FOSSIL FUEL ECONOMICS

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ABSTRACT

A large number of fossil energy processes are now in various stages of research and development around the world to produce substitute fuels for conventional oil and gas. Process design and cost estimation of new processes is an invaluable part of the development process to guide R&D to the most promising processes and to place experimental emphasis on technical problems of greatest priority. Types of design and cost estimation are described as well as the uncertainties involved in the resulting estimates as they depend on data quality and the level of estimate detail. Project and process contingencies are given which have been found to be appropriate to account for the expected underestimation.

Cost evaluations are described for coal gasification processes taken from the recent C.F. Braun & Co. report which compares new process developments with commercial Lurgi coal gasification. Costs of approximately $5 per million Btu are indicated. Coal liquefaction costs for processes currently at the pilot plant stage of development are discussed. Liquid product costs are indicated between about $3.50 and $5.00 per million Btu. Power generation is examined on the basis of near-term new and retrofitted plants as well as the longer range potential of combined cycle technology.

INTRODUCTION

Preliminary design and cost estimating of fossil energy processes is the principal means of determining the practical advantages and disadvantages that a given process has compared with others which produce similar products. The results of such comparisons are of particular importance to research and development. They not only indicate those processes which offer promise of technical and economic feasibility in a future market, but also those sections of a process flow scheme which should receive the greatest attention during further development. It becomes quickly apparent that certain unit operations create the heaviest economic burdens on plant investment and product selling price. These areas then become prime targets for innovative engineering.

Successful process-related companies rely greatly on such process analysis to guide their development efforts and to point to new research projects. Inventors pay close attention as well since the royalty they will receive on a new patent will be negotiated as a portion of the savings created relative to the next best alternative.

U.S. Government research and development activities in fossil energy have grown beyond $500 million annually and decisions about program and project direction are strongly influenced by process analyses.

PROCESS DEVELOPMENT AND ANALYSIS

New heavy-industry process development is an expensive and risky enterprise usually conducted by large companies and governments, sometimes in joint venture. The 15 to 20 year development time to first commercialization which has been estimated for new coal conversion processes, for example, practically mandates government-industry cost sharing.

An example of liberal government cost sharing with industry to induce steady development of new coal conversion processes is illustrated by Figure 1. It represents a logical developmental sequence for a hypothetical case. Although no specific case would necessarily follow this example closely, perhaps the composite of a number of cases would be reasonably close.

The example indicates that after conceptual work, exploratory research follows to test scientific feasibility in a unit capable of about one ton of daily coal throughput. Over a period of one to four years for this phase, $10 million or more may be consumed. Next, a process development unit (PDU) is shown to gather the necessary physical, chemical and engineering data. About five years and $20 to $30 million is required for this phase. A large pilot plant is typically the next phase of development and requires about seven years to complete. Project cost for a 100 ton per day plant may approach $100 million. Finally, the last two stages shown by Figure 1 represent successively larger commercial prototype plants in final preparation for a full-sized 50,000 barrel per day plant (or its thermal equivalent if the product is other than oil). This development scheme is admittedly conservative and perhaps for some cases the exploratory research and PDU phases could be combined. Likewise the pilot plant and demonstration plant phases might be accomplished jointly by a plant size of several hundred tons per day capacity. Nevertheless, the time to reach commercialization would still be almost 15 years.

Guiding process development by design and cost engineering analysis is very important, but complicated by the need to compare estimates taken from various sources. Engineering design and cost estimating procedures and data will differ somewhat when different process groups have been involved. Any significant differences usually can be resolved when the material is well documented. However, two other factors must be considered when two or more estimates are to be compared. The first concerns the degree of engineering effort expended in the design and costing of each estimate. Greater engineering effort generally produces more accurate than that taken from smaller units such as PDU-sized equipment. The second concerns the quality or reliability of the data being used for the design. Data from the demonstration or commercial development phase is obviously more accurate than that taken from smaller units such as PDU-sized equipment.

These two sources of inconsistencies in estimates can be resolved by means of project and process contingencies. These are allowances to account for differences in the level of engineering effort and in data reliability, respectively. Application of these contingencies adjusts an estimate to a value equivalent to the completion of development when full data is available for all sections of the plant and an accurate detailed estimate can be made.

Project and process contingencies which are being used to compare and resolve process estimates in the Fossil Energy Program, U.S. Department of Energy, are shown in Figure 2. The process contingency is calculated as a percentage of the onsite portion of the plant and represents the additional investment necessary to improve or expand process equipment to reach design conditions, since data taken while developing a process tend to be optimistic. Project contingency is calculated as a percentage of the total onsite (including process contingency) and offsite investment and is then added to obtain the final investment. It allows for errors in cost estimating due to design assumptions, labor productivity and rate assumptions, late delivery of construction materials, and the like. Therefore, it reflects only the uncertainty of constructing a given plant for a given cost and does not depend on the uncertainty of the technical data. It does depend on the type of estimate made as shown in the figure. Typical engineering costs of producing these estimates for a 50,000 barrel per day coal conversion plant are given in parentheses.

The contingency figures shown in Figure 2 resulted from discussions with large U.S. processing firms over the last two years and are based on their process development and plant construction experience. Major contribution was received from Exxon Corporation.

A better understanding of various levels of cost estimates and the accuracy which can be expected from them can be gained by considering Figures 3, 4 and 5. Together these figures describe the basic differences between preliminary, definitive and detailed estimates.

The first step in developing an estimate is setting the design basis. All three estimate types require the same type of design basis information, with the exception that the site specification for the three differs. For example, a detailed design including detailed mechanical drawings requires specification of an actual site and core drillings may be necessary to determine foundation design.

The next step in process estimating is the process design itself (Figure 4). Differences in estimate accuracy are most obvious from consideration of the varying efforts expended in this step. In a preliminary design the effort ends with an equipment list, while in a definitive design detailed specifications are prepared, including piping and instrumentation specifications. This additional information requires a great deal more engineering effort to develop, but it is important to accuracy since process plants contain piping and instrumentation that may represent up to 40 percent of the plant capital investment. A detailed design includes the latter elements plus detailed engineering drawings and plans which may require hundreds of thousands of man-hours to produce. Of course, this effort is appropriate only when actual construction is planned.

The last step is the cost estimating process itself. For preliminary estimates, cost curves, experience factors, and rules of thumb are used, whereas for a definitive estimate, a more detailed estimating procedure is required. Vendor quotes, specific cost indexes, and projected financial conditions are appropriate. For a detailed study, one seeks vendor bids, finances under actual conditions, and studies actual labor rates and productivity for the area in question. Actual labor costs and productivity are extremely important factors which are generally overlooked. The availability of skilled craftsmen and the specifics of union rules vary in different parts of the United States and can have a large effect on the final plant cost.

Reconsidering Figure 2, it is clear that a final investment estimate varies a great deal as a result of the contingencies applied to it. Consider, for example, a coal liquefaction plant producing 50,000 barrels of product oil daily. Onsite investment might be roughly $750 million and offsite investment about $250 million. If these investments had been calculated using data of PDU quality by a preliminary type of estimate, process and project contingencies would be taken as 25 and 20 percent, respectively. Applying these contingencies results in a total investment estimate of $1,425 million or an increase of about 43 percent above the investment base of $1,000 million without contingencies.

COAL GASIFICATION ESTIMATES

Consistent cost estimates for coal gasification processes which are now under development have been made by C.F. Braun & Co. using western U.S. subbituminous coal with 250 million standard cubic feet per day of substitute natural gas production assumed as the standard plant size. The study examines the investments, operating costs, and the resulting prices of the HYGAS, BI-GAS, CO_2 Acceptor and Synthane processes compared with similar figures for the presently-commercial Lurgi gasification technology. Another phase of the same study which will soon be published examines the same processes using eastern U.S. coals.

Figure 6 is a plot of product costs for the various processes calculated by Braun for western coal, assuming 100 percent equity financing, 12 percent discounted cash flow (DCF) rate of return, and 1976 constant dollars. Braun used a 15 percent project contingency for all of these cases, but included no process contingencies in the onsite investments. Note that product costs can be plotted as straight lines when annual operating costs are plotted against total capital requirement.

From the figure one sees that the HYGAS case with the residual char gasified using a steam-oxygen gasifier appears to be the most attractive process at approximately \$4.25 per million Btu of product cost. The Lurgi process is about \$5.50 per million Btu as is the case for Synthane where excess char is sold outside the plant and slurry coal feeding to the gasifiers is used. BI-GAS and CO_2 Acceptor approach the low-cost HYGAS case. However, the HYGAS case with residual char gasified using a steam-iron gasifier is less attractive than LURGI, as are two Synthane cases which export electrical power for sale outside the plant.

The type of cost estimate performed by the Braun study is equivalent to a preliminary study and the 15 percent project contingency used is reasonable. However, no process contingencies were used to reflect the differing data quality available for the individual estimates. Given the PDU and pilot data quality of all of the data except Lurgi, process contingencies of 15 to 25 percent are indicated. A value of five percent is suitable for the Lurgi estimate. Application of these additional factors to Lurgi and the three estimates on the figure which are lower cost than Lurgi narrows their cost advantage over Lurgi by about 50 cents per million Btu. This has the result that only the HYGAS process retains an apparent advantage over Lurgi technology. Other processes appear marginal or higher cost compared with Lurgi technology.

COAL LIQUEFACTION ESTIMATES

At present several coal liquefaction processes are under development. These include such processes as Exxon Donor Solvent (EDS), H-Coal, and Solvent Refined Coal (SRC). Each of these processes makes liquid fuels with different physical properties. However, each of the processes has some flexibility to operate over a range between a heavier boiler fuel type of primary product and a lighter synthetic crude primary product, depending on liquefaction reactor space velocity.

A recent paper by Gulf (2) concerning the SRC process operated to produce a synthetic crude (although they view its best use as fuel to a boiler) indicates a price of \$3.21 per million Btu assuming 100 percent equity financing, 12 percent DCF and 1976 constant dollars. A 20 percent project contingency is included, but no process contingency was applied. Including a 20 percent process contingency increases the cost to about \$3.60 per million Btu. This is equivalent to about \$22 per barrel.

Preliminary estimates of other liquefaction processes within Fossil Energy indicate prices of \$30 per barrel and greater when using this same economic basis to produce a synthetic crude. However, since the various designs and cost estimates have been made by different concerns, it is not clear whether these cost differences are due to true process differences or merely to design philosophy differences among the various firms involved. This matter is currently under study.

POWER GENERATION ESTIMATES

New electric generation facilities can be based on a number of liquid and solid alternative fossil fuels. Figures 7 and 8 contrast various base load alternatives, showing the capital, operation and maintenance (O&M), and fuel components of total cost expressed as mills per kilowatt-hour of power generated. These power costs were derived from recent work done by Gilbert Associates (3) which determined capital and O&M costs for various alternatives. The fuel component was added to these by choosing recent cost ranges for the basic fuels used (Table I). An 800 megawatt electric plant size operating at 70 percent capacity factor is assumed and the basis is utility economics equivalent to a 10 percent DCF rate of return in 1975 constant dollars. A 15 percent project contingency was used in all cases with no process contingency.

In Figure 7, the No. 6 fuel oil case shows a variation in power cost of 28 to 33 mills per kilowatt-hour (the variation in the fuel component of this and all other cases represents the range shown in Table I). The natural gas case is less, but this fuel is now in scarce supply in the United States. SRC hot liquid refers to the Solvent Refined Coal liquefaction process operated so as to make a heavy liquid product which would solidify if cooled. This case and that for heavy synthetic coal liquid both indicate a significant cost increase compared to No. 6 fuel oil. The dashed area is added to emphasize the relative uncertainty of these estimates. Finally, medium Btu gas made off site and bought by the power plant at the range shown by Table I is also relatively expensive. Note that the capital and O&M components for all of these liquid cases are substantially the same and only the fuel components vary.

The solid fuel cases shown in Figure 8 show some interesting variations. Low sulfur coal without flue gas desulfurization (FGD) is very attractive and compares favorably with the use of natural gas on the previous figure. The high sulfur coal case with FGD illustrates the fact that the additional capital and O&M components due to the FGD equipment are not offset by the lower fuel cost of high sulfur coal. Similarly, installation and operation of an on site low Btu gas plant using high sulfur coal is not offset by the cheaper fuel.

The solid SRC case without FGD has the same low capital and O&M components as the low sulfur coal case but the expensive fuel prices this alternative well above the others. Next, cleaned high sulfur coal without FGD appears competitive with low sulfur coal. Finally, the two high sulfur coal cases using fluidized bed combustion and a low Btu gas, combined cycle system both look very competitive.

Retrofit of base load electric utilities is illustrated by Figure 9 using the same economic basis as before. Here the incremental cost of modifying solid and liquid fuel plants is shown by the three cost components. FGD adds only about 10 mills per kilowatt-hour but solid SRC adds over 20 mills. Among alternatives for retrofitting solid fuel plants, cleaned high sulfur coal adds the least or about five mills. For liquid plants, the heavy synthetic coal liquid and the medium Btu gas off site cases add about 10 mills per kilowatt-hour or more. The low Btu gas on site case adds nothing because the savings in fuel cost by using high sulfur coal to generate the gas offsets the capital and O&M components. The coal oil slurry case indicates a reduction, since the needed capital and O&M are not large and the savings in No. 6 fuel oil substituted by less expensive low sulfur coal more than offsets them.

The economics of steam generation by fluidized bed combustion (FBC) have recently been studied (4). Figure 10 contrasts FBC with conventional firing (CF) for both high and low sulfur coal; conventional firing with low sulfur fuel oil is shown for comparison. These costs show capital, O&M and fuel components (see Table I) calculated in 1975 constant dollars at a 10 percent DCF rate of return for a 100,000 pound per hour boiler. No process contingency was assumed, but a 20 percent project contingency was used.

For high sulfur coal, the FBC case is definitely lower cost than conventional firing with FGD. There is no relative improvement when using low sulfur coal, however. Note that the capital and O&M costs for a boiler based on low sulfur fuel oil is much less than the other cases. Of course, this is fully offset by the relatively higher cost of the fuel oil.

SUMMARY

Consistent process design and cost estimating procedures play an important role in guiding research and development. Application of proper process and project contingencies is a key element in obtaining realistic and comparable estimates.

Preliminary estimates have been made for many of the coal conversion and power generation alternatives now under development in the United States. Coal gasification and power generation economics are presently the most fully developed, but a number of studies are planned to better define the prospects for coal liquefaction.

REFERENCES

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3. "Assessment of Fossil Energy Technologies for Electric Power Generation," Vol. 1, prepared for the Office of Program Planning and Analysis, Fossil Energy, by Gilbert Associates, Inc., October 1976.

4. Farmer, M.H., Magee, E.M., and Spooner, F.M., "Application of Fluidized Bed Technology to Industrial Boilers," prepared for U.S. FEA/ERDA/EPA by Exxon Research and Engineering Company, Linden, N.J., January 1977.

TABLE I

FUEL COST TO POWER GENERATION

	Dollars per Million BTU
Liquid Fuels	
No. 6 Fuel Oil	2.12 - 2.86
Natural Gas	0.52 - 2.00
SRC Hot Liquid	3.00 - 5.00
Heavy Synthetic Coal Liquid	3.00 - 5.00
Medium BTU Gas	3.00 - 4.00
Solid Fuels	
Low Sulfur Coal	1.00 - 1.25
High Sulfur Coal	0.75 - 1.00
Solid SRC	3.00 - 5.00

Purpose, Size, Cost of Individual Coal Conversion Units

	Concept	Exploratory Research	Process Development Unit(PDU)	Pilot Plant	Demonstration Plant	Commercial Demo.
Purpose:	Discovery	Scientific Feasibility	Technical Feasibility	Economic Feasibility	Commercial Feasibility	Resolve Investment Uncertainties
Information:	Theory	Concept Proof	Physical, Chemical, Engineering Data	Engineering Parameters of Scale-up	Validate Process Economics, and Environmental/ Socioeconomic Impacts	Capital and Other Resource Requirements, Marketability of Products
Typical Size: 1/ (Tons/Day)	0 to 0.1	1.0	10	100	1,000	10,000
Capital Cost: 1/ (1976 Million $)	N.A.	$3 to $5	$10 to $15	$20 to $30	$100 to $200	$400 to $800
Annual Operating Cost, 1/ (1976 Million $)	N.A.	$3 to $5	$5 to $10	$10 to $15	$25 to $50	$80 to $160
Government Share: 1/ (Percent)	N.A.	100%	100%	66%	50%	0 to 50% (Cost if Venture Fails)

1/ Typical Values; each process is different & must be individually estimated.

Figure 1

PROJECT AND PROCESS CONTINGENCIES*

TYPE OF COST ESTIMATE

DEVELOPMENT PHASE — PROCESS % \ PROJECT %	STUDY ($2–5 x 10^4)	PRELIMINARY ($2–5 x 10^5)	DEFINITIVE ($2–5 x 10^6)	DETAILED ($2–5 x 10^7)
PDU	25 50	20 25		
PILOT	25 25	20 15	15 10	
DEMONSTRATION	25 15	20 10	15 5	10 5
COMMERCIAL	25 5	20 5	15 5	10 5

*PROCESS CONTINGENCY IS APPLIED TO ONSITES; OFFSITES ARE THEN ADDED AND PROJECT CONTINGENCY IS APPLIED TO THE TOTAL

Figure 2

DESIGN BASIS

PRELIMINARY ($0.2-0.5 X 10^6)	DEFINITIVE ($2-5 X 10^6)	DETAILED ($20-50 X 10^6)
• PRODUCT SPECS	• DO	• DO
• FEED SPECS	• DO	• DO
• DESIGN ASSUMPTIONS	• DO	• DO
• PROCESS DESCRIPTION	• DO	• DO
• UTILITY SPECS	• DO	• DO
• GENERAL SITE	• HYPOTHETICAL SITE	• ACTUAL SITE

Figure 3

PROCESS DESIGN

PRELIMINARY ($0.2-0.5 X 10^6)	DEFINITIVE ($2-5 X 10^6)	DETAILED ($20-50 X 10^6)
• FLOW DIAGRAM	• DO	• DO
• MATERIAL BALANCE	• DO	• DO
• ENERGY BALANCE	• DO	• DO
• OPERATING CONDITIONS	• DO	• DO
• PLOT PLAN	• DO	• DO
• ENVIRONMENTAL ASSESSMENT	• DO	• ENVIRONMENTAL IMPACT STATEMENT
• MAJOR EQUIPMENT SIZED	• ALL EQUIPMENT SIZED	• DO
• EQUIPMENT LIST	• EQUIPMENT LIST AND DETAILED SPECS	• DO
	• P AND I DIAGRAMS	• DO
	• PIPING SPECS	• DO
	• PROCESS RELATED STRUCTURAL SPECS	• COMPLETE STRUCTURAL DRAWINGS
		• DETAILED ENGINEERING DRAWINGS
		• PLANT ELEVATION DRAWINGS
		• PROCUREMENT AND CONSTRUCTION PLAN

Figure 4

PROCESS ECONOMICS

PRELIMINARY ($\$0.2\text{-}0.5 \times 10^6$)	DEFINITIVE ($\$2\text{-}5 \times 10^6$)	DETAILED ($\$20\text{-}50 \times 10^6$)
• COST CURVES	• DO	• VENDOR BIDS
• EXPERIENCE FACTORS	• VENDOR QUOTES ON MAJOR ITEMS	• ACTUAL LABOR COSTS AND PRODUCTIVITY
• RULES OF THUMB	• EXPERIENCE FACTORS BASED ON MORE DETAILED DRAWINGS	• DETAILED ENGINEERING EVALUATION
• GENERAL COST INDEXES	• SPECIFIC COST INDEXES	• FINANCING UNDER ACTUAL CONDITIONS
• ASSUMED FINANCIAL CONDITIONS	• PROJECTED FINANCIAL CONDITIONS	

Figure 5

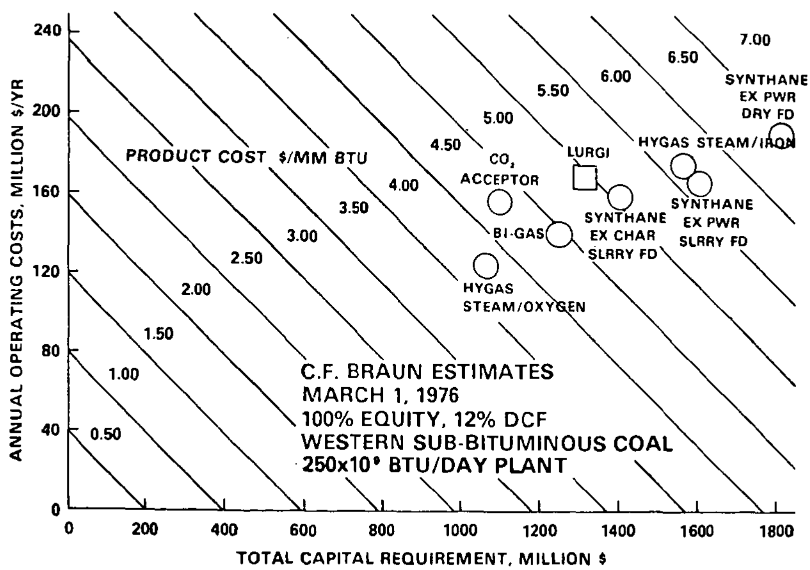


Figure 6

NEW ELECTRIC UTILITIES

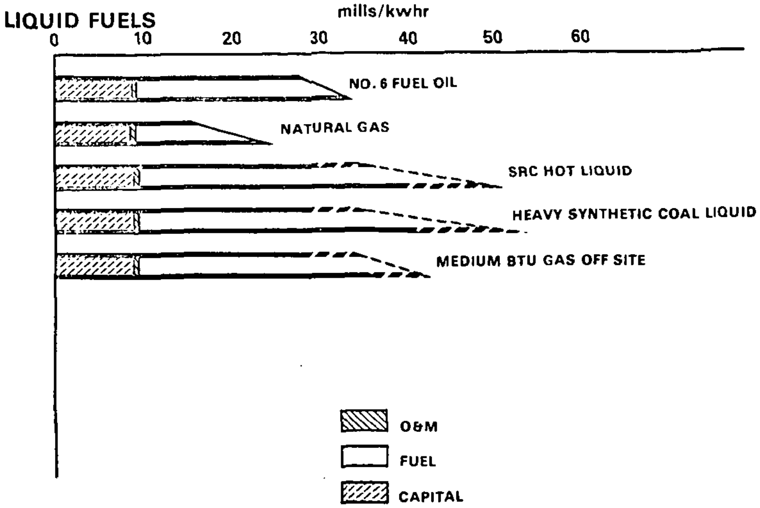


Figure 7

NEW ELECTRIC UTILITIES

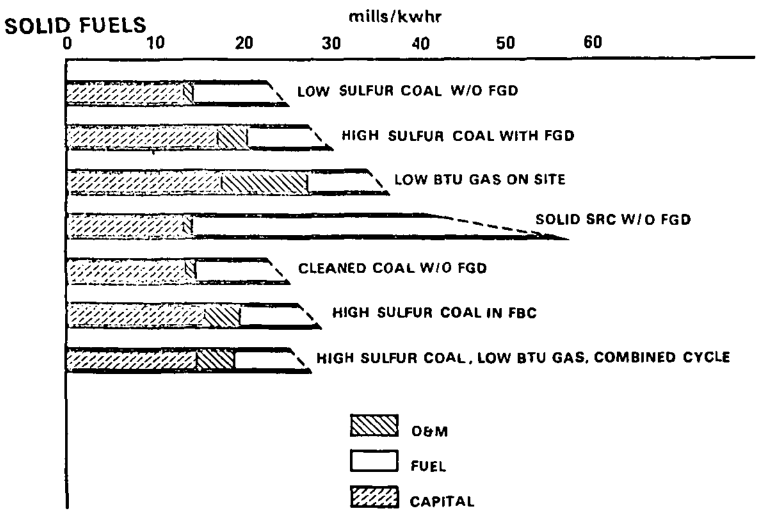
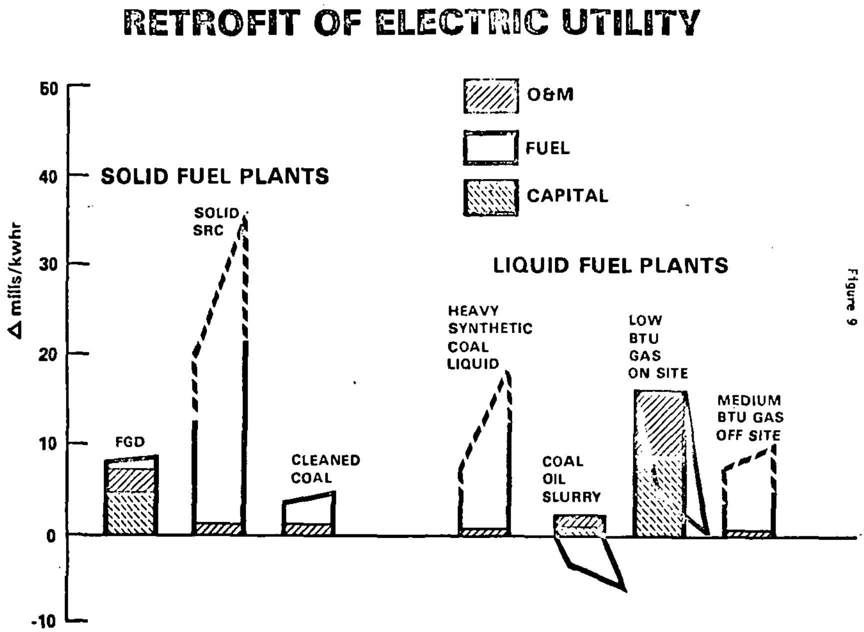
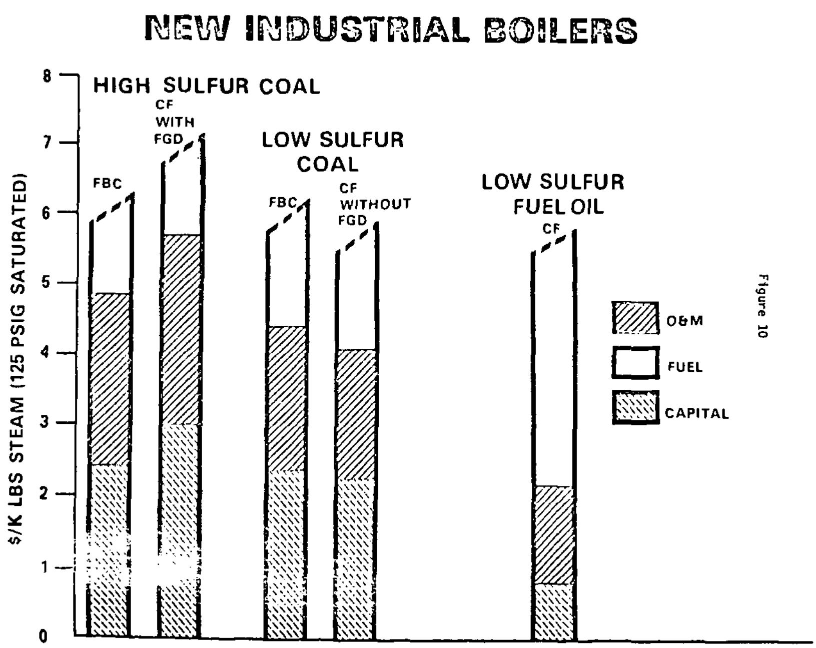


Figure 8


RETROFIT OF ELECTRIC UTILITY
50
40
30
20
10
0
-10
Δ mills/kwhr
SOLID FUEL PLANTS
FGD
SOLID SRC
CLEANED COAL
LIQUID FUEL PLANTS
HEAVY SYNTHETIC COAL LIQUID
COAL OIL SLURRY
LOW BTU GAS ON SITE
MEDIUM BTU GAS OFF SITE
O&M
FUEL
CAPITAL
Figure 9


NEW INDUSTRIAL BOILERS
8
7
6
5
4
3
2
1
0
$/K LBS STEAM (125 PSIG SATURATED)
HIGH SULFUR COAL
FBC
CF WITH FGD
LOW SULFUR COAL
FBC
CF WITHOUT FGD
LOW SULFUR FUEL OIL
CF
O&M
FUEL
CAPITAL
Figure 10