POWER PLANTS:

COAL VERSUS URANIUM AS A FUEL SOURCE - AN ECONOMIC ANALYSIS

by

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A Thesis submitted to the Faculty and the Board of Trustees of the Colorado School of Mines in partial fulfillment of the requirements for the degree of Master of Science, Mineral Economics.

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ABSTRACT

In the long term, the sources of energy may be a combination of fusion, solar, wind and geothermal forces. However, it is in the interim period, from the present to the time when natural energy sources can be harnessed, that is germane to this thesis. Coal and uranium are the primary energy sources discussed in the analysis. At present, the price trend of other fossil fuels (e.g. oil and gas) offsets an economic advantage, and they are not within the scope of this paper. Coal and uranium are compared as alternative but not necessarily mutually exclusive sources of energy for electrical power generation.

The first section spells out the criteria used to structure author in the analysis. Plant type, conversion rates, and escalation rates are discussed in this section.

The following three sections (e.g. Capital Costs, Operating and Maintenance, and Fuel Cycle) delineate the cost components of both a nuclear-fired power plant and a coal-fired power plant and estimate which plant type has an economic advantage. This distinction leads to a comparison of annual generation costs which in turn points out the

comparative advantage of a nuclear-fired power plant over a coal-fired power plant providing the latter type installs scrubbers. The actual dollar difference on capital cost between a nuclear plant and a coal plant using only tall stacks is highly dependent on interest and escalation rates. Fuel cost differences also greatly impact the final economic decision, but future fuel prices are difficult to predict.

After establishing current economic cost for both fuel sources for electrical power generation, attention is then focused on an analysis of the fuel supply picture and on electricity demand trends. This is done in the following section where it is shown that the supply outlook for uranium to the year 2000 is questionable due to the high degree of uncertainty of technological substitution (e.g. liquid metal breeder reactor for light water reactors) and to the scarcity of known recoverable reserves. Coal does not share this problem, but coal suffers from other uncertainties such as low labor productivity, stringent environmental regulations and expensive transportation costs.

An examination of the present and future demand by the utility industry for nuclear and coal reactors is then presented. In spite of uranium's economic advantage, the number of nuclear power plant orders for the next decade has dropped dramatically since 1975. In the conclusion, it is postulated that this trend reflects factors such as the unreliable supply picture of uranium fuel and political uncertainties. Even with steady uranium production the availability of supplies after year 2000 seem questionable, and any orders taken now for nuclear plants mean that a plant would be dependent on a uranium fuel supply through year 2015. Whether or not the uranium will be there is a moot point. The situation with coal-fired power plants is also not very encouraging if environmental regulations become more stringent (e.g. requiring SOx removal equipment) or if the real cost of fuel increases significantly.

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INTRODUCTION

Over the next twenty-five years, coal and uranium pose significantly as two major fuel sources for electrical energy production. Oil and gas are expensive alternatives, and the commercial development of solar, wind, fusion and geothermal resources is still distant. By limiting the scope of this proposal to an economic analysis of coal and uranium as fuel sources for base-load utility plants, some conclusions may be drawn regarding the mix and type of power plants that are economically preferable. No in-depth consideration will be given to the environmental arguments concerning both fuel alternatives other than to mention their indirect impact on such items as plant construction time.

To make a valid economic comparison of the two fuel alternatives, the projected costs and expenses of mining, fuel supply, capital, and electrical generation must be compared in constant dollars. To offset the differences in construction times between coal and nuclear (i.e. light water reactors), all costs have to be present-valued. Current literature on the subject often fails to sufficiently document cost estimates and escalation projections.

The common denominator in this analysis is the impact of fuel supply, construction and operating costs on total annual electrical generation costs measured in mills per kilowatt-hour. A standard, 1000 megawatt, base-load power plant that is adequate for an urban population of one million will serve as the hypothetical model.

Fuel costs analyzed in terms of minemouth production, processing, transportation, storage, thermal efficiency, disposal and reprocessing.

Capital costs include direct and indirect construction expenditures, cost of capital, and escalation adjustments.

Operating expenses and capacity factors are reviewed to the extent that they impact overall generating costs.

A final picture of projected electrical supply and demand are analyzed relevent to present industry orders for nuclear and coal-fired power plants over the next decade. This trend may give some insight into how the utility industry is responding to electrical costs and to anticipated electrical demand with regard to uranium and coal-fueled plant alternatives.

PARAMETERS

It is easy to establish enough constraints on an analysis such that the analysis no longer resembles reality. It is equally difficult to avoid that situation when working with significant technical differences as is the case with coal-fired and nuclear-fired power plants. Perhaps this is an exaggeration. Afterall, the end product is electricity. Much effort has been taken to equalize the basis of comparison so that cost components of both types of power plants are analyzed fairly. The following discussion of parameters is critical to the conclusion of this paper.

TIMING AND METHODOLOGY:

Because it is difficult to compare capital investment costs over different periods of time, present 1976 costs are escalated and then discounted for inflation and for rate of return calculations. The reason for doing this is that a coal-fired power plant normally takes seven years from conception to operation while a nuclear-fired power plant usually takes nine years. Depending on the plant type and on the technology involved, the actual periods could be longer or shorter. Coal power plant technology reflects years of experience and construction delays are less likely than the nuclear counterpart. Nuclear power plants often involve new technology and are subject to a proportionately larger number of federal and state restrictions. Thus, a nine year period for construction planning, engineering and obtaining permits is assumed for nuclear plants. Similarly, a seven year building period is assumed for coal plants.

Although each utility company has a different method of financing the initial capital investment, it is assumed in this paper that short-term interest rates for construction would average 9 percent given a grace period for the construction period with first payments being due in the initial year of operation.

A common estimate for capital cost with plant construction beginning in 1976 is $1 billion for a light water reactor, $800 million for a coal plant with scrubbers and $700 million for a coal plant with tall stacks. Since the projections are in the future and the plants have varying construction times, it is essential for comparison purposes to discount the cost estimate for nuclear (in 1985) and coal (in 1983) to 1976 constant dollars.

To calculate the uninflated 1976 value of future costs, a discount rate of ten percent has been assumed. Five percentage points are attributed to annual inflation and five percentage points are attributed to real rate of return.

This is not unreasonable since a common utility industry rate of return (ROR) is 10 percent, and this figure incorporates inflation. These issues will be analyzed in the conclusion of this paper.

Since capital investment costs are expected to escalate at 7.5 percent for five years and 5 percent for four years,* the 1976 cost of coal and uranium fuel is also escalated to 1983 and to 1985 respectively.

PRICING AND PROFITS:

This analysis concentrates on the investment cost involved in the coal versus nuclear power plant decision. Unlike most industries, the utility industry is a federally restricted monopoly and rates of return as well as pricing policies are governed by both the Federal Power Commission (FPC) and by state public utility commissions. Although regional incomes may vary, it is generally assumed that most electrical utility companies make a 10 percent rate of return.

What makes the electrical utility companies different from most industries is the huge capital investment required

*For a coal-fired plant, assume an escalation rate of 7.5 percent for four years and 5 percent for the remaining three years. Of the initial 7.5 percentage points, five points are directly attributed to inflation. Escalation includes inflation and any increase in real rate of growth.

Utility Industry Portfolio

Balance Sheet Percentages	Railroads	Auto	Chem	Utility
Cash and marketable securities	4.0	7.6	5.1	0.5
Receivables	3.9	8.6	16.4	3.8
Inventories	...	24.9	11.0	2.2
Other current assets	0.9	3.5	...	2.6
Plant and equipment (net)	78.7	44.6	49.5	90.0
Other assets	12.5	10.8	18.0	0.9
Total assets	100.0	100.0	100.0	100.0
Notes payable	...	...	12.8	3.1
Accounts payable	2.9	23.9	5.3	2.7
Accrued taxes	2.6	3.6	1.9	1.4
Other current liabilities	0.6	4.9	5.7	2.6
Long-term debt	35.2	3.4	30.4	43.3
Other liabilities	3.8	6.4	...	1.8
Preferred stock	...	...	...	9.4
Capital stock and capital surplus	16.7	6.8	27.8	25.3
Retained earnings and surplus reserves	38.2	50.0	16.1	10.5
Total liabilities and stockholder equity	100.0	100.0	100.0	100.0
Selected Ratios				
Current assets/current liabilities	1.45	1.38	1.25	0.92
Cash, marketable securities, and receivables/ current liabilities	0.96	0.50	1.20	0.44
Inventory turnover (X)	...	6.4X	6X	...
Receivables collection period (days)	20	19	64	44
Total debt/total assets	0.412	0.356	0.565	0.530
Long-term debt/capitalization	0.403	0.055	0.425	0.490
Net sales/total assets (turnover)	0.32	1.61	0.69	0.32
Net profits/total assets	0.052	0.059	0.057	0.048
Net profits/total net worth	0.102	0.105	0.137	0.107
Net profits/net sales profit margin	0.167	0.037	0.083	0.153

TABLE 1

to produce the final product. Generally speaking, plant and equipment average 90 percent of total portfolio assets in the utility industry. Correspondingly, long-term debt is high, averaging 43 percent of total liabilities and stockholder equity (see Table 1). This paper assesss which type of power plant (e.g. coal/scrubbers, coal/tall stacks, and nuclear/Light Water Reactor) has an economic advantage. It is assumed that all three plants would receive equal revenues for equal amounts of electrical output.

PLANT TYPE:

NUCLEAR

Originally the author chose to use the High Temperature, Gas-Cooled Reactor (HTGR) as a prototype because it was the most technologically advanced reactor in the United States. It uses considerably less uranium than the Light Water Reactors (e.g. Boiling Water Reactor and Pressurized Water Reactor), and it is more reliant on thorium (i.e. which sells for $8.00 per pound or $30.00 a pound less than uranium in 1976) than uranium by a factor of 18 to 1. One of the first HTGR plants built is located near Denver (330 mega-watt base-load reactor at Fort St. Vrain). Unfortunately, the economics look much better on the surface than in actual practice. According to the U.S. Bureau of Mines, all orders in the United States for commercial HTGRs were cancelled or delayed in 1975, and the primary manufacturer, General Atomic Company has ceased producing them. A combination of economic factors and mechanical difficulties during testing of the first commercial HTGR resulted in the collapse of the market. Finally, inflation and lower demand for electricity in the 1974-76 period made the economics of HTGR operations questionable.

The beauty of the HTGR unlike the Light Water Reactors (LWR) is that the thorium-uranium fuel combination super heats helium gas to a temperature of $1400^{o}F$ which in turn heats water to steam to run the turbine (see Appendix). Both types of LWRs directly heat water rather than helium gas, and the temperature limit is around $550^{o}F$. The super-heated helium gas can be recirculated and used again with only marginal energy input to raise its temperature. Steam, on the other hand, is cooled and precipitated so that it would require an equal amount of energy input as originally required in the beginning of the cycle.

The difference between the Boiling-Water Reactor (BWR) and the Pressurized-Water Reactor (PWR) is the method in which water is boiled or kept from boiling by high pressure. In a BWR, which is the most common nuclear reactor in the U.S., water is used as the coolant (i.e. it absorbs the fissioned heat). The water is brought into the reactor and is allowed to boil. It is then expelled from the reactor vessel as saturated steam, which drives a turbine to produce electrical power.

Typically, a BWR operates at a pressure of about 1,000 p.s.i and produces steam at about 550^{O}F. Although it is a simple system, it requires a large core for cooling, something a PWR does not.

The PWR keeps the water from boiling. Instead, water is pumped through the core and removed at the top as a heated liquid. The water is then circulated through a heat exchanger, where steam is produced from water in a secondary loop. The steam drives the turbine, and the cooled water in primary loop is returned to the reactor to again cool the core.

The PWR primary loop operates at a pressure of 2,000 p.s.i. and at an average temperature of 590^{O}F. The coolant in the PWR core (i.e. unlike some of the BWRs) does not directly contact the turbine, so the turbine area remains uncontaminated with radioactive materials. Also, the virtue of the high pressure reactor is that it allows a smaller surface area for the core.

Both types of LWRs are considered in this paper.

COAL

A typical 1,000 Megawatt, steam generated, coal base-load power plant has been selected for this paper. Capital costs in 1983 have been derived from industry data and discounted for inflation to ascertain 1976 costs. Construction costs are primarily based on an Ebasco Company study completed for the utility industry in mid-1975. Costs for items such as scrubbers, coal and ash storage facilities, earthwork, etc. have all been escalated to 1976 in order to achieve time and location parity for the 1,000 megawatt power plant prototype used in the analysis.

Two types of coal plants are used. A plant with scrubbers is presented, and should be considered essential given the recent federal Clean Air Act. The second type of coal power plant is without scrubbers, but it uses traditional tall stacks to limit the amount of fly ash in the atmosphere.

As this study indicates, the impact of regional fuel costs are reflected in the type of coal plant (e.g. scrubbers or tall stacks) employed. A power plant utilizing tall stacks is more likely to be found in the Midwest or Mountain States where low-sulfur coal is plentiful. The coal is usually cheaper for a variety of reasons, however, the hauling distance to a point of consumption might offset any savings in price due to the high quality of the coal. A plant utilizing scrubbers will most likely be located in either New England or the Mid-Atlantic States where the quality of the coal is primarily high sulfur. These distinctions and their bearing on electrical generation cost will be analyzed in the "Fuel Cycle" section of this paper.

FUEL EFFICIENCIES:

Although not analyzed in this paper, a discussion of fuel efficiencies is important to anyone attempting to understand the economics of power plants. The basic premise is that only one-third of the total quantity of thermal heat (i.e.measured in Btus) derived from either the burning of coal or from fissoning U-235 is converted into electrical energy (i.e. measured in Kilowatt-hours). In physics, the thermal efficiency factor is defined as the ratio of useful work to the heat absorbed (or "what you get" divided by "what you pay for").

$$\text{Thermal Efficiency} = \frac{W \cdot (100)}{Q_H}$$

Because of friction losses, the useful work delivered by an engine is less than the work "W", and the overall efficiency is less than the thermal efficiency.

Assuming a boiler temperature of 415^{O}F, a superheat of 65^{O}F above this temperature (i.e. 480^{O}F, and not 550^{O}F because there is not as much pressure) and a condenser temperature of 102^{O}F, the efficiency of an ideal cycle (i.e. Rankine cycle) is about 32 percent. Efficiencies of actual steam engines are, of course, considerably lower. However, many power plants utilize additional pressure or recycle steam so as to achieve higher efficiency ratios.

Typical thermal efficiencies for coal and nuclear power plants (i.e. as are used in this study) are 35 percent and 33 percent respectively. The HTGR has a thermal efficiency of 39 percent according to the Colorado Public Service Company in regard to its HTGR plant at Fort St. Vrain. Since the thermal efficiencies of the LWR and the coal steam generator are relatively the same, no effort to adjust generating cost will be made. This, of course, would not be true if an HTGR were the chosen prototype.

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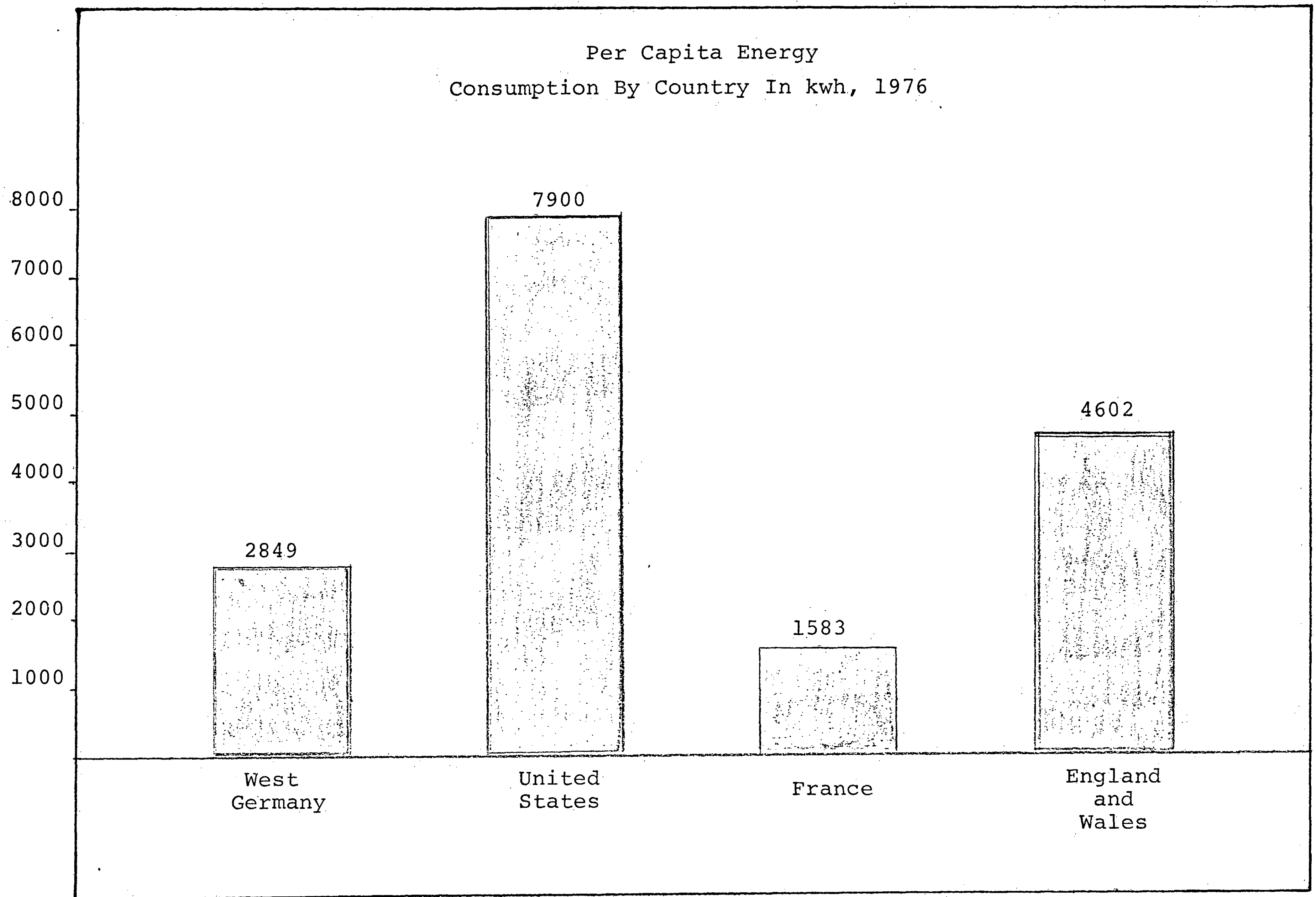
CONVERSION FACTORS:

For the purposes of this paper, it is assumed that a 1,000 Mw capacity power plant would be adequate to service an urban area with a population of one million. This is a common assumption that is used in many other studies in calculating power plant generating efficiencies and capital cost components. It is further assumed that the urban center has a normal distribution of commercial, industrial and residential electrical consumers.

To have any significance, the plant rating (i.e. kilowatt capacity) must be considered against actual, annual output of of electricity measured in kilowatt-hours. Estimates of average kwh per capita consumption are skewed. Research into recent M.I.T., Stanford Research Institute, American Nuclear Society and other power plant studies failed to produce any reference to average kwh production or consumption. Finally, a range of 6,000 kwh to 9,000 kwh per capita was ascertained from numerous other abstracts on the subject matter*. The deviation in range is due in part to plant capacity factors and to methods of statistical measurement. An average per capita consumption figure may not perfectly represent the average electrical output per type of utility, but it should give an approximation. As a matter of interest, per capita energy consumption by selected user nations is shown in Figure 1.

Other Estimates are taken from:

1. ENERCOM, Energy Resources, 1977/78, Denver, 1977.
2. Edison Electric Institute, New York, Feb.1978.
3. "Q and A, Nuclear Power and The Environment," American Nuclear Society, Hinsdale, Illinois, April 1976.



Source: <u>ENERCOM</u>, Energy Resources, Inc., Denver, 1977-78, p.27.

FIGURE 1

Working backwards from a median per capita figure of 7,900 kwh, an urban population of one million would use a total of 7.9 billion kwh per year. This translates into a plant capacity of approximately 900 million kw assuming 365 days and 24 hours per day operation annually. This is not too far from the original 1,000 Mw estimate. If the median per capita usage were 6,000 kwh, then total plant electrical generation would be closer to 650,000 kw or a 65 percent capacity factor as opposed to a 90 percent factor using the median per capita estimate. In fact, based on past records, nuclear and coal plants have a capacity rating ranging from 60 percent to 70 percent. Apparently, the 900 million kwh figure is high, although both estimates will be considered throughout this paper. The issue of plant capacity is discussed later.

CAPITAL COSTS

Projecting capital investment cost requires considerable foresight given recent high inflation rates and escalated production costs. Add to this, the pervasive effect of inflation on construction and interest costs, and the end result can only be an order of magnitude estimate. It is also impossible to accurately compare coal and nuclear power plants if the average construction time for the former is seven years compared to nine years for the latter. In this paper, construction time, loosely defined, means from the date the architect-engineer is authorized to start preparing specifications for equipment (i.e. 1976) to the date of initial operation (i.e. 1985 for nuclear and 1983 for coal).

There are several ways to compare capital costs. Stanford Research Institute (SRI)[1] simply took 1975 estimates based on a utility industry survey. Their estimates were based on 1,000 Mw coal and nuclear power plants beginning operations in 1985. Reconstructing their capital cost estimates in inflated dollars and their minimum ROR, an approximate value of $1 billion was reached for a nuclear plant with a corresponding value of $800 million to $700 million for a coal power plant depending on whether or not scrubbers were used. Other estimates by M.I.T.[2] and by

Hardie and Chamberlin[3] writing for Nuclear Technology were fairly close, although both parties assumed levelized dollars through 1985 and again from 1985 to 2014, implying a thirty-year life.* Hardie and Chamberlin were the only ones to discount 1985 costs for inflation and for a minimum rate of return (ROR) in order to attain present values in 1976. However, Hardie and Chamberlin ignored the fact that a coal plant would begin operations in 1983 and not in 1985. They assumed that both a coal and a nuclear plant have equal construction times (e.g. 1976-1985), while this is obviously not the case for a coal-fired plant.

Table 2 indicates the inflated cost based on what major utility companies estimate to be the 1985 cost of a nuclear power plant conceived in 1976. The escalation rate is 7.5 percent (i.e. 1976-1981) and 5 percent (i.e. 1981-1985) based on consensus from utility industry annual reports. Direct costs are made up of structures, site improvements, reactor, turbine and electric plant equipment, and miscellaneous plant accounts. Indirect costs include the owner's general, administrative and payroll costs during the design and construction phases of the plant plus architect-engineer and construction administration costs.

*The term "levelized" refers to a constant dollar amount that would recover all operating and capital expenses.

[1]NUCLEAR (1,000 Megawatt)
Summary of 1985 Power Plant Costs
($000,000)

Capital Cost	1976	1985
[1]Direct:	240	340
Materials	110	160
Construction	130	180
Indirect	85	110
Contingency (15%)	48	68
Interest During Construction @ 9% (from 1976 to 1985)	70	201
[2]Escalation	80	275
Total Capital Cost	523	994
[3]Initial Fuel Cost: 450 S.T. of U_{235}	50.75	78.66
Decommissioning	20.00	25.00

[1]Costs are for LWR initiated in 1976 and completed in 1985.

[2]Escalation - 7.5 percent (to 1981), 5 percent (1982-1985). Escalation is taken on all capital items except contingency costs.

[3]Does not include capitalized return on pre-payments for initial futures contract since there is no comparable charge to a coal-fired power plant in this analysis.

TABLE 2

[1]COAL

Summary of 1983 Power Plant Costs (1,000 Megawatt)
($000,000)

Capital Cost	With Scrubbers 1976	With Scrubbers 1983	Without Scrubbers 1976	Without Scrubbers 1983
Direct:	245	360	185	270
Materials	65	95	70	105
Construction	110	155	115	165
SO_2 Removal	70	110	-	-
Indirect:	60	80	60	80
Contingencies (10%):	30	45	25	35
Interest During Construction: (at 9%)	55	138	45	110
[2]Escalation	60	195	55	158
Total Capital Cost	450	818	370	653
Decommissioning	21	26	15	20

[1]Costs are initiated in 1976 and completed in 1983.

[2]Escalation - 7.5 percent (1976 to 1979) and 5 percent (1980-1983). Escalation is taken on all capital items except contingency costs.

TABLE 3

Other indirect costs include such items as travel expense, liability insurance, construction permit fees, operator training and start-up costs, taxes and insurance during contruction.

Interest during construction is 9 percent and is calculated at the beginning of the first draw-down of funds in 1976. For clarity, the amount of funds used over the nine year construction period is levelized through 1985. Contingency funds are not included as interest bearing debt since during the construction phase a utility company's net working capital can be assumed to be above average. This higher than average liquidity (see Table 1) would normally be available for contingency funding should the need arise.

Although not included in capital cost calculations, initial start-up cost of fuel is shown in Tables 2 and 4. The cost of 450 short tons of uranium fuel is escalated at 8 percent from its 1976 price to its projected price in 1985. It is also assumed that the utility company would purchase a futures contract in 1976 for delivery in 1984-1985. Presently, futures contracts for 1981 yellow cake range from $44.00 to $43.00 per pound depending on the type of contract (see Table 25 in Appendix for United Nuclear's contract pricing).

The decommissioning cost of $25 million is extrapolated from a 1976 American Nuclear Society publication[4] which based its estimates on a small nuclear plant (i.e. Hallam nuclear power plant) that was converted to a fossil-fueled power station at a cost of $6 million. Decommissioning costs for coal and nuclear plants have a 1976 cost of less than one percent after discounting at a 10 percent rate of return over the plant's lifetime.

Capital investment costs for coal are presented in Table 3. The distinction between a plant utilizing scrubbers and a plant resorting to tall stacks is included because the high capital cost of a SO_x scrubber should be isolated for comparative purposes in an analysis. Whether or not a scrubber is used in a coal-fired plant is dependent on the sulfur content of the steam coal. Scrubbers would only be employed if the sulfur content exceeded 0.8 percent. This means that most western coal would be acceptable while eastern coal would not. Unfortunately, western coal is significantly distant from the Northeast where the concentration of consumer demand for energy is the greatest. The impact of scrubbers and transportation on fuel costs is presented in more detail in the next section of this paper.

Initial Fuel Costs - f.o.b. Coal
($000,000)

	With Scrubbers		Without Scrubbers	
	1976	1983	1976	1983
Coal Purchase Price	20.00 46.00	34.28 78.84	10.00 23.00	17.14 39.42
Transportation Cost	--	--	14.95	25.62
Total	46.00	78.84	37.95	65.04

Notes:

(1) Coal f.o.b. purchase price for high sulfur coal (i.e. necessitating scrubbers) is given a higher weighted price of $20.00 er ton. Since the high sulfur coal is assumed to be near the point of consumption which is not uncommon in the East coast. hypothetical transportation cost are considered minimal.

(2) Coal f.o.b. purchase price for low sulfur coal (i.e. allowing only the use of only tall stacks and not scrubbers) is given a weighted average of $10.00 per ton.

(3) Both 1976 coal f.o.b. prices are escalated at an 8% rate. Five percentage points are attributed to inflation and three percentage points are attributed to other real increases in cost.

(4) For analytical reasons, it is assumed that a coal plant will purchase a years supply of coal in the preceeding six months. This would amount to a purchase of 2.3 million short tons.

(5) Transportation costs (e.g. low sulfur coal/without scrubbers) is assumed to be 13.0 mills/ton-mile in 1976. Given a 500 mile transport distance from mine mouth to point of consumption.

TABLE 4

Nuclear and Coal Capital Costs
Constant $ (1976)
($000,000)

	LWR	Coal/Scrubbers	Coal/Tall Stacks
1976 estimated cost for a plant operating in 1985	994.000	818.00	653.00
[1]Constant Dollar Capital Cost (in 1976 $)	640.75	581.34	464.07

[1]The escalation rate of 7.5% for the first five years of the LWR and for the first 4 years of the coal plant includes a 5% inflation factor. After this initial period, the 5% rate of return to the utility companies is 10% which includes five percentage points each for inflation and for real rate of return.

TABLE 5

TABLE 6

Capital Investment Time Chart

NUCLEAR

Item		1976	77	78	79	80	81	82	83	84	1985-----2014		2025----2017	
	Date:	1976	77	78	79	80	81	82	83	84	1985-----2014		2025----2017	
	Year:	0	1	2	3	4	5	6	7	8	9	38	39	41
Direct: Construction														
Indirect														
Contingency														
Interest														
Fuel														
Decommissioning														

COAL

	Date:	1976	77	78	79	80	81	82	1983-----2012		2013----2015	
	Year:	0	1	2	3	4	5	6	7	36	37	39
Direct Construction												
Indirect												
Contingency												
Interest												
Fuel												
Transportation												
Decommissioning												

For comparative reasons, Table 4 uses the equivalent cost of one years supply of coal* (i.e. compared to an initial purchase of 450 tons of uranium for a nuclear plant). Table 2 levelizes the initial fuel purchase in the analysis since 450 tons of uranium actually exceeds the required demand for a one year supply. A one year supply of coal is estimated to be 2.3 million short tons at an escalated 1983 price of $26.00 per ton from a 1976, f.o.b. price of $15.00 per ton. The total cost including transportation (i.e. 500 miles from the minemouth) is $87.40 million. This cost is allocated from the end of 1982 to half way through the first year of operation in 1983.

Direct construction costs by 1983 are $360 million for a coal plant with scrubbers and $270 million for a coal plant with tall stacks. The contribution of scrubbers to the total, direct cost is 31 percent.

A contingency fee is set at 10 percent which is less than the nuclear contingency fee of 15 percent due to the fact that there is less time delay for coal plants based on a proven, well-developed, historical construction tract record.

Table 5 is used to compare capital cost in constant

*In reality most electrical generating power plants only stockpile an average 42-day supply. The TVA had a 72-day supply just prior to the 1977-78 coal strike. A 42-day supply would cost approximately $10.05 million including transportation costs.

dollars for year 1976 when both plants are presumed to be in the planning stage. This analysis is important given the wide discrepancy in reported capital costs. For example, Washington Public Power Supply System reports a cost of approximately $1,000 million for a 1,000 Mw plant in 1984 while Commonwealth Edison estimates costs ranging from $425 million to $450 million for a nuclear plant of the same scale for the same time. Taking a hypothetical $1,000 million plant and discounting to 1976 from 1985 using a 10 percent discount rate yields approximately $426 million.

The $426 million figure mentioned in connection with Washington Public Power and Commonwealth Edison reflects present value capital cost at a 10 percent rate of return on a commonly accepted 1985 future value capital cost estimate of $1,000 million. Table 2 shows a 1976 cost of $523 million which is higher than the $425 to $450 million estimate for two reasons. First, the lower estimate is derived from a future cost of $1,000 million, and its discount rate is the escalation rate(i.e. 7.5 percent) rather than the cost of capital rate of 10 percent. Second, Commonwealth Edison's estimate precedes the author's estimate by one year (e.g. 1975-1984 rather than 1976-1985) so that a year difference will obviously contribute to some discrepancy in the two estimates.

An analysis of comparative plant costs shows that current 1976 dollar capital cost of a nuclear plant exceeds the cost of both a coal plant with and one without scrubbers by $73 million and $153 million respectively (see Tables 2 and 3). What really creates the cost difference between the two types of power plants are escalation cost, interest cost and the size of the contingency fee (i.e. 15 percent for nuclear and 10 percent for coal).

As mentioned earlier, the 1976 nuclear plant capital cost estimate is based on a mix of actual and estimated plant costs. The statistical validity of actual plant costs would be weak because of the limited number in the sample (e.g. 63 operating, nuclear power plants).

The 1985 plant capital cost estimate is based on what various sources now think it will take to build a plant for operation by that date. These are typical of the estimates used by industry for their future analysis. Clearly, the estimates vary, but as shown previously, a typical escalation rate of 7.5 percent for five years and 5 percent for the remaining four years represents an average estimate in 1976 for 1985 costs.

Nevertheless, the message from these analyses is clear. Although capital costs of nuclear power plants are expected to double by 1985, the main factors driving up the costs are interest and escalation. Interest and escalation rates are essentially uncontrollable, but time to construct is not, and there appears to be ample room for improvement in terms of construction standardization and efficient, predictable regulatory decisions by the Nuclear Regulatory Commission (NRC).

The escalation rate and the inflation rate remain the same for all three prototypes. The escalation rates of 7.5 percent and 5 percent reflect industry averages. The 10 percent discount rate reflects the minimum cost of capital to a utility company. Although the debt or equity costs may be lower than 10 percent, the author feels that the 10 percent figure accurately represents a utility's opportunity cost of capital based on FPC findings and industry annual reports. Table 1 shows the large proportion of long-term debt for portfolio averages of utility companies (e.g. 43.3 percent).*

It appears that the difference in capital cost between nuclear and coal power plants is substantial. While coal plant capital costs are obviously sensitive to the scrubber option, nuclear capital costs are sensitive to time delays and corresponding increases in the cost of money.

*In reality, a utility company might finance through equity expansion or through other non-equity debt instruments.

There are many other variables which have been assumed in this paper that would almost certainly change the impact of capital costs. For example, a thirty year life has been assumed for both types of plant. Clearly, if the lifetime of a nuclear plant exceeded thirty years, the amortized capital cost over the operating life of the plant would be reduced. Of course the same would be true for a coal-fired plant. Case studies on nuclear plants are fairly limited, so it is difficult to project actual plant lifetimes.

Another factor that would impact the magnitude of capital cost would be a change in the discount rate from 8 percent to 10 percent to 12 percent. The M.I.T. study employed both of these factors (i.e. increased lifetime and reduced discount rates) and found that given a 40 year lifetime (i.e. at 10 percent cost of capital) the capital cost of a nuclear power plant decreased by a factor of 2 mills per kwh or approximately $16 million per year more than that of a comparable coal plant. At a 10 percent cost of money, the LWR plant capital cost decreased at a rate of approximately 3 mills per kwh or $23.7 million more annually than a coal-fired plant given a thirty year lifetime. It is difficult to directly incorporate these figures into this paper without some qualification since the M.I.T. study used different plant ratings and different component costs; but they do reflect the sensitivity of capital costs of both power plant models to lifetimes and to cost of capital.

For purposes of comparison, Table 7 and Figure 2 show capital cost with variable lifetimes and discount rates derived from Tables 2 and 3.

It does seem clear that capital costs of nuclear plants are favored by an extended lifetime of 40 years and by a reduced cost of capital. The benefit is illustrated by the constant difference between the nuclear line and the fossil fuel lines in Figure 2. Actually this fact seems intuitively obvious given the sensitivity of nuclear capital cost to longer construction periods (i.e. nine years versus seven for coal) and to construction delays reflected in higher contingency fees (i.e. 15 percent versus 10 percent for coal). All of these costs are detailed in Tables 2 and 4.

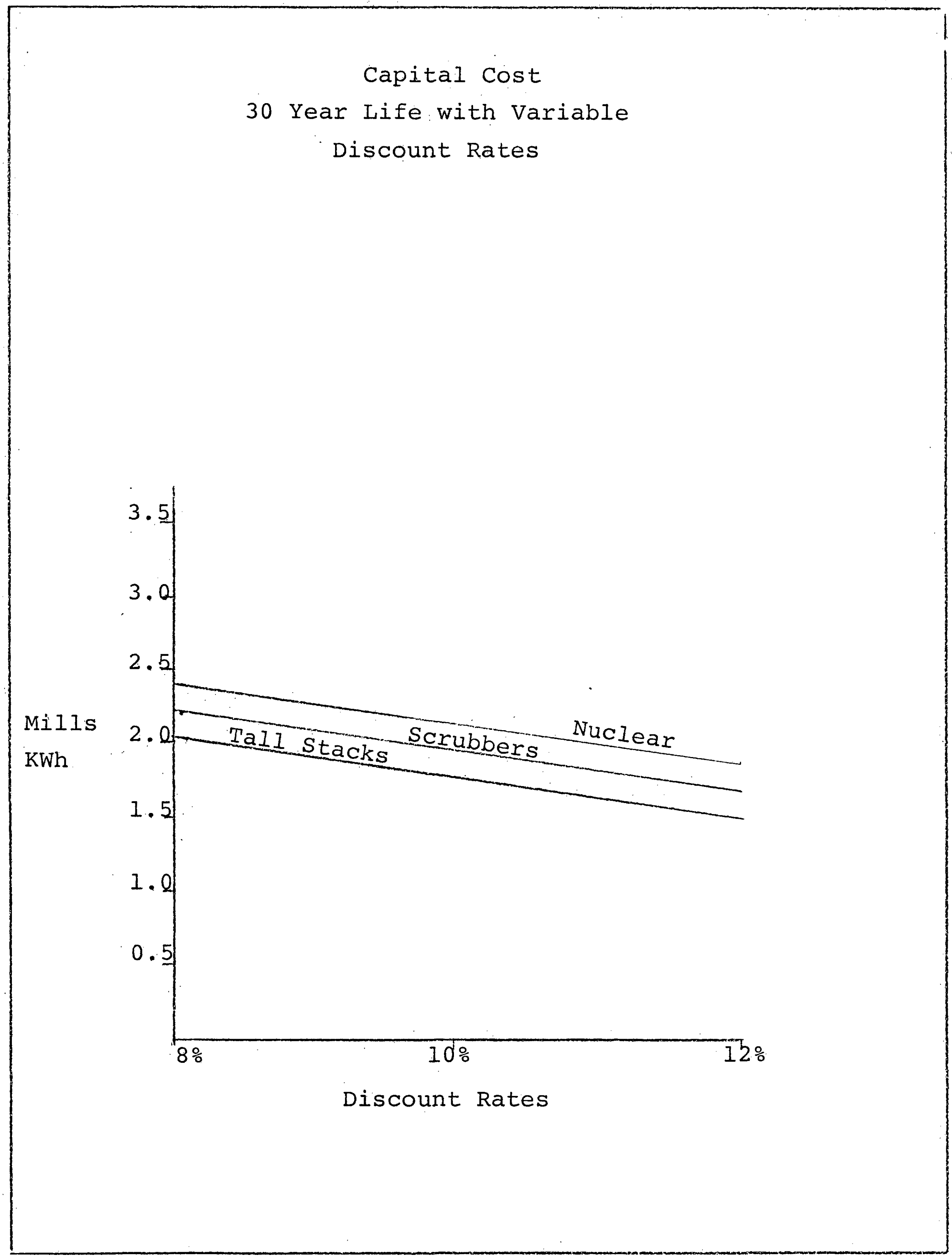
Working on the premise that an increase in nuclear capital cost is proportionate to an increase in coal capital cost, then any significant comparative economic advantage between the two systems requires an analysis of other component costs.

Incremental Changes in Generating Cost Due to Impact of Discount Rates & Plant Lifetimes on Capital Costs (mills/kwh)

Life (yrs)		Discount Rate 8%	10%	12%
	Nuclear	3.57	3.11	2.77
20	Scrubbers	3.20	2.87	2.58
	Tall Stacks	2.80	2.51	2.25
	Nuclear	2.37	2.08	1.85
30	Scrubbers	2.13	1.91	1.72
	Tall Stacks	1.86	1.67	1.52
	Nuclear	1.78	1.56	1.39
40	Scrubbers	1.60	1.43	1.29
	Tall Stacks	1.40	1.25	1.13

TABLE 7

FIGURE 2



Capital Cost
30 Year Life with Variable
Discount Rates
3.5
3.0
2.5
2.0
1.5
1.0
0.5
Mills
KWh
Nuclear
Scrubbers
Tall Stacks
8%
10%
12%
Discount Rates

OPERATIONS AND MAINTENANCE

Again, there are numerous estimates regarding operations and maintenance (O/M) costs for nuclear and coal-fired power plants. Even two LWR plants with the same megawatt capacity might have different O/M costs. For the purpose of consistency, this paper will discuss estimates from other sources, but will only use the author's own generated cost estimates. Also, to be precise, it should be stated that O/M costs are a summation of labor, maintenance and insurance costs to the utility company and are usually measured in mills per kwh.

Other source estimates for a 1,000 megawatt HTGR or LWRs may vary from approximately 0.5 mills per Kwh to 3.0 mills per kwh. In this paper, a value of 1.44 mills per Kwh for a nuclear plant was derived. An average O/M cost for a coal plant is generally assumed to range from 1.0 to 2.5 mills per kwh with an additional cost of 0.8 mills per kwh for scrubbers. The M.I.T. study used an average O/M cost of almost twice the prevailing average due to personnel training cost involved with the typical high turnover in the Defense Department.

The author's estimates are as follows:

TABLE 8
1976
Operation and Maintenance
Costs for a 1,000 Mw Plant
(mills/kwh)

	Nuclear	Coal Scrubbers	Coal (Tall Stacks)
Maintenance	0.30	1.25	1.00
Labor	1.01	1.50	0.92
Insurance	0.13	0.04	0.05
Total	1.44	2.79	1.97

O/M costs for a coal plant with scrubbers are significant considering the lower 1.97 mills per kwh, tall stack alternative. In total dollar cost, assuming an average annual output of 7.9 billion kilowatt-hours, a coal plant with scrubbers is $10.67 million per year more expensive than a nuclear plant. A coal plant without scrubbers is $4.19 million per year more expensive than a nuclear plant.

FUEL CYCLE

Just as nuclear-fired power plants are supposed to be sensitive to capital costs, fossil-fired power plants are supposedly sensitive to fuel costs. To measure fuel sensitivities, several ground rules must be established.

First, the type of fuel must be selected. For coal, this could translate into anything from lignite to anthracite. The type of uranium used will be yellow cake (U_3O_8) which sells on the LME (1977) spot market at an approximate price of $42.00 per pound. A 1976 price of $38.00 per pound is assumed for the calculations in this section since 1976 is the base year. The following table derived from 1976 Keystone Coal Industry Index indicates the fuel conversion factors and facts which are a prerequisite to making any fossil fuel/uranium comparisons.

Fuel Conversion Factors

Product	Unit	Btu
Bituminous Coal & Lignite:		
Consumption Average	S.T.	24,050,000
Electric Generation	S.T.	23,750,000
U_3O_8	Pound	200,000,000
Nuclear Power*	kwh	10,660

Fuel Conversion Facts

Product	Approximate Heat Value
1 Ton of Bituminous Coal	50.72 grams (0.112 lb.) U_3O_8
1 Pound U_3O_8 in Concentrate, (yellow cake)	8.9 Tons of Coal

Now to determine the actual f.o.b. cost of fuel, several assumptions must be made. First, regarding a coal-fired plant, two site locations are considered. The first plant site is located at the coal minemouth thereby reducing high transportation cost, but incurring other costs such as transmission line capital costs and transmission inefficiencies over long distances. By assuming a 500 mile distance of the plant from a central power consumption point, the transmission line loss would be approximately 0.05 mill

*Output of nuclear power is converted to theoretical energy inputs (i.e. thermal energy) calculated from national heat rates for fossil-fueled steam-electric plants.

per kwh according to the SRI study. The alternative cost of train transportation would be 15.0 mills per ton-mile or $17.25 million per year based on an average annual consumption of 2.3 million short tons. In reality, the cost is even greater because one, forty unit-car train hauling 160,000 tons every twenty-five days loses approximately 1 percent of its payload to wind forces by the time it reaches its destination.

Another alternative is transportation by slurry line. A slurry line is estimated to be 20 percent more efficient than train transportation.[5] In spite of the savings, slurry lines have confronted strong political opposition from the railroad industry. In addition, this estimate ignores the cost of water loss or returning the water to its source, namely the dry regions of western United States.

Once the coal is at the plant, it must be stored. After the coal is burned, the waste ash must also be stored or dumped at a pre-selected site, ideally not too far from the plant. The projected capital cost for storage facilities and for ash dumping grounds are estimated to be $35.45 million. This figure does not include labor and equipment which would probably run an additional $5 million per annum (i.e. including depreciation). It should be pointed out that the utilization of a scrubber would reduce generation efficiency by 6 percent necessitating a 6.38 percent increase in Btu (thermal) input. This would cost as much as $3.00 million and would include additional coal and transportation costs.

The actual amount of coal consumption and waste ash generated by a coal-fired plant in comparison to a nuclear-fired plant is shown in Table 9.

The price of coal, unlike that of uranium, is far more sensitive to geographic location. For the purposes of this paper, an f.o.b. coal price of $15.00 per ton with an average Btu content of 11,182 per pound has been selected. Clearly, some coal-fired plants have purchased or inventoried coal for less such as Texas Utilities Company's $0.30 per million Btus purchase of Texas lignite twenty years ago. Their purchase falls well below the current market price as shown in Table 11. For analytical purposes, coal costs are assumed to reflect more recent contract prices of coal.

To get some idea of the regional impact on coal prices, the following table is presented:

Fuel Consumption and Waste[1]
(1,000 Mw Plant)

	Hourly	Daily	Annual
Fuel Consumption			
Coal	690,000 lbs.	8,300 tons	2,300,000 tons
Uranium	3 lbs.	74 lbs.	15 tons
Waste Production			
Coal (ashes)	69,000 lbs.	830 tons	230,000 tons
Uranium (total)	27 lbs.	640 lbs.	170 tons
High Level Fission Product Waste	2.6 lbs.	61 lbs.	15 tons
Other Waste	24.0 lbs.	580 lbs.	155 tons

[1]Adjusted for author's estimate of average consumption (i.e. 170 tons uranium per year).

Source: Amercian Nuclear Society, April 1976

TABLE 9

Table 10

1976 f.o.b. Coal Prices

Plant Location	Coal Prices ($ per ton)
Northeast	30.00
East, North Central	17.00
South Atlantic	25.00
West, South Central	4.00
Mountain	6.00
Pacific	9.00

Source: Keystone, 1976, Nuclear Technology, Mid-April, 1977; Coal Week, 1976 & 1978.

The above table clearly illustrates the comparative advantage of a coal-fired power plant in the Mountain, West, and South Central states. The Northeast is another story particularly since it is highly reliant on imported oil rather than domestic coal. Thus, in this paper it is prudent to distinguish whether or not one is comparing high (Northeast), low (Mountain) or average coal prices with uranium prices. Further, the use or non-use of scrubbers must be clearly stated in all calculations.

A summary of the coal fuel cycle cost is shown in Tables 11, 12 and 13 assuming different operating plant capacities.

Fuel Cost

Fuel Type	Units	Btu/unit	$/mBtu
[1]Lignite (f.o.b.)	S.T.	16,000,000	0.50
Bituminous Coal (f.o.b.)	S.T.	22,364,000	0.67
Oil	Barrel	5,800,000	2.07
Natural Gas	Cubic Feet	1,032	1.81
U_3O_8	Pound	200,000,000	0.21

[1]Business Week, November 28, 1977 and Keystone Industrial Index.

TABLE 11

Coal - 1976 Cost
(90% Capacity)

Cost Item	Low Sulfur	Cost (mill/kwh) High Sulfur	Avg. High & Low	
Coal Price (f.o.b.)	1.16	8.73	4.36	4.36
Transportation Cost	2.18	--	2.18	--
With Scrubbers (high sulfur coal)[1]	--	0.35	--	0.35
Total	3.34	9.08	6.54	4.71

[1]Cost only accounts for the 6% efficiency loss of thermal energy input due to the use of scrubbers.

TABLE 12

Coal - 1976 Cost
(60% Capacity)

Cost Item	Low Sulfur	Cost (mills/kwh) High Sulfur	Avg. High & Low	
Coal Price (f.o.b.)	1.53	11.50	5.75	5.75
Transportation Cost	2.78	--	2.78	--
With Scrubbers (high sulfur coal)[1]	--	0.46	--	0.46
Total	3.71	11.96	8.53	6.21

[1]Cost only accounts for the 6% efficiency loss of thermal energy input due to the use of scrubbers.

TABLE 13

Generally speaking, the low cost of western, low sulfur coal is adversely affected by the high cost of rail transportation. High sulfur eastern coal is more expensive due to high production cost in spite of its close proximity to coal power plants.

Table 12 shows the wide price disparity to be highly dependent on transportation costs and regional costs. Tables 12 and 13 also show the economic impact of plant capacity given a 90 percent to 60 percent range. Greater treatment of this cost variation will be presented in the "Generation Cost" section. The estimate of 9.08 mills/kwh reflects the high cost of eastern coal. The fuel cost attributable to scrubbers (i.e. 0.35 mills/kwh) is relatively modest. This is because the component costs of scrubbers are attributed not to the fuel cycle costs but to O/M and capital costs. Even though West and South Central coal (e.g. Texas lignite) or the Mountain States' low sulfur coal is relatively cheap, the hypothetical cost of 500 miles of train transportation to the east coast more than offsets the low f.o.b. coal price. By comparison, these costs point out the cost efficiency of transporting uranium due to its light weight and high Btu to volume ratio.

Component nuclear fuel costs do not parallel those of coal. While uranium is less cumbersome and easier to transport, it is costly to fabricate and to enrich, and it has its own slew of processing and disposal problems.

Assuming the cost of uranium transportation to be negligible, a breakdown of other nuclear fuel cycle costs is shown in Table 14.

In the fuel cycle, uranium appears to be more sensitive to changes in the price of yellow cake than to other costs; although its sensitivity to price hardly reflects the magnitude of coal's sensitivity to its corresponding price and transportation costs.

On a mill/kwh basis, the uranium fuel cycle (i.e. 2.81 mills/kwh) cost less than all four examples of the coal fuel cycle. According to Table 11 on a mBtu basis, the price of U_3O_8 is considerably less than all other energy sources. 1983 escalated costs for coal transported 500 miles to the plant are $13.62 million more than 1985 fuel costs for a nuclear plant. However, this difference becomes further exaggerated when allowing for the high initial requirement of U-235 (i.e. 450 tons) and for the discrepancy in the year of initial operation. If prices for both coal and enriched uranium were discounted for escalation (i.e. 8 percent) back to 1976, the coal and uranium price would be $15.00 per ton and $63.25 per pound of U-235 (or $38.00/pound U_3O_8) respectively.

1976 Uranium Fuel Costs - 1,000 Mw Plant [1]
(Mills/kwh)

Stage	90% Capacity	60% Capacity
U_3O_8 ($38.00 per lb) [2]	1.50	2.17
Conversion	0.05	0.07
Enrichment	0.63	0.91
Fabrication	0.30	0.43
Reprocessing & Waste Management	0.33	0.47
Total	2.81	4.05

Source: Extrapolated from "Electric Light and Power" magazine, September, 1976.

[1] Based on a 29% U-235 tails assay.

[2] Costs are based on an LWR with reload and load average of 170 tons/year.

[3] No credit is given for a fuel credit since there is no such policy at present. Several other studies have assumed a fuel credit which would amount to 12% of the total (mills/kwh) cost. If a fuel credit were given then the total cost for the fuel cycle would be reduced.

TABLE 14

GENERATION COSTS

From the information developed in the preceeding analysis, it is now possible to compare annual generation costs for nuclear and coal-fired power plants. The comparisons which are denominated in mills per kilowatt-hour, are shown in Tables 15 and 16. The sensitivity of total generation cost to changes in component costs and in capacity factors is outlined in Table 17 and Figure 3. Table 17 indicates the percent change in component cost necessary to raise total generation costs by one mill (i.e. in 1983 for a coal-fired plant and in 1985 for a nuclear-fired plant).

Generation costs for nuclear power plants are especially sensitive to capital costs. In fact, it would take only a 1.54 percent increase in levelized capital cost to raise the generation cost by one mill. This strong sensitivity is due, no doubt, to the large initial capital investment required to license, plan, and construct a nuclear power plant. Since the major capital cost components are interest and escalation, the seriousness of reducing construction time to the date of initial commercial operation is obvious.

Generation cost will increase at a smaller rate than capital cost. Capital cost almost doubles from 1976 (e.g.

Generating Costs for
A Nuclear Power Plant (mills/kwh)

	1976	1985
Capital Cost	9.74	20.10
Operating & Maintenance	1.44	2.52
Fuel	4.05	8.10
Total	15.23	30.72

Notes:

(1) Capacity Factor of 60%

(2) Capital cost assumes straight line depreciation over a thirty year life, 9% interest charge on debt and decommissioning costs.

(3) O&M costs escalate 7.5% from 1976-1981 and 5% from 1981-1985.

(4) Fuel costs escalate at 8% per annum. Five percentage points are inflation and three percentage points reflect a real rise in price.

(5) O&M and fuel costs are levelized over the thirty year life time.

(6) See Table 14 for component costs of fuel.

TABLE 15

Generating Costs for Coal
Power Plants with Scrubbers and with Tall Stacks
(mills/kwh)

	Scrubbers		Tall Stacks	
	1976	1983	1976	1983
Capital Cost	8.51	14.59	6.99	11.65
Operating and Maintenance	2.79	4.32	1.97	3.04
Fuel	8.53	14.62	6.21	00.64
Total	19.83	33.53	15.17	25.33

Notes:

(1) Capacity factor of 60%

(2) Capital cost assumes straight time depreciation over a thirty year life, 9% interest charge on debt and decommissioning costs.

(3) O&M costs escalate at 7.5% from 1976-1980 and at 5% from 1981-1983.

(4) Fuel costs escalate at 8% per annum. Five percentage points are attributed to inflation and three percentage points reflects a real rise in price.

(5) O&M costs and fuel costs are levelized over the thirty year lifetime.

(6) See Table 12 for component costs of fuel.

TABLE 16

$523 million) to 1985 (e.g. $994 million) while total generation cost increases by a factor of 65 percent for every 100 percent increase in capital cost. Of all the sensitivity variables analyzed, nuclear capital cost affects total generating the most intensely.

Nuclear generation costs are not so severely tied to fuel cost. A 3.85 percent increase in the cost of fuel would raise generation cost one mill/kwh. This means that a 100 percent increase in fuel cost would incur a 25 percent increase in total generation costs. A capacity factor of 60 percent, however, has the same impact as capital cost. A 60 percent factor represents the low end of the scale for the average range of operating nuclear power plants. Clearly, if a higher factor were used, then the efficiency of nuclear power plants would be significantly enhanced by the same 100 percent to 65 percent (i.e. capacity change to generation cost change) ratio found in capital costs.

Other fuel cycle costs such as enrichment, fabrication and reprocessing are not included in the analysis because their impact on total generation cost is significantly lower. Based on other sources,[6] it would take an increase of anywhere from 100 percent to 300 percent in these fuel cycle costs to raise the total generation cost by 5 percent to 10 percent.

Sensitivity Analysis:

Percent Increase in Cost to Raise Generating Cost
One Mill per kwh in 1983 (for Coal)
and 1985 (for Nuclear)

Sensitivity Variable	Fossil Unit Tall Stacks	Fossil Unit Scrubbers	Nuclear Unit
Fuel:			
U_3O_8	--	--	3.85
Coal	2.38	2.27	--
Capital Cost	2.17	2.30	1.54
O&M	8.33	7.69	12.50
Capacity Factor	2.35	2.30	1.60

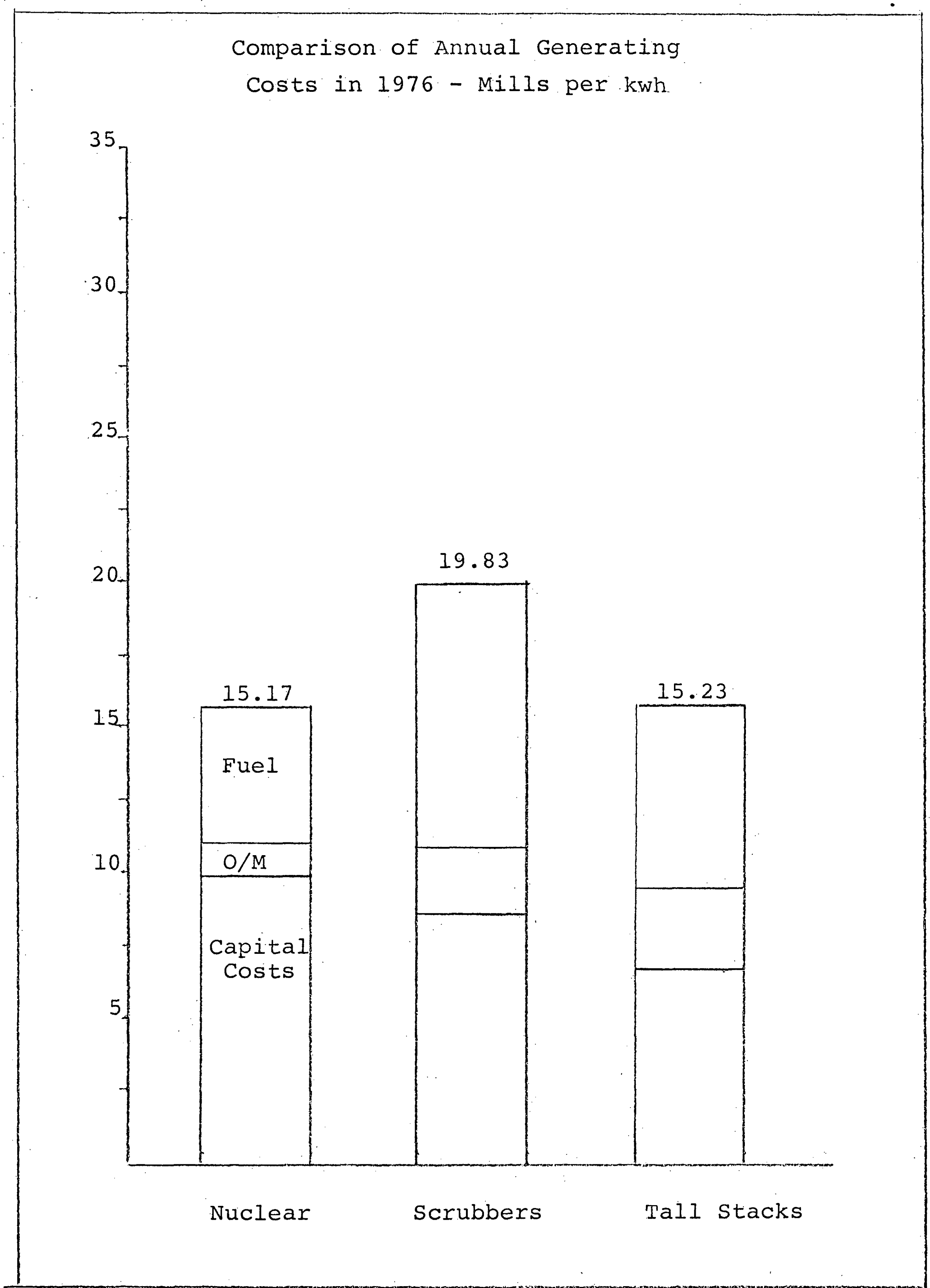
Notes:

(1) All data is based on the same component costs developed in Tables 15 and 16.

(2) For example, it would take a 3.85% increase per annum in the price of U_3O_8 to raise total generating cost of electricity by one mill. This would amount to an increase in the 1976 price of $38.00/lb to $39.44/lb in 1977.

TABLE 17

FIGURE 3


Comparison of Annual Generating
Costs in 1976 - Mills per kwh
35
30
25
20
15
10
5
15.17
Fuel
O/M
Capital
Costs
19.83
15.23
Nuclear
Scrubbers
Tall Stacks

Unlike the degrees of sensitivities in nuclear plant capital costs, fuel cost and capacity factor variables all seem to have a similar impact on total generating costs. Coal power plants utilizing tall stacks have already been shown to cost significantly less than power plants with SO_x scrubbers. As previously mentioned, coal prices vary by regional location, and it is in the Northeast where higher coal prices prevail and where SO_x removal devices are required. In other regions such as the Middle Atlantic, Mid-West and Pacific areas, coal is cheaper (i.e. f.o.b. price) and SO_x removal equipment is not mandated. These regional differences are reflected in Table 18. In the sensitivity analysis, fuel costs in either type of coal power plant must increase by approximately 2.25 percent to raise the total generating cost by one mill. While this is a difference of only 0.79 percentage points over the 3.04 percent factor for nuclear fuel, it is an increase of 26 percent when comparing the two fuel types. Thus, if coal prices rise from only \$20.00/ton to \$20.50/ton, the total generating cost will rise by one mill.

Conversely, a 100 percent increase in capital cost would increase total generating costs by 44 percent as opposed to a 65 percent increase in nuclear, capital induced generating costs.

In regard to regionalism, the impact of different cost indices should be included in the generation cost analysis. Nuclear power plant estimates were based on a "national" prototype because it was assumed that the cost of uranium fuel would be indifferent to location given to minimal cost of transportation. Construction costs do vary by region and have a measurable impact on nuclear capital cost. Using a Department of Commerce statistical index for construction cost with a national index of 100, the index would be as follows:

TABLE 18

Construction Cost Indices - 1976

Region	Index
New England, Middle Atlantic	105
East & West North Central & Mountain	
South Atlantic, East South Central, West South Central & Pacific	88-93
National Average	100

The regional fuel costs for coal have already been introduced (see Table 10) and coal capital costs undergo the same regional variances as nuclear capital costs. An important and a distinguishing feature between the two alternative power plant prototypes is the latitude given for improvement. Clearly, nuclear technology will undergo many changes before the construction and engineering of a LWR can be systematized much like a coal-fired plant is today. The marginal improvements available to coal-fired power plants are minimal in comparison. Furthermore, a major cost contributer that might be looming in the future is SO_x removal equipment, and it has been shown that the cost of scrubbers seriously affects the economic viability of coal-fired power plants, particularly in regions with sulfur laden coal.

FUEL SUPPLY & ENERGY DEMAND

URANIUM

The problems of adequate U_3O_8 supplies, enrichment capacity and nuclear waste recovery/disposal are dependent on technical, political and economic considerations. Technical problems are resolvable, and it appears that with time many previous engineering and fuel processing difficulties will be overcome. Political problems are preeminent in any nuclear power considerations. Costly construction delays due to either opposition on environmental grounds or federal regulatory bottlenecks have forced many utilities and nuclear plant manufacturers to restrict or stop development of nuclear-powered generation facilities. Lack of definitive governmental policy has created uncertainty among utility companies regarding large capital-intensive investments in nuclear plants. Government portions on breeder reactor development, waste disposal procedures, and gas diffusion enrichment must be clearly stated in order for new investments in nuclear generatng capacity to be forthcoming. Finally, economic problems must also be addressed, particularly in regard to capital costs and to the nuclear fuel cycle. The impact of the latter two cost elements has already been discussed with regard to their contribution to total generation costs. An explanation of major cost contributions to the nuclear fuel cycle (e.g. mining, milling, UF_6 production, fuel reprocessing, waste management, etc.) is presented in the Appendix. Other significant economic factors such as fuel supply and demand projections, enrichment capacity, and reactor fuel coverage for the next twenty-five years are presented along with a similar discussion of coal supply and demand economics in the following analyses.

Adequacy of Future Uranium Supplies:

The amount of yellow cake needed to meet projected demand requirements between 1976 and 2000 was forecast by Energy Research and Development Agency (now Department of Energy) to range broadly between 1,015,000 tons and 1,480,000 tons. Present known reserves which could be produced at costs under $30.00 per pound are 640,000 tons. This creates a significant shortfall and requires that substantial exploration and development work be undertaken to increase supplies between now and the year 2000, and beyond.

These supply resources are physically present and can be developed at a price. In an environment where substantial additional supplies are clearly needed, the long term fundamental pressure on the price structure of uranium will be for higher prices to usher forth incremental supplies which would be produced at higher costs.

Adequacy of Enrichment Capacity:

Enrichment capacity is critical to nuclear-fired power plants. Not only is enrichment capacity important, but so is the cost which could have a direct bearing on the final generated product.

The supply availability of enrichment capacity, or lack of it, has a direct bearing on the demand for uranium. Although U.S. utilities have received little government assurance that adequate enrichment capacity will be available, enrichment capacity can be purchased in other nations at prices approximately 40 percent to 50 percent higher than rates presently charged by the Department of Energy.

Fuel Inventory and Reactor Coverage:

Up to now, government estimates regarding the availability of uranium have emphasized the future introduction of the liquid metal breeder reactor which would markedly reduce dependence on uranium. Given today's political and environmental climate, too great a dependence on the breeder reactor as an energy source may be optimistic.

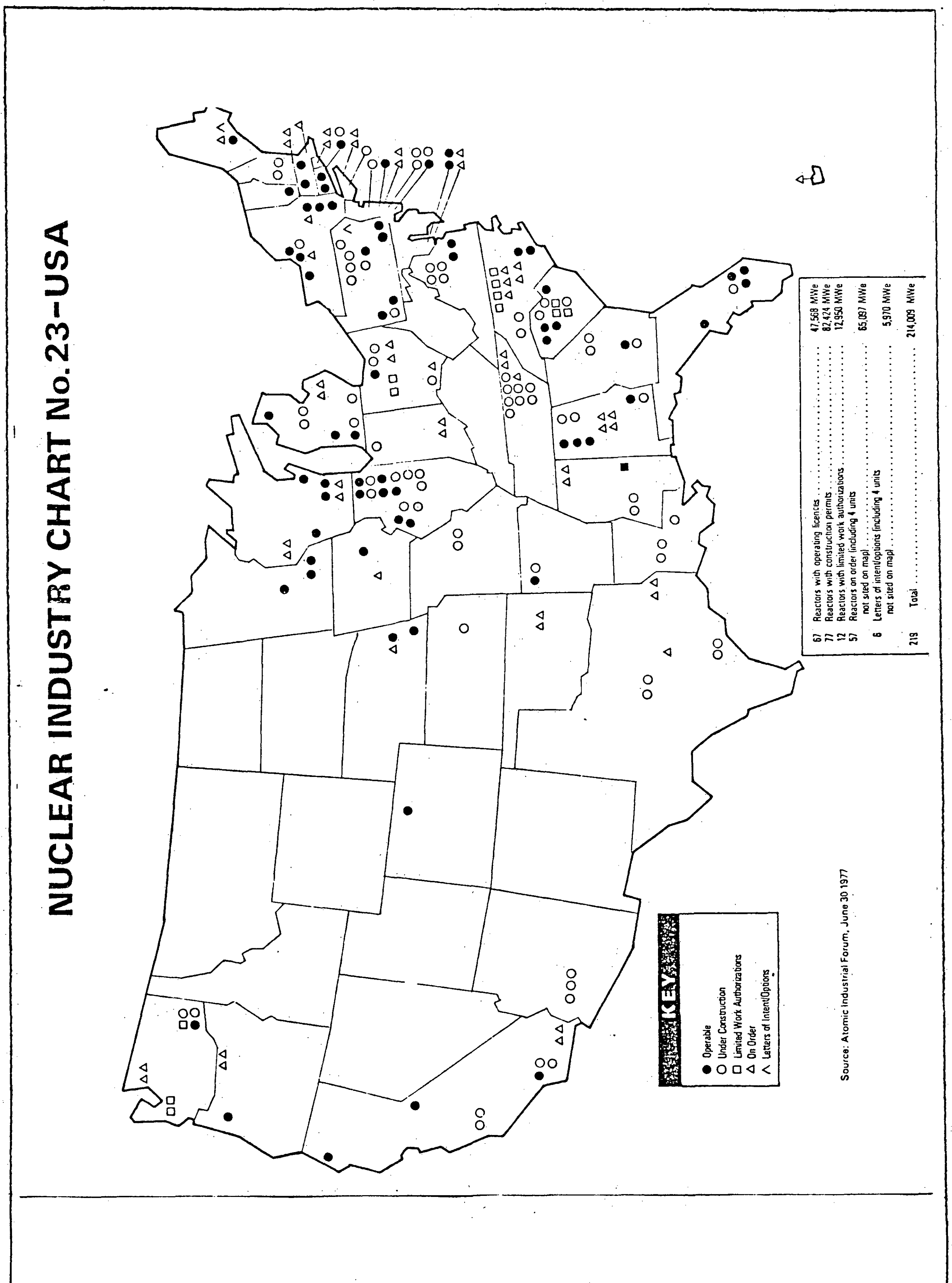

NUCLEAR INDUSTRY CHART No. 23-USA
KEY
Operable
Under Construction
Limited Work Authorizations
On Order
Letters of Intent/Options
Source: Atomic Industrial Forum, June 30 1977
67 Reactors with operating licences .... 47,568 MWe
77 Reactors with construction permits .... 82,424 MWe
12 Reactors with limited work authorizations .... 12,950 MWe
57 Reactors on order (including 4 units not sited on map) .... 65,097 MWe
6 Letters of intent/options (including 4 units not sited on map) .... 5,970 MWe
219 Total .... 214,009 MWe

FIGURE 4

To get some idea of potential uranium demand, some perspective of nuclear power plant orders for the next decade is necessary. The map and directory in Figure 4 is from the Atomic Industrial Forum, Inc. as of June 30, 1977.

Based on the total number of megawatt capacity (i.e. 214,000 Mw) as shown in the directory, the author estimates that the quantity of uranium demanded over a thirty year plant lifetime would range from 867,000 tons to 1,090,000 tons. This is a rough estimate, and it is based on conversions used in the text of this paper. For example, a low estimate assumes a previous ten to twenty years of operation for the existing 67 reactors and a thirty year life for all new or planned reactors with an average annual fuel consumption of 170 tons of U_3O_8. Other researchers have used different variables. A Society of Mining Engineers article used the inventory requirements shown in Table 19. If the lifetime were forty years, then the cumulative amount of U_3O_8 demanded would have a range of 1,156,000 tons to 1,455,000 tons. This amount would have to be available over a fifty to fifty-five year period beginning in 1976. What these estimates do not take into account is the possibility of additional nuclear power plants being ordered beyond what has been projected as of 1976. It also excludes foreign demand for uranium (see Table 20), although there is a possibility

Country	Foreign Uranium Resources (000 tons U_3O_8) Reasonably Assured	Estimated Additional (\$30 per lb U_3O_8)	Totals
Sweden	390	--	390
Australia	316	100	416
S. and S.W. Africa	357	96	453
Canada	216	545	761
Spain	30	55	85
France	71	53	124
Niger	65	39	104
Algeria	36	--	36
Argentina	27	51	78
Others	152	111	263
Totals	1,660	1,050	2,710

Source: ERDA, 1975

TABLE 19

Foreign Production Capability
(000 tons U_3O_8)

	1975	1980	1985
Australia	--	7,000	17,000
Canada	8,500	16,000	16,000
France, Gabon, and Niger	5,000	10,000	12,000
S. and S.W. Africa	5,000	13,000	18,000
Others	1,000	2,600	7,000
Totals	19,500	48,600	70,000

Source: ERDA, 1975

TABLE 20

that several Common Market nations and Japan may be willing to and capable of developing a liquid metal breeder reactor. This would, of course, lessen foreign demand for uranium. Because of these uncertainties, it is difficult to estimate the highest possible national and world demand level for uranium although a low-level demand is forecast.

In 1975, ERDA projected a potential U.S. nuclear generating capacity of 800,000 Mw for year 2000. This estimate assumed that plutonium would be recycled in 75 percent of reactors by 1983 with sufficient plutonium set aside for a breeder program after 1983. If the 800,000 Mw estimate were to be taken seriously and plutonium excluded from the system, then the amount of uranium fuel required, assuming thirty year plant lifetime, would be approximately 4.08 million tons! Conversely, if plutonium is included in the system then only 1.66 million tons of uranium would be needed (see Table 21).

Perhaps a more realistic estimate done in 1977 for 1990 by the U.S. Department of Energy is shown below and is also indicated in Figure 5.

Forecast of U.S. Nuclear Power Growth and Yellowcake Demand

End of Year	Generating Capacity (GWe)	Yellowcake (000 tons of U_3O_8) Annual	Yellowcake (000 tons of U_3O_8) Cumulative
1975	39.7	11.17	12
1980	76.0	22.9	103
1985	185.0	45.5	284
1990	340.0	74.3	597
1995	545.0	104.2	1,056
2000	800.0	129.2	1,660

Source: ERDA. Note: U_3O_8 demand is based on the following assumptions: 70% capacity factor; 0.3% U-235 tails; fuel reprocessing to begin in 1978; plutonium recycled in 75% of reactors by 1983; sufficient Pu set aside for breeder program after 1985.

TABLE 21

Forecast of U.S. Nuclear Power
Electric Generating Capacity

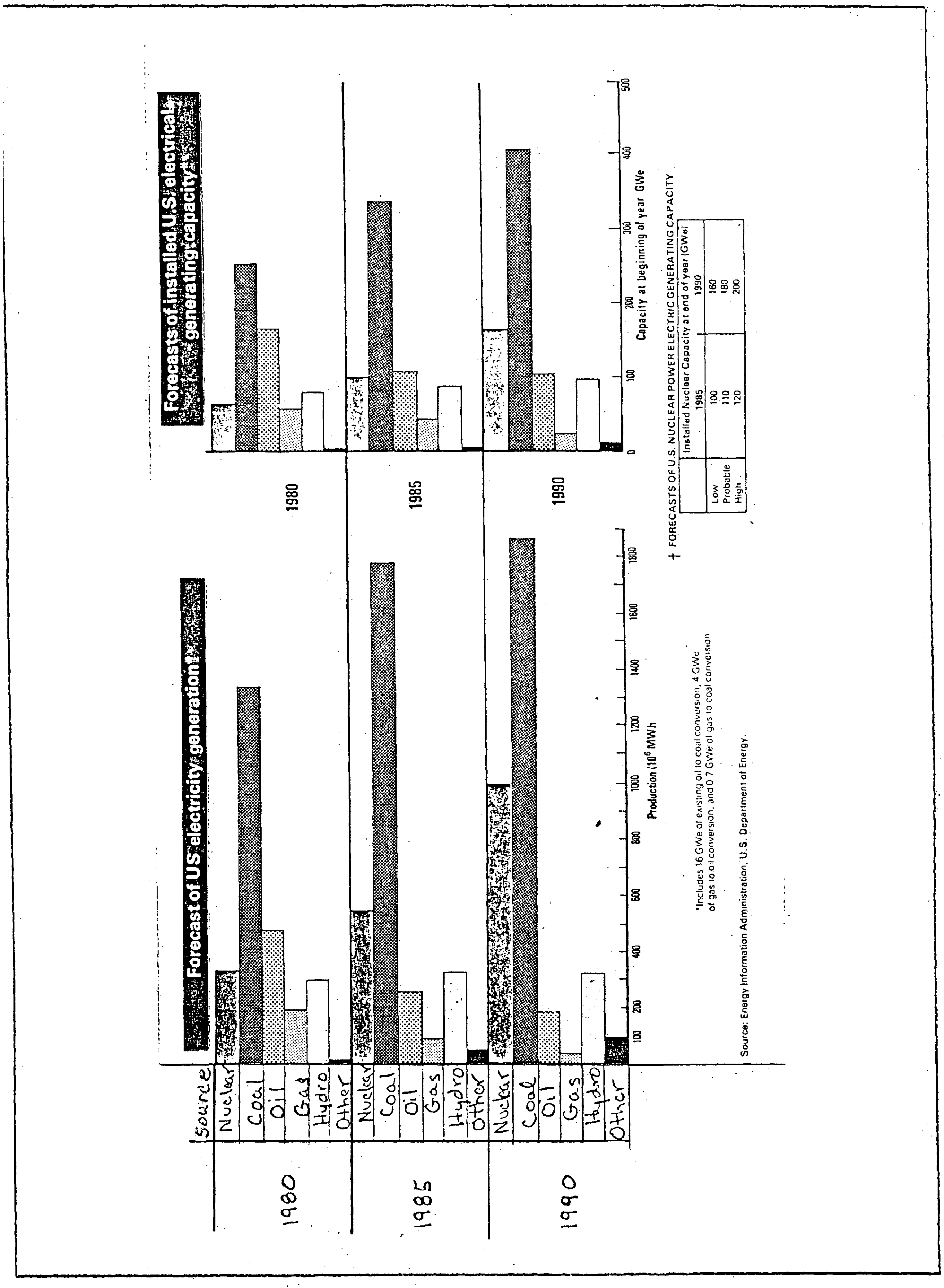
Installed Nuclear Capacity at End of Year (Mw)

	1985	1990
Low	100,000	160,000
Probable	110,000	180,000
High	120,000	200,000

Source: Energy Information Administration, U.S. Department of Energy, 1975.

Using the probable amount of 180,000 Mw for 1990, and again assuming an average uranium demand of 170 tons per year per reactor (i.e. note the fact that an HTGR would require an average of only 103 tons per year) then 1990 cumulative demand would be approximately 918,000 tons given a 30 year plant lifetime.

A summary of the impact of nuclear plant growth, estimated Mw generation and the corresponding supplies of U_3O_8 will be presented in the conclusion.



Forecast of US electricity generation*‡
Forecasts of installed U.S. electrical generating capacity*†
Source
1980
1985
1990
Nuclear
Coal
Oil
Gas
Hydro
Other
100 200 400 600 800 1000 1200 1400 1600 1800
Production (10^6 MWh)
0 100 200 300 400 500
Capacity at beginning of year GWe
† FORECASTS OF U.S. NUCLEAR POWER ELECTRIC GENERATING CAPACITY
Installed Nuclear Capacity at end of year (GWe)
1985 1990
Low 100 160
Probable 110 180
High 120 200
*Includes 16 GWe of existing oil to coal conversion, 4 GWe of gas to oil conversion, and 0.7 GWe of gas to coal conversion
Source: Energy Information Administration, U.S. Department of Energy.

FIGURE 5

COAL

The coal supply and demand problem is not one of physical scarcity like that of uranium. Few experts contest the fact that there are enough coal reserves to meet future power needs for several hundred years. The critical question has to do with the costs of extraction and transportation and the ensuing environmental entanglements.

Recent legislation (e.g. Clean Air Act of 1977) has caused considerable alarm in the coal industry because of the high capital cost of scrubbers which are estimated to be $80 million and the associated 6 percent loss of thermal energy. In addition, scrubbers add incremental cost to overall operations such that whatever advantage they may have over nuclear plants in terms of capital cost might be lost.

Actually, the impact of scrubbers on capital cost is not nearly as significant as the impact of fuel and transportation costs. As indicated in Table 16, the additional mills per kwh attributed to actual fuel cost far exceed any impact from other generating cost components. Thus, the factors that affect the price of coal will also have a tremendous affect on the viability of coal-fired power plants utilizing scrubbers.

Coal Usage By Industry - 1975 and 1976
(000,000 tons)

	1976	1975	% Change
Electric Utilities	443.0	403.2	+9.9
Coking Coal	87.0	83.2	+4.6
General Industry	64.0	62.5	+2.4
Retail Deliveries	5.0	5.0	---
Total Domestic Use	599.0	554.6	+8.0
Canada	17.0	16.7	+1.8
Overseas	45.0	48.9	-8.0
Total Consumption	661.0	620.2	+6.6
Production	665.0	646.0	+2.9

Source: National Coal Association Economics Committee

TABLE 22

In the last five years, coal has been making significant progress in capturing a larger percentage of the electric utility power generation market. Table 22, produced by the National Coal Association Economics Committee, shows that while coal production was predicted to increase 2.9 percent in 1976, coal consumption by utility companies increased 9.9 percent. According to the table, electric utilities may utilize two-thirds of the coal produced in 1976. It was announced that the Federal Energy Administration had ordered 48 new electric utility plants to incorporate coal burning facilities that will require 84 million tons of coal.

Under the Carter program, coal production is expected to double, rising to more than a billion tons by 1985 from 665 millions tons in 1976. That would increase coal's share of the total energy picture to 29 percent from 18 percent. The National Coal Association's most recent figures show that by 1986 utilities are expected to build 259 new coal-fired plants, bringing total coal consumption by utilities up to 850 million tons from today's 448 million tons.

Whether or not the production capacity for coal will be adequate is dependent upon labor productivity, transportation efficiency (i.e. possibly the use slurry lines) and the demand for coal. If the price of coal exceeds the inflation rate then it could easily affect the real cost of electricity produced.

CONCLUSION

Now that generation costs have been derived for nuclear and coal-fired plant prototypes, several conclusions can be drawn.

Capital cost had the greatest impact on annual generation costs. Capital cost represented two-thirds the total generation costs for a nuclear power plant and one half the total generation costs for both types of coal plants. Generation costs were extremely sensitive to capital cost in the nuclear power plant example. A 100 percent increase in capital cost would raise total generation cost by 65 percent, while a coal power plant would impact generation costs by approximately 45 percent. This difference is not surprising, given the magnitude of escalation and interest expenses due to the extended time period required to build a nuclear power plant.

Regional factors influence the capital construction cost of power plants. It was shown that construction costs in New England were approximately 15 percent greater than construction cost in such areas as Texas or South, Central United States. A 15 percent decrease in construction cost would decrease generation cost by 1.75 mills per kwh to 2.24

mills per kwh for 1985 coal-fired power plants (i.e. tall stacks and scrubbers, respectively) and by 3.02 mills per kwh for 1985 nuclear-fired power plants. Although a 3 mill per kwh reduction does not make nuclear generation costs lower than that of a coal plant without SO_x removal equipment, it lessens the economic margin between the two plant alternatives by almost 50 percent.

Since capital costs are primarily a function of elapsed construction time, any decrease in construction time could greatly improve the economic disposition of nuclear plants. If, for example, predictable regulatory procedures were enforced or if engineering plans for LWRs could be standardized, then the front end capital cost factors would be reduced. Conversely, any additional delay in construction time, such as an additional year, would increase capital cost by as much as 15 percent to 20 percent.

Fuel cycle costs are probably the most difficult to project. Mining, milling fabricating and enrichment processes for uranium are not just dependent on the supply and demand market cnditions, but they are also dependent on political postures of domestic and foreign governments. Alleged cartels, uranium embargoes, federal enrichment and waste dispsal plans are just a few examples of political overtones. Coal suffers a similar plight given the sensitivity of coal production to strikes and corporate intransigence. In fact, several utility companies such as Duquense Light Company of Pennsylvania claim that their interest in nuclear power was to create a hedge against coal strikes.

Nuclear fuel has a significantly smaller impact on total generating cost. In fact, nuclear fuel cost would have to change by a magnitude of 60 percent more than a change in the cost of coal in order to have the same impact as coal on total generation costs. To state the comparison in another manner, a 20 percent increase in the price of U_3O_8 would increase generation costs by only 5.2 percent. A 20 percent increase in the price of coal would increase generation cost anywhere from 8.4 percent to 8.8 percent depending on fuel and plant type (i.e. tall stacks or scrubbers).

Clearly, SO_x removal equipment considerably changes the desirability of the coal-fired power plant alternative. Based on the hypothetical models, a coal-fired power plant that is operationable in 1983 is cheaper than either the nuclear or coal-fired power plant utilizing scrubbers. This is an important difference and reflects the ongoing economic controversy over which alternative is the most efficient. Since generation costs are more sensitive to coal prices than to uranium prices, there is some doubt about the economic advantage of non-scrubber (i.e. clean coal) coal-fired power plants. However, it is especially important to realize that the choices are not mutually exclusive and that the non-scrubber power plant alternative is limited only to those regions where energy demand and electrical generation are close to low sulfur coal deposits.

Capacity is another important economic variable, and is often used as an argument against proponents of nuclear power. This is so because nuclear power plants have had a capacity average of 60 percent while coal power plants have often rated 10 percentage points higher. Generation costs are very sensitive to capacity ratings. A decrease in nuclear plant capacity by 10 percent would increase generation costs by 6.25 percent while a 10 percent decrease in coal plant capacity would increase generation cost by 4.30 percent. In effect, a nuclear plant is almost 33 percent more sensitive to changes in capacity than a coal plant. Of course, this type of sensitivity works both ways and if a nuclear power plant can operate at 70 percent to 80 percent capacity then its economic efficiency exceeds that of a coal power plant. Based on industry estimates, a nuclear capacity factor of 55 percent to 60 percent represents the break even point with a standard coal-fired plant using the same rating.[8]

Table 23

Total Generating Costs (mills/kwh)

	1976	1983	1985
Nuclear	15.23	--	30.72
Coal			
Scrubbers (SO_x)	19.83	33.52	--
Tall Stacks only	15.17	25.33	--

Nuclear-fired power plants have an economic advantage over coal-fired power plants that use SO_x equipment. Any real rise in coal cost (e.g. f.o.b. or c.i.f.) or any reduction in capital cost of nuclear plants could make nuclear power plants more economical than coal power plants without SO_x equipment. If capacity factors increase from 60 percent to 70 percent for nuclear power plants, then the economic advantage is further enhanced.

TABLE 24

Sensitivity Analysis 1983/85

% Increase/decrease in Cost Variable	Factor	% Change in Generating Costs
+50	- Nuclear Capital Cost -	+32.5
+50	- Coal Capital Cost -	+23.4
+50	- Nuclear Fuel Cycle Cost -	+13.10
+50	- Coal Fuel Cycle Cost -	+21.6
-20	- Nuclear Capacity -	+12.5
-20	- Coal Capacity -	+ 8.6

Note: 1. 1983 costs are for a coal-fired power plant with construction beginning in 1976. 1985 costs are for a nuclear-fired power plant with construction beginning in 1976.

2. The generating costs for both types of coal power plants are averaged for purposes of clarity.

The Tennessee Valley Authority, which has the country's largest committment to nuclear power, has consistently posted lower nuclear generated power cost than coal generated power costs. Although, TVA's nuclear costs are below the national average, the utility estimates that the total cost of generating power in its 12 coal plants is 14 mills per kwh, compared to 6.1 mills per kwh for its Browns Ferry nuclear plant.

In spite of TVA's enthusiam and the low generation cost ascribed to the nuclear power plant prototype in this paper,

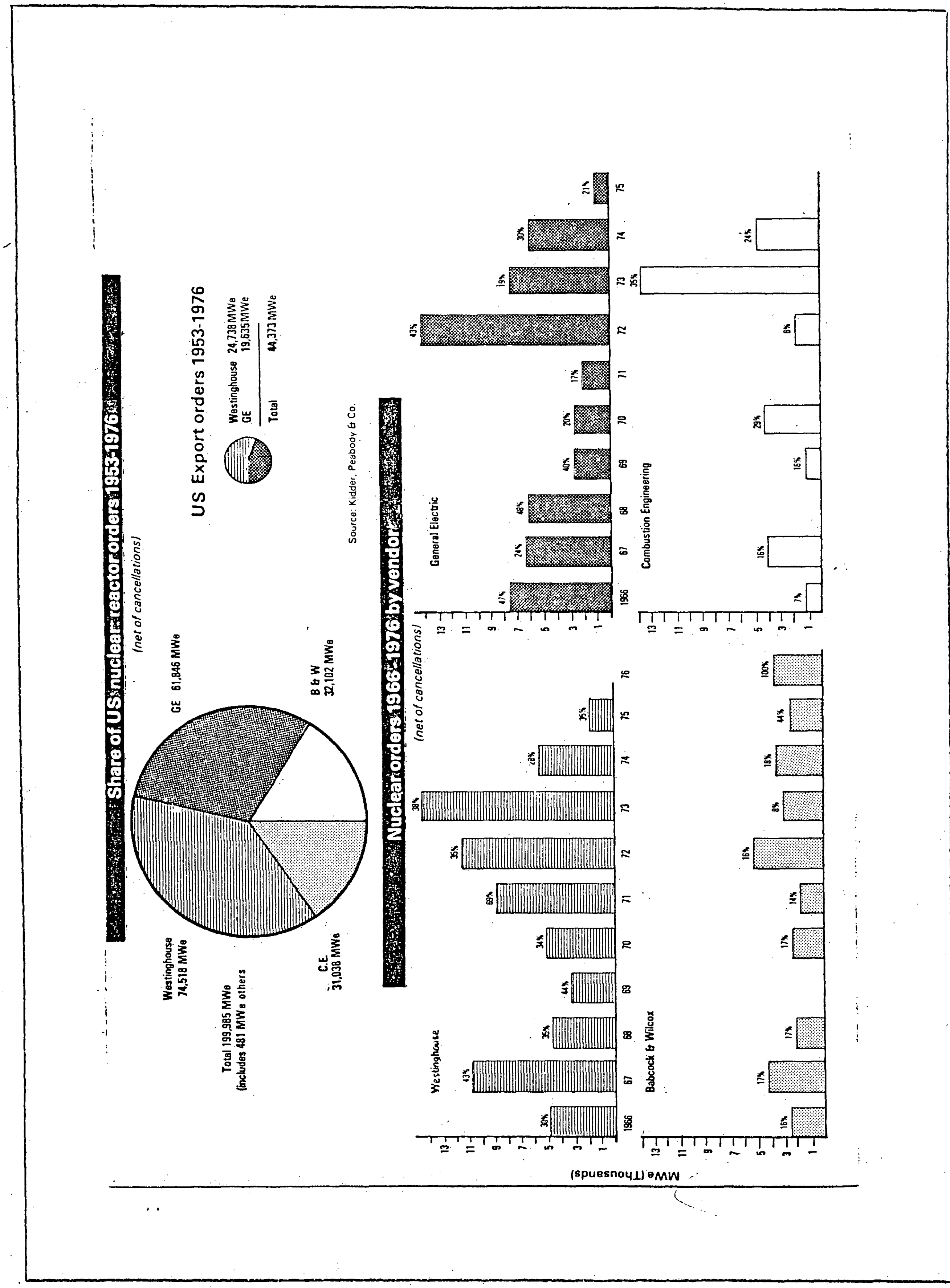

Share of US nuclear reactor orders 1953-1976
(net of cancellations)
GE 61,846 MWe
B & W 32,102 MWe
C.E. 31,038 MWe
Westinghouse 74,518 MWe
Total 199,985 MWe (includes 481 MWe others
US Export orders 1953-1976
Westinghouse 24,738 MWe
GE 19,635 MWe
Total 44,373 MWe
Source: Kidder, Peabody & Co.
Nuclear orders 1966-1976 by vendor
(net of cancellations)
MWe (Thousands)
Westinghouse
General Electric
Babcock & Wilcox
Combustion Engineering

FIGURE 7

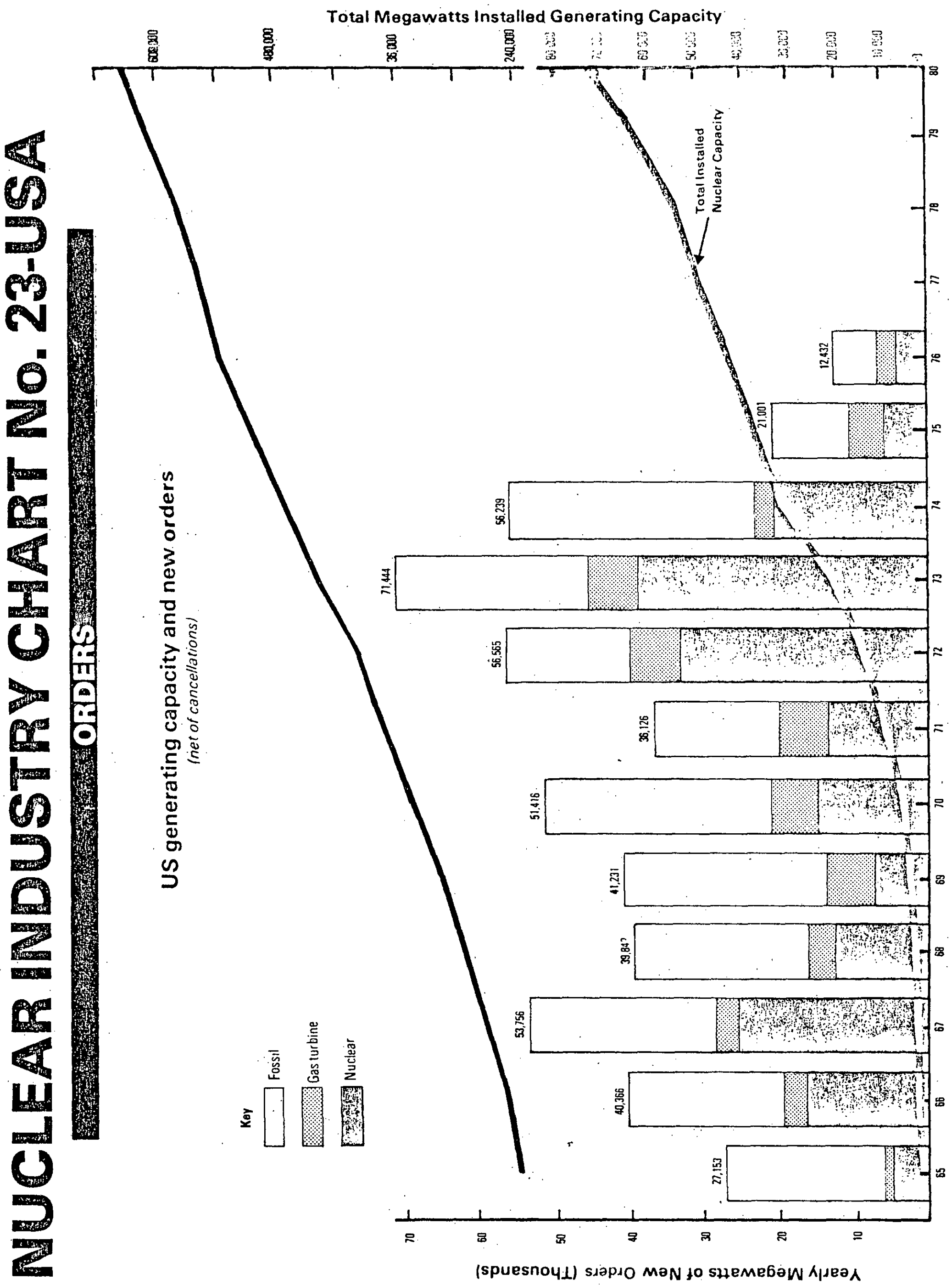
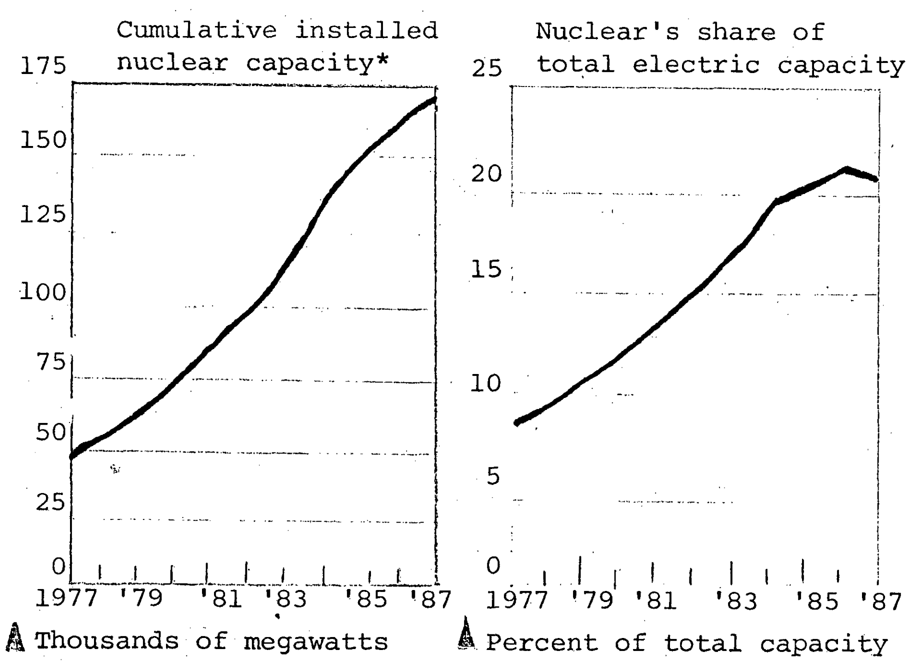

NUCLEAR INDUSTRY CHART No. 23-USA
ORDERS
US generating capacity and new orders
(net of cancellations)
Key
Fossil
Gas turbine
Nuclear
Total Megawatts Installed Generating Capacity
600,000
480,000
240,000
Total Installed Nuclear Capacity
Yearly Megawatts of New Orders (Thousands)
70
60
50
40
30
20
10
27,153
40,366
53,756
41,231
51,416
36,126
56,565
71,444
56,239
21,001
12,432
65
66
67
68
69
70
71
72
73
74
75
76
77
78
79
80

FIGURE 8

there has been a minimal demand by utilities for nuclear power plants. Although many of the reasons for this slack in demand transcend economics, economic factors do have a strong bearing on many of them.

Figures 6 and 7 indicate the cyclical nature of nuclear power plant orders. During the period from 1970 to the middle of 1974, there were over one hundred orders. There were only four new orders in 1977 and three in 1976. While order backlogs make it likely that the total megawatts supplied by nuclear power will grow, the lack of orders now could mean a levelling off or even a decline in nuclear's share of the total energy mix when backlogs are exhausted (see Figure 8).

Figure 8



Data: Atomic Industrial Forum

*Assumes all plants on order or under construction will be completed on current schedule

To an extent, a backlog in orders has had an impact on the recent downturn in nuclear plant demand. However, this can be interpreted to mean that nuclear power's share of total domestic electrical generation will steadily decline beginning in 1985 and that no viable, immediate economical alternatives exist.

Capital financing has become a major obstacle given the excessive costs of escalation and inflation. Banks have been reluctant to commit large amounts of capital when the payback period and cash flows are so distant. Utility companies are increasingly being forced to seek external funds since internally generated funds (i.e. rate increases which are controlled by quasi-public regulatory agencies) are not sufficient. According to the Edison Electric Institute, 55 percent of construction financing will come from external funds specifically in the form of equity issues. Equity issues (e.g. common stock and convertible debentures) seem to be the only financing alternative given the existing high cost of long-term debt.

The uncertainty of uranium supplies is also a critical question. It has already been shown how 1976 proven domestic reserves will not be adequate for the number of nuclear plants operating in the year 2000. Of course, if the breeder reactor receives administrative consent, then domestic uranium supplies might be adequate. By the year 2000, foreign uranium supplies will be offset by equally strong foreign demand. Other dark areas such as protracted safety deadlocks, spent reactor fuel disposal and lack of adequate enrichment facilities by 1985 have augmented the degree of uncertainty clouding the future of nuclear power.

Coal suffers no less a fate. Given the sensitivity of generation cost to coal prices, any real price increases will definitely have a deleterious affect on coal generation. In addition, if SO_x equipment is mandated, then the capital cost advantage of coal power plants may soon be lost.

In any event, the coal versus nuclear power plant alternative is more than just an economic debate, although economics play a primary role in the decision-making process. Although both alternatives are, at present, the cheapest forms of electrical production with expansion potential, future prospects do not guarantee continued, cheap power production. Unfortunately, the plethora of uncertainities in the future adversely affects the accuracy of projected economic comparisons. Nevertheless, future economic evaluations are necessary for today's decisions regarding the development of electrical power.

APPENDIX

United Nuclear Company
Scheduled Production v. Delivery Commitments
(Pounds in thousands)

Fiscal Year Ended March 31	Scheduled Production	*Committed Pounds	Average Price/Pound	*Uncommitted Production Available for Sale
1979	4,500	2,320	$35.55	2.180
1980	5,200	1,106	23.39	4,094
1981	6,200	1,100	44.24	5,100
1982	6,500	200	59.00	6,300
1983	7,000	100	62.00	6,900

TABLE 25

TABLE 26

Explanation of the Nuclear Fuel Cycle

Step	Description	Amount Needed to Serve 1,000 MWe Reactor
Mining	Underground mining and surface mining of ore	263,000 tons per initial core 94,000 tons per reload
Milling	Mechanically and chemically refine ore to "yellow cake." Usually done near the mine	526 tons per initial core 187 tons per reload
UF_6 production	Convert "yellow cake" to gas for enrichment	420 metric tons uranium (MTU) per initial core 150 MTU per reload
Enrichment	Concentrate natural uranium content of U-235 at 0.7% to between 2% and 4% concentration Current technology being upgraded and new technologies being tested Modern plant with capacity of 9 million separative work units (SWU) requires about 2,500 MWe electric plant to run	9 million SWU plant serves about 125 power plants

TABLE 26 (Cont'd.)

Explanation of the Nuclear Fuel Cycle

Current Status (Cont'd)	Institution Involved (Cont'd)	Expansion Issues (Cont'd)
illion tons capacity	Independent mining companies Large resource companies	U.S. known and estimated reserves are about 3.5 million tons of U_3O_8 (ore mined today has about 4 pounds U_3O_8 per ton of ore) at up to $30 per pound U_3O_8 It takes about 8 years to explore, find, and begin mining ore
		Major expansion effort needed-could require between $1.5 billion and $3+ billion in capital
000 tons capacity 000 tons production	Miners and chemical companies	Run out of capacity at a minimum by 1980, possibly within 2 or 3 years
000 MTU capacity us 9,000 MTU coming stream by 1977/1978	Chemical company Resource company	At minimum, no expansion needed by 1980 if planned expansion comes on stream
		By 1985, minimum need is for another 10,000 MTU capacity
		Accelerated program could require 10,000 MTU capacity by 1980 $30 million capital per 5,000 MTU block of capacity
sting capacity plus nned upgrades could st until mid-1980s	Federal Government Private ownership being encouraged	A 9 million SWU plant cost between $4 billion and $5 billion and takes up to 9 years from design to start-up
		Depending on foreign commitments, capacity could be short before mid-1980 which would require early start at expansion

TABLE 26 (Cont'd.)

Explanation of the Nuclear Fuel Cycle

Step (cont.)	Description (cont.)	Amount Needed to Serve 1,000 MWe Reactor (cont.)
l rication	Convert enriched UF_6 gas to solid ans assemble in "burnable" fuel rod elements	90 MTU per initial core 25 MTU per reload
lity power nt	Converts energy in uranium to electricity	Not applicable
te fuel	"Burned" up fuel bundles which if left in reactor can significantly reduce ability of reactor to sustain chain reaction needed to operate Has concentration of lightly less than 1% U-235 plus contains about 0.6% plutonium "bred" in the reactor	Produces about 25 MTU per year, total weight about 50 tons
l rocessing	Objective is to recover usable uranium and plutonium from waste	See waste fuel above
te agement	Problem is high-level waste whether recycling proceeds or not. Problem is safe waste management essentially forever be- cause of the level of radiation and the long life of the radioactive isotope	One year's output when reprocessed produces about 10,000 gallons of waste which when solidified and mixed with inert material take up about 70 cubic feet.

TABLE 26 (Cont'd.)

Explanation of the Nuclear Fuel Cycle

.rrent Status (cont.)	Institution Involved (cont.)	Expansion Issues (cont.)
.rrent capacity about 500 MTU	Nuclear steam system suppliers, oil company, others	Ultimate capacity and nature of capacity depend on whether plutonium will be recycled At minimum about 2,000 MTU more capacity needed by 1985; maximum up to 8,000 MTU new capacity requirements to 1985
plants with 36,000 'e capacity out 150 plants on der with at least 100 coming operational fore 1985	Public utilities and federally owned utilities	To be discussed later in chapter
000 MTU backlog in on- .te storage pools (tempo- .ry storage at power .ant) re backlog stored at noperating reprocessing .cilities	Public utilities and federally owned utilities	What to do with it and when: o Reprocess o Temporarily store and then reprocess it o Finally, permanently manage Expansion of temporary storage will be needed to handle waste fuel
commercial operations w anned capacity about 300 tons by 1980	Private companies: chemical and nuclear service	Will reprocessing be economic, i.e., will the value of usable fuel produced by recycling, reenriching, fabricating, etc., be greater than the cost incurred to do it-or should waste fuels be processed and sent directly to permanent waste management?
deral Government will cide how to manage gh-level wastes		

urce: Compiled from information in The Nuclear Fuel Cycle, June 1975 'ashington, D.C.: Atomic Industrial Forum, Inc.) and printed in "The onomics of Electric Power Generation: 1975-2000," by Michael Murray, blished in The Nuclear Power Controversy, Prentice-Hall, N.I., 1976.

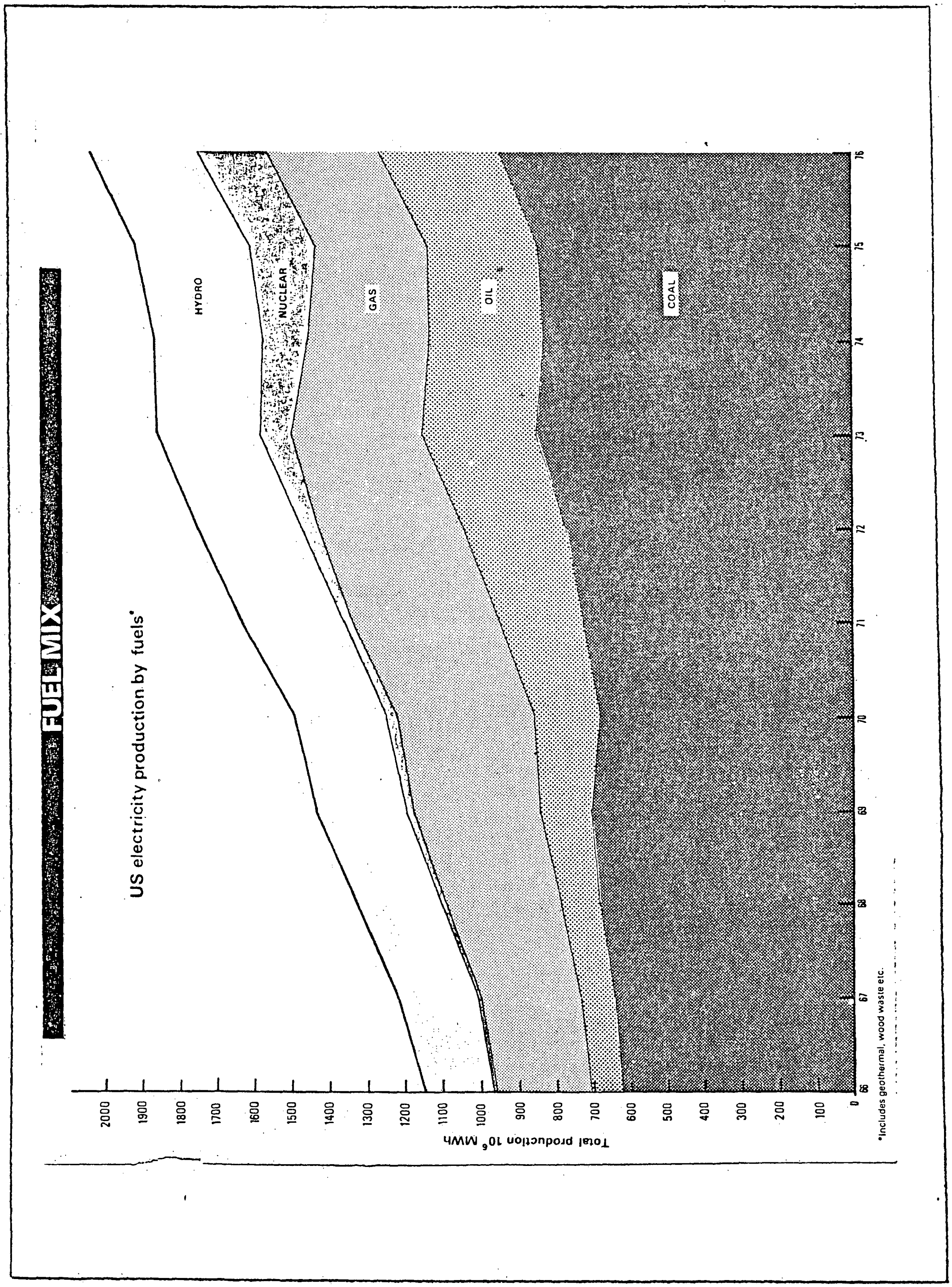

FUEL MIX
US electricity production by fuels*
HYDRO
NUCLEAR
GAS
OIL
COAL
Total production 10^6 MWh
0
100
200
300
400
500
600
700
800
900
1000
1100
1200
1300
1400
1500
1600
1700
1800
1900
2000
66
67
68
69
70
71
72
73
74
75
76
*Includes geothermal, wood waste etc.

Figure 9

FIGURE 10

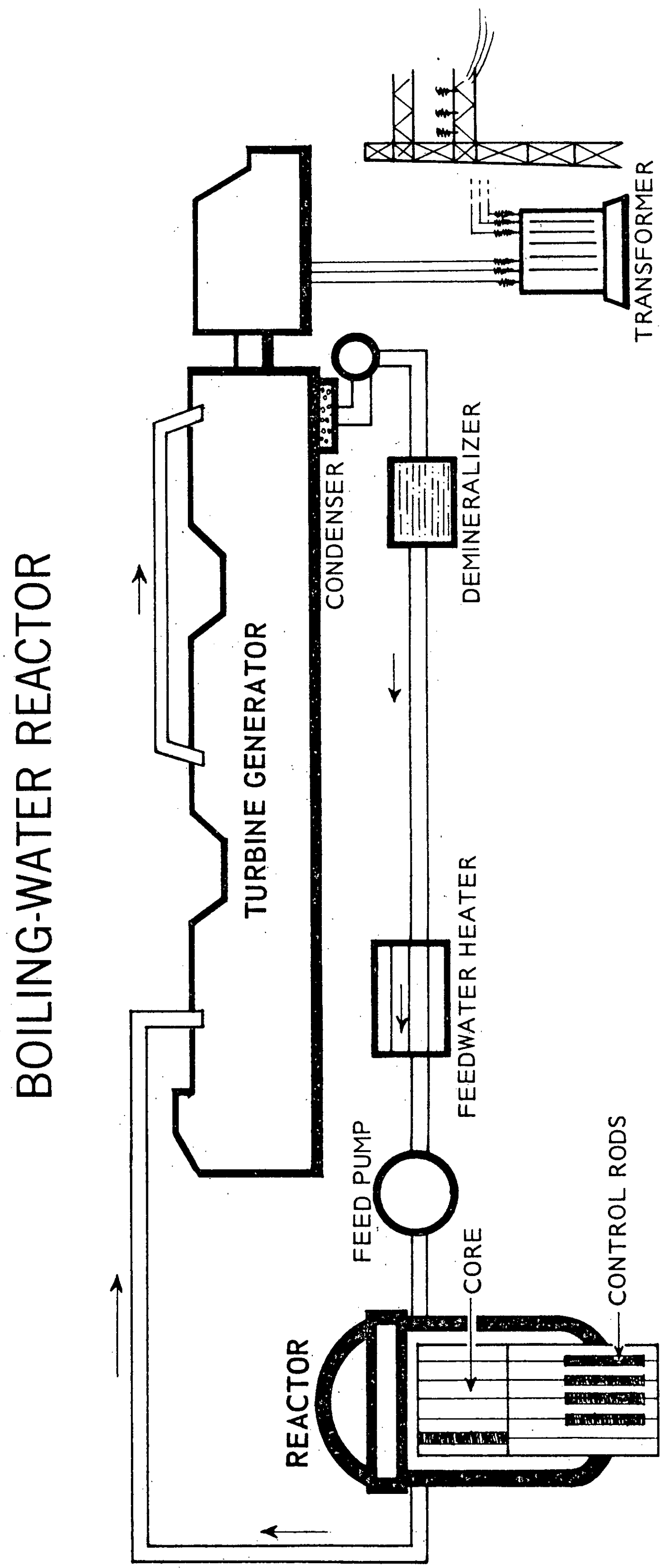

BOILING-WATER REACTOR
TURBINE GENERATOR
CONDENSER
DEMINERALIZER
TRANSFORMER
FEEDWATER HEATER
FEED PUMP
CORE
CONTROL RODS
REACTOR

FIGURE 11

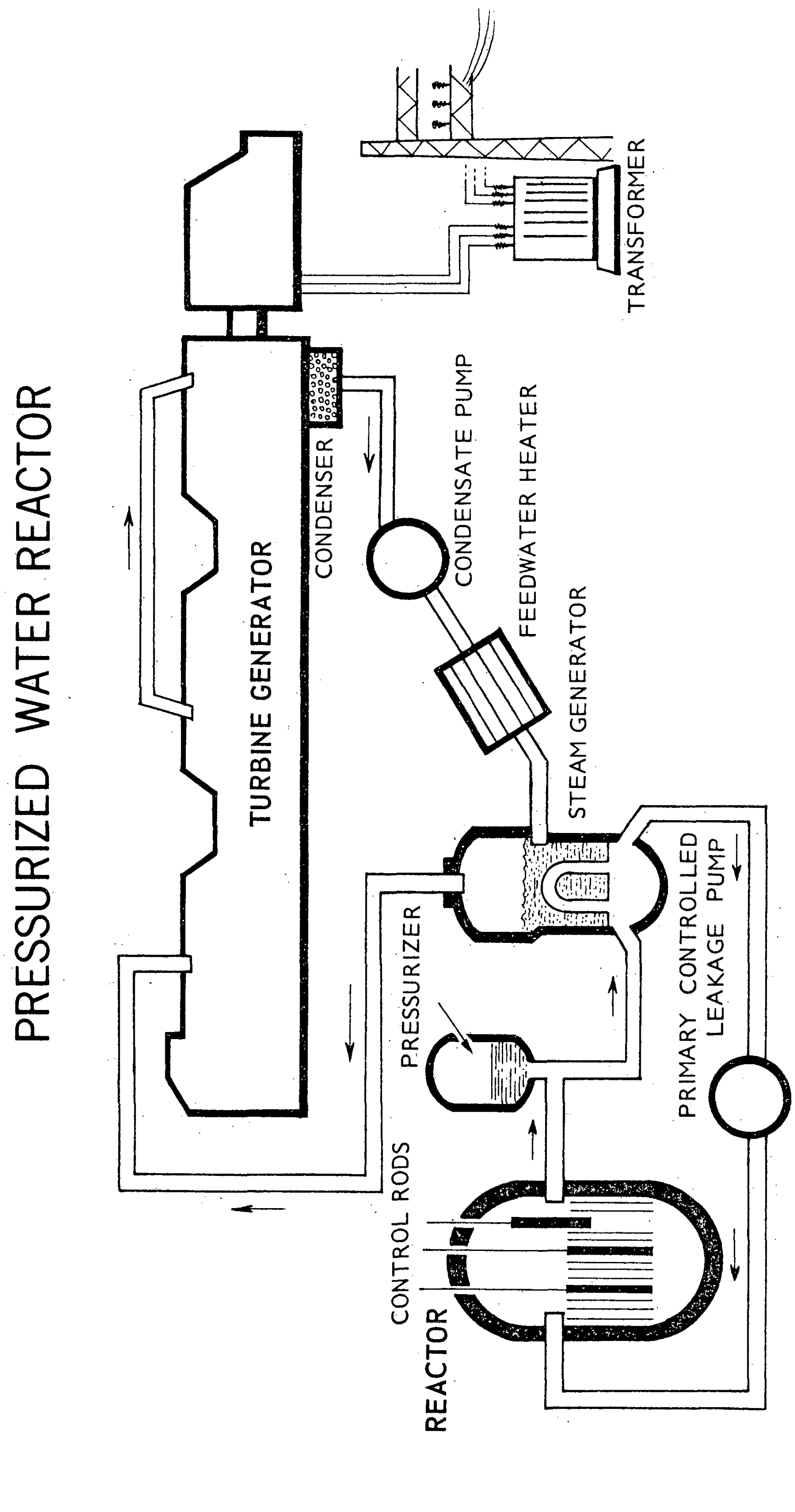

PRESSURIZED WATER REACTOR
TURBINE GENERATOR
CONDENSER
CONDENSATE PUMP
FEEDWATER HEATER
STEAM GENERATOR
TRANSFORMER
PRESSURIZER
PRIMARY CONTROLLED LEAKAGE PUMP
CONTROL RODS
REACTOR

FIGURE 12

HIGH-TEMPERATURE, GAS-COOLED REACTOR

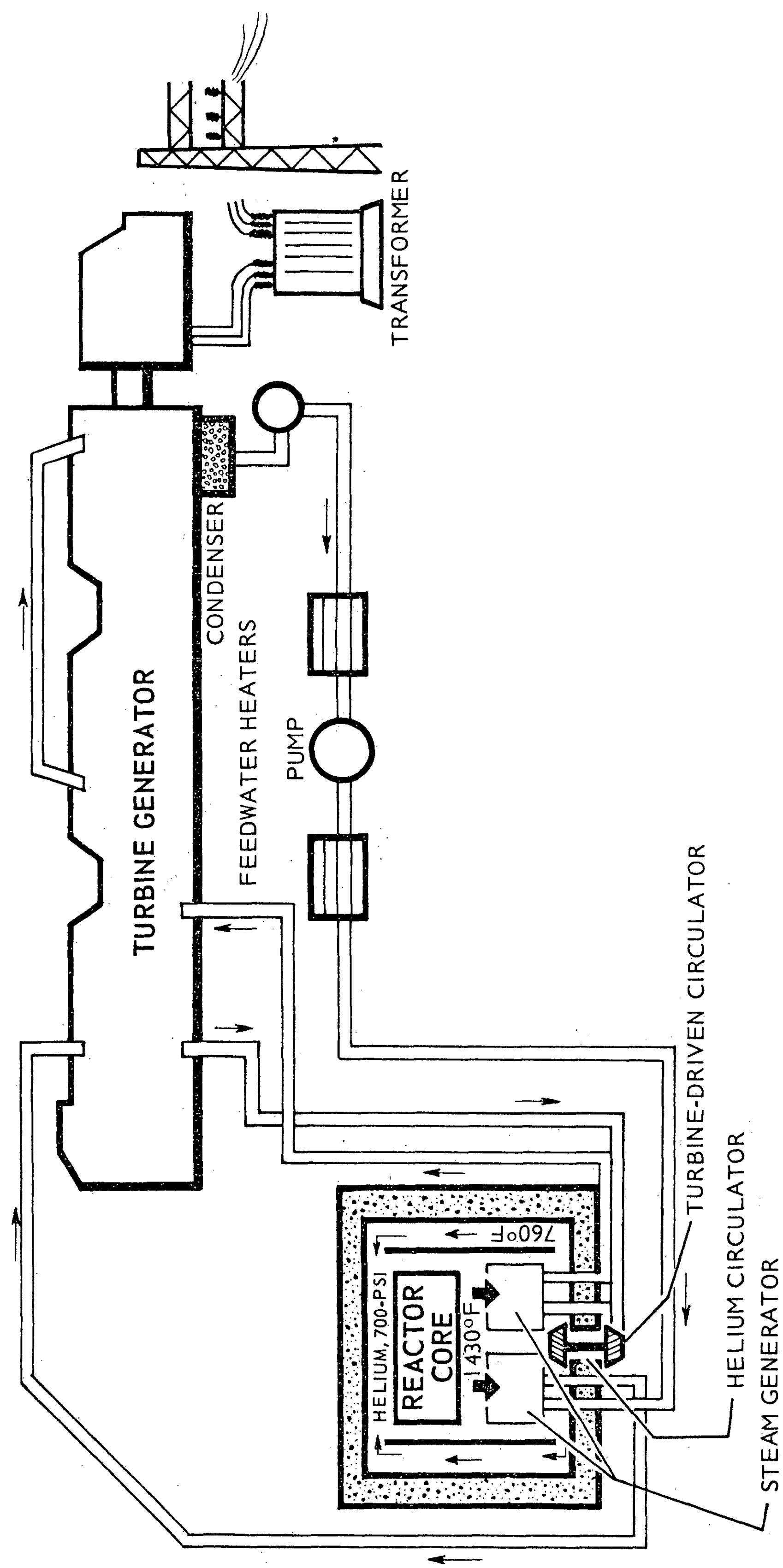
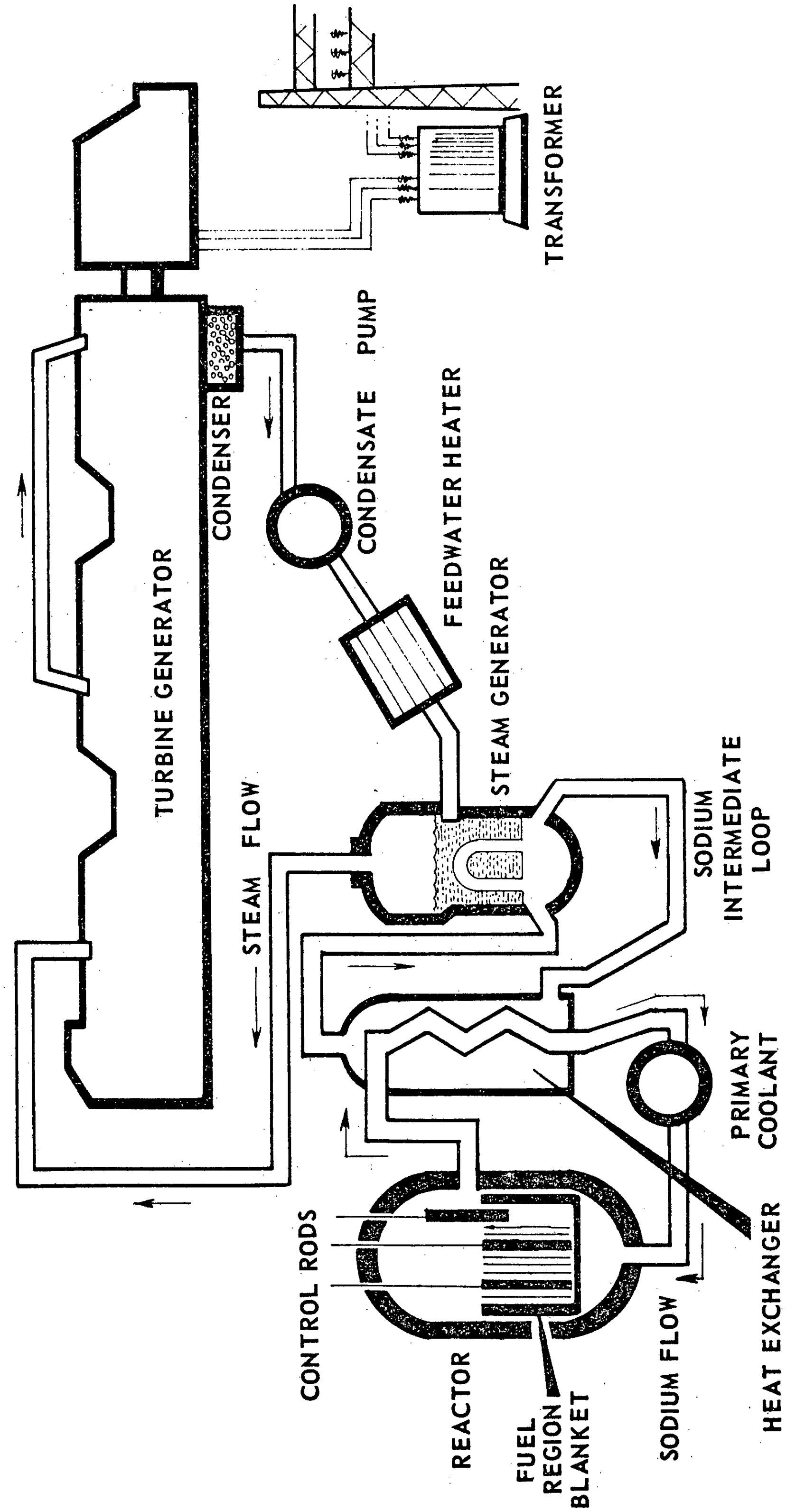


FIGURE 13

LIQUID METAL FAST BREEDER REACTOR



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