CHAPTER 1
DESCRIPTION OF PROPOSED PROJECT

1. Description of Proposed Project

1.1 Brief Description of Project and of Companies Involved

The ANG Coal Gasification Company (ANGCGC) proposes to construct and operate a coal gasification plant and the necessary support facilities in southwestern North Dakota. The plant, which would use the Lurgi gasification process, would produce an average 250 million cubic feet (MMcf) per day of synthetic natural gas (SNG). The U.S. Bureau of Reclamation proposes to enter into a water service agreement with ANGCGC for up to 17,000 acre-feet of water annually for gasifying the coal, cooling needs, and mine operations. The water would be provided from Garrison Reservoir (Lake Sakakawea) through a 40-year water service contract.

ANGCGC is a subsidiary of American Natural Resources Company (ANR), a holding company which holds all of the common stock in ANGCGC, Michigan Wisconsin Pipe Line Company, ANG Production Company, Michigan Consolidated Gas Company, and one-half of the common stock in Great Lakes Gas Transmission Company. Together these companies make up what is known as the "American Natural Resources System" (Figure 1-1).

Michigan Wisconsin Pipe Line Company (Michigan-Wisconsin) owns and operates an extensive natural gas pipeline system which spans the United States from the Gulf Coast to the Canadian border and supplies gas to 54 gas distributing utilities. The area served has a total population of over 8 million people in Michigan, Wisconsin, Iowa, Illinois, Indiana, Kansas, Ohio, and Tennessee.

Michigan-Wisconsin, in response to its need for additional gas to serve its customers, initiated a program to determine the feasibility of, and to select a site for, a coal gasification complex. Parameters considered were size of coal reserves, mining costs, environmental concerns, production costs, water availability, and gas transportation costs (Section 8.2). North Dakota coal reserves were selected and Michigan-Wisconsin entered into an agreement with the North American Coal Corporation (NACCO) through its subsidiary Coteau Properties Company (Coteau Properties) for options on 1.5 billion tons of low sulfur coal in and around Mercer County for future gasification needs.

As the coal gasification program developed, ANGCGC was organized to construct and operate the proposed facilities. A contract to mine the coal for ANGCGC would be executed with Coteau Properties.

Figure 1-1 American Natural Resources System

To transport the SNG produced, Great Lakes Gas Transmission Company (Great Lakes) would extend its existing gas transmission system from Minnesota into North Dakota. The proposed 20-inch product gas pipeline (product pipeline) would extend 365 miles from Great Lakes' existing Thief River Falls Compressor Station to Mercer County. Burlington Northern Railroad (Burlington Northern) would extend a 9.0-mile railroad spur from its existing lines in Mercer County to provide materials to the gasification facilities and to transport byproducts for sale. Wastes (i.e., ash and sludge) from operation of the plant would be buried in the mines.

After release of the Draft Statement, Natural Gas Pipeline Company of America (NGPC) joined ANGCGC as a coowner of the proposed project. ANGCGC would remain as project administrator and be responsible for all phases of construction and operation of the project. However, half of the cost of the project would be paid by NGPC and half the SNG produced would be conveyed to NGPC's market area (Chicago).

Construction of the plant would occur in two phases beginning in 1978. Each phase would include all facilities necessary to produce an average 125 MMcf/day. Phase I would be placed into operation (in 1981) before construction begins on Phase II so that operating data and experience can be used to incorporate design improvements into the second phase. Phased construction would also result in lower socioeconomic impacts in the local area compared to unphased construction of the full plant capacity. Construction of the second phase of the plant is tentative but would begin about 1983 and be completed by about 1987. This statement will be concerned with the construction, operation, and impact of a full 250 MMcf/day plant.

As currently proposed, the cost of the product gas would be distributed among all of the ANR gas system customers (i.e., rolled-in). Cost estimates based on noninflated late 1975 dollars per MMBtu (.97 thousand cubic feet) would be:

Michigan	Plant Synthesis	Pipeline Transport	Distribution	Total
Incremental	\$3.63	\$0.69	\$0.55	\$4.87
Rolled-In	-	-	-	1.54
Wisconsin				
Incremental	3.63	0.69	0.92	5.24
Rolled-In	-	-	-	1.94

The above incremental cost totals are used only to develop rolled-in costs; the gas would be sold only on a rolled-in basis.

1.2 Purpose and Need

1.2.1 Domestic Energy Supply and Demand

Natural gas, electricity, fuel oil, and low sulfur coal are in short supply today in many areas of the United States. Current demands for natural gas exceed the present and future supply. Figure 1-2 (from Federal Energy Administration's 1976 National Energy Outlook) depicts energy consumption in the United States from 1950 to the present and projected into the year 1990. Beginning in 1950, the United States changed from a net exporter of energy to a net importer. Since 1958, energy imports have increased at rates of 7 to 10 percent per year (1).

Total energy use in the United States has more than doubled since 1950, increasing at a rate of 4.25 percent per year (2). During the same period, domestic energy production has increased at an annual rate of only 3 percent; and, during recent years, production increase has slowed to less than 1 percent.

Figure 1-3 shows domestic gas reserves and annual consumption from 1947 to present. It is evident that there will soon be a large unsatisified demand for natural gas even if all available sources are developed to the greatest possible extent. Moreover, the gas supply will continue to decline unless new sources of natural gas are discovered, significant volumes of SNG are produced from coal, or other means of producing natural gas are found.

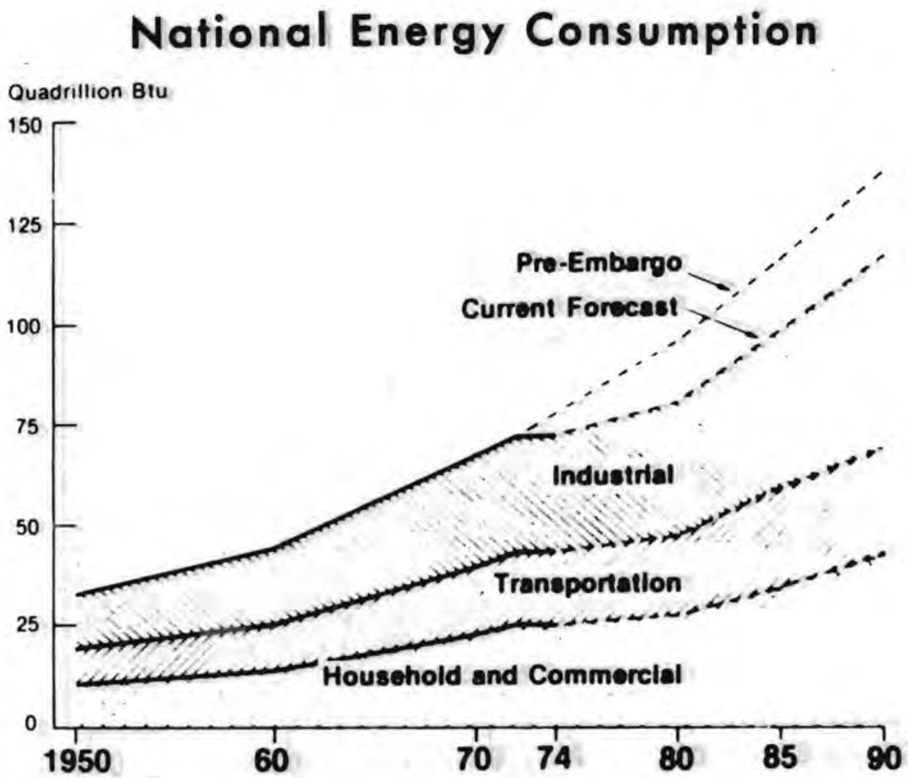
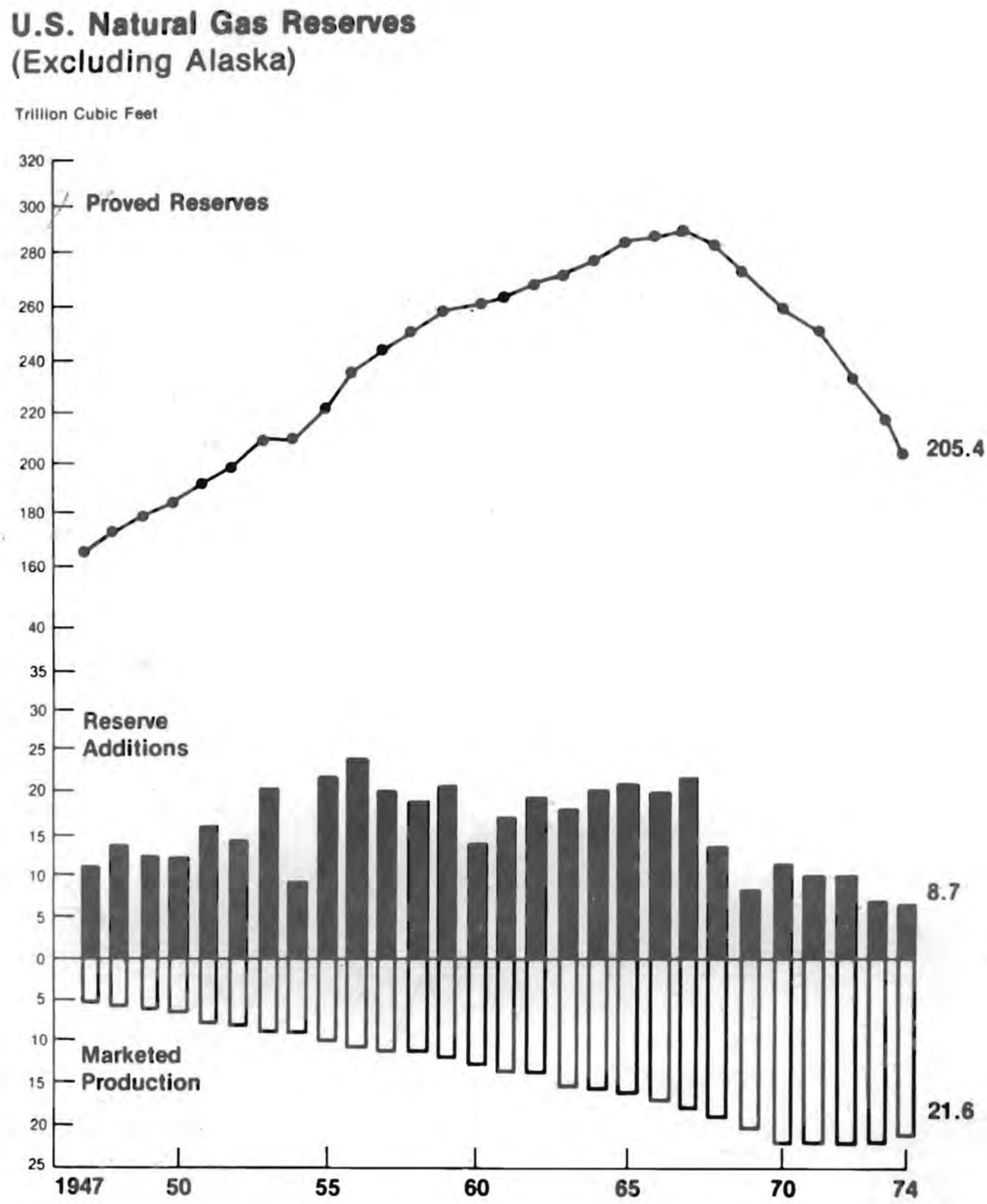


Figure 1-2



Source: American Gas Association

Figure 1-3

There were several reasons for the demand for natural gas. Pipelines were built after World War II forming a transport network which made gas available throughout much of the country. A large number of homes and industries became dependent on natural gas due to its low price, clean burning characteristics, and availability. Industries on "interruptible" gas contracts could enjoy a relatively continuous supply of energy at a very low price. Since 1967, however, industrial interruptions have become common, and in some areas new industrial customers are being turned away entirely.

Total proven reserves of natural gas in the U.S. reached a peak of 293 trillion cubic feet (Tcf) in 1967. Until that time, natural gas reserve additions exceeded production each year. Since 1968, production has exceeded reserve additions except for 1970 when Alaska's Prudhoe Bay reserves were added to the proved reserves (75). During the past 8 years, reserve additions in the lower 48 states have averaged 9.3 Tcf annually compared to an average production of 21.4 Tcf. In 1975 proven reserves with and without Alaska were 237 and 205 Tcf, respectively.

Deregulation of natural gas wellhead prices has been proposed as the most immediately available method of stimulating natural gas production. Proponents of deregulation cite that increased prices would stimulate exploration and development, and the higher prices would lower the demand for natural gas through the increased use of less costly fuels and increased conservation. The opponents of deregulation counter that such deregulation would place hardships on the residential customer, cause increased inflation, produce a drop in the gross national product, deplete reserves, and provide windfall profits to the gas companies.

In July 1976, the Federal Power Commission in Opinion No. 770 authorized an increase in the price of natural gas sold in interestate commerce. This rate increase is expected to increase natural gas supplies for the short-term; however, recoverable reserves are limited and for the long-term the U.S. will need to find alternative means of producing energy (See Section 8.3 for alternatives).

1.2.2 Need for Project

The need for the proposed project is based on Michigan-Wisconsin's need for additional gas supplies to fulfill its customer's requirements. About 5 years ago, a long-range forecast was made comparing Michigan-Wisconsin system requirements with natural gas supplies from traditional sources through the year 1995. The major conclusion of the forecast was that Michigan-Wisconsin, like most natural gas transmission companies, will not have sufficient gas supplies from its traditional sources to meet its long-range requirements.

Table 1-1 summarizes Michigan-Wisconsin's projected natural gas supply requirements by priority, supplies, and proportion of priorities served. These projections do not include any new additions of domestic reserves that might occur (86).

Customers are allocated gas on a priority basis. Priority 1 customers have gas allocated to them before any of the other priorities are considered. This scheme continues through all 9 priorities with priority 9 being allocated gas only after the previous 8 priorities have been fully served. The priorities are defined as follows:

1. Residential, small commercial (< 50 Mcf (thousand cubic feet) on a peak day).

2. Large commercial (50 Mcf or more on a peak day), firm industrial requirements for plant protection, feedstock, and process needs, and pipeline customer storage injection requirements.

3. All industrial requirements not specified in 2, 4, 5, 6, 7, 8, and 9.

4. Firm industrial requirements for boiler fuel use at less than 3,000 Mcf/day but more than 1,500 Mcf/day where alternate fuel capabilities can meet such requirements.

5. Firm industrial requirements for boiler fuel (more than 3,000 Mcf/day) where alternate fuel capabilities can meet such requirements.

6. Interruptible requirements of more than 300 Mcf/day and less than 1,500 Mcf/day, where alternate fuel capabilities can meet such requirements.

7. Interruptible requirements between 1,500 Mcf/day and 3,000 Mcf/day, where alternate fuel capabilities can meet such requirements.

8. Interruptible requirements between 3,000 Mcf/day and 10,000 Mcf/day, where alternate fuel capabilities can meet such requirements.

9. Interruptible requirements more than 10,000 Mcf/day, where alternate fuel capabilities can meet such requirements.

As of September 1, 1975, gas service to priorities 6 through 9 was curtailed by Michigan-Wisconsin. As can be seen from Table 1-1, Michigan-Wisconsin will need new natural gas supplies by 1982 to continue serving residential and small commercial customers.

Table 1-1

MICHIGAN WISCONSIN PIPE LINE COMPANY

Requirements, Gas Supplies and Priorities Served
(Volumes in MMcf @ 14.73 Psia)

	1975	1976	1977	1978	1979	1980	1981	1982	1983	1984
Requirements by F.P.C. Priorities										
Priority 1	492,461	516,677	535,793	555,665	573,834	591,986	610,188	628,411	646,630	664,509
Priority 2	212,304	233,252	245,006	265,965	286,469	302,647	314,527	332,019	347,274	364,208
Priority 3	78,771	82,246	85,448	89,143	92,210	95,322	98,419	101,504	104,610	107,652
Priority 4	12,977	13,130	13,580	14,104	14,561	15,026	15,494	15,972	16,456	16,946
Priority 5	29,587	28,442	29,363	30,648	31,635	32,667	33,749	34,884	36,076	37,325
Priority 6	19,373	21,151	21,668	22,087	22,505	22,924	23,343	23,761	24,180	24,564
Priority 7	5,999	8,147	8,185	8,224	8,262	8,301	8,340	8,378	8,417	8,456
Priority 8	23,336	26,102	26,400	26,698	26,996	27,295	27,593	27,891	28,189	28,438
Priority 9	21,967	18,366	16,366	16,366	16,366	16,366	16,366	16,366	16,366	16,366
Total Requirements	896,775	947,513	981,809	1,028,900	1,072,838	1,112,534	1,148,019	1,189,186	1,228,198	1,268,464
Supplies										
Producers-Owned and Contracted	703,782	666,315	667,361	586,573	518,323	456,458	391,861	332,406	276,792	234,709
Pipeline Supplier Purchases	165,018	163,685	162,639	162,639	162,639	162,639	162,639	161,236	159,903	158,637
Arctic Gas	-	-	-	-	-	34,960	69,350	69,350	69,350	69,350
Substitute Natural Gas	-	-	-	-	-	-	-	22,812	22,812	22,812
Total Supplies	868,800	830,000	830,000	749,212	680,962	654,057	623,850	585,604	528,857	485,508
Proportion of Priorities Served										
Priority 1	100%	100%	100%	100%	100%	100%	100%	100%	92%	83%
Priority 2	100%	100%	100%	73%	37%	21%	20%	8%	-	-
Priority 3	100%	97%	58%	-	-	-	-	-	-	-
Priority 4	100%	-	-	-	-	-	-	-	-	-
Priority 5	100%	-	-	-	-	-	-	-	-	-
Priority 6	100%	-	-	-	-	-	-	-	-	-
Priority 7	100%	-	-	-	-	-	-	-	-	-
Priority 8	74%	-	-	-	-	-	-	-	-	-
Priority 9	-	-	-	-	-	-	-	-	-	-

Source: Michigan-Wisconsin Pipeline Company

The proposed gasification plant would supply an average 250 MMcf/day of SNG or over 91 billion cubic feet (Bcf) annually. This would amount to 23.7 percent of the 1975 gas requirements of Michigan Consolidated's 1 million customers.

1.3 Permits, Approvals, and Certifications Required

The following major permits and approvals must be obtained by ANGCGC before construction and operation of the coal gasification facility can begin:

Federal Agencies	Permit and/or Approval
U.S. Army Corps of Engineers	Easement for Water Intake, Pipeline, and Access Road; Section 10 Permits for Water Intake and Pipeline Crossings of Major Streams; Section 404 Permits for Wetland Disturbance
Environmental Protection Agency	New Source Performance and Air Quality Significant Deterioration Review, Deep Well Disposal Review
Federal Power Commission	Certificate of Public Convenience and Necessity
Federal Aeronautical Administration	Application for and Notice of Proposed Construction for Structures over Regulated Heights
U.S. Bureau of Reclamation	Water Service Contract, Environmental Impact Statement
State Agencies	
North Dakota Public Service Commission	Plant Certificate of Site Compatibility, Water Pipeline Certificate of Site Compatibility, Water Pipeline Transmission Facility Route Permit, Mining Plan

North Dakota Department of Health - Environmental Engineering Division	Permit to Construct (Air Pollution Control Permit) Permit to Operate (Air Pollution Control Permit)
Water Supply and Pollution Control Division	NPDES Permit for Deep Well Disposal, NPDES Permit for Mine Drainage Disposal, Solid Waste Disposal Permit
North Dakota Department of Health	License for Radioactive Measuring Device Operations, Hazardous Waste Control Plan, Wells for Temporary Water Supply, Sewage Treatment Plant
North Dakota State Highway Department	Rail Siding Crossing, Pipeline Construction on Highway ROW
North Dakota State Water Commission and State Engineer	Appropriation of Underground Water, North Dakota State Water Permit (conditional permit obtained)
North Dakota Secretary of State	Certificate of Authority for Foreign Corporation to Transact Business
North Dakota Unemployment Compensation Divison of Employment Security Bureau	Application for Coverage by ANGCGC
North Dakota Workman's Compensation Bureau	Coverage by ANGCGC
Mercer County	
Board of Commissioners	Petition for Access to County Roads, Petition for Vacating County Road and Closing Section Lines, Certificate of Zoning Compliance, Plantsite Rezoning, Conditional Use Permit
Soil Conservation District	Erosion and Sediment Control Plan

1.4 Relationship to Other Projects

1.4.1 Industrial

a. Basin Electric Coal-Fired Powerplant

Basin Electric has proposed the construction of two 440-megawatt (MW) coal-fired electric generating units adjacent to the ANGCGC gasification complex. The generating complex would be on the north side of the proposed gasification site and the two companies would share the water intake system, plant access road, and railroad spur (Figure 1-6). The Basin Electric plant would use the excess coal fines (coal particles too small for gasification) from ANGCGC's operation for the generation of electricity thus eliminating the need to transport the fines for sale elsewhere. The mining operations, coal handling and storage facilities, as well as ash handling and disposal, would also be shared, resulting in a more economical coal production system for both.

Basin Electric's environmental report was not scheduled for completion until September 1977; thus, it was decided to proceed with this environmental statement for the ANGCGC proposal and for the Rural Electrification Administration (REA) to prepare the environmental statement for the powerplant. This suggestion was approved at a meeting between the Council on Environmental Quality (CEQ), Environmental Protection Agency (EPA), REA, and Department of the Interior in Washington, D.C., because other statements are being prepared that would cover the cumulative impacts of these and other projects. These statements are detailed in Section 1.4.2. However, Sections 3.1.1.3, 3.3, and 3.6 of this statement consider the cumulative air quality and socioeconomic impacts of the two facilities; other impacts associated with the Basin Electric project, such as transmission lines, switchyards, wastewater discharges, etc., will be addressed in REA's environmental statement.

The construction of both facilities is phased. Construction on the first phase of the gasification plant is scheduled to begin in the spring of 1978. Basin Electric would also begin construction on the first 440-MW unit in the spring of 1978. The construction of the second electric generating unit would begin about 2 years later (1980), and construction on the second phase of the gasification facilities would commence 2 to 3 years after that (1982 or 1983).

The annual coal requirement for both facilities would be 14.6 million tons, or an increase of 20 percent (about 100 acres annually) over that required by the gasification plant alone. The increase is relatively small because about one-third of Basin Electric's coal needs would be met by ANGCGC's excess fines. The water permit applications of both ANGCGC and Basin Electric have been approved by the North Dakota State Water Commission; Basin Electric had requested 19,000 acre-feet annually for powerplant needs.

b. Coyote Station - Coal-Fired Powerplant

A consortium of five utility companies has proposed the construction of a powerplant 3.5 miles south of Beulah. Montana-Dakota Utilities (MDU) would operate the plant which would consist of two 440-MW units to be completed in 1985. Coal consumption would be 4.4 million tons/year from the Knife River Coal Company's existing mines at the proposed site. An 11,000 acre-feet/year water application for Missouri River water for one 440-MW unit (taken from below Garrison Dam) has been approved by the North Dakota State Water Commission; the second unit would require an additional 10,000 acre-feet/year.

Because the proposed Coyote plantsite is only about 10 miles south of the ANGCGC and Basin Electric project sites, it is probable that some overlap would occur in the air quality impacts of the proposed projects. Also, the influx of workers associated with the Coyote powerplant would be superimposed on that resulting from the ANGCGC and Basin Electric projects. The cumulative impacts of these projects are covered briefly in Section 3.6 and will also be covered in the Bureau of Land Management (BLM) and State of North Dakota's West-Central North Dakota Energy Development Environmental Statement (EIS) (see next Section). The site-specific EIS for the Coyote powerplant is being prepared by REA.

c. Natural Gas Pipeline Company of America (NGPC)

The NGPC has proposed the construction of a coal gasification complex near Dunn Center in Dunn County. The complex would be composed of one 250 MMcf/day gasification plant and ancillary facilities. The plant would require about 13.9 million tons of coal and 17,500 acre-feet of water annually. A permit application to take water from Lake Sakakawea has been denied by the North Dakota State Water Commission.

d. Minnkota Power Cooperative (MPC)

MPC is currently constructing a 440-MW coal-fired power generating unit near Center, Oliver County, adjacent to an existing 235-MW unit completed in 1970. The new unit is scheduled for completion by June 1977. This unit will use about 2.8 million tons of coal and 5,700 acre-feet of water annually.

e. Possible Future Developments

The original water permit applications of both ANGCGC and NGPC to the State of North Dakota each requested 68,000 acre-feet of water annually for four 250 MMcf/day coal gasification plants. Action on seven of the eight proposed plants has been deferred by the State of North Dakota, but they represent possible future developments in the area. In addition, Consolidation Coal Company is considering opening up two new strip mines in Mercer County (Renner's Cove and Dakota Star) if a market is found, and expanding their existing Glenharold mine near Stanton if Basin Electric builds a third coal-fired generating unit at its existing Leland Olds plant.

f. Use of Natural Resources

The five actually proposed industrial developments would use coal, water, and land resources. The ANGCGC and Basin Electric plants would be supplied coal from leases held by Coteau Properties with possible future supplements from nearby Federal coal reserves. The Coyote plant would be provided coal from Knife River Coal Company leases and the NGPC plant would obtain coal from American Metals Climax leases just east of Dunn Center. MPC will obtain coal from the existing Baukol-Noonan mine near Center. ANGCGC, Basin Electric, and NGPC would obtain water from Lake Sakakawea; MDU (Coyote) and MPC propose to pump water from the Missouri River below Stanton. Table 1-2 summarizes the cumulative use of major resources by these projects.

1.4.2 Governmental

a. Bureau of Land Management (BLM) - North Dakota Regional EIS

BLM has been designated the lead Federal agency for preparing a West-Central North Dakota Energy Development EIS with the State of North Dakota. This EIS will address the cumulative environmental impacts resulting from coal-mining and related industrial development in the western North Dakota counties of Oliver, Mercer, Dunn, McLean, Stark, Morton, and Burleigh. The EIS will cover the cumulative impacts of the ANGCGC, Basin Electric, NGPC, Consolidation Coal Company, and Coyote proposals and associated facilities. The draft statement is scheduled for release about October 26, 1977.

b. Bureau of Reclamation

The Bureau of Reclamation has recently completed a draft environmental statement entitled "Water for Energy - Missouri River Reservoirs" (102) on the impacts in the Upper Missouri River coal region resulting

TABLE 1-2

Summary of Resource Use by Proposed Projects

Project	Maximum Water Use (ac.ft./yr)	Coal (tons/year)	Total Land Disturbance (acres)
ANGCGC	17,000	9.4×10^6	14,000
Basin Electric	19,000	5.2×10^6	500 1/
MDU (Coyote)	21,000	4.4×10^6	2,500 2/
NGPC	17,500	13.9×10^6	11,000
MPC	5,700	2.8×10^6	1,600
Totals	80,200	35.3×10^6	29,600

1/ Acreage disturbed by mining is included in the ANGCGC figure.

2/ Estimate based on acres disturbed/million tons of coal of other projects.

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from the use of up to 1 million acre-feet of water from the Missouri main-stem reservoirs for coal related industrial development. The ANGCGC, Basin Electric, and NGPC facilities were included in the hypothetical industrial development scenario.

c. Other Studies

The Yellowstone Level B Study, under Missouri River Basin Commission lead, and the Regional Environmental Assessment Program (REAP) are Federal and State sponsored studies currently underway which will also look at cumulative impacts of coal related industrial development within their areas of concern. Portions of data gathered in these studies would be applicable to western North Dakota.

1.5 Detailed Project Description

1.5.1 Location

The site selected for the coal gasification complex is approximately 65 miles northwest of Bismarck, North Dakota. The site lies in a multistate region generally known as the Northern Great Plains (Figure 1-4). Within North Dakota, the site lies south of Lake Sakakawea, a large reservoir formed by Garrison Dam on the Missouri River (Figure 1-5). Straight line distances to North Dakota cities are: 65 miles SE to Bismarck, 65 miles NNE to Minot, 58 miles SW to Dickinson, and 100 miles NW to Williston. Local municipalities nearby include: Beulah, 7 miles SSE; Hazen, 11 miles SE; and Zap, 7 miles SSW.

The plant and mine would lie entirely within Mercer County (Figure 1-6), 7 miles south of Lake Sakakawea, and 4.5 miles north of State Route 200. The Fort Berthold Indian Reservation is located 9 miles to the northwest.

1.5.2 Land Requirements

The site for the coal gasification complex includes both the plantsite and the minesite (Figure 1-6). Land to be acquired for the ANGCGC and Basin Electric plantsites would consist of 1,575 acres (1,127 acres for ANGCGC and 448 for Basin Electric). Of the total acreage, about 535 acres would be occupied by ANGCGC's buildings, process equipment, and coal storage. The remainder of ANGCGC's property (about 592 acres) would be used for construction laydown, areas to deposit overburden from the initial mining cuts, or remain unused.

In addition to the plantsite proper, a railroad spur would be extended from an existing Burlington Northern railroad spur (near Hazen) 9.0 miles to the plant. Also, about 6.2 miles of new roads would be built near the plant and mine. An underground water pipeline, 7.6 miles in length, would be constructed from Lake Sakakawea southward to the plantsite. The product pipeline, about 365 miles long, would carry the SNG to Thief River Falls, Minnesota, where it would be comingled with natural gas for transmission to the Michigan-Wisconsin market area. These associated facilities would be constructed at full capacity during Phase I construction.

The proposed minesite consists of four areas within close proximity of the plant (Figure 1-6). Three areas are located adjacent to the plantsite and one is located about 5 miles northeast. Approximately 500 acres per year would be mined, involving about 12,500 acres

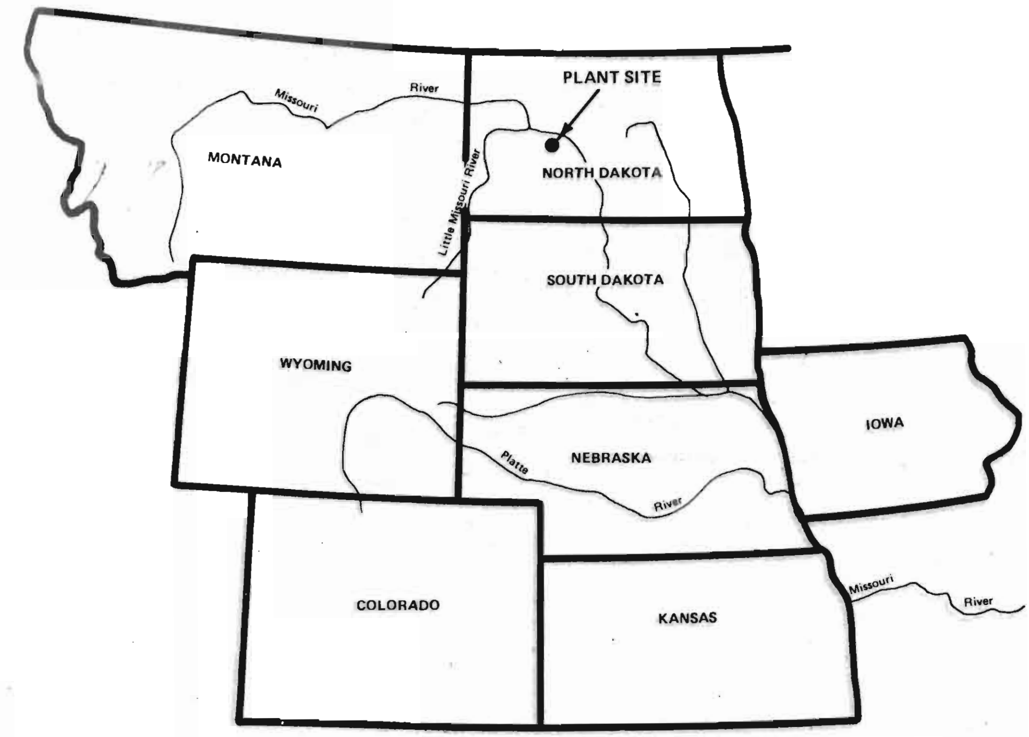


Figure 1-4 LOCATION OF PLANT SITE WITHIN THE NORTHERN GREAT PLAINS

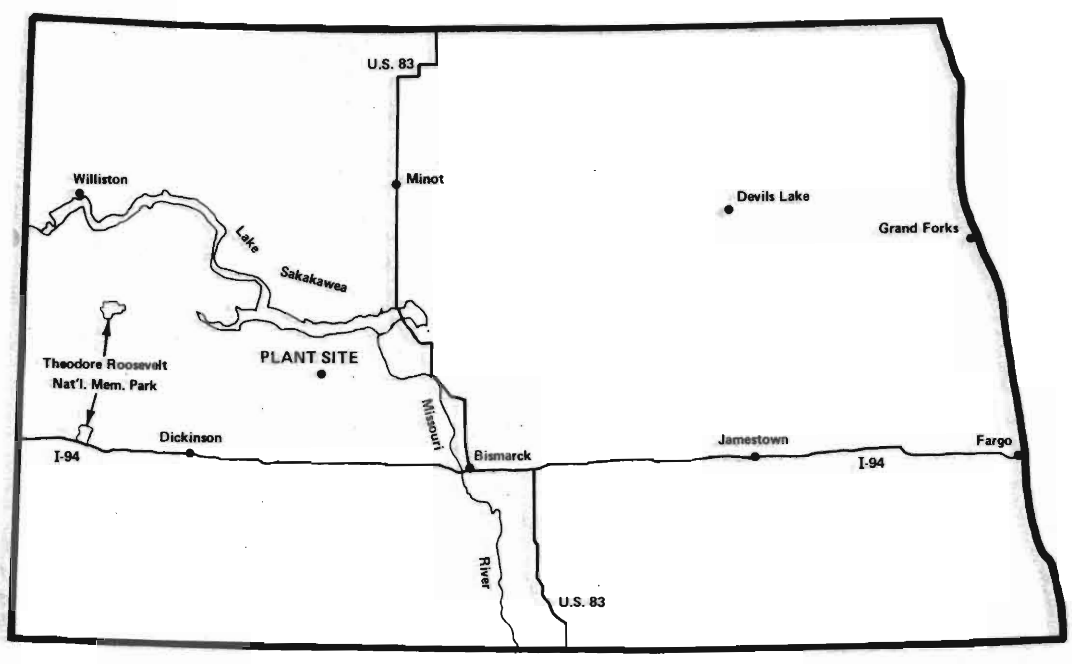


Figure 1-5 MERCER COUNTY COMPLEX - LOCATION IN NORTH DAKOTA

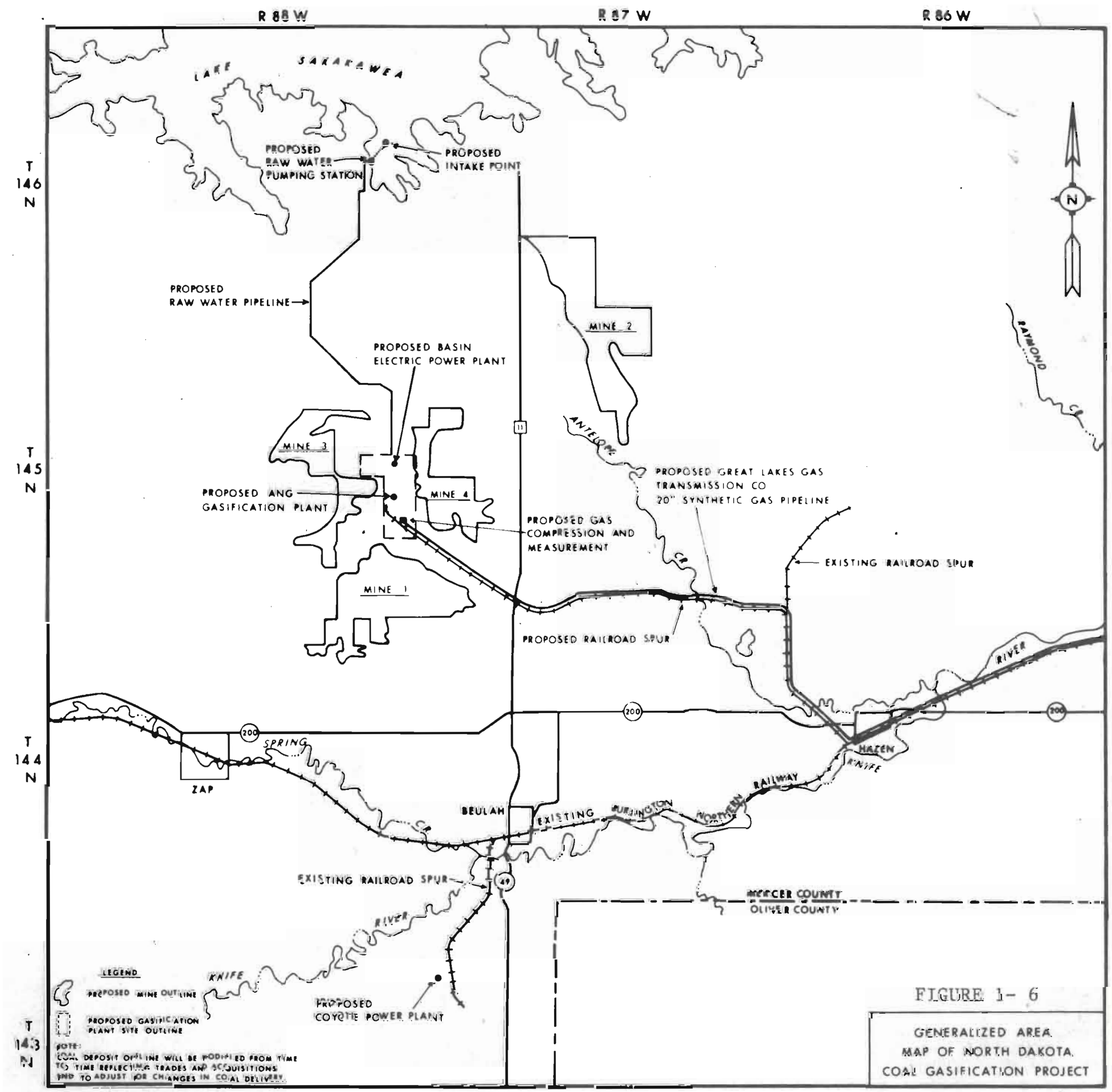


FIGURE 1- 6

GENERALIZED AREA MAP OF NORTH DAKOTA COAL GASIFICATION PROJECT during the first 25 years of mine operation. The mining plan would allow the majority of land within the mine area to remain in its current use until mining reaches each segment. Reclamation would commence as soon as mining of each segment was completed.

Total land disturbed by the proposed project and associated facilities would be as follows:

Function	Acreage
Plantsite	535
Mining	12,500
Water Intake & Pipeline	138
Railroad Spur	219
Roads	83
Product Pipeline & Compressor Stations	2,222
Total	15,697

The land requirements of the plantsite, water intake and pipeline, railroad spur, and product pipeline (including two 10-acre compressor station sites) are relatively firmly established; the acreage disturbed by mining could vary somewhat (as much as 10 percent) as the depth and thickness of the coal seams are more accurately established. In addition to the 365-mile SNG pipeline, 217 miles of 36-inch pipeline may be required parallel to the Great Lakes pipeline system in Minnesota, Wisconsin, and Michigan, and 28 miles of 30-inch pipeline and 20,000 horsepower of compression facilities may be needed parallel to the Michigan-Wisconsin pipeline system in Michigan and Wisconsin. These facilities would carry regular natural gas comingled with SNG and the impacts of these additional facilities are beyond the scope of this EIS.

1.5.3 Coal Mining

1.5.3.1 General

a. Project Requirements

The coal gasification plant requires approximately 31,500 tons of lignite per annual average day.1/ To satisfy this requirement and that of Basin Electric, mining operations are designed to produce about 56,000 tons/day (14.6 million tons/year) of lignite on a 5 day/week basis. Coal would be surface mined at the four locations within the Beulah-Hazen coalfield and would be conveyed from the mine to the coal preparation plant by 150-ton bottom dump trucks operating over a network of private haul roads. A tentative mining plan is shown in Figure 1-7.

1/ Annual average day refers to 365 24-hour days and averages in down-time. Stream day refers to 332 24-hour days; thus, stream day values are about 10 percent higher than average values but it would be the actual operating day.

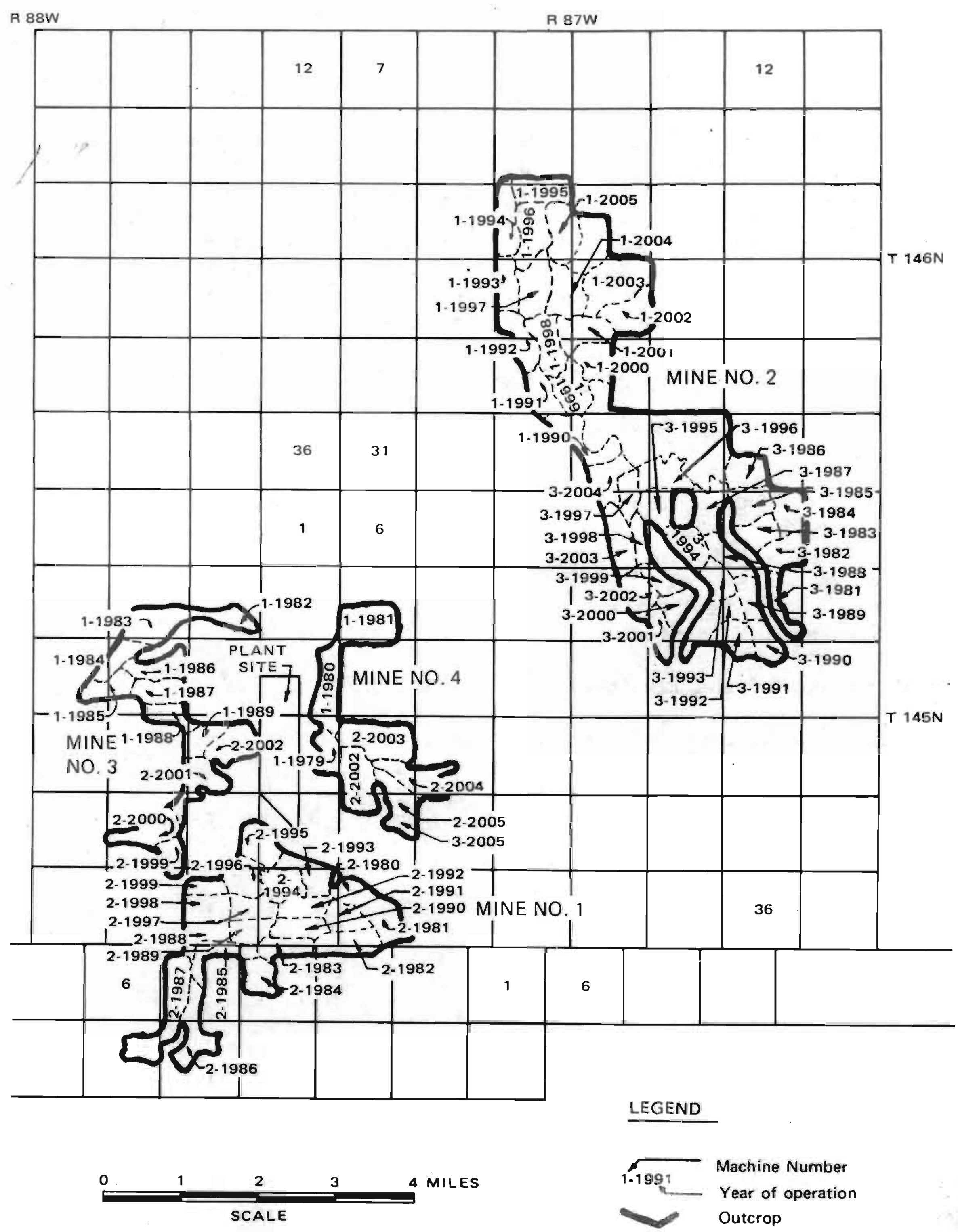


Figure 1-7 BEULAH-HAZEN COAL FIELD-SEQUENCE OF MINING LAYOUT

b. Coal Resources

The estimated size of the coal reserves near the plant-mine site is about 1.5 billion tons (947 million currently recoverable tons). All of the coal to be mined for the proposed project could come from private coal leases held by Coteau Properties. However, the Federal Government has retained extensive coal-rights in the area and at some future date some of these rights could be obtained by Coteau Properties for use by ANGCGC. (See Section 8.1.3.6 for a discussion of the Federal coal alternative.)

c. Coal Characteristics

The proximate analysis of the run-of-mine lignite (107 samples) is as follows:

Constituent	Percent by Weight
Moisture	35.98
Ash	7.42
Fixed Carbon	23.39
Volatiles	27.21

Heat content of the lignite is about 7,230 Btu/lb.

The ultimate analysis of the run-of-mine lignite on a dry, ash-free basis (DAF) is:

Element	Percent by Weight
Carbon	71.45
Hydrogen	4.81
Oxygen	21.01
Nitrogen	1.44
Sulfur	1.26
Chloride	.02

Except for being crushed and screened, the run-of-mine lignite would not changed in any way prior to gasification. Since the lignite would not be washed, its composition prior to gasification would remain the same as the run-of-mine coal. The results of three trace element analysis of coal from the Beulah-Zap bed are shown in Table 1-3.

d. Equipment Used in Mining

Equipment which would be used in mining is listed in Table 1-4. All of the heavy equipment, exclusive of the electrically powered

TABLE 1-3

Comparison of Trace Element Analyses Performed on the Beulah-Zap Coal Seam

(Parts per Million by Weight)

Element	Bureau of Mines[1]	Commercial Testing & Engineering Co.[2]	Sasol[3]
Ag	-	.07	0.1
As	0	2.3	30
B	12	130	300
Ba	60	100	2500
Be	.12	.42	2.0
Br	-	1.5	-
Cd	-	.63	<0.1
Co	6.0	.84	2.0
Cr	6.0	1.4	6.0
Cu	1.2	6.4	5.
F	-	83.	24.
Ga	1.2	.46	-
Ge	1.2	.03	-
Hg	-	.09	.05
La	0	1.1	-
Li	12.	4.3	20
Mn	12.	50	-
Mo	1.2	1.5	0.5
Nb	0	1.4	-
Nd	0	3.4	-
Ni	1.2	5.9	3.0
Pb	1.2	.67	20
Rb	12.	.4	-
Ru	-	.4	-
Sb	-	.12	.1
Sc	6.	<0.1	-
Se	-	1.3	1.0
Sn	0.6	.25	4
Sr	600	570	-
Th	-	.56	1.
Ti	440	-	-
U	-	.27	1.
V	12	2.7	10
Y	6.	4.	-
Zn	12.	2.1	.6
Zr	60	68	-

1. Calculated by Zubovic, USGS, 1961 from the data of Abernathy et al., US Bureau of Mines, 1969.

2. Trace element analysis performed for The North American Coal Corporation on December 5, 1973. Based on one sample.

3. Analysis performed under contract to ANG Coal Gasification Company on October 28, 1974 by South African Coal, Oil, and Gas Corporation Limited. Based on 48 subsamples of one sample.

TABLE 1-4

Vehicular Equipment to be Used in Mining

Item	Number of Units	Estimate Hours Per Day Per Unit	Total Equipment Hours Per Year (Estimate)
STRIPPING EQUIPMENT			
1. Bulldozers	4	12	17472
LOADING EQUIPMENT			
1. Front-end loader (20 cu. yd.)	2	6	2700
2. Explosives trucks	4	12	10800
3. Bulldozers	4	12	10800
COAL AND ASH HANDLING			
1. Bottom dump coal haulers (150 ton)	16	21	75600
2. End dump ash trucks (50 ton)	4	21	30576
ROAD CONSTRUCTION AND MAINTENANCE			
1. Compactor	1	12	2700
2. Road graders	3	21	14175
3. Water trucks (5,000 gal.)	8	21	37800
4. Dump trucks (15 ton)	4	10	9000
5. Front-end loader (10 cu. yd.)	2	10	4500
6. Hydraulic backhoe (2 cu. yd.)	1	8	1800
7. Hydraulic crane (15 ton)	1	6	1350
8. Bulldozers	3	12	8100
9. Scrapers (32 cu. yd.)	3	12	8100
SUPPLY AND MAINTENANCE			
1. Supply trucks (flat bed)	4	10	9000
2. Fuel trucks	4	18	16200
3. Welding trucks	4	8	7200
4. Service and lube trucks	4	12	10800
5. Field maintenance trucks	2	8	3600
PERSONNEL TRANSPORT			
1. Station wagons, pickups, crew cabs	36	12	97200
RECLAMATION EQUIPMENT			
1. Scrapers (32 cu. yd.)	9	18	38880
2. Bulldozers	9	18	38880
ELECTRICALLY POWERED EQUIPMENT			
1. Draglines (100 cu. yd.)	4	24	35040
2. Coal loaders	4	21	30576

draglines and coal loaders, would be diesel powered. The supply and maintenance and personnel transport vehicles would be gasoline powered. Major equipment, such as draglines, would be shipped to the project site unassembled. The equipment would then be assembled at the mine shop complex near the plantsite.

e. Power and Water Supply

Power would be distributed to the mines from an Oliver-Mercer Electric Coop. substation adjacent to the Basin Electric substation. Power would be run underground about one-half mile north of the substation and from that point would be distributed overhead to the various mine areas. The power requirements for the mine would be approximately 25 to 30 MW.

The mines would require about 140 million gallons of water/year for dust abatement purposes. This water would be obtained from an environmentally acceptable waste stream from the gasification plant or excess water in the mine pits. About 19 million gallons of potable water would also be required; this water would either come from existing wells or from the potable water supply at the gasification plant.

1.5.3.2 Mining Operations and Reclamation

The lignite seam in the Beulah-Hazen coalfield (Beulah-Zap bed) is almost horizontal, has good continuity and quality, and averages 14 feet thick. The mining plan is based upon balancing the overburden (which averages 70-80 feet thick) to coal ratio among four large (100 cubic yard class) draglines for the entire life of the mine. The sequence of mining operations would be as follows:

a. Topsoil would first be removed from an initial mining area and stockpiled by wheeled tractor-scrapers. Since the initial stockpile could be in place for up to several years, it would be protected from wind erosion by seeding. Initial mining would begin where the overburden is about 20 feet thick. A "box" cut would be made by the dragline with the resulting spoil (excavated overburden) piled in a windrow on the surface outside of the minable coal reserve limit. A pit, about 5,000 feet long by 120 feet wide, would be excavated down to the coal surface, with provisions for truck ramps established on the spoil side of the cut.

b. Behind the dragline, the lignite would be bladed off and cleaned with a rotary broom. Drilling and blasting, using an ammonium nitrate-fuel oil mixture to fracture the lignite, follow. On the average, blasting would occur one time per workday per pit; usually during the evening shift. A crawler-mounted electric loading shovel of 18- to 20-cubic-yard capacity would then dig and load the fractured coal into 150-ton diesel-powered bottom dump trucks. These trucks transport the coal over haul roads to the dump station where they would arrive at the rate of 20/hour.

c. The dragline would reverse its direction at the planned pit end and move to its starting point on the highwall side of the cut. Once repositioned, the dragline would dig into the highwall, establishing a new digging face. Spoil from this new highwall inset cut would be placed in the old pit, now cleared of all coal by the loading shovel which advances away from the dragline. The sequence described continues, resulting in long parallel spoil windrows (Figure 1-8).

d. The second or third spoil windrow back from the pit (depending on timing and stability factors) would be leveled by bulldozers to a rolling or flat topography, depending upon the prescribed reclamation plan (Section 4.2.4). Finally, up to 5 feet of topsoil would be distributed by wheeled tractor-scrapers. The topsoil may be brought either from stockpiles or the highwall side of the cut as needs dictate. Final grading of topsoil and seeding would be done just prior to the growing season.

All operations in mining are closely interrelated. The burial of processed ash with overburden illustrates the point. Ash haul trucks (50-ton, rear-end dump diesel trucks with special bodies) would traverse haul roads partly in conjunction with coal trucks. Ash would be dumped in the mining area and covered with the overburden that the dragline would deposit in a previously mined pit. The ash would generally be buried about 80 to 100 feet below the surface.

Typical plan views of the mining system are shown in Figures 1-9 and 1-10. These sketches do not detail the treatment of final highwalls which would be trimmed down to conform with the rehabilitation plan. In general, however, the dragline would make a final pass, filling the final pit with overburden which had been stockpiled above the highwall in the previous pass, and also sloping the highwall itself.

Final shaping and grading would be done by bulldozer to attain the prescribed slopes approved by the North Dakota Public Service Commission. Topsoil from the highwall stockpile would then be placed by a scraper followed by seeding. A more detailed reclamation plan is included in Section 4.2.4.

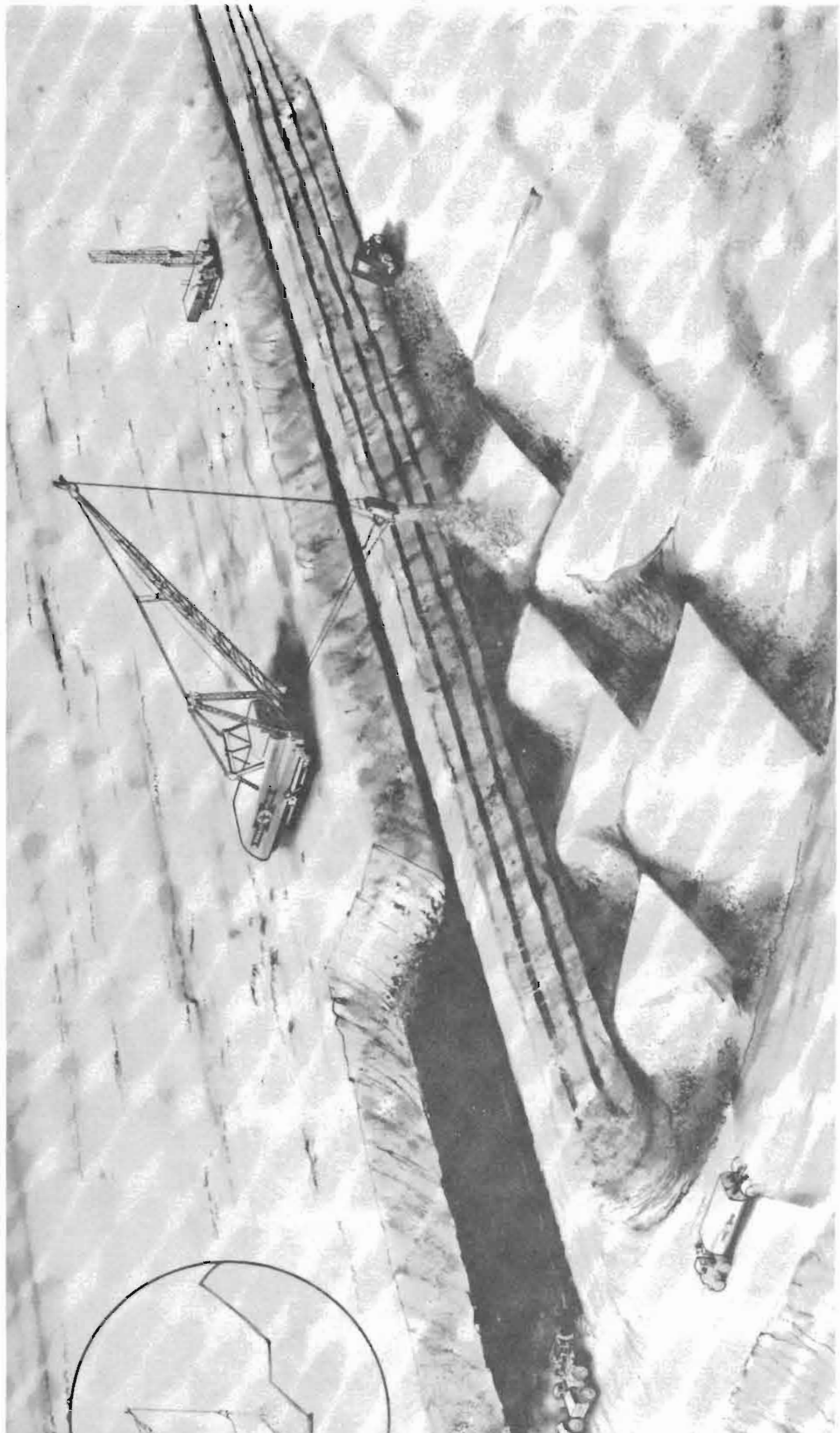


FIGURE 1-8. Typical Strip-Mining Operation

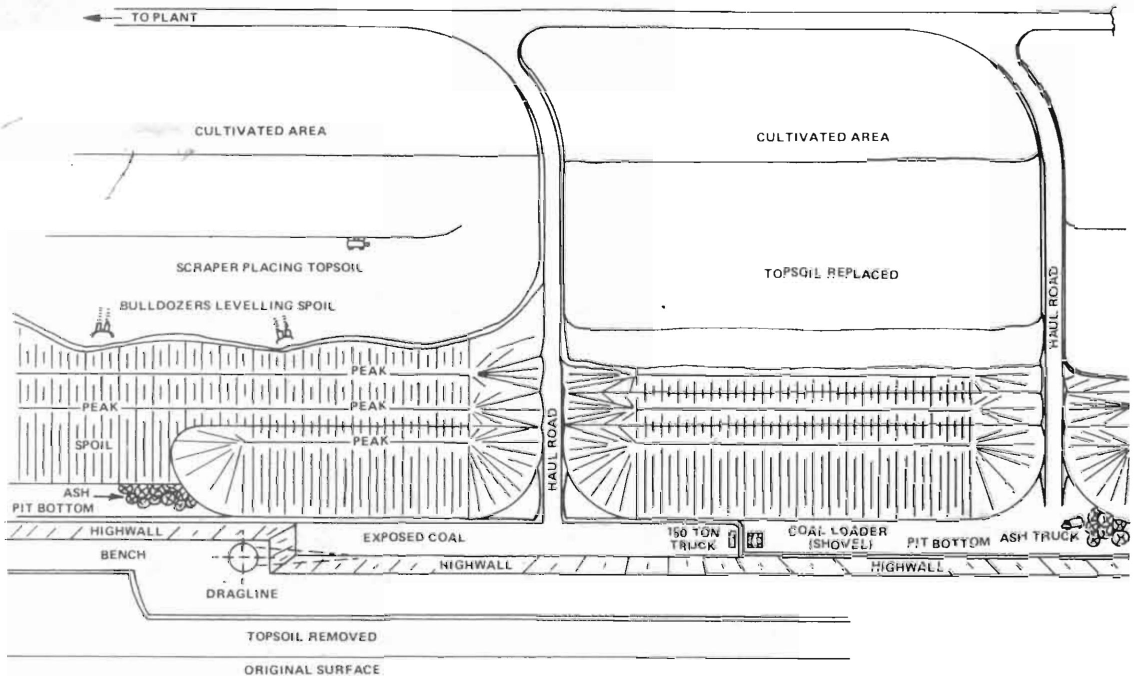


Figure 1-9 NORTH DAKOTA MINING WITH TOPSOIL REPLACED BY TRACTOR-SCRAPER

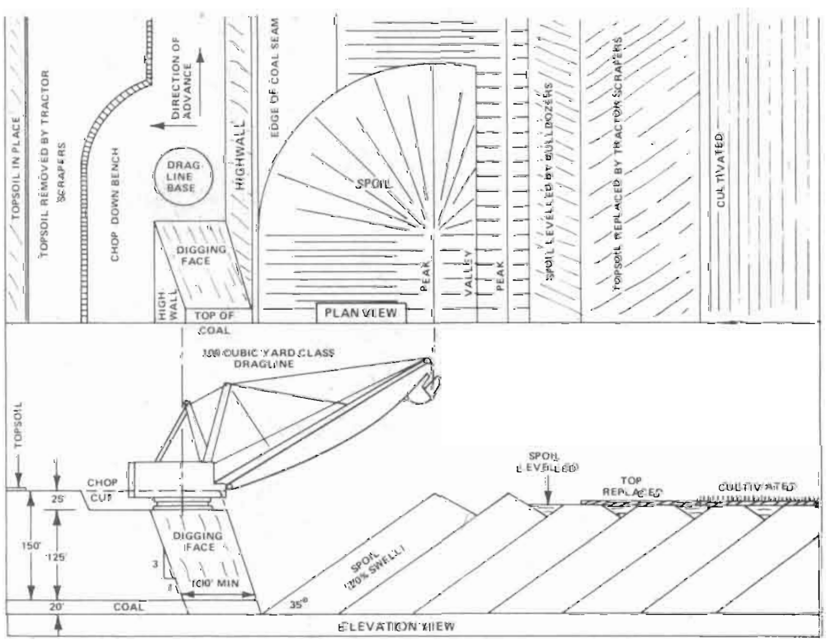


Figure 1-10 PLAN AND ELEVATION VIEWS OF TYPICAL DRAGLINE MINING

1.5.4 Coal Gasification Plant

1.5.4.1 General

(1) Access

One major access road would be constructed for the plant connecting the plantsite with County Road 11 along the proposed product pipeline and railroad access (Figure 1-6). It would be a paved two-lane primary road. Other access would be available from the west and north by existing unpaved county roads.

The water pipeline would be maintained via existing county roads. Construction access would be supplied by temporary dirt roads in the plantsite. As noted in Section 1.5.6.3, a railroad would also afford access to the plantsite, especially for heavy construction material and removal of byproducts.

(2) Construction

Construction of the first phase of the proposed gasification plant would start in 1978. The first phase would be fully operational by 1981. Construction of the second phase would start in 1983 and be completed in 1987. The ultimate production capacity of 250 MMcf/day would be reached by 1988. An artist's representation of the completed facility is shown in Figure 1-11.

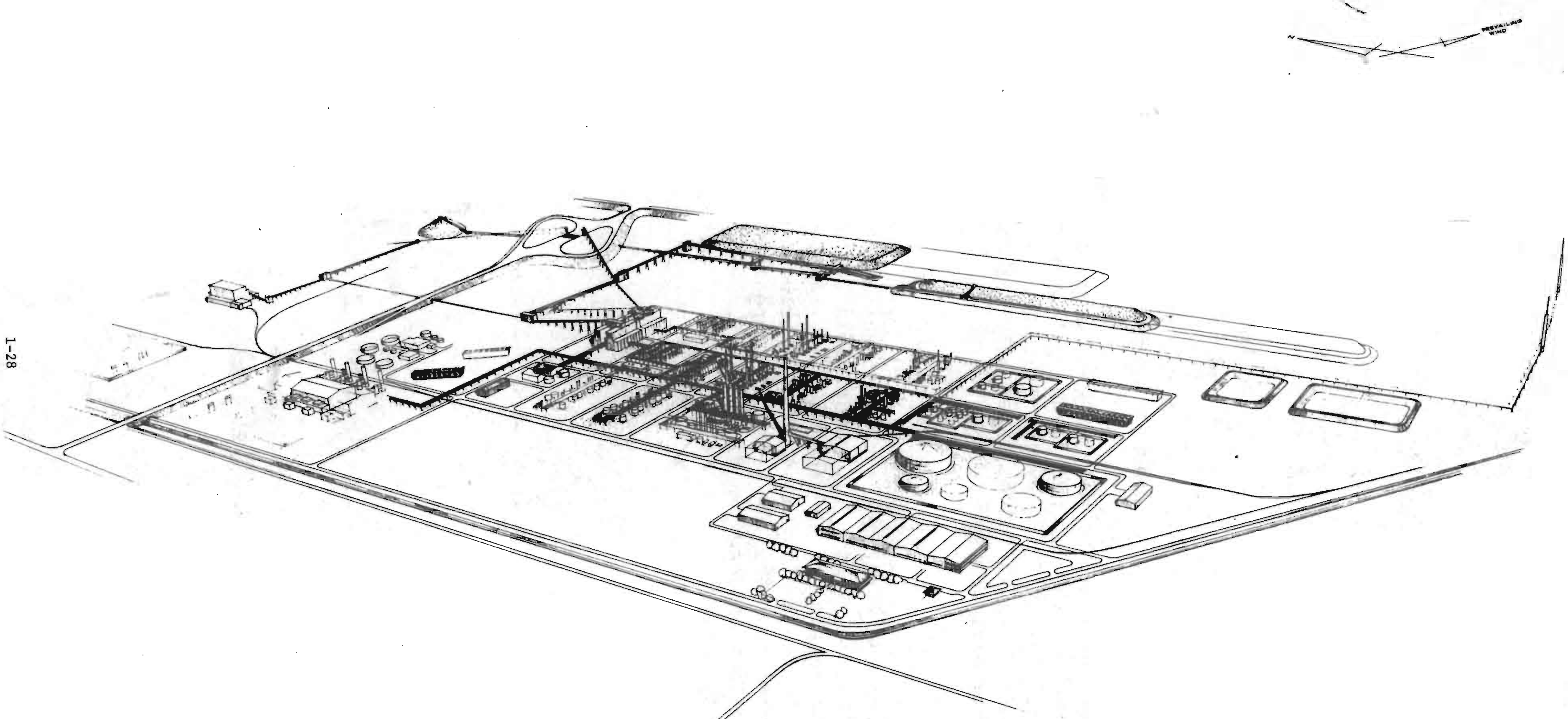
(3) Personnel Requirements

The estimated number of construction and operations workers needed for the plant and mine by year would be as follows:

Average Manpower Requirements

	1978	1979	1980	1981	1982	1983	1984	1985	1986	1987	1988-2015
Construction											
Plant	312	1077	1796	812	300	267	808	1121	1136	313	0
Mine	130	320	250	240	30	200	200	200	0	0	0
Operation											
Plant	0	0	0	414	414	414	414	414	414	640	640
Mine	47	81	147	278	278	278	278	278	310	360	360
Total	489	1478	2193	1744	1022	1159	1700	2013	1860	1313	1000

The peak labor force requirements would occur in 1980 and 1985.



ANG COAL GASIFICATION PROJECT
NORTH DAKOTA

FIGURE 1-11

LUMMUS	THE LUMMUS COMPANY, BLOOMFIELD DIVISION
SCALE	DWG. NO. SKE-7102-902-1

(4) Construction Camp

A construction camp to house about 20 percent of the annual work force plus seasonal peaks would be built by ANGCGC in the vicinity of the plantsite but outside the main perimeter. The complex would be laid out similar to a motel; housing units would house one or two workers to a room. Appropriate dining, laundry, parking, and recreation facilities would also be provided.

Water for the camp would be provided from onsite wells until the water pipeline from Lake Sakakawea is operational. Sanitary sewage would be gathered and treated in a package plant of activated sludge extended aeration design that would provide primary and secondary treatment. Discharge from the sewage treatment plant would be further polished in an oxidation pond before release. Solid wastes would be collected by a private refuse service.

Power for the camp would be provided from the plant substation (Section 1.5.4.7); a step-down transformer would be located at the construction camp to obtain necessary voltage levels. Telephone communications would be provided from cables installed to serve permanent plant facilities.

(5) General Plant Makeup and Layout

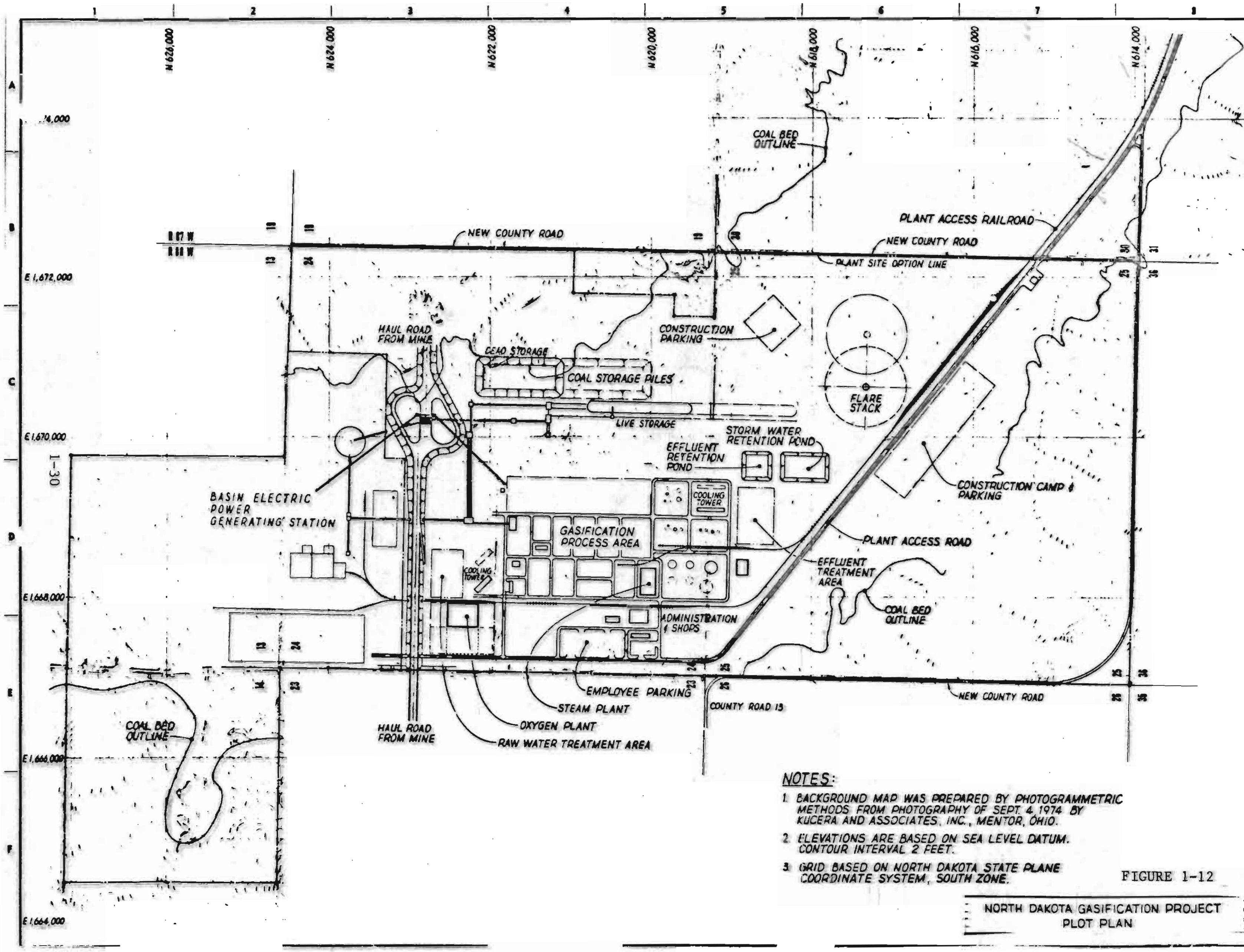
The coal gasification plant is essentially a self-sufficient facility designed to produce 250 MMcf of SNG/annual average day or about 275 MMcf/stream day. The plant would consist of the following process areas:

a. Coal preparation, handling, and storage;
b. Storage reclaim system;
c. Screening system;
d. Gasifier feed system;
e. Gasification units; and
f. Utilities.

Each area is described in detail below; general plant layout is shown in Figure 1-12.

1.5.4.2 Coal Preparation, Storage, and Handling

The proposed coal storage and handling system is shown schematically in Figure 1-13. The system is designed to receive and crush up to 4,000 tons of lignite from the mine per hour on an 18-hour day, 5-day-per-week basis. After crushing, weighing, and sampling, the



NOTES:

1. BACKGROUND MAP WAS PREPARED BY PHOTOGRAMMETRIC METHODS FROM PHOTOGRAPHY OF SEPT. 4, 1974 BY KUCERA AND ASSOCIATES, INC., MENTOR, OHIO.
2. ELEVATIONS ARE BASED ON SEA LEVEL DATUM. CONTOUR INTERVAL 2 FEET.
3. GRID BASED ON NORTH DAKOTA STATE PLANE COORDINATE SYSTEM, SOUTH ZONE.

FIGURE 1-12

NORTH DAKOTA GASIFICATION PROJECT
PLOT PLAN

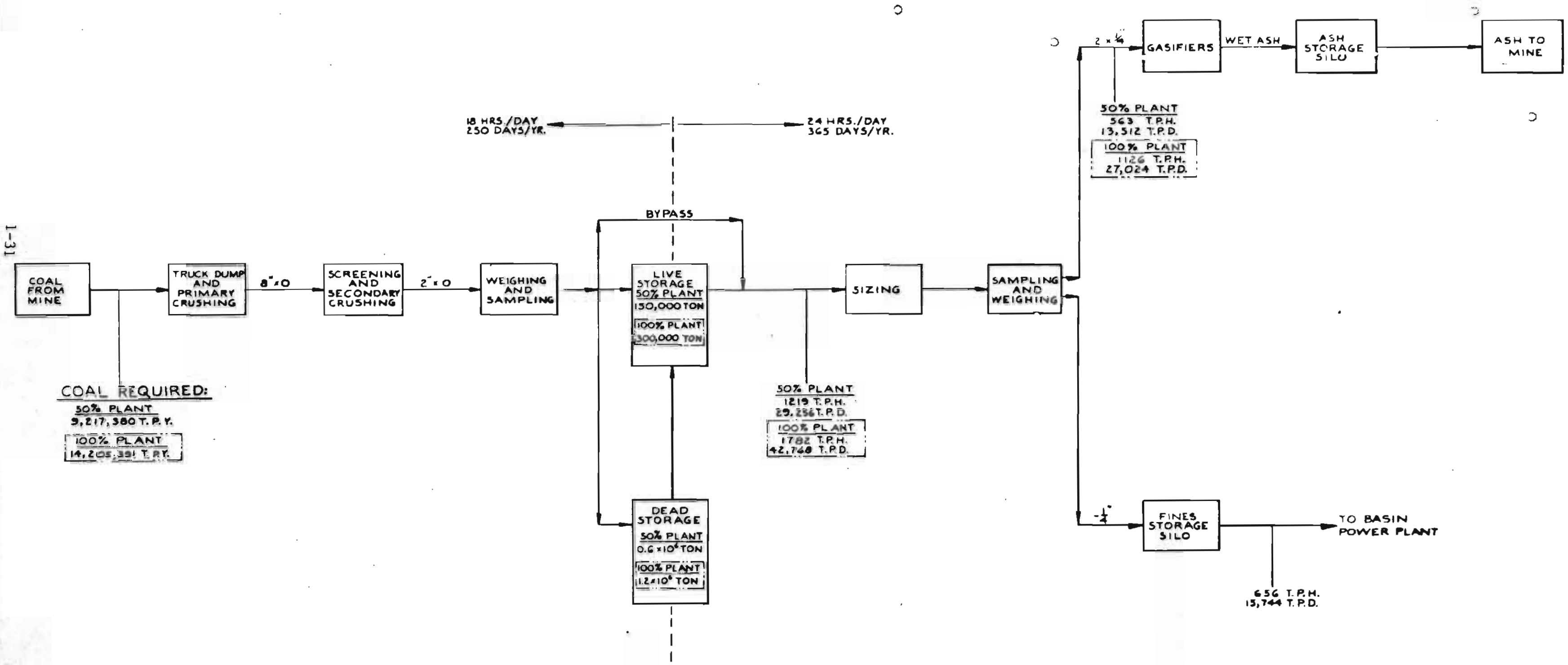


FIGURE 1-13

50% PLANT BASED ON 50% ANG & 2 UNIT POWER PLANT.
100% PLANT BASED ON 100% ANG & 2 UNIT POWER PLANT.
DAILY REQUIREMENTS BASED ON 91% SERVICE FACTOR

SCALE: NONE
DESIGNED BY R. PARKER 6-7-76
DRAWN BY R. PARKER 6-7-76

KAISER ENGINEERS

ANG COAL GASIFICATION COMPANY
NORTH DAKOTA GASIFICATION PROJECT
SCHEMATIC FLOW DIAGRAM
COAL AND ASH HANDLING

JOB No. 7381

coal would be conveyed to either an active or inactive storage pile for future use. The reclaim rate from storage would be approximately 1,780 tons per hour (tph), 24 hours/day, for sizing and delivery to the gasifiers. The gasifiers would require approximately 1,140 tph of the crushed and sized lignite. The remaining coal fines, approximately 640 tph, would be transported to Basin Electric by a conveyor for use in their powerplant. Figure 1-13 shows the tonnage required for feeding the gasifiers and the powerplant.

Raw lignite coal would be delivered to the truck dump station in 150-ton bottom dump trucks. The station can accommodate up to four trucks simultaneously. The coal would drop into a bin and be fed into one of the four primary crushers.

The crushers are designed to reduce the coal size from 36 inches in diameter to 8 inches while generating a minimum of coal fines. Any of three crusher-feeder systems would handle the normal daily tonnage requirements. The product of the primary crushers would drop onto a belt conveyor system to be weighed and conveyed to the first transfer point. At this point, the coal would be transfered to the screening and secondary crushing station.

All screening would take place on four 8- x 20-foot single deck screens for proper sizing. The undersize product of the screen would fall into a 4,000 tph collecting conveyor. The oversize screen product would be discharged from the screen into the secondary crushers. The crushers would reduce and discharge the product onto the same collecting conveyor as the undersize product. The screening and crushing area would be enclosed and equipped with bag-type filters to reduce fugitive coal dust.

The crushed product would be conveyed to a transfer station, where it would be sampled and analyzed to determine moisture and ash content and heating value to insure proper operation of the gasifiers. The lignite may be diverted to (1) active (live) storage piles, (2) inactive (dead) storage piles, or (3) the live storage reclaim belts. The normal route would be to live storage.

The live storage would consist of one 300,000-ton pile, part of which would be above and part below grade. The pile would be fed from a traveling boom stacker receiving coal from the 4,000 tph conveyor, which originated at the secondary crushing station. Actual live storage would be sufficient for about 7 days of gasifier plant production.

The dead storage would consist of a 1,200,000-ton pile sufficient to feed the plant for 30 days. Half this pile would be established during Phase I construction and the balance built up during Phase II construction.

The dead storage would be laid down and compacted in 1-foot layers to prevent fires by spontaneous combustion. Bulldozers and tractor-scrapers would be used to build up and spread the pile from the feed point. The pile would be approximately 1,200 feet square and about 30 feet high. To reduce wind caused fugitive dust, the slopes around the perimeters of the pile would be kept to a maximum of 20 percent grade and a latex coating applied. When the stacker or conveyor to live storage or reclaiming system is out of operation, the crushed lignite can either be compacted there and become part of dead storage or can be fed to the live storage reclaim conveyors.

1.5.4.3 Storage Reclaim System

Normally, the live storage feeds the plant on a day-to-day basis. The dead storage would be used only during extended shutdowns or strikes in the mine.

Reclaim from live storage at the rate of 1,780 tph would be accomplished with rotary plow feeders located in two tunnels beneath the live storage pile. The rotary plows would traverse the full length of the tunnel beneath the live storage and unload onto conveyors supplying the secondary screening bin.

The traveling boom with the rotary plow reclaim system would not produce a homogeneous feed to the gasifiers; however, a certain amount of mixing would be accomplished by the differential motion between stacking and reclaiming. Reclamation from dead storage would be accomplished by front-end loaders and trucks transferring material to the live storage pile. The reclaim conveyor would transfer the lignite to the screen surge at the hoppers in the secondary screening building.

1.5.4.4 Screening System

Lignite reclaimed from live storage via the reclaim belt would be transferred to the secondary screening building for final sizing of the gasifier feed. These conveyors would enter the building and evenly distribute coal over the screen feed hopper. The 1,800-ton capacity hopper would feed all the sizers through variable vibrating feeders. The sizing would separate the fines from the properly sized coal and deposit each on separate conveyors.

The properly sized coal would be sampled and delivered to the gasifier feed belt. The undersize fines product would be sampled, weighed, and delivered to one of two 5,000-ton storage silos which provide surge capacity between the ANGCGC and Basin Electric plants.

1.5.4.5 Gasifier Feed System

The gasifier feed system would consist of two sets of conveyors which would be used alternately and independently. Each system would consist of a feed conveyor, diverting chute, transfer belt, and a reversing shuttle conveyor over each line of gasifiers.

The presized coal would fall onto one of the two gasifier feed belts. The gasifier feed conveyor would leave the coal screening building and enter the gasifier building perpendicular to, and in the middle of, the gasifier feed bins. At the top of the first line of gasifiers, the feed belt would discharge through a diverting chute to either the shuttle conveyor on top of the first line of gasifiers or the transfer belt to the second line of gasifiers.

If one part of the conveyor system is not working, the entire system from the screening building to the bins would be switched to the standby system.

1.5.4.6 Gasification Units

The gasification plant proper would include all process units necessary to produce pipeline quality gas from presized lignite. The main process area would consist of the two following major systems:

a. A gasification system composed of six process units:

(1) Gasification;
(2) Shift conversion;
(3) Gas cooling;
(4) Rectisol unit;
(5) Methanation; and
(6) Gas compression and drying.

b. A byproduct recovery system composed of three process units:

(1) Gas liquor separation;
(2) Phenosolvan unit; and
(3) Ammonia recovery.

Most of the process units would be open-air outdoor structures located as shown in Figure 1-11.

a. Gasification System

(1) Gasification

The plant would contain 26 gasifiers; approximately 23 of these would be required to be in operation to produce 250 MMcf/day of SNG. The coal received from the mine, after preparation and classification, would be transported by a coal belt conveyor to storage bins on top of the gasifiers. The coal would be brought to gasifier pressure in a coal lock. About 98 percent of the gas escaping during the operation of the coal lock would be collected and fed into the process; the remaining 2 percent would be exhausted by air ejectors. Rotating coal distributors would feed the coal evenly across the gasifier vessel where the coal would be converted into gas under pressure (Figure 1-14). While the coal travels from top to bottom of the gasifier, it is dried, devolatized, and gasified.

A mixture of oxygen and superheated steam is required for gasification. Part of the steam necessary for the process would be generated in the water jacket surrounding the gasifier. The oxygen-steam mixture would be introduced through a bottom rotating grate into the ash bed. At a moderately high pressure, the partial combustion of the coal with oxygen would supply the heat necessary for the gasification reactions. The temperature of the gas leaving the gasifier would be about 523^{o} F; its pressure about 427 psig.

The composition of raw gas leaving the gasifiers would be as follows:

Components	Percent by Weight
Dry Gas	51.7378
Water	45.4125
Hydrogen Cyanide	.0002
Chlorides	.0016
Tar	1.6125
Oil	.3669
Naphtha	.1834
Phenols	.3125
Fatty Acids	.0881
Dust	.2845

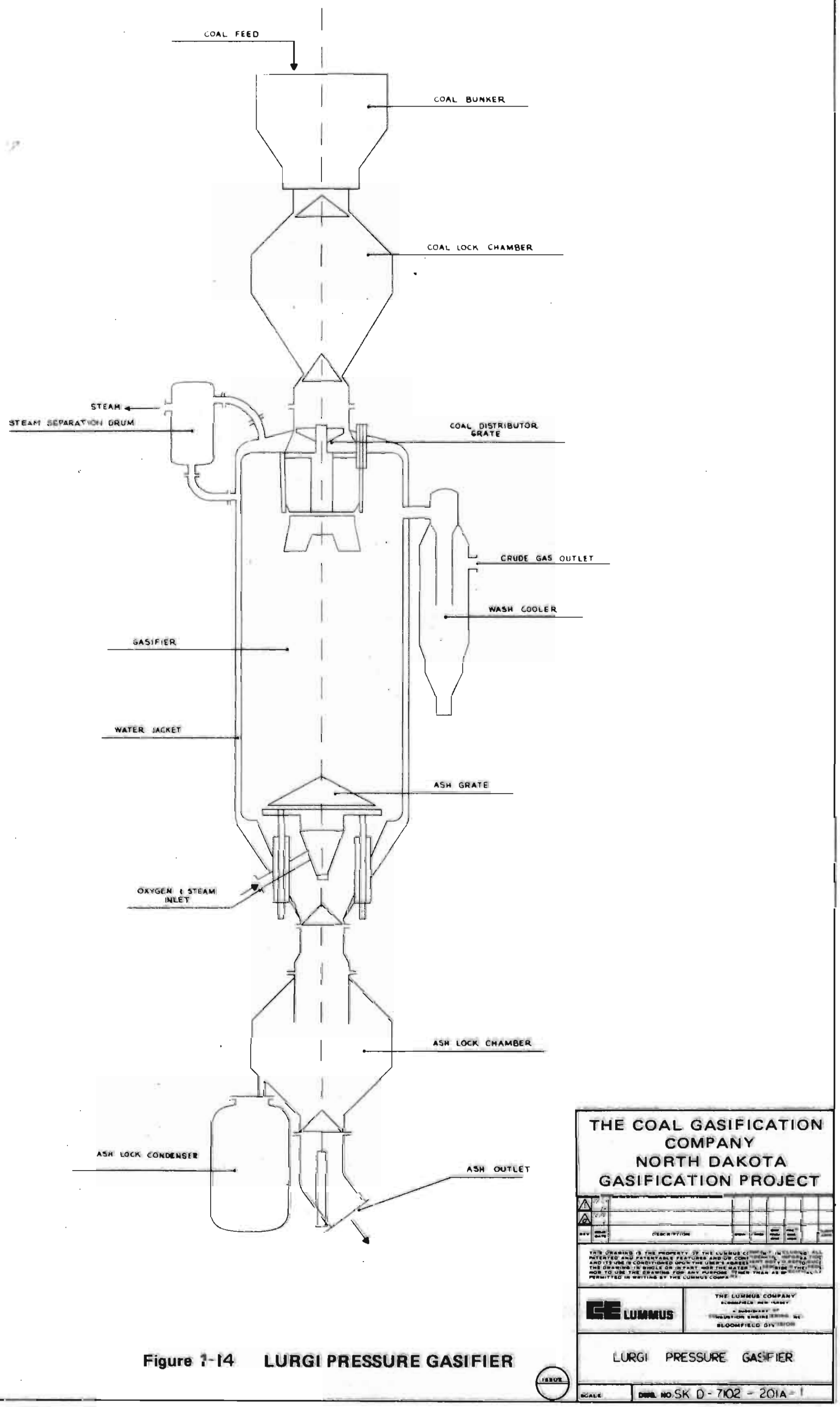


Figure 1-14 LURGI PRESSURE GASIFIER

The composition of the dry gas would be (see Appendix A for definitions):

Compound	Molecular Percent
H_2	38.77
CO	15.63
CO_2	32.52
CH_4	10.805
C_2H_6	.495
C_2H_4	.07
C_3H_8	.08
C_3H_6	.07
C_4H_{10}	.04
C_4H_8	.07
N_2	.07
Ar	.05
H_2S	.35
COS	.01
Organic Sulf.	.01
NH_3	.96

The hot product gas would be conveyed from the vessels to the shift conversion and crude gas cooling units. The ash would be removed by a rotating grate at the bottom of the gasifier and discharged semiautomatically through an ash-lock. As the ash is discharged, a water quench would be applied. About one-third of the water would be evaporated; the rest would remain with the ash. Excess water would be separated from the ash, prior to its disposal in the mines. A block flow diagram of the entire process is shown in Figure 1-15.

(2) Shift Conversion

The amount of methane (the principal component of natural gas) in the crude gas from the gasification unit would be quite low and further chemical conversion of the crude gas to increase the methane content is necessary. This conversion would be performed in the Crude Gas Shift and Methanation Units. The shift conversion unit is designed to produce the hydrogen (H_2) required to adjust the H_2:CO ratio for the methanation unit. This would be accomplished through the "water gas shift" reaction carried out over a catalyst in the presence of steam as follows:

$$CO + H_2O \rightarrow CO_2 + H_2 + 16{,}538 \text{ Btu per lb. mole}$$

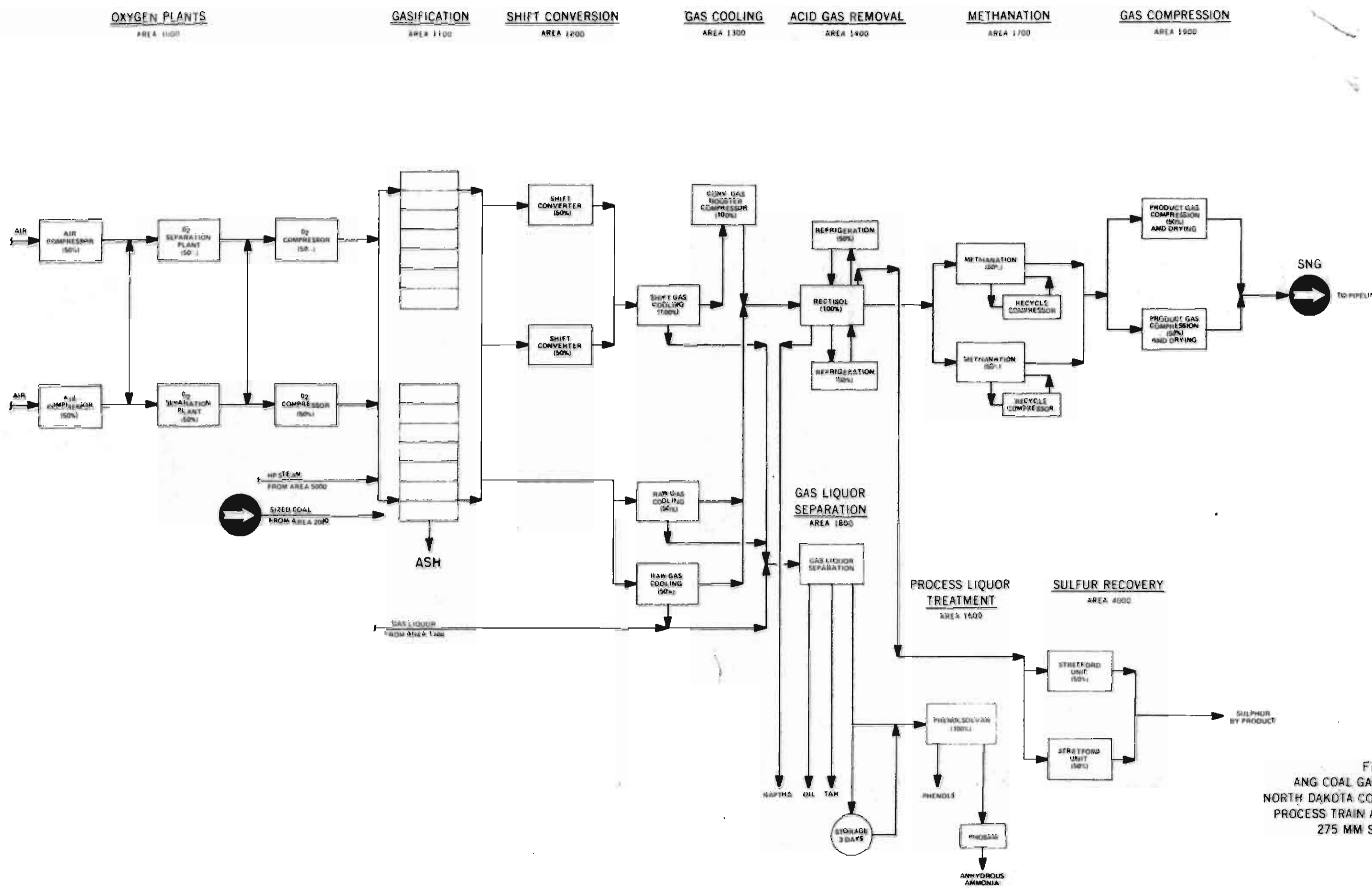


Figure I-15
ANG COAL GASIFICATION COMPANY
NORTH DAKOTA COAL GASIFICATION PROJECT
PROCESS TRAIN ARRANGEMENT DIAGRAM
275 MM SCF/SD CAPACITY

Approximately 33 percent of the total crude gas would be subject to shift conversion with the balance bypassed directly to the gas cooling unit. The proportions of the two gas streams would be adjusted to achieve the desired H_2:CO ratio for methanation.

(3) Gas Cooling

The gas cooling unit is designed to cool the raw gas from gasification and shift conversion and to remove the heavier hydrocarbons and unreacted steam before low temperature purification. The cooling scheme is arranged to recover and utilize as much of the process heat as practical; further cooling would be accomplished in water coolers.

The gas cooling for each phase of the gasification plant would be accomplished in three parallel trains. Two trains would be used for cooling the crude gas bypassing the shift conversion area and the other train for cooling the converted gas. Converted gas would be compressed and combined with the crude gas stream. The mixed gas stream, having a predetermined H_2:CO ratio, would be conveyed to the gas purification unit. The condensate from gas cooling would go to the gas liquor separation unit for recovery of tar and oil.

(4) Rectisol

The gas purification unit would utilize the Rectisol process to remove carbon dioxide (CO_2), sulfur compounds, and other impurities from the raw gas. A flow diagram of the process is shown in Appendix B. Sulfur compounds (H_2S and COS) would be removed to a level of less than 0.1 ppm (by volume) and the sulfur free gas then passed to methanation.

(5) Methanation

The methanation unit would convert the low Btu synthetic gas to methane-rich high Btu gas by the following exothermic reactions:

$$CO + 3H_2 \rightarrow CH_4 + H_2O + 94{,}250 \text{ Btu per lb. mole } CH_4$$

$$CO_2 + 4H_2 \rightarrow CH_4 + 2H_2O + 77{,}700 \text{ Btu per lb. mole } CH_4$$

Other minor reactions which would take place are the hydrogeneration of ethylene to ethane and hydrocracking of ethane to methane. About 60 percent of the methane in the final product would be produced here.

Feed gas entering the unit from each gas purification unit (Rectisol) would be heated and then mixed with recycled methanated effluent gas before being methanated in parallel catalytic reactors. Diluting the feed gas with methanated effluent would limit the temperature rise across the reactors. The reactors are designed as fixed bed downflow units employing a pelleted reduced nickel-type catalyst.

The reaction heat would be removed by generation of 1300 psig steam in waste heat exchangers at the outlet from each reactor.

Gas leaving the synthesis loop would be passed through a cleanup reactor (final methanation reactor) to accomplish essentially complete conversion of carbon monoxide (CO), and then cooled by successive heat exchange with fresh feed gas, air, and cooling water. Water condensed from the gas would be separated and forwarded for recovery as boiler feed water. The net product would be sent to the gas compression unit.

(6) Gas Compression and Drying

This section is designed to deliver the SNG to the pipeline at a pressure of 1,440 pounds per square inch (psig). The product gas compression system would consist of four parallel systems of centrifugal compressors, driven by condensing steam turbines. The product would be dry, in addition to having the CO_2 content reduced to below 0.4 percent. Final product gas would now be ready for metering and discharge to the pipeline for distribution. Final drying of the product gas to pipeline gas specifications would be accomplished by a glycol dehydration unit.

The specification of the SNG product is given below:

Constituent	Percent by Volume
CH_4	95.95
H_2	3.00
CO	0.05
CO_2	0.40
N_2	0.60
Heating Value	970 Btu/Standard Cubic Foot (Minimum)

b. Byproduct Recovery

(1) Gas Liquor Separation

The gas liquor would contain tar, tar oil, naphtha, and dissolved compounds such as phenols, ammonia, CO_2, and hydrogen sulfide

(H_2S). Tar is defined as a heavier-than-water organic liquid phase, while tar oil is the lighter-than-water organic liquid phase.

The gas liquor separation is designed to clean up tarry and oily gas liquors by separating the incoming streams into tar, tar oil, recycled gas liquor, and clarified aqueous liquor streams. Flash gases released from the gas liquor by pressure reduction would be scrubbed to remove ammonia.

The gas liquor streams originating from the gasification, shift conversion, and gas cooling units would be cooled, combined, and reduced in pressure. The entrained gases, consisting primarily of CO_2 but with traces of CH_4, CO, NH_3, and H_2S, would be released and passed through a water scrubber for recovery of ammonia and then to a low pressure flare for incineration. A flow diagram of the process is shown in Appendix B.

(2) Phenosolvan

The process water from the Gas Liquor Separation Unit, which would be contaminated with phenols, ammonia, H_2S, and CO_2, would be treated in the Phenosolvan Unit for removal of phenols prior to being transferred to the ammonia recovery area.

The incoming process water would be passed through extractors where an organic solvent is used to extract phenols. The organic solvent would be distilled and separated from the phenol and recycled to the extractors for reuse. The crude phenol byproduct would be recovered and transferred to storage for subsequent use as part of the byproducts feed to the boilers.

(3) Ammonia Recovery

The Ammonia Recovery unit would use the Phosam-W Process which involves the selective absorption of ammonia from the gas liquor leaving the Phenosolvan Unit by a water solution of ammonium phosphates (Appendix B). The Phosam-W Process would also remove the CO_2 and H_2S from the process water which would then be used in the process cooling water tower.

A materials balance for the gasification plant, a trace element mass balance, a plant energy balance, and pollutant emission and abatement parameters are also presented in Appendix B. The thermal efficiency of the gasification process is about 84.6 percent; that is, 84.6 percent of the heating value of the coal used in the process would be recovered in the product gas and byproducts.

owever, because a large portion of the byproduct production would used to generate steam (see next Section), the overall efficiency the entire operation would be about 66.7 percent.

1.5.4.7 Utilities

In addition to facilities physically involved in the coal preparation and gasification phase, a group of supporting utilities are required for plant operation. These include such items as:

a. Steam generation and distribution;
b. Power distribution;
c. Oxygen production;
d. Raw water supply and water treatment;
e. Fire protection; and
f. Plant communications.

Although these utilities serve a supporting role in the gasification process, their dependability would be necessary to maintain safe and efficient plant operation at all times.

a. Steam Generation and Distribution

The normal steam requirements of the gasification plant would be supplied from two sources; in-plant boilers which would be fired by certain of the plant liquid byproducts and waste heat recovery from plant processes. High pressure steam (1300 and 550 psig) would be used primarily to drive compressors and large pumps, and as process steam for coal gasification. The plant boilers would generate only 1300 psig steam. Lower level steam, mostly from waste heat exchangers, would be used for smaller turbine drives, and process and heating applications.

The following amounts of byproducts would be burned per stream day for the generation of steam:

Tar	192,330 gal
Oil	70,758 gal
Naphtha	39,804 gal
Phenols	35,752 gal

In case of a plant upset which results in the loss of high pressure steam generation, emergency steam would be purchased from Basin Electric.

b. Power Distribution

The electrical power for the gasification plant would be provided on overhead transmission lines from the Basin Electric substation.

The power distribution system would operate at 13.8 kv to supply all local plant substations where the power would be transformed to the appropriate voltage. The wattage requirements for the plant would be about 135 MW. Total requirements, including mining operations would be about 160 MW.

Power to the pump station (water intake) would be provided over two separate circuits. One circuit would run underground from the plant to the pump station along the water pipeline route. The second, back-up, circuit would be extended from the Oliver-Mercer Electric Coop. area distribution system overhead to the pumphouse except for the final 3,000 feet which would be underground.

Power for construction would be provided by Oliver-Mercer Electric Coop., the REA cooperative serving local areas in Oliver and Mercer Counties. Power would be provided from a 13.8-kv substation located on the construction site; this substation would also provide power to the construction camp. A peak construction requirement of 15 MW is estimated for the period 1978-79 for both the ANGCGC and Basin Electric projects.

At the end of the plant life (about 25 years), the overhead powerline and its support towers to the plant would be removed. The pump station and its feeder circuits and the mine distribution system would be turned over to Basin Electric for the continued operation of their powerplant.

c. Oxygen Production

The oxygen facilities are designed to provide 6,000 tpd of gaseous oxygen to the process plant with an oxygen purity of 99.5 percent. Four parallel process trains would be utilized consisting of both turbine-driven and electric motor-driven axial/centrifugal air compressors, air separation units (cold box), and turbine-driven and electric motor-driven centrifugal oxygen compressors. The air separation units would use low temperature liquefaction and fractionation to separate and purify the major constituents of air (oxygen, nitrogen, and noble gases).

d. Raw Water Supply and Water Treatment

The raw water would be piped from Lake Sakakawea (Garrison Reservoir) through a submerged intake in Renner Bay (Figure 1-6). Pump capacity would be installed to meet the peak operating requirements of both the gasification plant and Basin Electric's powerplant of approximately 22,500 gpm or about 36,000 acre-feet/year. The sequence of water treating steps (with flow rates), water balance, and the interrelation with waste treatment are shown in Figure 1-16.

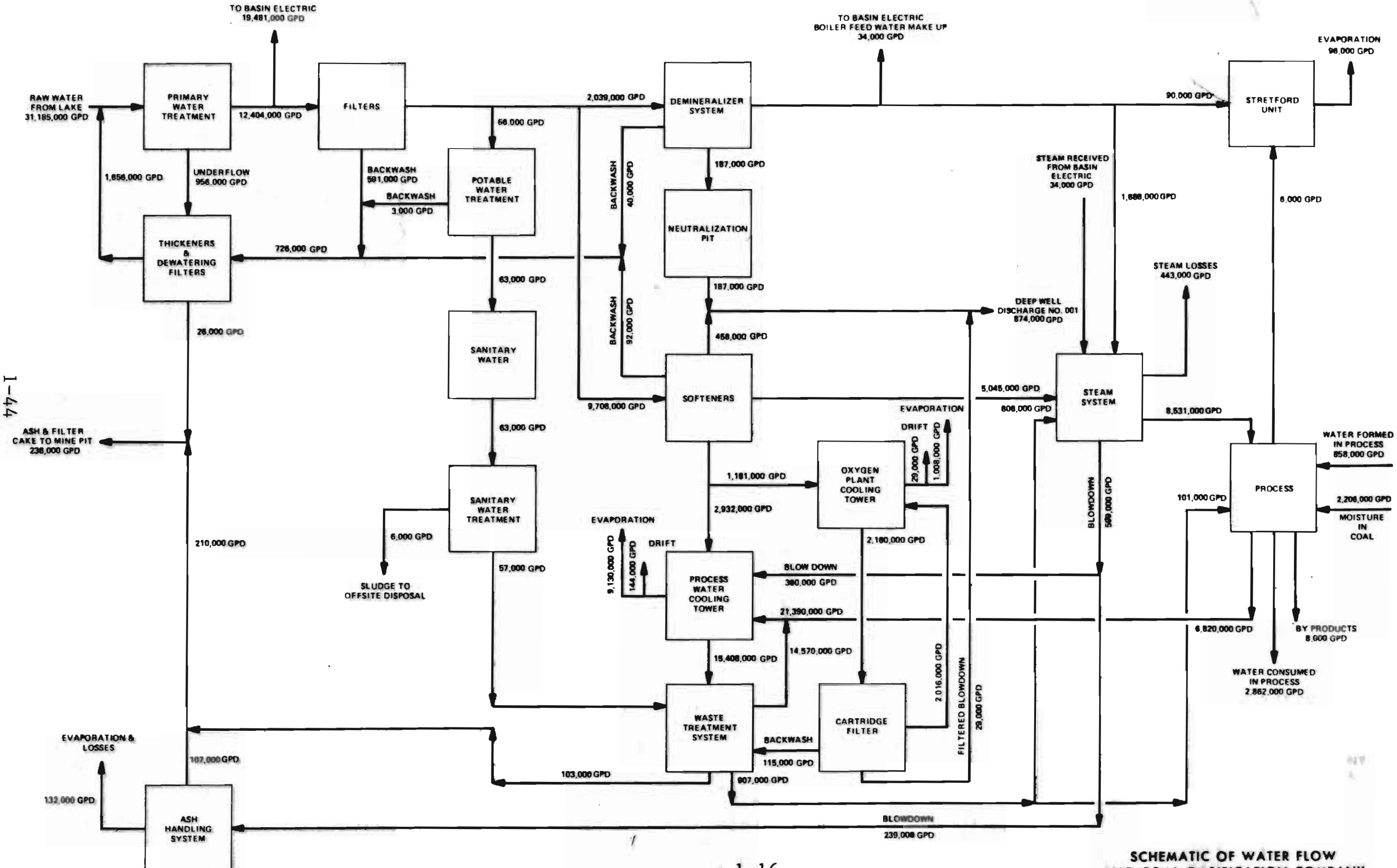


FIGURE 1-16

SCHEMATIC OF WATER FLOW
ANG COAL GASIFICATION COMPANY
MERCER COUNTY, NORTH DAKOTA
REVISED JULY 1, 1977

Incoming raw water would be preheated prior to treatment to insure efficient operation of the clarifier during the winter. Upon entering the plant, the raw water would be processed in a suspended-solids contact softener-clarifier. Alum, lime, and poly-electrolytes would be added to reduce the silt content and calcium hardness of the raw water. The clarifier underflow (silt and $CaCO_3$) would be processed in a thickener and then sent to ash handling where it would be buried in the mine with the ash. The thickener overflow would be returned to the clarifier. Clarified water would then be provided to both the Basin Electric powerplant and the gasification facilities.

A portion of the clarified water, about 820 gpm, would be used as cooling tower makeup for the oxygen plant. This water would be pH adjusted with sulfuric acid and treated with chlorine to control algal growth. One of two corrosion inhibitor systems would be used, either chromate with a subsequent removal system, or an organo-phosphate.

The remainder of the clarified water would be filtered through anthracite pressure filters to further lower the turbidity. A portion of this water would be sent to the potable water system after pH adjustment, chlorine addition, and activated carbon treatment. The potable water distribution system would be buried 6-1/2 feet deep to protect against freezing and would consist of a looped piping system serving use points, as required. In addition to supplying potable water to the major plant buildings, the system would also supply the plant safety showers and eye baths.

Zeolite softeners would remove calcium and magnesium from the low and medium pressure boiler feed water. The softeners would be regenerated with sodium chloride with the spent regenerant and rinse stream routed to the deep well for disposal. The softened water would be stored in a 1.44 million gallon surge tank from which it would be pumped to the low and medium pressure steam deaerators and then to the boilers.

e. Fire Protection System

The fire protection system would be a common system shared between the gasification plant and the Basin Electric powerplant. It would consist of a fire water loop with two water sources; one would be the powerplant cooling tower basin, and the other source would be the gasification plant clear well. Chemical and foam fire suppression equipment and mobile equipment would also be used where appropriate.

The fire water loop would consist of a piped network around the operating and tankage areas and would be provided with isolation valves so that portions of the system may be isolated for repair or maintenance. Fire hydrants would be provided in all areas of the gasification plant and powerplant.

f. Plant Communications

The gasification plant would be provided with two communication systems: telephone and radio. An in-plant dial telephone system would be installed. This system would be automatically monitored against failure to the degree that it is acceptable for fire reporting and thereby negates the need for a separate fire alarm system. The system would allow outside communication from designated telephones.

Communications to the water intake pump house would be remote controlled from the plant via an underground telephone cable. Level controls in the water storage sump at the plant would keep operating personnel aware of water consumption and supply. By resetting the controls and therefore altering the number of pumps operating (or their output), the water supply could be constantly regulated from the plant.

1.5.5 Pollution Control and Abatement

1.5.5.1 General

Pollution control and abatement facilities for the coal gasification plant are designed to limit the discharge of potential pollutants. Most byproducts arising from the gasification processes, rather than being disposed of, would either be recovered for sale or used in the plant. Five sources of potential pollutants require special treatment:

a. Wastewater
b. Gaseous effluent
c. Cooling facilities
d. Solid wastes
e. Liquid byproducts

Abatement methods and facilities for each of these sources are discussed in detail below.

1.5.5.2 Wastewater Treatment

No waste streams would be discharged to surface waters from the coal gasification plant. Water would be recovered to the maximum possible extent for reuse. The portion that is not recovered would be either disposed of with the waste solids, lost as vapor from cooling processes or disposed of in the deep well (Figure 1-16).

a. Treatment Facilities for General Service Water and Surface Runoff

All process areas, including areas around pumps and other sources of contaminated liquids, would be paved with concrete. Water drainage from these areas would be collected in contaminated water sewers and transported to a 570,000 ft^3 (6-acre) retention pond.

Water that is not evaporated would first be treated in a gravity oil separator followed by flocculation and clarification. The oil recovered would be incinerated. The sludge from the clarifier would be sent to the raw water thickener and then to the ash handling system for burial in the mine. The clarifier overflow would be sent to the process water cooling tower.

Stormwater runoff from clean areas on the plantsite and natural drainage from surrounding areas would be collected in open ditches and culverts and routed into a 3.75 million ft^3 retention pond. Since inflow would be intermittent and only during storms, there would not be any outflow from this pond unless a storm exceeded the 25-year flood event.

Mining and reclamation will require impoundments to intercept runoff and mine-pit water. These impoundments would be designed to withstand a 25-year flood event as required by the North Dakota State Engineer's Office, State Water Commission and MESA laws.

b. Domestic Sewage Treatment Facilities

About 50,000 gpd of domestic sewage would be biologically treated in a package-type sanitary waste treatment unit. This unit includes facilities for biological oxidation, clarification, and chlorination. Solids accumulating in this unit would be used as a soil conditioner in the reclamation program. The effluent from the sanitary waste treatment unit would be reused in the ash handling facilities or other process areas. Additional capacity would be installed to handle the larger sewage treatment load during the construction period.

c. Multieffect Evaporator

The blowdown stream from the process water cooling tower would be purified in a multieffect evaporator. The evaporated water would be condensed and used as low pressure steam boiler feed water and a portion would be sent to the Phosam-W ammonia recovery plant. Sludge from the evaporators consisting of 92 percent water, 6 percent acetate, 1 percent phenols, and 1 percent inorganic salts would be buried in the mine at a rate of 70 gallons/minute. This would result in 1,950 lbs of acetate salts, 325 lbs of phenolic salts, and 325 lbs of inorganic salts being buried in the mine each hour.

d. Other Wastewater Treatment Facilities

Due to buildup of impurities in the liquid phase of the Stretford sulfur recovery unit, a small purge would be required. The purge stream would be sent to a recovery system to reuse the chemicals.

e. Deep Well Disposal

The regeneration wastes for the softened and demineralized water streams would be combined with low pressure steam blowdown; these streams are not amenable to further reuse and would be disposed via a deep well. The estimated chemical composition of the total stream (234 gpm average;Phase I) for deep well disposal is shown in Table 5. Details of a study by Woodward-Clyde Consultants as to the feasibility of the deep well are presented in Section 2.1.3,1c.

TABLE 1-5

WASTE STREAM TO DEEP WELL DISPOSAL

PARAMETER	CONCENTRATION (mg/1)
$CaSO_4$	540
$MgSO_4$	460
Na_2SO_4	6460
$NaCl$	2770
$NaHCO_3$	110
$CaCl_2$	860
$MgCl_2$	730

Source: The Lummus Company, July 1975

1.5.5.3 Gaseous Effluent Systems

Sources of gaseous emissions from this plant would be the steam boiler and superheater, flares (from both the gasifiers and emergency systems), start-up incinerator, air flows from the cooling towers, oxygen plants (N_2), byproduct and chemical storage, refuse incinerator, and coal and ash handling area. Effluent from all sources except the incinerators and flares would be passed into the atmosphere through a common 400-foot stack.

The refuse incinerator would have a load of 1 to 2 tons per day (tpd). (Federal New Source Performance standards only apply if loads are more than 50 tpd.) According to preliminary calculations, the incinerator flue gas would be 60,000 standard cubic feet (scf) per hour with a particulate concentration of 0.2 grains per scf.

All lignite handling and preparation facilities, including crushers, screens, conveyors, and transfer points, would be enclosed to prevent nuisance dust emissions. At potential particulate matter emission sites, hoods operating under suction would be installed to capture the dust. The ventilation air streams would convey the captured dust pneumatically via ducting to the respective baghouses. Baghouse dust collectors are designed to reduce the particulate concentration of 257 m^3/sec of the air stream to about 0.02 grains per scf. Thus, emissions related to these sources would total about 93.3 lbs/hr of TSP.

The steam boiler and superheater, the flares, the start-up incinerator, and byproduct and chemical storage are discussed in the following sections on the control of specific air pollutants. Properties of the fuels to be utilized in the plant are shown in Table 1-6. Pollutant emissions and abatement efficiencies are presented in Appendix B; air quality regulations are discussed in Section 4.1.2.1.

a. Sulfur

The gas purification unit would utilize the Rectisol process to remove sulfur compounds, CO_2, and other contaminants from the raw gas. The design of the sulfur recovery system is based on coal containing an average 1.3 percent sulfur on dry ash free (DAF) basis. Sulfur compounds would be removed to a level of less than 0.1 ppm (by volume). H_2S and CO_2 would be recovered in the Ammonia Recovery unit. These two acid gas streams would be sent to the Stretford sulfur recovery plant for sulfur recovery.

The Stretford process would operate on a continuous regenerative basis using a dilute aqueous solution containing sodium carbonate, sodium bicarbonate, sodium metavanadate, and anthraquinone disulfonic acid (ADA).

The H_2S in the entering gas stream would be absorbed by the alkaline carbonate solution countercurrently in an open grid absorption tower, forming bisulfide ions. The sulfide would then be oxidized to free sulfur by the metavanadate,

$$HS^- + 2V^{+5} \longrightarrow 2V^{+4}4 + S + H^+$$

TABLE 1-6

PROPERTIES AND QUANTITIES OF COAL AND LIQUID BYPRODUCT FUELS

Area	Fuel Type	Rate Lbs/hr	Rate SCFM	Rate MMBtu/hr (HHV)
Coal Gasification	Coal (DAF)	1,343,900	-	16,200
Steam Boilers	Tar	70,120	-	1,140
	Tar Oil	9,390	-	160
Superheater	Tar Oil	14,000	-	240
	Naphtha	11,520	-	215
	Phenol	13,750	-	190
	Stretford Tail Gas	-	277,280	680
	Coal Lock Ejector Gas		520	10

Ash and Sulfur Analysis:

Fuel Type	Ash Wt. %	Percent Sulfur Weight	Percent Sulfur Volume
Coal	6.13 1/	1.3 2/	-
Tar	0.45	0.65	-
Tar Oil	-	0.52	-
Naphtha	-	1.60	-
Phenol	-	0	-
Stretford Tail Gas	-	-	0.029
Coal Lock Ejector Gas	-		0.32

1/ On as received basis (34.3%M)
2/ On DAF Basis

This reaction would proceed during the absorption step and would be completed in a holding vessel. The solution would be regenerated by reoxidation of V^{+5} to V^{+4}. This would be accomplished by sparging with air in a separate vessel with ADA as a catalyst for the reaction. The sulfur formed would be separated as a froth from the solution and processed to produce a salable liquid sulfur byproduct. The excess air from the sparging step would be released to the atmosphere. This air would contain only CO_2 and water vapor.

The Stretford process would convert H_2S to elemental sulfur. Other sulfur compounds, such as COS and CS_2, are unaffected by the process. The tail gas, therefore, would be combusted in the superheater furnaces, described below.

A small degree of oxidation of sulfides to thiosulfate and sulfate would occur. These salts are nonregenerable and require a liquid purge. Sulfuric acid would be added to this purge stream to reduce the pH to around 2. The stream would then be flash-stripped. The stripper bottoms would be centrifuged to remove sulfur and sent to a vacuum crystallizer. The $Na_2SO_4 \cdot 10H_2O$ would be crystallized, centrifuged, and sent to a Na_2SO_4 dryer. After addition of Na_2CO_3 the liquor would be returned to the Stretford process.

The Na_2SO_4 dryer would be fired with either a light fuel oil or sulfur-free gas (about 7 MMBtu per hour). The flue gas from the dryer would pass through cyclones to remove any residual Na_2SO_4 dust and would be mixed with the steam boiler flue gases. The Na_2SO_4 product would be sold.

Some of the sulfur in the coal feed would end up in the byproduct tar, tar oil, and naphtha. The steam boilers would be fired with the tar and tar oil. The superheater furnaces would be fired with the rest of the tar oil and the naphtha and phenol, simultaneously combusting the Stretford tail gas. The combined tar and tar oil would have an SO_2 emission rate of 0.78 lb. SO_2/MMBtu and the combined tar oil, naphtha, and phenol would have a SO_2 emission rate of 0.80 lb. SO_2/MMBtu. Including the Stretford tail gas, the superheater emission rate would be 0.96 lb. SO_2/MMBtu. (See Section 4.1.2.1 for discussion of air quality standards.) A sulfur disposition diagram for the entire process is shown in Appendix B.

b. Nitrogen Oxides

There would be two sources of nitrogen oxides (NO_x) during combustion: fixation of nitrogen from the combustion air and the nitrogen content of the fuel itself.

The formation of NO_x due to the nitrogen in the air depends on the size, type, and arrangement of burners, the heat flux in the fired equipment involved, and the adiabatic flame temperature. The size, type, and arrangement of the liquid fuel burners in the steam boilers and superheater furnaces would be such that the NO_x formation would be low. The combustion of the waste gas in the superheater furnace would not produce NO_x and would have some quenching effects on NO_x production from the tar.

Because the tar and tar oil would be derived from lignite, which is high in nitrogen and oxygen, the tar and tar oil would also be high in nitrogen and oxygen. Therefore, more NO_x would be produced during the combustion of the tar and tar oil than during combustion of a commercial liquid fossil-fuel.

Preliminary estimates of NO_x emissions indicate that the emission from the steam boilers would be 0.6 lb. NO_x/MMBtu and from the superheater furnaces would be 0.5 lb. NO_x/MMBtu. (For the liquid fuels only; based on the combined liquid and gas fuel streams, the emission from the superheater furnace would be 0.24 lb. NO_x per MMBtu.) See Section 4.1.2.1 for a discussion of air quality standards.

c. Particulates

The flue gas from the steam boilers would be passed through electrostatic precipitators (fly ash removal efficiency of about 80 percent) to reduce the ash concentration to about 0.03 grains/scf. This corresponds to an emission rate of 0.1 lb. TSP/MMBtu.

The superheater furnace flue gas would not need particulate emission control. The ash concentration in the superheater flue gas would be about 0.02 grains/scf with a corresponding emission rate of 0.06 lb. TSP/MMBtu (based only on the heat input from the liquid fuels).

d. Hydrocarbons

Hydrocarbon vapors and gases containing traces of hydrocarbons would be collected and combusted. The Stretford tail gas (previously discussed in the section on sulfur) would be combusted in the superheater.

During start-up and shut-down, the raw gas from the gasifiers would be incinerated in a separate start-up incinerator. This incinerator would have a separate stack, approximately 120 feet tall.

Two elevated flare stacks would be used to incinerate emergency hydrocarbon vapors emanating from safety valves and overriding pressure controllers. Each flare would be capable of flaring 25 percent of the total plant gas production.

Steam injection into the flared gas stream would be used to obtain smokeless conditions for normal flaring. In the event of a plant-wide emergency, however, the quantity of gas relieved may exceed the smokeless burning capacity of the flare. These occurrences are unpredictable and would be of short duration (1 hour).

The flare stacks (including the gas liquor low pressure flare) would be self-supporting and include ignitors, flame front generators, molecular seal, and continuous pilots. Ladders and access platforms would be provided on the flare stack to facilitate maintenance. The two main flare stacks would be 200 feet above grade and have a tip diameter of 36 inches. The low pressure flare stack would be 120 feet above grade with a 10-inch diameter. The flare stack locations are shown in Figure 1-12; estimated emissions from the flare stacks are presented in Appendix B.

The estimated characteristics of each of the gaseous streams and the combined stream are listed in Table 1-7. The gaseous effluent treatment system is shown schematically in Figure 1-17.

1.5.5.4 Cooling Facilities

a. Air Cooling

Air cooling would be used within the plant to reduce water consumption. High-level cooling surfaces would be cooled with air or a combination of air and water cooling, depending on initial temperature and the required heat transfer rate.

b. Cooling Towers

Two cooling towers would be provided to handle additional plant heat rejection:

- a cooling tower using gas liquor process water from the Phenosolvan and Gas Liquor Separation units.

- a cooling tower for the oxygen plant, using clarified fresh water. (A separate tower is required for the oxygen plant to eliminate the hazard associated with the presence of any hydrocarbons entering the oxygen plant system.)

Cooling water from the process gas liquor and the fresh water cooling towers would be utilized to the maximum possible extent.

TABLE 1-7

ESTIMATED OPERATING CONDITIONS DUE TO FUEL COMBUSTION

	Steam Boilers	Superheater Furnaces	Rotary Dryers	From Stack Tip
Flow Rate, SCFM	260,460	550,150	Negligible	810,610
Pressure, in WG	2	1		1
Temperature, ^{o}F	400	500		410
Dew Point, ^{o}F	148	108		140
Fired Duty, MMBTU/Hr (HHV)	1,300 (liquid)	645 (liquid) 700 (gas)	7 (fuel gas)	2,652
Emissions, lbs/hr				
SO_2	1,010	1,596 (417 liquid) (1,179 gas)		2,606
NO_x	780	320		1,100
Particulates	130	40		170
Stack Heights	400 ft.			
Stack Diameter	24 ft.			

NOTE: Above figures are for maximum sulfur coal.

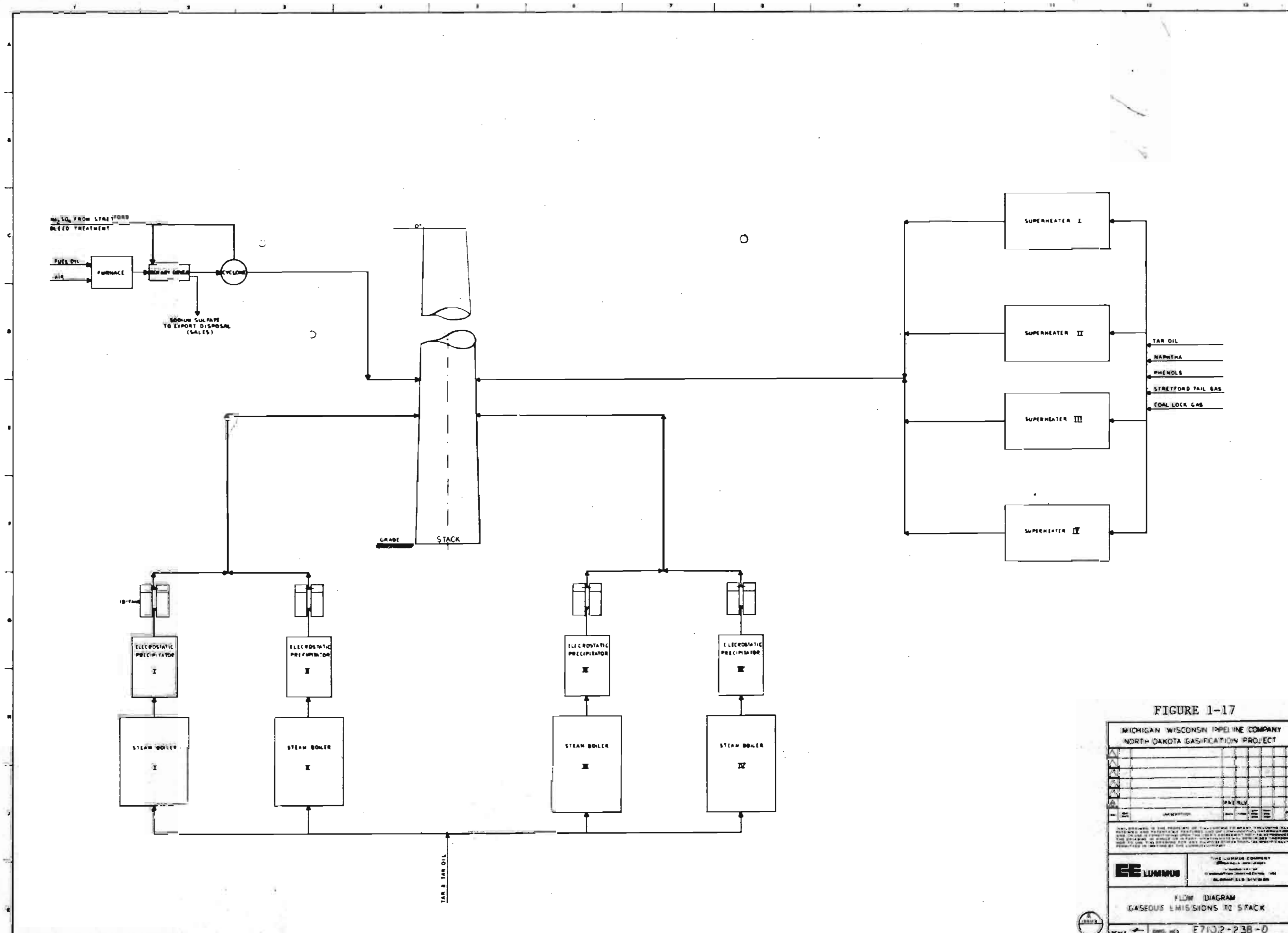

Na2SO4 FROM STRETFORD BLEED TREATMENT
FUEL OIL
AIR
FURNACE
CYCLONE
SODIUM SULFATE TO EXPORT DISPOSAL (SALES)
GRADE
STACK
SUPERHEATER I
SUPERHEATER II
SUPERHEATER III
SUPERHEATER IV
TAR OIL
NAPHTHA
PHENOLS
STRETFORD TAIL GAS
COAL LOCK GAS
ELECROSTATIC PRECIPITATOR I
ELECROSTATIC PRECIPITATOR II
ELECROSTATIC PRECIPITATOR III
ELECROSTATIC PRECIPITATOR IV
STEAM BOILER I
STEAM BOILER II
STEAM BOILER III
STEAM BOILER IV
TAR & TAR OIL
MICHIGAN WISCONSIN PIPELINE COMPANY
NORTH DAKOTA GASIFICATION PROJECT
LUMMUS
FLOW DIAGRAM
GASEOUS EMISSIONS TO STACK
E7102-238-0

FIGURE 1-17

Both of these cooling systems are designed for two-stage use of the circulating cooling water by first passing the cooling water through a service requiring a low process temperature followed by a high temperature service. For example, cooling water would be used first in the compressor intercoolers and then in the turbine surface condensors of a steam turbine-driven compressor.

The estimated rates of water loss due to evaporation and drift from each tower are listed in Table 1-8. The process gas liquor cooling tower would be designed to minimize drift loss.

TABLE 1-8

COOLING TOWER CHARACTERISTICS

Characteristic	Process Gas-Liquor Cooling Tower	Oxygen Plant Cooling Tower
Duty, MMBtu/hr 1/	3,906	350
Circulation, gpm	200,520	40,000
Temperature, ^{o}F		
a. Supply	82	82
b. Return	118	100
Make-Up Water, gpm 2/	7,020	820
Number of Circulating Pumps		
a. Operating	6	4
b. Spare	1	1
Estimated Water Loss		
a. Evaporation, gpm	6,340	700
b. Drift, gpm	100	20
c. Blowdown, gpm	580	100
d. Total	7,020	820

1/ At temperature 190^{o} F (Duty included in tower rating)

2/ Total make-up requirements, including recovered gas-liquor. About 25 percent is nonprocess water during the summer; during winter no fresh water is required.

c. Other Evaporative Losses

Besides drift and evaporative losses of water from the cooling towers, water from other processes would also be lost to the atmosphere by evaporation. A summary of these estimated losses is presented below:

Source	Evaporated Water Loss, gpm
Multieffect Evaporators	400
Stretford Unit	67
Ash Handling	92
Water Clarifiers, Thickeners, and Pond	Negligible

The total amount of water discharged to the atmosphere from the above processes and cooling towers during summer would be about 7,720 gpm; discharges during winter would total about 5,790 gpm.

1.5.5.5 Solid Wastes

Four types of solid wastes requiring disposal would be generated at the plant:

1. Ash from the gasifiers, evaporator residue, and fly ash from steam boilers;

2. Inorganic sludge and silt from raw water treatment;

3. Sludge from the package-type biological treatment unit for sanitary sewage; and

4. Refuse (i.e. paper, cartons, rags, wood scraps, etc.)

The ash would be dewatered in the ash handling facilities and then returned to the mine. Residue from the multiple-effect evaporators and the inorganic sludge and silt from raw water treatment would also be disposed of at the mine with the ash. Sludge from the biological wastewater treatment plant would be returned to the mine for use as a soil conditioner. The refuse would be burned in an incinerator.

The ash discharged from each of two lines of gasifiers would be quenched and sluiced down a sloping sluiceway to 1/2-inch vibrating screens. The plus 1/2-inch material would be discharged onto a conveyor belt; the water and minus 1/2-inch ash would be discharged to four rake classifiers. The classifiers would remove the plus 1/2-mm material and deposit it on the same conveyor with the screen oversize. The combined screen and classifier discharge would be about 75 tph of 15 percent moisture ash.

The excess water along with the minus 1/2-mm fraction, estimated to constitute 15 percent of the total ash, would overflow the classifier to the classifier sump. During normal operations, the ash slurry entering the sump would be about 1.0 percent solids by weight and would amount to approximately 15 tph.

From the classifier sump, the water and fine ash would be pumped to two 60-foot-diameter thickeners for settling. The clarified overflow (7800 gpm) from the thickener, plus 200 gpm of make-up water would be reused in the hydraulic ash sluicing system. The underflow from the thickener would be fed to top feed belt type vacuum filters. The minus 1/2-mm material collected by the filters would be discharged to the ash removal conveyor.

The total ash production (approximately 90 tph) would be conveyed to a covered ash bin which would be emptied periodically into a 50-ton truck (making 1.5 trips/hr) for disposal in the mine. The ash bin would be heated and insulated to prevent the ash and condensate from freezing during the winter.

The fly ash, collected by the electrostatic precipitators on the byproducts fired boilers, would be separately hauled to mine for disposal. Ash burial was described in Section 1.5.3.2.

1.5.5.6 Byproducts

During the processing of coal to SNG, several liquid byproducts would be produced. Onsite storage facilities for these byproducts would be provided, with a minimum 15-day storage capacity, except for the anhydrous ammonia. The anhydrous ammonia would be stored as a liquid at atmospheric pressure in a single-wall, insulated tank having a vapor recovery refrigeration system and providing 30 days' storage capacity. Tar, tar oil, naphtha, and phenol byproducts would be utilized as fuel within the plant.

All storage tanks would be located in diked areas and fire protection provided (Section 1.5.4.7). Each diked area would be capable of holding the entire contents of each storage tank. The interior surfaces of the diked areas would be coated with an impervious material; any excess buildup of water would be pumped to the retention pond.

The elemental sulfur produced by the sulfur recovery unit would be stored in molten state in a below grade storage pit equipped with steam heating coils. The pit, located within the battery limits of the sulfur recovery unit would be fully enclosed, sealed, and made of concrete. It would be provided with submerged loading pumps and rail loading facilities.

North Dakota and Federal EPA regulations concerning emission of hydrocarbons from storage tanks have been followed to determine which storage tanks require either a floating roof or a vapor recovery system. (The regulations provide: If the true vapor pressure of the petroleum liquid is equal to or greater than 1.5 psia, but less than or equal to 11.1 psia, a floating roof or vapor recovery system is necessary. If the true vapor pressure is greater than 11.1 psia, vapor recovery is needed.)

A summary of the storage tank characteristics is presented in Table 1-9.

1.5.6 Associated Systems

1.5.6.1 Product Gas Pipeline

Product gas from the plant would be transported by a 20-inch pipeline system owned and operated by Great Lakes, about 365 miles to their Thief River Falls Compressor Station in Minnesota. With a few minor exceptions, the proposed pipeline would use existing Burlington Northern and Soo Line Railroad rights-of-way almost the entire route (Figure 1-18). Because of the constraints of the existing rights-of-ways, special construction procedures would be used which allow construction in a width of less than 50 feet. The average distance of the pipeline from the centerline of the railroad would be about 40 feet. The total land disturbed by pipeline construction would be 2,190 acres of which new right-of-way (ROW) requirements would amount to 79 acres. After construction the new ROW would be maintained, and existing ROW would revert to its previous condition.

The proposed facilities include a 20-inch buried steel pipeline, five communication towers, a series of main-line valves spaced 15 to 20 miles apart, two gas compression facilities, and a district headquarters in Devils Lake, North Dakota. These facilities would require an additional 32 acres of land.

Construction would be continuous over the 365-mile length of the pipeline using four main-line construction crews (spreads) and special spreads for construction through towns, the Missouri River crossing, and the dry land crossing of the Snake Creek Embankment between Lake Sakakawea and Lake Audubon. The main-line spreads would vary from 87 to 98 miles in length.

Construction procedures of a typical main-line spread are illustrated in Figure 1-19. Within each spread there is an activity zone of continuous operation, consisting of all procedures between starting on the untouched ROW to cleanup and restoration. Clearing and grading would start with the removal of obstacles such as trees,

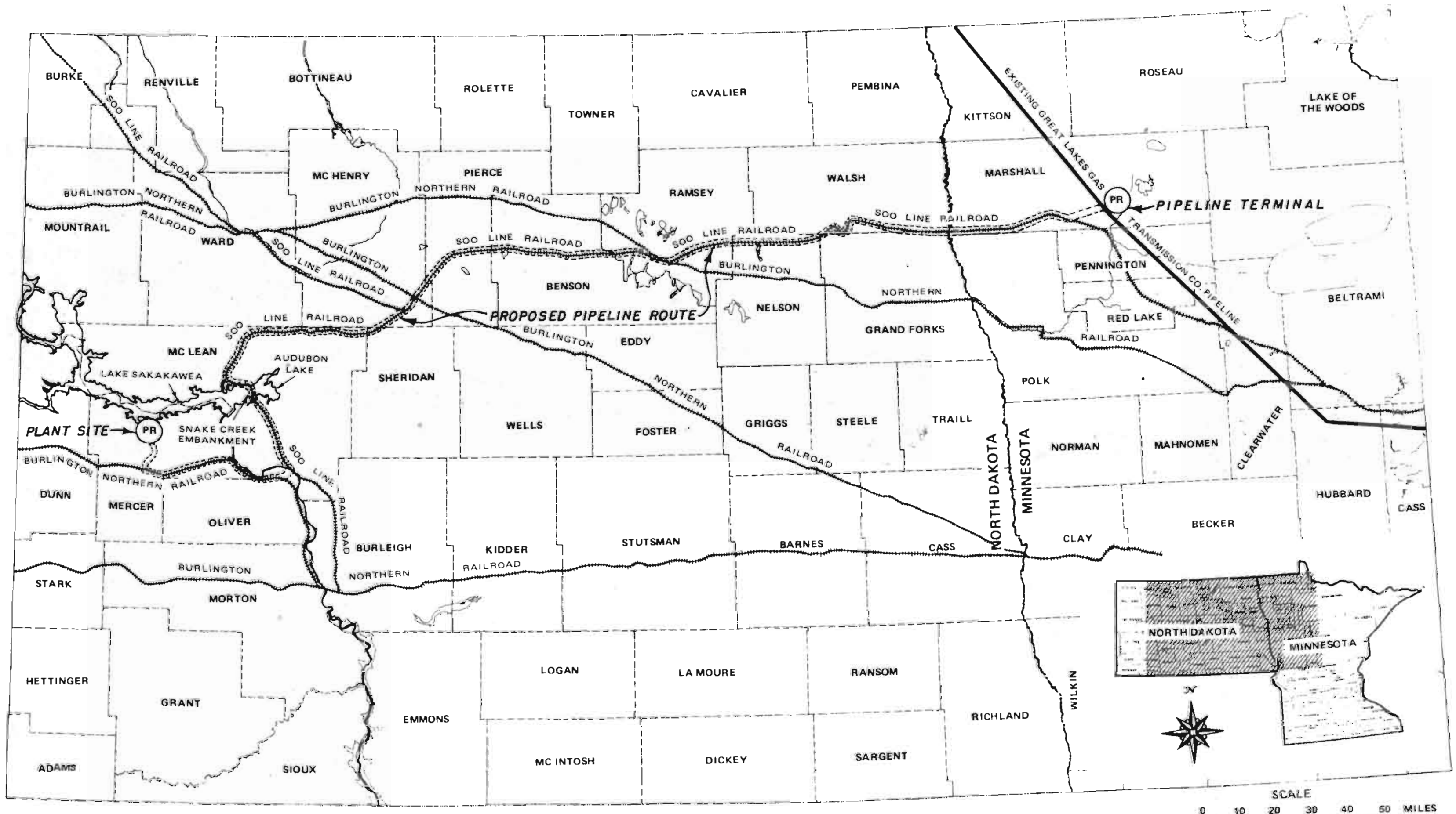
TABLE 1-9

BYPRODUCT AND CHEMICAL STORAGE TANK CHARACTERISTICS

Chemical	Amount Produced	Storage Capacity Number	Storage Capacity Capacity per Tank	Tank Diameter, ft.	Tank Height, ft.	Total Emissions, Bbl/yr 1)	Type
Tar	192,300 gal/day	2	35,810 Bbl	80.0	40.0	20	B
Tar Oil	70,800 gal/day	2	13,600 Bbl	45.0	48.0	14	B
Naphtha	39,800 gal/day	2	7,160 Bbl	40.0	32.0	108	A
Crude Phenol	35,800 gal/day	2	7,160 Bbl	40.0	32.0	6	B
Anhydrous Ammonia	215 tons/day	2	3,000 tons			0	C (insulated)
Slop Oil		1	1,010 Bbl	21.4	16.0	0.06	B
Fuel Oil #2		1	5,020 Bbl	33.5	32.0	0.07	B
Sulfur	160 tons/day					0	Pit
Methanol (100%)		1	2,020 Bbl	21.4	32.0	0	C
Phenosolvan (100% Di-isopropyl ether) solvent		1	5,000 Bbl			0	D

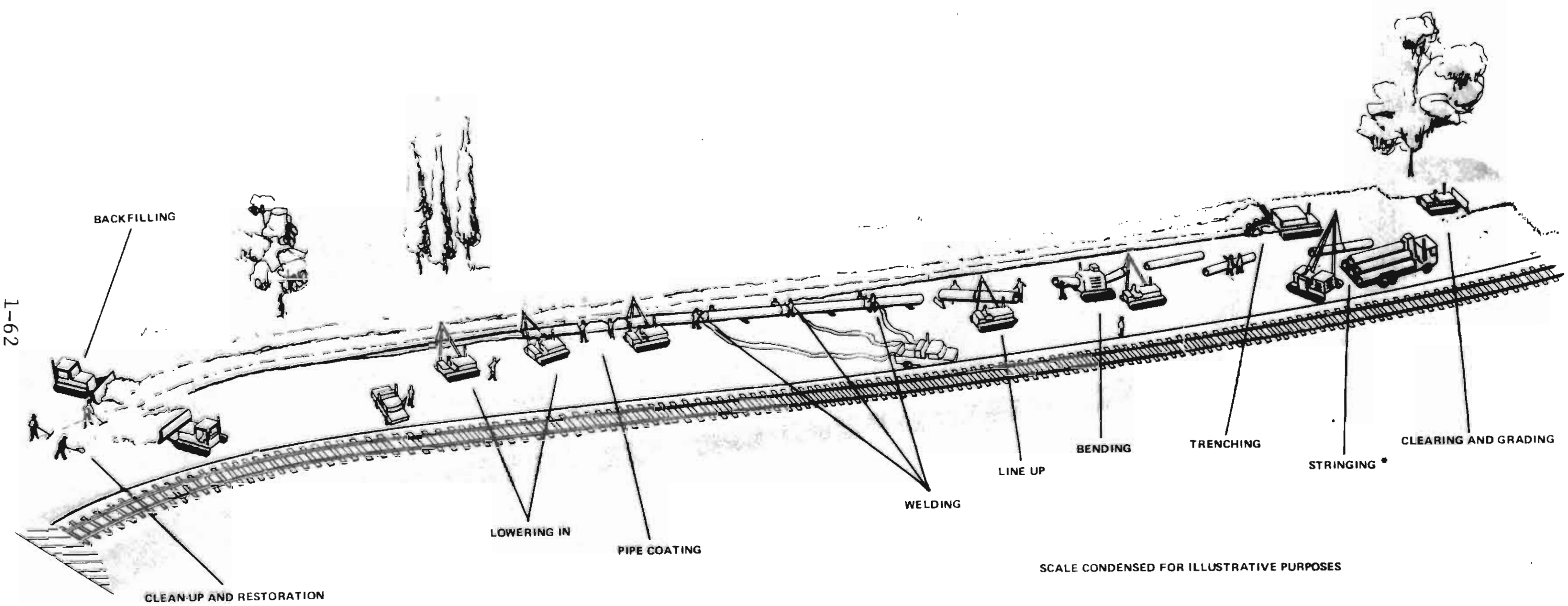
A: APl Type Floating Roof
B: APl Type Cone Roof, with Steam Coil
C: APl Type Cone Roof with Vapor Recovery
D: Horizontal Tank with Vapor Recovery

1) Preliminary estimate (based on equations in API-2518: "Evaporation Loss From Fixed-Roof Tanks," API-2523: "Petrochemical Evaporation Loss From Storage Tanks and API-2517: Evaporation From Floating-Roof Tanks")



PROPOSED ROUTE OF THE PRODUCT GAS PIPELINE

FIGURE 1-18



TYPICAL PIPELINE CONSTRUCTION SPREAD

* STRINGING WILL BE FROM RAIL CARS WHERE POSSIBLE

Figure 1-19

rocks, brush, and logs. Topsoil, to a typical depth of 8 inches, would be segregated where required by an agency or landowner. The topsoil would be stored on the outermost edge of the railroad ROW. Partial leveling and smoothing of abrupt contours would also be performed at this time.

During the stringing operation, pipe would be brought to the construction zone on railroad cars and unloaded by crane along the ROW in a continuous line. The pipe required for stream and road crossings would be stockpiled near each crossing. The trenching operation would involve excavating the ditch by means of a trenching machine or mechanical backhoe. The typical trench depth would be about 6½ feet. Rock-laden areas may require some drilling and blasting.

If necessary, the pipe would be bent to compensate for minor variations in alignment, and then lined up and welded. The pipe would be laid on supports in a continuous line along the side of the trench, and the welding and subsequent inspection performed according to Department of Transportation Regulations (Title 49, CFR, DOT, Part 192 - Transportation of Natural and Other Gas by Pipeline: Minimum Federal Safety Standards).

In the pipe coating operation the pipe would be cleaned and primed prior to coating using sideboom tractors with cradles and a traveling cleaning and priming machine. After priming, the pipe would be coated and wrapped. Sideboom tractors would again be used to apply coal tar, asphalt, or other material while asbestos felt and heavy kraft paper are simultaneously wound around the pipe. Following wrapping, an electronic Holiday detector would be used to inspect the coated surface for defects.

After the pipe has been coated and inspected, it would be lowered into the trench by sideboom crawler tractors with special belt slings for handling the coated pipe. The trench would then be backfilled with the previously excavated material. Then the topsoil would be bulldozed back over the pipeline area and normal contours and drainage restored. Revegetation would be consistent with the existing vegetation, except that trees and large bushes would not be established.

Special construction methods required during main-line spread construction would include: (1) tunneling under existing roads, highways, and railroads; (2) construction of temporary drains where existing drains are disturbed; (3) excavation of streambeds during low water and timed to avoid fish migration and spawning periods; (4) use of floating excavation equipment to cross the Missouri River; (5) construction around existing structures; and

(6) relocation of the existing telephone cable and drain system at the Snake Creek embankment crossing.

With the exception of the Missouri River crossing, perennial streams would be crossed by excavating from the bank using backhoes or draglines. Some blasting may be required. Crossings would be timed to avoid known periods of flood potential and of fish migration and spawning. The excavated material would be deposited on either the streambed or adjacent banks. The pipe would be buried beneath the scour depth of the stream to prevent subsequent exposure. Streambanks would be restored to their original elevation and grade, erosion control structures installed where necessary, and shrubbery planted.

For the Missouri River crossing, the trench would be opened with either a clam shell or dragline mounted on a barge. To ensure pipeline integrity during flood periods, the pipe would be concrete-coated and buried 2 to 5 feet below scour depth. The pipe would be installed by a set of pulling cables strung across the river and the pipe pulled by winch from a prefabrication area on the other side. About 50 days would be required for construction which would be done during late summer; this is normally the low flow period.

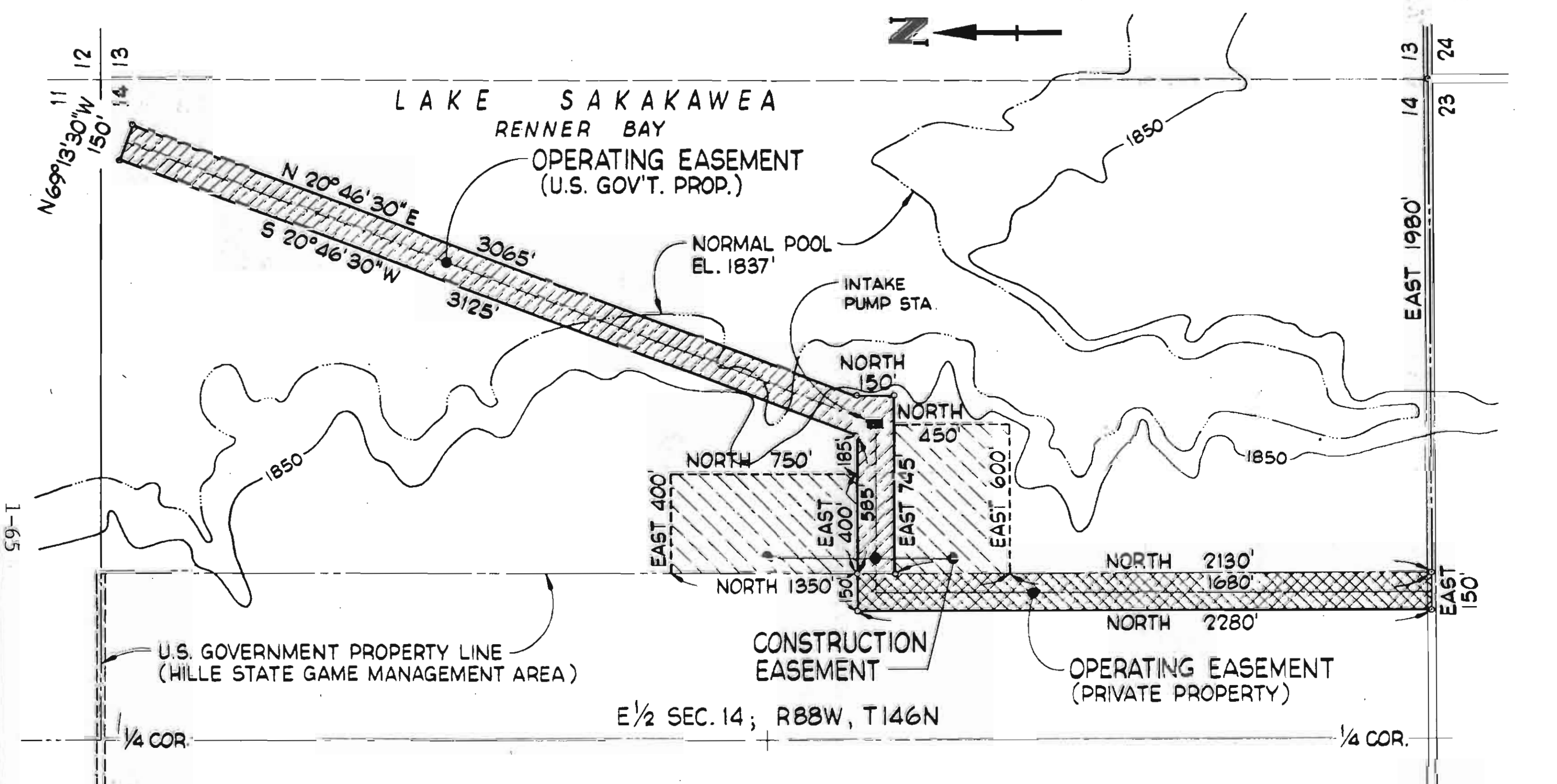
After construction, hydrostatic testing of the pipeline will be performed. Sources of hydrostatic test water have not yet been determined, but a study will be done prior to construction to locate the several suitable water sources required. Once a section of the pipeline has been tested, the test water would be discharged into natural drainages.

The SNG output from Phase I of the gasification plant would not require compression, so the two compressor stations would not be built until Phase II construction. Each compressor station site is planned to enclose 10 acres. These sites have not been specifically identified but would be in the vicinity of Mile 120 in McLean County and Mile 240 in Ramsey County, both in North Dakota.

Each compressor station would consist of a small, combination office-warehouse and a separate compressor building enclosing a SNG operated gas-turbine compressor.

1.5.6.2 Water Intake and Pipeline

The raw water intake structure would be located in Lake Sakakawea at the west arm of Renner Bay (Figure 1-20). The intake would be located 67 feet below normal pool elevation (Figure 1-21). The submerged intake would insure the necessary supply of water at minimum probable pool elevation. Medium-sized (¼ inch) fish screens would be provided on the intake; maximum intake velocity would be about 0.5 ft/sec.



NOTE:
ALL DISTANCES & BEARINGS SHOWN ARE BASED ON SCALED MEASUREMENTS FROM 7.5 MIN. U.S. GEOLOGICAL SURVEY MAP; BEULAH NE, N. DAK., 1969 & ARE APPROXIMATE.

0 500 1000 1500 FEET

REV. R-1, 2-24-75; REV. R-2, 5-13-76; REV. R-3, 5-24-76; REV. R-4, 9-10-76

Figure 1-20
BOUNDARY DESCRIPTION
FOR
CONSTRUCTION & OPERATING EASEMENTS
FOR A
WATER INTAKE & TRANSMISSION PIPELINE
FOR
MICHIGAN WISCONSIN PIPELINE COMPANY
IN MERCER COUNTY, NORTH DAKOTA

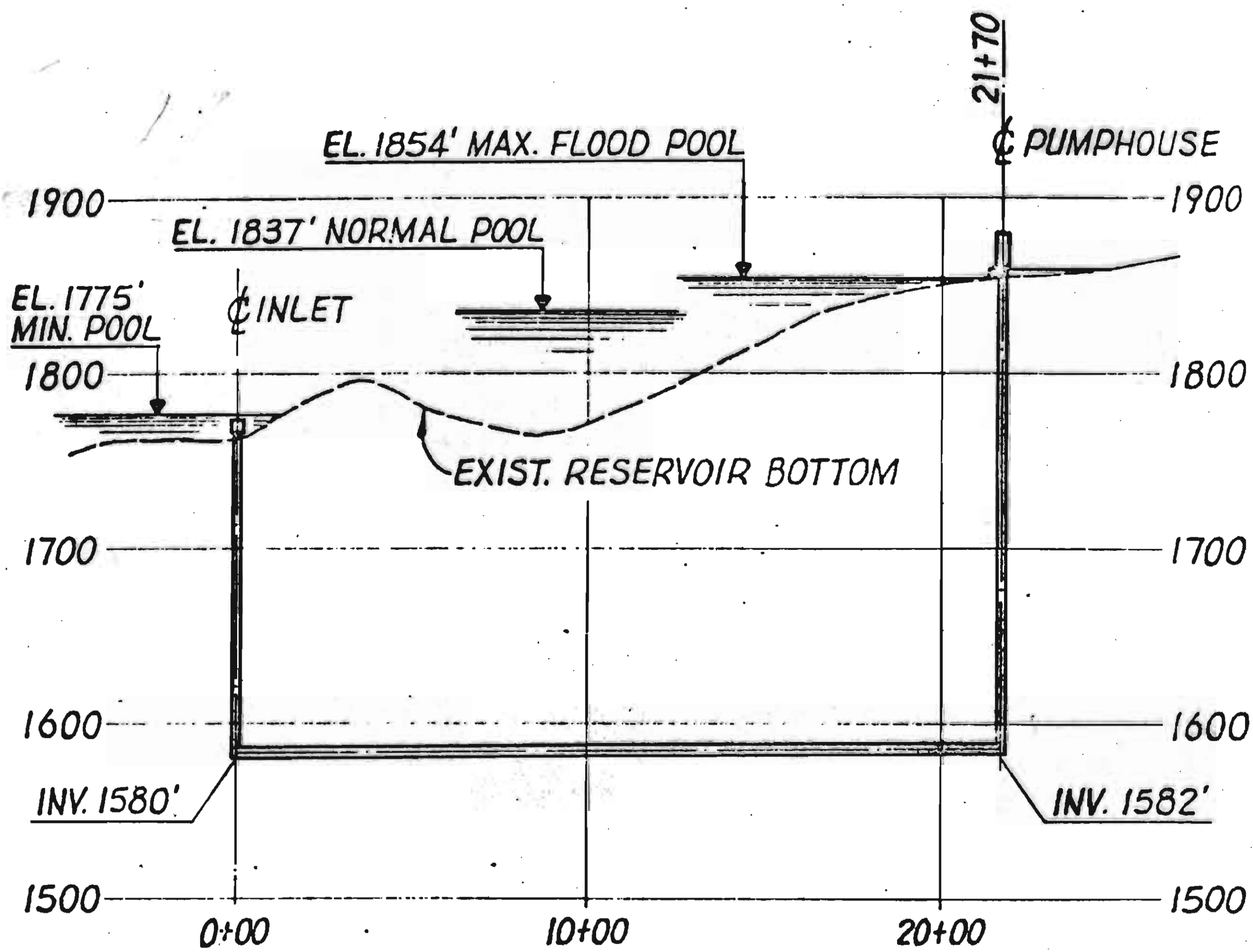


Figure I-21

ANG COAL GASIFICATION COMPANY

PROFILE

RAW WATER INTAKE

SCALE: 1" = 500'

Water would be conveyed by gravity from the offshore intake to an onshore pumping station. Pumps would be provided to deliver water at varying rates depending on plant requirements. Standby pumps would be installed to insure the delivery of water at all times. The water would be pumped to the plant via a 42-inch underground pipeline, as shown in Figure 1-22, extending 7.6 miles to the plant.

For construction, a precast intake structure would be set in place and a tunnel extended to it from the pumping facility. Tunnel excavation material would be deposited on shore, contoured, and seeded with native grasses in accordance with the Corps of Engineers' permit stipulations. The pipeline would be constructed using the basic procedure described for the product gas pipeline.

1.5.6.3 Railroad Spur

A railroad spur would be constructed generally eastward about 9.0 miles to an existing Truax Traer spur which would require upgrading 3.1 miles southward to the existing Burlington Northern mainline (Figure 1-6). (The existing spur is not currently in use.) It would be used to bring building materials and equipment into the plantsite and export byproducts for sale. A rail-mounted track layer would be used to construct the spur after the initial grading by bulldozers. After construction, the 150-foot ROW would grow back to the seminatural weedy vegetation characteristic of railroad ROW's in the area.

During plant construction, rail traffic on the spur is estimated at an average of 63 cars/week. During operations, rail traffic for the gasification plant and mine is estimated to average 39 cars/week, plus 10 cars/week of limestone for the powerplant, for a total of 49 cars/week.

Total construction materials, commodities, consumables, and plant equipment required for construction of the gasification plant, powerplant, and mine is estimated at 675,000 tons. About 10 percent of this (67,500 tons) would be delivered by truck; the remaining 90 percent (609,500 tons) would be brought in via the rail spur.

1.5.7 Maintenance Procedures

To assure reliability and to meet all Federal and State safety requirements, periodic maintenance is scheduled for all operating equipment. This includes inspection of all high pressure piping systems, major equipment, rotating equipment, and all critical operational areas for any abnormalities. Corrosion control would

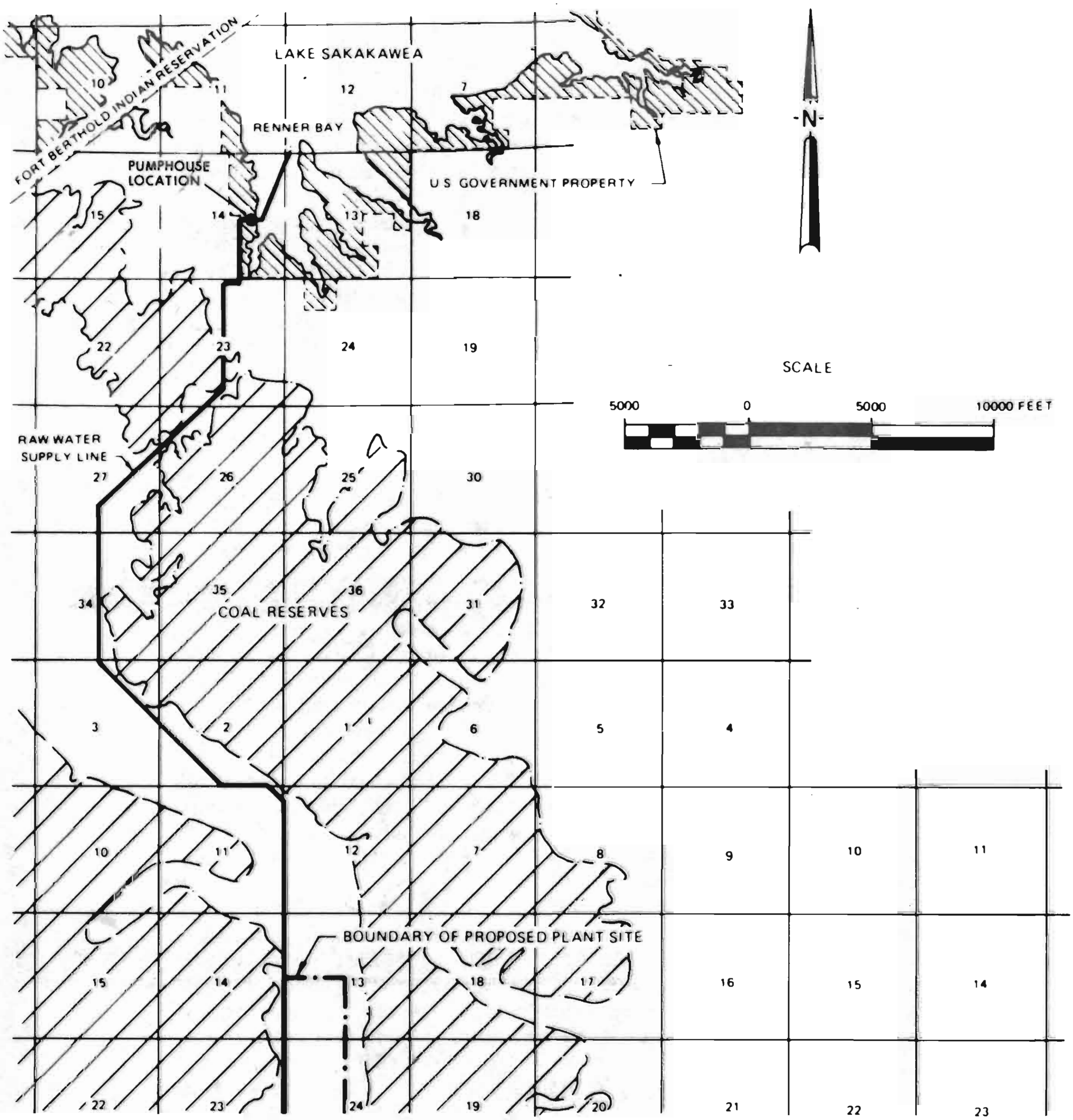


Figure 1-22 **NORTH DAKOTA COAL GASIFICATION PROJECT - RAW WATER SUPPLY LINE**

be carried out to insure that no piece of operating equipment is subject to unanticipated excessive corrosion rates. Maintenance procedures are also provided to respond to abnormal occurrences.

The design of each major unit of operating equipment includes complete instrumentation and interlocking systems to notify plant personnel in the event of equipment malfunction and, where necessary, to shut down the plant. In general, rectifying the problem would involve isolating the equipment, venting to the flare system, inspecting the equipment, and making any necessary repairs.

During operation of the plant, certain equipment would require regular internal inspection. These units are isolated, as described above, vented to the flare system, purged, and blanked off and inspected to determine and report condition of equipment.

Scheduled maintenance should have no effect on plant output since certain major operating equipment is duplicated (spared) to prevent reduction in gas production. The conservative sparing of major key pieces of equipment in the design of the facility assures the reliability of the plant being on-stream for 91 percent of the year. However, some equipment that is out-of-service would reduce gas output during the required period of maintenance. Presently no assumptions can be made as to how much down time would occur.

Associated with maintenance and on-stream reliability are the safety aspects of the specific chemicals and equipment required for production. Defending against human and/or mechanical error is of prime importance in the design and operation of this facility. All equipment will be designed for safety and reliability. Adequate provision for movement of personnel and equipment in case of emergency is incorporated in the conceptual layout of the facility. Equipment (pumps, absorbent material, etc.) would be on hand for rapid cleanup of accidental spills of oil and other hazardous materials.

The process areas would have detecting devices to forewarn of any impending danger in operation. Various temperature, pressure and level alarms, and shutdown circuits, known as interlocks, would be incorporated to minimize potential hazards. All required vessels would have safety relief valves to protect personnel and equipment from dangerous buildup of pressure. Any emission from the safety valves is piped into an emergency relief system which includes emergency venting lines. The products are piped to a smokeless flare stack to burn the hydrocarbons to CO_2 and water. All equipment containing flammable and potentially hazardous materials would be electrically grounded.

The activities associated with coal handling have been designed to maximize safety aspects. To prevent spontaneous combustion of the coal, the dormant or "dead storage" piles are laid down and compacted in 1-foot layers. The pile slopes would be at maximum to the angle of the repose to reduce coal dusting and thereby decrease hazards associated with coal dust. All coal handling equipment would have sufficient ventilation and properly grounded collection equipment to reduce coal dust explosion; this equipment would be designed and installed in accordance with the Federal Health and Safety Act of 1969.

Pipelines would be inspected and maintained in accordance with standards set forth in 49 CFR 192 by the Office of Pipeline Safety. This includes continuous surveillance of facilities, investigation of all possible failures, and immediate correction when necessary. In addition, pipeline patrols would conduct surface inspections to set schedules.