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TECHNOLOGY ASSESSMENT GUIDE
NO. 3
LURGI MEDIUM-BTU GASIFICATION

CHAPTER ONE: EXECUTIVE SUMMARY

1.1 OVERALL PROSPECTS FOR THE TECHNOLOGY

The Lurgi oxygen blown gasification system described in this assessment produces a medium-Btu fuel gas suitable for use as an industrial fuel, a feedstock for chemical synthesis (including upgrading by methanation to pipeline quality gas), and as a fuel for combined cycle power generation. The mature state of the Lurgi technology is a great advantage for its inclusion in systems of this nature, despite its inherently lower thermal efficiency. It has already been selected as the basis for the ANG high-Btu coal gasification facility in North Dakota (see TAG 5), and is planned for use in Sasol III, the South African indirect coal liquefaction facility. Numerous other facilities worldwide attest to the popularity of this system. This should continue for the near term until more efficient advanced generation gasifiers (including the slagging version of the Lurgi) gain enough operating experience to gain widespread commercial acceptance.

1.2 ENGINEERING ASPECTS

The dry-ash Lurgi gasifiers represent first generation coal gasification technology. The fact that this gasifier is designed to produce ash in a dry, non-slagged form is responsible for its rather poor thermal efficiency (cold gas gasifier efficiency 68%) in comparison to other gasification systems.

The reason for the low efficiency lies in the use of large quantities of live steam to control bed temperatures below the ash softening point of the coal being used. Most of the enthalpy in the steam which is used for this purpose is never recovered in useful form. The requirement to maintain bed temperatures below the ash softening point is critical to proper operation of the gasifier, and must be adequately monitored to prevent temperature excursions. Production of ash wastes in a non-slagged form also increases the chance of leaching harmful materials into groundwaters.

Operation of the gasifier at low temperatures (to prevent slagging), favors methane production, especially at the elevated pressures used in this design. However, since reaction rate is highly dependent on temperature, gasifier throughput is considerably lower than comparably sized gasifiers operating at higher temperatures.

Because of its countercurrent flow arrangement, with coal coming in at the top of the gasifier and reactant and product gases rising upward, there is a minimum size for feed coal. Below this minimum size (approximately 1/4") coal particles are entrained out of the gasifier before reacting. Therefore, fines cannot be fed together with the sized coal feed in the top of the gasifier. As much as 10 percent of total coal feed rate can be in the form of fines if they are fed with steam through tuyeres in the bottom of the reactor. This poses a problem when feeding many coals, since fines are generated in the crushing process, often in excess of 10 percent. In addition lignitic coals have a tendency to decrepitate, or produce fines, during drying. Some sources also feel that lignite has an increased propensity to generate fines when crushing, although this has not been established by a laboratory evaluation. Coal fines which cannot be handled by the

Lurgi gasifiers will be sold for use in a pulverized coal power plant. Alternatively, had the process design called for the use of an entrained flow gasifier in addition to the Lurgi units, all of the coal fed to the gasification plant could have been used without the need for export sales.

The countercurrent flow arrangement is also responsible for the considerable production of tars, oils, phenols, naphthas, and other unreacted hydrocarbons. As coal enters the top of the reactor, hot gases begin to warm it to reaction temperature. The coal passes through several temperature stages, most notably devolatilization, prior to gasification and combustion further down in the bed.

In the devolatilization zone, the coal loses its volatile components to the vapor phase, most of which are carried out of the gasifier with the raw gas before having a chance to react. Once cooled downstream, these volatile components condense, thereby coating the surfaces of heat exchangers and other process equipment. A water treatment problem is also created since considerable quantities of water also condense with these volatile materials. Biological wastewater treating is generally an effective method for handling these contaminated water streams. It is possible that variations in feedstock and process conditions may produce a range of wastewater concentrations which will be too great for the chosen organism to deal with. Blending may be used to achieve some degree of consistency, but it is possible that different organisms may have to be used from time to time. Although this is not a major concern, it is one of the few uncertainties associated with the process.

Downstream of the gasifier the gas is cooled against steam generation, which is then used for power recovery. The cooled gas is scrubbed for removal of H_2S, and is then ready for sale following expansion. Removal of CO_2 could be carried out in the acid gas removal portion, depending on the end use of the gas. This would most likely be done if the gas were to be used as a chemical feedstock or were to be transmitted moderate distances via pipeline, but not required for nearby boiler fuel applications or combined cycle power generation.

The present design calls for the use of advanced generation rotating equipment in the air separation plant to achieve higher efficiencies in the gas compression step. Although the use of this equipment is somewhat experimental, conventional equipment is fully available which is highly reliable. Therefore, for the purposes of this assessment, the gas compression operation will be considered fully reliable. All other equipment used in the plant have been completely characterized by years of operating experience and also have high reliabilities.

1.3 CURRENT COSTS

The total capital requirement for this 50×10^{12} Btu/year plant is $911.3 million, which is dominated by a plant investment of $625 million. Interest during construction is a major expense ($206 million), with the remainder composed of working and start-up capital, royalties and catalysts and chemicals.

Annual operating and maintenance costs (at a 90% plant capacity factor), exclusive of coal costs total $46 million and are largely composed of taxes and insurance, and labor.

Sulfur and ammonia are given by-product credits totaling \$7.5 million per year for a net annual O&M cost of \$39 million. Taken together with a 20 percent capital charge, these operating costs result in a product cost of \$4.91/10^6 Btu, which is exclusive of coal costs. At \$1.50/10^6 Btu coal cost, total product costs are estimated at \$7.07/10^6 Btu.

1.4 RESEARCH AND DEVELOPMENT DIRECTIONS

The Lurgi gasification technology and other process subsystems used in the plant are well characterized through years of practical industrial experience. One exception already mentioned is the rotating equipment used for air compression in the air separation plant. In addition to this, the choice of biological culture used in the waste-water treatment facility is subject to change depending on site, resource and time variables.

Research on gasifier improvement for the Lurgi system is taking place in the form of slagging rather than dry-ash gasification (see TAG 6c). This approach differs significantly from dry-ash gasification even though both systems are fixed-bed designs. Most observers consider the slagging Lurgi gasifier as an entirely separate, second generation system.

2.1 GENERAL DESCRIPTION OF THE TECHNOLOGY

The Lurgi gasifier is an oxygen-blown, moving bed gasifier used to produce a medium- (300 Btu/scf HHV) Btu fuel gas and hydrocarbon liquids. In addition, for the plant configuration investigated, a net excess of electric power is produced by utilizing waste heat.

Coal for the process is recovered from storage in the 1/4 to 1-1/2 inch size range and conveyed to the coal-hopper where it is fed by gravity to a depressurized coal lock. Once the lock is pressurized, it is discharged into the reactor.

The coal charged to the reactor encounters a slowly moving bed with several distinct reaction zones. In the top-most zone coal is preheated and dried by the crude gas leaving the reactor. Further down, the coal is devolatilized and gasification begins. At the bottom of the load, carbon reacts with oxygen exothermally, producing the energy for gasification. Only a neglible amount of unburned carbon remains in the ash which is discharged in dry form at the bottom of the gasifier. Oxygen and steam at 340 psig and approximately 400°F enter at the bottom of the gasifier and are heated as they rise to the combustion zone.

The crude gas leaving the gasifier contains significant quantities of tars, oils, naphthas, phenols, ammonia, hydrogen sulfide, and a small amount of unreacted coal, char, and ash dust. The gas is washed and quenched to remove the high boiling tar fractions. Solids are removed with the condensed tar. Process condensate containing dusty tar liquors is treated to separate the ammonia from the hydrocarbon liquids. The acid gas from this treatment process is sent to sulfur recovery.

Acid gas is removed from the raw gas and transmitted to a Claus sulfur plant where elemental sulfur is removed. Tail gas from the Claus unit is further treated using the Beavon-Stretford process to remove the remaining sulfur. The intermediate-Btu product gas is expanded to recover power in cases where the user is nearby. If the product must be transmitted (up to approximately 100 miles), compression rather than expansion may be called for. Long transmission distances such as those used for natural gas cannot be justified due to the lower energy content of medium-Btu gas.

2.2 PROCESS FLOW, ENERGY, AND MATERIAL BALANCES

Plant area numbers designating the various units which are integral to the Lurgi oxidant-blown moving-bed gasifier are listed in Table 2-1. The interaction of these units is depicted by the conceptualized process flow diagram, Figure 2-1. A detailed analysis of the process streams is given in Table 2-2. An overall plant energy and material balance is given in Table 2-3.

2.3 PLANT SITING AND SIZING ISSUES AND CONSTRAINTS

The dry-ash Lurgi plant is sized to produce approximately 117 x 10^9 Btu/day of medium-Btu fuel gas. Other products, primarily naphthas and tars, contribute an additional 30 x10^9 Btu/day. Because of the low energy content of the product gas (relative to natural gas) users of the product would have to be located within a radius of approximately 100 miles, to make the transportation of the gas economically attractive. The plant might be located as an integral part of an energy park, or simply in an industrialized area. Users for the other products would also have to be located nearby, since none are high value

Table 2-1

Relevant Plant Area Numbers for Lurgi

100	COAL STORAGE AND HANDLING	
		110 Coal Storage
		120 Coal Handling
200	COAL PREPARATION	
		210 Coal Crushing
		240 Drying
		250 Size Classification
300	GASIFICATION	
		310 Gasification
		320 Ash Quench and Handling
1200	RAW GAS COOLING	
		1220 Gas Quenching and Cooling
1300	ACID GAS REMOVAL	
		1310 H_2S Removal
1400	SULFUR RECOVERY AND TAIL GAS TREATING	
		1410 Sulfur Recovery
		1420 Tail Gas Treating
1600	GAS EXPANSION	
1900	AIR SEPARATION	
2000	UTILITIES AND SUPPORT SYSTEMS	
		2010 Power Recovery and Steam Generation
		2020 Wastewater Treating and Water Supply
2100	OFFSITES AND MISCELLANEOUS	

Figure 2-1

Lurgi Oxygen Blown Conceptualized Process Flow Diagram

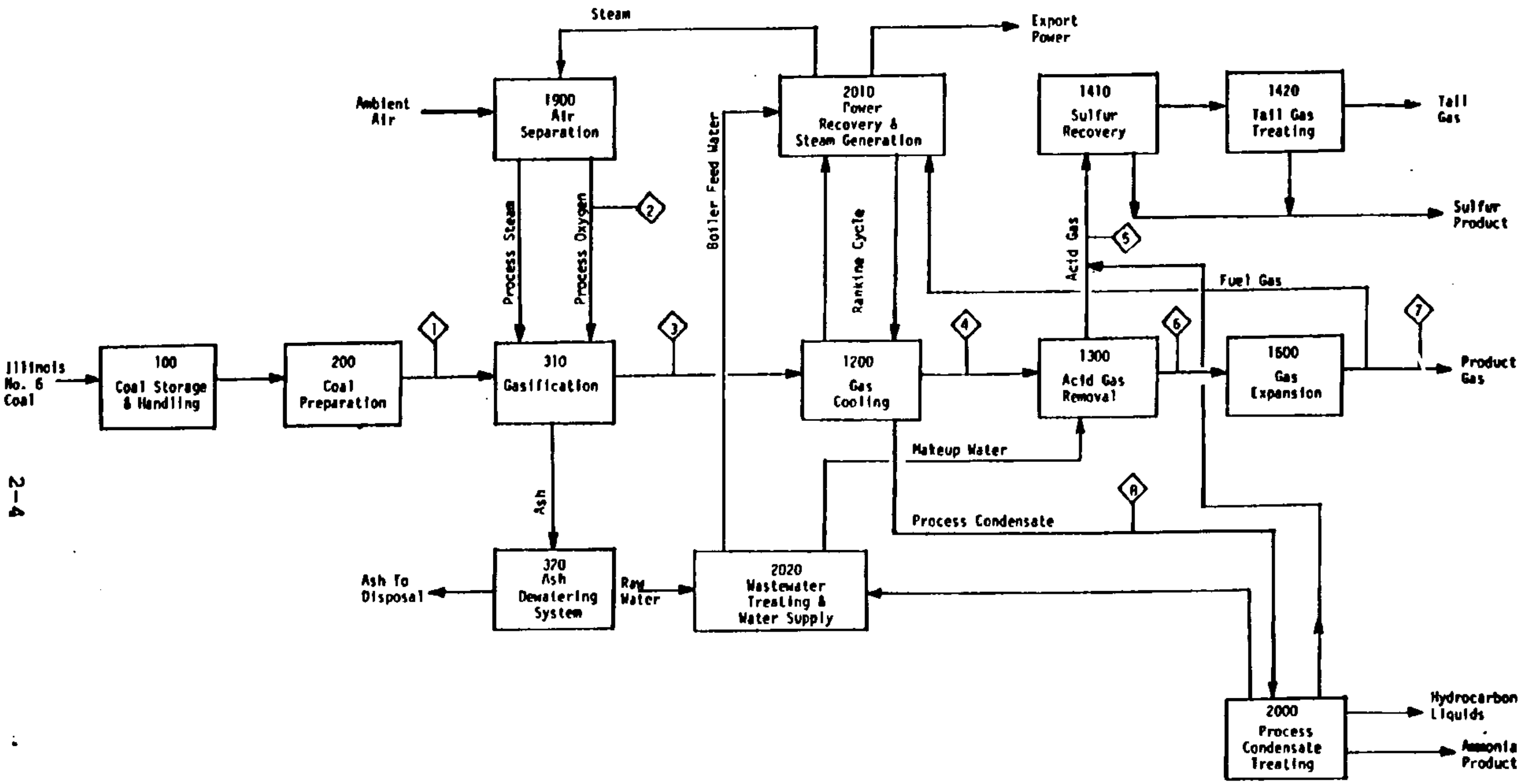

Table 2-2

Lurgi Detailed Process Streams

Stream No.	1		2		3		4		5		6		7		8	
Description	Coal Feed		Process Oxygen		Gasifier Effluent		Washed & Cooled Gas		Acid Gas		Sweet Gas		Net Product Gas		Process Condensate	
Temperature (°F)			321		380		100		120		103		102			
Pressure (psig)			340		302		242		7		237		25			
Component	MPH	MOL%	MPH	MOL%	MPH	MOL%	MPH	MOL%	MPH	MOL%	MPH	MOL%	MPH	MOL%	MPH	MOL%
CH_4					1444.4	3.30	1444.4	8.69	6.0	.59	1422.7	9.29	979.0	9.18		
C_2H_4					42.9	.10	42.9	.26	2.9	.28	37.5	.24	27.2	.25		
C_2H_6					65.6	.15	65.6	.39	1.5	.15	62.8	.41	43.6	.41		
H_2					7057.7	16.13	7057.7	42.46	1.6	.16	7033.1	45.9	4802.3	45.03		
CO					2528.0	5.78	2528.0	15.21	2.5	.25	2505.5	16.35	1718.8	16.12		
CO_2					5155.8	11.78	5155.8	31.02	736.6	73.05	4145.5	27.06	2918.3	28.20		
H_2S					198.6	.45	198.6	1.19	177.8	17.64	10.9	.07	14.1	.13		
COS					8.7	.02	8.7	.05	1.9	.20	6.2	.04	4.5	.04		
NH_3					135.3	.31									135.3	.50
N_2			55.1	2	62.0	.14	62.0	.37			62.0	.41	42.4	.40		
O_2			2715.0	98												
H_2O					27065.5	61.84	59.9	.36	77.3	7.68	35.2	.23	26.4	.24	27005.6	99.50
Total MPH			2770.1	100	43764.1	100.00	16623.1	100.00	1008.2	100.00	15321.4	100.00	10665.3	100.00	27140.9	100.00
T,O,P,N and Others (lb/hr)					8052										8052	
Total (lb/hr)	744,800		88,427		845,289		347,930		40,251		295,749		210,548		497,359	

Table 2-3

Dry-Ash Lurgi Energy Balance Based On Illinois No. 6 Coal Feed

Input	Mass Flow Rate, TPD		Btu Content MM Btu/Day
Coal (12,235 Btu/lb HHV)	8938		218,690
Output			
Product Gas	2527		117,410
Naphthas and Tars	621		19,560
Sulfur	276		2,230
Ammonia	110		2,140
Electricity	-		5,020
		Total	146,360

Note: Values are for 100% plant capacity.

Overall Process Efficiency $= \frac{146,360}{218,690} = 66.9\%$

commodities. A fair number of such site locations exist within the United States for a plant of this size. A tripling or quadrupling of plant size could limit the number of suitable sites to less than a dozen; however, this is dependent upon the number of users which are equipped to use the medium-Btu fuel gas. Retrofitting and new construction will increase the number of available sites. The resources of the area in which the plant is sited must be capable of supplying in excess of 3 million tons of coal per year, unless this quantity of coal is transported long distance by rail or barge.

2.4 RAW MATERIAL AND SUPPORT SYSTEM REQUIREMENTS

2.4.1 Coal Quantities and Quality

For the plant envisioned in this report, coal would be a medium volatile bituminous coal, specifically Illinois No. 6. Proximate and ultimate analyses of Illinois No. 6 are given in Table 2-4. Raw coal will be run-of-mine, but will be washed and sized 1-1/2 to 1/4 inch, prior to gasification. Fines cannot be used and are sold. Approximately 3.3 million tons of coal per year will be required to meet the 50 x 10^{12} Btu/year fuel output.

2.4.2 Catalysts and Other Required Materials

Catalysts and chemicals required for the Lurgi unit are primarily consumed in the demineralizer, cooling tower and boiler feedwater treating. Makeup is due to solution losses in the acid gas removal and tail gas treating units and replacement of catalyst in the sulfur recovery unit. The Lurgi moving-bed gasifier itself needs no chemicals or catalysts.

Table 2-4

Illinois #6 Coal Analysis

Proximate Analysis	
Moisture	4.2 wt. %
Ash	9.6
Fixed Carbon	52.0
Volatile Matter	34.2
	100.0
Ultimate Analysis - MAF* Coal	
Carbon	77.26 wt. %
Hydrogen	5.92
Oxygen	11.14
Nitrogen	1.39
Sulfur	4.29
	100.00
Heating Value - As Received	
Higher Heating Value (HHV)	12,235 Btu/lb
Net Heating Value (LHV)	11,709 Btu/lb

*Moisture and Ash Free

2.4.3 Water Requirements

The plant will use about 3.9 million gallons per day of raw water. The water will be demineralized prior to use. In addition, all water used for steam will be deaerated before steam generation.

2.5 EFFECT OF COAL TYPE

The fixed-bed non-slagging Lurgi gasification reactor is the only component in the medium-Btu gas plant which places requirements on coal type, and is the most affected by coal variability. As in most other fixed-bed reactors, caking or swelling coals cannot be gasified without pretreatment or the use of a mechanical stirring device within the bed. Gasification temperatures are kept low to prevent slagging, but this also results in low gas production per unit reactor volume. Highly reactive coals or coals with catalytic mineral matter may therefore show some advantages in reactor throughput.

Coals high in volatile matter and moisture content will produce larger quantities of tars and oils, which will affect the performance of downstream heat exchange equipment and the design of the wastewater treatment system. The design of the acid gas treatment system will depend strongly on the concentration of H_2S and CO_2 in the sour gas; H_2S concentration is determined primarily by coal sulfur content.

Coals high in ash and moisture or those with low heating values will reduce the thermal output of the system. Larger coal throughputs will be required to meet the desired plant energy output.

2.6 AIR POLLUTION CONTROL TECHNOLOGY

2.6.1 Ability of Existing Technology to Meet Regulations

No unusual emissions are expected from the Lurgi medium-Btu gasification process; conventional technology for particulate removal and sulfur removal has been proven in similar systems for many years in a variety of applications.

Particulate emissions may be controlled by electrostatic precipitators, baghouses or cyclones, depending on the temperature and volumetric flow rate of the gas stream carrying the particulate. Fugitive particulates from coal storage and handling activities may be controlled by the same techniques or by simply providing adequate covered storage for the plant areas. Other possible particulate sources include reactor offgas, ash cooling and disposal, cooling tower operation and acid gas absorber offgas (product gas).

Any of the amine-based or aqueous carbonate based acid gas removal systems would adequately remove H_2S or H_2S and CO_2 from the raw gas to produce an environmentally acceptable gaseous fuel. The Claus technology for converting H_2S into elemental sulfur has been known for over 100 years, and is supported by a broad base of commercial experience. Purification of Claus tail gases is also well understood and would present no difficulties for the designer of a commercial scale plant.

2.6.2 Air Pollution Control Technology Impacts on Process Efficiency

Unlike some synthetic fuels plants which contain sulfur-sensitive catalysts, the sulfur removal units incorporated in this conceptual design have been included only for environmental control. These systems are integral to plant design and operation, and although they are a major contributor to capital cost, they are not a highly significant consumer of energy as compared to total plant energy production. No estimates are available for efficiency loss due to operation of the systems.

2.7 WATER POLLUTION CONTROL TECHNOLOGY

In all likelihood, the design of a commercial industrial fuel or synthesis gas plant based on this technology would incorporate the concept of zero liquid discharge, to meet the stipulations in P.L. 92-500. Under these conditions, no surface discharge would occur. Deep well disposal could be used for water treatment effluent and boiler blowdown from the plant. Other waters leaving the plant will include any water contained in the ashes and sludges (which could be dispersed at the mine site) and water evaporation from cooling towers. The use of the cooling tower as a means of disposal of the impaired quality water in the gasification plant might help to meet the "zero effluent discharge" goal, but the impact on the environment resulting from the air pollutants in the evaporated water must be studied.

Treatment of wastewater from the phenol recovery plant ("Phenosolvan" unit) may be satisfactorily achieved by biological techniques, but future designs will probably use Phenosolvan effluent as cooling tower make-up if this practice does not result in unacceptable environmental impact and equipment deterioration.

Design and operating characteristics of the plant water treatment system will depend very specifically on coal characteristics and gasifier operating conditions. In all likelihood the operation of such a treatment system will be quite reliable and will meet plant water-reuse objectives.

2.7.2 Water Recycling Systems

The recycling of process water can be an effective method for the control of aqueous phase contaminants as well as being an efficient use of natural resources. In order to meet a design objective of zero liquid discharge to adjacent surface water, the water required for the operation of the plant complexes would have to be treated and recycled within the plant boundaries to the maximum extent possible. The major portion of the aqueous effluent discharged from each plant area would be evaporated. Cooling tower evaporation could account for about one-tenth of this value. In addition to evaporative water discharge, liquid will accompany the solids and sludges as well as sediment from evaporation ponds, all of which are returned to the mine for burial. The bulk of the solids (primarily ash) returned to the mine for burial will contain about 18 percent water by weight, but the water content of the sludges returned for burial cannot be estimated with reasonable accuracy from the data available.

Besides the aqueous liquid discharges there will be other fluid by-products recovered during synthesis gas production. None of these materials will be disposed of by direct discharge to the environment.

2.7.3 Impacts on Plant Efficiency

Water recycling and treatment systems are necessary for the conservation of natural resources and protection of the environment from emission of hazardous materials. Primary energy users in these process operations are pumps and reaction vessels (requiring low levels of process heat). Extensive reliance on water recycling in the dry-ash Lurgi facility may result in a total impact on process efficiency of approximately 2 percent.

2.8 SOLID WASTE HANDLING

2.8.1 Disposal Requirements

Most of the solid wastes generated by a gasification complex are derived from the coal feedstock that is used. The waste quantity is directly related to the ash content of the coal. In addition, there are solids derived from raw water treatment and solids derived from the use of chemicals used in various processing steps. Ash is discharged from the Lurgi gasifiers and from boilers used for the production of steam and power. Also, fly ash is recovered from particulate removal systems used on the stack gases from combustion equipment. Where stack gas scrubbing is employed on flue gases, calcium salts of sulfur compounds are produced. These solid wastes, particularly gasifier ash and boiler ash, are often handled in hydraulic sluiceways and delivered to a loading point where they are dewatered and hauled to the mine for burial. They are handled wet to minimize dust evolution; even after dewatering, the material generally contains 20 to 30 percent water. The sludges obtained from raw water treatment and the calcium salts from stack gas scrubbing can be handled in much the same manner and are mixed with the ash.

The primary method of solid waste disposal is by mine burial, usually at depths of 50 to 100 feet or more below the surface of the reclaimed mine land area. As mine burial takes place, the wastes will be hydrologically isolated as much as possible from the adjacent groundwater system. In this way the possible leaching of compounds from the buried wastes by percolating surface water will have a minimal effect on the quality of the adjacent groundwater systems.

The preceding discussion of solid waste control and disposal has not included dust evolution from coal preparation, handling, and storage facilities. These problems are generally handled by one or more of the following:

1. The use of water sprays which may include a wetting agent.

2. The compaction of large long-term storage piles in approximately one-foot lifts possibly including a spray which induces crust formation.

3. The use of covered conveyors with adequate ventilation and the passing of discharged air through bag filters and similar arrangement where the coal is charged to the operating bunkers.

4. Adequate ventilation and baghouse collection of particulate where dry coal crushing and screening operations are being conducted.

The collected particulate is disposed of by mine burial.

2.8.2 Leaching Problems

The leaching of metal ions and other hazardous materials from unslagged gasifier ash and gasification plant sludges has been demonstrated in laboratory simulations. The extent of leaching in an actual burial situation will depend on many factors; among the most important are water pH, and the physical structure and chemical nature of the ash.

Solid wastes and sludges are, at this time, unregulated by government agencies. There is, however, significant research being conducted to establish the probable impact of solid waste disposal and to establish techniques to minimize the potential impact. Present permitting requirements force examination of and approval of the mining, solid waste disposal, and reclamation plans for each facility. The potential for disposing of some of the plant's waste water in the sludges in the mined area is high. This practice, if implemented, will probably precipitate controls on sludge disposal. Existing waste water treatment technology could probably treat sludge additive liquids to environmentally acceptable limits prior to disposal. Hydrologic isolation techniques either exist or can probably be developed should an impact be found due to leaching or sludge liquid drainage, but technology for post-disposal treatment does not exist.

2.9 OCCUPATIONAL SAFETY

Coal handling and preparation will expose workers to coal dust, noise, and risk of fire. Coal storage areas must be wetted to reduce both dust and the risk of fire. Workers' hearing must be protected from the noise of coal crushing and screening operations.

The high pressure of the gasifier and the liquid by-products of Lurgi gasification also present risks to workers. The high pressure of the gasifier increases the possibility of gas leaks, which will expose workers to hot gases containing asphyxiants and carcinogens. The Lurgi system by-products, including tar, tar-oil, phenols, naphtha and ammonia, are all toxic. Tar, phenols, tar-oil and naphtha contain carcinogens and can cause skin irritation on contact with the worker. Contact could occur during cleaning, maintenance or through accidents.

2.10 PROCESS PERFORMANCE FACTORS

2.10.1 Product Characteristics and Marketability

There are two basic products derived from the Lurgi oxygen-blown gasification plant: medium-Btu gas and hydrocarbon liquids. Sulfur, ammonia and electricity are by-products. Each of these products and by-products have characteristics which will affect their marketability.

- SNG: Raw synthesis gas generated by the Lurgi unit is a medium-Btu (300 Btu/scf) product composed primarily of hydrogen, carbon dioxide and monoxide, and hydrocarbons. The relative amounts of the components are listed below.

Component	Mol %
H_2	45.03
CO_2	28.20
CO	16.12
CH_4, C_2H_4, C_2H_6	9.84
H_2S, COS	.17
N_2	.40
H_2O	.24

This synthesis gas could be used as boiler fuel or if methanated, as a source of residential fuel. A major potential use for the gas is as a feedstock for chemical synthesis.

- Hydrocarbon Liquids: The hydrocarbon liquid products include naphthas, tars, oils, phenols, and other minor components. The lighter liquids can be separated and upgraded for use as high quality fuels. Heavier hydrocarbons are valuable for use as boiler fuel. Phenols and other such compounds may be used for chemical synthesis. An ultimate analysis of the bulk liquids is given below.

Component	Mol %
Carbon	80.0
Hydrogen	6.6
Oxygen	10.6
Nitrogen	1.1
Sulfur	1.7

- Sulfur: The sulfur is suitable without furtner processing, for any industrial application requiring sulfur. However, it might be surmised that as coal gasification and liquefaction increases, the supply of sulfur will exceed demand, rendering the product marginally marketable.

- Ammonia: The ammonia product can be sold as a valuable fertilizer base, or as a feedstock for chemical synthesis activities.

2.10.2 Capacity Factors, Felixibility, and Reliability

The dry-ash Lurgi plant was designed to operate at a 90 percent capacity factor. Because of the extensive experience base with this gasifier, and the other components of the medium-Btu plant, achievement of this goal following the first year of start-up activities should not prove difficult.

The gasifier itself is capable of a 4:1 turndown ratio. The turndown ratios of other process units and the number of process trains would allow the plant to display this degree of throughput flexibility, although operation of the plant at very low throughputs would not be economically advisable for long periods of time.

The vast commercial experience logged for the Lurgi gasifier and all gasification plant components suggests that extremely reliable performance can be expected.

2.11 TECHNOLOGY STATUS AND DEVELOPMENT POTENTIAL

2.11.1 Current Status

The Lurgi dry-ash moving bed gasifier is a well developed technology with commercial scale applications starting in 1935 and continuing to the present day. The largest plant currently in operation is the Sasol I and II indirect liquefaction plants located in South Africa. A further Sasol expansion, Sasol III is now under construction, and is also based on this gasification technology.

The Great Plains Gasification Associates are in the final design stages for a large pipeline gas plant located in North Dakota. The plant will feed lignite to dry-ash Lurgi gasifiers.

No Lurgi gasifiers are in use in the United States to provide medium-Btu gas for industrial fuel or chemical synthesis. Many such plants are operating at various locations around the world, however.

2.11.2 Key Technical Uncertainties

The compression and expansion equipment used in the oxidant feed facilities for this study is an extension of the present state-of-the-art in rotating machinery. The gas expander is a radial in-flow design capable of high energy extraction per stage. Advanced generation expanders, such as this, are presently under fabrication and are expected to be operational in the near future. Conventional systems are available which are well known but operate at lower efficiencies.

Lurgi gasifier operation is well characterized.

2.11.3 Availability for Commercial Production

The Lurgi gasification system is fully available for commercial use.

2.12 REGIONAL FACTORS INFLUENCING ECONOMICS

2.12.1 Resource Constraints

The Lurgi plant envisioned in this study would require approximately 3 million tons of coal and 6 million tons of raw water per year throughout the operational lifespan of the plant.

2.12.2 Environmental Control Constraints

Since one important application of this system is for the production of industrial fuel gas or synthesis gas, locating the plant in these geographic areas may be difficult because of nonattainment.

2.12.3 Siting Constraints

Because the transportation of raw materials can readily escalate product coals, it is essential that the complex be located near the required coal and water resources.

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CHAPTER THREE: ECONOMIC ANALYSIS

This section contains data on the costs of the Lurgi oxygen-blown medium-Btu gasification system.

3.1 METHODOLOGY AND INTRODUCTION

3.1.1 Economic Analysis Methodology

The economic analysis relies on a conceptual design for a commercial-scale medium-Btu coal gasification plant using Lurgi technology (3-1). The economic information presented in the report was adjusted for inflation, contingencies were added, and the plant was scaled to a capacity of 50 trillion Btu per year.

3.1.2 Scaling Exponents

The reference plant had a capacity of 61.7 trillion Btu per year which was scaled to 50 trillion Btu per year. The scaling exponent used for each area is shown in Table 3-1. Scaling exponents were chosen on the basis of whether the plant design (3-1) called for a several-train design of the area or one or two trains. If several trains were used, a scaling exponent of 1.0 was applied, because scaling the plant would involve adding new modules with no scale economies. In the cases with one or two trains, additions to plant capacity would involve increasing equipment sizes. Within these trains, economies of scale would apply.

TABLE 3-1

SCALING EXPONENTS: LURGI SYSTEM

AREA		SCALING EXPONENT
200	Coal preparation	0.7
300	Gasification	1.0
1200	Raw gas cooling	1.0
1300	Acid gas removal	1.0
1900	Air separation	1.0
2000	Utilities and support systems	0.7

3.1.3 Price Indices

Costs for the reference plant were updated from 1976 dollars to third-quarter 1980 dollars using the indices and methods described in the Background section.

3.1.4 Economic Criteria

The standard economic criteria discussed in the Background section were used to estimate the total capital requirements and the plant product costs. The same basis used to estimate operating costs in the reference (3-1) was used here. The schedule of investments over the three-year construction period was 25 percent, 50 percent, 25 percent.

3.1.5 Contingencies

A project contingency of 15 percent was added to the subtotal of all area and unit costs. The project contingency is meant to cover costs which usually arise as plant design progresses from conceptual to final.

A process contingency of 10 percent of the cost of the Raw Gas Cooling Area is added to account for cost increases which may arise as attempts are made to improve this technology.

3.2 CAPITAL COSTS

3.2.1 Itemized Capital Costs

The total plant investment amounts to $625.1 million, as is shown in Table 3-2 of which a large portion is accounted for in utilities and offsites, in Area 2000 and equipment (such as steam generation and wastewater treating) in Area 2100. Areas 2000 and 2100 account for 46.8 percent of costs before contingencies and sales tax. Gasification would absorb $86.2 million, and raw gas cooling $71.2 million.

The Total Capital Requirement amounts to $911.3 million, as is shown in Table 3-2. Besides the Total Plant Investment of $625.1 million, Interest During Construction is an important cost, at $205.6 million. Start-up and Working Capital absorb $37.5 million and $38.1 million, respectively. Minor costs include Paid-up Royalties, at $31 million, and the Initial Charge of Catalysts and Chemicals, at $1.9 million.

3.2.2 Variability of the Capital Cost Estimate

The Lurgi gasification system has been used extensively in commercial applications, as have the other technologies

TABLE 3-2

TOTAL CAPITAL REQUIREMENT: LURGI SYSTEM[a]

AREA	ITEM	COST (10^6 $)	PERCENT OF SUBTOTAL
100	Coal storage and handling	(in 200)	--
200	Coal preparation	16.7	3.2
300	Gasification	86.2	16.4
1200	Raw gas cooling	71.0	13.5
1300	Acid gas removal and gas cleaning	43.0	8.2
1400	Sulfur recovery and tail gas treating	(in 1300)	--
1900	Air separation	62.7	11.9
2000	Utilities and support systems	245.8	46.8
2100	Offsites and miscellaneous	(in 2000)	--
	Subtotal	525.4	100.0
	Project contingency	78.8	
	Process contingency	8.6	
	Sales tax	12.3	
	Total plant investment	625.1	
	Interest during construction	205.6	
	Start-up	37.5	
	Working capital	38.1	
	Paid-up royalties	3.1	
	Initial charge of catalysts and chemicals	1.9	
	Total capital requirement	911.3	

[a]Source: 3-1, updated, and scaled to 50 trillion Btu per year by ERCO.

used in this plant (air separation, acid gas clean-up, coal preparation, etc.). Therefore, technical problems will not be a source of major cost uncertainty.

The cost estimate used as a reference was based on a preliminary equipment sizing and costing. No major equipment items were deleted from the estimate. The estimate was targeted to be accurate within ±20 percent (3-2, p. 97). Because of inaccuracies introduced into the estimate by scaling and updating, this confidence interval should be increased to ± 30 percent.

3.3 OPERATING AND MAINTENANCE COSTS

3.3.1 Itemized Operating and Maintenance Expenses

Gross annual operating and maintenance (O&M) costs total $46.1 million, as is shown in Table 3-3. The largest component of these costs is local taxes and insurance, at $15.6 million. Maintenance materials would cost $7.8 million. Total plant labor is $14 million.

The plant will produce by-product sulfur and ammonia in addition to its main hydrocarbon and electricity outputs. Annual ammonia production is valued at $4.6 million, and sulfur at $2.9 million, for a total by-product credit of $7.5 million. This credit partially offsets the gross O&M costs, for a net cost of $38.6 million.

TABLE 3-3

OPERATING AND MAINTENANCE COSTS - LURGI SYSTEM[a]

ITEM	COST (10^6 \$)	PERCENT OF TOTAL
Administration and general overhead	6.4	13.9
Local taxes and insurance	15.6	33.8
Labor		
Operation	5.6	12.1
Maintenance	5.2	11.3
Administrative and support	3.2	6.9
Total	14.0	30.3
Maintenance materials	7.8	16.9
Catalysts and chemicals	0.7	1.5
Solids disposal	0.4	0.9
Utilities	1.2	2.6
Total	46.1	100.0
By-Product Credits	(10^6 \$)	
Ammonia	(4.6)	
Sulfur	(2.9)	
Total	(7.5)	
Net O & M Costs	(10^6 \$)	
Gross O & M costs	46.1	
By-product credit	(7.5)	
Total	38.6	

[a]Source: (3-1), updated to third-quarter 1980 dollars and scaled to 50 trillion Btu/yr by ERCO. A 90 percent operating factor was assumed.

3.3.2 Variability of Operating and Maintenance Costs

Most of the operating and maintenance costs (maintenance materials and labor, local taxes and insurance) were estimated directly from the capital cost estimate. Other costs, such as operating labor, catalysts and chemicals, utilities, and solids disposal, are process dependent. No major technological uncertainties are associated with the process. Therefore, the variability of the O&M costs is within the ±30 percent estimated for the capital costs.

3.4 EFFECT OF TECHNOLOGY DEVELOPMENT ON COSTS

As the total number of Lurgi gasification plants increases, costs should fall in real dollars as the effects of experience improve methods. The theory of cost reduction because of the effects of the experience is explained in the Background section.

Gasification and raw gas cooling are immature areas incorporating technologies which would benefit from experience. They account for approximately 30 percent of the total plant investment. Other areas have large volumes of accumulated production, so little further cost reduction in these areas can be expected as more Lurgi plants are built. However, these could possibly be made smaller as more plants are constructed. For example, perhaps a means to use less steam will be developed, reducing the size of the Steam Generation unit. Therefore, 30 percent must be considered a lower limit on the percent of plant costs accounted for by immature technology.

With a maximum experience factor of 10 percent, the experience factor of the Lurgi technology would be the 30 percent of costs accounted for by immature technology times the 10 percent maximum, or 3 percent. Each doubling of Lurgi production capacity would result in at least a 3 percent reduction in real costs because of experience.

3.5 PRODUCT COSTS

The Lurgi process described here has three main products: medium-Btu gas, electricity, and liquid hydrocarbons. Average product costs on a dollars-per-million-Btu basis are presented in this section. It is assumed here that electricity has a heating value of 10,000 Btu per kWh. The theoretical heating value of electricity is 3,412 Btu per kWh. The value of 10,000 Btu per kWh is used here to allow for the amount of alternative energy which would be burned to generate an equal amount of electricity. Hydrocarbon outputs were assigned a heating value equal to their Higher Heating Value.

The product costs have three discrete components: capital charges, operating and maintenance (O&M) costs, and coal costs. Costs of the product without the coal cost (non-fuel cost) indicate the cost of converting the coal into gas. A non-fuel product cost can be computed using the capital and O&M costs, with the formula given in the Background section.

The total capital requirement of the plant is $911.3 million from Table 3-1 and yearly net O&M costs are $38.6 million from Table 3-2. Therefore, the non-fuel product cost is:

$$P = \frac{(\$911.3 \times 10^6 \times 20\%) + \$38.6 \times 10^6}{(50 \times 10^{12} \text{ Btu}) \times 90\% \text{ capacity}}$$

$$= \underset{\text{(capital costs)}}{\$4.05/10^6 \text{ Btu}} + \underset{\text{(O\&M costs)}}{\$0.86/10^6 \text{ Btu}}$$

$$= \underset{\text{(non-fuel product cost)}}{\$4.91/10^6 \text{ Btu}}$$

The non-fuel product cost of \$4.91 per 10^6 Btu can be combined with a coal cost to yield a total product cost. The overall coal-to-product heating value efficiency of the process is 69.3 percent (with electricity at 10,000 Btu/kWh). Assuming coal is \$1.50 per 10^6 Btu implies that the fuel for the plant would cost \$2.16 per 10^6 Btu. Therefore, the total energy cost would be:

$$E = \underset{\text{(non-fuel costs)}}{\$4.91/10^6 \text{ Btu}} + \underset{\text{(coal costs)}}{\$2.16/10^6 \text{ Btu}}$$

$$= \underset{\text{(total product cost)}}{\$7.07/10^6 \text{ Btu}}$$

The average total product cost would be \$7.07 per 10^6 Btu.

References

3-1. Chandra, K., B. McElmurry, and S. Smelser (Fluor Engineers and Constructors), "Economics of Fuel Gas From Coal - An Update Including the British Gas Corporation's Slagging Gasifier." Electric Power Research Institute AF-782, May 1978.