TECHNOLOGY ASSESSMENT GUIDE

NO. 6b

EXXON CATALYTIC COAL GASIFICATION

CHAPTER ONE: EXECUTIVE SUMMARY

1.1 OVERALL PROSPECTS FOR THE TECHNOLOGY

For over 12 years, the Exxon Research and Engineering Company has been developing (under government sponsorship) the Catalytic Coal Gasification process to produce a pipeline quality gas. The Process Development phase has just recently been completed, with demonstration of the one ton per day Process Development Unit.

The process displays a unique three step approach to coal gasification in which endothermic and exothermic reactions are combined to give an overall process for conversion which is almost thermally neutral. However, the economic success of the process strongly depends on the ability to recover a very high percentage of the expensive potassium based catalyst used to promote gasification. Catalyst recovery has been demonstrated in the PDU, but better recovery will have to be achieved with larger scale experiments if the process is to be commercially viable. Improved gas production rates will also be important in improving process economics.

1.2 ENGINEERING ASPECTS

The Exxon Catalytic Coal Gasification (CCG) process produces high concentrations of methane directly in the gasifier. This fact allows high quality SNG to be cryogenically separated prior to recycle of the remaining synthesis gas back to the reactor. Methane production is thermodynamically favored in the gasifier at the lower operating temperatures of the process. However, low reaction temperatures are not conducive to fast reaction rates, giving rise to the need for catalyst addition.

The catalysts being studied by Exxon for use in this process are basic and weakly acidic salts of potassium. The use of potassium salts has three major benefits with respect to coal gasification:

- The rate of steam gasification is increased:
  $2\ CH + 2H_2O \longrightarrow 2CO + 3H_2$
- Methanation equilibrium is promoted:
  $2CO + 2H_2 \rightleftharpoons CH_4 + CO_2$
- Swelling and agglomeration of caking coals is reduced.

High rates of catalyst recovery could be achieved by a simple water leaching step if the catalyst remained water soluble. Virtually all of the catalyst leaves the reactor with the ash material, and approximately 70 percent of it (the catalyst) is water soluble at this point in the process. The exact percentage of water soluble catalyst strongly depends on the initial concentration and nature of the coal ash. Most of the remaining insoluble catalyst is in the form of potassium aluminosilicate, which will require added measures for its recovery, such as the addition of calcium hydroxide or other bases. Regardless of what degree of feed catalyst is recovered, some amount of make-up catalyst in the form of potassium hydroxide will be required.

Several significant advantages may be attributed to the Exxon Catalytic Coal Gasification process:

- Since high yields of methane are produced directly, no shift or methanation steps are required
- Problems associated with slagging operation are eliminated
- Caking coals are more easily gasified due to the presence of the catalyst
- Tars and oils are not produced, simplifying wastewater treatment
- Low temperature gasification permits the application of existing technology to recover high level heat from the gasifier effluent
- Moderate reaction conditions mitigate materials and operating problems
- Oxygen is not required for gasification

The process is still some years away from being a commercial reality. Most important at this stage will be demonstration of catalyst recovery, and stable process operation for extended periods. The process is plagued by low gas production rates, despite the use of the catalyst. Only about 10 percent of the capacity of the slagging Lurgi has been demonstrated. This is primarily an economic drawback but may nevertheless delay the introduction of the process.

1.3 CURRENT COSTS

The total capital requirement for this 91.25×10^{12} Btu/year (250 million standard cubic feet per day) plant is \$2.65 billion, which is dominated by a plant investment of \$1.68 billion and interest during construction of \$771 million.

Annual operating and maintenance costs (at a 90% plant capacity factor) total \$150 million, 35 percent of which goes for catalysts and chemicals. Operating and maintenance supplies are the single largest cost group, totaling 37 percent of costs. By-product credits for sulfur, ammonia and sulfuric acid offset total operating and maintenance costs to \$134 million.

Taken together with a 20 percent capital charge, these operating costs result in a product cost of $8.09/10^6 Btu, which is exclusive of coal costs.

1.4 RESEARCH AND DEVELOPMENT DIRECTIONS

At least two key milestones must yet be proven for the Exxon CCG process: 1) stable, continuous operation for long periods; and 2) high efficiency catalyst recovery. As development work progresses, process economics will be reviewed at regular intervals, the results of which will serve as important inputs to the development plan.

CHAPTER TWO: ENGINEERING SPECIFICATIONS

2.1 GENERAL DESCRIPTION OF THE TECHNOLOGY

Since 1968, Exxon Research and Engineering Company has been developing a catalytic coal gasification process (CCG) to produce substitute natural gas (SNG). The chemistry of Exxon's process can be presented in three major reaction steps. In the first step, coal is gasified with steam to produce hydrogen and carbon monoxide. This is a highly endothermic reaction requiring about 32 kcal of heat input for every mole of carbon gasified. The second step is the water gas shift reaction, which is slightly exothermic. The third step produces methane and steam from the hydrogen and carbon monoxide produced in step two. This reaction is very exothermic and releases as much heat as was consumed by the steam gasification reaction of step one. The summation of all three reactions is steam and carbon reacting to make methane and carbon dioxide.

$$2H_2O + 2C \longrightarrow CH_4 + CO_2 \quad \text{Thermally Neutral}$$ [1]

If this reaction could be made to take place in one reactor, virtually no heat would be required. This is the desired reaction for the production of substitute natural gas.

The Exxon catalytic gasification process combines all three of these reactions in a one-step gasification process. Potassium hydroxide or potassium carbonate catalyst solution is sprayed on the coal and reacted with steam at 1275°F in a fluid bed gasifier. The mixture of product gases is then separated and all of the hydrogen and carbon monoxide in the product gas is recycled back to the gasifier. The methanation reaction is also catalyzed, enhancing the utilization of the H_2/CO recycle. In the net reaction (see above) only carbon dioxide and methane are produced, and virtually no heat input is required for the gasifier.

2.2 PROCESS FLOW, ENERGY, AND MATERIAL BALANCES[1]

Relevant plant area numbers for the Exxon CCG process are shown in Table 2-1. The conceptualized process flow diagram is illustrated in Figure 2-1. Each of the numbered streams in the flow diagram is identified in Table 2-2. Table 2-2 presents a detailed material balance, by stream, for the entire facility. The overall material and energy balance is summarized in Table 2-3.

Table 2-1

Relevant Exxon CCG Plant Area Numbers

100	COAL STORAGE AND HANDLING	
		110 Coal Storage
		120 Coal Handling and Storage
200	COAL PREPARATION	
		240 Coal Drying/Catalyst Addition
		280 Preheat Furance and Gasifier Feed/ Effluent Exchanger
300	GASIFICATION	
		310 Gasification
500	PRODUCT SEPARATION AND PROCESSING	
		530 Solids Withdrawal Slurrying
		540 Catalyst Recovery and Water Wash
1200	RAW GAS COOLING	
		1220 Gas Quenching and Cooling
1300	ACID GAS REMOVAL AND GAS CLEANING	
		1310 H_2S and CO_2 Removal
		1320 Methane Recovery
1400	SULFUR RECOVERY AND TAIL GAS TREATING	
		1410 Sulfur Recovery
2000	UTILITIES AND SUPPORT SYSTEMS	
		2030 Solids Disposal
2100	OFFSITES AND MISCELLANEOUS	
		2120 Catalyst and Lime Recovery and Storage
		2130 Offsite Boilers

Figure 2-1

Exxon CCG Conceptualized Process Flow Diagram

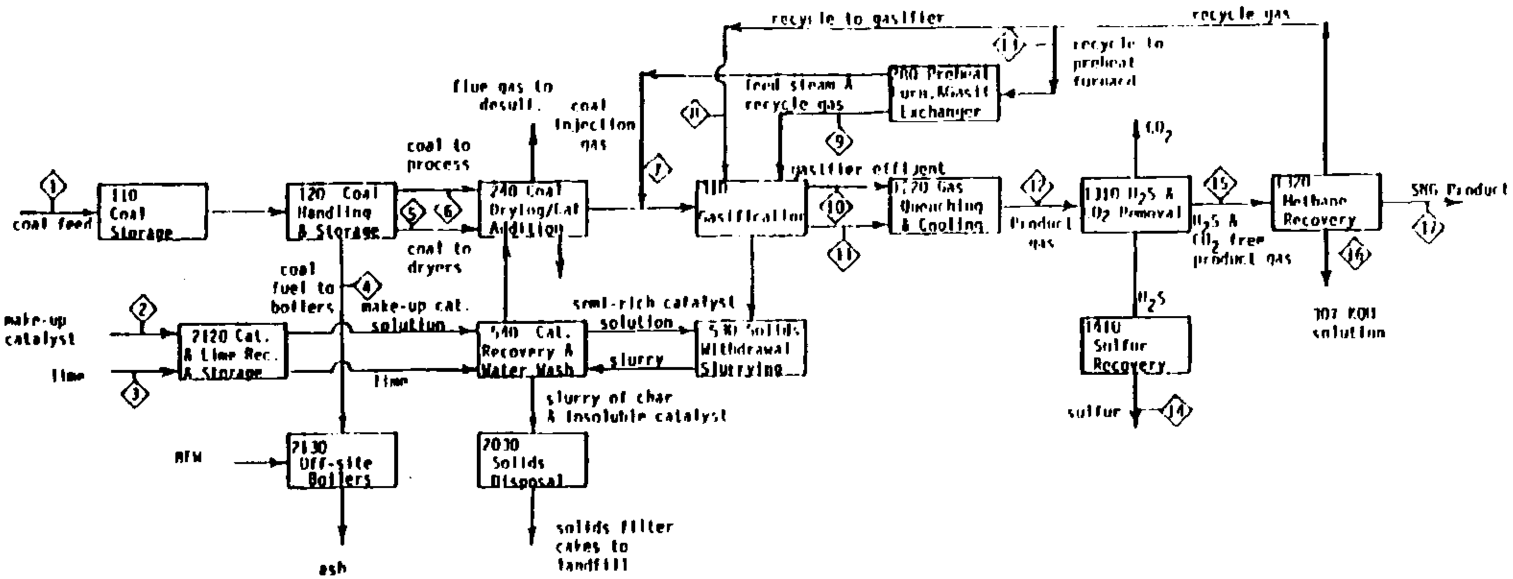

Table 2-2

Exxon CCG Detailed Material Balance for Process Streams

Stream No.	1		2		3		4		5		6		7		8		9	
Description	Coal feed		30% KOH solution		Lime, 97% CaO		Coal fuel to boilers		Coal fuel to to dryers		Coal to process		Coal injection gas		Recycle to gasifier		Gasifier feed steam and recycle gas	
Temperature, °F													800		175		1543	
Pressure, PSIG													540		540		505	
Flow, klb/hr, mole %	klb/hr		klb/hr		klb/hr		klb/hr		klb/hr		klb/hr		klb/hr	mole %	klb/hr	mole %	klb/hr	mole %
CO													35.417	18.21	11.143	18.02	171.855	4.82
CO_2													0.214	0.07	0.128	1.32	69.741	1.24
H_2													9.096	65.47	2.898	65.59	58.411	22.91
H_2O													0.035	0.03			167.372	65.65
CH_4													11.010	9.99	3.534	0.10	67.518	3.31
C_2H_6																		
H_2S																		
COS																		
NH_3																		
N_2													12.124	6.21	3.869	6.26	73.695	2.06
Total, klb/hr	1475.800		15.323		81.481		230.264		57.566		1175.800		67.985		21.571		608.594	

Stream No.	10		11		12		13		14		15		16		17	
Description	Gasifier effluent		Char withdrawal quench effluent		Product gas		Recycle to preheat furnace		Sulfur		H_2S and CO_2 free product gas		CH_4 for fuel and refrigeration make-up		SNG product	
Temperature, °F	1275		320		2		175				2					
Pressure, PSIG	485		435		415		585				475					
Flow, klb/hr, mole %	klb/hr	mole %	klb/hr	mole %	klb/hr	mole %	klb/hr	mole %	klb/hr		klb/hr	mole %	klb/hr		klb/hr	
CO	263.040	6.07	23.375	14.92	286.116	12.06	250.781	18.21			285.299	12.06				
CO_2	974.615	14.31	0.171	0.07	1.884	0.04	1.584	0.07			1.884	0.04				
H_2	67.326	21.75	6.00	53.58	73.296	43.2	64.401	65.47			73.296	43.2				
H_2O	899.869	32.31	18.302	18.17	0.210	0.01	0.192	0.02			0.210	0.01				
CH_4	521.660	22.13	7.317	8.17	549.550	40.52	78.618	9.99			549.550	40.52				
C_2H_6	0.146	>0.01														
H_2S	31.329	0.60														
COS	0.817	0.01														
NH_3	19.518	0.07														
N_2	89.687	2.07	7.983	5.09	97.670	4.16	85.819	6.23			97.669	4.16				
Total, klb/hr	2894.134		63.146		1008.727		481.396		29.424		1008.727		25.135		435.764	

Table 2-3

Overall Material and Energy Balance

Input	Mass Flow Rate klb/Hr	Gross Heating Value MM Btu/Hr
Coal gasifier	1175.800	11981.0
Coal to dryer fuel and offsite boilers	287.830	2925.0
Total Input	1463.630	14906.0[1]
Products		
Product gas	435.764	10938.0[2]
Sulfur	29.424	118.0
Total Products	465.188	11056.0

Overall Plant Efficiency $= \frac{11056}{14907} = 74.1\%$

[1]Illinois No. 6 Seam Coal Heating Value = 13650 Btu/lb (DAF), 10190 Btu/lb, as received

[2]Product gas heating value = 1067 Btu/SCF = 25.10 k Btu/lb

2.3 PLANT SIZING AND SITING ISSUES AND CONSTRAINTS

The plant is assumed to be a minemouth operation in Illinois. The feedstock is an Illinois No. 6 coal. The plant produces 250 billion Btu per day of SNG. Steam is generated in offsite coal fired boilers with flue gas desulfurization, and electric power is purchased.

2.4 RAW MATERIALS AND SUPPORT SYSTEM REQUIREMENTS

2.4.1 Coal Quantities and Composition

The design basis developed by Exxon for the CCG unit assumes an Illinois No. 6 seam coal feedstock. In order to achieve the 250 billion Btu per day energy output in the product gas, the required feed rate is 14,100 tons per day of bituminous coal to the gasifiers, and 3,450 tons per day to dryer fuel and offsite boilers. The composition of the Illinois No. 6 feed is presented in Table 2-4.

Table 2-4

Composition of Illinois No. 6 Bituminous Coal

Proximate Analysis (as received), wt %	
Volatile Matter	32.90
Fixed Carbon	38.21
Ash	16.89
Moisture	12.00
Total	100.00
Ultimate Analysis (dry basis) wt %	
C	62.70
H	4.67
O	7.85
N	1.18
S	4.25
Cl	0.16
Ash	19.19
Total	100.00
Free Swelling Index	2-1/2 to 3-1/2

Source: Reference 2-2

2.4.2 Catalysts and Other Required Materials

The maj· chemicals required for the CCG process and the required rates are summarized as follows:

Chemical	Requirements
K_2CO_3 (15 wt% on dry feed coal)	2115 TPD
KOH Makeup (30 wt%)	204 TPD
Lime (97% CaO)	1085 TPD

Source: References 2-3, 2-4

2.4.3 Water Requirements

The water requirements for onsite equipment are calculated based on the item-by-item equipment specifications. The normal requirements for offsite facilities are developed in parallel with sizing calculations. The water requirements are presented in Table 2-5.

Table 2-5

Water Requirements

Utility	Requirements			
	Normal Onsites	Normal Offsites	Intermittent Loads & Capacity Allowances(1)	Total Design Capacity
Raw Water, GPM	- - - - 7,100 - - - -		3,100	10,200
Boiler Feed Water Treating, GPM(2)	- - - - 3,550 - - - -		960	4,500
Cooling Water, GPM	58,300	16,500	18,500	93,200

Notes:

(1) This column includes:

- Capacity for intermittent requirements.
- Allowance for estimated increases in utilities loads during project development (except no allowance on gasifier steam rate).
- An additional allowance for reserve capacity in source facilities (e.g., offsite boilers, BFW treating, cooling tower, etc.).

(2) Includes treating for BFW makeup to low pressure and high pressure steam generation services.

Source: Reference 2-4

2.5 EFFECT OF COAL TYPE

A range of feedstocks have been tested in the fluidized bed gasifier. Table 2-6 presents a summary of the runs in which Illinois bituminous coal was burned, using potassium carbonate (K_2CO_3) catalyst and recycled K_2CO_3 catalyst, as well as two other tests in which potassium hydroxide catalyst was used with subbituminous coal and lignite feeds.

The results for the two bituminous cases are almost identical. The third and fourth tests, using the cheaper KOH catalyst, allow for a performance comparison of subbituminous and lignite feedstocks. Column 3 indicates that a 10 wt% loading of KOH yields good carbon and steam conversions for the subbituminous coal. The lignite requires a higher catalyst loading to get acceptable carbon and steam conversions. This is due to the high ash content of lignite which deactivates the catalyst by forming inactive potassium alumina silicate. More catalyst is therefore required to make up for this effect.

The data in Table 2-6 indicates that a full range of coals can be run in the catalytic coal gasification process.

Table 2-6

Effect of Coal Type in CCG

	Illinois Bituminous K_2CO_3	Illinois Bituminous Recycle	Subbituminous KOH	Lignite KOH
Temperature, °F	1300	1300	1300	1300
Catalyst Loading, Wt %	15	15	10	13
Coal Rate, Lb/Hr	10	11	11	11
Steam Rate, Lb/Hr	15	16	18	17
Carbon Conversion, %	85–90	85	88	85
Steam Conversion, %	50–60	55	50	45

Source: Reference 2-1

2.6 AIR POLLUTION CONTROL TECHNOLOGY

The Exxon catalytic gasification process includes a number of units which treat gaseous effluents. The sour water stripper removes 225 tons of NH_3 per day. The H_2S which comes off this system is sent to the sulfur recovery unit, where 353 tons per day of elemental sulfur are produced.

Flue gas from the dryers is treated in the flue gas desulfurization unit, which produces 387 tons per day of sulfuric acid. The technology is commercially proven and capable of achieving environmental standards.

2.7 WATER POLLUTION CONTROL TECHNOLOGY

Stripped water from the sour water stripping and NH_3 recovery system is sent offsite for treating.

2.8 SOLID WASTE HANDLING

The waste solids handling and disposal facility treats the fines filter cake and the slurry of char and soluble catalyst. The solids produced in this unit is sent to landfill.

2.9 OSHA ISSUES

The coal storage and preparation areas may expose workers to coal dust and noise from milling operations. Coal dust can cause black lung disease, but can be controlled by wetting the coal pile. If dry, the coal storage area may also spontaneously combust.

The gasification process produces unutilized carbon in the form of char which is slurried with ash for disposal. The ash is likely to be a very fine (thus easily respirable) material high in carcinogenic trace metals. The char is likely to contain polynuclear aromatic hydrocarbons, many of which are carcinogens or co-carcinogens. Therefore, exposure to the ash/char slurry must be avoided.

2.10 PROCESS PERFORMANCE FACTORS

2.10.1 Product Characteristics and Marketability

The Exxon Catalytic Coal Gasification produces high-Btu gas as its only product. The quality of the gas is determined by the operation of the cryogenic separation system, which is used to separate the product gas (methane) from the recycle gas which consists primarily of hydrogen, nitrogen and carbon monoxide. Methane content in the product gas can therefore be adjusted to any desired value by manipulation of the distillation column reflux rate, but in actual practice would be greater than 99 percent (essentially pure methane). This gas is highly suitable as a substitute for natural gas in virtually all commercial applications, but would require the addition of malodorous compounds (such as mercaptans) for leak detection if used in residential service.

2.10.2 Capacity Factors, Flexibility, and Reliability

Because of the experimental, unproven nature of the CCG process, estimates of commercial plant capacity factors, flexibility, and reliability are largely speculative. However, it is reasonable to presume that such a commercial plant could be operated to achieve the 90 percent capacity factor assumed in preparing the economic estimates for this report (chapter three).

Flexibility in operational throughput of the plant is determined by the least flexible process unit in the operating sequence. This is likely to be the fluid bed gasifier, since a fairly narrow range of gas velocities is required (1.8 to 2.4 feet per second). Depending too on the number of process trains used in the plant, entire trains could be shut down to adjust throughput. It is safe to say that economic factors will constrain plant throughput flexibility more severely than technical factors over long periods of time (sustained operation at low capacity factors makes poor use of capital investment dollars).

The process is quite flexible in the type of coal used as feedstock, but care must be taken to assure that the mineral matter in the coal will not adversely affect the catalyst recovery system or the rate of catalyst recovery, especially in light of the sensitivity of total operating cost to catalyst use rates.

The reliability of a commercial plant based on this technology is unknown due to the developmental nature of the process. However, conventional equipment is used in most of the plant areas, and is expected to provide highly reliable operation. Reliability problems will be more likely to appear in the catalyst feed and recovery systems, and in the fluid bed gasifier itself.

2.11 TECHNOLOGY STATUS AND DEVELOPMENT POTENTIAL

Exxon Research and Engineering Company is presently performing a three phase development program for the catalytic coal gasification process. The major work entails the operation of the process development unit (PDU). Table 2-7 summarizes the current operation of the PDU. As of April, 1980, many long runs of the PDU gasification unit have been achieved on catalyzed Illinois coal, with the operation time totaling more than 2000 hours. The carbon conversions and product gas compositions from these tests were approaching the study design targets.

Table 2-8 outlines the overall development plan for the catalytic coal gasification program. Phase I is currently in progress, and should be completed by July, 1981. The objective of this phase of the program is to demonstrate the feasibility of the catalytic process on Illinois bituminous coal.

Phase II will be aimed at expanding the data base for the process. A major objective of this work is to determine the preferred conditions for several other coals of interest in catalytic gasification and thereby demonstrate the flexibility of the process to handle a wide variety of coal feedstocks. The third phase of the program will be the precommercialization phase in which the major emphasis will be the design, construction, and operation of a large pilot plant to obtain scale-up design data for the commercial plant.

Table 2-7

PDU Operations Status

- Many Long Runs of Gasification Section Achieved
  - Catalyzed Illinois Coal
  - 2000 Hours Operation
- Conversions Approaching Study Design Targets
- Agglomerates Found in Bottom of Reactor
  - Reduced/Eliminated by Increasing Feed Gas Velocity
- Gas Separation Section Started Up Smoothly
  - Integrated Operation Achieved
- Catalyst Recovery Section Started up Smoothly Also
  - Water Wash Mode
  - Silicate and Sulfate Present in Recovered Catalyst
- Integrated Operation Now in Progress

Source: Reference 2-1

Table 2-8

CCG Development Program

- Development - Phase I (7/78 - 7/81)
  - Demonstrate Feasibility on Illinois Bituminous Coal
    - + Joint Funding by DOE and GRI
    - + Integrated Operations at Preferred Conditions

- Development - Phase II
  - Determine Preferred Conditions for Several Coals of Interest
  - Demonstrate Feasibility of Several Process Improvements
  - Develop Study Design for Conceptualized Commercial CCG Plant

- Precommercialization Phase
  - Design, Construct and Operate LPP to Obtain Scale-Up Design Data

Source: Reference 2-1

2.12 REGIONAL FACTORS INFLUENCING ECONOMICS

2.12.1 Resource Constraints

In addition to requirements for coal and water at steady supply rates and reasonable costs, the Exxon CCG process requires a secure source of catalyst. This potassium based catalyst is essential to the operation of the plant, and is consumed in relatively large quantities. Price stability is particularly important, since catalyst costs account for a major portion of operating costs.

2.12.2 Environmental Control Constraints

Financial burdens imposed as a result of meeting environmental regulations can be significant in terms of capital and/or operating costs. Special regulations may apply to the solid waste due to the potential leachability of potassium based catalyst residues. Regulations will be site specific and will be determined by a set of technical and political factors. Technical factors include local meteorology, topography and existing air quality.

2.12.3 Siting Constraints

Factors of supply availability and cost for coal, water and catalyst will be important determinants of site location. Environmental regulations will also impact the choice. Other important factors will be taxation rate, land cost, and proximity to rail, barge, and pipeline gas distribution systems.

References

2-1. Fant, B.T. and E.A. Euker, Jr. Exxon's Catalytic Coal Gasification Process, Exxon Research and Engineering Company, for Presentation to the First International Gas Research Conference, June 9-12, 1980, Chicago, Illinois.

2-2. Coal Gasification Pilot Plant Studies, Quarterly Report for July 1 - September 30, 1979, Institute of Gas Technology, U.S. DOE, May 1980.

2-3. Gallagher, J.E., Jr. and C.A. Euker, Jr. Catalytic Coal Gasification for SNG Manufacture, Exxon Research and Engineering Company, Energy Research, Vol. 4, pp. 137-147, 1980, Presented at the 6th Annual Conference on Coal Gasification, Liquefaction, and Conversion to Electricity, University of Pittsburgh, July 31 - August 2, 1979.

2-4. Exxon Catalytic Coal Gasification Process Predevelopment Program, Final Project Report, December 1978, Exxon Research and Engineering Company, Baytown, Texas.

CHAPTER THREE: ECONOMIC ANALYSIS

This part contains data on the costs of the Exxon Catalytic Coal Gasification process.

3.1 Introduction and Methodology

3.1.1 Economic Analysis Methodology

The economic analysis relies on a preliminary commercial size plant design made by Exxon (3-1). The economic data presented in the Exxon report were adjusted for inflation and scaled to a plant size of 250 billion Btu per day. This plant size was judged to be the typical size for commercial scale plants. The reliability of the adjusted data was assessed and the data were used to compute non-fuel and total product costs for the facility.

3.1.2 Scaling Exponents

The Exxon design was for a plant sized at 257 billion Btu per day which was scaled down to 250 billion Btu per day. Different scaling exponents were applied to the various sections of the plant and types of operating costs. Different scaling exponents are used because economies of scale are not the same for all costs. Because the scale-down from the Exxon design to the standard size was only 2.7 percent, the use of the different scaling exponents did not have a significant impact on the economic analysis. The scaling exponents used are presented in Table 3-1.

TABLE 3-1

COST SCALING EXPONENTS

ITEM	SCALING FACTOR
Gasification Area	0.97
All Other Plant Areas	0.87
Labor, Maintenance, Administration and General Overhead	0.57
Supplies, Electricity, Catalysts and Chemicals, Water, Ash Disposal	1.00

Source: Derived from Reference 3-2.

3.1.3 Price Indices

Costs in the Exxon report were presented in January, 1978 dollars. These costs were corrected to third quarter 1980 dollars by the method explained in the Background.

3.1.4 Economic Criteria

The economic criteria used were explained in the Background. The construction schedule is:

- 15 percent third year before start-up.
- 45 percent second year before start-up.
- 30 percent first year before start-up.
- 10 percent year of start-up.

(From Reference 3-1.)

3.1.5 Contingencies

Two contingencies were applied to the capital cost estimates: a process contingency and a project contingency. The process contingency covers technical uncertainties within a particular process which might cause costs to increase. The process contingency percentage applied to each area is shown in Table 3-2. Gasification, not yet at the pilot plant stage, receives a 50 percent contingency. Coal preparation and raw gas cooling, which have a small amount of technical uncertainty, both receive a 10 percent contingency. All other areas were judged to be fully commercially developed and received no process contingency.

A project contingency of 15 percent was applied to the total of the costs of each area and unit (not including process contingencies) and contractor's fees. This project contingency is meant to allow for unanticipated cost increases, which usually arise as the plant design is made more complete.

3.2 Capital Costs

3.2.1 Itemized Capital Costs

Total Plant Investment, the cost of constructing the SNG facility, amounts to $1,680 million, as is shown in Table 3-3. The biggest element of Total Plant Investment is the utilities and support system of $391 million. The Gasification Area, at $236 million, is an important contributor to costs. The Process and Project contingencies add $290 million.

TABLE 3-2

PROCESS CONTINGENCY BY PLANT AREA

NUMBER	ITEM	CONTINGENCY (PERCENT)
100	Coal storage and handling	0
200	Coal preparation	10
300	Gasification and power recovery	50
1200	Raw gas cooling	10
1300	Acid gas removal and gas cleaning	0
1400	Sulfur recovery and tail gas treating	0
1700	Shift conversion	0
1800	Methanation	0
1900	Air separation	0
2000	Utilities and support systems	0
2010	Offsites and miscellaneous	0

Source: EPCO.

TABLE 3-3

TOTAL CAPITAL REQUIREMENT: EXXON CATALYTIC[a]

AREA	ITEM	COST[b] (10^6 $)	PERCENT OF SUBTOTAL
100	Coal Storage and Handling	62	4.5
200	Coal Preparation	74	5.3
300	Gasification	236	17.0
1200	Raw Gas Cooling	147	10.6
1300	Acid Gas Removal and Gas Cleaning	24	1.7
1400	Sulfur Recovery and Tail Gas Treating	186	13.4
1800	Methanation	89	6.4
2000	Utilities and Support Systems	391	28.1
2100	Offsites and Miscellaneous	181	13.0
	Subtotal	1390	100.0
	Process Contingency	81	
	Project Contingency	209	
	Total Plant Investment	1680	
	Interest During Construction	771	
	Starting Costs	101	
	Working Capital	102	
	Total	2654	

[a]Source: Reference 3-1, updated by ERCO.
[b]Third Quarter, 1980 dollars.

Total Plant Investment is also combined with the other components of plant capital requirement in Table 3-3. The Total Capital Requirement is $2,654 million, with Total Plant Investment contributing $1,680 million and Interest During Construction $771 million. Starting costs, which cover the plant shakedown period, total $101 million. Working Capital, which accounts for production costs before revenues are received, add $102 million to the total capital requirement.

3.2.3 Variability of Capital Costs

The Exxon plant design was a large-scale effort involving over five man-years. Preliminary flow-sheets were worked out and major equipment was specified. Major equipment costs not available from Exxon files were obtained from vendor quotes. Exxon added indirect costs to the equipment costs, which amounted to about 50% of equipment costs.

The level of detail in the Exxon report falls between the "study estimate" and "budget authorization" accuracy levels defined in the Chemical Engineers Handbook (3-3). This suggests that the estimate is reliable within ±25 percent. Because the technology is not fully developed, this uncertainty factor should be increased to ±30 percent.

The contingency and the large provision for offsites included in this estimate, reduce the risk that unanticipated costs will cause the estimate to be too low. However, the Exxon catalytic process is not yet technically proven, and has not reached the pilot plant testing stage (January 1981). The capital cost estimate was based on computer simulations and bench scale tests. Therefore, unanticipated technical problems could alter process economics.

3.3 Operating and Maintenance Costs

3.3.1 Itemized Operating and Maintenance Costs

Annual operating and maintenance (O&M) costs excluding fuel feed are presented in Table 3-4. These costs assume a 90 percent operating factor. Total expenses are $149.7 million. The most important components of operating and maintenance costs are supplies and catalysts, which together account for 72.3 percent of the operating and maintenance costs.

Supplies and catalysts are a large portion of capital costs because the process requires large amounts of KOH catalyst. This catalyst is sprayed on the coal prior to gasification. KOH will cost $31 million annually.

The Exxon Catalytic process produces by-product sulfur, ammonia and sulfuric acid. The value of each by-product is also given in Table 3-4.

Subtracting the by-product credits of $15.9 million from the operating and maintenance costs of $149.7 million yields a net annual operating and maintenance cost of $133.8 million as is shown in Table 3-4.

3.3.2 Variability of Operating and Maintenance Costs

The Exxon report included provisions for plant operation and overhead. No large gaps, which would cause underestimation of costs, were identified.

TABLE 3-4

NET ANNUAL OPERATING AND MAINTENANCE COSTS[a]
(90% CAPACITY FACTOR)

ITEM	COST[c] (10^6 $)	PERCENT OF TOTAL
Administration and General Overhead	6.6	4.4
Local Taxes and Insurance[b]	0	0
Labor		
Process Operation	25.2	16.8
Maintenance	N/A	0
Supervision	8.0	5.4
Total	33.2	22.2
Supplies (includes overheads)		
Operating	N/A	
Maintenance	N/A	
Total	55.4	37.0
Catalysts and Chemicals	52.9	35.3
Utilities	.9	.6
Ash Disposal	.7	.4
Total Operating and Maintenance Costs	149.7	100
By-Product Credits	(10^6 $)	
Sulfur	(4.1)	
Sulfuric Acid	(10.3)	
Ammonia	(1.5)	
Total	(15.9)	
Net O & M Costs	ANNUAL COSTS (10^6 $)	
Gross O & M Costs	149.7	
By-Product Credits	(15.9)	
Total	133.8	

[a]Source: Reference 3-1, updated by ERCO.
N/A - not available

[b]included in supplies

[c]Third quarter, 1980 dollars.

Exxon assumed that it would receive a 15% discount on KOH needed for the process. This discount would be realized through the construction of a dedicated KOH plant near the SNG plant. If the dedicated plant were not constructed, the $31 million of catalyst and chemical charges accounted for by KOH would increase by approximately 15%, or $4.7 million. This $4.7 million increase would have a minor effect on operating and maintenance costs.

3.4 Effect of Technology Development On Costs

As the Exxon catalytic process is commercialized, the cost of constructing Exxon catalytic SNG plants will fall. New techniques and better methods of using older techniques will be developed. As was explained in the Background, 10 percent has been estimated as the upper limit on the experience factor for new energy technologies.

The 10 percent experience factor is valid only for the section of plant using new technology. Most components of the plant would employ mature technologies whose costs would decline little as more Exxon Catalytic SNG plants were built. The accumulated volume of production of these components is so large that the construction of one or several Exxon Catalytic plants would result in negligible cost reductions because of experience. Novel areas, including gasification and raw gas cooling, account for 27.2 percent of total plant investment (from Table 3-3). With the share of the contingencies assignable to these areas (about 48%), the novel areas account for approximately 35 percent of total plant investment. The experience factor is then 35 percent of the 10 percent maximum, or 3.5 percent. Each doubling of Exxon catalytic SNG capacity might result in a 3.5 percent reduction in unit capital costs.

Exxon (3-4) suggests that mature technology SNG plants could have gas cost savings of 16 to 21 percent. Besides the capital cost savings described above, these savings include reduced operating expenses. This projection seems optimistic.

3.5 Gas Costs

The cost of the product gas is composed of three components: capital charges associated with plant capital costs, plant operating and maintenance (O&M) costs, and coal costs. The cost of the gas excluding the cost of coal (non-fuel costs) indicates the cost of converting the coal to synthetic fuel. Non-fuel gas costs can be computed from capital charges and O&M costs according to the formula given in the Background.

$$P = \frac{(\$2654 \times 10^6 \times 20\%) + (\$133.8 \times 10^6)}{(91.25 \times 10^{12} \text{ Btu} \times 90\%)}$$

$$P = \underset{\text{(Capital Costs)}}{\$6.46/10^6 \text{ Btu}} + \underset{\text{(O \& M Costs)}}{\$1.63/10^6 \text{ Btu}}$$

$$P = \underset{\text{(Non-Fuel Product Costs)}}{\$8.09/10^6 \text{ Btu}}$$

This estimate of $\$8.09/10^6$ Btu excluding fuel is only as accurate as the capital and operating costs discussed above. Therefore, it should be considered the midpoint of a range of plus or minus 30 percent.

The non-fuel gas costs can be combined with a coal cost to yield a total product cost. The overall coal to gas thermal efficiency of the process is 73.3 percent, and coal was assumed to cost $1.50/10^6$ Btu. Therefore, the coal cost would be $2.05/10^6$ Btu, and the total product cost would be $10.14/10^6$ Btu.

References

3-1. Kalina, T., Nahas, N.C., (Exxon Research and Engineering Co.) "Exxon Catalytic Coal Gasification Process Predevelopment Program", United States Department of Energy, December 1978. FE-2369-24.

3-2. Bechtel Corp., "Effect of Plant Size on the Cost of Producing Industrial Gas", United States Department of Energy, March, 1976. FE/WAPO/2526-1.

3-3. Perry, Robert H. and Cecil H. Chilton, eds., Chemical Engineers Handbook, Fifth Edition, (New York: McGraw-Hill, 1973) Chapter 25, pp. 12-17.

3-4. Derived from savings described in reference 3-1, page 152. Exxon stated savings could be $0.75-1.00/MMBtu based on a gas cost of $4.789. This corresponds to 16-21%.