be reduced as will the reserve capacity of the power system serving the area in question. The second source of costs is the dramatic effect the changeover, from the Midwestern to Western coal by a large number of utilities, would have on the economies of both regions. The following comments, taken from the literature, demonstrate the importance of these sources of costs, even if they do not provide the basis for a quantification.

TABLE 1. Coal Costs

Source	Type of Coal	FOB Mine ¢/MBtu	FOB Mine $/ton	Transportation Mills ton-mi	Transportation To Ill $/ton	Delivered Cost ¢/MBtu	Delivered Cost $/ton	Comment	Year
MIT[1]	W	13.2	2.25						1972
"	"	15.8	2.68						1980
"	"			7.5					1972
"	"					64	11.2	To Chicago	1973
"	"					64		Total 150M ton	1980
"	"					128	22.4	Total 300M ton	1980
"	E low S		11.50					250M tons/yr	1980
"	W		2.68						1980
"	E high S	64							1980
"	"								1980
"	Plus FGD	122	29.30						1980
Ill Geo Survey[11]	Avg/all	19				28			1969
"	"	31							1973
"	"					34			1971
"	All		4.86				6.86		1972
"	MW		6.81			42	8.81		1972
"	Wyo		3.74						1972
"	Mont		2.03						1972
"	W					62.78		To Ill	1973
"	MW					31.38		To Ill	1973
Argonne	Wyo	19.16	3.47					To Minn, Wisc, Ill	1973
"	"	17.15	3.11						1972
"	"	15.13	2.71						1973
"	"	15.03	2.71						1974
"	"	15.30	2.76						1975
"	"	17.11	3.20						1976
"	"	17.11	3.20						1977
"	W					62.55			1972
"	W					64.52			1973

TABLE 1 (Contd.)

Source	Type of Coal	FOB Mine ¢/MBtu	FOB Mine $/ton	Transportation Mills ton-mi	Transportation To Ill $/ton	Delivered Cost ¢/MBtu	Delivered Cost $/ton	Comment	Year
Argonne	All coal used by MW utilities					35.60			1971
"	"					50.40			1972
"	"					52.50			1973
Argonne	W					61.21		Pd by Ill utilities	1972 3rd Q
"	"					62.52			1972 4th Q
"	"					63.57			1973 1st Q
"	"					61.84			1973 2nd Q
"	"					64.22			1973 3rd Q
"	"					68.44			1973 4th Q
"	MW					36.93			1972 3rd Q
"	"					38.14			1972 4th Q
"	"					36.97			1973 1st Q
"	"					40.36			1973 2nd Q
"	"					40.49			1973 3rd Q
"	"					43.82			1973 4th Q
SOCTAP[6]	W							30.00 Del to AEP	1973
SOCTAP	West Va							18.01 Del to AEP	1973

Abbr: W, Western; MW, Midwestern; E, Eastern

CONVERSION OF PLANTS TO USE OF LOW SULFUR COAL

The low Btu content and high moisture content of Western coal resulted in reduced maximum generating capability in a test run at the TVA Johnsonville plant of from 15 to 30%. Therefore, the burning of about 35% more coal was required to achieve the same level of generating capability. The coal handling facilities at the TVA plant do not have the capacity to handle an increased tonnage of this magnitude.[8] In most TVA plants, there is not sufficient space available to install additional pieces of this massive equipment without rearranging much of the other equipment in the plant. Further, plant unloading and conveying facilities would have to be increased in capacity and the coal stockpiles enlarged. If TVA switched completely to low sulfur coal, the resulting reduction in its generating capacity would find it unable to meet the demands upon it for power.

The conversion of a plant designed for high sulfur Midwestern fuel to low sulfur Western fuel may not be a straightforward process. Consider the following example, based on two coals:[12] (1) Randolph, Ill.: 10.53% moisture, 12.72% ash, 3.45% S, 10,899 Btu/lb; (2) Carlson, Wyoming: 13.32% moisture, 10.52% ash, 0.36% S, 9843 Btu/lb. Notice that the differences in moisture and heating value are nowhere near the maximum differences reported. If 1200 tons are burned per day to produce 100 Mw, then there are over 80 tons of SO_2 in the stack gas (1 lb S $\rightarrow$ 2 lb SO_2) or 3150 ppm SO_2 if the high sulfur coal is burned. If low sulfur coal is burned, to produce 100 Mw, 9 tons of SO_2 is produced yielding 300 ppm in the stack gas. In reality 85 to 95% of SO_2 produced goes to stack gas and the balance remains in fly ash. Thus, use of low sulfur coal results in a much lighter load on the FGD system.

What are the operating difficulties? The temperature at which the ash in most coals becomes liquid is 2050-2900°F. At temperatures, 200°F below the melting temperature, the ash becomes a sticky solid adhering to walls and causing operating difficulties. The ash from low sulfur coal has a different liquefaction temperature causing obvious operating difficulties. In a cyclone furnace, molten ash remains liquid and drops into an outlet hopper for removal. A fraction remains suspended and moves toward the stack. Cyclone separators remove the larger portion but particles 5 microns or less remain suspended. These require use of an electrostatic precipitator. The electrostatic precipitators have high efficiency with high sulfur coals but some designs have difficulty when low sulfur coal is used.

With high sulfur coal, the flue gases contain fly ash particles in an atmosphere of SO_2 and H_2O. These react at the surface of the ash to form a conducting layer that lowers the resistivity of the ash particles. Then the particle, when it contacts the collecting plate of an electrostatic precipitator, can slowly lose its charge and will adhere to the plate until it is knocked off into the collecting hopper. With low sulfur coal the concentration of SO_2 is too low to form the conducting layer and therefore unacceptable amounts of the ash remain in the stream getting past the precipitator.

The importance of the indirect costs of a switch to Western coal by a utility in the TVA size class can be estimated[8] on the basis of the following factors.

1. In the 1972, TVA paid $185 million to coal producers and truckers in the Appalachian and Midwestern coal fields. These payments have a substantial multiplier effect.

2. In 1972, TVA paid $34.5 million to area rail and barge companies. Most of this amount would be shifted to other transport companies.

3. The current TVA transportation bill of $34.5 million would rise to over $345.0 million (1972$). Most of this would be paid to companies outside the Valley region.

4. Fuel shifting would have a serious impact on the economies of Tennessee, Kentucky, and Illinois, which produce most of TVA's present supply. It purchases over 1/3 of Tennessee's and 1/5 of Kentucky's coal production. Approximately 6000 to 7000 miners would be displaced in southern Appalachian and Midwestern coal fields. Industries that support mining would be adversely affected.

5. Most of the money paid to TVA by its customers would be spent in Western states.

6. Millions of dollars would be lost from the Valley economy and in addition, the Valley people would pay more for electricity. Western coal for Widows Creek or Kingston would cost about 75% more than regional coal. The cost of Western coal is expected to increase sharply.

7. Existing coal contracts would be cancelled at substantial cost.

8. Use of low sulfur Western coal would require replacement or modification of electrostatic precipitators. Larger precipitators seem to be required.

9. Reliability of TVA would be lessened because of the increased distance to basic fuel supplies.

This section concludes with a sampling of comments from the literature. With respect to Eastern versus Western coal, the Appalachian Research and Defense Fund[6] estimates that a major utility, American Electric Power, will have to pay $30/ton for delivered low sulfur Western coal (equivalent to approximately 176¢/MBtu). The highest price currently paid for West Virginia coal is $18/ton, with an average of between $14 and $15/ton (equivalent to approximately 65¢/MBtu). Using the highest price for West Virginia coal, Western coal would cost about 66% more, which roughly matches TVA figures. Compare these costs for Eastern power companies with those shown for Midwestern companies in Table 1.

The United Mine Workers state that during the next 10 years over 500 coal-fired electric generating units will go on steam (FPC data) and demand for coal will increase to 1.5 billion tons/yr or three times the current consumption.[6] Expansion of Eastern deep mines is more expensive than buying and transporting Western stripmined coal. With effective anti-stripmine legislation, expansion of Eastern deep mines would be competitive.[6]

There is some question about the general availability of low sulfur coal and the cost increments involved in its substitution for local coal. It is certain that the availability of low sulfur Western coal in the near future, even if stripmining is permitted to expand, would not be adequate to meet the demands of an electric utility industry determined to switch all its coal-fired operation to low sulfur coal. The question concerning the feasibility and desirability of a switch to low sulfur coal, which invariably involves a long-term contract with the supplier, is almost as difficult as the question with respect to the feasibility and desirability of FGD systems to be discussed in the Flue Gas Desulfurization Systems section.

Some vague statements concerning the costs of these two alternatives and plans to use one or the other have found their way into the literature. Some examples are presented below: (Sources: Item 1, Refs. 7 and 13. Items 2-6, Ref. 6)

1. "FGD costs are comparable to low sulfur fuel cost increments."

2. "Ohio Edison cannot obtain low sulfur coal."

3. "Louisville Gas and Electric has concluded that use of an FGD system is more economical and in the better interests of the state than fuel switching."

4. "Duquesne Light Co. concluded that FGD systems, specifically tail-gas scrubbing, were the most practical means of complying with emission regulations as contrasted with the use of low sulfur fuels."

5. "Commonwealth Edison has a strong incentive to use Illinois coal. Low sulfur coal costs more than twice as much as Illinois coal. However, regulations adopted by Chicago forced Commonwealth Edison to look for low sulfur coal. In spite of a multitude of combustion problems, the low sulfur coal is being used because these problems are easier to solve than the problems posed by FGD." Further, Commonwealth Edison views coal gasification as having high probability of near-term success. It is expected to be less expensive for <u>new</u> stations and environmentally superior to FGD.

6. "62% of the total coal field capacity of American Power Electric Co. will use acceptably low sulfur fuel by 1976. The company is now negotiating for a total of 16.5 million tons annually of low sulfur Western coal." The West Virginia Air Pollution Control Commission claims that the annual operating cost at the American Power Kammer Plant using FGD and local coal would be $11 million less than importing low sulfur Western coal."

The translation of the Clean Air Act ambient air quality standards into emission standards and into % S in coal standards results in different % S restrictions in different areas. Further, the sulfur content of Western coal varies. Consequently, many "low sulfur fuel" installations using Montana coal would require the use of an FGD scheme in states where the restriction on sulfur content is less than 1% (e.g., Illinois, Arizona). The costs of the FGD installation must be added to the fuel cost increments from switching, and the total must be compared with the cost of an FGD installation capable of handling local high sulfur coal.

The cost is not the only consideration in a choice between low sulfur fuel and FGD. In most states, increased operating costs incurred because of an increase in fuel costs, such as would result from a switch from local to Western coal, can be passed on to consumers in the form of rate increases with no action required by the local regulatory body. This is not true of costs incurred to install an FGD system. Descriptions and cost estimates for FGD systems are presented in the next section.

FLUE GAS DESULFURIZATION SYSTEMS (FGD)

This section on FGD systems is divided into several subsections. First, a general model for the estimation of FGD costs is developed, followed by some statements culled from the literature concerning FGD costs. The subsection on costs is followed by a section on the technological feasibility of FGD systems. This section begins with a brief description of the various proposed processes, followed by some comments from the literature by users, vendors, and advocates; and by a detailed description of the operating experience of one FGD installation. Finally, the problems associated with the disposal of waste products generated by the FGD systems are presented.

COSTS

There are several aspects to the costs of scrubbing systems that must be considered. In the literature, two kinds of cost estimates are to be found. If the author is concerned with the impending installation of an FGD system on an existing plant (retrofit) or even a new plant, then the costs he estimates are likely to be those that are based on a new and untried technology being installed, almost for the first time. Naturally these costs will be relatively high. If the author is interested in the steady-state costs of adding FGD to the power generation system on a routine basis, then the cost estimated will be much lower. Both kinds of costs are considered in this section, beginning with an interesting combination of the two concepts.

Burchard, Rochelle, Schofield and Smith[14] attempted to make an engineering-economic study of FGD systems. They used TVA Widows Creek Unit 8 as the basis for their calculations. Table 2a provides a description of the capital cost items associated with this unit. The major items appear to be: ductwork, reheaters and soot blowers, scrubber-area steel structures, scrubbers, piping, electrical work, and electrical transmission plant and construction facilities. Each of these items contributed between $1 and $3 million to the $22,360,000 in direct capital costs. The total capital costs are $42 million (without pond), the difference being accounted for by shakedown modification and contingencies ($10 million) and indirect costs ($10.6 million). Thus, the direct costs of equipment and erection account for about 50% of the capital costs. Table 2b indicates that almost two-thirds

TABLE 2a. Widows Creek Unit 8 550-Mw Capacity Limestone Wet Scrubber Facility Capital Cost Estimate Summary[a]

Item	Estimated Cost[b] (K$)
Grading, landscaping, yard drainage, surfacing	177
Roads, sidewalks, bridges	608
Power house modifications	35
Electrical equipment building	100
Ductwork	2,000
Fans	960
Reheaters and soot blowers (includes steam & condensate piping)	1,525
Railroad facilities	320
Ball mill building	200
Limestone grinding facilities	255
Limestone conveying facilities	919
Limestone storage facilities	562
Mobile equipment for limestone handling	155
Scrubber area foundations	350
Scrubber area steel structures	1,110
Scrubbers	1,280
Pumps	765
Tanks (including linings and agitators)	390
Entrainment separators	150
Piping	2,471
Elevator	80
Painting	30
Instruments and controls	550
Electrical work	2,821
Electrical transmission plant	1,526
Cranes and hoists	92
Solids disposal area	767
Construction facilities	2,162
Total direct cost subtotal	22,360
Field general expense	2,670
Allowance for shakedown modifications	2,000
Contingencies	4,370
Total field construction subtotal	31,400

TABLE 2a (Contd.)

Item	Estimated Cost[b] (K$)
Indirect costs	
Engineering design	2,500
Manager's office - Office of Engineering Design and construction	100
Power office (Research, Development & Coordination)	2,480
Initial limestone supply and preoperational testing	1,200
Employee compensation benefits	300
Administrative and general expenses	400
Interest during construction	3,380
Other	240
Total indirect cost subtotal	10,600
Total project cost excluding supplemental pond costs	42,000
Additional supplemental pond cost allocation	
Direct costs	1,280
Field general expenses	128
Contingencies	210
Indirect costs	18
Subtotal	1,636
Total project cost including supplemental pond costs	$43,636,000

[a]Table taken from: B.G. McKinney, A.F. Little, and J.A. Hudson, "The TVA Widows Creek Scrubbing Facility Part I Full Scale Facility," prepared for presentation at Flue Gas Desulfurization Symposium sponsored by EPA, New Orleans, La., May 14-17, 1973.

[b]Cost of land not included.

Notes:

1. The total project cost with additional pond cost allocations from separate authorization contains a total of about $2.8 million ($2.2 million direct cost) for scrubber effluent solids disposal pond. The pond will have an effective capacity of 4.5 million cu yd that will last about 7 years at projected Unit 8 load factors, based on present expected settling characteristics. The pond dikes are designed so that they can be elevated at an estimated cost of about $1.6 million ($1.2 million direct costs).

2. The estimate includes about $2.1 million ($1.2 million direct costs) for solids disposal, over and above the pond costs.

3. The estimate includes about $7.0 million ($4.0 million direct costs) for limestone handling and storage and grinding facilities.

TABLE 2b. Estimated Annual Operating Cost
TVA Widows Creek Unit 8
Limestone Scrubbing System[a]

Item	Estimated Annual Cost, K$[b]			
	Limestone Processing[c]	Scrubber Area	Solids Disposal	Total
Direct Costs				
Raw material - limestone[d]	-	821	-	821
Conversion Costs				
Operating labor & supervision[e]	27	105	27	159
Utilities	42	986	5	1033
Analyses	10	30	10	50
Maintenance[f]	220	1390	130	1740
Subtotal conversion costs	299	2511	172	2982
Subtotal direct costs	299	3332	172	3803
Indirect Costs				
Capital charges[g]	700	3170	770	4640
Overhead				
Plant, 20% conversion cost	60	502	34	596
Admin, 10% operating labor	3	10	3	16
Subtotal overhead	63	512	37	612
Subtotal indirect costs	763	3682	807	5252
Total annual operating cost	1062	7014	979	9055
Operating cost, mills/kw-hr generated	0.34	2.24	0.31	2.89

[a]For source of table, see Table 2a.

[b]Based on capacity factor of 65% (3135 x 10^6 kw-hr/year generated).

[c]Limestone handling, grinding and storage facilities.

[d]273,600 tons limestone at $3/ton delivered.

[e]Operating labor and supervision at $6/hr.

[f]Annual maintenance costs are based on 4.0, 6.0, and 3.0% of total field construction of $5.6 million, $23.1 million, and $4.3 million, respectively, for limestone, scrubber and solids disposal area.

[g]Annual capital charges based on 10% of total investment (25-yr life) except capital charges on $2.8 million for pond costs in the solids disposal area are based on 20% (7-yr life). For investor-owned facilities, capital charges portion would be higher due to difference in cost of money, taxes, estimate of cost than @ 3.5 mills/kw hr.

NOTE: Capital charges are 50% of total. Capacity factor 65% used here may be high for a 10-yr-old unit. Lowering it increases cost per kw-hr.

of the total annualized costs are due to the capital costs, with the remainder being operating costs. Consequently, an increase in annual plant-load factor will lead to the distribution of the fixed portion of the annualized expenses over a larger number of output units (kw-hr), and the operating costs on a kw-hr-produced basis will fall dramatically as the number of electrical units produced increases. Average operating costs of FGD systems on plants used only for peaking service will be much higher than for base load plants. These short-run scale economies are not to be confused with the long-run economies stemming from average annualized costs as a function of the generating capacity of the boiler-generator on which the system is installed.

Table 2c illustrates the size of the task of installing FGD systems on all of TVA's coal-fired plants. In addition to the size of the task, the importance of the annualized capital costs as more than 50% of the total annual cost should be noted.

The analysis carried out by Burchard et al[14] makes use of cost data and estimates from EPA, TVA, M. W. Kellog, Catalytic Inc., Bechtel, Chemico, Monsanto, Wellman-Lord and Stone, and Webster/Ionics. Processes that produce "saleable" products are evaluated as if they all produced the preferred product, sulfur, as the by-product. The costs developed are expected to be representative of process costs after widespread installation even though they are based on experience to date. They are not representative of one-of-a-kind installations, and therefore they fall on the low side of our range of estimates.

The following notation is used throughout.

D = direct
I = indirect
F = variables with the subscripts
s = scrubbing
a = alkali handling
o = other
c = contractor
u = user

Process direct costs are divided into those associated with scrubbing, D_s, and those with alkali handling, D_a. The scrubbing system varies in size dependent upon the gas rate, F_s, while the alkali handling system varies in size dependent upon the sulfur removal rate, F_a. These costs include labor and material specifically associated with process equipment.

TABLE 2c. Estimated Capital and Annual Cost of Adding SO_2 Removal Systems on All TVA Coal-Fired Plants[14]

Cost	Amount (M$)
Capital Cost	
Installed cost of scrubber - Widows Creek Unit 8 at $76/kw	42
Installed cost of scrubbers on remaining 17,176,000 kw on system at $68/kw[a]	1,168
Total installed cost of scrubbers	1,210
Annual Cost	
Annualized capital charges on $1.2 billion investment at 10%	120
Annual operating and maintenance expense at 1.2 mills/kw-hr[b]	105
Total annual cost	225

[a]The weighted average estimate of installing scrubbers on all TVA units other than Widows Creek Unit 8 is $68/kw. This is based on the Widows Creek Unit 8 estimates less certain costs associated with the prototype development of the Widows Creek unit. Also, considerations such as plant layout and available space for installing the equipment was taken into account in estimating costs at each TVA plant.

For comparison, the cost of the limestone scrubber installed on Commonwealth Edison's Will County Station has been reported as $85/kw, not including sludge treatment costs.

[b]Based on estimate for Widows Creek Unit 8, distributed as follows:

	Mills/kw-hr
Raw material - limestone at $3.00/ton delivered	0.26
Operating labor and supervision	0.05
Utilities	0.33
Analyses	0.01
Maintenance	0.55
Total direct operating and maintenance	1.20

Other direct costs, D_o, include site preparation and off-site expenses, which are expressed as a percentage of process direct costs. Contractor indirect costs, I_c, include engineering, field overheads, contingencies and other expenses. These are expressed as a percentage of total direct costs. Interest, escalation during construction and process modifications are considered user-indirect costs, I_u, and are expressed as a percentage of total direct costs plus contractor-indirect costs.

Capital cost estimates for five-scrubbing projects currently in use or in planning were developed.[14] The estimates derived through the engineering-economic cost analysis varied from contractor estimates from minus 22% to plus 19%. The total capital cost is given by equation 1:

$$C = (D_s F_s F_r + D_a F_a S_r)(1 + D_o)(1 + I_c)(1 + I_u) \qquad (1)$$

In addition to the notation introduced above, let:

D_s be measured in \$/kw; D_a be measured in \$-hr/lb S

D_o be measured as (\$/kw of other direct costs)/(\$/kw process direct costs)

F_r be the retrofit difficulty factor

F_a be the sulfur rate scale factor

F_s be the gas flow rate and the scrubber configuration adjustment factor

I_c be measured as (\$/kw contractor indirect)/(\$/kw total direct)

I_u be measured as (\$/kw user indirect cost)/(\$/kw total direct plus contractor indirect)

S_r be the sulfur rate measured in lb S/kw-hr.

The authors found the following ranges for each of the variables: C (20-80); D_s (6.5-12) without particulate control; D_s (10.5-15) with particulate control; D_a (250-635), D_o (.10-.20); F_s (0.8 1.4); F_r (1.0-1.5); F_a (0.5-2.0); I_c (0.25-0.50); I_u (0.12-0.25); S_r (.003-.07).

For Will County C was estimated at \$68/kw. The original contractor estimate was \$57/kw, with subsequent modification to \$78/kw, and Commonwealth Edison now estimates it at \$108/kw. For Widows Creek the estimate was \$49/kw in contrast to the contractor's estimate of \$27/kw. An estimate of \$36/kw as opposed to the contractor's \$40/kw for KC La Cygne plant was developed and one of \$34 vs the contractor's \$39/kw for the Boston Edison Mystic Plant. Will County is a retrofit for a 166-Mw plant using 4% S coal; Widows Creek is a retrofit for a 550-Mw plant using 4% S coal; Northern States is a new 1360-Mw plant using 1% S coal; KC La Cygne is a new 820-Mw plant using 5% S coal; and Boston Edison is a 150-Mw, 2% S oil-fired plant.

Table 3 gives the direct costs for four scrubbing system configurations (described in detail later in this section), based on the Widows Creek 500-Mw, 4-scrubber system treated as new rather than retrofit. In spite of what appears to be an advantage for clear-solution operations, the authors[14] conclude: "In general the type of scrubber does not greatly affect the investment cost since the vessel size is determined primarily by entrainment considerations in the air-water system and not by scrubber parameters." The incremental process-direct-investment cost for particulate removal varies from \$2.9 to \$4.2/kw. Incremental investment, including all direct and indirect costs, would be \$5 to \$10/kw, which is comparable to the investment for an electrostatic precipitator. There seems to be no economic advantage to controlling particulates by scrubbers rather than precipitators, or vice versa.

Scrubbers are generally restricted by technological considerations to a maximum gas flow rate of 300,000 scfm. This is roughly equivalent to the gas production from a 150-Mw, boiler-generator unit. Thus, scrubbers for large plants are expected to be modular. The cost of an individual scrubber changes with size (based on flue gas rate) according to a factor of 0.65. The cost per scrubber should be lower when more than one scrubber is installed at a time. The costs per scrubber are assumed to vary with the number of scrubbers to the minus 0.15 factor. These features are combined in a single factor F_s, which is the relative scrubber direct costs compared to the 500-Mw, 4-scrubber system summarized in Table 3.

Let:

F_s be the relative scrubber direct cost compared to a 500-Mw, four scrubber system used as a base case

n be the number of scrubbers, $n^o = 4$ where the superscript identifies the base case

TABLE 3. Scrubbing Process Direct Costs[a] (D_s)[14]
($/kw)

Process Component	Lime/Limestone Scrubber Alone	Lime/Limestone Scrubber W/Venturi[b]	Clear Solution SO_2 Scrubber Alone	Clear Solution SO_2 Scrubber W/Venturi[b]
Scrubber and mist eliminator	3.20	3.60	2.00	3.50
Recirculation	3.00	4.80	0.50	1.50
Structural	0.60	0.70	0.50	1.00
Electrical and instruments	0.60	1.00	0.30	0.60
Ductwork and dampers	2.40	2.40	2.40	2.90
Bypass ductwork and dampers	0.75	0.75	0.75	1.00
Fans	0.80	1.00	0.70	0.90
Reheat: direct fired	0.80	0.80	0.80	0.80
Scrubbing Process Direct Costs, Old Plants (D_s)	12.15	15.05	7.95	12.20
Credit for New Plants[c]	-1.50	-1.50	-1.50	-1.50
Scrubbing Process Direct Costs, New Plants (D_s)	10.65	13.55	6.45	10.70

[a]Basis 500Mw, 4-module, new power plant, 1972$. Assume 2 scfm/kw.
[b]Scrubbing process direct costs with a particulate collection venturi included.
[c]The 1.50 expended on retrofit of old plants.

TABLE 4. Alkali Handling, Base Case Direct Capital Cost[14]
(D_a Basis: 500 Mw, 3.5% S Coal, 5 ton S/hr, 1972$, 80% Load Factor)

Process	$-hr/lb S	$/kw[a]
Limestone scrubbing	425	8.5
Lime scrubbing	230	4.6
MgO scrubbing/regeneration	600	12.0
Caustic scrubbing with thermal regeneration	540	10.8
Caustic scrubbing with electrolytic regeneration	635	11.5

[a]Applicable only where sulfur removal rate is 0.02 lb/kw-hr ↔ 500-Mw plant, 3.5%-S coal.

Q be the total system size in Mw assuming 2scfm/kw of flue gas. $Q_o = 500$

Q_o be the scrubber module size in Mw. $Q_o^o = 125$ Mw
Q_o max = 150 Mw.

The equation determined in Ref. 14 for F_s may be written:

$$F_s = \left(\frac{Q^o/n^o}{Q/n}\right)\left(\frac{Q/n}{Q^o/n^o}\right)^{.65}(n/n^o)^{-.15}$$

Recognizing that $Q_o = Q/n$ and that $Q_o^o = Q^o/n^o = 500/4=125$ and that $n^o = 4$ we have:

$$F_s = 6.67(n^{.20}/Q^{.35}). \qquad (2)$$

Notice the implicit assumption that when several scrubbers are used, they are all the same size.

Example 1: Consider a 150-Mw plant using 1 scrubber. $F_s = 1.154$. If we assume no retrofit problems the cost for scrubbers in this plant is 15.05x1.154 = \$17.37/kw if limestone or lime scrubbing is used. The value of D_a = \$15.05/kw was obtained from Table 3.

Example 2: Consider the same 150-Mw plant using two scrubbers each of 75-Mw size. $F_s = 6.67(150)^{-.35}(2)^{.20} = 1.33$. $F_sD_s = (15.05)(1.33) = \$20.02/\text{kw}$.

Example 3: Consider a 700-Mw plant. It would use 700/150 = 4.67 or 5 scrubbers. $D_sF_s = (15.05)(6.67)(700)^{-.35}(5)^{.20} = \$14.13/\text{kw}$.

Example 4: Suppose that the plant of Example 3 decided to use four, 150-Mw scrubbers and one, 100-Mw scrubber. Now we compute total cost as if we had a 600-Mw and a 100-Mw plant.

$$D_sF_s(600) = 600(15.05)(6.67)(600)^{-.35}(4)^{.2} = 8427$$

$$D_sF_s(100) = 100(15.05)(6.67)(100)^{-.35}(1)^{.2} = 2007.67$$

the total is 10434.67 or 10434.67/700 = \$14.91/kw .

Example 5: The size of the scrubber depends on the flue gas rate. The equation for F_s uses the plant size and scrubber size Q and Q_o as surrogates. The conversion assumed is that each kw of capacity generates 2 scfm of flue gas. Suppose we have a 500-Mw plant that generates 3 scfm/kw. This will mean that the number of scrubbers required for this plant will be the same as those required for a 500(3/2) = 750-Mw plant that generates flue gas at the rate of 2 scfm/kw. This plant requires 750/150 = 5 scrubbers.

$$D_sF_s = (15.05)(6.67)(5)^{.2}(500)^{-.35} = \$15.79/\text{kw} .$$

Notice that the increased flue gas rate over the rate assumed for the base case affects the value of n used in the equation for F_s, but that the value of Q is still the given plant capacity.

These examples confirm both the economics of scale in direct scrubbing cost and the advantages of using equal-sized scrubbers. If scrubbers are to be added to a plant sequentially, each installation should be treated as a separate plant. If a 1000-Mw plant gets 400 Mw of scrubbers one year and 600 Mw in a later year, costs should be calculated for a 400-Mw installation and then for a 600-Mw installation as if the two were different plants.

The remaining factor in the first term of Eq. 1 is F_r, the retrofit factor. M. W. Kellog and Co. qualitatively estimated retrofit factors based on visits to plants said to represent 25% of the coal- and oil-fired capacity in the U.S. The retrofit ratings do not include routine site preparation required for all plants, which is included under the category of other direct costs. The retrofit factors as reported in Ref. 14 are given in the following table:

Unit Size (Mw)	Age of Unit (Yrs) 0-9	10-19	20+
0 -99	-	-	1.51
100 -199	-	1.34	1.45
200 -499	1.33	1.29	-
500+	1.26	-	-

To compute direct scrubbing costs per kw for a plant of total size Q proceed as follows:

(a) Select D_s from Table 3 according to the type of scrubber and whether the plant is new or in use.

(b) Determine the number of scrubbers as the next integer larger than Q'/150 unless that fraction is an integer. Q' is the plant capacity in Mw if the flue gas rate is 2 scfm. Otherwise it is the adjusted capacity as illustrated in Example 5.

(c) Compute $F_s = 6.67n^{.2}Q^{-.35}$ where Q is the plant capacity in Mw regardless of the flue gas rate.

(d) Find F_r from the table just above.

(e) $D_sF_sF_r$ = capital cost per kw in 1972$.

The second term of the first bracket in Eq. 1 is concerned with the direct costs of alkali handling. These costs are a function of the amount of sulfur removed and the type of process used. The base case is the 500-Mw plant using 3.5% S coal and 90% removal efficiency. This results in removal of 5 tons S/hr for the base plant. The base case alkali handling costs are given as D_a in Table 4. The units of D_a are $-hr/lb S reflecting the dependence of alkali handling costs on the sulfur removal rate S (tons/hr).

The size adjustment factor, F_a, also depends on the sulfur removal rate. As reported in Ref. 14, the size factor depends on the ratio of the base case sulfur removal rate to the rate for the plant in question raised to the .33 power.

$$F_a = (5/S)^{.33} \tag{3}$$

Example 6: Consider a plant with sulfur rate of 6.5 tons/hr. $F_a = (5/6.5)^{.33}$ = .9175. Then, if a limestone scrubber is used D_aF_a = (425)(.9175) = $389.94-hr/lb S. This must be converted into $/kw using the conversion factor S_r.

$$S_r = \text{(tons S/hr)(2000 lbs/ton)}(Qx10^3)^{-1} = \text{lb S/hr-kw} .$$

Then $D_aF_aS_a = 425(5)^{.33}(6.5)^{.67}(2000)(550{,}000)^{-1}$ = $9.25/kw where it is assumed that the plant capacity, Q, is 550 Mw.

Example 7: Consider a 500 Mw plant yielding S = 5 tons/hr. $F_a = 1$. $D_a = 425$ and $S_a = (5)(200)(500{,}000)^{-1} = (1/50)$.

$$D_a F_a S_a = \$8.5/\text{kw} .$$

Example 8: Double the size of the plant of Example 7. $D_a = 425$. S = 10 tons/hr. $S_a = (10)(2000)/(1{,}000{,}000) = 1/50$. $F_a = (5/10)^{.33} = .794$. Cost = (425)(.794)(1/50) = \$6.75/kw .

Example 9: Assume that a plant produces 1 tons of S per 100 Mw of capacity when 3.5% S coal is used. Presumably, 5% S coal would produce (5/3.5) = 1.43 tons of S/100 Mw. Then a 500-Mw plant using 5% S coal generates S = 7.15 tons S/hr. $S_a = (7.15)(2000)/500{,}000$ or .0286. $D_a = 425$ assuming limestone scrubbing is used.

$$F_a = (5/7.15)^{.33} = .888$$

$$\text{Cost} = (.0286)(.888)(425) = \$10.79/\text{kw}.$$

This example indicates that even though there are scale economies in \$ per lb of S removed per hr, it is more expensive to use 5% S coal than 3.5% coal in terms of alkali handling.

In computing the direct cost of alkali handling the following procedure is suggested:

(1) Choose the appropriate value of D_a from Table 4

(2) Compute $F_a = (5/S)^{.33}$ if limestone, lime, MgO, and caustic with thermal regeneration scrubbing are being considered and $(5/S)^{.18}$ for caustic scrubbing with electrolytic regeneration. S is measured in tons S/hr.

(3) Compute $S_a = S(2000)(Qx10^3)^{-1}$. (lbs S/hr-kw)

(4) Compute $D_a F_a S_a$. (\$/kw)

The sulfur rate S depends on many factors peculiar to the plant under consideration. It may be estimated using the following steps:

(capacity in Mw)(10^3kw/Mw)(8760hr/yr) = (poss. kw-hr/yr)
(poss. kw-hr/yr)(plant load factor) = actual kw-hr/yr
(actual kw-hr/yr)(plant heat rate Btu/kw-hr) = (Btu/yr)
(Btu/yr)(Coal H.V. Btu/lb)$^{-1}$ = (lb coal/yr)
(lb coal/yr)(fraction of coal that is sulfur) = (lb S/yr)
(lb S generated/yr)(fraction of S removed)$(2000)^{-1}$
= tons S removed/yr

$$\frac{\text{(tons S removed/yr)}}{\text{(8760hr/yr)(plant load factor)}} = \frac{\text{tons S removed}}{\text{operating hr}}$$

= S for use in F_a and S_a .

Next, compute the sum $D_sF_sF_r + D_aF_aS_a$. These are the direct capital costs of the scrubbing installation measured in \$/kw. They must be modified to include other capital costs.

In some industries, the direct costs of material and labor are sufficient to characterize the relative costs of the processes. However, the indirect costs of a scrubbing installation may be greater than the direct costs, so the latter must be considered. A summary of other direct and indirect costs is given in Table 5. These costs fall into three groups: (1) other direct costs incurred by the contractor, (2) contractor indirect costs and (3) indirect costs incurred by the user or not included in the contractor estimates. Smaller projects usually have relatively larger indirect costs. The ranges shown in Table 5 reflect this and the fact that poor retrofit conditions may increase construction time and modification required.

Taking the midrange for each item as shown in Table 5 yields capital costs in \$/kw as:

$$C = (D_sF_sF_r + D_aF_aS_r)(1.15)(1.375)(1.185) = (D_sF_sF_r + D_aF_aS_r)(1.874).$$

ANNUALIZED COSTS

Annualized costs include: (1) utility and raw material consumption, (2) operating labor costs, (3) maintenance costs, and (4) capital charges. We use the following notation with the expected range of values shown in parentheses ( ).

TABLE 5. Summary of Variable Direct and Indirect Scrubbing Installation Costs[14]

Process Direct		% of Process Direct: 100%
Other Direct (D_o)	Process Direct 10-20%	
Site preparation	4-6%	
Winterizing	0-5%	
Buildings	2-3%	
Service faci	4-6%	
Total Direct ($D_s+D_a+D_o$)		110-120%
Contractor Indirects (I_c)	Total Direct 25-50%	
Engineering, home office exp.	10-15%	
Construction expense	5-15%	
Contractor's fee & overhead	5-10%	
Contingency	5-10%	
Subtotal Investment		
(Total Direct + Contractor Indirect = $D_a+D_s+D_o+I_c$)		137-180%
User Indirects (I_u)	Subtotal Investment 12-25%	
Interest during construction	5%	
Startup and modification	5-10%	
Escalation	2-10%	
Total Investment ($D_a+D_s+D_o+I_c+I_u$)		154-225%
Other Costs Sometimes Included but not Included Here	Total Investment 27-75%	
First year's operation	5-10%	
Stack	5-10%	
Fan & ductwork credit for new plants	5-10%	
Precipitator credit	10-20%	
Utility overhead	10-20%	
R&D expense	2- 5%	

$A_t \triangleq$ total annualized costs in \$/yr (10^5 - 10^7)

$U_s \triangleq$ scrubber utility cost \$/scfm/yr (0.60 - 0.80)

$Q \triangleq$ design flue gas rate scfm (2×10^5 - 3×10^6)

$S \triangleq$ design sulfur removal rate tons/hr (10^3 - 10^5)

$U_a \triangleq$ alkali handling utilities and raw materials cost \$/tons of S (18 - 68)

$L \triangleq$ yearly average load factor (0.3 - 0.8)

$L_o \triangleq$ operating labor cost including overhead, \$/yr (10^5 - 3×10^5)

M = maintenance as a fraction of capital equipment including overhead (0.05 - 0.10)

R_c = capitalization rate based on total investment capital (0.12 - 0.25)

C' = total capital investment, \$, (10^6 - 10^8)

$$A_t = (U_sQ + 8760SU_a)L + L_o + MLC + R_cC' \qquad (4)$$

Estimates for A_t for each of the processes under consideration are given in Table 6, and the sensitivity of A_t to changes in parameter values is given in Table 7. The most striking aspect of Table 6 is the surprisingly small differences in costs between processes. Table 7 reveals that operating costs are a strong function of plant parameters like size, load factor, and sulfur content. In limestone scrubbing, for example, the most important parameters are sulfur content and size. When all parameters are considered, the rather extensive range, 1.1 to 1.7 mills/kw-hr, of all possible costs is particularly important, since it far exceeds the range of differences between types of processes at their normal levels.

For a given power plant application, i.e., fixed plant size, fuels, etc., several conditions and parameters magnify the differences in processes. The cost of waste disposal is important. At a cost of waste disposal below \$2/ton, limestone scrubbing is favored over lime scrubbing. Breakeven costs for comparison of regenerable and throw-away processes vary between \$1.40 and \$3.00/ton/sludge.

TABLE 6. Process Costs[14]

	Annualized Cost (mills/kw-hr)	Capital Cost ($/kw)
Limestone scrubbing	2.46	36.3[b]
Lime scrubbing	2.30	34.6[b]
MgO scrubbing/regeneration	2.22[a]	46.2[a]
Alkali scrubbing with thermal regeneration	2.40	46.0
Alkali scrubbing with electrolytic regeneration	2.40	45.2

Base Case: 500 Mw, 3.5% S coal, 1972 dollars: 1.0 Mscfm, 5.0 ton S/hr; 60% load factor particulate scrubbing; 1.25 retrofit factor, other direct and indirect costs are 70% of process direct costs, waste disposal at $4.00/ton/ sludge (wet).

[a]Based on production of H_2SO_4, cost of S production is 2.4 mills/kw-hr, $49.41/kw.
[b]Pond costs are not included, they would add $5-$10/kw.

TABLE 7. Sensitivity of Annualized Cost (Limestone Scrubbing)[14]

Parameter	Base	Range	Cost Range[a] Mills/kw-hr	% Variation Relative to Base Cost[b]
Sulfur content	3.5%	0.7-7%	1.8-3.19	57
Plant Size	500 Mw	1000-100	2.2-3.44	50
Load Factor	60%	80-40	2.14-2.97	34
Indirect Costs	70%	70-140%	2.46-3.08	25
Waste Disposal	$3/ton	$1-5	2.16-2.76	24
Retrofit Factor	1.25	1.0-1.5	2.20-2.72	21
Particulate	Scrubbing	No-Yes	2.16-2.46	12
Total variation of combined effect of all factors at low cost levels to all factors at high cost levels			1.08-7.66	267

[a]All other parameters are held at base conditions while the parameter in question is varied over its range.
[b]Cost at base case is 2.46 mills/kw-hr.

Utility costs for scrubbers, U_s, and utility raw material costs, U_a, for each of the 5 alkali handling systems are given in Table 8. U_s is proportional to the quantity of flue gas, while in alkali handling the costs are proportional to the amount of sulfur handled. The annual costs are calculated by determining the yearly quantity of flue gas and sulfur handled and then multiplying by the appropriate factors in Table 8.

The unit costs for utilities and materials are estimates of the most typical levels.[14] For example, costs for caustic scrubbing with electrolytic regeneration assume the use of off-peak power. In the costs for caustic scrubbing with thermal regeneration, use of low pressure turbine bleed (15-30 psia) steam is assumed. Half of the 37 plants fell in the range of \$3-\$5/ton for limestone. Annualized costs for waste disposal vary from \$1 to \$7/ton of sludge and the authors[14] used \$3/ton. They also assumed a value of \$15/ton for sulfur (or sulfur content in H_2SO_4) as resale.

Operating labor inputs, L_o, vary from 15,000 to 40,000 manhours/yr. A constant labor, supervision, and overhead cost of \$75,000 was assumed for scrubber operations and \$150,000 for alkali handling. This cost is a major fraction of operating costs only for the very small plants.[14]

Maintenance costs (M) are not well established. A maintenance charge of 5% of total investment at full load and proportional to the load factor for actual costs was assumed. The maintenance costs for a plant averaging 60% load over the year would be 3% of total investment. This must be increased for plant overhead of 50%. Thus 5% → 7.5% and 3% → 4.5% of investment. This is the MLC term of Eq. 4, e.g., MLC = (.075)(.60)C.[14]

The final term in Eq. 4 relates to capital charges. These include components for depreciation, return on investment, federal tax, local tax, and insurance. The economic life of present scrubbers or of scrubbers installed is difficult to estimate because of technological progress, variable input and by-product prices, and of the value of the land used for waste disposal. A typical capitalization rate, R_c, over the lifetime of the project is given in Table 9.

Burchard and his co-authors used their estimating procedure to compute costs for many potential installations of limestone scrubbing.[14] Their results indicate that 25% of the oil- and coal-fired capacity could be retrof

TABLE 8. Utility and Raw Material Cost Summary[14]

Scrubbing Costs	\$/scfm-yr, U_s	Mills/kw-hr[a]
SO_2 alone	0.61	0.14
Incremental Particulate	0.16	0.18
Both	0.77	0.18
Alkali Handling Costs	**\$/Ton S, U_a**	**Mills/kw-hr[b]**
Limestone scrubbing	68	0.68
Lime scrubbing	68	0.68
MgO: acid	18	0.18
Caustic scrub & thermal regeneration → S	45	0.45
Caustic scrub & electrolytic regeneration → S	44	0.44
Product credit for regeneration processes	15[c]	0.15

[a]Basis: 2 scfm/kw and 1972\$

[b]Basis: 0.02 lb S/kw-hr (3.5% S coal)

[c]Credit can vary from less than 0 to \$60/ton S.

TABLE 9. Typical Capitalization Rate (R_c)[14]

Depreciation	15-yr st. line,[a] interim replacement	6.65% + .35
Interest	50% debt at 8% average	2.00%
Return on investment	50% equity @ 12% average	3.00%
Federal taxes	Same as return on investment	3.00%
Local taxes	67% of Federal	2.00%
Insurance		0.80%
Average levelized capital charges		17.5 %

[a]Special consideration may be made for financing environmental control systems. The 5-year depreciation allowance would reduce levelized capital charges 1 to 2%. Municipal tax free financing is being made available for some installations at interest costs of 5 to 6%. Total debt financing with tax free bonds would permit capital charges as low as 9 to 10%.

at a cost of 1.3 to 1.8 mills/kw-hr. An additional 25% could be retrofit for 1.8 to 2.0 mills/kw-hr. It is important to recall the reported broad range of costs, depending on the parameter values chosen, as illustrated in Table 7. If low sulfur fuel were available at a premium over high sulfur coal of 20¢/MBtu (equivalent to about 2 mills/kw-hr), 50% of the utility capacity could more economically use FGD than they could low sulfur fuel. Figures 1, 2, and 3 summarize the results of the comparison of FGD costs and clean fuel costs.[14] Notice that while the upper range of high sulfur fuel costs, as depicted in Fig. 3, corresponds reasonably well with those portrayed in Table 1, the upper range for low sulfur fuel-delivered-costs shown in Fig. 3 is higher than that depicted in Table 1. As the authors point out, Fig. 3 has been constructed for the worst-case as far as low sulfur Western coal is concerned, since the calculations are based on the assumption that Western coal would be used in the northeastern United States.

The magnitude of the costs generated by the analysis of Ref. 14 must be compared with other estimates. Cost estimates taken from Refs. 6 and 7 are reproduced here as Table 10. There is no obvious explanation for the differences in the cost estimates from the two sources. Notice that the increment associated with the use of low sulfur coal is in the same range as that associated with the use of FGD systems.

Often, it will be necessary to convert from cost figures on one basis to cost figures on another basis. For example, Ref. 9 discusses a 1000-Mw plant with a 60%-average load factor and 9500-Btu heat rate. This plant would require 50×10^{12} Btu/yr or 2260×10^{3} tons of coal/yr. It would handle a maximum of two million scfm or flue gas, and the sulfur dioxide concentration in that flue gas would be 2400 ppm by volume.

Before looking further at cost estimates appearing in the literature, let us summarize the analysis thus far presented. Something on the order of 3 mills/kw-hr might be appropriate as a general estimate of the added cost of power generation due to FGD. If the annual inflation rate is to be 7.5%, with the 3 mills assumed to be in terms of 1973$, then the cost of FGD in 1970 was 2.41 mills/kw-hr and 3.46 mills/kw-hr in 1975. This level of estimated costs may be too low. Ring and Fox[15] project a cost in the range of 5.75 to 7.3 mills/kw-hr, which is substantially above the other estimates. Ring and Fox estimates are the most recent that are available.

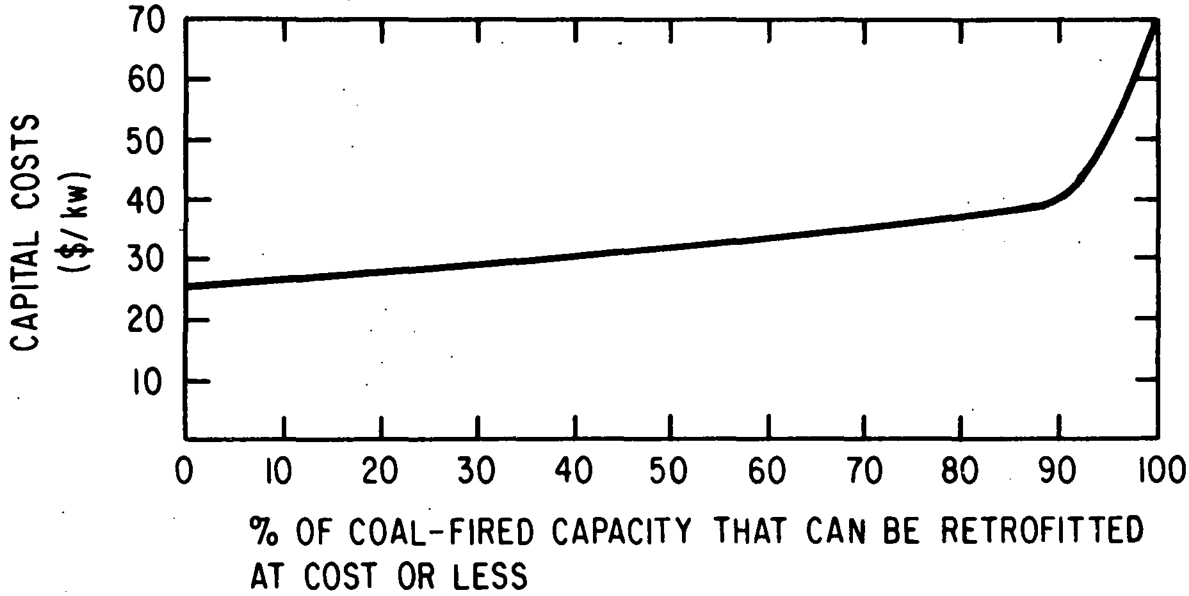


Fig. 1. Distribution of Capital Costs over Utility Population. (Limestone costs do not include pond costs for sludge disposal.)[14]

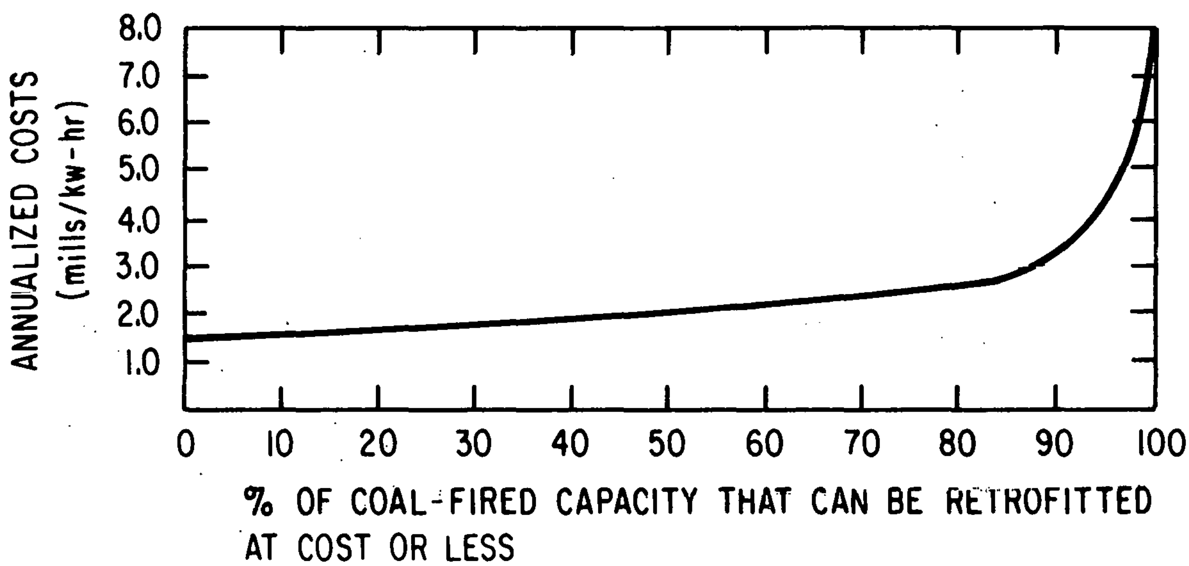


Fig. 2. Distribution of Annualized Costs over Utility Population. (Limestone scrubbing waste disposal @ $3/ton.)[14]

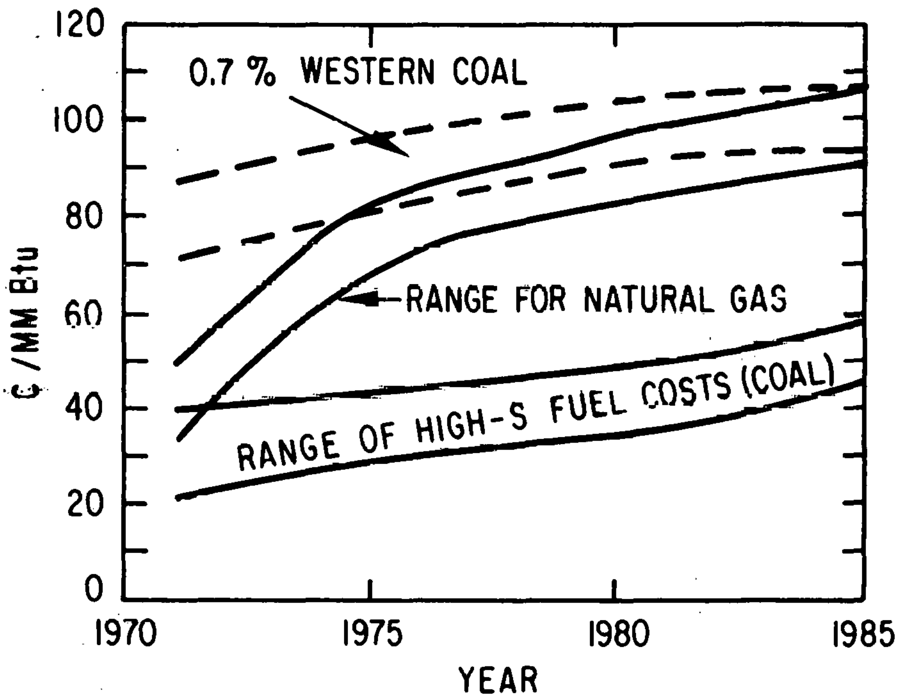


Fig. 3. Electric Utility Fuel Price Projections 1971-1985 for Northeastern U.S. in Actual Dollars. (Data based on 1971 Westinghouse Report to EPA.)[14]

TABLE 10. Comparisons of SO_2 Control Process Systems for Coal-Fired Power Plants[6,7]

Item	Reactant input requirements	Throw-away or recovery	Approx invest coal-fired boiler costs[a] ($/kw)	Approx annual costs[b] (mills/kw-hr) No credit for S recovery	Approx annual costs[b] (mills/kw-hr) Credit for S recovery	SO_2 removal efficiency
Coal-fired power plant	N/A	N/A	200	8.9[c]	N/A	N/A
Low S fuel increment (coal & oil)	N/A	N/A	N/A	2.0-4.0 (2.0-6.0)	N/A	N/A
Wet lime/limestone/$Ca(OH)_2$ slurry scrubbing	Lime/100-120% stoich Limestone/ 120-150% stoich	Throw-away $CaSO_3/CaSO_4$	35-52 (27-46)	1.5-2.4 (1.1-2.2)	N/A	80-90%
MgO	MgO alkali; carbon & fuel for regeneration & drying	Recovery of conc. H_2SO_4 or elem. S	36-66 (33-58)	1.6-3.0 (1.5-3.0)	1.4-2.8 (1.2-2.7)	90%
Monsanto CAT-OX (add-on)	Catalyst V_2O_5 (periodic replacement) & fuel for heat	Recovery of dilute H_2SO_4 or S	43-67 (41-64)	1.6-2.7 (1.5-2.6)	1.5-2.6 (1.3-2.4)	85-90%
W-L process (soluble sodium scbg w/ regeneration)	Sodium make-up & heat for regeneration requirements	Recovery conc. H_2SO_4 or S	40-68 (38-65)	1.5-3.2 (1.4-3.0)	1.2-2.8 (1.1-2.7)	90%
Double alkali process	Sodium make-up + lime/limestone/ 100-130% stoich	Throw-away $CaSO_3/CaSO_4$	26-47 (25-45)	1.2-2.2 (1.1-2.1)	N/A	90%

a. Generally where a cost range is indicated, the lower end refers to a new unit (1000 Mw), while the high end refers to a 200-Mw retrofit unit. Costs include particulate removal and are in 1973 dollars.
b. Assumptions: Costs calculated at 80% load factor, fixed charges per year ~ 18% of capital costs.
c. Includes environmental controls to minimize land and water pollution.

Ring and Fox also present a list of "throw-away" process installations that are considered "placed in operation on coal-fired boilers." These data appear in Table 11. Similar data for systems with recovery appear in Table 12. EPA indicates that orders have been placed for another 35 domestic units with a combined capacity of 15,700-Mw capacity. Most of these are throw-away lime or limestone scrubbing processes.

Cost data appear scattered throughout the literature. The costs reported vary a great deal from source to source. Because of this usually unexplained variance in the reported costs, no report would be complete without a sampling of the diverse opinions. Often the reported data refer to almost "one of a kind" installations. In any case the cost of FGD systems must be compared to the costs of alternatives and to the overall cost of producing electricity. The 1972 average national consumer costs for power were about 17.8 mills/kw-hr, while the average cost of FGD, according to EPA, is about 2.0 mills/kw-hr. On the basis of these figures, consumer costs for electricity could rise by 18%. Of course, the consumer costs of electricity have increased substantially since the above estimate was made and the estimated cost of FGD seems much too low. The 18% figure is a national average and the increase in costs would be much larger for consumers living in areas that generate power exclusively through the burning of coal.

With the possible exception of the Commonwealth Edison Will County limestone scrubbing units,[16,16a,17] some reports from TVA[18,19] and an EPA document,[14] most of the available cost information comes from comments made at various hearings.[6,20,21] The costs reported or estimated are usually rough estimates of the capital cost in dollars per kw of installed capacity and of the annualized costs in $/kw-hr of energy production. In many cases no indication of how these costs might change with generating capacity or output rate is given. In some cases, the FGD alternative under consideration is not even specified. With saleable product processes, it is difficult to determine what allowance, if any, has been made for the revenue generated from the sale of the by-product (usually S or H_2SO_4). Operating experience is so limited that it is not surprising to find that little operating cost data exists. In order to provide a feel for the range of estimates and associated comments found in the literature, the following paragraphs are presented without comment.

TABLE 11. Stack Gas Desulfurization Throw-away Process Installations[15]

Location	Vendor	Size, Mw	Reagent	Startup	Operation
Union Electric, Meramec	CE	120	Limestone (injection)	9-68	20% availability over 3-year period - shutdown
Kansas P&L, Lawrence	CE	125	Limestone (injection)	12-68	
Kansas P&L, Lawrence	CE	430	Limestone (injection)	11-71	Poor reliability - SO_2 removal < 75%
Comm. Edison, Will Co.	B&W	156	Limestone	2-72	16-20% availability since 2/72
Mitsui Alum., Miike	Chemico	156	Carbide lime	7-72	Has run 441 days without causing plant shutdown
KC P&L, Hawthorn	CE	100	Limestone (injection)	8-72	About 20% availability 1st yr - conversion to tail-end limestone addition has improved availability
KC P&L, Hawthorn	CE	100	Limestone (injection)	11-72	
Louisville G&E, Paddy's Run	CE	65	Carbide lime	4-73	40% availability first 6 months, improving
Dequesne Lt., Phillips	Chemico	150	Lime	4-73	Major shutdown 10-73, equipment problems
KC P&L, La Cygne	B&W	820	Limestone	6-73	Good availability at 40% of capacity
Ariz, PS, Cholla	RC	115	Limestone	10-73	

TABLE 12. Stack Gas Desulfurization Recovery Processes Installations[15]

Location	Developer	Size	Reagent	Product	Startup	Comment
Boston Edison, Mystic	Chemico	155 Mw	Magnesia	H_2SO_4	4-72	Approx. 50% availability
Potomac E&P, Dickerson	Chemico	95 Mw	Magnesia	H_2SO_4	9-73	Previous crystal form, problems appear solved
Phila. Elec. Eddystone	United Engrs.	120 Mw	Magnesia	H_2SO_4	Early May	-
Illinois Pwr. Wood River	Monsanto	110 Mw	Catalytic	H_2SO_4	10-72	80% H_2SO_4 product, reheat problems
NIPSCO, Mitchell	WPG/Allied	110 Mw	Na_2SO_3	S	1975	SO_2 reduced w/natural gas

Limestone scrubbing is the only feasible FGD system for retrofitting the Mitchell Station. The estimated cost is $62/kw with annualized operating cost including sludge disposal, estimated at 4 mills/kw-hr.[6]

The Bailey Plant (NIPSCO) can be retrofitted with a scrubber in 38-48 months at an estimated cost of $57/kw. Offsite sludge disposal would be required, not included in the cost. Another estimate for the same plant, by a different agency is $47/kw. Sargent and Lundy concluded that an FGD system could be retrofitted and installed for $56/kw and annual operating costs, not including sludge disposal, of 1.4 mills/kw-hr in 39-45 months.

The Wabash River Station can be retrofitted with a limestone FGD system at an estimated installed cost of $66/kw, including sludge disposal and an annualized operating cost of 3.7 mills/kw-hr.

The Cholla Station of Arizona Public Service estimates the cost of an FGD system for its 115-Mw plant at $30-40/kw not including sludge disposal or foundations. The existing 115-Mw unit at La Cholla Plant was retrofitted and placed on line October 1973. It is not operating satisfactorily but the capital cost was $52/kw.

Use of tail gas scrubbing with a Chemico system by Duquesne Power and Light is estimated to result in costs of $75/kw and 2.11 mills/kw-hr.

Southern California Edison estimates FGD costs at $62.5/kw.

The Commonwealth Edison limestone scrubber at Will County has estimated capital costs of $108/kw with estimated annualized cost of 10 mills/kw-hr. This is a development installation and the true cost of additional installations should lie between these figures and the overly optimistic EPA figures.

The 1600-Mw Mansfield Plant of Ohio Edison is equipped with a Chemico Lime FGD system with estimated system capital costs of $83/kw. The annual cost is 2.7 mills/kw-hr. This system has not been adequately demonstrated for commercial reliability, but Ohio Edison feels that it is the most advanced. Contracts with suppliers for this system have been a major stumbling block.

One vendor, Kennecott, presented cost estimates for FGD systems that are approximately 50% higher than those quoted by Mr. F. Princiotta[7] speaking for EPA. Another vendor, Combustion Engineering Associates, stated that their current FGD installed cost estimate is between $30-40/kw. On the other hand, Peabody Engineering Systems, who have worked with Detroit Edison, state that experience indicates capital costs of FGD systems run $40-50/kw installed.

Davy Power Gas, a vendor promoting the use of the Wellman-Lord Process, estimates capital costs at $35/kw installed, with operating costs of 2 mills/kw-hr.

Universal Oil Products, another vendor, estimates that for a 200-Mw station using 3.5% S coal with guaranteed sulfur dioxide removal efficiency of 85% and using a Limestone FGD system, the capital cost would be $36/kw, including waste handling facilities.

In the summary of the SOCTAP Report,[21] the statement is made that the capital costs for new plants range from $30 to $50/kw with a $40/kw average. Retrofit costs are in the $45-to-$65-kw range. Annualized operating costs have a range of 1.1 to 3.0 mills/kw-hr with a mean of 2.

Estimates appearing in the published literature give a range of $30 to $70/kw.[22] Regardless of the range, the EPA states that FGD capital costs are comparable to the cost of using low sulfur fuel. Table 10 presented earlier, offers a summary of these costs. According to this table and to the EPA testimony, FGD costs are not particularly sensitive to the process types, being more dependent on such factors as the size of the power plant, whether the installation is on a new power plant or is being retrofitted on an older one, the amount of sulfur and ash in the fuel, the pollution control requirements, the price of the reactant, and the costs of solid waste disposal.[7] The mean annualized operating costs of FGD systems of 2 mills/kw-hr is to be contrasted with the cost of producing electricity of approximately 9 mills/kw-hr with a price to the consumer of 20 mills/kw-hr.[2]

Other estimates from the published literature include an estimate of capital costs of the range $60 to $100/kw by Engdahl,[5] a cost for limestone scrubbing of $40/kw on a new plant by Slack and Falkenburg,[23] and $50/kw for a retrofit and $30/kw for new plants reported by Olds.[24] Davis expects that new plants will incur incremental capital costs of about $40/kw while retrofit plants will have capital costs of $45 to $65/kw and possibly as high as $80/kw.[25]

Battelle presents data for investment costs on 6 real processes and installations, which tend to bear out the contention that the costs do not differ greatly between the various processes.[2] In addition, Battelle estimates the capital costs as a function of plant size for two processes. These data are presented in Tables 13a and 13b.

The estimate of costs developed by the Environmental Protection Agency and repeated in various places is given in Table 14.

One of the major costs of operating an FGD system is the cost of sludge disposal. Commonwealth Edison has stated that disposal costs could exceed $17/dry ton of sludge. In fact, Commonwealth Edison stated that its actual costs were $17.10 for a dry ton of sludge, but they are expected to decrease as operating efficiency with the sludge removal system improves. IU Conversion Systems estimate that for a 1000-Mw plant system, a system currently offered by IU to handle ash and sludge wastes from fuel containing 10% ash and 3% sulfur would cost $1.50 to $2.50/ton of converted product. On the other hand, the Chemfix Division of Environmental Sciences Incorporated has treated more than 40 million gallons of various industrial sludges over the past 2-1/2 years. Current cost quotes run from between $7 to $10/ton; cost of removal to a land fill site is not included. Sludge disposal costs at the Phillips Station of Duquesne Light Company are estimated at $14 to $15 per dry ton.[6]

TABLE 13a. Investment Costs ($/kw)[2]

Process	125-Mw Plant	750-Mw Plant
A	46.9	27.3
B	41.5	24.2
C	48.8	
D	46.1	
La Cygne		43 (820 Mw)
Key West	20 (37 Mw)	

Note: Processes A, B, C, D are real processes but Battelle does not feel free to release the names. Key West and La Cygne costs are public and both are Limestone Scrubbers. La Cygne is an expensive stainless steel construction with rubber-lined equipment. Key West uses low cost construction for use with a low sulfur, ash-free fuel oil.

Despite variations, a ballpark figure is $50/kw, including costs of solid and liquid waste disposal <=> an increase in electricity costs of 1-2 mills/kw-hr.

TABLE 13b. Capital and Operating Costs as Functions of Plant Size[2]

Process	200-Mw	400-Mw	600-Mw	800-Mw	1000-Mw
$SO_3 \rightarrow HSO_4$ scrubbing electrolytic regeneration[a]					
Capital Cost $/kw	90	67	58	55	54
Operating Cost $/yr/kw	24	20	18	17	17
Difference in Operating Cost		4	2	1	0
Limestone Scrubbing					
Capital Cost $/kw	68	47	41	40	41
Operating Cost $/yr/kw	20	17.5	15.5	15	14.5
Difference in Operating Cost		2.5	2	.5	.5

[a]According to Battelle, most of the other processes fall between these two.

TABLE 14. Cost Comparison - SO_2 Control Processes for Coal-Fired Power Plants[13]

Type	Capital Cost $/kw	Annualized Cost mills/kw-hr	SO_2 Removal Eff. %
Basic power plant	200	8.9[a]	-
Low S fuel	-	2.0-4.0	-
Lime/limestone	35-52	1.5-2.4	80-90
MgO	36-66	1.4-2.8	90
CAT-OX	43-67	1.5-2.6	85-90
Wellman-Lord	40-68	1.2-2.8	90
Double alkali	26-47	1.2-2.2	90

[a]Cost to consumer is about 20 mills/kw-hr.

Sometimes costs are estimated in terms of the total effects on the consumer. It is estimated that a 40% increase in electrical revenues will be required to pay for the installation and operation of an FGD system at Louisville Gas and Electric Company Paddy's Run plant.[6] It has been estimated that the total increased cost resulting from the efforts to control sulfur dioxide will be on the order of 15% to 20% (Sec. 17).[6] The Tennessee Valley Authority (Sec 38),[6] indicates that FGD implementation costs for the entire power system are analogous to a 30% increase in revenue requirements. The Sierra Club (Sec 53),[6] on the other hand, estimates that the increased costs required for the control of sulfur dioxide are on the order of 15% to 17%. The Environmental Protection Agency, as usual, has the lower cost estimates.[7] On the basis of their estimate of the annual costs for stack gas cleaning in the range of 2 mills/kw-hr and contrasting this with the cost of electricity, a production cost of 9 mills/kw-hr and a price to consumers of 20 mills/kw-hr, they estimate that the average increase in electricity cost to consumers will be about 3 to 6% assuming 100,000 to 200,000 Mw of installed FGD capacity by 1983, respectively. They do admit that for those utility systems that are predominantly coal users, price increases could be as high as 15%. The EPA position is effectively summarized by the following quotation taken from Ref. 7: "Since FGD costs are comparable to the low sulfur fuel cost increment and are a reasonable fraction of electrical generating costs, FGD costs, although significant, are not considered prohibitive."

Capital costs are very much the same for the various processes that have been suggested. Further, they represent approximately 1/6 to 1/3 of the costs of the balance of the electric generating plant. However, there may be substantial economies of scale. The reader is advised to refer to Tables 6, 7, 10, 13a, 13b, and 14. These cost estimates differ significantly from the capital cost of \$76/kw for the TVA Widows Creek Plant listed in Table 2c and \$108/kw reported for the Commonwealth Edison plant. The question of economies of scale is complicated by the tendency of the utilities to install scrubbers on a modular basis. Then a 500-Mw plant is supplied with scrubbing facilities identical in size and operation to those installed in a 100-Mw plant. Finally, many of the cost figures reported in the literature may be too high for typical installation because they are based upon the size of the developmental units that are in the 100- to 200-Mw range. However, notice that the Widows Creek plant is in the 500-Mw range.

DESCRIPTION OF FGD SYSTEMS

Space limitations do not permit the detailed development of technical descriptions of each of the FGD systems. However, some brief description is necessary as a prelude to our next topic, the availability, reliability, and feasibility of FGD systems. The following descriptions are based upon Appendix A of Princiotta's report.[7]

Lime and Limestone FGD - Throw-away

Three variations of this process are (1) use of limestone ($CaCO_3$) added to the scrubber circuit, (2) use of hydrated lime ($CA(OH)_2$) added to the scrubber circuit, and (3) use of limestone injected in the boiler effecting calcination to lime with subsequent lime slurry scrubbing. The lime or limestone slurry is placed in contact with the flue gas containing SO_2 in various ways. The basic chemical reactions are: (1) $CaCO_3 + SO_2 + 1/2\ H_2O \rightarrow CaSO_3 \cdot 1/2\ H_2O + CO_2$ and $CA(OH)_2 + SO_2 \rightarrow CaSO_3 \cdot 1/2\ H_2O + 1/2\ H_2O$. The calcium sulfite sludge that is formed by the reaction is troublesome and must be de-watered. According to EPA the advantages and disadvantages of lime/limestone systems can be summarized as follows: (1) relatively low capital and operating costs, (2) potentially high SO_2 removal, (3) ability to simultaneously remove both SO_2 and particulates, (4) most fully characterized of flue gas desulfurization systems, (5) requirement to dispose of large quantities of waste sludge in an environmentally acceptable manner, and (6) if not carefully designed and operated, a tendency toward chemical scaling, plugging and erosion problems. The process will be described in more detail later when the operating experience of Will County scrubber is presented. The dry limestone injection system has been discarded and discontinued where it was installed because of poor removal efficiencies and severe plugging difficulties.

Double Alkali FGD Process - Throw-away

This is the only other throw-away process to normally receive serious consideration. The many double alkali process variations involve the scrubbing of flue gases with a clear liquor containing dissolved sodium or ammonium salts, followed by treatment of the spent liquor with lime or limestone in a reaction producing a throw-away sludge for disposal with regenerated alkali liquor for scrubbing. For a sodium-based system, the typical reactions are:

$$Na_2SO_3 + H_2O + SO_2 \rightarrow 2NaHSO_3 \text{, and}$$

$$2NaHSO_3 + Ca(OH)_2 \rightarrow NaSO_3 + 3/2H_2O + CaSO_3 \cdot 1/2H_2O \quad .$$

The advantages and disadvantages of double alkali systems are: (1) relatively low capital and operating costs, (2) very high removal efficiencies, (3) use of clear-solution scrubbing, which minimizes solids buildup and erosion problems, offering potential for high reliability, (4) ability to simultaneously remove SO_2 and particulates, (5) requirements to dispose of large quantities of waste sludge in an environmentally acceptable manner, and (6) design complexities necessary to deal with the following problems: a) necessity to prevent excessive purge of sodium sulfate produced as a result of oxidation since sodium sulfate is difficult to regenerate and b) necessity to avoid scrubbing with clear liquid saturated with calcium sulfate, which could lead to scaling.

Magnesium Oxide FGD - Saleable Product

The Chemico-basic MgO process utilizes an aqueous slurry of magnesium oxide, magnesium sulfite and magnesium sulfate to scrub sulfur dioxide from flue gas. The major reaction involves the formation of additional magnesium sulfite through combination of SO_2 and MgO. Magnesium sulfite removed from the scrubber is dried and subsequently calcined to drive off SO_2 and regenerate active MgO for return to the scrubber loop. The regeneration can be done either at the power plant or at some remote location, since the magnesium sulfite and magnesium oxide are stable solids capable of being shipped. The SO_2 generated in the calcining operating can be converted to high grade sulfuric acid or to elemental sulfur. The advantages and disadvantages are: (1) sulfur can recovered as high grade acid or elemental sulfur, depending upon the equipment provided for regeneration; (2) regeneration can be accomplished at a location quite distant from the power plant (e.g., at an existing H_2SO_4 plant), thus permitting the use of a central regeneration facility servicing several flue gas cleaning locations; (3) by maintaining adequate inventories of MgO, extended outages of the regeneration facility can be tolerated without interruption of the pollution control facility;

(4) process reliability has benefitted from the modifications and investigations at Boston Edison and will continue to improve; and (5) the major disadvantage of the process is the lack of reliable long-term operating experience and lack of coal-fired experience.

Wellman-Lord FGD - Saleable Product

This process utilizes a sodium sulfite-sodium bisulfite solution to absorb SO_2. The spent absorbent, which is rich in bisulfite, is processed in a steam-heated evaporator, regenerating active sodium sulfite and producing a stream of SO_2 for further processing. The chemical reactions can be summarized as: Absorption - $SO_2 + Na_2SO_3 + H_2O \rightarrow 2NaHSO_3$ and regeneration, $2NaHSO_3$ heat $\rightarrow Na_2SO_3 + SO_2 + H_2O$. Inactive sodium sulfate is formed by three mechanisms; SO_3 absorption, disproportionation, and sulfite oxidation. Sodium sulfate must be purged from the system in order to maintain adequate levels of active sulfite in the absorber/evaporator.

The advantages and disadvantages are: (1) simplicity and reliability of the various unit operations involved; (2) when mated with the proper process, ability to produce elemental sulfur, or high grade sulfuric acid; (3) capable of achieving very high sulfur removal; (4) provided with surge capacity before and after the absorber to handle flue gas surges and to enhance system reliability; (5) many applications (not on coal-fired power generation) and considerable operating experience provide a high confidence for success in future applications; (6) need to sell or dispose of a quantity of purge solids (Na_2SO_4); (7) high energy demand results in derating of power station (3 to 6% figure given by EPA seems too low); and (8) there are no coal-fired applications in operation.

Catalytic Oxidation FGD - Saleable Product

The Monsanto CAT-OX process utilizes catalytic oxidation to convert most of the SO_2 present to SO_3 for subsequent removal by an acid absorbing tower followed by a fiber packed mist eliminator to remove H_2SO_4 mist. For retrofit applications, the flue gases from the boiler are passed through a high efficiency (99.6%) precipitator and then heated to 850°F as preparation for the CAT-OX step. The strength of the acid produced is about 80%, which is suitable to fertilizer production.

The advantages and disadvantages are: (1) generates a product that in certain limited locations can be disposed of by sale; (2) operating costs are relatively low; (3) achieves 85% or better SO_2 removal over a wide range of SO_2 input concentrations; (4) CAT-OX must be used near an appropriate acid user and dilute acid can be difficult to market in large quantities in some locations; (5) capital costs are high; and (6) reliability and maintenance costs are not currently established due to lack of operating experience.

Note that this process requires gas at relatively high temperatures, which suggests treatment of the gas before it has completed its power circuit and is about to enter the stack. This would require cutting into the gas train. Consequently, this CAT-OX process is seldom considered as a retrofit possibility.

AVAILABILITY AND RELIABILITY OF FGD SYSTEMS

The questions of availability and reliability cannot be treated separately. The current availability of any FGD system is being hotly debated. The argument turns on the meaning to be associated with the term "available." Users demand that FGD systems be as reliable in their operation as other equipment in the electric power industry. Vendors and other advocates of the early adoption of FGD systems use a less severe definition of availability.

There are two questions to be answered: (1) Given the present state of the technological development of FGD systems, how fast can the equipment be supplied by vendors? (2) What is the current state of technology with respect to the commercial usability of FGD systems? The first question, which is a bit easier, is the first to be discussed below.

The rate of installation of FGD systems depends upon the demand for such systems by power generating companies and the availability of the supply of such systems provided by vendors. According to the EPA,[26] the cumulative need for flue gas desulfurization will be about 66,000 Mw by the end of 1975, 73,000 Mw by the end of 1977 and 90,000 Mw by the end of 1980. These projections depend on the simultaneous projections of the availability of low sulfur coal and are to be interpreted as the most probable figures. The need for FGD systems is based on the necessity to meet the air quality standards. Of course, the demand for FGD is not simply the total demand for coal-fired power minus the power that can be generated by the quantity of low sulfur coal available. As shown in the cost section, the indirect costs of a massive switch to low sulfur coal may lead utilities to adopt FGD systems even if low sulfur coal were available to them.

The supply of equipment is complicated by interpretations of "availability" as discussed above. For present purposes, availability is taken to mean that the vendors are able to supply equipment of the given state of technology to the customer. Equipment vendors are generally optimistic concerning the status and future of FGD. Seven vendors[26] stated that they are now prepared to offer full-scale commercial systems. These vendors are confident in the technology to the extent that they are willing to install one kind or another of FGD systems.

A key factor determining the rate at which systems could be installed is the length of time an installation takes. A vendor may state that four systems could be installed at a time; but, if each system takes four years to install, then he is able, on the average, to install one a year. The experiences to date indicate that, of the six actual installations reported,[26] the time from the decision to put in FGD to the compliance with standards was between 27 and 36 months. EPA consultants estimate that it should take 27 months, while utilities and utility consultants estimate 36-48 months. Vendors estimate 30-36 months. Often, a modular development program is followed whereby one scrubber is installed and operating data are gathered before other modules are installed. In these cases, the time may be 41-60 months. It seems reasonable to consider 2-1/2 to 3 years as the normal installation time in those cases where the modular experimental procedure is not followed.

The problem is a complex one, and several surveys of vendors have been made. SOCTAP evaluated 15 sulfur oxide control system vendors and projected that three or four could expand rapidly and that another three or four could expand at a slower rate. The remaining 7-9 vendors were considered to have unproven abilities, and the panel felt that they would not play an important role until the late 1970s. SOCTAP also predicted that some new vendors would enter the market. The Industrial Gas Cleaning Institute conducted a survey of 24 vendors, including some who are not members of the Industrial

Gas Cleaning Institute. They asked for each company's assessment of its unconstrained capacity to provide commercial sulfur oxide control systems. Unlike the SOCTAP survey, the Industrial Gas Cleaning Institute survey did not consider the possibility of material and labor shortages.

The major present problem of vendors is that only a small market for their wares exists. The EPA has developed estimates of the cumulative vendor capacity and need for the installation of FGD systems over time; see following table:

Cumulative FGD Vendor Capacity Estimates (Mw)	1976	1977	1978	1979	1980
SOCTAP	10,000	25,000	50,000	78,000	115,000
IGCI[a]	23,000	50,000	80,000	120,000	bgr[b]
Hearing Panel		25,000	60,000	100,000	bgr[b]
EPA Need Estimate	65,000	73,000	75,000	78,000	85,000

[a]Industrial Gas Cleaning Institute.
[b]Beyond graph range of source (Ref. 26).

It is very important to notice that, although present installation of FGD systems seems to be limited by the demand by users for the systems, the vendor capacity is expected to grow at a very rapid rate; so that in the relatively short time up to 1977 or 1979 vendor capacity will equal or exceed the needed capacity. Notice that these figures are cumulative; so that, when we say that by 1980 the capacity is 115,000 Mw, we mean that from this time forward until 1980 the vendors could install a total of 115,000 Mw of FGD capacity. Similarly, when we say that by 1980 the need is 85,000 Mw, it means that by 1980 there will be 85,000 Mw of coal-burning, power-generating capacity that is expected to need FGD in order to meet the primary standards of the Clean Air Act. In other words, need is defined to be what is necessary to meet primary standards, taking account of capacity expansions. Need estimates are based on assumptions concerning the availability of low sulfur coal.

These data indicate that there is some force that is driving the vendors to increase their capacity to install FGD systems at a rapid rate. Actual installations of FGD systems are, of course, far less than the EPA estimates of need at the present time and probably, given the long lead reasons, assuming the trend in vendor capacity continues or goes on as projected, for utilities to postpone installation. They might feel that when capacity to install systems reaches and exceeds the total need, the price of the systems may fall.

Because orders must be placed soon (perhaps it is already too late) for scrubbers to be installed in 1976-77, vendor capacity through that period is largely limited by existing experience and capability of vendors. Consequently, the panel has estimated that capacity during this period would be more likely to follow the more conservative SOCTAP estimates. Capacity in the later 1970s, however, will be dependent upon the extent to which additional vendors gain experience and the extent to which all vendors increase their capacities. This increase will depend largely upon the market the vendors envision. The major determinant of this market apparently will be the vigor with which the states and the federal EPA push sulfur oxide compliance requirements. Since the EPA expects to push these requirements vigorously, their estimates for the later 1970s come closer to the Industrial Gas Cleaning Institute's more optimistic estimate of capacities. Consequently, we could expect that capacity would equal need sometime during 1977. The needs for scrubbers on all oil-fired power plants and large industrial boilers are not included. Also, these figures for FGD needs do not include existing state implementation plans, which may require controls beyond those needed for the attainment of primary standards. Delays in meeting air quality requirements have recently been proposed by the Ford Administration. If adopted, the process just described will be delayed.

Table 15 lists the installations of FGD systems planned or operating as of 1973.[7] Caution must be exercised in interpreting the word "operational" as used in the table. For example, the Will County plant is listed as operational and, as the description by Commonwealth Edison of that installation will show, it is anything but operational on a routine basis. Table 16 presents a list of processes offered by each of the major vendors with a brief description of each and a note on its availability.

TABLE 15. Planned and Operating Flue Gas Desulfurization Units on U.S. Power Plants as of September 1973 [7]

(Limestone Scrubbing: 10)

Utility Company Power Station	New or Retrofit	Size of FGD Unit (Mw)	Process Vendor	Fuel and Sulfur Content	Status (Startup Date)
Commonwealth Edison Will County No. 1	R	156	B&W	Coal, 3.5%	Operational (Feb. 1972)
Kansas City Power & Light, Hawthorn No. 4	R	100	CE	Coal, 3.5%	Operational (Aug. 1972)
Kansas City Power & Light, La Cygne Sta.	N	820	B&W	Coal, 5%	Operational (June 1973)
Arizona Public Service Cholla Station	R	115	Research Cottrell	Coal, 0.4-1.0%	Under const (Oct. 1973)
Detroit Edison St. Clair No. 6	R	180	Peabody Engineering	Coal, 3.7%	Under const (Dec. 1973)
Southern California Edison (operating agent) Mohave Sta.	R	160	UOP	Coal 0.5-0.8%	Under const (March 1974)
TVA Widows Creek No. 8	R	550	TVA	Coal, 3.7%	Under const (May 1975)
Northern States Power Sherburn County No. 1	N	680	CE	Coal, 1%	Under const (May 1976)
Public Service of Indiana, Gibson Sta.	N	650	CE	Coal, 1.5%	Planned (1976)
Northern States Power Sherburn County No. 2	N	680	CE	Coal, 1%	Planned (May 1977)

TABLE 15 (Contd.) (Lime Scrubbing: 10)

Utility Company Power Station	New or Retrofit	Size of FGD Unit (Mw)	Process Vendor	Fuel and Sulfur Content	Status (Startup Date)
Union Electric Co. Meramec No. 2	R	156	CE	Coal, 3%	Abandoned (Sept. 1968)
Kansas Power & Light Lawrence No. 4	R	125	CE	Coal, 3.5%	Operational (Dec. 1968)
Kansas Power & Light Lawrence No. 5	N	430	CE	Coal, 3.5%	Operational (Nov. 1971)
Kansas City Power & Light, Hawthorn No. 3	R	100	CE	Coal, 3.5%	Operational (Nov. 1972)
Louisville Gas & Electric Paddy's Run No. 6	R	70	CE	Coal, 3%	Operational (April 1973)
Duquesne Light Co. Phillips Station	R	100	Chemico	Coal, 2%	Under const (Nov. 1973)
Southern California Edison (operating agent) Mohave Sta.	R	160	SCE/Stearns-Roger	Coal 0.5-0.8%	Under const (Dec. 1973)
Ohio Edison/Mansfield Sta. (2 units)	N	1650	Chemico	Coal, 4.3%	Under const (Early 1975)
Montana Power Colstrip No. 1 & 2	N	720	CEA	Coal, 0.8%	Under const (May 1975)
Columbus & Southern Conesville No. 5 & 6	N	750	Not selected		Planned (1976)

TABLE 15 (Contd.) (L/LS Not Selected: 9)

Utility Company Power Station	New or Retrofit	Size of FGD Unit (Mw)	Process Vendor	Fuel and Sulfur Content	Status (Startup Date)
Salt River Project Navajo No. 1	N	750	Not selected	Coal, 0.5-0.8%	Const start 11/74 (3/76)
Salt River Project Navajo No. 2	N	750	"	Coal, 0.5-0.8%	Const start 10/75 (10/76)
Arizona Public Ser. Four Corners No. 1	R	175	"	Coal, 0.75%	Const start 10/75 (10/76)
Arizona Public Ser. Four Corners No. 2	R	175	"	Coal, 0.75%	Const start 11/75 (12/76)
Southern California Edison (operating agent) Mohave No. 1 & 2	R	1180	"	Coal, 0.5-0.8%	Planned (12/76)
Arizona Public Ser. Four Corners No. 3	R	229	"	Coal, 0.75%	Const start 6/76 (3/77)
Salt River Project Navajo No. 3	N	750	"	Coal, 0.5-0.8%	Const start 3/76 (3/77)
Arizona Public Ser. Four Corners No. 4	R	800	"	Coal, 0.75%	Const start 9/75 (4/77)
Arizona Public Ser. Four Corners No. 5	R	800	"	Coal, 0.75%	Const start 11/76 (6/77)

TABLE 15 (Contd.) (MgO Scrubbing: 3)

Utility Company Power Station	New or Retrofit	Size of FGD Unit (Mw)	Process Vendor	Fuel and Sulfur Content	Status (Startup Date)
Boston Edison Mystic No. 6	R	150	Chemico	Oil, 2.5%	Operational (April 1972
Potomac Electric & Power Dickerson No. 3	R	100	Chemico	Coal, 2%	Operational (Sept. 1973)
Philadelphia Electric Eddystone No. 1	R	120	United Engineers	Coal, 2.5%	Under const (Dec. 1973)
		Other SO_2 Control Systems: 5			
Catalytic Oxidation (CAT-OX)					
Illinois Power Co. Wood River No. 4	R	110	Monsanto	Coal, 3.2%	Operational (Oct. 1972)
Wellman-Lord					
Northern Indiana Public Service D. H. Mitchell No. 11	R	115	Davy Power-gas/Allied Chemical	Coal, 3.5%	Under const (Early 1975)
Aqueous Sodium Base Scrubbing, Non-Regenerable					
Nevada Power Reid Gardner No. 1 & 2	R	250	CEA	Coal, 0.5-1.0%	Under const (Dec. 1973)
Nevada Power Reid Gardner No. 3	R	125	CEA	Coal, 0.5-1.0%	Under const (1975)
Dry Adsorption					
Indiana & Michigan Electric, Tanner's Creek Station	R	150	B&W/Esso	Coal	Under const (1974)

TABLE 15 (Contd.) (Process Not Selected: 5)

Utility Company Power Station	New or Retrofit	Size of FGD Unit (Mw)	Process Vendor	Fuel and Sulfur Content	Status (Startup Date)
Public Service of New Mexico San Juan No. 2	R	100	Not selected	Coal, 0.8%	Planned (Nov. 1974)
Potomac Electric & Power Chalk Point No. 3	N	630	" "	Oil	Planned (1975)
Potomac Electric & Power Chalk Point No. 4	N	630	" "	Oil	Planned (1976)
Potomac Electric & Power Dickerson No. 4	N	800	" "	Coal, 2%	Planned (1976)
Potomac Electric & Power Dickerson No. 5	N	800	" "	Coal, 2%	Planned (1977)

TABLE 16. Listing of Processes (For Demonstration or Being Studied on Full-Scale Equipment)[26]

Fabricators	Process
Babcock and Wilcox	(A) MgO slurry scrubbing/thermal regeneration (A) Limestone slurry scrubbing/non-regenerable.
Chemical Constr Co	(A) MgO slurry scrubbing/thermal regeneration (A) Limestone slurry scrubbing/non-regenerable (A) Lime slurry scrubbing/non-regenerable
Combustion Eng	(A) Boiler injected lime slurry scrubbing/non-regenerable (A) Lime slurry scrubbing/non-regenerable (A) Limestone slurry scrubbing/non-regenerable
Combustion Equipment Arthur D. Little	(A) Sodium sol. scrubbing/non-regenerable (A) Sodium sol. scrubbing/line regeneration
Commonwealth Assoc	(A) Char sorption/thermal regeneration
EPA-TVA	(B) Boiler injected limestone, dry sorption/non-regenerable (B) Limestone slurry scrubbing/non-regenerable
Esso Research and Eng Babcock and Wilcox	(A) Solid sorption/reducing gas regeneration
Foster-Wheeler	(A) Char sorption/thermal regeneration (A) Char sorption/H_2O regeneration (A) Boiler injected lime, dry sorption/non-regenerable
Monsanto	(A) Direct catalysis to H_2SO_4
Peabody Eng	(A) Limestone slurry scrubbing/non-regenerable
UOP	(A) Limestone slurry scrubbing/non-regenerable
Research - Cottrell	(A) Lime slurry scrubbing/non-regenerable (A) Limestone slurry scrubbing/non-regenerable
Stone and Webster/Ionics	(A) Na solution scrubbing/electrolytic regeneration
Wellman Power Gas	(A) Na solution scrubbing/thermal regeneration
Zurn Industries	(A) Limestone slurry scrubbing

TABLE 16 (Contd.)

Notes:

(A) → processes currently offered for commercial use. Based on willingness of developer to install his process on full-scale operating plant.

(B) → processes being studied on large-scale processes.

Variety of Processes:[26]

1. Non-regenerable limestone or lime slurry processes offered by 7. All involve scrubbing with water slurry and all produce a waste calcium sulfite/sulfate sludge. Attractive for relative simplicity, availability of reactants and lack of dependence on markets for by-products.

   Drawbacks: scale accumulation, large quantity of waste. (corrosion)

2. Na sol. scrubbing offered by 3. In Comb. Equip. Assoc. reactant is regenerated with lime to produce calcium sulfate sludge. No scaling problems. Equip. compact relative to limestone. Requires sludge disposal. Wellman Power Gas process produces concentrated SO_2. Has been operated successfully. Na scrubbing with electrolytic regeneration of reactant is also offered.

   Advantage → produces high purity by-products and virtually no wastes but requires lots of power.

3. MgO slurry offered by 2. Both use thermal regeneration to produce SO_2. Processes regenerate and recycle MgO and rely on sales of S or H_2SO_4 to offset the higher costs of regenerable processes. Paper industry has used.

4. Char process-Adsorption of SO_2 on activated char offered by 2. Thermal regeneration produces a high concentration stream of SO_2. Foster-Wheeler also offers a version that is regenerated with H_2O and produces dilute H_2SO_4. Both developed in Germany.

   Advantage → don't cool the gases as much as wet scrubbers. Equipment large and complex.

5. Direct Conversion of SO_X to H_2SO_4 by passing flue gas through cat. fed. (Monsanto). Simplicity is attractive. Produces effluents low in particulates as well as low in SO_2. Equipment more costly than scrubbers. Applicable only where acid can be marketed.

Turning now to the question of technological feasibility, diverse viewpoints appear in the literature. The strongest advocates of the immediate use of FGD systems have been the Environmental Protection Agency (EPA) and the vendors who sell FGD systems. Their views are included in the Final Report of the Sulfur Oxide Control Technology Assessment Panel (SOCTAP).[6] These views are amplified by the material in Ref. 21. The use of FGD is considered a key part of the SO_2 control strategies. The SOCTAP panel investigation set out to provide "quantification of the availability of stack gas cleaning systems to steam electric utilities in 1975, 1977, and beyond; and to provide identification of actions required to maximize the utilization of these systems."[21] Some of the SOCTAP panel conclusions follow.

The SOCTAP report states that technology does not appear to be a limiting factor in the utilization of stack gas cleaning. The Federal Power Commission, a member of the SOCTAP panel, with DOC, OST/CEQ, and EPA, does not agree with this conclusion. "The SOCTAP task force believes that the required high reliability of FGD systems will be achieved with the early resolution of a number of engineering problems to which specified solutions already have been developed and demonstrated at one or another location." An additional 18 months operating experience (or by 1974 since the report is dated 12/4/72) should effectively remove most engineering barriers to the application of stack gas cleaning to many facilities, according to the SOCTAP report. This optimistic point of view does not appear to have been borne out.

SOCTAP denotes two general categories of FGD systems: (a) throw-away product systems where the sulfur product is disposed of as waste or (b) saleable product systems where the sulfur product is marketed. The state of the art of SO_X desulfurization technology has advanced rapidly over the last year (1972) according to SOCTAP. They considered two throw-away product systems -- Chemico's calcium hydroxide scrubbing system in Japan (Mitsui) and Babcock and Wilcox's limestone scrubbing system on a Commonwealth Edison boiler in Chicago (Will County) -- and two saleable product systems -- Chemico's regenerative magnesium oxide process on a Boston Edison plant (oil-fired Mystic), and a Wellman-Lord alkali scrubbing with thermal regeneration sodium sulfite process on a boiler in Japan -- particularly significant.

According to SOCTAP, the calcium hydroxide scrubbing system installed at the Mitsui Aluminum plant in Japan has exhibited reliable, essentially trouble-free operation, with sulfur removal efficiencies of 80 to 90%, since startup in March 1972. This plant will come up repeatedly in future discussions since EPA uses it as evidence that U.S. utilities have no technologically-based excuses for not meeting the emission limitations. The Wellman-Lord scrubbing unit at the Japan Mitsubishi Synthetic Rubber plant has accumulated over 9000 hours of reliable operation since June 1971 with a removal efficiency of 90%.

Short-term testing of the B&W wet limestone scrubber at Commonwealth Edison's Will County plant and Chemico's wet magnesium oxide scrubber at Boston Edison's Mystic plant have exhibited removal efficiencies of 75-80% and 90%, respectively. It did not appear to the SOCTAP panel that there were insurmountable chemistry-related problems at these higher removal efficiencies for those two plants. These systems started up in early 1972, but demister problems at the Will County plant and mechanical problems experienced at both plants have precluded the accumulation of data (October 1972) of long-term test data. The record of the Will County plant is presented in detail later in this section. According to SOCTAP the only U.S. plants that have achieved sufficient operating experience to report long-term average removal rates are the Combustion Engineering limestone injection wet scrubbing systems. The removal efficiencies of these plants used with high sulfur coal are too low to meet the emission standards. These systems are very prone to chemical scaling and are generally considered obsolete today. Some existing installations have been discontinued.

The degree to which any or all of the systems are usable on commercial, coal-fired electric power generating plants is the subject of continuing debate. The SOCTAP panel, led by the EPA, feels that at least the lime/limestone system is ready for commercial application. They are supported by various vendors who feel that several of their systems are commercially feasible. By and large the power companies dissent. The following paragraphs are statements by persons representing various concerned entities and generally are addressed to this question. The comments are repeated to give the reader the flavor of the arguments and the "evidence" that is presented. The general flavor is what is sought. Any bias that comes through in the selection is unintentional.

The Lousiville Gas and Electric Paddy's Run plant, a full scale FGD demonstration, operated intermittently from 4/73 to 10/73 at 85% removal efficiency. The closed-loop operation was used with 30% to 100% of the plant load with no difficulty. A bypass lets the boiler operate even when the scrubbers don't (1.5% to 4.2% S in coal).[6]

A regenerative MgO system operated intermittently since April 1972 (Boston Edison) with high SO_2 removal without plugging and with H_2SO_4 sold locally. Reliability of this oil fired unit is satisfactory.[6]

Kansas City Power and Light installed a limestone wet scrubber on their 825-Mw La Cygne Station (new), which went into commercial service in June 1973 using a B&W unit and local high sulfur coal. They feel that it will take 2 to 3 years to debug.[6]

The first commercially-sized demonstration installation of the Monsanto CAT-OX has been installed on the Illinois Power Wood River Unit No. 4 (103 Mw) with funding by Illinois Power and EPA.[6]

Philadelphia Electric Company is now installing a 120-Mw regenerative FGD system at their Eddystone Station.[6]

Davy Power Gas (a vendor) states that the Wellman-Lord process has, since 1970, been in viable operation on a full-scale sulfuric acid plant with sulfur dioxide concentrations 3 times that of power plants. In all applications these systems have started up smoothly and run virtually continuously. They claim the process is technologically proven for coal-fired U.S. plants and that the mechanical reliability of the equipment is well established. Davy could design and engineer 4 or 5 FGD systems annually.[6]

Potomac Electric Power Company feels that the cost of throw-away systems is too high. They plan a 100 Mw-MgO installation. Unit started 9/13/73. Longest in-service run to date was 60 hours.[6]

EPA contends that FGD technology represents a viable means of achieving power plant SO_2 control while allowing use of plentiful high sulfur fuels. The required reliability of FGD systems has been achieved on selected units.[7] To date the most successful operation of a throw-away system has been the Chemico lime scrubber process in Japan. EPA puts a great deal of emphasis on this Japanese installation. Approximately 85% of the boiler capacity built in the last 10 years can be retrofitted according to EPA.[7]

The Will County unit of Commonwealth Edison is a 163-Mw unit built in 1955 and using 4% S coal. Two identical scrubbers were designed each to take 1/2 of the flue gas. The gas passes through a precipitator to a Venturi scrubber, to a pressure spray of water, to an absorber packed with plastic spheres and coated with a limestone slurry. The gas goes on to a demister, to a reheater, and to the stack. The used limestone slurry goes to a waste pond. Problems encountered: demister plugging, gas flow weakened the reheat structure, scaling after a relatively long run, limestone blinding characterized by drastic reduction in removal efficiency, and a drop in pH regardless of the rate of fresh limestone addition, and severe acid attack on the reheat tubes. The longest run was 23 days and the availability was 27%.[16] There is a significant sludge disposal problem. The stabilized sludge is not acceptable as landfill under present solid waste disposal regulations. One ton of sludge is produced for every three tons of coal burned.

It will be 1975 before a demonstration of high sulfur dioxide removal and 90% reliability for 1 year of operation is achieved. Then it would take several more years to equip existing units.[24]

Chemico's Mitsui scrubber is a lime-limestone scrubber similar to Will County's. It doesn't plug or scale. Chemico claims this is due to very careful pH control.[21]

Add-on processes operate on the flue gas after it has passed through all parts of the power generating process as it is about to enter the stack. Processes that require higher temperatures must be located toward the front of the plant and incur the cost of cutting into the gas train. All SO_2 processes in the U.S., in an advanced state of development, involve use of wet scrubbers except the CAT-OX process, which is a high temperature process.[20]

An experimental lime/limestone wet scrubber has been installed by TVA at Shawnee. It uses three parallel scrubbers of different design. Each scrubber is designed to handle the equivalent of the gas flow from a 10-Mw, coal-fired unit. Problems encountered include: scale buildup in scrubbers and in mist eliminators; corrosion of mist eliminators; erosion of spray nozzles; erosion of scrubber packing; erosion of scrubber grids; binding of fan inlet dampers due to solids deposition and difficulties in measuring slurry density and pH level.[21]

Union Electric-Meramac Station was the first large-scale installation of a stack gas cleaning system. It used Combustion Engineering's limestone injection wet scrubbing system on a 150-Mw, coal-fired boiler. It was abandoned December 1971 after 3 years of intermittent, unsuccessful operation. Plugging in the boiler and deposits in the scrubbers caused excessive downtime. This installation is cited by EPA in the Federal Register as evidence of a demonstrated technology.[19] A similar limestone injection scheme was used on Kansas City Power and Light Hawthorn Stations. They experienced similar problems. Their La Cygne Station has a gas cleaning unit built into the new 800-Mw unit. It uses pulverized limestone fed into the scrubber circuit. Performance has been extremely poor.[19]

The Mitsui plant differs from U.S. practice. In the U.S. the stock inlet SO_2 concentration is 2500-3000 ppm, while in Japan at the Mitsui plant its 1600-1800 ppm. An electric utility operates under varying loads, while the Mitsui unit operates under steady loads. United States plants operate with high inlet ash concentrations, while Mitsui operates with very efficient precipitators. Mitsui operates with calcium hydroxide obtained as acetylene plant wastes. This material is suspected of having physical properties different from commercially calcined and hydrated material used in the U.S.

There are indications that the Mitsui plant either operates, or is forced to operate, by discharging a significant portion of liquor containing a high dissolved-solids level to a nearby watercourse. When the load varies, it is difficult to control the pH level to the degree Mitsui feels is necessary to prevent scaling. Only closed-loop operation will be permitted in the U.S. Open-loop operation permits addition of fresh water without dissolved materials to the recycle water and this makes it easier to prevent scaling. Recycling is a particularly serious complication of the calcium based scrubbing systems because of the tendency of calcium salts to supersaturate, which promotes scaling. It is important to note that the Mitsui plant operates without scaling at an inlet pH of 7, while the Paddy's Run plant operates without scaling at a pH of 9.[19]

It would take TVA about 15 years from beginning to completion of a program to install SO_2 scrubbers on all of the TVA fossil-fueled plants, with 63 boilers. These processes produce a large quantity of waste, use large amounts of limestone that must be mined, and the processes require energy for their operation. If limestone scrubbing were used on all TVA plants, they would require 10% of the total crushed limestone of all grades sold or used by producers in the 3 States of Tennessee, Kentucky, and Alabama. Limestone quarrying is similar to stripmining. To make up for the energy used by scrubbers, an additional 900 Mw of capacity would be needed. This does not consider additional forced outages.[6]

Based on 40 years of experience and expenses of $25 million, Commonwealth Edison claims that reliable large-scale technology for control of sulfur dioxide does not exist. Further, no one can predict when this technology will be available. Commonwealth Edison feels that EPA should not view the utilities research and development scrubber installations as evidence of commercial feasibility.[6]

According to the Western Pennsylvania Power Company, the reliability of FGD Systems has not been demonstrated. Reliability can be demonstrated by one year of operation with 90% availability on a coal-fired boiler of over 100-Mw capacity.[6]

A consultant from NUS Company, based on a survey of the literature and limited plant inspection, concluded that reliable FGD systems are not yet available, and that vendors cannot meet the potential demand. The Public Service Company of Indiana agrees with the NUS consultant, as does Edison Electric, which cites a lack of demonstrated reliable FGD systems. The Edison Electric Institute, on the other hand, feels that corrosion and erosion are not major problems and demister plugging can be controlled. They contend that FGD Systems are technically feasible, but not economically viable, control processes.[6]

In spite of their agreement with the sentiments just expressed, the Public Service Company of New Mexico, who feel that no commercially proven techniques for controlling SO_2 emissions exist, are going ahead with a developmental installation.[6]

Duquesne Light Company feels that, due to the unproven nature of FGD systems, it is prudent to equip only the Phillips station with a Chemico unit.[6]

Evidence of limited scrubber reliability comes from the Four Corners Station of Arizona Power, which failed to meet load requirements 6 times in 1972 due to scrubber system failures.

To all of these comments, EPA responds by saying the FGD systems can operate successfully on coal-fired boilers with reliability as demonstrated for the past 18 months on the 156-Mw Mitsui unit. This installation has not experienced scaling, plugging, demister, or reheater problems or any serious erosion/corrosion during this period.[6]

Table 17 indicates the reliability experienced with various scrubber installations.

Battelle[27] used a delphi approach in which independents, vendors, and operators were asked about the reliability of various processes. Battelle gives the following results:

Availability by Percent and by Year

Process	10%	50%	90%
Lime/limestone scrubbing	1973	1975	1976
Double alkali	1975	1976	1978
Magnesium scrubbing	1973	1974	1976
Sodium sulfite/sodium bisulfite scrubbing	1974	1975	1976
Catalytic oxidation	1973	1974	1977

There is little difference among the various individual processes in terms of expected reliabilities. A 90% on-stream or availability factor for a closed-cycle, stack-gas treatment process on a 100-Mw-or-greater, coal-fired utility plant in the United States will not be available until 1976 at the earliest. One-third of the respondents in the Battelle survey felt that none of the major processes would achieve 90% availability until after 1980. Battelle's conclusion, which seems indisputable, is: "It is highly unlikely that most United States utilities can meet 1975 deadlines for compliance with federal and state sulfur dioxide emission regulations without shifting to gas, oil, or Western coal."[6]

The Environmental Protection Agency does not have an official position on which FGD systems are most feasible, at this time. However, a spokesman for the EPA, Mr. Frank Princiotta, feels that the hearings have established that lime/limestone scrubbing and Wellman-Lord scrubbing are both demonstrated and reliable. He goes on to say that, of the 75% of existing

TABLE 17. Descriptions of Demonstration System Reliability

Name		Capacity	Type	Startup	Longest Period of Continuous Op (days)			% Availability		
Lawrence	#4	125	Limestone-wet	11/68	Not meaningful			Not meaningful		
Lawrence	#5	430	Limestone-wet	6/71	50, but not all scrubbers simultaneously			Not meaningful		
Hawthorn	#3	130	Limestone-wet	11/72	One of two - 14			Low		
Hawthorn	#4	130	Limestone-wet	8/72	One of two - 13			Low		
Will County	#1	175	Limestone Add-on wet		1972	1973	Total	1972	1973	Total
Scrubber A				4/72	12	23		32.6	27.1	28.1
Scrubber B				2/72	6			26.0	5.1	13.9
Scrubber A & B			Now both shut down	5/72	6			8.1	0.9	4.7
Mystic Oil-fired	#6	150	MgO Scrubber	4/72	4			15.0		
Wood River	#4	100	CAT-OX	9/72	Operated only a few days before shutdown for reheat modifications					

fossil fuel power plants that could be retrofitted, approximately 50% of these have sufficient onsite sludge storage space. The Kentucky Air Pollution Control board, while it accepts the FGD concept, will not require it until satisfactory reliability has been demonstrated. It feels that it is unrealistic for EPA to require utilities to have operational facilities before 1980.[6] No alternative emission control technology to FGD is expected to make a major impact before 1980.

A continuing complaint that runs through the literature is the following: "In spite of the lack of proven scientific technology, many utilities have chosen to risk capital and facilities in a massive effort to develop such technology. It is ironic that these utilities are now having these very commitments held up as exemplifying the maturity of the technology." In many cases, it does appear to be true that EPA points to experimental and developmental installations of FGD systems as evidence of the technological reliability of the system. However, it should be pointed out that EPA has concentrated on a few installations, and in particular, on the Japanese Mitsui Aluminum Company installation, as evidence of the reliability of FGD systems.[5]

The pace of installation of FGD systems may be limited by the lack of power-generating capacity. During the time when the installation is being made, the associated generating units are not available. In most regions of the country if a massive move to FGD systems took place, the availability of power-generating capacity would be the factor limiting the pace of the installations. Further, system reserve capacity would be reduced by the parasitic power needs of most FGD systems.

The reliability figures presented in Table 17 and the estimates from the Battelle study indicate that any substantial adoption of FGD systems could severely reduce the reliability of a power system. Available reserves of power in most parts of the country are already below minimum desired levels. FGD systems, with their apparently inherent technological problems, could effectively reduce the reserves further. Of course, if bypasses were universally permitted so that the FGD system could be cut out whenever it malfunctioned, this effect on system reliability would be mitigated.

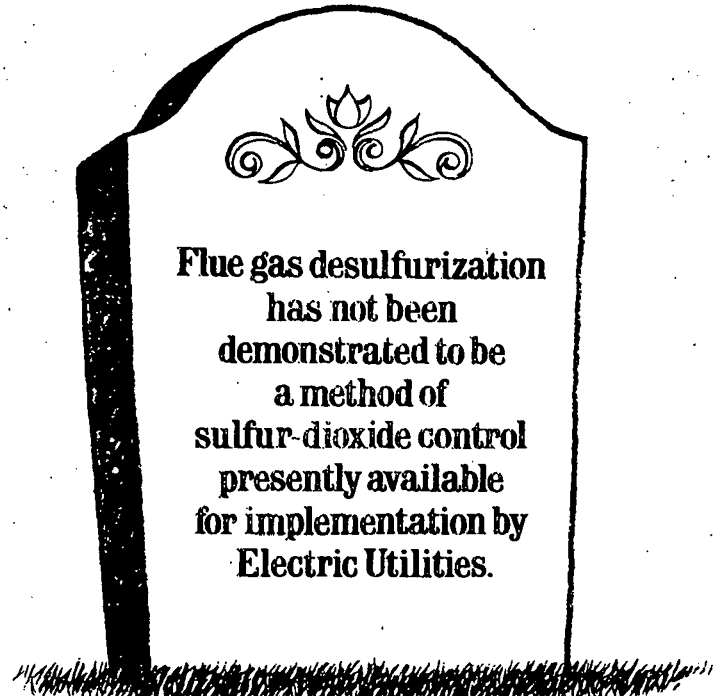
Recent attitudes of some power companies with respect to FGD systems are revealed by Fig. 4.

CASE HISTORY

The following case history is included here to give the reader a better insight into the installation and operation of an FGD system. Admittedly, the case study selected for inclusion emphasizes the problems encountered. It may not represent a typical installation. The example chosen is Commonwealth Edison Will County scrubber.[16,16a,17] In spring of 1970 Commonwealth Edison contracted Bechtel Corporation to investigate available sulfur removal systems. A wet scrubber system using limestone or lime was selected. Specifications were prepared by Bechtel and released for bid. Of the nine solicited bids, seven proposals were received. Babcock and Wilcox were the winners and they began detailed engineering work in September 1970. A formal purchase order was issued November 1970, with a project completion deadline of December 31, 1971. The B&W process is guaranteed to remove 98% of the fly ash and 76% of the sulfur dioxide. The guarantee was based on the use of 4% sulfur coal from Illinois.

The wet scrubber is retrofitted on a 163,000-kw (163-Mw), Babcock and Wilcox radiant cyclone boiler that was put into service in 1955. The wet scrubber system is divided into three parts; the limestone milling system, the wet scrubber and absorber, and the sludge disposal treatment and removal system. The limestone is taken from two, 260-ton-capacity, limestone storage silos and thrown into two full-sized, wet-ball mills. The result of the crushing operation is mixed with water and sent to a slurry tank. Each silo, when full, can supply the wet scrubber system for 24 hours of continuous operation. The required limestone is high in calcium carbonate, above 97%.

The wet scrubber system is made up of two identical systems, each taking half of the boiler flue gas. No explanation for the choice of two is given. Each system consists of two recirculation tanks, slurry recirculation pumps, a Venturi fly ash scrubber, a sulfur dioxide absorber, a flue gas reheater, and an I.D. booster fan.



Requiem for scrubbers

That epitaph is taken from a 417 page report just released by the hearing examiners for the Environmental Protection Agency of Ohio.

And in case you don't recognize it from the language they're talking about "stack gas scrubbers" — as undeveloped, unreliable and unacceptable for electric utility use.

The hearing took 12 long weeks. Grueling testimony, with thorough cross examination, by experts: engineers, lawyers, scientists, businessmen—even manufacturers of scrubbers themselves.

If ever there was a grilling this was it.

Undoubtedly the most comprehensive and up to date presentation on the control of power plant sulfur-dioxide emissions ever held in any forum, anywhere in this country.

The findings of this exhaustive report—which parallel our published position—cannot be seriously challenged by anyone wishing to avoid ridicule.

It covered every major scrubber test the Environmental Protection Agency has ever bragged about.

- Commonwealth Edison
- Illinois Power Co.
- Boston Edison
- Louisville Gas & Electric
- Mitsui Aluminum Plant
- Kansas City Power & Light
- Union Electric of St. Louis

One after the other the record shows they failed to meet the criteria established by the National Academy of Engineering.

They simply failed to demonstrate the degree of reliability necessary for electric utility use.

And yet, to this day, EPA insists these monstrous contraptions are available, work, are reliable . . . and electric utilities should invest many billions of dollars in them.

If that isn't fanning the fires of inflation, wasting precious assets and wrongfully burdening the electric costs of the American people, then we shouldn't be allowed to generate another kilowatt.

Are these examiners alone? They are not! Many respected authorities share their conclusion: The Tennessee Valley Authority. The Federal Energy Administration. The Atomic Energy Commission. The Federal Power Commission and others.

E.P.A.'s stubborn, continued plumping for stack gas scrubbers is an energy-paralyzing activity that is stalling vital legislation and severely inhibiting by uncertainty, investment in the development of new coal mines.

Isn't it about time someone redirected E.P.A.'s energies into more constructive channels?

American Electric Power System

Appalachian Power Co., Indiana & Michigan Electric Co., Kentucky Power Co., Kingsport Power Co., Michigan Power Co., Ohio Power Co., Wheeling Electric Co.

Fig. 4. Attitudes of Power Companies on FGD Systems
(Reprint permission granted by AEP)

Flue gas emerges from the boiler, passes through an existing electrostatic precipitator and on to the Venturi. Here the gas is forced through the Venturi throat and into a pressure spray of water coming from nozzles on each side of the Venturi. The removal of fly ash is effected by the collision of the particles with small water droplets. From the Venturi, the gas turns through the pump and then upward into the absorber. Here sulfur dioxide is removed as the gas, at greatly reduced velocity of about 10 feet per second, is forced through two separate stages of plastic spheres. These spheres, coated with limestone slurry, provide a wetting surface for the chemical reaction by direct contact between the sulfur dioxide in the flue gas and the calcium carbonate in the limestone slurry. The upward flow of flue gas over the downward flow of slurry causes a bouncing action of the spheres that provides the mechanical cleaning action required to prevent the buildup of solids on the spheres. The absorber outlet has a chevron type demister. The demister removes small droplets of slurry entrained in the flue gas in order to reduce particulate carry-over and to reduce the load on the reheater. The unit can be operated in ranges from 30 to 100% of the load range of the boiler.

The waste slurry is pumped to a settling pond or sludge treatment plant. The water runoff is recycled to the wet scrubber and milling system.

The power required to operate the wet scrubber system is an estimated 7000 kw or about 4% of the unit gross capacity of 177,000 kw.

The scrubber system is a full-sized demonstration unit, a prototype, erected under an accelerated overtime schedule and retrofitted on a unit with little available space. Therefore, the cost should not be considered as typical. It is probable that future units will be less costly. The investment costs are as follows:

Factors	Cost
B&W wet scrubber	$ 2,928,000
Equipment erection	5,556,000
Electrical equipment and erection	1,210,000
Foundations	923,000
Limestone handling system	204,000
Professional engineering	965,000
Mill and SO_2 building	193,000
Structural steel	375,000
Misc. equipment	946,000
Total	$13,300,000
Sludge Disposal System	1,700,000
	$15,000,000

Direct costs: $96/kw with sludge treatment
$85/kw w/o sludge treatment

In his November 1973 paper, Mr. Gifford includes indirect costs of $1,600,000 on the scrubber and $300,000 on sludge treatment for a total cost per kw of $108/kw with sludge treatment and $95/kw without it.[17]

Full load operation of the scrubber system requires 15 tons/hr of limestone input and produces 19 tons/hr of waste sludge. The cost to get rid of the sludge is estimated at between $7 and $10/ton, which includes the sludge treating plant operating cost. This cost per ton takes the sludge from the pond or directly from the sludge pipeline to the pond and converts it from toothpaste consistency to a solid, stable, nonreverting material. This was the original plan for the sludge. As we'll see it was not possible to carry it out.

The total annual cost is 42.4¢/MBtu before sludge disposal. On a new plant it is estimated that this could be reduced by 9¢ or 10¢/MBtu. If the plant were located so that sludge could be permanently ponded, this would be a final cost. However, the Will County plant is located where a limited pond (four to six months) is available and sludge treatment is a necessity. The additional annual cost is 10.2¢/MBtu. The total annual cost for the scrubber and sludge treating is 42.4¢/MBtu (roughly 4.24 mills/kw-hr).

Gifford[16,16a,17] provides a detailed description of the operating experience with this scrubber installation. The most serious initial problem, during which time the scrubber ran for relatively short periods of time on a continuous basis (58 hours was the maximum), was the continual plugging of the demister, which required hand washing during almost every outage. Vibration problems caused by the gas flows, particularly over the reheating rods, apparently weakened several structural joints in the system and required a substantial overhaul. The spray nozzles in the demister were relocated at a lower position, which kept any heavy deposits from forming. However, even with this change the hand washing was continued at every outage and some plugging was experienced.

The second scrubber, called the A scrubber in the report, was put in service on May 17, 1972 and ran for 270 hours, the longest period, of continuous operation for either scrubber. For a little over 54 hours, starting on June 3, both scrubbers were in operation. They had to be shut down because of a high differential pressure across the demisters, which resulted from severe plugging of both demisters. The A scrubber did manage to operate continuously with one minor outage of 4 hours, which was not due to the scrubber malfunction, for 21 days from July 24 to August 14. At that time, it was shut down to clean the demister and the Venturi nozzles. During this outage an inspection of the inside showed a moderate amount of scaling on the walls and grid plates. The scale thickness varied up to about 3/16 of an inch. This was the first scaling that had occurred and was found only in the one scrubber. The scale is composed of limestone and calcium sulfate. The longer run on the scrubber, completed from July to August, was made during the burning of high sulfur coal with an inlet sulfur dioxide reading of 1600 to 2800 ppm. Earlier runs had been made with a blend of coal yielding a sulfur dioxide concentration at the inlet of 900 to 1200 ppm. The latter are in the same range as the Mitsui Plant operation. Up to September 11, the A scrubber had operated a total of 1292 hours and the B scrubber a total of 1030 hours. The reliability was figured at 32.6% for the A scrubber, 26% for the B scrubber. According to Gifford, the two remaining major problems are the demister pluggage and the scaling. The scrubber was 90% effective in removing sulfur dioxide under normal conditions when in operation.

2

In November of 1973, Mr. Gifford issued another report on the experience of the Will County unit.[17] The 1973 operating experience with the A scrubber can be summarized by the following description.

It ran for 119 hours but then shut down because of a plugged demister. Then it ran for 15 days with two short outages caused by limestone blinding. At this outage, 60% of the demister capacity was plugged and the middle banks of reheater tubes were plugged. The reheater tubes developed many cracks and leaks and frequent replacement was necessary. There was evidence of severe acid attack on the tubes. Another run lasted from October 17 to November 2, 1973. At the end of that run, the demister was relatively clean and there was no hard scale on the absorber. The A scrubber was run again until November 9 when the demister plugged with hard scale, which required manual cleaning. No scale was found in the absorber nor on the reheater tubes. This run broke the previous operating record set in August 1972 by operating for 23 days. From January 1973 through November 1973 the A scrubber operated 1726 hours for an availability of 27.1%.

The 1973 operating experience with the B scrubber was even less successful. Many of the difficulties that plagued A also plagued B. The B scrubber went out of service on April 13, 1973 and was not put back into operation as B&W concentrated on A. From January 1973 through April 1973, B operated 329 hours for an availability of 5.1%. Simultaneous operation of A & B totaled 63 hours for an availability of 0.9%. Since the initial startup of the system through November 30, 1973, the A scrubber has operated together for 532 hours yielding availability percentages of 28.1%, 13.9%, and 4.7%.

Despite another year of horrendous operating experience, there is a note of hope in Gifford's description. The A scrubber did operate continuously from October 17 to November 9. Some progress seems to have been made in solving the problem of deposits in reheat tubes, although a metal for the tubes that will stand up without corrosion is still being sought. Plugging of the absorber system does not seem to be as frequent a problem as it has been in the past. However, the demister plugging still prevails and the vibration of the whole unit seems to cause numerous structural problems.

This unit was often cited in earlier EPA publications as a unit demonstrating the availability of FGD technology. In spite of Gifford's optimistic outlook, the history of this unit certainly should raise some doubts about its availability. For future reference, the costs associated with the Will County unit are presented below in Table 18. Note the sensitivity of the annual costs to changes in load factor. This merely represents a distribution of the major annual cost item, the carrying costs on the capital expenditure -- a fixed cost with respect to plant output -- over a larger number of output units.

WASTE PROBLEMS

Even the staunchest advocates of FGD systems admit that the disposal of waste sludge is an important, unresolved problem.[28] Many of the suggested processes, including some which employ regeneration of some reactants, produce a waste sludge ($CaSO_3 \cdot 1/2H_2O$) (e.g., double alkali), but waste disposal problems are generally associated with lime/limestone processes.

Even though lime/limestone scrubbing is not fully developed, utilities have preferred it to recovery processes because recovery is not only undeveloped in regard to process performance and reliability, but also from the standpoint of product disposal. There are several unresolved problems in disposing of the lime/limestone scrubber product, but at least there is not the market uncertainty associated with selling sulfur or sulfuric acid. The removal of sulfur dioxide from power plant stack gas greatly increases the amount of solid waste that must be discarded in relation to the normal fly ash. For plants burning typical mid-United States coal, say 3% sulfur and 12% ash, the weight of waste solids is approximately double on a dry basis, as compared with the usual output of fly ash. Of more importance from a disposal point of view, the volume of waste is increased even more than the weight. Fly ash contains little water after disposal. Lime/limestone sludge, however, is formed in a wet scrubbing operation and, therefore, must be dewatered to reduce the volume. Unfortunately, the calcium sulfite that is a major constituent of the sludge crystalizes as thin, small crystals that are very difficult to dewater. Therefore, a unit weight of sludge

TABLE 18. Will County Unit 1 Wet Scrubber
Estimated Annual Operating Cost[17]

(Capacity Factor 35%)

Scrubber System	$Annual Cost	$/ton of coal	¢/MBtu	Mills/ kw-hr
Carrying Charge on $14,900,000	$2,280,000	8.40	43.0	4.56
Property Tax on $14,900,000	298,000	1.10	5.6	0.60
Limestone @ $5.00/ton	230,000	0.85	4.3	0.46
Labor	88,000	0.32	1.6	0.18
Aux. Power	454,000	1.67	8.6	0.91
Reheat Steam	82,000	0.30	1.5	0.16
Maintenance	447,000	1.65	8.4	0.89
TOTAL	$3,879,000	14.29	73.0	7.76
Sludge Treatment				
Carrying Charge on $1,900,000	291,000	1.07	5.5	0.58
Property Tax on $1,900,000	38,000	0.14	0.7	0.08
Sludge Treatment @ $17.10 per ton	1,006,000	3.70	19.0	2.01
TOTAL	$1,335,000	4.91	25.2	2.67
Scrubber and Sludge Treatment Total Cost				
Capacity Factor @ 35%	$5,214,000	$19.20	98.2	10.43
" " @ 50%	$5,838,000	$15.05	77.0	8.17
" " @ 65%	$6,463,000	$12.81	65.2	6.94

solids on a dry basis normally occupies a much larger volume than does the same weight of fly ash. Even when the sludge material has been successfully dewatered, there is evidence to show that if left in the open, it reacquires its former state when subjected to either groundwater or rain.

A major problem facing the utilities, in addition to the technical ones, is a wide variation in solid waste and water pollution regulations. It is not surprising that the various utilities now operating, building, or planning lime/limestone scrubbing systems have followed widely divergent routes in sludge disposal.

Pond disposal with sluicing represents one alternative. Utilities have often disposed of fly ash by sluicing to a waste pond, discharging the sluice water to a watercourse, and abandoning the pond after it is filled with settled ash. Sludge disposal has sometimes followed a similar course. However, in many parts of the country, disposal of the sluice water into local watercourses is not permitted. In the Tennessee Valley Authority design for a ponding system at the 550-Mw Widows Creek Power Plant, the scrubber slurry containing about 15% solids, is pumped directly to the pond, the solids are settled out, and the supernatant liquor is recycled to the scrubbers. In this case, the pond serves the purpose of a thickener and further economy is achieved. Thickeners are not only expensive, but when located near the scrubbers, space is often a problem. In the design of a pond, a solids content of 40% in the settled solids was assumed. This corresponds to a pond volume requirement of about 1.4 cubic yards per thousand pounds of solid pumped to the disposal pond. Utilities that use or plan to use pond disposal include: Kansas Power and Light at Lawrence, Kansas City Power and Light at Hawthorn and La Cygne, Arizona Public Service at Cholla and Northern States Power at Sherburn.

A second alternative is pond disposal of thickened slurry. The sludge is settled in the thickener to a solids concentration of 30-40%. The underflow, which is about the same consistency as that obtained in a waste pond even after long settling, is thixotropic and can be pumped without any great difficulty. In the waste pond, the quiescent slurry sets up into a gel-type solid mass that is little different from the settled solids resulting from sluicing a more dilute slurry and recycling the liquor. This procedure requires a thickener but eliminates the cost of recycling sluice water, which can result in major cost saving if the pond is some distance from the scrubber area. However, so little experience has been obtained in the United States on pumping thick slurries that apparently there are no plans for using this method.

A third alternative is pond disposal of dewatered solids. The solids are dewatered by filtering or centrifuging to give a cake that can be hauled away by truck or other solids-handling equipment. In various test projects around the world, the solids content of the filter or centrifuge cake has usually been in the range of 45-70%. This method is expensive because of the equipment cost and the relatively high transport cost for solid-state waste. Sludge normally requires more pond volume than fly ash because the thin calcium sulfite crystals settle to a very loose and voluminous structure. Use of pressure in a vacuum filter or centrifuge, forces water out of the mass and the volume is decreased below that resulting from simple settling. Pressure-assisted dewatering can, therefore, be helpful. Reducing the water content from 70% to 50%, for example, can increase storage capacity of a pond by about 80%. The leading example of dewatered solids disposal is at the Paddy's Run Plant of Louisville Gas and Electric.

One criticism of any type of pond disposal is that the thixotropic (i.e., the tendency of a gel to become fluid with agitation) nature of the sludge probably precludes any use of the disposal area after the pond is filled. Indications are that, even after long standing, the sludge under the dried layer that forms on the top retains its original consistency. Moreover, if the mass is vibrated or otherwise disturbed, it can revert to the slurry form throughout. For example, on an experimental basis at the TVA facility, spent solids containing about 50% water were placed in an open air enclosure, protected from rainfall. After 30 days, the solids contained 36% water and appeared to be firm. Large cracks had developed. A load of 500 pounds per square foot, which is the minimum for recreational-use landfill, was placed on a four-foot-square surface. No settling of the load occurred during 10 days. However, when the solids were vibrated with a concrete vibrator, they fluidized and lost all loadbearing strength. In contrast, ponded fly ash dewaters well in settling and is not thixotropic. When the pond is full, the area can be used again with few restrictions.

In general, state and local regulations do not seem to be based on a knowledge of what can or cannot be done to improve the highly undesirable disposable properties of lime/limestone sludge.

Even if dewatered adequately, the thixotropic sludge could become fluid again if exposed to intensive agitation, particularly if it were exposed to water again, either by groundwater rising into it or by rainfall. If the calcium sulfite could be oxidized to calcium sulfate, that is, gypsum, the situation would be greatly improved. Gypsum crystals are relatively large and blocky, as compared with sulfite crystals, and dewater well by settling. In various efforts to find an economical method for oxidizing the sulfite to gypsum, results have not been promising. Where the gypsum can be sold for construction use, such as in Japan, the expensive oxidation process may yield a positive return. Another approach is to use a scrubbing process in which gypsum is the primary product, rather than the sulfite. Such processes include the Chiyoda (acid absorption) and the Hitachi and Lurgi (carbon absorption with limestone neutralization of the resulting weak sulfuric acid) methods that have been used in Japan. They are being tested there on very large-scale operations. In some areas in the United States, it is permissible to dispose of gypsum by creating large piles of it. There does not seem to be any substantial water pollution from the leaching of gypsum. Although such a piling scheme does exist in Tampa, Florida, for example, it is not approved for all areas. If the oxidation to gypsum and its subsequent storage is not a feasible alternative, then some other form of stabilizing the sulfite sludge is necessary. An extensive research program is currently underway by several organizations, including service companies such as Chicago Fly Ash, Dravo IUCS, and government organizations such as EPA and TVA, and numerous utilities.

In addition to acceptable strength of the waste solid mass, there is a great deal of activity underway on the problem of leaching and consequent pollution of groundwater. To prevent leaching, it is necessary to either line the pond or convert the sludge to a completely insoluble solid. Lining ponds is quite feasible, but it is also extremely expensive; the question is whether the cost is justifiable. Converting to a nonleachable solid may be possible, but it has not been proven on a scale that is meaningful. Of the sludge constituents, calcium sulfite is so insoluble that groundwater contamination seems likely to be quite insignificant. Calcium sulfate, gypsum, is more soluble but, as noted earlier, very large piles of waste gypsum from phosphoric acid plants do not seem to be causing any leaching problem. As to heavy metal compounds, which have been emphasized particularly by environmental agencies, data gathering is still underway. Again, gypsum piles do not appear to cause such a hazard and the phosphate ore from which the gypsum is made contains various heavy metals, as most natural deposits do. Thus, there is little guidance to the utility industry on how to cope with the water pollution problem in sludge disposal. The rules are not yet set, except in a few local instances, and it is not clear how the presently existing rules can be met.

The only full-scale stabilization system known to have been in operation is that of the Commonwealth Edison Company at their Will County limestone scrubbing installation. This system, operated by a subsidiary of Commonwealth Edison, involves thickening scrubber slurry from 6-7% solids to 30-40% solids, pumping the underflow into concrete mixer trucks, adding lime and dry fly ash, and conveying the mix to an intermediate pond where it is dumped. After the mix sets in the pond, which requires varying lengths of time, it is excavated and piled to conserve pond space. The mass does not set hard enough to prevent excavation. The stabilized sludge then seems to be structurally stable, but leaching data have not been obtained. Because of high trucking costs, the system is very expensive and might be infeasible for a large plant because of the number of trucks required. Tables 19a and 19b indicate the magnitude of costs experienced at the Will County plant.

Duquesne Light (Phillips) will use a process involving mixing a proprietary material with the ash-sludge mixture, transporting it to a holding pond for settling, and removing the final product to a permanent disposal pond area. The final pond in this case will be lined and drained. Ohio Edison will have a similar system at the new Shipping Port plant (1750 Mw) now under construction. In both cases, Pennsylvania regulations require sludge stabilization and the companies were forced to take what was offered without any real assurance that it would work satisfactorily. Very few data have been published on the proprietary processes involved. In the West, the Navajo plant in northern Arizona near Lake Powell, 2250 Mw, is under construction. There dewatered sludge will be mixed with dry fly ash plus an

TABLE 19a. Sludge Treatment Costs - Will County Plant

COSTS

Capital investment of $432,000 for hardware for equipment furnished by Chicago Fly Ash and $141,000 for temporary basin construction; for a total of $573,000. No carrying charges on plant or equipment are included.

WILL COUNTY UNIT 1 WET SCRUBBER SLUDGE DISPOSAL OPERATING COSTS MAY THROUGH SEPTEMBER 1973

Total Sludge Treated (Dry solids basis)	$ 11,656
Total Stabilized Sludge to Disposal Basin	27,439
Direct Sludge Treatment Costs (Labor, redi-mix trucks, lime, fly ash, and front-end loader rental)	145,480
Disposal Basin Costs	11,465
Indirect Sludge Treatment Costs (Equipment rental, drag chain maint., misc. supplies)	16,331
Overheat and Profit (15%)	25,991
TOTAL COST	$ 199,267
Sludge Treatment Cost (Dry solids basis)	$17.10/ton
Sludge Treatment Cost (Stabilized sludge basis)	$ 7.26/ton

(Contrast this with the maximum of $3.00/ton allocated for sludge "removal" in the process cost tables.)

TABLE 19b. Will County Unit 1 Wet Scrubber Estimated Annual Operating Costs Sludge Treatment

Treatment	$ Annual Cost	$/Ton Coal	¢/MBtu	Mills/ kw-hr
Carrying Charge on $641,760	$ 98,189	.36	1.8	.20
Property Tax on $641,760	12,835	.05	.2	.03
Sludge Treatment @ $17.10/ton	1,005,942	3.70	19.0	2.01
Total Cost @ 35% C.F.	$1,116,966	4.11	21.0	2.24
Total Cost @ 50% C.F.	1,548,092	3.98	20.5	2.17
Total Cost @ 65% C.F.	1,979,212	3.92	20.1	2.13

Notes:
Costs based on 14-year remaining life. C.F. is the capacity or load factor.
Treatment cost does not include hauling off-site or disposal site fee.
Assumes scrubber operation whenever boiler-turbine operates.

additive, the mixture will be transported by truck, dumped near a canyon wall, and rolled to get compaction. It is expected that building terraces up the canyon wall will yield a satisfactory situation.

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TALL STACKS AND INTERMITTENT CONTROL

The preceding sections raise substantial doubt as to whether the emission standards developed from ambient air quality standards can be met by May 1975. This section considers the possibility of meeting the ambient air quality standards without necessarily meeting the emission standards.

The suggestion that ambient air quality can be improved by dispersing the emission of a coal-fired boiler over a wider area is certainly not a new one. In their testimony before the SOCTAP panel, American Electric Power Company pointed out the successful British experience with the use of tall stacks. 'Modern power plants with tall stacks can operate over extended periods without making any material addition to the general level of pollution in the areas in which they are situated."[6] The EPA, while permitting the use of dispersion techniques as a temporary expedient does not accept them as a permanent solution to the SO_2 control problem.[6] Environmental pressure groups adamantly object to dispersion as a long-term solution. They contend that tall stacks are not a solution, while admitting that if all air pollution generated by U.S. power companies were evenly dispersed over the country, the SO_2 concentrations would be only 6 parts per billion.[2]

The use of tall stacks and intermittent control as a medium- or long-range solution has some advocates. Edison Electric presented detailed testimony supporting the use of tall stacks for meeting the air quality standards, claiming they can be used with coal as high in sulfur content as 5%.[29] Ohio Edison has installed tall stacks on their Sammis and Burger plants 1967-1972 with no difficulty in meeting the air quality standards.[6] The utility industry generally, along with Edison Electric Institute, the Federal Power Commission,[29] and the Electric Power Research Institute disagree with EPA.

In addition to the EPA objection to tall stacks, based on their interpretation of the Clean Air Act as a mandate to require emission reductions, other objections are based on the possibility that tall stacks promote the oxidation of SO_2 to SO_3 with the result that H_2SO_4 mist is formed. The UMW union has voiced this objection and the possibility is admitted by TVA, a staunch advocate of the use of tall stacks.[6] The FPC, in taking a partially dissenting position vis a vis the SOCTAP report (it was a member of the panel), recommends that FGD systems be considered only as an option for evaluation along with other options for attaining air quality standards, such as tall stacks or supplementary control systems.[6] FPC made a stronger statement in favor of intermittent control techniques in February 1974.[29]

As a basis of comparisons, for a particular plant, the switch to low sulfur fuel might cost $12,000,000. An FGD SO_2 removal system might cost $20,000,000. A system of tall stacks with intermittent emission controls might cost $2,200,000.[13] Ambient air quality on an annual average basis would be approximately the same under each alternative.

The Japanese experience with FGD systems is often cited as proof that FGD systems can be made to work in a reliable manner. It is interesting to consider the procedure by which the Japanese government sets emission standards for SO_2. The standards are set according to an equation that relates the allowable emission rate to the product of the square of the effective stack height and a constant. The constant is specified on the basis of the severity of pollution in a given region. Local monitoring is performed to assess air quality on a continuous basis. Clearly, an increase in stack height means that the plant can have higher emissions. The Japanese, apparently, clearly recognize the relationship between stack height and ambient air quality.

TVA has argued that tall stacks are the <u>only</u> way in which the air quality standards can be met by the May 1975 date.[30] TVA feels that the most practical method for control of environmental effects of SO_X emissions from coal-fired power plants is the use of high stacks to limit concentrations of SO_X in the ambient air. They feel that ambient air quality standards can be met using tall stacks and <u>intermittent</u> SO_X control.

TVA makes this statement after considerable experience and expenditure on desulfurization schemes. For example, it has made an effort to develop scrubbing techniques. In 1970 it designed and installed a limestone scrubber on the 550-Mw Widows Creek Unit No. 8. This project, financed by TVA, will cost $42 million.

TVA claims to be in a unique position to evaluate the overall feasibility of scrubbers.[30] It has practical knowledge of operating a power system, it has had years of experience in evaluating the feasibility of chemical technologies, and it has studied for over 20 years the effects and control of SO_X. Basic chemical reactions for removing SO_2 are well known according to TVA, but, "engineering technology is still far from being able to achieve a reliable process -- one that is available most of the time when generating units must operate and that would remove sufficient quantities of SO_2 without significant, adverse environmental impacts."

TVA further feels that sufficient low sulfur fuel is not available. In summer 1972, TVA issued invitations for low sulfur coal that would meet emission standards. They felt the results were dismal since all of the responsive bids totaled only a fraction of the annual needs of one power plant. The TVA statement does not mention the length of contract that TVA was willing to undertake. TVA did obtain 20,000 tons of Western low sulfur coal. Its high moisture and low Btu content resulted in a generating capacity loss of between 15 and 30%. TVA claims that it does not have the extra reserves to make up such losses. Even if the fuel were available, wholesale fuel shifting is <u>not</u> a viable means of meeting the SO_2 emission standards for TVA.

TVA experts claim to have examined all the major stack gas cleaning installations throughout the world. In addition, the TVA-EPA-Bechtel pilot project at Shawnee is considered a very ambitious one. It has made significant progress, but nevertheless TVA feels that no stack gas cleaning system has yet achieved the requisite degree of reliability under operating conditions.

From dispersion studies, air quality monitoring, and experience with the intermittent SO_2 emission limitation program at its Paradise plant, TVA felt it did have the ability to achieve both the primary and secondary ambient air quality standards and do it quickly. In fact, they felt it could be met for all TVA plants by mid-1975.

Intermittent SO_2 emission limitation does not seem to be provided for in the implementation plans of most states. Nevertheless, TVA has begun a course of action designed to achieve all of the ambient standards for SO_2 around the 9 plants of the TVA system where the ambient air quality standards are not now being met. This involves 1000-foot stacks and operating intermittent SO_2 emission limitation programs. TVA claims that this is the only way in which the air quality standards can be met in 1975.

The real issue is whether such a control strategy can be used on a permanent basis by existing power plants, even after stack gas cleaning is fully developed. TVA admits that the use of scrubbers on new plants may be justified once reliability and waste disposal problems have been solved.[30]

EPA at first objected to all intermittent control strategies citing questionable reliability and enforcement difficulties. In light of the success of this method at plants where it has been tried, EPA has withdrawn its objections. However, its proposed regulations would permit their use (Federal Register proposed implementation plan guidelines for approval by states September 1973) only when necessary until constant emission limitation techniques become available. EPA feels that total atmospheric loading of SO_2 must be reduced. TVA finds no legal basis in the Clean Air Act for EPA's requiring constant emission reduction of SO_2 by existing power plants. EPA finds an implied preference in the Clean Air Act for constant emission reduction techniques.

In addition to the advantages of a short implementation period, TVA claims that tall stacks are much more economical than scrubbers.[30] Installation of scrubbers on all 63 of TVA's coal-fired generating plants would take about 15 years and would result in an estimated capital cost of over $1 billion. Amortization of investment and annual operating costs amount to more than $225 million each year. Of course, not all plants need scrubbers and TVA feels it would need "only" $150 million annually to meet the proposed new fixed emission standards. In contrast, the annual cost of TVA's program for achieving the ambient SO_2 standards is $17 million, including allowance for new tall stacks and the $42 million (capital cost) Widows Creek scrubber.

Use of tall stacks and SO_2 emission limitation programs for controlling SO_2 in ambient air, alone, make it possible to meet the ambient standards that EPA has itself found are sufficient to protect the public health and welfare from any known or anticipated adverse effects of SO_2. For this reason TVA cannot justify the huge expenditures and resulting adverse environmental effects that meeting the fixed emission standards will cause."[30] TVA has go ahead with the preparation for the installation of tall stacks, even without EPA approval of their method, as a long-term SO_2 control solution.

The TVA intermittent control scheme consists of the following components: (1) identification of the critical dispersion conditions for the plant; (2) determination of the necessary meteorological and operational parameters related to the critical dispersion conditions; (3) formulation of atmospheric dispersion models to characterize the dispersion conditions; and (4) establishment of procedures for obtaining meteorological and plant operational data, evaluation of these data, and taking the administrative action to reduce SO_2 emissions when necessary. This can usually be accomplished in a few months.

At the Paradise plant, a "forecast" program has been shown to be sufficient. This program involves collection of early morning meteorological and plant operational data, which is used in making predictions about adverse dispersion conditions that may occur later in the day. In other locations, such as Widows Creek, where the terrain makes accurate predictions more difficult, a real-time program will be required: involving continuous monitoring and evaluation of meteorological, plant operational, and ambient conditions; and taking action to reduce SO_2 emission when ambient SO_2 control levels appear to be threatened.

Both use of low sulfur coal and use of tall stacks would reduce the frequency of required generation reductions in any plant. The use of tall stacks would have the "advantage" of permitting the continued use of coal mined near TVA.

A fixed emission standard, unless it is applied at a level even below the new-source performance standard, may not ensure that ambient SO_2 standards are not exceeded at times due to particular meteorological conditions. At other times, under more favorable meteorological conditions, the fixed emission standards may be overly restrictive in terms of the ambient air quality standards.

The experience at the Paradise plant provides a view of the reliability of the intermittent SO_2 emission control program that ran September 1969 through November 1972. During that period, there were 106 days when the meteorological conditions would have required some SO_2 emission limitation if the plant had been operating at, or near, full capacity. Due to unit outage or below full-load operation, the actual generating load had to be reduced on only 41 days. The load reduction averaged 454-Mw with a range of 26 to 906. The load reduction generally took place between 9:00 AM and 2:00 PM with an average duration of 3.6 hours and extremes of 0.4 hours to 5.8 hours. The installation of this intermittent control scheme for the Paradise plant on a voluntary basis by TVA reduced almost to 0 the number of times the ambient SO_2 concentration at the designated (by EPA) monitoring points exceeded the 0.5 ppm requirement.

With intermittent control schemes based on ambient air quality, enforcement could become a problem. One cause of the difficulty is that the ambient air quality is the result of meteorological elements and the emissions of all polluters in the region. This is one of the secondary bases for EPA's objection to intermittent control. TVA feels that there are known equations relating emissions from primary sources to ambient air quality and that these can be used as a means for enforcement. One of the potentially major costs of intermittent control is the power lost because the plant operating level is reduced. This is mentioned by TVA,[8] Table 1, but is not stressed by them. Even though these interruptions may occur very infrequently, the power lost may be very important and costly.

TVA estimates costs, exclusive of power replacement or increased fuel costs as follows: program development costs are expected to average $323,000 per plant with a range of $269,000 to $526,000 and annual operating costs are estimated at an average $180,000 per program with a range of $132,000 to $254,000.

The material on tall stacks and intermittent control has relied heavily on reports published by TVA. A similar conclusion was reached by FPC[29] who undertook an investigation of air quality regulations on the adequacy of electric power supply. The source of much of the information included in their report is a series of questionnaires filled out by members of the nine Regional Reliability Councils.

If the constant emission regulations are strictly enforced, the report concludes that many of the nine regions, including the one in which Chicago is located, would have negative projected reserve. This is the so-called Mid-American Interpool Network or MAIN. Their projected reserve capacity of +17.3% if emission limitations were ignored would be reduced to -14.4% if emission limitations are strictly enforced. In these calculations, all capacity not now meeting the emission limits was removed.

Certainly, such low reserve capacities prevent maintenance and installation of FGD systems, and make it virtually impossible to meet demand. Power cannot be purchased from neighboring regions since all are short of reserve capacity.

"In all 8 (of the 9) affected regions, the reserve picture is affected less in 1977 than in 1975 due both to the retirement of some older units and to upgrading of existing capacity with stack gas cleaning facilities expected to be available by 1977 or through the use of environmentally acceptable fuels.[29]

Comprehensive studies by EPA and FPC confirm that there will be inadequate supplies of gas, low sulfur oil, and low sulfur coal to meet all requirements resulting from the constant emission regulation contained in state air quality implementation plans on a nationwide basis. Further, technology for FGD has not yet demonstrated a reliability compatible with the need of electric utility operation. Even if it were prudent to install FGD systems, industrial capacity to construct scrubbers is insufficient to attain needed coverage.

FPC supports the Clean Air Act mandate to protect human health by the achievement of ambient air quality standards.[29] "In recognition that these ambient standards must be achieved at the earliest possible date consistent with easing the Nation's energy problem, with maintaining adequate and reliable supplies of electric power, with improved conservation of natural resources, and at a reasonable cost to the public, it follows that control alternatives other than existing constant emission control types should be employed. The Supplemental Control System (intermittent) is a viable near-term alternative."

There is no question that these intermittent control schemes require constant monitoring of ambient air quality and that the enforcement requires relating the emission of primary sources to the air quality. These aspects apparently require a dispersion model that gives an accurate relationship that can be agreed to by EPA and the primary sources, and that might hold up in court.

Another unanswered question with respect to the use of intermittent control coupled with the use of tall stacks is the danger resulting from the acknowledged tendency of tall stacks to promote the formation of H_2SO_4 droplets.

In spite of the advantages of intermittent control and tall stacks relative to reliance on low sulfur fuel or on FGD systems for immediate use, it probably cannot be viewed as a long-run solution to the SO_2 control problem. A long-run solution must rely on a reduction in the quantity of SO_2 emissions into the atmosphere.

However, it may be possible to meet the immediate health needs as captured by the ambient air quality standards set forth in the Clean Air Act. A long-term solution would await the development, on a commercial scale, of coal gasification or liquefaction. In view of the very limited success achieved with FGD and the inherent limits on the supply of low sulfur coal coupled with the adverse economic consequences of full reliance on Western coal in the East and the resulting environmental degradation in the West, the use of a <u>temporary</u> immediate solution makes good sense. The temporary solution might be used for as long as 15 years.

One final note: The suggestion that a temporary form of control be used now is based on what must now be an assumption that coal gasification and liquefaction can be developed to an economical, technologically feasible process by 1990. Some comments in the literature indicate a general feeling that the potential success of coal gasification and/or coal liquefaction far exceeds that of FGD systems. The coal transformation schemes appear technologically complex and there seems little <u>a priori</u> reason for such optimism. This position is discussed further in the next section.

If the use of intermittent controls, tall stacks and low sulfur fuel is adopted as a generally acceptable "temporary" measure until coal gasification is commercially feasible, then some policy for the allocation of low sulfur coal must be developed. Like most other matters dealing with allocation, this policy, too, would be dependent on the locational attributes of the coal sources and the power plants.

COAL DESULFURIZATION: ALTERNATIVES TO FGD SYSTEMS

There are many processes under development, or proposed, for coal desulfurization. All, except beneficiation, involve conversion of the sulfur in the coal to hydrogen sulfide. Beneficiation, to effect pyrite removal by physical separation, is not considered here because the coals of interest in the Eastern and Midwestern locations cannot be desulfurized to acceptably low levels by this technique and because losses in coal are extraordinarily high.

A number of desulfurization processes involve extensive conversion of the coal to premium, higher cost liquid fuels or to high Btu pipeline gas (processes such as H-coal, Lurgi, high Btu gasification, or Hygas). Such processes will provide substitutes for natural petroleum and natural gas in the non-electric power sector of the economy. The substitute fuels will cost over $1.50/MBtu, and with efficiencies similar to those now attained with respect to the conversion of Btu to kw-hr, their use would result in a cost of almost 16 mills/kw-hr (using a ratio derived from the Commonwealth Edison plant that 7.3 mills/kw-hr was equivalent to $0.70/MBtu). It seems reasonable then, to put these processes aside as far as generation of fuel for the electric power industry is concerned. The remaining processes may be characterized as solvent refining, liquefaction, and low Btu gas processes.

SOLVENT-REFINED COAL

This process, as exemplified by the TAMCO process,[31,32] utilizes an internally generated hydrogen donor solvent, such as anthracene, to dissolve 90-95% of the coal under hydrogen pressure at 500-2000 psig and 750-900°F. Following separation of gases, the hot liquid is filtered for solids removal; then the solvent is flushed and recovered. The resultant de-ashed product is a brittle solid, melting at over 300°F. The process results in removal of only 50-70% of the organic sulfur from the coal; while the pyritic sulfur is rejected with the solids from the filtration step. As applied to Eastern or Midwestern coal, the process yields solvent-refined coal that is low in ash but contains slightly over 1% by weight of sulfur. Major problem areas of the process are the gel formation stage in the preheater and the filtration step. Filtration must be conducted at 550-700°F and 100-200 psig. The solids to be removed are 1-40 microns in size, so the filtration task is formidable. Reference 15 contains a schematic flow diagram of this process. Some pilot plants are about to start up.

COAL LIQUEFACTION

Consolidation coal technology is directed to the production of synthetic petroleum from coal. It employs a hydrogen donor solvent, high hydrogen partial pressure, and an embulating bed of Co-Mo catalyst. A pilot plant at Cresap, West Virginia discontinued operation in 1970 owing to operating problems. Recently both Gulf Oil and the Bureau of Mines announced pilot plant results for fixed bed catalytic liquefaction processes capable of 90-98% conversion to low sulfur, that is, below 0.5% S by weight of synthetic fuel oil. A rough, conservative estimate of catalytic liquefaction facilities necessary to produce 100,000 bpsd of low sulfur synthetic fuel oil (enough for about 4000 Mw of power plant capacity operated at 60% load factor) is $500 million.

LOW BTU GAS PROCESSES

Low Btu gas is the product of air gasification of coal. The process is best exemplified by the Lurgi moving bed gasification technology, although newer fluidized bed and entrained bed gasification methodology, including fluidized bed boilers, is under development. In a Lurgi technique, coal is gasified at 200-300 psig, and the tar, oil, and hydrogen sulfide are separated from the gasifier effluent. Low Btu gasification can be applied to existing coal-fired power plants, as shown schematically in Ref. 15.

For a typical existing 300-Mw power plant, the boiler capacity would be reduced about 10% by firing the low Btu gas. This capacity loss is about compensated for by the power generated from power recovery in the gasification section. Great hopes are held out for this process. A National Petroleum Council report states:[33] "The importance of this concept relates to the apparent indication that combined cycle plants could ultimately convert high sulfur coals to electricity at higher thermal efficiency and with less pollution than any other system, and this might possibly be achieved while lowering the investment in $/kw compared to conventional coal-burning plants." Using a Lurgi pressure gasification, the concept has been demonstrated, withou sulfur removal in a 170-Mw combined cycle plant by the German utility company, Steinkohlen-Elektrizität A.G., (STEAG) at their Lünen station. After two years of successful operation, they have recently announced plans for an 800-Mw unit based on the same principle, but with sulfur removal included. The new plant should be in operation by 1980.

Ring and Fox[15] have attempted to provide some cost comparisons between the economics of stack gas desulfurization vs coal desulfurization. These are indicated in Table 20 for retrofit on existing power plants. As shown in the very last line of the table, the costs are very much the same for burning coal with stack gas desulfurization and burning low Btu gas from coal using a Lurgi process, both of them in the range of 7-7 1/2 mills/kw-hr. The cost of burning synthetic fuel oil from coal is 5.9 mills/kw-hr. This is the least expensive of the three alternatives. However, for new plants, the costs of low Btu gas are the lowest of the three alternatives as shown in Table 21.

The limestone scrubbing costs[15] are higher than those presented earlier, and include the incorporation of design parameters that have recently been demonstrated as necessary to obtain the high reliability required by the electric power industry. The costs also include sludge treatment and disposal costs.

For coal desulfurization and liquefaction, the costs shown are believed to be very conservative estimates based upon limited information published about the Bureau of Mines SYNTHOIL process. Here it was postulated that a centrally located plant would dispense synthetic fuel oil to power plants in a surrounding area. The table indicates that synthetic fuel oil produced from coal has the potential of being the most economically viable method for fueling existing coal-based power plants. The approach has the practical advantages that the need for new, unknown, unproven chemical plant operations in the utility industry is obviated, reliability is greatly enhanced, and load swings are easily accommodated in a manner to which utility operators are accustomed. Finally, much less waste is produced and it is disposable without major environmental jeopardy. Comparative costs for new power plants are shown in Table 21. Strangely enough, the costs published for limestone scrubbing in this instance are the same as they were for

TABLE 20. Illustrative Stack Gas vs Coal Desulfurization Costs: Retrofit
(300 Mw Coal-Fired Power Plant-60% LF-3 Wt. %S Coal)[15]

Burning Coal w/Stack Gas Desulfurization		Burning Synthetic Fuel Oil from Coal		Burning Low-Btu Gas from Coal (Lurgi)	
Coal Fired (tpy)	675,000	Coal to Liquef. Plt. (tpy)	710,000	Coal to Gasif. Plt. (tpy)	800,000
SO_2 Emitted "	4,000	Oil Fired (bpd)	7,200	SO_2 Emitted	Negl.
Ash Produced "	67,500	SO_2 Emitted (tpy)	3,000	Sulfur Produced "	22,000
Sludge Produced "	250,000	Sulfur Produced "	15,000	Ash/Coal Fines Produced "	160,000
Limestone Consumed "	100,000	Ash/Coke Produced "	100,000		
Capital Costs	$/kw	Capital Costs	$/kw	Capital Costs	$/kw
4% Station Derate	10	Pro-Rata Coal Liquef. Plt.[a]	120	Gasif. Plt., Expanders, Desulf.	155
Wet Limestone Scrubber	95	Boiler & Firing Conversion	10	Boiler & Firing Conversion	10
Sludge Trtmt. & Disp.	15	Fuel Oil Storage	5	30 Mw Generator	2
	120		135		167
Total Capital	$35,000,000	Total Capital	$40,000,000	Total Capital	$50,000,000
Operating Costs	$/yr	Operating Costs[a]	$/yr	Operating Costs	$/yr
Carrying Chg. @ 15%	5,400,000	Carrying Chg. @ 15%	6,000,000	Carrying Chg. @ 15%	7,500,000
Prop. Tax @ 2%	720,000	Prop. Tax @ 2%	800,000	Prop. Tax @ 2%	1,000,000
Maintenance @ 3%	1,080,000	Maintenance @ 3%	1,200,000	Maintenance @ 3%	1,500,000
Oper. Labor & Supv.	200,000	Oper. Labor & Supv.	700,000	Oper. Labor & Supv.	1,200,000
Limestone @ $10/ton	1,000,000	Utilities	500,000	Utilities	500,000
Aux. Power @ 1¢/kw-hr	700,000	Chem. & Catalysts	360,000	Δ Coal @ $8/ton	1,000,000
Reheat Steam @ 55¢/M	120,000	(Fuel & Ash Handling)[b]	(500,000)	Total	$12,700,000
Sludge Trtg. @ $5/ton	1,250,000	Δ Coal @ $8/ton	280,000		
Total	$10,470,000	Total	$9,340,000		
Cost/¢MBtu	70	Cost/¢MBtu	59	Cost/¢MBtu	77
Cost/Mills/kw-hr	7.3	Cost/Mills/kw-hr	5.9	Cost/Mills/kw-hr	7.7

abbreviations:

bpd	= barrels per day	M	= million
kw	= kilowatt	MBtu	= million British thermal units
kw-hr	= kilowatt-hour	tpy	= tons per year

[a]Pro-rated from cap. cost ($500M) and oper. costs for 100,000 bpd Plant, incl. H_2 Plant.
[b]0.3 mills/kw-hr saving, per FPC.

TABLE 21. Comparison of Stack Gas vs Coal Desulfurization Costs: New (800 Mw Coal-Fired Power Plant-60% LF-3 Wt. %S Coal)[15]

Burning Coal w/Stack Gas Desulfurization		Burning Synthetic Fuel Oil from Coal		Burning Low-Btu Gas from Coal (Lurgi)	
Coal Fired	(tpy) 1,800,000	Coal to Liquef. PM.	(tpy) 1,900,000	Coal to Gasif. Plt.	(tpy) 2,000,000
SO_2 Produced	" 106,000	Oil Burned	(bpd) 19,000	SO_2 Emitted	Negl.
Ash Produced	" 180,000	SO_2 Produced	(tpy) 8,000	Sulfur Produced	" 54,000
Sludge Produced	" 670,000	Sulfur Produced[a]	" 40,000	Ash/Coal Fines Produced	" 400,000
Limestone Consumed	" 270,000	Ash/Coke Produced	" 270,000		
Capital Costs	$/kw	Capital Costs	$/kw	Capital Costs	$/kw
4% Station Derate	10	Pro-Rata Coal Liquef. Plt.[a]	120	(Stm. Power Plt. Saving	(160)
Wet Limestone Scrubber	95	(Utility Plt. Saving)	(60)	Gasif. Plt. Expanders, Desulf.	125
Sludge Trtmt. & Disp.	15	Fuel Oil Storage	5	325 Mw GT Generator	60
	120		65	26 Mw Generator	2
					27
Total Capital	$96,000,000	Total Capital	$52,000,000	Total Capital	22,000,000
Operating Costs	$/yr	Operating Costs[a]	$/yr	Operating Costs	$/yr
Carrying Chg. @ 15%	14,300,000	Carrying Charge @ 15%	7,800,000	Carrying Charge @ 15%	3,300,000
Prop. Tax @ 2%	1,900,000	Prop. Tax @ 2%	1,100,000	Prop. Tax @ 2%	440,000
Maintenance @ 3%	2,900,000	Maintenance @ 3%	1,680,000	Maintenance @ 3%	660,000
Oper. Labor & Supv.	530,000	Oper. Labor & Supv.	1,900,000	Oper. Labor & Supv.	3,700,000
Limestone @ $10/ton	2,700,000	Utilities	1,330,000	Utilities	1,300,000
Aux. Power @ 1¢/kw-hr	1,900,000	Chem. & Catalysts	980,000	Δ Coal Cost @ $8/ton	1,600,000
Reheat Steam @ 55¢/M	320,000	(Fuel & Ash Handling)[b]	(1,280,000)	Total	$11,000,000
Sludge Trtg. @ $5/ton	3,400,000	Δ Coal @ $8/ton	800,000		
Total	$27,950,000	Total	$14,130,000		
Cost/¢MBtu	70¢	Cost/¢MBtu	34¢	Cost/¢MBtu	28¢
Cost/Mills/kw-hr	7.3	Cost/Mills/kw-hr	3.4	Cost/Mills/kw-hr	2.6

abbreviations:

bpd	= barrels per day	M	= million
kw	= kilowatt	MBtu	= million British thermal units
kw-hr	= kilowatt-hour	tpy	= tons per year

[a]Pro-rated from cap. cost ($500M) and oper. costs for 100,000 bpd Plant, incl. H_2 Plant.
[b]0.3 mills/kw-hr saving, per FPC.

the retrofit. The costs of the other processes, as shown in Table 21, make them more attractive than the flue gas desulfurization, even if lower costs are assumed for the latter. The authors claim that the desulfurization costs are the same as those listed earlier for the retrofit case, because there is little economy of scale in the application of limestone scrubbing to plants above 300 Mw. This is not consistent with the information developed and reported earlier in the report.

For coal desulfurization/liquefaction, a new 800-Mw power plant utilizing coal-derived synthetic fuel oil need be designed only for oil firing. This results in substantial reduction in the cost of the power plant, but there is an offsetting, though not so large, increase in the cost of the synthetic fuel oil facility.

For a new power plant employing low Btu coal gasification, the costs shown are for a combined cycle plant of the type described by Lurgi.[34] A schematic diagram of this process appears in Ref. 15. Here a substantial reduction in the cost of the steam cycle power plant results, but there is an offsetting cost for the addition of gasification, sulfur removal, gas expander, and gas turbine generator facilities. Nonetheless, desulfurization cost is lower than for either limestone scrubbing or synthetic fuel oil firing. The low Btu gasification alternative seems to be more applicable to large, base-loaded plants because the gasification facilities are not as amenable to load changes as an oil-fired power plant.

Ring and Fox[15] conclude that throw-away stack gas desulfurization processes do not appear to be in the best interest of the nation. In addition to being uneconomical and having demonstrated poor reliability, the sludge disposal requirements are considered inimical to good overall environmental management if the processes are widely applied in the future. The continued development of recovery stack gas desulfurization processes, on the other hand, appears justified because these processes would not involve production of large volumes of objectionable or unmanageable by-products. Production of synthetic fuel oil and of low Btu gas are believed sufficiently attractive from economic, practical, and environmental standpoints that accelerated development should be undertaken. The synthetic fuel oil would find application in both existing and new power plants; while low Btu gasification, in conjunction with a combined cycle, appears quite attractive for base-loaded plants.

Engineers from Commonwealth Edison have made more detailed studies of low Btu gas as a strategy for power station emission control.[35,36] The electric utility industry is capital intensive, investing $3.50-$4.00 per $1.00 of annual revenue, in contrast to the chemical industry, for example which invests $0.50 to $0.75 per dollar of annual revenue. Since there is much greater capital risk in generating $1.00 of revenue on the part of utilities, they follow a conservative investment policy. Although conservative, Commonwealth Edison has $4 billion of physical plant budgeted for construction in the next five years. This budgeting for growth is made in response to a consumer electrical demand that doubles every 8-10 years, a trend that is expected to continue. However, higher rates have, at least temporarily, curtailed the rate of growth. Over time, the efficiency of generation has continually improved, but has now reached a plateau. In addition, automation has played an important role in the reduction of production costs. For example, there has been an increase in average productivity from 885 kw/man in 1952 to 3730 kw/man in 1971. Commonwealth Edison feels that nuclear power plants with high investment and low fuel costs will carry the bulk of their generation, with fossil-fired units covering the field from peak plants to base load plants. Recall that in Ref. 15 low Btu gas was considered particularly adaptable to base load plants.

Commonwealth Edison's studies and those of others indicate that the combined-cycle plant will become economical both in capital cost and in operating cost and will naturally evolve when higher fuel costs come along. Other studies indicated that the low Btu fuel supply was competitive with stack gas scrubbing, particularly for new installation. According to Commonwealth Edison, pipeline gas would cost in the range of $1.20-$1.50/MBtu in 1972$; while stack gas cleanup would cost $0.85-$0.95/MBtu and low Btu gas, $0.70-$0.85/MBtu. These calculations are an estimated price of a new fuel supply to a coal-fired unit. They are based on 1000-Mw capacity. The low Btu gas and stack gas scrubbing costs are comparable, and substantial savings result over synthetic pipeline gas. These results confirm those found in Ref. 15.

Commonwealth Edison has authorized (1972) Lurgi to make a definite cost estimate to equip a 120-Mw unit at Powerton Station with a clean fuel supply.[35]

Commonwealth Edison considers that low Btu gas as a fuel supply possesses several advantages over stack gas scrubbing. The two most important are: first, the low Btu gas supply, using the pressure gasifier, can generate a net excess of electric power through the use of an unfired expander turbine; this contrasts with the stack gas emission process, which has a parasitic drain of 5-10% of the power generated. Second, the gas purification processing in the gas supply system works to remove hydrogen sulfide, for which technology exists, instead of sulfur dioxide, and it has to work on less than 5% of the volume of the gases that would be processed in a stack gas scrubbing system. The cost of the Powerton project is as follows: for the gasification and purification systems - $7.4 million; for auxiliary support and power recovery - $3 million; for boiler modification - $1 million; for engineering contingencies, escalation, and operation - $6 million; or a total of $17.4 million. This would be a 120-Mw unit and a cost of $145/kw.

Clean power fuel is produced in the Lurgi Process by reacting coal under pressure with a mixture of air and steam. Virtually all ash is scrubbed from the gas; tars and liquid hydrocarbons are recirculated to the gasifier. The gas is desulfurized; then reduced in pressure through a power recovery expander turbine, which also supplies air for the gasifier and generates electric power. The resultant low Btu clean power fuel flows to modified burners of an existing boiler. The desulfurization process produces elemental sulfur through a Claus process and is expected to reduce emissions of sulfur dioxide about 90%. The gas from this process is expected to have a heat content of 150-200 Btu/scf. This is a much simpler process than that used in production of synthetic pipeline gas, nominally at 1000 Btu/scf, since there are no oxygen, no methanation, and no CO_2 shift conversion facilities required. Therefore, this process has lower capital requirements, a lower cost and higher energy recovery efficiency. Direct integration with a power plant will permit the recovery of a portion of the sensible heat, and an 80% overall efficiency of the gasification plant is expected.

There is a very high probability that gasification systems will be less costly than stack gas cleanup systems for a conventional station. Potential savings for new fossil stations may result when using the clean fuel, since precipitators and stack gas cleanup systems would be eliminated. Boilers and foundations would be smaller. Superstructure and structural steel requirements may be reduced. Cooling water requirements would be drastically reduced.

For new, integrated plants, the expected capital cost of a large-scale gasification process is about $80/kw, compared with a stack gas scrubbing process at $70/kw.[36] However, the gasification process allows equipment elsewhere in the plant to be eliminated, which would more than offset this cost differential. These reductions result from savings in the boiler and associated equipment, compared with a coal-fired unit, and from an increase in the capacity of the plant due to a difference in auxiliary power. Reductions are estimated to range up to $40/kw. The total capital cost differential could be as much as $30/kw in favor of gasification. When the gasification process is properly integrated into the power plant, savings in operation and maintenance may result in a total operating and maintenance cost only slightly higher than present-day, coal-fired plants. Net differential in operation and maintenance cost is estimated to be 0.75 mills/kw-hr lower for a plant equipped with a coal gasification process vs stack gas scrubbing. The overall plant efficiency is expected to be from 15-20% greater than with a stack gas scrubbing process. The fuel cost for coal gasification can be expected to be 0.5-1.0 mills/kw-hr greater. Thus, the total cost of power from a fossil-fired, steam generating plant could be 0.5-1.5 mills/kw-hr lower with low Btu gas as compared to using high sulfur coal and stack gas scrubbing. The most significant economic advantage of low Btu gasification has not yet been considered. Upgrading coal through pressure gasification allows coal to be used for power production cycles previously restricted to premium fuels, opening the door to potentially greater capital savings and higher efficiencies of the combined steam and gas turbine cycle. The fuel gas is made up of 1.5% by weight hydrogen, 39.2% nitrogen, 21.1% water, 22.1% carbon dioxide, 14% carbon monoxide, 2.1% methane. Detailed data on the operation of plants is given by Agosta, et al.[36]

The recent report by Adelman and his associates[1] contains some information on "synthetic" fuels. How these fuels can satisfy the Nation's demand for energy can be evaluated through the use of the following simple calculations. Substitute natural gas plants (high Btu 1000 Btu/scf) are assumed to have a production capacity of 250 million cu ft/day, consuming 16,000 tons of bituminous coal daily. One hundred such plants would produce only one-third of the current gas needs but would consume all the coal now being mined in the U.S.

A 40,000 bbl/day synthetic crude oil plant based on coal is equivalent to a 250 million cu ft/day substitute natural gas plant, in that the heating values of the products produced daily in the two plants are roughly equal. The synthetic crude oil plant would consume perhaps 10% less coal than a synthetic natural gas plant. However, 100 such synthetic crude plants would produce only about one quarter of the country's current 15-million-barrel daily consumption.

It must be recognized that cost information on the many synthetic fuel processes is extremely limited. All the costs reported by Adelman's group come from the open literature. They are presented in Table 22 for purposes of comparison with the costs presented earlier. To facilitate comparison of the processes, all costs listed are for plants producing fuel with a heating value of 2.50×10^{11} Btu/day. This is equivalent to 250 million scf of synthetic natural gas, 40,000 bbl/day of synthetic crude, or 12,500 tons/day of methanol. Plant cost estimates made and published in earlier years have been updated to allow for inflation.[1] Plant investments have been put as nearly as possible on an equal basis by including the same allowances for contingencies, startup, construction loans, etc. These plant investments do not include the mines, except in the case of shale operations, nor do they include housing for personnel; but otherwise they are claimed to be complete.[1]

These estimates are for very large plants and in these circumstances success in estimating capital costs to within 35% actual is considered unusually good. Further uncertainties are introduced since the original estimates were made by different groups whose design philosophies inevitably differed. Operating costs are presented in Table 23.

TABLE 22. Capital Costs for Synthetic Fuel Plants

Process	Capital Cost in Millions of 1973$
Substitute natural gas from coal, old technology	400
Substitute natural gas from coal, new technology	300-350
Synthetic natural gas from oil shale	350
Synthetic crude oil from coal	350
Synthetic crude oil from oil shale	450
Methanol from coal	350

TABLE 23. The Annual Operating Costs in Millions of 1973$ of Various Synthesizing Plants

(Each producing a daily product with a total heating value of 250 x 10^9 Btu)

Cost	Synthetic Natural Gas from Coal		Synthetic Crude from		Methanol from Coal
	Using Old Technology	Using New Technology	Coal	Oil Shale	
Capital at 15%/yr	59	44	51	57	51
Operating costs	22	16	22	22	44
Fuel costs	48	44	37	37	48
Total costs	129	104	110	96	143
Cost/MBtu product	1.56	1.26	1.33	1.17	1.73
Cost/bbl oil equiv.	9.05	7.30	7.70	6.80	10.00

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