

Section 15

ECONOMICS OF THE NORTH ALABAMA COAL
TO METHANOL PROJECT

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OVERVIEW

The Tennessee Valley Authority (TVA) began work on a commercial coal gasification project in 1979. This evolved into a coal-to-methanol plant using the Texaco gasification process to convert 3400 tons of Illinois No. 6 coal into 2200 tons per day of methanol (213 million gallons per year). In February 1985, the North Alabama Coal to Methanol Consortium, which was seeking financial assistance to take over the project from TVA, withdrew the project from the U. S. Synthetic Fuels Corporation's (SFC) Fourth General Solicitation. TVA is currently placing the project in a defense energy reserve status to be reactivated if and when required by national security considerations.

During its nearly six-year history, the project size, product slate, and financing were governed by economic considerations. More than a dozen major cost/financial estimates and innumerable economic studies were made. On the order of \$50 million in engineering work by TVA, Stearns Catalytic, C. F. Braun, Raymond Kaiser Engineers, Texaco, GKT (Krupp Koppers), and others stands behind these estimates. Estimates for three different plant configurations each met the SFC's requirements for the Level II/III design and derivative cost estimate. Such estimates are suitable for negotiating binding agreements for financial assistance.

This paper traces the evolution of the different estimates, the underlying design work, and their objectives. It also indicates the trends in unit capital and operating costs which resulted. The most notable conclusions are:

- Early, nonsite specific estimates from the literature resulted in significantly lower unit costs than subsequent estimates based on the design of an actual plant to be built at TVA's Murphy Hill site in North Alabama.
- After correcting for inflation, the estimated operating costs from the different coal to methanol configurations analyzed between 1981 and 1985 remained remarkably constant. The required selling price per unit of output, including capital charges, increased somewhat but these can readily be attributable to economies of scale. The plant size was significantly reduced twice during the period. (See figure 1.)

- Both the capital and operating cost estimates tend to be higher than the generic conceptual studies reported in the literature. This is due in part to the fact that the plant uses existing proven technology rather than projected technical improvements and that actual designs and operating plans were used for many cost elements rather than rule of thumb factors. Since the estimates were to be the basis for negotiations with the SFC, sufficient contingencies to protect the interests of both the consortium members and the SFC were provided and clearly identified. Finally, since this was to be a free standing business venture, all project costs, including all funds spent by TVA and projected to be spent by the owners, were included. Frequently, such owners' management, development, and startup costs are not fully identified and provided for.
- Using a relatively simple method for calculating the average capital cost per unit, we estimate that the required selling price of a gallon of methanol from the current Texaco configuration is about \$1.25 per gallon in 1985 dollars. The net operating cost (after byproduct credits) is \$0.53 per gallon.
- By eliminating the project costs already spent by TVA which are not applicable to the present configuration, by eliminating the contingency needed to reduce the probability of a capital cost overrun from 50 percent to 30 percent and by using "real" interest rates (instead of market rates) to calculate the capital cost per unit, it is possible to project a levelized total cost of \$0.90 to \$0.95 per gallon in 1985 dollars. Increases in plant size, use of lower cost coal, and progress along a learning curve would further reduce the levelized cost of methanol from coal.

PROJECT EVOLUTION (FIGURE 2)

In 1979, TVA initiated a task force effort to determine if and how it should proceed to build a commercial coal gasification plant in the Tennessee Valley. Estimates in the literature suggested that a generic plant using 20,000 tons of coal per day to produce medium Btu gas equivalent to 50,000 barrels of oil per day could be built for \$2 billion or less. The output from such a plant would be pipelined to existing and new industrial facilities for use as a fuel and/or feedstock. Using a relatively simple method for calculating the average capital cost per unit, we estimated that TVA could produce and sell the medium Btu gas at \$5 per million Btu or less, excluding pipeline transmission (1980 dollars used throughout unless otherwise noted).

To obtain a better insight into the design and economics of a plant to be built in the Tennessee Valley to TVA specifications, we engaged three architect/engineer firms to prepare conceptual designs using several different gasification technologies. The results, which became available in late 1980, suggested that

medium Btu gas from a 50,000 barrels of oil equivalent per day plant would sell for about \$7 per million. The Koppers Totzcek (K-T) design produced gas 10 percent more costly than the Texaco design.

Both the \$5 and \$7 per million gas prices were above the then current natural gas prices but quite close to distillate fuel oil. At that time, natural gas prices were expected to reach parity with distillate shortly after deregulation in 1985. The rapid increases in real energy prices then being projected made the project appear to be economic without price supports or subsidies.

In early 1981, the project underwent several major changes. As the result of shifts in Federal government priorities and programs, it was decided to shift from a TVA-owned/government-financed project to a privately owned project with financial assistance from the SFC. To make private sponsorship more feasible, the project size was cut in half to the equivalent of 25,000 barrels of oil per day. The K-T technology was selected on the basis of technological readiness to proceed on an accelerated schedule. These changes resulted in a medium Btu gas price of \$8.00 to \$8.50 per million Btu (using the same calculational procedure employed for the previous estimates). With leveraged private investment, tax benefits, and SFC loan guarantees, a \$6.50 per million Btu price increasing at a 10 percent general inflation rate produced a suitable rate of return on equity. The impact of different financing mechanisms is discussed further in the last section of this paper.

Later in 1981, as the result of changing market conditions and inputs from the then forming Consortium, the product slate was shifted to methanol and the plant size reduced in half again. Even though the total Btu's of the methanol produced was less than half the Btu's of the medium Btu gas from the larger plant, the significantly higher form value of the methanol in the market place justified the change. During this period the list price of methanol was about \$0.75 per gallon and average market prices \$0.60 to \$0.65 per gallon. Based on a conceptual design prepared by C. F. Braun, who had been selected as project architect/engineer, we estimated the cost of the smaller plant to be about \$1 billion (1980 dollars excluding inflation and interest during construction). This work suggested that it would be possible to sell methanol for a 1980 price of about \$0.90 per gallon. The down-sizing penalty was 10 percent. The financial analyses employed by the Consortium for presentation to the SFC used several methanol market price forecasts. They showed that the plant would be viable if SFC price guarantees

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covered the chance that market prices would not achieve the significant real growth rates then being projected for the 1980s and beyond.

During early 1982, C. F. Braun prepared a preliminary design and cost estimate for a K-T plant producing 375 million gallons of methanol per year (essentially the same size as discussed above). This effort reflected extensive engineering work by GKT (Krupp Koppers) using the design coal and specifications for the North Alabama project. It included optimization efforts to reduce costs. The result was a product price estimate of \$0.90 per gallon in 1982 dollars or \$0.78 per gallon in 1980 dollars. The capital costs increased by 13 percent, less than the rate of inflation. Significant savings were also achieved in operating costs. The combination of private sector leveraged financing with SFC and price loan guarantees provided a satisfactory return at an \$0.85 per gallon (1982 dollars) market price inflating at 1 percent above inflation (total 9 percent). During this period the list price for methanol remained high, but market prices began to erode. This meant that the required SFC price guarantees needed to become price subsidies rather than "insurance."

In late 1982, TVA, C. F. Braun, GKT, and Raymond Kaiser Engineers (the construction manager) completed the design cost estimate for a K-T methanol plant producing 388 million gallons of methanol per year. As a result of more complete engineering, the estimated capital cost increased by 6 percent on a unit basis. Since this estimate was to be the basis for negotiations with the SFC, the Consortium added contingencies to reduce the likelihood of a cost overrun. We developed the concept of unassigned costs and contingencies. Unassigned costs represent the amounts which must be added to the unit-by-unit engineering estimates to achieve a 50 percent probability of cost overrun. The numbers were initially based on corporate experience and judgement, and later on extensive statistical analysis. Our concept of contingency is the additional amounts required to lower the probability of overrun to 30 percent (or less). The net effect of these changes was a 1982 price of \$1.02 per gallon (\$0.88 in 1980 dollars). The project financial analysis was able to accept these changes with the same escalating \$0.85 per gallon price line (1982 dollars), but at a lower rate of return.

As the Consortium proceeded into preliminary negotiations with the SFC during early 1983, the impacts of the changing energy price structure became clearer. After their rapid runup in the 1979-1981 period, world oil prices started to fall. This had relatively little impact on the estimated capital cost of building the plant

(in constant dollars), but it reduced inflation and projected market prices. The result was a significant increase in required financial assistance. This factor, when coupled with shrinking oil demand, led the Consortium and SFC to rethink the project size and financing.

In an effort to reduce the total SFC financial assistance, the project size was further reduced even though preliminary estimates showed that this would significantly increase unit capital and operating costs. While the previous reduction in size (from 700 to 350 million gallons per year) resulted in a 10 percent unit cost increase, the decrease from 388 to 206 million gallons per year increased the unit cost by 35 percent. Based on our experience it appears that significant economy-of-scale penalties are encountered below 350 million gallons of methanol per year (25,000 barrels of oil equivalent per day) but that they are not so large above this plant size.

By January 1984, the engineering team completed a Level II/III design cost and estimate based on the reduced size K-T plant. The capital cost in constant 1984 dollars was only about 15 percent less than the 1982 cost of the larger plant. The resulting methanol price was \$1.53 in 1984 dollars (\$1.24 in 1980 dollars). This increase reflected significant increases in the fixed operating costs per unit as well as the unit capital cost. An innovative financing approach enabled the Consortium to continue discussions with the SFC.

In January 1984, as the result of continuing pressure on project economics coupled with technical progress and experience with the Texaco gasification technology, the Consortium and TVA switched to the Texaco process. The initial comparisons showed the Texaco quench design to have 19 percent lower operating costs and 12 percent reduction in required selling price. Thus the initial Texaco estimate resulted in a product price of about \$1.36 per gallon in 1984 dollars or \$1.10 in 1980 dollars. The Texaco radiant design was evaluated but found not to be cost effective in the North Alabama application.

During the remainder of the year, Stearns Catalytic, Texaco, Raymond Kaiser, and TVA worked to develop a Level II/III design and derivative cost estimate based on the Texaco design. In late 1984, SFC representatives reviewed the design and cost estimate work and concluded that it would meet their requirements.

The results of this effort indicated a net operating cost (after byproduct credits) of \$0.53 per gallon (1985 dollars) and a projected price of \$1.25 per

gallon (\$0.99 in 1980 dollars). This represents a 10 percent reduction over the preliminary Texaco estimate and nearly 25 percent over the Level II/III K-T estimate made a year earlier. This difference can be attributed to improved engineering definition, optimization, and other factors in addition to the technology change.

Even though the engineering design and cost estimates were heading in the right direction, current and projected methanol market prices were not really cooperating to make the project viable. The current methanol market price (\$0.40 - 0.45 per gallon) is below the net operating cost of the plant and may well remain below for years if current oil price projections and methanol imports keep domestic prices low. Such a situation would have made it impossible for the project to continue operation after the SFC price support period. This was one of the major reasons for mothballing the project.

The current Texaco design and cost estimate would provide the basis for reactivating the project. In the event of an energy market change, we would begin with this engineering work to design and build the plant.

CURRENT TEXACO-BASED COST ESTIMATE

The current Texaco-based design and cost estimate reflect on a standalone, greenfield plant built on TVA's Murphy Hill site in Marshall County, Alabama. It receives coal by barge, raw water from the Tennessee River, and electricity from the TVA system. It ships methanol and molten sulfur by barge and argon by truck and discharges treated waste water into the river. The configuration shown in figure 3 provides for all of these functions.

The unit sizing and sparing plan shown in table I indicates that spare capacity would be provided in coal preparation, gasification, and sulfur recovery. These spares were found to be necessary to achieve an online capacity factor approaching 90 percent. Additional data and RAM modeling would be used during the detailed design process to confirm the cost effectiveness of these decisions.

The capital cost estimate was built up from many detailed elements as outlined in tables II, III, and IV, and figure 4. The owner costs include the \$110 million already spent by TVA on the project plus funds for a strong owners' project organization during the design and construction. The project management

organization would continue through the startup period with funds provided under nonconstruction capital costs.

Figure 4 indicates where the direct construction costs are spent in terms of the major process, utility, and civil units. The plant location on the site has been shifted several times to minimize construction costs. Stearns Catalytic has studied additional plant layouts which could result in further savings during detailed design.

The direct and indirect costs elements are shown in tables III and IV. They resulted from a significant planning effort by Raymond Kaiser Engineers. They organized the plant construction activity into packages which would form the basis for construction contracting. At this stage, no major prefabrication program is included in the estimate. The site's river location would lend itself to such an approach, however.

Table V presents the total production costs for the current Texaco-based design. Illinois-basin coal is barged to the plant at a cost representing current long-term contract conditions. Electricity is purchased from the TVA system since numerous tradeoff studies have shown that it is more cost effective to purchase TVA power than to build a boiler with appropriate air pollution controls to produce steam or electricity for mechanical drives. The fixed costs include normal plant operations and maintenance plus the front office costs (i.e., marketing) associated with running an independent venture. The plant is designed to produce merchant-grade argon and sulfur, so appropriate credits are included. The per unit capital cost is calculated using the same simplified technique as was used throughout the paper. It provides for the plant construction cost, nonconstruction capital cost, the funds already spent by TVA, a contingency allowance to reduce the chance of an overrun to 30 percent, and interest during construction. This results in a required selling price of \$1.25 per gallon in 1985 dollars. Of this total, the funds already spent by TVA and the contingency are each about \$.07 per gallon.

IMPLICATIONS FOR FUTURE COMMERCIAL PROJECTS

The capital and operating cost estimates for the North Alabama Coal to Methanol Project are the result of extensive engineering work based on specific plant configurations and assumptions. These estimates were converted into required

selling prices by means of a consistent but relatively simplistic formula. The resulting prices are useful for assessing trends noted in this paper, but their absolute value is subject to misinterpretation.

Project decisions were made on the basis of detailed financial analyses prepared by Kidder, Peabody and Company, Inc., and reviewed by senior executives from the North Alabama Coal to Methanol Consortium member companies. These individuals were concerned with the financial implications of the project, assisted by the SFC, on their own firm's financial position. We did not calculate levelized required selling prices, but rather focused on projected methanol market prices, required SFC guarantees, and returns to the sponsors.

A levelized cost or selling price is also useful when developing national policies. The problem is that the absolute value of such a number is affected more by financial tax and economic assumptions than it is by technology or plant design. One of our studies showed that the four available or near available gasification technologies produced methanol at required selling prices in a ± 5 percent range. As discussed below, financial and scale choices have a much larger impact.

Capital intensive projects such as synthetic fuels plants produce products that are more expensive per unit in real terms during the early years of operation than they are during later years. The value of the capital used in the early years of operation is not depreciated while later it is. This situation is exacerbated by inflation which results in increasing product prices while real costs are decreasing. Investors must, therefore, borrow resources to construct and operate the plant during the early years and rely on future operations and inflation to pay them back. There are three major sources of these resources--retained earnings or equity, borrowing from banks or bondholders, and borrowing from the government through the Federal income tax system (investment tax credits and accelerated depreciation defer tax payments for firms with other tax liabilities). The rules and requirements governing these are constantly changing. Modest changes in the ratio of debt to equity and in the applicability of investment tax credits can affect the required constant real selling price by 25 or 30 percent. Interest rates, inflation, and the rates of return on equity required by individual investors can likewise have significant effects. Thus the choice of financial and economic assumptions will largely determine the unit cost of capital and, therefore, the required selling price.

For policy purposes, it is useful to calculate a required selling price based on elimination of the project costs already spent by TVA but not applicable to the present configuration and elimination of the contingencies needed to reduce the probabilities of a capital cost overrun from 50 percent to 30 percent. This drops the \$1.25 price to about \$1.10. Furthermore, replacing the market interest rate of 11 percent with a "real" interest rate of 6 to 7 percent would reduce the required selling price to the \$0.90 to \$0.95 range. It could be argued that this represents a more representative inflation free levelized value.

Economies of scale also play a major role in the required per unit selling price. Just as the North Alabama Project economics suffered when the plant size was reduced, the economics of another project would benefit with increased size. A plant the size of our two-module (775 million gallon per year) design may be able to achieve a required selling price below \$.80 per gallon using financial assumptions similar to those resulting in \$1.25 per gallon for the current design. This is still above current methanol market prices but comparable to gasoline on a volumetric basis. The big question is when market forces and other factors will make it attractive enough for a private firm to invest in a commercial coal-to-methanol plant.

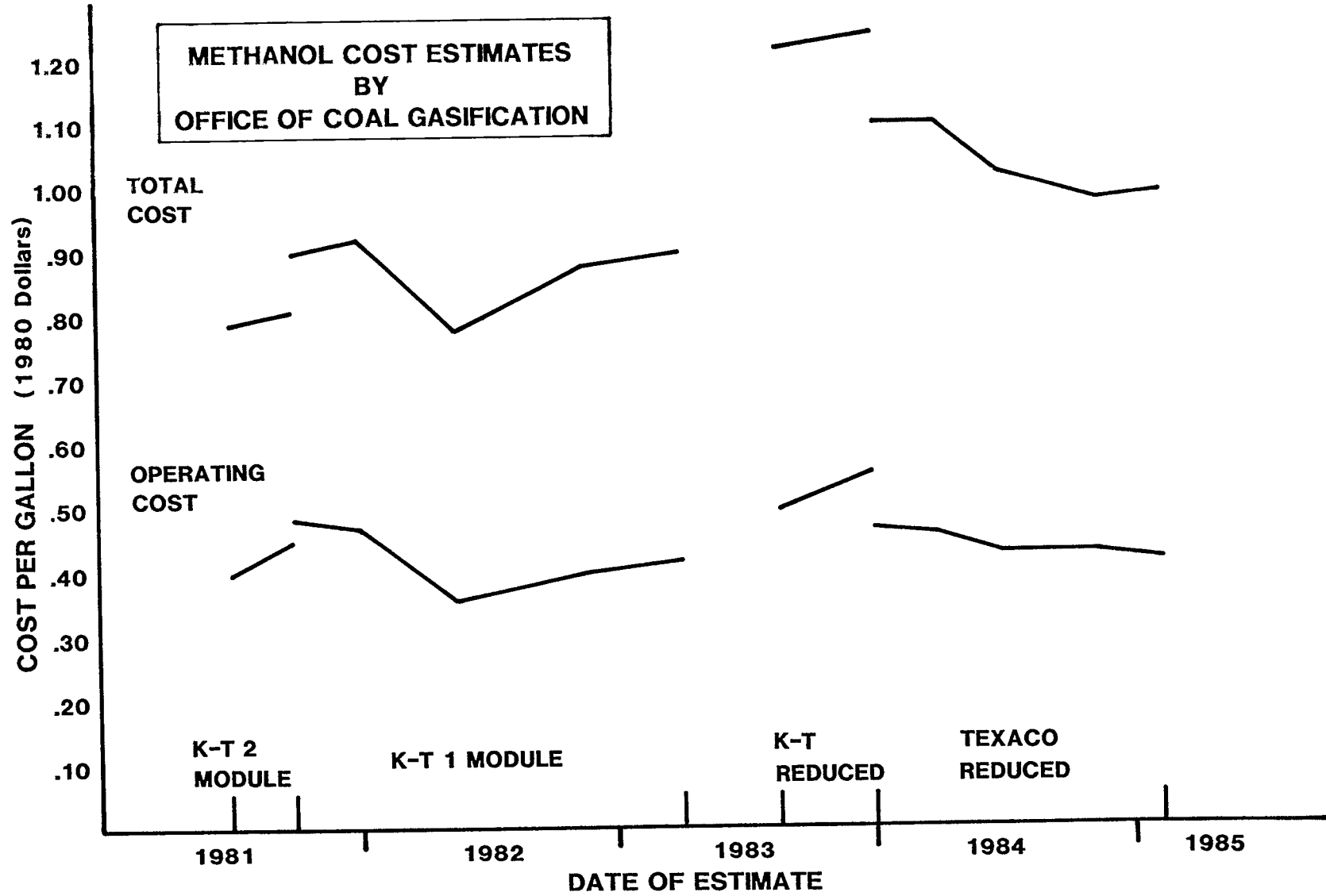


FIGURE 1

PROJECT EVOLUTION

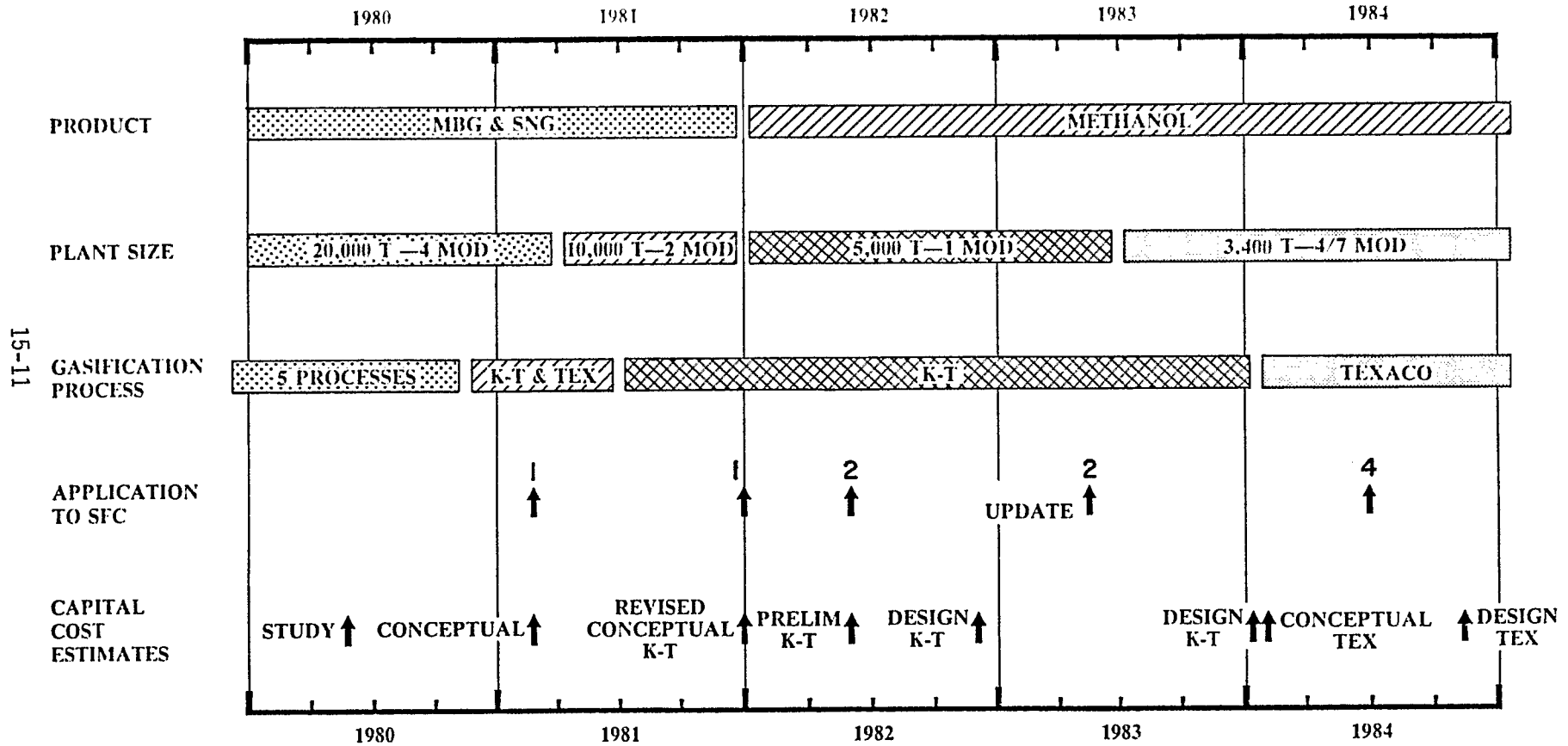


FIGURE 2

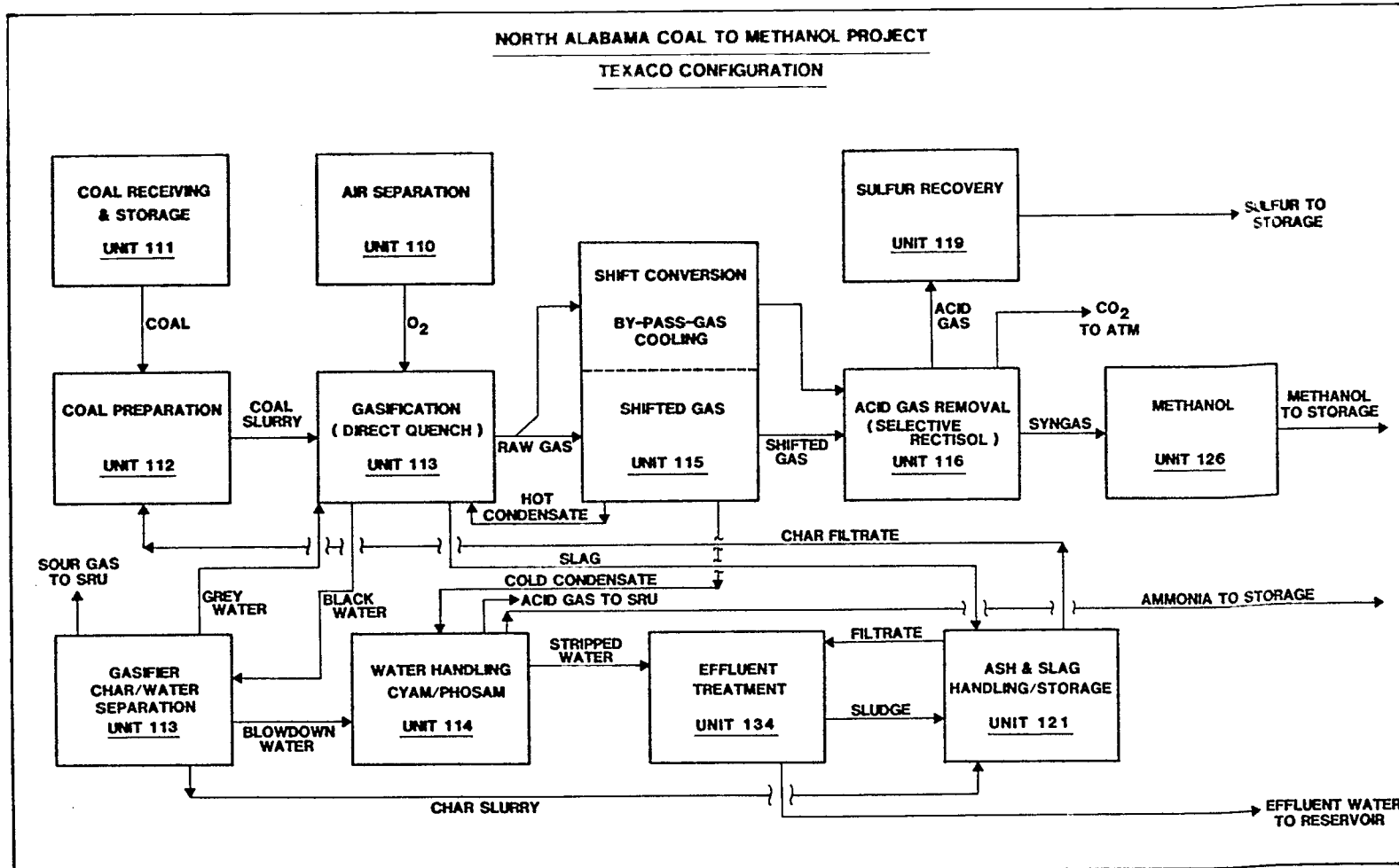


FIGURE 3

DIRECT CONSTRUCTION COSTS

PERCENT OF TOTAL

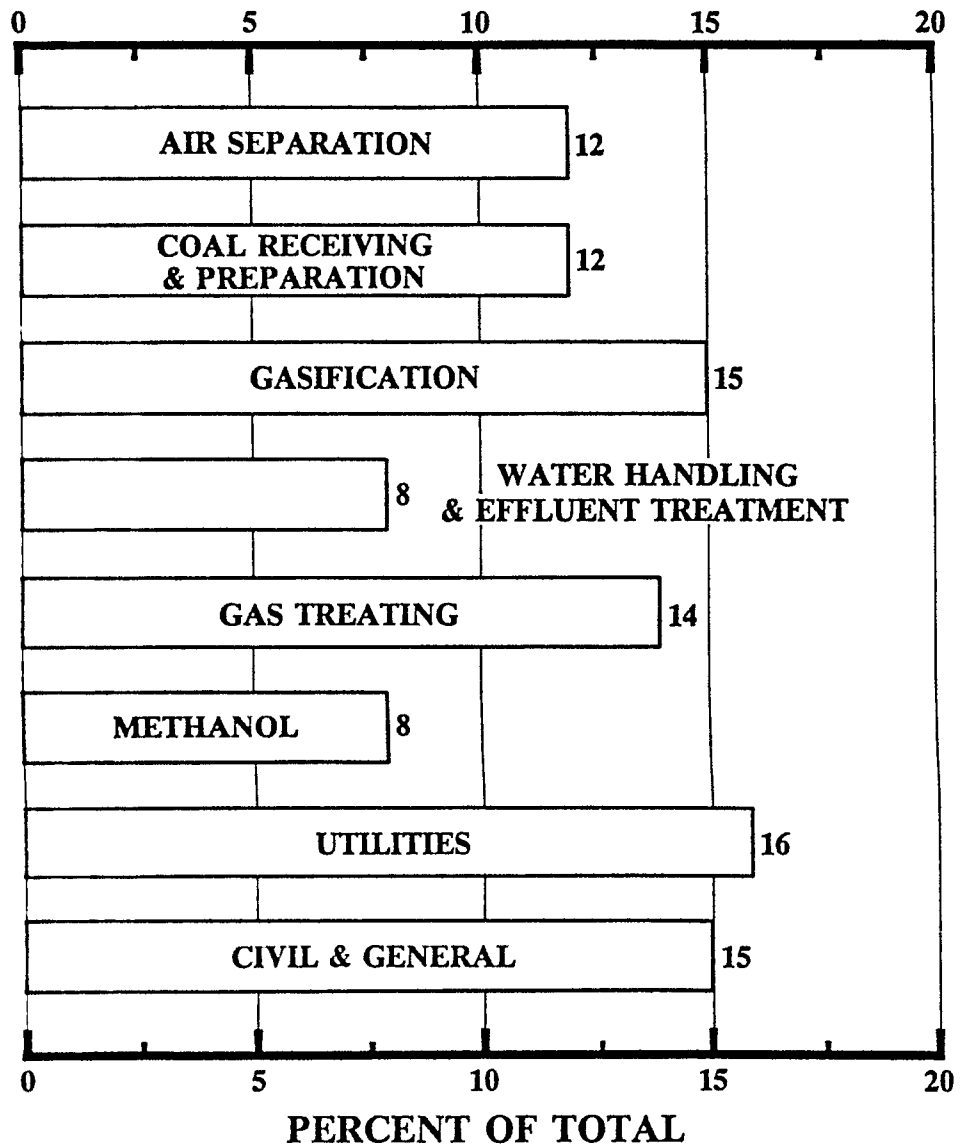


FIGURE 4

Table I

UNIT SIZING

<u>Process Units</u>	<u>No. of Trains (Oper + Sp)</u>	<u>Process Description</u>	<u>Nominal Unit Capacity</u>	<u>Performance Criteria</u>
Air Separation	2+0	Air Products	3100 T/D Oxygen	99.5% Purity
Coal Preparation	2+1	Ball Mills	3400 T/D Coal	62% Slurry Conc.
Gasification	3+2	Texaco	160-MM SCFD Syngas (1100 T/D Coal/Gasifier)	Maximized Useful Gas
Water Handling	1+0	Cyam/Phosam-W	520 Gal/min	S-, CN-, and NH ₃ Removal
Shift Conversion	1+0	Sour Shift	160-MM SCFD Syngas	2.27 H/CO ₂ Ratio
Acid Gas Removal	1+0	Rectisol	160-MM SCFD Syngas	0.1 PPM Sulfur & 3% CO ₂ In Syngas ²
Sulfur Recovery	1+1	Claus	105 LT/D Sulfur	99.75% Sulfur Recovery
Tail Gas Treatment	1+0	Scot		
Methanol Synthesis	1+0	Lurgi	2200 T/D Methanol	Grade AA
Effluent Treatment	1+0	Biological/ Phys. Chem.	1200 Gal/min	Suitable for BACT w/o Zero Discharge

Table II
CAPITAL COST ESTIMATE

Construction	<u>Percent of Total</u>
<ul style="list-style-type: none"> ● Owner Costs (Studies, Engineering, Design, Tests, Environmental, Project Management, Licenses, early Site Costs) 	27
<ul style="list-style-type: none"> ● Plant Construction (Direct) 87% (Indirect) 13% 	52
Nonconstruction	
<ul style="list-style-type: none"> ● Prestartup and Startup ● Working Capital 	9 3
Project Contingency	<u>9</u> 100

Table III

DIRECT PLANT CONSTRUCTION COST

- Craft Labor, Benefits, and Burdens
- Materials
- Equipment
- Construction Equipment Usage
- Construction Overhead
- Sales Taxes

Table IV

INDIRECT CONSTRUCTION COST

- Construction Management Services
 - Contracting/contract ADM
 - Managing direct hire construction
 - Project control
 - Materials/equipment controls
 - Site utilization
 - Construction engineering
 - QA/QC
 - Labor relations

- Construction Plant
 - Construction offices
 - Warehouse and labor
 - Temporary roads/parking
 - Shops
 - Security/medical/fire
 - Temporary power and lighting

Table V

METHANOL PRODUCTION COSTS
(1985 Dollars per Gallon)

Coal	.21
Electricity	.08
Fuel, etc.	<u>.03</u>
Subtotal	.32
Fixed costs	<u>.25</u>
Total	.57
Byproduct credit	<u>.04</u>
Net production cost	.53
Cost of capital*	<u>.72</u>
	1.25

*Based on plant construction cost of \$908 million plus \$133 million nonconstruction capital (1985 dollars).