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High-Sulfur Coal for Generating Electricity

James T. Dunham, Carl Rampacek, T. A. Henrie

The United States has an abundance of coal. Coal reserves economically recoverable by today's mining technology are estimated at 200 billion tons (*1*), and total domestic coal resources are of the order of 3 trillion tons, or enough to meet a large part of our energy needs for centuries (*2*). We are experiencing an energy shortage in the 1970's, despite such vast amounts of coal, because we have become overdependent on natural gas and oil to supply some of our increasing energy needs, among them that for electrical power.

Electricity provides about 25 percent of our total energy needs. According to a Department of the Interior study (*3*), per capita use of electricity increased from slightly more than 2000 kilowatt-hours in 1950 to 7800 kwh in 1971, and is projected to reach about 32,000 kwh by the year 2000.

Cheap, convenient low-sulfur oil and natural gas are competing with coal as the preferred fuel for the electric utility market (Table 1). While annual consumption of coal for power plants in the northeastern and east northcentral regions of the United States stayed approximately constant in the 6 years from 1966 to 1971, oil consumption has increased by factors of 3 and 25 in these regions, respectively, and gas consumption has increased by up to a factor of 3 (*4–6*). Continued use of petroleum and natural gas at the present rate will aggravate the serious supply problems for these fuels.

Programs under way to augment our oil and gas supplies and to diversify our energy base (*7*), such as coal gasification, extracting oil from western oil shales, harnessing solar energy, wind, and geothermal steam and brines, will have little impact on electricity generating needs for many years. Similarly, although nuclear reactor power plants are expected to provide up to 25 percent of the demand for electricity by 1985 and up to 50 percent by 2000, these optimistic estimates assume the timely development of the fast breeder reactor program and satisfactory solution of environmental problems in siting and operating nuclear reactors. In the meantime, fossil fuel–fired power plants must supply a large part of our electrical power demands, and only coal is available in the United States in sufficient quantity to provide this energy for the next 25 years.

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Air Pollution from Coal Combustion

An important factor influencing the change in the pattern of energy use in thermal electrical power generation from coal to oil or gas in recent years has been the limitation on the emission of pollutants to the atmosphere. Air pollution regulations affecting power plants are primarily concerned with three pollutants: particulates, nitrogen oxides, and sulfur oxides. Of these three, sulfur oxides are of the most concern from a regulatory standpoint. Ambient air quality standards (Table 2) and emission standards (Table 3) can generally be met only by burning coal containing 1 percent sulfur or less (*8, 9*). In coal, sulfur occurs in both the inorganic and organic forms. Substantial amounts of inorganic sulfur, mostly pyrite, can be removed by mechanical cleaning, but the organic sulfur cannot. Because the sulfur in high-sulfur (3 to 6 percent) coal is often about half pyrite and half organic, mechanical cleaning alone does not reduce the sulfur content to the point that the coal can be burned without exceeding the emission standards for sulfur oxides.

Fuel trends in the heavily populated and industrialized regions reflect the impact of air pollution regulations on the use of coal. Burning low-sulfur oil or natural gas has been one method of controlling sulfur oxide emissions, but when switching to oil or gas has not been feasible, utilities have turned to low-sulfur coal, often at great expense because of high transportation costs. Most of the available low-sulfur coal in the United States is in the West, and much of that in the East is captive and used by the metallurgical industry. Accordingly, utilities in Chicago meet air pollution regulations by using low-sulfur coal mined in Montana and Wyoming and pay as much as $8.50 per ton for unit train rail haulage.

In his report to Congress on the energy situation on 23 January 1974, President Nixon urged postponement of the implementation date for air pollution standards to permit conversion of oil- and gas-fired electric generating plants to the use of coal. On 6 February 1974, a report issued by the Federal Energy Office (*10*) cited ten eastern plants that converted from oil to high-sulfur coal and several other plants that were willing to convert if environmental, technical, transportation, and supply obstacles could be overcome. These actions have freed some oil and gas for other uses. In 1973, use of coal for generating electricity increased slightly at the expense of oil and natural gas (*11*). However, widespread conversions by established utilities or construction of new plants designed to burn high-sulfur coal are unlikely unless utilities can be assured that they can ultimately comply with air quality regulations.

Table 1. Sources of energy for generating electricity in 1972 [from (*5*)].

Source	Electricity generated (percent of total)
Coal	42.2
Natural gas	22.1
Petroleum	16.9
Hydroelectric	15.7
Nuclear	3.1
Geothermal	Negligible

Control of Sulfur Oxides at Power Plants

One of the major deterrents to the unlimited and widespread use of coal for generating electricity in the United States, particularly in the Midwest and East, is the quality of the combustion gases released to the atmosphere. If high-sulfur coal is burned, there are three alternatives for producing gaseous emissions meeting air quality standards: (i) Coal can be converted to a sulfur-free fuel; (ii) coal can be burned directly at a rate and under conditions that generate emissions meeting ambient air quality standards; or (iii) coal can be burned and the sulfur oxide gases removed during combustion or before discharge of flue gases to the atmosphere. In the near future, sulfur-free fuels derived from coal by gasification or liquefaction will, at best, have limited application in electrical power generation. The other alternatives are more likely for immediate and short-range use.

Tall Stacks and Curtailment

Before establishment of air quality standards, it was common practice to burn high-sulfur coal and vent the combustion gases to the atmosphere through tall stacks to disperse the sulfur oxides, nitrogen oxides, and particulates. By reducing the rate of coal burning and venting through the tall stacks, ambient air quality standards can be achieved in some cases, but under no conditions can emission standards be met.

The curtailment technique consists of monitoring concentrations of sulfur dioxide at ground level near the power plant and meteorologically forecasting unfavorable atmospheric conditions that

Table 2. National ambient air quality standards. Primary standards are those which protect public health and secondary standards protect public welfare; ppm, parts per million [from (*8*)].

Standards	Concentration		Description
	μg/m^3	ppm	
	Sulfur oxides		
Primary	80	0.03	Annual arithmetic mean
	365	0.14	24-hour maximum*
Secondary	1300	0.5	3-hour maximum*
	Particulates		
Primary	75		Annual geometric mean
	260		24-hour maximum*
Secondary	60		Annual geometric mean
	150		24-hour maximum*
	Nitrogen oxides		
Primary and secondary	100	0.05	Annual arithmetic mean

*Not to be exceeded more than once per year.

Table 3. Emission performance standards for fossil fuel–fired steam generation units with heat input of more than 250 million British thermal units per hour (1 Btu = 1.06 × 10^3 joules; 1 pound = 0.453 kilogram) [from (*9*)].

Pollutant	Fuel	Maximum emission per 10^6 Btu heat input (pounds per 2-hour average)
Sulfur oxides	Liquid	0.8
	Solid	1.2
Particulates	All	0.1
Nitrogen oxides	Gaseous	0.2
	Liquid	0.3
	Solid	0.7

might force the gas from the stack to ground level. When adverse conditions are indicated, electrical power generation is curtailed to the degree necessary to maintain the ground level sulfur dioxide content of the air below the ambient air quality limits. This control strategy, called the "closed-loop system" or "intermittent control system," has been used for controlling sulfur dioxide emissions at copper smelters in Tacoma, Washington, and El Paso, Texas. The Tennessee Valley Authority has demonstrated the technique at its Paradise steam plant in west central Kentucky (*12*). The Environmental Protection Agency (EPA) has recognized this method of control as supplemental to emission controls and suitable for some power plants (*13*).

Curtailment is simple and cheap, and can be implemented almost immediately for some degree of sulfur dioxide emission control from generating plants. However, extensive use of the procedure would reduce electricity generating capacity. This method of control should be considered a stopgap measure to permit burning of high-sulfur coal until positive methods for controlling sulfur oxides become available.

Removing Sulfur Dioxide from Flue Gases

Research to develop technology for removing sulfur dioxide from gases generated during coal combustion in electric utility boilers covers a span of 40 years in the United States and abroad. These processes include (i) injecting limestone or lime into the combustion chamber to produce a throwaway product; (ii) high-temperature regenerative systems (that is, those that recycle the absorbent) using solid absorbents to concentrate sulfur dioxide gas for conversion to sulfuric acid or sulfur; (iii) direct catalytic oxidation of the dilute flue gases to sulfur trioxide and then to sulfuric acid; (iv) wet scrubbing of the cooled gases with alkaline solutions or slurries to yield throwaway products; and (v) wet scrubbing with regenerative solutions to produce either liquid sulfur dioxide, sulfuric acid, or elemental sulfur. This technology is still controversial, with opinions varying as to the reliability, operating and capital costs, and acceptability of the end products or byproducts of the various processes.

In a 1970 study of available technology for stack gas cleanup made by the National Academy of Engineering (*14*), it was stated that "contrary to widely held belief, commercially proven technology for control of sulfur oxides from combustion processes does not exist." In May 1972, a federal interagency committee responsible for evaluating state air implementation plans formed an interagency task force to evaluate flue gas desulfurization systems. The task force, designated the Sulfur Oxide Control Technology Assessment Panel (SOCTAP), issued its final report on 15 April 1973 (*15*). Having examined the status of stack gas cleaning in the United States and Japan, the task force concluded that the removal of sulfur oxides from stack gases is technologically feasible in installations of commercial size, and that a large number of the nation's coal-fired steam electric plants can ultimately be fitted with commercially available stack gas cleaning systems. Of many processes considered, four wet-scrubbing systems were rated as sufficiently developed for full-scale commercial application within the next 5 years; these processes were as follows: wet limestone or lime scrubbing, magnesium oxide scrubbing with regeneration, catalytic oxidation, and wet sodium base scrubbing with regeneration. Solid absorbent regenerative systems were eliminated as technically deficient or not far enough advanced for application in the near future; several regenerative wet scrubbing systems still being developed were not considered. The method of dry lime or limestone injection in utility boilers fired with powdered coal, in which sulfur oxides are recovered as dry compounds together with the fly ash, was also rejected because flue gases did not meet emission standards for sulfur oxides and the quantities of lime or limestone required were excessive. Serious operating problems also were encountered, including boiler fouling and degraded performance of electrostatic precipitators. Dry limestone injection into a fluidized-bed boiler might capture enough sulfur dioxide to meet emission standards, but the quantity of limestone required is excessive, about 300 pounds per ton of coal burned (*16*) [1 pound = 0.45 kilogram; 1 ton of coal (always short ton) = 0.9 metric ton]. Fluidized-bed boilers are only in the experimental stage and, because of their large size as compared to conventional boilers, are not likely to be readily accepted by utilities.

The EPA supported the SOCTAP conclusions and evaluations in testimony at public hearing (*17*), and added double-alkali sodium scrubbing systems to the list of commercially viable processes. The citrate process, also studied by EPA (*18*), was later added to the list of promising desulfurization systems.

Utility representatives at the public hearing did not agree with EPA's conclusions and testified about operating difficulties with the scrubbers that are installed. They claimed that reliability of units 100 megawatts or larger has not been demonstrated adequately enough to warrant the conclusion that the control systems are commercially available. Another major concern of the utility representatives was the disposal problem attendant with the throwaway control systems. These systems—lime or limestone wet scrubbing and double-alkali scrubbing—produce calcium sulfate and calcium sulfite, which have no market value and must be disposed of in permanent impoundment areas.

The processes considered most advanced have only been tested in a limited number of large-scale demonstration projects, if any, and the controversy continues as to whether the technology is reliable enough for widespread application to coal-fired utility boilers. Large-scale test programs now under way or being planned (*17*) may, in the next 2 or 3 years, solve the engineering design and operating problems to assure fully reliable sulfur oxide control systems. In the meantime, promising new processes now being developed should be available for installation before the end of this decade. Concerned parties are appraising cautiously the more thoroughly researched and advanced processes with regard to their merits and deficiencies.

Wet Limestone or Lime Scrubbing

The wet limestone and lime absorption processes are the most thoroughly studied of all sulfur dioxide control systems. In these systems (*19*), (i) dry lime or limestone is injected into the boiler and the partly reacted material is removed in a wet scrubber; or (ii) slurries of lime or limestone are reacted with sulfur dioxide in scrubbing towers to form calcium sulfates and sulfites which are collected and impounded. In limestone scrubbing systems, efficiency of sulfur dioxide removal depends on intimate contact between solid and gas phases, and it is necessary to install large scrubbers, recirculate large volumes of slurry, and grind the limestone to extremely fine size (−200 mesh) to achieve an acceptable degree of sulfur dioxide absorption. In addition, limestone utilization is poor, as much as 350 pounds per ton of high-sulfur coal burned. Absorption is more efficient with hydrated lime slurry than with limestone, but construction and operation of a kiln is required for quicklime production.

Wet limestone or lime scrubbing removes particulate matter as well as sulfur dioxide. Although the systems are designed to recycle the scrubbing fluid, the thickened sludges discharged to the impoundment area contain about 50 percent water and require large settling areas for dewatering and stabilization of the solids. Lime or limestone slurry scrubbers are capable of removing up to 90 percent of the sulfur oxides from a typical flue gas containing 0.2 to 0.3 percent sulfur dioxide.

The reliability of limestone or lime scrubbers remains questionable. One lime scrubber in Japan reportedly has operated with near 100 percent availability for 1½ years; in the United States, a scrubber using carbide sludge (calcium hydroxide) has been in reasonably trouble-free operation for 1000 hours.

Several studies have been published on the estimated costs for installing and operating limestone and lime scrubber systems (*17, 20*). Some data are also available on the costs of actual installations. Estimates for capital cost generally range between $27 and $46 per installed kilowatt of capacity. Annualized costs, those which the consumer can translate into the increase in the cost of electricity, range from 1.1 to 1.2 mill/kwh. The as-produced cost of electricity averages about 9 mill/kwh whereas the price to customers averages about 20 mill/kwh. The lower estimates are for new plants of large size, 1000 Mw, and the higher numbers are for retrofitting existing plants of 200-Mw capacity.

With regard to land and water pollution, the purity of the limestone or lime is of considerable concern. Pure limestone is not readily available, because most contains some magnesium. Inasmuch as magnesium sulfate is water-soluble, the throwaway products generated with limestone or lime containing appreciable quantities of magnesium might present a disposal problem, particularly in areas of moderate or excessive rainfall. The soluble magnesium salts might leach and contaminate water at the surface or underground.

The cost associated with disposal of sludge varies appreciably. For some plants, the lack of a nearby sludge disposal site eliminates throwaway systems from the choices of control processes.

Despite the disposal problems, the limestone and wet lime processes are currently the most popular for U.S. power plants. About 28 utilities have selected one of these processes; in seven plants, the process is approaching operational stage (*17*).

Magnesium Oxide Scrubbing

The magnesium oxide scrubbing system is similar to the wet limestone and lime processes (*15, 21*), but it has not been as extensively tested. Magnesium sulfite and sulfate salts are formed by reacting a magnesium oxide slurry with the sulfur dioxide in the flue gas. The scrubber slurry is processed to separate the fly ash, then thickened, followed by crystallization to obtain magnesium salts. The salts are then calcined with carbon at a temperature of 980° to 1090°C to recover 15 percent sulfur dioxide gas. Regenerated magnesium oxide is recycled to the scrubber system. The sulfur dioxide can be liquefied or converted to sulfur or sulfuric acid. Because of the steps involved—thickening, fly ash separation, magnesium salt crystallization, and thermal decomposition—the regeneration is relatively costly.

Long-term reliability of this process has not been demonstrated. Only two units have been installed. One, an oil-fired boiler, was reported to be available 85 to 90 percent of the time during a 2-month period. Capital costs estimates for the process range from $33 per kilowatt of capacity for a new 1000-Mw plant up to $58 per kilowatt for retrofitting a 200-Mw existing plant. The estimated annualized costs are 1.5 and 3.0 mill/kwh for the same plants if no credit for sale of acid is assumed. Marketing the acid would reduce costs only slightly, perhaps 0.3 mill/kwh (*17*). In certain situations it might be necessary to neutralize the acid with limestone or lime and impound the calcium sulfite and sulfate at additional expense.

Advantages of magnesium oxide scrubbing are that the regeneration of the magnesium oxide need not be performed at the power plant site, and a centrally located regeneration facility could service several plants. The process can remove enough sulfur dioxide from flue gases to meet emission standards, but reliability and operating costs must be verified. Current plant tests should provide this information.

Catalytic Oxidation

This process is a variation of the contact sulfuric acid process applied to the extremely dilute gases discharged by utility plants (*22*). The contact process produces 98 percent sulfuric acid from gas containing 3.5 percent sulfur dioxide or higher. There is no technological limitation, other than cost, in treating more dilute gases, but the gases must be thoroughly cleaned and the plants must be designed to treat large volumes.

In the catalytic oxidation process, flue gas, after thorough cleaning in cyclones and electrostatic precipitators, is passed over a catalyst to convert the sulfur dioxide to sulfur trioxide. This combines with the moisture present to form sulfuric acid of about 80 percent strength. This product has limited market value, and large quantities might pose a disposal problem.

In existing power plants, the clean flue gas from the electrostatic precipitators is not hot enough for catalytic conversion and must be reheated to 455°C. The retrofit version of this process has only been tested in pilot plants, but an acceptance test on a 110-Mw coal-fired boiler reportedly achieved 85 percent removal of sulfur dioxide. In a proposed design for new power plants, heat exchangers and hot electrostatic precipitators eliminate the need to reheat the gas. This design, however, has not been tested on a large scale.

Information is not available regarding system reliability, but performance of the particulate cleaning system will influence the percentage of time that the unit is out of operation. Costs are estimated at $41 to $64 per kilowatt, and annualized costs range from 1.5 to 2.6 mill/kwh (*17*). The need to clean particulate matter from the catalyst bed in the acid unit almost continuously, together with reheating and maintaining the large volumes of reaction gases at proper reaction temperatures for effective catalysis, are problems requiring further study.

Wet Sodium-Base Scrubbing

There are several sodium-base scrubbing systems; in the most advanced process, a sodium sulfite-bisulfite solution is used to absorb the sulfur dioxide and convert the sulfite to bisulfite (*23*). In this system, the flue gas must be cleaned thoroughly to remove particulates and must be cooled to about 55°C for effective absorption of the sulfur dioxide. A portion of the liquor is steam-stripped to recover strong sulfur dioxide and is then evaporated to recover sodium sulfite crystals for recycling. The sulfur dioxide can be used to make sulfuric acid or elemental sulfur. Since some oxidation of sulfite to sulfate occurs in the absorber, it is necessary to bleed off part of the solution and make up losses with caustic. Bleeding also controls buildup of particulate matter in the system. The process is capable of removing 90 percent or more of the sulfur dioxide from dilute gases, and has been installed at chemical plants and on oil-fired boilers. Experience in these plants probably has provided more accurate operating cost data than is available for most other advanced processes.

Process reliability greater than 95 percent for more than 2 years has been reported in one instance, for an oil-fired boiler. The process has not been tested at a coal-burning plant, but a demonstration project is planned to begin in 1975. Capital cost estimates range from $38 to $65 per kilowatt with corresponding annualized costs from 1.4 to 3.0 mill/kwh if no credit for byproduct acid or sulfur is assumed (*17*).

No serious technological limitations in the process are apparent. Any reluctance about widespread adoption probably stems from uncertainty about the amount of sulfite to sulfate oxidation and the high annualized costs.

Double Alkali Scrubbing

Although not as well developed as wet limestone or lime scrubbing, this process has potential because it eliminates scaling problems associated with the limestone and lime systems. The scrubbing liquor is an alkaline solution of sodium or ammonium sulfates and sulfites, and efficiency of sulfur dioxide removal is high (*15*). Loaded scrubber effluent is treated with either limestone or lime to recover a throwaway sludge of calcium sulfates and sulfites and to regenerate the solution, which is returned to the scrubber. Development has largely been focused on the sodium system.

Cost estimates for the sodium double-alkali process as applied to utility power plants are encouraging, with capital investment cost ranging as low as $25 per kilowatt for a new 1000-Mw unit. Retrofitting a 200-Mw unit is estimated to cost $45 per kilowatt. Estimated annualized costs for these plants are 1.1 and 2.1 mill/kwh, respectively (*17*). An EPA evaluation has indicated that the double alkali and citrate processes may be up to 20 percent less costly than processes such as wet limestone or sodium-base scrubbing (*18*).

Double alkali scrubbing has the same disadvantages as other throwaway processes, including the need for adding sodium or ammonium salt. However, because of its high efficiency and freedom from scaling in the scrubbing unit, the process is receiving increased attention.

Citrate System

The citrate process is one of the more attractive systems that has emerged in the past several years for flue gas desulfurization (*7, 24*). Developed by the Bureau of Mines to remove sulfur dioxide from nonferrous smelter stack gases, the process has the advantage that elemental sulfur is recovered without the need for intermediate sulfur dioxide regeneration. The system, which is considered among the least costly of the advanced processes (*18*), comprises (i) washing the flue gas to remove particulates and sulfur trioxide, and to cool the gas below 66°C; (ii) absorption of sulfur dioxide in a buffered sodium citrate–citric acid solution in a packed tower; (iii) reaction of the loaded solution with hydrogen sulfide in a closed vessel to form elemental sulfur; and (iv) separation of sulfur from the regenerated solution by oil flotation followed by melting. Hydrogen sulfide for the sulfur precipitation step is generated by reacting part of the recovered sulfur with natural gas and steam.

Recently the bureau began testing the process in a pilot plant with capacity of 1000 standard cubic feet per minute (scfm) at the Bunker Hill lead smelter, Kellogg, Idaho. More than 95 percent removal of sulfur dioxide has been achieved without difficulty from a gas stream containing 0.5 percent sulfur dioxide.

Since June 1973, the process has been tested in a 2000-scfm demonstration unit at a coal-fired steam generating plant in Terre Haute, Indiana (*25*). Tests on gas containing 0.27 percent sulfur dioxide, generated by burning coal containing 3 percent sulfur, have largely confirmed Bureau of Mines findings. Although the citrate process has been proposed for producing elemental sulfur, it also is possible to recover sulfur dioxide for conversion to acid by incorporating a steam-stripping step.

Estimated capital cost of a citrate process desulfurization unit for a 1000-Mw plant burning coal containing 3 percent sulfur is $31 million. Annualized costs would be 1.4 mill/kwh, if no credit for the 214 long tons of sulfur produced daily is assumed.

Summary

We must expand the use of coal for electricity generation as rapidly as possible to help alleviate the immediate oil and natural gas shortage, which threatens to become more acute unless the pattern of energy use is changed.

It is not likely, nor is it proposed, that coal should completely replace oil or gas in power generation; geographic location of plants and ready availability of high- or low-sulfur coal will to some extent dictate the choice of fuel. However, replacing 50 percent of the oil and gas now used in power generation would release more than 200 million barrels of oil and 1.9 trillion cubic feet of natural gas (1 barrel of oil = 0.16 m^3; 1 cubic foot = 2.8×10^{-2} m^3) annually for other uses such as home and commercial heating, transportation, chemical feedstock, and selected industrial and manufacturing uses. Even more important, use of coal instead of oil or gas in new fossil fuel–fired electrical generating plants would go far toward conserving natural gas resources and holding the line on increased petroleum imports.

In recent years, U.S. pollution regulations restricting sulfur oxide emissions from power plants have been one of the major deterrents to the use of the high-rank, high-sulfur coals of the Midwest and East. Reliable flue gas desulfurization processes that permit burning of these coals without adverse environmental effects are approaching full development and should encourage wider use of coal in electricity generation for the next 25 years. Estimates indicate that more than 40 sulfur dioxide scrubbing units will be installed on power plants totaling about 20,000-Mw capacity by late 1976 (*15*). The cost of these units will approach $750 million. Although this is not a significant amount of our coal-fired generating capacity, these installations should give impetus to construction of more and larger ones by 1980 and the next decade; this would refute the tenet that wide use of coal and a clean environment are mutually exclusive. As the choice of proved scrubbing technology broadens, no single process will dominate the market. Individual utilities, in addition to considering the economics, will be faced with making choices on the basis of the type of coal burned; water, land, and air pollution regulations; and the marketability of the end products.

The cost of flue gas desulfurization will be high, ranging from 1.2 to 3.2 mill/kwh. The average increase in electricity cost to consumers is expected to be about 3 to 6 percent, and in some instances as much as 15 percent. However, the added burden may not be as high as that of dependence on foreign oil, both in terms of price and reliability of supply. Combustion of high-sulfur coal followed by stack gas cleanup appears to be the cheapest alternative for meeting our electricity needs in the next few decades.

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Nuclear Eclectic Power

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Enough work has been done to permit a reasonable assessment of the major issues of nuclear power. Most of the recent fluctuations in energy patterns tend to reinforce what seemed evident even several years ago: a massive switch to nuclear power for electric energy generation, and perhaps later for other purposes. The total installed electric utility generating capacity in the United States is expected to be 480,000 megawatts by the end of 1974 (*1*); the average generation rate in March 1974 was 212,000 Mw (*2*). The present nuclear installed capacity is about 30,000 Mw. Serious predictions of 1,000,000 Mw of nuclear power installed by A.D. 2000 may come true; the total cost of those nuclear plants would be more than $600 billion. The grand total, including factories to produce the equipment and facilities to enrich uranium, process fuel, and handle wastes, may come to $1 trillion, plus the cost of transmitting and distributing the energy. Also, as alternate fuel costs rise, nuclear heat will become interesting for large-scale industrial and commercial applications. If events turn out this way, nuclear power will constitute the largest coherent technological plunge to date, with long-lasting consequences.

Any assessment of nuclear power, to be useful, must be comparative; the question is, compared to what? Until about A.D. 2000, the major choices are nuclear power, fossil fuels (of various sorts), or nothing, in varying proportions. In the 21st century, they are advanced nuclear power, increasingly sophisticated chemical fuels, probably derived from coal or oil shales, perhaps hydrogen (but made with nuclear power), perhaps solar power (more likely for many small-scale applications, in my opinion), or nothing. Beyond that era, resource limitations increasingly exclude fossil fuels. The

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