Centralized Alternatives: Synthetic Fuels (2.5)

Overview (2.5-1)

Easily extractable sources of relatively clean energy are rapidly dwindling worldwide and becoming increasingly expensive. Their scarcity threatens U.S. national security. Development of new energy resources has become both an urgent national priority and an increasingly competitive commercial venture.

One promising source of new energy is the manufacture of synthetic fuels (synfuels) from coal and oil shale. Synthetic fuels are obtained by converting a carbonaceous material to another form. Synfuels include low-, medium-, and high-Btu gas, liquid fuels such as fuel oil, diesel, gasoline, methanol, and clean solid fuels.

Since the resource base for synfuels is coal and oil shale, it is important to quantify this resource base. With coal, quality is also important. Coal quality and heat content vary greatly. The fraction of carbon in the coal increases and the moisture content decreases from lignite to anthracite.[126] The U.S. coal fields, excluding Alaska, and types of coal found in these fields are shown in Figure 2.5-1.

Regional distribution of the demonstrated coal reserves is shown on Table 2.5-1. This reserve refers only to identified resources suitable for mining by present methods, where 50 percent of the reserve is recoverable. Almost half of the nation's coal is found in the Northern Great Plains and the Rocky Mountain region where more than 40 percent of the coal can be surface mined. Surface or strip mining can be done more economically and with a much higher proportion of the coal recovered. It is estimated that the nation's coal reserves are sufficient to satisfy the U.S. needs for 200 years at current rates of consumption.[127, 128]

Oil shale is sedimentary rock containing organic matter which when heated to its pyrolysis temperature yields "kerogen." The spent residue, or tailings, are composed mainly of inorganic matter. Shale with about seven percent by weight of organic matter yields approximately ten gallons of oil per ton (.04 liters/kg) of shale. High grade oil shale is considered to be shale with an organic content greater than fourteen percent that yields 25 gallons (.1 liters/kg) or more of oil per ton of shale and is found in seams at least ten feet thick (3 m). In general, oil shale deposits tend to be significantly thicker than coal seams and shale is considerably harder than coal.[129, 130, 131]

Significant quantities of lower grade oil shale are found in many areas of the United States, especially in the same region as the coal reserves. However, the greatest potential for commercial production rests with high grade oil shale located in the areas of Colorado, Utah and Wyoming in what is called the Green River Formation. (See Figure 2.5-2). The identified high grade shales with yields in excess of 25 gallons per ton (.1 liters/kg) have an oil equivalence of approximately 570 to 620 billion barrels. The most productive and accessible zones are estimated to yield about half of this amount.

Figure 2.5-1[132]

COAL FIELDS OF THE CONTERMINOUS UNITED STATES

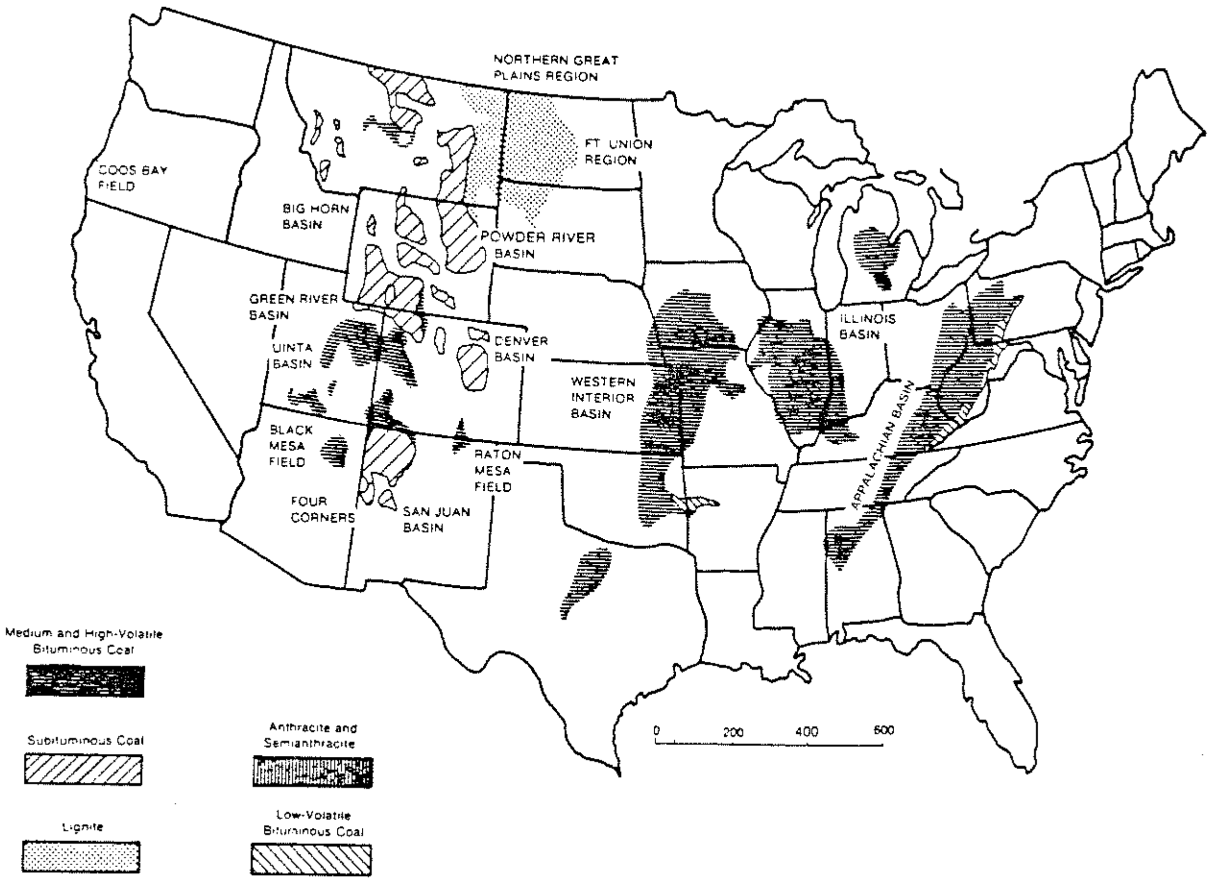


Table 2.5-1[133]

DEMONSTRATED U.S. COAL RESERVES BY REGION AND METHOD OF MINING 10^9 TONS (9.1 x 10 kg)

Region	Underground	Surface	Total
Northern Great Plains and Rocky Mountains	113 (51.3)	86 (39)	199 (90.3)
Appalachian Basin	97 (44)	16 (7.3)	113 (51.3)
Illinois Basin	71 (32.2)	18 (8.2)	89 (40.4)
Other	16 (7.3)	17 (7.7)	33 (15)
TOTAL	297 (134.7)	137 (62.1)	434 (196.9)

Synthetic Fuels from Coal (2.5-2)

Coal is a flexible primary fuel which can be used in its solid form to fuel a conventional boiler, a fluidized bed, or a magnetohydrodynamic facility. Alternately, it can be converted to liquid or gaseous synthetic fuels and used in conventional systems, or in advanced systems specifically designed to match synthetic fuel properties.

Table 2.5-2 lists the various technology options for converting coal to synthetic fuels. Also included are estimated dates for commercial availabilities along with estimated costs in 1980 dollars. It is significant that coal gasification is the initial step in producing several of the listed synthetic fuels. The gas produced from coal may be burned directly to generate process heat or electricity or it may be further processed to produce synthetic natural gas (SNG) or methanol. SNG and methanol can also be used to produce process heat and electricity and, in the case of methanol, can be used in transportation.[134, 135]

Low-and Medium-Btu Coal Gasification (2.5-3)

Coal can be gasified to produce either a low- or a medium-Btu gas. Low-Btu gas is produced by using air to supply oxygen to a gasifier. It has a heating value of 100 to 250 Btu per standard cubic foot (scf) (320-800 Btu per standard cubic meter). Low-Btu gas can be burned directly to produce process heat or electricity. It is not used, however, as a feedstock for SNG or methanol production. Medium-Btu gas is produced by supplying pure oxygen to the gasifier. It has a heating value of 250 to 450 Btu per scf (800-1,440 Btu per standard cubic meter). Medium-Btu gas has the potential for further processing into SNG or methanol. Figure 2.5-3 illustrates conversion of coal and low- and medium-Btu gas.

The production processes for both low- and medium-Btu gas are similar and, therefore, only the medium-Btu gas process will be discussed. It should be noted that several of the principal coal gasification technologies can be used for either low- or medium-Btu gas production including Lurgi, Koppers-Totzek, and Texaco systems.

Many processes for producing medium-Btu gas from coal have been investigated. In general, they start with the partial oxidation of coal in the presence of steam and oxygen. The gas produced contains combustible components including carbon monoxide, hydrogren, and methane, as well as noncombustible gases such as carbon dioxide and sulfur compounds.[136, 137, 138]

Before it can be used, the gas must be cleaned to remove impurities such as hydrogen sulfide and carbon disulfide. Depending on the particular process, carbon dioxide content may also be reduced. If medium-Btu gas is to be used for SNG or methanol production, it must also undergo shift conversion to increase the hydrogen concentration of the gas. The gasifier produces solid and liquid wastes which require disposal.[139]

Figure 2.5-2[140]

OIL SHALE AREAS OF THE GREEN RIVER FORMATION IN COLORADO, UTAH, AND WYOMING

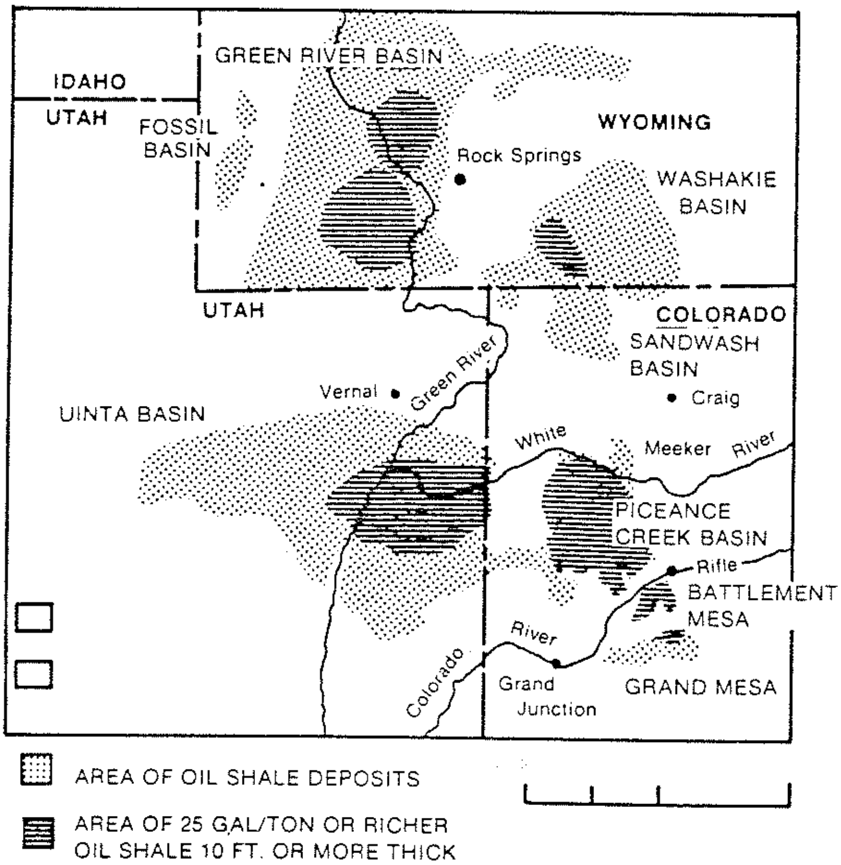


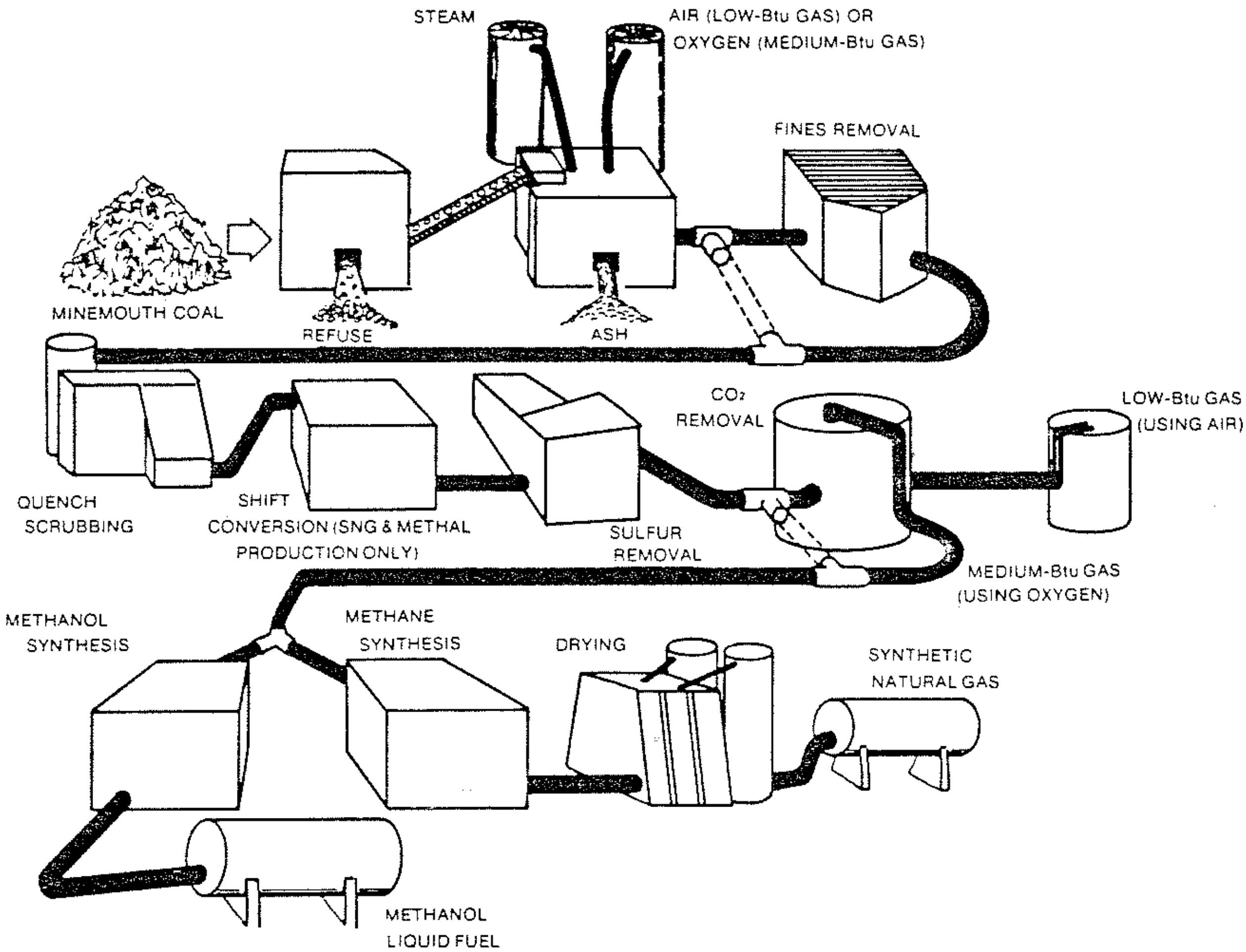
Table 2.5-2[141]

SYNTHETIC FUELS FROM COAL

Technology	Commercially Available	Estimated Cost $/Million Btu (1980)
Low-, Medium-Btu Gas	1985	4.40 - 6.60
Synthetic Natural Gas	1985	5.50 - 8.80
Methanol From Coal	1986	6.92 - 7.90
Synthetic Oil	1990	5.50 - 7.70

Figure 2.5-3[142]

COAL GASIFICATION



Proposed or planned coal gasification products in the U.S. include a variety of first and second generation medium-Btu gas processes. First generation processes are in commercial operation in various parts of the world, but not in the U.S. Second generation processes are being developed to improve efficiency and operation flexibility. A selected list of coal gasification processes including those receiving the most attention in the United States is provided in Table 2.5-3.

Commercial suppliers currently exist for the first generation gasifiers such as the Lurgi and Kopper-Totzek. However, commercial suppliers do not exist for second generation systems such as the Texaco process and the necessary technology is still evolving.

Recent estimates for medium-Btu coal gasification range from $4 to $6 per million Btu in 1979 dollars. These costs compare to costs of over $5 per million Btu for #2 diesel fuel. However, the coal gasification cost estimates are based on mine mouth production and do not include transportation costs.[143]

In summary, medium-Btu coal gasification processes are commercially available at reasonable costs. The technology has been commercially demonstrated abroad. The applicability of this experience to the U.S. is uncertain because of differences in economic conditions and environmental regulations. It is also significant that economies of scale are important with medium-Btu gas production. Economies of scale dictate that commercial facilities be relatively large, or equivalent to 500 MW power generation stations. On the other hand, low-Btu gas production is not especially dependent on economies of scale.[144, 145]

Coal-Derived Synthetic Natural Gas (2.5-4)

Synthetic natural gas (SNG) is a potential substitute for natural gas and may be used in conventional systems. SNG is a methane-rich, high-Btu gas which has had many of the impurities removed. Its heating value is approximately 1000 Btu per standard cubic foot (3,200 Btu per standard cubic meter). It can be produced from coal, agricultural and lumber residues, municipal solid waste and many other organic materials. The principal method of producing SNG is from the gasification of coal. Gasification and processing can occur at the mine mouth where the SNG can be introduced into the natural gas pipeline system.

There are several major steps in the process for producing SNG from coal. The coal is first gasified to produce medium-Btu gas. The medium-Btu gas must then undergo a shift-conversion process to increase its hydrogen concentration in order to achieve the appropriate hydrogen-carbon ratio for producing methane (CH_4), the primary constituent of SNG. In the final methanation step, the gas is reacted catalytically to form methane from carbon monoxide and hydrogen. After drying, the resulting high-Btu SNG is ready for on-site use or for transmission by pipeline. Pilot demonstrations of catalytic methanation to obtain SNG from medium-Btu gas from coal have been performed in Scotland, South Africa, and Austria.

The Department of Energy (DOE) notes that all of the individual process units required for a SNG-from-coal production facility using first generation gasifiers have operated commercially at numerous plants for purposes of producing SNG from feedstocks other than coal. There is, however, some technical risk in integrating coal gasification and SNG production components into a working commercial scale system.

Large SNG plants previously proposed in the U.S., for example, the El Paso, Wesco and Mercer projects, have been based on first generation Lurgi coal gasification processes. The Mercer County, North Dakota, project may be the nation's first SNG commercial demonstration plant. It would produce 125 million cubic feet of SNG daily.[147]

Suppliers exist for the technology to produce SNG from medium-Btu gas. These include the Institute for Gas Technology, Girdler and Conoco companies.[148]

Table 2.5-3[146]

SELECTED MEDIUM-BTU COAL GASIFICATION PROCESSES

Process	Description	Status	Examples of Proposed Uses In the United Stated
First Generation			
Lurgi	Fixed bed process operating at 350-450 psi pressure which favors the formation of methane in the gasifier and reduces product transmissions costs (gas is already pressurized). Disadvantages include the production of liquid hydrocarbon by-products that must be separated and difficulty in handling U.S. eastern bituminous coal.	Approximately 20 plants in commercial operation outside U.S., the largest being the SASOL I plant in South Africa.	Mercer Co., N.D., planned SNG facility, 15,000 tpd, 1983 start date.
Koppers-Totzek	Entrained flow gasifier operating at atmospheric pressure. Does not generate hydrocarbon by-products.	Sixteen plants in commercial operation outside U.S. primarily for ammonia production; also used in a small-scale methnol-from coal plant in South Africa.	W.R. Grace & Co., for a proposed methanol-from coal facility in Colorado, 10,000 tpd, feasibility study planned for near future.
Winkler	Low-pressure fluidized bed process.	Existing commerical installations include seven plants in Germany.	None identified.
Second Generation			
Stagging-Lurgi	Adaption of the first generation Lurgi process improved to include greater coal throughput and recycling of hydrocarbon by-products.	Pilot plant operated in Westfield, Scotland.	None identified.
Texaco	Pressurized entrained flow gasifier. Generates no hydrocarbon by-products.	A 150 tpd unit operating in West Germany for over a year.	Southern California Edison for a proposed demonstration integrated coal gasification combined cycle power plant in Southern California, 1000 tpd, operation planned for 1983. DOE/W.R. Grace & Co. for methanol production, in Kentucky, 29,000 tpd, in intial design phase with operation possible by 1966.
U-Gas	Pressurized fluidized bed design.	A 24 tpd pilot plant operated in Chicago by the Inst. of Gas Technology.	DOE/Memphis Light, Gas & Water for industrial fuel use in Memphis, 316 tpd planned for mid-1980s.

Various factors such as inflation and construction lead times affect the estimated cost of future coal gasification plants. Recent estimates project a cost for SNG between $5 and $8 per million Btu in 1979 dollars. The current cost of Canadian natural gas is $4.65 per million Btu. The price of natural gas will continue to increase to approximately $6 per million Btu. DOE projections for SNG conclude that SNG will be marginally competitve with natural gas under an assumed high natural gas price. Arthur Seler, Jr., Chairman of American Natural Resources Company which leads the consortium building the Mercer County Project, forecast a delivered price from that plant of approximately $7.25 per million Btu in 1983. He believes this will prove competitive as the costs of other energy sources escalate.[149, 150, 151, 152]

The lack of commercial demonstration, variation and uncertainty in cost estimates for SNG from coal gas and uncertainty about future costs of competing fuels cause a corresponding uncertainty in the commercial availability of SNG.

Comparing the estimated cost of SNG with the rising prices of petroleum products suggests that coal-derived SNG could be used in certain conventional applications, such a power plants, at a reasonable cost. Overall, however, it appears that a commercial demonstration may be needed to evaluate the economic feasibility of SNG production. The potential problems in integrating the medium-Btu gasification and methanation processes into a commercial plant and the possible impacts on reliability and other perfomance characteristics must be defined. A commercial demonstration would help to reduce the uncertainty of producing SNG from coal and may be a necessary step to establish SNG from coal as a viable energy alternative. Finally, as with medium-Btu gasification, SNG facilities will be subject to economies of scale which dictate that facilities be relatively large and centralized.[153]

Methanol from Coal (2.5-5)

Methanol, a liquid fuel derived from coal and other organic materials such as wood and petroleum, could be used as a fuel in conventional utility and industrial systems as well as in the transportation sector. Methanol (CH_3OH), like SNG, can be synthesized by catalytically reacting medium-Btu gas produced by any coal gasification process which produces CO/H_2 mixtures.

The synthesizing of methanol from medium-Btu gas is a well proven technology. At least two companies (Imperial Chemical Industries and Lurgi) offer proprietary processes with guarantees backed by multiple commercial-scale plant operating experience.

A small subcommercial-scale plant for the production of methanol from coal-based medium-Btu gas using the Koppers-Totzek gasification process and the Imperial Chemical Industries methanol process has been operating at the Modderfontein, South Africa plant site for over two years.[154]

No commercial-size methanol-from-coal plants currently exist. Based on the size of a number of proposed projects, however, it is reasonable to expect that a commercial-size plant would probably use at least 5,000 tons (4.5 million kg) of coal per day. Methanol production, however, is in commercial operation using feedstocks such as natural gas and naptha. The use of coal creates additional technical requirements, such as a need for continuous and reliable high-efficiency gas clean-up to avoid poisoning the methanol synthesis catalyst.[155, 156]

Several commercial projects to produce methanol from coal are now being pursued in the U.S. which could lead to commercial demonstration by 1986. This time frame requires that commitments to construct must begin soon since the permitting process and construction will require at least five years. Wentworth Brothers, Inc. have completed the preliminary engineering and economic evaluations for three potential projects; they selected the Texaco process for coal gasification.

W.R. Grace and Company plans to do a feasibility study for a plant in northwestern Colorado for producing 5,000 tons (4.5 million kg) of methanol per day from coal. The study is expected to take six months and a decision to proceed with the project is expected within a year. Grace plans to use the Kopper-Totzek gasifiers. As also noted in Table 2.5-3, Grace is beginning design analysis for a methanol-from-coal plant, using Texaco gasifiers, where the methanol would then be converted to gasoline. Two other major coal-to-methanol projects are under consideration in the U.S. by Conoco and Texas Eastern. They plan to use the Lurgi gasifier.

Methanol from coal is on the verge of being an economically competitive alternative to coal for power production or as a transportation fuel. However, cost estimates will continue to be subject to uncertainties until more experience is gained.

The commercial availability of coal-derived methanol is uncertain for reasons similar to those for coal-derived SNG. The demonstration of an integrated system is important to establish the technology for gas clean-up, to avoid methanol-synthesis catalyst poisoning, to determine operating requirements, and to study process economics. As with SNG production, methanol production from coal is subject to economies of scale.[157]

Synthetic Oil from Coal (2.5-6)

Potentially, several coal-hydroliquefaction processes could be used to produce synthetic oil for conventional applications. In hydroliquefaction, coal is dissolved in an appropriate solvent, then reacted with hydrogen to produce liquid fuel oils. Synthetic oil would require refining in a process similar to that for crude oil. The resulting synthetic fuels could substitute for residual fuel oil or distillate fuel in conventional systems.[158, 159]

Although no plants are now in operation, Germany used the Bergius process for catalytic hydrogenation of coal to make approximately 90 percent of its aviation gasoline in World War II. All modern hydroliquefaction processes are descendants of this process.

The DOE has noted that the H-Coal, Donor Solvent and Solvent Refined Coal (SRC) processes have received significant attention in the U.S. A small five-ton-per-day SRC plant has been operating since 1975; a single module of a commercial-scale plant for each of the SRC processes is in the design phase; a 600-ton-per-day H-Coal plant is under construction; and a 250-ton-per-day Exxon Donor Solvent plant is under construction. Some of these processes could be commercially available by 1990. Currently, however, there are no suppliers in existence to commercially produce synthetic oil from coal. Estimated production costs for synthetic oil are in the range of $5 to $7 per million Btu.[160]

There are significant technical differences between synthetic oil production and the gasification process which lead to questions regarding the long-term desirability of developing the liquefaction technologies. Since dried coal is required for the hydroliquefacton processes, use of western coals with higher moisture content may severely reduce the thermal efficiency. Further, the coal liquefaction process does not function well with western coals due to their high oxygen content, high alkalinity and low sulfur levels, and because the high oxygen content results in massive consumption of process gas. The high alkalinity interferes with catalytic reactions, and the low sulfur levels inhibit the dissolution of the coal in the solvent. These suggest that the cost of liquefying many western coals would likely be higher than for eastern coals.[161]

Synthetic Fuels from Oil Shale (2.5-7)

Unlike coal which can be readily used in its solid form or converted to several synthetic fuels, synthetic fuels from oil shale will consist primarily of synthetic crude oil. While it is technically feasible to gasify shale oil, the economics and usefulness of such action are not justified. On the other hand, the attractiveness of oil shale development is that the end product, syncride, is readily adaptable to the existing petroleum infrastructure from refining to the use in utility, industrial and transportation sectors.[162]

Figure 2.5-4 is a block diagram for oil shale development. the conversion of oil shale to finished fuels or other products such as chemical feedstocks requires a series of processing steps. Numerous specific processes can be generically grouped as follows:

1. True in-situ (TIS) processes in which the oil shale is left underground and is heated by injecting hot fluids;

2. Modified in-situ (MIS) processes in which a portion of the shale deposit is mined and the rest is fractured with explosives to create a highly permeable zone through which hot fluids can be circulated;

3. Above Ground Retorting (AGR) processes in which the shale is mined, crushed, and heated in vessels near the mine site.[163]

True In-Situ Processing (TIS) (2.5-8)

Numerous types of TIS processes have been proposed and differences between the processes relate to varying methods for preparing and heating the oil shale deposit. All processes use a system of injection and production wells drilled according to a prescribed pattern. All processes can be generally described by the following steps:

1. Dewatering, if the deposit occurs in a ground water area;

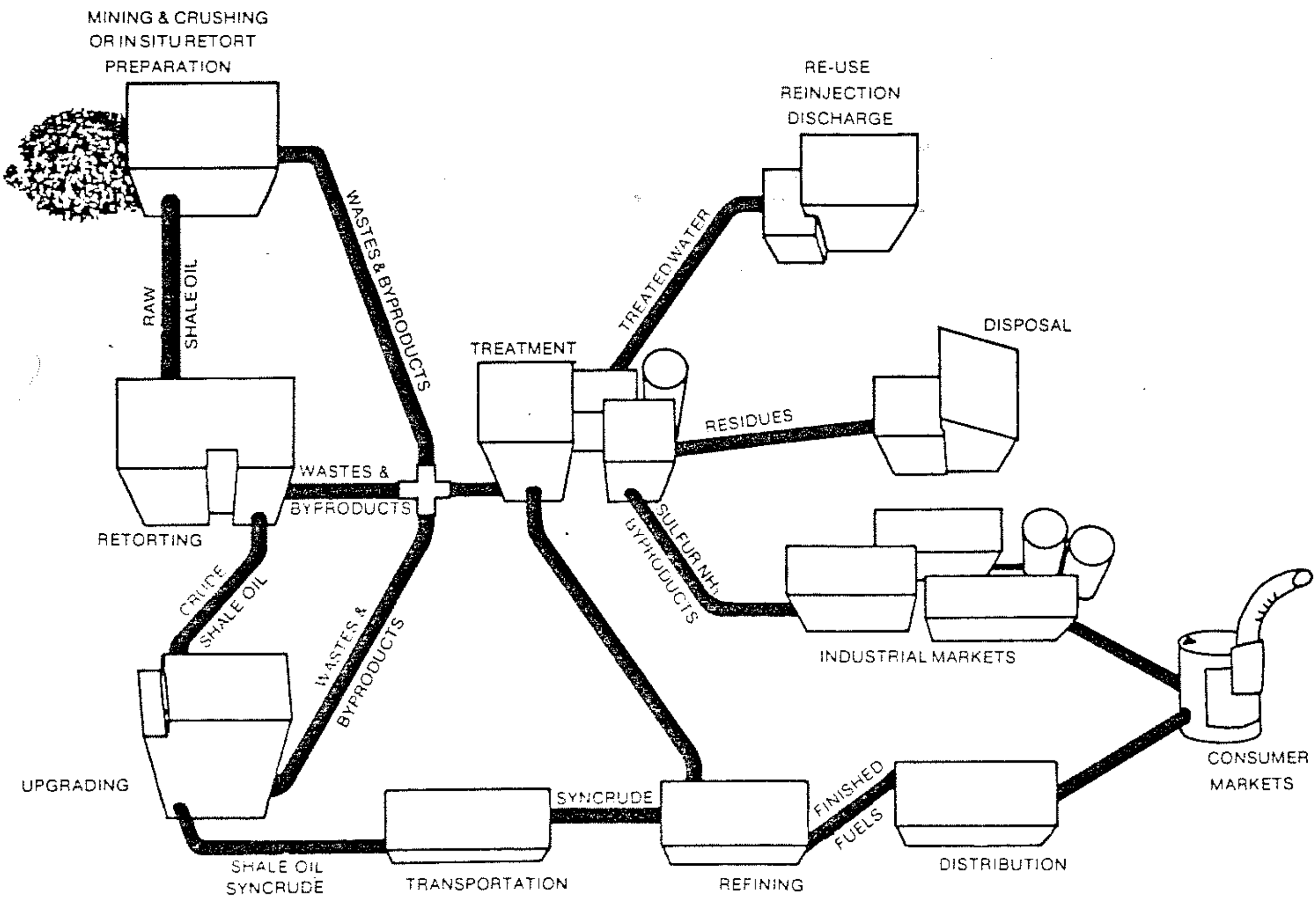
2. Fracturing or rubbling, if the deposit is not already permeable to fluid flow;

3. Injection of a hot fluid or ignition of a portion of the bed to provide heat for pyrolysis; and

4. Recovery of the oil and gases through production wells.

Figure 2.5-4[164]

OIL SHALE UTILIZATION



In all cases, the permeability of the shale to hot fluids is a critical variable, and that permeability is primarily responsible for the low oil recoveries often associated with TIS processing. That is, large impermeable blocks of shale in the fractured formation cannot be fully retorted in a reasonable length of time, or in some instances irregular fractures can cause the heat carrier to bypass large sections of the deposit.[165, 166]

Research regarding TIS processes is still required. There are currently no commercial-scale plants operating, although the DOE and Geokinetics plan to develop a commercial-scale operation with a production capacity of 2,000 barrels per day by 1982.[167, 168]

Modified In-Situ Processing (MIS) (2.5-9)

In the MIS process, some shale is mined from the deposit and then explosives are detonated in the remaining deposit to increase the permeability of the oil shale. This procedure creates a chimney-shaped underground retort filled with broken shale. Access tunnels are sealed and an injection hole is drilled from the surface to the top of the fractured shale. The shale is ignited at the top by injecting air and burning fuel gas, and heat from the combustion of the top layers is carried downward in the gas stream. The bottom of the oil shale is pyrolyzed and oil vapors are swept down the retort to a sump from which they are pumped to the surface. The burning zone moves down the retort fueled by residual carbon in the retorted layers. When the zone reaches the bottom of the retort, the flow of air is stopped and combustion stops.

Occidental Oil Shale, Inc., a subsidiary of Occidental Petroleum Company, has demonstrated the MIS process on a nearly commercial scale. Numerous other companies are also conducting research and development programs with MIS. If present plans are followed, Occidental's technology could be used to produce 57,000 barrels per day by 1985.[169, 170]

The MIS processes are more advanced than TIS methods. The principal advantages of MIS are that large deposits can be retorted, oil recovery ratios are high, and relatively few surface facilities are required. However, some mining and disposal of solid wastes on the surface are required and the oil recovery per unit of ore processed is low relative to above ground retorting methods. In addition, the burned-out MIS retorts have the potential for ground water pollution.[171, 172]

Above Ground Retorting (AGR) (2.5-10)

Above Ground Retorting differs from the in-situ processes in that all the shale feedstock is mined. The principal advantage of AGR is the oil recovery efficiency.

Above Ground Retorts are grouped into four classes:

1. Class 1: Heat is transferred by conduction through the retort wall. The Fischer assay retort is in this class and is used to estimate potential shale oil yields. Its oil yield is the standard against which the retorting efficiencies of all other retorts are compared. Because conduction heating is very slow, no modern industrial retorts are in Class 1.

2. Class 2: Heat is transferred by flowing gases generated within the retort by combustion of carbonaceous retorted shale and pyrolysis gases. Retorts in this class are directly heated and produce a spent shale low in residual carbon and low-Btu retort gas. Their thermal efficiencies are relatively high; however, recovery efficiencies are relatively low (about 80-90 percent of Fischer assay).

3. Class 3: Heat is transferred by gases that are heated outside of the retort vessel. These retorts produce a carbonaceous spent shale and a high-Btu gas. Thermal efficiencies are relatively low, but oil recovery efficiencies are high (90-100 percent of Fischer assay).

4. Class 4: Heat is transferred by mixing hot solid particles with oil shale. These retorts achieve high oil yields similar to Class 3 retorts and produce a high Btu gas. The spent shale may or may not contain carbon and thermal efficiencies vary depending on whether the spent shale is used as the heat carrier.

Specific retort designs are under development for each class.[173, 173]

Each of the various oil shale processing options, TIS, MIS and AGR, has its particular advantages and disadvantages. The greatest advantage of TIS processing is that mining is not required and spent shale is not produced on the surface. The technical, economic, and environmental problems associated with AGR waste disposal, and thereby avoided. MIS does involve mining and aboveground waste disposal, although to a lesser extent than with AGR. However, the MIS waste is either overburden or raw oil shale. Both materials are found naturally exposed on the surfaces of deeper canyons in oil shale basins. Although raw shale has low concentrations of the soluble salts, it does contain soluble organic materials that could be leached from the disposal piles. It should be noted that the presence of spent shale underground has the potential to cause environmental problems because soluble salts could be leached by ground water.[175, 176] Therefore, environmental controls will also be needed for TIS and MIS processes.

The advantage of AGR is that the conditions within retorts can be controlled to achieve very high oil recovery rates. Retorting efficiencies for MIS are lower, and much lower for TIS, because of the difficulty in obtaining a uniform distribution of broken shale. AGR processing maintain a minimum retorting efficiency of 80 percent, MIS processing is less than 60 percent efficient, and TIS is two to four percent efficient.

It is expected that yields from MIS retorts could be increased, but it is doubtful that recoveries can reach those of carefully controlled AGR. On the other hand, the present low efficiencies of MIS operations are partially compensated for by their ability to convert very large sections of an oil shale deposit, by the ability to process shale of a lower quality than would be practical for AGR, and by their lower cost of preparing the shale for retorting.

Finally, the crude shale oil properties differ significantly between the AGR and in-situ processing methods. Specifically, AGR crude shale oil is better suited for distillate fuel production, whereas in-situ processed shale oil is better suited to gasoline production. In addition, it is certain that new refineries and refinery retrofits will be required to process crude shale oil.[177, 178, 179]

Current analysis indicates that domestic oil shale resources contain nearly 1,800 billion barrels of oil. About 84 percent of U.S. oil shale deposits lie in Colorado, ten percent are in Utah, and six percent are in Wyoming.[180] Companies developing oil shale are concentrating in Colorado because of its vast reserves and high quality deposits.

Shale oil is very expensive in terms of resources. It takes a great deal of energy and capital to mine the shale, heat it, process it, and treat the enormous quantities of resultant waste. Both the conventional and in-situ methods use process heat and mechanical energy. (It has been suggested that the in-situ recovery methods use nuclear explosives to break down and heat the fractured rock.)[181]

Oil shale processing also uses large quantities of water, approximately 39 gallons (147.6 liters) per barrel of shale oil. The U.S. Environmmental Protection Agency estimates that two to five gallons per ton (.02 liters per kg) of shale will be contaminated by toxic chemicals, minerals, and trace elements as a result of processing.[182] The Colorado Water Conservation Board estimates that a one billion barrel per day oil shale industry would consume 120,000 to 190,000 acre feet of water per year. According to the Western States Water Council, the production of shale oil could compete disastrously with agricultural water demands, as could other western energy conservation industries. The Council points out that, "To allow the energy industry to acquire water rights at the market place could result in the new allocation of limited waters to energy while reshaping established economies with perhaps locally the greatest impact being on irrigated agriculture."[183]

Oil shale ventures have so far been stymied by economic as well as enviromental problems. The estimated cost of a barrel of shale oil is $25 to $30 in 1979 dollars. The oil shale industry is currently anticipating that hikes in the landed price of OPEC crude and federal subsidies or tax credits will improve the economic viability of their products. Morton M. Winston, President of Tosco Corp., a diversified refining and coal company, envisions the kickoff of the shale oil industry: "The first couple of shale ventures inherently will be very risky from an economic standpoint, but we're optimistic that an energy program that clears up uncertainties about environmental requirements and helps stabilize markets that are capriciously regulated can't help but results in the development of an on-going oil shale industry."[184] Occidental Petroleum, Tosco, and other firms are investing millions of dollars each month in anticipation of the potential profits from oil shale products. Lightweight home heating oil, gasoline, diesel, and jet fuel made from shale oil promise huge profits in future earnings.[185]

In the past, uncertainties have led to project cancellations, but revitalized government interest and the rising price of conventional fuels are giving the oil shale industry new hope. The heyday of the oil shale industry appears to be coming, but serious energy and water limitations must be mitigated first.

Remote Natural Gas (2.5-11)

Natural gas is a high quality conventional fuel which generally requires little upgrading prior to end use. However, being a gas, the maximum distance it can be economically transported is somewhat limited. Therefore, in order to develop these reserves the gas must be compressed, liquefied (LNG), or converted to another fuel such as methanol. The technologies for LNG and methanol production are commercially available today and "off-the-shelf" packaged plants are readily available from numerous suppliers, particularly for methanol synthesis from natural gas. The major barrier to developing these resources today is economic. LNG and methanol are still not economically competitive with convetional fuels. In addition, with LNG, there are technical and safety issues yet to be resolved.

The remote-natural-gas-to-synthetic-fuels concept is particularly interesting in a strategic sense given the current commercial status of conversion technologies and required construction lead times.

Future of Synthetic Fuels (2.5-12)

Aside from significant synthetic fuels development efforts undertaken by a number of major U.S. energy corporations, the U.S. government launched a massive $88 billion synfuels development program in June 1980 when President Carter signed legislation (S. 932) establishing the U.S. Synthetic Fuels Corporation. The Corporation is an independent federal entity charged with providing incentives to private companies to construct synfuels plants. The Corporation's goal is a national synfuels capability of 500,000 barrels per day by 1987 and two million barrels per day by 1992--all from domestic fuel resources.

Under the new Energy Security Act (PL 96-294), the Corporation is charged with primary national responsibility for developing synfuels plants. "Because of the nature of its activities, which are principally to provide financial assistance to the private sector, the Corporation is expected to function much like a private corporation entity such as a bank or other financial institution."[186]

Phase 1 of the national program is expected to be a "sifting" process in the synthetic fuels effort in which a diversity of processes and technologies will be encouraged in order to determine the best potential for each hydro-carbon feedstock (biomass is also included in the effort). Prior to the expiration of this phase, a detailed report from the Corporation will be submitted to Congress. The report will include:

1. The economic and technical feasibility of each facility, including information on product quality, quantity and cost of production.

2. The environmental effects of operating the facilities, as well as projected environmental damage, including water quantity.

3. Recommendations on the mix of technologies to be supported, and recommendations on subsequent funding phases.

In following this strategy, the Corporation will look at other federal programs such as PL 96-126, the Defense Production Act (Part A), and other DOE synfuels programs. Under the Energy Security Act, the President is given expanded authority within the Defense Production Act to initiate a "fast start" interim synfuels program which will catalyze the national effort in the next few years. The comprehensive strategy to be given to the Congress must be approved by a Joint Resolution in order to initiate the primary funding phase of the national effort, a $68 billion "set aside" to fund Phase II.

The Corporation will give preference to the following, in order of decreasing priority: 1) Purchase agreements, priced guarantees, and loan guarantees; 2) Loans; and 3) Joint Ventures. Subject to appropriation, the Corporation is authorized to assume obligations up to $20 billion under PL 96-126 and up to $3 billion under Defense Production Act authorities. The Corporation is scheduled to terminate on September 30, 1997.

Under the terms of Title II of the Energy Security Act, up to $1.5 billion is authorized for biomass energy projects with an emphasis on alcohol fuel plants and waste-to-energy facilities. Title III requires the setting of annual energy production and comsumption targets by the Department of Energy in order to provide a working mechanism for energy policy cooperation between the Congress and the executive branch of government. Title IV provides for increased funding of a range of energy conservation efforts and small technology development in various solar and renewable energy technologies. Of special interest, from a strategic energy perspective, is a modest program for $10 million to "demonstrate energy self-sufficiency through the use of renewable energy resources in one or more states" over a three year period.

Specific technologies cited in Title IV for development on a local scale are small hydro resources and photovoltaic solar programs in federal facilities. The Secretary of Energy is given authority to utilize a seven percent discount rate and marginal fuel costs in determining and calculating alternative energy and conservation improvements to federal buildings. Title V establishes a Solar and Conservation Bank within the Department of Housing and Urban Development, which will fund a variety of household and commercial solar and conservation efforts.

Additional sections of the law set up programs for industrial energy conservation, geothermal energy development ($85 million on FY 1981-85), and environmental assessments of "acid rain" and carbon dioxide problems stemming from synfuel combustion. Title VIII orders the administration to resume filling the Strategic Petroleum Reserve at a rate of at least 100,000 barrels per day.[187]

Forecasting Electricity (2.6)

Historically, demand forecasting was a straightforward exercise. As the energy economy expanded, the electrical system doubled in size each decade. This process was halted, perhaps permanently, by the 1973-74 oil boycott. Since that winter, demand uncertainties have affected most of the nation's utilities, and historic growth rates have not prevailed.

Forecasts are important since lead times for the construction of new power plants can range from ten to fifteen years (e.g. in the case of large coal and nuclear plants), and utilities must have an idea of future demand to make such large capital investments. One analysis summarizes the issues as follows: "Forecasting is made more complicated by uncertainty over the consumer response to recent price increases and uncertainty over the effect of changes in rate design and changes in the price and availability of oil and natural gas."[188]

Despite current uncertainties in demand for electrical power which affects decisions regarding construction of new power plants, a number of major energy studies predict a major shift to electricity within the next two decades. The following forecasts in Table 2.6-1, compiled from recent reports by national government and industry studies, indicate the predicted supply of electricity in the year 2000 (or as otherwise noted) as a percentage of national energy consumption from all sources.

Table 2.6-1[189]

ELECTRICITY AS A PERCENTAGE OF U.S. ENERGY IN THE YEAR 2000
(unless otherwise noted)

Resources for the Future	40%
IEA (Institute for Energy Analysis)	50%
CONAES (Committee on Nuclear and Alternative Energy Systems)	36% (2010)
MOPPS (Market Oriented Program Planning Study)	40%
EIA (Energy Information Administration)	35% (1990)
Edison Electric Institute	42%

There is considerable dispute over growth rates, which have dramatically fallen since the Arab embargo of 1973 (California utilities are growing at less than two percent per year), and the relative contribution of electricity as a future energy source. Today, conservation efforts are successful in many areas in dampening demand for electricity. Other factors, such as an increasing tendency towards smaller, more efficient power plants, may serve to slow and even curtail the high growth rates for electricity. The electrical system is changing in a number of ways, and a critical component of this change, smaller systems, has been brought about by a reevaluation of the "economies of scale," that smaller systems may provide.

Energy Systems and Economies of Scale (2.7)

As we have seen, the electric utility industry began in the late 19th century as a highly decentralized enterprise. Small power facilities served neighborhoods and were fueled largely by coal and hydroelectric power. In the early years of electric power, high costs to consumers were a result of high construction costs and fuel costs. Transmission lines and distribution centers, the essential infrastructure of the industry, were expensive to build and maintain. As the industry grew, costs were reduced by building larger, more efficient power plants and transmission facilities. By 1975, power plants over 500 MW capacity had increased to 222 facilities from 155 in 1950.[190]

The trend towards large electrical power plants and related systems was caused by the desire to improve efficiency by gaining economies of scale in equipment and fuel usage. Small individual electric utilities were consolidated into larger systems.

The concept of size versus efficiency is important in considering any investment project such as a power plant. It is of course not the only efficiency consideration. One criterion which is used to ascertain the optimal size is know as "economies of scale." The concept technically involves the use of the "long-run average (or unit) cost," or LAC. Average cost is obtained by dividing total costs by the level of output (or activity). The reason for the distinction between long-run and short-run is that during the short period, certain factors in production processes (such as the scale of the plant) may be fixed. As the relevant time frame is expanded, however, these initially fixed factors are variable and can be changed in relation to other factors of production. Investment projects are analyzed in terms of their efficiency over a time period that is commensurate with the useful life of their most inflexible ("fixed") factor of production.

Figure 2.7-1 depicts the long-run average cost curve (sometimes referred to as the "planning curve"). The concept of economies of scale is seen by noting that the LAC declines between activity size 0 and activity size X_1, stays the same until X_2 is reached, and then turns upward as the diseconomies of scale segment of the curve is reached.

When economies of scale exist, long-run average costs fall as activity size increases. This may be due to:

1. Advantages of division and specialization of labor and machinery which are positively correlated with increased size;

2. Larger sizes may eliminate "indivisibilities," or large cost disadvantages accruing to the use of highly specialized and expensive labor and machinery and size less than a certain magnitude;

3. The best use of the latest technology, which is feasible only for large quantities of output;

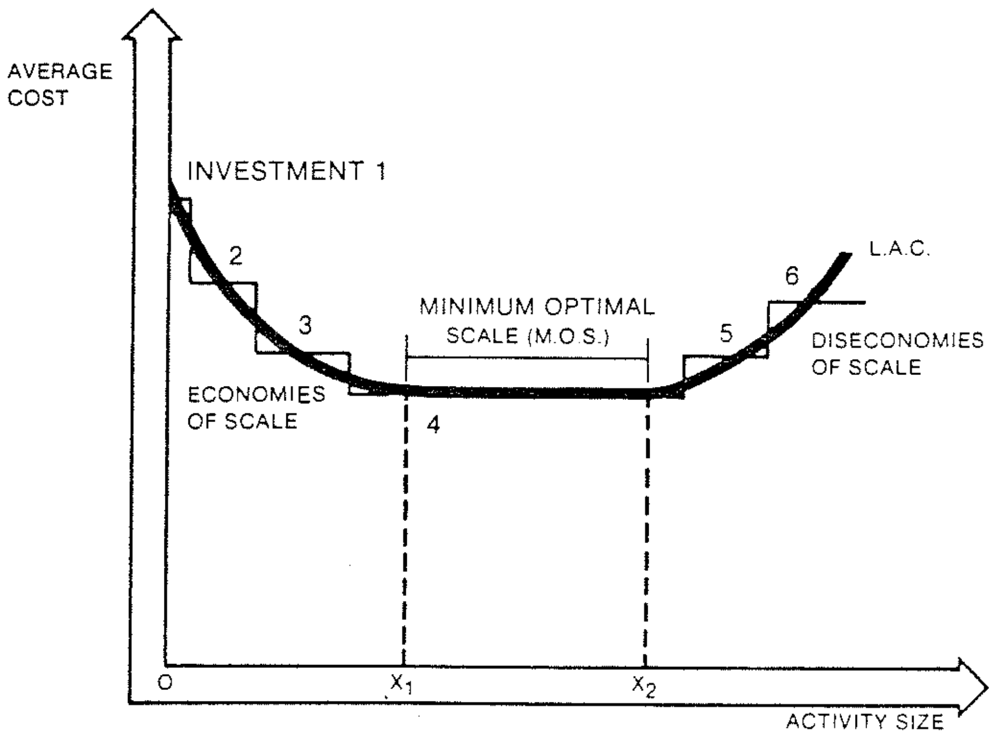
4. Economies from high volume purchasing and shipping;

5. The availability of necessary maintenance crews and spare parts, in case of breakdown, only at large scales of operation.

Diseconomies of scale occur when the activity size increases beyond the lowest point (or range) of the LAC. An example might be that increasing numbers of workers are assigned to a given unit of equipment, (or conversely, increasing amounts of equipment are assigned to a given work force) resulting in higher unit output costs as production is increased beyond the "optimal" (i.e., most productive) mix.

Figure 2.7-1[191]

LONG-RUN AVERAGE COST CURVE (LAC)



It is difficult to usefully apply the concept of "economies of scale" in a static environment (i.e., for a "snapshot" in time in which technology and other considerations are held constant). To make the analysis more realistic, one important consideration is that activities typically cannot be expanded continuously. Movement along the LAC curve is actually made discreetly, in "step-like" jumps. During the period between the initial investment and the next added increment of investment, excess capacity will exist. An optimal size must be reached to gain the full economies of scale available for this level of investment.

Research by Manne and Erlenkotter has indicated that it is important to consider is the relationships of uncertainty factors (incorporated analytically by economists using the "discount rate").[192] For example, if unstable financial conditions or some other significant cause of uncertainty as to the profitability of a given activity exist, the discount rate (which reflects the uncertainty of future return) will be concomitantly high. This may cause a planner to curtail an investment short of the point of full actual economies of scale as a means of reducing the magnitude of potential loss if the investment, for whatever reason, does not meet "expected" performance.

The market structure in which a certain activity takes place is another consideration relevant to a discussion of economies of scale. If, for example, an industry is a "natural monopoly," i.e., if economies of scale allow a single firm to serve the market at lower unit cost than with two or more firms, then the extent to which the single firm is allowed to grow to its full cost advantage will affect the extent to which the available economies of scale can be realized.

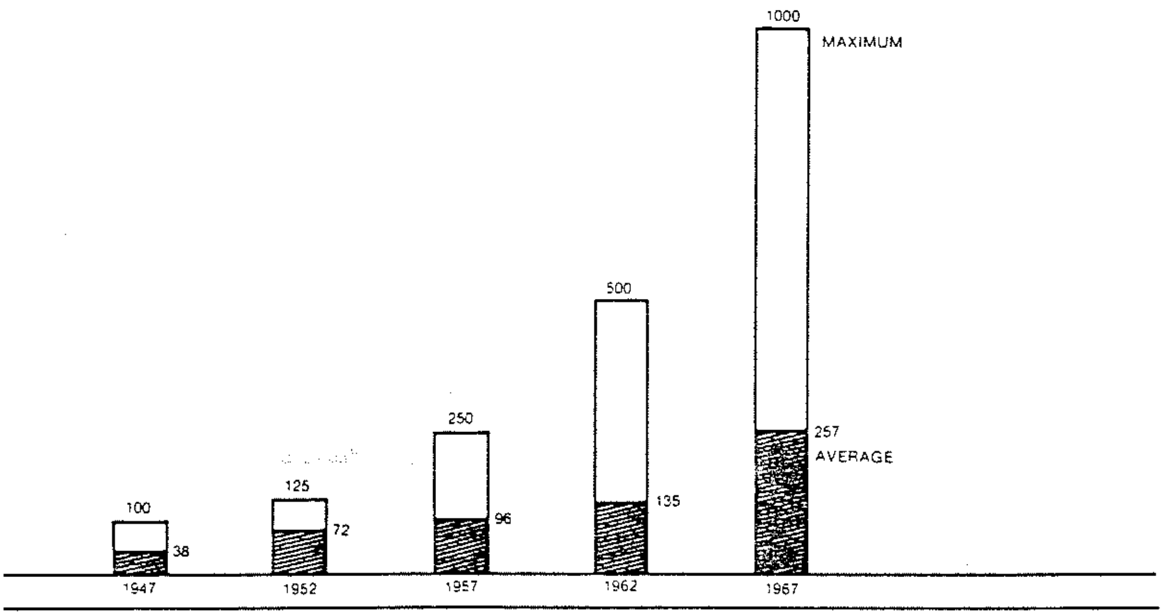
The electric utility industry is a "natural monopoly." Average production costs, for instance, have declined for coal-fired steam-turbine generating plants up to designed plant sizes of at least 750 megawatts. Recent studies, however, have reduced the confidence in continuing advantages of increased scale in the electric utility industry as financial, electrical demand and performance uncertainty has increased.[193]

In a paper presented at the American Power Conference in 1968, R.R. Bennett of Ebasco Services, Inc. predicted that large electric power generating stations in the 1980s would include individual units of 3000 MW and aggregate generating capacity of 12,000 MW. He predicted that, as a consequence of this increase in scale size, most of the small power stations in service at that time would become obsolete and be retired before 1990.

Figure 2.7-2 illustrates the growth trend in average and maximum steam electric generator unit size at the time of Bennett's report.[194] From 1947 to 1967 the average unit size increased by more than 700 percent (i.e., from 38 MW to 267 MW). During the same period, the largest unit size increased 1,000 percent (from 100 MW to 1,000 MW).

Figure 2.7-2[195]

AVERAGE AND MAXIMUM STEAM UNIT SIZE, 1947-1967, IN MEGAWATTS



Nuclear units enjoyed similar increases in scale as illustrated in Table 2.7-1.[196] At the time of Bennett's report, it was estimated that the scale size of 1,100 MW for nuclear units was only a temporary plateau. Similarly, General Electric Company studies predicted Boiling Water Reactor (BWR) nuclear steam supply systems with unit sizes up to 10,000 MW. Similar studies by Gulf Atomic indicated that 10,000 MW high temperature gas-cooled reactors were also feasible, and for sodium-cooled reactors, scale sizes were extrapolated to even greater scales. Clearly, none of this mega-scale construction of facilities has occurred.

Table 2.7-1[197]

INCREASE IN THE SIZE OF NUCLEAR UNITS

Year of Initial Operation	Largest Nuclear Unit Installed in Year, MW	Average Nuclear Unit Installed in Year, MW
1960	200	200
1961	175	175
1962	255	120
1963	70	40
1964	---	---
1965	---	---
1966	790	270
1967	40	40
1968	640	420
1969	1,030	590
1970	1,150	730
1971	1,150	770
1972	1,100	850
1973	1,100	860

The design factors used in the above mentioned engineering-feasibility studies included assessments of future supplies of cooling water and fuel availability, environmental limitations, electric system limitations, limitations on the design, manufacture and shipment of major plant components, and land requirements. Yet, despite the fact that these engineering analyses were performed by the most skilled technical people of the time and at considerable expense, they were wrong. The reason is that other (uncertainty) factors assumed to be "constant" in these studies were actually variable.

In a recent article published by the International Institute for Applied Systems Analysis, such non-economic factors (uncertainty factors) relevant to choice of scale (i.e., political, social, economic, technological, organizational, managerial, and financial) were examined. It was found that the relative "discount" significance of these factors varies not only from case to case, but also with the level of scale (size of investment) decision considered.[198]

Three major sources of "diseconomies of scale" found above were:

1. The engineering cost of the generation equipment is by no means the total capital cost of a power station. Construction time for very large units of plant size has increased because of the present necessity of extended, on-the-construction-site fabrication. This leads to greater accumulated financial charge even before the plant starts to earn revenue.

2. The more intense demands on materials and components (e.g. the greater the length of boiler tubing), the greater the probability of breakdowns of equipment, thereby reducing effective available capacity in actual operation.

3. The greater time lags required in the planning of large plants' construction mean that forecasts have to be made further ahead, with correspondingly greater uncertainty. Therefore, the level of reserve capacity to be installed to achieve a specified level of security of supply must also increase.[199]

The Trend to Small Power Plants (2.8)

In a recent study conducted by Andrew Ford of the Los Alamos Scientific Laboratory (LASL) and Irving Yabroff of SRI, International, small-scale coal-fired power plants were compared to large plants.[200] The study stems from the $3 billion proposed project at Kaiparowits, Utah, in which a 5,000 MW coal-fired power plant was abandoned before completion after thirteen years of an unresolved constroversy over polluting the air of surrounding national parks.[201] Several other power plant sites have been abandoned lending credence to the theory that perhaps it is not necessarily true that the "bigger" plants are "better," as it once seemed. The study concludes that decentralization is necessary for the following reasons:

> Although the small plants have a higher capital cost per kilowatt of installed capacity and their dispersed siting requires a greater investment in railroad and transmission lines, they still enjoy eleven percent capital cost advantage over the large plant because less capacity must be built.* For the same reason, lower annual operating and maintenance costs for the generating facilities more than offset the small plants' higher fuel cost to give them a two percent annual cost advantage.[202] (See Table 2.8-1).

Having established the cost/benefit trade-offs available by use of the small-scale plant, Ford next considered "system reliability." Every generating unit is periodically shut down for repairs for a certain number of hours every year. To also account for possible accidents that would temporarily cut off electricity supply, all generating systems have a "reserve margin." Ideally the reserve margin ranges from fifteen percent to 25 percent above peak load demands. In practice, larger units require larger reserve margins because they have a higher "forced outage rate" (necessary repair and maintenance time), and because they must be able to replace a large percentage of total capacity (reflecting the large share of electricity generation they have in the first place). Using several different estimates of capital costs, forced outage rates, and fuel costs, Ford concluded that small plants provided a greater degree of reliability, and that overall they proved to be more economical than large plants.

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*Note: Ford's study is based on a realistic comparison of a large-scale plant scenario and a small-scale plant scenario. Each power plant produced 3,000 MW of coal-fired electricity; the large plant's electricity came from four 750 MW units whereas the small plant used six 500 MW units to generate electricity. By studying each plant's effective load-carrying capability (ELCC), however, Ford discovered "that only nine 250 MW units provide approximately the same effective addition in system capacity as four 750 MW units."[203]

Table 2.8-1[204]

PRESENT VALUE OF CAPITAL AND OPERATING COST, SMALL UNIT AND LARGE UNIT PLANS (IN MILLIONS OF 1977 DOLLARS)

	SMALL STATION PLAN (Nine 250 MW Units)	LARGE STATION PLAN (Four 750 MW Units)
Present Value of Capital Cost		
Generation	$ 609.7	$ 829.3
Transmission	256.2	253.4
Coal Transportation	105.2	84.0
Total Present Value Capital Cost	$ 971.1	$1,166.7
Present Value of Operating Cost		
Generation	$2,369.4	$2,415.7
Transmission	69.1	69.1
Coal Transportation	50.5	35.6
Total Present Value Operating Cost	$2,489.0	$2,520.4
Total Present Value Cost	$3,460.1	$3,687.1

Similar to Ford's reliability measure, another method of measuring system reliability, indicating the disparity between "availability" rates of small- and large-scale power plants, was undertaken by Anson in 1977 Electric Power Research Institute study. Anson reported that "the availability of baseload units averaged 83 percent for units smaller than 380 MW, 77 percent for units between 390 MW and 599 MW, and 73 percent for units larger than 600 MW."[205]

Small power plants offer numerous advantages during the multi-faceted, complicated site selection process which provide Ford with his third set of criteria. Two important advantages are: 1) The smaller plant emits fewer pollutants than a large plant, thus enabling small plant siting in locations where large power plants would be unacceptable; and 2) "Smaller power plants have historically required about twenty percent less time to gain permit approvals."[206] Small plants also face one significant disadvantage during site selection: More sites for the increased number of plants must be found and approved. Ford claims that presently "the procedural complexity of undergoing repeated site approval hearings probably outweigh, in the long run, the greater ease any single small plant may have in gaining approval."[207]

The LASL group points out that the prevailing high level of uncertainty makes the accuracy of future projections difficult to achieve. This can cause severe capital losses to a utility that overbuilds its plant capacity based on inaccurate forecasts. The advantage that construction of small plants offers is the substantially shorter lead times compared to larger plants. A typical large plant requires three to four years for licensing and seven to nine years to construct. A small plant only requires two to three years for permit approval and four to five years to construct.

The degree of uncertainty in forecasting is therefore somewhat diminished when the lead time is not as long, which improves the accuracy of electricity supply and demand projections. Thus, the likelihood of overbuilding or underbuilding plant capacity is lessened. Another benefit derived from a shorter forecasting time frame is that "it also makes the utilities' arguments for power needs more convincing before state commissions."[208]

Another advantage of small plants relates to the levels of water usage. Smaller power plants use less water than larger plants, and environmental impacts will not be as significant as with a single, large unit. Thus, the number of possible site locations is expanded and the likelihood of permit approval improves.

A study conducted by Leonard of the Radian Corporation and Miller of the University of Oklahoma indicated that "the construction of dispersed, small units could allow greater exploitation of resources without an increase in problems associated with air pollution."[209] Additionally, a Clark University study concluded that "coal plants of 400 MW or less and nuclear plants of 800 MW or less have distinctly better performance records than large plants of both types."[210]

A further indication of the trend toward small power plants can be seen from several developmental efforts by utilities and the nuclear industry to scale down fusion and thermal nuclear plants. Recognizing that, "Huge (fusion) facilities have not proved to be an effective focus for development programs to get new commercial enterprises started," C.P. Ashworth, a mechanical engineer with California's Pacific Gas & Electric Company, presented a cogent argument for "small fusion" at a 1980 American Association of the Advancement of Science symposium.[211]

Based on the experience of the scientific community, the nuclear industry and utilities with fission reactors, Ashworth argued against the assumption that huge-scale facilities must be developed to bring fusion technology "on-line." The massive amounts of capital and materials required have tended to focus the research and development efforts on one or two large projects.

> Huge projects represent long periods where nothing much that looks like progress appears to be getting done at a time when cash outlays are very large. Huge first-of-a-kind projects are very prone to schedule lengthening which makes these periods of no progress become interminable. Schedule stretchout seems to breed conditions which lead to delays on top

> of delays. Eventually, program time becomes extended to the point where a favorable outcome is no longer assured no matter how important and well justified the concept. Thinking big has affected the pace, and quite possibly in some cases the outcome, in many energy development attempts--notably breeders, gas reactors, coal gasification, uranium enrichment and MHD. It can be argued that in these cases there was no choice. But in fusion, there appear to be choices that could speed up development.[212]

Large-scale facilities not only set the pace of development, they also set the course. This tends to preclude alternative designs and concepts from development budgets and to create a dampening effect on risky but necessary innovation. "With the small facility focus, many inputs get into the act, including rivalry and competition between institutions pursuing different projects--the small facilities route can lead us to attractive commercial fusion energy sooner."[213]

The use of large-scale nuclear facilities for electric power production has become more and more questionable in terms of the expense and safety factors involved. Atomic Energy of Canada, Ltd. (AEC), a government-owned nuclear company, recently announced plans to develop the Slowpoke, (Safe low-power critical experiment), "the cheapest and smallest reactor ever designed for commercial use."[214]

Rather than provide superheated steam to run electrical turbines, Slowpoke would produce hot water to heat buildings. Small-scale reactors for direct heat applications are being researched in France, Scandinavia and the Soviet Union. AEC estimates that Slowpoke can be built for as little as $850,000. The cost for a thermal kilowatt from Slowpoke would be $425 compared to $400 to $465 for equivalent power generated by conventional nuclear reactors.[215]

The advantages of the small-scale approach to nuclear reactors are in the sheer simplicity of design.

> The reactor is modeled after small, pool-type research reactors used at many universities. Its vessel is a 25 foot-deep concrete-lined pool dug in the ground. The small fuel core is immersed directly in the water-filled pool. The nuclear reaction heats the water in the pool to 190°F and the heat is removed through a double loop of heat exchangers that isolate the heated water from the radioactive core.[216]

Expensive cost and potentially faulty safety factors associated with large-scale nuclear power plants can be avoided with development of small systems such as Slowpoke.

The Slowpoke concept is especially interesting in light of its potential for dispersion and decentralization.

> Officials at Canada's AEC point out that Slowpoke...does not require the elaborate core-cooling safeguards of the large reactors, and it eliminates the need for district distribution systems required for French and Soviet approaches...Slowpoke will offset the economies of scale of the bigger projects...(and may be used) in many parts of the world where petroleum is expensive and district heating systems are not practical.[217]

All of the above studies lead to the conclusion that long lead times, high capital costs, shrinking economies of scale, and operation reliability problems with large units could be lessened with smaller, dispersed power plants.[218]

SECTION 2

ENERGY: EXISTING SYSTEMS AND TRENDS

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