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Coal and the Present Energy Situation

Abundant coal reserves can be used to alleviate the oil and gas shortage.

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Oil and gas now provide three-fourths of the energy used in the United States—approximately 17 million barrels of oil and 65 billion cubic feet of gas per day. We can no longer meet the demand for these fossil fuels from domestic sources. Nevertheless, use of oil and gas has been steadily increasing, as have been imports of these two commodities.

Coal, on the other hand, is an abundant domestic resource, yet it supplies only 17 percent of our energy needs. We not only can meet our own coal requirements from domestic sources but are exporting $1 billion worth of coal annually. And yet use of coal in the United States is not increasing.

This situation has now reached ominous proportions. While huge coal deposits remain undeveloped, imports of oil and gas increase. To continue along this road is foolish in the extreme. Not only does our balance of trade suffer, but these imported supplies of oil and gas can be easily cut off—witness what has just occurred in the Middle East—and when that happens our national security is threatened.

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For the next few years, the principal means of increasing domestic energy supplies and certainly the first step to take is to substitute coal for the oil and gas now being used in electric generating plants. In the 1980's, gas and oil produced from coal and from oil shale should become available in sufficient quantities to help ease the petroleum and natural gas shortage.

It is hoped that atomic energy will ultimately become a significant contributor to the energy needs of this country. In the far future we will also learn how to use the abundant solar energy reaching us each day and not have to depend on that stored in fossil fuels. Neither atomic energy nor solar energy, however, can be expected to help significantly to relieve our present energy imbalance.

Use of Coal in Electric Generating Plants

The nation now uses coal for only about 55 percent of the electric power generated from fossil fuels (*1*). The power generated, capacity, and annual fuel consumption are approximately as given in Table 1. For coal to replace oil and gas in the generation of electricity, about 288 million tons of coal per year would be required, in addition to the 350 million tons a year now used by electric utilities. This additional use of coal would replace the 1.2 million barrels of oil used each day by electric utilities. Our daily oil imports averaged 5.9 million barrels for the first 9 months of 1973 (*2*). By substituting coal, therefore, we could reduce the requirement for imported oil by 20 percent.

Looking to the near future, the capacity of U.S. electric generating plants using fossil fuels will be increased by approximately 134,000 megawatts in the next 5 years (*3*). The use of coal has been planned for about half this capacity, requiring some 150 million tons of coal annually by 1978. If the plants projected to use oil go on-stream as planned, over 1.25 million additional barrels of oil will be required daily. Clearly, our foreign petroleum requirements can be significantly reduced within the next few years if we move quickly and effectively to replace oil and gas by coal for present and planned use in power plants.

Deterrents to Increased Use of Coal

Despite our enormous coal reserves, despite the fact that coal is generally a lower priced source of electricity than either petroleum or uranium, and despite the rapidly increasing demand for electric power, the amount of coal used in the United States has remained almost constant at about 550 million tons per year for the past few years.

The chief reasons for the lack of expansion in the utilization of coal are (i) the low cost, convenience, and ready availability of natural gas; (ii) the convenience of oil and the availability of low-sulfur oil; (iii) the inability of power companies to obtain assured long-range supplies of low-sulfur coal, which will be required in the near future as clean-air regulations become effective; (iv) uncertainty regarding practicability and costs of processes for removing sulfur from coal or from power plant stack gases, which could make the readily available high-sulfur coals usable; (v) increasingly stringent environmental and health-and-safety regulations affecting the mining of coal; and (vi) recurrent transportation problems.

With supplies of oil and gas now becoming uncertain, the first two of these deterrents are disappearing. If the technology can be developed so that it becomes practical to remove sulfur from the high-sulfur coals abundant in the Midwest and East, the next two deterrents will also vanish. The only major problems then remaining would be our ability to produce and to transport coal in the quantities required.

Table 1. Present annual use of fossil fuels in electric power generation. Abbreviations: kwh, kilowatt-hours; Mw, megawatts; bbl, barrels; scf, standard cubic feet.

Fuel	Power generated (10^9 kwh)	Capacity (Mw)	Consumption
Coal	771	156,375	351×10^6 tons
Oil	272	53,921	432×10^6 bbl
Gas	376	76,569	3764×10^9 scf

Sulfur Removal

Sulfur removal is, of course, extremely important in view of the high sulfur content of most coal now being mined for electric power generation and the upcoming federal, state, and local clean-air regulations. The high-rank bituminous coals of the Midwest and East characteristically contain more than 3 percent sulfur (*4*). Only 11 percent of the reserves contain 1 percent or less sulfur, and these are largely held for metallurgical use. Proposed clean-air standards generally require less than 1 percent sulfur, and some local standards place the maximum allowable amount of sulfur in the fuel as low as 0.3 percent. Fine crushing and cleaning of the coal can remove up to 50 percent of the inorganic sulfur, which on the average accounts for about half the sulfur in coal. Therefore, most midwestern and eastern coals still cannot meet the standards, even with the most modern coal preparation techniques. But such coal cleaning is a desirable first step.

Within the Bureau of Mines, studies are being made to determine the sulfur release potential of coal from the principal coal beds of the United States and the amenability of these coals to inorganic sulfur reduction by conventional coal cleaning processes, to evaluate the performance of coal washing devices for reducing the sulfur content of coals, to develop a computer program for predicting the optimal combination of coal preparation equipment for sulfur reduction, and to develop coal preparation techniques to separate fine-sized coal from pyrite. The bureau's program directed at desulfurizing fine-sized coal by froth flotation (*5*) has culminated in a unique two-stage flotation process in which pyrite is selectively floated from coal. Results to date have shown that up to 90 percent of the pyritic sulfur can be removed from some coals by the two-stage technique with excellent recovery of clean coal. The major part of the nonpyritic sulfur contained in coals is tied up in organic compounds and is not removable by any of the known processes of physical preparation.

It is possible to remove some or most of the sulfur during combustion by feeding limestone into a furnace operating with a fluidized bed of coal. To date, this has not been proved commercially, but various techniques that look promising are being researched. Work on the air pollution aspects of the fluidized-bed boiler has been under study since 1967 with the support of the Environmental Protection Agency.

Work performed thus far (*6*) indicates that the fluidized-bed boiler will meet EPA's standards for sulfur oxides, nitrogen oxides, and fly ash for new coal-fired boilers. In the case of sulfur control, it has been found that for 100 pounds of coal containing 4 percent sulfur, 15 pounds of limestone are required to remove 90 percent of the sulfur.

At present, removal of SO_2 from the stack gases (*7*) offers the most practical solution to the problem of sulfur reduction. Satisfactory commercial operation has not yet been achieved in the United States, but experimentation is well advanced on a number of systems (*8*). These include catalytic oxidation of SO_2 and removal of SO_2 by scrubbing with lime, limestone, double alkali, magnesium oxide, sodium sulfate, or sodium citrate. Based on various operating experiences in this country and Japan, the technological feasibility of flue-gas desulfurization in commercial-sized installations now seems to be established. It is probable that by 1976 power plants with a total capacity of several thousand megawatts will have flue-gas desulfurization systems in operation (*8*).

The citrate process (*9*) developed by the Bureau of Mines at its Salt Lake City laboratory is possibly the most practical of the various systems for SO_2 removal and probably less costly than most (*10*). It is currently being demonstrated at a plant in Terre Haute, Indiana. The process comprises the following steps.

1) The SO_2-bearing gas is cooled to between 45° and 65°C and cleaned of sulfuric acid mist and solid particles.

2) The SO_2 is absorbed from the cooled and cleaned gas by a solution of sodium citrate, citric acid, and sodium thiosulfate.

3) Absorbed SO_2 is reacted with added H_2S, precipitating elemental sulfur and regenerating the solution for recycle.

4) Sulfur is separated from the solution by oil flotation and melting.

The Bureau of Mines originally developed this process of SO_2 removal for treating smelter stack gases. The process was tested successfully 2 years ago on a small scale at the San Manuel copper smelter in Arizona and will soon be further evaluated at a pilot plant under construction at the Bunker Hill Company lead smelter in Kellogg, Idaho. Meanwhile, the bureau is cooperating in the Terre Haute pilot program, which is jointly sponsored by Pfizer Inc., Arthur G. McKee & Co., and Peabody Engineering Corp. The demonstration test (*11*), under way since June 1973, is being conducted on gases containing about 0.25 percent SO_2. These gases result from the burning of an Indiana coal that contains about 4 percent sulfur. Although the steam facility is much smaller than that required for an electric power generating unit, it is believed that the effluent gas is similar to power-plant gases. Therefore, results should be indicative of those likely to be obtained when processing actual power-plant effluents.

The pilot plant is scaled to process 2000 standard cubic feet per minute of gas containing about 0.25 percent SO_2. Initial results in the plant have demonstrated that more than 95 percent of the SO_2 can be removed from the flue gases. Based on the preliminary data obtained from the pilot facility, projections of the capital cost and operating costs have just been released by the companies. Capital costs for a 200-megawatt power plant have been estimated at $31 per kilowatt capacity. This compares favorably with the estimated capital cost of $45 per kilowatt capacity when a nonregenerative limestone process is used. Operating costs of the citrate process, including amortization of the capital investment, were estimated at 1.3 mills per kilowatt-hour, compared to 2.1 mills per kilowatt-hour for the limestone process. These estimates compare favorably with those made earlier by the Bureau of Mines (*9*) for the process, which indicated that for a 1000-megawatt plant burning bituminous coal [25 million British thermal units (Btu) per ton] with 3 percent sulfur, the citrate process would add about 1.4 mills per kilowatt-hour (or $4.10 per ton of coal burned) to power costs, without credit for the sulfur recovered.

It appears, therefore, that for an additional cost of about $4 per ton of coal the sulfur regulations can be met, with elemental sulfur as a by-product. This compares with the cost of about $9 per ton for shipping low-sulfur coal into the Midwest from Wyoming, the energy for the shipment coming from scarce petroleum. And the Wyoming coal has a lower heating value than midwestern coal. With the cost of imported oil rising rapidly, using midwestern or eastern coal should be less expensive than using oil, even with this additional cost of $4 per ton for sulfur removal.

Expansion of Coal Production

The second problem is expansion of coal production and transportation facilities if coal is to replace oil and gas in electric generating plants. To meet an increase in demand of, say, 60 million tons of coal a year, or about 10 percent per year in total production, the coal companies must be given an adequate incentive, and it must be possible for them to mine the coal in such a way as to meet government environmental and health-and-safety standards. As to the former, the principal incentive is an assured market for the coal over a 20- to 30-year period at an acceptable price to the producer.

With regard to government regulations, those currently in force which are applicable to strip mining do not have a serious effect on coal production. Costs for land reclamation range from about 10 to 50 cents per ton of coal mined. As for underground coal mining, the health-and-safety regulations are difficult and expensive to meet and are believed to be partly responsible for the decrease in productivity in underground coal mining that has occurred during the past few years. Coal companies, however, are continually doing a better job of compliance and are learning to live with these regulations.

Unless government action requires it, however, the demand for coal to replace oil in electric generating plants may not increase significantly. It does appear that some such action may finally be taken, as a consequence of the recent oil boycott and rising crude oil prices.

Coal Gasification and Liquefaction

I have talked about the short range—to about 1980. What about the longer range, say the period 1980 to 2000? Conversion of coal to a clean gaseous or liquid fuel should, over the longer range, be on a large enough scale to have a significant impact in meeting energy requirements. But these fuels will be expensive and will certainly not be in large-scale production for a decade or more. Coal conversion is also costly from a conservation standpoint, for about 25 percent of the energy in coal is lost in converting it to gas or oil.

Two kinds of gases from coal are currently being considered for commercial development. They are characterized arbitrarily by their heating value.

High-Btu gas, commonly referred to as substitute natural gas (SNG), has a heating value of about 1000 Btu per cubic foot, and, as the name implies, it has the same chemical and physical properties as natural gas and is completely interchangeable with natural gas.

Until recently, energy projections did not anticipate a demand for synthetic fuel gases having a heating value lower than SNG. There are compelling incentives now, however, to develop processes that will convert coal to a clean, low-Btu gas for power generation and for certain industrial operations that converted from coal to natural gas years ago, when natural gas was cheap and abundant. Low-Btu gas has a heating value in the range 100 to 200 Btu per cubic foot.

High-Btu Gas (SNG)

Beginning with laboratory and small pilot-plant research on coal gasification, the Bureau of Mines has developed a comparatively simple process for converting coal to SNG. It is known as the Synthane process (*12*). A large Synthane pilot plant has been designed and is now under construction at the bureau's energy research center in Pittsburgh, Pennsylvania. The plant should be ready for operation in the fall of 1974.

About 75 tons of coal will be gasified daily at this plant so that the bureau can obtain the data required to evaluate the technical and economic feasibility of a full-scale, commercial-size Synthane plant. It would be 200 times larger than the pilot plant and would produce 250 million cubic feet of SNG daily from about 15,000 tons of bituminous coal.

Several other high-Btu gas demonstration plants (*13*), each using a somewhat different process, are in operation or under construction. Among these are the Hygas process, developed by the Institute of Gas Technology, the CO_2-Acceptor Coal-Gasification process, developed by the Consolidation Coal Company, and the Bi-Gas process, developed by Bituminous Coal Research, Inc. These projects are being funded jointly by the American Gas Association and the Office of Coal Research of the Department of the Interior.

These processes differ in important respects, and which of the processes may prove the most practical for commercial operation will probably not be known for 2 or 3 years. In all these processes a low-Btu gas is first obtained, its composition is shifted so that it has a ratio of hydrogen to carbon monoxide of 3 to 1, and it is cleaned and transformed into methane.

The cost of an SNG plant having an output of 250 million cubic feet daily is estimated to be about $300 million. The cost of the gas in present dollars would be about $1.50 per thousand cubic feet or per million Btu's.

Low-Btu Gas

A low-Btu gas from coal, which can be fed into an appropriate turbine system for power generation, is an attractive possibility. The Bureau of Mines has developed a high-pressure, stirred, fixed-bed producer to make clean, low-Btu gas (*14*). A pilot plant gasifying 18 tons of coal daily is located at the bureau's energy research center in Morgantown, West Virginia. It is equipped with a variable-speed rotating grate and a stirrer in the fuel bed. The stirring mechanism is unique in having compound rotating and reciprocating action, which prevents coal bridging and agglomeration in the fuel bed.

Fixed-bed gasification of coarse-sized coal is an old concept, but it had some limitations that the bureau's gasifier has overcome. First, the installation can handle strongly caking coals. Strongly caking eastern bituminous coals have been successfully gasified with air and steam into a gas with a heating value of 150 Btu per cubic foot. Second, the finer sizes as well as the coarser sizes of coal can be gasified. Coal feeds with more than 50 percent in the size fraction less than ¼ inch have been gasified as successfully as larger sizes of coal. Both improvements are important because they make fixed-bed gasification more versatile.

Underground, or in situ, coal gasification (*15*), if successfully developed, would provide a commercial low-Btu gas and at the same time eliminate many of the health, safety, and environmental problems associated with conventional production of coal by mining. Between 1946 and 1958 the Bureau of Mines made field studies of underground gasification at Gorgas, Alabama. That program was terminated when the data obtained showed that the process was not economically feasible—at that time.

Technology has improved markedly in many aspects of underground gasification since those first experiments. These improvements are mainly in the fields of fracture and permeability orientation, explosive fracturing, and directional drilling. Each has potential for improving the technology and economics of underground gasification, and the bureau has resumed laboratory and field studies of the technique. Project goals include maximizing the recovery of the energy available in the coal bed and achieving steady-state operation for extended periods.

The bureau is now making field tests in underground gasification of subbituminous coal near Hanna, Wyoming, to obtain a low-Btu gas that can be piped to the surface and cleaned to produce a nonpolluting fuel (*16*). At Hanna, 16 wells were drilled over a 4-acre area into a coal seam 30 feet thick lying about 400 feet below the surface. Permeability of the coal bed around a centrally located borehole was increased by hydraulic fracturing. The coal was ignited, and gasification has been maintained continuously by injecting combustion air through boreholes farther from the center. After 8 months of injecting air, product gas is currently flowing to the surface at the rate of about 2.5 million standard cubic feet per day, the maximum flow rate which the present equipment can handle. The heating value of the gas averages 140 to 150 Btu/scf. The gas is composed of about 5 percent methane, 10 percent carbon monoxide, 15 percent hydrogen, 15 percent carbon dioxide, and 55 percent nitrogen. About 25 tons per day of coal is being consumed. Judging from the carbon material balance, the process is yielding between 50 and 55 scf of gas per pound of coal, or is about 75 percent efficient. A backward burning procedure without prior fracture of the coal has recently been found to be highly successful.

The Bureau of Mines intends to begin in the near future a parallel project demonstrating underground coal gasification in the Appalachian coal fields. This will provide additional useful information, inasmuch as the eastern coals and their geological environment are significantly different from those in Wyoming.

In three types of coal occurrences, underground gasification may turn out to be the most practical means of utilizing the energy from coal: (i) Very deep coal seams, where mining is extremely hazardous and expensive, or which cannot be mined at all with present techniques. These deep seams contain high concentrations of methane, which are a danger in coal mining but an asset in underground gasification. (ii) Thick underground seams, common in the West, where a thickness of 30 feet is not unusual and where coal beds over 100 feet thick occur. In these thick seams, where they are buried too deep for surface mining, only 25 percent or less of the coal can be recovered by using present mining technology. With underground gasification most of the heating value of the coal should be recoverable. (iii) Coal seams that are not especially deep or thick but are impractical to mine because of bad roof conditions, thinness, high ash content, or other problems.

Liquid from Coal

A low-sulfur liquid from coal, to be used as a fuel oil, has possibilities. One of the most attractive processes is now in operation in a small-scale pilot plant at the Bureau of Mines' energy research laboratory near Pittsburgh. The bureau's Synthoil process (*17*) involves passing a mixture of coal and oil derived from coal along with hydrogen through a fixed bed of cobalt molybdate alumina catalyst pellets. The gas rate is adjusted to maintain turbulence inside the reactor, preventing deposit buildup on the catalyst and improving contact between the coal and catalyst.

The operability of this continuous hydro-desulfurization process has been demonstrated. In one test of the process, a low-value strip-mined coal, containing 4.6 percent sulfur and 17 percent ash, was processed to yield 3 barrels of oil per ton of coal. The product contained only 0.2 percent sulfur and 1.0 percent ash, and the ash content was further reduced to 0.1 percent by filtration.

Recoverable Methane in Coal Beds

Coal beds contain methane gas, which is the same as our pipeline natural gas. Coal beds at the surface have ordinarily lost most of this methane, but deeper seams retain it. Some of the deeper coal beds in the Appalachian fields produce over 12 million cubic feet of methane per day (*18*) during the mining of the coal. The greatest peril of underground coal mining has been explosions and fires initiated by ignition of this gas, which is flushed out of the mine with ventilating air. The Bureau of Mines has been exploring ways of bleeding off this gas from coal seams as a safety measure (*19*). Bureau engineers now report (*20*) that newly developed drainage techniques appear practical as a means of recovering the gas. They estimate that underground coal on the average contains about 200 cubic feet of methane per ton of coal. Minable coal beds in the conterminous United States therefore contain about 260 trillion cubic feet of methane, an amount about equal to the nation's present proved reserves of natural gas. The locations of most of the coal beds are already known, so that only minor investments in exploration and modest advances in technology would be required to tap this large resource of natural gas and at the same time to increase the safety and lower the cost of mining coal. One of the problems here is that in some states oil and gas rights are separate from coal rights and a question exists as to who owns the gas.

Underground Coal Mining

I would like to close with one further thought. As the production of coal from underground mines increases, more consideration should be given to changing mining techniques and to long-range planning, with the objective of lessening waste of coal and damage to the surface.

In the United States, underground mining recovers only a little over half the coal, on the average. The rest is left chiefly as pillars to support the roof—for a few years. Eventually the pillars give way, the roof caves, the surface subsides, and the coal left becomes very difficult to ever recover. We can and should recover a much higher percentage of the coal, and the surface subsidence problem should be taken care of now, not left for the next generation. Incentives, regulation, and long-range planning are required, along with improved technology, if underground mining is not to turn into a worse menace and a much worse waste of resources than strip mining.

Conclusion

To summarize, we must make greater use of coal, an energy resource that the nation has in great abundance, if we are to approach our former position of self-sufficiency in energy production.

The first step is to move immediately to replace the oil and gas used in electric generating plants with coal and to require that coal be used in fossil fuel electric plants planned or under construction in the next few years. The technology to remove sulfur and particulates from the stack gases is at hand, and therefore environmental regulations can be met.

Producing and transporting the required increased tonnages of coal are problems that can be met with appropriate incentives to the coal and transportation industries. Improved mining technology would be helpful but is not a requirement.

Oil and gas from coal should be in significant commercial production in about a decade. Underground, or in situ, gasification of coal, now in field tests, looks promising as a practical process for recovering the energy from coal, especially in deep or thick beds that cannot be mined efficiently.

Recoverable methane occurs in coal beds in the United States in an amount approximately equal to the total reserves of natural gas—about 260 trillion cubic feet. This large reserve of natural gas should be exploited as quickly as possible. Only minor investments in exploration and modest advances in technology are required.

Finally, as coal production is expanded, adequate planning and the most modern technology should be used to ensure that coal is extracted with maximum recovery and with minimum damage to the environment.

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