TECHNOLOGY ASSESSMENT GUIDE

NO. 6a

IGT HYGAS

CHAPTER ONE: EXECUTIVE SUMMARY

1.1 OVERALL PROSPECTS FOR THE TECHNOLOGY

The HYGAS process for high-Btu gas production was developed by the Institute of Gas Technology in the late 1960's under sponsorship of the American Gas Association and the Office of Coal Research. Initial pilot plant operation of a 75 TPD unit began in 1974 and was continued until 1980.

The heart of the process is a unique arrangement of pressurized fluidized-bed reactors which successively treat the incoming coal to drying, two stages of hydrogasification and finally steam oxygen gasification. Successful operation of the system requires smooth operation of many gas-solids contacting devices, including four fluidized beds and several pneumatic solids transfer lines. Although the process appears technically feasible from a conceptual standpoint, pilot plant operating during the entire test program was plagued with many operational problems.

These technical uncertainties and recent doubts as to the financial viability of the process have jeopardized continued funding of the project. Despite several attractive features of the HYGAS approach, these important problems must be resolved before this process can again be considered a feasible alternative.

1.2 ENGINEERING ASPECTS

Coal is first crushed and sized, followed by slurrying in a light oil prior to pressurization and injection into the first fluid bed. There the coal is dehydrated and devolatilized, followed by the first step of hydrogasification. Before reacting completely, the coal is transferred to a higher temperature fluid bed for more severe hydrogasification. The last step is steam oxygen gasification which generates hydrogen and carbon monoxide which participate in hydrogasification reactions (along with steam) in the upper beds.

The most notable feature about the gasifier effluent is the high methane content, due to the high pressure of operation. Carbon dioxide is also quite high, and CO is relatively low for an oxygen blown gasifier. The gas heating value is high, reflecting the high methane content. Oxygen consumption is relatively low, averaging around 0.23 lb O_2/lb coal for low-rank coals and approximately 0.25 lb O_2/lb coal (as fed to the gasifier) for bituminous coals. Steam consumption is quite high, averaging more than 1 lb/lb coal, but not as high as in the dry ash Lurgi gasifier.

The HYGAS process has the advantage of having been tested with a variety of coals, from lignite to bituminous. The slurry feed system used in the process prevents the loss of gases experienced in lockhopper operation. The high methane content in the raw gas reduces the size of downstream methanation equipment; approximately two-thirds of the final methane content is produced in the gasifier.

The thermal efficiency of the HYGAS process is enhanced by lower temperature operation which limits sensible heat losses, by the slurry feed system which reduces compression requirements associated with lockhopper operation, and by high methane production in the gasifier. In general, the series arrangement of the fluidized beds provides sufficient inventory of fuel to in sure safe and steady operation.

The HYGAS process has not yet been developed sufficiently to proceed with a commercial scale design. The gasifier is oriented to methane production which is a clear advantage in SNG applications but not in some low- and medium-Btu gas uses. Caking coals will require pretreatment to prevent blockage of slurry discharge and transfer lines, as well as agglomeration in the reactors. Although the efficiency of conversion of coal to methane is higher in the HYGAS process than for systems based on fixed bed gasifiers, consistent operation above 80 percent coal to gas conversion for bituminous coal was not achieved. One factor limiting coal conversion is the carbon content of the ash withdrawn from the gasifier, which is projected to be approximately 10 to 25 percent, representing a 2 to 3 percent loss of feed carbon. The use of low-rank coals may alleviate this problem to some extent, due to their greater reactivity. Low-rank coals also maintain the advantage over agglomerating coals (which require pretreatment) of not plugging the slurry discharge and high temperature transfer lines. However, the tendency for dried low-rank coals to reabsorb moisture may limit solids content in slurry lines if an aqueous slurry medium is used. Fines are not a problem in the HYGAS process which uses pulverized coal as a feedstock. Although ash from the HYGAS gasifier contains approximately 10 to 25 percent carbon, it may still be disposed of by landfill.

Wastewater streams undergo moderate treatment and are recycled to the gasifier. Toxic element studies have been completed for the plant, and acid gases will undergo conventional removal and sulfur recovery to protect catalysts and meet environmental standards.

1.3 CURRENT COSTS

The total capital requirement for this 91.25×10^{12} Btu/year plant is $1.74 billion which is dominated by a plant investment of $1.25 billion and interest during construction of $327 million. Start-up costs and working capital are $76 and $75 million respectively, with the remainder composed of catalysts and chemicals, and royalties.

Annual operating and maintenance costs (at a plant capacity factor of 90%) total $102 million exclusive of coal costs. Major elements in this cost are taxes and insurance, maintenance labor, G&A, and maintenance supplies.

Taken together with a 20 percent capital charge, these costs result in a product cost of $\$4.79/10^6$ Btu, which is exclusive of coal costs.

1.4 RESEARCH AND DEVELOPMENT DIRECTIONS

Due to the uncertain financial future of the HYGAS project, no pilot plant experimentation is planned in the foreseeable future. However, if interest in the process is ever regenerated, R&D activities will focus on achieving stable long-term operation of the process. Of particular interest will be the durability of solids handling components, such as slurry pumps and the tungsten carbide ash discharge nozzle.

CHAPTER TWO: ENGINEERING SPECIFICATIONS

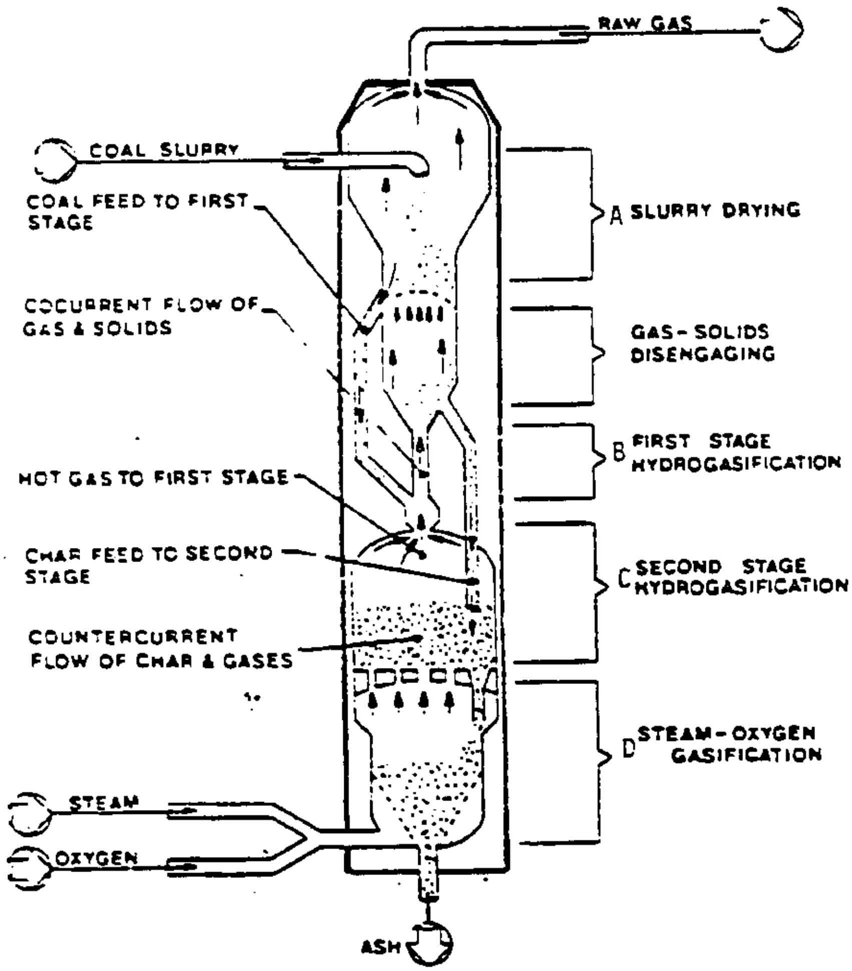
2.1 GENERAL DESCRIPTION OF THE TECHNOLOGY

The HYGAS Process is a second-generation, high-pressure, steam-oxygen gasification process developed by the Institute of Gas Technology (IGT). The process is designed to convert all ranks of coal to a high-Btu substitute natural gas.

Coal is crushed, screened, and fed to an agitated tank where it is slurried in light oil. If the feed is a caking coal, a pretreatment step occurs in an air-fluidized bed. The slurry is fed into the gasifier at high pressure. The reactor, operated at 500 to 1200 psi, has four internally connected fluidized beds. The upper bed dries the coal slurry in an environment of 1300 to 1500°F (see Figure 2-1, Section A). The coal flows by gravity into a dilute phase riser stage which is the first step of hydrogasification (Section B). In this stage coal particles are heated to 1100°F by hot gases, which react with about 20 percent of the coal to produce methane. The partially reacted coal, or char, flows to the second gasification step (Section C), and is heated in a fluidized bed to about 1700°F. Here the char is further gasified by the steam and hydrogen-rich gas rising from the steam-oxygen gasification stage below. The third gasification stage (Section D) receives steam and oxygen feed streams. The ascending stream of hot gas provides heat and hydrogen to the rest of the reactor. A methane-rich raw gas and residual char are produced when hydrogen-rich gas and steam react with char.

The high-ash spent char from the lower bed of the reaction vessel is sent through a solids control valve and carried away by steam. The char is mixed with water to form a slurry. This slurry is filtered at low pressure and the filtrate is recycled to the quench vessel.

Figure 2-1
HYGAS Gasifier



Source: Reference 2-1

Raw gas produced is cooled by its upward passage through the first stage of the gasifier and drying bed. This gas is collected for removal of carbonization products and sulfur impurities. The light oil recovered at this point is used for slurry preparation of coal feed. The gas is fed to a catalytic methanation process for additional hydrogenation and upgrading to high-Btu pipeline gas.

2.2 PROCESS FLOW, ENERGY, AND MATERIAL BALANCES

Relevant plant area numbers for the IGT HYGAS Process are listed in Table 2-1. The conceptualized process flow diagram for this process is illustrated in Figure 2-2. Table 2-2 presents the material balance for various streams represented in the flow diagram. The overall material and energy balance is summarized in Table 2.3.

2.3 PLANT SIZING AND SIZING ISSUES AND CONSTRAINTS

The plant size chosen for this assessment is 250 million SCFD, which is expected to be typical of a commercial pipeline quality gas plant. A plant of this size will require several hundred acres of fairly level land with good access to rail and/or barge transportation. In addition, the plant should be located near an existing natural gas pipeline system to avoid capital costs for pipeline construction. The resources of the area should be capable of meeting water requirements on a long term basis.

Table 2-1

Relevant IGT HYGAS Plant Area Numbers

110	Coal Storage	
270	Coal Pretreatment	
300	GASIFICATION	
		310 Gasification
1200	RAW GAS COOLING	
		1220 Gas Quenching and Cooling
1400	SULFUR RECOVERY AND TAIL GAS TREATING	
		1410 Sulfur Recovery
1700	SHIFT CONVERSION	
1800	METHANATION	
1900	AIR SEPARATION	
2000	UTILITIES AND SUPPORT SYSTEMS	
		2010 Steam Generation and Power Recovery
		2020 Wastewater Treating
		2030 Solids Disposal
2100	OFFSITES AND MISCELLANEOUS	

Figure 2-2

IGT HYGAS Conceptualized Process Flow Diagram

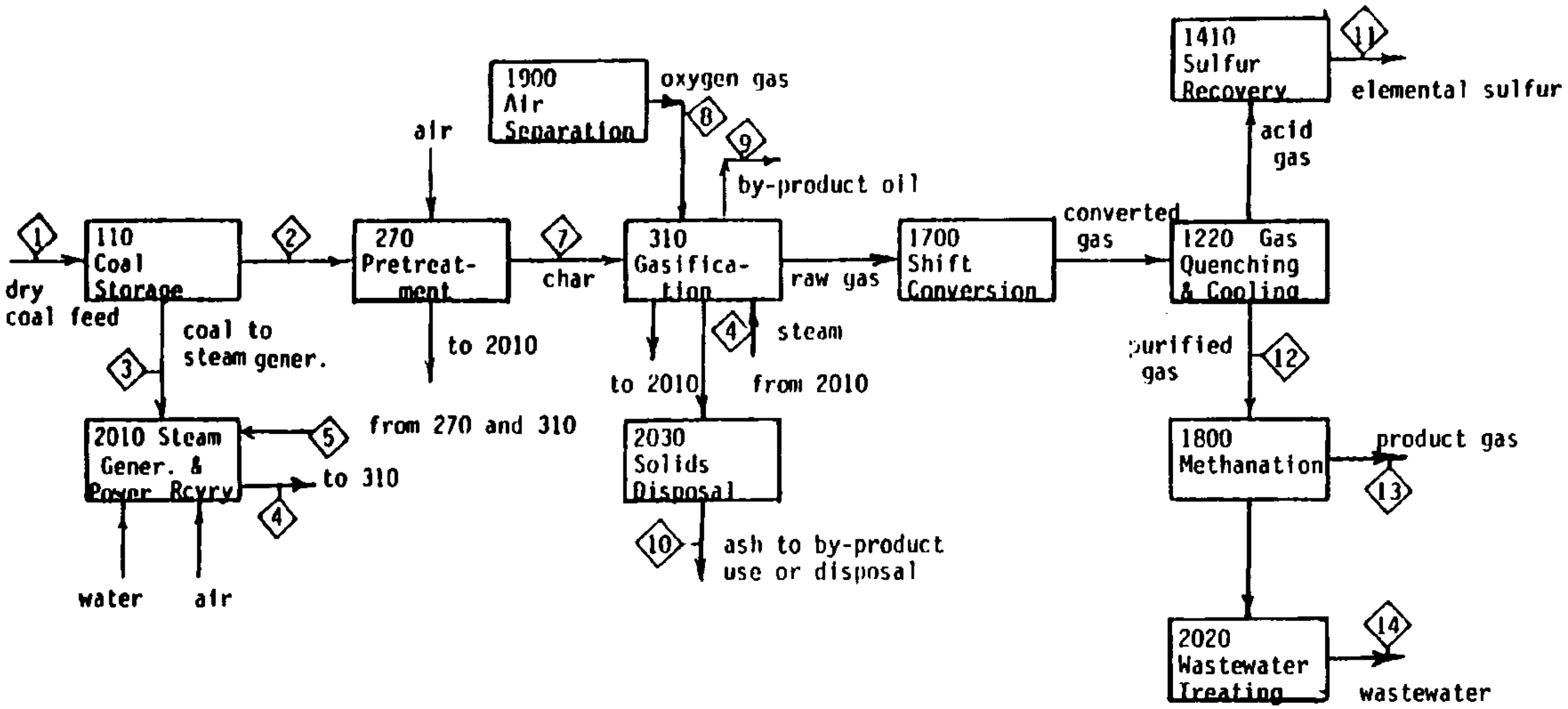


Table 2-2

IGT HYGAS Detailed Material Balance for Process Streams

Stream No.	1	2	3	4	5	6	7
Description	Dry coal feed	Coal to pretreatment	Coal to steam generation	Steam	Spent char (carbon component)	Air	Char (carbon component)
Temperature, °F							
Pressure, PSIG							
Flow	klb/hr	klb/hr	klb/hr	klb/hr	klb/hr	klb/hr	klb/hr
CH_4							
H_2							
CO_2							839.9
N_2							
CO							
H_2O							
Total	1418.1	157.7	3.3	1588.1	156.6	1551.2	839.9

Stream No.	8	9	10	11	12		13		14
Description	Oxygen	By-product oil	Ash	Elemental sulfur	Purified gas		SNG		Wastewater
Temperature, °F									
Pressure, PSIG									
Flow	klb/hr	klb/hr	klb/hr	klb/hr	klb/hr	mole %	klb/hr	mole %	klb/hr
CH_4					283.2	29.27	4531.104	97.68	
H_2					55.1	5.70	0.696	1.04	
CO_2					629.2	65.03	20.416	0.75	
N_2							3.248	0.49	
CO								0.03	
H_2O								0.01	
Total	306.01	75.04	303.0	207.555	967.5		4555.464		103.323

Table 2-3

Overall Material and Energy Balance

Input	Mass Flow Rate klb/Hr	Gross Heating Value MM Btu/Hr
Coal to process	1418.1	14450.44
Coal reacted in preheater	157.7	1606.97
Coal to steam plant	3.3	33.62
Total Input	1579.1	16091.03[a]
Products		
Product gas	447.8	10057.59[b]
By-product oil	75.0	1329.00
Phenol	7.3	124.54
Ammonia	10.3	124.42
Sulfur	207.6	832.48
Total Products	748.0	12343.61

Overall Plant Efficiency: $\frac{12343}{16091} = 76.7\%$

[a]Illinois No. 6 Seam, HV = 13650 Btu/lb (D.A.F.)
HV = 10190 Btu/lb as received

[b]Product gas heating value = 991 Btu/SCF = 23311 Btu/lb

2.4 RAW MATERIAL AND SUPPORT SYSTEM REQUIREMENTS

2.4.1 Coal Quantities and Quality

A total of 21,215 TPD of Illinois No. 6 Seam coal will be fed to the IGT HYGAS unit. The gasifier processes 19,040 TPD of the feedstock, while 2,130 TPD are reacted in the preheater and 45 TPD are sent to the steam plant. The composition of the Illinois No. 6 is summarized in Table 3.

2.5 EFFECT OF COAL TYPE

The Institute of Gas Technology has conducted pilot plant studies with three types of coal feeds; Montana lignite, Montana Rosebud subbituminous, and two types of Illinois No. 6 Seam bituminous coal. A summary of the HYGAS plant operations is presented in Table 4 by each of the three coal types. Data for the total gasifier operating hours and total coal feed is included in this table. The first tests were performed with lignite before the steam-oxygen gasification process was integrated into the HYGAS pilot plant. Later, ten tests were conducted with the lignite utilizing the integrated steam-oxygen gasifier. These tests established the technical feasibility of the process with lignite as a feedstock and terminated with Test 37.

The next series of tests were conducted with an Illinois No. 6 feed. Because of their tendency to agglomerate, an additional step is required in the HYGAS process when bituminous coals are fed. This step takes place in a low-temperature, low-pressure, fluidized-bed, air oxidation

Table 2-4

Characteristics of the Coal Gasified in the HYGAS Process Design

Coal Type	Illinois No. 6
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

Table 2-5

Summary of HYGAS Plant Operations by Coal Type

Coal Type	Total Gasifier Operating Hours	Total Coal Feed Tons
Montana Lignite	4097	7080
Montana Rosebud Subbituminous	554	1800
Illinois No. 6 Bituminous	3376	8650
Total	8027	17530

Source: Reference 2-3

system, destroying the agglomerating properties of the coal and allowing free-flowing pulverized feed to be delivered to the HYGAS reactor. The tests were performed with the highly-caking Illinois No. 6 coal to determine the operating conditions required for its effective pretreatment. Successful pretreater operating conditions were established during this study, which terminated with Test 54, an extended test which established the technical feasibility of operating the HYGAS process with a caking bituminous coal.

Table 2-6 presents the operating conditions for these extended gasification tests. Test 37 ran for 363 hours with Montana lignite, demonstrating the HYGAS process with this feedstock. A highly-caking Illinois No. 6 coal was gasified for 228 hours in test 54. Operations with a mildly-caking Illinois No. 6 bituminous took place during Tests 59-73. Pre-treater operation is required with this coal feed.

In Table 2-7 the operating data for selected tests are compared. The highly-reactive lignite and subbituminous coals can be gasified at relatively high char conversions or coal conversions at low maximum temperatures in the steam-oxygen gasification (SOG) zone (see Tests 37 and 54, Table 2-7). It is necessary to go to higher maximum temperatures in the SOG zone in order to achieve the goal of 90 percent char conversion with the bituminous coal feeds.

Table 2-6

Summary of Extended Gasification Tests in the HYGAS Pilot Plant

Test No.	Dates	Self-Sustained Operation, Hrs.	Pressure, psig	Total Coal Feed to Plant, Tons	MAF Char Conversions, %	Remarks
37	6/22/75 to 7/08/75	363	1050	1023	91*	Established technical feasibility with lignite coal operation.
54	6/30/76 to 7/11/76	228	980	958	55	Established technical feasibility with bituminous coal operation.
64	8/18/77 to 8/27/77	203	1026	511	86	First long self-sustained operation at high char conversions with Peabody No. 10 Mine coal. SOG clinker formation.
66	10/05/77 to 10/17/77	281	918	624	90	Completely clinker-free operation at high char conversions.
67	11/07/77 to 11/22/77	350	922	819	81	Reached 3 tons/hr char feed rate to reactor. SOG clinker formation.
71	4/13/78 to 4/28/78	264	513	552	90	Operated with low steam to char ratio, 1.35; obtained high char conversion with clinker-free operation.
72	5/19/78 to 5/30/78	229	538	503	73**	First test with nominal 14 by 80 mesh feed - low steam to char ratio, 1.25; very small SOG clinker formation, did not interfere with operation.

1. Test 37 operated with Montana Lignite Coal.
2. Test 54 operated with Sahara Mine bituminous coal, all other tests operated with Peabody No. 10 Mine bituminous coal.
3. SOG identified the steam-oxygen gasifier.
4. MAF, moisture, ash-free.

* Coal Conversion.

** Test 72 MAF char conversion value is preliminary.

Source: Reference 2-3

Table 2-7

Comparison of Operating Data From Selected Tests

Test No.	Superficial Velocity ft/s	Average Maximum Temperature, °F	Pressure, psig	Steam Feed, lb/hr	Char Conversion %
37	0.62	1545	1050	5879	91
54	0.70	1614	980	6394	55
64	0.94	1755	1026	7842	86
66	1.22	1721	918	9522	90
71	1.09	1735	513	4636	90

Source: Reference 2-3

Pilot plant and PDU experience indicates that the most important variable in prevention of ash sintering as the operating temperatures are increased, has been a corresponding increase in superficial gas velocity in the SOG zone. In Tests 37 and 54 it was learned that the superficial gas velocity must be increased corresponding to the temperature increases.

2.6 AIR POLLUTION CONTROL TECHNOLOGY

IGT has completed studies to determine the fate of toxic trace elements in the feed coal during processing in the pilot plant and acid gases from gas purification will undergo sulfur recovery and cleanup to meet air quality standards before being discharged. The sulfur recovery and cleanup efforts will also protect process catalysts.

2.7 WATER POLLUTION CONTROL TECHNOLOGY

Wastewater streams will undergo moderate treatment before being recycled to the gasifier. Quench water is also recycled. Water requirements depend on the process configuration. The water requirements of the HYGAS pilot plant can not be directly scaled to commercial- or demonstration-plant sizes.

2.8 SOLID WASTE HANDLING

Ash formed is quenched in water, depressurized, filtered, and sent to disposal. Ash contains 10-25 percent carbon and should be disposed of by landfill.

2.9 OSHA ISSUES

Coal handling and preparation will expose the worker to coal dust, to danger of fire from spontaneous combustion of coal and to noise. Coal dust can cause black lung disease, but can be controlled by wetting coal storage areas. Wetting the storage area will also reduce fire risk.

The light oil produced as a by-product in the HYGAS process contains high concentrations of benzene, a known carcinogen. Therefore, exposure to the coal slurry (which is made with the light oil) and exposure to the light oil itself must be minimized. Risks will be largest during maintenance and clearing operations, when workers will be exposed to residues on equipment. Protective clothing and frequent showers will reduce risk.

2.10 PROCESS PERFORMANCE FACTORS

2.10.1 Product Characteristics and Marketability

The composition of the product gas from the HYGAS plant is given below.

Compound	Mol % (% by Volume)
CH_4	97.68
H_2	1.04
CO_2	0.75
N_2	0.49
CO	0.03
H_2O	0.01

The higher heating value of this gas is approximately 1038 Btu/SCF. The gas is of sufficient quality to pass AGA specifications for pipeline distribution for sale to commercial users. Sales to residential consumers may require the addition of mercaptans or other malodorous compounds to enhance leak detection. The gas is an excellent replacement for natural gas in virtually every application.

2.10.2 Capacity Factors, Flexibility, and Reliability

The IGT-HYGAS facility is designed to operate at a 90 percent capacity factor, producing pipeline quality gas as its only product. Because of the fact that the plant has been operated only at the pilot scale however, estimates of the capacity factor, flexibility, and reliability for a commercial facility can only be regarded as speculative. Operational flexibility is determined by the turndown ratio of the individual process units. Plant throughput flexibility would most likely be determined by limitations on the fluidized bed operating range, which could be as low as 2:1. Of course, a full sized plant would encounter economic constraints on throughput before reaching this limit. Due to considerable operating problems in the pilot plant, the reliability of a commercial plant can be best described as uncertain at this time.

2.11 TECHNOLOGY STATUS AND DEVELOPMENT POTENTIAL

The process has been demonstrated at the pilot plant level. Process flow diagrams, heat and material balances, and piping and instrumentation diagrams are being prepared for two different cases. IGT is ready to commence the demonstration phase. The process has considerable potential assuming that technical problems relating to the operation of the fluid bed reactor can be resolved.

2.12 REGIONAL FACTORS INFLUENCING ECONOMICS

2.12.1 Resource Constraints

The ability of the plant to use a wide range of coal feedstocks gives it some protection from supply interruptions or price increases from any given supplier. This also allows more freedom in the initial siting of the plant to take advantage of attractive coal prices which may be geographically specific.

The use of water recycling in the plant gives added flexibility to locate the plant in areas of minimal water resources or regulated water supplies. Extensive water recycling is associated with higher capital costs but results in more favorable operating costs due to the savings in purchased water.

2.12.2 Environmental Control Constraints

Gaseous, aqueous and solid effluents generated by the plant are described in Sections 2.6, 2.7, and 2.8 respectively. Regional regulations governing the specific types and quantities of pollutants produced would be determined on technical grounds by local meteorology, topography and existing air quality. The conditions imposed upon the plant can have a severe impact on capital and/or operating costs in each of the three pollutant areas, depending on the severity of the regulations. The exact impact can only be determined for a particular plant site; accurate prediction of the worst possible case is impossible at this time due to the lack of current guidelines for coal gasification plants. Owing to the competitive nature of the natural gas market however, it is easy to envision a case in which fairly restrictive regulations could make a plant venture uneconomic.

2.12.3 Siting Constraints

As indicated above, site selection may be a critical factor in project economics relative to constraints imposed by resource availability and environmental regulations. However, it can be anticipated that sites which are desirable in these respects may also be higher in cost, either for the initial purchase or for taxation rates, thus offsetting to some degree the advantages mentioned above.

References

2-1. Hartman, H.R., et al. Low-Btu Coal Gasification Processes, Vol. 2, Selected Process Descriptions, Oak Ridge National Laboratory, November 1978.

2-2. Coal Gasification Pilot Plant Support Studies, Quarterly Report for July 1 - September 30, 1979, FE-2806-6, Institute of Gas Technology, Chicago, Illinois, U.S. DOE, May 1980.

2-3. Bair, W.G. The Data Base for the HYGAS Process Commercial/ Demonstration Plant Design, Institute of Gas Technology, Chicago, Illinois, Presented at the Fifth Annual International Conference on Coal Gasification, Liquefaction, and Conversion to Electricity, University of Pittsburgh, August 1-3, 1978.

CHAPTER THREE: ECONOMIC ANALYSIS

This section contains data on the capital and operating costs, excluding fuel, of the HYGAS process. In Section 3.1, the methodology employed is explained. Section 3.2 details capital costs for a commercial scale HYGAS plant. Section 3.3 discusses operating and maintenance costs. In Section 3.4, the effect of experience on capital costs is assessed. Section 3.5 contains a computation of gas costs, excluding fuel.

3.1 Introduction and Methodology

3.1.1 Economic Analysis Methodology

The economic analysis relied on an order-of-magnitude estimate for the capital and operating costs of a HYGAS plant utilizing steam-oxygen technology and gasifying Western coal (3-1). The material presented in this estimate was adjusted to account for inflation since the original reference was written. After adjustment of the costs of individual components, capital and operating costs (excluding coal) of a HYGAS plant in third quarter 1980 dollars were computed. The cost of the gas was then determined.

3.1.2 Scaling Factors

The capacity of the commercial plant described in (3-1) was 250 billion Btu per day. Because this size was judged to be typical for a commercial size gasification plant, no scaling was necessary.

3.1.3 Price Indices

Costs presented in Reference 3-1 were expressed in 1976 dollars. These were corrected to 1980, third-quarter dollars using the methodology presented in the background.

3.1.4 Economic Criteria

In addition to correcting equipment costs to 1980 dollars, it was necessary to correct the accounts of working capital, start-up costs, and interest during construction. The following methodology was used:

- o Interest During Construction: Average borrowing period times 15 percent interest times total plant investment. The average borrowing period was 1.75 years. Source of borrowing period: (3-1)
- o Start-Up Costs: 6 percent of total plant investment.
- o Working Capital: 6.1 percent of total plant investment.

Zero escalation during construction was assumed. Plant life is 20 years. The capacity factor is 90 percent.

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 percent process contingency applied to each area is shown in Table 3-1. Gasification, at the pilot plant stage, receives a 25 percent contingency. Sulfur recovery and acid gas removal, 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

Total plant investment by area and unit is shown in Table 3-2. This table also breaks down costs as a percentage of the total plant investment. The gasification section represents a relatively small portion of capital investment (8 percent including contingencies and fees). As a result, if costs for the gasification process were to double, the $1,245.5 million total plant investment would increase by only 5 percent. Area 2000, Utilities and Support Systems, which would cost $304.8 million, accounts for the largest portion of any of the plant areas, 24.5 percent of total plant investment. Acid gas removal and gas cleaning, at $150 million, is also a costly area.

The total capital requirement for the project would be $1,738.3 million, as is shown in Table 3-3. Aside from

TABLE 3-1

PROCESS CONTINGENCY BY PLANT AREA

NUMBER	ITEM	CONTINGENCY (PERCENT)
100	Coal storage and handling	0
200	Coal preparation	0
300	Gasification and power recovery	25
1200	Raw gas cooling	0
1300	Acid gas removal and gas cleaning	10
1400	Sulfur recovery and tail gas treating	10
1700	Shift conversion	0
1800	Methanation	0
1900	Air separation	0
2000	Utilities and support systems	0
2010	Offsites and miscellaneous	0

TABLE 3-2

TOTAL PLANT INVESTMENT[a]

AREA	UNIT	ITEM	COST[b] (10^6 $)	PERCENT OF TOTAL PLANT INVESTMENT
100		Coal Storage and Handling	18	1.4
200		Coal Preparation	59.6	4.8
300		Gasification and Power Recovery	62.4	5.0
1200		Raw Gas Cooling	26.3	2.1
1300		Acid Gas Removal and Gas Cleaning	150	12.0
1400		Sulfur Recovery and Tail Gas Treating	83.2	6.7
1700		Shift Conversion	43	3.5
1800		Methanation	41.3	3.3
1900		Air Separation	62.4	5.0
2000		Utilities and Support Systems		
	2010	Steam Generation and Power Recovery	188.5	15.1
	2020	Wastewater Treating and Water Supply	104.0	8.4
	2030	Solids Disposal	12.3	1.0
2100		Offsites and Miscellaneous	94.2	7.6
		Contractor's Fees	104.4	8.4
		Subtotal	1,049.6	84.3
		Project Contingency	157	12.6
		Process Contingency	38.9	3.1
		Total Plant Investment	1,245.5	100

[a]Source: (3-1), updated by ERCO.
[b]Third quarter 1980 dollars.

TABLE 3-3

TOTAL CAPITAL REQUIREMENT[a]

ITEM	COST (10^6 \$)[b]	PERCENT OF TOTAL PLANT INVESTMENT
Total Plant Investment	1,245.5	71.7
Escalation During Construction	0	0
Interest During Construction	327	18.8
Initial Charge of Catalysts and Chemicals	12.9	0.7
Royalties/Intangible Assets/Land and Land Rights	2.2	0.1
Starting Costs	76.0	4.4
Working Capital	74.7	4.3
Total Capital Requirement	1,738.3	100

[a]Source: (3-1).
[b]Third quarter 1980 dollars.

total plant investment, interest during construction is the largest component of the capital requirement, $327 million, or 18.8 percent. Miscellaneous charges include the initial charge of catalysts and chemicals, royalties, starting costs, and working capital. These total $165.8 million.

3.2.2 Capital Cost Uncertainties

The estimate presented above is highly variable. Within Reference 3-1, it is described as an "order-of-magnitude" estimate, which would place these capital costs within ± 30 percent. There is reason to suspect, however, that the cost estimates are off more than 30 percent. For example the Great Plains Gasification Project in Mercer County, North Dakota, is currently estimated to cost $2.4 billion (3-2), versus $1.7 billion for the HYGAS plant. This project, employing Lurgi technology, will produce 137 billion Btu/day, about 55 percent of the capacity of the HYGAS plant discussed here. Thus, for a smaller plant, costs are about 40 percent higher. The direct comparison is somewhat misleading, because the Great Plains project costs include escalation during construction and mine development. Even allowing for escalation and more development, the $1.7 billion HYGAS estimate is still 50 percent lower than the projected costs of the Great Plains project. It is possible that a commercialized HYGAS system might be less expensive than a comparable Lurgi system, but at this time Lurgi technology is more developed.

3.3 Operating and Maintenance Costs

3.3.1 Itemized Operating and Maintenance Costs

Annual, non-fuel, operating and maintenance costs are shown in Table 3-4. These costs assume a 90 percent operating factor. Labor, local taxes, and insurance are the most important elements of operating and maintenance costs. Gross yearly operating and maintenance costs are $102.2 million.

The HYGAS process produces by-product sulfur, ammonia, and light oil. As Table 3-4 also shows, these credits, at a 90 percent capacity factor, are valued at $56.3 million.

Combining the gross O&M costs and the by-product credits yields a net O&M cost of $45.3 million/year.

3.3.2 Variability of Operating and Maintenance Costs

Operating costs depend on the type and size of the equipment operated. Maintenance costs are computed as a fraction of capital costs. Direct operating costs (process labor, operating supplies, catalysts, chemicals, and purchased water), 11 percent of the total, are probably not highly variable because they are process-dependent. Other costs, 89 percent of the total, are calculated at least in part from the plant investment costs and therefore are also underestimated by the same magnitude as the capital cost estimate. Thus, 89 percent of operating and maintenance costs will increase by about the same proportion as any increase in capital cost.

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TABLE 3-4

NET ANNUAL OPERATING AND MAINTENANCE COSTS--
90 PERCENT CAPACITY FACTOR[a]

ITEM	ANNUAL COST (10^6 $)	PERCENT OF TOTAL
Administration and General Overhead	18.1	17.8
Local Taxes and Insurance	32.6	31.9
Labor		
Process Operation	3.9	3.9
Maintenance	21.2	20.7
Supervision	5.1	5.0
Total	30.2	29.6
Supplies		
Operating	1.2	1.2
Maintenance	14.1	13.8
Total	15.3	15.0
Catalysts and chemicals		
Catalysts	2.8	2.8
Chemicals	2.7	2.6
Total	5.5	5.4
Purchased Water	0.5	0.5
Total	102.2	100.0
	(10^6 $)	
By-Product Credits		
Sulfur	(1.2)	
Ammonia	(4.1)	
Light Oil	(51.6)	
Total	(56.9)	
	(10^6 $)	
Net O&M Costs		
Gross O&M Costs	102.2	
By-Product Credits	(56.9)	
Net O&M Costs	45.3	

[a]Source: (3-1).

[b]Third quarter 1980 dollars.

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Because by-product production is process-dependent, the amount of by-products (assuming a 90% capacity factor) is not variable. On a value basis, 92 percent of the by-product credit is earned by light oil production. The price of light oil is likely to increase as the cost of fuels increases. Sulfur and ammonia prices have risen little in recent years, so that credits for these by-products are not likely to increase much in the future.

3.4 Effect of Experience on Costs

As the number of HYGAS plants in service increases, capital costs will decline due to the effects of experience.

The 10 percent maximum experience factor discussed in the Background is valid only for the novel section of the plant costs. Most components of a Hygas plant would employ mature technologies whose costs would decline little as more Hygas plants are built. Taking mature components into account results in an experience factor for the HYGAS steam-oxygen process of about 2 percent (3-3). In constant dollars, the second HYGAS commercial plant could be expected to cost 2 percent less than the first, and the fourth 4 percent less than the first.

3.5 Non-Fuel 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 according to the formula given in the Background, the total capital requirement of \$1,738.3 million from Table 3-3, and the net O&M costs of \$45.3 million from Table 3-4.

The formula yields a non-fuel gas price of:

$$P = \frac{(\$1738.3 \times 10^6 \times 20\%) + \$45.3 \times 10^6}{91.25 \times 10^{12} \text{Btu} \times 90\% \text{ capacity}}$$

$$P = \$4.23/10^6 \text{ Btu} + \$.55/10^6 \text{ Btu}$$

$$P = \$4.78/10^6 \text{ Btu}$$

(non-fuel product costs)

Based on the assumptions made in this report, a gas cost of $\$4.78/10^6$ Btu for a 1980 plant, excluding the cost of coal, is projected. The non-fuel gas cost can be combined with a coal cost to yield a total product cost. Overall efficiency of the HYGAS process is 62.5 percent. With coal at $\$1.50/10^6$ Btu, the coal cost would be $\$2.40/10^6$ Btu. Combining the coal cost with the non-fuel cost of $\$4.78/10^6$ Btu yields a total product cost of $\$7.18/10^6$ Btu.

References

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3-3 Hederman, W.F. (Rand Corporation) "Prospects for the Commercialization of High-Btu Coal Gasification," United States Department of Energy, R-2294-DOE, April 1978, pp. 48-50.